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UNDERGROUND GASIFICATION FOR STEEPLY DIPPING COAL BEDS

Phase I Report: Appendix C. Parametric Cost Estimate
September 30, 1977—February 28, 1978

May 1978

Work Performed Under Contract No. EF-77-C-03-1472

Gulf Research and Development Company
Pittsburgh, Pennsylvania

and

TRW Energy Systems Planning Division
McLean, Virginia

MASTER

U. S. DEPARTMENT OF ENERGY

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APPENDIX C

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APPENDIX C

PARAMETRIC COST ESTIMATE FOR COMMERCIAL UNDERGROUND COAL GASIFICATION

C.1.0 INTRODUCTION

In the course of our studies on underground coal gasification, Gulf Research & Development Company has developed a proprietary computer program to calculate economics for a conceptual commercial UCG plant as applied to horizontal coal seams. In order to convert this program to use with steeply dipping beds, it will be necessary to modify the sections which contain concepts and calculations related to well layout, drilling, and field piping to interconnect wells and various production facilities. GR&DC expects to make these modifications sometime during Phase II of their DOE contract, although the work will not be funded by the contract and the model will remain proprietary.

The present program cannot provide SDB economics. However, there are various factors such as those related to the coal seam, those related to operating conditions, and those related to process results which may be independent of whether the coal bed is horizontal or tilted. A number of factors have been varied over a considerable range to show their effect on economics for a horizontal bed application. It is believed these results should be helpful in designing experimental field studies in steeply dipping beds.

It is important to note that many of the operational parameters which have a direct effect on gasification economics (such as pressure) can also have an indirect effect because of their concomitant effect on such variables as leakage, gas composition, etc. At present, we do not know what these relationships are, although we have tried to show at least directionally how some expected relationships can affect economic results. Until process modeling is better defined, economic modeling will be subject to such uncertainty.

C.2.0 SUMMARY

The economics of operating a conceptual underground coal gasification process were determined for a plant which produces 152×10^3 GJ/d (144×10^9 Btu/d) of low-heating-value gas from a horizontal seam of subbituminous coal located in the western United States. The gasifying medium was air. This size plant furnishes sufficient gas to generate approximately 600 MW of electric power.

The mathematical model used for the economic studies permits the effects of many resource, operational, and production variables to be studied. Sixteen different cases were run in which individual parameters were varied and four cases were run in which two or more parameters were varied together. When a parameter was not being varied, it was held constant at the base value shown in Table C-I. The range of values through which the parameters were varied is shown in Table C-II.

A brief summary of the effect of varying the parameters on the price of LHV gas is included in Table C-II. The results obtained with the economic model are shown in more detail in Table C-IV and in Figures C-3 through C-22, and are discussed in a later section.

Table C-II shows the effects of the parameters over the whole range through which they were varied. These effects were also determined for a 50% increase in the value of each variable near the midpoint of its range. Table C-III shows the variables in decreasing order of their percentage effect on sales gas price.

Table C-III shows that the most effective way to reduce the cost of gas from UCG is to increase its heating value. This decreases the plant size, number of wells, coal consumed, and fuel requirements. The next most effective ways are to increase product gas recovery and air utilization, i.e., to minimize leakage. To express these effects in another way, each 2% increase in either air or gas leakage increases the sales gas price by 1%. Again, decreased leakage results in smaller plants, fewer wells, less coal consumption, and lower fuel requirements all of which reduce final costs.

Table C-I

BASE PARAMETER VALUES FOR PARAMETRIC COST ANALYSIS

<u>PARAMETER STUDIED</u>	<u>BASE VALUE</u>
<u>COAL DATA</u>	
Seam depth, m (ft)	183 (600)
Seam thickness, m (ft)	9.1 (30)
Density, t/ha-m (T/acre-ft)	13 970 (1900)
Heat content, kJ/kg (Btu/lb)	18 600 (8000)
<u>OPERATIONAL</u>	
Well spacing, ha (acres)	0.81 (2)
Aspect ratio (Note a)	1
Production rate/well, m ³ /d (10 ⁶ scf/d)	141 580 (5)
Injection air rate, m ³ /t coal (scf/T)	1605 (51 430)
Injection air pressure, kPa (psig)	790 (100)
Production wellhead pressure, kPa (psig)	445 (50)
Sales gas delivery pressure, kPa (psig)	1310 (175)
Water/O ₂ consumption rate, weight	1.5
<u>PRODUCTION</u>	
Gas production rate, m ³ /t coal (scf/T)	2620 (84 000)
Gas composition, mol % H ₂	18.0
CO	18.0
CH ₄	5.0
C ₂ H ₆	0.5
CO ₂	10.0
H ₂ S	0.1
N ₂ +Ar	48.4
Gas heating value, kJ/m ³ (Btu/scf)	6560 (176)
Sweep efficiency, %	100
Air utilization, %	100
Gas recovery, %	100

Note a: Aspect ratio = distance between production rows divided by distance between wells in row.

Table C-II.

SUMMARY OF PARAMETER VARIATIONS AND THEIR EFFECT ON UCG ECONOMICS

PARAMETER STUDIED	Range of Parameter		Sales Gas Price, \$/GJ(\$/10 ⁶ Btu)	
	Low	High	At Low Range	At High Range
COAL SEAM				
Depth, m (ft)	91 (300)	233 (764)	1.70 (1.79)	1.80 (1.90)
Seam thickness, m (ft)	1.5 (5)	10.4 (34)	2.30 (2.43)	1.74 (1.84)
Coal density, t/ha-m (T/acre-ft)	13 970 (1900)	27 480 (3737)	1.76 (1.86)	1.71 (1.80)
OPERATIONAL				
Well spacing, ha (acres)	0.28 (0.7)	1.58 (3.9)	1.72 (1.82)	1.90 (2.00)
Aspect ratio (Note a)	0.2	8.9	2.45 (2.59)	1.53 (1.61)
Production rate/well, m ³ /d (10 ⁶ scf/d)	65 103 (2.3)	274 670 (9.7)	2.80 (2.95)	1.53 (1.61)
Air rate, m ³ /t coal (scf/T coal)	1055 (33 810)	1915 (61 430)	1.50 (1.58)	2.04 (2.15)
Air pressure, kPa (psig)	480 (55)	1480 (200)	1.65 (1.74)	1.91 (2.02)
Production wellhead pressure kPa (psig)	240 (20)	745 (93)	2.78 (2.93)	1.35 (1.42)
PRODUCTION				
Gas rate, m ³ /t coal (scf/T coal)	1875 (60 000)	3230 (103 500)	2.27 (2.39)	1.56 (1.65)
CH ₄ in product gas, mol %	2.1	7.0	2.55 (2.69)	1.46 (1.54)
H ₂ in product gas, mol %	12.6	21.3	2.14 (2.26)	1.59 (1.68)
Gas heating value, kJ/m ³ (Btu/scf)	4580 (123)	8380 (225)	4.10 (4.33)	1.18 (1.25)
Sweep efficiency (coal usage), %	25	97	2.20 (2.32)	1.76 (1.86)
Air utilization, %	40	98	3.86 (4.07)	1.78 (1.88)
Gas recovery, %	40	98	4.42 (4.66)	1.78 (1.85)
COMBINED PARAMETERS				
Air rate, m ³ /t coal (scf/T coal)	1070 (34 290)	1850 (59 140)	1.85 (1.95)	1.73 (1.83)
Gas rate, m ³ /t coal (scf/T coal)	1870 (60 000)	3230 (103 500)		
Air pressure, kPa (psig)	410 (45)	1010 (132)	2.50 (2.64)	1.30 (1.37)
Production pressure, kPa (psig)	240 (20)	840 (107)		
Depth, m (ft)	76 (250)	182 (598)	2.92 (3.08)	1.15 (1.21)
Air pressure, kPa (psig)	370 (39)	1310 (175)		
Production pressure, kPa (psig)	200 (14)	1135 (150)		
Depth, m (ft)	76 (250)	182 (598)	3.12 (3.29)	2.20 (2.32)
Air Pressure, kPa (psig)	370 (39)	1310 (175)		
Production pressure, kPa (psig)	200 (14)	1135 (150)		
Air leakage, %	5	30		
Gas leakage, %	5	30		

Note a: Aspect ratio = distance between production rows divided by distance between wells in row.

Table C-III

EFFECT OF 50% INCREASE IN PARAMETER
VALUE ON LHV GAS SALES PRICE

<u>Parameter</u>	<u>Change in Sales Gas Price, %</u>
Product gas heating value	-54.0
Product gas recovery	-30.4
Air utilization	-26.8
Gas production/t coal	-24.2
Injection air/t coal	+23.5
Methane content of gas	-20.7
Hydrogen content of gas	-20.6
Production wellhead pressure	-16.9
Production rate/well	-9.5
Sweep efficiency	-4.9
Aspect ratio	-4.7
Well spacing	+3.8
Injection air pressure	+3.8
Coal seam thickness	-3.5
Coal seam depth	+2.1
Coal concentration/unit surface area	-1.6

Gas production per ton of coal and air injection per ton of coal have large but opposite effects on gas price as they are increased. Since gas production will most likely be a function of the amount of air injected, these parameters tend to offset each other. This effect is shown by the relatively flat curve of Figure C-19.

An increase of 50% in either the methane or the hydrogen content of the product gas has about the same effect on sales gas price. The decrease in price is due to the increase in heating value of the gas, caused by the increased methane or hydrogen content. The essential element appears to be to obtain increased heating value and the manner in which this is accomplished does not greatly matter from a cost per unit of heat standpoint.

Increased production wellhead pressure has a beneficial effect on gas price because the conceptual plant design requires that the production gas be compressed to 1135 kPa (150 psig) for pipelining to the main plant. The high cost of field compressors and their operation can be reduced by the increased wellhead pressure. This increased wellhead pressure can only be obtained by increasing inlet air pressure, but because the amount of air to be compressed is only about 57% as great as the amount of production gas, the net cost of sales gas is reduced.

The remaining parameters have only moderate effects on the gas price. This arises because their effects are in large measure connected to well costs and field piping, and these constitute a minor portion of the plant investment and operating cost in the conceptual plant.

In addition to the relationship of gas production and air injection mentioned above, other parameters also are certainly related. Outlet and inlet pressure; depth and pressure; and depth, pressure, and leakage are three sets which have been examined in this study. In the first two of these three, the effect of outlet pressure dominates the combined effects so that the curves which are shown in Figures C-20 and C-21 resemble those of Figure C-11 (wellhead pressure only). In the last set,

the effect of increasing pressure dominates at low leakage rates, but as leakage increases due to pressure, the gas price reaches a minimum and begins to climb again (Figure C-22).

The relationships developed in this study are determined by the values assigned to all of the variables, and the interactions which could be studied are almost limitless. One variable which has not been studied is the pressure at which sales gas is delivered. If this can be reduced, it may be possible that pressure parameters will be less important. The relationships between operational parameters and process results will be developed as part of the experimental program. These can be tested quickly and easily in the economic model as the experimental investigations proceed.

One definite limitation in this study is that it applies only to horizontal coal seams. In order to apply such a study to steeply dipping beds, it will be necessary to develop a conceptual plant and mathematical model for that configuration. Many of the parameters would be expected to have similar effects for either horizontal or steeply dipping beds. However, because well costs are greater in steeply dipping beds and because field piping may involve greater costs as the wells are spaced in a single row along the seam, some of the parameters may have increased effects in the SDB process. Some parameters which should be particularly examined in the steeply dipping bed model are well depth, seam thickness (as it affects drilling costs), well spacing, production rate per well, and sweep efficiency. The whole concept of optimizing the positioning of wells, field piping, and gas handling plants must be carefully considered in designing the conceptual plant.

C.3.0 DESCRIPTION OF CONCEPTUAL PLANT AND ECONOMIC CALCULATIONS

C.3.1 GR&DC ECONOMIC MODEL OF UCG

Gulf Research & Development Company has been investigating in situ processing of coal for energy recovery since the early 1960's.⁽¹⁾ Of course, much more work was done earlier in other countries, as well

as in the United States by our own government, with most of the work being done in horizontal seams. As Gulf's interest in underground coal gasification increased, it was decided that it would be expedient to have a computerized means to calculate the economics for the process in order to ascertain the effects of the many variables involved. The development and use of the GR&DC model have been reported in several earlier papers.(2-5)

To develop a mathematical model, it was necessary to define a conceptual gas production system. Since most previous work has been done in horizontal beds, this system was chosen for computer modeling. The commercial gasification system as conceived contains three distinct operational areas: the actual production facilities, the production field station, and the main plant. In addition, numerous pipelines are required to interconnect the different facilities. The computer program is designed for locations in the eastern or western United States, to use air or oxygen for gasification, to use water or steam injection, and to produce low-heating-value gas, medium-heating-value gas, or synthetic pipeline gas. The last two gases are produced using oxygen as the gasifying medium. The injection and production wells may be linked by either pneumatic linking or by the backward link-forward burn technique.

A diagram of the production configuration is shown in Figure C-1 and the associated surface facilities are shown in Figure C-2. The computer program first mathematically constructs an array of wells and surface facilities sufficiently large to produce the designated sales gas volume and plant energy requirements. After the injection and production wells are linked, production begins and material produced is conducted to the transportable field production station. Here the gas is cooled, coal liquids and liquid water are separated, and the produced gas is compressed for transmission to the gas treatment plant. The production station is located near the active pattern to reduce gathering line pressure drop. The gas treatment facility, however, is located at a fixed site outside the active area for protection against surface

Figure C-1. GAS PRODUCTION CONFIGURATION

Figure C-2. PLAN VIEW OF SURFACE FACILITIES

subsidence. Also located at the gas plant site are the oxygen plant or air compressors and water supply system. Delivery lines run to the active site where distribution lines connect to each injection well. Figure C-2 includes a schematic diagram of this piping system.

With this concept, high pressure linking operations proceed ahead of the lower pressure gasification operation. The production water is reinjected for gasification, but when the amount of water produced is greater than the desired injection quantity, the excess is injected into disposal wells in the burned-out area. In locations where water is plentiful, fresh water is used for steam generation, and all the produced water is disposed.

At periodic intervals, the field production station is moved as the advancing active zone approaches. Sufficient excess equipment capacity reduces the effect of this move on continuous gas production capability.

The field production facilities include the injection, production and disposal wells, the steam generators, and the equipment and wells utilized for linking operations. Injection and production wells are assumed to be cased and cemented through the coal. The production well casing I.D. is a function of gas flow rate and a specified pressure drop criterion. The steam generators are located near the injection wells to reduce heat losses. In water-deficient areas, thermosludge steam generators⁽⁶⁾ are used to enable utilization of production water. The steam generators are moved along with the production area and sufficient extra capacity is included to enable interruption-free relocation.

The field station includes gas coolers, field separators for gas and liquid separation and gas cleanup, and compressors required for transmission of the produced gas to the central facilities. Separators, oil dehydrators, gas coolers, liquid storage facilities, and compressors are sized according to assumed or calculated conditions using accepted

formulae. Compressor interstage temperature is limited to 150°C. Flexibility for continuous operation is provided by requiring 25% equipment standby capacity.

The central gas treatment plant design varies according to end production requirements. A gas produced with oxygen may be upgraded by acid gas ($\text{H}_2\text{S} + \text{CO}_2$) removal to provide medium-heating-value (MHV) gas for fuel or synthesis feedstock. It may also be converted into synthetic pipeline gas (SPG) by shift conversion, purification, and then methanation to a pipeline quality of 834 MJ/kmol (945 Btu/SCF). A gas produced from air injection has a low heat value but would be suitable for nearby consumption as a fuel once sulfur compounds are removed. This type of product gas will be called low-heating-value (LHV) gas. The hot potassium carbonate process, as described by McCrea and Field,⁽⁷⁾ is used for both MHV gas and LHV gas purification plants. Process parameters are adjusted to remove nearly all CO_2 in the MHV gas, but only about 25% of the CO_2 with more selective H_2S absorption in the LHV gas case. If CO_2 can be tolerated in the end product, savings are realized both in plant capital and energy requirements. A Claus sulfur plant is used to convert H_2S in the concentrated acid gas stream to elemental sulfur for by-product sales.

The oxygen plant or the air compressor facility is located near the main gas treatment plant. The oxygen plant requirement is calculated with a maximum single train size of 0.66 Mt/a (2000 tons/day). Air compression is by gas turbine powered compressors of approximately 75 kW (10 000 HP) capacity. Capital cost, as well as operating cost, varies with the required injection pressure. This, in turn, is a function of the assumed pressure gradient required to maintain gas flow underground, depth of cover, and pressure drop in the surface piping.

The piping requirements can be divided into four systems: an oxygen or air system, a product system, a water system, and a fuel gas system. Pipe diameters and wall thickness are calculated according to flow rate, fluid pressure, and pressure drop requirements. All piping is assumed to be carbon steel, except for the oxygen lines which must be stainless steel.

In order to supply the energy requirement of the gasification plant, a portion of the produced gas is split off for use as plant fuel. Selective H_2S and partial CO_2 removal is used to desulfurize the fuel gas. This fuel is used in gas turbines and boilers to provide gas compression at the field production station, regeneration steam for the gas purification process, shift conversion steam, power for the sulfur plant, oxidant at the required injection pressure for gasification and linking, steam for injection, and final compression of the product gas to the required delivery pressure. The fuel purification plant is integrated into the product purification facility for the MHV gas or LHV gas product options. For the SPG option, the fuel purification plant is located within the field station. Only a small amount of energy is purchased as commercial electrical power.

The capital requirements and operational expenses for the production operations gas purification plants, oxygen manufacture, and air compression were obtained from Gulf experience and a variety of other sources. Every effort was made to design surface-system components and estimate equipment capital costs accurately so that the principal uncertainty in the results would lie in the gasification assumptions.

Drilling and completion costs have fluctuated wildly in the last several years under demand pressures and equipment shortages. However, recent data on a large number of infill holes, as well as published costs,⁽⁸⁾ were used to estimate drilling costs of \$62/m (\$19/ft), drilled, cased and cemented, plus \$4400 fixed cost per injection well and \$3300 for each production well. Casing is considered non-recoverable, but tubing and packers used in the injection well are reused.

Surface piping material costs of \$0.50/kg for carbon steel and \$3.20/kg for stainless steel came from a variety of sources.^(9,10) Labor costs for installing piping were derived from a correlation⁽¹¹⁾ of extensive data from the literature, including a pipeline industry survey

report.⁽¹²⁾ Half of this value is charged for disassembling installed piping systems.

Compressor and steam generator capital costs data were taken from recent manufacturers' literature and quotations. The costs of tankage, separators, and gas coolers came from Gulf data and assorted references.^(9,13) The costs of clearing, grading and building access roads, electrical substations and water supply systems came from Gulf data and Guthrie's manual.⁽⁹⁾

Cost data for the oxygen plant and the SPG plant were provided by the GR&DC Planning and Economics Division.⁽¹⁴⁾ The SPG plant costs were based on submissions to the FPC for surface plant construction. Cost and operating data for the hot carbonate gas clean-up process came from McCrea and Field.⁽⁷⁾ Higher capital requirements for the gas processing plants of 7% are used for western U.S. A 10% higher cost for labor intensive construction operations in western U.S. was used to account for the more severe weather conditions.

Annual capital charges are 13% of the total capital for utility financing based on 75/25 debt equity ratio, 15% return on equity, 8.5% interest rate, 48% federal income tax and 4% depreciation (25-year term). For equity financing, the annual charge is 24% of total capital based on 20% return on capital before taxes and 4% depreciation. All of the results are indexed using Nelson Cost Indexes⁽¹⁵⁾ to any desired time frame.

The program calculates the capital requirements for the hypothetical commercial facility as well as the prices for the synthetic pipeline gas, synthesis gas, and low-heating-value gas. Inputs to the program are:

- Capacity of the facility and type of gas
- Coal seam thickness and depth
- Gasifying fluid composition: oxygen or air, water or steam
- Composition of the produced gas
- Injection flow rate and production yields
- Well spacing and configuration
- Sweep efficiency (coal utilization)
- Oxygen or air utilization (i.e., leakage)
- Location, western or eastern U.S.
- Linking technique, backward burn or pneumatic
- Gas recovery (i.e., leakage)
- Cost indexes for desired time period

The program does not presently include the capability of calculating economics for steeply dipping coal beds; however, the program will be expanded for this use in the near future.

C.3.2 PARAMETERS STUDIED

A total of twenty cases were examined in the parametric study. These cases are listed in Table C-IV which shows the base value for each variable which remained unchanged as other parameters were studied and the range over which they were varied.

One set of variables which affect the economics of the underground coal gasification process is that which is fixed by the characteristics of the coal resource and by specifications for the commercial plant. These variables are:

- +● Coal seam depth
- +● Coal seam thickness
- +● Coal concentration (tons/acre-ft of horizontal surface)
- Capacity of plant
- Type of product gas

Table C-IV

COMMERCIAL UCG PROCESS PARAMETER VALUES

	Range		
	Base	Low	High
<u>COAL SEAM DATA</u>			
Depth, m (ft)	183 (600)	91 (300)	233 (764)
Thickness, m (ft)	9.1 (30)	1.5 (5)	10.4 (34)
Density, t/ha-m (T/acre-ft)	13 970 (1 900)	13 970 (1 900)	27 480 (3 737)
Heating Value, kJ/kg (Btu/lb)	18 600 (8 000)		
<u>OPERATIONAL PARAMETERS</u>			
Well spacing, ha (acres)	0.81 (2)	0.28 (0.7)	1.58 (3.9)
Aspect ratio (Note)	1	0.2	8.9
Production rate/well, m ³ /d (10 ⁶ scf/d)	141 580 (5)	65 130 (2.3)	274 670 (9.7)
Air rate, m ³ /t coal (scf/T coal)	1 605 (51 430)	1 055 (33 810)	1 915 (61 430)
Air pressure, kPa (psig)	790 (100)	480 (55)	1 480 (200)
Production pressure, kPa (psig)	445 (50)	240 (20)	745 (93)
Sales gas pressure, kPa (psig)	1 310 (175)		
<u>PRODUCTION PARAMETERS</u>			
Gas rate, m ³ /t coal (scf/T coal)	2 620 (84 000)	1 875 (60 000)	3 230 (103 500)
Gas composition, mol %			
H ₂	18.0	12.6	23.0
CO	18.0	12.6	23.0
CH ₄	5.0	3.5	6.4
C ₂ H ₆	0.5	0.4	0.6
CO ₂	10.0	10.0	10.0
H ₂ S	0.1	0.1	0.1
N ₂ + Ar	48.4	60.8	36.9
Gas heating value, kJ/m ³ (Btu/scf)	6 560 (176)	4 580 (123)	8 380 (225)
Sweep efficiency, %	100	25	97
Air utilization, %	100	40	98
Gas recovery, %	100	40	98
<u>COMBINED PARAMETERS</u>			
H ₂ , mol %	18.0	12.6	21.3
N ₂ + Ar, mol %	48.4	53.8	45.1
Gas heating value, kJ/m ³ (Btu/scf)	6 560 (176)	5 920 (159)	6 970 (187)
CH ₄ , mol %	5.0	2.1	7.0
N ₂ + Ar, mol %	48.4	51.3	46.4
Gas heating value, kJ/m ³ (Btu/scf)	6 560 (176)	5 440 (146)	7 300 (196)
Air rate, m ³ /t coal (scf/T coal)	1 605 (51 430)	1 070 (34 290)	1 850 (59 140)
Gas rate, m ³ /t coal (scf/T coal)	2 620 (84 000)	1 870 (60 000)	3 230 (103 500)
Air pressure, kPa (psig)	790 (100)	410 (45)	1 010 (132)
Production pressure, kPa (psig)	445 (50)	240 (20)	840 (107)
Depth, m (ft)	183 (600)	76 (250)	182 (598)
Air pressure, kPa (psig)	790 (100)	370 (39)	1 310 (175)
Production pressure, kPa (psig)	445 (50)	200 (14)	1 135 (150)
Depth, m (ft)	183 (600)	76 (250)	182 (598)
Air pressure, kPa (psig)	790 (100)	370 (39)	1 310 (175)
Production pressure, kPa (psig)	445 (50)	200 (14)	1 135 (150)
Air leakage, %	0	5	30
Gas leakage, %	0	5	30

 Note - aspect ratio = distance between production rows divided by distance between wells in row.

- Location, eastern or western U.S.
- Linking technique, backward link or pneumatic
- Cost indexes for desired time period.

The parameters which were varied in this study are marked by a (+). The capacity of the plant was set at 152×10^3 GJ/d (144×10^9 Btu/d) of low-heating-value gas, located in the western U.S., and using the backward link-forward burn technique. The results were indexed to January, 1978. The coal seam depth and thickness will, of course, be fixed at our experimental site but may influence our selection of alternate sites or depth of operation in a steeply dipping bed. The coal concentration in tons-acre ft of horizontal surface varies only with coal density for horizontal seams, but increases in inclined beds as the dip angle increases. The effect of this variable on economics may also be of interest in studying alternate sites.

A second set of variables is comprised of those which are directly subject to the control of the plant operator. These are:

- +● Well spacing (acres)
- +● Well configuration (aspect ratio, distance between production rows divided by distance between wells in row)
- +● Production rate per well (well size)
- +● Injection gas flow rate
- +● Injection gas pressure
- +● Production wellhead pressure
 - Injection water flow rate
 - Injection gas temperature (possibly)

The items marked with a (+) are those which were individually varied in this parametric study, although it is probable that injection gas flow rate and injection gas pressure are related to each other. Injection gas flow rate, production wellhead pressure, and injection water flow rate are to be varied in the experimental field program. Injection water

affects the process economics only slightly in a direct fashion unless the water is injected as steam and this is not contemplated in the experimental work. The amount of water injected may have a considerable effect on product heating value and thus indirectly affect the product cost. However, this is a relationship which is yet to be developed. The effect of gas temperature is also unknown and is presently not included in the conceptual plant.

A third set of variables which affect process economics is the process results, which are not subject to the operator's control except as they are affected by the variables in the two groups above. These dependent variables are:

- +● Product gas flow rate
- +● Product gas composition
- +● Sweep efficiency (coal utilization)
- +● Oxygen or air utilization (leakage)
- +● Gas recovery (leakage)

As stated, these variables may be subject to indirect control, but the mathematical relationships are presently unknown or in an early stage of development. All of these parameters were studied individually using the economic model, and three procedures for varying gas composition were included.

Each of the sixteen variables (three for product gas composition) noted by the (+) above was varied individually to show its effect on process economics. In addition, several parameters which would likely vary together were studied. These combinations were:

- Product gas flow rate = 1.75 times injection gas flow rate
- Injection gas pressure, kPa (psig) = 170 (25) plus production wellhead pressure, kPa (psig)

- Injection and production pressure increase with increased depth.
- Injection and production pressure as well as air and product gas leakage increase with increased depth.

The results of the twenty parametric cases are discussed in the following section.

C.3.3 RESULTS OF PARAMETRIC STUDIES

The results obtained from the parametric study are summarized in Table C-V and are shown graphically in Figures C-3 through C-22. The tabulated data show the values of the parameters in the base case and the extreme value of only those parameters which were varied in the other cases. Where no values are shown they are the same as in the base case. The economic model calculates a large amount of information, and selected values which show sales gas production and heating value, coal requirements, major items of initial plant investment, total manufacturing expense, and sales gas price are included in the table. The graphs show how sales gas price varied as the main parameter being studied varied over its selected range. A detailed analysis of the effect of each parameter is given in this section.

These parametric studies are nominally applicable to horizontal coal seams only. A brief qualitative estimate of the expected effect of the parameter in steeply dipping beds is included in the discussion, but a true evaluation cannot be made until a conceptual plant is designed, slant well costs developed, and process data obtained from the experimental program.

C.3.3.1 Effect of Coal Seam Depth

Coal seam depth only was varied over a range of 91-233 m (300-764 feet) with no other parameters changing. The results show that

TABLE C-V

PARAMETRIC COST ESTIMATE FOR COMMERCIAL UNDERGROUND COAL GASIFICATION

BASIS - Making 152×10^3 GJ/d (144×10^3 Btu/d) of Low-Heating Value Gas For Sales by Air Gasification of Subbituminous Coals in A Horizontal Bed Using Backward Linking.

CASE NUMBER (Note a)	BASE	1	2	3	4	5	6	7	8	9	10
COAL DATA											
Seam Depth, m (ft)	183 (600)	91 (300)	233 (764)								
Seam Thickness, m (ft)	9.1 (30)			1.5 (5)	10.4 (34)						
Density, t/ha-m (t/acre-ft)	13 970 (1 900)					13 970 (1 900)	27 480 (3 737)				
Heat Content, kJ/kg (Btu/lb)	18 600 (8 000)										
OPERATIONAL PARAMETERS											
Well Spacing, ha (acres)	0.31 (2)							0.28 (0.7)	1.56 (3.9)		
Aspect Ratio (Note b)	1									0.2	8.9
Production Rate/Well, m ³ /d (10 ³ scf/d)	141 580 (5)										
Air Injection Rate, m ³ /t Coal (scf/T Coal)	1 605 (51 430)										
Air Injection Pressure, kPa (psig)	790 (100)										
Production Wellhead Pressure, kPa (psig)	445 (50)										
Sales Gas Delivery Pressure, kPa (psig)	1 310 (175)										
Water/O ₂ Consumption Ratio, by Weight	1.5										
PRODUCTION PARAMETERS											
Gas Production Rate, m ³ /t Coal (scf T Coal)	2 620 (84 000)										
Gas Composition, mol %											
H ₂	18.3										
CO	10.3										
CH ₄	5.0										
C ₂ H ₆	0.5										
CO ₂	10.9										
H ₂ S	0.1										
N ₂ + Ar	48.4										
Gas Heating Value, kJ/m ³ (Btu/scf)	6 560 (176)										
Sweep Efficiency, %	100										
Air Utilization, %	100										
Gas Recovery, %	100										
ECONOMIC MODEL RESULTS											
Sales Gas, % of Total Gas Product	65.0			2.7	65.1		65.3	66.4	63.3	58.6	67.4
Sales Gas Heating Value, kJ/m ³ (Btu/scf)	6 740 (181)										
Coal Consumed (25-yr Life), 10 ⁶ t (10 ⁶ T)	112 (123)			115 (127)			111 (122)	109 (120)	114 (126)	23 (136)	108 (119)
Cost of Initial Wells, \$10 ⁶	8	5	10	10						9	
Cost of Field Piping, \$10 ⁶	21	18	24	26				13	29	52	9
Cost of Field Compressors, \$10 ⁶	68			72				60	80	110	54
Total Field Operations Investment, \$10 ⁶	152	143	159	179			150	132	178	256	116
Total Injection Air Investment, \$10 ⁶	67			76			66	66	70	75	65
LHV Gas Cleanup Investment, \$10 ⁶	37			38					38	39	
Total Plant Investment, \$10 ⁶	236	247	263	293			253	235	236	370	218
Total Manufacturing Expense, \$/GJ (\$/10 ⁶ Btu)	0.53 (0.56)	0.51 (0.54)	0.54 (0.57)	0.90 (0.95)	0.52 (0.55)		0.49 (0.52)	0.60 (0.63)	0.53 (0.56)	0.67 (0.71)	0.48 (0.51)
Sales Gas Price, Equity Financing, \$/GJ (\$/10 ⁶ Btu)	1.76 (1.86)	1.70 (1.79)	1.80 (1.90)	2.30 (2.43)	1.74 (1.84)		1.71 (1.90)	1.72 (1.82)	1.90 (2.00)	2.45 (2.59)	1.53 (1.61)

Note a: For the sake of clarity, only the values which change from the base case are shown. All other values are the same as in the base case.

b: Rate of distance between production rows to distance between production wells in a row.

TABLE C-V (Cont.)

PARAMETRIC COST ESTIMATE FOR COMMERCIAL UNDERGROUND COAL GASIFICATION

BASIS - Making 152×10^3 GJ/d (144×10^3 Btu/d) of Low-Heating Value Gas for Sales by Air Gasification of Subbituminous Coal in a Horizontal Bed Using Backward Linking.

CASE NUMBER (Note a)	BASE	11	12	13	14	15	16	17	18	19	20
COAL DATA											
Seam Depth, m (ft)	183 (600)										
Seam Thickness, m (ft)	9.1 (30)										
Density, t/ha-m (T/acre-ft)	13 970 (1 900)										
Heat Content, kJ/kg (Btu/lb)	18 600 (8 000)										
OPERATIONAL PARAMETERS											
Well Spacing, ka (acres)	0.81 (2)										
Aspect Ratio (Note b)	1										
Production Rate/Well, m ³ /d (10 ⁶ scf/c)	141 580 (5)	65 130 (2.3)	274 670 (9.7)								
Air Injection Rate, m ³ /t Coal (scf/T Coal)	1 605 (51 430)			1 055 (33 810)	1 915 (61 430)						
Air Injection Pressure, kPa (psig)	790 (100)					480 (55)	1 480 (200)				
Production Wellhead Pressure, kPa (psig)	445 (50)							240 (20)	745 (93)		
Sales Gas Delivery Pressure, kPa (psig)	1 310 (175)										
Water/O ₂ Consumption Ratio, by Weight	1.5										
PRODUCTION PARAMETERS											
Gas Production Rate, m ³ /t Coal (scf/T Coal)	2 620 (84 000)									1 875 (60 000)	3 230 (103 500)
Gas Composition mol, %											
H ₂	18.0										
CO	18.0										
CH ₄	5.0										
C ₂ H ₆	0.5										
CO ₂	10.0										
H ₂ S	0.1										
N ₂ + A ^b	48.4										
Gas Heating Value, kJ/m ³ (Btu/scf)	6 560 (176)										
Sweep Efficiency, %	100										
Air Utilization, %	100										
Gas Recovery, %	100										
ECONOMIC MODEL RESULTS											
Sales Gas, % of Total Gas Product	65.0	56.5	66.9	68.6	61.6	67.5	62.0	52.4	72.1	59.8	67.4
Sales Gas Heating Value, kJ/m ³ (Btu/scf)	6 740 (181)										
Coal Consumed (25-yr Life), 10 ⁶ t (10 ⁶ T)	112 (123)	128 (141)	108 (119)	106 (117)	118 (130)	107 (118)	117 (129)	139 (153)	101 (111)	170 (187)	87 (96)
Cost of Initial Wells, \$10 ⁶	8	19	5		9		9	10		9	
Cost of Field Piping, \$10 ⁶	21	38	12	16	25	22	20	32	16	29	17
Cost of Field Compressors, \$10 ⁶	68	127	58	64	74	66	73	162	30	76	66
Total Field Operations Investment, \$10 ⁶	152	304	118	138	166	148	158	298	92	180	141
Total Injection Air Investment, \$10 ⁶	67	78	66	45	92	52	87	84	61	104	52
LHV Gas Cleanup Investment, \$10 ⁶	37	40		36	38		38	42	35	39	
Total Plant Investment, \$10 ⁶	256	422	221	219	296	237	283	424	188	323	230
Total Manufacturing Expense, \$/GJ (¢/10 ⁶ Btu)	0.53 (0.56)	0.77 (0.81)	0.47 (0.50)	0.45 (0.47)	0.62 (0.65)	0.51 (0.54)	0.56 (0.59)	0.74 (0.78)	0.45 (0.47)	0.72 (0.76)	0.46 (0.48)
Sales Price, Equity Financing, \$/GJ (¢/10 ⁶ Btu)	1.76 (1.86)	2.80 (2.95)	1.53 (1.61)	1.50 (1.58)	2.04 (2.15)	1.65 (1.74)	1.91 (2.02)	2.78 (2.93)	1.35 (1.42)	2.27 (2.39)	1.56 (1.65)

Note a: For the sake of clarity, only the values which change from the base case are shown. All other values are the same as in the base case.

b: Ratio of distance between production rows to distance between production wells in a row.

TABLE C-V (cont.)

PARAMETRIC COST ESTIMATE FOR COMMERCIAL UNDERGROUND COAL GASIFICATION

BASIS - Making 152×10^3 GJ/d (144×10^9 Btu/d) of Low Heating Value Gas for Sales by Air Gasification of Subbituminous Coal in a Horizontal Bed Using Backward Linking.

CASE NUMBER (Note a)	BASE	21	22	23	24	25	26	27	28	29	30
COAL DATA											
Seam Depth, m	183										
(ft)	(600)										
Seam Thickness, m	9.1										
(ft)	(30)										
Density, t/ha-m	13 970										
(T/acre-ft)	(1 900)										
Heat Content, kJ/kg	13 600										
(Btu/lb)	(8 000)										
OPERATIONAL PARAMETERS											
Well Spacing, m	0.81										
(acres)	(2)										
Aspect Ratio (Note b)	1										
Production Rate/Well, m ³ /d	141 580										
(10 ⁶ scf/d)	(5)										
Air Injection Rate, m ³ /t Coal	1 605										
(scf/T Coal)	(51 430)										
Air Injection Pressure, kPa	790										
(psig)	(100)										
Production Wellhead Pressure, kPa	445										
(psig)	(50)										
Sales Gas Delivery Pressure, kPa	1 310										
(psig)	(175)										
Water/O ₂ Consumption Ratio, by Weight	1.5										
PRODUCTION PARAMETERS											
Gas Production Rate, m ³ /t Coal	2 620										
(scf/T Coal)	(84 000)										
Gas Composition, mol %											
H ₂	18.0				1.6		12.6		3.0		
CO	18.0						12.6		21.0		
CH ₄	5.0	2.1	7.0				3.5		6.0		
C ₂ H ₆	0.5						0.4		0.6		
CO ₂	10.0						10.0		10.0		
H ₂ S	0.1						0.1		0.1		
N ₂ + Ar	48.4	51.3	46.4	53.8	45.1	60.8	36.9				
Gas Heating Value, kJ/m ³	6 560	5 440	7 300	5 920	6 970	4 580	8 380				
(Btu/scf)	(176)	(146)	(196)	(159)	(187)	(123)	(225)				
Sweep Efficiency, %	100							25			
Air Utilization, %	100								97		
Gas Recovery, %	100									40	98
ECONOMIC MODEL RESULTS											
Sales Gas, % of Total Gas Product	65.0	56.1	69.1	60.2	67.3	44.1	73.5	63.5			
Sales Gas Heating Value, kJ/m ³	6 740	5 590	7 530	6 070	7 150	4 730	8 610			46.1	6.7
(Btu/scf)	(181)	(150)	(202)	(163)	(192)	(127)	(231)				
Coal Consumed (25-yr Life), 10 ⁶ t	112	155	94	133	102	235	77	14		157	
(10 ⁶ T)	(123)	(171)	(104)	(147)	(112)	(259)	(85)	(12.7)		(173)	
Cost of Initial Wells, \$10 ⁶	8	11	7	10	16	6	6			1	
Cost of Field Piping, \$10 ⁶	21	37	15	28	18	70	11	22		58	
Cost of Field Compressors, \$10 ⁶	68	106	56	86	61	187	44	71		107	69
Total Field Operations Investment, \$10 ⁶	152	234	122	190	135	404	97	167		266	154
Total Injection Air Investment, \$10 ⁶	67	94	57	81	61	146	46	74		240	69
LHV Gas Cleanup Investment, \$10 ⁶	37	48	33	43	35	64	28	38		45	
Total Plant Investment, \$10 ⁶	256	376	212	314	231	614	171	279		551	260
Total Manufacturing Expense, \$/GJ	0.53	0.75	0.45	0.64	0.47	1.16	0.36	0.86		1.21	0.53
(\$/10 ⁶ Btu)	(0.56)	(0.79)	(0.47)	(0.67)	(0.51)	(1.22)	(0.38)	(0.91)		(1.28)	(0.56)
Sales Gas Price, Equity Financing, \$/GJ	1.76	2.55	1.46	2.14	1.59	4.10	1.18	2.20		3.86	1.78
(\$/10 ⁶ Btu)	(1.86)	(2.69)	(1.54)	(2.26)	(1.68)	(4.33)	(1.25)	(2.37)		(4.07)	(1.88)

Note a: For the sake of clarity, only the values which change from the base case are shown. All other values are the same as in the base case.

b: Ratio of distance between production rows to distance between production rows in a well.

TABLE C-V (Cont.)

PARAMETRIC COST ESTIMATE FOR COMMERCIAL UNDERGROUND COAL GASIFICATION

BASIS - Making 152×10^3 GJ/d (144×10^3 Btu/d) of Low-Heating Value Gas for Sales by Air Gasification of Subbituminous Coal in a Horizontal Bed Using Backward Linking.

CASE NUMBER (Note a)	BASE	31	32	33	34	35	36	37	38	39	40
COAL DATA											
Seam Depth, m (ft)	183 (600)							76 (250)	82 (598)	76 (250)	82 (598)
Seam Thickness, m (ft)	9.1 (30)										
Density, t/ha-m (T/acre-ft)	13 970 (1 900)										
Heat Content, kJ/kg (Btu/lb)	18 600 (8 000)										
OPERATIONAL PARAMETERS											
Well Spacing, ha (acres)	0.81 (2)										
Aspect Ratio (Note b)	1										
Production Rate/Well, m ³ /d (10 ⁶ scf/d)	141 500 (5)										
Air Injection Rate, m ³ /t Coal (scf/T Coal)	1 605 (51 430)			1 070 (34 290)	1 850 (59 140)						
Air Injection Pressure, kPa (psig)	790 (100)					410 (45)	1 010 (132)	370 (39)	1 310 (175)	370 (39)	1 310 (175)
Production Wellhead Pressure, kPa (psig)	445 (50)					240 (20)	840 (10*)	200 (14)	1 135 (150)	200 (14)	1 135 (150)
Sales Gas Delivery Pressure, kPa (psig)	1 310 (175)										
Water/O ₂ Consumption Ratio, by Weight	1.5										
PRODUCTION PARAMETERS											
Gas Production Rate, m ³ /t Coal (scf/T Coal)	2 620 (84 000)			1 870 (60 000)	3 230 (103 500)						
Gas Consumption, mol % H ₂	18.0										
CO	18.0										
CH ₄	5.0										
C ₂ H ₆	0.5										
CO ₂	10.0										
H ₂ S	0.1										
N ₂ + Ar	48.4										
Gas Heating Value, kJ/m ³ (Btu/scf)	6 560 (176)										
Sweep Efficiency, %	100										
Air Utilization, %	100										
Gas Recovery, %	100	80	90							95	70
ECONOMIC MODEL RESULTS											
Sales Gas, % of Total Gas Produced	65.0	44.2	64.7	64.7	65.1	55.9	72.1	50.7	75.3	49.2	60.2
Sales Gas Heating Value, kJ/m ³ (Btu/scf)	6 740 (181)										
Coal Consumed (25-yr Life), 10 ⁶ t (10 ⁶ T)	112 (123)	400 (422)	114 (126)	157 (173)	91 (100)	130 (143)	100 (110)	140 (158)	96 (106)	155 (171)	170 (187)
Cost of Initial Wells, \$10 ⁶	8	12				10	7	6	7	6	8
Cost of Field Piping, \$10 ⁶	21	64		22		32	15	33	13	36	27
Cost of Field Compressors, \$10 ⁶	68	114	69	69		148	23	197	6	207	9
Total Field Operations Investment, \$10 ⁶	152	252	154	157	150	277	90	340	53	358	84
Total Injection Air Investment, \$10 ⁶	67	280	69	69		59	65	66	69	75	173
LHV Gas Cleanup Investment, \$10 ⁶	37	46				40	35	43	35	44	39
Total Plant Investment, \$10 ⁶	256	598	260	263	254	376	181	449	157	477	296
Total Manufacturing Expense, \$/GJ (\$/10 ⁶ Btu)	0.53 (0.56)	1.54 (1.62)	0.54 (0.57)	0.58 (0.61)	0.51 (0.54)	0.69 (0.73)	0.43 (0.45)	0.77 (0.81)	0.40 (0.42)	0.82 (0.87)	0.78 (0.82)
Sales Gas Price, Equity Financing, \$/GJ (\$/10 ⁶ Btu)	1.76 (1.86)	4.42 (4.66)	1.78 (1.88)	1.85 (1.95)	1.73 (1.83)	2.50 (2.64)	1.30 (1.37)	2.92 (3.03)	1.15 (1.21)	3.12 (3.29)	2.20 (2.32)

Note a: For the sake of clarity, only the values which change from the base case are shown. All other values are the same as in the base case.

b: Ratio of distance between production rows to distance between production wells in a row.

FIGURE C-3. EFFECT OF COAL SEAM DEPTH ON ENERGY COST

FIGURE C-4. EFFECT OF COAL SEAM THICKNESS ON ENERGY COST

FIGURE C-5. EFFECT OF COAL CONCENTRATION ON ENERGY COST

FIGURE C-6. EFFECT OF INJECTION WELL SPACING ON ENERGY COST

FIGURE C-7. EFFECT OF ASPECT RATIO (DISTANCE BETWEEN PRODUCTION ROWS ÷ DISTANCE BETWEEN WELLS IN ROW) ON ENERGY COST

FIGURE C-8. EFFECT OF PRODUCTION WELL FLOW RATE ON ENERGY COST

FIGURE C-9. EFFECT OF OXYGEN CONSUMPTION RATE ON ENERGY COST - CONSTANT GAS YIELD

FIGURE C-10. EFFECT OF AIR INJECTION PRESSURE ON ENERGY COST - CONSTANT WELLHEAD PRESSURE

PARAMETRIC COST ESTIMATE
FOR COMMERCIAL UNDERGROUND COAL GASIFICATION
144 x 10⁹ BTU/D OF LHV SALES GAS FROM HORIZONTAL BED OF SUBBITUMINOUS COAL

FIGURE C-11. EFFECT OF WELLHEAD PRESSURE ON ENERGY COST -
CONSTANT AIR INJECTION PRESSURE

PARAMETRIC COST ESTIMATE
FOR COMMERCIAL UNDERGROUND COAL GASIFICATION
144 x 10⁹ BTU/D OF LHV SALES GAS FROM HORIZONTAL BED OF SUBBITUMINOUS COAL

FIGURE C-12. EFFECT OF GAS YIELD ON ENERGY COST -
CONSTANT OXYGEN CONSUMPTION

PARAMETRIC COST ESTIMATE
FOR COMMERCIAL UNDERGROUND COAL GASIFICATION
144 x 10⁹ BTU/D OF LHV SALES GAS FROM HORIZONTAL BED OF SUBBITUMINOUS COAL

FIGURE C-13. EFFECT OF METHANE CONTENT OF GAS ON ENERGY COST

PARAMETRIC COST ESTIMATE
FOR COMMERCIAL UNDERGROUND COAL GASIFICATION
144 x 10⁹ BTU/D OF LHV SALES GAS FROM HORIZONTAL BED OF SUBBITUMINOUS COAL

FIGURE C-14. EFFECT OF HYDROGEN CONTENT OF GAS ON ENERGY COST

FIGURE C-15. EFFECT OF HEATING VALUE OF GAS ON ENERGY COST

FIGURE C-16. EFFECT OF COAL UTILIZATION ON ENERGY COST

FIGURE C-17. EFFECT OF AIR UTILIZATION ON ENERGY COST

FIGURE C-18. EFFECT OF PRODUCT GAS LEAKAGE ON ENERGY COST

FIGURE C-19. EFFECT OF GAS YIELD ON ENERGY COST -
CONSTANT RATIO (1.75) OF GAS TO AIR INJECTED

FIGURE C-20. EFFECT OF WELLHEAD PRESSURE ON ENERGY COST -
CONSTANT PRESSURE DROP IN GASIFIER (25 PSI)

FIGURE C-21. EFFECT OF COAL SEAM DEPTH ON ENERGY COST -
INLET AND OUTLET PRESSURE INCREASED WITH DEPTH

FIGURE C-22. EFFECT OF SEAM DEPTH ON ENERGY COST - PRESSURES
AND LEAKAGE (AIR AND GAS) INCREASING WITH DEPTH

the cost of wells varied directly with depth and that the cost of field piping also increased. This resulted in an increase in total plant investment and manufacturing cost; but since wells and field piping are only a relatively small fraction (9-13%) of the total plant investment, the increase in gas price with well depth was only about 6%. This is also evident from the flatness of the curve in Figure C-3.

In a steeply dipping bed operation, the cost of wells would be more of a factor, but even a doubling of well costs would not be expected to cause coal seam depth to be as important as several other parameters. On the other hand, well depth may be linked to other parameters such as pressure and gas leakage as will be discussed further on.

C.3.3.2 Effect of Coal Seam Thickness

The effect of coal seam thickness was studied over the range of 1.4-10.4 m (5-34 ft). The total plant investment was about 14% higher for the thinner seam, but the manufacturing expense was about 73% higher because the thinner seam provides less coal to each well and consequently more wells, field piping, etc., are required during the life of the plant. These expenses, after the initial plant is completed, are treated as manufacturing expenses in the economic model. The final sales gas price was about 32% higher in the thinner seam. Figure C-4 shows that effect of seam thickness is increasingly greater as the seam becomes thinner and that there is little effect above about 9 m (30 ft).

It seems reasonable to expect that the effect of coal seam thickness would be directionally similar in horizontal and steeply dipping beds. However, if the drilling becomes more difficult to control in thin SDB seams, the magnitude of the effect would be greater because of this. In addition, because slant wells are more expensive, the effect on manufacturing expense caused by more wells in thin seams would be even greater in SDB than in horizontal seams.

C.3.3.3 Effect of Coal Concentration on Energy Cost

This parameter was included to illustrate the effect of one aspect of steeply dipping beds, i.e., as the dip angle increases the tonnage of coal beneath each acre of horizontal surface also increases. Of course, this is only an imaginary effect with a horizontal bed, but its theoretical effect can be determined. As may be seen from Cases 5 and 6 in Table C-V and in Figure C-5, the effect of coal concentration is very small. There is almost no effect on plant investment and a relatively small decrease (about 7%) in manufacturing expense due to fewer wells each year as coal concentration increases. The sales gas price is about 3% less at the higher coal concentration.

Because of the theoretical aspect of this calculation, it may very well be that it does not really show the effect for steeply dipping beds. It is anticipated that there will be a similar but greater effect in the SDB case, and there may also be an interacting effect with seam thickness.

C.3.3.4 Effect of Injection Well Spacing

The effect of well spacing expressed as the number of acres for each well is the first of the parameters studied which can be controlled, although there will be physical characteristics, especially linking distances, which set actual limits. Well spacing was varied from 0.28-1.58 ha (0.7-3.9 acres), and as a result the field piping and air compressor investments increased with the total investment increasing about 22%. On the other hand, with increased well spacing each well has a longer life and fewer new wells are required each year so that total manufacturing expense decreased about 11%. The overall effect was an increase in gas price of about 10% when going from dense to sparse well spacing. As shown in Figure C-6, there is apparently a minimum gas price for this set of parameters at a spacing of one well per acre.

It is difficult to predict the effect of well spacing on costs in the steeply dipping bed case.

C.3.3.5 Effect of Aspect Ratio

Aspect ratio is defined as the ratio of the distance between production rows to the distance between wells in a row. In a steeply dipping bed with one long production row, the aspect ratio can be considered as either zero or infinity depending on how one looks at it. With the present economic model, the effect of varying the aspect ratio from 0.2 to 8.9 is quite marked. However, the program still sets up multiple rows of wells and thus does not approach the steeply dipping bed configuration of a single row. It is interesting to note in Figure C-7 that the gas price decreases rapidly as the aspect ratio increases from 0.2 to 1.0 and much more slowly beyond that point. As shown in Table C-V for Cases 9 and 10, the cost of field piping and air compressors is much higher at the lower aspect ratio and is due to the fact that the manifolds carrying air to the injection wells are about seven times as long.

Although aspect ratio has no meaning as a parameter in the steeply dipping bed case, the results of varying this parameter in a horizontal bed show that it will be very important to provide a conceptual design for SDB which will avoid long lengths of pipe carrying large volumes of air.

C.3.3.6 Effect of Production Well Flow Rate

The rate of flow from each production well has a marked effect on sales gas price as may be seen in Table C-V, Cases 11 and 12, and in Figure C-8. The main reason for this is that for a fixed size plant, the number of wells will be inversely proportional to the flow rate in each well. The cost of each well does not increase in the same proportion. The amount of field piping and compressor requirements is also reduced

with fewer and larger wells. With the smaller wells there is more power required and, since the conceptual plant produces its own fuel requirements, the total gas production and coal consumption is larger with the lower production gas flow. The net effect of a four-fold increase in production well flow is a reduction of 45% in sales gas price.

In the steeply dipping bed, one would expect a similar effect to take place.

C.3.3.7 Effect of Air Injection Rate

The air injection rate is the first parameter on the list which could be varied in a given plant after the plant was installed and in operation. The economic model does not show this simple effect because the model assumes that when the air injection is changed in a case, then the plant is sized and operated for 25 years at this rate. Furthermore, in this particular instance shown in Figure C-9 and in Table C-V, Cases 13 and 14, no dependent effects such as changes in pressure, gas production rate, or gas quality are taken into account. The changes which are noted with increased air rate from 1055 m³/t coal (33 810 scf/T) to 1915 m³/t coal (61 430 scf/T) are increases in field piping, field compressors, and air compressors which lead to a 35% increase in plant investment. The increase in compressor costs leads to higher total gas production and higher coal consumption and also to higher yearly manufacturing expense. The net effect is a 36% increase in sales gas price for this 82% increase in air injection rate. With the same limitations of changing this single parameter the effect in steeply dipping beds would be similar.

C.3.3.8 Effect of Air Injection Pressure

The effect of increasing the inlet air pressure from 480 kPa (55 psig) to 1480 kPa (200 psig) with all other variables constant as Cases 15 and 16 in Table C-V and in Figure C-10. The increase of 264% in injection pressure results in an increase of 16% in the price of the

sales gas. The increased pressure requires increases in air compressor costs and fuel for operations so that total gas production must also increase. The increased air compressor cost is the main reason for the increase in total plant investment; the increased fuel costs account for most of the increased manufacturing cost. The effect of increased injection pressure by itself would be expected to be the same in steeply dipping bed operations.

C.3.3.9 Effect of Production Wellhead Pressure

The base case in the parametric study used an air injection pressure of 790 kPa (100 psig) and it is conceivable that with a low pressure drop through the wells and the reaction zone it would be possible to vary the production wellhead pressure. In this parametric study the wellhead pressure was varied between 240 kPa (20 psig) and 745 kPa (93 psig) with all else remaining constant. As shown in Figure C-11' and Cases 17 and 18 of Table C-V, the change in wellhead pressure had a great effect on the sales gas price. The main reason for this effect is that the sales gas is delivered at 1310 kPa (175 psig) and the cost of field compressors is \$162 million at 240 kPa (20 psig) well head pressure versus only \$30 million at 745 kPa (93 psig). The fuel required for field compression is almost six times as great at the lower wellhead pressure so that the total gas production and concomitant coal consumption is about 38% greater in that case.

As a result of reduced compressor costs and fuel consumption, the higher wellhead pressure sales gas price was only about 48% of that at the lower pressure. A similar effect would probably be obtained in steeply dipping beds. However, as will be shown later, the increased wellhead pressure may itself cause other changes such as increased leakage which would tend to increase the final sales price for a fixed plant output. Inasmuch as leakage may be more pronounced in a steeply dipping bed than in horizontal beds, any advantage accruing from decreased compressor costs will be offset, perhaps completely.

C.3.3.10 Effect of Gas Yield

Cases 19 and 20 in Table C-V and Figure C-12 show the effect of product gas yield per ton of coal consumed if all other variables remain constant. As might be expected, the increase in gas yield results in lower investments and lower sales gas price. At the low gas yield it is necessary to provide more wells, more field piping, and more compressors so that the total plant investment is about 29% greater than at the high gas yield. By the same token, more wells are required each year and almost twice as much coal is consumed at the low gas yield so that total manufacturing expense is about 58% higher than at the high gas yield. The same result would probably be obtained in the steeply dipping bed case.

It does not seem likely that gas yield would increase without some changes in other variables. To date, however, the variables which change gas yield are not identified except that increased injection flow usually results in increased product gas flow. This relationship will be discussed further on.

C.3.3.11 Effect of Gas Composition

One of the most important aspects of underground coal gasification is the quality of the gas produced. This quality is generally synonymous with the gas heating value, which is affected by gas composition. Gas heating value can vary with changes in the ratios of various heat-producing gases or in the percentage of non-heat-producing gases which the product gas contains. Without any real knowledge of how such changes would be accomplished, the economic model was used to determine the effect of changing the product gas methane content, the product gas hydrogen content, and the product gas total heat-producing gas content, with all of the other parameters held constant.

C.3.3.11.1 Effect of Product Gas Methane Content

Figure C-13 and Cases 21 and 22 in Table C-V show the effect of varying the methane content of the product gas from 2.1 to 7.0 mol%. All of the other components of the gas except nitrogen were held constant. From Table C-V, it may be seen that increasing the methane content of the gas resulted in a higher gas heating value (by about 34%), which in turn increased the sales gas as a percent of total gas product, reduced the total coal requirement, and reduced the total plant investment by about 44%. The total manufacturing cost was reduced by 40% and the sales gas price was reduced by about 43%.

A similar change in gas composition in a steeply dipping bed configuration would have similar effects.

C.3.3.11.2 Effect of Product Gas Hydrogen Content

The effect of varying hydrogen in the product gas from 12.6 to 21.3 mol% while holding the remaining gases (except nitrogen) constant is shown in Figure C-14 and Cases 23 and 24 of Table C-V. Again, the increase in hydrogen increased the heating value of the product gas (about 18%) but to a lesser extent than for the same change in methane content because of the lower heating value of hydrogen. All of the other effects were in the same direction but of lesser magnitude as when methane was increased. The total plant investment was lowered by 26%, the total manufacturing expense was lowered by 24%, and the sales gas price was lowered by 26% with the increase in hydrogen content. Results in a steeply dipping bed operation would be expected to be similar.

C.3.3.11.3 Effect of Total Gas Composition

The effects of increasing all of the gas heating-producing components to produce a gas ranging in heating value from 4590 kJ/m³ (123 Btu/scf) to 8380 kJ/m³ (225 Btu/scf) are shown in Figure C-15 and

Cases 25 and 26 of Table C-V. The increase in heating value in this case was about 83%. Since the heating value of the gas is used by the economic model in calculating the required size of a plant for a given output and the costs are calculated for that size plant, the effects of increasing the heating value of the gas by 83% were directionally the same as in the methane and hydrogen cases but were much greater. In this case, the total plant investment was reduced by 72%, the total manufacturing cost was reduced by 69%, and the sales gas price was reduced by 71%. Again, similar effects would be expected in a steeply dipping bed configuration.

C.3.3.12 Effect of Efficiency of Coal Utilization

The efficiency with which the coal resource is converted to salable gas in underground coal gasification will also have an effect on the gas price. This effect is shown in Figure C-16 and in Cases 27 and 28 of Table C-V. Case 28 is about the same as the base case in sweep efficiency (97% instead of 100%) and this change did not affect investments or costs. When sweep efficiency dropped to 25%, the total plant investment did not change markedly, only from \$256 million to \$279 million or an increase of 9%; but with the low resource recovery, it is necessary to drill new wells with much greater frequency and the manufacturing expense was increased by 62%. The net result of the low sweep efficiency was to increase sales gas price by 25%.

Inasmuch as the cost of well drilling will be higher in the steeply dipping bed operations it may be that low sweep efficiency will have a greater effect than in horizontal beds. On the other hand, the cost of coal is included in the manufacturing expense and is based not only on the coal reacted but also on that left behind. Since coal in steeply dipping beds may be less expensive than that in horizontal seams the increased cost of drilling in steeply dipping beds may be offset to at least some extent.

C.3.3.13 Effect of Air Utilization (Leakage)

Figure C-17 and Cases 29 and 30 in Table C-V show the great effect which air leakage has on the economics of the underground coal gasification process. Air leakage results in a chain of events which cause this ultimate effect. When air leaks, it is necessary to provide a greater flow from the compressor, this in turn requires more compressors for a given sales gas production, and more compressors require more product gas for their motive power. As may be seen, this is a snowballing effect and is reflected in the curve of Figure C-17 which becomes increasingly steep as air utilization declines, i.e., as leakage increases. All of the plant equipment must be increased as air leakage increases, total wells, field piping, field compressors, air compressors, etc. As a result, when air utilization dropped from 98% to 40%, the total plant investment increased from \$260 million to \$551 million, or about 112%. Manufacturing costs increased by 128%, and total sales gas price increased by 117%.

The effect of air leakage on plant economics would be similar in a steeply dipping bed. However, the problem of air leakage might be more difficult to contend with because the inclined strata may be more prone to leak.

C.3.3.14 Effect of Product Gas Leakage

The effect of product gas leakage on underground coal gasification economics is shown in Cases 31 and 32 of Table C-V and in Figure C-18. For an equal percent leakage, the effect of losing product gas is even greater than for losing injected air. The loss of gas means that more gas must be produced to meet sales requirements, more must be made for fuel requirements, etc., in the same snowballing fashion as for air

leakage. As a result, as gas recovery dropped from 98% to 40%, total plant investment increased by 130%, manufacturing costs increased by 184%, and sales gas price increased by 148%.

As with injection air leakage, gas losses in steeply dipping beds would have a similar effect to those in horizontal beds; but the problem of controlling leakage might be more difficult in steeply dipping beds.

C.3.3.15 Effect of Gas Yield with Constant Gas/Injection Air Ratio

As discussed earlier, increasing gas yield with all else constant resulted in a lower sales gas price, and increasing air injection rate with all else constant resulted in a higher sales gas price. A more likely situation would be that the gas yield would increase as the air injection rate increased and the model was used to calculate the economic results for such a case when the gas yield was 1.75 times the air injection rate. The results are summarized in Cases 33 and 34 of Table C-V and shown in Figure C-19.

When the gas and air were varied individually, there appeared to be a greater effect for increased gas yield than for increased air rate. When the two were varied together, the increased gas yield had the stronger effect and there was a small decrease in gas price. The total plant investment decreased by about 3%, manufacturing expense decreased by about 11%, and sales gas price decreased about 6%.

The effect of increased air injection and gas yield together would be similar in a steeply dipping bed situation.

C.3.3.16 Effect of Inlet and Outlet Pressure Varied Together

Figure C-10 shows the effect of increasing inlet pressure alone on UCG economics and Figure C-11 shows the effect of increasing outlet pressure. It seems reasonable that the system pressure drop would remain constant and that the inlet and outlet pressures would vary together, i.e., as pressure was regulated at the outlet wellhead any change would be reflected at the inlet. Cases 35 and 36 show the effect on costs for such a situation in which a constant pressure drop of 170 kPa (25 psi) was taken across the system. The effect on gas sales price is shown in Figure C-20.

Where the pressures were varied individually, increasing inlet pressure resulted in a modest increase in sales gas price and increasing outlet pressure resulted in marked decrease in price. As might be expected, then, the increase in both pressures together resulted in a decrease in sales gas price of somewhat lesser magnitude than when outlet pressure increased alone.

The cause of the lower price is to be found as before in the reduced needs for field gas compressors and the fuel with which to run them. Thus, the entire plant is reduced in size, well costs are lower, and total cost consumption is reduced. The effects would be similar in a steeply dipping bed operation.

C.3.3.17 Effect of Depth on Pressure and Costs

Figure C-3 shows that coal seam depth alone has a rather insignificant effect on the cost of low heating value gas. However, it seems reasonable to expect that most underground coal gasification will be carried out below the water table and that there will be a hydrostatic pressure head which will increase with depth. The relationship between depth and pressure was developed by assuming that the water table was

46 m (150 feet) below the surface, that the hydrostatic pressure would be 9.9 kPa (1.43 psi) for each 1.0 m (3.3 feet) of water depth, and that the pressure in the gasification zone would be 0.9 times hydrostatic. The inlet pressure was then calculated by the equation

$$\text{Inlet pressure, kPa} = (8.9) (\text{total well depth, m} - 46)$$

The outlet wellhead pressure was assumed to be 170 kPa (25 psi) less than the inlet.

The results of the study in which depth and pressure were varied together in this manner are contained in Cases 37 and 38 of Table C-V and in Figure C-21. The dominant variable in this relationship is the outlet pressure. Except for the well costs, which are lower at the shallower depths, the investments are relatively in the same order as those in Cases 17 and 18 (changing wellhead pressure only) and in Cases 35 and 36 (changing inlet and outlet pressures together). Well costs are a minor factor in this example which is for a horizontal coal seam and may be more of a factor for a steeply dipping bed; however, because of the strong effect of outlet pressure it is probable that the combined effect of well depth and pressure in the SDB case will be very similar.

C.3.3.18 Effect of Depth, Pressure, and Gas Leakage

The preceding case varied depth and pressure together. An additional factor which quite likely would vary with pressure is gas leakage, both of the injection air and the product gas. To make a study of this the same relationship of depth and pressure was assumed as above and gas leakage was assumed to vary linearly from 5% at the shallow depth (low pressures) to 30% at the maximum depth (high pressures). The results of this economic calculation are shown as Cases 39 and 40 in Table C-V and in Figure C-22.

It is difficult to discuss the results as they are found in Table C-V because the two cases are at the extremes of the range studied, but it is clear from Figure C-22 that the effect of outlet pressure is dominant at the shallower depths where leakage is small, whereas as leakage increases, its effect overcomes that of increased pressure and costs once again begin to rise. For the situation assumed here, there is an optimum well depth in the range of 122 m (400 feet), but in a real case or some other hypothetical case the optimum may be different, if indeed it exists at all. If leakage is very small the highest pressure consistent with other considerations becomes the most economical.

C.4.0 CONCLUSIONS

A mathematical model of a conceptualized commercial plant for underground coal gasification provides a means for rapidly determining the effects of many resource-related, operational, and process-result parameters on process economics. The effects are inter-related to a considerable extent and therefore, wherever possible, actual data for a specific case should be used.

The present model is only applicable to horizontal coal seams. Inasmuch as steeply dipping beds will greatly affect drilling and field piping costs, it will be necessary to revise the model in these areas to produce a model for the SDB case. When this is undertaken, all costs should be updated and close attention paid to well-layout and field piping to be sure these costs are optimized.

The parameters having the greatest effect on economics are product gas heating value and pressure. The first because it controls the size of the plant for a given energy output, and the second because it affects compressor requirements and leakage of inlet air and product gas. A sales gas pressure of 1310 kPa (175 psig) was arbitrarily chosen as that required to move the product through a pipeline and have a

suitable pressure at its point of consumption (presumably a power plant when making LHV gas). It would be desirable to keep this pressure as low as possible.

Because the computer model is fast and easy to use, it should be used freely to guide experimental work. The availability of a model specifically oriented to steeply dipping beds would be particularly desirable for the present SDB study.

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