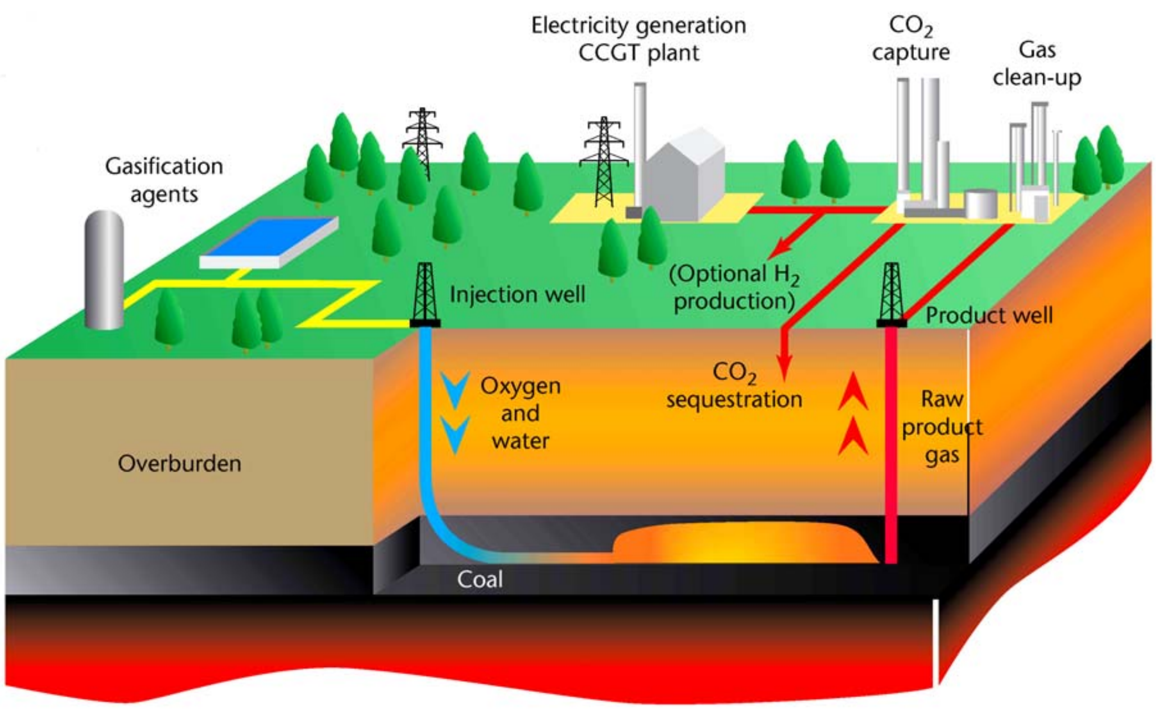
Viability of Underground Coal Gasification in the "Deep Coals" of the Powder River Basin, Wyoming



Prepared for the

Wyoming Business Council
Business and Industry Division
State Energy Office

GasTech, Inc.
Casper, Wyoming
June 2007

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Abbreviations

AFIT	After Federal Income Tax
BFIT	Before Federal Income Tax
BLM	Bureau of Land Management
CBM	Coal Bed Methane
CCP	Coal Combustion Processes
CCS	Carbon Capture and Sequestration
COE	Cost of Electricity
CRIP	Controlled Retracting Injection Point
DCF-ROR	Discounted Cash Flow Rate of Return
DME	Di-Methyl Ether
ECBMR	Enhanced Coal Bed Methane Recovery
EIS	Environmental Impact Statement
ELW	Extended Linked Well
EOR	Enhanced Oil Recovery
FT	Fischer-Tropsch Process
GIS	Geographic Information System
HHV	Higher Heating Value
HPA	High-Pressure Air
IGCC	Integrated Gasification Combined Cycle
LLL	Lawrence Livermore Laboratories
LPG	Liquefied Petroleum Gas
LVW	Linked Vertical Well
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NRHP	National Register of Historic Places
PRB	Powder River Basin
QA/QC	Quality Assurance/ Quality Control
R&DTL	Research and Development Testing License
RM1	Rocky Mountain 1 UCG Trial
RZCS	Reactor Zone Carbon Storage
scf	standard cubic feet
scfd	standard cubic feet per day
SCG	Surface Coal Gasification
SDB	Steeply Dipping Bed
SNG	Synthetic Natural Gas
TDS	Total Dissolved Solids
UCG	Underground Coal Gasification
UIC	Underground Injection Control
USFS	United States Forest Service
USGS	United States Geological Survey
WDEQ-AQD	Wyoming Department of Environmental Quality – Air Quality Division
WDEQ -LQD	Wyoming Department of Environmental Quality – Land Quality Division
WDEQ-WQD	Wyoming Department of Environmental Quality – Water Quality Division
WGS	Wyoming Geological Survey
WOGCC	Wyoming Oil and Gas Conservation Commission

Acknowledgements

This study was prepared under a grant from the Wyoming Business Council. GasTech would like to thank the Business Council and Mr. Thomas Fuller, Business and Industry Division, Manager, State Energy Program, for supporting this analysis of a potentially very significant new business development for Wyoming. This work has supported the concept that Underground Coal Gasification in deep Wyoming coals is viable. This opens up tremendous coal resources, which are otherwise not available to the economy of the State.

In the preparation of this report, GasTech has relied on a skilled pool of technical consultants. Major contributions, especially in UCG project definition and cost estimates, were made by B.C. Technologies, Laramie, Wyoming. Their key personnel were John Boysen, Deidre Boysen, Erin Bohnet, and Tarn Bohnet. Equally important was the contributions of Jim Covell, EG&G. Both Covell and Boysen have been involved in UCG pilots for over 25 years. Hence, they contributed a very real insight into the potential complexity and details of UCG, as well as the environmental impacts and mitigation schemes.

This report has built extensively on UCG research and trials conducted by the US Bureau of Mines, the Department of Energy and the Laramie Energy Research Center, and Lawrence Livermore National Lab. Current contact with LLNL has been with Dr. Julio Friedmann and Dr. Elizabeth Burton. Their recent work at LLNL has been focused on UCG and Carbon Capture and Sequestration. Access to numerous DOE publications on UCG through the extensive UCG library at B.C. Technologies has also been very helpful.

The Wyoming Geological Survey provided several special coal investigations. Thanks to Dr. Ron Surdam, Director, Mr. Nick Jones, coal geologist, and Dr. Yuri Ganshin, geophysicist.

Coal bed methane and oil and gas well data were provided by the Wyoming Oil and Gas Commission through their website and by special data extractions performed by Mr. Rick Marvel, engineering manager.

As this work was progressing, GasTech has maintained contact with the University of Wyoming, who has expressed ongoing interest in UCG. Thanks to Dr. William Gern, VP Research, Dr. Myron Allen, VP Academic Affairs, Dr. Gus Plumb, Dean of the College of Engineering, and Dr. Carol Frost, Interim Director School of Energy Resources. We hope that as UCG progresses in Wyoming, this clean coal research technology can become a “cornerstone” of the School of Energy Resource’s coal program.

Viability of Underground Coal Gasification in the "Deep Coals" of the Powder River Basin, Wyoming

1.0 EXECUTIVE SUMMARY

Coal is our most abundant fossil fuel. While oil and natural gas account for 64 percent of the world's energy consumption, they total only 31 percent of the world's known fossil fuel reserves. When known reserves and estimated future resources are considered, coal overshadows oil and gas, accounting for 95 percent of the known fossil fuel reserves plus resources. Additionally, one third of the world's coal is in the United States. We must develop new clean coal technologies to utilize our vast coal resources.

Background- Wyoming's energy resources most notably lie in the huge coal resources of the Powder River Basin (PRB). The US Geological Survey estimates that the Basin contains 510 billion tons of coal in place, but that 95%+ of that coal is not economically extractable by current mining technologies. These resources, at depths of 500 to 2,000 feet below the surface, are the "deep coals" of the Powder River Basin. Each square mile of the Powder River Basin Project area contains an average of 100 million tons of deep coal. Each ton of coal has 300 times the energy content of the coal bed methane (CBM) in that same ton of coal, thus making the coal a much higher value energy resource than the CBM.

These deep coals can be tapped by Underground Coal Gasification, or UCG. UCG involves drilling wells into the coal seam and injecting air or oxygen and steam into the deep coal seam. The coal is ignited in situ, and the hot product gases are captured in recovery wells. These hot, combustible gases recovered by UCG are called "synthetic gas" or "syngas". Syngas can be used for producing Fischer-Tropsch (FT) fuels, such as clean diesel, and can also be used to generate electric power in Integrated Gasification Combined-Cycle (IGCC) gas turbines. UCG trials indicate that UCG will have the lowest cost of liquid hydrocarbons and power generation of any clean coal technology. An average square mile of the Powder River Basin, containing 100 million tons of coal, can support a UCG IGCC power plant of 200 MW for about 100 years.

UCG development may occur in areas that geographically overlap coal bed methane and other oil and gas operations. The UCG development can either follow CBM extraction, or it can co-produce the methane with the UCG syngas. In any event, much installed oil and gas infrastructure may be useable for UCG products.

The benefits to Wyoming for developing commercial UCG in the Powder River Basin include:

- Access to most of the 510 billion tons of Powder River Basin deep coal which is otherwise "locked up", too deep for conventional mining
- Severance taxes, ad valorem taxes, and royalties on the coal extracted by UCG
- Ability to produce low cost F-T diesel, ammonium nitrate, and electricity for consumption in the PRB by existing coal operations
- Reduced environmental impact relative to open pit coal mining
- Low cost power generation for sale into an expanded grid serving out-of-state markets

- Use of extensive pipeline infrastructure, especially as Coal Bed Methane production is depleted, for the gathering and distribution of UCG gas products
- Low cost production of liquid hydrocarbons, as FT diesel, for export from Wyoming to the Colorado, Nevada, and California markets, and possibly DoD
- Potentially, the storage of sequestered CO_2 in cavities left after UCG coal harvesting.

The objective of this work is to evaluate the PRB coal geology, hydrology, infrastructure, environmental and permitting requirements and to analyze the possible UCG projects which could be developed in the PRB. Project economics on the possible UCG configurations are presented to evaluate the viability of UCG.

The PRB Resource- There are an estimated 510 billion tons of sub-bituminous coal in the PRB of Wyoming. These coals are found in extremely thick seams that are up to 200 feet thick. The total deep coal resource in the PRB has a contained energy content in excess of twenty times the total world energy consumption in 2002. However, only approximately five percent of the coal resource is at depths less than 500 feet and of adequate thickness to be extracted by open pit mining. The balance is at depths between 500 and 2,000 feet below the surface. These are the PRB "deep coals" evaluated for UCG in this report.

What is UCG- UCG is a mining method that utilizes injection and production wells drilled from the surface and linked together in the coal seam. Once linked, air and/or oxygen is injected. The coal is then ignited in a controlled manner to produce hot, combustible gases which are captured by the production wells. This process is conducted below the water table as water flows into the gasification zone and is utilized in the formation of the gas, known as syngas. The syngas is brought to the surface and cleaned for power generation and liquid hydrocarbon formulation.

History of UCG- The concept of UCG is thought to have been first conceived by Sir William Siemens in 1868, however, the first experimental work was led by William Ramsey in County Durham, United Kingdom in 1912. Ramsey was unable to complete this work before the beginning of World War I and all efforts to continue UCG development in Western Europe were discontinued until the end of World War II. Efforts to gasify coal have been conducted since that time in the U.S., Russia, England, Australia, France, Spain, Yugoslavia, Belgium, New Zealand, and China (Burton et al. 2005). The USSR's intensive research and development program during the 1930s, costing approximately $75 billion (US dollars in 2005), led to the operation of industrial scale UCG in the 1950s at several coal sites.

During the 1960s, all European work was stopped due to an abundance of energy and low oil and gas prices. In the U.S., several UCG programs were initiated in 1972, which built upon Russian experience and included the implementation of extensive field testing programs, the latter being supported by a number of research institutes and universities. These trials established the basic technology of UCG.

UCG vs. Surface Coal Gasification - UCG and surface coal gasification (SCG) can each be used to produce similar syngas that have identical downstream uses. Gasifying the coal in situ allows the energy extraction from large coal resources that are not economically or technically recoverable by conventional mining techniques. The hazards related to conventional mining are also reduced. Surface disruption is minimized as less surface space is required for a UCG facility, and surface handling of solid materials are eliminated i.e. coal and ash handling at the surface is not required. UCG consumes less surface water and generates less atmospheric pollution compared to SCG. Good thermal efficiencies can be expected as a result of the well insulated gasification cavity. Capital investment costs and syngas production costs are reduced by at least 25 percent compared to SCG (Draffin 1979).

Ground subsidence and leakage of gas from the cavity into adjacent strata such as nearby aquifers or groundwater are environmental concerns associated with UCG. Subsidence must be controlled by leaving adequate pillars in the coal seam to support the overburden stresses. This is accomplished by distributing the multiple geo-reactors properly. Groundwater must be protected by operating the geo-reactor at pressures below hydrostatic pressure. This ensures an in-flow of groundwater into the geo-reactor and prevents the forcing of gases out of the geo-reactor into the coal overburden. The process control variables, which include injection pressure, injection flow rate, oxygen and steam concentration, and well configuration, must be adjusted according to real-time surface measurements.

UCG and Coal Geology- The PRB in Wyoming is a structural and sedimentary basin located in the northeastern part of the state. It contains more than 8,000 feet of Upper Cretaceous and Tertiary rocks along the axis in the western part of the basin. The basin is asymmetrical with rocks dipping an average of 20-25 degrees along the western part of the Basin and 2 to 3 degrees in the eastern part of the Basin.

In the PRB, coals at depths less than 500 feet are available to strip mining and are not considered targets beds for UCG. For UCG consideration in this study, coals deeper than 500 feet and thicker than 30 feet have been included. This represents 307 billion tons of coal, or 74% of the coals deeper than 500 feet. For perspective, the current strip mines in the Basin produced about 440 million (0.44 billion) tons of coal collectively in 2006. The 307 billion tons of coal is a tremendous UCG resource.

UCG Suitability Selection- Based on geologic data from various sources, the coal zones in the PRB were evaluated for suitability for UCG development. The criteria applied are listed in Tables 5-1, 5-2, and 5-3. Based on these selection criteria, specific Townships have been selected as being highest priority for UCG development; they are listed in Table 5-5.

Hydrology and Subsidence- In the UCG operations, overburden material participates in the gasification process. The overburden participation increases as the UCG cavity matures and more overburden is exposed to the process. The major concerns with the UCG process and overburden are excessive subsidence, groundwater influx, mixing of aquifers (or water bearing strata), and groundwater contamination.

Subsidence is very site and design specific. Subsidence can be controlled by design. However full extraction of thick seams can result in high surface impact which would be incompatible with high surface use. In the PRB, the extraction plan and percentage resource recovery must be planned according to the site specific coal seam thickness, depth, and existing surface uses.

In UCG, groundwater influx into the geo-reactor is required for the gasification reactions to occur (Section 2.2.2). However, excess water influx consumes energy, cools the geo-reactor, and lowers the heating content of the syngas. Site selection is important to verify that groundwater influx will be within acceptable ranges. Therefore, lower permeability mudstones overlying the geo-reactor are favorable rather than higher permeability sandstone units.

Permitting UCG - UCG activities in Wyoming are regulated primarily by the Department of Environmental Quality. Section 7 details the permitting process and estimated time for acquiring requisite permits. Key environmental performance standards relate to impacts to groundwater, surface water, air quality, and surface uses of the affected permit area.

PRB Infrastructure – The PRB has a long history of agricultural and energy development. This has resulted in a network of roads, power lines, pipelines, and railroads which will support future UCG development. In selecting areas considered most prospective for UCG, the infrastructure was considered.

However, the existing surface and subsurface uses in the PRB also represent potential conflicts for UCG development. One potential conflict is between CBM operator and existing deeper oil and gas producers and the UCG developer. The most likely resolution of these conflicts is by having sequential development, especially of CBM. As CBM is depleted from the east side of the Basin to the west, the CBM infrastructure of wells, gathering systems, and pipelines all will have value to the UCG operator. UCG developments, which may reach commercial scale in the PRB over the next 5 to 10 years, will find many CBM areas depleted by that time. Deeper oil and gas well bores will need to be avoided by a safe distance. Where deeper the oil and gas operation is significantly depleted, these reservoirs may benefit from carbon dioxide injection and enhanced oil recovery, or these reservoirs may simply serve as a sequestration site for carbon dioxide. Therefore, a potential conflict may have synergistic benefits for both the oil and gas lessee and the UCG developer.

UCG Configurations- All UCG configurations require at least two wells completed in the coal seam, one for injection of oxidant and one for syngas product recovery. Oxidant can be air or oxygen enriched. In so-called air-blown systems, the resulting syngas has a low BTU value, about 150 BTU/scf. The oxygen-blown systems produce medium BTU syngas, about 300 BTU/scf, as there is less dilution by nitrogen.

Once the wells are completed, they must be linked together prior to gasification initiation. Several methods of linking are discussed and the preferred method selected. The linking conduit between wells must be the highest permeability path for the produced syngas to follow such that the syngas is captured at the production well and does not escape into the coal seam.

The syngas can be used for manufacture of synthetic natural gas (SNG), for power generation, Gas to Liquids, as formulation of clean diesel fuel, or other chemical synthesis, including hydrogen, methanol, ammonia, and di-methyl ether (DME) production. The various processes are described.

UCG can also be used in combinations of these processes, known as poly-generation. For example, a UCG facility many have an air blown process using the product gas to fire a combined cycle power plant which could generate the power necessary for the UCG process as well as an oxygen separation plant. This would allow for the production of electrical power and medium-BTU syngas to be used as feedstock for heating or other technologies previously described.

Carbon Capture, Storage, and Sequestration - Carbon capture and sequestration (CCS) is the process to remove and store "greenhouse gases" from process streams to reduce buildup of these gases in the atmosphere. CO_2 is a major greenhouse gas of concern in fossil fuel processes. CCS usually involves extraction, separation, collection, compression, transporting, and geologic storage. UCG processes have the same CCS options as surface gasification processes except for the potential to store the captured CO_2 in spent UCG cavities. This has been referred to as Reactor Zone Carbon Storage, or RZCS (Burton et al. 2005). This unique feature of UCG CCS, although requiring further testing, may make UCG the lowest cost clean coal technology for CCS.

Economics Conclusions of UCG in the PRB- The capital and operating costs for surface gasification facilities are somewhat available in the literature and from engineering firms and vendors that supply surface gasification process facilities. However, the capital and operating costs for UCG are literally absent from the literature, at least in any level of detail that would be useful for planning and economic scoping purposes. Therefore, in this report, we have concentrated the most effort in describing the UCG configuration, operating methods and preferred methods, and the capital and operating costs of UCG, especially in the PRB. This has required extensive modification and updating to UCG cost models developed by the primary contributors to this report. This should provide the most useful information for planners interested in evaluating UCG in the PRB and elsewhere.

Markets for electricity, SNG, clean liquid hydrocarbon fuels, and ammonia products exist with in the PRB. Existing pipelines provide take-away capacity. For electricity, at least three new transmission projects are being analyzed which would require an additional 1,400 MW of new power generating capacity in this part of Wyoming.

The air-fired UCG raw syngas production costs were evaluated for a base case typical of much of the deep coal in the PRB. The base case considered a 112 foot thick coal seam in the PRB with a depth to the top of the coal of 1,054 feet. The UCG facility utilized a 200 foot process well spacing. The base case air-fired UCG facility produces low-BTU syngas with a HHV of 150 BTU/scf. This compares conservatively with the ARCO Rocky Hill air-fired UCG test in the PRB, where syngas with an average HHV in excess of 200 BTU/scf was produced. The base case conservatively estimated a 65 percent coal resource recovery leaving pillars in the coal seam to control subsidence.

The base case air-fired UCG facility will produce adequate syngas to fuel a 200 MW power generation plant for twenty years and only consume 0.27 square miles of the coal seam. The base case facility would require $58.3 MM total investment and $13.5 MM annual operating expenses, resulting in a raw low-BTU UCG syngas cost of $1.62/MM BTU, including all state taxes, royalty, and a 15% return on investment. Sensitivities on coal seam depth, thickness, heating value, recovery, and well spacing are also presented and discussed. These result in a range of raw syngas costs of $1.40 to $2.35 per MMBTU.

These raw syngas costs have been tied to the economics of a 200 MW air-fired UCG-IGCC power plant in the PRB. Total capital cost of $263 million for the combined UCG-IGCC plant, with annual operating costs of $19.9 million, yields an After Federal Income Tax (AFIT) return of 18.3% DCF-ROR, and an NPV@15% discount of $44.3 million, using an average electricity sales price of $62 per MW-hr. Such a plant would return a 15% DCF-ROR at an electricity sales price of $51.68. Sensitivities on +/- 25% on capital costs, operating costs, and electricity sales price are given, resulting in a range of DCF-ROR's from 13% to 23%.

The UCG-IGCC configuration has been further compared to a "mined-coal" surface gasifier IGCC power plant. The results are summarized as:

	Surface Gasifier IGCC	UCG IGCC	% UCG Advantage
Capital/kW Installed	$1,544	$1,180	24%
Op Cost, $/MW-hr sold	$21.99	$11.96	46%
Breakeven Sales Price for 15% ROI	$80.60	$51.68	36%
DCFROR (as described here)	10.39%	18.28%	75%
Payback, years	10.77	7.64	29%

The UCG IGCC has clear cost advantages across the board.

Oxygen-blown UCG has also been evaluated for producing medium BTU syngas suitable for feedstock for FT or other chemical synthesis. The resulting medium BTU syngas has an estimated HHV of 306 MM BTU/scf and a cost of $2.55 per MMBTU, with the same assumptions as the air-fired UCG, including a 15% return on investment.

Because most oxygen-blown UCG systems have included steam injection, we have further investigated the cost impact of adding steam injection to the oxygen stream. This results in a high cost penalty, raising the overall cost of the medium BTU syngas to $3.49 per MMBTU. Because previous analysis of the Rocky Mountain 1 test concluded that the steam injection was actually water at the injection well head temperature and pressure (Boysen et al 1998), we believe that oxygen fired UCG is functional without steam injection. Therefore, medium BTU syngas can be produced for closer to the $2.55 per MMBTU than the steam injection at $3.49 per MMBTU.

These oxygen-fired UCG economics have also been evaluated for an FT plant utilizing the medium BTU UCG syngas. A modest size UCG FT project, producing 10,000 barrels per day of naptha and diesel combined, has a total capital cost of $622 million and annual operating costs of $53.2 million. This yields an NPV @ 15% discount of $103.5 million, and a DCF-ROR of 18.0%. The payback is a moderate 7.7 years. After reaching steady state production, it produces about $142 million in cash flow from gross revenues of $257.7 million. Sensitivities on capital costs, operating costs, and revenues being varied from 75% to 125% of the base case produce DCF-ROR's ranging from 11% to 23%.

In summary, UCG in most of the deep coal seams in the PRB is economically feasible and economically favorable compared to surface coal gasification. These advantages hold for air-fired UCG used in an IGCC power plant as well as for oxygen-fired UCG used in an FT plant.

Resource Conclusions on UCG in the PRB – The coal deposits in the Powder River Basin of Wyoming are thick, laterally continuous, and nearly flat lying. These deposits are ideal for development by Underground Coal Gasification because:

- Thick, deep coal beds, from 30 to over 200 feet thick and below 500 feet deep, provide a 307 billion ton UCG resource
- This resource is in a small area and has good thermal characteristics for the UCG process
- Commonly overlain by thick siltstone strata, the coals have a favorable structural and hydrologic setting
- The coals are sub-bituminous in rank, having adequate heat value (8,200 BTU/lb) and good reactivity to the UCG process
- The coals are low ash, averaging 6%, which is waste left in the UCG cavity
- There is no significant faulting (possible conduits for gas loss) in most of the Basin
- Coals depths of 500 ft + are below most aquifers and the deeper horizons, over 1,000 feet deep, will minimize surface effects of subsidence
- There are no intrusive rocks in the coal seams
- There is adequate hydraulic head, often several hundred feet, above the coal seams
- The coal is non-swelling upon heating, very favorable for UCG, and
- Coal permeability is high, helping to establish well linking before UCG ignition.

Environmental Conclusions of UCG in the PRB- The thick deep coal seams of the PRB can be harvested using UCG and be protective of groundwater, air resources, and with minimum subsidence. Protection of these environmental values requires correct site selection, site characterization, impact definition, and impact mitigation. The operating "lessons learned" of previous UCG operations, especially the "Clean Cavity" concepts developed at Rocky Mountain 1, should be incorporated into the future UCG operations. UCG can be conducted in the PRB with acceptable environmental consequences.

Recommended UCG Development Program - The commercial development of UCG technology has the potential to open up vast coal resources of the Powder River Basin of Wyoming for energy production and fuel generation far into the future. The recommended development components for UCG commercialization consist of the following:

- Selection of the UCG technology and end use with the greatest potential for commercial development.
- Select a suitable site to demonstrate UCG feasibility and commercial potential.

- Demonstrate UCG technology in the thick coals of the PRB on a pre-commercial scale.
- From the experience gained in the demonstration, expand the UCG demonstration to commercial operation.
- With the initial commercial operation underway, evaluate and develop other end use potential.

A pre-commercial demonstration project, using several commercial sized UCG modules, should be installed and operated for approximately one year. All commercial cost , operating, and environmental data should be collected to allow scale up to a small commercial operation. The demonstration project should be air-blown and generate electricity. The first commercial project should scale up UCG operations, generate electricity, and introduce and test value-products. Expansion to full commercial will include oxygen-blown UCG to provide feed stocks for value-product plants.

UCG, both air- and oxygen-blown, should have diverse applications for power generation, transportation fuel formulation, and other value-products. This industry, because of the immense UCG resources in the Powder River Basin, should operate for many decades with tremendous economic benefits for Wyoming.

2.0 INTRODUCTION

Coal is our most abundant fossil fuel. While oil and natural gas account for 64 percent of the world's energy consumption, they total only 31 percent of the world's known fossil fuel reserves. When known reserves and estimated future resources are considered, coal overshadows oil and gas, accounting for 95 percent of the known fossil fuel reserves plus resources. Therefore, a shift in our energy consumption away from oil and gas, and to coal, is inevitably in the world's energy future.

There are an estimated 510 billion tons of sub-bituminous coal the PRB in Wyoming. These coals are found in extremely thick seams that are up to 200 feet thick. The total deep coal resource in the PRB has a contained energy content in excess of twenty times the total world energy consumption in 2002. However, only five percent of the coal resource is accessible to open pit mining. The balance is at depths between 500 and 2,000 feet below the surface. These are the PRB "deep coals" (GasTech Evaluation 2005).

"The PRB is the single most important coal basin in the U.S. in terms of production, supplying over 37 percent of the total coal produced in the U.S. in 2003" (USGS 2007). PRB coals are known worldwide for their low sulfur content and their moderately high heating value. These coals are recovered extensively with conventional surface mining on the east side of the basin. In 2006, Wyoming mines produced 440 million tons of sub-bituminous coal. In addition, coal bed methane (CBM) recovery is occurring on a large scale throughout the basin. In 2006, 368 BCF of methane was recovered from 16,550 producing CBM wells in the PRB (WOGCC 2007). Many of the coal seams in the PRB have been penetrated by oil and gas and CBM wells and determined to be too deep for economic recovery by current mining technologies. Of the 500+ billion tons of coal in the PRB, 95 percent is too deep for economic extraction by surface mining (USGS 1999). However, it is that same depth that makes these coals an appropriate target for development using UCG.

Test trials for UCG began in Wyoming around 1975 and ended in 1995. The trials proved that UCG was possible, however not economical at the time. The trials also verified the possibility of the commercialization of UCG in the Powder River Basin. The Rocky Hill trial was conducted by ARCO Coal in Campbell County, WY in 1978 and gasified Wyodak coal. The test was successful because of the high heating value of the product gases produced and the limited groundwater contamination that resulted. Three UCG trials (Hoe Creek I – III) were also conducted in the 1970s by Lawrence Livermore National Laboratory in Campbell County, WY, that tested the feasibility of gasifying coal in the much shallower Felix seam. These tests were not considered successful for reasons that included improper site selection and over-pressurization of the UCG reactor that led to contamination of fresh water aquifers. The purpose of this study is to expand on the findings of previous tests by confirming the suitability of PRB deep coals for recovery using UCG, and evaluating locations across the basin, with knowledge gained regarding UCG strategies in the past twenty years, for their suitability as sites for a UCG trial.

2.1 WHAT IS UCG?

UCG is a mining method that utilizes injection and production wells drilled from the surface and linked together in the coal seam. Once linked, air and/or oxygen is injected. The coal is then ignited in a controlled manner to produce hot, combustible gases that are captured by the production wells, brought to the surface, and cleaned for power generation and liquid hydrocarbon formulation.

The UCG process produces commercial quantities of gas for power generation and for chemical processes such as clean diesel fuel formulation. UCG enjoys the advantages of surface gasification of coal with lower capital and operating costs to produce the same end products.

UCG gas, also known as syngas, is suitable for combustion in a gas turbine to produce electricity. Relative to all other coal-based generating technologies, UCG has the lowest Cost-of-Electricity (COE), which has been estimated to be as low as $34/MW-hr for Integrated Gasification Combined Cycle (IGCC) generation. UCG also has the same opportunity for carbon capture as surface gasification, with much lower costs than carbon capture in conventional coal-fired generating plants. Moreover, the deep cavities left by UCG may be suitable for carbon sequestration of dense-phase carbon dioxide, an attribute that no other clean coal technology can provide. Syngas can also be used to formulate synthetic natural gas, hydrogen, clean fuels, ammonia, and other chemical products. UCG syngas is the lowest-cost feedstock for these formulation processes.

UCG is a proven technology for converting unmineable coal seams into recoverable energy. In its most basic configuration, UCG involves the drilling of two wells from the surface to the coal seam. Various methods are used to connect or link the wells within the coal seam. UCG relies on the natural permeability of the coal seam to transmit gases to and from the combustion zone, or on an enhanced permeability created through reversed combustion, a drilled inseam channel, or hydro-fracturing. Linkage of the two wells is crucial to UCG success, as the highest permeability (lowest resistance) path for the produced gases must be to the production well. After linking, full production begins by igniting the coal seam and injecting air, oxygen, and/or steam into one well, the injection well, and producing hot combustible gas, called syngas. The zone of gasification is sometimes referred to as a "geo-reactor" as it is a gasification reactor in situ in the coal seam. The syngas recovered at the second well, the production well, is taken to the surface for processing. The UCG process is conducted below the water table. Ground water flows into the gasification zone and is utilized in the formation of the syngas. The syngas is cleaned and processed on the surface for use in power generation and/or liquid hydrocarbon formulation. There are many variations to this process and they are discussed in later sections of this report.

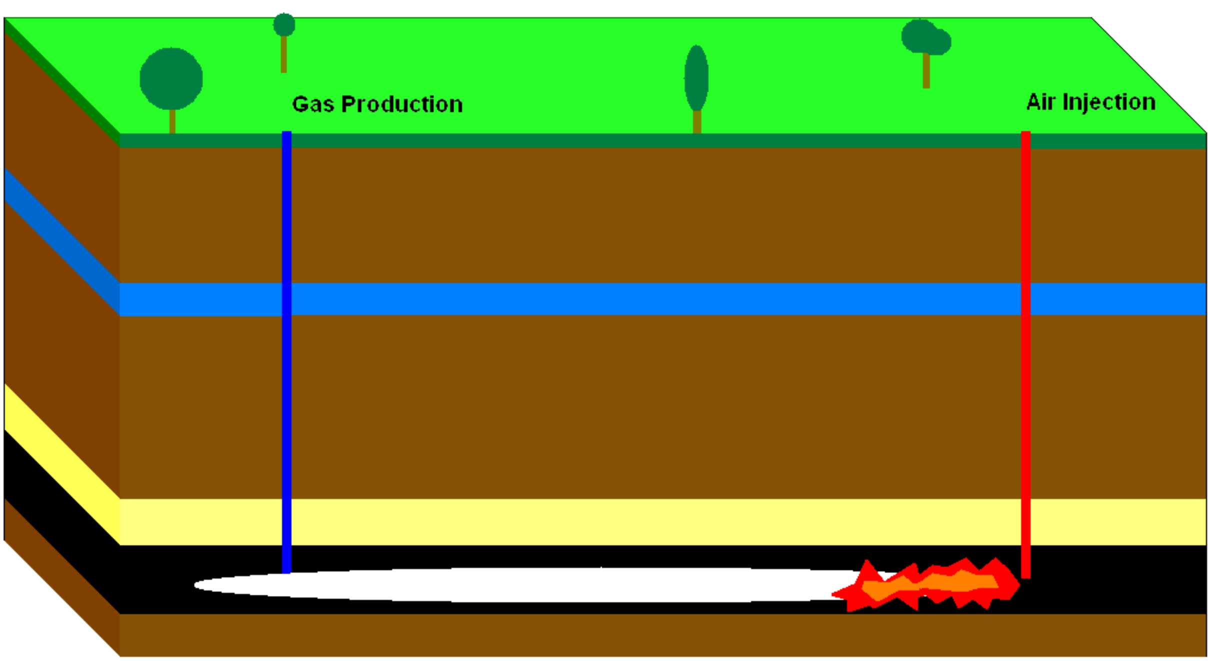


FIGURE 2-1 BASIC UNDERGROUND GASIFICATION PROCESS

Figure 2-1 is a schematic that shows the basic UCG process configuration (Diversified Energy 2007).

Figure 2-2 is a schematic that shows the main components of a commercial UCG site for power generation.

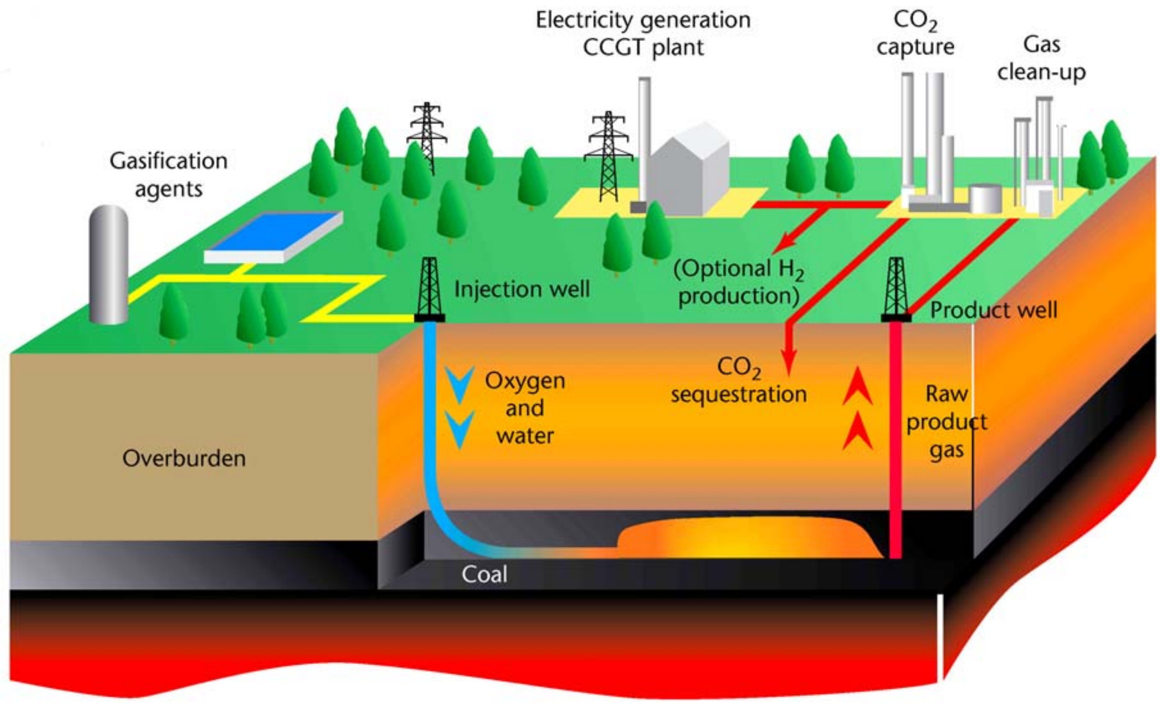


FIGURE 2-2. COMPONENTS OF A COMMERCIAL UCG SITE FOR POWER GENERATION

2.2 UCG CHEMISTRY

The chemical structure of coal is very complicated, and contains a myriad of structural forms that include a variety of organic and inorganic constituents. The chemical constituents of coal are generally very reactive, particularly for the lower ranked coals such as the PRB sub-bituminous coals. When coals are heated to temperatures greater than 500^0F, coal begins to thermally degrade (pyrolysis or carbonization). The chemical structure of the coal begins to change. Gases and liquids begin to evolve. The gases are mostly carbon-based but also include some inorganic constituents such as hydrogen sulfide and ammonia. Coal pyrolysis continues to approximately 1800^0F; however, most pyrolysis products evolve at temperatures below 1200^0F. The solid material (char) resulting from the pyrolysis process contains mostly elemental carbon (char) and inorganic residue (ash). The char provides the energy source to propagate the UCG process. The liquid products of coal pyrolysis include water, light oils, and tars. The tars are viscous with relatively high pour points. The relative yields of the pyrolysis products (percent moisture-ash-free, at 1470^0F) for a subbituminous coal are shown below (Cameron Engineers 1975):

Char	60.3
Water (formed)	10.5
Tar	9.2
Light Oil	1.3
Gas	18.3
Hydrogen Sulfide	0.4

The pyrolysis gas constituents and percent concentrations for the gas at 1400^0F are:

Carbon Dioxide	12.0
Carbon Monoxide	17.3
Hydrogen	43.6
Methane	26.5

Small concentrations of higher hydrocarbon gases are also generated.

2.2.1 UCG Process

Figure 2-3 shows the conceptual design of the UCG process. There are three concurrent parts or phases of the UCG process. The first part is oxidation where air or oxygen is injected into the coal to burn the char and coal near the coal injection point. The basic reactions of the oxidation process are shown in equations 1 through 3.

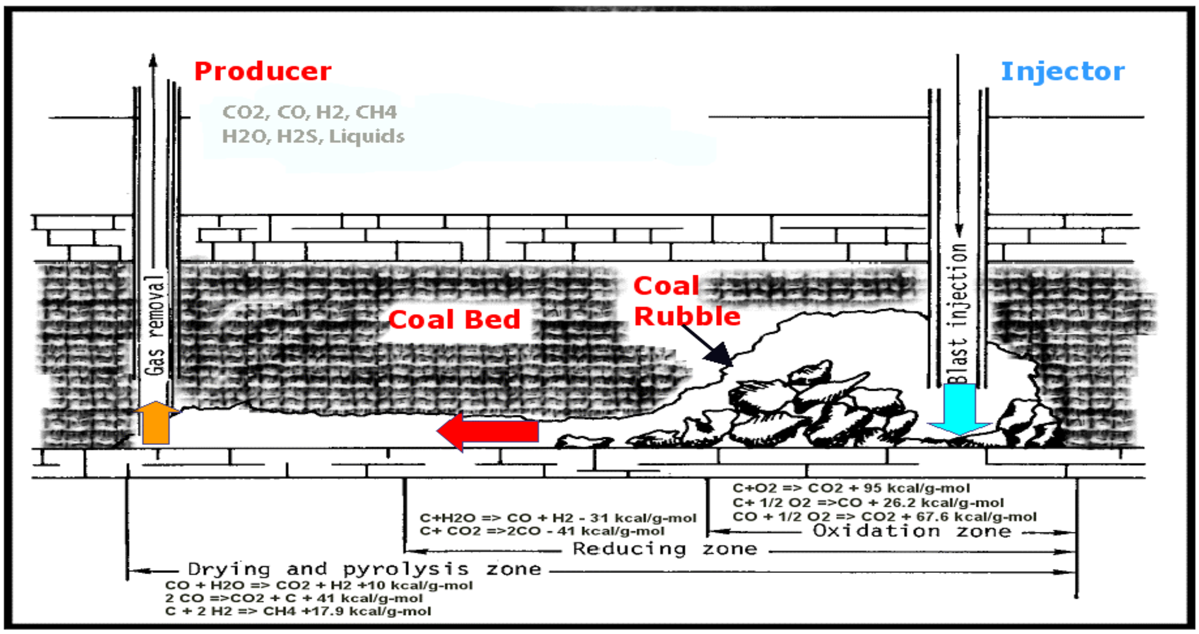


FIGURE 2-3. THE UCG PROCESS

$$C + O_2 \Rightarrow CO_2 + 95 \text{ Kcal/g-mole} \quad (1)$$

$$C + O_2/2 \Rightarrow CO + 26 \text{ Kcal/g-mole} \quad (2)$$

$$CO + O_2/2 \Rightarrow CO_2 + 67.6 \text{ Kcal/g-mole} \quad (3)$$

The heat generated during oxidation, fuels the other two parts of the UCG process, reduction and the drying and pyrolysis. The temperature in the UCG reactor generated from the oxidation phase can exceed 2800^0F.

The second phase of the process is reduction. Reduction occurs after oxygen is consumed in the oxidation phase. Because of the high temperatures in the UCG reactor, the products of the oxidation and pyrolysis reactions, CH_4, CO_2, CO, and H_2O, thermally decompose and react with each other and the char. Reactions 4 and 5 are the most important reactions of the gasification process.

$$C + H_2O => CO + H_2 – 31 \text{ Kcal/g-mole} \quad (4)$$

$$C + CO_2 => 2\ CO – 41 \text{ Kcal/g-mole} \quad (5)$$

Methane also degrades at the high temperatures of the UCG reactor according to Reaction 6 and 7.

$$CH_4 + 2\ H_2O => CO_2 + 4\ H_2 – 46 \text{ Kcal/g-mole} \quad (6)$$

$$CH_4 + H_2O => CO_2 + 3\ H_2 – 54 \text{ Kcal/g-mole} \quad (7)$$

As the gases pass through the subsurface channel in the coal into the production well, some gas cooling occurs. This reverses the direction of equations 4-7 with a reduction of H_2 and CO concentrations and increased concentrations of CO_2 and CH_4.

Another important reaction that occurs in the UCG process is the gas-shift reaction that affects the relative concentrations of H_2, CO, and CO_2. Equation 8 shows this reaction.

$$CO + H_2O => CO_2 + H_2 + 7 \text{ Kcal/g-mole} \quad (8)$$

As the gas composition changes with the reduction in gas temperatures in the subsurface, the heating value of the gas changes very little. This results from the almost equal trade-off between the H_2 and CO concentrations with the CH_4 concentration.

The final phase of the UCG process is pyrolysis and drying. The hot gases within the UCG reactor vaporize the water in the coal and pyrolyze the coal. Reaction 9 shows the products of the drying and pyrolysis products.

$$\text{Coal} + H_2O_{liq} + \text{Heat} => \text{Char} + H_2O_{Gas} + \text{Gases} \quad (9)$$

Some of the gaseous products condense to tar and oil liquids as described previously. Constituents of the non-condensable gases were described previously.

2.2.2 Site Selection Impacts on the UCG Process Chemistry

Site specific characteristics are important in determining the potential for efficient UCG operations. The most efficient use of the energy generated in the oxidation phase of the UCG process is the pyrolysis of the coal and the reduction reactions. Energy used to vaporize excessive water and overburden material detract from the beneficial use of the oxidation energy. For these reasons, high water content and influx, coal seam thickness, and overburden interaction are important considerations for selecting a UCG site.

As shown in Equations 4, 5, 6, 7, 8, and 9, water participates in UCG reactions and is a reactant in the important steam-char reaction (Equation 4). However, excessive water participation causes reduced process efficiency. Excessive water vaporization can result from high water content in the coal, excessive water influx caused by high permeability in the coal or overburden or collapse of overburden with high water content. Excessive groundwater volatilization reduces the UCG reactor temperature and that reduces the resultant gas heating value. At temperatures greater than approximately 1300^0F, the disassociation of CO_2 to CO will increase CO to concentrations greater than CO_2. As temperatures decrease below this temperature, CO concentration decrease and CO_2 concentrations increase. Soviet experience has shown that increased water inflow rate decreased product gas heating value (Gregg and Olness 1976).

Coal seam thickness is also important in gasification efficiency and the resultant heating value of the UCG product gas. For thin coal seams, thermal conduction to exposed overburden or water influx from the overburden will reduce the temperature of the gasification reactor and will result in reduced product gas quality (heating value). The time to expose the overburden to the UCG process is directly related to the coal seam thickness and the vertical location of the UCG channel. The thick coal seams of the PRB will provide for low overburden interaction.

2.3 UCG IN THE PRB

The U. S. is striving to reduce its reliance on foreign energy supplies and is actively seeking technologies that can recover unconventional domestic resources such as the deep coal found in the PRB. Historically, tests completed on PRB coal seams indicate that UCG can be successfully conducted, and results from the economic analysis provided in Section 10.0 show that it can be done at costs that compare favorably with other gasification strategies. However, because of the variability of coals and the geologic conditions in which the coals reside, results are highly dependent on site selection. This study examines coal seams in locations throughout the PRB and considers variables that are critical to successful site selection. Technical, regulatory and economic issues are elements that were used in the determination of PRB coal suitability for UCG development.

The PRB coal is attractive for UCG development due to coal type and abundance. The Wyodak, which is the target coal seam in the PRB, averages approximately 100 feet in thickness. When a coal seam is this thick, fewer wells need to be drilled to achieve the same production as from thinner seams. The UCG production in the PRB would continue almost indefinitely due to the estimated 510 billion tons of coal, which has the energy equivalent of about 1.4 trillion barrels of oil. Also, the PRB coal has low sulfur and ash content and is especially favorable for meeting strict emissions requirements.

Table 2-1, which was developed using data from research described in Section 5.0, summarizes selected UCG attributes and compares it to those attributes in the PRB. The coals of the PRB, in virtually every attribute, are suitable or superior for UCG.

TABLE 2-1. COMPARISON OF OPTIMAL COAL ATTRIBUTES WITH PRB COAL ATTRIBUTES.

Coal Attribute	Optimal	Powder River Basin
Seam Thickness	30+ Feet	30 – 250 Feet
Rank	Sub-bituminous to High Volatile Bituminous	Sub-bituminous "B"
Ash	<40%	6.4%
Faulting	Rare	Rare
Depth	>1,000 Feet	500 – 2,500 feet
Dip	0 – 20 Degrees	1 – 3 Degrees
Intrusions	Minimal	None
Immediate Roof	Strong, Stable	Low Permeability Siltstone
Hydraulic Head	>600 Feet	500 – 2,500 Feet
Swelling Character	Non-swelling	Non-swelling
Coal Permeability	High	High
Water Quality	Poor	Stock Quality
Natural Gas Availability	Available, Low Cost	Very Low Cost

While the PRB area is sparsely populated, there are still many avenues available to market the products from UCG. The PRB has a well-developed energy infrastructure of roads, power- and pipe-lines, and support service industry. Electrical transmission infrastructure is currently being considered to Utah, Nevada, California, and to the Denver, CO and Phoenix, AZ areas. The high demand for and ease of transportation of liquid hydrocarbon products makes them attractive. Several major natural gas pipelines in the PRB could be utilized if synthetic natural gas production was chosen. A market for the manufacture of clean synthetic diesel could be found in the existing coal mines and through railroad industry demand. Ammonia and fertilizer production could be considered as well as manufacture of ammonium nitrate for blasting agents.

3.0 UNDERGROUND COAL GASIFICATION

3.1 HISTORICAL OVERVIEW OF UCG

The concept of UCG is thought to have been first conceived by Sir William Siemens in 1868, however, the first experimental work was led by William Ramsey in County Durham, United Kingdom in 1912. Ramsey was unable to complete this work before the beginning of World War I and all efforts to continue UCG development in Western Europe were discontinued until the end of World War II. Efforts to gasify coal have been conducted since that time in the U.S., Russia, England, Australia, France, Spain, Yugoslavia, Belgium, New Zealand, and China (Burton et al. 2005).

Russia was the first country to heavily research and test the feasibility of gasifying coal seams in situ. The Soviet decision to pursue UCG was made in 1928, and the first field experiments were conducted during the 1930s (Gunn 1976). The USSR's intensive research and development program during the 1930s, costing approximately $75 billion (US dollars in 2005), led to the operation of industrial scale UCG in the 1950s at several coal sites. Activity subsequently declined due to the discovery of extensive natural gas resources in the USSR. The only site in operation today is located in Angren, Uzbekistan.

Between the years 1944 and 1959, the shortage in energy and the diffusion of the results of the UCG experiments in the USSR (1934-1940) created new interest for UCG in Western European coal mining countries. The first research work was directed to the development of UCG in thin seams at shallow depths. The stream method was tested in Belgium on the site of Bois-la Dame (1948) and in Morocco, on the site of Djerada (1949). The borehole method was tested on shallow coal seams in Great Britain at the sites of Newman Spinney and Bayton (1949-1950). A few years later, a first attempt was made to develop a commercial pilot plant: the P5 Trial in Newman Spinney, Derbyshire (1958-1959). Although gasification was successful, the National Coal Board later abandoned the project for economic reasons (The Coal Authority 2006). During the 1960s, all European work was stopped due to an abundance of energy and low oil prices. In the U.S., a UCG program was initiated in 1972, which built upon Russian experience and included the implementation of an extensive field testing program, the latter being supported by a number of research institutes and universities. These trials established the basic technology of UCG.

3.1.1 Former Soviet Commercial Experience

As stated earlier, the former Soviet Union was the first country to heavily research and test the feasibility of UCG. This research peaked in the mid-to-late 1960s, then had a dramatic decline in the early 1970s. Commercial-scale production of gas was achieved at numerous locations and for long periods of time, most notably at Angren, Shatskaya, Kamen, Yuzhno-Abinsk, and Podmoskovia. Uzbekistan is still operating its UCG facility at Angren, a facility they initiated operations in 1959. Table 3-1 (Burton et al. 2005) summarizes the former Soviet Union's UCG trials.

TABLE 3-1. SUMMARY OF SOVIET UNION UCG TRIALS

Basin	Site	Development Date	Coal Type	Depth (ft)	Seam Thickness (ft)	Energy Content (BTU/lb)	Gasification Characteristics
Donets	Shakhta	1933	Anthracite	Depth unknown, dipping 19-22^0	1.3	--	67.2 – 140.0 BTU/scf
	Lisichansk	1933	Bituminous	79-453 ft, steeply dipping 20-60^0	1.3 – 8.9	8100 - 9000	33.6 – 246.4 BTU/scf Alt. air and steam3.5 x 10^9 ft^3/yr (1959)
	Gorlovka	1935	Bituminous	131-361ft, Steeply dipping 70^0	6.2	--	100 – 112 BTU/yr (steam and O_2)
	Kamensk	1960					
Kuznets	Leninskt	1933	Bituminous	92-98ft Dipping 20^0	15.9	--	100 – 269 BTU/scf
	Yuzhno-Abinsk	Podzemgaz Station 1955	Bituminous	Steeply dipping 55-70^0	6.6 – 29.5	9000 – 10,800	112 BTU/scf 13.7 x 10^9 ft^3/yr (1965)
	Stalinsk	1960	--	--	--	--	--
Moscow	Krutova Mine	1932	Lignite	53-66ft, Horizontal	6.6	--	110 BTU/scf
	Podmoskovia Station (Tula)	1940	Lignite	131-197ft, Horizontal	6.6 – 13.1	3600 - 9000	78.4 – 100 BTU/scf 16.2 x 10^9 ft^3/yr
Near Tashkent	Shatskaya Angren	1960 1962	Lignite	361-820ft, Horizontal 5-15^0	13.1 – 78.7	6570	89.6 – 95.3 BTU/scf 49.4 x 109 ft^3/yr (1965)

3.1.2 U.S. Trials

UCG trials in the United States started in the 1940s and advanced the technology of control through the use of the controlled retracting injection point (CRIP) technique and oxygen injection. By the end of the 1980s, UCG was considered in the U.S. to be a technology ready for commercialization. Although commercial projects were evaluated, most notably the synthetic natural gas (SNG) plant at Rawlins, WY, the low cost of natural gas in the early 1990s prevented these projects from being realized. During the period between 1960 and 1990, 33 UCG tests were conducted. Several of those tests were completed in the State of Wyoming. A selection of these tests and their results are summarized in the following sections.

3.1.2.1 Gorgas Underground Gasification Project (1946-1947 and 1950)

The Synthetic Fuels Act of 1944 authorized UCG research. The first U.S. UCG experiment was conducted in Gorgas, Alabama in 1946-1947 by the Bureau of Mines and the Alabama Power Company.

In 1950, they conducted a second UCG test at the same location. The process they utilized in the second test involved connecting mine entries (tunnels) that were over 150 feet deep containing 42 inch thick coal seams, to the surface by boreholes drilled at 300 foot intervals. The coal was then fired and the energy was obtained in the form of hot products of combustion. The test was considered unsuccessful due to leakages. Additional experiments were conducted in the 1950s using grouted boreholes and other gasification methods. Those tests showed that it was possible to produce gas and adjust the quality of the products; however, the processes were not economically viable (Bureau of Mines 2001).

3.1.2.2 The Hanna Trials (1972-1979)

Hanna I (1972-1973). Hanna I was the first of four underground coal gasification trails initiated by the Bureau of Mines in 1972. The Hanna site contained a 30 ft thick sub-bituminous coal seam ranging in depth from 350 ft to 400 ft. Preparation of the trial began in 1972 with first attempt at ignition beginning in March of 1973. Permeability was established and ignition of the coal seam began. After 18 hours of operation low permeability conditions began to affect injection rates, low permeability was presumed to be caused by formation of coal tars in the combustion zone. The well was then shut down and vented, after re-igniting injection rates were at acceptable levels. However, the gas recovery factor had fallen to 16 percent indicating that during venting the well casing had been damaged and injection air was being lost to the overburden. Heating values achieved during the forward combustion phase ranged between 29 BTU/scf to 263 BTU/scf, this wide range of heating values is due to the losses of injection air to the combustion zone.

Reverse combustion was attempted next in May of 1973. Injection rates and pressures were similar to those seen during the forward combustion phase, however after several weeks large volumes of gases began flowing from the production well indicating that excellent communication between wells had been established. The heating values of this test were below 100 BTU/scf. The second reverse combustion test followed the construction of a large flare. This test exhibited similar characteristics to the first reverse combustion test, however heating values ranged from 109 to 166 BTU/scf.. This was due to the increased air injection rates. Initial problems with the second phase began when a bypassing condition started. This bypass allowed injection air to bypass the combustion zone and react with the product gases creating a high temperature condition that was resolved by making changes in the air injection system.

The duration of Hanna I was approximately 180 days. Gasification of 4,000 tons of coal occurred during this time. The average heating value was 126 BTU/scf and 1.6 x 10^6 scf/day of dry gas was produced. This test proved feasibility of UCG and gave rise to issues associated with forward and reverse combustion such as plugging of fractures, bypass conditions, system pressure maintenance and control of gas loses and heating values.

Hanna II (1975-1976). Hanna II was a three-phase trial starting in April of 1975. Phase I was initiated to further investigate the reverse combustion technique. This phase proved the feasibility of seam preparation using reverse combustion. Completion of the wells near the bottom of the coal seam allowed for linking to occur in the bottom half of the seam, preventing any gas overriding. Phase I lasted for 38 days of gasification between two wells consuming approximately 48 tons of coal per day. The gases were produced at a rate of 2.7 MM scfd with a heating value of 152 BTU/scf.

Phase II consisted of linking two sets of wells by reverse combustion while utilizing extensive instrumentation to indicate the linkage path. This instrumentation showed the placement of a narrow linkage path at the bottom of the coal seam and also showed the combustion front was utilizing the entire 30 ft thick seam. Phase II consisted of 27 days of gasification producing 8.6 MM scfd with a heating value of 175 BTU/scf. This phase consumed more than 100 tons of coal per day.

Phase III began immediately after Phase II. This phase planned to simultaneously inject into two wells and produce a broad reverse combustion link utilizing one of the links created in Phase II as a line source for air injection. This operation did not succeed and the test was continued using one well pair. Approximately 4,200 tons of coal was used during this 38 day burn which produced gases of 138 BTU/scf. (Brandenburg et al. 1976).

Hanna III (1977). The Hanna III experiment was designed to investigate the effects of UCG on ground water quality. This test utilized the reverse combustion technique in June of 1977. Communication between wells was determined to be successful when injection rates increased dramatically and injection pressure dropped. Gasification was then started and continued normally until production well temperatures increased which indicated lack of groundwater. Gasification was suspended until a water injection system was installed. Gasification was started again and continued until temperatures increased once more, at which time the gasification was terminated. This trial lasted 38 days and produced an average heating values of 130 BTU/scf and consumed approximately 2,850 tons of coal.

Hanna IV (1977-1979). Hanna IV started in late 1977 and continued into1979. It was the largest in scope of the Hanna experiments and was conducted to determine the commercialization scale of UCG. The first phase of Hanna IV was unsuccessful due to the drop of the gas heating value of the product gas. After the addition of two injection wells, the product gas never exceeded 90 BTU/scf, which was also considered unsuccessful. The second phase of Hanna IV was also considered unsuccessful. Researchers determined that geologic faults within the test area, not recognized prior to the test, caused the failed UCG attempts. The duration of Hanna IV was 24 days and 1500 tons of coal were consumed producing an average heating value of 133 BTU/scf (Covell et al. 1980).

3.1.2.3 Hoe Creek (1975-1979)

In the early 1970s Lawrence Livermore Laboratories (LLL) became interested in developing a commercial process for gasifying western coals to produce pipeline quality gas. In 1972, they developed a unique approach to in situ coal gasification. The LLL approach utilized an array of chemical explosives that were detonated to enhance the permeability of a reaction zone within a thick bed of coal. They believed that a permeable, fractured coal bed within a relatively impermeable medium should permit intimate mixing of the coal and the reactants (oxygen and steam) and allow heat transfer and reactant access to the coal. They hypothesized that the low permeability of the surroundings should minimize leakage of reactants and products from the fractured zone. In essence, the LLL concept is much like an underground packed bed reactor, which is described in Section 9.

Hoe Creek I (1975). Hoe Creek I was carried out by LLL on November 5, 1975 in the PRB in Campbell County, Wyoming, and was a "simple 2-spot fracturing experiment." It tested the concept they had developed in 1972 and consisted of two – 750 lb. explosive charges fired simultaneously at the bottom of the Felix 2 coal seam. This seam is approximately 20 feet thick and 160 feet deep. Results from this test showed that communication between the wells was insufficient for gasification. During the 11 days of gasification, 129 tons of coal was gasified producing product gas with an average heating value of 102 BTU/scf. The experiment was deemed unsuccessful (Stephens et al. 1976).

Hoe Creek II (1977). In September 1977, LLL started Hoe Creek II 58 day gasification process to test reverse combustion linking. Good quality gas with an average heating value, 108 BTU/scf, was produced during the first part of the test. However, an override situation developed which caused combustion to occur across the top of the coal seam. The gasification zone of the test moved rapidly from the Felix 2 coal seam into the overlying Felix 1 coal seam. Groundwater contamination resulted from the test because of sustained gas lost during gasification. This led to a sharp decline in the quality of gas.

Switching from one injection well to a line of three wells improved the quality of gas in the last part of the test. A total of 2,480 tons of coal was gasified (Hill et al. 1978).

Hoe Creek III (1979). In 1979, LLL started Hoe Creek III. The objective was to evaluate directionally drilled links and to utilize oxygen injection. During the test the roof collapsed on the burn cavity and the gasification zone moved from the Felix 2 coal seam to the thinner Felix 1 coal seam. During the 47 day gasification process, before the roof collapsed, 3950 tons of coal were gasified producing an average heating value of 217 BTU/scf. The Hoe Creek experiments experienced groundwater contamination and surface subsidence. Groundwater contamination resulted from gas losses during gasification. Surface subsidence resulted from the shallow depths and relatively unconsolidated overburden material. The Hoe Creek tests were not considered successful for reasons that included improper site selection and over-pressurization of the UCG reactor which lead to contamination of fresh water aquifers (Stephens et al. 1976).

3.1.2.4 Easterwood Texas UCG (1977)

During 1977, all field work of the Texas A&M University UCG test was conducted on University property at the Easterwood test site. This one day trial was conducted to determine the feasibility of UCG using Texas lignite coal. That day, two tons of coal were consumed producing a range of heating values from 35 to 114 BTU/scf. Results from the test showed that the lignite could be ignited, however immediate problems occurred that included sand control, excessive water production, and by-passing of the injected air or produced gas (Strickland and Jennings 1978).

3.1.2.5 Rocky Hill (1978)

The Rocky Hill test was conducted in 1978 in the PRB in Campbell County, Wyoming for the Thunder Basin Coal Company. The 60 day test was conducted in the thick Wyodak coal seam and was considered successful because of the high heating value (200 BTU/scf) of the product gas and limited groundwater contamination. In all 3,600 tons of coal were gasified. There was also little to no subsidence during and after the testing (Hunkin et al. 1984).

3.1.2.6 Tennessee Colony Test (1978 – 1979)

The Tennessee Colony Test was conducted from 1978 through 1979. The purpose of this test was to determine the feasibility of gasifying Texas lignite. The Tennessee Colony test consisted of two trials, comparing air and oxygen/steam injection. The first trial, utilizing air injection, spanned 197 days of gasification producing a gas with an average heating value of 81 BTU/scf. The second phase of the test, the oxygen/steam phase, gasified 212 tons of coal over the course of 10 days. The average heating value of this phase two gas is 230 BTU/scf. The conclusions of the two phase trial are that low quality gas can be produced in the wet lignite seam, and that a higher quality gas could be produced if a larger gasifier and seam isolation were incorporated into the design (Haney 1979).

3.1.2.7 Pricetown 1 (1979)

The 12 day Pricetown I UCG test was conducted in 1979 by Morgantown Energy Technology Center. This test consumed 350 tons of coal producing gas with an average heating value of 127 BTU/scf; however, it was considered unsuccessful. The test was executed in a swelling bituminous coal in West Virginia. The modeling and the results from Pricetown I show that it is imperative to utilize steam/oxygen injection to provide adequate temperatures to sustain combustion, disseminate tars and to alleviate potential plugging problems, and to provide an optimum product gas for commercialization (Gibbs and Eddy 1983).

3.1.2.8 The Rawlins Tests (1979-1981)

Rawlins Test No. 1 (1979). The Rawlins Test No. 1 was conducted in 1979 in Carbon County near Rawlins, Wyoming. This trial was a collaborative effort between the Gulf Research and Development Company and the U.S. Department of Energy. The purpose of this trial was twofold: to test the suitability of UCG in steeply dipping coal beds and explore the use of air injection versus oxygen. This first test, using air injection, was conducted on an accelerated schedule, lasting only 30 days and consumed 1020 tons of coal with an average heating value of 150 BTU/scf. The second test, utilizing oxygen injection lasted only 5 days and consumed 200 tons of coal producing and average heating value of 250 BTU/scf. The coal seam utilized in the Rawlins Tests is approximately 390 feet deep and 20 feet thick. The results of Rawlins No. 1 were deemed successful.

Rawlins Test No. 2 (1981). The second Rawlins test was completed in 1981. The purpose of this trial was to investigate three modes of operation utilizing oxygen including slant, vertical and dual injection. Results of this trial showed that slant injection operation was clearly the most efficient of the three. In total, 8600 tons of coal were gasified during this 65 day trial producing gas with an average heating value of 350 BTU/scf (Ahner et al. 1982).

3.1.2.9 Tono Basin Tests (1982)

The first of the Tono Basin Tests, the Large Block Test, was conducted in the winter of 1981-1982 in Centralia, Washington, and was a small scale 20 day CRIP test. The basic idea of the CRIP concept is to start a new burn in fresh coal, upstream of the previous burn, whenever the quality of the product gas falls to an uneconomic level. To start a new burn, a section of the injection pipe is burned off to establish a new injection point. The first test proved successful, gasifying 140 tons of coal, and led to a second test, the 28 day Centralia Partial Seam CRIP Test. This trial was conducted shortly after the completion of the Large Block Test and gasified 2000 tons of coal with an average heating value of 255 BTU/scf. Trial results showed that the coal in that location was suitable for UCG; the slant production well worked well; pressure drops were manageable; gas losses were small; and water influx was reduced when using slant production (Hill et al. 1984).

3.1.2.10 Rocky Mountain 1 (1986 – 1988)

The Rocky Mountain 1 (RM1) UCG Trial was conducted from November 1987 to February 1988 in Carbon County, Wyoming. The RM1 test site was located adjacent to the Hanna test area. The test was also conducted in the same 30 foot subbituminous coal as the Hanna test series. This trial simultaneously tested two linking technologies, the Extended Linked Well (ELW) and CRIP. The test successfully produced high heating value gas over sustained operations. The ELW test lasted 57 days, consuming 4,443 tons of coal and producing an average heating value of 261 BTU/scf. The CRIP trial lasted a total of 93 days and gasified 11,227 tons of coal with average gas heating values of 287 BTU/scf. This test also showed that the Clean Cavern Concept dramatically lowered the environmental impact of UCG. The Clean Cavern Concept was developed to control the contamination of groundwater and define the operational constraints that minimize groundwater contamination. Having been verified, the constraints are minimization of gas loss, reduction of post-burn pyrolysis, and sustained flow of pyrolysis products into the UCG cavity. In practice the minimization of gas loss is implemented through different linking techniques, although not enough information was available to show a preference. During post burn venting, steam was injected and the wells are allowed to produce gas. Contaminates, which are typically ammonia, miscellaneous organics, sulfide, sulfate and small amounts of arsenic and boron, are dissolved in the steam and produced (Boysen et al. 1988). Environmental impacts were minimal and showed that UCG can be conducted without environmental problems (Covell et al. 1988). RM1 is considered the most successful UCG test in the U.S., both technically and environmentally.

TABLE 3-2. SUMMARY OF U.S. UCG TRIALS

UCG Trial Name	Year	Duration (days)	Quality (BTU/scf)	Dry Gas Production (10^6 scf/day)	Coal Gasified (tons)
Hanna I	1973/74	180	126	1.6	4000
Hanna II-I	1975	38	152	1.7	1260
Hanna II-II	1975	25	175	8.5	2520
Hanna II-III	1976	38	138	12.0	4200
Hanna III	1977	38	130	10.0	2850
Hanna IV	1977/79	24	133	8.3	1500
Hoe Creek I	1976	11	102	1.2	129
Hoe Creek II	1977	58	108	3.3	2480
Hoe Creek III	1979	47	217 (oxygen)	3.4	3950
Easterwood	1977	1	35-114	0.3	2
Rocky Hill	1978	60	200	4.7	3600
Tennessee Colony	1978/79	197	81	2.5	-
		10	230 (oxygen)	1.0	212
Pricetown I	1979	12	127	3.4	350
Rawlins I	1979	30	150	3.8	1020
		5	250 (oxygen)	3.4	200
Rawlins II	1981	65	350 (oxygen)	7-12	8600
Tono Basin	1982	20	-	-	140
	1983	28	255	-	2000
Rocky Mountain I (ELW)	1986/88	57	261	-	4443
(CRIP)		93	287	-	11227

3.1.2.11 Carbon County UCG (1995).

In 1995, Williams Energy conducted a UCG pilot project in Carbon County near Rawlins, WY. This test was located adjacent to the Rawlins UCG trials that were conducted by Gulf Research and Development Company in the late 1970s. The test was conducted in the same coal seam as the Rawlins tests; however it was performed at deeper levels. The purpose of the test was to corroborate earlier studies that demonstrated the feasibility of using UCG in steeply dipping coal beds. The test was unsuccessful and resulted in groundwater contamination due to poor well linkage and operation of the UCG reactor above hydrostatic pressures.

3.1.3 Other Global UCG Trials

UCG has been gaining popularity worldwide as a strategy for recovering resources considered uneconomical to recover through conventional mining. This acceptance of UCG is accelerating and commercialization is being approached at several sites. The following is a review of current global efforts to develop the technology.

3.1.3.1 French UCG Tests

The French began testing the UCG process in 1981, with the first test located at Bruay-en-Artois in northern France. The purpose of this test was to determine the feasibility of UCG in deep coal (over 3,281 feet deep). The results of this test showed that fracturing was necessary due to the pressure in the coal seam. The test had to be shut down because plugging occurred in the production wells.

In 1984, GEGS (Study Group on Underground Coal Gasification) conducted a pilot test in La Haute-Deule, France. The purpose of this test was to see how the coal reacted with several different mixtures of nitrogen, oxygen, and carbon dioxide and to examine its hydraulic linking properties. Gasification was never achieved. The test results showed that reverse combustion linking was favorable, the addition of propane improved coal combustion, and that self-ignition never occurred during the test (Gadelle et al. 1985).

3.1.3.2 Thulin, Belgium Trial (1982 – 1987)

In 1982, a joint Belgian-German team ran its first trial in Thulin, Belgium. The purpose of this test was to see if reverse combustion linking was possible. This first test failed due to self-ignition of the coal in the vicinity of the injection well and the high level of back pressure at the recovery well. Linking was not achieved and the test was terminated.

A second trial was conducted in 1983 at the same location and lasted only a few days. The test showed that the injection of liquid carbon dioxide did not prevent self-ignition, and the hot and aggressive environment they encountered required the use of high quality materials (Sonntag et al. 1984). A third test was conducted in 1984 that allowed 15 tons of coal to be gasified. Even though this was achieved, there was no evidence that the wells were able to communicate due to the lack of permeability. In 1985 they drilled the deepest hole yet (2,854 feet) of their experiments, but were unsuccessful in their effort to gasify it. In 1986 another trial was conducted, but was terminated due to a quick decrease in permeability. The joint Belgian-German testing at Thulin was concluded in March 1988 (Chandell et al. 1988).

3.1.3.3 European Trials (1992 – 1999)

In 1989, the European Working Group on UCG recommended that a series of trials be undertaken to evaluate the commercial feasibility of UCG in the thinner, deeper and more disturbed coal seams typical of Europe. They recommended conducting the first trial at an intermediate depth of around 1,640 feet. If successful gasification occurred, later trials would follow to test UCG operations at a depth of about 3,280 feet, and would evaluate power generation from the resultant production gas. The first of these proposed trials became the Spanish Trial which was conducted from 1992 to 1999 (Green 2004).

Spanish UCG Trial (1992 – 1999). The first Spanish trial began in 1992 and was completed in mid-1999. It was undertaken by Spain, the UK, and Belgium with the support of the European Commission, and took place at a site called “El Tremedal” in the Teruel Province of northeastern Spain. As previously mentioned, the purpose of this test was to determine the feasibility of gasifying coal at depths greater than 1,640 feet. The site was chosen based on its geological suitability, coal seam depth (1,800 feet), and the availability of extensive borehole data. The test was successfully completed, although the number of operating hours was low. It demonstrated the feasibly of gasification at depth, the viability of directional drilling for well construction and intersection, and the benefits of a controllable injection and ignition point (Green 2004).

3.1.3.4 UK UCG Program (1999-present)

Largely as a result of the Spanish Trial's outcomes, the Department of Trade and Industry Technology (DTI) identified UCG as one of the potential future technologies for the development of the UK's large coal reserves. Technology targets include improved accuracy of in-seam drilling, assessment of UCG gas utilization in a gas turbine, estimates of landward coal reserves that could be technically suited to UCG, identification of a site for a semi-commercial trial of UCG, identification of the parameters that UCG would have to meet to compete with current North Sea gas production costs, and a pre-feasibility study for the exploitation of UCG offshore in the southern portion of the North Sea by 1999. An initial pre-feasibility study was completed in January 2000 by the DTI in conjunction with the Coal Authority, and work then began on the selection of a UK site for a drilling and in-seam gasification trial. This work has been completed and compiled into a report that emphasized the growing importance of environmental issues. It is available on the DTI website (http://www.dti.gov.uk). Paper feasibility studies have also been initiated to continue the examination of technological advances (Green 2004).

3.1.3.5 Australian UCG Tests

A UCG trial conducted by a private company, Linc Energy Limited (Australia), was initiated in 1999 and was conducted near the town of Chinchilla in Queensland, Australia. The goal of the test was to determine the feasibility of long-term power production and the creation of liquid fuels using UCG technology. Up until the end of the controlled shutdown program, which was concluded in April 2003, the demonstration involved the gasification of 35,000 tons of coal and resulted in successful environmental performance according to independent audit reports. Results from an evaluation of the product gas composition showed that gas turbine units such as the GE Frame 6B can operate satisfactorily on air blown UCG gas. The facility is currently being maintained in preparation for a gas turbine and gas-cleanup plant, and Linc Energy, Ltd. recently announced plans for a large coal-to-liquids plant at the site in collaboration with Syntroleum Corporation (Burton et al. 2005).

3.1.3.6 Chinese UCG Tests

China has the largest UCG program currently underway. Since the late 1980s, sixteen UCG trials have been carried out or are currently operating. Chinese trials utilize abandoned galleries of disused coal mines for the gasification. Vertical boreholes are drilled into the gallery to act as the injection and production wells. A system of alternating air and steam injection is used to improve the production of hydrogen. The UCG Center at the China University of Mining and Technology in Beijing is testing UCG in abandoned coal mines. A project in Shanxi Province that was planned to commence in 2004 will use UCG gas for the production of ammonia and hydrogen production. Small-scale power production schemes using converted coal boilers or gas turbines are also under consideration. A technology transfer study between the UK and China on UCG is currently underway. A technical center for UCG has been set up at the University of Beijing, and a technical exchange of information on UCG is taking place with the UK (Green 2004).

3.1.3.7 Eskom Test, South Africa

Eskom, a very large coal-fired utility in South Africa, has been investigating UCG at its Majuba 4,100 MW power plant since 2001. Feasibility studies have culminated in a UCG pilot which was ignited January 20, 2007, and has successfully passed its first 1,000 hours of gasification, producing 6 million scf/d of syngas. Based on that success, the utility is considering a fast-track commercialization project to install six 350 MW IGCC turbine plants over the next four years, to be powered by syngas. If pursued, the gas requirement will be almost 600 MM scf/d. This would be about two to three times the largest UCG installation operated in the former Soviet Union. This would also mark true, free-world commercialization of UCG.

3.1.3.8 Other Current Global UCG Efforts

Feasibility studies have been undertaken recently by New Zealand, and a small trial burn was initiated at Huntley in 1994 with U.S. technical advice. In Japan, the University of Tokyo and other private interests have been conducting technical and economic studies of UCG on a small scale during the past decade and are considering conducting a trial in the near future at a currently undisclosed location. India, Pakistan and some Eastern European countries, like Ukraine and Romania maintain an interest in UCG and are also considering UCG trials. Russia maintains technical expertise in UCG at the Russian Academy of Sciences in Moscow (Green 2004).

3.2 COMPARISON OF UNDERGROUND COAL GASIFICATION WITH SURFACE COAL GASIFICATION

UCG and surface coal gasification (SCG) can each be used to produce similar syngas that have identical downstream uses. However, there are several characteristics of each that differentiate these technologies. The following discussion identifies the differences between these two processes and the advantages and disadvantages of each gasification technique.

3.2.1 Advantages of Surface Coal Gasification

One of the advantages of surface coal gasification is the flexibility it offers for building the required surface gasification reactor anywhere without regard to geographic and distribution restrictions such as those that constrain UCG (Wieber 1979). This is offset by the requirement to transport the feed coal to the SCG if it is not located at or near the coal source. Another advantage is that SCG is conducted in a chemical reactor, which allows better process control. In SCG, the coal size, feed rate, moisture and water content, chemical additives, and reactor pressure are some of the process variables which can be modified and controlled. In addition, SCG is an environmentally favorable process compared to conventional coal fired boilers, producing less hazardous emissions which can be removed from the process stream. The product syngas can be used for a wide variety of products, including power generation, synthetic natural gas, chemical feedstock and conversion to liquid fuels. SCG allows for CO_2 removal with acceptable cost and energy penalty. Minimal gas losses occur with surface coal gasification (Sawhney 2006).

3.2.2 Disadvantages of Surface Coal Gasification

SCG requires the coal be mined by conventional methods and transported to the gasifier site. Mining and transporting coal is an expensive and labor intensive process that has inherent health, safety and environmental issues. Coal mining also causes large surface disturbances (Wieber 1979). SCG must dispose of the residual products of gasification such as the ash and slag (Friedmann 2006). High capital costs are associated with the gasification reactor and required equipment, and process water requirements are significant.

3.2.3 Advantages of Underground Coal Gasification

There are both economic and environmental benefits associated with UCG. Gasifying the coal in situ allows the energy extraction from large coal resources that are not economically or technically recoverable by conventional mining techniques. The hazards related to conventional mining are also reduced. Surface disruption is minimized as less surface space is required for a UCG facility, and surface handling of solid materials are eliminated i.e. coal and ash handling at the surface is not required. UCG consumes less water and generates less atmospheric pollution compared to SCG. Good thermal efficiencies can be expected as a result of the well-insulated gasification cavity. Capital investment costs and syngas production costs are reduced by at least 25 percent compared to SCG (Draffin 1979).

A comparison of these SCG and UCG technologies shows the economical advantages that UCG has over SCG. UCG has reduced plant investment costs, much lower coal costs, lower solid waste disposal costs than SCG. This is because solid wastes are mostly left in the cavity, the coal seam provides the gasification reactor, and mining and handling of the coal is not required. UCG investment costs are 25-50 percent lower than SCG, and operating costs are reduced by 20 to 30 percent, making the end product far more competitive (Wieber 1979). UCG uses much less labor than coal mining and surface gasification, greatly reducing operating costs (Boysen et al. 1997). Due to the modular nature of UCG, plants can be sized closer to near-term market projections, lowering initial investment and increasing investment return rates. UCG plants have the potential for gradual expansion to match market demands (Wieber 1979).

One of the most important comparisons to be made is the coal resource available to UCG and SCG. Large coal resources exist that cannot be mined, however, most of those deposits can be gasified in place. The UCG technology could potentially quadruple the U.S. useable coal reserves (Zukor and Burwell 1979).

3.2.4 Potential Disadvantages of Underground Coal Gasification

UCG has several potential disadvantages that must be addressed. Previous tests have demonstrated that the natural permeability of the coal seam to transmit the gases to and from the combustion zone can be unreliable. Linking methods such as reverse combustion, hydro-fracing and directional drilling can be used to establish the flow path. For gasification over long distances in the coal seam, a properly constructed in-seam channel is required before the coal seam is ignited and the gasification is initiated. Ground subsidence and leakage of gas from the cavity into adjacent strata such as nearby aquifers or groundwater are environmental concerns associated with UCG. Subsidence must be controlled by leaving adequate pillars in the coal seam to support the overburden stresses. This is accomplished by distributing the multiple geo-reactors properly. Groundwater must be protected by operating the geo-reactor at pressures below hydrostatic pressure. This ensures an in-flow of groundwater into the geo-reactor and prevents the forcing of gases out of the geo-reactor into the coal overburden. The process control variables, which include injection pressure, injection flow rate, oxygen and steam concentration, and well configuration, must be adjusted according to real-time surface measurements. Processing the syngas to downstream products at the site of the coal deposit may increase the costs of transporting the gas products, and the low heating value of the syngas makes it uneconomical to transport long distances (Draffin 1979).

4.0 GEOLOGY OF THE POWDER RIVER BASIN

4.1 INTRODUCTION

Major sub-bituminous coal resources occur in the Fort Union Formation (Paleocene) in the PRB in Wyoming. Much of the geologic information presented in this report is summarized from USGS publications, notably USGS Professional Paper 1625A (USGS 1999).

Fort Union strata make up the surface bedrock along the margins of the PRB. These strata are conformably underlain by the Lance Formation (Upper Cretaceous) and conformably overlain (in the basin center) by the Wasatch Formation (Eocene). The coaly nature of the Fort Union strata was first documented in mid-1850s by Kemble (Bryans 1987).

In 1861, Hayden first named the lignite beds between the Platte River and Pumpkin Buttes as the Great Group, which was renamed the Fort Union Group (Hayden 1861). The upper part of this group was named ”tertiary,” based on plant fossils.

4.2 GEOLOGICAL SETTING

The PRB in Wyoming is a structural and sedimentary basin located in the northeastern part of the state. It contains more than 8,000 feet of Upper Cretaceous and Tertiary rocks along the axis in the western part of the basin. The basin is asymmetrical with rocks dipping an average of 20-25 degrees along the western part of the Basin and 2 to 3 degrees in the eastern part of the Basin.

Paleocene Laramide positive structures representing basement-block uplifts include the Bighorn uplift on the west, the Casper arch-Laramie Range-Hartville uplift on the south. These uplifts provided the Fort Union sediments, which comprised mainly reworked Cretaceous fine- and coarse-grained rocks.

The Fort Union Formation is more than 5,200 feet thick along the basin axis in the western part of the Basin. The Fort Union Formation is divided, in ascending stratigraphic order, into the Tullock, Lebo, and Tongue River Members. The Tullock Member is up to 740 feet thick, the Lebo Member is up to 2,600 feet thick, and the Tongue River Member is as much as 1,860 feet thick. Subdivision of Fort Union Formation is based on the color, dominant lithology, and thickness variation of the rock units. The coal beds of the Tullock Member are thin to thick compared to the coal beds of the Tongue River Member, which are mainly thick; the Lebo Member includes very thin and sparse coal beds and carbonaceous mudstone. For UCG targets, the very thick coal beds of the Tongue River Member have been targeted, especially the Wyodak-Anderson coal beds which have supported prolific coal production on the eastern side of the basin.

4.3 DEPOSITIONAL SETTING

The deposition of the Fort Union sediments and the origin of the very thick coal seams, (beds more than 200 feet thick) has been controversial. The traditional interpretation of the origin of coal in the fluvial system, is deposition in swamps formed on floodplains and abandoned river belts.

These very thick organic deposits of these fluvial swamps were interpreted by Flores (1986) as raised bogs formed in a wet, tropical-subtropical climate. To accumulate very thick peat or coal beds, the raised bogs must be influenced by either local subsidence or basin subsidence. Thickening of peat deposits, and the resulting thick coal beds, may be explained by stacking of peat deposits separated by organic or inorganic partings. A combination of proper paleo-climate and tectonic setting was required to develop these extremely thick and unusually laterally persistent coal beds of the Fort Union Formation.

4.4 Coal Geology

The coal geology and stratigraphy of the Fort Union Formation differ in the vertical and lateral patterns of coal beds and associated clastic rocks. The vertical stratigraphic pattern in the Tullock Member consists of abundant thick sandstone interbedded with siltstone and mudstone and less abundant, thin (a few inches to several feet) coal and carbonaceous beds. The Lebo Member consists of abundant mudstone, subordinate siltstone and sandstone, and sparse coal and carbonaceous mudstone. The Tongue River Member contains abundant sandstone, siltstone, mudstone, and sparse limestone and carbonaceous shale. Coal beds are abundant and range from thin (a few inches) to very thick (more than 200 feet).

There has been an evolution in the interpretation of the coal stratigraphy of the Tongue River Member from coal existing as tabular, laterally continuous beds more than fifty miles in extent to the existence of more complex, laterally merging and splitting beds and zones.

Complex correlation is displayed by splitting and merging of the Wyodak-Anderson beds. The Wyodak-Anderson coal zone is distributed basin-wide in Wyoming and Montana. Split coal beds merge to form a single bed, later splitting, overlapping, and shingling. This accounts for the variable distribution of coal deposits, from local to widespread, in the Tongue River Member of the Fort Union Formation. This complex splitting, which occurs over miles, requires that evaluation for UCG be made on a site-specific basis, not on a regional basis.

4.5 Coal Resources

Early estimates of the coal resources in the PRB were based mainly on outcrop data from shallow coal beds in the Tongue River Member. The majority of the studies were evaluating shallow (less than 100 feet of overburden) coal seams that were recoverable by strip mining. More recent studies have been more global, estimating the total resource in the PRB. Glass (1976) estimated the coal resources in four formations in the Cretaceous, Paleocene, and Eocene rocks in the Powder River Basin in Wyoming to be 600-700 billion short tons. Trent (1986) estimated resources of greater than five foot thick coal beds down to depths of 3,000 feet to be 775 billion short tons for non-leased Federally-owned coal in 243 quadrangles in the PRB.

In the central part of the Powder River Basin in Wyoming, the Wyodak-Anderson coal zone coalesces from five coal beds of the Anderson and Canyon coal into a bed as much as 202 feet thick known as "Big George" coal. This coal is a single bed varying from 46 to 202 feet thick within a 950 square mile area at depths of greater than 1,100 feet below the surface (Pierce et al. 1982). Basin-wide, the resource of the Wyodak-Anderson coal zone is estimated to be as much as 510 billion short tons (USGS 1999). These are the target coals for UCG which have been evaluated in this study (USGS 1999).

Table 4.1 summarizes the thickness distribution of coal seams in the PRB of Wyoming. This analysis is based upon the coal database that was developed for this study; see Section 5.2. This analysis has eliminated all coal beds that are at depths shallower than 500 feet, as they are considered to be at depths available for conventional strip mining. Those beds below 500 feet in depth average about 1,500 feet deep, but range from 501 to 2,730 feet in depth.

In the PRB in Wyoming, outside of current mine strip mine lease areas, there is a total of 510 billion tons of coal in beds 2.5 feet thick or thicker. Of these 510 billion tons, 415 billion tons are at depths of 500 feet or deeper. Of these 415 billion tons, only coals that are 30 feet thick or thicker have been included in this study for UCG consideration.

TABLE 4-1. DEEP (>500 FEET) COAL RESOURCES IN THE WYODAK COAL SEAM, WYOMING

Thickness, feet	% of Tonnage	Cum % of Tonnage	Tonnage, million tons	Cum Tonnage million tons
0-29	26%	26%	108,000	108,000
30-39	11%	37%	46,000	154,000
40-49	9%	46%	37,000	191,000
50-59	7%	53%	29,000	220,000
60-69	7%	60%	29,000	249,000
70-79	7%	67%	29,000	278,000
80-89	7%	74%	29,000	307,000
90-100	9%	83%	37,000	345,000
>100	17%	100%	71,000	415,000

This represents 307,000 million (307 billion) tons of coal, or 74% percent of the coals deeper than 500 feet. Of coals thicker than 30 feet thick, the average (tonnage weighted) thickness is 70 feet. This certainly demonstrates that the vast majority of the thick, deep coals in the PRB meet UCG thickness criteria. In addition, these coals are mostly concentrated in Johnson and Campbell Counties. Attachment 4-1 shows the distribution of the thick deep coals. Attachment 4-2 shows that the majority of these thick coals are at depths greater than 500 feet, with the majority at depths below 1,000 feet. These huge resources of thick deep coal are geologically very well-suited for UCG development. Attachment 4-3 provides a geologic overview of the basin.

Regionally, the different coal zones merge, split, and pinch out laterally in complex patterns, and can be traced intermittently over distances of several tens of miles. Along the eastern margin and within the south central portion of the PRB, predominantly one coal bed occurs in the Wyodak-Anderson. Within the north-central and western portions of the basin, there are typically three or more coal beds. Within the remaining portions of the basin, there are predominantly two coal beds.

Most coal seams throughout the PRB are interbedded with shale, sandstone, mudstone and siltstone. Large partings, merges, and splits were observed in the USGS PRB Cross- Section Maps described in Section 5.0. The partings likely are either claystone, siltstone, or sandstone. Smaller partings and lenses exist within the coal seams. However, they are often not recorded in well or drilling logs.

A number of fluvial channels exist in and around the coal zones throughout the PRB. A large channel zone was identified in the southwest area of the Gillette Coal Field. This coal field encompasses a large segment of the eastern PRB. This channel area affects the coal in townships T. 40N to T. 44N and ranges R. 71W to R. 74W. The coal seams are thin or absent in these areas.

4.6 COAL QUALITY

Actively mined coal from the Wyodak-Anderson coal zone in the PRB in Wyoming is considered to be "clean coal." This coal zone contains a low- sulfur, sub-bituminous coal resource that has the following arithmetic mean values (on an as-received basis) for coal that is not presently being mined or under lease to be mined in the future: moisture-27.66 percent, ash-6.44 percent, total sulfur-0.48 percent, calorific value-8,220 BTU/lb, and moist, mineral-matter-free BTU-8,820. The relatively constant calorific value of the PRB coals and the low ash content are both very attractive for UCG. The sub-bituminous coals are more reactive than higher rank coals, and they have better ignitability characteristics.

The Wyodak-Anderson coal contains lower concentrations of trace elements of environmental concern (formerly known as hazardous air pollutants) than other Fort Union coal. Arithmetic mean concentration (in parts per million and on whole-coal and remnant-moisture basis), based on about 160 coal samples from the Wyodak seam in the PRB, of elements of environmental concern for coal in the Wyodak-Anderson coal zone are: antimony-0.50, arsenic-2.6, beryllium-0.54, cadmium-0.21, chromium-6.1, cobalt-1.9, lead-3.0, manganese-26, mercury—0.13, nickel-4.6, selenium–1.1, and uranium-1.3. Higher concentrations are found in high ash content beds, indicating that the trace elements are concentrated in the ash. For UCG, where the ash stays in the geo-reactor, this will keep the produced syngas even lower in these elements of environmental concern.

USGS (1994) found that high concentrations of these trace elements are directly related to high ash contents of the coal. Groundwater is also known to elevate concentrations of trace elements, particularly sodium (Hildebrand 1988). Flores et al. (1994) suggested that debris derived from uplifts adjoining the PRB also contributed to the kind and concentrations of the trace elements.

4.7 COALBED METHANE RESOURCE

The presence of methane in Fort Union coal was reported by USGS investigators over 50 years ago (Olive 1957; Lowry and Cummings 1966; Whitcomb et al. 1966; Hobbs 1978; Boreck and Weaver 1984). A number of flowing artesian wells at shallow depths (245 to 415 feet) contained substantial amounts of methane as reported by Olive (1957), Lowry and Cummings (1966), and Whitcomb et al. (1966). Hobbs (1978) identified methane in fifteen shallow drill holes in the Recluse area of northeastern Campbell County and south of Gillette, Wyoming. Drill holes for coal-bed methane were drilled to depths of no more than 500 feet and penetrated the Wyodak-Anderson zone in the Recluse area, which includes the Anderson and Canyon coal beds

Methane has been encountered in the coal beds as well as in overlying sandstone and interbedded sandstone and shale beds. Gas flow rates varying from a trace in shale interbeds to more than 1,000,000 scfd in thick coals have been recorded. Hobbs (1978) suggested that there could be potential methane production from the Anderson and Canyon coal beds and from the fluvial channel sandstone between the coal beds and possibly below the Canyon coal. Coa lbed methane exploration and development in the PRB has rapidly accelerated in the past several years. Thousands of wells have been drilled and recent operator forecasts projected more than 30,000 additional wells to be drilled over the next several years. Development of shallow (less than 1,000 feet deep) Fort Union coal-bed methane is confined to Campbell and Sheridan Counties, Wyoming, and Big Horn County, Montana. The major lease area in Wyoming is in T. 39W, R. 71W to T. 58N, R. 75W. Here the targeted coal beds are mainly the Anderson and Canyon of the Wyodak-Anderson coal zone.

Perhaps the most promising CBM play for the deep (greater than 1,000 feet) Wyodak-Anderson (or Big George and Sussex) coal bed and zone in the southwestern part of the basin in Wyoming is in T. 41N, R. 76W to T. 54N, R. 79W. The Wyodak-Anderson coal bed in this area is as much as 202 feet thick and the Wyodak-Anderson coal zone is as much as 550 feet thick. It contains as many as eleven coal beds that average 25 feet thick (Boreck and Weaver 1984; Hardie and Van Gosen 1986). The isopach map of the Wyodak-Anderson coal zone in this area exhibits a series of coal bodies that have from 150 to more than 200 feet of net coal thickness. These coal bodies are surrounded by an elongate (more than 1,000 square-mile area) coal body that has from 100 to 150 feet of net coal thickness. The coal beds and zone generally range from 1,000 to 2,000 feet deep. The stratigraphic variation in this play shows that the northern part of the area includes merged beds of the Big George coal reaching as much as 202 feet thick. They split southward and merge with the Sussex coal, which is as much as 138 feet thick. Where the coal beds are split, they are interbedded, overlain, and underlain by fluvial channel sandstone**.** Where the coal beds are merged they are overlain and underlain by similar rock types. The clastic rocks, particularly the sandstone, potentially contain recoverable methane that has migrated from the coal.

Boreck and Weaver (1984) reported methane from a USGS test drill hole in the Wyodak-Anderson (or Big George coal bed) in the central part of the basin in Johnson County, Wyoming. Desorption data from seven coal core samples from this test hole ranged from 56 to 74 standard cubic ft/ton (scf/t). Methane recovered from these coal core samples indicated biogenic origin. Core analysis (three samples) of the Wyodak-Anderson or Big George coal bed at the Betop Incorporated Dead Horse Creek 8-32 well in Campbell County, Wyoming, indicated a gas content from 26 to 44 scf/t and an average of 39 scf/t .

Utilizing the minimum (26 scf/t) and maximum (74 scf/t) desorption data from the USGS drill hole and the Betop well and the coal resource estimate (550 billion short tons) by Ellis and others (1999) provide an estimate of the CBM resource for the Wyodak-Anderson coal bed and zone basin-wide. Other coal beds and zones above and below the Anderson-Wyodak coal bed and zone in the Fort Union Formation (Wall, 25 feet thick; Pawnee, 60 feet thick; Knobloch, 70 feet thick; Rosebud, 20 feet thick; Broadus, 30 feet thick) and in the Wasatch Formation (Felix, 40 feet thick, and Lake de Smet coal, 250 feet thick) are possible targets for coal bed methane. Using an average gas content of 50 scf/t and a resource of 550 billion tons coal, the in-place CBM resource is estimated to be 27.5 TCF methane. (www.wogcc.state.wy.us/coalbedchart.cfm April 2007).

4.8 CONCLUSIONS

Fort Union coal, which represents a significant energy resource in the PRB in Wyoming and Montana, has been mined and developed since 1886. The most important current use of this coal resource is energy fuel for mine-mouth power plants and many other electric power generating plants outside the basin. Currently, open-pit mines develop the Wyodak-Anderson and equivalent coal beds and the Rosebud coal beds and zones. Production from these mines supports 144 electric power plants in 26 states of the contiguous United States and three foreign countries. The electric power plants are located in the western, mid-western, southern, and southeastern parts of the United States. Coal production in 2006 from surface mines in the PRB attained more than 440 million short tons.

The true potential of the PRB coals is development for UCG. This will allow the development of the deep coals, greater than 500 feet deep. There is a total resource of 307 billion tons of deep coal suitable for UCG in the PRB.

5.0 DEVELOPMENT OF THE GEOLOGIC UCG SUITABILITY DECISION TOOLS

Data on the geology of the PRB was acquired from a variety of sources including the Wyoming Oil and Gas Conservation Commission (WOGCC) and the USGS. This information was compiled into an ACCESS database that served as the foundation for many decisions regarding the optimum site location for potential UCG projects in the PRB. That database is referred to as the PRB UCG Database. The sources of the data as well as what was acquired from them are described below.

5.1 UCG SUITABILITY RANKING SCALE

A UCG Suitability Ranking Scale was developed using data from past UCG trials to provide conformity during the PRB coal suitability evaluation process. Coal seam depth, seam thickness, overburden characteristics, and partings were critical in initial screenings to determine the suitability of PRB coals for UCG. Additional criteria were evaluated such as proximity of the potential UCG site to oil and gas activity, and to roads and pipelines. The UCG Suitability Ranking Scale was used extensively during the development of the PRB UCG Database. The site features evaluation criteria are provided in Table 5-1. The following ranking scale is used in each of the following tables: 0 = Unacceptable, 1 = Acceptable, 2 = Good, 3 = Superior.

TABLE 5-1. UCG RANKING SCALE FOR PRB SITE FEATURES

UCG RANKING SCALE FOR PRB SITE FEATURES		
Criteria	**Rank**	**Remarks**
Topography		
Flat	3	
Rolling	2	
Incised	1	
Current Land Use		
Developed	0	Avoid
Agricultural	1	
Grazing	2	
Alluvial Valley Floor		
Present	0	Cannot Permit
Absent	2	

Table 5-2 contains the geologic ranking criteria.

TABLE 5-2. UCG RANKING SCALE FOR PRB GEOLOGY

UCG RANKING SCALE FOR PRB GEOLOGY		
Criteria	**Rank**	**Remarks**
Depth, Ft.		
<500	0	Subject to Strip Mining
500 - 1000	2	
1000 – 1500	3	Less Groundwater Impact
>1500	2	Higher Well Costs
Thickness, Ft.		
<30	0	
30 – 100	3	Better thermal properties; lower well costs
>100	2	Potential difficulty gasifying entire seam
Quality		
<8000	1	Lignite
>8000	2	Most sub-bituminous
Uniform Seam		
Variable	1	
Uniform	2	
Shallow Overburden Coals		
Present	0	If Present May Be Strippable
Absent	2	
Aquitard Thickness, Ft.		
<20	0	
20 – 50	1	
>50	2	Thicker Is Better
Faulting		
Common	0	Potential for Leakage
Absent	2	
Partings		
No Partings	1	
Thick Seam, Thin Partings	1	
Thin Seam, Thin Parting & Underlying Coal Seam	3	Ideal for UCG

Table 5-3 contains the criteria used to rank the infrastructure availability in the basin.

TABLE 5-3. UCG RANKING SCALE FOR PRB INFRASTRUCTURE

UCG RANKING SCALE FOR PRB INFRASTRUCTURE		
Criteria	**Rank**	**Remarks**
Roads		
None	1	
Paved	2	
Power Lines		
>10 Miles	0	
5-10 Miles	1	
2-5 Miles	2	
<2 Miles	3	
Pipelines		
>10 Miles	0	
5-10 Miles	1	
2-5 Miles	2	
<2 Miles	3	

5.2 PRB UCG DATABASE

An ACCESS database was developed for the purpose of containing all the coal data acquired during the evaluation of the PRB coals for possible UCG development. Data from the following sources were included. The database was used extensively as a decision tool for this viability study and was further used for the development of custom Geographic Information Systems (GIS) maps following its conversion to a geodatabase.

5.2.1 Cross Sections/USGS Map Data

Four USGS maps/data sets were utilized to collect information about coal strata found in the PRB. The USGS maps were drilling logs collected from various oil and gas developers who operated oil and gas wells in the northern, central, southwestern and southeastern portions of the basin. These data sets are summarized below.

Map I-1959A (1990). This presentation included a discussion of the stratigraphic framework of the Fort Union Formation coal bearing strata in the northern and central portion of the PRB. Sixty-five cross sections were evaluated with only seven meeting the UCG project criteria of location on the Wyoming side of the PRB, depth of the coal seam greater than 500 feet, and coal seam thickness greater than 30 feet. Sand depth and thickness data were also collected from logs that met the coal seam depth and thickness criteria.

Map I-1959-B (1990). This presentation included a discussion of the stratigraphic framework of the Fort Union Formation coal bearing strata in the southeastern portion of the PRB. Thirty-two logs were evaluated with twenty-three meeting the UCG project criteria of location in the Wyoming side of the PRB, depth greater than 500 feet, and coal seam thickness greater than 30 feet. Sand depth and thickness data were also collected with those logs that met the coal seam criteria.

Map 1-1959-C (1991). This presentation included a discussion of the stratigraphic framework of the Fort Union Formation coal bearing strata in the southwestern portion of the PRB. Twenty-five logs were evaluated with nineteen meeting the UCG project criteria of location in the Wyoming side of the PRB, coal seam depth greater than 500 feet, and coal seam thickness greater than thirty feet. Sand depth and thickness data were also collected for logs that met the coal seam criteria described above.

Map I-1959-D (1992). This presentation included a discussion of the stratigraphic framework of the Fort Union Formation coal bearing strata in the central portion of the PRB. Forty-four drilling logs were evaluated with twenty-eight meeting the UCG project criteria of location in the Wyoming side of the PRB, coal seam depth greater than 500 feet, and coal seam thickness greater than thirty feet. Sand depth and thickness data was also collected from cross sections that met the coal seam depth and thickness criteria.

5.2.2 Drilling Logs

One hundred thirty three drilling logs were evaluated to acquire coals seam depth and thicknesses in locations across the PRB. One drilling log described the Hoe Creek UCG Remediation data for a well located in T. 47N, R. 72W, Sec.7. Its total depth was 930 feet and it provided a lithographic description for the overburden following the conclusion of the UCG test at that location.

The remaining 132 drilling logs were acquired from the WOGCC website. Coal seam depth and thickness were evaluated basin-wide along with available information concerning depth and thickness of sand zones in the overburden.

5.2.3 USGS Wyodak Coal Database

The USGS developed the Wyoming Coal Occurrences database that contained drilling log data for wells across the State of Wyoming (USGS OFR 99-376 1999). All log data for wells outside of Campbell, Johnson, Sheridan and Converse Counties were removed, which left approximately 62,141 records for wells drilled in the PRB. A second screening eliminated many drilling logs within these counties that did not indicate the presence of coal seams with thickness greater than 30 feet and/or depth greater than 500 feet. From this analysis, locations that were more suitable for UCG development became apparent and led to the definition of boundaries within which UCG could be most viable.

At this point, data from the drilling log analyses were added to the database. This addition increased the general knowledge about the coal seams and overburden in the PRB, which added to the usefulness of the database as a decision tool. Table 5-4 shows the townships and ranges that were ultimately included for further consideration as potential UCG pilot test sites. This area is graphically shown on the map in Attachment 5-1.

TABLE 5-4. LOCATIONS OF COAL BEDS IN THE PRB WITH POTENTIAL FOR UCG DEVELOPMENT

Township	Range
42N – 48N	72W
42N – 50N	73W
41N – 53N	74W
41N – 53N	75W
41N – 53N	76W
42N – 53N	77W
46N – 52N	78W
47N – 52N	79W
51N	80W

Based on coal seam depth and thickness, infrastructure, and topography, the eastern PRB south of Township 51 provide excellent conditions for initial UCG development. The area has an abundance of thick, deep coal seams with sufficient overburden for UCG. The infrastructure is well developed because of coal bed methane development in the area. The topography is relatively flat with rolling terrain and occasional scoria hills. Table 5-5 lists the township and ranges considered the best areas for initial UCG development. The area represented in Table 5-5 is approximately 1,500 square miles with over 50 million tons per square mile of UCG resource.

TABLE 5-5. RECOMMENDED AREAS FOR INITIAL UCG DEVELOPMENT

Township	Range
42N – 50N	73W
41N – 50N	74W
41N – 50N	75W
41N – 53N	76W

In the next screening, well log records in the USGS database were selectively excluded based on criteria such as general basin geology, topographical features, and other exclusionary findings such as locations where faulting has been mapped.

5.2.4 USGS Topographical Map Analysis

Having limited the most prospective areas in the PRB for UCG with the above-described criteria to these townships and ranges, USGS 7 ½ minute topographic maps were reviewed on a Section-by-Section basis for obvious geographic features that would interfere with UCG development. Sections that had elevation changes greater than 500 feet, or had significant surface water in them, or were labeled as cultural or historical sites were excluded from further consideration. These exclusion criteria were added to the PRB UCG Database.

5.2.5 UCG Suitability Maps

Upon completion of the PRB UCG Database, it was converted into a geodatabase that would be suitable for the development of ArcView maps. In addition, publicly available map layers from the WOGCC, the USGS, and ESRI (a software development corporation) were added to enhance some of the views. These maps are included as attachments to this report.

6.0 HYDROLOGY OF THE POWDER RIVER BASIN

In developing a UCG project, the water contained in the coal will be consumed, as well as water which will flow into the geo-reactor (see Section 2.2.1.). The amount of this influx will be determined by the permeability of the surrounding rocks and the hydrostatic head on the coal. Excessive water consumption may lower the hydrostatic head in the area of UCG which could affect shallower water wells. Excessive water influx can potentially retard the UCG gasification process efficiency. Unlike CBM activities, UCG does not require pumping of significant volumes of groundwater and the attendant disposal issues.

In addition to water consumption and its effect on UCG, there is a potential for UCG activities to contaminate groundwater. Therefore, site-specific hydrologic conditions must be evaluated to assess this potential and select sites with minimal opportunities for groundwater contamination. Operational controls are also recommended to reduce the potential for groundwater contamination.

6.1 DATA SOURCES UTILIZED IN HYDROLOGIC EVALUATION

Assessing regional hydrogeologic data is a key step in determining UCG pilot plant site suitability. Based on a thorough evaluation, fault and fracture systems can be identified and avoided. Competing water use areas such as domestic wells must also be identified and avoided. Data to complete this assessment was acquired from a variety of sources that included review of USGS topographic maps, evaluation of the WOGCC oil and gas database for water production associated with particular coal seams, review of the Wyoming Office of the State Engineer's water well database, and review of the PRB UCG Database. Permits for surface coal mines served as an additional resource, as did water quality reports that were available through the WOGCC website. Drilling logs for CBM wells in the basin also provided useful data pertaining to aquifers above and below candidate coal seams.

6.2 WATER-BEARING FORMATIONS (AQUIFERS)

Within the Powder River structural basin, the rock formations containing the coal seams of interest (i.e. those meeting the criteria of at least 30 feet thick and a minimum depth of 500 feet) include the Paleocene Fort Union Formation and the Eocene Wasatch Formation. Coal seams are relatively laterally-continuous across the basin, on the order of tens of miles, but repeatedly split and converge laterally. Conversely, the sandstones, siltstones, shales, and claystones between the coals are laterally discontinuous, pinching out over relatively short distances on the order of tens to hundreds of feet. Their vertical thickness and lateral extent is highly variable.

Excluding the coal, the Wasatch and the Fort Union Formations are hydraulically isolated from each other to a varying degree, as indicated by hydraulic head differences across the clay layers above and below the coal (Davis 1976). Areas where fluvial, lacustrine, paludal and deltaic sediments exist next to the coal may function as aquifers. Occasional massive paleochannels of coarser sandstone occur in the sequence. These scattered sandstone lenses are isolated from one another by siltstone and shale layers, occurring between the coals and functioning as aquitards.

6.2.1 Fort Union Formation

The Fort Union Formation is divided, in ascending order, into the Tullock, Lebo, and Tongue River Members. This subdivision is based on dominant lithology, thickness variation, and color of the rock units (Flores 1999). The Fort Union Formation consists of coals, sandstones, siltstones, and claystones. Over most of the basin, the coals in the upper portion of the Fort Union are separated from sands in the overlying Wasatch Formation by continuous, low-permeability claystone and siltstone units of variable thickness. Sandstones may occur in direct contact with the coal, but occurrences are over limited areas because of the lenticular nature of the sandstone units in the upper Fort Union and lower Wasatch (AHA and GEC 2002).

AHA and GEC (2002) estimated that the Tullock Member of the Fort Union is an average thickness of 1,110 feet with an average of 430 feet of sand, or 39 percent sand. The Tullock Member consists of fine to medium-grained sandstone layers and thin coal seams interbedded with siltstone, shale and carbonaceous shale. The sandstone content of the Tullock ranges from 21 to 88 percent, making this an important aquifer with yields of 200 to 300 gpm for municipal and industrial use.

The Lebo Member confining unit is estimated at an average thickness of 1009 feet with an average of 250 feet sand, or 25 percent sand. Where the Lebo is easily identified, it provides a hydraulic separation between the Tullock Member and the coals in the upper part of the Fort Union.

The lower part of the Tongue River/Lebo Member consists of sandstone lenses within a shale and siltstone matrix. The Tongue River Member identified in the northern part of the basin contains many discontinuous, lenticular sandstone layers. AHA and GEC (2002) estimated that the average combined Wasatch Formation – Upper Fort Union (Tongue River Member) thickness is 2,035 feet, of which an average of 1,018 feet, or 50 percent, is sand. The Tongue River Member contains the coals which are to be evaluated for UCG. Over most of the PRB, these coals are separated from overlying sands by continuous, low-permeability claystone and siltstone units (AHA and GEC 2002). In most cases these claystone units are at least 30 feet thick but range up to 363 feet thick. These conditions are ideally suited for UCG development.

Groundwater in these coals tends to be confined due to the overall predominance of these low-permeability claystones. Confined aquifer conditions in these coals are well documented by the USGS and in mine permit packages.

Yields in Fort Union Formation wells are from the fine-grained sandstone, jointed coal, and clinker beds (burned coal exposed at land surface), ranging up to 150 gallons per minute (gpm) were reported by Hodson et al. (1973). Both the sandstone and coal aquifers produce adequate yield for municipal and industrial water supplies. The City of Gillette derives part of its water supply from the Fort Union Formation (AHA and GEC 2002).

6.2.2 Wasatch Formation

The Wasatch Formation overlies the Fort Union Formation and is exposed at the surface over most of the basin (see Attachment 4-3). The Wasatch is comprised of interbedded fine- to medium-grained sandstone, siltstone, claystone, and coal layers. The sandstones compose roughly one-third of the sequence, tend to be lenticular and laterally discontinuous, and are used locally for stock water supply. The finer claystone – siltstone layers are more laterally continuous and function as hydraulic confining units ranging in thickness from 11 to 363 feet; in most areas, the claystone confining unit is at least thirty feet thick (AHA and GEC 2002). The large variation in thickness is dependent on the presence of sands in the lower part of the Wasatch.

Wasatch Formation sandstone lenses or sand channels yield 10 to 50 gpm in the northern portion of the basin, whereas wells completed in the southern portion of the basin can yield as much as 500 gpm (AHA and GEC 2002). The laterally discontinuous, lenticular, fine- to medium-grained sandstones are of limited areal extent but can provide adequate quantities of water for stock use. Horizontal hydraulic conductivities reported from PRB pump tests of Wasatch Formation sandstone layers range from 2 to 20.2 feet per day (ft/d). The sandstone aquifer thicknesses pump tested ranged from 20 to 120 feet.

The Wasatch finer claystone – siltstone layers are more laterally continuous and function as hydraulic confining units. Interbedded low-permeability claystone layers act as aquitards to vertical movement throughout the thickness of the Wasatch Formation. The siltstones and claystones generally do not yield enough water even for intermittent livestock use. Tests of vertical hydraulic conductivity--typically one to two orders of magnitude less than the horizontal value--of PRB claystone units ranged from 2.4×10^{-5} to 3.1×10^{-2} ft/d and are summarized in Table 6-1.

In general, the hydrologic conditions of the PRB are sufficient for UCG development. Areas where thick aquitard units exist adjacent to the top of the coal seam are ideally suited for UCG. Large areas exist across the PRB that possess these hydrologic conditions. The presence of an aquitard formation above the coal seam protects the UCG process from excessive water influx caused by roof collapse.

6.2.3 Coal Seams

The laterally-continuous but repeatedly splitting and merging Fort Union and Wasatch coal seams themselves function as confined aquifers, with groundwater flow primarily through the fractures within the coal. The Wyodak Coal, outcropping on the eastern side of the PRB, can be confined by fluvial to paludal silt, sand, and shale aquitards. Even when the overlying unit is a sandstone aquifer, it is generally local in nature and does not prevent the dewatering of the coal beds for CBM production. However, these areas should be down-graded for UCG development. The Canyon, Cook and Wall coal seams may have thick fluvial sands overlying the coals and may be gas productive themselves. Again, these fluvial sand aquifers can be dewatered and CBM can be produced. There are split multiple coal seams in the northern and northeastern part of the PRB. The Big George coal in the central basin is the thickest coal seam in the PRB. The Big George reaches 200 feet in thickness and is generally confined by fluvial to paludal shales and silts. Logs for wells in this seam show a thin fluvial sand aquifer overlying the coal. The sandstone aquifer does not inhibit the depressuring of the Big George for gas production.

TABLE 6-1. AQUIFER TEST DATA

Aquifer Tested		TEST LOCATION			aquifer thickness feet		Drawdown, Feet		Hydraulic Conductivity K, feet/day		Storage Coefficient S		N qty tests summarized
		Sec	T	R									
non-coal	Between Anderson & Rider coals	25	52	73	23		5.7		3.1		8.0E-05		1
non-coal	Wasatch	13	50	72	80	120	14	23.0	3.7	14.4	1.6E-04	7.0E-04	4
non-coal	Wasatch	11	51	72	44	45	1.3	4.2	2.4	4.0	1.3E-01	1.9E-01	2
non-coal	Wasatch		~46 [Caballo Rojo mine]	~71	57		0.6	2.6	2	3.20	3.2E-03	2.1E-02	2
non-coal	Wasatch Sand	n/a	Ruby Ranch		20	57	n/a		2.2	20.2	2.3E-06	3.0E-02	28
non-coal	Wasatch/Ft Union Sandstone	5	54	84	12		n/a		1.1		3.5E-04		1
non-coal	Wasatch Clay Confining Units	n/a	Ruby Ranch		n/a		n/a		2.4E-05	0.03	n/a		8
coal	Anderson & Canyon Coals [Upper Ft. Union]	n/a	52	72	49	122	18.1	25.7	1.3	5	2.3E-04	3.0E-03	6
coal	Big George Coal [Upper Ft. Union]	n/a	Campbell Co		51	63	4.2	14.3	1.4	2.6	6.7E-05	2.2E-04	13
coal	Big George Coal [Upper Ft. Union]	n/a	Johnson Co		112	180	n/a		0.24	1.29	1.8E-04	4.5E-04	18
coal	Canyon Coal [Upper Ft. Union]	25	52	73	62	70	1	1.3	0.7	0.9	3.0E-04	1.2E-02	2
coal	Canyon Coal [Upper Ft. Union]	n/a	~40 [Antelope Mine]	~70	29	31	n/a		8.3	11	2.6E-05	2.7E-05	2
coal	Coal & Sandstone [Ft. Union Fm]	32	52	72	140		n/a		35.9		3.8E-04	8.5E-04	3
coal	Coal [Ft. Union Fm]	24	48	71	32	38	8.7	11.8	0.5	0.7	7.0E-04	4.0E-03	2
coal	Coal [Ft. Union Fm]	32	52	72	90	120	n/a		3.9	13.7	2.3E-04	1.8E-03	7

TABLE 6-1 AQUIFER TEST DATA (CONTINUED)

Aquifer Tested		TEST LOCATION			Aquifer Thickness Feet		Drawdown, Feet		Hydraulic Conductivity K, feet/day		Storage Coefficients		N qty Tests Summarized
		Sec	T	R									
Coal	Felix Coal [Wasatch Fm]	7	47	72	9	25	n/a		3.6	10.7	1.6E-02	2.0E-02	4
coal	Fort Union Sandstone	27	55	84	4		n/a		0.3		9.0E-05		1
coal	Roland Coal [Upper Ft. Union]	11	51	72	25		n/a		0.6		1.6E-04	2.8E-04	5
coal	Smith Coal [Upper Ft. Union]	10	51	72	5		n/a		17.4		1.9E-04		1
coal	Smith Coal [Upper Ft. Union]	11	51	72	80		n/a		0.5	0.8	2.1E-04	1.6E-03	6
coal	Wyodak Coal [Upper Ft. Union]	28	42	70	60		n/a		25		2.3E-04		1
coal	Wyodak-Anderson Coal [Upper Ft. Union]	29	40	71	104		8.5		2.1		6.4E-04		1
coal	Wyodak-Anderson Coal [Upper Ft. Union]	9	42	70	62		1.3		3		2.9E-04		1
coal	Wyodak-Anderson Coal [Upper Ft. Union]	11	43	70	25		4.2		0.2		6.9E-04		1
coal	Wyodak-Anderson Coal [Upper Ft. Union]	17, 19, 29, 32	46	73	34	37	2.5	4	1.5	32.7	3.2E-04	1.0E-03	4
coal	Wyodak-Anderson Coal [Upper Ft. Union]	7	47	72	n/a		n/a		n/a		1.0E-02	1.1E-02	2
coal	Wyodak-Anderson Coal [Upper Ft. Union]	20	50	71	100		4.6		0.3		5.2E-04		1
coal	Wyodak-Anderson Coal [Upper Ft. Union]	29	50	71	55	119	2	8.2	0.9	1.5	6.5E-04	1.1E-01	4
coal	Wyodak-Anderson Coal [Upper Ft. Union]	33	50	71	58		12.3		1		4.0E-03		1
coal	Wyodak-Anderson Coal [Upper Ft. Union]	n/a	~46 [Cabala Room mine]	~71	71	72	0.4	3	5.7	19	3.0E-04	7.0E-04	4

(AHA and GEC 2002)
K- hydraulic conductivity n/a- not available S-Storage coefficient, dimensionless

6.3 SURFACE WATER

Three types of streams are present in the PRB: perennial, ephemeral, and interrupted (Rankl and Lowry 1990). Most of the streams within the PRB are intermittent or ephemeral. The largest rivers in the basin, which are the Powder River, Little Powder River, Cheyenne River, Belle Fourche River, and Tongue River are not ephemeral. The perennial streams in the PRB originate either in the mountains and flow through the basin, or originate within the basin. An interrupted stream contains perennial stretches with intervening intermittent or ephemeral stretches. Groundwater base flow, in the few streams where it is present, is from local groundwater flow rather than a regional system (Rankl and Lowry 1990). A map showing surface water locations is included as Attachment 6-1.

The area's streams have characteristically high total dissolved solids (TDS) concentrations with average and median TDS greater than 2,000 mg/L (Lowry et al. 1986), with the exception of streams on the west side of the PRB draining the Bighorn Mountains. The alkalinities of most of the area's streams are high (greater than 100 mg/L, average and median concentrations greater than 200 mg/L). Sodium is the major cation and sulfate the major anion in most of the PRB's streams. Calcium and magnesium, though not typically the dominant ions, make the stream water typically very hard. Chloride is a major anion only in Salt Creek, a tributary to the Powder River, because of the surface discharge of high-chloride oilfield production water.

The relatively high alkalinity of the area's soils, surface water and groundwater provides a large buffering capacity that tends to neutralize any sulfuric acid that might be formed through oxidation of pyrite or other sulfide minerals commonly associated with coal mining operations. Surface water pH values tend to be alkaline, even downstream from surface coal mines (Lowry et al. 1986).

Campbell County is located in the central Powder River geologic basin and is drained by the Powder, Little Missouri, Belle Fourche and Cheyenne Rivers, which are all tributaries of the Missouri River System. Allocation of surface waters in the Belle Fourche and Powder River drainages is controlled by interstate stream compacts while no compact agreements apply to waters of the Cheyenne and Little Missouri drainages. The Little Powder River and the Middle Powder River are located north of Gillette, and the Upper Bell Fourche and the Upper Cheyenne River are located south of Gillette.

Streams originating in Campbell County are mainly ephemeral, flowing only during time of high surface runoff. However, flooding from heavy snowmelt and summer rainstorms has occurred occasionally along most of the major streams. Adequate stream flow data is lacking for most tributaries. Major stream patterns are dendritic and the tributaries have dominantly parallel patterns. Natural chemical quality of the surface waters is related to the mineralogy of the rocks and varies inversely with the discharge.

The dominant use of available surface water is presently agricultural. Numerous small stock water reservoirs impound water on many of the tributaries. Sparse vegetation and erodable Tertiary rocks result in high-suspended stream sediment loads which are a problem in impoundments (Breckenridge et al. 1974).

The major streams draining Sheridan County are the Tongue, Powder, and Little Bighorn Rivers and their tributaries, and all ultimately join the Yellowstone River. Surface water use is controlled by a compact governing the division of Yellowstone River waters between Wyoming, Montana, and North Dakota. Although the Tongue and Powder Rivers normally have unappropriated and unused waters available for division, no compact water is available during drought years. Storage would be required to develop compact water. Stream flow is mainly from precipitation in the Bighorn Mountains, and is highest during runoff periods in May and June. Streams draining the basin areas generally have low flows and high sediment loads. Use of surface water in Sheridan County is primarily for irrigation and stock water, and there are literally hundreds of stock ponds. Its third major use is for municipal water supplies in Sheridan, Dayton and Ranchester (WGS 1978).

Crazy Woman Creek and the Upper Powder River are located in the middle portion of Johnson County. The Middle Fork of the Powder River, the South Fork of the Powder River, and Salt Creek are located in the southern portion of the county. Johnson County is drained by the Powder River and its tributaries. Most of these streams begin in the Bighorn Mountains where the precipitation is highest. Heavy winter snow packs and rainfall caused by air rising over the Bighorns provides most of the runoff during the months of April through July. The flow and character of surface streams depends on geology, topography, vegetation and climate. Non-mountain streams have low flows and high sediment loads. Soil erosion is a problem in the basin area due to sparse cover, easily eroded soils and nonresistant rock units. Reservoir storage projects are confronted with high siltation rates and evaporation losses. Some surface stream flows are apparently lost to groundwater recharge as they cross carbonate rocks in the mountains, but most of the stream flows emerge as springs and seeps in the foothills.

Traditionally the main use of surface water in Johnson County is irrigation along the stream valleys. The municipal supplies of Buffalo and Kaycee also depend on surface water. Water appropriation in the Powder River is controlled under the Yellowstone River Compact which provides that no water can be diverted from the basin without consent of all signatory states (Wendell et al. 1976). Antelope Creek, Dry Fork of the Cheyenne River, Lightning Creek and Middle North Platte River extend through Converse County.

Specific sections of land that are traversed by surface water were eliminated from further considerations as UCG development sites. This elimination was made with the intention of reducing potential environmental concerns associated with the development of UCG.

6.4 GROUNDWATER

Groundwater quality and quantity are considered poor in Campbell County. Many of the PRB aquifers have low permeability and contain unfavorable soluble minerals. Most of the groundwater in Campbell County is produced from sands in the Wasatch, Fort Union, and Fox Hills formations. Other formations are deeply buried in the subsurface and outcrop many miles away on the flanks of the Black Hills Uplift and Bighorn Mountains. Recharge to the aquifers occurs on outcrop from precipitation and surface streams or from subsurface contact with other water-bearing units. Fort Union and Wasatch wells generally produce 10 to 20 gpm.

Groundwater is predominantly used for livestock and domestic purposes in Campbell County. Very little groundwater is used for irrigation mainly because of the high mineral content. Energy development in the county has stimulated interest in new water sources. Although the Madison Limestone produces large volumes of water in areas of fracturing and cavernous weathering near the mountains, it is deeply buried in Campbell County and its water productivity characteristics are not well known (Breckenridge et al. 1974).

In Sheridan County, waters suitable for domestic or stock use can be produced from the Lance Formation, Bearpaw Shale, Parkman Sandstone, and Tensleep Sandstone. Tensleep, Amsden and Flathead Formation waters are of good irrigation quality. Domestic water from the Fort Union Formation may have high iron and total dissolved solids. While Fort Union water may be acceptable for stock use, its high sodium and bicarbonate contents make it poor for irrigation. Domestic water from the Wasatch Formation usually exceeds the standard for total dissolved solids. Agricultural water from the Wasatch is variable in suitability. Both of these major Tertiary aquifers may contain objectionable levels of hydrogen sulfide (WGS 1978). Table 6-2 provides water quality data for selected coals in the PRB.

TABLE 6-2. POWDER RIVER BASIN SELECTED GROUNDWATER QUALITY DATA

Producing Formation	Sample ID	Depth feet bgs	Sample Location			Selected Constituents							Source
			Sec	T	R	TDS mg/L	Con-duct-ivity umhos/cm	pH s.u.	Alkalinity mg/L	Cyanide µg/L	Sulfate mg/L	Phenolics, Total Recoverable µg/L	
Wasatch Formation	USGS 434420105355001	205	35	44	73	n/a	n/a	7.8	n/a	n/a	672	n/a	a
Wasatch Formation	46-77-31	203	31	46	77	364	583	8.3	n/a	n/a	149	n/a	b
Wasatch Formation	USGS 441020105535001	160	32	49	75	n/a	n/a	8.4	n/a	n/a	1.2	n/a	a
Wasatch Formation	50-79-19	600	19	50	79	1260	1670	7.5	n/a	n/a	569	n/a	b
Wasatch Formation	51-79-16	164	16	51	79	672	1060	7.7	n/a	n/a	183	n/a	b
Wasatch Formation	52-79-12	160	12	52	79	598	960	7.6	n/a	n/a	1.3	n/a	b
Wasatch Formation	USGS 443820106264001	120	24	54	80		4910	7.6	n/a	n/a	3010	n/a	a
Fort Union Formation	48-77-25	605	25	48	77	544	879	7.6	n/a	n/a	16	n/a	b
Fort Union Formation	49-77-21	600	21	49	77	635	1030	8.8	n/a	n/a	2.3	n/a	b
Fort Union Formation	50-77-29	575	29	50	77	794	1300	8.3	n/a	n/a	4.6	n/a	b
Fort Union Formation	51-77-20	580	20	51	77	529	860	7.9	n/a	n/a	2	n/a	b
Fort Union Formation	51-77-20	758	20	51	77	1020	1600	8	n/a	n/a	0.3	n/a	b
Fort Union Formation	52-77-3	828	3	52	77	1250	1900	8	n/a	n/a	1.5	n/a	b
Lance Formation	51-83-4	205	4	51	83	2650	2800	7.7	n/a	n/a	1430	n/a	b
Anderson Coal	West Kitty Lease		36	51	74	637	1050	8	570	<5	<5	16	c
Big George Coal	WY0037435-002		36	44	74	507	809	7.6	445	<5	<1	<10	c
Big George Coal	A2-009		10	48	77	2690	4110	8.2	2450	<5	22	32	c
Big George Coal	DP_WY0041939_001_ET2 40NENW_16_48N_78W		16	48	78	1610	2380	8	1450	<5	1	<50	c
Big George Coal	WY0049158-002		24	48	79	1600	2550	7.4	1490	<5	<1	<10	c
Big George Coal	ME LLC 43-18 96		18	49	76	1370	2160	7.4	1310	<5	<1	<50	c
Burgess Coal	Boeck State 13B-17		17	55	82	1040	1660	8	945	<5	<1	14	c
Wall Coal	PW_13_16_50_75W		16	50	75	1460	2350	7.1	1320	<5	<5	<10	c

Sources:

a- Whitcomb et al., 1966: *Ground Water Resources and Geology of Northern and Central Johnson County, Wyoming*, USGS Water, Supply Paper 1806.

b- U.S. Geological Survey on-line database: http://waterdata.usgs.gov/wy/nwis/gwsi

c- coal-bed methane well or water discharge sampled by CBM producers/operators

mg/L – milligrams per liter µg/L - micrograms per liter

TDS – total dissolved solids umhos/cm – micromhos per centimeter

Groundwater in Johnson County is produced from several geologic formations. Aquifer characteristics of the units are generally favorable near the recharge area in the Bighorns but unproven farther eastward. Recharge occurs from precipitation and infiltration from streams crossing the outcrop in the narrow belt of steeply dipping sediments along the Bighorns. Some formational water movement occurs, mainly in areas of secondary permeability from fracturing and solution. Wells in some formations flow at the surface because of artesian pressure. Alluvial deposits along the river valleys are unconfined or water table aquifers. They receive part of their recharge from irrigation water.

Paleozoic formations with the best groundwater potential are the Madison and Tensleep formations. Other favorable units are the Bighorn Dolomite and Flathead Sandstone. The most favorable Mesozoic aquifers include the Cloverly, Mesaverde, Fox Hills and Lance formations. Cenozoic formations are the most common source of groundwater for domestic and stock uses and include the Tertiary Fort Union, Wasatch, Arikaree and White River formations as well as Quaternary alluvium.

Groundwater quality in Johnson County ranges from good to highly mineralized, depending on the aquifer. Both "hard" and "soft" waters occur throughout the county. The most common water types are sulfate and bicarbonate with calcium and sodium the dominant cations. Although Precambrian rocks have small water yields, the water usually contains less than 100 mg/L of dissolved solids. Both Paleozoic and Mesozoic rocks contain a variable range of dissolved solids, from less than 100 mg/L to 4000 mg/L. Cenozoic rocks have even more variability, from less than 100 mg/L to 8000 mg/L. (Wendell et al. 1976).

6.4.1 Groundwater Flow and Discharge

Regional net groundwater flow is stratigraphically controlled and northward toward the Powder River. Groundwater flow paths are complex and the extent of flow between hydrogeologic units within the PRB is not well understood. Several studies have been made of the groundwater flow system in the various lower Tertiary aquifers in the PRB, although each reaches somewhat different conclusions about the relative importance of different hydrogeologic units.

Generally, the groundwater system can be divided into two general flow systems: an upper, localized flow pattern controlled by topography that occurs in aquifers at depths of approximately 200 feet or less and a lower, regional northward flow pattern that occurs at depths between approximately 200 and 1,200 feet. Groundwater discharge areas for aquifers less than 200 feet deep typically coincide with valleys of perennial and intermittent streams. Water enters the shallow system by infiltration, flows downslope, and discharges to streams and rivers. Vertical movement between aquifers does occur, but the movement rate is unknown.

6.4.2 Groundwater Recharge

The PRB is semiarid, receiving approximately 10 to 15 inches of annual precipitation, most of which occurs between April and June. Recharge is via runoff in creek valleys, surface infiltration, and standing water in playas and impoundments. Infiltration can be very high in areas of more permeable surface geology such as the clinker (burned coal exposed at land surface) that occurs in the outcrop areas of the coal units in the Wasatch and Fort Union. Recharge and discharge also occur locally where coal underlies valley fill deposits. Recharge is primarily from inflow at outcrop areas. However, infiltration of surface water in creek valleys is considered the most important source of recharge to underlying alluvium and shallow bedrock aquifers. Regional studies indicate stream infiltration (recharge) rates ranging from 0.43

to 26.5 acre-feet per mile for individual storm runoff events. An average loss of flow per valley mile along the Powder River below Arvada, Wyoming was 0.31 cubic feet per second per mile (AHA and GEC 2002).

Recharge to the upper Fort Union is thought to occur on a regional basis through leakage from the overlying Wasatch Formation. Groundwater in the upper Fort Union Formation coals, down-dip of the outcrop, tends to be confined by the low-permeability claystone of the overlying Wasatch Formation and a thick underlying sequence of siltstone and claystone (AHA and GEC 2002). Localized lenticular sandstone units that are in direct contact with the coal are themselves confined by overlying claystones and can be considered part of the confined coal aquifer.

Hydraulic connection between the deep sandstones of the Wasatch and the coals of the upper portion of the For Union is limited by the low-permeability claystones in the lower part of the Wasatch that separate the two units. However, there is potential for leakage from the sands into the coal if the water level in the coal is lower than in the overlying sands. A study with paired wells demonstrated that a 40-foot thick claystone unit provided a significant hydraulic barrier but allowed a small amount of leakage from the overlying sandstone into the pumped coal (AHA and GEC 2002).

6.4.3 Groundwater Use and Quality

Groundwater for domestic consumption is derived predominantly from the Wasatch and Fort Union aquifers. Approximately 25 percent of the nearly 27,000 permitted non-CBM waters wells in the PRB are used for domestic purposes. About 1.5 percent of the permitted wells are used for irrigation or municipal uses. The remaining 75 percent of wells are used for stock watering or other purposes. Approximately 65 percent of domestic consumption of groundwater occurs in the Belle Fourche River and upper Tongue River basins, where most of the PRB population resides (AHA and GEC 2002).

Because of the discharge permit requirement to monitor CBM water quality over time, there is presently much information available on water quality produced from coals undergoing CBM development. CBM produced water must be analyzed for naturally occurring ions and metals as part of the National Pollutant Discharge Elimination System (NPDES) discharge permit requirements. Table 6-2 lists selected constituents of interest to UCG development for which data could be found. Man-made organic compounds and other refined hydrocarbon products (e.g. benzene, ethylbenzene, toluene, and xylenes; polynuclear aromatic hydrocarbons) are not monitored routinely in CBM produced or non-CBM water, as the PRB is mostly undeveloped and non-industrial, and the potential for existing man-made pollutants is very low.

Conversely, there is relatively little information available on groundwater quality produced from water-bearing non-coal formations between the coal seams. Although private domestic supply wells are completed in these formations, water quality either is not tested, or the test results are typically not reported to public agencies from whom it would be readily accessible.

The majority of PRB groundwater wells and springs have TDS concentrations greater than 500 milligrams per liter (mg/L), with high calcium, magnesium, and sulfate. Wells close to recharge areas generally have the lowest TDS, whereas wells distant from the recharge areas have higher TDS (Lowry et al. 1986). TDS usually increases with depth. Groundwater produced from the Fort Union Formation is mostly sodium bicarbonate and, to a lesser extent, sodium sulfate type. Groundwater produced from the Wasatch Formation is dominantly sodium sulfate and sodium bicarbonate type with TDS typically ranging from 500 to 1,500 mg/L (Hodson et al. 1973).

6.4.4. Groundwater Quantity

The volume of recoverable groundwater in the sandstones within the Tongue River-Wasatch aquifer, the Lebo confining layer, and the Tullock aquifer was calculated by AHA and GEC (2002) from the volume of sandstone in each of these units multiplied by the estimated percent-specific yield value for sandstone (13 percent). The volume of recoverable groundwater in the coals within the Tongue River-Wasatch aquifer was calculated from the volume of coal multiplied by the estimated percent-specific yield value for coal (0.4 percent). Specific yield is the ratio of the volume of water that drains from a saturated rock owing to the attraction of gravity to the total volume of the rock. It is low, 0.3 percent for coal, and over 30 times higher, 13 percent, for the sandstones in these rock volumes. As a result, because the sandstones are much thicker than the coals, and because of their high specific yield, most of the recoverable groundwater occurs in the sandstone units. The recoverable groundwater in the coals is only a small fraction of the recoverable groundwater in the sandstones. As summarized by AHA and GEC (2002), of a total recoverable groundwater volume of 1.4 billion acre-feet of water in the PRB, only 0.2 percent, or 2.5 million acre-feet, occurs in the coals.

6.5 HYDROLOGIC CONDITIONS AND SUBSIDENCE ISSUES RELEVANT TO UCG

In the UCG operations, overburden material participates in the gasification process. The overburden participation increases as the UCG cavity matures and more overburden is exposed to the process. The major concerns with the UCG process and overburden are excessive subsidence, groundwater influx, mixing of aquifers (or water bearing strata), and groundwater contamination.

Subsidence is the downward movement of subsurface material due to mining and the creation of an underground void that caves in. The surface settling, or ground movement, can occur over the void, and extend beyond the void, to the angle of draw, usually accepted to be 35 degrees outside of the vertical from the edge of the void. Subsidence can create surface disruptions, excessive groundwater influx into the UCG reactor, the mixing of groundwater of separate water-bearing units, and groundwater contamination. Subsidence can be controlled, as it is in underground mining where surface movement is not desired. The amount of subsidence is influenced by the depth of the void, the size and geometry of the void, the rock strengths of the materials above the void, fractures in the rocks, layering in the rocks, and whether the void is filled with water, filled with solid materials, or even pressurized above hydrostatic pressure.

For conceptual subsidence evaluation, we have investigated the following conditions. The coal beds are from 30 to 100 feet thick, at depth of 500 to 2,000 feet. We assume that there is groundwater present. The residual ash and char could be 20% to 50% of the in-place coal. The coal beds will be assumed flat and near horizontal. The coal will be accessed by directionally drilled horizontal holes.

The extraction could range from full extraction to partial extraction. The selection of the mining strategy has a major impact on the subsidence potential. The trade off of extraction, subsidence impact (environmental impact) and resource recovery is very site specific but can result in a mine plan with very low subsidence potential but a corresponding low resource recovery.

Full extraction may not be possible if pressures need to be maintained at different values during operations and during closure but for the subsidence impacts full extraction represents the worst-case scenario. Panels separated by pillars of unheated (undisturbed) coal can be designed to limit subsidence and to allow coal gasification in controlled conditions.

If the lateral dimensions of the panel are large, then subsidence resulting from UCG can be expected to be 60% to 90% of the vertical extent of the coal removed. If the coal seam is 100 feet thick and the residual char and ash is 20% then the ultimate vertical surface subsidence will be in the range of 60% to 90% of 100 feet times 0.8, or from 48 to 72 feet. For a design with a limited panel width and adequate pillars the subsidence can be less than 0.5 foot. Panel widths of 1/3 to ½ the depth and pillars of equal with to the panel width may result in minimal subsidence assuming that the overburden rocks are competent, say strengths greater than 3,000 psi. (Agapito and Associates 2006).

At shallow depth the surface impacts will be greater than for deeper coal seams. If the depth is less than 100 feet, or as much as 200 feet, sinkholes could develop. For depths greater than this the surface subsidence should be gradual with some surface cracking above the perimeter of the panel.

Surface strains and tilts are usually the most concern for surface structures. Subsidence can impact pipelines, roads, dams, bridges, houses, power lines and other surface features such as ponds, lakes, historic markers etc.

The impact of the ground deformation on the groundwater is of concern to both the operator and the general public, groundwater users, and regulatory agencies. For the operator, impacting any overlying aquifers can cause water inflow and additional heat losses. The groundwater could be a source of agricultural water or domestic water. If the groundwater has over 10,000 ppm TDS (total dissolved solids) the aquifer may be exempt from EPA regulation. The groundwater may be essentially unaffected by the ground motion accompanying UCG if the aquifer is separated from the caved and fractured zones that develop above the coal seam. The caved and fractured zones together can extend up to 10 to 20 times the thickness of the extracted seam; so for a 100-foot seam, with various char content, the cave and fractured zones could be 500 to 1800 feet thick. Aquifers in this zone could be drained. Above this the strata will deform but not fracture, except for occasional slip along bedding and along preexisting joints, and can act as an aquitard. This favors deeper coal beds in that the shallower thick beds will result in caving to the surface thereby impacting overlying aquifers.

Subsidence is very site and design specific. Subsidence is common with underground coal mining, full extraction trona mining, and groundwater extraction. Subsidence can be controlled by design. However full extraction of thick seams would result in high surface impact and would be incompatible with high surface use. Some sparsely populated areas with little or no surface structures may be compatible with 48 to 72 feet or more of subsidence but generally this would be greater than that commonly tolerated. In longwall mining of coal and trona subsidence of 3 to 6 feet is typical and is acceptable in remote areas. In Pennsylvania and other east coast mining areas with higher population densities great care is taken to protect gas and water pipelines and property owners when mining is in progress below their properties or right of ways. In the west where the population density is low and farming non-intensive there is more tolerance of subsidence.

Several overburden characteristics are essential for successful UCG operations. No high production aquifers should be within the expected vertical subsidence volume. Water influx into the gasification cavity can substantially reduce gasification efficiency. The Soviets published the effect of "gasification intensity," which is the tons of coal gasified per hour versus the water influx rate and the heat content of the produced gas. At low gasification intensities, one-ton coal per hour, the heating value of the syngas drops from approximately 125 BTU/scf with a low water intrusion rate of 15 gpm, to only about 25 BTU/scf at high water intrusion rates of 150 gpm. At higher gasification intensities, e.g. ten tons coal per hour, the reduction in syngas heating value is almost eliminated. The Soviet data shows that heating value is always increased with increased gasification intensity and reduced water intrusion (Gregg and Olness 1976).

Also, the water in these aquifers is likely to be used for domestic or livestock purposes. Ideally, the immediate overburden unit should be a thick vertical section of an aquitard such as a claystone or shale. Low production water-bearing units are also acceptable.

Fortunately in the PRB, the rocks above the coal section are predominantly claystones, with a typical thickness of thirty feet but ranging up to several hundred feet. These low permeability claystones, and the small specific yield of the water from the coal itself, will both restrict water influx into the geo-reactor. In addition, as water flows into the reactor, it will be converted to steam at some small distance from the combustion zone. This phase change is accompanied by a huge volume increase that creates a "steam jacket" around the reactor, further reducing the influx of groundwater.

In the PRB, the Fort Union Formation is a consolidated rock unit and is not being substantially dewatered. Instead, the Fort Union Formation is being only partially dewatered to the top of the coal seam. The bedrock underlying the surface is compacted and consolidated sandstone. Claystone is present instead of unconsolidated clay. However, saturated bedrock, such as sandstone can compress if water is removed under certain conditions.

Using a formula to estimate how much a confined aquifer may compress when water is removed, it appears that for CBM development levels analyzed in the Wyodak CBM Project Environmental Impact Statement (EIS), minor aquifer compression up to one half inch may occur in the coal beds that are being developed for CBM in the Gillette area. That entire compression, however, may not be transmitted to the surface. To date, no surface subsidence has been associated with significant municipal water withdrawals in the Gillette area (BLM 2003).

The most important approach to mitigating the impacts of subsidence is resource selection. These include claystone overlying the target coals, thicker is better; deeper coals will have less surface expression of subsidence; structurally competent overburden materials (well cemented, and rigid); absence of really consolidated sand units; and absence of thick water-bearing units used for domestic consumption.

7.0 PERMITTING AND ENVIRONMENTAL CONSIDERATIONS

7.1 WYOMING REGULATIONS

The State of Wyoming maintains primacy in the issuance of permits for in situ projects where the state rules are "as stringent as" federal regulations. Major federal authority for establishing permitting requirements for in situ processes are the following:

- Safe Drinking Water Act (EPA administered)
- Underground Injection Control (UIC) Program (EPA administered)
- Surface Mining Reclamation & Control Act (OSM administered)
- National Environmental Policy Act (Federal projects)
- Endangered Species Act
- Mineral Leasing Act
- Antiquities Act
- Archaeological Resources Public Protection Act

State of Wyoming authority and requirements are described in the following regulation and statutes:

- Title 35, Wyoming Environmental Quality Act
- Title 41, Water Statutes
- Coal Rules and Regulations

Other federal, state, and local regulations and statutes may apply in industrial siting of UCG facilities.

7.1.1 Wyoming Permitting Approach

Wyoming's approach to regulating in situ processes is to address surface activities and subsurface activities differently. Surface activities are regulated according to surface coal mining regulations per Wyoming Statutes 35-11-103(e)(xx). The subsurface activities are regulated as "in situ mining" per Wyoming Statutes 35-11-103(f)(iv). The requirements from these two sections are combined in the Permit to Mine. Table 1, which is based on data described in this report and others, identifies the major and secondary permits likely required for an UCG facility.

Wyoming uses two similar permitting tracks for in situ siting of UCG type facilities. The Research and Development Testing License (R&DTL) and the Permit to Mine are the two permitting tracks. The R&DTL is for applications of new technologies and applications of proven technologies in new resources. It permits for smaller permitting areas and better protection of proprietary information (WDEQ - LQD 2006). The R&DTL must be renewed annually. The Permit To Mine is for proven technologies in proven resources (e.g. surface coal mine in Powder River Basin). It is suggested that an R&DTL approach be used for UCG application in the Powder River Basin of Wyoming. If federal lands or minerals are involved in the project, the Office of Surface Mining (OSM) must review all project plans and permits.

Table 7-1 provides only an overview of key regulatory requirements. Additional permits, approvals and other authorizations could be required.

TABLE 7-1. PERMITS REQUIRED FOR A UCG PROJECT

Permit Name	Permitting Authority	Nature of Permit and Authority
Air Quality - Permit to Construct	WDEQ-AQD	Regulates air emissions from all facilities under the Clean Air Act and the Wyoming Environmental Quality Act.
Permit to Mine	WDEQ-LQD	Regulates surface mining operations under the Surface Mining and Control Act
Notification to Explore for Coal by Drilling	WDEQ-LQD	Regulates coal exploration by drilling in accordance with Chapter 14 of the LQD's Rules and Regulations.
NPDES Permit/ WYPDES Permit	WDEQ-WQD	Approval to allow discharge of excess water generated at the UCG facility. Authorized under the Clean Water Act.
Class III Underground Injection Control Well Permit	WDEQ-WQD	Regulates construction, operation and maintenance of UIC process wells for groundwater protection. Permit is granted as part of the R&D license.
General Storm Water Permit	WDEQ-WQD	Permit provides authorization to discharge storm water associated with construction activities under NPDES.
Section 404 Permit	U.S. Army Corps of Engineers	Controls placement of dredged or fill material in waters of the United States and adjacent wetlands under Sec. 404 of the Clean Water Act of 1972 (40 CFR 122-123). It also covers pipeline and road crossings of streams (intermittent and perennial) and wetlands.
Water Well Permit	WY State Engineer's Office	Permit to drill well and appropriate water.
Right-of-Way Grant(s)	Bureau of Land Management (BLM)	Rights-of-way grants on BLM-managed lands are an authorization to use a specific piece of public land for specific facilities for a specific period of time. ROWs are authorized by Title V of the Federal Land Policy and Management Act.
Roadway and/or Non-Roadway Easements	WY Office of State Lands and Investments	Roadway and/or Non-Roadway easements are authorized under Chapter 3 – Easements of the Board of Land Commissioners Rules and Regulations and can be filed for ditches, overhead wires, pipelines, railroads, reservoirs, roads, snow fences, etc. on state lands.
Oversize & Over-length Load Permits - Access permit	WY Department of Transportation (WDOT)	Permits for oversize, over-length and overweight loads and highway access construction are authorized in Chapters 17 and 20 of WDOT Rules & Regulations.
Preliminary Biological Assessment	U.S. Fish and Wildlife Service	The assessment is required to evaluate the presence (potential or actual) of endangered and/or threatened species in the permit area.
Special Use Permit	Campbell County Commissioners	Permit to construct buildings and gas wells for UCG project on land zoned for agriculture use (See Chapter 7 – Zoning Regulations.

WDEQ = Wyoming Department of Environmental Quality
LQD = Land Quality Division; WQD = Water Quality Division; AQD = Air Quality Division

7.1.2 Wyoming Regulatory Agencies

The Wyoming Department of Environmental Quality (WDEQ) is the state agency responsible for approving and monitoring permitting applications for industrial facilities. The WDEQ consists of three divisions, the Land Quality Division (LQD), the Water Quality Division (WQD), and the Air Quality Division (AQD). Each division is geographically divided into districts; however, the districts do not correspond across divisions. For example, LQD has three districts and AQD has five.

The LQD is the lead division for permitting in situ projects and all permits are coordinated through them. A recent change from past permit administration is the delegation of permitting responsibility from the Cheyenne office to the field districts. For projects in the central and northern Powder River Basin, permitting responsibility resides at LQD, District 2, in Sheridan.

The Wyoming State Engineers Office regulates water and monitoring wells. Well permits and "Statement of Completion" notices are required for each water and monitoring well.

7.1.3 Pre-Permitting Requirements

The major pre-permitting requirement is the selection of a site. For UCG consideration this usually requires a precursor hydrologic and geologic evaluation followed by a site characterization program. The site characterization program usually includes the drilling of wells with subsequent well testing. The characterization program also provides information required for license or permit submittal.

7.2 R&DTL PREPARATION

The R&DTL is the major permitting document. The R&DTL application has four sections: the Adjudication File, Baseline Information, the Mine Plan, and the Reclamation Plan. WDEQ provides a number of documents and guidelines to assist in the preparation of the R&DTL and "Permit to Mine". The main guide documents for UCG projects are LQD Rules and Regulations (Chapter 18, In Situ Mining 2005b) and LQD Guideline No. 4, In Situ Mining. Several other guidelines assist in the preparation and planning for individual components of the R&DTL.

WDEQ provides a number of documents and guidelines to assist in the preparation of the R&DTL and "Permit to Mine". The main guide documents for UCG projects are LQD Rules and Regulations (Chapter 18, In Situ Mining 2005b) and LQD Guideline No. 4, In Situ Mining (1994c).

7.3 ADJUDICATION FILE

The adjudication file is a collation of legal forms, location information, insurance documents, and reclamation performance bond. The bond assures the operator/owner complies with the reclamation requirements given in the approved reclamation plan. The amount of the bond depends on the approved reclamation plan and calculations based on WDEQ instructions. Individual components of the Adjudication File are described in the following subsections.

7.3.1 Prepare Form 5, R & D License, In Situ

The applicant must complete and submit Form 5 – R & D Testing License, In Situ Permit and Form 3, License to Mine Application (MINE PERMIT ONLY). A Reclamation Bond must also be secured. A variety of options are available for the Reclamation Bond, however it must be obtained prior to submitting permit.

7.3.2 Surface Owner Consent and Right of Entry

The applicant must complete Form 8, which is the Surface Owner Consent form. This form documents that all surface owners have viewed the Mine Plan.

7.3.3 Certification of Public Liability (applicable to R & D License)

The applicant must obtain an original certificate with a notarized signature. A rider must be attached that requires the insurance company to notify the LQD whenever substantive changes occur or the policy is cancelled or not renewed.

7.3.4 Appendix A, Owners Surface/Mineral Rights, Permit Area

This appendix is required for the R&D License and the In Situ Permit. The applicant must provide a list of names and last known addresses of owners of record of the surface area within the permit/license area, a list of names and last known addresses of owners of record of the mineral rights within the permit/license area, and maps showing the locations of ownership of surface and mineral rights owners.

7.3.5 Appendix B, Owners Surface Mineral Rights, Adjacent Area

This appendix address lands adjacent to the permit or license area. A list of names and last known addresses of owners of record of surface rights of lands immediately adjacent to the proposed permit area and any other persons having a valid legal estate of record within one-half mile of the permit/license area such as water rights and rights of way owners must be created. A list of names and last known addresses of owners of record of coal immediately adjacent to the proposed license area must also be developed. Maps showing the locations of the ownership of above are a component of Appendix B.

7.3.6 Appendix C, Tabulation of Lands

Lands in the permit area are to be tabulated on LQD Forms C-1 and C-2 and must be signed by the applicant. They include tabulation of lands in the proposed license area by legal subdivision, section, township, range, county and municipal corporation, and number of acres for each entry listed; separate tabulation of lands in the proposed license area where no right to mine is claimed with the number of acres for each entry; tabulation of lands which are located within other license areas in the state and a copy of the agreement with the other permittees/licensees; and an original USGS topographic map, clearly outlining and identifying the lands within the proposed permit area.

7.3.7 Appendix D, R&D Testing License Supportive Information

The requirements for this appendix are described in detail in Section 7.4.

7.3.8 Appendix E, Maps

Appendix E contains project maps. This appendix is required for coal ventures and suggested for license applications. Applicant should create map(s) that include lands to be affected over the life of the project and the drainage area within and surrounding the proposed permit area. The map should also include the location and names of all existing roads, railroads, public or private rights of way and easements, utility lines, pipelines, buildings, lakes, streams, creeks, springs and other surface water courses, oil wells, gas wells, and water wells. It should outline the probable limits of all areas previously disturbed or to be disturbed by underground or surface mining, whether active or inactive, within or adjacent to the proposed permit area. Ownership and use of all buildings on or adjacent to the permit area must be identified. Political boundaries of special districts such as water, police, fire, conservation; public and private parks; cemeteries; Indian burial grounds; areas mentioned in Chapter XII, Section 1(a)(v)A and B of the Land Quality Coal rules and Regulations as applicable.

7.3.9 Statement of Compliance

In the Statement of Compliance, which is applicable to coal applications, the applicant must list all notices of violations incurred by applicant for any U.S. surface coal mines operated during the three years prior to the date of the application. The applicant must state whether the applicant or entities controlled by or under control… have had any mining permits suspended or revoked. A list all licenses, permits and approvals needed to conduct the operation must be provided. The applicant's MSHA number and copies of all DEQ and State Engineer permits and approvals, or list identification numbers must be submitted and the applicant should state whether the proposed area to be mined is within an area designated or being studied for designation as unsuitable for surface coal mining and state whether the permit area is within an area where mining is prohibited.

7.3.10 Identification of Interest

The Identification of Interest section, which is applicable to coal applications, requires the applicant to list all owners of record of the property to be mined including legal and equitable owners, leaseholders, and purchasers of record under a real estate contract. If the applicant or any surface or mineral owner is a corporation or partnership, a list of the names and addresses of every officer, partner, director, principal, and resident agent must be given. The names and addresses of all principal shareholders of the applicant must be listed. The names of all surface coal mines operated by the applicant or principal shareholders during the preceding five years must be listed. All current, pending and previous U.S. surface coal mining permits held by the applicant, partner, or principal shareholder subsequent to 1970 must be provided. The regulatory authority must be identified. Finally, a statement of all lands, interests in land, options, or pending bids made by the applicant for lands contiguous to the permit area should be provided.

7.3.11 Proof of Publication

The Proof of Publication section, which is applicable to Form 1 applications and coal R&D licenses, requires applicants to publish notice of their desire to begin mining operations at a particular location. The LQD provides a publication notice format that must be utilized by the applicant. Publication and notification does not begin until written consent from the LQD has been received by the applicant.

7.3.12 Proof of Filing

The Proof of Filing requirement, which is applicable to Form 1 applications and coal R&D licenses, requires the applicant to submit an original, signed affidavit of filing from the appropriate county courthouse just prior to start of publication.

7.3.13 Proof of Notification

The Proof of Notification, which is applicable to Form 1 and Form 5 R&D requires applicant to send notice within five days after the publication to all above owners of record. Original certified mail receipts must be submitted to LQD for validation.

7.4 R & D TESTING LICENSE, SUPPORTIVE INFORMATION, APPENDIX D

Appendix D is the core of the process and requires extensive resources to complete. It provides all background information for the R&DTL and requires physical surveys and evaluations. It provides the baseline conditions from which environmental impacts will be determined. Elements of Appendix D are described below.

7.4.1 Appendix D-1 and D-2 Preparation, Past and Present Land Use

Appendix D-1 is a description of the past and present land use of the permit area. No survey is required for this appendix. Appendix D-2 involves preparing a brief history of the permit area.

7.4.2 Appendix D-3 Preparation, Archaeological and Paleontological

Appendix D-3 entails preparing an investigative report of the archaeological and paleontological resources of the permit area based on the results of a site inspection. A survey must be conducted in accordance with LQD Guideline 11, Reporting Cultural and Paleontological Resources within the Mine Permit Area (1994f). This appendix will be submitted as a confidential document to protect sensitive archaeological sites.

7.4.3 Appendix D-4 Preparation, Climatology

Appendix D-4 is a report documenting the climatological data from the past year. This data should be obtained from the National Oceanic and Atmospheric Administration station nearest the license area. Data collection for this appendix may potentially require the installation of a monitoring station.

7.4.4 Appendix D-5 Preparation, Geologic Assessment

The Geologic Assessment describes the regional geology and local geology determined during characterization and other phases. Supportive maps and aerial photos of the permit site are required.

Regional geology should be briefly described using referenced and published information. LQD Guideline No. 8, Hydrology (2005a), provides guidance for this Appendix D section.

7.4.4.1 Evaluate Site Monitoring Wells

Using monitoring and process wells, evaluate and describe permit area geology.

7.4.4.2 Create Cross-Sections

Geology in the license area should be described using geologic cross-sections and should be confirmed with geophysical logs and field investigation. Guideline No. 8 should be referenced for the information and level of detail suggested for the cross sections.

7.4.5 Appendix D-6 Preparation, Hydrology

This appendix should describe methods used to identify the surface water and groundwater system within the regional and license area. Potentiometric surface maps should be developed with sufficient data points to spatially define affected aquifers and should be superimposed on topographic maps of sufficient scale for analysis. Wells used in developing the potentiometric surface map should all be located and identified on the map with the particular water elevation and date of observation at each well shown. LQD Guideline No. 8, Hydrology (2005a), provides guidance for this Appendix D section.

7.4.5.1 Evaluate Existing Data

Evaluate and describe regional hydrology using referenced and published information.

7.4.5.2 Design and Install Monitoring Well System

Design groundwater and surface water monitoring system. Seek interim approval for design from WDEQ and Wyoming State Engineers Office. Install groundwater-monitoring wells. Draft a monitoring plan to include quality assurance and control (QA/QC) procedures.

7.4.5.3 Conduct Monitoring Well Testing

Conduct hydrology testing after monitoring wells installed.

7.4.5.4 Conduct and Evaluate First Baseline Sampling

Sample groundwater from monitoring wells immediately after hydrology testing is completed. Validate analytical data based on QA/QC procedures.

7.4.5.5 Conduct and Evaluate Second Baseline Sampling

Sample groundwater three months after first baseline sampling is started. Validate analytical data based on QA/QC procedures.

7.4.5.6 Conduct and Evaluate Third Baseline Sampling

Sample groundwater six months after first baseline sampling is started. Validate analytical data based on QA/QC procedures.

7.4.5.7 Conduct and Evaluate Fourth Baseline Sampling

Sample groundwater nine months after first baseline sampling is started. Validate analytical data based on QA/QC procedures.

7.4.5.8 Evaluate Surface Water and Water Rights

Evaluate all seasonal and live water sources in and adjacent to the license area.

7.4.5.9 Evaluate Existing Wells and Abandoned Wells

The applicant should identify all known pre-mining wells and drill holes in the license and adjacent area. Plugging should be verified.

7.4.6 Appendix D-7 Preparation, Soil Assessment

A Soil Inventory (Guideline 1, Topsoil and Overburden) must be completed prior to submitting the application. Data collection requirements for this appendix vary according to how much soil will be disturbed. The data required for ten acres or less includes preparing a soil inventory map, profile descriptions, and quantitative estimates of topsoil where significant disturbance will occur. The requirements for more than ten acres are also identified in LQD Guideline No. 1 (1994a).

7.4.7 Appendix D-8 Preparation, Vegetation

Appendix D-8 describes the vegetation inventory of the license area. The inventory should be conducted according to LQD Guideline No. 2 (1994b). Mapping and data collection are required to complete the inventory. Photographs of vegetation communities that will be disturbed must be provided according to a proscribed LQD format. Documentation of threatened or endangered plant species and/or noxious weeks must be provided for extended reference areas.

7.4.8 Appendix D-9 Preparation, Wildlife

Appendix D-9 documents the wildlife within the permit area. Applicant is required to list the vertebrate distribution, make vertebrate observations and identify habitat affinity. Rare, threatened or endangered species should be identified and described in this report and wildlife survey. LQD Guideline No. 5, Wildlife (1994d) describes requirements for this appendix. Wildlife evaluation may span a year due to the seasonal variations in wildlife populations and wildlife management impacts (hunting). The Wyoming Game and Fish Department should be consulted in formulating plans for Appendix D-9.

7.4.9 Appendix D-ll, Alluvial Valley Floor

LQD Guideline No. 9, Alluvial Valley Floors (1994e), describes requirements for addressing alluvial valley floors within and adjacent to the license area.

7.5 MINERAL EXTRACTION PLAN (MINE PLAN)

The mine plan provides design, construction, and operation information. It also includes information on waste disposal and monitoring procedures. Elements of the mine plan are described in the following subsections.

7.5.1 Engineering Design

Engineering design discusses experimental techniques to be tested and prediction of the expected results. During mining, on-site data collected should be in sufficient detail so that an analysis may be performed for the predictions made in the application. The experiments and predictions could include: performance of equipment under operating conditions, well completion, well development and boring techniques, excursion prediction and control, lixiviant chemistry, identification of best restoration methods, subsidence research or any other research topics. The license area should be limited to the minimum acreage possible.

A general discussion and description of the operation which identifies the goals of the operation, life of the project, mineral to be mined, etc. must be included in this section.

7.5.2 Site Preparation Requirements

Site preparation activities include development of a permit area location map and topsoil removal (description and timetable for topsoil removal, any other surface disturbances, stock piling, etc.). Wildlife and archaeology mitigation should include mitigation measures that are to be taken to alleviate impacts to wildlife and archeology (including measures taken to prevent wildlife use of evaporation ponds). Hydrologic control features including designs and engineering of surface water hydrologic control features should be placed within this section. Appropriate permits should be obtained from the WQD with notice of application provided to the LQD. Applicant should consult with the WQD concerning an NPDES permit.

7.5.3 Process Descriptions and Timetables

Production process and timetables should be included in this section. It will include a description of special fluid and chemical flow paths and spill control and cleanup procedures should be outlined. Major chemical reactions or physical processes anticipated should be described. Surface hydraulic equipment should be identified along with a map locating the typical configuration of the piping planned for the well field area and a description of the system should be submitted. The production zone location should be identified and production zone confinement should be described. Well completion data and the mechanical integrity of the wells should be discussed.

7.5.4 Excursion Detection and Management

The component on excursions should include an introduction, a section on the monitoring well network, the frequency of monitoring upper control limits during mining, parameters, corrective actions, and reporting excursions.

7.5.5 Subsidence Detection and Control

Subsidence detection instrumentation and instrumentation monitoring is described. Mitigation and reclamation procedures are also described.

7.5.6 Copies of Associated Permits

This section includes **c**opies of approved state and federal permits associated with the application e.g. well permits, pond construction permits, discharge permits, fish and wildlife service permits.

7.6 RECLAMATION PLAN

The reclamation plan addresses all potential environmental impacts resulting from the permitted operation. It includes surface, groundwater, and subsidence reclamation. Well abandonment is also addressed.

7.6.1 Aquifer Restoration Description and Monitoring Plan

A plan must be provided showing how the applicant will address aquifer restoration in the permit area. The plan must include an introduction, the methodology, a description of the monitor well network, and plans for groundwater restoration. It should describe stability and an evaluation of the stability data. Determination of the best practicable technology, and a determination of groundwater restoration success at the end of the stability period should also be addressed.

7.6.2 Surface Reclamation Description and Reclamation Schedule and Costs

The surface reclamation plan must include a discussion of post-mining land use, disposal of buildings and facilities, toxic materials, topography, surface preparation, re-vegetation, protection of newly seeded areas, well abandonment, and subsidence.

Reclamation costs are based on the State of Wyoming being the contractor and LQD Guideline No. 12, Standardized Reclamation Performance Bond Format and Cost Calculation Methods (LQD 2006).

7.7 R&D RATIONALE AND DESCRIPTION

The R&D License also requires the applicant to include a research section with the permit application. This section should include an introduction (including identification of procedures to be tested and evaluated in this particular geologic setting), an identification and description of the research methods, records and reporting, and disposal of product. The permit applicant should include a plan for submitting technical summaries of research results. Confidential status of some materials or records can be requested.

7.8 KEY ENVIRONMENTAL PERFORMANCE PARAMETERS

7.8.1 Impacts to Groundwater

A groundwater monitoring network will be required by the WDEQ to monitor any potential changes to existing groundwater levels and quality surrounding the UCG pilot site. This would involve installation of monitoring wells. Groundwater will be monitored before, during, and after gasification operations. Constituents to be monitored will depend on WDEQ requirements.

7.8.1.1 Wyoming State Engineer's Office Well Permits and Statements of Completion

Prior to drilling, all process and water monitoring wells associated with the UCG Project must be permitted with the Wyoming State Engineer's Office. For each well, the operator must complete an Application for Permit to Appropriate Groundwater. This application should contain information on the location of the well and the volume of water to be appropriated in addition to general information regarding the application. Once the well is completed, the operator must submit a Statement of Completion and Description of the Well for each of the wells containing information on the casing, pump, quality of water, etc. (Energy Technology Partners 2005)

7.8.1.2 Class III or V Underground Injection Control Well Permits

All process wells associated with UCG Projects are considered Class III UIC wells. A separate permit is not required for the process wells associated with a UCG Project because the permit is granted as a part of the R&D License. The WQD is responsible for issuing UIC permits under the Federal Clean Water Act and the WQD is involved in the review process of the R&D License application. Because they are considered UIC wells, all production and injection wells (process wells) must be checked for mechanical integrity every five years and the test procedures must be approved by the EPA (Energy Technology Partners 2005).

7.8.2 Impacts to Surface Waters

7.8.2.1 Section 404 Permit

Section 404 of the Clean Water Act establishes a program to regulate the discharge of dredged and fill material into waters of the United States, including wetlands. The need for obtaining this permit could be avoided if disturbance to wetlands and streams are avoided. This could probably be done easily for the UCG facilities and well field, however, if linear facilities are required, it can be become difficult to avoid disturbance to streams. Activities in waters of the United States that are regulated under this program include fills for development, and conversion of wetlands to uplands for farming and forestry. The basic premise of the program is that no discharge of dredged or fill material can be permitted if a practicable alternative exists that is less damaging to the aquatic environment or if the nation's waters would be significantly degraded. In other words, when you apply for a permit, you must show that you have taken steps to avoid wetland impacts where practicable; minimized potential impacts to wetlands; and provided compensation for any remaining, unavoidable impacts through activities to restore or create wetlands.

Regulated activities are controlled by a permit review process. An individual permit is usually required for potentially significant impacts. However, for most discharges that will have only minimal adverse effects, the Army Corps of Engineers often grants up-front general permits. These may be issued on a nationwide, regional, or state basis for particular categories of activities (for example, minor road crossings, utility line backfill, and bedding) as a means to expedite the permitting process. It is most likely that any permit required for UCG activities in the PRB would fall in the general permit category. If the coverage for the proposed activity falls under a general permit, no public notice is necessary and the general permit could be granted within approximately sixty days of the date of application. (Energy Technology Partners 2005)

7.8.2. NPDES Permit

Operation of a UCG Project in the PRB would most certainly generate excess water which must be either discharged, transported to a wastewater facility or injected. Transport of the water to a wastewater facility can be cost prohibitive depending on the volume of water and distance of water to be transported. A Class V UIC well is another option. However, it can have a very lengthy permitting process associated with it.

Therefore, the most feasible disposal method of the excess water would be to treat and discharge. The discharge must be permitted under the NPDES permit (Section 304 of the Clean Water Act). In Wyoming, the name of the program has been changed to Wyoming Pollutant Discharge Elimination System (WYPDES) and is administered by the WQD. The issued permits contain limitations and conditions that will assure that the state's surface water quality standards are protected.

Application for an Individual WYDES Permit must contain (in addition to general information), a description of the activities that are required to obtain an WYPDES permit and where the activity includes treatment facilities associated with the discharge, a site diagram of the treatment facilities associated with the discharge and the outfall locations. Also required are the expected quality and quantity of effluent proposed for discharge, flow rate in million gallons per day and whether the proposed discharge would be continuous or intermittent. A description of the treatment process must also be included.

Once an application has been submitted to WQD, it must undergo a completeness review by WQD (45 days). Once the application is deemed complete, WQD prepares a draft permit which is made available to the public for inspection and comment. WQD will incorporate public comment into the draft permit and issue a permit within 180 days, which will contain effluent limitations and requirements for effluent monitoring. (Energy Technology Partners 2005)

7.8.2.3 General Storm Water Permit

Construction projects that disturb five or more acres are covered under the general construction storm water permit. The five acres of disturbance does not have to be contiguous. It is reasonable that a UCG Project would disturb more than five acres and coverage under the general permit would be required. To obtain coverage under the general construction storm water permit, the operator must submit a Notice of Intent to WQD to request the coverage. The administrator will review each Notice Of Intent and make a completeness determination within thirty days of receipt at which time the administrator can make a determination on issuance or denial of the authorization for coverage under the general permit and apply conditions of authorization (Energy Technology Partners 2005)

7.8.3 Air Quality Considerations

Trials have shown that cavity growth and methane production increase with the depth of gasification. The process at depth is more efficient and air emissions will be correspondingly less. In addition, the prospects of watercourse contamination, subsidence and gas escape will be substantially reduced with a deeper coal seam.

Air quality is permitted and monitored by the AQD, who derives their authority from the Federal Clean Air Act and the Environmental Quality Act. The AQD has developed certain Standards and Regulations to be followed in compliance with the Clean Air Act and the Wyoming Environmental Quality Act. According to the Wyoming Environmental Quality Act, any facility that has the potential to emit one hundred tons or more per year of any pollutant regulated under the Clean Air Act and is a major stationary source, is required to obtain an operating permit. There are other conditions that would also require an operating permit but it is reasonable to expect that a UCG Project would have emissions of more than 100 tons per year of a pollutant regulated under the Clean Air Act and therefore, an air quality operating permit would be required.

Before any work is begun on a facility (ground disturbance), the operator is required to obtain a construction permit. The permit application must include site information, plans, descriptions, specifications, and drawings showing the design of the source, the nature and amount of the emissions and the manner in which it will be operated and controlled. A detailed schedule for construction must also be included. Existing concentration levels of all affected pollutants must be established. This may require that the operator conduct continuous ambient air quality monitoring analyses to assure that adequate data are available. A general guideline is that data be gathered continuously over a one year period preceding the date of application. If existing data is available, it may be sufficient for this requirement. The application must show that the proposed facility will comply with all rules and regulations of the AQD and with the intent of the Wyoming Environmental Quality Act; will not prevent the attainment or maintenance of any ambient air quality standard; and will not cause significant deterioration of existing ambient air quality in the region as defined by any Wyoming standard or regulation that might address significant deterioration. The UCG plant will be located in accordance with proper land use planning as determined by the appropriate state or local agency charged with such responsibility and will utilize the Best Available Control Technology. The plant will have provisions for measuring the emissions of significant air contaminants; will achieve the performance specified in the application of the permit to construct or modify; and will not emit any air pollutant in amounts which will prevent attainment or maintenance by any other state or interfere with measures required by the Federal Clean Air Act to be included in the applicable Implementation Plan for any other state to prevent significant deterioration of air quality or to protect visibility.

Each application will be reviewed within thirty days of submission for completeness. If the application is deemed complete, the Administrator will propose approval, conditional approval or denial and will publish the proposal within sixty days of the determination. The permit to construct would remain in effect until the permit to operate is granted. The approval to construct will become invalid if construction is not commenced within 24 months after receipt of approval. An operating permit application must be submitted to AQD within twelve months of commencing operation. (Energy Technology Partners 2005)

7.8.4 Surface Impacts

Subsidence is the process that can create surface disruptions, excessive groundwater influx, mixing groundwater of separate water-bearing units, and groundwater contamination. Subsidence results when the roof collapses into the void volume created from the removal of coal in the UCG process. In UCG application, particularly commercial application, subsidence will occur. It is important to mitigate any detrimental effects of the subsidence.

7.9 PERMITTING STRATEGY

The permitting strategy is based on the experiences of the authors, interviews with regulatory personnel, review of environmental regulations, and a review of a relatively recent permit application (Carbon County UCG Project). The strategy will include suggested communication protocols, relationship elements, and timing suggestions.

7.9.1 Working with Regulatory Personnel

The most important element in a cost-effective permitting approach is to develop a good working relationship with the regulatory personnel who will be reviewing and approving the permit applications. The relationship should be developed based on respect, communication, and documentation.

7.9.1.1 Communications with Regulatory Personnel

Lines of communication should be established at the earliest possible time. Responsible regulatory personnel need to be identified. The organization responsible for the project needs to designate a representative to serve as the main contact with the regulatory agencies. A backup representative should also be designated. The selected individuals should have the authority to represent the organization.

Information meetings with regulatory personnel should be conducted at the project's inception. At the meetings, a project description is presented including planned environmental controls. Regulatory personnel should be questioned on their view of the important areas that need to be addressed in the permitting applications.

Frequent status meetings with regulatory personnel should be conducted during the permitting process. Outlines and schedules for the individual sections should be presented and discussed. These meetings should be conducted on a monthly basis.

7.9.1.2 Documentation

All communications should be documented. This includes phone calls, e-mails, and meetings. Copies of all communication documents should be copied to the appropriate environmental regulatory agencies for review. This is especially important for verbal agreements.

7.9.2 Permitting Application – Schedule Reduction

A realistic timeframe for the entire permit application phase is 20-24 months after site selection. This requires an extensive resource effort. The Carbon County UCG project took approximately 24 months from site selection to application approval. A review of the permitting applications for a UCG project plus interviews with regulatory personnel revealed some methods that have the potential to reduce the permit application period to 18-20 months. A number of recommendations follow for reducing the permitting time requirement.

7.9.2.1 Stay on State Lands to Eliminate One Layer of Review

Federal properties and mineral rights require the application of the National Environmental Policy Act. State and private lands do not have this requirement. The selected property should be private surface and mineral ownership. Federal rights of way for roads should also be avoided if possible. Potential time-savings: 2-6 weeks.

7.9.2.2 Develop Conceptual Design and Project Description Early

The development of the conceptual design and project description should begin immediately after the decision to proceed with the project. These elements of the project can begin before the site is selected and should be presented to the regulatory agencies at the initial meetings. Potential time-savings: 2-6 weeks.

7.9.2.3 Get Early Agreement on Application Content

Based on regulations and discussions with regulatory personnel, define specifics of the various application sections. An outline of the specifics should be drafted and submitted to the regulatory agencies for comment. All regulatory agencies responsible for the permit approvals should review the permit application specifics. Potential time-savings: up to six months.

7.9.2.4 Negotiate Application Submittal With Reduced Baseline Monitoring

Appendix D-9, Hydrology, requires four quarters of groundwater baseline-monitoring before application submittal. The applying organization should negotiate with the WDEQ to allow permit application with two or three quarterly sampling events. The remaining sampling events would still be conducted and would be amended into the permit after they are completed. Potential time-savings: up to three months.

7.9.2.5 Incorporate RM1 Protocols for Best Available Control Technology

Groundwater remediation plans should incorporate the protocols developed from the environmentally successful RM1 UCG test. These protocols are designed to minimize impacts and reduce remediation costs. The protocols are supported by WDEQ personnel.

7.9.2.6 Perform Required Surveys Early

After site selection, required surveys should begin at the earliest time possible. This is particularly important for surveys that have seasonal multiple survey requirements (e.g. wildlife survey). Some surveys need to be conducted prior to surface disturbance. Required surveys include: Appendix D-3, Archaeological and Paleontological, LQD Guideline 11; Appendix D-4, Climatology, may require the installation of a monitoring station; Appendix D-7, Soil Assessment, Soil Inventory, LQD Guideline 1; Appendix D-8, Vegetation, Vegetation Survey, LQD Guideline 2 and Appendix D-9, Wildlife, Requires Seasonal Surveys, LQD Guideline 5.

7.9.2.7 Thoroughly Address Critical Concerns

The permitting organization must thoroughly address four critical areas: groundwater contamination, aquifer interconnections, subsidence, and surface reclamation.

7.9.2.8 Submit a Complete Application

Efforts should be made to submit a complete application for the completeness and technical reviews. Review of the Carbon County UCG permit application showed that WDEQ requested substantial information and clarification after the permitting application was submitted. This probably delayed issuing the permit approval. Potential time-savings: up to six months.

7.9.2.9 Respond Immediately to Requests

Request for information or clarifications from regulatory agencies require immediate and complete responses to reduce review time. Potential time-savings: up to 8 weeks.

7.9.2.10 Prepare for Public Comments

The project developer should expect and be prepared for public comments. These will likely come from environmental groups. Public meetings to present the project and environmental remediation plans could reduce the impacts of these public comments. Potential time-savings: up to 8 weeks.

7.9.2.11 Permitting Timeline

A timeline for completing the permitting process has been provided as Attachment 7-1.

8. 0 INFRASTRUCTURE AND SITE CONDITIONS

8.1 SURFACE AND SUBSURFACE (MINERAL) OWNERSHIP OF LAND IN THE PRB

Surface ownership is identified in Attachment 8-1 and Table 8-1 summarizes the amount of surface ownership in the PRB. A total of 77.8 percent of the surface ownership in the basin is private, while approximately 14 percent is federal with the BLM managing approximately eleven percent, and the US Forest Service (USFS) managing approximately three percent. The USFS land is in the Thunder Basin National Grassland and is administered by the Medicine Bow – Routt National Forest. The State of Wyoming owns approximately eight percent of the land in the PRB, most of which is State Trust land provided to the state by the federal government at the time of statehood to support public schools and a limited number of other public facilities. The Wyoming Office of State Lands and Investments administers state lands (ENSR 2005). The map in Attachment 8-1 differentiates between federal and non-federal surface land ownership.

TABLE 8-1. SUMMARY OF SURFACE OWNERSHIP IN THE PRB

Ownership	Acres	Percent
BLM -- Federal	873,438	11.0
USFS -- Federal	254,592	3.2
State of Wyoming	628,702	7.9
Private	6,158,638	77.8
Total	**7,915,370**	**100.0**

In contrast to the surface ownership, mineral rights in much of the basin are "split-estates," meaning the surface owner is different from the owner of the mineral rights. In much of the area, the surface is privately owned, but the mineral rights are at least partly federally owned. Although the federal government owns all mineral rights on large portions of the basin, there are also sizable areas where it owns only the coal rights and somewhat smaller areas where it owns only oil and gas rights. There are a few small areas where the federal government owns coal and oil and gas rights, but no others; and where it owns other rights such as uranium and bentonite, and salable minerals, such as sand and gravel. Generally, where the USFS or the BLM manages the surface estate, the federal government also owns all of the mineral rights. The minerals ownership patterns generally are much more complex where the surface rights are privately owned. The State of Wyoming typically owns the mineral rights for a majority of the state trust lands, although there also are areas where the federal government owns mineral rights on state surface lands.

The map in Attachment 8-2 identifies locations in the PRB where the mineral or subsurface rights are federally owned. Metadata for this figure was acquired from the USGS. Nonfederal areas are owned by state and private interests. In addition, there are areas scattered throughout the basin where the federal government owns no mineral rights. The largest of these is in western Sheridan County and northwest Johnson County from the Bighorn National Forest boundary eastward beyond I-90 and I-25. There is a similar large area in a broad swath along I-25, across Converse County and a smaller area along the eastern boundary of Campbell County, approximately ten miles east of Gillette.

Surface and subsurface (mineral) ownership information was obtained by reviewing maps provided in the PRB EIS. In addition, CBM well data, obtained from the WOGCC website, was referenced.

8.2 CURRENT LAND USE CONSIDERATIONS

The principal current land use in the PRB is agricultural (grazing) with energy development following closely. Energy development includes oil and gas field development and surface and sub-surface coal mining. Land use is dominated by ranches that raise cattle, sheep and smaller numbers of bison. Attachment 8-3 (Land Use) shows the vast amounts of rangeland in this area.

8.2.1 Grazing/Agriculture

Land in the Powder River Basin has historically been used for agricultural purposes which include the raising and grazing of livestock (cattle and sheep), and the farming of hay crops for winter feed. The drought that occurred from 1930 - 1940 severely damaged the farming industry and caused the abandonment of many homesteads, which resulted in the land reverting to range. Grazing is the current dominant agricultural land use today. Principal crops are wheat, oats, barley and hay grown under dry land farming methods. Because of the low precipitation and shallow soils, much of the land in Campbell County is better suited to raising cattle and sheep than to cultivating crops.

8.2.2 Energy Development

Energy development is also a major land use and includes the extraction of oil, gas (natural gas and coal bed methane), and coal. The first commercial oil field discovery in Campbell County was made in 1948, but it wasn't until the 1960s that oil became an important industry. Since then, the county has become a leader statewide for drilling activity and new discoveries. Development of coal bed methane natural gas is a recent major land use in the basin. Although it has been known for many years that methane often vents from shallow water wells and coal exploration drill holes in the PRB, drilling for CBM only began in 1986. The first economic production of CBM from the PRB occurred in the Rawhide Butte field north of Gillette, where production began in 1989. CBM development has been expanding rapidly since 1993 and began accelerating in 1997. During the period of 1976 to 1996, 1169 CBM wells were drilled. CBM drilling during 1997 to 1999 increased dramatically to 4,379 wells. During 2000, CBM development activity exploded and 3,831 new wells were drilled in the PRB. About 4000 CBM wells were producing as of October 2000. From January 1994 through May 2001, CBM production increased at a rate of 65 percent per year. During 2000, a total of 150,544,625 million cubic feet (mcf) of methane and 370,994,154 bbl of water were produced from PRB coal beds in Wyoming. By the end of 2006, about 23,500 CBM wells were drilled or permitted for drilling in the basin. Table 8-2 summarizes current CBM activity in the PRB using data from the WOGCC web site (WOGCC 2007).

TABLE 8-2. CBM ACTIVITY IN THE PRB BY COUNTY

County	Number of Completed Wells	Total Gas Produced in 2006 (mcf)
Campbell	16,274	238,736,345
Converse	64	168,733
Johnson	3,499	50,672,230
Sheridan	3,702	46,140,370
Totals:	***23,539***	***335,717,678***

Coal mining has also been a substantial land use in the basin. When early settlers came to northeastern Wyoming in the early 1900s, they used coal to heat their farm and ranch houses and later used it to provide electricity. Coal is extracted using either underground mining or surface mining techniques. Underground mining was a key land use in Sheridan County, and has accounted for 78 percent or 47.8 million tons of Sheridan County's cumulative coal production (61.5 million tons). This tonnage has come from 69 or deeper mines, most of which are located in the Acme area north of Sheridan. Strip mining began in 1939, accounted for more annual production than underground mines by 1952, and completely replaced deep mining by 1959. In 1977, one strip mine produced all the coal mined in Sheridan County. This one active mine, the Big Horn No. 1 strip mine, is owned by Big Horn Coal Company, a subsidiary of Peter Kiewit Sons, Inc. The mine is located near Acme, Wyoming, about six miles north of Sheridan. Most of Big Horn's coal is sold to power plants in Illinois, Missouri and South Dakota. As in many of the state's early coal-producing counties, most tonnage from Sheridan County has come from underground mines, rather than strip mines. The largest underground coal mines in Sheridan County were in the Acme area and developed the Monarch, Carney or various Dietz coals of the Fort Union Formation. All of these mines were "mined out" before the 1970s and are currently inactive (WGS 1978).

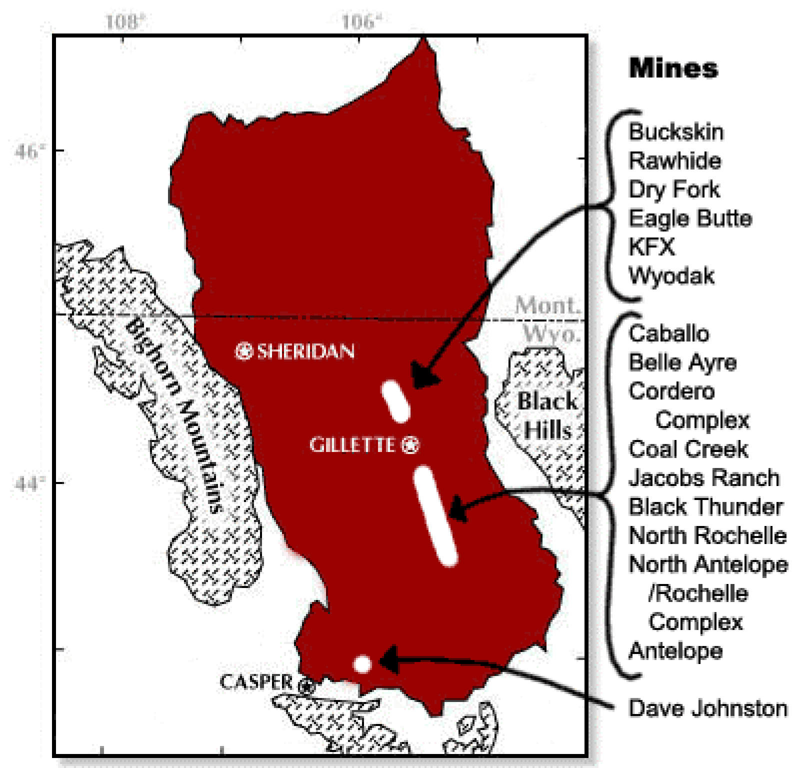


FIGURE 8-1. LOCATION OF PRB COAL MINES

Recorded coal mining in Johnson County dates back to 1888 however, no significant production has ever come from the county. Annual production peaked in 1922 at only 16,221 tons. Soon after World War II, production began a rapid decline that culminated in the closing of Johnson County's last coal mine in 1957. Johnson County's cumulative coal production from 70 years of mining is only 462,041 tons -- of which underground mining accounts for 99.9 percent of the total. During the county's long mining history, no less than 66 mines were operated, at first to supply Buffalo and Fort McKinney and later to supply other communities and ranches in and around the county. Small wagon mines were operated all along the coal outcrops in central and southern Johnson County with the larger mines centered around Buffalo.

In 2006, twelve mine complexes were operating in the PRB. All but one are in line north and south of the city of Gillette, and all of them mine the 100-foot thick Wyodak coal seam. Figure 8-1 identifies the approximate locations of these mines (University of Wyoming 2004). In 2006, Wyoming surface coal mines produced over 440 million tons of coal, making Wyoming the largest coal producer and the largest energy-exporting state in the U.S. The vast majority of this production, about 93 percent, was from the mines on the east side of the PRB.

8.3 UCG SITE SELECTION CRITERIA – SURFACE CONSIDERATIONS

8.3.1 Cultural and Paleontological Resources in the PRB

Since the first people arrived in the PRB approximately 12,000 years ago, the occupants of this region have left behind an abundant cultural record. Cultural resources in the PRB range from stone circles, or "tipi rings," to ceramics, to the Bozeman Trail, and historic ranches. This is seen in the archaeological record, historic record, and Native American affiliation with the area. In addition to human occupation, a paleontological record is present in local fossil bearing formations. These geologic deposits are of scientific worth and are valued as well as cultural resources.

Cultural and paleontological resources of importance in this study, as outlined by the LQD Guideline No. 11: Reporting Cultural and Paleontological Resources within Mine Permit Areas, include those classified as cultural, historic, prehistoric and paleontological. The guidelines further state that an inventory of all cultural or paleontological resources in the proposed area of development be conducted. All recorded articles then must be evaluated for "significance" which, in cultural resources is determined by eligibility for National Register of Historic Places (NRHP), and for paleontological resources is evaluated by a certified professional paleontologist. Finally, a mitigation process must precede any further development through either avoidance or data recovery (LQD 1994f).

8.3.1.1 Cultural Resources

Several Native American tribes are known to have ties to the PRB. These people include the Arikara, Crow, Lakota/Dakota, Arapaho, Kiowa, Comanche, Blackfeet, Cheyenne, and Shoshone (BLM 2007). However, "general ethnographies…. do not provide information on specific resources in the study that are likely to be traditional cultural concerns because these resources are considered confidential by the tribes" (ENSR 2005)

Traditional cultural resources are found both in the archaeological record and in oral history, as there is not always physical evidence. Areas of potential concern include unique features on the landscape such as prominences or buttes (e.g. Devil's Tower), flowing water (especially near buttes), any area with rock art, vision quests, rock cairns, or medicine wheels. However, a sacred site is not always obvious as more common archaeological sites such as tipi rings and game drives possibly have religious significance as well (ENSR 2005).

8.3.1.2 Historic Resources

There are three known "significant" historic resources in the proposed UCG development area. Two segments of the Bozeman Trail, the Nine Mile Segment (Campbell County) and the Ross Flat Segment (Converse County), as well as a historic bridge in Johnson County are listed on the National Register of Historic Places. However, there are hundreds of other historic sites that have not necessarily been nominated for the NRHP that should be treated as potentially eligible and either evaluated further or altogether avoided (Wyoming SHPO 2007).

8.3.1.3 Prehistoric Resources

The archaeological record of the PRB spans approximately 12,000 years of occupation (Frison 1991). As a result, thousands of sites have been discovered in this area. The materials recorded vary greatly, some of which are tipi rings, rock art, game drives, ceramics, bone beds, rock alignments, artifact scatters, stone material procurement areas and weaponry creating an extensive archaeological record (Wyoming SHPO 2007).

8.3.1.4 Paleontological Resources

Paleontological data pertaining to the PRB is fairly scarce, as little research has been conducted. However, it is certain that paleontological resources are present throughout (Dale Hanson, personal communication 2007). Different geological formations contain vertebrate, invertebrate, plant, and trace fossils. The PRB EIS (Chapter 3) discusses the paleontological resources within the PRB as such: the Wasatch Formation and Fort Union Formation are the two most prominent geological units in the project area as well as two of the most fossiliferous. Neither is greatly exposed as the bedrock is mostly covered with vegetation. The Wasatch Formation creates the bedrock within the proposed UCG development area and is known to contain the remains of small, rodent-sized animals. This formation regularly contains fossil bearing Eocene and Paleocene deposits and over 156 localities have been recorded. Tertiary paleontological deposits are present in the Fort Union formation and although fossils are abundant, no significant sites have been recorded.

8.3.1.5 Permitting Requirements

At this time it is unclear in the wording of the DEQ guideline whether it is necessary for tribal consultation prior to area development. If so, it is during the final period of cultural investigation (before mitigation) that affiliated tribes will express any concerns regarding the location of a UCG facility. Even if tribal consultation is not necessary, it is still important to avoid the aforementioned areas as they often are of archaeological or historic value as well as cultural importance.

After specific land has been selected for use, it will be necessary to research the SHPO database and conduct a systematic survey on lands that have not been previously surveyed. An archaeological survey will also be required and any archaeological/historic sites they find must be reported before land development can occur (LQD 1994f).

8.3.2 Wildlife Concerns in the PRB

The abundant wildlife in the PRB is a concern in land development, especially mineral production. Wildlife thrives in the region due to a variety of resources and enhances the local economy through hunting, fishing, and wildlife viewing (BLM 2007). Mineral development tends to have more of a short-term effect on the environment and the Coal Review - Section 2.4 (ENSR 2005) states that, "direct impacts to wildlife populations… could include limited direct mortalities, habitat loss or alteration, habitat fragmentation, and animal displacement. Indirect impacts could include increased noise, additional human presence, and the potential for increased vehicle-related mortalities." The DEQ incorporates wildlife guidelines (LQD 1994d) into their permitting process in order to better protect local wildlife and fisheries.

8.3.2.1 LQD Wildlife Regulations

The DEQ outlines specific regulations regarding wildlife and mine permitting. It states that a wildlife inventory is necessary prior to land development in order to provide data on the composition of the wildlife community, species diversity, and habitat affinity prior to mining; mining impacts upon wildlife and habitat; and effectiveness of mitigation and reclamation proposals. The inventory should include a description of the vertebrate fauna of the area (potential, actual, habitat description, habitat affinity), seasonal data collection (big game, upland game birds, raptors, waterfowl and shorebirds, passerine birds, other mammals, threatened and endangered species, reptiles and amphibians, and fish), data analysis, a mitigation plan, and a reclamation plan. Furthermore, federal laws pertaining to wildlife (particularly those pertaining to endangered species) must be followed. Finally, a monitoring plan must be submitted and followed by the developer. This monitoring will be custom fit to each specific mine site (LQD 1994d).

8.3.2.2 Wildlife Habitat

According to the BLM Coal Review - Section 2.4, the most common habitats affected by coal mining are the mixed-grass and short-grass prairies as well as sagebrush shrublands. Also affected, although to a lesser extent, are coniferous forest, riparian/wetland, and aquatic habitats. Much is known about various habitats and the resident species. Through current literature, information is accessible pertaining to the habitat fragmentation of: big game, upland game birds, raptors, and other non-game birds. There is at least basic literature available on all of the habitats and species in the PRB. There are some species that receive special "sensitive" status through federal lists, the BLM, the USFS, and the Wyoming Game and Fish Department.

The guidelines for the DEQ permit require an inventory however; they also note that it is possible to bypass a yearlong physical inventory as long as equivalent information (collected in the past five years) is cited. This exception may factor into the selection of a UCG development area.

8.3.3 Vegetation in the PRB

A major concern in site development and restoration is the preservation of the original vegetation composition. Short-term land use, such as mining, allows for site restoration upon the conclusion of mineral production and is mandatory through the DEQ. Proper re-vegetation is important for several reasons pertaining to post-mining land use, as "land use is directly supported by the existing plant communities" (WDEQ 1994b).

Very specific vegetation guidelines are outlined in the LQD Guideline No. 2 (1994b) that are mandatory in permitting a site. The guideline outlines the acceptable procedures for conducting baseline vegetation inventories, sampling procedures, successful re-vegetation planning, restoration, and testing for successful reclamation. The guidelines are very precise in how the area is to be sampled, re-seeded, and maintained.

The most common vegetation is known to include mixed-grass and short-grass prairies as well as sagebrush shrublands (ENSR 2005). However, LQD Guideline No. 2 (1994b) requests that the developer inventory the selected site as opposed to using existing general vegetation data (e.g. general data on short grass prairies) to better provide for successful re-vegetation.

8.3.4 Infrastructure

The costs associated with creating an entirely new infrastructure to service a UCG demonstration facility are significant. Locating the UCG demonstration project in an area where adequate infrastructure already exists can considerably reduce impacts and costs. The benefit of locating the site near existing power lines and/or natural gas pipelines is also obvious. However, locating a UCG facility on directly over existing pipelines could result in damage to the pipeline from surface subsidence.

A careful review of maps from a variety of sources were analyzed to locate major roads, cities, railroad corridors, natural gas pipelines, oilfield and natural gas activity, coal bed methane activity, surface coal mines, and airfield locations. GIS layers from sources such as ESRI and the USGS were compiled for use with this analysis so reviewers could readily observe activity throughout the basin. Using this analysis, areas were identified that would be either suitable or unsuitable for UCG based on infrastructure availability. A ranking system was utilized that included the following criteria:

- Areas that could be accessed by a paved road were preferable to areas without paved roads.
- Areas with natural gas pipelines within two miles were preferable to those areas where pipelines were at a greater distance.
- Areas where power lines were within two miles were preferable to locations where power was not immediately accessible.
- Areas where coal bed methane wells appeared to be mostly depleted were most preferable, areas where no coal bed methane was currently developed were considered good but not excellent, and areas where coal bed methane wells are currently and actively being produced were considered unacceptable as sites for a UCG facility at this time. Subsequent UCG development can follow CBM activities and utilize existing well bores and other surface infrastructure.
- Oil and gas fields were considered with the concern that actively producing fields might be adversely affected if a UCG facility was sited at less than three miles distance. Depleted oil and gas fields could prove beneficial for carbon sequestration.

This information was added to the PRB UCG Database that was described in Section 5.0.

8.3.4.1 Transportation – Roads, Rail Roads and Air Service

<u>Primary Roadways-</u> In the approximately 120 mile by 140 miles area of the PRB, there are only two four-lane interstate highways. Interstate 25 (I-25), extends north-south from the Colorado border south of Cheyenne, through Douglas (Converse Co.), Casper (Natrona Co.), and Buffalo (Johnson Co.), and merges with Interstate 90 (I-90) at Buffalo. I-90 enters northern Campbell County from the east, passes through Gillette and continues in a westerly direction through Johnson County to Buffalo, then continues in a northerly direction to Sheridan (Sheridan Co.). At Sheridan, it continues in a northerly direction into

Montana. Primary two-lane highways in the basin include U.S. Highways 14 and 16. Highway 16 enters Wyoming from South Dakota and extends in a northwesterly direction to Moorcroft, where it merges with Highway 14 and extends through Gillette. It continues in a northerly direction from Gillette to U-Cross, where the two highways separate. Highway 14 continues in a westerly direction until it leaves Sheridan County. It continues across the northern portion of the state and terminates at Yellowstone National Park. Highway 16 continues in a southwesterly direction until it exits Johnson County and terminates at Worland.

Secondary Roadways- Campbell County is bisected on a north-south route by State Highway 59, which is a two lane, paved road that extends from Converse County through Gillette in Campbell County, and into Montana. State Highway 387 extends in an east-west direction from T. 44 N, R. 71W in Campbell County to T. 41N, R. 78W in Johnson County. State Highway 50 extends southerly from Gillette to intersect with State Highway 387 at approximately its mid-point between Linch and Wright. Savageton, WY is located at the midpoint of this highway.

Several short segments of U.S. highways and secondary state roads and numerous county roads also provide local access to public and private lands. In addition, there is a complex network of essentially unimproved and only minimally maintained, local roads serving the area, some of which are not open to public access without landowner permission (ENSR 2005). Primary roads and highways are identified on Attachment 8-4.

Railroad Lines- Railroad lines also traverse the PRB and are primarily used for transportation of cargo such as coal and livestock. The major railroad lines are Union Pacific and Burlington Northern. The Union Pacific Railroad runs north from Converse County through Campbell County and becomes Burlington Northern southeast of Gillette. Burlington Northern tees horizontally due east of Gillette and runs east to Crook County and west to Sheridan County. Spurs are located outside of Wright in Campbell County (Rag/Amax Coal Company) and another in central Campbell County (same ownership). Attachment 7-5 shows the location and ownership of all rail lines in the state and specifically the counties in the PRB.

Current coal train traffic averages approximately 144 coal unit trains (loaded and empty) per day; 110 on the southern route and 34 on the northern route. The volume of coal shipped per train ranges from 118 to 135 one hundred ton cars. Over 75 percent of the coal trains currently head south out of the PRB (ENSR 2005).

8.3.4.2 Current and Proposed Power Line Distribution

There are two major electric power line corridors through the PRB, both running in a generally north-south direction. Both corridors contain 230-kilovolt power lines. The westerly corridor essentially parallels the I-90 corridor southward from the Montana border, passes around the City of Sheridan on the east, passes the City of Buffalo, also on the east side, and then connects into the I-25 corridor, which it parallels through Casper, Douglas, and on south to the Laramie River Station near Wheatland. The second major electric transmission corridor runs along the east side of the PRB. As part of the regional grid, it connects the Wyodak/Neil Simpson/Wygen Power Plant complex near Gillette to the 750 MW Dave Johnston Power Plant operated by Rocky Mountain Power near Glenrock (ENSR 2005).

Electric transmission capacity in Wyoming is changing. The Department of Energy recently completed an energy corridor study and recommended several improvements to Wyoming's power transmission system. Under Recommendations One and Two, line capacity would be increased by adding a 345 KV line from the Colorado border to Gillette, roughly following the Interstate 25 highway corridor. Four Phase Shifters would be added to boost power, two of which are located in the PRB area.

Recommendation Two addresses additional power transmission in other parts of Wyoming (Waddington 2006). A study conducted in Fall 2005 by a public/private partnership consisting of the Wyoming Infrastructure Authority, Trans-Elect, and Western Area Power Administration indicated that the increased power transmission in the PRB would be well received and economically beneficial to the state and is currently under investigation by the study group.

Attachment 8-4 (Infrastructure) locates major highways, rivers, key cities, the electrical power corridor, and railroads in the PRB. Knowing the location of these key elements is essential for the proper location of a UCG facility.

8.3.4.3 Major Pipeline Locations

Major natural gas pipelines are located and identified on Attachment 8-4. Due to a long history of oil and natural gas production, the PRB is home to an extensive network of oil and gas transportation pipelines. Currently, the gas collection network is expanding as new areas are being developed for CBM production. Among the major crude oil lines are the 18-inch Belle Fourche pipeline running northeast from a junction near Kaycee to the Montana State line near the Campbell-Crook County line, and the 18-inch Rocky Mountain Pipeline System running south to Casper from the same junction northeast of Kaycee.

There are numerous large diameter natural gas pipelines carrying gas from the extensive network of gathering lines to markets outside the basin, mainly to the south. There are a pair of parallel 24-inch Fort Union Gas Gathering System lines running nearly straight south from southeast of Gillette to the I-25 corridor west of Douglas. There is a 24-inch Thunder Creek Gas Services line also running nearly straight south from gas fields northwest of Gillette to the I-25 corridor between Douglas and Casper. There are two 16-inch lines running southerly from the Western Gas Resources processing plant northeast of Wright. One is a Kinder Morgan operating line, which parallels SR-59 into Douglas. The other is a McCulloch Interstate Gas Company line which runs approximately 15 miles farther west, crossing the I-25 corridor west of Douglas. There are numerous smaller natural gas gathering and transmission lines that cross the PRB that are operated by nineteen pipeline companies (ENSR 2005).

The CMS Gas Gathering System in Campbell County extends from north to south, beginning at T. 58N, R. 75W and terminates at T. 56N, R. 75W. A McCulloch Gas Transmission Company (MGTC) pipeline also runs in a northeasterly direction from the northwest corner of Campbell County to about T.45N, R. 71W, where many pipelines appear to converge. A Big Horn Gas Gathering (BHGG) pipeline extends from north to south on the western side of the county from about T. 53N, R. 76W (where it has continued from Sheridan County) to T. 48N, R. 74W, where it intersects with the Fort Union Gas Gathering System – a pipeline which continues to run in a southerly direction into Converse County, where it leaves the basin. Another MGTC pipeline, which also runs north to south through the county, originates in T. 56N, R. 69W and runs south through Crook County, then re-enters Campbell County at T. 46N, R. 69W and terminates in T. 47N, R. 70W. A Western Gas Resources pipeline that originated in Johnson County, enters Campbell County at T. 46N, R. 77W and terminates at T. 43N, R. 74W.

The BHGG System extends easterly from the northwestern corner of the PRB in Sheridan County into Campbell County. It begins at T. 57N, R. 83W and terminates at T. 54N, R. 76W. The CMS Gas Gathering System runs approximately parallel to it. A third gas gathering system, the Bitter Creek Pipeline, also runs in the same general vicinity through Sheridan County. A fourth gas gathering system, the Williston Basin Interstate eight-inch pipeline extends north-south, originating near the city of Sheridan and extending into Johnson County. It becomes a six-inch pipeline operated by Northern Gas Company at approximately T. 45N, R. 82W and that pipeline extends into Natrona County.

The McCulloch Interstate Gas Company operates a six-inch pipeline that connects with the Williston Basin Interstate pipeline in Johnson County. It runs in an easterly direction from about T. 48N, R. 82W to Carbon County, then proceeds northeasterly to T. 51N, R. 72W where it intersects with the McCullough Interstate Gas Company's pipeline. The eighteen-inch Rawhide Pipeline extends from T. 45N, R. 79W in Johnson County in a northeasterly direction, through Campbell County to a point where it crosses the South Dakota border. The Thunder Creek Gas Services (TCGS) Pipeline extends in an easterly direction across Campbell County and terminates at T. 44N, R 70W. TCGS has a second pipeline that originates in southeastern Johnson County at T. 45N, R. 78W and dips southerly, then takes a sharp turn northeasterly, crossing into Campbell county in T. 45N, R. 76W. It extends through Campbell County to approximately T. 44N, R. 70W.

Several pipelines of varied sizes are located in Converse County. Most of them run on a north-south course through the county. Examples of these pipelines are the 24-inch Thunder Creek Pipeline, which extends from Douglas (on the west side of the county), in a northerly direction into Campbell County; the 24-inch Fort Union Gas Gathering System, which transverses the county in a north-south direction in the center of the county, and the 16-inch McCullough Interstate Gas Company pipeline, which transverses the county in a north-south direction on the eastern side of the county. Several smaller pipelines transverse the county in an east-west direction.

8.4 OIL AND GAS CONFLICTS AND POSSIBLE RESOLUTIONS

All activities on public lands draw concern for potential environmental impacts, and energy development is a major target for these concerns. The Final Environmental Impact Statement (BLM 2003) for oil and gas development in the PRB focused on impacts to:

- aquifers present in and down gradient of the project area,
- the quantity and distribution of surface water in and downstream of the project area,
- the quality of surface water in and downstream of the project area,
- the potential to adversely affect current uses of those surface waters,
- contamination of soils in and downstream of the project area,
- air quality and visibility, vegetation in and downstream of the project area - including wetlands and riparian areas, species of wildlife and their habitats (in particular, key species and habitats), fisheries and aquatic habitats, and the project area's ecological integrity and biological diversity, and
- special-concern species, particular threatened, endangered, candidate, or sensitive species of plants and animals and, rangeland resources and grazing operations.

All of these concerns must be addressed by the operator in the permitting process, impacts defined, mitigative actions proposed, and reclamation plans outlined. Additionally, the operator must be bonded for the impacts of his proposed activities and their impacts.

These same concerns would also be applicable to the UCG and will need to be addressed during the permitting process. Additional considerations pertaining to UCG include regulatory compliance with the Clean Air Act (1970), the Clean Water Act, and the Surface Mining Control and Reclamation Act (1977). In addition to the list of potential environmental concerns summarized here, UCG has inherent conflict with the oil and gas operator, both deeper oil and gas and CBM operators.

8.4.1. Deeper Oil and Gas Production

In areas where the coal seam has favorable UCG characteristics, existing oil and gas operations must be avoided. Obviously the deeper oil and/or gas well penetrates and is cased through the coal seam as it is completed in a deeper geologic horizon. The UCG process, which burns through the coal and consumes the coal seam, must avoid existing oil and gas coal well bores, and with a margin of safety distance which must be determined. If the oil or gas well is depleted, or nearly so, it may be possible for the UCG operator to contractually take over the well and use it for deep geologic sequestration of CO_2. This could also result in EOR benefits to the oil and gas operator in older oil fields. Therefore, proximity to existing oil and gas operations does not preclude UCG development. Indeed, depleted reservoirs are potential carbon sequestration sites.

8.4.2. CBM Production

The CBM operator is producing methane from the coals by pumping water to reduce the hydrostatic pressure on the coal, allowing CBM to desorb from the coal and be produced. Those coals in the PRB which are ideal for CBM production are also ideal for UCG. Again, a natural conflict can exist between the CBM operator and the UCG operator. However, the coal contains approximately 300 times the energy content of the released CBM gas (about 50,000 BTU/ton of coal in the CBM while the same ton of coal has over 16,000,000 BTU/ton of thermal energy). Therefore, the UCG has a much higher energy density and energy value than the CBM.

The conflict between CBM operator and UCG can be resolved in several ways:

- Sequential Development - the CBM operator depletes the CBM before UCG operations commence. As UCG develops as an industry in the PRB, it will have a future life of 50 to 100 years. Commercial UCG probably will not be initiated for five to ten years from now. In that time, many CBM wells that are on the east side of the PRB will be depleted and abandoned.

- Buy Out- the UCG operator acquires the CBM lessee's rights. If this is done late in the CBM well life, the cost to buy out the CBM operator will be reasonable.

- Co-Production - in areas where CBM has not worked well, or has not yet been initiated, the CBM and UCG operators may "co-produce" the CBM with the syngas and take an agreed-upon product value split. Although the energy value is 300 times greater in the coal, the CBM may marginally improve the heating value of the produced syngas.

- Staggered Development - in areas where UCG can be developed in portions of CBM fields that are depleted, adjacent to remaining CBM production, the CO_2 captured from the syngas stream can be used for ECBMR, helping the economics of the CBM operation.

Therefore, the natural conflict between the two resource development schemes can be advantageously resolved. Initial developments for UCG in the PRB will probably be on the east side of the basin where CBM has already depleted significant coal volumes.

9.0 POSSIBLE UCG PROJECT CONFIGURATIONS

To develop a sense of possible UCG configurations, one must first look at the slate of products that can be derived from coal gas. For example, the Dakota Gasification Company operates the Great Plains Synfuels Plant near Beulah, ND. The Great Plains Synfuel Plant is a coal gasification facility that produces synthetic natural gas along with a number of valuable byproducts, such as ammonium sulfate, liquid nitrogen, naphtha and phenol. This plant has been in commercial operation since the early 1980's and is a prime example of coal gas use (Dakota Gasification Company 2007). Sasol, another company utilizing coal gas, employs the Fischer-Tropsch process to develop automotive fuels and oils along with other petrochemical compounds. Sasol, operating out of Johannesburg, South Africa, has had commercial operations using coal gas since the 1950s (Sasol 2000). Integrated Gasification Combined Cycle is another coal gas process, used to generate electricity, and is commercially demonstrated by several power generation companies including Tampa Electric's Polk Power Station. The 260 MW Polk Power Station uses surface gasification to provide fuel for a combustion turbine that is combined with a conventional steam turbine through the use of a heat recovery steam generator. IGCC has proven to be an environmentally and economically favorable process due to its use of clean gas and high efficiency technologies (Tampa Electric 2001).

The above-mentioned technologies all utilize surface coal gasification technologies that require mining, transportation and preparation of coal as well as management of coal waste products. However, UCG technology is capable of producing coal gas of similar quality and composition as surface gasifiers used in the previously mentioned technologies. Furthermore, UCG has the potential to quadruple U.S. coal reserves, due to the enormous amount of unmineable coal that exists in the U.S. (Zukor and Burwell 1979). "The PRB is the single most important coal basin in the U.S. production-wise, supplying over 37 percent of the total coal produced in the U.S. in 2003."(USGS 2007). This statement emphasizes the amount of coal in the PRB. However, 95 percent of the coal in the PRB is too deep for conventional surface or underground mining and would be suitable for UCG. As was recognized almost thirty years ago, "One of the most attractive coal deposits in the U.S. for underground gasification is in the Powder River Basin of Wyoming and Montana. This one basin, 200 miles long and 70 miles wide, contains an estimated 1.3 trillion tons of thick, sub-bituminous coal, most of it too deep to mine. More than 100 billion tons could be recovered by the underground gasification process." (LLNL 1978)

9.1 METHODS FOR SYNGAS PRODUCTION VIA UCG

Syngas production is defined as the production of low-BTU syngas, using air as the oxidant, or medium-BTU gas using oxygen and steam as the oxidant. The terms "air-blown" and "air-fired", or "oxygen-blown" and "oxygen-fired" are used interchangeably in the literature and in this report.

The combustible gases in the syngas are primarily carbon monoxide and hydrogen with lesser amounts of methane. Table 9.1 provides a comparison of gas high heating value (HHV) and composition of typical low-BTU syngas. Table 9-1 is from the air-blown phase of the Hanna II Phase II field experiment. Oxygen-blown facilities will greatly increase syngas heating values due to the lack of nitrogen present in the oxidant. Nitrogen removal from the syngas product is an expensive process at the present, therefore air-blown facilities are limited in their uses for economic reasons. Oxygen-blown facilities will remove the nitrogen before it is introduced to the gasification reaction, which creates a syngas with much higher heating values and makes the product more economical for uses off site. However, the oxygen-blown system requires an air separation facility which greatly increases capital and operating costs. Figure 9-1 shows a flow diagram of a conventional UCG facility.

There are many configurations to produce syngas via UCG. Upon consideration of the previously described UCG tests, some methods are more favorable due to reduced environmental impacts and improved product gas quality.

TABLE 9-1. COMPARISON OF LOW- AND MEDIUM-BTU GASES

Gas Composition and Heating Value			
Syngas Constituent	Dry Basis Air-Blown, %	Dry Basis Oxygen-Blown, %	Dry Basis Oxygen-Blown with CO_2 Removal, %
H_2	16.7	32.7	42.5
O_2	0.0	0.0	0.0
N_2	48.8	0.0	0.0
CH_4	5.4	10.6	13.7
CO	16.1	31.5	41.0
C_2H_6	0.4	0.8	1.0
CO_2	11.8	23.1	0.0
C_3H_8	0.1	0.2	0.3
C_3H_6	0.1	0.2	0.3
I-C_4	0.0	0.0	0.0
N-C_4	0.0	0.0	0.0
AR	0.5	1.0	1.3
H_2O	0.0	0.0	0.0
Total	100.0	100.0	100.0
HHV (BTU/scf)	175	342	444

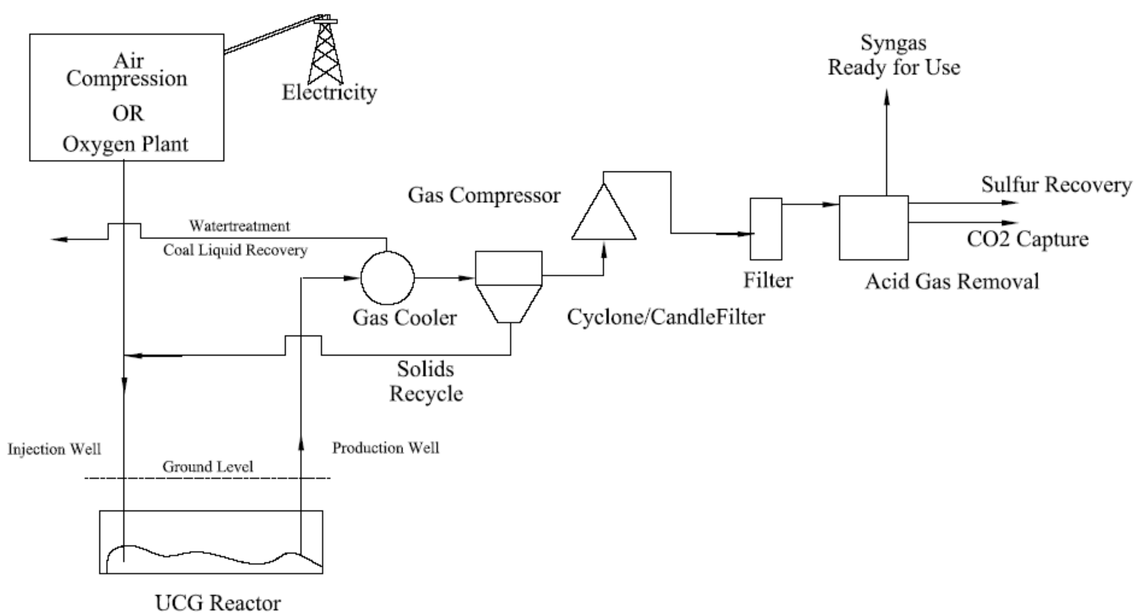


FIGURE 9-1. BLOCK FLOW DIAGRAM OF A CONVENTIONAL UCG FACILITY

All of the methods for UCG involve two steps. Step One is the preparation of the coal seam to increase its permeability, the linking step, and Step Two is gasification of the coal (Boysen and Gunn 1979). The well linkage must establish the path between the wells as the highest permeability (lowest resistance) path for the syngas. This allows gasification to proceed at relatively low pressures and high flow rates with all the produced gas leaving the geo-reactor at the production well.

All UCG processes are similar in that they require a minimum of two boreholes; one to inject the oxidant and start ignition, the other to recover the gas produced. Figure 9-2 shows this process. This can be achieved several ways depending on site selection. The most common practice would be the use of two vertical boreholes placed 40 to 500 feet apart. Other methods include directional drilling parallel to the coal seam or slant drilling at the angle of a steeply dipping coal bed.

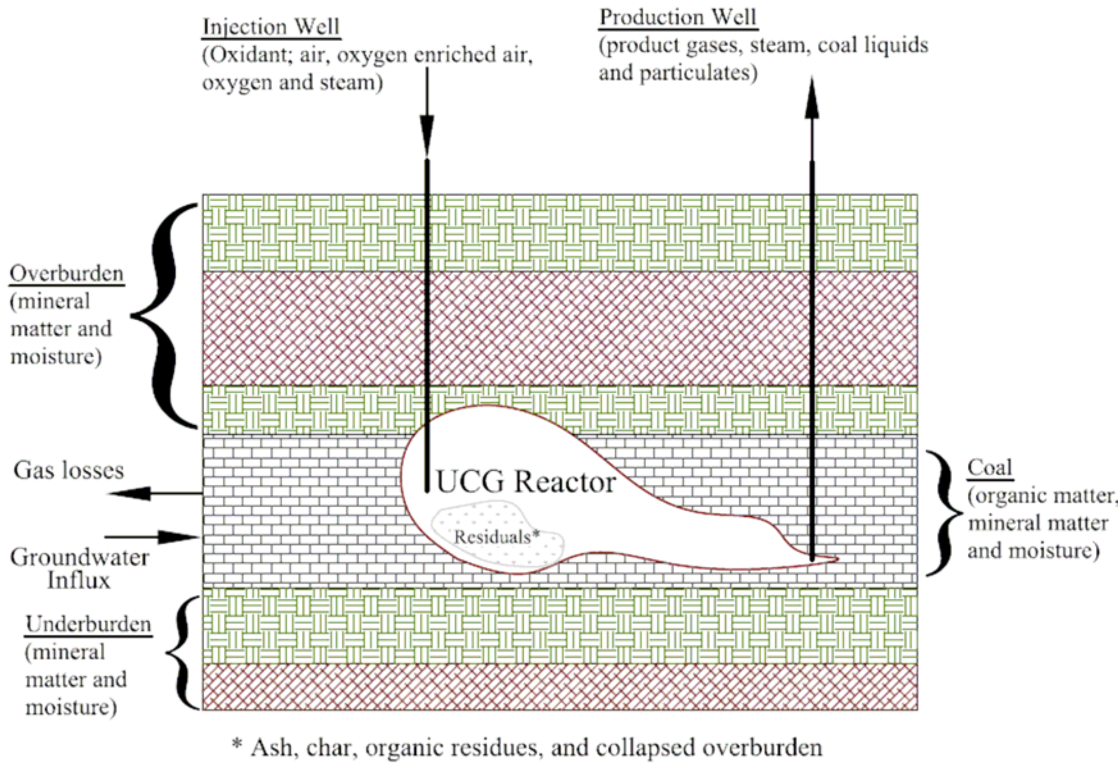


FIGURE 9-2. UCG REACTOR PROCESS

The major UCG process concepts are listed below.

The Linked Vertical Well (LVW) process was developed by the Laramie Energy Research Center at the Hanna, WY site. This process, shown in Figure 9.3, uses two vertical wells for injection and production and it utilizes the reverse combustion technique to create permeability in the coal seam (Wieber and Sikri 1976).

The Longwall Generator process was developed by the Morgantown Energy Research Center. This process uses directional drilling to place injection wells parallel to the coal seam and similar parallel wells are drilled to recover the product gases (Wieber and Sikri 1976).

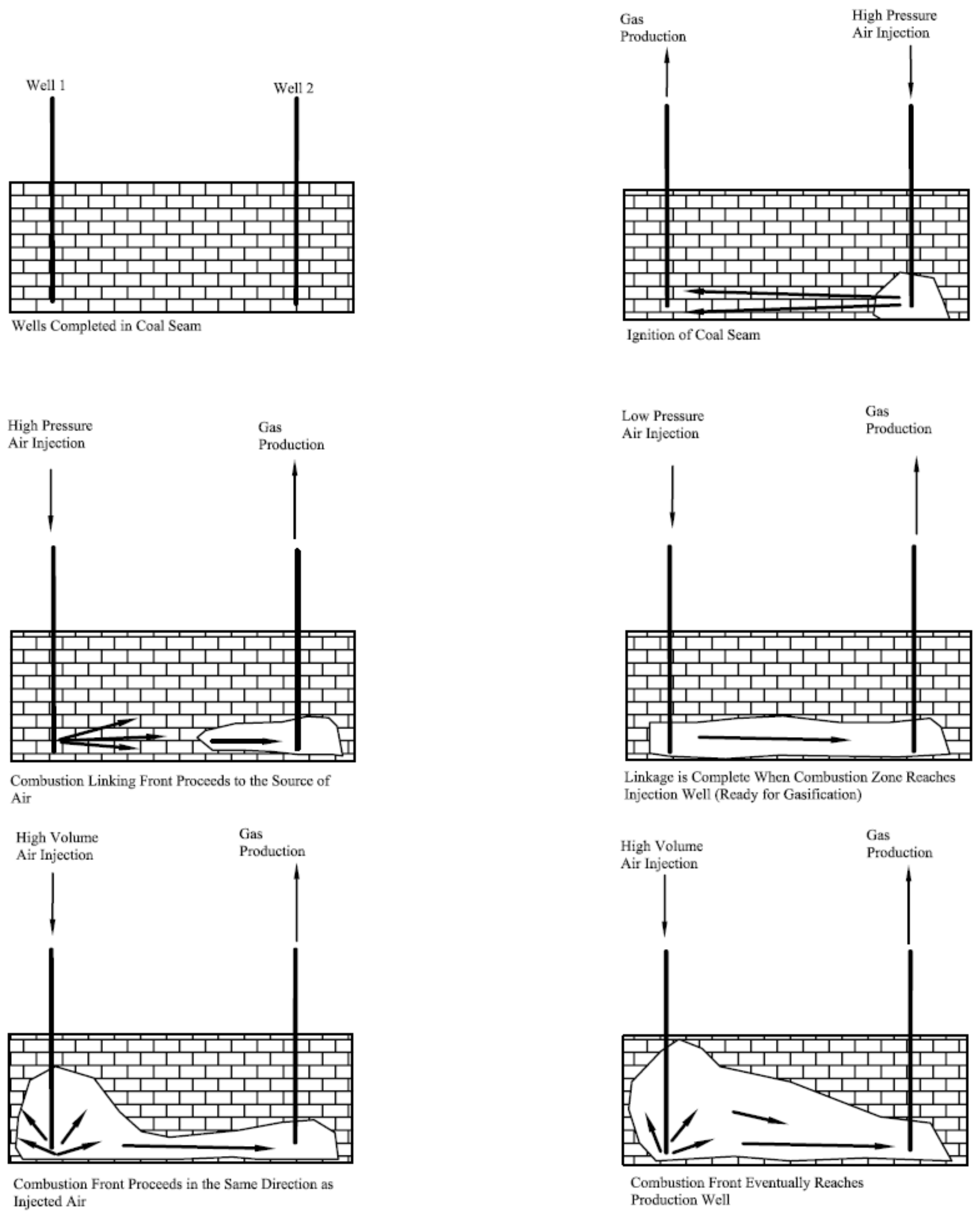


FIGURE 9-3. LVW PROCESS USING THE REVERSE COMBUSTION LINKING TECHNIQUE

The Steeply Dipping Bed concept is a process that could be used at sites where the coal seam is at an angle with respect to the surface. A vertical borehole is placed at the bottom of the coal seam for air injection and the borehole for recovery of the product gas is drilled at the angle of the coal seam. This process is site dependant because not all coal seams are steeply dipping (Wieber and Sikri 1976).

The Packed Bed concept is a process that uses vertical bore holes for injection and production wells. However, this process differs from the others because it is designed to create permeability of the coal seam using explosives. This process was developed by Lawrence Livermore Laboratory and is not considered further because it was not effective when tested in field trials(Wieber and Sikri 1976).

The Extended Linked Well configuration, which is similar to LVW, uses vertical injection wells and a horizontal production well located at the bottom of the seam to create communication between the wells (Cena et al. 1988).

The Controlled Retracting Injection Point is a process that utilizes a retractable oxidant injection well directionally drilled parallel to the bottom of the coal seam. This process allows for the injection point to be retracted as the gasification cavity matures and consumes the coal. The production well is drilled in a horizontal configuration similar to that of the injection well (Cena et al. 1988). This is depicted schematically in Figure 2-2.

The Frac/Forward Combustion process uses vertical injection and production wells. High pressure fracturing with forward combustion is used to establish well linking. This process has environmental concerns since the high pressure fracturing may result in uncontrolled creation of pathways for gas to flow that may not be in the direction of the production well, therefore contaminating the surroundings.

In summary, once a borehole configuration is established, the next process is to increase the permeability of the coal seam. Some methods for preparing the coal seam to increase its permeability are hydraulic, pneumatic, and explosive fracturing; reverse combustion linking of wells; drilling horizontal boreholes through the coal seam, and partial mining. The ELW and CRIP processes inherently create a path for gas flow due to their horizontal production wells. However, linking the wells while drilling, due to the inaccuracy of directional drilling, is difficult so reverse combustion may still be required to complete the link. Again, upon consideration of the previously mentioned UCG tests some methods of increasing permeability are favored. This is due to the fact that methods such as high pressure fracturing or explosive fracturing can greatly increase the odds of gas loss and environmental contamination.

The UCG process selection depends upon the properties of the coal, coal seam, UCG site, and desired UCG product. Therefore, optimum process design is different for each site and each product.

9.2 SYNTHETIC NATURAL GAS PRODUCTION

A simplified block flow diagram of conventional SNG production from the gasification of coal or lignite is illustrated in Figure 9-4. This diagram is representative of the Great Plains commercial SNG production plant operating in Beulah, North Dakota since 1984. In the Great Plains facility, lignite is surfaced mined by conventional methods. The lignite is then prepared for both gasification to make SNG and combustion to make the steam and electric power that are required for the SNG production. The preparation of the lignite involves crushing and screening. The larger size fraction of the lignite is fed to surface gasifiers and the smaller size fraction of the lignite is fed to the electric power plant where steam and electricity are produced. The electricity produced is primarily used to run the air compressors, oxygen plant, Rectisol and refrigeration unit, and the product gas compressors along with smaller amounts required to operate the remainder of the gasification facility. Steam produced is used for power generation and also fed to the gasifiers (Pollock 1992).

Air is compressed and fed to the oxygen plant where nitrogen, krypton, and xenon gases are removed leaving a highly pure oxygen stream which is compressed and fed to the lignite gasifiers. As previously mentioned, steam and lignite are also fed to the gasifiers. In the gasifiers, the lignite is partially combusted, pyrolyzed, and gasified in a fashion similar to that previously described for UCG. One key difference in the surface gasification of lignite compared to UCG is that the ash from the coal must be removed from the gasifiers and disposed of in an environmentally acceptable fashion (Pollock 1992). Figure 9-4 is a conventional SNG production flow diagram and shows this process.

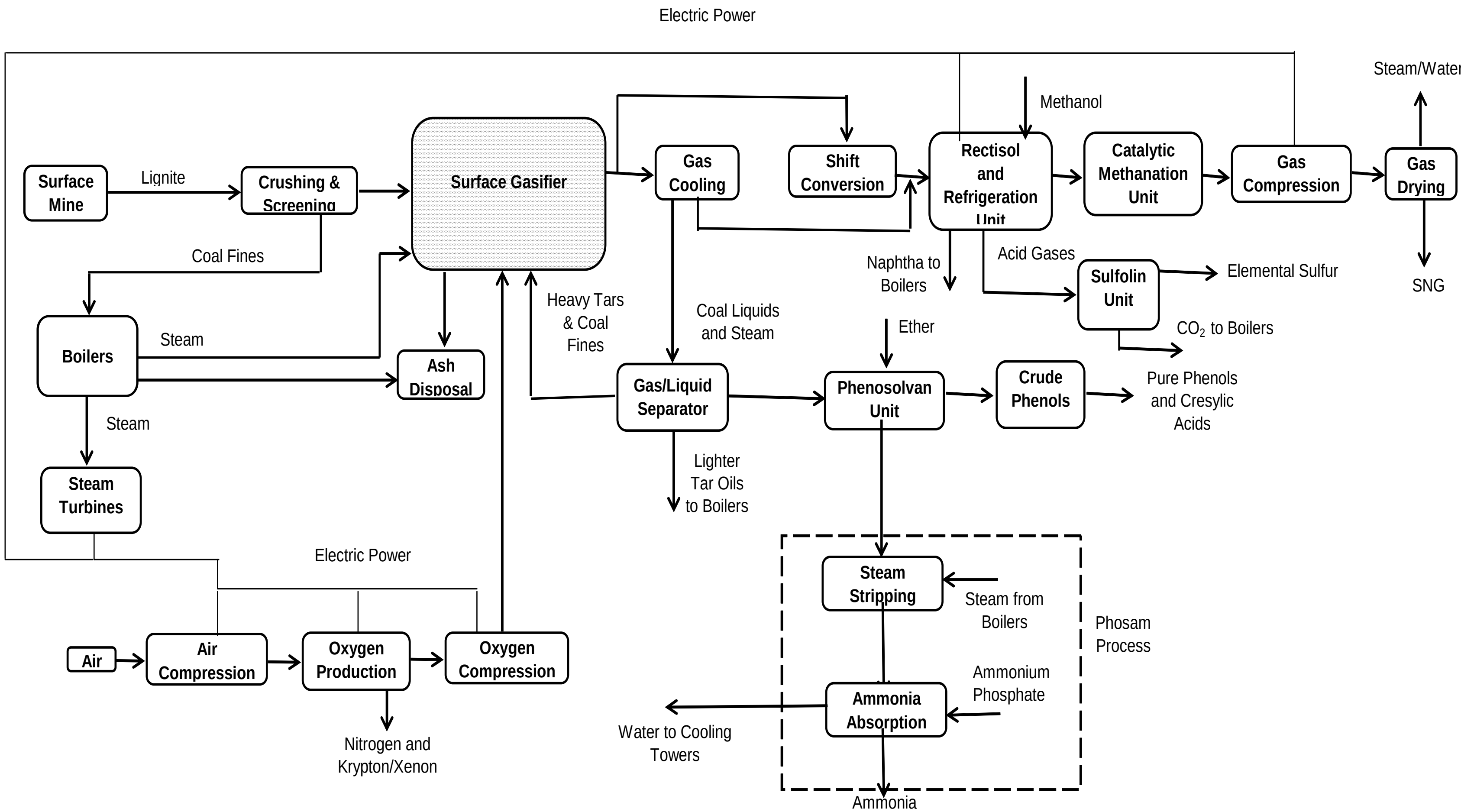


FIGURE 9-4. CONVENTIONAL SNG PRODUCTION FLOW DIAGRAM

A portion of the non-condensable medium-BTU gas produced is fed to shift conversion reactors where the ratio of hydrogen to carbon monoxide is increased so that the ratio of the total medium-BTU gas stream fed to the methanation unit is approximately 3:1. Coal liquids and steam are condensed from the remaining portion of the medium-BTU gas stream produced in the gasifiers and then this gas stream is re-mixed with the gases exiting the shift conversion reactors. The mixed gas stream is then fed to a Rectisol unit where it is washed with methanol and cooled in a refrigeration unit to remove carbon dioxide, naphtha, and hydrogen sulfide from the gas. The naphtha in the methanol stream exiting the Rectisol unit is burned in the boilers as a portion of the fuel required for the generation of steam. Acid gases (primarily carbon dioxide and hydrogen sulfide) are removed from the methanol stream and fed to a Sulfolin unit where the sulfur in the hydrogen sulfide in the gas stream is converted into elemental sulfur. The gas stream exiting the sulfur recovery unit is primarily carbon dioxide and is fed to the boilers (Pollock 1992).

The cooled and cleaned non-condensable gas stream exiting the Rectisol unit contains primarily methane from the lignite gasification and hydrogen and carbon monoxide created from both the gasification and shift conversion processes. This gas is fed to a catalytic methanation unit where a nickel catalyst in the unit causes the carbon monoxide to mix with the hydrogen in the gas to react and produce methane and steam/water. This gas is cooled to condense and remove the steam/water. The dried non-condensable gas, which contains primarily methane, has a heating value of 960 BTU/scf which is the equivalent of natural gas. Figure 9-4 shows that the SNG produced in this fashion can be compressed, transported, and used as natural gas (Pollock 1992).

The Great Plains plant also has a number of process units added to the plant to improve the economics of SNG production by recovering petrochemical by-products from the coal liquids and steam condensed from the medium-BTU gas exiting the gasifiers. These condensables are first fed to a separator where heavy coal tars and tar oils are decanted from the solution. The heavy tars, which also include coal fines, are recycled back to the gasifiers. The lighter tar oils are fed to the boilers where they are combusted to reduce the fuel requirements for the steam and electric power generation. The remaining solution contains ammonia, phenols, dissolved gases, and water. The phenols are first removed from the solution in a Phenosolvan unit which uses ether to extract crude phenols that are purified to produce high purity phenols and cresylic acids to be sold as by-products. Next, ammonia is removed from the solution by the Phosam process which uses steam stripping followed by ammonia absorption in an aqueous solution of ammonium phosphate. The ammonia is then recovered from the solution and the anhydrous ammonia is sold as another high value by-product. Figure 9-4 shows that the remaining solution, which is primarily water, is used as cooling water for the process (Pollock 1992).

9.3 POWER GENERATION USING INTEGRATED GASIFICATION COMBINED CYCLE

Using UCG for direct power generation is an ideal process, especially utilizing an air blown UCG reactor. The inherently low-BTU gas is uneconomical to transport long distances; therefore, it would be advantageous to use the gas in a combined cycle configuration on or near the UCG site. This process is shown in Figure 9-5 UCG-IGCC. This application of the UCG syngas will allow for the UCG facility to be electrically independent and generate income from electricity sales. Furthermore, integration of a combined cycle power plant with UCG technology can produce a highly efficient low-emission facility.

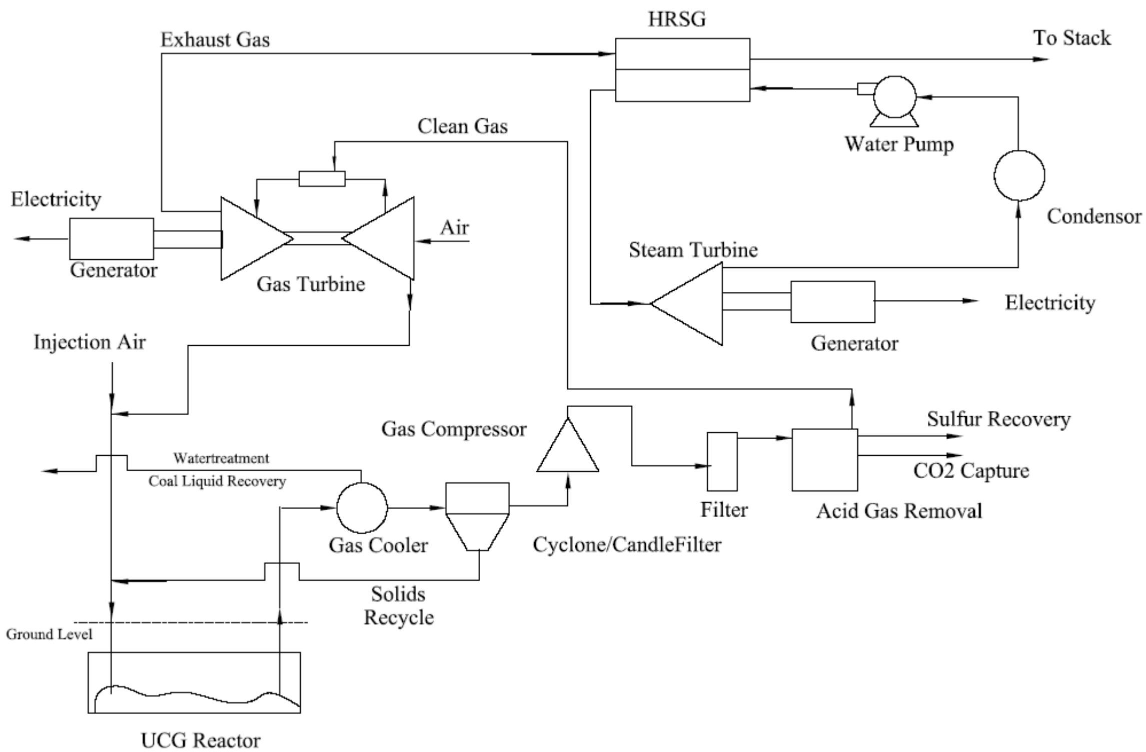


FIGURE 9-5. UGC-IGCC POWER PLANT FLOW DIAGRAM

9.4 GAS TO LIQUIDS USING THE FISCHER-TROPSCH PROCESS

The FT process is a chemical reaction utilizing an iron or cobalt catalyst to form liquid hydrocarbons from syngas composed of carbon monoxide and hydrogen. This process is capable of producing liquid fuels such as diesel and naphtha. A simple FT process is shown in the flow diagram, Figure 9-6. Through the use of an oxygen-blown UCG facility, it is possible to create the syngas needed for a FT facility. The FT technology is currently being developed and marketed by companies such as Rentech, Inc. and Sasol. Both have proprietary FT process technology and produce various hydrocarbons while utilizing surface gasification of coal.

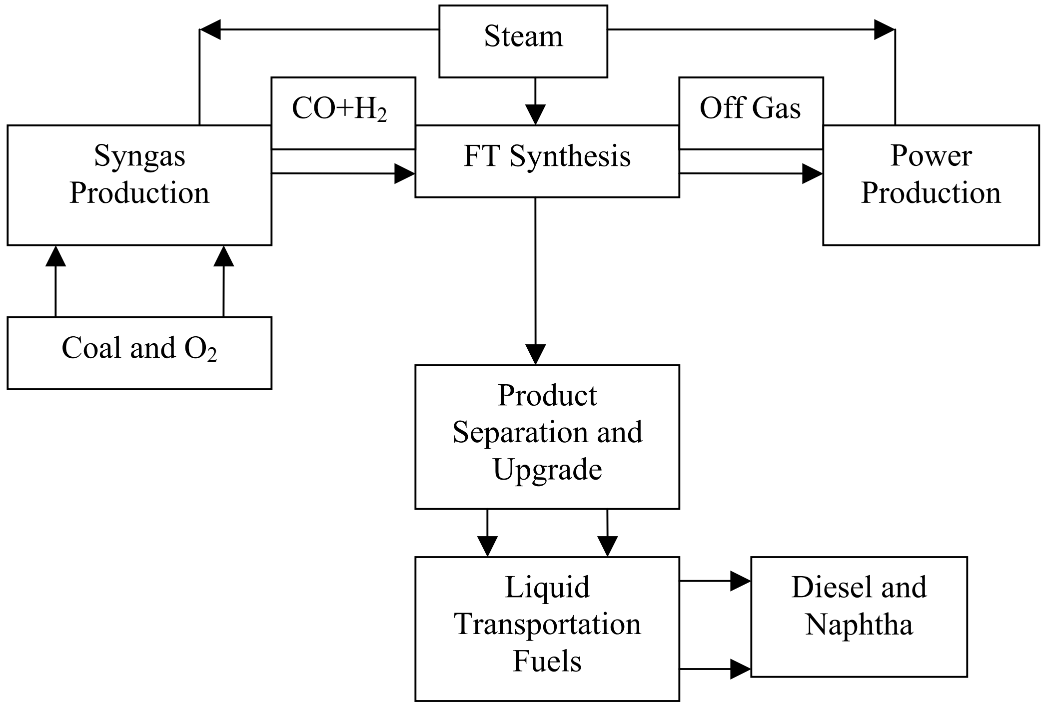


FIGURE 9-6. FISCHER-TROPSCH PROCESS

9.5 ALTERNATIVE OPTION FOR SYNGAS USE

There are several other technologies available requiring the use of syngas to produce ammonia, hydrogen and methanol. The following sections provide a brief discussion of these technologies and how they may be used with syngas from UCG.

9.5.1 Ammonia Production

For the production of ammonia, after preparation of the syngas, further processing is required to achieve a highly concentrated hydrogen stream. From there nitrogen is added and the gas is mixed. "Typically, the composition of conventionally prepared synthesis gas is about 74 percent hydrogen, 0.8-1.0 percent methane, 0.32 percent argon with the balance being nitrogen" (Agarwal 2004). This proportions the hydrogen and nitrogen in a direct 3:1 ratio with slight excess of hydrogen which is desired. This entering gas is compressed and fed to the reactor.

The reactor for the ammonia synthesis typically operates at high pressure to achieve economic feasibility. The normal pressure for the reactor varies but is usually above 100 atm. The temperature ranges from 660^0F – 930^0F. A catalyst is used to drive the reaction, the choice catalyst for the last decade has been iron based. A ruthenium-based catalyst is also available, which has a slight increase in reacting surface area and large increase in reactor efficiency. By-products of the reactor are efficient heat generation that can be used in steam generation plants as well as the compressor for the preparation of the synthesis gas. The reactor's per pass conversion is 20-30 percent for the iron-based catalyst.

Immediately following the reactor is ammonia separation and the remaining gas is recycled to the reactor. Cleansing of the ammonia gas is done typically by methanation. The gas produced is then condensed. The purge stream follows for methane and argon created from the methanation and after scrubbing with water the methane can be sold as a high quality natural gas. The water used to scrub the methane and argon is also used to cool the ammonia gas before hydrogen recovery and typically the ammonia is then extracted and cooled in the refrigeration compressor (Agarwal 2004).

9.5.2 Hydrogen Production

Another processing method for syngas is direct hydrogen production. This involves the purification of the syngas into hydrogen gas. This is done mostly by adsorption and cryogenic methods. Pressure swing adsorption has the advantage of a lower cost of production, and new technologies have advanced the processing capacity almost to that of cryogenic methods. Recently the majority of hydrogen separation has been done by adsorption, though cryogenic processing is still widely used.

The pressure swing adsorption method of purification starts with a selective adsorbent bed that works to adsorb the impurities (CO_2, CO and N_2) while the gas is passed through the bed. A pure hydrogen stream exits the bed and exists at high pressure. After the membrane bed becomes saturated it goes through regeneration that typically entails co-current depressurization that decreases the amount of hydrogen lost to the bed. Next the unit is fully depressurized counter-currently and the impure gas is purged. Hydrogen gas from another adsorbing unit is used to run both the co-current and the full depressurization. When the bed is pressurized again, another unit in the co-current depressurization stage is used to provide hydrogen rich gas. Typically this method requires six or more adsorption units (NATCO 2003).

9.5.3 Methanol Production

Once a suitable syngas has been produced, methanol can be created through the use of a catalyst. This process is similar to the production of other chemical feedstocks differing only in the catalyst used and the design of the reactor vessel. The carbon monoxide and hydrogen from the syngas react on the catalyst mixture of copper, zinc oxide and alumina. This reaction is performed at 50-100 atm and 480^0F. The balanced reaction is $CO + 2\ H_2 \rightarrow CH_3OH$. Methanol can be used as a chemical feedstock, extractant, solvent, or a gasoline replacement.

Production of di-methyl ether (DME) is yet another product to add to the range of options available from syngas. Until recently, indirect DME production, which is done by intermediate synthesis of methanol, has dominated the market. While this is limited by thermodynamic equilibrium, a mix of reaction catalysts to form the DME in solution has eliminated that problem. This technology is still relatively new. Only a few plants have been put into operation but the technology has performed well. Using a combination of catalysts, syngas can be converted to DME by a number of different reactions (JFE Holdings 2002). Researchers at the University of Missouri have developed a liquid phase DME production process with the following reaction chemistry:

$$CO_2 + 3H_2 = CH_3OH + H_2O \ (1)$$
$$CO + H_2O = CO_2 + H_2 \ (2)$$
$$2CH_3OH = CH_3OCH_3 + H_2O \ (3)$$

This single stage process has both scientific and economic significance. DME can offer a variety of gasoline-range hydrocarbons and lower olefins (Lee 2006).

At this point there are still many varieties of reaction methods. The common problem faced is the high heat buildup of the reaction and efficient removal. JFE Holdings has successfully implemented a slurry based operation that allows the quick removal of heat through a steam generator used in the reactor. This plant was put into operation in 2004 at 100 ton/day with a 99.6 percent product purity (JFE Holdings 2002). Other proposed methods are being built in Iran and other Middle Eastern countries (Haldor Topsoe 2007).

9.6 POLY-GENERATION

Poly-generation can be defined as a combination of two or more of the above described technologies. For example, a UCG facility utilizing an air-blown process could use the product gas to fire a combined cycle power plant which could generate the power necessary for the UCG process as well as an oxygen separation plant. This would allow for the production of electrical power and medium-BTU syngas to be used as feedstock for heating or other technologies previously described; see Figure 9-7. Poly-generation facilities have the added economic benefit of utilizing the many technologies available for syngas use.

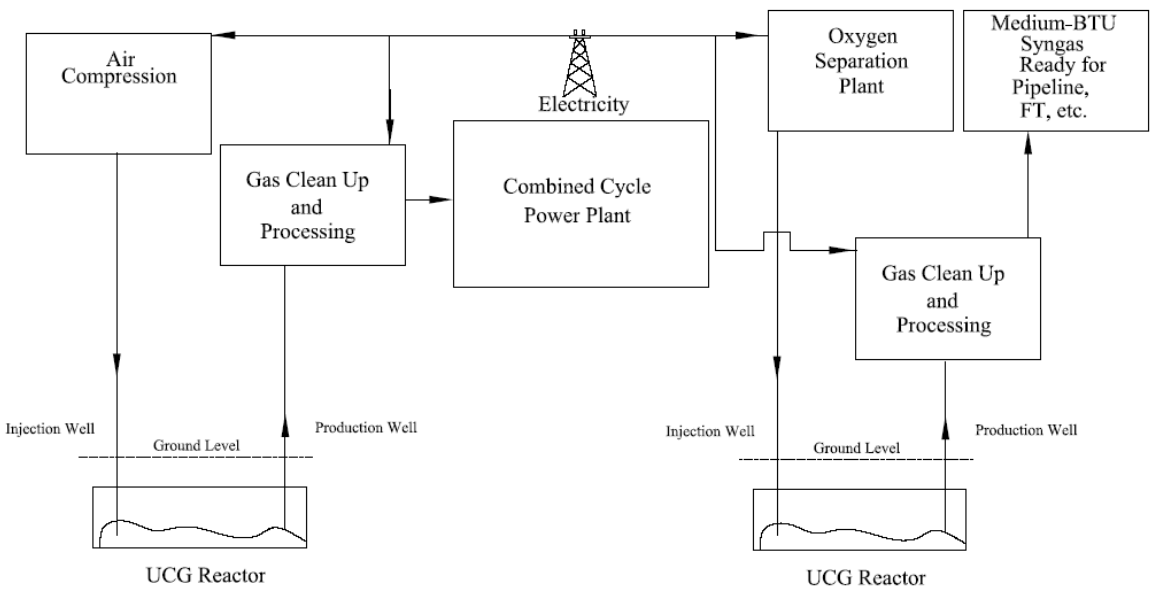


FIGURE 9-7. POLY-GENERATION BLOCK FLOW DIAGRAM.

9.7 CARBON CAPTURE AND SEQUESTRATION

Carbon capture and sequestration (CCS) is the process to remove and store "greenhouse gases" from process streams to reduce buildup of these gases in the atmosphere. CO_2 is a major greenhouse gas of concern in fossil fuel processes. CCS usually involves extraction, separation, collection, compression, transporting, and geologic storage. Storage in geologic formations can be as adsorbed gases and liquefied gases. For CO_2 stored as liquid, the CO_2 must be stored at supercritical conditions. This requires the depth to be greater than 2,600 feet. Abandoned oil and gas reservoirs, coal seams, and brine formations are considered as potential storage resources. CCS may be synergistically applied for ECBMR and EOR. CO_2 can also be reacted to form a solid product for storage. An example is the reaction of CO_2 with calcium oxide to form calcium carbonate:

$$CO_2 + CaO = CaCO_3 \text{ (limestone)}$$

CCS is an energy intensive process and can add significant costs to a project. The extra power consumption for a coal-based IGCC system is estimated to be 14-25 percent (IPCC 2005). To capture CO_2 from flue gas from a pulverized coal-fired power plant, the energy penalty is much greater, up to forty percent. Because of the energy requirements for the CCS, additional CO_2 is produced through the additional power generation which is required to meet the base load. Besides the extra costs for power, extra costs are incurred for the separation, collection, compression, transportation, and injection of the CO_2.

9.7.1 Carbon Capture in Surface Gasification Processes

The amount of CO_2 produced from surface gasification processes depends on the gasification technology used and the final gasification products. Most gasification processes generate 15-30 percent CO_2 in the produced syngas during gasification. If the gas is used for power generation, other carbon containing gases (CO, CH_4, and C_nH_{2n+2}) will ultimately produce CO_2 as they are burned. Other gasification systems to produce other products such as synthetic natural gas, synthetic liquid fuels, etc. will also produce additional CO_2. In addition, the end use of these synthetic hydrocarbons will also create CO_2.

Rentech, Inc. with co-funding from the Wyoming Business Council, evaluated an IGCC/Fischer-Tropsch process for the PRB (Rentech 2005). The plant size was a 10,000 barrels per day of fuel and 100 MWE power generation. As part of their study, Rentech included an evaluation of CCS. The report evaluated the feasibility of using a clean CO_2 stream for ECBMR and EOR.

Rentech determined there was more than sufficient coal volumes within the Powder River Basin to accept the entire CO_2 production from the plant. In ECBMR, CO_2 will displace methane (CH_4) adsorbed on the coal and the CH_4 will be produced from production wells. The coals are estimated to have ten times the storage capacity for CO_2 than for CH_4. Rentech determined that ECBMR was not economical unless there was a modest carbon credit.

Rentech determined that there was not sufficient EOR resource within their study area to store their entire CO_2 generation. They did indicate that CCS for their process would be profitable for CO_2 at a price of \$7.50 per ton or greater (Rentech 2005).

The Great Plains Coal Gasification Plant near Beulah, North Dakota started CO_2 shipments in 2000 for use in EOR. The CO_2 is shipped to an oil field near Weyburn, Saskatchewan, Canada. Approximately 1.5 million tons of CO_2 are shipped to the field per year.

9.7.2 Carbon Capture in Coal Combustion Processes

CCS in coal combustion processes (CCP) is similar to surface coal gasification processes except that the CO_2 is captured post-combustion and that almost all carbon in the coal is converted to CO_2. In surface gasification, the CO_2 will normally be captured from the gasification stream before it is combusted or reacted to form various products. In CCP, CO_2 is captured from an exhaust high in nitrogen concentration. Because of the dilution of the flue gas stream with nitrogen, the cost of CO_2 capture post-combustion in CCP is considerably higher than carbon capture from a gasification stream where oxygen and steam have been used in the gasifying process.

According to Thambimuthu (2005), current commercial CO_2 capture systems can reduce CO_2 emissions with an 85% to 95% capture efficiency. This capture cost results in an increased COE of \$12 to \$36 per MW-hr. This corresponds to a 40% to 85% percent increase in COE for pulverized coal, 35% to 70% increase for Natural Gas Combined Cycle, and 20% to 55% percent for an IGCC plant using bituminous coal. These costs include compression but not transportation or sequestration costs. Obviously, the energy penalty and associated costs of CCS in a CCP plant are much higher than for an IGCC plant. The possibility of mandated CCS in the future is a strong motivation for coal-fueled process owners to be evaluating gasification rather than coal combustion. CCP has the same geologic storage options and costs as the surface coal gasification.

9.7.3 Sequestration Options for UCG Processes

UCG processes have the same CCS options as surface gasification processes except for the potential to store the captured CO_2 in spent UCG cavities. This has been referred to as Reactor Zone Carbon Storage, or RZCS (Burton et al. 2005). In RZCS, captured CO_2 can be stored in spent cavities, i.e. the cavities left by the UCG consumption of the coal seam. However, for liquid storage, the CO_2 must be stored at depths greater than 2,600 feet (Burton et al. 2005). At lesser depths, the CO_2 will be sub-critical and will be a dense phase, but may still be suitable for RZCS. UCG creates cavities as great as eighty percent of the volume of the gasified coal. The "spent" cavity is estimated to have the capacity to store about thirty percent of the total CO_2 produced from the gasification of the coal. Advantages for storage in UCG cavities include large storage volumes, existing wells may be used for CO_2 injection, and self-sealing caused by coal physical changes in the presence of CO_2. Coal in the presence of CO_2 swells and plasticizes and may seal the natural fractures (cleats) in the coal seam. In addition, the coal surrounding the spent cavity may be fused and have very low permeability, thus preventing escape of stored CO_2.

There are several potential problems with RZCS. First, the spent cavity is structurally disturbed and may have fractures extending upward from the cavity. These fractures may allow leakage of CO_2 out of the reactor zone storage site. Second, carbon storage in the reactor zone may result in the formation of carbonic acid in the groundwater. This acid could mobilize metals from the ash, char, coal, and other geologic materials it contacts. The extent of this potential RZCS process needs to be evaluated. Nonetheless, UCG is the only clean coal technology which has the potential for creating its own sequestration sites. The cavities may still have well systems installed which would facilitate RZCS which could minimize the overall cost of CCS.

A potential problem for using CO_2 for enhanced coal bed methane recovery is the possible decrease in coal permeability caused by the coal swelling and plasticization. The CO_2 may have to be injected into fractures which require that the CO_2 be injected at pressures greater than lithostatic. This could create vertical fractures above the injection point that could breach confinement. Tests need to be conducted to evaluate the potential for ECBMR.

In many areas in which UCG will have application, especially in the PRB, there is historic oil and gas production from deep (>5,000 feet) isolated formations. These deep zones may be candidates for CO_2 injection and sequestration, plus they have the added economic and energy benefit of possible EOR. Even if EOR is not strictly economic on a stand-alone basis, the incremental oil production resulting from CO_2 injection will still lower the overall cost of CCS.

CCS for UCG processes are as feasible as the other gasification and combustion processes. UCG CCS may have the advantage of storage in caverns created by the UCG process. The feasibility of UCG cavity storage needs to be evaluated ether in the laboratory or field test site (Green 2004).

Figure 9-8 (Green 2004) shows how CO_2 sequestration might be achieved in conjunction with UCG. Gasifying the coal seam would leave highly porous cavities. As these volumes cool down, the abandoned cavities would be accessed by directional drilling or through the existing production boreholes. CO_2 would then be injected at high pressure for storage and retention. For permanent CO_2 sequestration, the depth and strata conditions must be suitable.

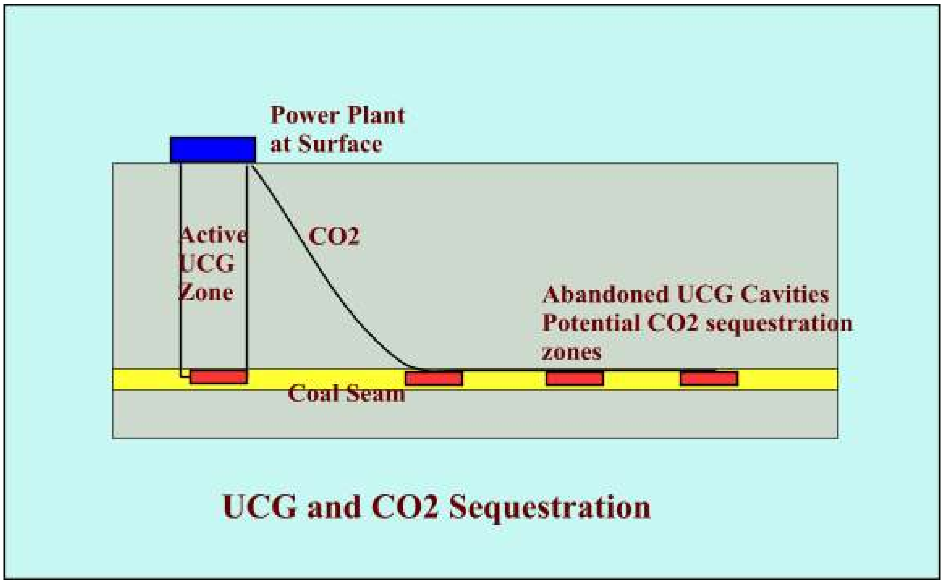


FIGURE 9-8. UCG AND CO_2 SEQUESTRATION

In conclusion, UCG has the potential for producing its own sequestration sites, which is a unique feature. In addition to that potential, UCG has access to the more conventional geologic sequestration sites such as deep marine formations. Until CCS is mandated, it is unlikely that any combination of CCS strategies will be independently economic.

10.0 PROJECT ECONOMICS

10.1 MARKETS FOR UCG PRODUCTS FROM THE PRB

The variety of products that can be made from low- and medium-BTU gas produced from coal is discussed in the previous section. The primary commercially-demonstrated processes to produce high value product from coal syngas are: SNG, electric power, and liquid transportation fuels. In addition, a variety of specialty organic chemicals can be produced as by-products from these processes. Also, while not yet operated on a commercial-scale, the production of methanol from coal syngas has been shown technically feasible. Further, the methanol can be processed to produce DME, which is suitable for use as an environmentally friendly substitute for liquefied petroleum gas.

The infrastructure to transport and market SNG is already well developed in the PRB. Major natural gas pipelines are in place and accessible in the basin and established gas gathering systems cover most of the PRB. Potential markets for SNG produced in the PRB exist in a major portion of the U.S., although currently an abundance of natural gas is produced from the basin at a reasonable cost. For this reason, in the near-term SNG produced from coal will compete to some degree with conventional natural gas and CBM. However, production of SNG from the vast deep coal resources in the PRB will eventually be required for national economic health and security.

As discussed in Section 8.0, the PRB is currently approximately 75% encircled by a major electrical power transmission line. Also, additional power transmission lines are in the planning stage to construct transmission capacity to Salt Lake, Las Vegas, California, and Phoenix. The Rocky Mountain Area Transmission Study (RMATS 2004) recommends significant export projects which would require two 500 KV lines for export. This recommendation would require 1,400 MW of generation additions in the PRB. UCG IGCC generation in the PRB would provide a clean coal substitute for pulverized coal and act as a hedge against volatile natural gas prices. In effect, the electric power generation market is also substantial both in the near-term and in the long-term.

The market for liquid transportation fuels produced from coal is tremendous and growing. With the U.S. dependence on foreign oil and declining world reserves, all domestic liquid hydrocarbon production at competitive prices will be readily integrated into domestic markets. Further, oil pipelines existing in the basin are under-utilized and transportation liquids can be economically shipped to market. The markets for DME as a substitute for LPG should be similar to liquid transportation fuels once DME is accepted as a substitute for LPG on a world-wide basis. Rentech (2005) provides a good overview of FT liquid markets in Wyoming.

In the following sections, we will estimate the economics of air-blown, oxygen-blown, and oxygen/steam UCG sequentially. As air-blown is the first and most basic form of UCG, it will be evaluated in the most detail. Oxygen and oxygen/steam UCG will build upon the air-blown case and use much of the same design basis data. The terms air-blown and air-fired are used interchangeably in this report and in the literature.

None of the analyses in this study include costs for carbon capture or sequestration.

10.2 ECONOMICS FOR AIR-FIRED TECHNICALLY VIABLE UCG PRODUCTS

10.2.1 Design Basis of Air-Fired UCG Economics

The UCG economics have been estimated in two ways in this study. First, having defined the process design and capital and operating costs, the cost of producing syngas, in Dollars per MM BTU, has been estimated. This cost includes all capital and operating costs, royalties, severance taxes, ad valorem taxes, and a 15% return on investment. It does not include Federal Income Tax. For the base case, defined in detail in Section 10.2, this cost is $1.62/MM BTU. This cost can be compared to other competing fuel costs. Second, the economics have been estimated for two specific UCG projects. In this report, an air-blown UCG 200 MW IGCC power plant has been evaluated, and an oxygen-blown UCG Fischer Tropsch facility has been evaluated. These projects include all costs and are presented on an After Federal Income Tax basis for comparison to other energy projects. Full details are in this Section 10.

The capital and operating costs for surface gasification facilities are generally available in the literature and from engineering firms and vendors that supply surface gasification process facilities. However, the capital and operating costs for UCG are literally absent from the literature, at least in any level of detail that would be useful for planning and economic scoping purposes. Therefore, in this report, we have concentrated the most effort in describing the UCG configuration, operating methods and preferred methods, and the capital and operating costs of UCG, especially in the PRB. This has required extensive modification and updating to UCG cost models developed by the primary contributors to this report. This should provide the most useful information for planners interested in evaluating UCG in the PRB and elsewhere.

Selection of the UCG process is based on economics, the results of previous UCG research, and environmental issues as discussed in Section 9. Based on these criteria, the UCG process selected for analysis in this report is the LVW process, which uses reverse combustion to increase the permeability of the coal seam between process wells. It was selected because it has been successfully used in the USSR, the U.S., and in particular the PRB. The other UCG processes that have been successful and demonstrated as reasonably reliable are the linkage with horizontal well bore, the steeply dipping bed (SDB) process, processes utilizing boreholes, and forward combustion/fracturing.

The LVW process is the least expensive method successfully demonstrated for increasing the permeability of the coal seam. While the SDB process has been proven very reliable and economic, the suitable PRB coal resources are not steeply dipping. The UCG technologies employing directional drilling e.g. ELW and CRIP, have exhibited similar success and reliability to the LVW. However, the LVW process does not require directionally drilled boreholes. The elimination of directional drilling reduces start-up and operating expenses.

Also, the LVW process has an important environmental advantage over forward combustion/fracturing. That is, when high-pressure air or oxidant is injected to establish communications between process wells, air, not product gas, is lost to the underground formation in the LVW process. Product gases produced follow the carbonized path of least resistance (link) to the production well. Air is the only fluid loss that occurs during the linking process. This is important because it has been shown that gas lost to the underground formation during UCG is a primary mechanism causing groundwater contamination in UCG. Conversely, in forward combustion/fracturing the high-pressure air or oxidant that is injected first contacts the combustion zone and reacts to make gas. This gas is then forced into the formation towards the production well. As the gas flows towards the production well, a portion of the gas is lost to the formation. If the gas encounters a high permeability zone away from the process well during this process, it can be transported a significant distance in the formation until linking is complete. This type of gas loss can result in groundwater contamination that can be difficult and expensive to remediate.

It will be necessary to consider both air and oxygen injection and possibly steam/oxygen injection in the UCG economic analyses due to the gas cleanup requirements of the potential UCG products. In the case of electric power generation using UCG-IGCC, air injection is feasible. In the cases of SNG, transportation liquids produced using the FT process and methanol production, oxygen injection and possibly oxygen and steam injection will be necessary.

10.2.1.1 Well Field Description and Process Module Definition

The starting point of the process calculation is the definition of the basic UCG process unit referred to as the module. For the two-well module, the module is defined as the volume of coal confined within a square area having dimensions equal to the well spacing. Each module has two wells passing through the outer edges of the volume at the midpoints of the width as shown in Figure 10-1. A two-well module layout will be used in the economic analyses.

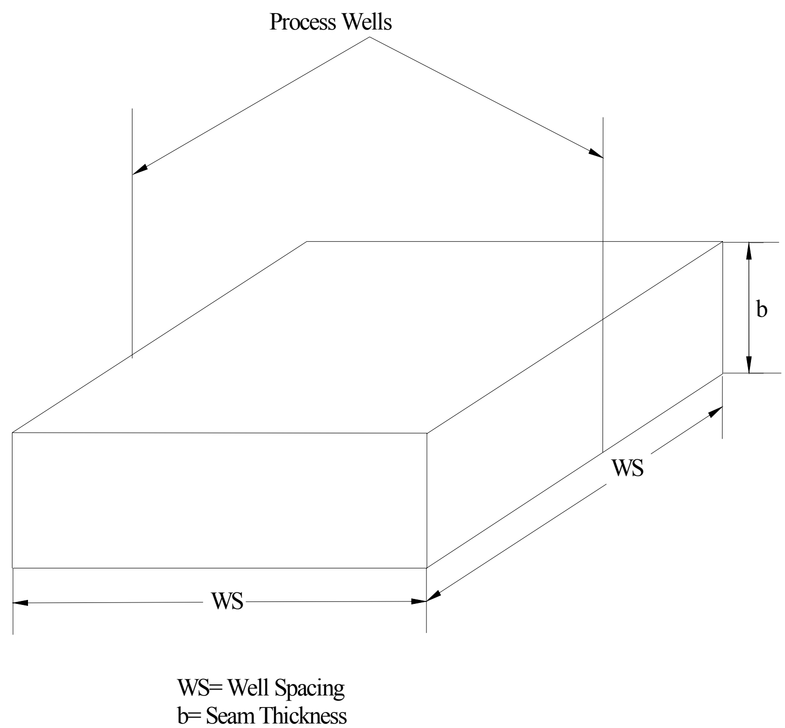
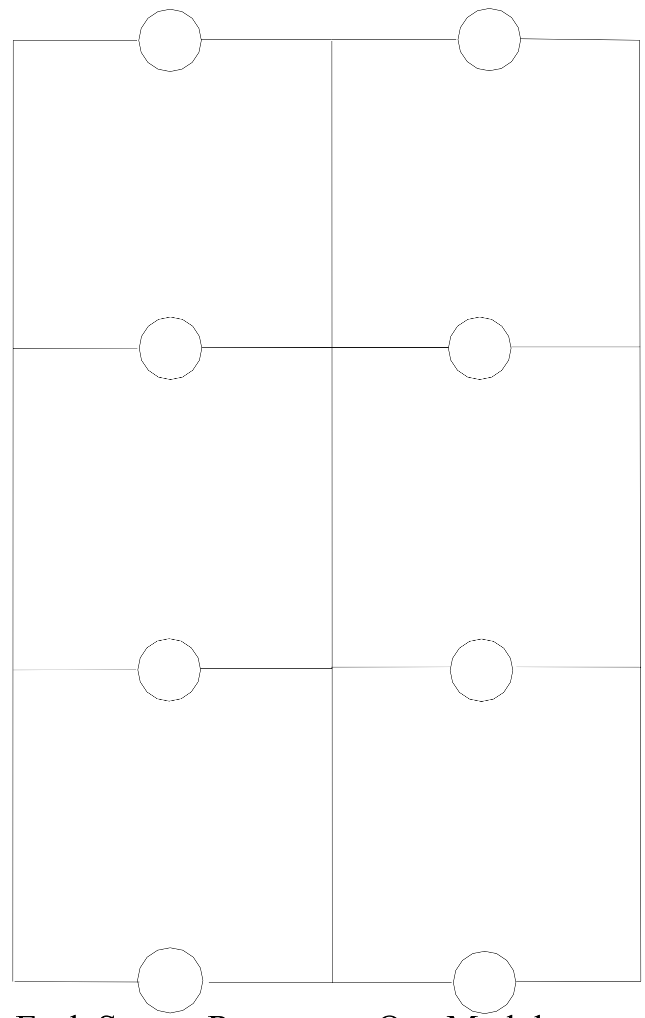


FIGURE 10-1. PROCESS MODULE

In the design of the UCG well field using two-well modules, each well will be utilized first as an air injection well and then as a gas production well for the succeeding module. When two-well modules are placed end to end, each module shares its production with two neighboring modules. After a module is gasified, the injection well of the module becomes the production well of the next module. Therefore, after the initial module in a row, one well is necessary for the construction of additional modules in that row (Figure 10-2).

The module concept is important in the design calculations of the UCG plant since many of the plant sizing calculations are performed on a module basis. The plant sizing and economic calculations are performed in a fashion similar to that described in the literature (Boysen and Gunn 1979). The literature provides a complete description of the plant sizing calculations.



Each Square Represents One Module

FIGURE 10-2. LAYOUT OF MODULES

In a commercial-scale UCG operation using two-well modules, continuous operation is achieved by relaying the gasification down parallel lines (rows) of modules. Figure 10-3 represents the well field layout for two-well modules at the time of plant start-up. Surface piping is used to achieve relaying of gasification and linking activities. Prior to plant start-up, the wells are used for local hydrogeologic characterization of the module. If the results of this characterization indicate the presence of geologic anomalies that adversely affect UCG, the module will not be gasified. A fire is ignited in each production well. Reverse combustion is achieved by the injection of low volumes of high-pressure air into the injection well that flows to the production well. When the reverse combustion link is completed for each module in Module Rows 1, 2, 3, and 4; the well field is prepared for the start of gasification. The start-up of two-well modules is staggered in time. Linking of wells is performed continuously during the plant operation. Relaying the gasification pattern down the rows of wells is achieved by switching the wellhead piping when necessary (Figure 10-3).

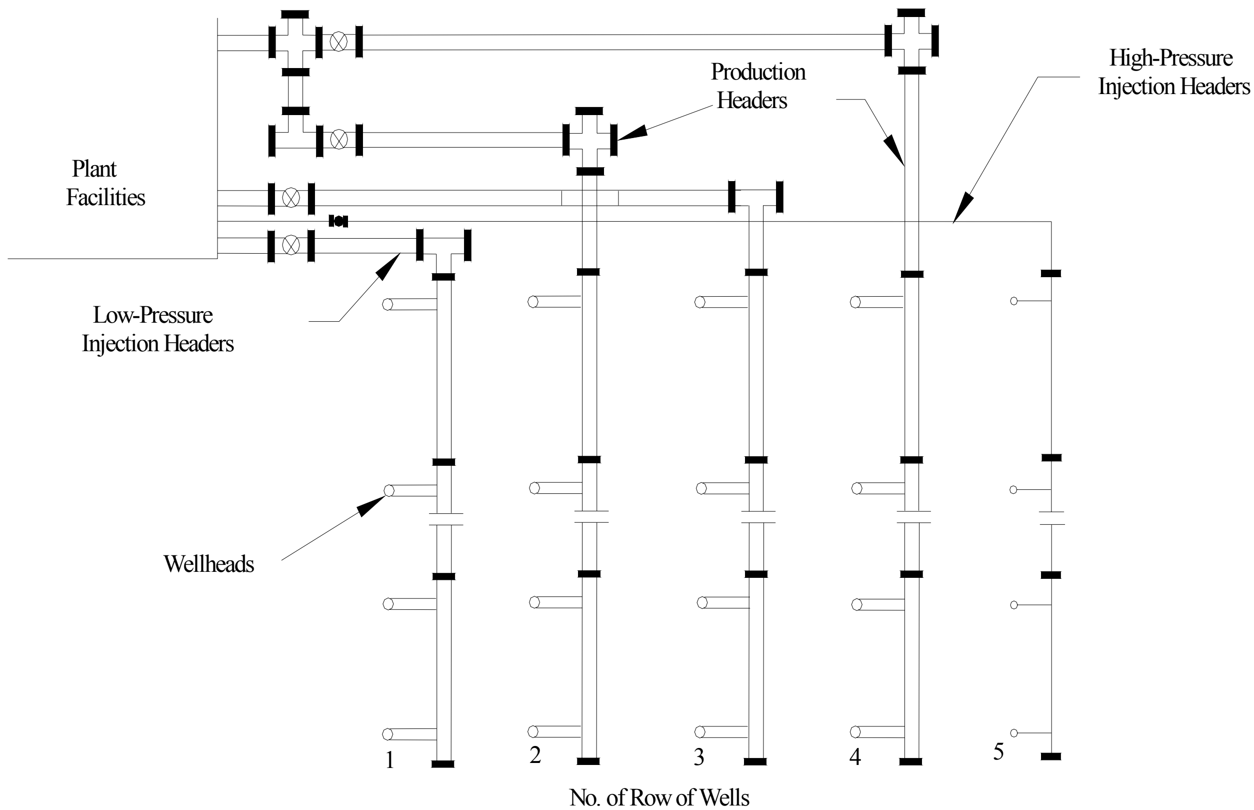


FIGURE 10-3. UCG WELL FIELD LAYOUT FOR TWO-WELL MODULES

10.2.1.2 Facility Design

The major design items required for the facility are process and monitor wells (drilling, casing, and completion); pipe and fittings (pipe, flanges, fittings, valves, controls, and fasteners); compression in the air-fired UCG plant; an oxygen plant and steam boilers in the oxygen/steam UCG plant; and the facility. The facility includes buildings, heavy equipment, shop equipment, and major electrical and analytical equipment. Standard engineering practices are be used in the sizing and design of these items. Details regarding the exact specification of the items for the 200 MW IGCC project are provided in the next section.

10.2.1.3 Plant Layout

The UCG facility consists of two general components: the surface facilities and the well field. The surface facilities include air compression equipment or an oxygen plant and steam boilers, buildings, machinery, and data acquisition, process control, and process monitoring equipment.

Figure 10-4 illustrates the general plant layout for an air-fired UCG facility. The compression equipment provides air for gasification and linking activities and includes compressors capable of providing large volumes of low-pressure air (LPA) for forward gasification; compressors capable of providing small volumes of high-pressure air (HPA) for reverse combustion linking; low-BTU gas turbines and motor control centers to provide power to drive the compressors; and buildings to house the air compressors.

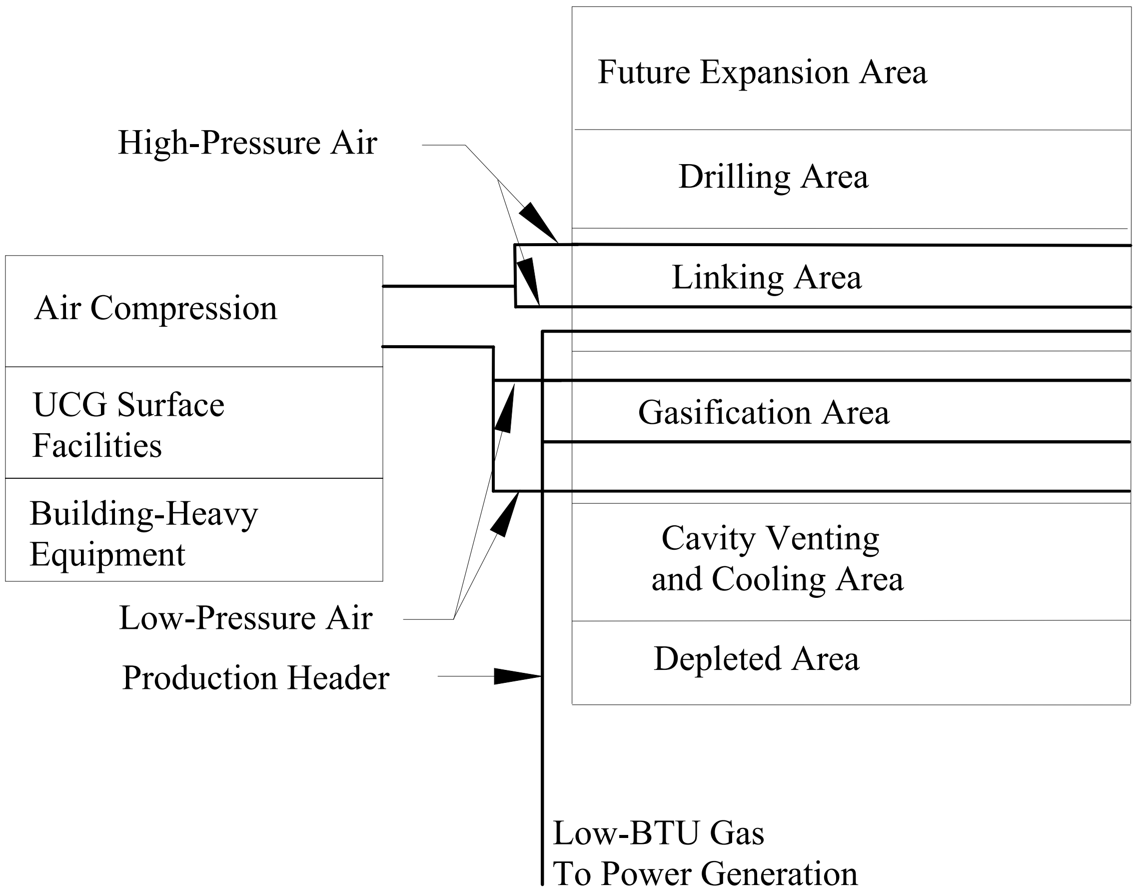


FIGURE 10-4. GENERAL PLANT LAYOUT

The activities in the UCG well field are illustrated in Figure 10-4. After the first module in each line of modules is gasified, the well field is divided into six areas. The depleted area is the region over the coal that has been gasified. Activities performed here are subsidence monitoring, groundwater monitoring and sampling, and eventually well abandonment. The cavity venting and cooling area is the area over the coal that has been recently gasified. The activity performed is sustained venting of steam and gases produced from the cavity. This procedure was used successfully at the RM1 field test to clean the cavity and prevent groundwater contamination (Covell et al. 1988). The forward gasification of coal is performed in the gasification area. Process wells, wellhead piping, surface piping for low-pressure air injection and product gas gathering are required equipment. Activity in the gasification area consists of controlling injection air and product gas flows and periodic movement of piping. The linking area is where process wells, piping for high-pressure air injection, and product gas gathering piping are used to perform reverse combustion linking. Activities in this section are similar to those in the gasification area.

The drilling area is where the process wells required for the UCG operation are drilled. Well drilling, logging and completion, and hydrologic characterization activities are performed in this area using drilling rigs, well completion equipment, and wellheads. In addition to the drilling and completion activities, hydrologic draw-down, build-up, and air acceptance testing will be conducted to evaluate the local hydro-geologic characteristics of the individual wells. The future expansion area is where preparation of the topography for drilling additional process wells is conducted. The activities in this area also include surveying of well locations and preparation of roads.

10.2.1.4 Well Field Operation

Figure 10-5 illustrates the well field as it appears at the time of plant startup. For clarification, the operation of the UCG plant well field is discussed in detail. To simplify discussion of the well field operation, the module in Module Row 1 and Module Line 1 will be referred to M1-1, the module in Module Row 1 and Module Line 2 will be referred to M1-2, the module in Module Row 2 and Module Line 1 will be referred to M2-1, and so forth.

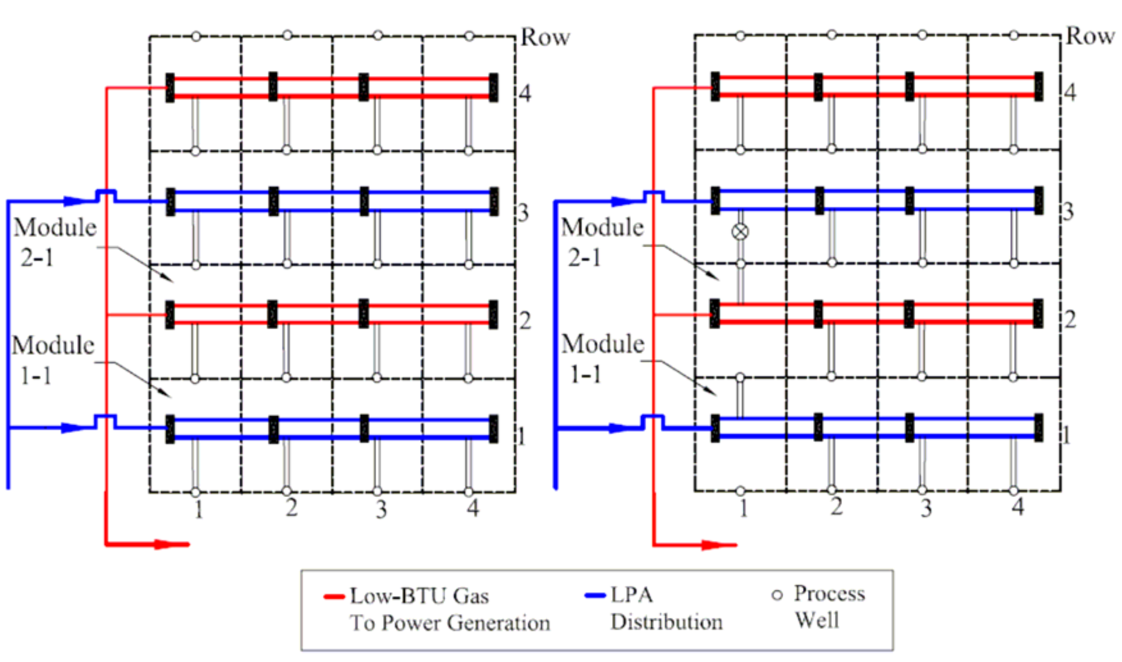


FIGURE 10-5. PLANT STARTUP WELL FIELD

Figure 10-5 shows the configuration of the well field at plant start-up. Four lines of modules are constructed prior to plant start-up. During the operation of the UCG plant, four modules will be simultaneously gasified. The gasification of the modules will be staggered in time to assist the operator in maintaining a constant product quality (Gregg and Olness 1976). The lines of modules are separated by a distance equal to the spacing between wells of one module. A pillar with a thickness of approximately 100 feet should be left between module rows when gasification of the modules is completed. This pillar between the rows of modules helps prevent cross-flow during the gasification of the modules. It also allows the modules to be vented and cooled immediately after gasification and helps to minimize surface subsidence. Preventing cross-flow of gases between modules helps maintain high process efficiency. Immediate venting and cooling of the modules after gasification is necessary to prevent groundwater contamination (Boysen et al. 1990).

Figure 10-5 also illustrates the air compressors, LPA and HPA injection piping, and gas production piping that are required. LPA and HPA piping is moved to the next module in the row when the gasification and linking of a module are completed. As the wells required to construct new modules are completed, production piping will be extended to that module. The main production piping has one expansion loop per module to relieve thermal expansion stress. Piping connecting the production wells to the main production piping is moved to new modules after the venting and cooling of a module is completed. The piping connecting the production wells to the production piping has three 90^0 bends to relieve thermal stress. Also, all production piping has a tee, instead of an elbow, at each 90^0 bend. The tees are used to create an impact pocket, which prevents erosion of the pipe at the bend.

Initially, there being no depleted area, necessary linkages for all modules in Module Rows 1 and 2 are completed at the time of plant start-up. Gasification is initiated in M1-1. When the gasification of M1-1 is 25 percent complete (after approximately 43 days), gasification is initiated in M1-3. After approximately 86 days, gasification of M1-1 is fifty percent complete and gasification of M1-3 is 25 percent complete. At this time, gasification of M1-2 is initiated. Similarly, after approximately 130 days, gasification of M1-1 is 75 percent complete, gasification of M1-3 is 50 percent complete, and gasification of M1-2 is 25 percent complete. At this time, gasification of M1-4 is initiated. After 173 days, gasification of M1-1 is completed, the LPA injection piping is moved from M1-1 to M2-1, and drilling of process wells for M4-1 begins. The operation of the well field continues in a similar fashion throughout the life of the UCG facility.

10.2.1.5 Air-fired UCG Plant Description

A general description of the air-fired UCG plant considered in the economic analyses and the operating assumptions required for the resulting plant design are provided in Table 10-1. The UCG plant design is sized to produce the syngas feed to a 200 MW UCG-IGCC power plant. That project is discussed in Section 10.2.4 of this report. The air-fired plant design assumes the gasification is conducted in a PRB coal seam that is 112 foot thick with the top of the coal seam lying at a depth of 1,054 feet. The average hydrostatic head at the bottom of the coal seam (1,166 foot depth) is 474 psia. The average HHV of the coal is assumed to be 8,200 BTU/lb (as received or in-place) and the in-place density of the coal is assumed to be 81 lb/ft^3. These are actual conditions at a selected site in the PRB.

TABLE 10-1. AIR-FIRED UCG PLANT DESCRIPTION AND OPERATION / 200 MW UCG IGCC

Plant Description:
Total Energy Production Rate = 1.74 x 10^9 BTU/hr = 229.4 MW at 45% Efficiency Energy Required for UCG Air Compressors = 2.2 x 10^8 BTU/hr = 29.4 MW Energy for Electrical Power Generation = 1.52 x 10^9 BTU/hr = 200 MW Plant Load Factor = 95% Plant Life = 20 Years
UCG Process Operation:
Average Dry Gas HHV = 150 BTU/scf Module Coal Recovery = 65% Gas Losses = 0% Gasification Thermal Efficiency = 81% Dry Gas Produced / Air Injected = 1.53 mole/mole
Coal Seam Gasified:
Coal HHV = 8200 BTU/lb (as received) Coal Density = 81 lb/ft^3 (in-place) Average Seam Depth = 1,054 feet Average Seam Thickness = 112 feet Hydrostatic Head at Depth = 474 psia Total Area of Coal Gasified in Plant Life = 0.27 mi^2

The air-fired UCG plant is sized to provide fuel for the generation of 200 MW, assuming that 7,587 BTU/KW-hr are required for generation. This would be typical of IGCC power generation with an efficiency of 45 percent. The UCG facility is assumed to operate for twenty years with a 95 percent load, or stream factor. The high load factor is acceptable because four or more largely independent gasifiers are operating simultaneously. Lower plant load factors in surface gasifiers are typical because they have only one or two gasifiers. The first assumption made in the preliminary design and economic evaluation of the air-fired UCG plant is that an average dry product gas HHV of 150 BTU/scf will be obtained in the operation. Based on experience with Hanna Coal of a similar HHV (Boysen and Gunn 1979), this assumption also corresponds to a UCG process thermal efficiency equal to 81 percent, 1.53 moles of dry low-BTU gas produced for each mole of air injected and 2.0 moles of wet gas are produced for each mole of air injected. Additional assumptions necessary in the economic evaluation are that 65 percent of the coal in each module is gasified and long-term product gas losses are maintained at zero by restraining the pressure in the gasification cavity to below hydrostatic pressure and by venting the cavities after gasification of a module is completed.

The assumption that 65 percent of the coal in a module is gasified is conservative because values exceeding eighty percent have been achieved in UCG testing. The 65 percent value is conservatively used to account for both leaving pillars in the coal seam to reduce subsidence and for the fact that failure to achieve a reverse combustion linkage will inevitably happen during twenty years of plant operation.

10.2.1.6 Well Field Design

The initial well field design is illustrated in Figure 10-3 and its operation was previously discussed. The specific details regarding the well field design are illustrated in Table 10-2. The process wells in UCG serve several functions. The injection wells are used as a source for air injection into the coal seam and the production wells are used to collect the product gas during gasification, linking, and venting of the cavities. In addition, all the process wells are also used in the hydrogeologic evaluation of the coal seam and well field, and in the long-term monitoring of the coal seam aquifer's hydrostatic head and water quality.

The process wells required for start-up are considered to be capital investment and those required to construct new modules during the operation of the UCG well field and plant are considered annual operating expenses.

The design of the UCG well field (Figure 10-3) for the air-fired UCG plant is such that the module ahead of the module in gasification is linked and ready for gasification. The second module ahead of the module being gasified is piped and ready for linking. Therefore, three modules in each line are constructed prior to plant start-up. In addition, two additional lines of modules are constructed for each operating module. Thus, the number of wells required for start-up of the air-fired UCG plant is equal to approximately five times the number of modules in operation. For the air-fired UCG plant, 25 wells will be drilled for plant start-up.

This design provides a sufficient distance between gasification, linking, and drilling activities to allow each activity to proceed without interference. In addition, duplicate lines of modules provide additional time for these activities and facilitate the venting and cooling of the UCG cavities after gasification.

The number of wells drilled annually is equal to the module consumption rate. The drilling and completion of one of these wells can easily be performed in less than five days. Since gasification of each module will require roughly 173 days, only one drilling rig should be required on the site during operations on an intermittent basis.

The process wells are nominally twelve-inch diameter (schedule 40 SDT) with a 12.00-inch inside diameter. This size was determined based upon optimization of process economics. The calculated pressure losses in the surface lines and wells are major factors in the economic optimization of the plant design. Various inside diameters for the process wells were considered and the selected diameter resulted in the minimum calculated syngas production price. The inlet and outlet pressures for linking, injection and gas production are also illustrated in Table 10-2, along with assumed maximum temperatures and mass flow rates.

TABLE 10-2. WELL FIELD DESIGN

Modules:			
Well Spacing = 200 feet Modules Consumption Rate = 0.027 modules/day Number of Operating Modules = 5 Module Life = 173 days Average Air Injection Rate (Gasification) = 23497 scfm/module Maximum Air Injection Rate (gasification) = 56000 scfm/module			
Drilling:			
Process Well Inside Diameter = 12.00 inches Depth Drilled = 1166 feet Depth Cased = 1161 feet Wells Required for Start-up = 25 Wells Required Annually = 9			
Well and Wellhead Design:	**Linking**	**Injection**	**Production**
Inlet Pressure, psia	1179	479	464
Outlet Pressure, psia	1179	474	424
Pressure Drop, psi	0	5	40
Length, feet	1261	1261	1261
Maximum Wellhead Temperature, °F	150	150	1000
Maximum Mass Flow, lb/sec	0.1	71.3	118.2
Wellhead Equipment Requirements:		**Start-up**	**Annual**
Amount Purchased:			
Pipe, feet		2222	500
Raised-face Slip-on Flanges, each		341	16
Blind Flanges, each		61	--
Weld Tees, each		11	--
Weld Elbows, each		11	--
Full-bore Valves, each		44	--
Automatic Flow Control Valves, each		11	--
Automatic Pressure Control Valves, each		11	--
Pressure Transducers, each		35	--
Orifice Flanges, each		44	--
Orifice Plates, each		66	11
Flange Bolts, each		4624	128

The process wells are drilled to the bottom of the coal seam and cased to within five feet of the bottom of the seam. The piping connecting the injection wells to the LPA distribution lines is illustrated in Figure 10-6, and the piping connecting the production wells to the product gas collection lines is illustrated in Figure 10-7. The injection piping will be moved to the next module in a line of modules once gasification of a module is completed. The production piping will be moved to the next module in the line to be linked after venting and cooling of the UCG cavity.

The injection wellhead piping also includes equipment for monitoring and controlling the flow of injection air to each module and is shown in Figure 10-6. Similarly, the wellhead piping for each production well includes equipment for monitoring the product gas flow and controlling the production pressure/flow rate.

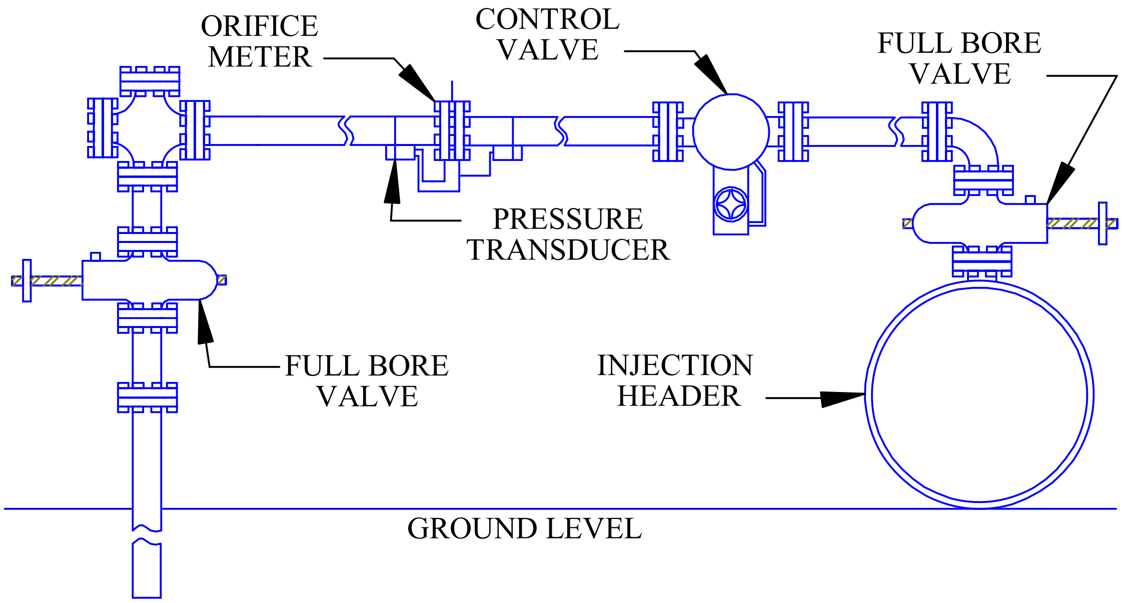


FIGURE 10-6. WELLHEAD INJECTION PIPING

For plant start-up, two sets of injection wellhead piping and two sets of production wellhead piping are required for each operating module and the purchase of ten percent excess is considered. The wellhead pipe, valves, controls, instruments, and fittings required for the start-up of the air-fired UCG plant are listed in Table 10-2. The amount of pipe purchased annually to replace worn or damaged wellhead pipe is assumed to be 500 feet. In addition, flanges to connect new process wells to the production headers and blind flanges to seal wells in consumed modules and their connections to the production headers are required annually.

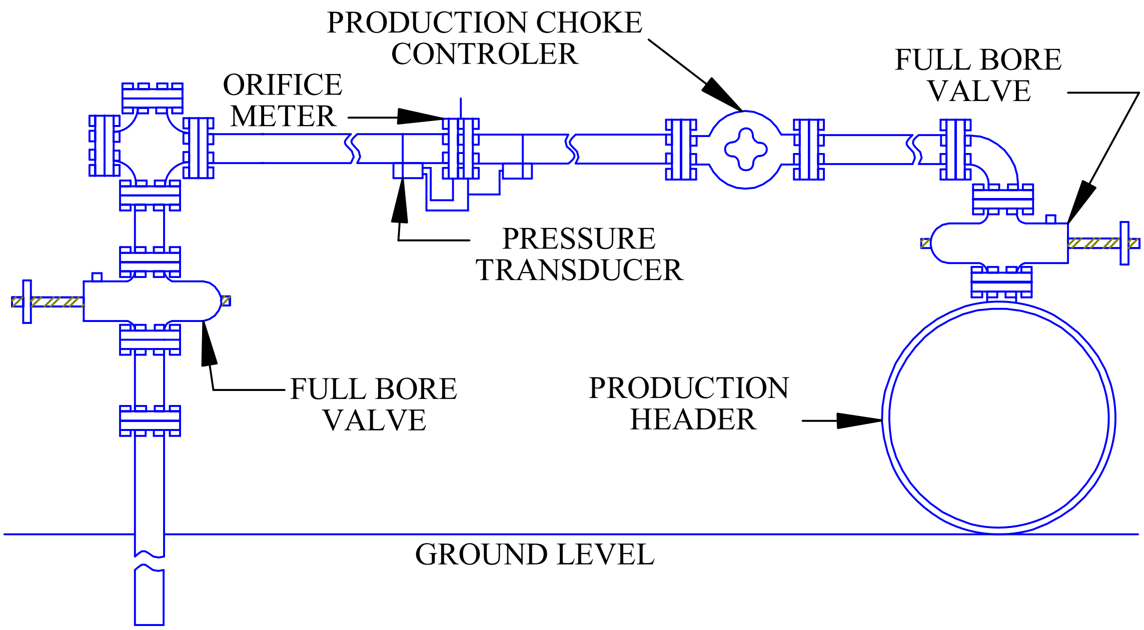


FIGURE 10-7. WELLHEAD PRODUCTION PIPING

10.2.1.7 Air Injection Piping and Production Header

HPA required for reverse combustion linking is transported to process injection wells from the booster air compressors in piping similar to that used to supply the LPA for gasification (Figure 10-7). In addition, pipe to connect the wellhead piping for LPA injection to the air compressors is required along with piping for the well field production headers. The HPA supply systems are used during reverse combustion linking of a module. These systems are disconnected and moved to the next module in the line after linking is achieved.

The HPA and LPA injection headers are designed to supply the air to the coal seam at the lithostatic and hydrostatic pressures of the bottom of the coal seam, respectively when the injection headers are at their maximum length during the 20 year air-fired UCG plant operation. For the air-fired plant, an equivalent maximum length of 8,917 feet of pipe for the injection headers was used in pipe sizing and pressure drop calculations.

The HPA supply system is two-inch nominal pipe size, designed to supply HPA for reverse combustion linking to two adjacent lines of modules. Therefore, two HPA supply systems will be required for the air-fired UCG plant. The total length of pipe required for start-up of the HPA supply system is 6,481 feet. The amount of pipe for the HPA injection system should be purchased annually because the expanding well field is 816 feet.

The LPA distribution system is eighteen-inch nominal pipe size, designed to supply LPA for forward gasification to two adjacent lines of modules. Therefore, two LPA supply systems will be required for the air-fired UCG plant. The total length of pipe required for start-up of the LPA supply system is 4,281 feet. The amount of pipe for the LPA supply system should also be purchased annually because the expanding well field is also 816 feet.

The well field production header for each module will have one flanged inlet connecting to each set of production wellhead piping. The production wellhead piping for a module will be connected to the well field production header prior to the start of reverse combustion linking of the modules. The gas produced from a module during linking will be collected in the header. The production wellhead piping will remain connected to the header during gasification and the initial venting and cooling of the module. All gas produced from the module during these activities will be collected.

After initial venting and cooling of a module, the production wellhead piping will be disconnected from the header, moved, and connected to the newly constructed module in the line. The header inlets for the production wellhead piping for the module will be capped with blind flanges when the wellhead piping is moved. When a new module is constructed in a line of modules, the well field production header is extended. An isolation valve is provided for each header to isolate it when blind flanges are installed and the header is extended. Low-BTU gas flow to the power generation facility will not be interrupted when wellhead piping is moved or when the header is extended because modules in other lines are being gasified and linked when these activities are being performed. This is another advantage of the well field design: duplicate lines of modules.

The air-fired UCG plant will require a total of two well field production headers. At the time of plant start-up, the well field production headers will be constructed for five rows of modules in each line. Therefore, initial well field production header construction will require pipe and fittings sufficient for connecting ten modules (Figure 10-3).

The well field production headers are connected to a product gas collection line used to transport the low-BTU gas to the power generating plant. The well field production headers are connected to the collection line, again using tees and blind flanges to prevent erosion at the bend. The product gas collection line is designed to be the same size as the production headers.

The well field production headers and product gas collection line are designed to supply the low-BTU gas to the power plant at a minimum pressure of 350 psig, when the production headers are at their maximum length during the twenty-year air-fired UCG plant operation. For the air-fired plant, an equivalent maximum length of 8,917 feet of pipe for the product gas collection line was used in pipe sizing and pressure drop calculations.

The delivery pressure of the low-BTU gas to the power plant was selected so that if the gas was used to fuel an combined cycle power generation plant it would arrive at the generation plant at the desired pressure for gas turbine operation without the need for additional compression.

The initial and annual purchases of pipe, valves and fittings required for the HPA supply, LPA connection, and well field production header and gas collection systems are listed in Table 10-3. Again, ten percent excess is purchased for each item.

TABLE 10-3. SURFACE PIPING SYSTEMS

Design of Surface Piping Systems:			
	HPA Injection	**LPA Distribution**	**Production Header**
I.D., inches	2.067	17.286	21.00
Inlet Pressure, psia	1241	502	424
Outlet Pressure, psia	1179	479	363
Pressure Drop, psia	62.4	23	61.5
Maximum Length, feet	8917	8917	8917
Average Temperature, ^{0}F	150	150	250
Max. Mass Flow, lb/sec	1.56	149.6	248.0

Pipe Valves, and Fittings Required for HPA Injection:		
Amount purchased:	Start-up	Annual
Pipe, feet	6481	816
Raised-face Slip-on Flanges, each	173	8
Elbows, each	22	--
Tees, each	15	1
Valves, each	24	--
Automatic Flow Control Valves, each	11	--
Pressure Transducers, each	22	--
Orifice Flanges, each	22	--
Orifice Plates, each	11	--
Flange Bolts, each	1084	36

Pipe, Valves, and Fittings Required for LPA Connection:		
Amount Purchased:	Start-up	Annual
Pipe, feet	4281	816
Raised-face Slip-on Flanges, each	52	8
Blind Flanges, each	4	1
Tees, each	4	1
Valves, each	3	--
Flange Bolts, each	744	108

Pipe, Valves, and Fittings Required for Production Headers:		
Amount Purchased:	Start-up	Annual
Pipe, feet	4281	816
Raised-face Slip-on Flanges, each	52	9
Blind Flanges, each	6	2
Orifice Flanges, each	3	--
Orifice Plates, each	4	--
Crosses, each	4	1
Full-bore Valves, each	3	--
Flange Bolts, each	804	132

10.2.1.8 Groundwater Monitor Wells

It will be necessary to install groundwater monitor wells to acquire baseline water quality data and hydrostatic heads for the aquifers at the site. This information will be required for the permitting of the air-fired UCG plant and is also necessary for additional geologic evaluation of the UCG plant site. Monitoring of the groundwater quality and hydrostatic heads will continue during the operation of the demonstration plant to insure the operation is environmentally safe and to detect excursions.

The air-fired UCG plant, which is sized to deliver sufficient fuel to generate 200 MW of electrical power, will consume roughly 0.27 mi^2 over its twenty-year life. The coal seam aquifer is the most critical to monitor. An outer ring of sixteen monitor wells in the coal seam aquifer will be located one hundred feet inside the perimeter of the permitted section. Another ring of twelve monitor wells in the coal seam aquifer will be located 300 feet inside the outer ring. Eight additional monitor wells will be completed into other aquifers at the site.

The monitor wells are expected to be steel cased and screened with PVC. The size of the casing is four-inch nominal with an inner diameter of approximately 3.75 inches.

10.2.1.9 Air Compression Systems

The equipment required for the air compression systems includes: compressors to supply HPA and instrument air, compressors to supply LPA, gas turbine drive motors and control, and concrete pad and building.

HPA is provided by booster-compressors designed to compress LPA discharged from the primary compressor. The HPA compressors provide the small volumes of air required for reverse combustion linking. The HPA compressor is sized to provide 1,225 scfm of air at 1,241 psia. This quantity of air is sufficient to provide HPA required for linkage of modules.

The discharge pressure is based upon the required flow rate, the pressure drop in the HPA supply system, and the lithostatic pressure at the bottom of the coal seam being gasified. The design of the HPA compressor provides the required flow of air to the base of the injection at a pressure equal to the lithostatic pressure at the bottom of the coal seam. One psi/foot of depth is used to estimate the lithostatic pressure at the top of the coal seam. Thus, the design HPA injection pressure is 1,179 psia as the air arrives at the bottom of the injection well.

A 95 percent energy efficiency was used in the sizing of the reciprocating compressor. The HPA compressor is sized at 86 hp. A ten percent excess factor is used for compressor sizing so a total of 95 hp of HPA compressor is recommended for the air-fired UCG plant. Table 10-4 provides a summary of the HPA compressor requirements.

The LPA required for gasification is provided for both rotary (axial flow) and reciprocating type air compressors. The LPA compressors provide the large volumes of air required for forward gasification, supply required instrument air, and supply compressed air to the HPA compressors. The LPA compressors provide 118,710 scfm of air at 502.4 psia.

The LPA compressor discharge pressure is based upon the 118,710 scfm flow rate, the pressure drop characteristics of the LPA supply system, and the hydrostatic pressure of the coal seam being gasified. The design of the LPA compressor provides the required flow of air to the base of the injection well at a pressure equal to the hydrostatic pressure of the coal seam. The hydrostatic pressure of the coal seam is 379 psia at a depth of 1,166 to the bottom of the coal seam.

The energy efficiency assumed in the sizing of the LPA compressor system is 85 percent. The LPA compressors are sized at 39,526 hp. A ten percent excess factor is again used for compressor sizing so a total of 43,918 hp of LPA compressors are recommended for the air-fired UCG plant. Table 10-4 also provides a summary of the LPA compressor requirements.

TABLE 10-4. COMPRESSOR REQUIREMENTS

HPA Compressors:	
Capacity, scfm	1225
Inlet Pressure, psia	502
Discharge Pressure, psia	1241
Number of Stages	1
Compression Ratio/Stage	2.5
Size Purchased, hp	95
LPA Compressors:	
Capacity, scfm	118709
Inlet Pressure, psia	12.7
Discharge Pressure, psia	502
Number of Stages	3
Compression Ratio/Stage	3.41
Size Purchased, hp	43918

Both the HPA and LPA compressors are to be driven directly by low-BTU gas turbines. The HPA and LPA air compressors drive turbines and controls are housed in a building.

10.2.1.10 Site Requirements

The site requirements are grouped into three categories: buildings, heavy equipment, and major electrical equipment. The total area required for buildings for the air-fired UCG plant is 17,000 ft^2. The buildings will provide a shop and space for fabrication of surface piping, a bay for heavy equipment maintenance, an electronics workshop, space for parts storage, facilities for personnel, a process control room, computer facilities, a laboratory for gas analysis, and office space.

Heavy equipment is required for site preparation, movement of wellhead and air supply piping, fabrication and installation of new well field production header piping, movement of air compressor and control trailers, well testing, and transportation. The following heavy equipment is required for the air-fired UCG plant operation: a mobile crane, a fork lift, a D-9 caterpillar, a front end loader, a six wheel, 3/4 ton pickups, and pulling rigs.

The major electrical equipment required for the air-fired UCG plant operation consists of a process control computer, process analysis computer, A/D and I/P signal converters, interface cards, monitors, a printer, and three gas chromatographs.

10.2.1.11. Personnel Requirements

The personnel requirements for the air-fired UCG plant are as follows: one plant superintendent, three engineers, one geologist, two secretaries, six welders, twenty operating technicians, eight laborers, twelve maintenance men, four mechanics, six heavy equipment operators, five shift foreman, one maintenance foreman, and one fabrication foreman.

10.2.2 Air-Fired UCG Plant Economics

Economic Basis. After determination of the equipment and personnel requirements and costs for the air-fired UCG plant, an economic evaluation of the project was completed. The economic basis chosen for evaluation of the project economics is provided in Table 10-5.

TABLE 10-5. ECONOMIC BASIS FOR THE AIR-FIRED UCG PLANT

Item	**Cost Basis**
Currency	2006 $ US
Plant Load Factor	95%
Plant Life	20 Years
Depreciation	Straight Line
Debt to Equity Ratio	100 % Equity
Return on Equity	15% Annually
Bond Interest Rate	Not Applicable
Bond Life	Not Applicable
Tax Life	Not Considered Here
Combined Corporate, Federal, State, and Local Income Tax Rate	Not Considered Here
Coal Royalties	$0.05/10^6 BTU Recovered
Salvage Value	0
Construction Period	2 Years

Results of the Air-fired UCG Plant Economic Analysis. A probable operation of the air-fired UCG plant is assumed to assess the commercial potential of the UCG facility. The probable operation assumed is that used in the design of the UCG facility. A summary of the key operating parameters assumed for base case operation of an air-fired UCG plant sized to provide sufficient low-BTU gas to fuel a 200 MW combined cycle electric power generation plant is provided in Table 10-6. Other necessary parameters are assumed to have values equal to those presented in the previous sections. The calculation method for determination of the required selling price of the gas produced from the air-fired UCG plant is a discounted cash flow return on investment method as described in the literature (Boysen and Gunn 1979).

TABLE 10-6. AIR-FIRED UCG PLANT OPERATING PARAMETERS

Operating Parameter	Value Assumed
Distance of Reverse Combustion Links	200 feet
Average Dry Product Gas HHV	150 BTU/scf
Amount of Coal in the Modules Gasified	65%
Amount of Product Gas Lost	0%
Average Depth at Top of Coal Seam	1054 feet
Average Thickness of Coal Seam	112 feet

Table 10-7 summarizes the capital investment requirements for an air-fired UCG Plant. The total investment for the air-fired UCG plant includes the cost of drilling the process wells required for plant startup; the cost of the air compression facility which includes the costs of the HPA compressors, the LPA compressors, buildings to house the compressors, and drive turbines; the cost of piping and accessories (pipe, pipe accessories, flow control and metering equipment, and valves); the cost of site facilities (heavy equipment, computer and electrical equipment, buildings, and the groundwater monitor well network); working capital; and salaries paid during construction. The cost data provided are the installed equipment cost and the excess materials purchased. The total investment required for the air-fired UCG facility is $58.34 MM including installed capital costs and working capital.

TABLE 10-7. AIR-FIRED UCG PLANT CAPITAL INVESTMENT REQUIREMENTS

Item	% of Total
Drilling:	
Unit Cost = $118.59/foot	
25 Wells Required for Start-up	
Total Cost = $3.46 MM	5.9
Air Compression:	
LPA – Unit Cost = $785/hp	
HPA and LPA = 43,918 hp Purchased	
HPA – Unit Cost = $785/hp, 95 hp Purchased	
Compression Cost = $34.55 MM	59.2
Piping and Accessories:	
Pipe Cost = $1.16 MM	
Piping Accessories = $0.50 MM	
Flow, Control, and Metering = $0.85 MM	
Valves = $1.02 MM	
Total Piping Cost = $3.53 MM	6.1
Site Facilities:	
Heavy Equipment = $2.16 MM	
PCs and Electrical Equipment = $0.86 MM	
Buildings = $1.04 MM	
Monitor Wells = $1.48 MM	
Total Site Costs = $5.54 MM	9.5
Working Capital = $1.12 MM	1.9
Salaries During Construction = $10.14 MM	17.4

Annual operating expenses for the air-fired UCG plant include the cost of drilling the new process wells required annually; the coal royalty based upon BTUs recovered; salaries and wages; the cost of replacement piping and accessories required; maintenance costs; and taxes and insurance.

The annual drilling cost for new wells is determined by multiplying cost per foot by the depth drilled per well and the number of wells drilled each year.

The coal royalty on state leases in Wyoming is eight percent of assessed value. For purposes of calculating taxes, a coal value of $10 per ton has been used. This is based on the published coal spot price for 8,800 BTU PRB coal, which was $9.90 per ton on December 15, 2006 (USEIA 2006). Therefore, the coal royalty is $0.80/ton of coal consumed. Because the coal is recovered in gaseous form, the coal royalty is based upon MMBTU recovered. For the PRB coal, there are 16.4 MMBTU/ton, assuming an 8,200 BTU/lb higher heating value for the coal. Thus the coal royalty is $0.05/MMBTU recovered.

The staffing salaries stated were determined based upon current State of Wyoming labor costs for each position needed at the UCG facility. All hourly personnel are assumed to have a ten percent over time premium and a fifty percent fringe benefit cost. Foremen are assumed to receive a ten percent bonus premium and a fifty percent fringe benefit cost. All professional staffing costs are assessed the fifty percent fringe benefit cost. The staffing needed and the corresponding salaries are shown below in Table 10-8.

TABLE 10-8. UCG PLANT STAFFING REQUIREMENTS AND SALARIES

Staff Position(Amount)	**Yearly Salary**	**Total Salary Including FB & OT**
Plant Supervisor (1)	$ 78,070	$ 117,105
Engineer (3)	$ 71,760	$ 322,920
Geologist (1)	$ 66,701	$ 100,052
Shift Foreman (5)	$ 48,560	$ 400,620
Maintenance Forman (1)	$ 51,430	$ 84,860
Fabrication Foreman (1)	$ 51,430	$ 84,860
Secretary (2)	$ 25,290	$ 83,457
Welder (6)	$ 45,140	$ 446,866
Heavy Equipment Operator (6)	$ 45,140	$ 446,846
Mechanic (4)	$ 45,140	$ 297,924
Maintenance Personnel (12)	$ 45,140	$ 893,772
Operators (20)	$ 42,030	$ 1,386,990
Laborer (8)	$ 30,500	$ 402,600
Total (90)		**$ 5.07 MM**

The annual cost of pipe is determined based upon current vendor cost data an estimated pipe replacement needs.

Depreciation was assumed to be straight line over the twenty-year plant life, based upon the installed capital investment. The salvage value for the UCG plant is assumed to be zero.

The annual maintenance costs are estimated to be equal to five percent of the installed capital cost of the air compressors and site facilities.

Annual taxes include severance tax, ad valorem tax and property tax. The severance tax is 3.75% of the assessed value of the coal and the ad valorem tax mill levy averages 6.1 percent of the assessed value of the coal. As with the coal royalty calculation, a coal value of $10/ton is used. The property tax in Wyoming is 11.5 percent multiplied by the 6.1 percent mill levy rate and then multiplied by the assessed value of the industrial facility. The cost of facility insurance is commonly based upon the gross product sales value. Since the low-BTU gas produced will be used to make a product the cost of facility insurance will be considered when determined the economics of the combined process.

The annual operating expense breakdown is summarized in Table 10-9. The total annual operating expense required for the air-fired UCG facility is $13.47 MM.

TABLE 10-9 AIR-FIRED UCG PLANT ANNUAL OPERATING EXPENSES

Item	% of Total
Drilling: Unit Cost = $118.59/ft 9 Wells/Year Required Drilling Cost = $1.28 MM	9.5
Coal Royalty: Unit Cost = $0.05/MM BTU Recovered 14,492,160 MM BTU/Year Coal Cost = $0.71 MM	5.3
Salaries = $5.1 MM	37.6
Pipe = $0.27 MM	2.0
Depreciation = $2.86 MM	21.2
Maintenance Costs = $2.01 MM	14.9
Taxes = $1.27 MM	9.4

Operation of the air-fired UCG plant according to the base case assumptions would result in a raw syngas cost to the electric power generation plant of $1.62/MM BTU, assuming the investment is amortized in twenty years which includes a fifteen percent return on equity. It is important to remember that this price is for a low-BTU syngas supplied to the combined cycle power generation plant at 350 psig. This gaseous form of the fuel enables high efficiency power generation technologies to be utilized. Further, this premium fuel can be produced from the vast quantity of domestic coal that cannot be economically mined by conventional technologies.

It appears economic to operate the air-fired UCG facility under the conditions assumed for the base case operation. Considerable economic benefit would be obtained from operation of a 200 MW high efficiency combined cycle electrical power generation plant utilizing the low-BTU gas as fuel. A summary of the plant economics is provided in Table 10-10.

TABLE 10-10. AIR-FIRED UCG PLANT ECONOMIC SUMMARY

Item	Cost
Raw Syngas Production Cost	$1.62/MM BTU
Capital Investment (Installed) Working Capital Total Investment	$57.22 MM $1.12 MM $58.34 MM
Annual Operating Expenses	$13.47 MM

10.2.3. Sensitivity of Key Parameters to Air-Fired UCG Economics

In order to assess the commercial economic potential of UCG of deep coals in the PRB, the economic sensitivity of a potential UCG facility is examined by assuming possible ranges of values for the key UCG operating parameters in Table 10-11. Analysis of the economic sensitivity of commercial UCG operations also provides data to evaluate the economic risk of development as well as the economic potential. In the sensitivity analyses, all base case parameters except one are held constant and the sensitivity of the UCG syngas cost to the varied parameter is determined.

TABLE 10-11. VALUES FOR UCG BASE CASE PARAMETERS

Parameter	Base Case Value
Average Depth at Top of Coal Seam	1054 ft
Average Thickness of Coal Seam	112 ft
Well Spacing	200 ft
Average Dry Product Gas HHV	150 BTU/scf
Resource Recovery	65%

10.2.3.1 Depth

The depth of the coal seam is an important economic parameter. Greater depths increase the costs of drilling and air compression significantly and to a lesser degree the costs of site facilities (monitor wells), pipe, and accessories. One problem did arise in assessing the economic sensitivity of the UCG syngas cost to the coal seam depth. As previously discussed, the assumed commercial UCG operation would feed low-BTU gas to the end-user facility at 350 psig. In this case the gas would arrive at a pressure suitable for UCG-IGCC power generation. When considering the economic sensitivity of the UCG syngas cost to the seam depth it was found that for depths less than 860 feet to the top of the coal, it is not possible to inject at a pressure less than the coal seam hydrostatic pressure and deliver the gas to the end-user facility at 350 psig. For this reason, the sensitivity of the UCG syngas cost to the coal seam depth is also determined for a low-BTU gas delivery pressure to the end-user facility equal to 100 psig. The results of both UCG syngas cost sensitivities are shown in Figure 10-8. Interestingly, the gas cost sensitivity to coal seam depth at 350 psig is minimum at near 1,000 feet. When the gas is delivered to the end-user facility at 100 psig, the sensitivity is near linear.

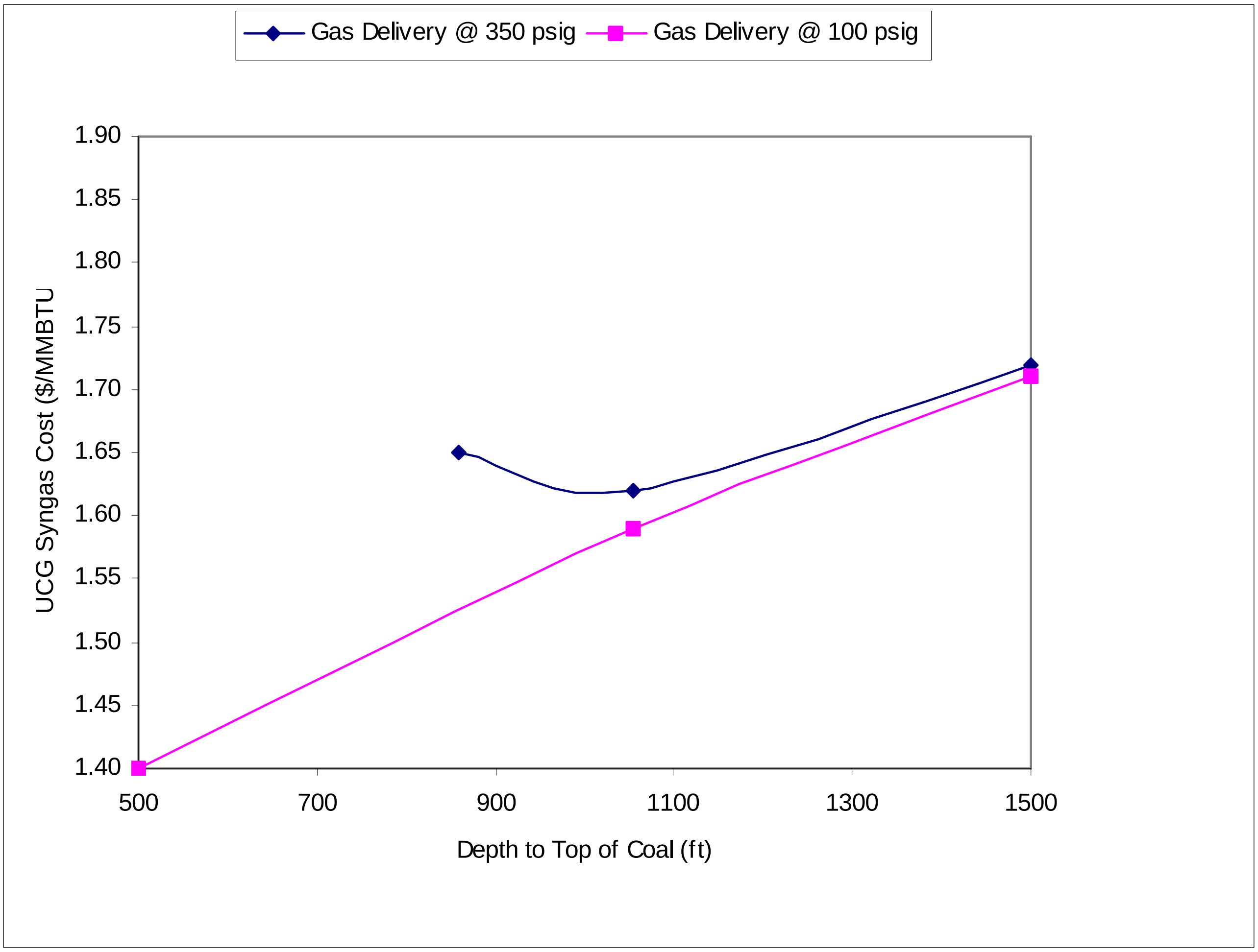


FIGURE 10-8. UCG SYNGAS COST SENSITIVITY TO COAL SEAM DEPTH

10.2.3.2 Thickness

The thickness of the coal is another important economic parameter. Thicker coal seams allow more energy to be gasified by each well pair, thereby reducing drilling costs. The UCG syngas cost sensitivity to coal seam thickness is illustrated in Figure 10-9. The UCG syngas cost sensitivity to coal seam thickness is asymptotic in shape with strong economic sensitivity in thin seams. However, the tremendously thick coal seams in the PRB study area fall near the flat part of the sensitivity curve where the syngas costs are not as sensitive. In fact, over the range considered (50 to 112 feet), the results are all economically favorable.

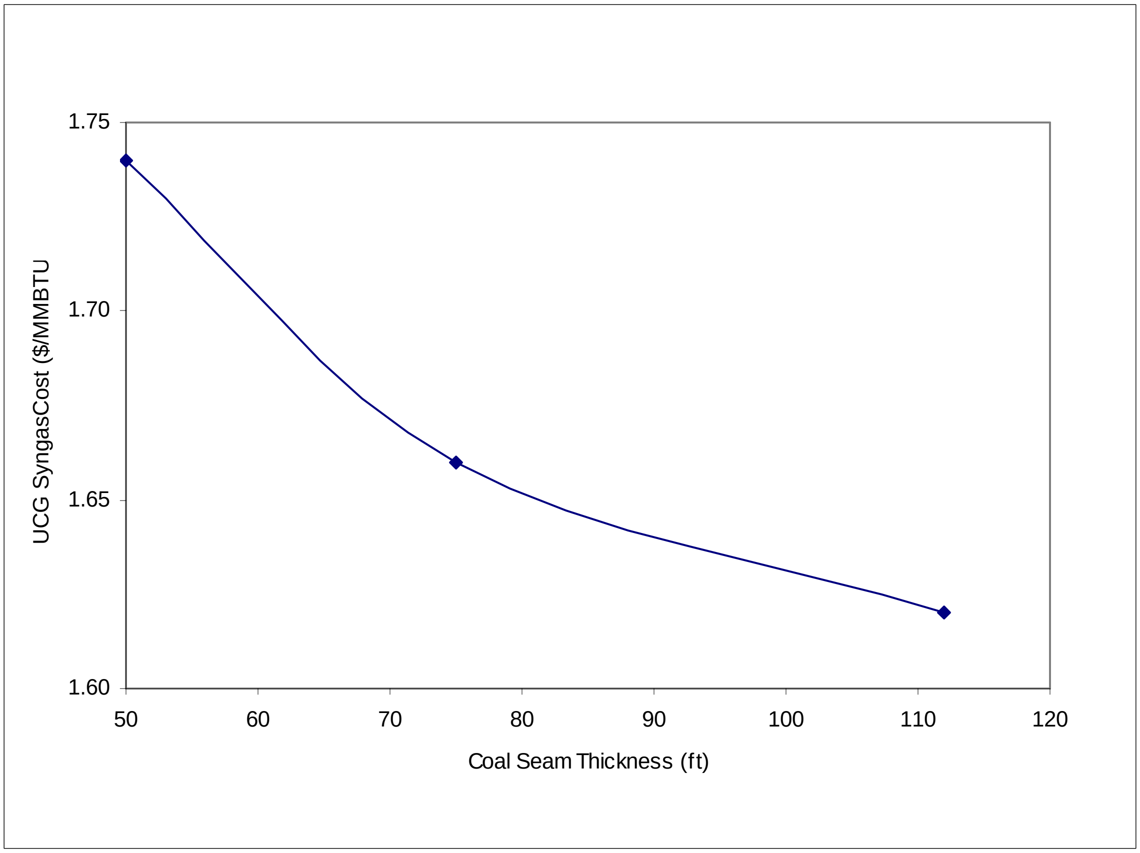


FIGURE 10-9 . UCG SYNGAS COST SENSITIVITY TO COAL SEAM THICKNESS

10.2.3.3 Well Spacing

The distance at which linking of process wells can be reliably achieved will determine the spacing of the process wells. The well spacing is an economically important process parameter that is dependent upon the characteristics of the specific coal seam. The UCG syngas cost sensitivity to the process well spacing is illustrated in Figure 10-10. Since the coal seams considered appear to be predominantly without significant faulting or large vertical fracture networks, it may be possible to link over distances of 200 feet or greater with a high degree of reliability. Further, many of the coal seams appear to have impermeable ash zones located in the lower part of the coal seams. These zones can be advantageous to linking over large distances. In addition, the substantial seam thickness typical of the coal in the PRB is more amenable to greater well spacing. However, detailed site characterization is required to determine the process well spacing. The economic sensitivity UCG syngas cost to the process well spacing is examined considering distances from 60 to 200 feet to be conservative. Again this sensitivity is asymptotic in shape with the greater the well spacing the more economic the plant operation. As the data indicate, a process well spacing in excess of 100 feet is required to reach the point where the asymptote begins to flatten. Since the base case seam thickness is 112 feet, linking process wells of a distance of 100 feet should be readily achievable.

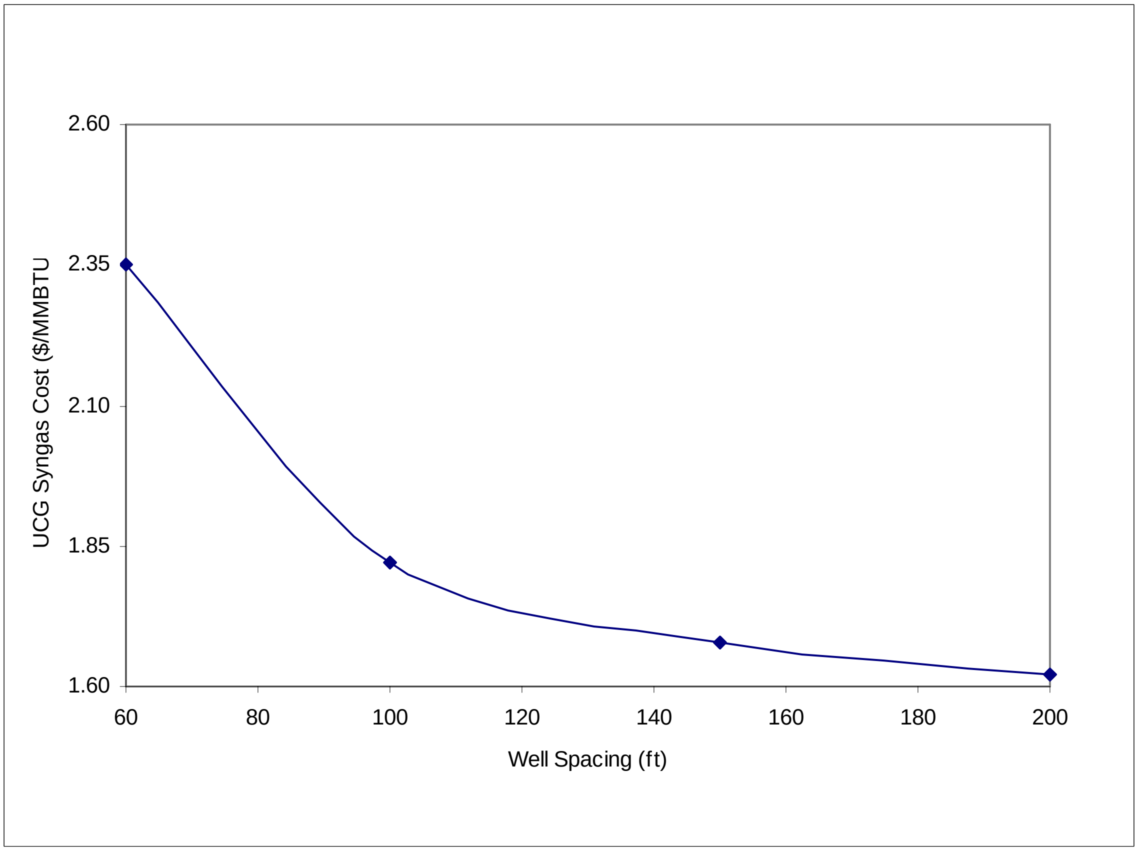


FIGURE 10-10. UCG SYNGAS COST SENSITIVITY TO PROCESS WELL SPACING

10.2.3.4 Gas Heating Value

The UCG syngas cost sensitivity to UCG syngas HHV is illustrated in Figure 10-11. The sensitivity of the UCG syngas cost to the HHV is examined by considering a range of values from 100 to 175 BTU/scf. Again, as expected, a higher average UCG syngas HHV results in a lower UCG syngas cost. These data indicate that a syngas HHV in excess of 125 BTU/scf results in a reasonably favorable UCG syngas cost. As a point of reference, the average UCG syngas HHV produced during ARCO's Rocky Hill UCG Test in the PRB exceeded 200 BTU/scf.

10.2.3.5 Resource Recovery

The UCG syngas cost sensitivity to amount of the coal resource recovered is illustrated in Figure 10-12. The sensitivity of the UCG syngas cost to the resource recovery is examined by considering a range of values from 50 to 80 percent. The sensitivity of the UCG syngas cost to the resource recovery is minor over the range of values considered. The UCG syngas cost varied only $0.08/MMBTU over the entire range considered.

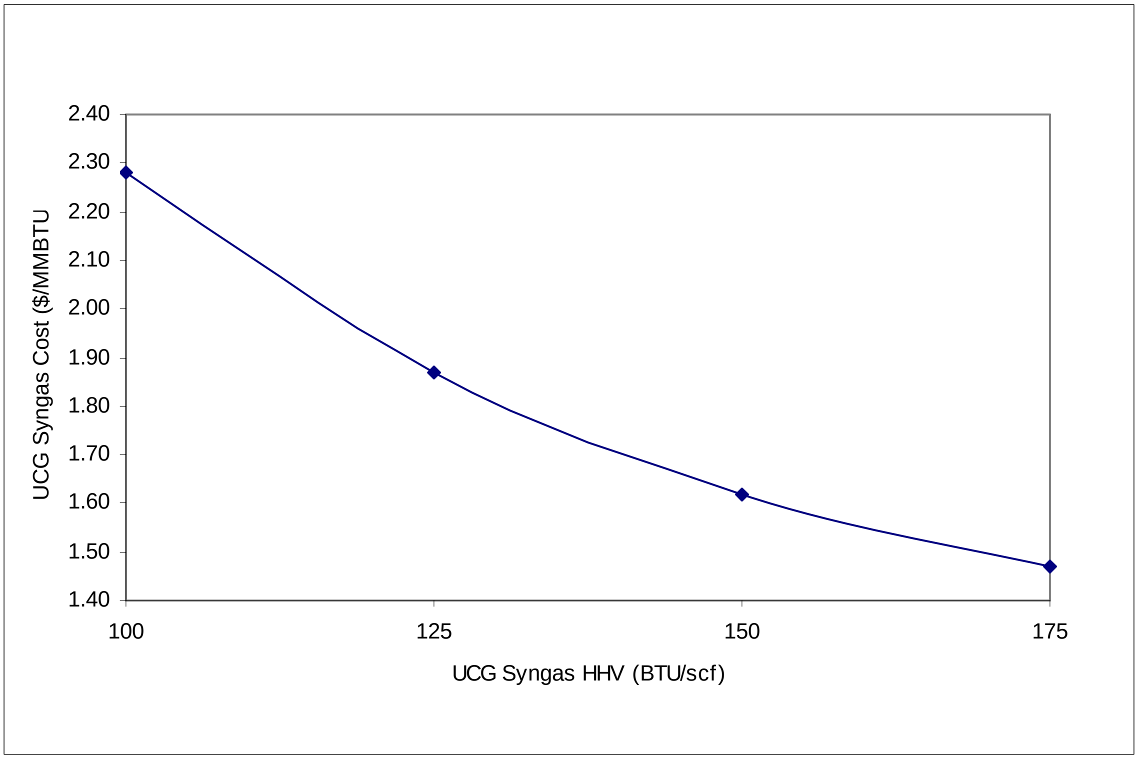


FIGURE 10-11. UCG SYNGAS COST SENSITIVITY TO SYNGAS HHV

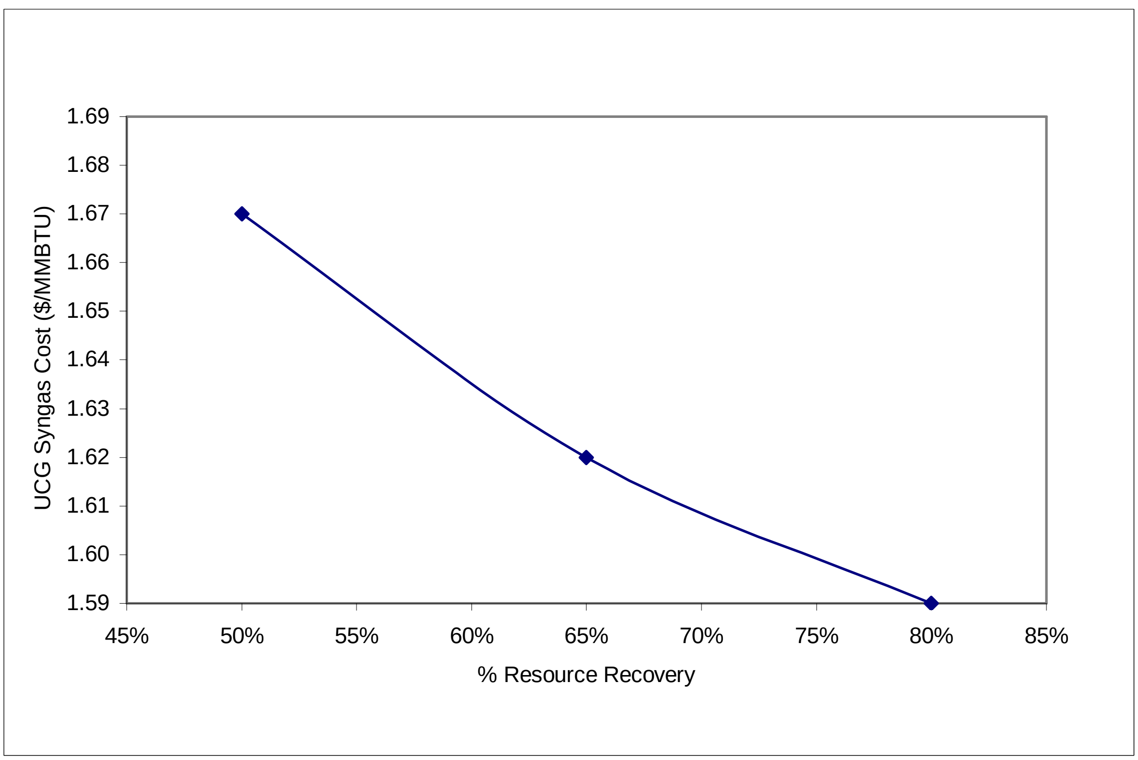


FIGURE 10-12. UCG SYNGAS COST SENSITIVITY TO RESOURCE RECOVERY

10.2.4 Capital and Operating Costs for Air-Fired UCG-IGCC

The results of Section 10.2.1 and Section 10.2.2, describing a UCG project capable of producing the syngas feed for a 200 MW UCG-IGCC power plant, have been used to further estimate the economics of that 200 MW plant operating on syngas. Results of the economic modeling were developed through the use of published capital cost data for previously built IGCC facilities. However, these data were modified to encompass the use of UCG instead of surface gasification. This section will describe the economics related to production of power through the use of a UCG-IGCC facility which is shown below in Figure 10-13.

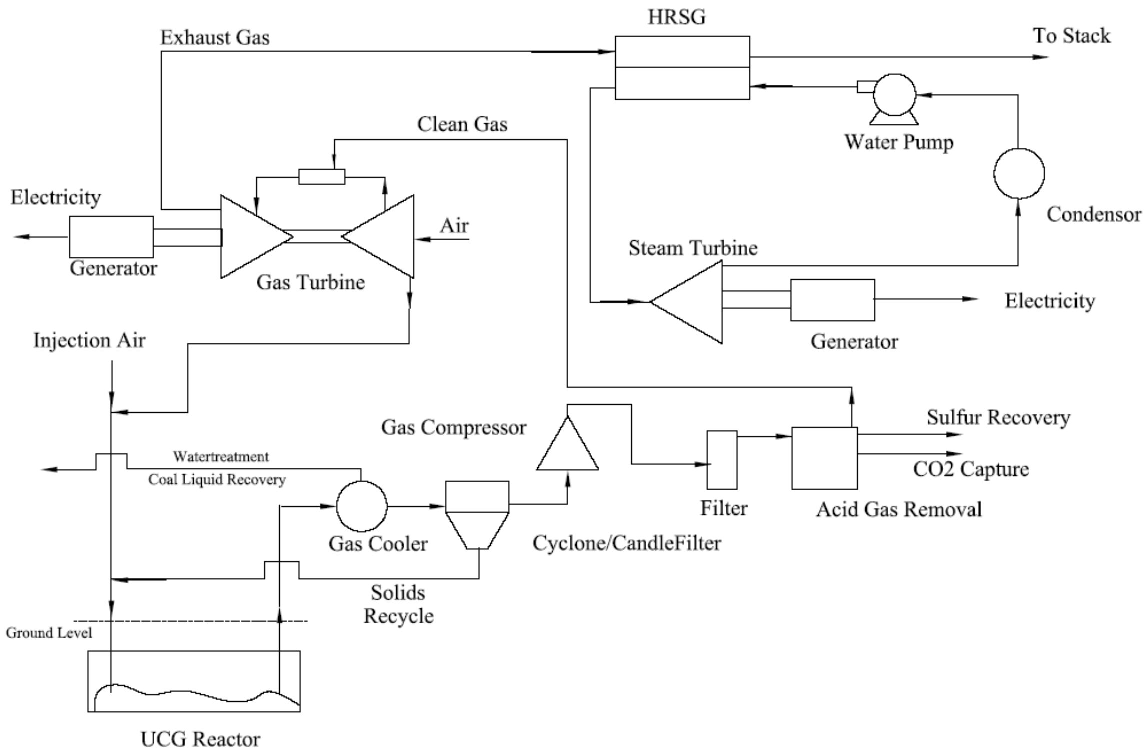


FIGURE 10-13. AIR-FIRED UCG-IGCC FACILITY FLOW DIAGRAM

Capital costs for IGCC facilities were adapted from a study by Harvard University business school and are shown in Table 10-12 (Rosenberg 2004). These values were used to develop estimates of the major plant processes and their contribution to the capital costs.

TABLE 10-12. IGCC PROCESS COMPONENTS COST DISTRIBUTION

Process Description	Share of Cost
Coal Handling Equipment	12%
Gasifier, ASU and Syngas Cooling	30%
Gas Clean-up and Piping	7%
Combined-Cycle Power Block	33%
Remaining Components and Control Systems	18%

Because a UCG IGCC facility has been selected, the cost share of the coal handling equipment, surface gasifier, air separation unit and gas cooling system can be eliminated. These sections of the plant will be replaced by the UCG facility. The UCG facility has been estimated to require a total investment of $58.34 MM as described in the previous section.

Using $1400/KW as the base case IGCC cost in 2003 dollars, this is escalated to $1544/KW in 2006 dollars (Infomine 2007). Considering a 200MW plant, the cost of the IGCC facility sections was calculated and are shown in Table 10-13. The UCG facility will contribute $286/KW-hr to the total UCG-IGCC plant.

TABLE 10-13. IGCC FACILITY CAPITAL COSTS

ICGG Facility Component Costs		
Gas Cleanup and Piping	7.0%	$21.6 MM
Combined Cycle Power Block	33.0%	$101.9 MM
Remaining Components and Control Systems	18.0%	$55.6 MM
Total		**$179.1 MM**

TABLE 10-14. TOTAL UCG-IGCC FACILITY CAPITAL COST WITHOUT WORKING CAPITAL

Total UCG-IGCC Capital Cost		
UCG Capital	$286 /KW-hr	$57.2 MM
IGCC Capital	$895 /KW-hr	$179.1 MM
Total	**$1,182 /KW-hr**	**$263.3 MM**

Next, annual operating costs were estimated based upon the operating costs of the Polk Power Station (Tampa Electric 2004). The values estimated were adapted to the UCG-IGCC expected costs. These costs are summarized below in Table 10-15. These costs reflect that the syngas will be transferred from the UCG plant at cost; the UCG costs have been described in the previous section of this report. Project economics will be based on the total UCG-IGCC investment and operating costs.

TABLE 10-15. ANNUAL OPERATING COSTS FOR UCG-IGCC FACILITY

IGCC Annual Operating Costs	
Salaries	$3,724,000
Low-BTU Syngas	at cost
Propane	$28,324
Catalysts and Chemicals	$1,000,000
O&M-Power Block, Common and Water	$2,000,000
Equipment Replacement and Upgrades	$2,000,000
Total Operating Expenses	**$8,752,000**

The syngas fuel requirements developed for the low-BTU gas were conceived by allowing for a 95 percent load factor and 1,520 MM BTU/hr consumption rate. This low-BTU gas is considered in this analysis to be transferred to the IGCC at cost. Propane needed for pilot lights was also considered using a consumption rate of 40 gal/day. The annual propane cost at $1.94/gal is $28,324. The remaining annual operating costs for chemicals, catalysts, O&M for the power block and equipment replacement were estimated from operating experience at the Polk Power Station (Tampa Electric 2004).

The staffing salaries stated were developed by considering current costs in Wyoming costs for each position needed at the power station. Also included in this value is a ten percent over time premium and a fifty percent fringe benefit cost. The staffing needed and the corresponding salaries are shown below in Table 10-16. The number of staff required for each position was developed by first considering the staffing used at the Polk Power station (Tampa Electric 2004). The number of personnel was then adjusted to suit the needs of an UCG-IGCC facility.

TABLE 10-16. STAFFING REQUIREMENTS AND SALARIES FOR UCG-IGCC FACILITY

Staff Position (number)	Yearly Salary	Total Salary Including FB & OT
Plant Supervisor (1)	$ 78,070	$ 117,105
Engineer (6)	$ 71,760	$ 645,840
Shift Foreman (5)	$ 48,560	$ 400,620
Maintenance Forman (2)	$ 51,430	$ 169,719
Fabrication Foreman (2)	$ 51,430	$ 169,719
Secretary (2)	$ 25,290	$ 83,457
Welder (5)	$ 45,140	$ 372,405
Heavy Equipment Operator (5)	$ 45,140	$ 372,405
Mechanic (5)	$ 45,140	$ 372,405
Maintenance Personnel (5)	$ 45,140	$ 372,405
Operators (5)	$ 42,030	$ 346,748
Laborer (6)	$ 30,500	$ 301,950
Total (49)		**$3.724MM**

Property taxes and insurance were then estimated. Property taxes were estimated based upon the State of Wyoming property tax rates.

Property Tax/yr = Total Capital Cost * Mill Levy Rate * Tax Rate (Industrial Facilities)

The calculated property taxes are summarized below in Table 10-17. No reduction was made as the plant aged.

TABLE 10-17. ASSESSED PROPERTY TAXES FOR A UCG- IGCC FACILITY

Property Taxes	
Power Plant Total Capital Cost	$ 179.1 MM
Property Tax – Industrial Facilities	11.5%
Mill Levy Rate	6.1%
Property Tax/yr	**$ 1.25 MM**

Insurance rates for an industrial facility of this nature can be estimated based upon gross annual product sales value. Power generation available for sale was calculated considering the 200MW plant with a 95 percent capacity factor. This yields 1,664,400,000 KW-hr/yr. For this insurance cost estimate, a sales price of $0.05/KW-hr was used. The insurance premium is estimated as 1.5 percent of the gross annual product sales making yearly insurance cost $1,248,000. The total annual expenses are summarized in Table 10-18.

TABLE 10-18. TOTAL YEARLY EXPENSES FOR AIR-FIRED UCG-IGCC FACILITY

Areas of Expense	Yearly Amount
Total Operating Expenses	$8,752,000
Property Taxes	$1,256,400
Insurance	$1,248,000
UCG Section Operating Expenses	$8,660,000
Total Annual Expenses	**$19,916,000**
KW-hr/yr	1,664,400,000

10.2.5. Economic Analysis of Air-Fired UCG-IGCC

The financial model used in this study is based on a class of financial models called discounted cash flow (DCF) models. Net Present Value (NPV) is defined as present worth of positive cash flows plus present worth of negative cash flows both discounted at the minimum acceptable rate of return. NPV is a measure of whether there is sufficient present worth positive cash flow to cover the present worth negative cash flow and provide the necessary return on investment. The Discounted Cash Flow Rate of Return (DCF-ROR) is the discount rate that makes NPV equal to zero.

In evaluating the economic viability of UCG-IGCC in the PRB, these model outputs are useful as they allow comparison of different configurations of plant, capital requirements, projected profitability, and comparison of UCG syngas plant with surface gasifier syngas production.

For mutually exclusive project choices, as UCG vs. surface gasifier at the same plant location, the project with the largest NPV will maximize profits to the investor. The DCFROR will allow the investor to select projects that meet his minimum acceptable rate of return.

10.2.5.1. Assumptions for UCG IGCC

The following assumptions have been used in these economic analyses:

1. UCG capital and operating costs as described in Section 10.2.2, producing a syngas stream capable of feeding a 200 MW UCG-IGCC power plant. Analysis in constant 2006 dollars.

2. IGCC capital as outlined in Section 10.2.4. is based on breakdown of IGCC process components) and total IGCC cost of $1544/KW installed (Rosenberg et al. 2004), escalated to 2006 using Plant Services Cost Index (Infomine 2007)). IGCC operating costs based on estimated salaries and actual IGCC operating data (Tampa Electric 2004).

3. Analysis is After Federal Income Tax (AFIT), 35% tax rate, corporate tax entity.

4. Depreciation by Modified Accelerated Cost Recovery System, 20-year class life given to major capital items.

5. Three year construction, IGCC one-third each year, UCG 40% in year 2, 60% in year 3; 25 year project life; 50% production in Year 4 (first year of production), 100% in Year 5.

6. Severance tax for coal based on 3.75% of gross value of underground coal estimated to be gasified based on produced syngas volumes.

7. Ad valorem tax for coal based on 6.1% mill levy on gross value of coal estimated to be gasified based on produced syngas volumes.

8. State royalty for coal based on 8% of gross value of coal estimated to be gasified based on produced syngas volumes.

9. Coal value (for taxes and royalty) of $10 per ton, based on 12/15/2006 published spot price for 8,800 BTU PRB coal of $9.90 per ton (USEIA 2006).

10. Property tax on facilities is actual cost times 11.5% times mill levy rate.

11. Insurance on facilities estimated as 1.5% of annual gross product sales revenue.

12. 200 MW plant with 95% capacity factor producing 1,664,400 MW-hr/year. The high plant capacity factor is justified by having multiple UCG gasifiers operating simultaneously. Surface gasifiers, with one or two gasifiers, have capacity factors around 85%. The power block capacity factor is usually in excess of 95%.

13. 100% equity case, no leveraging of economics.

14. No salvage value.

10.2.5.2. Electricity Sales Price

Over the next 20 years, EIA projects coal-based electricity pricing in the Rocky Mountain Region in the range of $47 to $57 per MW-hr, in 2003 dollars (Rentech 2005). For California, EIA projects sales prices in the $60 to $77 range.

The Rocky Mountain Area Transmission Study (RMATS 2004) analyzed four electricity export options to move electricity to higher priced western markets. Their economic analyses indicated that these projects were economically justifiable. Moreover, they would require 1,400 MW of new coal-based generating capacity in Central Wyoming.

Therefore, it is likely that access to higher priced markets will become available in the time frame necessary to commercialize UCG in the PRB. Price ranges for electricity sales of $47, the lower end, to $77, the upper end, will be used. The midpoint of these ranges, $62 per MW-hr, has been used as the base case electricity selling price. As these are in 2003 dollars vs. the other economic data in this study in 2006 dollars, the estimated revenues will be conservatively stated.

10.2.5.3. Base Case Economic Estimates UCG-IGCC

The base case, with $62 per MW-hr electricity sales price, results in the UCG-IGCC project having a DCF-ROR of 18.3% and an NPV @ 15% discount rate of $44.3 million. Payback from project start, including construction, is a modest 7.6 years.

Annual gross revenues of about $103 million provide AFIT annual cash flow of about $56 million after royalty, operating expenses, ad valorem, severance and federal taxes are deducted. Annual cash flow projections are included in Appendix 1 to this report.

The 200 MW UCG-IGCC project returns a 15% DCFROR with electricity pricing $51.68 per MW-hr, the so-called "break even" revenue.

10.2.6. Base Case Economic Sensitivities Air-Fired UCG-IGCC

The base case, the 200 MW air-fired UCG IGCC project summarized above, has also been evaluated by varying the expected revenues, capital costs, and operating costs by plus and minus 25 percent.

10.2.6.1. Revenues

The sales price of electricity used in the base case is $62 per MW-hr. As discussed in 10.2.5.2, the estimated ranges for electricity sales in the Rocky Mountains is expected to be from $47 to $77 per MW-hr, a range of -24% to +24%. Revenues could vary within this range due to changes in electricity pricing, or due to lower plant capacity at basically the same fixed operating costs. In this study, the revenues have been varied from 75 percent of the base to 125 percent, and the resulting DCF-ROR is presented in Figure 10-14.

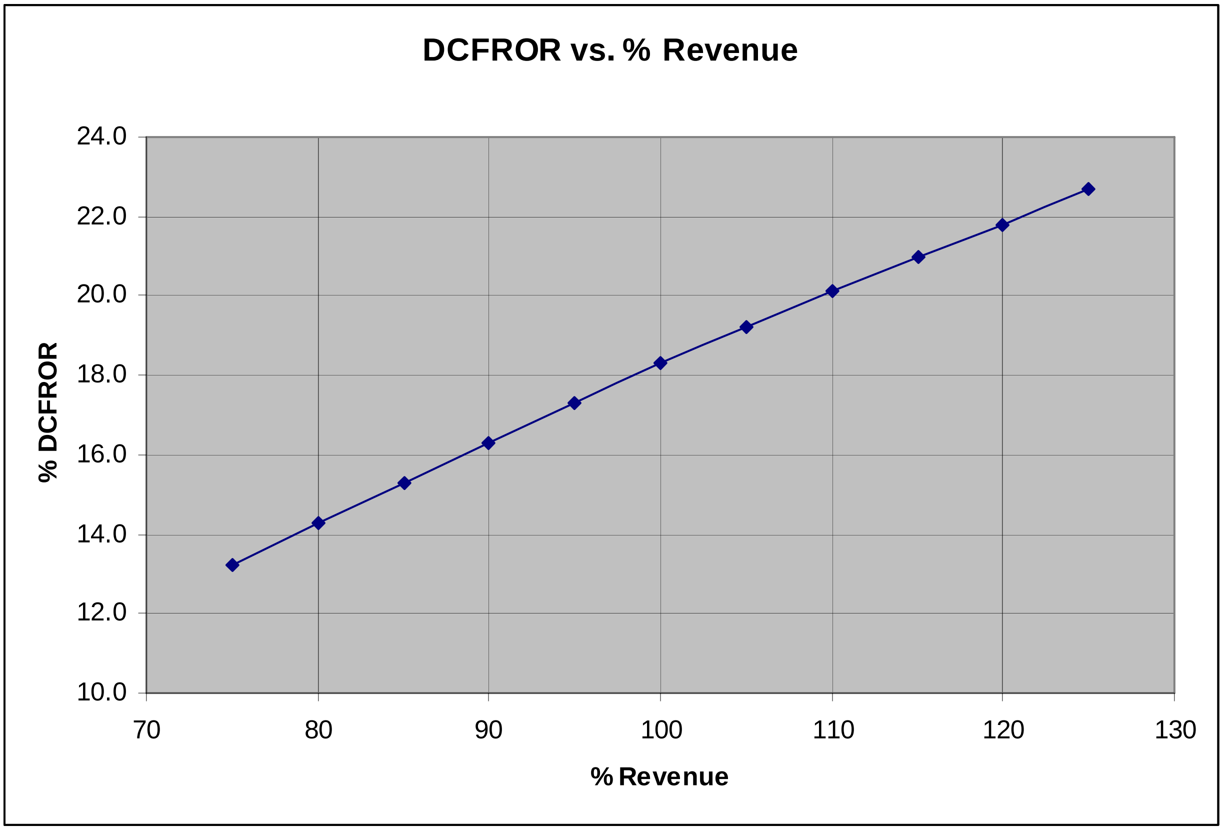


FIGURE 10-14. BASE CASE SENSITIVITY TO CHANGES IN REVENUE

At the lower end of the revenue sensitivity, the project rate of return approaches 13 percent, which may fall below the hurdle rate for investors. Generally, the percent DCF-ROR improves about 2 percent for each 10 percent increase in revenue.

10.2.6.2. Capital Costs

The required capital costs have also been varied from 75% to 125% of the base case. The result is presented in Figure 10-15. The DCF-ROR decreases about 2 percent for every 10% increase in capital costs, falling below 15 percent rate of return at about 125 percent of the base case. As the project rate of return is quite sensitive to capital costs, they should be estimated carefully. The UCG component of the UCG IGCC project has not been constructed at commercial scale outside of the Former Soviet Union. Therefore, use of a cost model with considerable detail, as presented earlier in 10.2.1, 10.2.2, and 10.2.3, is recommended in evaluating a UCG project. In this UCG IGCC project, the UCG capital is about 22 percent of the total capital cost (Table 10-14).

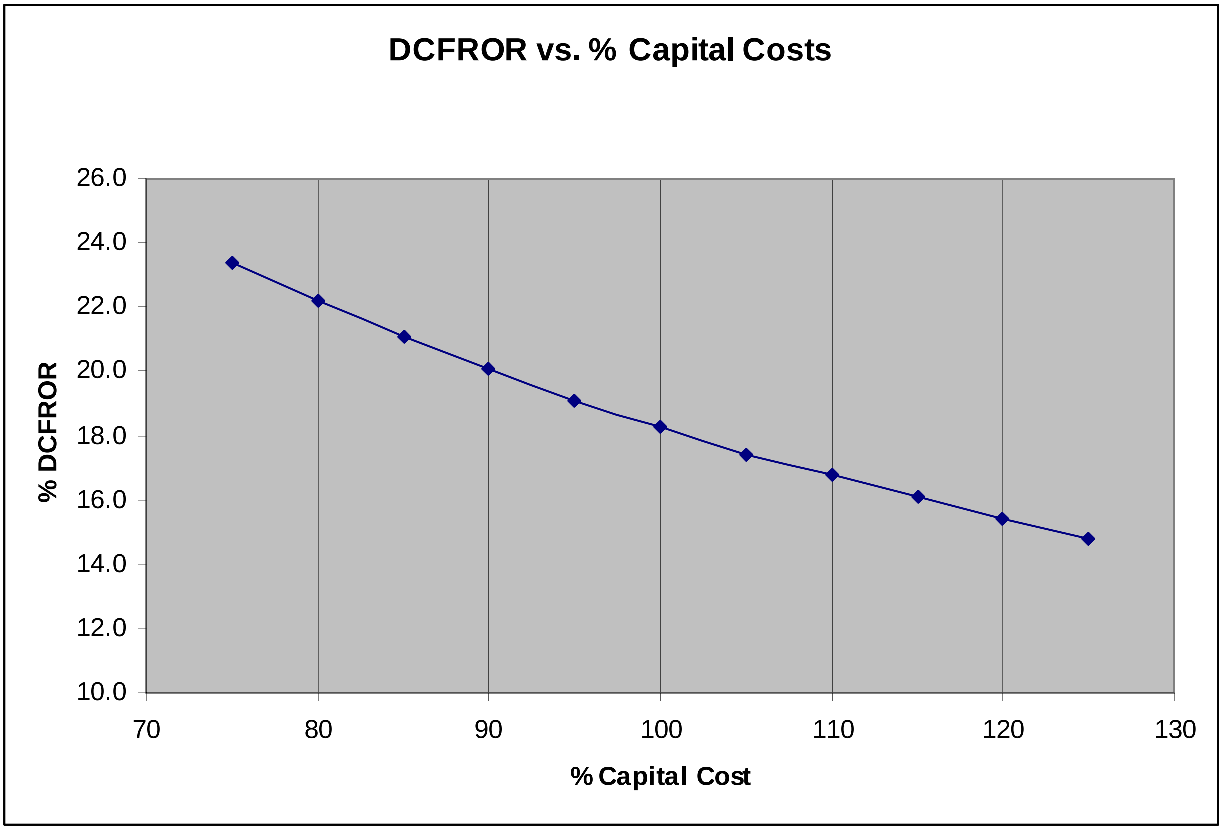


FIGURE 10-15. BASE CASE SENSITIVITIES TO CHANGES IN CAPITAL COSTS

10.2.6.3. Operating Costs

Figure 10-16 summarizes the sensitivities of rate of return vs. changes in the operating expenses. This project is obviously much less sensitive to changes in the operating costs than to equal percentage changes in capital costs and/or revenues. Each 10% increase in operating costs only results in a decrease of about 0.4% in the DCF-ROR.

These economic sensitivities are near linear and approximately additive. That is, a range of changes in revenue, capital, and operating costs can be estimated by adding (or subtracting) the effect of each change on the DCF-ROR. For instance, a +25% capital cost change and a –25% revenue change will have an additive negative effect on the DCF-ROR of -8.5%, resulting in a DCF-ROR calculated of 10.32%. Adding the two separate impacts together yields a negative effect on the DCF-ROR of -8.0%. Therefore, these three graphs can be used to estimate the DCF-ROR of various combinations of revenues, capital, and operating costs for the base case UCG IGCC project.

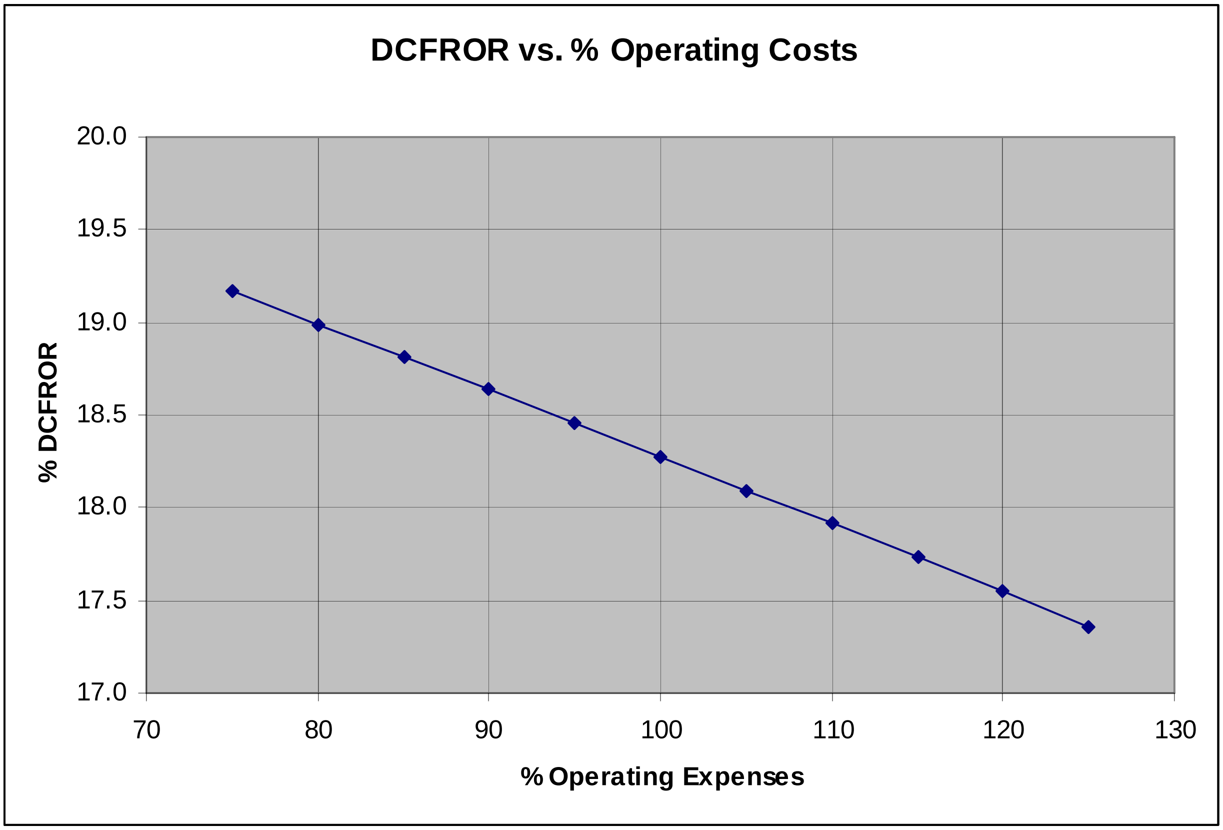


FIGURE 10-16. BASE CASE SENSITIVITIES TO CHANGES IN OPERATING EXPENSES

10.2.7. Comparison to 550 MW Surface Gasifier IGCC Economics

Published operating and capital cost data are available for surface gasifier IGCC projects, both those which are operating and proposed projects (Rosenberg et al. 2004). One of these, a "reference case" 550 MW IGCC surface gasifier plant, has been modeled in this study for comparison to the UCG IGCC project. In this report, the term "IGCC" refers to a coal-fueled surface gasifier IGCC power plant. Although the IGCC plant is substantially larger than the UCG IGCC base case plant, which should give it an economy of scale advantage, it is useful to compare the relative economics of these two.

10.2.7.1. Assumptions

The following assumptions have been used in the surface gasifier IGCC economic analysis:

1.) Capital and operating costs as published for a 550 MW IGCC power plant. Analysis in constant 2006 dollars.

2.) IGCC capital costs escalated to June 2006 dollars from 2003, escalator of 1.103 (Infomine 2007).

3.) Analysis is After Federal Income Tax (AFIT), 35% tax rate, corporate tax entity.

4.) Depreciation by Modified Accelerated Cost Recovery System, 20-year class life given to major capital items.

5.) Three year construction, IGCC one-third each year; 50% production in year 4 (first year of production), 100% in Year 5.

6.) Severance tax for coal paid by coal fuel supplier.

7.) Ad valorem tax for coal paid by coal fuel supplier.

8.) State coal royalty paid by coal fuel supplier.

9.) Property tax on facilities is actual cost times 11.5% times mill levy rate.

10.) Insurance on facilities estimated as 1.5% of annual gross product sales revenue.

11.) 550 MW plant with 85% capacity factor producing 4,095,300 MW-hr/year.

12.) 100% equity case, no leveraging of economics.

13.) No salvage value.

10.2.7.2. 550 MW IGCC Reference Case Economics

With the above assumptions, the IGCC 550 MW power plant has a DCFROR of 10.4%. The NPV at a 15% discount rate is -$199.7 million, with a payback period of 10.8 years. The annual cash flows from this case are in Appendix 1.

For this IGCC case to return a 15% DCFROR, the electricity sales price would need to be $80.60 per MW-hr. This is above the upper range of expected electricity prices. Therefore, for IGCC to become an economically competitive generating option, one or more of the following must occur:

1.) IGCC must be used in conjunction with UCG, lowering capital and fuel costs.

2.) Electricity prices must rise to a point where IGCC is economically competitive.

3.) Carbon capture must be mandated such that IGCC, with its lower costs for carbon capture than for pulverized coal combustion, will be economic.

4.) Leveraged financing must be used, possibly with government loan guarantees to get lower interest rates.

In comparison with UCG IGCC, the surface gasifier configuration is substantially less attractive. Table 10-19 shows this comparison.

TABLE 10-19. COMPARISON OF SURFACE GASIFIER COSTS WITH AIR-FIRED UCG IGCC.

	Surface Gasifier IGCC	UCG IGCC	% UCG Advantage
Capital/KW Installed	$1,544	$1,180	24%
Op Cost, $/MW-hr sold	$21.99	$11.96	46%
Breakeven Sales Price for 15% ROI	$80.60	$51.68	36%
DCFROR (as described here)	10.39%	18.28%	75%
Payback, years	10.77	7.64	29%

10.3 OXYGEN-FIRED UCG ECONOMICS COMPARISON

Oxygen-fired UCG systems are similar to the air-fired UCG systems except that an oxygen-enriched injection stream is used rather than air. General process module design and module layout are the same in the oxygen-fired system as in the air-fired system. General well field operations are also similar to air-fired systems. Sections 10.3.1.1-10.3.1.11 describe the general design of the oxygen-fired UCG plant.

Most previously tested oxygen-fired systems also incorporated steam injection for safety and process considerations. Analysis from a previous oxygen-fired UCG system at Rocky Mountain 1 showed that the intended steam injection was actually water at the wellhead injection conditions (Boysen et al. 1998). The injection of liquid water did not have a detrimental impact to the process. For this reason, this evaluation of the oxygen-fired UCG system does not include steam injection. The addition of steam injection is not necessary for oxygen injection systems and would significantly increase product gas costs. Section 10.4 discusses the costs for adding steam injection to the oxygen-fired system.

10.3.1 Design Basis of Oxygen-Fired UCG

10.3.1.1 Well Field and Process Module for Oxygen-fired UCG Systems

The module design and configuration are the same as the design and configuration for the air-fired system described in Section 10.2.1.1. Modules would use the LVW process to establish well communication. The major difference in the design of the module for oxygen injection is a reduction in well bore size and module surface piping. Module design and layout are the same as those illustrated in Figures 10-1, 10-2, and 10-3. With respect to Figure 10-3, oxygen injection occurs through the low-pressure injection header.

10.3.1.2 Oxygen-fired Facility Design

The oxygen-fired system requires similar facilities as the air-fired system (see Section 10.2.1.2) except an air separation plant (ASP, also referred to as an Air Separation Unit, or ASU, in the literature) replaces the LPA compressors. Oxygen from the ASP is of sufficient pressure for module injection. The use of oxygen eliminates the requirement for low-pressure air compressors. If water injection is required, water atomization and injection equipment may be required but will be of minimal expense.

10.3.1.3 Oxygen-fired Plant Layout

Correspondingly, the plant layout is the same as the layout described in Section 10.2.1.3 for the air-fired system except the ASP replaces the LPA compressors. HPA compressors are still required for linking of process wells in the oxygen-fired plant. For the oxygen-fired UCG plant, Figure 10-4 would need to be modified to replace the low air injection to the gasification area with oxygen from the ASP.

10.3.1.4 Oxygen-fired Well Field Operations.

Well field operations are similar to air-fired UCG operations described in Section 10.2.1.4 and depicted in Figure 10-5. Again, the main difference is that oxygen distribution piping replaces LPA distribution piping.

10.3.1.5 Oxygen-fired UCG Plant Description

A general description of the oxygen-fired UCG plant and assumptions for the plant design are provided in Table 10-20. Electric power required for operation of the ASP is estimated at 425 KW-hr per ton of oxygen delivered. The oxygen-fired UCG plant will require 1440 tons/day of oxygen which equates to an electric power requirement of 612,000 KW-hr/day or 25.5 MW of continuous demand. The dry gas heating value of 306 BTU/scf is on a nitrogen-free basis generated from Hanna coal experience (Boysen and Gunn 1979; Boysen et al. 1998). This gas HHV also corresponds to a thermal efficiency of 81 percent.

TABLE 10-20. OXYGEN-FIRED UCG PLANT DESCRIPTION AND OPERATION

Plant Description:
Total Energy Production Rate = 1.52 x 10^9 BTU/hr Energy Required for UCG Air Compressors = 2.2 x 10^6 BTU/hr Energy Required for Electric Power for the ASP = 1.68 x 10^8 BTU/hr Plant Load Factor = 95% Plant Life = 20 Years
UCG Process Operation:
Average Dry Gas HHV = 306 BTU/scf Module Coal Recovery = 65% Gas Losses = 0% Gasification Thermal Efficiency = 81% Dry Gas Produced / Oxygen Injection= 3.84 mole/mole
Coal Seam Gasified:
Coal HHV = 8200 BTU/lb (as received) Coal Density = 81 lb/ft^3 (in-place) Average Seam Depth = 1,054 feet Average Seam Thickness = 112 feet Hydrostatic Head at Depth = 474 psia Total Area of Coal Gasified in Plant Life = 0.232 mi^2

10.3.1.6 Oxygen-fired UCG Well Field Design

Table 10-21 presents the details of the well field design. Figure 10-3 shows the design. As previously mentioned, the LPA headers in Figure 10-3 will be the oxygen injection headers for oxygen-fired systems. As in the air-fired systems, the injection wells serve several functions.

The process wells are nominally six-inch diameter (schedule 40 SDT) with a 6.065-inch inside diameter. This size was determined based upon optimization of process economics. The calculated pressure losses in the surface lines and wells are major factors in the economic optimization of the plant design. Various inside diameters for the process wells were considered and the selected diameter resulted in the minimum calculated syngas production cost. The inlet and outlet pressures for linking, injection and gas production are also illustrated in Table 10-21, along with assumed maximum temperatures and design maximum mass flow rates.

The process wells are drilled to the bottom of the coal seam and cased to within five feet of the bottom of the seam. The piping connecting the injection wells to the oxygen distribution lines is illustrated in Figure 10-6, and the piping connecting the production wells to the product gas collection lines is illustrated in Figure 10-7. The injection piping will be moved to the next module in a line of modules once gasification of a module is completed. The production piping will be moved to the next module in the line to be linked after venting and cooling of the UCG cavity.

10.3.1.7 Injection Piping and Production Header

HPA required for reverse combustion linking is transported to process injection wells from the four stage HPA compressors in piping similar to that used to supply the oxygen for gasification (Figure 10-7). In addition, pipe to connect the wellhead piping for oxygen injection to the ASP is required along with piping for the well field production headers. The HPA supply systems are used during reverse combustion linking of a module. These systems are disconnected and moved to the next module in the line after linking is achieved.

TABLE 10-21. OXYGEN-FIRED WELL FIELD DESIGN

Modules:			
Well Spacing = 200 feet Modules Consumption Rate = 0.023 modules/day Number of Operating Modules = 5 Module Life = 173 days Average Oxygen Injection Rate (Gasification) = 4,308 scfm/module Maximum Oxygen Injection Rate (Gasification) = 14,560 scfm/module			
Drilling:			
Process Well Inside Diameter = 6.065 inches Depth Drilled = 1,166 feet Depth Cased = 1,161 feet Wells Required for Start-up = 25 Wells Required Annually = 8			
Well and Wellhead Design:	**Linking**	**Injection**	**Production**
Inlet Pressure, psia	1179	488	464
Outlet Pressure, psia	1179	474	366
Pressure Drop, psi	0	14.0	98.6
Length, feet	1261	1261	1261
Maximum Wellhead Temperature, °F	150	150	1000
Maximum Mass Flow, lb/sec	0.13	20.49	30.73
Wellhead Equipment Requirements:		**Start-up**	**Annual**
Amount Purchased:			
Pipe, feet		2222	500
Raised-face Slip-on Flanges, each		341	14
Blind Flanges, each		61	--
Weld Tees, each		11	--
Weld Elbows, each		11	--
Full-bore Valves, each		44	--
Automatic Flow Control Valves, each		11	--
Automatic Pressure Control Valves, each		11	--
Pressure Transducers, each		35	--
Orifice Flanges, each		44	--
Orifice Plates, each		66	9
Flange Bolts, each		4624	128

The HPA header is designed to supply the air to the coal seam at the lithostatic and the oxygen injection header is designed to supply oxygen at the hydrostatic pressures of the bottom of the coal seam when the injection headers are at their maximum length during the 20-year oxygen-fired UCG plant operation. For the oxygen-fired plant, an equivalent maximum length of 7,972 feet of pipe for the injection headers was used in pipe sizing and pressure drop calculations.

The HPA supply system is two-inch nominal pipe size, designed to supply HPA for reverse combustion linking to two adjacent lines of modules. Therefore, two HPA supply systems will be required for the air-fired UCG plant. The total length of pipe required for start-up of the HPA supply system is 6,377 feet. The length of pipe for the HPA injection system should be purchased annually because the expanding well field is 712 feet.

The oxygen distribution system is twelve-inch nominal pipe size, designed to supply oxygen for forward gasification to two adjacent lines of modules. Therefore, two oxygen supply systems will be required for the oxygen-fired UCG plant. The total length of pipe required for start-up of the oxygen supply system is 4,177 feet. The length of pipe for the oxygen supply system must also be purchased annually because the expanding well field is also 712 feet.

The well field production headers and product gas collection line are designed to supply the medium-BTU gas at a minimum pressure of 350 psig, when the production headers are at their maximum length during the twenty-year oxygen-fired UCG plant operation. For the oxygen-fired plant, an equivalent maximum length of 7,972 feet of pipe for the product gas collection line was used in pipe sizing and pressure drop calculations.

The initial and annual purchases of pipe, valves and fittings required for the HPA supply, oxygen connection, and well field production header and gas collection systems are listed in Table 10-22. Again, ten percent excess is purchased for each item.

10.3.1.8 Groundwater Monitoring Wells

There is no difference in the scope of the monitoring well system described in Section 10.2.1.8.

10.3.1.9 Air Compression System

The equipment required for the air compression systems includes: compressors to supply HPA and instrument air and the concrete pad and building. No LPA is required for the oxygen-fired system.

HPA is provided by four-stage compressors. The HPA compressors provide the small volumes of air required for reverse combustion linking. The HPA compressor is sized to provide 1,070 scfm of air at 1,221 psia. This quantity of air is sufficient to provide HPA required for linkage of modules.

The discharge pressure is based upon the required flow rate, the pressure drop in the HPA supply system, and the lithostatic pressure at the bottom of the coal seam being gasified. The design of the HPA compressor provides the required flow of air to the base of the injection at a pressure equal to the lithostatic pressure at the bottom of the coal seam. One psi/foot of depth is used to estimate the lithostatic pressure at the top of the coal seam. Thus, the design HPA injection pressure is 1,179 psia as the air arrives at the bottom of the injection well. A 95 percent energy efficiency was used in the sizing of the reciprocating compressor. The HPA compressor is sized at 391 hp. A ten percent excess factor is used for compressor sizing so a total of 434 hp of HPA compressor is recommended for the air-fired UCG plant. Table 10-23 provides a summary of the HPA compressor requirements.

TABLE 10-22. OXYGEN-FIRED UCG SURFACE PIPING SYSTEMS

Design of Surface Piping Systems:

	HPA Injection	Oxygen Distribution	Production Header
I.D., inches	2.067	12.000	19.000
Inlet Pressure, psia	1222	494	366
Outlet Pressure, psia	1179	488	363
Pressure Drop, psia	42.8	6.1	3.0
Maximum Length, feet	7972	7972	7972
Average Temperature, ^{0}F	150	150	250
Max. Mass Flow, lb/sec	1.36	30.31	45.46

Pipe, Valves, and Fittings Required for HPA Injection:

Amount Purchased:	Start-up	Annual
Pipe, feet	6377	712
Raised-face Slip-on Flanges, each	172	7
Elbows, each	22	--
Tees, each	15	1
Valves, each	24	--
Automatic Flow Control Valves, each	11	--
Pressure Transducers, each	35	--
Orifice Flanges, each	22	--
Orifice Plates, each	11	--
Flange Bolts, each	1080	32

Pipe, Valves, and Fittings Required for Oxygen Connection:

Amount Purchased:	Start-up	Annual
Pipe, feet	4177	712
Raised-face Slip-on Flanges, each	51	7
Blind Flanges, each	6	1
Tees, each	4	1
Valves, each	3	--
Flange Bolts, each	488	64

Pipe, Valves, and Fittings Required for Production Headers:

Amount Purchased:	Start-up	Annual
Pipe, feet	4177	816
Raised-face Slip-on Flanges, each	51	8
Blind Flanges, each	6	2
Orifice Flanges, each	3	--
Orifice Plates, each	4	--
Crosses, each	4	1
Full-bore Valves, each	3	--
Flange Bolts, each	792	120

TABLE 10-23. OXYGEN-FIRED UCG COMPRESSOR REQUIREMENTS

HPA Compressors:	
Capacity, scfm Inlet Pressure, psia Discharge Pressure, psia Number of Stages Size Purchased, hp	1069 13 1221 4 434

10.3.1.10 Site Requirements

The site requirements are essentially the same as the air-fired system described in Section 10.2.1.10.

10.3.1.11 Personnel Requirements

The personnel requirements for the oxygen-fired system are the same as the air-fired system described in Section 10.2.1.11.

10.3.2. Oxygen-Fired UCG Plant Economics

Economic Basis. After determination of the equipment and personnel requirements and costs for the oxygen-fired UCG plant, an economic evaluation of the project was completed. The economic basis chosen for evaluation of the project economics is provided in Table 10-5 of Section 10.2.2.

Results of the Oxygen-fired UCG Plant Economic Analysis. A probable operation of the oxygen-fired UCG plant is assumed to assess the commercial potential of the UCG facility. The probable operation assumed is that used in the design of the UCG facility. A summary of the key operating parameters assumed for base case operation of an oxygen-fired UCG plant sized to provide medium-BTU gas is the same as the air-fired system in Table 10-6. The calculation method for determination of the required selling price of the gas produced from the oxygen-fired UCG plant is a discounted cash flow return on investment method as described in the literature (Boysen and Gunn 1979).

Table 10-24 summarizes the capital investment requirements for an oxygen-fired UCG Plant. The total investment for the oxygen-fired UCG plant includes the cost of drilling the process wells required for plant startup; the cost of the HPA air compression facility which includes the costs of the HPA compressors, buildings to house the compressors; air separation facility; the cost of piping and accessories (pipe, pipe accessories, flow control and metering equipment, and valves); the cost of site facilities (heavy equipment, computer and electrical equipment, buildings, and the groundwater monitor well network); working capital; and salaries paid during construction. The cost data provided are the installed equipment cost and the excess materials purchased. The total investment required for the oxygen-fired UCG facility is $69.59 MM including installed capital costs and working capital.

Annual operating expenses for the oxygen-fired UCG plant include the cost of drilling the new process wells required annually; the coal royalty; salaries and wages; the cost of replacement piping and accessories required; maintenance costs; taxes and insurance and electricity to run the ASP.

As in the air-fired UCG case, the coal royalty applied in the oxygen-fired UCG case is $0.05/MMBTU recovered. The staffing needed and the corresponding salaries are the same as the air-fired plant and are shown in Table 10-8.

TABLE 10-24. OXYGEN-FIRED UCG PLANT CAPITAL INVESTMENT REQUIREMENTS

Item	% of Total
Drilling:	
Unit Cost = $61.68/foot	
25 Wells Required for Start-up	
Total Cost = $1.80MM	2.6
Injection Supply System:	
Air Separation Plant to Supply 95% Oxygen	
Unit Cost = $33.33 M /tons O_2/day, 1440 tons O_2/day capacity purchased	
HPA – Unit Cost = $785/hp, 434 hp Purchased	
Injection Supply Cost = $48.35 MM	69.5
Piping and Accessories:	
Pipe Cost = $0.80 MM	
Piping Accessories = $0.19 MM	
Flow, Control, and Metering = $0.38 MM	
Valves = $0.42 MM	
Total Piping Cost = $1.78 MM	2.6
Site Facilities:	
Heavy Equipment = $2.16 MM	
PCs and Electrical Equipment = $0.86 MM	
Buildings = $1.04 MM	
Monitor Wells = $1.48 MM	
Total Site Costs = $5.54 MM	8.0
Working Capital = $1.98 MM	2.9
Salaries During Construction = $10.14 MM	14.6

The annual cost of pipe is determined based upon current vendor cost data an estimated pipe replacement needs.

Depreciation was assumed to be straight line over the twenty-year plant life, based upon the installed capital investment. The salvage value for the UCG plant is assumed to be zero.

The annual maintenance costs are estimated to be equal to five percent of the installed capital cost of the air compressors and site facilities.

As in the air-fired UCG case, annual taxes include severance tax, ad valorem tax and property tax. The severance tax is 3.75% of the assessed value of the coal and the ad valorem tax mill levy averages 6.1 percent of the assessed value of the coal ($10/ton). The property tax in Wyoming is 11.5 percent multiplied by the 6.1 percent mill levy rate and then multiplied by the assessed value of the industrial facility. Again, since the medium-BTU gas produced will be used to make a product the cost of facility insurance will be considered when the economics of the combined process are determined.

The electricity required to operate the ASP is based upon a vendor provided power requirement. The power required to make one ton of oxygen in an ASP operating at similar conditions is 425 KW-hr. The cost of the electricity is based upon the air-fired UCG-IGCC break-even case discussed in Section 10.2.5.3. The cost electricity to operate the ASP is $51.68/MW-hr.

The annual operating expense breakdown is summarized in Table 10-25. The total annual operating expense required for the oxygen-fired UCG facility is $23.78 MM.

TABLE 10-25. OXYGEN-FIRED UCG PLANT ANNUAL OPERATING EXPENSES

Item	% of Total
Drilling: Unit Cost = $61.68/ft 8 Wells/Year Required Drilling Cost = $0.58 MM	2.5
Coal Royalty: Unit Cost = $0.05/MM BTU Recovered 12,646,180 MM BTU/Year Coal Cost = $0.62 MM	2.6
Salaries = $5.07 MM	21.3
Pipe = $0.16 MM	0.7
Depreciation = $3.38 MM	14.2
Maintenance Costs = $2.69 MM	11.3
Taxes = $1.23 MM	5.2
Electricity = $10.04 MM	42.2

Operation of the oxygen-fired UCG plant according to the base case assumptions would result in a raw medium-BTU syngas cost of $2.55/MM BTU, assuming the investment is amortized in twenty years which includes a fifteen percent return on equity. A summary of the plant economics is provided in Table 10-26.

TABLE 10-26. OXYGEN-FIRED UCG PLANT ECONOMIC SUMMARY

Item	Cost
Raw Syngas Production Cost	$2.55/MM BTU
Capital Investment (Installed)	$67.61 MM
Working Capital	$1.98 MM
Total Investment	$69.59 MM
Annual Operating Expenses	$23.78 MM

The $2.55/MM BTU compares to the $1.62/MM BTU for the air-fired low BTU syngas estimated in Section 10.2.2. This increase in raw syngas cost of $0.93/MM BTU between these two products gases may be offset or eliminated if the higher-cost medium BTU syngas is used in downstream synthesis of liquid hydrocarbons or other high value products. This configuration is addressed in Section 10.5.

10.4 STEAM/OXYGEN-FIRED UCG

As previously discussed, prior UCG oxygen-fired systems included steam injection along with the oxygen. It has been theorized that because of the higher relative concentration of the oxygen, additional water reactant would be required for the gasification reactions. This probably will not be required for the relatively high moisture content, wet PRB coals. In the case additional water is required, the additional water may be added as an atomized liquid rather than steam. The addition of atomized liquid water instead of steam significantly reduces the costs of oxygen-fired UCG operations. Because steam addition has been used in earlier test, this section is included to question the necessity of steam addition, and to summarize the high cost and economic impact of requiring steam injection in the UCG design.

In future UCG tests in the PRB that intend to utilize oxygen injection, it should be determined if the addition of steam and/or water is necessary to provide adequate water for the gasification reactions. If the water is necessary, then addition of atomized water, at a very low cost at the injection well, should be tested before steam addition is utilized. The large cost impact of steam addition is justifiable only if the syngas heating value is substantially increased, or other operating advantages are realized.

10.4.1 Design Basis for Steam/Oxygen Fired UCG

Post-gasification analyses of the successful Rocky Mountain 1 test (Boysen et al. 1990) confirm that the steam injected during the gasification of the two RM1 UCG cavities was actually hot water before it reached the injection wellheads. Based upon the results of the material and energy balances for the RM1 UCG cavities, the addition of the hot water instead of steam did not significantly reduce the efficiency of the UCG process. In addition, the injection of water instead of steam may improve injection well survival. At nearly pure oxygen concentrations, high combustion temperatures may occur that could threaten the survival of the injection well. The injection of liquid water could be used as a method to moderate combustion temperatures.

If steam/oxygen injection is required to produce a medium heating value product, the addition of steam will have a significant impact on the oxygen-fired UCG operations. The economics of the steam addition are discussed in the following sections.

10.4.1.1 Design Considerations for the Addition of Steam to Oxygen-fired UCG

Most aspects of the steam/oxygen-fired UCG plant are the same as the oxygen-fired systems except for the addition of the steam plant. The steam plant would be fired by the medium heating value product gas and would require water pretreatment equipment, boilers and gas clean-up equipment. The capacity of the plant is increased to provide the medium heating value fuel for the boilers and the process injection piping sizes are increased for the addition flow of the steam.

The well field, module design, and module layout are identical to the air-fired and oxygen-fired systems. The plant layout is the same as the oxygen-fired plant except for the addition of the steam plant. The well field operations also are the same as the oxygen-fired system except that the steam is added to the injection header with the oxygen.

10.4.1.2 Steam/Oxygen-fired Plant Description

A general description of the oxygen-fired UCG plant and assumptions for the plant design are provided in Table 10-27. As in the oxygen-fired UCG, electric power for the operation of the ASP will be purchased at a rate of $51.68/MW-hr. The dry gas HHV equal to 306 BTU/scf is used along with the corresponding gasification thermal efficiency of 81 percent.

TABLE 10-27. STEAM/OXYGEN-FIRED UCG PLANT DESCRIPTION AND OPERATION

Plant Description:
Total Energy Production Rate = 1.88 x 10^9 BTU/hr Energy Required for UCG Air Compressors = 2.75 x 10^6 BTU/hr Energy Used for Electricity to Run ASP = 2.07 x 10^8 BTU/hr Energy Used for Steam Generation = 1.62 x 10^8 BTU/hr Plant Load Factor = 95% Plant Life = 20 Years
UCG Process Operation:
Average Dry Gas HHV = 306 BTU/scf Module Coal Recovery = 65% Gas Losses = 0% Gasification Thermal Efficiency = 81% Dry Gas Produced /Oxygen Injection= 3.84 mole/mole
Coal Seam Gasified:
Coal HHV = 8200 BTU/lb (as received) Coal Density = 81 lb/ft^3 (in-place) Average Seam Depth = 1,054 feet Average Seam Thickness = 112 feet Hydrostatic Head at Depth = 474 psia Total Area of Coal Gasified in Plant Life = 0.232 mi^2

10.4.1.3 Steam/Oxygen-fired UCG Well Field Design

Table 10-28 presents the details of the well field design.

TABLE 10-28. STEAM/OXYGEN-FIRED WELL FIELD DESIGN

Modules:			
Well Spacing = 200 feet Modules Consumption Rate = 0.029 modules/day Number of Operating Modules = 5 Module Life = 173 days Average Oxygen Injection Rate (Gasification) = 5329 scfm/module Maximum Steam/Oxygen Injection Rate (Gasification) = 29120 scfm/module			
Drilling:			
Process Well Inside Diameter = 7.981 inches Depth Drilled = 1,166 feet Depth Cased = 1,161 feet Wells Required for Start-up = 25 Wells Required Annually = 10			
Well and Wellhead Design:	**Linking**	**Injection**	**Production**
Inlet Pressure, psia	1179	487	464
Outlet Pressure, psia	1179	474	369
Pressure Drop, psi	0	13.2	94.8
Length, feet	1261	1261	1261
Maximum Wellhead Temperature, ^{0}F	150	150	1000
Maximum Mass Flow, lb/sec	0.13	40.98	61.47
Wellhead Equipment Requirements:		**Start-up**	**Annual**
Amount Purchased:			
Pipe, feet		2222	500
Raised-face Slip-on Flanges, each		341	16
Blind Flanges, each		61	--
Weld Tees, each		11	--
Weld Elbows, each		11	--
Full-bore Valves, each		44	--
Automatic Flow Control Valves, each		11	--
Automatic Pressure Control Valves, each		11	--
Pressure Transducers, each		35	--
Orifice Flanges, each		44	--
Orifice Plates, each		66	9
Flange Bolts, each		3468	96

10.4.1.4 Steam/Oxygen Injection Piping and Production Header

Table 29 presents the steam/oxygen injection piping and production header.

TABLE 10-29. STEAM/OXYGEN SURFACE PIPING SYSTEMS

Design of Surface Piping Systems:			
	HPA Injection	**Injection Header**	**Production Header**
I.D., in	2.067	12.000	19.000
Inlet Pressure, psia	1255	510	369
Outlet Pressure, psia	1179	487	363
Pressure Drop, psia	76.1	23.0	6.8
Maximum Length, feet	9507	9507	9507
Average Temperature, °F	150	150	250
Max. Mass Flow, lb/sec	1.68	56.25	56.25

Pipe, Valves, and Fittings Required for HPA Injection:		
Amount Purchased:	Start-up	Annual
Pipe, feet	6546	881
Raised-face Slip-on Flanges, each	174	11
Elbows, each	22	--
Tees, each	15	1
Valves, each	24	--
Automatic Flow Control Valves, each	11	--
Pressure Transducers, each	35	--
Orifice Flanges, each	22	--
Orifice Plates, each	11	--
Flange Bolts, each	1088	52

Pipe, Valves, and Fittings Required for Steam/Oxygen Connection:		
Amount Purchased:	Start-up	Annual
Pipe, feet	4346	881
Raised-face Slip-on Flanges, each	53	11
Blind Flanges, each	4	2
Tees, each	4	2
Valves, each	3	--
Flange Bolts, each	504	104

Pipe, Valves, and Fittings Required for Production Headers:		
Amount Purchased:	Start-up	Annual
Pipe, feet	4346	881
Raised-face Slip-on Flanges, each	53	31
Blind Flanges, each	6	4
Orifice Flanges, each	3	--
Orifice Plates, each	4	--
Crosses, each	4	1
Full-bore Valves, each	3	--
Flange Bolts, each	816	204

10.4.1.5 Steam/Oxygen Compressor and Boiler Requirements

Table 10-30 Summarizes the compressor and boiler requirements for the steam/oxygen-fired plant.

TABLE 10-30. STEAM/OXYGEN-FIRED UCG COMPRESSOR AND BOILER REQUIREMENTS

HPA Compressors:	
Capacity @ 90% Load, scfm	1323
Inlet Pressure, psia	13
Discharge Pressure, psia	1255
Number of Stages	4
Compression Ratio/Stage	2.5
Size Purchased, hp	541
Boilers (up to 600 psia @580 ^{0}F)	
Capacity @ 90% Load, scfm	26,646
Discharge Pressure, psia	510.4
Purchased Capacity, scfm	29,311

10.4.1.6 Steam/Oxygen Site and Personnel Requirements

The site and personnel requirements are the same as the oxygen-fired and air-fired systems.

10.4.2 Steam/Oxygen-Fired Plant Economics

Economic Basis. After determination of the equipment and personnel requirements and costs for the steam/oxygen-fired UCG plant, an economic evaluation of the project was completed. The economic basis chosen for evaluation of the project economics is provided in Table 10-5 of Section 10.2.2.

Results of the Oxygen-fired UCG Plant Economic Analysis. A probable operation of the steam/oxygen-fired UCG plant is assumed to assess the commercial potential of the UCG facility. The probable operation assumed is that used in the design of the UCG facility. A summary of the key operating parameters assumed for base case operation of an oxygen-fired UCG plant sized to provide medium-BTU gas is the same as the air-fired system in Table 10-6. The calculation method for determination of the required selling price of the gas produced from the oxygen-fired UCG plant is a discounted cash flow return on investment method as described in the literature (Boysen and Gunn 1979).

Table 10-31 summarizes the capital investment requirements for an oxygen-fired UCG Plant. The total investment for the steam/oxygen-fired UCG plant includes the cost of drilling the process wells required for plant startup; the cost of the HPA air compression facility which includes the costs of the HPA compressors, buildings to house the compressors; air separation facility; the cost of the steam plant; the cost of piping and accessories (pipe, pipe accessories, flow control and metering equipment, and valves); the cost of site facilities (heavy equipment, computer and electrical equipment, buildings, and the groundwater monitor well network); working capital; and salaries paid during construction. The total investment required for the steam/oxygen-fired UCG facility is $108.61 MM including installed capital costs and working capital.

Annual operating expenses for the steam/oxygen-fired UCG plant include the cost of drilling the new process wells required annually; the coal royalty based upon BTUs recovered; salaries and wages; the cost of replacement piping and accessories required; maintenance costs; and taxes and insurance and the cost of electricity purchased to run the ASP.

The coal royalty is eight percent of assessed value. A coal value of $10 per ton is used resulting in a coal royalty of $0.05/MMBTU recovered.

TABLE 10-31. STEAM/ OXYGEN-FIRED UCG PLANT CAPITAL INVESTMENT REQUIREMENTS

Item	% of Total
Drilling:	
Unit Cost = $76.78/foot	
25 Wells Required for Start-up	
Total Cost = $2.24 MM	2.1
Injection Supply System:	
Air Separation Plant to Supply 95% Oxygen	
Unit Cost = $33.33 M /ton/day of O_2 capacity, 1782 tons/day O_2 Pur.	
HPA – Unit Cost = $785/hp, 541 hp Purchased	
Steam Plant = $891/scfm, 26646 scfm Purchased	
Injection Supply Cost = $85.93 MM	79.1
Piping and Accessories:	
Pipe Cost = $0.87 MM	
Piping Accessories = $0.27 MM	
Flow, Control, and Metering = $0.55 MM	
Valves = $0.50 MM	
Total Piping Cost = $2.18 MM	2.0
Site Facilities:	
Heavy Equipment = $2.16 MM	
PCs and Electrical Equipment = $0.86 MM	
Buildings = $1.04 MM	
Monitor Wells = $1.48 MM	
Total Site Costs = $5.54 MM	5.1
Working Capital = $2.58 MM	2.4
Salaries During Construction = $10.14 MM	9.3

The staffing needed and the corresponding salaries are the same as the air-fired plant and are shown in Table 10-8. The annual cost of pipe is determined based upon current vendor cost data an estimated pipe replacement needs. Depreciation is assumed to be straight line over the twenty-year plant life, based upon the installed capital investment. The salvage value for the UCG plant is assumed to be zero.

The annual maintenance costs are estimated to be equal to five percent of the installed capital cost of the air compressors and site facilities.

As with the other cases, annual taxes include severance tax, ad valorem tax and property tax. The severance tax is 3.75 percent of the assessed value of the coal and the ad valorem tax mill levy averages 6.1 percent of the assessed value of the coal. As with the coal royalty calculation, a coal value of $10/ton is used. The property tax in Wyoming is 11.5 percent multiplied by the 6.1 percent mill levy rate and then multiplied by the assessed value of the industrial facility. The cost of facility insurance is commonly based upon the gross product sales value. Since the medium-BTU gas produced will be used to make a product the cost of facility insurance will be considered when determined the economics of the combined process.

The annual operating expense breakdown is summarized in Table 10-32. The total annual operating expense required for the steam/oxygen-fired UCG facility is $30.925 MM.

TABLE 10-32. STEAM/OXYGEN-FIRED UCG PLANT ANNUAL OPERATING EXPENSES

Item	% of Total
Drilling: Unit Cost = $76.78/ft 10 Wells/Year Required Drilling Cost = $0.90 MM	2.9
Coal Royalty: Unit Cost = $0.61/MM BTU Recovered 15,645,790 MM BTU/Year Coal Cost = $0.76MM	2.5
Salaries = $5.07 MM	16.4
Pipe = $0.22 MM	0.7
Depreciation = $5.30 MM	17.1
Maintenance Costs = $4.57 MM	14.8
Taxes = $1.68 MM	5.4
Electricity = $12.42 MM	40.2

Operation of the steam/oxygen-fired UCG plant according to the base case assumptions results in a raw syngas cost of $3.49/MM BTU, assuming the investment is amortized in twenty years with a fifteen percent return on equity

A summary of the plant economics is provided in Table 10-33.

TABLE 10-33 STEAM/OXYGEN-FIRED UCG PLANT ECONOMIC SUMMARY

Item	Cost
Raw Syngas Production Cost	$3.49/MM BTU
Capital Investment (Installed) Working Capital Total Investment	$106.036 MM $2.577 MM $108.613 MM
Annual Operating Expenses	$30.925 MM

This cost of medium BTU syngas is $0.94/ MM BTU higher than the cost without steam injection. This extra cost is predominantly from the capital and operating cost of the steam plant. Based on the Rocky Mountain 1 test, where the injected steam was later analyzed to have been water at the injection well, the addition of steam is apparently not warranted. In future UCG tests in the PRB that intend to utilize oxygen injection, it should be determined if the addition of steam and/or water is necessary to provide adequate water for the gasification reactions. If the water is necessary, then addition of atomized water, at a very low cost at the injection well, should be tested before steam addition is utilized. The large cost impact of steam addition is justifiable only if the syngas heating value is substantially increased, or other operating advantages are realized.

10.5 OXYGEN-FIRED UCG-FT POWER PLANT

10.5.1. Design Basis for Oxygen-Fired UCG – FT Power Plant

The oxygen-fired UCG facility has been further investigated to focus on utilizing the syngas for Fischer-Tropsch (FT) fuel production as well as power production. The 10,200 bbl/day FT fuel plant described by Rentech, Inc. (2005) is used for comparison. Their Once-Through FT process utilizes oxygen-fired surface gasification to provide syngas for a 255 MW power block as well as 10,200 BBL/day of FT fuels. The UCG FT power plant process described in this section is modeled based upon the Rentech Once-Through design. Thus, the FT and IGCC plant designs, performance and economics are based on the Rentech published data. Only the gasifier has been changed. An oxygen-fueled UCG plant and its corresponding air-separation plant (ASP) are used in place of the coal preparation, surface gasifier, CO_2 recycle conveying system, ASP and the solid waste disposal system used in the Rentech process.

The oxygen-fired UCG facility assumes the UCG process performance and design described in Table 10-34 and is shown coupled with the FT and power block facility in Figure 10-17.

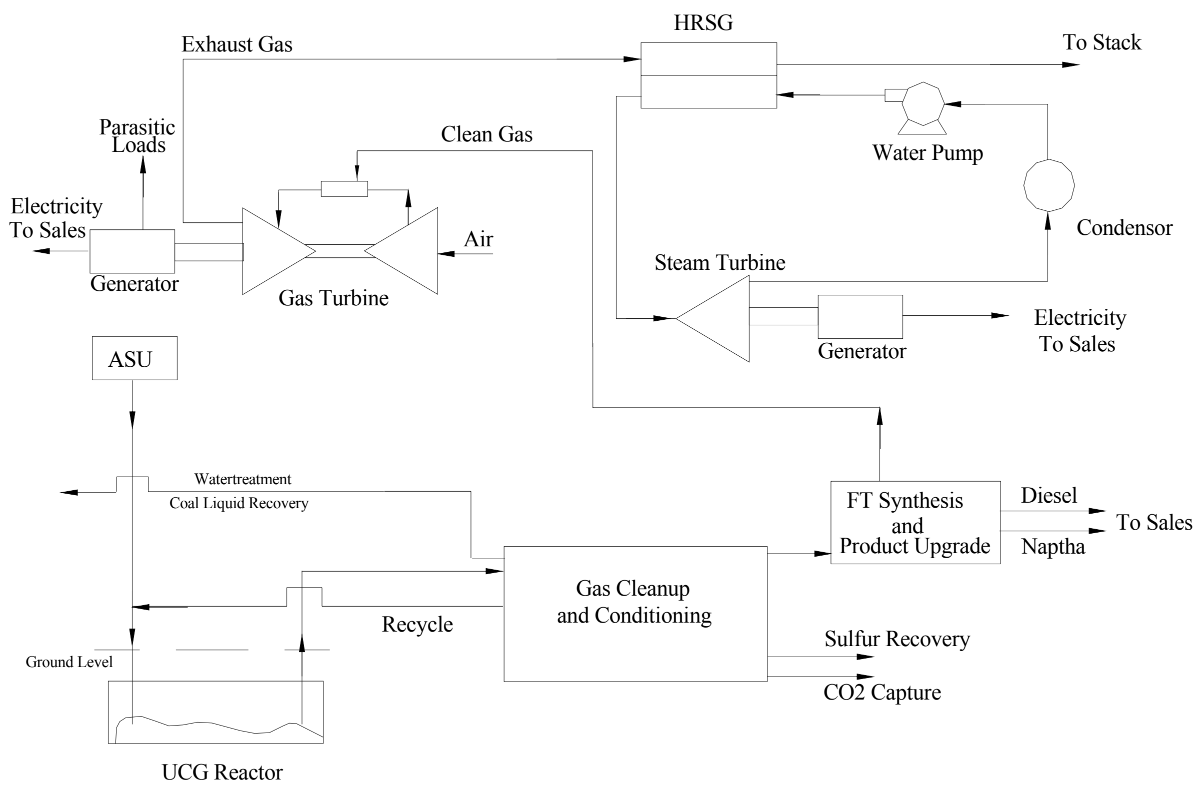


FIGURE 10-17. OXYGEN-FIRED UCG-FT POWER PLANT FLOW DIAGRAM

TABLE 10-34. OXYGEN-FIRED UCG PLANT SUMMARY

Oxygen-Fired UCG Facility
200 ft Well Spacing 112 ft seam thickness 1054 ft depth to top of coal 306 BTU/scf Gas HHV 65% Resource Recovery 0% Gas loss

The UCG facility is capable of equal syngas production rates required to sustain 255 MW power block and produce 10,200 BBL/day of FT fuels. Purification and conditioning can easily create syngas compositions equal to that of the syngas used in the FT process.

Table 10-35 shows the raw syngas composition and flow from the proposed UCG facility. Furthermore, the achievable clean syngas values reported in the Rentch publication are shown.

TABLE 10-35. SYNGAS COMPOSITION AND FLOW SUMMARY

SG Composition		
Composition	Raw SG	Clean SG
H_2 vol.%	30.1%	42.4%
CO vol.%	30.2%	53.0%
CO_2 vol.%	28.4%	3.8%
N_2+AR vol.%	1.1%	0.6%
CH_4 vol.%	8.9%	0.1%
C_2+ vol.%	1.2%	0.1%
HHV BTU/scf	306	Not Reported
SG Flow Rate MMscfd	395	296

Table 10-36 shows a comparison of the coal and oxygen consumed by each gasification process. The UCG facility can produce syngas with sufficient heating values, composition and flow to meet the demands of the proposed Rentech process using the same PRB coal. Reasons for the increased coal consumption in the UCG process include the use of 8,200 BTU/lb HHV while Rentech used 8,550 BTU/lb HHV. In addition, Rentech reduced the moisture content in the coal from 30 to 10 wt % using low grade heat recovery, which UCG does not do.

TABLE 10-36. CONSUMPTIONS AND PRODUCTION RATE COMPARISON

UCG-FT Power Plant		**Rentech Once Through**	
Coal, STPD	8977	Coal, STPD	7650
Oxygen, TPD	4770	Oxygen, TPD	4270
Raw SG, MMscfd	395	Not Reported	
Clean SG, MMscfd	296	Clean SG, MMscfd	296

10.5.2. Oxygen-Fired UCG FT Capital Costs

The Rentech process utilizes surface gasification that inherently requires coal handling and coal preparation facilities. These facilities have a large impact on the capital expenditures for this process, which are not necessary for the UCG plant. Furthermore, UCG studies have shown similar magnitudes as the Rentech process for the ASP. As shown in the following capital cost comparison, Table 10-37, the Rentech ASP is quoted to be $89 MM. Capital costs for an ASP provided by Praxair indicate that a base case ASP providing 1500 ton/day is approximately $50 MM. Considering the oxygen volume requirements for a facility of this size, capital costs for the ASP would be approximately $160 MM, which is a substantially more than the cost included in the Rentech study. This deserves further investigation. Based upon the information provided by Praxair, the Rentech facility would require $142 MM in capital for their ASP. If the Rentech ASP capital estimate were used here, it would lower the capital cost for the ASP by $71 MM. The syngas cleanup, power block, and FT loops in the UCG-FT power plant are the same as was used in the Rentech Once-Through case.

TABLE 10-37. CAPITAL COST COMPARISON

UCG-FT Power Plant ($ MM)		Once Through ($ MM)	
UCG	52	Gasification and Conditioning	224
ASP (4770 TPD)	160	ASP (4270 TPD)	89
FT Synthesis and Upgrading	86	FT Synthesis and Upgrading	86
Steam and Power	136	Steam and Power	136
Utilities, Infrastructure	99	Utilities, Infrastructure	99
Commissioning and Permitting	24	Commissioning and Permitting Coal	24
Gas Conditioning	65	Handling	82
Total	622		740

Capital costs comparisons show the large impacts of surface gasification to the costs, due to the coal handling equipment. Removal of the coal handling equipment reduces the capital by $82 MM and further reduction of $107 MM arises from surface gasification and gas conditioning costs. Eliminating this loop should also decrease the parasitic power loads further increasing the economic advantages of using UCG.

10.5.3. Oxygen-Fired UCG FT Operating Expenses

Annual operating expenses used are shown in Table 10-38. These operating expenses will cover the requirements needed for the UCG-FT Power Plant, since the UCG case will eliminate the coal handling/preparation, solid waste disposal, and will require fewer personnel to operate the gasification loop.

TABLE 10-38. OPERATING EXPENSES

Annual Operating Expenses ($ MM)	
Plant Operating Expenses includes:	45.3
Catalysts	
Chemicals	
Waste Disposal	
Overheads	
Salaries	
Plant Insurance	
Royalties	2.5
Severance and Ad Valorem Taxes	3.1
Wellfield Development	2.3
Total	53.2

10.5.4. Oxygen-Fired UCG FT Revenues

Using Rentech (2005) pricing for the naptha and diesel fuel, and the electricity pricing as described in Section 10.2.5.2, Table 10-39 shows the UCG-FT plant revenues at 95% plant capacity. The net power exported may increase significantly depending on the reduced parasitic loads of the UCG facility.

Removing the coal preparation, as well as the required electric loads of a surface gasifier and CO_2 recycle conveying system, will likely increase gross revenues due to the ability to export more power to the grid.

TABLE 10-39. UCG-FT POWER PLANT REVENUES

Plant Revenues ($ MM)		
FT Naphtha-	1640 BBL/day @ $30/BBL	17.1
FT Diesel-	8560 BBL/day @ $63/BBL	187.0
Net Power Export-	104 MWe @ $0.062/KW-hr	53.6
Total		257.7

10.5.5. Oxygen-Fired UCG FT Economics

The following assumptions have been used in these economic analyses:

1. UCG and FT facility capital and operating costs as described in Sections 10.5.2 and 10.5.3, producing a syngas stream capable of feeding an FT plant as described in 10.5.1. Analysis in constant 2006 dollars.

2. FT costs after Rentech (2005) and UCG costs from this analysis.

3. Analysis is After Federal Income Tax (AFIT), 35% tax rate, corporate tax entity.

4. Depreciation by Modified Accelerated Cost Recovery System, 20-year class life given to major capital items.

5. Three year construction, 20% in year 1, 50% in year 2, 30% in year 3; 25 year project life; 50% production in Year 4 (first year of production), 100% in Year 5.

6. Severance tax for coal based on 3.75% of gross value of underground coal estimated to be gasified based on produced syngas volumes.

7. Ad valorem tax for coal based on 6.1% mill levy on gross value of coal estimated to be gasified based on produced syngas volumes.

8. State royalty based on 8% of gross value of coal estimated to be gasified based on produced syngas volumes.

9. Coal value (for taxes and royalty) of $10 per ton, based on 12/15/2006 published spot price for 8800 BTU PRB coal of $9.90 per ton (USEIA 2006).

10. Property tax on facilities is included in Rentech annual operating cost estimate.

11. Insurance on facilities is included in Rentech annual operating cost estimate.

12. 95% plant capacity factor.

13. 100% equity case, no leveraging of economics.

14. No salvage value.

This modest size UCG-FT project has an NPV @ 15% discount of $103.5 million, and a DCF-ROR of 18.0%. The payback is a moderate 7.7 years. After reaching steady state production, it produces about $142 million in cash flow from gross revenues of $257.7 million. The annual cash flows are in Appendix 1.

The UCG-FT project returns a 15% DCF-ROR with revenues at 84% of the base case values given in Table 10-39.

The oxygen-fired UCG option has an acceptable rate of return and is an attractive option considering the amount of coal resource available to UCG.

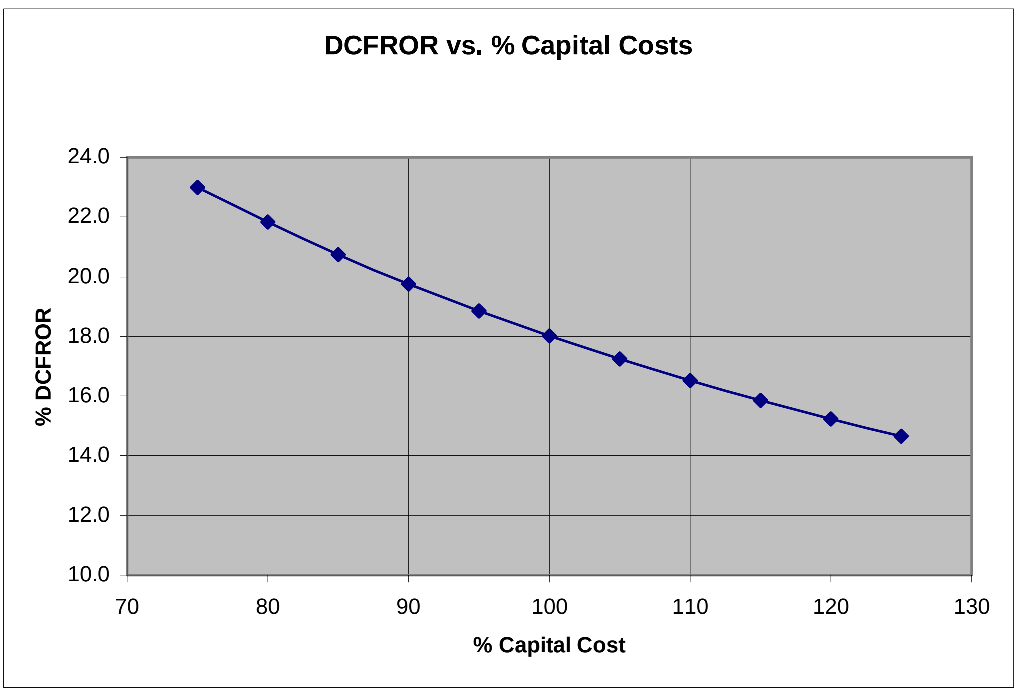
10.5.6. Oxygen-Fired UCG FT Economic Sensitivities

The following graphs summarize the sensitivity of the UCG-FT project rate of return for capital costs, revenues, and operating costs being varied from plus and minus 25% of the base case.

10.5.6.1. Oxygen-Fired UCG-FT Capital Cost Sensitivity

Figure 10-18 depicts the variation in DCF-ROR for the FT project as capital costs are varied. At the lower end, the DCF-ROR is about 23%. At the upper end of capital costs, the DCF-ROR still remains close to 15%, the presumed minimum acceptable rate of return.

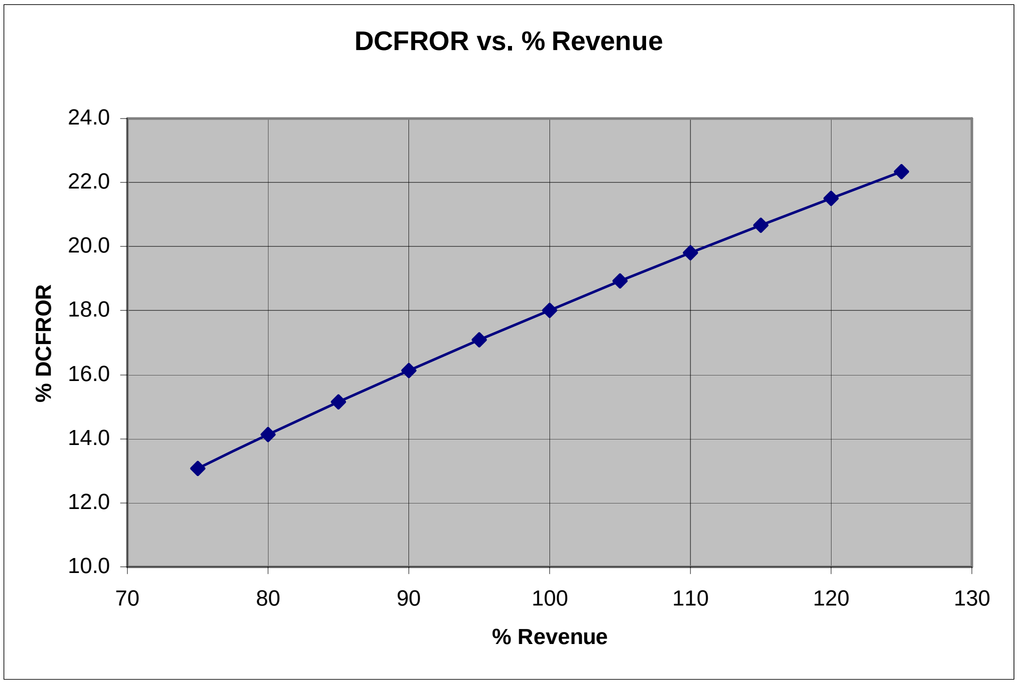
FIGURE 10-18. UCG-FT ROR SENSITIVITY TO CAPITAL COST



10.5.6.2. Oxygen-Fired UCG-FT Revenue Sensitivity

The sensitivity of DCF-ROR to expected revenues is shown in Figure 10-19. The rate of return falls below 15% at about 85% of expected revenues. As stated in the UCG-FT analysis, there may be additional electricity sales, due to the decreased plant parasitic load, which would boost the revenues above the base case.

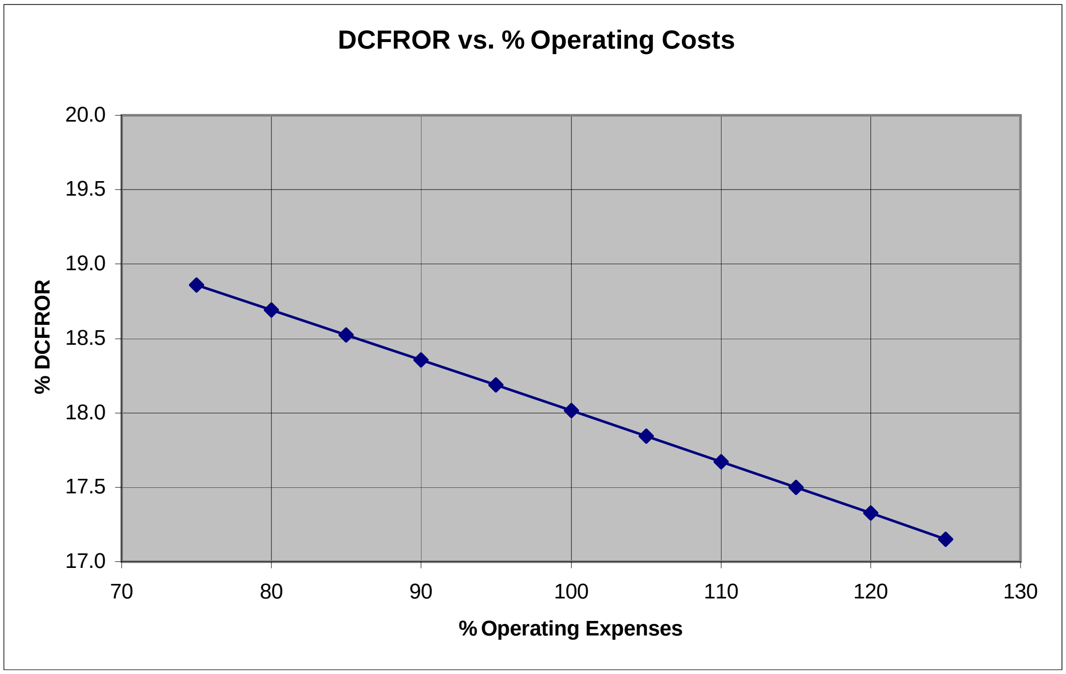
FIGURE 10-19. UCG-FT ROR SENSITIVITY TO REVENUE



10.5.6.3. Oxygen-Fired UCG-FT Operating Cost Sensitivity

Figure 10-20 shows the sensitivity of DCF-ROR versus changes in the operating cost estimates. A 25% change in the operating cost results in less than a 1% change in the rate of return. Therefore, the economics are realtively insensitive to the operating cost variations.

FIGURE 10-20. UCG-FT ROR SENSITIVITY TO OPERATING COSTS



10.5.7. Comparison of UCG FT versus "Straight" FT Project

As a comparison for the economics of the UCG project, the "straight" FT project, using surface mined coal and surface gasification, was estimated. Capital costs of the straight FT project are higher due to coal handling and gasifier circuits; see Table 10-37. Operating costs have been adjusted to eliminate royalty and production taxes on the coal fed to the FT plant. The operating cost for the UCG FT includes new well installation costs. Comparison is made in Table 10-40.

TABLE 10-40. COMPARISON OF UCG FT VS. STRAIGHT FT PROJECT

Category	UCG FT	Straight FT
Capital Cost	$622MM	$740MM
Operating Cost per year	$53.2MM	$45.3MM
Revenues per year	$257.7MM	$257.7MM
DCF-ROR	18.1%	16.1%
NPV @ 15% Discount Rate	$103.5MM	$43.8MM

Because of the reduced capital, the UCG FT project has better projected economics than the "straight" FT project. Both projects can improve the rate of return substantially by leveraging the capital with debt financing.

11.0 CONCLUSIONS AND RECOMMENDATIONS ON UCG VIABILITY

11.1 TECHNICAL CONCLUSIONS

11.1.1 PRB Coal Evaluation for UCG Development Potential.

The most important characteristics for UCG potential are coal type, coal seam thickness, depth, and distribution, parting thickness and locations within the coal seams, and the presence of structural deformations.

Within the PRB, coals are almost extensively classified as sub-bituminous. Heating values generally range from 7,000 to 9,000 BTU/lb and average around 8,200 BTU/lb on an as-received basis. Coal heating values are higher at the northwest section of the PRB. All Fort Union coals are of adequate rank and heating value for UCG development.

Coal seam thickness greater than 30 feet is deemed adequate for UCG development. Thickness impacts gasification efficiency and economics, as thicker coals are more efficient and economical. Thicker coals do have the potential negative impact of greater subsidence. Except for one UCG test in West Virginia, UCG experience in the US has been in sub-bituminous coals greater than twenty feet in thickness. Based on the review of the coal geology, most of the Basin contains adequate coal thickness for UCG development.

Coal seam depths greater than 500 feet and less than 2,000 feet are considered candidates for UCG development. Coal seams less than 500 feet are considered as targets for conventional mining methods. Non-coal partings and lenses within a coal seam are of a secondary importance in evaluating a resource for UCG potential. Thin partings and lenses low in the coal seam can be beneficial in restricting the communication link between process wells to be low in the seam. As UCG develops in coal above the link, it is important to keep the link near the bottom of the coal seam. These partings should be less than twenty feet in thickness and in the lower third of the coal seam to have a beneficial effect. For coals equal to or greater than 30 feet in thickness at depths below 500 feet, the PRB contains 307 billion tons of UCG target. If 65% can be gasified, leaving allowance for pillars, then there is 200 billion tons of UCG-recoverable coal in the PRB.

Structural (faulting and folding) considerations are important in UCG resource selection. Faults and folds can cause problems with linking, introduce excessive water influx, and promote premature roof collapse. Areas of high faulting frequency should be avoided. Except for the fringes of the northern and eastern flank of the PRB, low fault frequency has been observed. Some faulting was also observed in the north along the Wyoming border and in the area north-northwest of Gillette. Faulting has also been observed in the extreme southern section of the basin. More extensive faulting probably exists on the western flank of the PRB due to the more extreme uplift of the Big Horn Mountains. Large frequencies of faulting have been observed in the northwest section of the PRB. Based on the known faulting information, only the extreme northwestern section of the basin should be excluded from consideration for UCG development potential.

11.1.2 Powder River Basin Overburden Evaluation for UCG Development Potential.

Several consistent overburden characteristics are observed in the PRB above the large coal deposits. Numerous channel sands exist. Most non-coal and non-sand units are soft claystones and siltstones. The sand units are very discontinuous. Even thick sand deposits (>50 feet) can disappear within several hundred yards. The sand units are unconsolidated or loosely consolidated.

Ideally, the overburden above the coal would consist of a large thickness of competent aquitard material such as shale or siltstone. Low groundwater-producing, competent sandstone would also be acceptable overburden material. The least acceptable overburden material adjacent to the coal seam would be thick, high groundwater-producing, unconsolidated sand. The problems with thick, high groundwater-producing sand units are they are more likely to be used for domestic and livestock water and can severely impact gasification efficiency. Considering most sand units are not extensive in area, adjacent thin (thin relative to the coal thickness) sand units can be tolerated in UCG operations.

The overburden strata expected above the Fort Union Coals are soft claystones and siltstones, sand units, shales, and sub-bituminous coals. The evaluation of the overburden in the PRB is based on the following criteria:

- *Thickness and nature of immediate overburden unit.* Thick siltstone, claystone, or shale are preferable. Thin sand units (<20 feet) will be considered based on underlying coal thickness.

- *No thick sand units (>50 feet) within 100 feet of top of coal seam.* Sand units are likely to be impacted by subsidence within 200 feet that can impact UCG operations and groundwater use.

- *No thick sand units (>50 feet) within 1000 feet of surface.* Large sand units within 1000 feet of the surface are likely to be used for domestic and livestock water.

- *Subsidence will propagate a minimum of 200 feet.* The likely overburden material will subside. Operation design (use of pillars) will be required to limit subsidence to only 200 feet

- *Thick aquitard units can limit subsidence impacts to overlying sand units.* Thick aquitard units will likely maintain hydraulic isolation ability even if subsided and will reduce the extent of subsidence.

Even though overburden considerations are the most restrictive of all the considerations, large areas of the PRB remain acceptable for UCG development.

11.2 ECONOMIC CONCLUSIONS

The raw UCG syngas production costs were evaluated for a base case typical of much of the deep coal in the PRB. The base case considered a 112-foot thick coal seam in the PRB with a depth to the top of the coal of 1,054 feet. The UCG facility utilized a 200 foot process well spacing. The base case air-fired UCG facility produces low-BTU syngas with a HHV of 150 BTU/scf. This compares conservatively with the ARCO Rocky Hill air-fired UCG test in the PRB, where syngas with an average HHV in excess of 200 BTU/scf was produced. The base case conservatively estimated a 65 percent coal resource recovery, leaving pillars in the coal seam to control subsidence. The base case air-fired UCG facility will produce adequate syngas to fuel a 200 MW power generation plant for twenty years and only consume 0.27 square miles of the coal seam. The base case facility would require $58.3 MM total investment and $13.5 MM annual operating expenses, resulting in a raw low-BTU UCG syngas cost of $1.62/MM BTU, including all state taxes, royalty, and a 15% return on investment. Sensitivities on coal seam depth, thickness, heating value, recovery, and well spacing are also presented and discussed. These result in a range of raw syngas costs of $1.40 to $2.35 per MMBTU.

These raw syngas costs have been tied to the economics of a 200 MW air-fired UCG-IGCC power plant in the PRB. Total capital cost of $263 million for the combined UCG-IGCC plant, with annual operating costs of $19.9 million, yields an After Federal Income Tax (AFIT) return of 18.3% DCF-ROR, and an NPV@15% discount of $44.3 million, using an average electricity sales price of $62 per MW-hr. Such a plant would return a 15% DCF-ROR at an electricity sales price of $51.68. Sensitivities on +/- 20% on capital costs, operating costs, and electricity sales price are given, resulting in a range of DCF-ROR's from 13% to 23%.

The UCG IGCC configuration has been further compared to a "mined-coal" surface gasifier IGCC power plant. The results are summarized as:

TABLE 11-1. UCG-IGCC ECONOMIC COMPARISON

	Surface Gasifier IGCC	UCG-IGCC	% UCG Advantage
Capital/kW Installed	$1,544	$1,180	24%
Op Cost, $/MW-hr sold	$21.99	$11.96	46%
Breakeven Sales Price for 15% ROI	$80.60	$51.68	36%
DCFROR (as described here)	10.4%	18.3%	75%
Payback, years	10.77	7.64	29%

The UCG IGCC has clear cost advantages across the board.

In addition to the air-fired economics summarized above, oxygen-fired UCG has also been evaluated for producing medium BTU syngas suitable for feedstock for F-T or other chemical synthesis. In this configuration, the Air Separation Plant (ASP) to produce a 95% pure oxygen injection stream is a major capital and operating cost. However, it eliminates the LPA compressor requirements as it delivers oxidant at adequate pressures for direct injection. Also, injection and production headers and well sizes are reduced dramatically. Full details are given in Section 10. The resulting medium BTU syngas has an estimated HHV of 306 MM BTU/scf and a cost of $2.55 per MMBTU, with the same assumptions as the air fired UCG, including a 15% return on investment.

Because most oxygen-fired UCG systems have included steam injection, we have further investigated the cost impact of adding steam injection to the oxygen stream. This results in a high cost penalty, raising the overall cost of the medium BTU syngas to $3.49 per MMBTU. Because previous analysis of the Rocky Mountain 1 test concluded that the steam injection was actually water at the injection well head temperature and pressure (Boysen et al 1998), we believe that oxygen fired UCG is functional without steam injection. Therefore, medium BTU syngas can be produced for closer to the $2.55 per MMBTU than the steam injection at $3.49 per MMBTU.

These oxygen-fired UCG economics have also been evaluated for an FT plant utilizing the medium BTU UCG syngas. A modest size UCG-FT project, producing 10,000 barrels per day of naptha and diesel combined, has a total capital cost of $622 million and annual operating costs of $53.2 million. This yields an NPV @ 15% discount of $103.5 million, and a DCF-ROR of 18.0%. The payback is a moderate 7.7 years. After reaching steady state production, it produces about $142 million in cash flow from gross revenues of $257.7 million. Sensitiivites on capital costs, operating costs, and revenues being varied from 75% to 125% of the base case produce DCF-ROR's ranging from 11% to 23% .

In summary, UCG in most of the deep coal seams in the PRB is economically feasible and economically favorable compared to surface coal gasification. These advantages hold for air-fired UCG used in an IGCC power plant as well as for oxygen-fired UCG used in an FT plant.

11.3 ENVIRONMENTAL CONCLUSIONS

Large UCG resources exist in the PRB with suitable environmental conditions. Because of the huge volumes of recoverable coal resource available through UCG, selecting the right site for the project can reduce environmental impacts and minimize the time involved in permitting. Large sand units in the overburden should be avoided. Domestic water sources in the overburden also should be avoided. An aquitard formation is preferable overburden material.

Contamination of groundwater an environmental impact which can. Proper well linkage methodology and successful well linkage is critical. Minimizing gas loss from the UCG cavity is most crucial in minimizing groundwater contamination. Therefore, operating the UCG geo-reactor at pressures below hydrostatic pressure is key to avoiding gas losses and groundwater impacts. The effect of ground deformation on the groundwater must be addressed when a site is selected. Impacting overlying aquifers can cause water inflow and additional heat losses in the UCG cavity. Groundwater may be essentially unaffected by the ground motion accompanying UCG if the aquifer is separated from the caved and fractured zones that develop above the coal seam. Completing the UCG activities using the RM-1 "clean cavity" technology will minimize impacts to groundwater.

Operation and remediation protocols developed and tested in the RM1 UCG test should be incorporated in PRB operation plans. Avoidance of groundwater contamination is more acceptable and more cost effective than subsequent remediation. Complete mitigation and remediation plans should be developed early to reduce permitting time and remediation bond. The permitting for a UCG demonstration in the PRB can be accomplished in 24-30 months.

Subsidence is a potential environmental impact of UCG which must be minimized. Subsidence can impact pipelines, roads, dams, bridges, houses, power lines and other surface features. Deep coals reduce the surface impacts of subsidence when gasified. The trade-off between subsidence impact and resource recovery is site specific. Residual ash and char from gasification could be 20% to 50% percent of in-place coal and will reduce subsidence. Also, the cavities will be under hydrostatic pressure which will also reduce subsidence. UCG mining panels separated by pillars of undisturbed coal can be designed to limit subsidence.

UCG can be conducted in the PRB with acceptable environmental consequences.

11.4 RECOMMENDATIONS FOR UCG DEVELOPMENT IN THE PRB OF WYOMING

Based on the results presented in this report, a recommended development program has been formulated to bring UCG technology to commercial realization in the PRB. The commercial development of UCG technology has the potential to open up vast coal resources of the Powder River Basin of northeastern Wyoming for energy production and fuel generation far into the future. The recommended development components for UCG commercialization consist of the following:

- Selection of the UCG technology and end use with the most potential for commercial development.
- Select a suitable site to demonstrate UCG feasibility and commercial potential.
- Demonstrate UCG technology in the thick coals of the PRB on a pre-commercial scale.
- From the experience gained in the demonstration, expand the UCG demonstration to commercial operation.
- With the initial commercial operation underway, evaluate and develop other end use potential.

11.4.1 Recommendation for UCG Technology and Product Utilization

Based on the economics and complexity, an air-fired UCG plant with power generation is recommended for initial development. The air-fired UCG plant/power generation system is the simplest UCG/end use configuration. Of the UCG configurations evaluated (air-fired, oxygen-fired, and steam/oxygen-fired), the air-fired system produces the cheapest cost per unit of energy ($1.62/MM BTU). Capital costs are lower than other configurations because of the large capital costs associated with the air separation and steam plants associated with the other UCG configurations.

There are only two options of end use for air-fired gasification, direct power generation and IGCC. Both end use systems generate electrical power. IGCC possesses greater efficiency; however, the process is more complex and the capital costs are greater.

The disadvantage to air-fired UCG systems are restricted end use options and carbon dioxide separation. As mentioned, end use option is restricted to power generation. Other options such as Fischer-Tropsch (FT) liquids or synthetic natural gas require low nitrogen concentrations. The high nitrogen concentrations in the air-fired UCG gas make carbon dioxide removal prohibitively expensive.

11.4.2 Demonstration Resource Selection and Characterization

A suitable site based on sufficient characterization must be selected to demonstrate the commercial potential of UCG. The geologic and hydrologic characteristics of the site should be thoroughly characterized to assist in interpretation. A site with favorable UCG characteristics should easily be selected because of the large favorable resources that were identified in the PRB. Large variations in the geologic and hydrologic characteristics in the demonstration area should be avoided to reduce complications in the interpretation of the demonstration data. The geologic and hydrologic characteristics should be similar to that expected in the commercial location. This includes coal seam depth and thickness.

11.4.3 Pre-Commercial Demonstration

A pre-commercial demonstration should be conducted prior to the expansion to commercial operation for obvious reasons. The demonstration design should be as close to the commercial plant as possible. Because of the modular design of the commercial plant (described in Section 10), the demonstration design should consist of two or more of the commercial modules. Instrumentation should be more extensive than the commercial plant to gain a better understanding of the interaction between the UCG process and the geologic and hydrologic environment in the PRB. Instrumentation requirements include process and environmental monitoring. For environmental monitoring, instrumentation needs to address groundwater, air quality, and subsidence monitoring.

Demonstration operations should be similar to commercial operations on a modular basis. Air injection rates, production rates, module life, gas compositions, and gas cleanup requirements for a commercial plant should be easily defined for commercial operations from the demonstration data. Environmental characteristics of subsidence, groundwater contamination, and subsurface gas containment should be delineated.

Although not required for the demonstration of the UCG process in the thick coals of the PRB, product gas treatment and utilization should also be demonstrated to facilitate expansion to a commercial size facility. To avoid complications associated with a complicated use scenario, the utilization scheme should be direct electrical generation. Direct electrical generation can be achieved through the use of a reciprocating engine or turbine. Both generating systems have been fueled successfully using low heating value gas. The power generation can also be modularized to match the UCG plant to facilitate expansion to a commercial plant.

11.4.4 Expansion to Commercial Operation

With the successful completion of the demonstration, expansion to a commercial operation could occur. Because of the modular configuration of the UCG and power generation plants, expansion to a commercial-sized plant could easily be accomplished. Existing demonstration facilities and infrastructure could be used. Transfer from the demonstration-sized operations to a commercial-sized operation could be ramped.

The initial commercial operation should focus on direct electrical generation because of the reduced risk, capital costs, and lower complexity than an FT project. As experience is gained, operations could be expanded to an IGCC configuration. The initial commercial plant would provide 200 MW of electricity. The generators would be powered with turbines capable of utilizing low heating value synthetic gas.

11.4.5 Modification of End Product Generation

The operations of the commercial power generation plant could also test oxygen, oxygen/water, or oxygen/steam-fired system without interruption of normal operations. A demonstration-scale air separations plant and steam plant can be added. One module of the plant could be dedicated for oxygen-fired operations with side streams to feed test units for valued-products such as synthetic natural gas, FT liquids, hydrogen, DME, and ammonia production.

Based on results of the value-product test units, objectives of the investors, and economic conditions, value-product plants could be built. The existing power generation plant could be used to supply the parasitic loads of the new plant (s). As shown in Section 10, the low costs associated with UCG-generated power would offer superior economic advantage over other energy sources.

UCG, both air- and oxygen-blown, should have diverse applications for power generation, transportation fuel formulation, and other value-products. This industry, because of the immense UCG resources in the Powder River Basin, should operate for many decades with tremendous economic benefits for Wyoming.

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Appendix 1

PRB UCG Viability Analysis

Economic Case Annual Cash Flows
June 2007

Project ID UCG200 is 200 MW UCG project.
Project ID IGCC550 is 550 MW IGCC project.
Project ID UCGFT is UCG FT project.
Project ID FT is “straight” FT project.

(All Values in Thousands)
Title : 200 MW UCG IGCC
Project ID : UCG200
Run Date : 3/30/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Reversion at 09/13 Reversion Amount: 227141.00

Period Ending	12/08	12/09	12/10	12/11	12/12	12/13
Revenue	0	0	0	51,596	103,193	103,193
-Royalties	0	0	0	-333	-666	-666
Net Revenue	0	0	0	51,264	102,527	102,527
-Oper Costs	0	0	0	-9,958	-19,916	-19,916
-Sever, Ad-Val	0	0	0	-410	-820	-820
-Depreciation	0	0	0	-15,968	-26,226	-18,242
-Writeoffs	0	0	0	0	0	0
Taxable	0	0	0	24,928	55,566	63,549
-Tax @ 35%	0	0	0	-8,725	-19,448	-22,242
Net Income	0	0	0	16,203	36,118	41,307
+Depreciation	0	0	0	15,968	26,226	18,242
+Writeoffs	0	0	0	0	0	0
-Capitl Costs	-63,000	-83,700	-103,030	0	0	0
Cash Flow	-63,000	-83,700	-103,030	32,171	62,343	59,549

Period Ending	12/14	12/15	12/16	12/17	12/18	12/19
Revenue	103,193	103,193	103,193	103,193	103,193	103,193
-Royalties	-666	-666	-666	-666	-666	-666
Net Revenue	102,527	102,527	102,527	102,527	102,527	102,527
-Oper Costs	-19,916	-19,916	-19,916	-19,916	-19,916	-19,916
-Sever, Ad-Val	-820	-820	-820	-820	-820	-820
-Depreciation	-15,433	-12,708	-11,755	-10,873	-10,058	-9,924
-Writeoffs	0	0	0	0	0	0
Taxable	66,358	69,083	70,036	70,918	71,733	71,868
-Tax @ 35%	-23,225	-24,179	-24,513	-24,821	-25,107	-25,154
Net Income	43,133	44,904	45,524	46,097	46,627	46,714
+Depreciation	15,433	12,708	11,755	10,873	10,058	9,924
+Writeoffs	0	0	0	0	0	0
-Capitl Costs	0	0	0	0	0	0
Cash Flow	58,566	57,612	57,279	56,970	56,685	56,638

(All Values in Thousands) Page 2

Title : 200 MW UCG IGCC
Project ID : UCG200
Run Date : 3/30/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/20	12/21	12/22	12/23	12/24	12/25
Revenue	103,193	103,193	103,193	103,193	103,193	103,193
-Royalties	-666	-666	-666	-666	-666	-666
Net Revenue	102,527	102,527	102,527	102,527	102,527	102,527
-Oper Costs	-19,916	-19,916	-19,916	-19,916	-19,916	-19,916
-Sever, Ad-Val	-820	-820	-820	-820	-820	-820
-Depreciation	-9,924	-9,924	-9,924	-9,924	-9,924	-9,924
-Writeoffs	0	0	0	0	0	0
Taxable	71,868	71,868	71,868	71,868	71,868	71,868
-Tax @ 35%	-25,154	-25,154	-25,154	-25,154	-25,154	-25,154
Net Income	46,714	46,714	46,714	46,714	46,714	46,714
+Depreciation	9,924	9,924	9,924	9,924	9,924	9,924
+Writeoffs	0	0	0	0	0	0
-Capitl Costs	0	0	0	0	0	0
Cash Flow	56,638	56,638	56,638	56,638	56,638	56,638

Period Ending	12/26	12/27	12/28	12/29	12/30	12/31
Revenue	103,193	103,193	103,193	103,193	103,193	103,193
-Royalties	-666	-666	-666	-666	-666	-666
Net Revenue	102,527	102,527	102,527	102,527	102,527	102,527
-Oper Costs	-19,916	-19,916	-19,916	-19,916	-19,916	-19,916
-Sever, Ad-Val	-820	-820	-820	-820	-820	-820
-Depreciation	-9,924	-9,924	-9,924	-9,924	-9,924	-4,962
-Writeoffs	0	0	0	0	0	0
Taxable	71,868	71,868	71,868	71,868	71,868	76,829
-Tax @ 35%	-25,154	-25,154	-25,154	-25,154	-25,154	-26,890
Net Income	46,714	46,714	46,714	46,714	46,714	49,939
+Depreciation	9,924	9,924	9,924	9,924	9,924	4,962
+Writeoffs	0	0	0	0	0	0
-Capitl Costs	0	0	0	0	0	0
Cash Flow	56,638	56,638	56,638	56,638	56,638	54,901

(All Values in Thousands) Page 3

Title : 200 MW UCG IGCC
Project ID : UCG200
Run Date : 3/30/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/32	12/33	Salv.
Revenue	103,193	103,193	4,420
-Royalties	-666	-666	0
Net Revenue	102,527	102,527	0
-Oper Costs	-19,916	-19,916	0
-Sever, Ad-Val	-820	-820	0
-Depreciation	0	0	0
-Writeoffs	0	0	-4,420
Taxable	81,791	81,791	0
-Tax @ 35%	-28,627	-28,627	0
Net Income	53,164	53,164	0
+Depreciation	0	0	0
+Writeoffs	0	0	4,420
-Capitl Costs	0	0	0
Cash Flow	53,164	53,164	4,420

Title : 550 MW IGCC
Project ID : IGCC550
Run Date : 4/3/2007
Evaluation Date : 01/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/08	12/09	12/10	12/11	12/12
Revenue	0	0	0	126,976	253,890
-Oper Costs	0	0	0	-45,036	-90,073
-Sever, Ad-Val	0	0	0	-5,860	-5,860
-Depreciation	0	0	0	-31,838	-61,287
-Writeoffs	0	0	0	0	0
Taxable	0	0	0	44,243	96,670
-Tax @ 35%	0	0	0	-15,485	-33,834
Net Income	0	0	0	28,758	62,835
+Depreciation	0	0	0	31,838	61,287
+Writeoffs	0	0	0	0	0
-Capitl Costs	-306,500	-283,000	-283,000	0	0
Cash Flow	-306,500	-283,000	-283,000	60,595	124,123

Period Ending	12/13	12/14	12/15	12/16	12/17
Revenue	253,890	253,890	253,890	253,890	253,890
-Oper Costs	-90,073	-90,073	-90,073	-90,073	-90,073
-Sever, Ad-Val	-5,860	-5,860	-5,860	-5,860	-5,860
-Depreciation	-56,691	-52,439	-48,506	-44,868	-41,503
-Writeoffs	0	0	0	0	0
Taxable	101,266	105,518	109,451	113,089	116,454
-Tax @ 35%	-35,443	-36,931	-38,308	-39,581	-40,759
Net Income	65,823	68,587	71,143	73,508	75,695
+Depreciation	56,691	52,439	48,506	44,868	41,503
+Writeoffs	0	0	0	0	0
-Capitl Costs	0	0	0	0	0
Cash Flow	122,514	121,026	119,649	118,376	117,198

Title : 550 MW IGCC
Project ID : IGCC550
Run Date : 4/3/2007
Evaluation Date : 01/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/18	12/19	12/20	12/21	12/22
Revenue	253,890	253,890	253,890	253,890	253,890
-Oper Costs	-90,073	-90,073	-90,073	-90,073	-90,073
-Sever, Ad-Val	-5,860	-5,860	-5,860	-5,860	-5,860
-Depreciation	-38,390	-37,878	-37,878	-37,878	-37,878
-Writeoffs	0	0	0	0	0
Taxable	119,567	120,079	120,079	120,079	120,079
-Tax @ 35%	-41,848	-42,028	-42,028	-42,028	-42,028
Net Income	77,718	78,051	78,051	78,051	78,051
+Depreciation	38,390	37,878	37,878	37,878	37,878
+Writeoffs	0	0	0	0	0
-Capitl Costs	0	0	0	0	0
Cash Flow	116,109	115,929	115,929	115,929	115,929

Period Ending	12/23	12/24	12/25	12/26	12/27
Revenue	253,890	253,890	253,890	253,890	253,890
-Oper Costs	-90,073	-90,073	-90,073	-90,073	-90,073
-Sever, Ad-Val	-5,860	-5,860	-5,860	-5,860	-5,860
-Depreciation	-37,878	-37,878	-37,878	-37,878	-37,878
-Writeoffs	0	0	0	0	0
Taxable	120,079	120,079	120,079	120,079	120,079
-Tax @ 35%	-42,028	-42,028	-42,028	-42,028	-42,028
Net Income	78,051	78,051	78,051	78,051	78,051
+Depreciation	37,878	37,878	37,878	37,878	37,878
+Writeoffs	0	0	0	0	0
-Capitl Costs	0	0	0	0	0
Cash Flow	115,929	115,929	115,929	115,929	115,929

Title : 550 MW IGCC
Project ID : IGCC550
Run Date : 4/3/2007
Evaluation Date : 01/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/28	12/29	12/30	12/31	12/32
Revenue	253,890	253,890	253,890	253,890	253,890
-Oper Costs	-90,073	-90,073	-90,073	-90,073	-90,073
-Sever, Ad-Val	-5,860	-5,860	-5,860	-5,860	-5,860
-Depreciation	-37,878	-37,878	-37,878	-18,939	0
-Writeoffs	0	0	0	0	0
Taxable	120,079	120,079	120,079	139,018	157,957
-Tax @ 35%	-42,028	-42,028	-42,028	-48,656	-55,285
Net Income	78,051	78,051	78,051	90,362	102,672
+Depreciation	37,878	37,878	37,878	18,939	0
+Writeoffs	0	0	0	0	0
-Capitl Costs	0	0	0	0	0
Cash Flow	115,929	115,929	115,929	109,301	102,672

Period Ending	12/33	Salv.
Revenue	253,890	23,500
-Oper Costs	-90,073	0
-Sever, Ad-Val	-5,860	0
-Depreciation	0	0
-Writeoffs	0	-23,500
Taxable	157,957	0
-Tax @ 35%	-55,285	0
Net Income	102,672	0
+Depreciation	0	0
+Writeoffs	0	23,500
-Capitl Costs	0	0
Cash Flow	102,672	23,500

(All Values in Thousands)

Title : UCG FT
Project ID : UCGFT
Run Date : 5/1/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Reversion at 05/12 Reversion Amount: 227141.00

Period Ending	12/08	12/09	12/10	12/11	12/12	12/13
Revenue	0	0	0	128,862	257,718	257,718
-Royalties	0	0	0	-1,340	-2,680	-2,680
Net Revenue	0	0	0	127,522	255,037	255,037
-Oper Costs	0	0	0	-23,800	-47,600	-47,600
-Sever, Ad-Val	0	0	0	-1,529	-3,057	-3,057
-Depreciation	0	0	0	-23,325	-44,901	-41,533
Taxable	0	0	0	78,868	159,480	162,847
-Tax @ 35%	0	0	0	-27,604	-55,818	-56,996
Net Income	0	0	0	51,264	103,662	105,851
+Depreciation	0	0	0	23,325	44,901	41,533
-Capitl Costs	-124,400	-311,000	-186,600	0	0	0
Cash Flow	-124,400	-311,000	-186,600	74,589	148,562	147,384

Period Ending	12/14	12/15	12/16	12/17	12/18	12/19
Revenue	257,718	257,718	257,718	257,718	257,718	257,718
-Royalties	-2,680	-2,680	-2,680	-2,680	-2,680	-2,680
Net Revenue	255,037	255,037	255,037	255,037	255,037	255,037
-Oper Costs	-47,600	-47,600	-47,600	-47,600	-47,600	-47,600
-Sever, Ad-Val	-3,057	-3,057	-3,057	-3,057	-3,057	-3,057
-Depreciation	-38,418	-35,537	-32,871	-30,406	-28,126	-27,751
Taxable	165,962	168,843	171,509	173,974	176,255	176,630
-Tax @ 35%	-58,087	-59,095	-60,028	-60,891	-61,689	-61,820
Net Income	107,875	109,748	111,481	113,083	114,565	114,809
+Depreciation	38,418	35,537	32,871	30,406	28,126	27,751
-Capitl Costs	0	0	0	0	0	0
Cash Flow	146,293	145,285	144,352	143,489	142,691	142,560

(All Values in Thousands)

Title : UCG FT
Project ID : UCGFT
Run Date : 5/1/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/20	12/21	12/22	12/23	12/24	12/25
Revenue	257,718	257,718	257,718	257,718	257,718	257,718
-Royalties	-2,680	-2,680	-2,680	-2,680	-2,680	-2,680
Net Revenue	255,037	255,037	255,037	255,037	255,037	255,037
-Oper Costs	-47,600	-47,600	-47,600	-47,600	-47,600	-47,600
-Sever, Ad-Val	-3,057	-3,057	-3,057	-3,057	-3,057	-3,057
-Depreciation	-27,751	-27,751	-27,751	-27,751	-27,751	-27,751
Taxable	176,630	176,630	176,630	176,630	176,630	176,630
-Tax @ 35%	-61,820	-61,820	-61,820	-61,820	-61,820	-61,820
Net Income	114,809	114,809	114,809	114,809	114,809	114,809
+Depreciation	27,751	27,751	27,751	27,751	27,751	27,751
-Capitl Costs	0	0	0	0	0	0
Cash Flow	142,560	142,560	142,560	142,560	142,560	142,560

Period Ending	12/26	12/27	12/28	12/29	12/30	12/31
Revenue	257,718	257,718	257,718	257,718	257,718	257,718
-Royalties	-2,680	-2,680	-2,680	-2,680	-2,680	-2,680
Net Revenue	255,037	255,037	255,037	255,037	255,037	255,037
-Oper Costs	-47,600	-47,600	-47,600	-47,600	-47,600	-47,600
-Sever, Ad-Val	-3,057	-3,057	-3,057	-3,057	-3,057	-3,057
-Depreciation	-27,751	-27,751	-27,751	-27,751	-27,751	-13,875
Taxable	176,630	176,630	176,630	176,630	176,630	190,505
-Tax @ 35%	-61,820	-61,820	-61,820	-61,820	-61,820	-66,677
Net Income	114,809	114,809	114,809	114,809	114,809	123,828
+Depreciation	27,751	27,751	27,751	27,751	27,751	13,875
-Capitl Costs	0	0	0	0	0	0
Cash Flow	142,560	142,560	142,560	142,560	142,560	137,703

(All Values in Thousands) Page 3

Title : UCG FT
Project ID : UCGFT
Run Date : 5/1/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/32	12/33
Revenue	257,718	257,718
-Royalties	-2,680	-2,680
Net Revenue	255,037	255,037
-Oper Costs	-47,600	-47,600
-Sever, Ad-Val	-3,057	-3,057
-Depreciation	0	0
Taxable	204,380	204,380
-Tax @ 35%	-71,533	-71,533
Net Income	132,847	132,847
+Depreciation	0	0
-Capitl Costs	0	0
Cash Flow	132,847	132,847

(All Values in Thousands)   Page   1

Title   : FT
Project ID : FT
Run Date   : 5/3/2007
Evaluation Date : 02/07
Project Start   : 01/08
Evaluator : GasTech

Reversion at 05/12 Reversion Amount: 227141.00

Period Ending	12/08	12/09	12/10	12/11	12/12	12/13
Revenue	0	0	0	128,862	257,718	257,718
-Oper Costs	0	0	0	-22,650	-45,300	-45,300
-Depreciation	0	0	0	-27,750	-53,419	-49,412
Taxable	0	0	0	78,462	158,999	163,005
-Tax @ 35%	0	0	0	-27,462	-55,650	-57,052
Net Income	0	0	0	51,000	103,349	105,953
+Depreciation	0	0	0	27,750	53,419	49,412
-Capitl Costs	-148,000	-370,000	-222,000	0	0	0
Cash Flow	-148,000	-370,000	-222,000	78,750	156,768	155,366

Period Ending	12/14	12/15	12/16	12/17	12/18	12/19
Revenue	257,718	257,718	257,718	257,718	257,718	257,718
-Oper Costs	-45,300	-45,300	-45,300	-45,300	-45,300	-45,300
-Depreciation	-45,706	-42,278	-39,108	-36,174	-33,461	-33,015
Taxable	166,711	170,139	173,310	176,243	178,956	179,402
-Tax @ 35%	-58,349	-59,549	-60,659	-61,685	-62,635	-62,791
Net Income	108,362	110,591	112,652	114,558	116,322	116,612
+Depreciation	45,706	42,278	39,108	36,174	33,461	33,015
-Capitl Costs	0	0	0	0	0	0
Cash Flow	154,069	152,869	151,759	150,733	149,783	149,627

(All Values in Thousands) Page 2

Title : FT
Project ID : FT
Run Date : 5/3/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/20	12/21	12/22	12/23	12/24	12/25
Revenue	257,718	257,718	257,718	257,718	257,718	257,718
-Oper Costs	-45,300	-45,300	-45,300	-45,300	-45,300	-45,300
-Depreciation	-33,015	-33,015	-33,015	-33,015	-33,015	-33,015
Taxable	179,402	179,402	179,402	179,402	179,402	179,402
-Tax @ 35%	-62,791	-62,791	-62,791	-62,791	-62,791	-62,791
Net Income	116,612	116,612	116,612	116,612	116,612	116,612
+Depreciation	33,015	33,015	33,015	33,015	33,015	33,015
-Capitl Costs	0	0	0	0	0	0
Cash Flow	149,627	149,627	149,627	149,627	149,627	149,627

Period Ending	12/26	12/27	12/28	12/29	12/30	12/31
Revenue	257,718	257,718	257,718	257,718	257,718	257,718
-Oper Costs	-45,300	-45,300	-45,300	-45,300	-45,300	-45,300
-Depreciation	-33,015	-33,015	-33,015	-33,015	-33,015	-16,508
Taxable	179,402	179,402	179,402	179,402	179,402	195,910
-Tax @ 35%	-62,791	-62,791	-62,791	-62,791	-62,791	-68,569
Net Income	116,612	116,612	116,612	116,612	116,612	127,342
+Depreciation	33,015	33,015	33,015	33,015	33,015	16,508
-Capitl Costs	0	0	0	0	0	0
Cash Flow	149,627	149,627	149,627	149,627	149,627	143,849

(All Values in Thousands) Page 3

Title : FT
Project ID : FT
Run Date : 5/3/2007
Evaluation Date : 02/07
Project Start : 01/08
Evaluator : GasTech

Period Ending	12/32	12/33
Revenue	257,718	257,718
-Oper Costs	-45,300	-45,300
-Depreciation	0	0
Taxable	212,418	212,418
-Tax @ 35%	-74,346	-74,346
Net Income	138,072	138,072
+Depreciation	0	0
-Capitl Costs	0	0
Cash Flow	138,072	138,072

Attachments

PRB UCG Viability Analysis

June 2007