I. HYDRATES GAS ECONOMICS MODEL

(HGEM)

MODEL DESCRIPTION

**Evaluation of the Gas Production Economics
of the Gas Hydrate Cyclic Thermal Injection Model**

Topical Report

**V.A. Kuuskraa
E. Hammersheimb
W. Sawyer**

May 1985

Work Performed Under Contract No.: DE-AC21-82MC19239

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Lewin and Associates, Inc.
Washington, D.C.

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BACKGROUND

Methane hydrates are a potentially large, but uncertain, future source of natural gas:

- The resource in-place is estimated at 2,700 Tcf;
- Efficient extraction of this potential gas source requires:
 - understanding of the complex mechanisms that govern the release and production of this gas;
 - development and use of advanced extraction technology; and
 - efficient field development practices;
- However, there are considerable uncertainties as to the economics of producing methane hydrates, particularly on the technical viability and economic efficiency of using advanced extraction technologies.

NEED FOR A HYDRATE
GAS ECONOMICS MODEL

To provide an improved analytical base for methane hydrates, there is a pressing need for a methane hydrates gas economics model that:

- Is geologically reflective of the complex geophysical and geochemical characteristics of the methane hydrates;
- Can directly simulate alternative and novel extraction technologies;
- Is based on engineering calculations of heat and mass balances and ultimately simulation of fluid flow through a porous medium;
- Contains up-to-date engineering-based field development and stimulation costs; and
- Provides a capacity to measure the economic competitiveness of alternative extraction technologies.

The proposed GEM model for methane hydrates has been built with these features in mind.

PURPOSE OF THE
GEM MODEL

The Gas Economics Model (GEM) for methane hydrates has been developed to provide an improved analytical framework for:

- Measuring the benefits of extraction R&D for methane hydrates-based natural gas;
- Integrating the research information gathered by the methane hydrates R&D sub-program; and
- Providing updated estimates of the future gas potential from methane hydrates.

In addition, the GEM Model enables the user to examine single-well or multi-area gas recovery, costs and economics. Also, it provides the user a standard set of input values specific to a given area or allows the user to input his or her own values.

**SAMPLE USES FOR
THE GEM MODEL**

The GEM Model can be used to analyze numerous research and policy issues for methane hydrates, such as:

1. Setting R&D Performance Goals. What level of heat injection and hydrate dissociation is required to reach commercial levels of gas production?
2. Matching Appropriate Technology to Resources. What types of geological settings would be most preferable for hydrate production using:
 - Dissociation by pressure reduction;
 - Intermittent steam injection by steam soak;
 - Continuous steam injection by steam drive; and
 - In-situ combustion?
3. Estimating the Value of Improved Geological Information. What is the impact of gathering more precise geological data on selected reservoir properties or additional data from certain geographical areas?
4. Estimating Future Gas Supplies as a Function of Price. How large is the gas potential from methane hydrates at:
 - Potential near-term gas prices of about \$4.00/Mcf;
 - Potential future gas prices of \$8.00/Mcf?

**STRUCTURE OF THE
GEM MODEL**

The GEM Model for methane hydrates consists of five integrated sub-models:

The output of the model provides measures of resource in-place, producible gas, costs, and economic viability under alternative technology or financial conditions.

**AVAILABLE GEM
MODEL OPTIONS**

The model provides a series of input and output options to the user:

<u>MODEL COMPONENT</u>	<u>USER INPUT OPTIONS</u>	<u>USER OUTPUT OPTIONS</u>
1. Geologic Sub-Model	<ul style="list-style-type: none">● Geographic Area<ul style="list-style-type: none">- Onshore- Offshore	<ul style="list-style-type: none">● Level of Analysis<ul style="list-style-type: none">- Individual Well- Multi-Well Project
2. Technology Sub-Model	<ul style="list-style-type: none">● Alternate Extraction Technology<ul style="list-style-type: none">- Depressurization- Steam SoakSteam Drive- Combustion	
3. Gas Production Sub-Model	<ul style="list-style-type: none">● Variable Spacing<ul style="list-style-type: none">- 5 to 40 Acres	<ul style="list-style-type: none">● Years of Production
4. Engineering Costing Sub-Model	<ul style="list-style-type: none">● Standard Costs by Depth/Area● User Selected Input Values	<ul style="list-style-type: none">● Investment Requirements<ul style="list-style-type: none">- Total- Per Mcf● Operating Costs<ul style="list-style-type: none">- Annual- Per Mcf
5. Economics Sub-Model	<ul style="list-style-type: none">● Standard Financial Values for Area● User Selected Input Values	<ul style="list-style-type: none">● Minimum Required Gas Price● Financial Return for Given Gas Price<ul style="list-style-type: none">- ROR- Net Present Value

Each of these five sub-models is further discussed in the following pages.

GEOLOGICAL
SUB-MODEL

The geological sub-model will be derived from METC supported work by USGS and other contractors. For purposes of the current analysis, the following reservoir properties are assumed for onshore Alaska and offshore deep water settings:

<u>Reservoir Properties</u>	<u>Onshore Alaska</u>	<u>Offshore Deep Water</u>
1. Depth, ft.		
● Drilled	2,000	2,000
● Water	-	2,000
2. Pressure, psia	1,400	1,400
3. Temperature, deg F	46	46
4. Net Pay, ft.	100	100
5. Porosity, %	30	30
6. Hydrate Saturation, %	100	100

In addition, a series of additional values on rock properties and other items are required to operate the hydrate model, as shown in Exhibit 1.

EXHIBIT 1

RESERVOIR AND PROCESS PARAMETERS
REQUIRED FOR METHANE HYDRATES
GEOLOGIC MODEL

ROCK PROPERTIES

- Specific heat of reservoir rock 0.2 BTU/lb. deg F

- Densities of rock
 - reservoir 167 lb./cu.ft.
 - overburden (shale) 167 lb./cu.ft.
 - underburden (shale) 167 lb./cu.ft.

- Heat capacity of reservoir rock 35 BTU/cu.ft. deg F

- Thermal conductivities of rock
 - reservoir 1.0 BTU/hr-ft. deg F
 - overburden (shale) 1.0 BTU/hr-ft. deg F
 - underburden (shale) 1.0 BTU/hr-ft. deg F

The table below shows the amount of hydrate in-place as a function of the hydrate net thickness and the areal extent of hydrate dissociation. As the table shows, to achieve a production rate of 500 Mcf per day, a resource in excess of 2,000 MMcf would need to be in-place. This requires hydrates of at least 50 feet in thickness and an area of dissociation, over 10 years, of more than 10 acres, or any combination in excess of 2,000 acre-feet.

METHANE HYDRATE
GAS IN-PLACE*
(MMcf)

Net Pay. Ft.	Areal Extent				
	(Acres)				
	1	5	10	20	40
1	2.12	10.6	21.2	42.4	84.8
10	21.2	106	212	424	848
50	106	530	1,060	2,120	4,240
100	212	1,060	2,120	4,240	8,480
200	424	2,120	4,240	8,480	16,960

*Assuming 30 porosity, 90% saturated hydrate.

TECHNOLOGY
SUB-MODEL

The technology sub-model will establish which of the alternative extraction processes are to be used for hydrate dissociation and production. The alternatives are:

- Steam soak,
- Depressurization,
- Steam drive, and
- Combustion.

At the present time, only the steam soak option is available for use.

**GAS PRODUCTION
SUB-MODEL**

The gas production sub-model will calculate the gas recovery rates based on the input values from the geological setting and the technology selected for hydrate dissociation and production.

Input values required for operating the model in the steam soak mode include:

- Initial void volume,
- Maximum steam injection rate,
- Maximum gas/water production rate,
- Maximum allowed reservoir pressure,
- Ending steam temperature profile, and
- Steam quality, temperature, and pressure.

**ENGINEERING-BASED
COSTING SUB-MODEL**

The engineering-based costing model will develop site specific costs based on location, well depth, gas production rate, and steam injection rate.

The tables below show the basic cost equations and values to be used for the onshore and the offshore versions of the Hydrate GEM Model.

The engineering-based categories, the proposed cost equations, and a sample cost calculations for a 2,000-foot well on 10 acre spacing producing 500 Mcf/d of methane and injecting 200 B/D of steam are shown in Exhibit 2 for onshore Alaska.

The engineering-based categories, proposed cost equations, and a sample costs calculations for a 32 slot platform, in 2,000 feet of water, with 2,000' per well below the mudline, producing 1,000 Mcf/D per well and injecting 400 B/D per well of steam are shown in Exhibit 3 for offshore Blake Bahamas.

More detailed descriptions of the onshore and offshore engineering-based costing submodels are given in Attachments A and B.

EXHIBIT 2

**ENGINEERING COSTING FOR
ALASKA ONSHORE
HYDRATE GEM**

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for Sample</u> <u>2,000 Foot Well</u> (1984\$)
1. Pre-Development Costs	-	-
2. Development Costs for Wells		
● Drilling and Completion	$2 * [82,000(\exp 0.26 * \text{Depth} * 10^{-3})]$	\$275,900
● Insulated Tubing	\$27 (Depth)	54,000
● Well Production Equipment	$2 * [\$65,000 + \$30(\text{Mcf/d}) + \$5(\text{Depth})]$	180,000
● Gathering System	$2 * [\$5,000 + \$10(\text{Mcf/d}) + \$1(\text{Depth})]$	24,000
● Lease Equipment	$2 * [\$10,000 + \$40(\text{Mcf/d})]$	60,000
● Dehydrator	$2 * [\$15,000]$	30,000
● Allocated Dry Holes	-	-
● Special Lease Costs	-	-
3. Process Specific Costs		
● Steam Generator	$2 * [\$650,000 \times \frac{\text{BBL/D Steam Injected}}{3,500 \times 0.90}]$	82,500
● Steam Manifold & Lines	$2 * [\$8,750/\text{Acre}] * (\text{Acres})$	175,000
● Heater Treater and Vapor Recovery	$2 * [\$5,500/\text{Acre}] * (\text{Acres})$	110,000
● Produced Water Recycle Plant	$2 * [\$75 \text{ BBL/D Steam Injected}]$	30,000

EXHIBIT 2

**ENGINEERING COSTING FOR
ALASKA ONSHORE
HYDRATE GEM
(continued)**

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for Sample</u> <u>2,000 Foot Well</u> (1984\$)
4. Well Operating and Maintenance Costs	$2*[10,000+4(\text{Mcf/d})+4(\text{Depth})]$	\$ 40,000
5. Process-Specific Operating Costs		
● Generator O&M (Gas Fired)	$2*[\$0.10*\text{BBL Steam Injected}]*(\text{365}*\text{BBL/D})$	14,600
● Water Recycle Plant	$2*[\$0.125*\text{BBL Steam Injected}]*(\text{365}*\text{BBL/D})$	18,250
● Water Disposal*	-	-
6. Fuel Costs		
● Lease Fuel	(Assumes produced natural gas is used as fuel)	

* Produced water is recycled and reinjected as steam.

EXHIBIT 3
ENGINEERING COSTING FOR
OFFSHORE BLAKE BAHAMAS
HYDRATE GEM

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	Costs for a Sample 2,000 Foot Well in 2,000 Feet of Water (1,000 1984\$)
1. Pre-Development Costs	-	-
2. Platform Costs		
● Tension Leg Platform	$\$64,000 + \$10(\text{Water Depth}) + \$62(\text{Slots})$ $(\$0.65 * \text{Water Depth} * \text{Slots})$	\$127,580
3. Development Costs for Wells		
● Well Drilling and Completion	$(\$460,000 + 130(\text{Well Depth} - 2,000)) * \text{Slots}$	23,040
● Insulated Tubing	$\$27 (\text{Total Depth})(\text{Slots})$	3,460
● Well Production Equipment	$(\text{Slots}) * 1.5 * [\$65,000 + \$30(\text{Mcf/d/Well}) + \$5(\text{Total Depth})]$	5,520
● Gathering System	$(\text{Slots}) * 1.5 * [\$5,000 + \$10(\text{Mcf/d/Well}) + \$1(\text{Total Depth})]$	910
● Lease Equipment	$(\text{Slots}) * 1.5 * [\$10,000 + \$40(\text{Mcf/d/Well})]$	2,400
● Dehydrator	$(\text{Slots}) * 1.5 * [\$15,000]$	720
● Allocated Dry Holes	-	-
● Special Lease Costs	-	-

EXHIBIT 3
ENGINEERING COSTING FOR
OFFSHORE ELAKE BAHAMAS
HYDRATE GEM
(continued)

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	Costs for a Sample 2,000 Foot Well in <u>2,000 Feet of Water</u> (1,000 1984\$)
3. Process Specific Costs		
● Steam Generator	$1.5 * [\$650,000 \times \frac{\text{BBL/D Steam Injected}}{3,500 \times 0.90}] (\text{Slots})$	\$3,900
● Steam Manifold & Lines	$1.5 * [\$85,000/\text{Slot}] * (\text{Slots})$	4,080
● Heater Treater and Vapor Recovery	$1.5 * [\$55,000/\text{Slot}] * (\text{Slots})$	2,640
● Produced Water Recycle Plant	$1.5 * [\$75 \text{ BBL/D Steam Injected}] * (\text{Slots})$	1,440
4. Well Operating and Maintenance Costs		
	$1,700,000 + 500(\text{Water Depth, Ft}) + 5(\text{Well Depth})(\text{Slots}) + 5(\text{Mcf/D Platform})$	3,500
5. Process-Specific Operating Costs		
● Generator O&M (Gas Fired)	$(\text{Slots}) * 1.1 * [\$0.10 * \text{BBL Steam Injected}] * (365 * \text{BBL/D})$	700
● Water Recycle Plant	$(\text{Slots}) * 1.5 * [\$0.125 * \text{BBL Steam Injected}] * (365 * \text{BBL/D})$	440
● Water Disposal*	-	-
6. Fuel Costs		
● Lease Fuel	(Assumes produced natural gas is used as fuel)	

* Produced water is recycled and reinjected as steam.

**ECONOMICS
SUB-MODEL**

A. Basic Features

The Economics Sub-model of GEM captures the engineering costs and links these to:

- Gas prices
- Other financially based costs, such as:
 - royalties
 - production and severance taxes
- Corporate taxes and tax credits
- Depreciation
- Timing of investment

B. Nature of the Output

The model develops year-by-year cash flows and links these with a discounting algorithm to provide:

1. Net present value of the investment, at a given discount rate.
2. The minimum required gas price, at a given discount or hurdle rate of return.

In addition, the model provides various cost and financial performance measures, such as:

1. Discounted Cash Flow to Investment Ratio
2. Payback of Investment
3. Investment Costs per Mcf gas recovered
4. Operating Costs per Mcf gas recovered

ECONOMICS
SUB-MODEL (Continued)

C. Financial Parameters

The key financial parameters and accounting conventions used by the GEM Model are provided in Exhibit 4.

EXHIBIT 4

FINANCIAL VARIABLES AND ACCOUNTING CONVENTIONS

In addition to calculating the engineering-based operating and investment costs, the GEM model uses a series of additional parameters to establish the economic feasibility of a project, as discussed below:

I. FINANCIAL PARAMETERS

The key financial parameters used by the model are, as follows:

A. Overhead Charges

Operating Overhead Rate	0.20
Investment GVA Rate	0.10

B. Tax Rate

Federal Tax Rate	0.46
State Tax Rate	0.08 for Alaska 0 for Offshore OCS

Investment Tax Credit Rate (on Tangible Investment)	0.10
--	------

Severance and Other Production Tax Rate	0.08 for Alaska 0 for Offshore OCS
--	---------------------------------------

C. <u>Royalty Rate</u>	0.125 for Alaska 0.167 for Offshore OCS
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D. <u>Discount Rate</u>	User Set (Default 10%)
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II. ACCOUNTING CONVENTIONS

Geological/geographical exploration and leasehold acquisition costs are capitalized and cost depleted. Intangible costs are expensed in the year incurred. Tangible costs are capitalized and depreciated using straight line depreciation.

GEM MODEL
USER OUTPUT

The GEM Model will provide the user a series of output options, as follows:

- Single line printout of gas recovery and minimum required economic price;
- Detailed investment and operating cost calculations;
- Year-by-year schedule of gas production, investment costs, and operating costs; and
- Full pro-forma cash flow projections, year by year and in summary.

-
-
-

ATTACHEMENTS

ATTACHMENT A
ENGINEERING COST MODEL
ALASKA ONSHORE

GAS HYDRATES FIELD DEVELOPMENT AND PRODUCTION COSTS
ALASKA ONSHORE

INTRODUCTION

THIS WORKING PAPER SETS FORTH THE CAPITAL AND OPERATING COSTS FOR DEVELOPING AND PRODUCING GAS HYDRATES FROM THE ONSHORE AREAS OF THE NORTH SLOPE OF ALASKA. IT CONTAINS: (1) INDIVIDUAL COST EQUATIONS FOR THE KEY COST ITEMS, IN 1984 DOLLARS; (2) ADJUSTMENTS TO THESE COST EQUATIONS TO ACCOUNT FOR TRANSPORTATION OF MATERIALS TO ALASKA AND FOR WORKING IN THE ARCTIC SETTING; (3) A SAMPLE CALCULATION FOR A SINGLE 2,000-FOOT WELL, PRODUCING 500 MCF/D AS WELL AS A FULL SCALE 64 WELL FACILITY PRODUCING 32 MMCF/D; AND, (4) THE SOURCES USED FOR THE INDIVIDUAL COST EQUATIONS.

THE MATERIAL IN THE WORKING PAPER IS ORGANIZED AS FOLLOWS:

I. CAPITAL COSTS

- A. Drilling and Completion Costs per Well
 - 1. Regular Well Drilling and Completion Costs
 - 2. Additional Costs for Insulated Tubing
- B. Production and Lease Equipment Costs
- C. Steam Generator Costs
- D. Field Development Costs Associated with the Steam Plant
- E. Water Plant Costs
- F. Summary of Capital Costs
- G. Other Costs

II. OPERATING COSTS

- A. Well Operating and Maintenance Costs
 - 1. Normal Well Operating and Maintenance Costs
 - 2. Special Operating and Maintenance Costs
- B. Process Specific Operating Costs
 - 1. Steam Generator Operating and Maintenance Costs
 - 2. Water Recycling Plant
 - 3. Water Disposal
- C. Fuel Requirements
- D. Summary of Operating Costs
- E. Other Costs

III. AGGREGATE FACILITY COSTS

- A. Overview
- B. Capital and Operating Costs
- C. Gas Production
- D. Selected Cost Ratios

I. CAPITAL COSTS

A. DRILLING AND COMPLETION COSTS PER WELL

1. REGULAR WELL DRILLING AND COMPLETION COSTS. THESE COSTS ARE PRIMARILY A FUNCTION OF DEPTH. THE COST EQUATION IS:

$$2 * (\$82,000 (\text{EXP}(0.26 * \text{DEPTH} \times 10^{-3}))).$$

THIS COST IS MULTIPLIED BY TWO TO ACCOUNT FOR DRILLING IN THE ARCTIC SETTING.

- D&C COSTS FOR A 2,000' WELL = $2 * 82,000 (\text{EXP}(0.26 * 2))$
= \$275,900/WELL

SOURCE: DEVELOPED BY LEWIN FROM DOE/EIA - O347 (1984); TABLE 5. COMPOSITE DRILLING COSTS AND INDEXES BY DEPTH FOR AREA (1), THE WESTERN AREA.

2. ADDITIONAL COSTS FOR INSULATED TUBING. THE COSTS FOR INSULATED TUBING ARE \$25/FT., FOB, SEATTLE, WASHINGTON. A COST OF \$2/FT IS ADDED FOR TRANSPORTATION TO THE NORTH SLOPE OF ALASKA.

- INSULATED TUBING COSTS FOR A 2,000' WELL = $(25 + 2) (2,000)$
= \$54,000/WELL

SOURCE: LEWIN INDUSTRIAL VENDOR SURVEY (MARCH, 1985).

CAPITAL COSTS (CONT.)

B. PRODUCTION AND LEASE EQUIPMENT COSTS

BEYOND DRILLING AND COMPLETING THE WELL, THE COSTS NEED TO INCLUDE PRODUCING EQUIPMENT FOR LIFTING THE WATER, AND FOR SURFACE LEASE FACILITIES SUCH AS FLOW LINES AND CONNECTIONS, GATHERING SYSTEM, THE PRODUCTION PACKAGE, STORAGE TANKS, AND DEHYDRATION EQUIPMENT.

THESE PRODUCTION AND LEASE EQUIPMENT COSTS ARE PRIMARILY A FUNCTION OF GAS PRODUCTION RATE AND DEPTH. THE COST EQUATIONS ARE:

1. DOWNHOLE PRODUCING EQUIPMENT -- $\$65,000 + \$30(\text{MCFD}) + \$5(\text{DEPTH, FT})$
2. GATHERING SYSTEM -- $\$5,000 + \$10(\text{MCFD}) + \$1(\text{DEPTH, FT})$
3. SURFACE LEASE EQUIPMENT -- $\$10,000 + \$40(\text{MCFD})$
4. DEHYDRATOR -- $\$15,000$

COMPOSITE	
PRODUCTION AND LEASE	
EQUIPMENT COSTS:	<hr/> $\$95,000 + \$80(\text{MCFD}) + \$6(\text{DEPTH, FT})$

THESE COSTS ARE MULTIPLIED BY TWO TO ACCOUNT FOR SHIPMENT TO AND INSTALLATION IN THE ARCTIC SETTING.

- P&LE COSTS FOR A 2,000' WELL, PRODUCING 500 MCFD
$$= 2 * (95,000 + 80(500) + 6(2,000))$$
$$= \$294,000/\text{WELL}$$

SOURCE: DOE/EIA - 0185 (1983) ; UPDATED TO 1984\$ BY LEWIN DERIVED COST INDEXES.

I. CAPITAL COSTS (CONT.)

C. STEAM GENERATOR COSTS

THE COST FOR A STEAM GENERATOR FIRED BY LEASE-GAS IS \$650,000 FOR A 50 MMBTU/HR AND 3,500 BHPD UNIT.

THIS COST IS MULTIPLIED BY TWO TO ACCOUNT FOR COSTS OF SHIPMENT TO AND INSTALLATION IN THE ARCTIC SETTING.

A SINGLE 50 MMBTU/HR UNIT OPERATING AT 90% CAPACITY COULD SERVE 16 INJECTION WELLS AT AN AVERAGE STEAM INJECTION RATE OF 200 BBL/DAY/WELL.

- STEAM GENERATOR COSTS FOR A 200 BPD OPERATION =
 $2 * (650,000)(200/3,500 * 0.90) = \$82,500/\text{WELL}$

SINCE NATURAL GAS IS ASSUMED TO BE THE FUEL, NO ADDITIONAL COSTS ARE ADDED FOR SCUBBER UNITS.

SOURCE: NPC, ENHANCED OIL RECOVERY STUDY, 1984.

D. FIELD DEVELOPMENT COSTS ASSOCIATED WITH THE STEAM PLANT

THE FIELD DEVELOPMENT COSTS SPECIFIC TO OPERATING A STEAM INJECTION FACILITY INCLUDE:

1. STEAM MANIFOLD AND FLOW LINES @ \$8,750/ACRE
2. HEATER TREATER AND VAPOR RECOVERY UNIT @ \$5,500/ACRE
 - HEATER TREATER @ \$1,000/ACRE
 - VAPOR RECOVERY UNIT @ \$4,500/ACRE

CAPITAL COSTS (CONT.)

THE COMPOSITE FIELD DEVELOPMENT COSTS ASSOCIATED WITH A STEAM PLANT ARE \$14,250 PER ACRE. THESE COSTS ARE MULTIPLIED BY TWO FOR TRANSPORTATION TO AND INSTALLATION ON THE NORTH SLOPE OF ALASKA.

- FIELD DEVELOPMENT COSTS FOR A 10-ACRE PATTERN = $2 * (14,250 * 10)$
= \$285,000/WELL

SOURCE: NPC, ENHANCED OIL RECOVERY STUDY, 1984; DOE/EIA-0185 (1983); UPDATED AND MODIFIED BY LEWIN.

E. WATER PLANT COSTS

THE PRODUCED WATER RECYCLE PLANT CAPITAL COSTS ARE SCALED TO THE VOLUMES OF WATER TO BE RECYCLED AND EQUAL \$75/BBL PER DAY OF STEAM INJECTED.

THESE COSTS ARE MULTIPLIED BY TWO TO ACCOUNT FOR CONSTRUCTION OF THE PLANT IN THE ARCTIC SETTING.

- WATER PLANT COSTS FOR A 200 BPD FACILITY = $2 * 75(200) = \$30,000/WELL$

SOURCE: NPC, ENHANCED OIL RECOVERY STUDY, 1984.

I. CAPITAL COSTS (continued)

F. SUMMARY OF CAPITAL COSTS

TABULATED BELOW ARE THE CAPITAL INVESTMENT COSTS FOR A SAMPLE 2,000-FOOT WELL, DRILLED AND COMPLETED ONSHORE ON THE NORTH SLOPE OF ALASKA FOR THERMAL INJECTION OF 200 BPD OF STEAM AND PRODUCING 500 MCF PER DAY:

<u>COST ITEM</u>	<u>COST EQUATIONS</u>	<u>SAMPLE COSTS</u>
1. WELL DRILLING AND COMPLETION	2 * \$82,000 (EXP 0.26 * DEPTH FT X 10 ⁻³)	\$275,900
2. INSULATED TUBING	\$27/FOOT	\$ 54,000
3. PRODUCTION AND LEASE EQUIPMENT	2 * (\$95,000 + \$80(MCFD) + 6(DEPTH, FT))	\$294,000
4. STEAM GENERATOR	2 * (\$650,000 * $\frac{\text{BPD, STEAM}}{3,500 \text{ BWPD} * 0.90}$)	\$82,500
5. STEAM PLANT FIELD DEVELOPMENT	2 * (\$14,250/ACRE)	\$285,000
6. WATER PLANT	2 * (\$75 * BWPD)	<u>\$30,000</u>
TOTAL CAPITAL COSTS/WELL		\$1,021,400

G. OTHER COSTS

A ONE TIME CHARGE OF 10% OF TOTAL CAPITAL COSTS IS ASSIGNED TO THE PROJECT TO ACCOUNT FOR ENGINEERING AND OTHER GENERAL COSTS.

II. OPERATING COSTS

A. WELL OPERATING AND MAINTENANCE COSTS

1. NORMAL WELL OPERATING AND MAINTENANCE COSTS. THESE COSTS ARE A FUNCTION OF GAS FLOW RATE AND WELL DEPTH. THE COST EQUATION IS:

$$\$10,000 + \$4 (\text{GAS FLOW RATE, MCFT}) + \$4 (\text{WELL DEPTH, FT.})$$

THIS COST IS MULTIPLIED BY TWO TO ACCOUNT FOR OPERATIONS IN THE ARCTIC SETTING.

- ANNUAL O&M COSTS FOR A 2,000' WELL PRODUCING 500 MCFT
= 2 * (10,000 + 4 (500) + 4 (2,000)) = \$40,000/WELL

SOURCE: CONSTRUCTED BY LEWIN FROM DOE/EIA-0185 (1983); TABLES A12-A14; DIRECT ANNUAL OPERATING COSTS AND INDEXES FOR SECONDARY OIL PRODUCTION IN WEST TEXAS (FOR NORMAL OPERATING & MAINTENANCE PLUS SURFACE MAINTENANCE) AND TABLES H6-H8 FOR ANNUAL OPERATING COST AND INDEXES FOR GAS PRODUCTION IN WEST TEXAS; COSTS ARE MULTIPLIED BY 1.08 TO ACCOUNT FOR OIL FIELD INFLATION IN 1984.

2. SPECIAL OPERATING AND MAINTENANCE COSTS. NONE

B. PROCESS SPECIFIC OPERATING COSTS

1. STEAM GENERATOR OPERATING AND MAINTENANCE COSTS. THE COST EQUATION IS: \$0.10 PER BARREL OF STEAM (WATER EQUIVALENT) INJECTED FOR A GAS FIRED 50 MMBTU/HR. AND 3,500 BHPD CAPACITY UNIT.

II. OPERATING COSTS (continued)

THIS COST IS MULTIPLIED BY TWO TO ACCOUNT FOR OPERATIONS IN THE ARCTIC SETTING.

- ANNUAL STEAM GENERATOR O&M COSTS FOR A 200 BPD OPERATION
= $2 * 0.10 * 200 * 365 = \$14,600/\text{WELL}$

SOURCE: NPC ENHANCED OIL RECOVERY, 1984; CONVERTED BY LEWIN TO COSTS PER BARREL OF STEAM GENERATED.

2. WATER RECYCLING PLANT OPERATING COSTS. THE COST EQUATION IS \$0.125 PER BARREL OF STEAM (WATER EQUIVALENT) RECYCLED.

- ANNUAL WATER RECYCLING PLANT COSTS FOR A 200 BPD OPERATION
= $2 * 0.125 * 200 * 365 = \$18,250/\text{WELL}$.

SOURCE: NPC ENHANCED OIL RECOVERY, 1984.

3. WATER DISPOSAL OPERATING COSTS. THE COST EQUATION IS \$0.025 PER BARREL OF WATER DISPOSED. PRODUCED WATER IS ASSUMED TO BE RECYCLED AND USED FOR REINJECTION.

SOURCE: NPC ENHANCED OIL RECOVERY, 1984.

C. FUEL REQUIREMENTS

ASSUMING THE USE OF 1,000 BTU PER POUND STEAM, A FUEL CONTENT OF 1,000 BTU PER CUBIC FOOT FOR THE LEASE GAS, AND 87% CONVERSION EFFICIENCY, APPROXIMATELY 0.4 MCF OF NATURAL GAS WOULD BE CONSUMED PER BARREL OF STEAM (WATER EQUIVALENT) GENERATED.

- ANNUAL FUEL REQUIREMENTS FOR A 200 BPD OPERATION = $0.4 * 200 * 365$
= 29,200 MCF/WELL.

SOURCE: LEWIN, 1985; BASED ON ENERGY BALANCE CALCULATIONS

NOTE: THIS AMOUNT OF NATURAL GAS USED FOR LEASE FUEL WOULD BE SUBTRACTED FROM GROSS ANNUAL PRODUCTION.

II. OPERATING COSTS (continued)

D. SUMMARY OF OPERATING COSTS

TABULATED BELOW ARE THE OPERATING AND MAINTENANCE COSTS FOR A SAMPLE 2,000 FOOT WELL OPERATING ON THE NORTH SLOPE OF ALASKA, ENTAILING STEAM INJECTION OF 200 BPD AND PRODUCING 500 MCF PER DAY OF DISSOCIATED HYDRATE BASED NATURAL GAS.

<u>COST ITEM</u>	<u>COST EQUATIONS</u>	<u>SAMPLE COSTS</u>
1. ANNUAL WELL O&M	$2 * (\$10,000 + \$4 (\text{MCFD}) + \$4 (\text{DEPTH, FT}))$	\$40,000
2. SPECIAL O&M	--	-
3. STEAM GENERATOR O&M	$\$0.10 (\text{BPD, STEAM}) * 365 \text{ D/YR.}$	\$14,600
4. WATER RECYCLE PLANT	$\$0.125 (\text{BPD, STEAM}) * 365 \text{ D/YR.}$	\$18,200
5. WATER DISPOSAL	*	*
6. FUEL REQUIREMENTS	$(0.4 \text{ MCF}) * ((\text{BPD, STEAM}) * 365 \text{ D/YR.}))$	**
ANNUAL OPERATING COSTS/WELL		\$72,800

* PRODUCED WATER IS RECYCLED FOR REINJECTION.

** 29,200 MCF WOULD BE SUBTRACTED FROM YEARLY GAS PRODUCTION FOR LEASE FUEL.

E. OTHER COSTS

A YEARLY G&A CHARGE OF 20% ON OPERATIONS AND MAINTENANCE IS ADDED TO THESE COSTS.

III. AGGREGATE FACILITY COSTS

A. OVERVIEW

SUMMARIZED BELOW ARE THE CAPITAL AND OPERATING COSTS FOR A FIELD SCALE METHANE HYDRATE PRODUCTION FACILITY INSTALLED ON THE NORTH SLOPE OF ALASKA. THE FACILITY CONSISTS OF:

- A SURFACE AREA OF 640 ACRES;
- 64 WELLS, DRILLED TO 2,000 FEET ON 10 ACRE SPACING;
- FOUR 50 MILLION BTU/HR STEAM GENERATORS;
- A STEAM INJECTION AND WATER HANDLING RATE OF 12,800 B/D;
- INSULATED SURFACE LINES AND INSULATED DOWN-HOLE TUBING; AND
- GAS PRODUCTION OF 500 MCF/D PER YEAR PER WELL, EQUAL TO 32,000 MCFD.

FIGURE 1 PROVIDES A GRAPHICAL REPRESENTATION FOR SUCH A FACILITY.

B. CAPITAL AND OPERATING COSTS

THE CAPITAL COSTS FOR THE FIELD SCALE FACILITY EQUAL \$66.3 MILLION, AS SHOWN IN THE TABLE BELOW:

<u>CAPITAL COSTS</u>	<u>COSTS (1984\$)</u> <u>(THOUSANDS)</u>
1. WELL DRILLING AND COMPLETION ,	17,700
2. INSULATED TUBING	3,500
3. PRODUCTION AND LEASE EQUIPMENT	18,800
4. STEAM GENERATOR	5,300
5. STEAM PLANT FIELD DEVELOPMENT	18,200
6. WATER PLANT	<u>1,900</u>
SUBTOTAL	65,400
7. ALLOCATED G&A @ 10%	<u>6,500</u>
TOTAL	71,900

FIGURE 1
**FIELD SCALE
METHANE HYDRATE PRODUCTION FACILITY**

REQUIRED FACILITIES:

1. 64 WELLS
2. 4, 50MMBTU/HR STEAM GENERATORS
3. 12,800 B/D WATER PLANT
4. 32,000 MCF/D GAS PRODUCTION FACILITIES

THE OPERATING COSTS FOR THE FACILITY ARE \$5.6 MILLION PER YEAR, AS SHOWN BELOW:

<u>ANNUAL OPERATING COSTS</u>	<u>COSTS (1984\$)</u> (THOUSANDS)
1. ANNUAL O&M	2,600
2. STEAM GENERATOR O&M	900
3. WATER RECYCLE PLANT	1,200
4. WATER DISPOSAL	*
SUBTOTAL	4,700
5. ALLOCATED G&A @ 20%	900
TOTAL O&M	5,600/YEAR

* PRODUCED WATER IS RECYCLED FOR REINJECTION.

C. GAS PRODUCTION

THIS 64 WELL FACILITY WOULD PRODUCE AT A RATE OF 32 MILLION CUBIC FEET OF NATURAL GAS PER DAY. AFTER SUBTRACTION OF GAS USED FOR LEASE FUEL, THE ANNUAL PRODUCTION WOULD BE 26.9 MILLION CUBIC FEET PER DAY. IN TEN YEARS, THE FACILITY WOULD PRODUCE 98.1 ^BILLION CUBIC FEET OF NATURAL GAS, AS SHOWN BELOW:

1. GROSS PRODUCTION	- 32,000 MCFD; 11,680,000 MCF/YR.
2. LESS: LEASE FUEL	- 5,100 MCFD; 1,870,000 MCF/YR.
3. NET PRODUCTION	- 26,900 MCFD; 9,810,000 MCF/YR.
4. 10 YEAR CUMULATIVE PRODUCTION	- 98,100,000 MCF

D. SELECTED COST RATIOS

ASSUMING A 10 YEAR PRODUCTION TIME, THE WELLHEAD CAPITAL AND OPERATING COSTS PER MCF, ROUNDED TO THE NEAREST \$0.10, ARE \$1.30 PER MCF, AS SHOWN BELOW:

CAPITAL COSTS PER MCF = \$0.70/MCF

O&M COSTS PER MCF = \$0.60/MCF

TOTAL = \$1.30/MCF

OTHER COSTS, SUCH AS ROYALTIES, STATE PRODUCTION AND SEVERANCE TAXES, INCOME TAXES AND A RETURN ON CAPITAL WOULD NEED TO BE ADDED TO ARRIVE AT AN OVERALL WELLHEAD COST (OR EQUIVALENT WELLHEAD SELLING PRICE) FOR THE NATURAL GAS PRODUCED FROM THIS FACILITY.

ATTACHMENT B
ENGINEERING COSTING MODEL
BLAKE BAHAMAS OFFSHORE

GAS HYDRATES FIELD DEVELOPMENT AND PRODUCTION COSTS
BLAKE BAHAMAS OFFSHORE

INTRODUCTION

THIS WORKING PAPER SETS FORTH THE CAPITAL AND OPERATING COSTS FOR DEVELOPING AND PRODUCING GAS HYDRATES FROM THE OFFSHORE AREAS OF THE SOUTHEAST COAST OF THE UNITED STATES. IT CONTAINS: (1) INDIVIDUAL COST EQUATIONS FOR THE KEY COST ITEMS, IN 1984 DOLLARS; (2) ADJUSTMENTS TO THESE COST EQUATIONS TO ACCOUNT FOR TRANSPORTATION OF MATERIALS OFFSHORE AND FOR WORKING IN AN OFFSHORE SETTING; (3) A SAMPLE CALCULATION FOR A 32 SLOT PLATFORM WITH 4,000-FOOT WELLS, 2,000 FEET OF DRILLED DEPTH AND 2,000 FEET OF WATER, EACH PRODUCING 1,000 MCF/D; AND, (4) THE SOURCES USED FOR THE INDIVIDUAL COST EQUATIONS.

THE MATERIAL IN THE WORKING PAPER IS ORGANIZED AS FOLLOWS:

I. CAPITAL COSTS

- A. Tension Leg Platform
- B. Drilling and Completion
 - 1. Regular Well Drilling and Completion
 - 2. Additional Costs for Insulated Tubing
- C. Production and Lease Equipment
- D. Steam Generator
- E. Field Development Costs Associated with the Steam Plant
- F. Water Plant
- G. Summary of Capital Costs
- H. Other Costs

II. OPERATING COSTS

- A. Well Operations and Maintenance
 - 1. Normal Well Operating and Maintenance
 - 2. Special Operating and Maintenance
- B. Process Specific Operations
 - 1. Steam Generator Operations and Maintenance
 - 2. Water Recycling Plant
 - 3. Water Disposal
- C. Fuel Requirements
- D. Summary of Operating Costs
- E. Other Costs

III. AGGREGATE FACILITY COSTS

- A. Overview
- B. Capital and Operating Costs
- C. Gas Production
- D. Selected Cost Ratios

I. CAPITAL COSTS

A. TENSION LEG PLATFORM COSTS. IN WATER DEPTHS GREATER THAN 1,200 FEET A COMPLAINT STRUCTURE, WHOSE COSTS BECOME LESS DEPENDENT ON WATER DEPTH, IS PREFERRABLE. THE TENSION LEG PLATFORM (TPL) USED BY CONOCO IN ITS NORTH SEA HUTTON FIELD IS AN EXAMPLE OF SUCH A STRUCTURE. THE COST EQUATION FOR THE TPL IS:

$$\begin{aligned} \bullet \text{ TENSION LEG PLATFORM} &= \$64,000,000 + 10,000 * (\text{WATER DEPTH, FT.}) + \\ &\quad (\text{SLOTS}) * (62,000 + 650 * \text{WATER DEPTH, FT.}) \\ &= \$64,000,000 + 10,000(2,000) + 32(62,000 \\ &\quad + 650(2,000)) \\ &= \$127,580,000/\text{PLATFORM} \end{aligned}$$

SOURCE: LEWIN CALCULATIONS OF WAVE FORCES AND MODIFICATIONS FROM ATTANASI, 1984 (JPT, DEC. 1984).

B. DRILLING AND COMPLETION COSTS PER WELL

1. REGULAR WELL DRILLING AND COMPLETION COSTS. AFTER ABOUT 2,000 FEET D&C COSTS BECOME DEPENDENT ON WELL DEPTH. THE COST EQUATION IS:

$$\begin{aligned} \bullet \text{ D\&C COSTS} &= \$460,000 + 130(\text{DEPTH} - 2,000) \\ &= \$460,000 + 130(4,000 - 2,000) \\ &= \$720,000/\text{WELL} \end{aligned}$$

SOURCE: NPC ENHANCED OIL RECOVERY WORKING PAPERS PREPARED BY GARLAND, EXHIBIT OF OFFSHORE DRILLING COSTS, 1984.

CAPITAL COSTS (CONT.)

2. ADDITIONAL COSTS FOR INSULATED TUBING. THE COSTS FOR INSULATED TUBING ARE \$25/FT., FOB, SEATTLE, WASHINGTON. A COST OF \$2/FT IS ADDED FOR TRANSPORTATION OFFSHORE.

- INSULATED TUBING COSTS FOR A 4,000' WELL = $(25 + 2) (4,000)$
= \$108,000/WELL

SOURCE: LEWIN INDUSTRIAL VENDOR SURVEY (MARCH, 1985).

C. PRODUCTION AND LEASE EQUIPMENT COSTS

BEYOND DRILLING AND COMPLETING THE WELL, THE COSTS NEED TO INCLUDE PRODUCING EQUIPMENT FOR LIFTING THE WATER, AND FOR SURFACE LEASE FACILITIES SUCH AS FLOW LINES AND CONNECTIONS, THE GATHERING SYSTEM, THE PRODUCTION PACKAGE, STORAGE TANKS AND DEHYDRATION EQUIPMENT.

THESE PRODUCTION AND LEASE EQUIPMENT COSTS ARE PRIMARILY A FUNCTION OF GAS PRODUCTION RATE AND DEPTH. THE COST EQUATIONS ARE:

1. DOWNHOLE PRODUCING EQUIPMENT	--	$\$65,000 + \$30(\text{MCFD}) + \$5(\text{TOTAL DEPTH, FT})$
2. GATHERING SYSTEM	--	$\$5,000 + \$10(\text{MCFD}) + \$1(\text{TOTAL DEPTH, FT})$
3. SURFACE LEASE EQUIPMENT	--	$\$10,000 + \$40(\text{MCFD})$
4. DEHYDRATOR	--	$\$15,000$

COMPOSITE
PRODUCTION AND LEASE
EQUIPMENT COSTS:

$\$95,000 + \$80(\text{MCFD}) + \$6(\text{TOTAL DEPTH, FT})$

I. CAPITAL COSTS (CONT.)

- THESE COSTS ARE MULTIPLIED BY 1.5 TO ACCOUNT FOR SHIPMENT TO AND INSTALLATION IN THE ARCTIC SETTING.

- P&LE COSTS FOR A 4,000' WELL, PRODUCING 500 MCFD
= $1.5 * (95,000 + 80(500) + 6(4,000))$
= \$298,500/WELL

SOURCE: DOE/EIA - 0185 (1983) ; UPDATED TO 1984\$ BY LEWIN DERIVED COST INDEXES.

D. STEAM GENERATOR COSTS

THE COST FOR A STEAM GENERATOR FIRED BY LEASE-GAS IS \$650,000 FOR A 50 MMBTU/HR AND 3,500 BHPD UNIT.

THIS COST IS MULTIPLIED BY 1.5 TO ACCOUNT FOR COSTS OF SHIPMENT TO AND INSTALLATION OFFSHORE.

FOUR 50 MMBTU/HR UNITS OPERATING AT 90% CAPACITY COULD SERVE 32 INJECTION WELLS AT AN AVERAGE STEAM INJECTION RATE OF 400 BBL/DAY/WELL.

- STEAM GENERATOR COSTS FOR A 200 BPD OPERATION
= $1.5 * (400/3,500 * 0.90)(650,000 * 4)$
= \$122,000/WELL

SINCE NATURAL GAS IS ASSUMED TO BE THE FUEL, NO ADDITIONAL COSTS ARE ADDED FOR SCUBBER UNITS.

SOURCE: NPC, ENHANCED OIL RECOVERY STUDY, 1984.

CAPITAL COSTS (CONT.)

- E. FIELD DEVELOPMENT COSTS ASSOCIATED WITH THE STEAM PLANT

-
-
-
THE FIELD DEVELOPMENT COSTS SPECIFIC TO OPERATING A STEAM INJECTION FACILITY INCLUDE:

1. STEAM MANIFOLD AND FLOW LINES @ \$85,000/SLOT
2. HEATER TREATER AND VAPOR RECOVERY UNIT @ \$55,000/SLOT
 - HEATER TREATER @ \$10,000/SLOT
 - VAPOR RECOVERY UNIT @ \$45,000/SLOT

THE COMPOSITE FIELD DEVELOPMENT COSTS ASSOCIATED WITH A STEAM PLANT ARE \$140,000 PER SLOT. THESE COSTS ARE MULTIPLIED BY 1.5 FOR TRANSPORTATION AND INSTALLATION ON THE OFFSHORE PLATFORM.

- FIELD DEVELOPMENT COSTS FOR EACH SLOT = $1.5 * (140,000)$
= \$210,000/WELL

SOURCE: NPC, ENHANCED OIL RECOVERY STUDY, 1984; DOE/EIA-0185 (1983); UPDATED AND MODIFIED BY LEWIN.

F. WATER PLANT COSTS

THE PRODUCED WATER RECYCLE PLANT CAPITAL COSTS ARE SCALED TO THE VOLUMES OF WATER TO BE RECYCLED AND EQUAL \$75/BBL PER DAY OF STEAM INJECTED.

THESE COSTS ARE MULTIPLIED BY 1.5 TO ACCOUNT FOR CONSTRUCTION OF THE PLANT OFFSHORE.

- WATER PLANT COSTS FOR A BPD PER WELL FACILITY = $1.5 * 75(400)$
= \$45,000/WELL

SOURCE: NPC, ENHANCED OIL RECOVERY STUDY, 1984.

I. CAPITAL COSTS (continued)

G. SUMMARY OF CAPITAL COSTS

TABULATED BELOW ARE THE CAPITAL INVESTMENT COSTS FOR A 32 SLOT PLATFORM WITH 4,000-FOOT WELLS, DRILLED IN 2,000 FEET OF WATER OFFSHORE AND COMPLETED FOR THERMAL INJECTION OF 400 BPD OF STEAM PER WELL AND PRODUCING 1,000 MCF PER DAY PER WELL:

<u>COST ITEM</u>	<u>COST EQUATIONS</u>	<u>TOTAL COSTS IN 1,000 \$</u>
1. TENSION LEG PLATFORM	$\$64,000 + \$10(\text{WATER DEPTH}) + \$62(\text{SLOTS})$ $(\$0.65 * \text{WATER DEPTH} * \text{SLOTS})$	\$127,580
2. WELL DRILLING AND COMPLETION	$(\$460,000 + 130(\text{WELL DEPTH} - 2,000)) * \text{SLOTS}$	\$ 23,040
3. INSULATED TUBING	\$27/FOOT	\$ 3,460
4. PRODUCTION AND LEASE EQUIPMENT	$1.5 * (\$95,000 + \$80(\text{MCFD}) + 6(\text{DEPTH, FT}))$	\$ 9,550
5. STEAM GENERATOR	$1.5 * (\$650,000 * \frac{\text{BPD (STEAM)}}{3,500 \text{ BHPD} * 0.90} * \text{SLOTS})$	\$ 3,900
6. STEAM PLANT FIELD DEVELOPMENT	$1.5 * (\$140,000 / \text{SLOT}) * \text{SLOTS}$	\$ 6,720
7. WATER PLANT	$1.5 * (\$75 * \text{BHPD} * \text{SLOTS})$	\$ <u>1,440</u>
TOTAL CAPITAL COSTS/WELL		\$195,700

H. OTHER COSTS

A ONE TIME CHARGE OF 10% OF TOTAL CAPITAL COSTS IS ASSIGNED TO THE PROJECT TO ACCOUNT FOR ENGINEERING AND OTHER GENERAL COSTS.

II. OPERATING COSTS

A. WELL OPERATING AND MAINTENANCE COSTS

1. NORMAL WELL OPERATING AND MAINTENANCE COSTS. O&M COSTS FOR THE PLATFORM ARE A FUNCTION OF THE NUMBER OF SLOTS (WELL), GAS FLOW RATE AND WELL DEPTH. THE COST EQUATION IS:

- $$\text{O\&M COSTS} = 1,700,000 + 500(\text{WATER DEPTH, FT}) + 5 * (\text{WELL DEPTH, FT})(\text{SLOTS}) + 5(\text{MCFD/PLATFORM})$$
- $$\begin{aligned} \text{ANNUAL O\&M COSTS} &= 1,700,000 + (500 * 2,000) + 5(4,000 * 32) \\ &\quad + 5(32,000) \\ &= \$3,500,000/\text{WELL} \end{aligned}$$

SOURCE: CONSTRUCTED BY LEWIN FROM DOE/EIA-0185 (1983); TABLES A12-A14; DIRECT ANNUAL OPERATING COSTS AND INDEXES FOR 18-SLOT PLATFORM IN THE GULF OF MEXICO.

2. SPECIAL OPERATING AND MAINTENANCE COSTS. NONE

B. PROCESS SPECIFIC OPERATING COSTS

1. STEAM GENERATOR OPERATING AND MAINTENANCE COSTS. THE COST EQUATION IS: \$0.10 PER BARREL OF STEAM (WATER EQUIVALENT) INJECTED FOR A GAS FIRED 50 MMBTU/HR. AND 3,500 BWPD CAPACITY UNIT.

THIS COST IS MULTIPLIED BY 1.5 TO ACCOUNT FOR OPERATIONS OFFSHORE.

- $$\begin{aligned} \text{ANNUAL STEAM GENERATOR O\&M COSTS FOR A 400 BPD OPERATION} \\ = 1.5 * 0.10 * 400 * 365 = \$21,900/\text{WELL} \end{aligned}$$

SOURCE: NPC ENHANCED OIL RECOVERY, 1984; CONVERTED BY LEWIN TO COSTS PER BARREL OF STEAM GENERATED.

II. OPERATING COSTS (continued)

2. WATER RECYCLING PLANT OPERATING COSTS. THE COST EQUATION IS \$0.125 PER BARREL OF STEAM (WATER EQUIVALENT) RECYCLED.

- ANNUAL WATER RECYCLING PLANT COSTS FOR A 400 BPD OPERATION
= $1.5 * 0.125 * 400 * 365 = \$27,400/\text{WELL}$.

SOURCE: NPC ENHANCED OIL RECOVERY, 1984.

3. WATER DISPOSAL OPERATING COSTS. THE COST EQUATION IS \$0.025 PER BARREL OF WATER DISPOSED. PRODUCED WATER IS ASSUMED TO BE RECYCLED AND USED FOR REINJECTION.

SOURCE: NPC ENHANCED OIL RECOVERY, 1984.

C. FUEL REQUIREMENTS

ASSUMING THE USE OF 1,000 BTU PER POUND STEAM, A FUEL CONTENT OF 1,000 BTU PER CUBIC FOOT FOR THE LEASE GAS, AND 87% CONVERSION EFFICIENCY, APPROXIMATELY 0.4 MCF OF NATURAL GAS WOULD BE CONSUMED PER BARREL OF STEAM (WATER EQUIVALENT) GENERATED.

- ANNUAL FUEL REQUIREMENTS FOR A 400 BPD OPERATION = $0.4 * 400 * 365$
= \$58,400 MCF/WELL.

SOURCE: LEWIN, 1985; BASED ON ENERGY BALANCE CALCULATIONS

NOTE: THIS AMOUNT OF NATURAL GAS USED FOR LEASE FUEL WOULD BE SUBTRACTED FROM GROSS ANNUAL PRODUCTION.

II. OPERATING COSTS (continued)

D. SUMMARY OF OPERATING COSTS

TABULATED BELOW ARE THE OPERATING AND MAINTENANCE COSTS FOR A SAMPLE 32-SLOT TENSION LEG PLATFORM WITH 4,000 FOOT WELL IN 2,000 FEET OF WATER DEPTH, ENTAILING STEAM INJECTION OF 400 BPD PER WELL AND PRODUCING 500 MCF PER DAY PER WELL OF DISSOCIATED HYDRATE BASED NATURAL GAS.

<u>COST ITEM</u>	<u>COST EQUATIONS</u>	<u>ANNUAL COSTS IN 1,000'S\$</u>
1. ANNUAL WELL O&M	$1,700,000 + 500(\text{WATER DEPTH, FT})$ $+ 5(\text{WELL DEPTH})(\text{SLOTS}) + 5(\text{MCF/D PLATFORM})$	\$ 3,500
2. SPECIAL O&M	--	-
3. STEAM GENERATOR O&M	$1.5 * \$0.10 (\text{BPD, STEAM}) * 365 \text{ D/YR.}$ $* \text{SLOTS}$	\$ 700
4. WATER RECYCLE PLANT	$1.5 * \$0.125 (\text{BPD, STEAM}) * 365 \text{ D/YR.}$ $* \text{SLOTS}$	\$ 880
5. WATER DISPOSAL	*	*
6. FUEL REQUIREMENTS	$(0.4 \text{ MCF}) * ((\text{BPD, STEAM}) * 365 \text{ D/YR.}))$ $* \text{SLOTS}$	**
ANNUAL OPERATING COSTS/WELL		\$ 5,080

* PRODUCED WATER IS RECYCLED FOR REINJECTION.

** 58,400 MCF WOULD BE SUBTRACTED FROM YEARLY GAS PRODUCTION FOR LEASE FUEL.

E. OTHER COSTS

A YEARLY G&A CHARGE OF 20% ON OPERATIONS AND MAINTENANCE IS ADDED TO THESE COSTS.

III. AGGREGATE FACILITY COSTS

A. OVERVIEW

SUMMARIZED BELOW ARE THE CAPITAL AND OPERATING COSTS FOR A METHANE HYDRATE PRODUCTION FACILITY INSTALLED OFFSHORE OF SOUTHEASTERN UNITED STATES. THE FACILITY CONSISTS OF:

- A LEASE AREA OF 640 ACRES; 20 ACRE SPACING
- 32 WELLS, DRILLED TO 4,000 FEET IN 2,000 FEET OF WATER;
- TWO 50 MILLION BTU/HR STEAM GENERATORS;
- A STEAM INJECTION AND WATER HANDLING RATE OF 12,800 B/D;
- INSULATED LINES AND INSULATED DOWN-HOLE TUBING; AND
- GAS PRODUCTION OF 1,000 MCF/D PER YEAR PER WELL, EQUAL TO 32,000 MCF/D.

B. CAPITAL AND OPERATING COSTS

THE CAPITAL COSTS FOR THIS FACILITY EQUAL \$188.2 MILLION, AS SHOWN IN THE TABLE BELOW:

<u>CAPITAL COSTS</u>	<u>COSTS (1984\$)</u> <u>(THOUSANDS)</u>
1. TENSION LEG PLATFORM	128,000
2. WELL DRILLING AND COMPLETION	23,000
3. INSULATED TUBING	3,500
4. PRODUCTION AND LEASE EQUIPMENT	9,600
5. STEAM GENERATOR	3,900
6. STEAM PLANT FIELD DEVELOPMENT	6,700
7. WATER PLANT	<u>1,400</u>
SUBTOTAL	176,100
8. ALLOCATED G&A @ 10%	<u>17,600</u>
TOTAL	193,700

THE OPERATING COSTS FOR THE FACILITY ARE \$5.1 MILLION PER YEAR, AS SHOWN BELOW:

<u>ANNUAL OPERATING COSTS</u>		<u>COSTS (1984\$)</u> (THOUSANDS)
1. ANNUAL O&M		\$3,500
2. STEAM GENERATOR O&M		700
3. WATER RECYCLE PLANT		880
4. WATER DISPOSAL		*
	SUBTOTAL	\$5,080
5. ALLOCATED G&A @ 20%		<u>1,020</u>
	TOTAL O&M	\$6,100/YEAR

* PRODUCED WATER IS RECYCLED FOR REINJECTION.

C. GAS PRODUCTION

THIS 32 WELL FACILITY WOULD PRODUCE AT A RATE OF 16 MILLION CUBIC FEET OF NATURAL GAS PER DAY. AFTER SUBTRACTION OF GAS USED FOR LEASE FUEL, THE ANNUAL PRODUCTION WOULD BE 13.5 MILLION CUBIC FEET PER DAY. IN 20 YEARS, THE FACILITY WOULD PRODUCE 98.1 BILLION CUBIC FEET OF NATURAL GAS, AS SHOWN BELOW:

1. GROSS PRODUCTION	-	32,000 MCF/D;	11,680,000 MCF/YR.
2. LESS: LEASE FUEL	-	5,100 MCF/D;	1,870,000 MCF/YR.
3. NET PRODUCTION	-	26,900 MCF/D;	9,810,000 MCF/YR.
4. 10 YEAR CUMULATIVE PRODUCTION	-	98,100,000 MCF	

D. SELECTED COST RATIOS

ASSUMING A 10 YEAR PRODUCTION TIME, THE WELLHEAD CAPITAL AND OPERATING COSTS PER MCF, ROUNDED TO THE NEAREST \$0.10, ARE \$2.60 PER MCF, AS SHOWN BELOW:

CAPITAL COSTS PER MCF	=	\$2.00/MCF
O&M COSTS PER MCF	=	<u>\$0.60/MCF</u>
TOTAL	=	\$2.60/MCF

OTHER COSTS, SUCH AS ROYALTIES, STATE PRODUCTION AND SEVERANCE TAXES, INCOME TAXES AND A RETURN ON CAPITAL WOULD NEED TO BE ADDED TO ARRIVE AT AN OVERALL WELLHEAD COST (OR EQUIVALENT WELLHEAD SELLING PRICE) FOR THE NATURAL GAS PRODUCED FROM THIS FACILITY.

II. HYDRATES GAS ECONOMICS MODEL

(HGEM)

USERS GUIDE

1.0 Introduction

The Hydrates Gas Economics Model (HGM) has been developed by Lewin and Associates, Inc., for the Morgantown Energy Technology Center (METC). Its purpose is to allow for the economic appraisal of gas production from gas hydrates in both onshore Alaska and offshore settings. The model is "user-friendly" such that, through its interactive application, the user can define the values desired for the important parameters affecting the economic appraisal of hydrates gas production.

The user can perform economic evaluations of gas hydrate projects in any of three ways:

- Define a required rate of return and determine the minimum required gas selling price,
- Define a gas selling price and determine the required rate of return on capital investment, and
- Define a gas price and required rate of return and calculate the cash flow resulting from a project.

For onshore Alaska, analysis is performed on a single well. For offshore settings, analysis is performed for a platform of a specified number of slots, for either a steam soak or a steam drive situation. Values for engineering costs are determined by location, reservoir depth, water depth (for offshore settings), steam injection rate, gas production rate, and whether or not produced water is recycled. Users have the option to use predetermined costs or define their own.

* * * * *

This document provides a prospective HGM user with the necessary information to execute the model. All required inputs to the model are described. In addition, the interactive features of the model are presented such that model and user responses are clearly described.

1.1 Input Data

Three data files serve as input to **HGEM**. These files are:

1. **TITLES.DAT** - consists of labels and other titles for the program output, and will generally not require any changes.
2. **HGEMA.INP** - consists of financial and process parameters
HGEMO.INP specific to hydrate gas production. Options are set as defaults, but most can be changed during model execution.
3. **HYD.INP** - consists of reservoir characteristics and production and injection streams specific to a particular situation.

The first file (**TITLES.DAT**) should not require any changes, and will not be described further in this User's Guide. The other three input data files are described below.

Note that in the data descriptions presented below, the term "Line" refers to a line of data in an input data file. All numeric input data are read from free format, and can be entered such that the input items are separated by commas or tabs. Character input data are read in formatted form. The specific format for character data items are specified where necessary.

1.1.1. **HGMO.INP and HGMA.INP**

The input data files **HGMO.INP** (offshore) and **HGMA.INP** (onshore Alaska) consists of financial and process parameters specific to specified gas hydrates project. The format of the data is as follows:

Line 1: PARAM(1), PARAM(2), PARAM(3), PARAM(4), PARAM(5), PARAM(6),
 PARAM(7), PARAM(8)

Line 2: PARAM(9), PARAM(10), PARAM(11), PARAM(12), PARAM(13), PARAM(14),
 PARAM(15)

Line 3: OPTN(1), OPTN(2), OPTN(3), OPTN(4), ADFAC, REG

Line 4: (**HGMO.INP**; Offshore) - NWELLS, NIWELLS, WD
 (**HGMA.INP**; Onshore Alaska) - NWELLS, ACRES

The definitions of these items are given below.

Line 1

PARAM(1): Operating costs overhead rate (fraction): Default = 0.20

PARAM(2): General and administrative (G&A) rates for investment costs
 (fraction): Default = 0.10

PARAM(3): Useful life of a capital investment for purposes of depreciation
 (YEARS): Default = 10 for onshore Alaska
 = 20 for offshore

PARAM(4): Royalty rate on revenues from hydrates gas production (fraction):
 Default = 0.125 for onshore Alaska
 = 0.167 for offshore

- PARAM(5): State severance tax rate on revenues from hydrates gas production
(fraction): Default = 0.08 for onshore Alaska
= 0.00 for offshore
- PARAM(6): Windfall profits tax rate on revenues from hydrates gas production
(fraction): Default = 0.0
- PARAM(7): Income tax credit rate on capital investment (fraction):
Default = 0.10
- PARAM(8): State income tax rate on revenues from hydrates gas production
(fraction): Default = 0.08 for onshore Alaska
= 0.00 for offshore
- PARAM(9): Federal income tax rate on revenues from hydrates gas production
(fraction): Default = 0.46

Line 2

- PARAM(10): Discount or rate of return factor: Default = 1.10 (for 10% ROR)
- PARAM(11): Year in which gas production begins (year):
Default = 2 for onshore Alaska
= 3 for offshore
- PARAM(12): Fraction of gross revenue modeled as the lease bonus payment,
which is capitalized and cost depleted (fraction): Default = 0.0
- PARAM(13): Year after a tangible investment to begin its depreciation
(Years): Default = 0.0
- PARAM(14): Reserved for possible future use (Currently = 0.0)
- PARAM(15): Reserved for possible future use (Currently = 0.0)

LINE 3

OPTN(1): Specifies whether cost escalation is in effect*
OPTN(1) = 1 : Cost escalation is in effect
OPTN(1) = 0 : Cost escalation is not in effect
Default = 0

OPTN(2): Specifies whether a lease bonus is determined
OPTN(2) = 1 : Lease bonus is determined
OPTN(2) = 0 : Lease bonus is not determined
Default = 0

OPTN(3): Reserved for possible future use (Currently = 0)

OPTN(4): Reserved for possible future use (Currently = 0)

ADFAC : Hostility and transportation cost adjustment factor. For certain costs items, costs are calculated based on installation in the onshore Lower 48. This factor adjusts these costs for either onshore Alaska or offshore settings
Default = 2.0 for onshore Alaska
= 1.5 for offshore

REG : Code specifying region to be analyzed
REG = 1 : Onshore Alaska
REG = 2 : Offshore

Examples of the HGRMO.INP and HGRMA.INP data files are presented in Appendix B-1.

* See Appendix A.

1.1.2. **HYD.INP**

The input data file **HYD.INP** consists of key reservoir characterization parameters and production and injection streams. Often the file will be output from a gas hydrates recovery model. The format of the file is as follows:

Line 1: IRES (A32)
Line 2: ITECH, NYRS, DEPTH
Line 3: Onshore Alaska: AGRES
 Offshore : NWELLS, NIWELLS, WD
Line 4: TSATF, T2F, H1, L,X
Line 5 to NYRS + 4 (from **HGRM.INP**): GPROD(IYR), Y1INJ(IYR), WATPROD(IYR)

The definitions of these items are given below.

Line 1

HEADIN: Heading identifying the file (Not to exceed 32 characters)

Line 2

ITECH: Specifies technology used for thermal stimulation

 ITECH = 1 : Steam soak

 ITECH = 2 : Steam drive

NYRS: Number of years of steam injection water production (years)

DEPTH: Reservoir depth (feet). For offshore, it is the depth below the
 mud line

Line 3

ACRES: Number of acres per well for an Alaska onshore hydrates gas
 production well

NWELLS: Number of gas/water production wells on an offshore platform*

NIWELLS: Number of steam injection wells on an offshore platform*

WD: Water depth (feet)

Line 4

TSATF: Temperature of saturated steam injected, °F (from THERM)

T2F: Final reservoir temperature (final temperature of produced water),
°F. (from THERM)

H1: Enthalpy of saturated liquid at TSATF, Btu/lb (from THERM)

L: Latent heat of vaporization at TSATF, Btu/lb (from THERM)

X: Steam quality, fraction (from THERM)

Lines 5 through NYRS + 4

GPROD(IYR): Gas production during the year (in Mcf) per production well

YLINJ(IYR): Steam injected for the year (in Ebbls of water equivalent) per
injection well

WATPROD(IYR): Water produced for the year (in Ebbls) per production well

Examples of HYD.INP data files are presented in Appendix B-2 for both the onshore Alaska and offshore settings.

*Under the steam soak case, wells are assumed to be dual completion, such that steam injection and gas/water production occur from the same well. Thus, NIWELLS = NWELLS equals the number of slots in the platform.

1.2 Running HGBM

Obviously, it is important that the parameters in HGBMO.INP or HGBMA.INP and HYD.INP correspond to the situation being modeled. However, HGBM offers the opportunity to alter certain parameters during execution. This allows for sensitivity analyses to be performed on specified parameters (e.g., tax rates or drilling costs) with all other parameters remaining constant.

1.2.1. Selecting the Solution Procedure

After the input data files HGBMO.INP or HGBMA.INP and HYD.INP have been established, HGBM is ready for execution. To execute the model, type RUN HGBM after the \$ prompt in the VAX/VMS operating system. The model will respond with:

```
ARE YOU PERFORMING THE ECONOMIC ANALYSIS
FOR ONSHORE ALASKA (ENTER 1)
OR OFFSHORE (ENTER 2) CONDITIONS
```

If the user intends to perform the economic analysis for an onshore Alaska setting, Option 1 should be selected. If analysis is to be performed for an offshore setting, Option 2 should be selected.

The model then responds with:

```
*****
LEWIN AND ASSOCIATES, INC.
ECONOMICS SUBROUTINE-GAS PRODUCTION FROM HYDRATES
INTERACTIVE DATA ENTRY

DO YOU WISH TO SOLVE FOR GAS PRICE (ENTER 1)
          RATE OF RETURN      (ENTER 2)
          OR SET BOTH         (ENTER 3)
*****
```

Option 1 allows the user to select a desired rate of return, and **HGEM** will determine the minimum economic gas price (in \$/Mcf) required to achieve this rate. Option 2 allows the user to select a desired gas price (in \$/Mcf) and **HGEM** determines the rate of return on capital obtained for that price. Option 3 allows the user to set both the gas price and desired rate of return with **HGEM** determining the resulting cash flow for the project.

If Option 1 is selected, the model responds with:

CURRENT DISCOUNT FACTOR = 1.10
ENTER NEW VALUE OR ZERO TO CONTINUE

The default discount factor is 1.10, corresponding to a 10% rate of return. If the user would like another discount factor (greater than 1.00), then that factor should be entered. Otherwise, the user should enter 0, and the default value (1.10) will be used.

If Option 2 is selected, the model responds with:

GAS PRICE, \$/Mcf 3.00
ENTER NEW VALUE OR ZERO TO CONTINUE

The default gas price is \$3.00/Mcf. If the user would like to use another gas price, that price should be entered. Otherwise, the user should enter 0, and the default value will be used.

If Option 0 is selected, the user would like to specify both the gas price and rate of return, with **HGEM** calculating the cash flow to result from the selection. Under this option, the model responds with:

CURRENT DISCOUNT FACTOR = 1.10
ENTER NEW VALUE OR ZERO TO CONTINUE

If the user is satisfied with the default value, then 0 should be entered. Otherwise the desired discount factor should be entered. The model then responds with:

GAS PRICE, \$/Mcf 3.00
ENTER NEW VALUE OR ZERO TO CONTINUE

Again, if the user is satisfied with the default value, 0 should be entered. Otherwise, the desired gas price should be entered.

1.2.2. Selecting Financial Parameters

After the desired solution procedure has been selected and the necessary parameters defined, the model responds with:

DEFAULT VALUES FOR THE FINANCIAL PARAMETERS ARE AS FOLLOWS:

ITEM 1:	OPERATING COST OVERHEAD (FRACTION)	0.2000
ITEM 2:	G & A RATE ON INVESTMENT (FRACTION)	0.1000
ITEM 3:	DEPRECIATION LIFE (YEARS)	10.0000
ITEM 4:	ROYALTY RATE (FRACTION)	0.1250 (for onshore Alaska) 0.1670 (for offshore)
ITEM 5:	SEVERANCE TAX RATE (FRACTION)	0.0800 (for onshore Alaska) 0.0000 (for offshore)
ITEM 6:	WINDFALL PROFITS TAX RATE (FRACTION)	0.0000
ITEM 7:	INCOME TAX CREDIT RATE (FRACTION)	0.1000
ITEM 8:	STATE INCOME TAX RATE (FRACTION)	0.0800 (for onshore Alaska) 0.0000 (for offshore)
ITEM 9:	FEDERAL INCOME TAX RATE (FRACTION)	0.4600
ITEM 10:	DISCOUNT FACTOR	1.1000
ITEM 11:	YEAR IN WHICH SALES BEGIN (YEAR)	2.0000 (for onshore Alaska) 3.0000 (for offshore)
ITEM 12:	LEASE BONUS CAPITAL. RATE (FRACTION)	0.0000

IF YOU WISH TO CHANGE ANY OF THESE VALUES,
ENTER THE NUMBER(S) OF THE ITEM(S) TO BE CHANGED,
ONE AT A TIME.
IF NO CHANGES ARE DESIRED ENTER 0 (ZERO)

The definitions of these items are as follows:

- ITEM 1: Overhead rate for operating costs (fraction): Default = 0.20
- ITEM 2: General and administrative (G&A) rates for investment costs
(fraction) : Default = 0.10
- ITEM 3: Useful life of a capital investment for purposes of depreciation
(years) : Default = 10
- ITEM 4: Royalty rate on revenues from hydrates gas production (fraction) :
Default = 0.125 for onshore Alaska
= 0.167 for offshore
- ITEM 5: State severance tax rate on revenues from hydrates gas production
(fraction) : Default = 0.08 for onshore Alaska
= 0.00 for offshore
- ITEM 6: Windfall profits tax rate on revenues from hydrates gas production
(fraction): Default = 0.00
- ITEM 7: Income tax credit rate on capital investment (fraction) :
Default = 0.10
- ITEM 8: State income tax rate on revenues from hydrates gas production
(fraction) : Default = 0.08 for onshore Alaska
= 0.00 for offshore
- ITEM 9: Federal income tax rate on revenues from hydrates gas production
(fraction) : Default = 0.46

ITEM 10: Discount or rate of return factor : Default = 1.10 (for 10% ROR)

ITEM 11: Year in which gas production sales begin (year) :

Default = 2 for onshore Alaska

= 3 for offshore

ITEM 12: Fraction of gross revenue modeled as the lease bonus payment, which is capitalized and cost depleted (fraction) : Default = 0.000

If no changes to the parameter values presented are required, the user should enter 0. If any changes are necessary, the user should enter the item number of the first parameter value to be changed. The model will prompt the user for the specific value desired. If other changes are required, the user should continue this process, changing one item at a time, until no additional parameter values require changing. At that point, the user should enter 0.

1.2.3. Selection of Cost Adjustment Factor

After the desired financial parameters have been selected the model responds with:

THE HOSTILITY AND TRANSPORTATION COST

ADJUSTMENT FACTOR FOR THE ALASKA ONSHORE

2.0

ENTER DESIRED VALUE OR ZERO IF THE GIVEN VALUE IS OKAY

for Alaska onshore, or

THE HOSTILITY AND TRANSPORTATION COST

ADJUSTMENT FACTOR FOR THE OFFSHORE

1.5

ENTER DESIRED VALUE OR ZERO IF THE GIVEN VALUE IS OKAY

for the offshore setting.

The hostility and transportation cost adjustment factor is applied to certain capital and operating cost items derived for drilling in the Lower 48, to bring those costs in line to what might be expected in the harsher environments in Alaska and the offshore. Cost adjustment factors of this type are commonly used in engineering costing. The default value selected are conventionally applied in performing cost estimation in the specified environments.

If the user wishes to specify a cost adjustment factor, that factor should be entered. If no change to the value specified is desired, the user should respond by entering 0 (zero).

1.2.4 Selection of Component Costs

Next, the model lists a series of capital and operating cost items along with the calculated default values for these items. The calculated cost defaults and model and user responses are specific to whether analysis is performed on the onshore Alaska or offshore setting. Also, analysis in the onshore Alaska is performed on a single-well basis, while analysis in the offshore setting is performed on the basis of an offshore platform. Because of the differences in the analysis procedure and model responses, the onshore Alaska and offshore situations are covered separately below.

1.2.4.1 Onshore Alaska

If the analysis for the onshore Alaska setting has been selected, the model lists a series of general capital cost items along with the calculated default values for these items (see Appendix C-1 for a description of the default cost equations). The model responds with the following:

DRILLING AND COMPLETION COSTS PER WELL	
FOR A 2,000.00 FOOT WELL (\$/WELL)	275,853.00
 COST FOR INSULATED TUBING (\$/FOOT)	 27.00
 PRODUCTION AND LEASE EQUIPMENT COSTS FOR A MAXIMUM	
GAS PRODUCTION RATE OF 1,415.14 MCF/DAY/WELL	

WELL PRODUCTION EQUIPMENT (\$/WELL)	234,908.00
GATHERING SYSTEM (\$/WELL)	42,303.00
LEASE EQUIPMENT (\$/WELL)	133,211.00
DEHYDRATOR (\$/WELL)	30,000.00

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

The model asks of any changes to the model-generated, default costs are desired. If no changes are desired, the user should respond by entering N. If a change to any of the listed items is desired, the user should respond by entering Y. At this point, the model will list the costs for each item, and ask if changes to the particular item are desired. If a change to the particular item is desired, the user should enter the appropriate value. If the value displayed for the item is adequate, the user should enter 0. A list of examples of the model responses is given below:

DRILLING AND COMPLETION COSTS PER WELL
FOR A 2,000.00 FOOT DEEP WELL 275,853.00
ENTER NEW VALUE OR ZERO TO CONTINUE

INSULATED TUBING COSTS PER FOOT 27.00
ENTER A NEW VALUE OR ZERO TO CONTINUE

PRODUCTION AND LEASE EQUIPMENT COSTS PER WELL
FOR A MAXIMUM GAS PRODUCTION RATE
PER WELL OF 1,415.14 MCF/DAY

PRODUCTION EQUIPMENT COSTS PER WELL 234,908.00
ENTER NEW VALUE OR ZERO TO CONTINUE

GATHERING SYSTEM COSTS PER WELL 42,303.00
ENTER NEW VALUE OR ZERO TO CONTINUE

LEASE EQUIPMENT COST PER WELL 133,211.00
ENTER NEW VALUE OR ZERO TO CONTINUE

DEHYDRATOR COSTS PER WELL 30,000.00
ENTER NEW VALUE OR ZERO TO CONTINUE

Next, the model lists a set of capital cost items which are specific to the steam injection facility, as follows:

PROCESS-SPECIFIC COSTS FOR STEAM INJECTION

FOR A MAXIMUM INJECTION RATE OF 911.35 BBL/DAY/WELL

STEAM GENERATOR COSTS FOR A 50 MMBTU,
3,500 BHPD FACILITY (90% EFFICIENCY) 650,000.00

SCRUBBER COST FOR STEAM GENERATOR 0.00

STEAM MANIFOLD AND FLOW LINES (\$/ACRE) 8,750.00

HEATER TREATER AND VAPOR RECOVERY UNIT
(\$/ACRE) 5,500.00

PRODUCED WATER RECYCLE PLANT (\$ PER BBL/DAY CAPACITY) 75.00

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

Again, if no change to these cost items are desired, the user should enter N. Otherwise, Y should be entered, and the model responds with the default cost for each of the above items, and the user should enter the value desired or zero if the given value is sufficient. A list of examples of the model responses is given below:

STEAM GENERATOR COSTS FOR A 50 MMBTU,
3,500 BHPD FACILITY (90% EFFICIENT) 650,000.00
ENTER NEW VALUE OR ZERO TO CONTINUE

SCRUBBER COSTS FOR STEAM GENERATOR 0.00
ENTER NEW VALUE OR ZERO TO CONTINUE

STEAM MANIFOLD AND FLOW LINE COSTS PER ACRE 8,750.00
ENTER NEW VALUE OR ZERO TO CONTINUE

HEATER TREATER AND VAPOR RECOVERY
SYSTEM COSTS PER ACRE 5,500.00
ENTER NEW VALUE OR ZERO TO CONTINUE

COSTS OF THE PRODUCED WATER RECYCLE PLANT,
IN \$ PER BBL/DAY CAPACITY 75.00
ENTER NEW VALUE OR ZERO TO CONTINUE

Next, the model lists the set of operating cost items, as follows:

AVERAGE ANNUAL PRIMARY OPERATING COSTS
FOR A 2,000.00 FOOT DEEP WELL
PRODUCING AN AVERAGE RATE OF 1,179.3
MCF/DAY/WELL 45,434.00

PROCESS-SPECIFIC OPERATING COSTS FOR AN AVERAGE
STEAM INJECTION RATE OF 759.5 BBL/DAY/WELL

O & M COSTS FOR STEAM GENERATION
(\$ PER BBL OF STEAM INJECTED) 0.1000

OPERATING COSTS FOR THE WATER RECYCLING PLANT
(\$ PER BBL OF STEAM INJECTED) 0.1250

COSTS FOR WATER DISPOSAL
(\$ PER BBL OF STEAM INJECTED) 0.0000

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

Again, if no changes to these costs items are desired, the user should enter N. Otherwise, Y should be entered, and the model responses with each cost item. The user should enter zero if the given value is sufficient, or should enter the value desired. The list of examples of the model responses is given below:

AVERAGE ANNUAL PRIMARY OPERATING COSTS FOR A
2,000 FOOT WELL PRODUCING AT AN
AVERAGE GAS PRODUCTION RATE OF 1,179.3 MCF/DAY/WELL 45,434.00
ENTER NEW VALUE OR ZERO TO CONTINUE

FOR AN AVERAGE STEAM INJECTION RATE OF
759.5 BBL/DAY/WELL

O & M COSTS FOR STEAM GENERATION,
\$ PER BBL STEAM INJECTED 0.1000
ENTER NEW VALUE OR ZERO TO CONTINUE

OPERATING COSTS FOR THE WATER RECYCLE PLANT,
\$ PER BBL STEAM INJECTED 0.1250
ENTER NEW VALUE OR ZERO TO CONTINUE

WATER DISPOSAL COSTS,
\$ PER BBL STEAM INJECTED 0.0000
ENTER NEW VALUE OR ZERO TO CONTINUE

Finally the model responds with:

TANGIBLE CAPITAL COSTS INCLUDE
40% OF ALL DRILLING & COMPLETION COSTS,
AND ALL OTHER CAPITAL COSTS

INTANGIBLE CAPITAL COSTS INCLUDE
60% OF ALL DRILLING & COMPLETION COSTS

DO YOU WISH TO CHANGE THIS ALLOCATION, Y OR N?

If this allocation of the tangible and intangible components of capital investment costs is adequate, the user should enter N. If the user would like to change this allocation, Y should be entered. If Y is entered, the model responds with:

ENTER PERCENT (%) OF DRILLING AND COMPLETION COST
WHICH ARE TANGIBLE

which prompts the user for the percentage of capital costs which is considered tangible. In response, the user should enter the desired value, as a percent.

1.2.4.2 Offshore

If analysis for the offshore setting has been selected, the model again lists a series of general capital cost items along with the calculated default values for these items (see Appendix C-2 or a description of the default cost equations). The model responds with the following:

FOR A 32. SLOT PLATFORM, IN
2,000 FEET OF WATER

THE COST OF A TENSION LEG PLATFORM	127,584,000.00
PLATFORM ABANDONMENT COSTS AT END OF PROJECT	2,900,000.00

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

The model asks if any changes to the model-generated, default costs are desired. If no changes are desired, the user should respond by entering N. If a change to any of the items is desired, the user should respond by entering Y. At this point, the model will list the costs for each item, and ask if changes to the particular item are desired. If a change to a particular item is desired, the user should enter the appropriate value. If the value displayed for the item is adequate, the user should enter 0. Example of model responses are given on the following page:

COST OF A TENSION LEG PLATFORM 127,584,000.00
ENTER NEW VALUE OR ZERO TO CONTINUE

PLATFORM ABANDONMENT COSTS AT END OF PROJECT 2,900,000.00
ENTER NEW VALUE OR ZERO TO CONTINUE

Next, the model lists the remaining general capital cost items along with the calculated default cost values, as follows:

DRILLING AND COMPLETION COSTS PER WELL
FOR A 2,000.00 FOOT WELL (\$/WELL) 720,000.00

COST FOR INSULATED TUBING (\$/FOOT) 27.00

PRODUCTION AND LEASE EQUIPMENT COSTS FOR A MAXIMUM
GAS PRODUCTION RATE OF 1,415.14 MCF/DAY/WELL

WELL PRODUCTION EQUIPMENT (\$/PRODUCTION WELL) 191,181.00
GATHERING SYSTEM (\$/PRODUCTION WELL) 34,727.00
LEASE EQUIPMENT (\$/PRODUCTION WELL) 99,908.00
DEHYDRATOR (\$/PRODUCTION WELL) 22,500.00

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

If no changes to these cost items are desired, the user should enter N. Otherwise, Y should be entered, and the model responds with the default cost value for each of the above items. The user should enter the value desired or zero if the given value is sufficient. A list of example model responses is given below:

DRILLING AND COMPLETION COSTS PER WELL
FOR A 2,000.00 FOOT DEEP WELL 720,000.00
ENTER NEW VALUE OR ZERO TO CONTINUE

INSULATED TUBING COSTS PER FOOT 27.00
ENTER NEW VALUE OR ZERO TO CONTINUE

PRODUCTION AND LEASE EQUIPMENT COSTS PER WELL
FOR A MAXIMUM GAS PRODUCTION RATE
PER WELL OF 1,415.14 MCF/DAY

PRODUCTION EQUIPMENT COSTS PER PRODUCTION WELL 191,181.00
ENTER NEW VALUE OR ZERO TO CONTINUE

GATHERING SYSTEM COSTS PER PRODUCTION WELL 34,727.00
ENTER NEW VALUE OR ZERO TO CONTINUE

LEASE EQUIPMENT COSTS PER PRODUCTION WELL 99,908.00
ENTER NEW VALUE OR ZERO TO CONTINUE

DEHYDRATOR COSTS PER PRODUCTION WELL 22,500.00
ENTER NEW VALUE OR ZERO TO CONTINUE

Next, the model lists a set of capital cost items which are specific to the steam injection facility, as follows:

PROCESS-SPECIFIC COSTS FOR STEAM INJECTION
FOR A MAXIMUM INJECTION RATE OF 911.35 BBL/DAY/WELL

STEAM GENERATOR COSTS FOR A 50 MMBTU, 3,500 BHPD FACILITY (90% EFFICIENCY)	650,000.00
SCRUBBER COST FOR STEAM GENERATOR	0.00
STEAM MANIFOLD AND FLOW LINES (\$/PLATFORM)	127,500.00
HEATER TREATER AND VAPOR RECOVERY UNIT (\$/PLATFORM)	82,500.00
PRODUCED WATER RECYCLE PLANT (\$ PER BBL/DAY CAPACITY)	75.00

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

Again, if no change to these cost items are desired, the user should enter N. Otherwise, Y should be entered, and the model responds with the default cost for each of the above items. The user should enter the value desired or zero if the given value is sufficient. A list of examples of the model responses is given below:

STEAM GENERATOR COSTS FOR A 50 MMBTU,
3,500 BWPD FACILITY (90% EFFICIENT) 650,000.00
ENTER NEW VALUE OR ZERO TO CONTINUE

SCRUBBER COSTS FOR STEAM GENERATOR 0.00
ENTER NEW VALUE OR ZERO TO CONTINUE

STEAM MANIFOLD AND FLOW LINE COSTS PER PLATFORM 127,500.00
ENTER NEW VALUE OR ZERO TO CONTINUE

HEATER TREATER AND VAPOR RECOVERY
SYSTEM COSTS PER PLATFORM 82,500.00
ENTER NEW VALUE OR ZERO TO CONTINUE
COSTS OF THE PRODUCED WATER RECYCLE PLANT,
IN \$ PER BBL/DAY CAPACITY 75.00
ENTER NEW VALUE OR ZERO TO CONTINUE

Next the model lists the set of operating cost items, as follows:

AVERAGE ANNUAL PLATFORM OPERATING COSTS
FOR 2,000 FOOT WELLS
IN 2,000 FEET OF WATER
PRODUCING AT AN AVERAGE RATE OF 1,179.3
MCF/DAY/WELL 3,566,423.00

PROCESS-SPECIFIC OPERATING COSTS OF AN AVERAGE
STEAM INJECTION RATE OF 759.5 BBL/DAY/WELL

O & M COSTS FOR STEAM GENERATION
(\$ PER BBL OF STEAM INJECTED) 0.1000

OPERATING COSTS FOR THE WATER RECYCLING PLANT
(\$ PER BBL ON STEAM INJECTED)

0.1250

COSTS FOR WATER DISPOSAL
(\$ PER BBL OF STEAM INJECTED)

0.0000

DO YOU WISH TO CHANGE ANY OF THESE COST VALUES
Y OR N

Again, if no changes to these costs items are desired, the user should enter N. Otherwise, Y should be entered, and the model responds with each cost item. The user should enter zero if the given value is sufficient, or should enter the value desired. The list of examples of the model responses is given below:

AVERAGE ANNUAL PLATFORM OPERATING COSTS FOR THE
2,000 FOOT WELLS PRODUCING AT AN
AVERAGE GAS PRODUCTION RATE OF 1,179.3 MCF/DAY/WELL 3,566,423.00
ENTER NEW VALUE OR ZERO TO CONTINUE

FOR AN AVERAGE STEAM INJECTION RATE OF
759.5 BBL/DAY/WELL

O & M COSTS FOR STEAM GENERATION,
\$ PER BBL STEAM INJECTED
ENTER NEW VALUE OR ZERO TO CONTINUE

0.1000

OPERATING COSTS FOR THE WATER RECYCLE PLANT,
\$ PER BBL STEAM INJECTED
ENTER NEW VALUE OR ZERO TO CONTINUE

0.1250

WATER DISPOSAL COSTS,
\$ PER BBL STEAM INJECTED
ENTER NEW VALUE OR ZERO TO CONTINUE

0.0000

Finally the model responds with:

TANGIBLE CAPITAL COSTS INCLUDE

30% OF ALL DRILLING & COMPLETION COSTS,

90% OF ALL PLATFORM COSTS

AND ALL OTHER CAPITAL COSTS

INTANGIBLE CAPITAL COSTS INCLUDE

10% OF ALL PLATFORM COSTS, AND

7% OF ALL DRILLING & COMPLETION COSTS

DO YOU WISH TO CHANGE THIS ALLOCATION, Y OR N

If this allocation of the tangible and intangible components of capital investment costs is adequate, the user should enter N. If the user would like to change this allocation, Y should be entered. If Y is entered, the model responds with:

ENTER PERCENT (%) OF DRILLING AND COMPLETION COSTS
WHICH ARE TANGIBLE

which prompts the user for the percentage of capital costs which is considered tangible. In response, the user should enter the desired value, as a percent.

At this point, the interactive data entry procedure of **HGEM** is complete, and the model informs the user of the output file name to which the model output has been written. An example of an output file from **HGEM** (file name **HGEM.OUT**) is presented in Appendix D.

APPENDIX A
COST ESCALATION

To establish a linkage between costs and changes in gas prices, the model employs the results of a detailed assessment prepared by the NPC* of price and cost trends over the period 1970-1982. Appropriate published indices were used to reduce all elements of cost and price to constant dollars. The base gas price is based on the energy value equivalent oil price of \$30/Bbl (or \$3.85/Mcf). Based on this analysis, the cost escalation factors were determined to be:

Fuel Cost Escalator: 100 percent of gas price change.

Drilling and Equipment Cost Escalator: 35 percent of gas price change.

Operating Cost Escalator: 20 percent of gas price change.

The factors are computed relative to a \$3.85 nominal gas price as follows.

$$\begin{aligned}\text{PRCHG} &= \text{Gas price change relative to } \$3.85/\text{Mcf} \\ &= (\text{GPRICE} - 3.85)/3.85\end{aligned}$$

Note: PRCHG is defined to be zero if GPRICE is less than \$3.85/Mcf.

$$\begin{aligned}\text{FUESC} &= \text{Fuel cost escalator} \\ &= 1.0 + \text{PRCHG}.\end{aligned}$$

$$\begin{aligned}\text{DECESC} &= \text{Drilling and equipment cost escalator} \\ &= 1.0 + 0.35 * \text{PRCHG}.\end{aligned}$$

$$\begin{aligned}\text{OPESC} &= \text{Operating cost escalator} \\ &= 1.0 + 0.2 * \text{PRCHG}.\end{aligned}$$

* Source: National Petroleum Council, EOB (Washington, DC, 1984).

APPENDIX B-1

EXAMPLE OF THE HGRMA.INP INPUT DATA FILE

(Onshore Alaska)

ALASKA ONSHORE SAMPLE
1,9,2000.
20.
128894.,55923.,125365.
301812.,142817.,305208.
379424.,160221.,324480.
529002.,342355.,665753.
592441.,401493.,718578.
524432.,380128.,660519.
532351.,420072.,704390.
553659.,314739.,613917.
331932.,277060.,455948.

Example of THE HGRMO.INP INPUT DATA FILE

(Offshore)

OFFSHORE GULF OF MEXICO EXAMPLE
1,9,2000.
32.,0.,2000.
128894.,55923.,125365.
301812.,142817.,305208.
379424.,160221.,324480.
529002.,342355.,665753.
592441.,401493.,718578.
524432.,380128.,660519.
532351.,420072.,704390.
553659.,314739.,613917.
331932.,277060.,455948.

APPENDIX B-2

EXAMPLE OF THE HYD. INP INPUT DATA FILE

(Onshore Alaska)

0.20,0.10,9.0,0.125,0.08,0.00,0.10,0.08,0.46,
1.10,2.0,0.000,0.0,0.0,0.0,
0,0,0,0,2.0,1,,

Example of the HYD. INP INPUT DATA FILE

(Offshore)

0.20,0.10,9.0,0.167,0.00,0.00,0.10,0.00,0.46,
1.10,3.0,0.000,0.0,0.0,0.0,
0,0,0,0,1.5,2

APPENDIX C
SAMPLE CALCULATIONS

APPENDIX C-1

ENGINEERING COSTING FOR
ALASKA ONSHORE
HYDRATE GEM

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for Sample</u> <u>2,000 Foot Well</u> (1984\$)
1. Pre-Development Costs	-	-
2. Development Costs for Wells		
● Drilling and Completion	$2 * [82,000(\exp 0.26 * \text{Depth} * 10^{-3})]$	\$275,900
● Insulated Tubing	\$27 (Depth)	54,000
● Well Production Equipment	$2 * [\$65,000 + \$30(\text{Mcf/d}) + \$5(\text{Depth})]$	180,000
● Gathering System	$2 * [\$5,000 + \$10(\text{Mcf/d}) + \$1(\text{Depth})]$	24,000
● Lease Equipment	$2 * [\$10,000 + \$40(\text{Mcf/d})]$	60,000
● Dehydrator	$2 * [\$15,000]$	30,000
● Allocated Dry Holes	-	-
● Special Lease Costs	-	-
3. Process Specific Costs		
● Steam Generator	$2 * [\$650,000 \times \frac{\text{BBL/D Steam Injected}}{3,500 \times 0.90}]$	82,500
● Steam Manifold & Lines	$2 * [\$8,750/\text{Acre}] * (\text{Acres})$	175,000
● Heater Treater and Vapor Recovery	$2 * [\$5,500/\text{Acre}] * (\text{Acres})$	110,000
● Produced Water Recycle Plant	$2 * [\$75 \text{ BBL/D Steam Injected}]$	30,000

APPENDIX C-1

ENGINEERING COSTING FOR
ALASKA ONSHORE
HYDRATE GEM
(continued)

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for Sample</u> <u>2,000 Foot Well</u> (1984\$)
4. Well Operating and Maintenance Costs	$2*[10,000+4(\text{Mcf/d})+4(\text{Depth})]$	\$ 40,000
5. Process-Specific Operating Costs		
o Generator O&M (Gas Fired)	$2*[\$0.10*\text{BBL Steam Injected}](365*\text{BBL/D})$	14,600
o Water Recycle Plant	$2*[\$0.125*\text{BBL Steam Injected}](365*\text{BBL/D})$	18,250
o Water Disposal*	-	-
6. Fuel Costs		
o Lease Fuel	(Assumes produced natural gas is used as fuel)	

* Produced water is recycled and reinjected as steam.

APPENDIX C-2
ENGINEERING COSTING FOR
OFFSHORE BLAKE BAHAMAS
HYDRATE GEM

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	Costs for a Sample 2,000 Foot Well in <u>2,000 Feet of Water</u> (1,000 1984\$)
1. Pre-Development Costs	-	-
2. Platform Costs		
o Tension Leg Platform	$\$64,000 + \$10(\text{Water Depth}) + \$62(\text{Slots})$ $(\$0.65 * \text{Water Depth} * \text{Slots})$	\$127,580
3. Development Costs for Wells		
o Well Drilling and Completion	$(\$460,000 + 130(\text{Well Depth} - 2,000)) * \text{Slots}$	23,040
o Insulated Tubing	$\$27 (\text{Total Depth})(\text{Slots})$	3,460
o Well Production Equipment	$(\text{Slots}) * 1.5 * [\$65,000 + \$30(\text{Mcf/d/Well}) + \$5(\text{Total Depth})]$	5,520
o Gathering System	$(\text{Slots}) * 1.5 * [\$5,000 + \$10(\text{Mcf/d/Well}) + \$1(\text{Total Depth})]$	910
o Lease Equipment	$(\text{Slots}) * 1.5 * [\$10,000 + \$40(\text{Mcf/d/Well})]$	2,400
o Dehydrator	$(\text{Slots}) * 1.5 * [\$15,000]$	720
o Allocated Dry Holes	-	-
o Special Lease Costs	-	-

APPENDIX C-2
ENGINEERING COSTING FOR
OFFSHORE ELAKE BAHAMAS
HYDRATE GEM
(continued)

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for a Sample</u> <u>2,000 Foot Well in</u> <u>2,000 Feet of Water</u> (1,000 1984\$)
3. Process Specific Costs		
o Steam Generator	$1.5 * [\$650,000 \times \frac{\text{EBL/D Steam Injected}}{3,500 \times 0.90}] (\text{Slots})$	\$3,900
o Steam Manifold & Lines	$1.5 * [\$85,000/\text{Slot}] * (\text{Slots})$	4,080
o Heater Treater and Vapor Recovery	$1.5 * [\$55,000/\text{Slot}] * (\text{Slots})$	2,640
o Produced Water Recycle Plant	$1.5 * [\$75 \text{ EBL/D Steam Injected}] * (\text{Slots})$	1,440
4. Well Operating and Maintenance Costs	$1,700,000 + 500(\text{Water Depth, Ft}) + 5(\text{Well Depth})(\text{Slots}) + 5(\text{Mcf/D Platform})$	3,500
5. Process-Specific Operating Costs		
o Generator O&M (Gas Fired)	$(\text{Slots}) * 1.5 * [\$0.10 * \text{EBL Steam Injected}] * (365 * \text{EBL/D})$	700
o Water Recycle Plant	$(\text{Slots}) * 1.5 * [\$0.125 * \text{EBL Steam Injected}] * (365 * \text{EBL/D})$	440
o Water Disposal*	-	-
6. Fuel Costs		
o Lease Fuel	(Assumes produced natural gas is used as fuel)	

* Produced water is recycled and reinjected as steam.

APPENDIX D
SAMPLE DGEM OUTPUT

1) HGEN./\OUT
22-MAY-85

LEWIN AND ASSOCIATES, INC.
COST AND ECONOMIC ANALYSIS
OF
GAS PRODUCTION FROM GAS HYDRATES

SUMMARY OF FIELD DEVELOPMENT AND PRODUCTION COSTS

ALASKA ONSHORE

STEAM SOAK

FINANCIAL ANALYSIS PARAMETERS

OPERATING COST OVERHEAD (FRACTION)	0.2000
G & A RATE ON INVESTMENT (FRACTION)	0.1000
DEPRECIATION LIFE (YEARS)	10.0000
ROYALTY RATE (FRACTION)	0.1250
SEVERANCE TAX RATE (FRACTION)	0.0800
WINDFALL PROFITS TAX RATE (FRACTION)	0.0000
INCOME TAX CREDIT RATE (FRACTION)	0.1000
STATE INCOME TAX RATE (FRACTION)	0.0800
FEDERAL INCOME TAX RATE (FRACTION)	0.4600
DISCOUNT FACTOR	1.1000
YEAR IN WHICH SALES BEGIN (YEAR)	2.0000
LEASE BONUS CAPITAL RATE (FRACTION)	0.0000
YEAR AFTER INVEST. TO BEGIN DEPRECIATION	0.0000

ALASKA ANALYSIS PERFORMED ON A PER WELL BASIS

WELL DEPTH (FEET)	2000.
MAX. STEAM INJECTION RATE PER WELL (BBL/DAY)	240.
MAX. DAILY PRODUCTION RATE PER WELL (MCF/DAY)	600.

ASSUMED STRAIGHT LINE DEPRECIATION

THE COST ADJUSTMENT FACTOR FOR THE ALASKA ONSHORE ENVIRONMENT IS 2.0
INDICATED BY AN "*" IN THE SUMMARY OF COSTS

CAPITAL COSTS PER WELL

COST CATEGORY	THOUSAND DOLLARS (1983)	
DEVELOPMENT COSTS		
DRILLING AND COMPLETION COSTS	275.9	*
INSULATED TUBING COSTS (\$27./FOOT)	54.0	
PRODUCTION AND LEASE EQUIPMENT COSTS FOR A GAS PRODUCTION RATE OF 600.0 MCF/DAY/WELL		
WELL PRODUCTION EQUIPMENT	186.0	*
GATHERING SYSTEM	26.0	*
LEASE EQUIPMENT	68.0	*
DEHYDRATOR	30.0	*
TOTAL PRODUCTION EQUIPMENT	310.0	*
TOTAL DEVELOPMENT COSTS	639.9	
PROCESS-SPECIFIC CAPITAL COSTS		
STEAM GENERATOR COSTS (90% CAPACITY) SIZED ACCORDING TO THE MAXIMUM STEAM INJECTION RATE IN THIS CASE, 0.077 UNITS ARE REQUIRED	99.9	*
SCRUBBER COST	0.0	*
STEAM MANIFOLD AND LINES	175.0	*
HEATER, TREATER AND VAPOR RECOVERY	110.0	*
PRODUCED WATER RECYCLE PLANT	36.0	*
TOTAL PROCESS-SPECIFIC COSTS	420.9	
TOTAL INVESTMENT	1060.7	

OVERLAGE ANNUAL OPERATING COSTS PER WELL

COST CATEGORY	THOUSAND DOLLARS (1983)	
PRIMARY AND SECONDARY OPERATING COSTS	40.0	*
PROCESS SPECIFIC OPERATING COSTS		
STEAM GENERATOR FUEL COSTS	0.0	*
GENERATOR O & M (\$0.10/BBL INJ.)	14.6	*
WATER RECYCLE PLANT (\$0.125/BBL INJ.)	18.3	*
WATER DISPOSAL (\$0.000/BBL INJ.)	0.0	*

TOTAL ANNUAL COSTS 72.9

TANGIBLE CAPITAL COSTS INCLUDE
40.% OF ALL DRILLING & COMPLETION COSTS,
AND ALL OTHER CAPITAL COSTS.

INTANGIBLE CAPITAL COSTS INCLUDE
60.% OF ALL DRILLING & COMPLETION COSTS.

PRODUCTION AND COST SUMMARY
ALASKA GAS HYDRATE PRODUCTION
WITH NO COST ESCALATION AND GROSS PRODUCTION

DRILLED DEPTH (FEET) 2000.0

YEAR	STEAM INJ (B/D)	GAS PROD GROSS (MCF/D)	CUM PROD (MMCF)	TANG INVEST (\$x1000)	INTANG INVEST (\$x1000)	PRIMARY OPER COST (\$x1000)	OTHER OPER COST (\$x1000)	INDIRECT CHARGES (TANG) (\$x1000)	INDIRECT CHARGES (INTANG) (\$x1000)	INDIRECT CHARGES (OPER) (\$x1000)
1	0.	0.	0.	895.	166.	0.	0.	90.	17.	0.
2	200.	500.	183.	0.	0.	40.	33.	0.	0.	15.
3	200.	500.	365.	0.	0.	40.	33.	0.	0.	15.
4	200.	500.	548.	0.	0.	40.	33.	0.	0.	15.
5	200.	500.	730.	0.	0.	40.	33.	0.	0.	15.
6	200.	500.	913.	0.	0.	40.	33.	0.	0.	15.
7	200.	500.	1095.	0.	0.	40.	33.	0.	0.	15.
8	200.	500.	1278.	0.	0.	40.	33.	0.	0.	15.
9	200.	500.	1460.	0.	0.	40.	33.	0.	0.	15.
10	200.	500.	1643.	0.	0.	40.	33.	0.	0.	15.
11	200.	500.	1825.	0.	0.	40.	33.	0.	0.	15.
			1825.	895.	166.	400.	329.	90.	17.	146.

MINIMUM ECONOMIC PRICE FOR GAS AT A 10.00 % DISCOUNT RATE IS \$ 2.40 /MMBTU

ASSUMED GAS SALES PRICE (\$/MCF): 2.40

PROJECT PRO FORMA BUDGET
...COST ESCALATION IS NOT IN EFFECT
.....VALUES SHOWN ARE IN 1983 DOLLARS

22-MAY-85

LEWIN AND ASSOCIATES, INC.
SUMMARY ECONOMICS OUTPUT REPORT
RESERVOIR I.D. ALASKA ONSHORE SAMPLE

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
TOTAL PRODUCTION (BOE)	0.	26431.	26431.	26431.	26431.	26431.	26431.	26431.
OIL PRODUCTION (BBL)	0.	0.	0.	0.	0.	0.	0.	0.
GAS PRODUCTION, NET (MCF)	0.	153300.	153300.	153300.	153300.	153300.	153300.	153300.
TOTAL INJECTION (BBL)	0.	73000.	73000.	73000.	73000.	73000.	73000.	73000.
WATER INJECTED (BBL)	0.	73000.	73000.	73000.	73000.	73000.	73000.	73000.
OTHER INJECTANT (BBL)	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL INVESTMENT	1060721.	0.	0.	0.	0.	0.	0.	0.
CAPITALIZED (TANGIBLE) INVESTMENT	895210.	0.	0.	0.	0.	0.	0.	0.
EXPENSED (INTANGIBLE) INVESTMENT	165512.	0.	0.	0.	0.	0.	0.	0.
CAPITALIZED LEASE BONUS	0.	0.	0.	0.	0.	0.	0.	0.
EXPENSED G&G	0.	0.	0.	0.	0.	0.	0.	0.

REVENUES:

OIL REVENUE	0.	0.	0.	0.	0.	0.	0.	0.
GAS REVENUE	0.	367435.	367435.	367435.	367435.	367435.	367435.	367435.
GROSS REVENUE BASED ON POSTED PRICE	0.	367435.	367435.	367435.	367435.	367435.	367435.	367435.
less ROYALTY	0.	45929.	45929.	45929.	45929.	45929.	45929.	45929.
less SEVERANCE TAX	0.	25720.	25720.	25720.	25720.	25720.	25720.	25720.
NET REVENUE	0.	295785.	295785.	295785.	295785.	295785.	295785.	295785.
COST OF OPERATIONS:								
FUEL & POWER COST	0.	0.	0.	0.	0.	0.	0.	0.
LABOR & MATERIALS COST	0.	54600.	54600.	54600.	54600.	54600.	54600.	54600.
WATER COST	0.	18250.	18250.	18250.	18250.	18250.	18250.	18250.
COST OF OTHER INJECTANTS	0.	0.	0.	0.	0.	0.	0.	0.
G&A ON INVESTMENT	106072.	0.	0.	0.	0.	0.	0.	0.
G&A ON OPERATIONS	0.	14570.	14570.	14570.	14570.	14570.	14570.	14570.
NET REVENUE FROM OPERATIONS	-106072.	208365.	208365.	208365.	208365.	208365.	208365.	208365.
less INTANGIBLE AND G&A	165512.	0.	0.	0.	0.	0.	0.	0.
less DEPRECIATION OF INVESTMENT	89521.	89521.	89521.	89521.	89521.	89521.	89521.	89521.
less RECOVERY OF LEASE BONUS	0.	0.	0.	0.	0.	0.	0.	0.
NET INCOME BEFORE TAXES	-361105.	118844.	118844.	118844.	118844.	118844.	118844.	118844.
less WINDFALL PROFITS TAX	0.	0.	0.	0.	0.	0.	0.	0.
TAXABLE INCOME	-361105.	118844.	118844.	118844.	118844.	118844.	118844.	118844.
less STATE TAX	-28888.	9508.	9508.	9508.	9508.	9508.	9508.	9508.
less FEDERAL TAX	-152819.	50295.	50295.	50295.	50295.	50295.	50295.	50295.
PLUS INCOME TAX CREDITS	89521.	0.	0.	0.	0.	0.	0.	0.
NET INCOME AFTER TAXES	-89876.	59042.	59042.	59042.	59042.	59042.	59042.	59042.
ADJUSTMENTS FOR CASH FLOW:								
less TANGIBLES & LEASE BONUS	895210.	0.	0.	0.	0.	0.	0.	0.
plus DEPRECIATION/REC. LEASE BONUS	89521.	89521.	89521.	89521.	89521.	89521.	89521.	89521.
AFTER TAX CASH FLOW	-895564.	148563.	148563.	148563.	148563.	148563.	148563.	148563.
DISCOUNTED AT 10%	-853887.	128772.	117065.	106423.	96748.	87953.	79957.	72688.

PROJECT PRO FORMA BUDGET

.. COST ESCALATION IS NOT IN EFFECT

.....VALUES SHOWN ARE IN 1983 DOLLARS

CONTINUED...

22-MAY-85

	YEAR 9	YEAR 10	YEAR 11	YEAR TOTAL	YEAR	YEAR	YEAR	YEAR
TOTAL PRODUCTION (BOE)	26431.	26431.	26431.	264310.	0.	0.	0.	0.
OIL PRODUCTION (BBL)	0.	0.	0.	0.	0.	0.	0.	0.
GAS PRODUCTION, NET (MCF)	153300.	153300.	153300.	1533000.	0.	0.	0.	0.
TOTAL INJECTION (BBL)	73000.	73000.	73000.	730000.	0.	0.	0.	0.
WATER INJECTED (BBL)	73000.	73000.	73000.	730000.	0.	0.	0.	0.
OTHER INJECTANT (BBL)	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL INVESTMENT	0.	0.	0.	1060721.	0.	0.	0.	0.
CAPITALIZED (INTANGIBLE) INVESTMENT	0.	0.	0.	895210.	0.	0.	0.	0.
EXPENSED (INTANGIBLE) INVESTMENT	0.	0.	0.	165512.	0.	0.	0.	0.
CAPITALIZED LEASE BONUS	0.	0.	0.	0.	0.	0.	0.	0.
EXPENSED GAO	0.	0.	0.	0.	0.	0.	0.	0.
REVENUES:								
OIL REVENUE	0.	0.	0.	0.	0.	0.	0.	0.
GAS REVENUE	367435.	367435.	367435.	3674352.	0.	0.	0.	0.
GROSS REVENUE BASED ON POSTED PRICE	367435.	367435.	367435.	3674352.	0.	0.	0.	0.
LESS ROYALTY	45929.	45929.	45929.	459294.	0.	0.	0.	0.
LESS COVENANCE TAX	25720.	25720.	25720.	257205.	0.	0.	0.	0.
NET REVENUE	295785.	295785.	295785.	2957853.	0.	0.	0.	0.
COST OF OPERATIONS:								
FUEL & POWER COST	0.	0.	0.	0.	0.	0.	0.	0.
LABOR & MATERIALS COST	54600.	54600.	54600.	546000.	0.	0.	0.	0.
WATER COST	18250.	18250.	18250.	182500.	0.	0.	0.	0.
COST OF OTHER INJECTANTS	0.	0.	0.	0.	0.	0.	0.	0.
SG ON INVESTMENT	0.	0.	0.	106072.	0.	0.	0.	0.
SG ON OPERATIONS	14570.	14570.	14570.	145700.	0.	0.	0.	0.
NET REVENUE FROM OPERATIONS	208365.	208365.	208365.	1977581.	0.	0.	0.	0.
LESS INTANGIBLE AND GAO	0.	0.	0.	165512.	0.	0.	0.	0.
LESS DEPLETION OF INVESTMENT	89521.	89521.	89521.	895210.	0.	0.	0.	0.
LESS RECOVERY OF LEASE BONUS	0.	0.	0.	0.	0.	0.	0.	0.
NET REVENUE BEFORE TAXES	118844.	118844.	118844.	916860.	0.	0.	0.	0.
LESS MINERAL PROFITS TAX	0.	0.	0.	0.	0.	0.	0.	0.
NET INCOME	118844.	118844.	118844.	916860.	0.	0.	0.	0.
LESS STATE TAX	9508.	9508.	9508.	73349.	0.	0.	0.	0.
LESS FEDERAL TAX	50295.	50295.	50295.	388015.	0.	0.	0.	0.
LESS INCOME TAX CREDITS	0.	0.	0.	89521.	0.	0.	0.	0.
NET INCOME AFTER TAXES	59042.	59042.	103516.	545017.	0.	0.	0.	0.
ADJUSTMENTS FOR CASH FLOW:								
LESS INTANGIBLES & LEASE BONUS	0.	0.	0.	895210.	0.	0.	0.	0.
LESS DEPRECIATION/REC. LEASE BONUS	148563.	148563.	103516.	545017.	0.	0.	0.	0.
AFTER TAX CASH FLOW	64080.	64080.	38053.	-74.	0.	0.	0.	0.
DISCOUNTED AT 10%								

ECONOMICS OF GAS PRODUCTION
FROM GAS HYDRATESALASKA ONSHORE SAMPLE
SUMMARY

COST CATEGORY

THOUSAND 1984 \$

\$/MCF

GAS REVENUES

3674.

2.40

TOTAL INVESTMENT	1167.	0.76
G&A ON INVESTMENT	106.	0.07
NORMAL DRILLING, COMPLETION, AND EQUIPMENT COSTS	640.	0.42
PROCESS-SPECIFIC COSTS FOR STEAM INJECTION EQUIPMENT	421.	0.27
 TOTAL OPERATING COSTS PLUS OVERHEAD	 874.	 0.57
OPERATING COSTS	400.	0.26
STEAM INJECTION OPERATING COSTS	329.	0.21
OVERHEAD ON OPERATIONS	146.	0.10
 FINANCIAL COSTS	 1088.	 0.71
ROYALTIES	459.	0.30
SEVERANCE TAXES	257.	0.17
FEDERAL AND STATE TAXES MINUS CREDITS	372.	0.24
 AFTER TAX CASH FLOW (RETURN ON INVESTMENT)	 545.	 0.36
 TOTAL GAS PRODUCTION (MMCF)	 1533.	

III. GAS HYDRATE PRODUCTION ECONOMICS

UNDER CYCLIC THERMAL INJECTION

PRELIMINARY ECONOMIC ASSESSMENT

A. SUMMARY OF RESULTS

INTRODUCTION

IN THIS ANALYSIS, THE HYDRATES GAS PRODUCTION ECONOMICS FROM CYCLIC THERMAL INJECTION WERE ASSESSED FOR TWO GEOLOGIC SETTINGS:

- ONSHORE NORTH SLOPE OF ALASKA, AND
- BLAKE BAHAMAS IN THE OFFSHORE ATLANTIC.

PRESENTED IN THIS SECTION ARE THE RESULTS OF A PRELIMINARY ECONOMIC ASSESSMENT OF THE HYDRATES GAS PRODUCTION ECONOMICS FOR THESE TWO SETTINGS. INCLUDED IN THE PRESENTATION ARE THE GEOLOGIC, RESERVOIR, AND ECONOMIC PARAMETERS ASSUMED FOR EACH SETTING, A SUMMARY OF THE COSTS OF HYDRATE GAS PRODUCTION, AND THE RESULTS OF THE ECONOMIC ANALYSES.

PRODUCTION MODEL RESULTS

RESULTS OF THE MODIFIED HYDMOD STEAM SOAK MODEL PREDICTED GAS PRODUCTION RATES OF ABOUT 400 MCF/D, STEAM INJECTION REQUIREMENTS OF ABOUT 140 BELS (WATER EQUIVALENT) PER DAY AND A INJECTED HEAT REQUIREMENT OF ABOUT 125,000 BTU/MCF PRODUCED GAS.

BASED ON THIS PRELIMINARY WORK, TWO ESTIMATED (SINGLE WELL) GAS PRODUCTION AND STEAM INJECTION STREAMS HAVE BEEN ESTABLISHED:

- THE STEAM SOAK MODEL WILL PRODUCE AN AVERAGE 500 MCF/D OF GAS IN RESPONSE TO A STEAM INJECTION RATE OF 200 BEL/DAY, OVER A PERIOD OF 10 YEARS (A 10-ACRE PATTERN AREA IS ASSUMED FOR THE STEAM SOAK CASE).
- THE STEAM DRIVE MODEL WILL PRODUCE AN AVERAGE 1,500 MCF/D IN RESPONSE TO A STEAM INJECTION RATE OF 600 BELS/DAY, OVER A PERIOD OF 8-12 YEARS. (LARGER WELL SPACING, ADDITIONAL INJECTION WELLS, AND A HIGHER VOLUME PRODUCTION PLANT WOULD BE REQUIRED FOR THE STEAM DRIVE PROCESS).

A SUMMARY OF RESERVOIR PROPERTIES USED IN THE MODEL IS GIVEN IN TABLE 1.

TABLE 1
ROCK, FLUID, AND STEAM PROPERTIES
USED IN THE MODIFIED HYMOD MODEL RUNS

RESERVOIR PROPERTIES

POROSITY.....	30 %
THICKNESS.....	100 ft
ROCK GRAIN DENSITY.....	167 lb/ft ³
ROCK HEAT CAPACITY.....	0.20 BTU/lb/ ^o F
WATER DENSITY.....	62.4 lb/ft ³
WATER HEAT CAPACITY.....	1.0 BTU/lb/ ^o F

HYDRATE

DENSITY.....	55.0 lb/ft ³
HEAT CAPACITY.....	0.61 BTU/lb/ ^o F
ENERGY CONTENT.....	180 ft ³ /ft ³

BASE/CAP ROCK

ROCK GRAIN DENSITY.....	167 lb/ft ³
HEAT CAPACITY.....	0.21 BTU/lb/ ^o F
THERMAL CONDUCTIVITY.....	1.3 BTU/hr/ft/ ^o F

STEAM PROPERTIES (AT THE GIVEN CONDITIONS)

STEAM INJECTION PRESSURE.....	2,000 psia
SATURATED STEAM TEMPERATURE.....	635.8 ^o F
LATENT HEAT OF VAPORIZATION.....	466.2 BTU/lb
SPECIFIC VOLUME OF SATURATED VAPOR.....	0.188 ft ³ /lb
SPECIFIC VOLUME OF SATURATED LIQUID.....	0.025 ft ³ /lb
ENTHALPY OF SATURATED LIQUID.....	672.1 BTU/lb
STEAM QUALITY.....	80 %

ENGINEERING AND ECONOMIC COSTS

AN ENGINEERING-BASED COSTING MODEL IS USED TO DEVELOP SITE SPECIFIC COSTS BASED ON LOCATION, WELL DEPTH, GAS PRODUCTION RATE, AND STEAM INJECTION RATE. THESE COSTS AND EQUATIONS ARE DERIVED FROM WORK BY LEWIN USING VENDOR QUOTES, INDUSTRIAL REFERENCES, AND DOE/EIA COST INDEXES FOR DRILLING AND WELL OPERATIONS.

SAMPLE COSTS ARE CALCULATED FOR:

- AN ONSHORE NORTH SLOPE OF ALASKA STEAM SOAK PROJECT INVOLVING 64 WELLS DRILLED TO 2,000-FOOT DEPTH, PRODUCING 32,000 MCF PER DAY OF METHANE IN RESPONSE TO 12,800 BARRELS (WATER EQUIVALENT) OF STEAM;
- AN OFFSHORE, BLAKE BAHAMAS STEAM SOAK PROJECT CONSISTING OF A 32-SLOT PLATFORM PRODUCING 16,000 MCF PER DAY OF METHANE AND USING 6,400 BARRELS PER DAY OF STEAM; AND
- A STEAM DRIVE PROJECT INVOLVING A 53-SLOT PLATFORM IN THE SAME OFFSHORE AREA PRODUCING 48,000 MCF PER DAY OF METHANE IN RESPONSE TO 19,200 BARRELS PER DAY OF INJECTED STEAM.

ONSHORE ALASKA

THE CAPITAL AND OPERATING COSTS FOR THE FIELD SCALE METHANE HYDRATE PRODUCTION FACILITY INSTALLED ON THE NORTH SLOPE OF ALASKA INCLUDE:

- A SURFACE AREA OF 640 ACRES;
- 64 WELLS, DRILLED TO 2,000 FEET ON 10-ACRE SPACING;
- FIVE 50 MILLION BTU/HR STEAM GENERATORS;
- A STEAM INJECTION AND WATER HANDLING RATE OF 12,800 B/D;
- INSULATED SURFACE LINES AND INSULATED DOWN-HOLE TUBING; AND
- GAS PRODUCTION OF 500 MCF/D PER WELL, EQUAL TO 32,000 MCF/D.

FIGURE 1 PROVIDES A GRAPHICAL REPRESENTATION FOR SUCH A FACILITY.

FIGURE 1

FIELD SCALE METHANE HYDRATE PRODUCTION FACILITY

REQUIRED FACILITIES:

1. 64 WELLS
2. 4, 50MMBTU/HR STEAM GENERATORS
3. 12,800 B/D WATER PLANT
4. 32,000 MCF/D GAS PRODUCTION FACILITIES

RESULTS OF ONSHORE ALASKA ECONOMIC ANALYSIS

- FOR A FIELD SCALE FACILITY PRODUCING FROM 64 WELLS AT 500 MCF/DAY/WELL IN RESPONSE TO A STEAM INJECTION RATE OF 200 EBL/DAY/WELL, THE FOLLOWING COSTS WOULD BE INCURRED, BASED ON THE RANGE ASSOCIATED WITH HOSTILITY AND TRANSPORTATION COST ADJUSTMENT FACTORS FROM 2.0 TO 4.0:
 1. CAPITAL COSTS FROM \$74.7 TO \$145.5 MILLION, BASED ON 64, 10-ACRE PATTERNS AT \$1.17 TO \$2.27 MILLION PER PATTERN.
 2. OPERATING COSTS FROM \$5.6 TO \$11.2 MILLION PER YEAR, BASED ON 64, 10-ACRE PATTERNS AT \$87,400 TO \$175,000 PER PATTERN PER YEAR.
 3. OTHER FINANCIAL COSTS (ROYALTIES, SEVERANCE TAXES, ETC.) OF \$69.6 TO \$136.4 MILLION OVER THE 10-YEAR PROJECT LIFE FOR THE 64 WELL FACILITY.
- BASED ON THIS ANALYSIS, GAS PRODUCTION FROM HYDRATES CAN ECONOMICALLY TAKE PLACE IN THE ONSHORE ALASKA REGION AT WELLHEAD GAS PRICES FROM \$2.40 TO \$4.70 PER MCF.

ADDITIONAL DETAILS ON THESE COSTS IS PROVIDED IN TABLE 2.

TABLE 2
METHANE HYDRATE GAS PRODUCTION FACILITY
COST COMPARISON FOR TWO COST ADJUSTMENT FACTORS*
ONSHORE ALASKA

Cost Component	Costs Per Well			
	Cost Factor = 2.0		Cost Factor = 4.0	
	1984\$ (Thousands)	\$/Mcf	1984\$ (Thousands)	\$/Mcf
1. Revenues	3,674	2.40	7,215	4.71
2. Total Investment	1,167	0.76	2,274	1.48
Regular Drilling & Equip.	640	0.42	1,226	0.13
Thermal Plant	421	0.27	842	0.80
G&A @ 10%	106	0.07	207	0.55
3. Operating Costs (10-Year Project Life)	874	0.57	1,748	1.14
Regular Operating Costs	400	0.26	800	0.52
Thermal Plant	329	0.21	657	0.43
Operating Overhead @ 20%	146	0.10	291	0.19
4. Financial Costs	1,088	0.71	2,132	1.39
Royalties	459	0.30	902	0.59
Severance Taxes	257	0.17	505	0.33
Income Taxes	372	0.24	725	0.47
5. Return on Capital (10% ROR)	545	0.36	1,061	0.69
Total Gas Production (MMcf)			1,533	

* THE HOSTILITY AND TRANSPORTATION COST ADJUSTMENT FACTOR IS APPLIED TO CERTAIN CAPITAL AND OPERATING COST ITEMS DERIVED FOR DRILLING IN THE LOWER 48, TO BRING THOSE COSTS IN LINE TO WHAT MIGHT BE EXPECTED IN THE HARSHER ENVIRONMENTS IN ALASKA AND THE OFFSHORE. COST ADJUSTMENT FACTORS OF THIS TYPE ARE COMMONLY USED IN ENGINEERING COSTING. FOR THIS ANALYSIS, THE COST ADJUSTMENT FACTORS FOR ONSHORE ALASKA WAS ASSUMED TO RANGE FROM 2.0-4.0.

OFFSHORE

CAPITAL AND OPERATING COSTS HAVE ALSO BEEN DEVELOPED FOR A STEAM SOAK AND A STEAM DRIVE METHANE HYDRATE PRODUCTION FACILITY INSTALLED OFFSHORE IN THE BLAKE BAHAMAS. THE FACILITY CONSISTS OF:

- A LEASE AREA OF 640 TO 960 ACRES;
- A 32- AND A 53-SLOT TENSION LEG PLATFORM, IN 2,000 FEET OF WATER;
- 32 PRODUCTION WELLS, DRILLED TO 2,000 FEET BELOW THE SEA FLOOR;
- 21 INJECTION WELLS (FOR THE STEAM DRIVE FACILITY);
- TWO TO SIX 50 MILLION BTU/HR STEAM GENERATORS;
- STEAM INJECTION AND WATER HANDLING RATES OF 6,400 TO 19,200 B/D;
- INSULATED LINES AND INSULATED DOWN-HOLE TUBING; AND
- GAS PRODUCTION OF 500 TO 1,500 MCF/D PER YEAR PER PRODUCTION WELL, EQUAL TO 16,000 TO 48,000 MCF/D PER PLATFORM.

FIGURE 2 PROVIDES A DIAGRAM OF THE FIELD PLAN FOR THE OFFSHORE FACILITY.

IN WATER DEPTHS GREATER THAN 1,200 FEET, A COMPLIANT STRUCTURE (WHOSE COSTS ARE LESS DEPENDENT ON WATER DEPTH) IS PREFERABLE. THE TENSION LEG WELL PLATFORM (TLWP) USED BY CONOCO IN THE GREEN CANYON AREA/GULF OF MEXICO FIELD IS AN EXAMPLE OF SUCH A STRUCTURE.

FIGURE 2
OFFSHORE HYDRATES STEAM DRIVE FIELD PLAN
- 32 Production Wells
- 21 Injection Wells

Prepared By: Lewin and Associates, Inc., 1985.

RESULTS OF THE OFFSHORE ECONOMIC ANALYSIS

- OFFSHORE DEVELOPMENT OF HYDRATES, BECAUSE OF SUBSTANTIALLY HIGHER CAPITAL COSTS ASSOCIATED WITH DRILLING AND PRODUCTION IN DEEPER WATERS, WILL REQUIRE SUBSTANTIALLY HIGHER PRODUCTION RATES THAN THOSE REQUIRED ONSHORE TO BE ECONOMICALLY VIABLE.
- IN PARTICULAR, STEAM SOAK RECOVERY PROCESSES WILL PROBABLY NOT RESULT IN GAS PRODUCTION RATES TO ENABLE PROJECTS TO PRODUCE GAS ECONOMICALLY. FOR EXAMPLE, A 32-WELL PLATFORM, PRODUCING AT 500 MCF/DAY/WELL, WOULD REQUIRE A WELLHEAD GAS PRICE OF \$8.30/MCF TO BE ECONOMIC.
- A STEAM DRIVE FACILITY, WITH 32 PRODUCTION WELLS AND 21 INJECTION WELLS, PRODUCING 1,500 MCF/DAY/WELL IN RESPONSE TO 914 BBL/DAY/WELL OF STEAM INJECTED, WOULD INCUR THE FOLLOWING COSTS:
 1. CAPITAL COSTS FROM \$574-736 MILLION.
 2. OPERATING COSTS OF \$7.64 MILLION/YEAR.
 3. OTHER FINANCIAL COSTS (ROYALTIES, TAXES, ETC.) OF \$152-227 MILLION OVER THE 8-12 YEAR PROJECT LIFE.
- BASED ON THE ANALYSIS, GAS PRODUCTION FROM HYDRATES CAN ECONOMICALLY TAKE PLACE OFFSHORE FROM A STEAM DRIVE FACILITY AT WELLHEAD GAS PRICES FROM \$4.20-4.90/MCF.

ADDITIONAL DETAILS ON THESE COSTS IS PROVIDED IN TABLE 3.

TABLE 3
METHANE HYDRATE GAS PRODUCTION FACILITY
COST COMPARISON FOR STEAM DRIVE AND STEAM SOAK FACILITIES

OFFSHORE BLAKE BAHAMAS				
Cost Adjustment Factor = 1.5*				
<u>Cost Component</u>	<u>Steam Soak</u>		<u>Steam Drive</u>	
	1984\$ (Millions)	\$/Mcf	1984\$ (Millions)	\$/Mcf
1. Revenues	812.7	8.28	574.1-785.9	4.17-4.88
2. Total Investment	192.5	1.96	255.5	1.45-2.17
Regular Drilling & Equip.	165.0	1.68	217.2	1.23-1.84
Thermal Plant	10.0	0.10	15.1	0.09-0.13
G&A @ 10%	17.5	0.18	23.2	0.13-0.20
3. Operating Costs	101.0	1.03	61.1- 91.7	0.52
Regular Operating Costs	68.4	0.70	32.0- 48.0	0.27
Thermal Plant	15.8	0.16	18.9- 28.4	0.16
Operating Overhead @ 20%	16.8	0.17	10.2- 15.3	0.09
4. Financial Costs	297.8	3.04	151.7-226.7	1.28-1.29
Royalties	135.7	1.38	95.9-122.9	0.70-0.80
Severance Taxes	-	-	-	-
Income Taxes	162.0	1.65	55.8-103.7	0.47-0.59
5. Return on Capital (10% ROR)	221.4	2.26	105.8-162.1	0.90-0.92
Total Gas Production (Bcf)		98.1		117.7-176.6

* HOSTILITY AND TRANSPORTATION COST ADJUSTMENT FACTOR IS APPLIED TO CERTAIN CAPITAL AND OPERATING COST ITEMS DERIVED FOR DRILLING IN THE LOWER 48, TO BRING THOSE COSTS IN LINE TO WHAT MIGHT BE EXPECTED IN THE HARSHER ENVIRONMENTS IN ALASKA AND THE OFFSHORE. COST ADJUSTMENT FACTORS OF THIS TYPE ARE COMMONLY USED IN ENGINEERING COSTING. FOR THIS ANALYSIS, THE COST ADJUSTMENT FACTOR FOR OFFSHORE WAS ASSUMED TO BE 1.5.

B. ATTACHMENT

"FEASIBILITY OF METHANE RECOVERY FROM GAS HYDRATES"

Presentation at the
U.S. Department of Energy
Peer Review of Unconventional Gas Recovery
Gas Hydrates Program
April 24-25, 1985

**FEASIBILITY OF METHANE RECOVERY
FROM GAS HYDRATES**

Vello A. Kuuskraa
Lewin and Associates, Inc.

For Presentation
at the

U.S. Department of Energy Peer Review of
Unconventional Gas Recovery Gas Hydrates Program

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Sponsored by
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FEASIBILITY OF METHANE RECOVERY FROM GAS HYDRATES

ABSTRACT

Gas hydrates have been posed as a massive resource base of natural gas. However, for hydrates to move from a scientifically interesting resource to a future potential source of domestic energy, a number of critical conditions will need to be met. One of these conditions is that hydrate recovery has a positive energy balance and that, with advanced extraction technology, they become economically affordable. This paper first evaluates the energy balance from a theoretical viewpoint, assuming there are no external heat losses. It then examines the actual energy and mass balances using a modified heat injection and flow model and provides preliminary estimates of the economic feasibility of hydrate recovery. The paper concludes that the hydrate energy balance appears favorable, and with new, efficient recovery technologies, hydrates could be produced at wellhead costs of \$2 to \$3 per Mcf on the North Slope of Alaska and from \$4 to \$8 per Mcf from offshore areas.

I. INTRODUCTION

Gas hydrates were discovered in 1810 in the laboratory, but over 150 years passed before the scientific community established that hydrates could and do occur naturally. It took the classical paper by D.L. Katz in 1971 to overcome previous conventional wisdom that "gas hydrates are not known to occur naturally on the earth" (Miller, 1961).^{1,2} Subsequent work has shown that hydrates can potentially occur under a large portion of the earth's surface, in arctic areas and beneath the deep waters offshore.

Resource estimates for gas hydrates vary widely because of incomplete resource data and the different methodologies used in assessing the resource. Currently, estimates of the hydrate resource range from 2,700 trillion cubic feet (Tcf) (McIver, 1979) to 3×10^8 Tcf worldwide (Dobrynin, 1979).^{3,4} The high estimate is five orders of magnitude larger than the latest U.S. Geological Survey's estimate of the world's reserves of natural gas.

II. NATURAL GAS HYDRATE DEPOSITS

Gas hydrates are physical combinations of gas and water where the gas molecules fit into a crystalline structure similar to ice. The amount of gas stored in a given volume of hydrate is much higher than when that gas occurs in a gaseous form. For example, a 100% saturated hydrate contains about 180 standard cubic feet (scf) of gas per cubic foot of hydrate.

In the 1960s and 1970s, naturally occurring hydrates of natural gas were discovered in permafrost areas and in offshore sediments under deep water. Currently known or suspected occurrences of hydrates have been identified onshore in the USSR, the United States and Canada and offshore in 24 locations, primarily along the Atlantic and Pacific Continental Shelf off

North and Central America and in the Black Sea, **FIGURE 1**. The presence of gas hydrates has been inferred in offshore Japan, Australia, Angola, Oman, and New Zealand.

In this paper, two different settings judged to contain significant volumes of gas hydrates are examined, the onshore area of the North Slope of Alaska and the offshore deep water area of the Blake Bahamas off the Atlantic Coast. While the paper examines hydrate reservoirs on their own merits, gas hydrates may also be found contiguous with conventional gas (or oil) accumulations. Here, hydrates may provide the trapping mechanism by blocking the pore throats or forming an impermeable barrier that seals the gas accumulation.

III. NATURAL OCCURRENCE OF HYDRATE-FAVORING AREAS

Naturally occurring gas hydrates are found in two geographical settings: (1) onshore, in sediments in and beneath thick permafrost; and (2) offshore, beneath water deeper than 1,500 feet.

A. Onshore

Terrestrial zones of hydrate stability occur in and under permafrost regions that cover more than 23 percent of the earth's land area, namely, Alaska, Canada, the USSR, the polar regions of Scandinavia, Greenland, and Antarctica. In the Mackenzie Delta of Canada, the methane hydrate stability zone, shown in **FIGURE 2**, ranges from 300 to 3,500 feet. Within this interval, methane hydrates occur both in permafrost down to 2,000 feet and in hydrated water crystals down to 3,500 feet.

B. Offshore

Hydrates of natural gas may also occur naturally in sediments beneath the world's oceans where a water depth of approximately 1,500 feet or more exists. Thus, offshore the areal extent of potential hydrate occurrence is

FIGURE 1
KNOWN AND INFERRED LOCATIONS OF GAS HYDRATES

SOURCE Kvenvolden, et al., 1982.

FIGURE 2
DETERMINATION OF GAS-HYDRATE ZONE,
MACKENZIE DELTA, CANADA

SOURCES Bily and Dick, 1974
Katz, 1971

FIGURE 3
HYDRATE-FORMING ZONES UNDER THE OCEAN BOTTOM

SOURCE Scott, M.I., et al. IGT, 1980.

$3 \times 10^8 \text{ km}^2$ (or 115 million square miles) -- more than 90 percent of the ocean basins. Offshore, the hydrate stability zone can be estimated using a similar methodology as that used onshore. The difference is that the hydrate interval starts close to the sea bottom, often in unconsolidated sediments, instead of at depths of 500 feet or more. **FIGURE 3** shows estimated hydrate-favoring zones in sediments at the margin of the Outer Continental Shelf.

IV. HYDRATE ENERGY BALANCE

The first step in evaluating the feasibility of hydrate recovery is the net energy balance -- the extent to which the energy content of the produced methane exceeds the energy expended to dissociate the gas hydrate.⁵

Two fundamentally different methods, thermal injection and depressurization, are available for decomposing hydrates. The energy inputs for hydrate dissociation may differ considerably, depending on which of these methods (or combination of methods) is used, as shown on the phase diagram of **FIGURE 4**.

Thermal injection, the introduction of heat into the reservoir, leads to relatively rapid decomposition of hydrate into gas and water, both of which are mobile and can be readily produced. Depressurization is a slower process and draws the required energy for hydrate dissociation from the reservoir itself. Because depressurization leads to a cooling of the reservoir, the water of the hydrate may form an ice phase if the extent of the cooling is large.

A. Energy Input

The energy input, H , required for dissociating methane consists of:

- (1) the sensible heat, H_S , required to bring the reservoir rock and fluids to the dissociation temperature from the original reservoir conditions; and,
- (2) the heat of dissociation, H_D , that effects a phase change and dissociates

FIGURE 4
PHASE DIAGRAM FOR METHANE HYDRATE UNDER
ALTERNATIVE PRODUCTION METHODS

SOURCE: Lewin and Associates, Inc.

the hydrate into gas and water (or ice). The overall energy input requirements are expressed in Equation 1:

$$\begin{array}{c} \text{Input Energy} \\ \text{Requirements} \end{array} = \begin{array}{c} \text{Sensible} \\ \text{Heat of} \\ \text{Rock + Fluids} \end{array} + \begin{array}{c} \text{Heat of} \\ \text{Dissociation} \end{array}$$

$$H = H_S + H_D \quad (1)$$

1. Sensible Heat Requirements

The sensible heat, H_S , required to raise a reservoir and its associated fluids from the initial reservoir temperature, T_R , to the dissociation temperature, T_D , is:

$$H_S = M (T_D - T_R) \quad (2)$$

where:

M = weighted volumetric heat capacity of the reservoir,
BTU/°F/ft³,

T_D = dissociation temperature, °F, and

T_R = initial reservoir temperature, °F.

Assuming the reservoir contains water, oil, free gas, and hydrate, the weighted volumetric heat capacity of the reservoir, M , is:

$$\begin{aligned} M = & (1 - \Phi) C_r \rho_r + \Phi S_w C_w \rho_w + \Phi S_o C_o \rho_o \\ & + \Phi S_g C_g \rho_g + \Phi S_H C_H \rho_H \end{aligned} \quad (3)$$

where:

Φ = Porosity, fraction

S = Saturation (water [w], oil [o], gas [g],
or hydrate [H]), fraction

C = Specific heat (rock, water, oil, gas or hydrate),
BTU/°F/lb

ρ = Density (rock, water, oil, gas or hydrate), lb/ft³

Example. For the purpose of illustration, a hydrate reservoir assumed to be representative of the North Slope is used for the energy balance calculations, TABLE 1. The reservoir temperature and pressure are 46°F (8°C) and 1,500 psi, respectively. To simplify the calculations and to evaluate the attractiveness of gas hydrate deposits, the reservoir is assumed to contain no associated oil or free gas and to be 90% saturated with methane.

a. Thermal Injection. The sensible heat required to raise the example reservoir to the dissociation temperature is calculated as follows:

STEP 1: Establish the dissociation temperature, T_D , from the hydrate phase diagram. For this sample reservoir (where no pressure increase is assumed from heat injection) the dissociation temperature will be 55°F (13°C or 286°K), as shown on Figure 4.

STEP 2: Calculate the sensible heat requirements, H_S , using Equations 2 and 3 and the rock, water, and hydrate properties summarized on Table 1. For the sample reservoir, the sensible heat required to bring the reservoir from its initial conditions to the dissociation temperature (55°F) is about 310 BTU per cubic foot of reservoir.

b. Depressurization. For the depressurization case, the change in reservoir temperature is dependent on the pressure at the hydrate interface. If pressure is maintained at 400 psi, the temperature change is negative, at -10°F (-6°C), Figure 4, and the sensible heat required is:

$$\begin{aligned} H_S &= (34.58 \text{ BTU/ft}^3/\text{°F}) (-10\text{°F}) \\ &= - 360 \text{ BTU/ft}^3 \end{aligned}$$

2. Heat of Dissociation Requirements

The heat of dissociation required to change the hydrate phase into gas and water or gas and ice can be calculated from simplified regression equations that express the dissociation energy as a linear function of temperature, as follows:

TABLE 1
ROCK, WATER AND HYDRATE PROPERTIES

Basic Properties:

$$\begin{aligned}\rho_r &= 167 \text{ lb/ft}^3 \\ C_r &= 0.2 \text{ BTU/lb/}^\circ\text{F} \\ \rho_w &= 62.4 \text{ lb/ft}^3 \\ C_w &= 1.0 \text{ BTU/lb/}^\circ\text{F} \\ \rho_H &= 55.7 \text{ lb/ft}^3 \\ C_H &= 0.67 \text{ BTU/lb/}^\circ\text{F (Structure I)}\end{aligned}$$

Example Reservoir Variables:

$$\begin{aligned}T_R &= 46^\circ\text{F}, 8^\circ\text{C}, 281^\circ\text{K} \\ \Phi &= 0.30 \\ P &= 1,500 \text{ psi} \\ S_H &= 1 \\ S_W &= S_o = S_g = 0\end{aligned}$$

$$H_{Diss}(\text{cal/g-mole}) = c + d * T \text{ (T in Kelvin)} \quad (4)$$

where, for methane hydrates:

$c = 6,534$ and $d = -12$; for T between 248°K (-25°C) and 273°K (0°C)

$c = 13,521$ and $d = -4$; for T between 273°K (0°C) and 298°K (25°C)

Example. The required energy to dissociate hydrates using thermal injection and using depressurization are illustrated in the following examples.

a. Thermal Injection. For the example reservoir, the dissociation temperature is 55°F (286°K), from Figure 4. The dissociation energy from Equation H is:

$$\begin{aligned} H_{Diss} &= 13,521 + (-4)(286) \\ &= 12,377 \text{ cal/g-mole of hydrate} \end{aligned}$$

Converting the units to BTU per cubic foot of hydrate, the dissociation energy is:

$$\begin{aligned} H_{Diss} &= (12,377)(0.8) \\ &= 9,900 \text{ BTU/ft}^3 \text{ of hydrate} \end{aligned}$$

The hydrate dissociation energy per cubic foot of porous reservoir rock (porosity equal to 30%) is then:

$$\begin{aligned} H_D &= H_{Diss} * \Phi \\ &= 9,900 (0.3) \\ &= 2,960 \text{ BTU/ft}^3 \text{ of reservoir} \end{aligned}$$

b. Depressurization. The calculations for the heat of dissociation using depressurization are similar to those of thermal injection. At a reservoir pressure of 400 psi, the dissociation temperature is 36°F (275°K), so the dissociation energy per cubic foot of reservoir is:

$$\begin{aligned}H_D &= 0.3 (13,521 + (-4)(275)) \\&= 3,726 \text{ cal/g-mole of reservoir} \\&= 3,726 (0.8) \\&= 2,980 \text{ BTU/ft}^3 \text{ of reservoir}\end{aligned}$$

In addition, energy may be required to maintain the reservoir pressure at 400 psi, which is not included in the calculation.

3. Total Dissociation Energy

The total dissociation energy is the sum of the sensible heat and the heat of dissociation, as expressed in Equation 1, and shown below for the two basic production schemes.

a. Thermal Injection. For the example reservoir, the total dissociation energy under thermal injection is 3,270 BTU per cubic foot of reservoir, as calculated below:

$$\begin{aligned}H &= H_S + H_D \\&= 310 + 2,960 \text{ BTU/ft}^3 \text{ of reservoir} \\&= 3,270 \text{ BTU/ft}^3 \text{ of reservoir}\end{aligned}$$

As shown by the previous example, the heat of dissociation is much larger than the sensible heat of the hydrate, 2,960 BTU/ft³ versus 310 BTU/ft³ of reservoir, and accounts for about 90% of the total energy input.

b. Depressurization. The total dissociation energy under depressurization at 400 psi is 2,620 BTU per cubic foot of reservoir, as shown below:

$$\begin{aligned}H &= H_S + H_D \\&= -360 + 2,980 \text{ BTU/ft}^3 \text{ of reservoir} \\&= 2,620 \text{ BTU/ft}^3 \text{ of reservoir}\end{aligned}$$

Under depressurization the rate of hydrate dissociation is controlled by pressure drop and internal heat flow from the earth to the hydrate interface. This natural heat flux can be treated as a "free" energy input since it does not require the injection of an external source of heat. Using an estimate for the earth's natural heat flux (Q) in permafrost regions as 0.3 to 0.8 BTU/ft²/day (Judge, 1973)⁶, the rate of dissociation may be approximated as a function of time (Δt) by using the following energy flow equation:

$$\text{Energy Input} = Q * \Delta t \quad (5)$$

B. Energy Output

The energy output, E, is independent of the production mechanism employed and depends solely on the amount of hydrocarbon contained in the hydrate reservoir. The energy contained in a cubic foot of reservoir rock when hydrate is dissociated into methane and water can be calculated as follows:

$$E = \Phi * V_H * HV \text{ BTU/ft}^3 \text{ of reservoir} \quad (6)$$

where:

Φ = porosity, fraction

V_H = volume of hydrocarbons at standard conditions in
one cubic foot of hydrate, scf/ft³

HV = heating value of gas, BTU/scf

Assuming methane with a heating value, HV, of 1,010 BTU per scf and a reservoir hydrocarbon content, V_H, of 163 scf of methane per cubic foot of hydrate (90% saturated, Structure I), the energy output equation simplifies to:

$$E = 165,000 * \Phi \text{ BTU/ft}^3 \text{ of reservoir} \quad (7)$$

Example. For the example reservoir, assuming a reservoir with 30% porosity, the energy production from one cubic foot of reservoir is:

$$\begin{aligned} E &= (0.3) (165,000) \text{ BTU/ft}^3 \text{ of reservoir} \\ &= 49,500 \text{ BTU/ft}^3 \text{ of reservoir} \end{aligned}$$

C. Energy Ratio and Balance

1. Thermal Injection

The energy ratio for the sample reservoir with a porosity of 30% and a dissociation temperature of 55°F (286°K) is 15.1, as shown below:

$$\frac{\text{Energy Out}}{\text{Energy In}} = \frac{49,500}{3,280} = 15.1$$

With no heat losses about 15 times more energy is produced than is used when hydrates are dissociated. The energy balance (net energy gain) is 46,220 BTU per cubic foot of reservoir, as follows:

$$\text{Energy Out (49,500 BTU/ft}^3) - \text{Energy In (3,280 BTU/ft}^3) = 46,220 \text{ BTU/ft}^3$$

2. Depressurization

The energy balance using depressurization is 49,500 BTU per cubic foot of reservoir. Since there are no input energy requirements to the depressurization process, an energy ratio cannot be calculated.

D. Comparison with Other Unconventional Resources

In terms of energy content and balance, methane hydrates are more like heavy oil and tar sands than unconventional gas. An attractive heavy oil reservoir contains about 150,000 BTU (150 ft³ gas equivalent) per cubic foot of reservoir. After adjusting for a recovery efficiency of 30 to 40%, the recoverable energy of 45,000 to 60,000 BTU per cubic foot of reservoir is similar to that for methane hydrates, as shown on **FIGURE 5**.

FIGURE 5
HYDRATE AND HEAVY OIL ENERGY BALANCE CALCULATIONS
(per cubic foot of reservoir)

● HYDRATE RECOVERY (Heat Injection)

Net Energy Balance: 45,100 BTU/ft³ of reservoir

Energy Efficiency: 11.3

● HEAVY OIL (Steam Drive)

Net Energy Balance: 49,400 BTU/ft³ of reservoir

Energy Efficiency: 3.3

V. ALTERNATIVE PRODUCTION METHODS

This section examines the use of heat via intermittent steam injection for recovering gas hydrates. This process, called cyclic steam injection or steam soak, is in current use in heavy oil reservoirs around the world. A diagrammatic scheme of cyclic steam injection is provided in FIGURE 6.

A. Simulation Model and Data Inputs

The computer model used for the study is a recently updated version of HYDMOD, originally developed by Lewin/Mr. Walter Sawyer and subsequently expanded by Mr. Gary Bayles, METC/DOE. The most current version, called HYMOD 2, being developed by Lewin, is an analytical model of steam injection that accounts for heat transfer, energy and mass balances and fluid flow in the hydrate reservoir. The key features of the model are as follows:

- Steam injection volumes are controlled by pressure build-up in the reservoir;
- Heat losses to the wellbore and to the overburden and underburden are determined;
- Steam is assumed to override and convect to the hydrate interface where the latent heat of the steam zone is used for initial hydrate dissociation;
- The soak time calculation is based on the conduction of specific heat via the radial penetration of the temperature profile to the hydrate interface; and,
- Gas and water production rates are based on a modified finite-difference, pseudo-steady state flow calculation, limited by the capacity of the installed production equipment.

FIGURE 6
STEAM SOAK STIMULATION PROCESS

SOURCE: Adapted by Lewin from NPC. EOR Study, 1984.

FIGURES 7 and 8 provide a diagram of two important steps in the modeled process, namely: (1) the steam injection and the building of the overriding steam zone; and (2) the collapse of the steam zone into the hot water cylinder. FIGURE 9 defines the temperature regimes illustrated in Figures 7 and 8, and shows the conduction of heat and the thermal decay of the hot water cylinder after injection. The last step of the modeled process, the subsequent production of gas and water, has been previously shown in Figure 6.

The key assumptions of the model are, as follows:

- The reservoir consists of a consolidated rock matrix;
- The stoichiometric composition of the hydrate is uniform throughout the reservoir, and 100% of the pore space is assumed to be filled by hydrate (100% saturation);
- Only methane hydrate (Structure I) is considered;
- No free gas is initially present in the reservoir;
- An initial void volume for steam injection of 196 ft³ is assumed, obtained by fracturing of the reservoir;
- All injected steam condenses to water;
- Residual water saturation in the reservoir is assumed to be 20%; and
- The reservoir rock in the dissociated region is sufficiently permeable (100+ md) to support the assumed steam injection and fluid drawdown rates.

The rock, fluid, and steam properties used in the model runs are given in TABLE 2.

B. Production Model Results and Assumptions

Because work is still progressing on HYMOD 2, only preliminary results for gas production and steam injection are available at the present time. A recently completed run of HYMOD 2 in a steam soak mode for five years provided gas production rates of about 400 Mcf/D, steam injection requirements of about

FIGURE 7
MODEL CONFIGURATION DURING STEAM INJECTION

Prepared By: Lewin and Associates, Inc., 1985.

FIGURE 8
MODEL CONFIGURATION AFTER STEAM INJECTION

Prepared By: Lewin and Associates, Inc., 1985.

FIGURE 9
TEMPERATURE DECAY AFTER STEAM INJECTION

SOURCE Modified by Lewin from Bayles (METC), 1984.

140 barrels (water equivalent) per day, and a heat requirement of 125,000 BTU per Mcf of produced gas (or 0.35 barrels of steam per Mcf of gas), with higher gas flow rates during the initial years. The thermal efficiency of the process was slowly decreasing, such that during the fifth year of production the heat injection requirements were about 0.37 barrels of steam per Mcf of produced gas. However, the model and process adaptations underway will increase the gas production rate and may improve the thermal efficiency.

Based on this preliminary work, two estimated (single well) gas production and steam injection streams have been developed for the given reservoir properties of Table 2:

- The steam soak model will produce an average of 500 Mcf/D of gas in response to a steam injection rate of 200 barrels per day, over a period of 10 years. (A 10-acre pattern area is used for the steam soak.)
- The steam drive model will produce an average of 1,500 Mcf/D in response to a steam injection rate of 600 barrels per day, over a period of 8 to 12 years. (Larger well spacing, additional injection wells, and a higher volume production plant would be required for the steam drive process.)

C. Engineering and Economic Costs

An engineering-based costing model is used to develop site specific costs based on location, well depth, gas production rate, and steam injection rate. These costs and equations are derived from work by Lewin using vendor quotes, industrial references, and DOE/EIA cost indexes for drilling and well operations.⁷

Sample costs are calculated for: (1) an onshore North Slope of Alaska steam soak project involving 64 wells drilled to 2,000-foot depth, producing 32,000 Mcf per day of methane in response to 12,800 barrels (water equivalent) of steam; (2) an offshore, Blake Bahamas steam soak project consisting of a 32-slot platform producing 16,000 Mcf per day of methane and using 6,400 barrels per day of steam; and (3) a steam drive project involving a 53-slot platform

TABLE 2

ROCK, FLUID, AND STEAM PROPERTIES
USED IN THE HYMOD 2 MODEL RUNS

RESERVOIR PROPERTIES

POROSITY.....	30 %
THICKNESS.....	100 ft
ROCK GRAIN DENSITY.....	167 lb/ft ³
ROCK HEAT CAPACITY.....	0.20 BTU/lb/°F
WATER DENSITY.....	62.4 lb/ft ³
WATER HEAT CAPACITY.....	1.0 BTU/lb/°F

HYDRATE

DENSITY.....	55.0 lb/ft ³
HEAT CAPACITY.....	0.61 BTU/lb/°F
ENERGY CONTENT.....	180 ft ³ /ft ³

BASE/CAP ROCK

ROCK GRAIN DENSITY.....	167 lb/ft ³
HEAT CAPACITY.....	0.21 BTU/lb/°F
THERMAL CONDUCTIVITY.....	1.3 BTU/hr/ft/°F

STEAM PROPERTIES (AT THE GIVEN CONDITIONS)

STEAM INJECTION PRESSURE.....	2,000 psia
SATURATED STEAM TEMPERATURE.....	635.8 °F
LATENT HEAT OF VAPORIZATION.....	466.2 BTU/lb
SPECIFIC VOLUME OF SATURATED VAPOR.....	0.188 ft ³ /lb
SPECIFIC VOLUME OF SATURATED LIQUID.....	0.025 ft ³ /lb
ENTHALPY OF SATURATED LIQUID.....	672.1 BTU/lb
STEAM QUALITY.....	80 %

in the same offshore area producing 48,000 Mcf per day of methane in response to 19,200 barrels per day of injected steam.

1. Onshore Costs

FIGURE 10

FIELD SCALE METHANE HYDRATE PRODUCTION FACILITY

REQUIRED FACILITIES:

1. 64 WELLS
2. 4, 50MMBTU/HR STEAM GENERATORS
3. 12,800 B/D WATER PLANT
4. 32,000 MCF/D GAS PRODUCTION FACILITIES

<u>ANNUAL OPERATING COSTS</u>		<u>COSTS (1984\$)</u> <u>(THOUSANDS)</u>
1. ANNUAL O&M		2,600
2. STEAM GENERATOR O&M		900
3. WATER RECYCLE PLANT		1,200
4. WATER DISPOSAL		*
	SUBTOTAL	<u>4,700</u>
5. ALLOCATED G&A @ 20%		<u>900</u>
	TOTAL O&M	5,600/YEAR

*Produced water is recycled for reinjection.

Additional detail on these costs is provided in Table A of Attachment 1.

b. Gas Production. This 64 well facility would produce at a rate of 32 million cubic feet of natural gas per day. After subtraction of gas used for lease fuel, the annual production would be 26.9 million cubic feet per day. In 10 years, the facility would produce 98.1 billion cubic feet of natural gas, as shown below:

1. GROSS METHANE PRODUCTION (Mcf/D)	32,000
2. LESS: LEASE FUEL (Mcf/D)	5,100
3. NET METHANE PRODUCTION (Mcf/D)	26,900
4. CUMULATIVE PRODUCTION OVER PROJECT LIFE (MMcf)	98,100 (10 years)

c. Selected Cost Ratios. Assuming a 10 year production time, the well-head capital and operating costs, rounded to the nearest \$0.10, are \$1.30 per Mcf, as shown below:

CAPITAL COSTS	\$0.70/Mcf
O&M COSTS	<u>0.60</u>
TOTAL	\$1.30/Mcf

d. Full Costs. Other costs, such as royalties, state production and severance taxes, income taxes and a return on capital are added to the capital and operating costs to arrive at an overall wellhead cost of \$2.40 per Mcf (or equivalent wellhead selling price) for the natural gas produced from this facility, as shown below (rounded to the nearest \$0.10):

CAPITAL COSTS	\$0.70/Mcf
OPERATING COSTS	0.60
FINANCIAL COSTS	
- ROYALTIES	0.30
- SEVERANCE TAX	0.20
- INCOME TAX	0.20
RETURN ON CAPITAL @ 10%	<u>0.40</u>
FULL COSTS	<u><u>2.40</u></u>

TABLE 3 provides additional detail on these costs. The table shows that the regular platform and well drilling costs of gas production account for 60% of capital and slightly over one half of annual operating costs. The introduction of the thermal plant (the steam injection facility) and its operation add the remainder of the costs. The table also shows that the financial "costs" of \$0.70 per Mcf allocated to this project by state and federal decree equal the underlying capital costs.

2. Offshore Costs

Capital and operating costs have also been developed for a steam soak and a steam drive methane hydrate production facility installed offshore in the Blake Bahamas. The facility consists of:

- A lease area of 640 to 960 acres;
- A 32- and a 53-slot tension leg platform, in 2,000 feet of water;
- 32 production wells, drilled to 2,000 feet below the sea floor;

TABLE 3
FIELD-SCALE METHANE HYDRATE
PRODUCTION FACILITY
TOTAL PROJECT COSTS
ONSHORE ALASKA

COST COMPONENT	ONSHORE COSTS	
	<u>1984\$</u> (Thousands)	<u>\$/Mcf</u>
1. Revenues	3,686	2.40
2. Capital Costs*	<u>1,124</u>	<u>0.73</u>
• Regular	624	0.41
• Thermal Plant	398	0.26
• G&A (10%)	102	0.07
3. Operating Costs*	<u>875</u>	<u>0.57</u>
• Regular	400	0.26
• Thermal Plant	329	0.21
• G&A (20%)	146	0.10
4. Financial	<u>1,121</u>	<u>0.73</u>
• Royalties	461	0.30
• Severance Tax	258	0.17
• Income Taxes	402	0.26
5. Return on Capital	567	<u>0.37</u>
Transportation from Wellhead to Market	**	
Cumulative Methane Production (Net)	1,533,000 Mcf	

* Including General and Administrative Expenses of 10% on capital costs and 20% on operating costs.

** Provided by pipeline company

- 21 injection wells (for the steam drive facility);
- Two to six 50 million BTU/hr steam generators;
- Steam injection and water handling rates of 6,400 to 19,200 B/D;
- Insulated lines and insulated down-hole tubing; and
- Gas production of 500 to 1,500 Mcf/D per year per production well, equal to 16,000 to 48,000 Mcf/D per platform.

FIGURE 11 provides a diagram of the field plan for the offshore facility.

a. Capital and Operating Costs. In water depths greater than 1,200 feet, a compliant structure (whose costs are less dependent on water depth) is preferable. The tension leg platform (TLP) used by CONOCO in its North Sea Hutton field is an example of such a structure, shown on FIGURE 12.

The capital costs for these two facilities are \$188 and \$248 million for the steam soak and the steam drive facilities respectively, as shown below:

CAPITAL COSTS	COSTS (1984\$) (THOUSANDS)	
	STEAM SOAK FACILITY	STEAM DRIVE FACILITY
1. TENSION LEG PLATFORM	127,600	156,200
2. WELL DRILLING AND COMPLETION	23,000	38,200
3. INSULATED TUBING	3,500	5,700
4. PRODUCTION AND LEASE EQUIPMENT	7,600	11,500
5. STEAM GENERATOR	2,000	6,000
6. STEAM PLANT FIELD DEVELOPMENT	6,700	5,300
7. WATER PLANT	700	2,200
	<hr/>	<hr/>
SUBTOTAL	171,100	225,100
8. ALLOCATED G&A @ 10%	17,100	22,500
	<hr/>	<hr/>
TOTAL	188,200	247,600
	<hr/>	<hr/>

FIGURE 11
OFFSHORE HYDRATES STEAM DRIVE FIELD PLAN
- 32 Production Wells
- 21 Injection Wells

Prepared By: Lewin and Associates, Inc., 1985.

FIGURE 12
CONOCO TENSION LEG PLATFORM
Hutton Field

HUTTON TLP DESIGN DATA

Dimensions, m (ft)

Deck	
Length	78 (256)
Breadth	74 (243)
Depth	12 (39.4)
Hull	
Length overall	93 (305)
Breadth overall	89 (292)
Draft at low astronomical tide	30 (93.4)
Main deck elevation above baseline	54 (177)
Eight columns	

Weight Summary, t*

Structure (including moorings)	22 000
Payload (including risers)	16 000
Ballast and miscellaneous	2 000
Total weight	40 000
Moorings pretension	12 000
Total displacement	52 000

*t = Mg

The TLP is a floating structure connected to the seabed by vertical mooring lines

Platform natural sway period relative to sea-state energy.

The operating cost for the facility range from \$5.1 to \$7.6 million per year, as shown below:

<u>ANNUAL OPERATING COSTS</u>	<u>COSTS (1984\$)</u> <u>(THOUSANDS)</u>	
	<u>STEAM SOAK FACILITY</u>	<u>STEAM DRIVE FACILITY</u>
1. ANNUAL O&M	3,420	4,000
2. STEAM GENERATOR O&M	350	1,050
3. WATER RECYCLE PLANT	440	1,310
4. WATER DISPOSAL	*	*
	<hr/>	<hr/>
SUBTOTAL	4,210	6,360
5. ALLOCATED G&A @ 20%	840	1,270
	<hr/>	<hr/>
TOTAL O&M	5,050/YEAR	7,630/YEAR

*Produced water is recycled for reinjection.

Additional details on these costs are provided in Tables B and C of Attachment 1.

b. Gas Production. Production would be at a rate of 16 million cubic feet of natural gas per day for the steam soak facility and 48 million cubic feet per day for the steam drive facility. After subtraction of the gas used for lease fuel, the annual net production would be from 13.5 to 40.3 million cubic feet per day. Over its life, the facility would produce from 98.1 to 176.6 billion cubic feet of natural gas, as shown below:

	<u>STEAM SOAK FACILITY</u>	<u>STEAM DRIVE FACILITY</u>
1. GROSS PRODUCTION (Mcf/D)	16,000	48,000
2. LESS: LEASE FUEL (Mcf/D)	2,500	7,700
3. NET METHANE PRODUCTION (Mcf/D)	13,500	40,300
4. CUMULATIVE PRODUCTION OVER PROJECT LIFE (MMcf)	98,100 (20 years)	117,700 - 176,600 (8 - 12 years)

c. Selected Cost Ratios. Assuming a 20-year production life for the steam soak project, and an 8-12 year project life for the steam drive facility, the wellhead capital and operating costs per Mcf, rounded to the nearest \$0.10, are \$3.00 per Mcf for the steam soak facility and from \$1.90 to \$2.70 per Mcf for the steam drive facility (assuming an 8-12 year life), as shown below:

	STEAM SOAK FACILITY (\$/Mcf)	STEAM DRIVE FACILITY (\$/Mcf)
CAPITAL COSTS	2.00	1.40 - 2.20
O&M COSTS	<u>1.00</u>	<u>0.50</u>
TOTAL	3.00	1.90 - 2.70

d. Full Costs. Other costs, such as federal royalties and income taxes and a return on capital are added to the capital and operating costs to arrive at an overall wellhead costs of \$4.20/Mcf to \$8.40/Mcf (or equivalent wellhead selling price) for the natural gas produced from these facilities, as shown below (rounded to the nearest \$0.10):

	STEAM SOAK FACILITY (\$/Mcf)	STEAM DRIVE FACILITY (\$/Mcf)
CAPITAL COSTS	2.00	1.40 - 2.20
OPERATING COSTS	1.00	0.50
FINANCIAL COSTS		
- ROYALTIES	1.40	0.70 - 0.80
- INCOME TAX	1.70	0.60 - 0.50
RETURN ON CAPITAL		
@ 10%	<u>2.30</u>	<u>1.00</u>
FULL COSTS	<u>8.40</u>	<u>4.20 - 5.00</u>

D. Sensitivity and Uncertainty Analysis

This section examines some of the factors that could affect the economic viability of methane hydrate recovery, such as the rate of return hurdle, uncertainty in costs, federal/state taxes, and royalties. The impact of these factors are examined for the onshore North Slope steam soak facility. For the offshore facility, because the choice and technical feasibility of the recovery technology dominates the uncertainty, no further sensitivity analysis is provided.

1. Sensitivity to Return on Capital. If a 15% rate of return on capital is required, this adds \$0.50 to the cost or minimum required selling price. Thus, \$2.90/Mcf would be required for the produced gas, compared to the \$2.40/Mcf under a 10% return on capital for the onshore North Slope facility.

2. Sensitivity to Royalty Payments and Taxes. One way to compare the costs of producing domestic gas hydrates with the costs of imported gas is to eliminate the federally-imposed royalty and income taxes, as no such taxes are levied on gas imports. Under this scenario, a minimum economic gas price of \$1.75 is required (including a 10% rate of return), compared to a gas price of \$2.40/Mcf under the traditional case.

3. Effect of Arctic Cost Factors on Economics. A cost factor of two was assumed on several capital and operating cost items to represent the fractional increase in costs that would be incurred due to operations in the Arctic setting versus on the West Coast. The use of a lower factor of 1.5 or a higher cost factor of 2.5 would lead to minimum gas price range of \$1.80 to \$3.00, as shown below:

<u>Minimum Economic Gas Price</u> (\$/Mcf)	
<u>Cost Factor</u>	<u>10% ROR</u>
1.5	1.83
2.0 (DEFAULT)	2.40
2.5	2.98

SUMMARY

Hydrates of natural gas exist as a potentially massive domestic energy resource, and provided they can be produced economically, could be an attractive source of domestic energy. Stimulation of hydrates by thermal injection proves to have a positive net energy balance based on theoretical calculations, and is superior to other resources of a similar nature, such as heavy oil. A cyclic steam injection recovery model has been developed to more accurately predict production from gas hydrate. In addition, engineering costing and financial analysis models are able to assess the potential economics of hydrate gas production. At the moment, the development of onshore hydrate resources with a steam soak facility appears viable. Using current estimates of potential production, hydrates could be produced economically at wellhead costs of \$2.00 to \$3.00 per Mcf on the North Slope of Alaska. Offshore development of the hydrates, because of higher capital costs associated with drilling and production in deeper waters, will require substantially greater production rates than those required onshore to be economically viable. Despite the economic drawbacks, offshore hydrate deposits could produce gas economically, at a wellhead cost of \$4 to \$8 per Mcf.

FEASIBILITY OF METHANE RECOVERY FROM GAS HYDRATES

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ATTACHMENT 1

Table A: Engineering Costing For Alaska Onshore Hydrate Facility

Table B: Engineering Costing For Blake Bahamas Offshore Hydrate
Steam Soak Facility

Table C: Engineering Costing For Blake Bahamas Offshore Hydrate
Steam Drive Facility

Table D: Financial Variables and Accounting Conventions

TABLE A
ENGINEERING COSTING FOR
ALASKA ONSHORE
HYDRATE FACILITY

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for Sample</u> <u>2,000-Foot Well</u> (1984\$)
1. Pre-Development Costs	-	-
2. Development Costs for Wells		
● Drilling and Completion	$2 \times 82,000 (\exp (0.26 \times \text{Depth} \times 10^{-3}))$	\$ 276,000
● Insulated Tubing	$\$27 * (\text{Depth})$	54,000
● Well Production Equipment	$2 * [\$65,000 + \$30 (\text{Mcf/D}) + \$5 (\text{Depth})]$	180,000
● Gathering System	$2 * [\$5,000 + \$10 (\text{Mcf/D}) + \$1 (\text{Depth})]$	24,000
● Lease Equipment	$2 * [\$10,000 + \$40 (\text{Mcf/D})]$	60,000
● Dehydrator	$2 * [\$15,000]$	<u>30,000</u>
SUBTOTAL		\$ 624,000
3. Process Specific Costs		
● Steam Generator	$2 * [\$650,000 \times \frac{\text{B/D Steam Injected}}{3,500 \times 0.90}]$	83,200
● Steam Manifold & Lines	$2 * [\$8,750/\text{Acre}]$	175,000
● Heater Treater and Vapor Recovery	$2 * [\$5,500/\text{Acre}]$	110,000
● Produced Water Recycle Plant	$2 * [\$75 \text{ B/D Steam Injected}]$	<u>30,000</u>
SUBTOTAL		\$ 398,000
TOTAL CAPITAL COSTS		\$1,022,000

TABLE A
ENGINEERING COSTING FOR
ALASKA ONSHORE
HYDRATE FACILITY

(continued)

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	<u>Costs for Sample</u> <u>2,000-Foot Well</u> (1984\$)
4. Well Operating and Maintenance Costs (Primary and Secondary)	$2*[\$10,000 + 4(\text{Mcf/D}) + 4(\text{Depth})]$	\$ 40,000
5. Process-Specific Operating Costs		
● Generator O&M (Gas Fired)	$2*[\$0.10*\text{Bbl Steam Injected}]$	14,600
● Water Recycle Plant	$2*[\$0.125*\text{Bbl Steam Injected}]$	18,300
● Water Disposal	$2*[\$0.025*\text{Bbl Steam Injected}]$	(Assumes water is recycled)
6. Fuel Costs		
● Lease Fuel	(Assumes produced natural gas is used as fuel)	<u> -</u>
TOTAL OPERATING COSTS		\$ 72,900

TABLE B
ENGINEERING COSTING FOR
BLAKE BAHAMAS OFFSHORE
HYDRATE STEAM SOAK FACILITY

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	Total Costs for 32-Slot Platform in 2,000 Feet of Water, 4,000-Foot Well (1984\$ - Thousands)
1. Pre-Development Costs	-	-
2. Development Costs for Wells		
● Tension Leg Platform	$\$64,000,000 + \$10,000 * (\text{Water Depth}) + \$62,000 * (\text{Slots}) + \$650 * (\text{Water Depth} * \text{Slots})$	127,580
● Drilling and Completion	$\$460,000 + 130 * (\text{Well Depth} - 2,000) * \text{Slots}$	23,040
● Insulated Tubing	$\$27 * (\text{Well Depth}) * \text{Slots}$	3,460
● Well Production Equipment	$1.5 * [\$65,000 + \$30(\text{Mcf/D}) + \$5(\text{Depth})] * \text{Slots}$	4,800
● Gathering System	$1.5 * [\$5,000 + \$10(\text{Mcf/D}) + \$1(\text{Depth})] * \text{Slots}$	670
● Lease Equipment	$1.5 * [\$10,000 + \$40(\text{Mcf/D}) * (\text{Slots})]$	1,440
● Dehydrator	$1.5 * [\$15,000 * (\text{Slots})]$	720
SUBTOTAL		161,710
3. Process Specific Costs		
● Steam Generator	$1.5 * [\$650,000 * \frac{\text{B/D Steam Injected}}{3,500 * 0.90}]$	1,980
● Steam Manifold & Lines	$1.5 * [\$85,000 * \text{Slots}]$	4,080

TABLE B
ENGINEERING COSTING FOR
BLAKE BAHAMAS OFFSHORE
HYDRATE STEAM SOAK FACILITY

(continued)

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	32 Slot Platform in 2,000 Feet of Water, <u>4,000-Foot Well</u> (1984\$)
● Heater Treater and Vapor Recovery	$1.5 * [\$55,000 * \text{Slots}]$	2,640
● Produced Water Recycle Plant	$1.5 * [\$75/\text{Bbl Per Day Steam Injected} * \text{Bbl Steam Injected/Per Day} * \text{Slots}]$	<u>720</u>
SUBTOTAL		9,420
TOTAL CAPITAL COSTS		171,130
4. Well Operating and Maintenance Costs	$(1,700,000 + 5 * (\text{Well Depth} (\text{Slots}) + 500 (\text{Water Depth}) + 5 (\text{Mcf/D Platform}))$	3,420
5. Process-Specific Operating Costs		
● Generator O&M (Gas Fired)	$1.5 * [\$0.10 * \text{Bbl Steam Injected/year} * \text{Slots}]$	350
● Water Recycle Plant	$1.5 * [\$0.125 * \text{Bbl Steam Injected/year} * \text{Slots}]$	440
● Water Disposal	(Assumes water is recycled)	-
6. Fuel Costs		
● Lease Fuel	(Assumes produced natural gas is used as fuel)	-
TOTAL ANNUAL OPERATING COSTS		<u>\$4,210</u>

TABLE C
ENGINEERING COSTING FOR
BLAKE BAHAMAS OFFSHORE
HYDRATE STEAM DRIVE FACILITY

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	53 Slot Platform in 2,000 Feet of Water, <u>4,000-Foot Well</u>
1. Pre-Development Costs	-	-
2. Development Costs for Wells		
● Tension Leg Platform	$\$64,000,000 + \$10,000 (\text{Water Depth}) + \$62,000 * (\text{Slots}) + 650 * \text{Water Depth} * \text{Slots}$	156,190
● Drilling and Completion	$\$460,000 + 130 (\text{Well Depth} - 2,000) * (\text{Slots})$	38,160
● Insulated Tubing	$\$27 (\text{Well Depth}) * (\text{Slots})$	5,720
● Well Production Equipment	$1.5 * [\$65,000 + \$30 (\text{Mcf/D}) + \$5 (\text{Depth})] * \text{Slots}$	6,240
● Gathering System	$1.5 * [\$5,000 + \$10 (\text{Mcf/D}) + \$1 (\text{Depth})] * \text{Slots}$	1,150
● Lease Equipment	$1.5 * [\$10,000 + \$40 (\text{Mcf/D})] * (\text{Slots})$	3,360
● Dehydrator	$1.5 * [\$15,000 * \text{Slots}]$	<u>720</u>
SUBTOTAL		211,540
3. Process Specific Costs		
● Steam Generator	$1.5 * [\$650,000 * \frac{\text{B/D Steam Injected}}{3,500 * 0.90}]$	5,990
● Steam Manifold & Lines	$1.5 * [\$85,000 * \text{Injection Wells}]$	2,680

TABLE C
ENGINEERING COSTING FOR
BLAKE BAHAMAS OFFSHORE
HYDRATE STEAM DRIVE FACILITY

(continued)

<u>Cost Category</u>	<u>Cost Equation</u> (1984\$)	53 Slot Platform in 2,000 Feet of Water, 4,000-Foot Well (1984)
● Heater Treater and Vapor Recovery	$1.5 * [\$55,000 * \text{Production Wells}]$	2,640
● Produced Water Recycle Plant	$1.5 * [\$75/\text{Bbl Per Day Steam Injected} * \text{Bbl Steam Injected/Per Day} * \text{Injection Wells}]$	<u>2,160</u>
SUBTOTAL		13,470
TOTAL CAPITAL COSTS		
4. Well Operating and Maintenance Costs	$(1,700,000 + 5 * (\text{Well Depth})$ $(\text{Slots}) + 500 (\text{Water Depth}) +$ $5 (\text{Mcf/D})$	4,000
5. Process-Specific Operating Costs		
● Generator O&M (Gas Fired)	$1.5 * [\$0.10 * \text{Bbl Steam Injected/}$ $\text{year} * \text{Injection Wells}]$	,050
● Water Recycle Plant	$1.5 * [\$0.125 * \text{Bbl Steam Injected/}$ $\text{year} * \text{Injection Wells}]$	1,310
● Water Disposal	(Assumes water is recycled)	-
6. Fuel Costs		
● Lease Fuel	(Assumes produced natural gas is used as fuel)	-
TOTAL ANNUAL OPERATING COSTS		<u>\$6,360</u>

TABLE D
FINANCIAL VARIABLES
AND ACCOUNTING CONVENTIONS

In addition to calculating the engineering-based operating and investment costs, the GEM Model uses a series of additional parameters to establish the economic feasibility of a project, as discussed below:

1. Financial Parameters. The key financial parameters used by the model are, as follows:

A. <u>Overhead Charges</u>	
Operating G&A Rate	0.20
Investment G&A Rate	0.10
B. <u>Tax Rate</u>	
Federal Tax Rate	0.46
State Tax Rate	0.08 For Alaska 0.00 For Offshore OCS
Investment Tax Credit Rate (On Tangible Investment)	0.10
Severance and Other Production Tax Rate	0.08 For Alaska 0.00 For Offshore OCS
C. <u>Royalty Rate</u>	0.125 For Alaska 0.167 For Offshore OCS
D. <u>Discount Rate</u>	User Set (Default 10%)

2. Accounting Conventions. Geological/geographical exploration and leasehold acquisition costs are capitalized and cost depleted. Intangible costs are expensed in the year incurred. Tangible costs are capitalized and depreciated, using double declining balance, with switchover to straight line later in the well life. Twenty percent of well drilling and completion and 100% of lease equipment costs are classified as tangible investment.

IV. CRITIQUE OF EXISTING GAS HYDRATE RECOVERY MODELS

PURPOSE FOR SUBTASK

THE PURPOSE OF THIS SUBTASK IS TO EXAMINE THE UNDERLYING CONCEPTUAL FRAMEWORK, ENGINEERING ASSUMPTIONS, TECHNICAL PARAMETERS, AND CURRENT COMPLETENESS OF FOUR EXISTING GAS HYDRATES PRODUCTION MODELS. A REVIEW OF THE STATUS OF THE MODELS IS PRESENTED, ALONG WITH RECOMMENDATIONS FOR FUTURE REQUIRED OR NEEDED ADAPTATIONS/MODIFICATIONS OF THESE MODELS FOR SIMULATING GAS PRODUCTION FROM HYDRATES.

1. REVIEW AND CRITIQUE
OF HYDRATE MODELS

REVIEW AND CRITIQUE
OF HYDRATE MODELS

FOUR EXISTING HYDRATE GAS RECOVERY MODELS ARE REVIEWED IN THE
SUBTASK. THESE MODELS ARE:

1. HYDMOD (VERSION 1)
 - STEAM SOAK
2. HYDEP (ADAPTED FROM SUGAR)
 - CONTINUOUS STEAM DRIVE
 - DEPRESSURIZATION
 - STEAM SOAK
3. DEPRESS (ADAPTED FROM HOLDER)
 - DEPRESSURIZATION
4. IN-SITU COMBUSTION
 - CONCEPTUAL MODEL WITH CALCULATIONS

1. REVIEW AND CRITIQUE
OF HYDMOD (VERSION 1)

IN THE REVIEW OF HYDMOD, A CYCLIC STEAM GAS RECOVERY MODEL, THE FOLLOWING MODEL FEATURES WERE ANALYZED:

- a. INITIAL VOID VOLUME
- b. STEAM INJECTION RATES
- c. INJECTED STEAM QUALITY
- d. HEAT LOSSES IN WELLBORE
- e. HEAT LOSSES TO OVER/UNDERBURDEN
- f. HEAT PENETRATION INTO HYDRATE FORMATION
- g. SOAK TIME ASSUMPTIONS
- h. WATER/GAS PRODUCTION RATES

EACH OF THE FEATURES ARE ANALYZED AND CRITIQUED IN THE FOLLOWING PAGES.

1a. WATER AND GAS PRODUCTION RATES

- CURRENT MODEL ASSUMPTIONS:
 - CONSTANT STEAM INJECTION RATE
 - CONSTANT GAS PRODUCTION RATE
 - CONSTANT WATER PRODUCTION RATE
- NATURE/EXTENT OF PROBLEM:
 - GAS AND WATER PRODUCTION RATES WILL BE LARGE AT FIRST AND DECLINE AS RESERVOIR (GAS) PRESSURE IS DEPLETED.
- PROPOSED MODEL CHANGES:
 - DEVELOP PSEUDO-STEADY-STATE ALGORITHM TO CALCULATE GAS AND WATER DECLINE RATES FOR GIVEN WELLHEAD PRESSURE AND RESERVOIR PRESSURE AT END OF EACH CYCLE.
- IMPACT OF MODEL CHANGES:
 - GAS AND WATER PRODUCTION TIMES AND THUS CYCLE TIME WILL BE SUBSTANTIALLY DECREASED.
 - GAS RECOVERY PER UNIT TIME WILL BE INCREASED.

1b. STEAM INJECTION RATE

- CURRENT MODEL ASSUMPTION/METHODOLOGY:

THE CURRENT MODEL USES A STEAM INJECTION RATE OF 200 B/D, INDEPENDENT OF FORMATION THICKNESS, PERMEABILITY OR VOID VOLUME.

- NATURE/EXTENT OF PROBLEM:

LOW STEAM INJECTION RATES LEAD TO HIGH WELLBORE AND FORMATION HEAT LOSSES, AND DELAY THE RATE OF GAS DISSOCIATION AND PRODUCTION.

CALIFORNIA AND OTHER STEAM SOAK OPERATORS INJECT ON THE ORDER OF 1,000 TO 2,000 BARRELS OF STEAM PER DAY INTO FORMATIONS WITH PROPERTIES SIMILAR TO THE HYDRATE ROCK MATRIX. THE TEXAS TAR SAND PROJECT (CONOCO) INJECTS OVER 3,000 B/D INTO THE INDUCED FRACTURE SYSTEM IN A 40 FOOT TAR ZONE.

- PROPOSED MODEL CHANGES:

INCREASE THE INJECTION RATES FOR STEAM SOAK TO A RANGE OF 1,000 TO 2,000 BARRELS (WATER EQUIVALENT) PER DAY; ALTERNATIVELY SET STEAM INJECTION RATES (IN B/D) AT 10 TIMES THE GROSS HYDRATE INTERVAL.

1c. INJECTED STEAM QUALITY

- CURRENT MODEL ASSUMPTIONS/METHODOLOGY:

THE CURRENT MODEL ASSUMES 70% QUALITY STEAM AT THE WELLHEAD.

- NATURE/EXTENT OF PROBLEM:

LOW STEAM QUALITY REDUCES THE AMOUNT OF LATENT HEAT (HEAT OF VAPORIZATION) AVAILABLE FOR HYDRATE DISSOCIATION. FOR EXAMPLE, 80% QUALITY STEAM (AT 1,400 PSIA) CONTAINS 1,060 BTU/LB, AND 70 TO 80 BTU/LB MORE THAN 70% QUALITY STEAM.

CALIFORNIA OPERATORS HAVE SWITCHED TO INSULATED STEAM LINES AND WELLHEADS AND SEEK TO USE HIGHER QUALITY WATER TO MAINTAIN THEIR SURFACE STEAM QUALITY AS HIGH AS POSSIBLE, EVEN ABOVE 80%.

- PROPOSED MODEL CHANGES:

INCREASE THE SURFACE QUALITY OF THE INJECTED STEAM TO 80%.

1d. HEAT LOSSES IN WELLBORE

- CURRENT MODEL ASSUMPTIONS/METHODOLOGY:
 - STEAM INJECTED THROUGH TUBING WHERE THE TUBING-CASING ANNULUS CONTAINS COMMERCIAL INSULATION WITH THERMAL CONDUCTIVITY OF 0.04 BTU/HR-FT.-°F
 - TOTAL WELLBORE HEAT LOSS CONSISTS OF THREE COMPONENTS:
 - (1) CONDUCTION THROUGH INSULATION IN ANNULUS
 - (2) RADIATION
 - (3) NATURAL CONVECTION
- NATURE/EXTENT OF PROBLEMS:
 - HEAT LOSSES SEEM HIGH (18-20%); MODEL RESETS FORMATION TEMPERATURE TO ORIGINAL CONDITIONS (T_o) DURING EACH CYCLE.
- PROPOSED CHANGES:
 - INCREASE INJECTION RATE;
 - LOWER THERMAL CONDUCTIVITY OF INSULATION TO 0.02 BTU/HR-FT.-°F; AND
 - INCORPORATE TIME BASED HEAT TRANSFER AND STORAGE AROUND WELLBORE.
- IMPACT OF PROPOSED CHANGES:
 - LOWER WELLBORE HEAT LOSSES TO ABOUT 5% AFTER FIRST CYCLE.

1e. HEAT LOSSES TO OVER/UNDERBURDEN

- CURRENT MODEL ASSUMPTIONS/METHODOLOGY:
 - HEAT LOSSES VIA CONDUCTION TO BASE AND CAP ROCK ARE ASSUMED TO BE IDENTICAL.
 - BASE AND CAP ROCK ARE ASSUMED TO BE AT ORIGINAL (INITIAL) TEMPERATURE (T_0) AT BEGINNING OF EACH CYCLE.
- NATURE/EXTENT OF PROBLEMS:
 - HEAT LOSSES TO UNDERBURDEN DURING STEAM INJECTION MAY BE SMALL OR NEGLIGIBLE DUE TO STEAM OVERRIDE.
 - CAP ROCK RETAINS HEAT FROM PREVIOUS CYCLE(S) AND THEREFORE SHOULD START AT HIGHER THAN INITIAL TEMPERATURE FOR ALL CYCLES AFTER THE FIRST.
- PROPOSED MODEL CHANGES:
 - CALCULATE NEW (T_1) AVERAGE CAP/BASE ROCK TEMPERATURE AT END OF EACH CYCLE AND USE THIS TO CALCULATE CONDUCTIVE HEAT LOSS DURING SUBSEQUENT CYCLE.
- IMPACT OF MODEL CHANGES:
 - LOWER OVERALL OVERBURDEN/UNDERBURDEN HEAT LOSSES

1f. HEAT PENETRATION INTO HYDRATE FORMATION

● CURRENT MODEL ASSUMPTION/METHODOLOGY:

THE CURRENT MODEL ALLOWS HEAT (OR THE HEATED FLUID) TO BE CONVECTED ONLY A SHORT DISTANCE INTO THE VOID VOLUME OF THE RESERVOIR. THIS REQUIRES THAT HEAT CONDUCTION, A MUCH SLOWER HEAT TRANSFER PROCESS, BE THE PRIMARY MEANS FOR TRANSMITTING THE HEAT FRONT TO THE HYDRATE FACE.

● NATURE/EXTENT OF PROBLEM:

CONVECTIVE HEAT FLOW RELIES ON THE FLUID FLOW PROPERTIES OF THE RESERVOIR AND, IN A POROUS MEDIUM IS CONSIDERABLY MORE RAPID THAN CONDUCTIVE HEAT FLOW. FOR EXAMPLE FOR THE SAMPLE CASE, STEAM VAPOR WILL FLOW AT ABOUT 50 FEET PER DAY (AND FASTER WITH GRAVITY SEGREGATION) WHILE LIQUID WILL FLOW AT ABOUT 1 FOOT PER DAY.

THE LIMITED RELIANCE OF THE MODEL ON CONVECTIVE HEAT FLOW LENGTHENS THE STEAM SOAK TIME AND LEADS TO CONSIDERABLY HIGHER HEAT LOSSES TO THE FORMATION OVER AND UNDERBURDEN.

● PROPOSED MODEL CHANGES:

INCREASE THE RADIUS OF STEAM CONVECTIVE FLOW TO THAT OF THE RADIUS OF THE DISSOCIATED ZONE AT THE START OF THE CYCLE. INCORPORATE VALUES FOR THE SPECIFIC VOLUME OF THE SATURATED VAPOR, WHICH IS ABOUT 50 TIMES THAT OF THE SATURATED VAPOR AT THE TEMPERATURE AND PRESSURE CONDITIONS USED IN THE SAMPLE PROBLEM.

1g. SOAK TIME ASSUMPTIONS

● CURRENT MODEL ASSUMPTIONS/METHODOLOGY:

- TEMPERATURE DISTRIBUTION AT END OF STEAM INJECTION IS APPROXIMATED BY A STEP FUNCTION; I.E., A "STEAM CYCLINDER" EXISTS AROUND THE INJECTION WELL.
 - STEAM ZONE PENETRATION DISTANCE (I.E., RADIUS OF THE "STEAM CYCLINDER") IS CALCULATED.
 - TIME REQUIRED FOR THE STEAM CYCLINDER STEP FUNCTION TO DISSIPATE UNTIL THE TEMPERATURE PROFILE REACHES THE (INITIAL) HYDRATE FRONT IS CALCULATED AND DEFINED TO BE THE SOAK TIME.
 - DISSIPATION OF THE STEAM CYCLINDER STEP FUNCTION IS CAUSED BY RADIAL CONDUCTION TOWARD THE HYDRATE INTERFACE AND VERTICAL CONDUCTION TO BASE AND CAP ROCK.
- NATURE/EXTENT OF PROBLEMS:
- STEAM ZONE MAY REACH HYDRATE VIA CONVECTION DURING INJECTION OR SHORTLY AFTER INJECTION IS STOPPED.
 - STEAM OVERRIDE WILL LIKELY OCCUR, THUS COMPLETELY CHANGING THE SHAPE OF THE STEAM PROFILE FROM THE ASSUMED CYLINDRICAL SHAPE.

1g. SOAK TIME ASSUMPTIONS (CONT.)

● PROPOSED MODEL MODIFICATIONS:

- DEVELOP ALTERNATIVE METHOD TO DETERMINE SOAK TIME, BASED ON THE ASSUMPTION OF STEAM OVERRIDE AND CONVECTION.
- ALLOW FOR DIFFERENT HEAT LOSSES TO BASE AND CAP ROCK BASED ON TEMPERATURE PROFILE CAUSED BY STEAM OVERRIDE.

● IMPACT OF MODEL CHANGES:

- SOAK TIME WILL LIKELY DECREASE SIGNIFICANTLY (E.G., FROM 1 YEAR TO 4-5 WEEKS).
- HEAT LOSS TO BASE ROCK WILL DECREASE.

2. REVIEW AND CRITIQUE OF
HYDEP (SUGAR ADAPTATION)

- A. DOCUMENTATION IS LIMITED: E.G., CAN THE MODEL BE USED FOR CONTINUOUS OR CYCLIC STEAM INJECTION? THE INPUT DATA DOES NOT INCLUDE STEAM PROPERTIES. IT IS NOT CLEAR THAT INJECTING WATER IS SUFFICIENT!
- B. MODEL HAS A CONVERGENCE PROBLEM: I.E., SEVERAL RUNS WERE ATTEMPTED WITH DIFFERENT PARAMETERS; EACH RUN TERMINATED AFTER SIX TO NINE TIME-STEPS WITH A TIME-STEP SIZE OF ABOUT 0.25 DAYS.
- C. AS A RESULT OF LIMITED DOCUMENTATION AND CONVERGENCE PROBLEMS, WE HAVE THUS FAR BEEN UNABLE TO USE THIS MODEL.

3. REVIEW AND CRITIQUE OF
DEPRESS (HOLDER ADAPTATION)

MODEL WILL NOT BE READY UNTIL SPRING OF 1985.

4. REVIEW AND CRITIQUE OF
IN-SITU COMBUSTION

- A. THE CALCULATIONS, EVEN UNDER THE RELATIVELY IDEAL CONDITIONS USED IN THE CONCEPTUAL MODEL, SHOW THAT FOR FORMATION POROSITIES MUCH BELOW 30%, THE COMBUSTION CAN NOT BE MAINTAINED.
- B. THE ENERGY EFFICIENCY OF THE PROCESS IS EXTREMELY LOW RANGING FROM 7% TO 24%, DEPENDING ON THE METHANE RATE OF DECOMPOSITION, AS FOLLOWS:

<u>METHANE</u> <u>DECOMPOSITION RATE</u> (LB MOLE/HR)	<u>ENERGY EFFICIENCY</u> (%)
1	7
10	19
100	24

UNDER LESS IDEAL SURFACE AREAS, SUCH AS A WEDGE (MORE COMMON TO COMBUSTION FRONTS) THE HEAT LOSSES WOULD BE HIGHER AND THE ENERGY EFFICIENCY LOWER.

- C. USE OF COMBUSTION POSES SEVERE SAFETY HAZARDS IN OFFSHORE OPERATIONS AND IS GENERALLY AVOIDED FOR THESE SETTINGS.
- D. COMBUSTION DOES NOT APPEAR TO BE COST COMPETITIVE WITH STEAM IN SHALLOWER, LESS THAN 4,000 FOOT RESERVOIRS.

TEST RUN FOR HYDMOD

ROCK AND FLUID PROPERTIES USED FOR HYDMOD RUNS

HYDRATE DENSITY	= 55 LBM/CU. FT.
WATER DENSITY	= 62 LBM/CU. FT.
ROCK GRAIN DENSITY	= 167 LM/CU. FT.
HEAT CAPACITY OF OVERBURDEN	= 0.21 BTU/LBM °F (35/167)
HEAT CAPACITY OF RESERVOIR ROCK	= 0.20 BTU/LBM °F
HEAT CAPACITY OF HYDRATE	= 0.61 BTU/LBM °F
HEAT CAPACITY OF WATER	= 1.0 BTU/LBM °F
THERMAL CONDUCTIVITY OF OVERBURDEN	= 1.3 BTU/HR. FT. °F

INITIAL AND BOUNDARY CONDITIONS
FOR
HYDMOD RUNS

RESERVOIR (HYDRATE) TEMPERATURE	= 39 °F
RESERVOIR (HYDRATE) PRESSURE	= 1,100 PSIA
TEMPERATURE IN STARTING VOLUME	= 44 °F
STARTING VOLUME DIMENSIONS	= 5.0 FT. RADIUS
	= 2.5%
STEAM INJECTION RATIO	= 200 BWPD
GAS PRODUCTION RATE	= 1,000 MCFD

HYDMOD/HYDALL RUNS

12/01/84

TMAX = 1,825 DAYS

SET 1: NO SOAK TIME (FLAG = 0.0)

OUT6.R1
OUT7.R1 ● = .30, H = 50 FT. (MEDIUM)

OUT6.R2
OUT6.R2 ● = .30, H = 200 FT. (HIGH)

OUT6.R3
OUT7.R3 ● = .20, H = 50 FT. (LOW)

SET 2: CALCULATED SOAK TIME (FLAG = -1.0)

OUT6.R4
OUT7.R4 ● = .30, H = 50 FT.

OUT6.R7
OUT6.R7 ● = .30, H = 100 FT.

OUT6.R5
OUT7.R5 ● = .30, H = 200 FT.

OUT6.R6
OUT6.R6 ● = .20, H = 50 FT.

V. SUMMARY OF HYDMOD MODIFICATIONS

IMPORTANT FEATURES OF THE ADAPTED VERSION OF HYDMOD

THE COMPUTER MODEL USED FOR THE STUDY IS AN UPDATED VERSION OF THE CYCLIC STEAM INJECTION MODEL HYDMOD, DEVELOPED BY LEWIN/WALTER SAWYER AND SUBSEQUENTLY EXPANDED BY GARY BAYLES, METC/DOE. THE CURRENT VERSION OF THE MODEL CONTAINS THE FOLLOWING FEATURES:

- MASS AND ENERGY BALANCE EQUATIONS TO CALCULATE HEATING OF RESERVOIR ROCK AND HYDRATE DISSOCIATION.
- WELLBORE HEAT LOSSES FOR STEAM INJECTED THROUGH INSULATED TUBING.
- SOAK TIME DETERMINED BY AN ANALYTICAL, CONDUCTIVE HEAT FLOW MODEL FOR RADIAL PENETRATION OF THE TEMPERATURE PROFILE TO THE HYDRATE INTERFACE.
- HEAT LOSSES TO THE UNDERBURDEN AND OVERBURDEN DURING STEAM SOAK DETERMINED BY AN ANALYTICAL UNIT SOLUTION ALGORITHM.
- THE ABOVE MODEL WAS ADAPTED FOR THIS TASK WITH THE FOLLOWING NEW FEATURES:
 - ALTERNATIVE VALUES FOR STEAM INJECTION RATE, SURFACE STEAM QUALITY, AND THERMAL CONDUCTIVITY OF INSULATED TUBING,
 - ALLOWING FOR HEATING OF THE EARTH ADJACENT TO THE WELLBORE,
 - ALLOWING FOR HEATING OF THE OVERBURDEN AND UNDERBURDEN, AND
 - ALLOWING FOR A PORTION OF THE STEAM TO REACH THE HYDRATE INTERFACE VIA STEAM OVERRIDE.

A DIAGRAMMATIC SCHEME OF CYCLIC STEAM INJECTION IS PROVIDED IN FIGURE 1.

FIGURE 1
STEAM SOAK STIMULATION PROCESS

SOURCE: Adapted by Lewin from NPC, EOR Study, 1984.

MODEL ASSUMPTIONS

THE KEY MODEL ASSUMPTIONS USED IN PERFORMING THE ANALYSIS INCLUDE:

- THE RESERVOIR CONSISTS OF A CONSOLIDATED ROCK MATRIX;
- THE STOICHIOMETRIC COMPOSITION OF THE HYDRATE IS UNIFORM THROUGHOUT THE RESERVOIR, AND 100% OF THE PORE SPACE IS ASSUMED TO BE FILLED BY HYDRATE (100% SATURATION);
- ONLY METHANE HYDRATE (STRUCTURE I) IS CONSIDERED;
- NO FREE GAS IS INITIALLY PRESENT IN THE RESERVOIR;
- AN INITIAL VOID VOLUME FOR STEAM INJECTION OF 196 FT^3 IS ASSUMED, OBTAINED BY FRACTURING OF THE RESERVOIR;
- ALL INJECTED STEAM CONDENSES TO WATER;
- RESIDUAL WATER SATURATION IN THE RESERVOIR IS ASSUMED TO BE 20%; AND
- THE RESERVOIR ROCK IN THE DISSOCIATED REGION IS SUFFICIENTLY PERMEABLE (100+ MD) TO SUPPORT THE ASSUMED STEAM INJECTION AND FLUID DRAWDOWN RATES.

THE ROCK, FLUID, AND STEAM PROPERTIES USED IN THE MODEL RUNS ARE GIVEN IN TABLE 1.

TABLE 1

ROCK, FLUID AND STEAM PROPERTIES USED IN THE MODEL RUNS

RESERVOIR PROPERTIES

Porosity	30%
Thickness	100 FT.
Rock Grain Density	167 LBM/CU-FT.
Heat Capacity	0.20 Btu/LBM-DEG F

HYDRATE

Density	55.0 LBM/CU-FT.
Heat Capacity	0.61 BTU/LBM-DEG F

BASE/CAP ROCK

Density	167 LBM/CU-FT.
Heat Capacity	0.21 BTU/LBM-DEG F
Thermal Conductivity	1.3 BTU/HR-FT-DEG F

STEAM PROPERTIES (at the given conditions)

Steam Injection Pressure	2000 PSIA
Saturated Steam Temperature	635.8 DEG F
Latent Heat of Vaporization	466.2 BTU/LB
Specific Volume of Saturated Vapor	0.188 FT ³ /LB
Specific Volume of Saturated Liquid	0.025 FT ³ /LB
Enthalpy of Saturated Liquid	672.1 BTU/LB
Steam Quality	80.0%
Density of Steam	6.41 LBM/CU-FT.
Steam Injection Rate	2000 BBL/DAY

MODEL PROCESS

FIGURES 2 AND 3 PROVIDE A DIAGRAM OF THE TWO IMPORTANT STEPS IN THE MODELING PROCESS, NAMELY:

- STEAM INJECTION AND THE DEVELOPMENT OF AN OVERRIDING STEAM ZONE,
- COLLAPSE OF THE STEAM ZONE INTO A HOT WATER CYLINDER.

FIGURE 4 ILLUSTRATES THE TEMPERATURE REGIME OCCURRING FOR THESE TWO STEPS AND SHOWS THE CONDUCTION OF HEAT AND THE THERMAL DECAY OF THE HOT WATER CYLINDER AFTER INJECTION.

THE FINAL PHASE OF THE MODEL, THE PRODUCTION OF GAS AND WATER, WAS PREVIOUSLY ILLUSTRATED IN FIGURE 1.

FIGURE 2

MODEL CONFIGURATION DURING STEAM INJECTION

Prepared By: Lewin and Associates, Inc., 1985.

FIGURE 3

MODEL CONFIGURATION AFTER STEAM INJECTION

Prepared By: Lewin and Associates, Inc., 1985.

FIGURE 4
TEMPERATURE DECAY AFTER STEAM INJECTION

SOURCE: Modified by Lewin from: Bayles (METC), 1984.

END

**DATE
FILMED**

8 / 27 / 92