Dr. 25 88

60
123/81
165-
MASTER

Dist-202
DTIS-23

DOE/ET/27085-1

**OPERATIONS RESEARCH AND SYSTEMS
ANALYSIS OF GEOPRESSURED-GEOTHERMAL
ENERGY IN LOUISIANA**

Final Report, June 1, 1978—August 31, 1979

By
Adrain E. Johnson, Jr.
Ann L. Bachman
Michael D. Grimes
Thomas A. Harrell

Ralph W. Pike
Thomas G. Ray
Deborah L. Saucier
Fred M. Wrighton

Work Performed Under Contract No. FG08-78ET27085

State of Louisiana
Department of Natural Resources
Baton Rouge, Louisiana

**U. S. DEPARTMENT OF ENERGY
Geothermal Energy**

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DISCLAIMER

"This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Printed Copy A13
Microfiche A01

OPERATIONS RESEARCH AND SYSTEMS ANALYSIS
OF GEOPRESSURED-GEOTHERMAL ENERGY
IN LOUISIANA

FINAL REPORT
FOR THE PERIOD

June 1, 1978 to August 31, 1979

Adrain E. Johnson, Jr., Principal Investigator

Faculty and Staff Associates

Ann L. Bachman
Michael D. Grimes
Thomas A. Harrell
Ralph W. Pike
Thomas G. Ray
Deborah L. Saucier
Fred M. Wrighton

State of Louisiana
Department of Natural Resources
Post Office Box 44156
Baton Rouge, Louisiana 70804

Prepared for the

U.S. Department of Energy
Nevada Operations Office
Originally issued under No. ET-78-G-08-1576
Final Contract No. DE-FG08-78ET27085

TABLE OF CONTENTS

ABSTRACT	iv
I. INTRODUCTION	1
II. OVERVIEW OF THE LOUISIANA GEOPRESSURED-GEOTHERMAL RESOURCE . . .	5
Introduction	5
Geopressured Energy Program	5
Test Wells and Wells of Opportunity Activities in Louisiana	7
An Overall Assessment of the Potential Commercial Viability of the Resource	9
III. REVIEW OF TASKS PERFORMED BY SYSTEMS ANALYSIS PROJECT	11
A. Workshop on Geopressured-Geothermal Resource Assessment . .	12
B. The Geopressure-Geothermal Technoeconomic Site Simulation Model	23
C. Application of the Technoeconomic Model to High-Potential Prospects in Louisiana	72
D. Development of a Correlation Procedure for Methane Solubilities in Geopressured Brines	76
E. Results of Sensitivity Studies and the Analysis of Alternative Proposals for Geopressured Development . . .	79
F. An Analysis of Legal and Institutional Impediments to the Development of the Geopressured Resource in Louisiana	81
G. Disposal of Fluids from Geopressured Aquifers	93
H. An Overview of the Problems of Subsidence Associated with Development of Geopressured-Geothermal Resources in Louisiana	100
I. Summary of the Socio-Economic Impacts of Geopressured- Geothermal Energy Development in Coastal Louisiana . . .	111
IV. CONCLUSIONS AND RECOMMENDATIONS	114
Resource Assessment	114
Commercial Viability of High-Potential Louisiana Prospects . .	115
The Potential for Commercial Development in Louisiana	117
Alternate Technology	117
Legal and Institutional Analysis	118
Subsurface Disposal	119
Socio-Economic Impacts	120

APPENDICES

1. A Description of the Technoeconomical Model Used to Analyze the Development Potential of Louisiana Geopressured Energy Prospects--Fred M. Wrighton, Adrain E. Johnson, Jr., and Thomas G. Ray 121
2. A Report of the Economic Analyses Completed to Date of the Most Promising Geopressured Energy Prospects in Louisiana--Adrain E. Johnson, Jr., Fred M. Wrighton, and Thomas G. Ray 132
3. The Correlation of Methane-Brine Solubility Data--Adrain E. Johnson, Jr. 168
4. Sensitivity of the Economics of a Geopressured Energy Prospect to Variations in Geologic Parameters--Thomas G. Ray and Adrain E. Johnson, Jr. 191
5. Economics of Alternative Geopressured Technologies--Fred M. Wrighton and Thomas G. Ray 203
6. Subsurface Disposal of Geopressured Fluids: Potential Geologic and Operational Problems with Recommendations for Disposal System Testing--Ann L. Bachman and Charles G. Smith 211
7. Subsurface Disposal: Hydrogeologic and Operational Concerns--Ann L. Bachman and Charles G. Smith 237
8. Assessing the Socio-Economic Impact of Geopressured/Geothermal Energy Development in Coastal Louisiana: A Preliminary Report--Michael D. Grimes and Deborah L. Saucier 246

ADDENDUM (Separate attachment to this report)

Workshop on Subsurface Disposal of Geopressured Fluids, Gulf Coast, Proceedings--Ann L. Bachman, Editor

ABSTRACT

A multi-disciplinary project team at Louisiana State University (LSU) was authorized under DOE grant number DE-FG08-78ET27085 to conduct a project entitled "Operations Research and Systems Analysis of Geopressured-Geothermal Energy Resources in Louisiana." The primary purpose of the grant was to provide a projection of the probable future contribution of the geopressured-geothermal energy resource in Louisiana to the overall energy requirements of the nation. Because resource assessment projects are not yet completed, the team concentrated on a number of associated objectives; namely, development of the tools and methodology for performing economic analyses, application of these tools to specific prospects about which adequate resource assessments have been made, identification of the impediments to resource development, and socio-economic analysis of the impact of development of the resource on these specific prospects. In this report an overview of the geopressured-geothermal resource activities in Louisiana is provided first, followed by a detailed discussion and review of the achievements of this project. Finally the major conclusions and findings of this project with respect to commercial viability, impediments, and social and economic impact are presented, and recommendations are made for future systems analysis work. In the Appendices are reproduced eight papers which were presented by project members as a result of the work reported here. The complete proceedings of the Workshop on Subsurface Disposal of Geopressured Fluids which was held as one of the activities of this project, accompany this report.

I

INTRODUCTION

This final report covers the activities conducted by a multidisciplinary team formed at Louisiana State University (LSU) to carry out work authorized under DOE grant number ET-78-G-08-1576 (later changed to DE-FG08-78ET27085) entitled "Operations Research and Systems Analysis of Geopressured-Geothermal Energy Resources in Louisiana." For purposes of brevity, this report will refer to the project and its team as the systems analysis project or team. The primary purpose of this grant was to provide a projection for DOE of the probable future contribution of the geopressured-geothermal energy resource in Louisiana to the overall energy requirements of the nation.

In order to accomplish this objective, the project team was requested to undertake specific tasks: (1) characterization and economic analysis of the resource, and an evaluation of its potential energy contribution (based on resource assessments to be conducted by a separate project team at LSU); (2) identification of the impediments to the development of the resource; (3) preparation of regional development scenarios for the resource; and (4) determination of the social and economic impacts of the projected resource development. The statement of work defined by DOE was patterned after previous projects which had been carried out for geothermal energy in western states, and it proposed that a similar study be conducted for the geopressured-geothermal resource in Louisiana.

The systems analysis project was initiated June 1, 1978, under a one year grant extending until May 31, 1979. During the first three months, the project team was gradually formed as the members completed work on previous commitments. Activities during this time consisted primarily of orientation and introductory analysis. A separate geopressured-geothermal resource

assessment project then underway at LSU (DOE contract number EY-76-S-05-4889, Bernard et al., running from August 16, 1977 to May 15, 1980) had been directed to rank the sixty-three specific geopressured-geothermal prospect sites which had been identified in a prior study in order to choose several high-potential sites for detailed analysis. These sites were to become the candidates for test wells to be drilled with DOE funds. However, this resource assessment project was not directed to develop the regional contour mapping of the resource properties and a definition of reservoir boundaries needed by the systems analysis project. (Later, in 1979, a DOE contract was let to LSU for this purpose, D. Bebout et al., Number DE-AS05-78ET-27021 extending into 1981.) It became clear that a regional map would not become available within the grant period of the systems analysis project. Besides the Bernard site-specific study, a revised USGS Gulf Coast geothermal resource assessment was also being conducted, and was subsequently reported.² However, this study, although regional in scope, was not made at the level of detail needed for producing a regional projection of economically feasible geopressured-geothermal energy development. Because of this, the project team recognized that the desired overall comprehensive analysis of the projected resource development for Louisiana could not be made within the allotted time-frame of the systems analysis project. Instead, only a perfunctory analysis would have been possible, which, if done, would have been inadequate with respect to the original primary aim of the grant.

In view of this, it was decided that the most effective way to conduct the systems analysis project was to postpone the objective of developing a comprehensive regional projection of "on line" geopressured-geothermal energy development until the regional mapping project of Bebout et al. could provide the required information, and instead to focus the efforts of the systems analysis team on as many of the associated objectives of the grant as practical. Accordingly, the tasks undertaken were (1) to develop the tools needed for economic analysis of both site-specific and regional mapping resource assessments, (2) using these tools, to analyze the high-potential specific prospects as soon as the data became available, (3) to identify and develop information concerning significant impediments to the resource development in Louisiana, and (4) to perform social and economic impact analyses of the high-potential prospects. In this way, the

methodology required for the postponed regional projection could be developed and tested through specific analyses on particular sites, many of the secondary objectives of the original project could in fact be accomplished, and, in addition, specific critical issues regarding the development of the geopressured-geothermal resource could be addressed by project team members qualified by their training, background and interest to study such problems.

In order to carry out the tasks described above, the one-year grant for the systems analysis project was extended at no additional cost to DOE for three months until August 31, 1979. This extension permitted the involvement of the entire project team for at least twelve months and also allowed time for inclusion of the site-specific resource assessment data reported by Bernard in June 1979¹ into the analyses being conducted. A second resource assessment of five prospects in addition to those reported by Bernard was undertaken by Dr. Zaki Bassiouni of LSU, but his project was not completed in time to be included in the work done here.

Section II of this report is an overview of geopressured-geothermal resource activities in Louisiana. The overview includes: (1) a summary of all LSU projects investigating various aspects of the potential resource; (2) a brief description of design test wells and "wells of opportunity" activities, both under way and planned, which will help further define the nature and limitations of the potential resource; and (3) an overall assessment of the potential commercial viability of the resource as interpreted from the studies, conferences, workshops, and research conducted by the systems analysis team during the grant period.

Section III is a detailed discussion and review of activities and results of the systems analysis project during the grant period. In Section IV the major conclusions and findings of the systems analysis project with respect to commercial viability, impediments, and social and economic impact are presented and recommendations are made for future systems analysis work. In Appendix A of this report is reproduced each of the eight papers presented by the members of the systems analysis project team at the Fourth Conference on Geopressured-Geothermal Energy at the University of Texas, Austin (October 1979), and at the Engineering Foundation Conference on Geopressured-Geothermal Energy at Sea Island, Georgia (January 1980). These papers, this final report, and the proceedings of the Workshop on Subsurface Disposal of Geopressured Fluids, Gulf Coast, at LSU (March 1979),

(accompanying this report as an Addendum) constitute the deliverables which resulted from this grant. In addition to these tangibles, there now resides at LSU a substantial quantity of experience and knowledge in most aspects of the geopressured-geothermal resource in Louisiana, as well as some useful analysis tools and methodology, which will continue to be applied to the resource as additional data and information are made available in the future.

References

1. Bernard, W. J., "Evaluation of five potential geopressure geothermal test sites in Southern Louisiana." Prepared for DOE Contract No. EY-76-S-05-4889. (Baton Rouge, La.: Petroleum Engineering Department, Louisiana State University, June 1979)
2. U.S. Geological Survey, "Assessment of Geothermal Resources of the United States--1978," L. J. P. Muffler, ed. Circular 790. (Arlington, Va.: USGS, 1979)

II

OVERVIEW OF THE LOUISIANA GEOPRESSURED-GEOTHERMAL RESOURCE

Introduction

Energy research at Louisiana State University (LSU) presently is funded at the level of \$3.3 million. This represents not only a significant commitment of industrial, state and federal funding, but it also represents a very significant commitment of university resources in terms of faculty and staff. LSU's commitment to long-term energy research has recently been officially recognized by the university administration in the establishment of the Office of Energy Programs. This office has university-wide responsibilities and reports to the Vice-Chancellor for Advanced Studies and Research, as shown in the attached LSU Organizational Chart. This office now has responsibility for LSU's campus-wide interdisciplinary Geopressured Energy Research Program.

Geopressured Energy Program

At LSU, interest in geopressured-geothermal energy zones dates back to the middle 1960's when the Department of Petroleum Engineering and the Department of Geology initiated a number of research projects and conducted a number of symposia related to these zones. The LSU Geopressured Energy Program got its start in about 1975 and was conducted at a modest level until 1977 when the program began to grow into a comprehensive interdisciplinary effort. The Division of Geothermal Energy (DGE) of the U.S. Department of Energy (DOE) currently funds, under four separate contracts, geopressured energy research projects at LSU as part of the geopressured energy program. These projects are listed below by category and project title.

Geopressured Energy Contracts at LSU

<u>CATEGORY</u>	<u>TITLE</u>
Geopressured Wells	Technical Support for Geopressured Well Activities in Louisiana
Operations Research	Operations Research and Systems Analysis of Geopressured-Geothermal Energy Resources in Louisiana
Resource Assessment	Site Specific Investigations of the Geopressure Energy Resources, Southern Louisiana
Geology	Geologic, Geophysical, and Geochemical Aspects of Site Specific Studies of the Geothermal-Geopressured Energy Resource of Southern Louisiana

In addition to the DOE-funded projects, LSU has developed and is developing funding from industry sources.

As the lead geopressured-geothermal research organization in Louisiana, LSU has assumed the responsibility for insuring that information gained from the geopressured-geothermal effort in Louisiana is collected, analyzed, and made available to others. Besides being essential in the current development program, much of this information will be of great value far in the future, particularly the geology of the sites, the results of the environmental monitoring program, the deformation properties of the rocks from the aquifers, the results of flow testing, and the engineering problems encountered.

The overall objective of the LSU on-going geopressured-geothermal program is to add technical support to the DOE program to develop the geopressured-geothermal resource. The specific objectives are:

- (1) to coordinate on-going and new projects funded by the geopressured-geothermal program,
- (2) to provide technical advice for the drilling and testing of the wells included in the DOE four-well and Wells-of-Opportunity programs in Louisiana,
- (3) to act as a repository for all data obtained from the geopressured-geothermal test wells drilled in Louisiana, and
- (4) to manage and supervise a comprehensive environmental monitoring program for each designed test well in Louisiana.

Test Wells and Wells of Opportunity
Activities in Louisiana

The Department of Energy is committed to a characterization of geopressured-geothermal resources in Louisiana through direct observation and measurement. This effort is being pursued through two methods: a) the design and drilling of a test well in an identified prospect, and b) the completion of dry gas or oil wells in a geopressured sand and testing of fluid, called the "Wells of Opportunity" program.

It is likely that there will be four design wells drilled in Louisiana in the near future. Two design well proposals have been funded and plans are under way to drill this year. These two wells are the Sweet Lake project, located about halfway between Lake Charles and Cameron, and the Parcperdue project, located just southwest of Lafayette (see attached map). Magma Gulf Company plans to drill the Sweet Lake prospect in late summer, 1980, and DOW expects to drill at Parcperdue, also during the summer of 1980. Two other design wells proposed with a high probability of funding are Gladys McCall No. 1, located in Southeast Cameron Parish, and Lafourche Crossing, to be contracted through the Louisiana Department of Natural Resources. Louisiana State University is responsible for monitoring the environmental work at Sweet Lake and Parcperdue, and will be responsible for the engineering and testing as well as the environmental monitoring at Lafourche Crossing.

In the Wells of Opportunity program, several have been tested and completed, including Delcambre, Beulah Simon and Fairfax F. Sutter (see map). Currently being tested as of July 21, 1980, is the Wainoco Girouard No. 1 in Lafayette Parish. Eaton Operating Company is conducting the tests and has 16 additional wells in Louisiana under consideration for the Wells of Opportunity program. All DOE programs described above were designed to determine the physical characteristics of the geopressured fluid (pressure, temperature, salinity, and methane content), and to determine the deliverability characteristics of the reservoir (volume, thickness, permeability, porosity, brine flow, and draw-down behavior).

LOUISIANA			
GEOTHERMAL	GEOPRESSURE	TEST-WELL	STATUS

Department of Natural Resources

Louisiana Geological Survey
C. G. Great, Director

October 1980

An Overall Assessment of the Potential Commercial
Viability of the Resource

The most pervasive impediment to commercial exploitation of the geopressured-geothermal resources of Louisiana is uncertainty about the various aspects of its development. Obviously, it is not the uncertainty itself but the degree of uncertainty which is the problem since all commercial ventures entail a certain amount of it.

In the case of the geopressured-geothermal resource, most of the uncertainty is associated with the physical characteristics of the resource and their consequent effect on the production rate and term achievable for methane gas, and the operating costs associated with production. At present, the focus of interest in the geopressured resource is on the recovery of methane gas from the brine. The thermal and hydraulic energy content of the geopressured fluid is considered of only secondary importance by most experts because (1) the temperature of the fluid is low (about 250°F) and (2) the uncertainties associated with well life make the payout of the electrical generating equipment very unattractive. The chemical content of the fluid is important since it may have a substantial effect on disposal costs. These costs may be an important component of operating costs. The technology seems to be available to cope with fluid disposal--but at what cost? These uncertainties are discussed in detail in sections III-C and III-G.

In addition to the uncertainty about the physical characteristics of the resource, there is limited concern over one of the possible consequences of production: subsidence. In south Louisiana even a minute amount of subsidence over a wide area can have substantial environmental effects from salt water encroachment and the possible loss of agricultural land. There is a tendency to discount this problem due to the tremendous production of oil and gas over the years and the minimal difficulty encountered in the past with subsidence. However, sustained fluid production rates of the magnitude required for a geopressured-geothermal development have yet to be experienced in Louisiana and the possibility of subsidence certainly exists. The problem and forecasting difficulties of potential subsidence are discussed in detail in Section III-H.

In this report, results are given from simulation analyses made on the five most promising sites identified by Bernard, June 1979. These

analyses disregarded uncertainty as an element of the analysis, using only most likely values for all parameters, but it will be incorporated in future work. One of the sites has a major fault separating the reservoir into two parts, so a total of six studies was conducted. Of the six sites, only two, Rockefeller Refuge and Southeast Pecan Island, provided a rate of return exceeding 15%. Not surprisingly, the most critical parameter affecting the rate of return was the gas content of the brine. A value of approximately 26 cubic feet per barrel was required to produce a 15% rate of return. The details of these simulations are discussed in Section III-B. The base case simulation consisted of a single production well with two disposal wells for the effluent. Alternatives to this base case such as surface disposal of the brine certainly enhanced the rate of return of a geopressured-geothermal development. This alternative and others are discussed in Section III-E.

At this point, near term commercial development of geopressured-geothermal resources in Louisiana does not appear likely. The combination of the substantial uncertainty and the marginal nature of the available return under existing economic conditions mitigate against early development. With additional research, test wells, and changing economic conditions these mitigating factors should be reduced or eliminated. In that event, the possibility of commercial development would be greatly enhanced.

III

REVIEW OF TASKS PERFORMED BY SYSTEMS ANALYSIS PROJECT

In this section the tasks which were identified and undertaken by the project team are reviewed and discussed. Most of these activities have already been reported on publicly at either the Fourth Geopressured-Geothermal Conference at Austin, Texas, in October 1979 or at the Engineering Foundation Conference at Sea Island, Georgia, in January 1980. The papers delivered at these conferences are reproduced and included in this final report as Appendices 1 through 8. In general the discussions presented in this section concentrate primarily on the conclusions and results of the work done; additional detail can be found, if desired, by referring to the appropriate paper in the Appendix. Some of the tasks, however, were not reported separately at a conference. For these, the discussion presented here includes additional detail as needed.

A. WORKSHOP ON GEOPRESSURED-GEOTHERMAL
RESOURCE ASSESSMENT

In early 1979, USGS circular 790¹⁹ became available, in which a revised assessment of the geopressured-geothermal resources in the Northern Gulf of Mexico basin was made. Previous estimates by various authors had been tabulated in an LSU report by Wilkins and Waguespack.²⁰ The previous estimates are reproduced here as Tables 1, 2, and 3, and the estimates from circular 790 are given Tables 4 and 5.

TABLE 1
ESTIMATES OF TOTAL GEOPRESSURED RESOURCE
(Louisiana-Texas Gulf Coast, Onshore and Offshore, in Quads)

Source	Thermal	Mechanical	Gas	Total
Brown - Hudson ¹			60,000-105,000	
Dorfman - Texas ³			5,735	
Hawkins - LSU ⁷ (Louisiana only)	19.5	1.2	13.6	34.3
Hise - LSU ⁸			3,000	
House ¹⁰ - Livermore			221.7	
Jones - LSU ¹¹ (sands and shales)			100,000	
(sands only)			49,000	
Karkalits - McNeese ¹²	60,000		12,000-30,000	
Myers - Livermore ¹³			0.1-2,650	
Papadopoulos - USGS ¹⁴ (assessed onshore only)	43,331	198	23,927	67,456
(unassessed only)		1½ to 2½ times assessed		
Schnadelbach - de LaREAL ¹⁵			111,500	
U.S. ERDA - MOPPS ¹⁸			3,000-40,000	
U.S. ERDA - Definition Report ¹⁷	44,000-176,000			

TABLE 2

ESTIMATES OF RECOVERABLE GEOPRESSURED ENERGY
(Louisiana-Texas Gulf Coast, Onshore and Offshore)

Source	Thermal Quads	Gas Quads	Electricity (MW-centuries)
Brown - Hudson ¹		2,400-52,000	
Dorfman - Texas ² (Texas only)			20,000
Dorfman - Texas ³		256	
Elmer - Tracor ⁵	529-2,058	2,000	
Gould - Intercomp ⁶ (onshore Texas only)		150	33,000
Hawkins - LSU ⁷ (Louisiana only)	<19.5	<13.6	
Hise - LSU ⁸		125	
House - Livermore ^{9,10}		222	5,990
Jones - LSU ¹¹		>1,146	
Myers - Livermore ¹³		.0001-1,000	0.1-100,000
Papadopoulos - USGS ¹⁴ (Plan 2)	1,424	768	38,140
(Plan 3--lower bounds)	- - - - 77.38 - - -		2,880
Trehan - Mitre ¹⁶			100,000
U.S. ERDA - Definition Report ¹⁷		500-2,000	33,400-110,000
U.S. ERDA - MOPPS ¹⁸		150-2,000	
Wilson - Dow ^{21,22} (Texas only)		45.6	8,000

TABLE 3

ASSUMPTIONS FOR VARIOUS RESOURCE ASSESSMENTS

	Dorfan	Gould	Hawkins	Hise	House	Jones	Myers	Papadopoulos	Schnadelbach
Area (sq. mi.)	100,000	60,000	42,000	100,000	30,600	154,000	29,000	55,970	
Area productive (%)		22.5			5		1-50		
Thickness (feet)	10,000	10,000	8,000	10,000	15,000	13,120-19,680	15,000	9,482-13,715	
Sandstone (%)	15	7.5	5.4	10	56	50	10-60	12-49	
Porosity (%)	22	20	20	20	20	25	15-35	18-22	
Dissolved Natural Gas (scf/bbl)	35	30-40	20.3	30	19-44	18.8-164	1-30	28.2-46.3	107
Water in Place (x 10 ¹² bbl)	164	10	.67	100	10.9	1,492	.126-88.2	657	1,042
Gas in Place (Tcf)	5,735	>300	13.6	3,000	221.7	100,000	.126-2,646	23,636	111,500
Recovery (%)	5	50		5	2-100	>1.1	.1-70	.12-3.3	
Recoverable Water (x 10 ¹² bbl)	8.2	5.0		5.0		>17.1	.000126-61.7	.79-21.7	
Recoverable Gas Content (scf/bbl)	30	30		25		30			
Recoverable Gas (Tcf)	256	150		125		>1.146	.0001-1,000	768	

TABLE 4

ACCESSIBLE FLUID RESOURCE BASE OF GEOPRESSURED-GEOTHERMAL ENERGY
IN THE NORTHERN GULF OF MEXICO BASIN BY DEPTH INTERVAL

(Volumes and energies given to two significant figures. However, if the first digit is 1, three significant figures are given in order more closely to approximate uniform percentage accuracy. Energy equivalent of methane considered to be $3.73 \times 10^7 \text{ J/m}^3$.)

Lithology	Interval number and depth to midpoint (ft) (m)		Volume of water in storage (10 ¹² m ³)	Thermal energy (10 ¹⁸ J)	METHANE ENERGY		Total thermal and methane energy (10 ¹⁸ J)	
					Thermal equivalent (10 ¹⁸ J)	Volume (10 ¹² m ³) (10 ² ft ³)		
Sandstone	1	2250 (686)	0.1	11	3	0.1	2.8	14
	2	3750 (1143)	.1	24	6	.2	5.9	30
	3	5250 (1600)	.3	60	20	.5	18.5	80
	4	6750 (2057)	.6	160	52	1.4	50	210
	5	8250 (2514)	1.2	380	130	3.5	124	520
	6	9750 (2972)	1.7	630	220	5.7	200	840
	7	11250 (3429)	2.1	900	320	8.6	310	1,220
	8	12750 (3886)	2.2	1,040	410	11.0	390	1,450
	9	14250 (4343)	2.2	1,130	530	14.0	500	1,660
	10	15750 (4800)	2.1	1,200	620	16.3	580	1,810
	11	17250 (5258)	1.7	80	570	15.2	540	1,550
	12	18750 (5715)	2.7	1,640	1,150	30	1,090	2,800
	13	20250 (6172)	1.3	870	550	14.7	530	1,420
	14	21750 (6629)	2.8	2,000	1,460	39	1,380	3,500
Sandstone	TOTAL-----		21	11,000	6,000	160	5,700	17,100
Shale	TOTAL-----		175	96,000	57,000	1,510	54,000	153,000
TOTALS-----			196	107,000	63,000	1,670	59,000	170,000

TABLE 5

ACCESSIBLE FLUID RESOURCE BASE OF GEOPRESSURED-GEOTHERMAL
ENERGY IN THE NORTHERN GULF OF MEXICO BASIN, BY AREA

(Energies given in units of 10^{18} joules rounded off to two significant figures or to three significant figures if the first digit is 1. Energy equivalent of methane considered to be 3.73×10^7 J/m³.)

		Sandstone	Shale	Total
Texas	Thermal	3,200	44,000	47,000
	Methane	<u>1,890</u>	<u>28,000</u>	<u>30,000</u>
	Total	5,100	72,000	77,000
Louisiana	Thermal	2,600	16,100	19,000
	Methane	<u>1,330</u>	<u>9,000</u>	<u>10,000</u>
	Total	4,000	25,000	29,000
Federal Outer Continental Shelf Area	Thermal	5,200	37,000	42,000
	Methane	<u>2,800</u>	<u>19,400</u>	<u>22,000</u>
	Total	8,000	56,000	64,000
TOTAL NORTHERN GULF OF MEXICO BASIN	THERMAL	11,000	96,000	107,000
	METHANE	<u>6,000</u>	<u>57,000</u>	<u>63,000</u>
	TOTAL	17,100	153,000	170,000

In order to evaluate the perceived status of the geopressured-geothermal resource assessments and to identify what, if any, steps are needed in the future, the systems analysis project team held a workshop on Gulf Coast geopressured-geothermal resource assessment on April 18-19, 1979. Representatives from every known group which had previously published a geopressured-geothermal resource assessment were invited, as well as others known to be actively concerned. A list of those invited to the workshop is given in Table 6, and the agenda of the workshop discussions is shown in Table 7.

In the following paragraphs, the consensus views of the workshop participants on major issues is reported, followed by a brief, edited version of the other discussion points of significance.

TABLE 6

INVITED TO THE WORKSHOP ON THE GEOPRESSURED-GEOTHERMAL
RESOURCES OF THE GULF COAST, APRIL 18-19, 1979

Bebout, Don Texas Bureau Economic Geology Austin, Texas	Luper, Ed Mississippi Geological Survey Jackson, MS
Bernard, Bill LSU Petroleum Eng. Baton Rouge, LA	Osborne, Dr. Robert H. Dept. of Geological Sciences University of Southern California Los Angeles, CA
Hise, Bill LSU Petroleum Eng. Baton Rouge, LA	Papadopoulos, Dr. F. S. USGS-WRD Reston, VA
Bassiouni, Zaki LSU Petroleum Eng. Baton Rouge, LA	Randolph, Philip L. (Leo Rogers) Institute of Gas Technology Chicago, Illinois
Cronquest, Chapman Gulf University Research Corp. Bellair, Texas	Swanson, R. K. Southwest Research Institute San Antonio, TX
Darnell, Grant S. AMOCO New Orleans, LA	Wallace, Ray U.S. Geological Survey Bay St. Louis, MS
Garg, S. K. Systems, Science and Software La Jolla, CA	Clarence O. Durham Magma-Gulf Geothermal 918 Daria Drive Houston, TX 77079
Gregory, A. R. Bureau of Economic Geology University of Texas at Austin	Frank Bland, Manager Central Exploration Division Chevron, U.S.A. 1111 Tulane Avenue New Orleans, LA 70112
Groat, Charles La. Geological Survey Baton Rouge, LA	

TABLE 7

WORKSHOP ON THE GEOPRESSURED-GEOTHERMAL RESOURCES OF
THE GULF COAST: ASSESSING THE ASSESSMENTS
April 18-19, 1979, Baton Rouge HILTON

Proposed List of Discussion Topics

Introduction

Background and Goals
Workshop Schedule and Formal Introduction of Participants
Assessment Terminology

Assessment of Resource Base

Geopressured-Geothermal Resource Base - 1978
Review and Discussion of Parameters
Volume of Sand
Porosity
Temperature
Pressure
Methane Content
Salinity
What are data sources for each parameter?
Is data base adequate?
What are limits of "accessible fluid resource base"?

Assessment of Recoverable Energy

Technological Limitations
Economic Limitations
Review and Discussion of Parameters
Volume of Sand
Environment of deposition
Fault boundaries
Reservoir size-distribution
Permeability
Variation with production
Relative permeability (gas; water)
Geographic variations
Depth variations
Reservoir Behavior
Drive mechanisms
Compressibility
Shale dewatering
Gas evolution/expansion
Recoverability
With natural drive
With fluid injection

Resolving Uncertainties

Recommendations
Physical Research
Reservoir Simulation
Site Specific Studies
Economic Evaluations
Other Suggestions

Summary of Consensus Views, Major Issues

- A major uncertainty and barrier to exploitation of the resource remains: the question of the distribution and sizes of the individual, continuous geopressured reservoirs. (The studies made with the technoeconomic model showed that a volume of one cubic mile is required for a reservoir to produce enough brine for a profitable venture.) A major task which has not yet been done for Louisiana is the detailed mapping of the geopressured-geothermal region utilizing geophysical logs and seismic data. This is essential for locating the most continuous, least-faulted reservoirs, and for making reliable predictions of the actual recoverable resource. This mapping alone, however, is not sufficient. Flow tests from test wells are needed to demonstrate the reliability of the mapping.
- Another major uncertainty remaining is the gas content of the brines. Existing experimental laboratory data on gas solubility do not cover the pressure, temperature, and salinity range adequately. Also unanswered is the question of whether the brine in place is indeed saturated with gas. Additional work on obtaining and correlating experimental data is needed, plus measurements of the gas content of the brines from exploratory wells to test whether saturation of the brine with gas is a normal occurrence.
- Obtaining data from the DOE test well program and the wells of opportunity program (assuming positive results) is the only method of resolving the uncertainties on methane content and reservoir productivity to the degree that will both lower the perceived risk and confirm the profitability enough to make the venture attractive to a prospective investor.
- The economically recoverable resource probably amounts to much less than 0.5% of the USGS-reported total resource base, and it is perceived primarily as the methane gas contained in the brine. Little interest is shown in the thermal energy.

Summary of Other Discussions

Much of the workshop discussion dealt with the significance which is attached to resource base estimates, that is, estimates of the total energy in place in the geopressed sediments of the Gulf Coast. These estimates are invariably large, equal to hundreds of times the nation's current annual energy demand, and from casual reading of reports on the resource base many people infer that a large fraction of the resource base may some day be recoverable. Since approximately 90% of the base is contained in shale, which is at present considered unrecoverable, the suggestion was made to exclude the energy in shales from resource base estimates in the future.

It was generally agreed that for an individual sandstone reservoir of known size, the ultimate recoverability of the brine should be from 3 to 5%, assuming an effective compressibility of from 0.5 to 1.0×10^{-5} psi⁻¹. If effective compressibilities lower than this are encountered, then recoverability will be correspondingly less.

Uncertainties about porosities, temperatures, and pressures were not considered as presenting significant impediments to exploiting the resource. Of course it is recognized that the lower expected temperatures in Louisiana (250° to 300°F) result in a lower expected gas content of the brine.

Similarly, the higher expected salinities for some reservoirs (100 ppm) result in a lower expected gas content for Louisiana brines.

Some concern was expressed that the expected high permeabilities for the Louisiana sandstones were not going to prove correct. Work under way by the National Petroleum Council indicated that the effective permeability of reservoirs at Pecan Island, as determined from production analyses, are significantly lower than predicted.

Recommended Future Needs

The workshop participants agreed that only three future actions are needed in the area of resource management:

- Acceleration of the DOE program of exploratory test wells and wells of opportunity. Data from these wells are needed to help resolve the uncertainties about reservoir producibility (vis-a-vis continuity and permeability) and gas content of the brine.

- Detailed mapping of the geopressed-geothermal region, utilizing geophysical logs and seismic data, is essential for further improvements in resource assessment and identification of prospects.
- Additional work in obtaining and correlating experimental data for gas solubility in brines at elevated pressures and temperatures is needed to permit more accurate prediction of recoverable gas from a prospect or a region.

References

1. Brown, William M., "100,000 Quads of Natural Gas?," Hudson Institute Research Memorandum #31, HI-2451/2P, July 1976.
2. Dorfman, Myron, and R. O. Kehle, "Potential Geothermal Resources of Texas," Texas University Bureau of Economic Geology Circular 74-4, 1974.
3. Dorfman, Myron H., "Natural gas from geopressed zones in the U.S. Gulf Coast basin," Gas Supply Review, American Gas Association, March 1977, vol. 5, no. 6.
4. Elmer, Donald B., "Geothermal energy and energy conservation: policy planning objectives," Geothermal Energy Magazine, vol. 5, no. 5, May 1977.
5. Elmer, Donald B., "Direct heat applications of geothermal energy resources and the Second Law of Thermodynamics," Transactions of the Geothermal Resources Council, vol. 1, May 1977, Davis, Calif.
6. Gould, T. L., and A. Spivak, "Production Economics of a Geopressed Geothermal Prospect," American Institute of Chemical Engineers, Paper No. 27E, March 1977.
7. Hawkins, Murray F., Jr., "Final Report--Investigations of the Geopressure Energy Resource of Southern Louisiana," Louisiana State University Petroleum Engineering Department, ERDA Contract No. EY-76-S-05-4889, April 15, 1977.
8. Hise, Bill R., "Natural gas from geopressed aquifers," in Board on Mineral Resources--Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, D.C., 1976.
9. House, P. A., P. M. Johnson, and D. F. Towse, "Potential power generation and gas production from Gulf Coast geopressed reservoirs," Proceedings of the First Geopressed Geothermal Energy Conference, University of Texas at Austin, 1975.
10. House, P. A., P. M. Johnson, and D. F. Towse, "Potential Power Generation and Gas Production from Gulf Coast Geopressed Reservoirs," Lawrence Livermore Report UCRL-51813, 1975.
11. Jones, Paul H., "Natural gas resources of the geopressed zones in the northern Gulf of Mexico basin," in Board on Mineral Resources--Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, D.C., 1976.

12. Karkalits, O. Carroll in "Underground Louisiana" by Jim Polster, New Orleans Magazine, September 1977.
13. Myers, B., R. Nelson, J. Howard, and R. Austin, "Some elements of the northern Gulf of Mexico basin geopressure energy resource," presented to American Association of Petroleum Geologists (April 2, 1974) UCRL-74807, Rev. 1, San Antonio, Texas.
14. Papadopoulos, S. S., R. H. Wallace, Jr., J. B. Wesselman, and R. E. Taylor, "Assessment of Onshore Geopressured-Geothermal Resources in the Northern Gulf of Mexico Basin," Assessment of Geothermal Resources of the United States--1975, D. E. White and D. L. Williams, editors, U.S. Geological Survey Circular 726, 1975.
15. Schnadelbach, T. W., Jr., "Inventory and Case Studies of Louisiana, Non-Electric Industrial Applications of Geopressured Geothermal Resources," Quarterly Progress Report by de Laureal Engineers, New Orleans, Louisiana, ERDA Contract No. EG-77-C-07-1629, February 28, 1977.
16. Trehan, Ranvir K., John G. Leigh, Felicia Williams, and Susan Pond, "Analysis of Geothermal Energy Development Scenarios," MITRE Technical Report, MTR-7220, ERDA/DGE Contract No. # (49-18)-2268, November 1976.
17. U.S. Energy Research and Development Administration, Division of Geothermal Energy, Definition Report, ERDA-86, October 1975, Washington, D.C.
18. U.S. Energy Research and Development Administration, "Market Oriented Program Planning Study (MOPPS)," May 24-26, 1977, draft report.
19. U.S. Geological Survey, "Assessment of Geothermal Resources of the United States--1978," L. J. P. Muffler, ed. Circular 790. (Arlington, Va.: USGS, 1979)
20. Wilkins, Bert, Jr., and Michael O. Waguespack, "Operations Research and Systems Analysis of Geopressured/Geothermal Resources in Louisiana." (Baton Rouge, La.: Office of Advanced Studies and Research, Louisiana State University, February 1978)
21. Wilson, John S., B. P. Shepherd, and S. Kaufman, "Economic analysis of the use of Texas geopressured geothermal resources for the production of electrical power," Proceedings of the First Geopressured Geothermal Energy Conference. University of Texas at Austin, 1975.
22. Wilson, John S., B. P. Shepherd, and S. Kaufman, "An Analysis of the Potential Use of Geothermal Energy for Power Generation along the Texas Gulf Coast," Report by Dow Chemical USA for the Governor's Energy Advisory Council, State of Texas, October 30, 1974.

B. THE GEOPRESSURE-GEOTHERMAL TECHNOECONOMIC SITE SIMULATION MODEL

A major effort in the systems analysis project went into developing a technoeconomic simulation model that could be used in analysis of geopressured prospects. The following is a complete description of the current version of the model. There is also included in Appendix 1 of this report a paper titled, "A Description of the Technoeconomical Model Used to Analyze the Development Potential of Louisiana Geopressured Energy Prospects," by F. M. Wrighton, Adrain E. Johnson, Jr., and Thomas G. Ray; this paper was delivered by Dr. Wrighton at the Fourth Geopressured-Geothermal Conference at Austin, Texas.

The Geopressure-Geothermal Technoeconomic Site Simulation Model (GPPROG) is designed to achieve the objective of providing a comprehensive set of parameters and economic data that will allow scientific and economic analysts to evaluate the commercial viability of a specific site. By using averages of key technical and economic parameters it will be possible to provide estimates of total economic resource recovery available in Louisiana.

The initial objective was to solve for the net present value of the investment and operation of the development, with other economic parameters as given. The next logical stage was to incorporate an iterative procedure to solve for the internal rate of return that produced a net present value of zero. Four other solution options have been added that use zero net present value as the solution criteria. The other values that can be solved for are: 1) the vector of the price of methane; 2) the tax rate; 3) minimum methane solubility; and 4) the minimum area of the reservoir. With all of the existing options there are 192 different ways to simulate a given prospect. Obviously, some combinations of the options are more relevant than others so that the set of different runs used in our analyses is

much smaller than the potential.

Economic Assumptions

The basic framework of analysis is a single well development consisting of one producing well, two disposal wells, and a separation plant. The specifics of the facility are described in the cost assumptions. The planning horizon of the analysis is the period 1985 to the year 2004, 20 years. Since all of the cost estimates used have their origin in pre-1979 interviews and literature, an inflation adjustment was used to bring the figures to a 1985 basis. The inflation adjustment for investment was accomplished using a weighted value of two components of the GNP Price Deflator: 1) Fixed Investment, Nonresidential, Structures; and 2) Fixed Investment, Nonresidential, Equipment. The weights were ninety percent for equipment and ten percent for structures. All forecast values were obtained from the most recent long-term standard forecast prepared by Chase Econometrics, Inc.¹ The GNP Implicit Price Deflator was used to adjust operating costs. The investment cost estimates that follow are given in both the original dated estimate and the forecast 1985 value.

Drilling Costs

Drilling costs are based on a study by the DOW Chemical Company.²

One Source Well	
7" Bore @ 16,000'	\$ 1,925,000
Two Disposal Wells	
7" Bore @ 6,000'	<u>1,200,000</u>
	\$ 3,125,000

This 1976 estimate has been price adjusted to a 1985 value of \$5,934,375.

Plant Costs

Plant costs, obtained from the same source,² represent a gas-water separation plant that does not include the process of separating the hydrocarbon liquids from the gas. It was assumed that separation of the hydrocarbon liquids would take place in a central facility operated by the company that buys the methane. The plant configuration and cost is as follows:

First Stage Separator (2000 psi)	\$ 95,000
Second Stage Separator (300 psi)	6,000
Third Stage Separator (150 psi)	5,000
Disposal Pumps (Two - 20 x 300 psia Head)	135,000
Collection Piping	73,000
Disposal Piping	195,000
	<u>\$ 509,000</u>

The second and third stage separators are probably not necessary, but the price is not substantial, so they were included anyway. This 1976 value was price adjusted to a 1985 value of \$966,591.

Depreciation

The term of depreciation is assumed to be ten years for the total investment. This is based on the presumption that Internal Revenue Service regulations will change before 1985 in industry's favor. As for the drilling investment, two-thirds is treated as an expense in the first year and one-third is depreciated. Four standard methods of depreciation are optional in the model but typically it is assumed that one of the accelerated methods will be used. Scrap value of the investment is assumed to be 20% of the initial investment.

Working Capital

Working capital presents a recurring cash drain in any operation to the extent that it increases over time. For the purposes of this simulation, working capital is defined as current assets minus current liabilities. Since it would entail considerable effort to prepare detailed financial statements to generate figures for working capital, it was decided to estimate it using an industry average. The financial condition of domestic interstate natural gas pipeline companies for the year 1977 was obtained from the U.S. Department of Energy.⁶ Working capital for all class A and B pipelines for December 31, 1977, was \$843 million. Operation and maintenance expenses for the year ending December 31, 1977, were \$17,596 million. The ratio of working capital to operation and maintenance expenses was .048. Therefore, working capital in the model is computed as 4.8% of operating and maintenance expenses each year. The increase in working capital each year is a negative cash flow, but at project termination the accumulated working capital represents a cash return.

Taxes

Income taxes are levied by both the federal government and the State of Louisiana. Federal income taxes are computed against net profit at 20% on the first \$25,000, 22% on income between \$25,000 and \$50,000, and 46% on income exceeding \$50,000. Corporate income tax in Louisiana is levied against federally defined taxable income at 4% of income up to \$25,000, 5% on income between \$25,000 and \$49,999, 6% on income of \$50,000 to \$99,999, 7% on income of \$100,000 to \$199,999, and 8% on income exceeding \$200,000. State severance taxes are calculated at 7¢ per Mcf on all methane gas that is produced. Depletion allowance in this analysis is treated as an accounting adjustment affecting taxes and is not reflected in the before-taxes profit. The production of natural gas from geopressured brines constitutes an exception to the repeal of the oil depletion allowance passed in 1975. Ten percent of gross income is allowed for depletion with the limitation that the deduction may not exceed 65% of taxable income. The excess which is disallowed for one tax year because of the limitation is carried over to following years.

A standard investment tax credit of 10% against the tax liability is provided for in the model for all depreciable investment. The credit is not allowed to exceed the tax liability. Any excess is carried forward to the legal limit of seven years. There is a special investment tax credit of an additional 10% allowed for investments made in "alternative energy property" which includes equipment that is used to exploit geopressured and geothermal resources. However, to be eligible for this credit, construction must be initiated before December 31, 1982. Since this model covers the period 1985-2004, this additional credit was not included.

Operating Costs

Operating costs are incorporated in the model in three categories: 1) general operation and maintenance costs; 2) well operating and maintenance costs; and 3) power costs for reinjection. The basis for the operating costs estimates is a separation plant with a processing capacity of 40,000 barrels of water daily, under normal conditions. The costs are on a per barrel basis to accommodate variable levels of production. General operation and maintenance costs and well operating and maintenance costs

were obtained from V. A. Kuuskraa.³

The well operating costs were downgraded slightly to take account of the fact that Kuuskraa's plant configuration included four reinjection wells, while this model uses two. Power costs were derived from a theoretical calculation of the horsepower required to drive the pumps for reinjection. This was then converted to electric power requirements. Current electric prices then provided a cost estimate for reinjection of 40,000 barrels of water daily. Projected operating costs are as follows:

General Operation and Maintenance	\$.015/barrel
Well Operation and Maintenance	.0082/barrel
Power Costs	.008/barrel

These costs are all in 1978 dollars and are price adjusted over the life of the project using the GNP price deflator. The forecast values of this index are from a Chase Econometrics¹ long-term forecast with a linear regression used to extrapolate beyond the forecast horizon.

Prices

Perhaps the most uncertain of all assumptions is the anticipated pattern of gas prices in the future. There is a scarcity, if not an absolute void, of forecasts that are industry based. Company forecasts are considered private so, again, as in other cases, we turned to an econometric forecast. The 1979 Chase forecast extended ten years into the future and the balance of the project term was estimated with a linear regression. The price in 1985 is \$6.17/Mcf and it rises over the twenty-year period to a value in the vicinity of \$20/Mcf.

Royalty Payments

Royalty payments to the lessor are assumed to be 8% of the gas produced. Although this is below current oil and gas royalties, we feel that the nature of the operation would allow a value of this level to be negotiated.

Structure of the Model

The technoeconomic model consists of a MAIN program and twenty-eight subroutines and functions. The MAIN program in this case can be considered an executive program since its execution determines the subroutine call schedule for any particular run. The user either specifies a number of decision parameters prior to execution, or the model will use default values or values retained in the data set from previous execution. Certain of these parameters must be established for any execution. For example, the simulation must be either Monte Carlo or deterministic, the discount rate must be established, and the type of depreciation schedule must be selected. Then the problem type must be established, the options being to: 1) solve for the rate of return, 2) find the discounted net present value, 3) solve for the minimum methane in solution, 4) solve for the minimum size of the reservoir in area, 5) solve for the price of methane, or 6) solve for the tax rate. In all the cases, with the exception of solving for minimum methane solubility, the analyst must either specify methane content or elect to solve for methane content within the model. If the price is solved for as a critical value, then the user must select from four options of how to create a price vector. These options are 1) adjust the existing forecast price vector, 2) estimate a linear function between price and time, 3) estimate a compound interest function between price and time, or 4) solve for a constant or average price. If the tax rate is the critical value sought, then the user must choose among adjusting 1) the federal income tax, 2) the State income tax, or 3) the severance tax. Once a set of options is selected then a hypothetical site or one of the Louisiana prospects is used for the base geologic data.

Figure 1 contains a list of the subroutines and functions that comprise the model classified as to whether they are engineering, statistical and Input/Output, or economic. Most of the subroutines perform the function that their name implies.

Some explanation is warranted, however, especially among those classified as engineering. RESERV is the heart of the model since pressure levels and flow rates are computed by that subroutine, using theoretical equations for a bounded circular aquifer. PROCES determines the gas volumes that are associated with the flow volumes determined by RESERV. VISC

ENGINEERING

STATISTICAL & I/O

ECONOMIC

RESERV

MAIN

INVEST

PROCES

MONTE

DISC

VISC

ITERAT

CSHFLW

SOLUTE

OUTPUT

REVENU

PSH20

COSTS

PHIH20

DEPREC

VPMS20

TAXES

HCH4

TAXCAL

VDPINT

INVESC

PHICH4

QUEUE

PHECH4

DEQUE

SLTOUT

DOWN

WKGCAP

SOURCE STATEMENTS - 1225

EXECUTION TIME - 6.99 CPU SECONDS

Figure 1. GPPROG subroutines and functions.

is a function that computes the viscosity of the fluid for utilization as an input in RESERV. SOLUTE and all the remaining engineering functions are used to compute the methane in solution in the brine. The MAIN program has already been described. MONTE is a statistical subroutine that accepts as input a triangular distribution of a variable and outputs a random value from the distribution. ITERAT, as its name implies, is a statistical subroutine that iterates the solution variable to identify the critical value. OUTPUT defines the format for printing the results of the simulation.

Given the results of the engineering subroutines, the economic subroutines compute the investment, revenue, costs, depreciation, taxes, investment tax credits, working capital, and, finally, the discounted cash flow of the development. The total model requires 1225 source statements and about seven cpu seconds for execution. The lengthy execution time can be attributed to the fact that the reservoir subroutine models the performance of the reservoir on a daily basis.

Figure 2 illustrates the subroutine call schedule for computing the net present value of a site. The flow is clear in that control moves from MAIN to the engineering subroutines, then to the specification of the required investment. The discounting subroutine requires the output of components of the standard cash flow equation generated by the balance of the economic subroutines. The call schedule for solving for critical values shown in Figure 3 is identical with the previous one, with the inclusion of ITERAT between DISC and OUTPUT. The call schedule for a Monte Carlo simulation shown in Figure 4 places subroutine MONTE after MAIN to convert the input values to randomly generated values from the appropriate distribution.

The details of each subroutine are explained in the following section. Each one is described separately and the source listing of each subroutine follows the description.

RESERV

This subroutine calculates the daily flow from the reservoir subject to the conditions input into the model. These conditions, in addition to reservoir and well parameters, are a maximum daily flow rate and a minimum well head pressure. The basic approach is to determine the time at which the finite reservoir characteristics will begin to affect the well performance and at that time to switch to finite reservoir equations. Until

Figure 2. Subroutine call schedule to compute net present values.

Figure 3. Subroutine call schedule to solve for critical variables.

Figure 4. Subroutine call schedule for Monte Carlo simulation.

that time, infinite reservoir assumptions are used. The subroutine calculates the bottom hole pressure and flow rates for each year of the well operation.

Three possibilities exist for well configurations using the model. These are as follows:

- (1) Single well in the center of an aquifer.
- (2) Multiple wells spaced in the center of evenly divided areas of the aquifer.
- (3) Cluster wells drilled in the center of the aquifer.

The first and second cases above take the total area of the aquifer and convert it into either a circle, or circles, of equivalent radii, after first dividing the area by the number of wells to be drilled.

Using the specified initial maximum flow rate, the subroutine checks each calculation of well head pressure against the minimum allowable. At the point that the pressure would drop below the minimum allowable, the flow rate is cut back by 20% in order to raise the well head pressure.

The basic procedures of calculation are the same regardless of which well configuration is used.

Input: Reservoir and well parameters, initial flow rate, and minimum well head pressure.

Output: Production rates over the specified life of the project, along with bottom hole and well head pressure.

```

SUBROUTINE RESERV(FLOW,PRESS,PRESSB,TEMP)
  DIMENSION FLOW(1),PRESS(1),TEMP(1),PRESSB(1)
  DIMENSION NSET(21),FLOWC(21)
  COMMON /BLK1/RATE,TDNPU,DISCFA,UCRET,SUMWC,PRICE(50),TAXRAT,
    +      FRLEAS,PDIFF(50)
  COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
    +      SNCH4,CH4SEP
  COMMON/BLK3/N,N,IDEPTP,IPTYPE,ITXTYP,IPRTYP,ITYPE,TENPO,PRESSO,
    +      NWELLS,BORE,DPIPE,CONPR,FLOWO
  COMMON /BLK4/PHIN,START,TDCF,F,XCH4,CH4NIN,NBUN,NDSP
  BPFL(XY) = 2.80E-7*XY**1.9*DEPTH/DPIPE**4.8
  NSETDH=20

```

```

C
C   THIS SUBROUTINE CALCULATES THE YEARLY FLOW IN BBL/DAY
C   AND THE WELL-HEAD PRESSURE IN PSIG.
C   THIS RESERVOIR MODEL WAS DEVELOPED BASED ON PARMIGIANO'S
C   METHODS OF BOUNDED CIRCULAR AQUIFER.
C

```

```

C      INITIALIZE START UP PRESSURE AND TEMPERATURE.
C      Q      IS THE TOTAL FLOW SINCE THE OPERATION STARTED.
C      DENS    DENSITY OF BRINE, GM/CC.
C      JYEAR   ---- DAY OF THE YEAR
C
C      DO 10 I=1,N
C      PRESS(I)=PRESS0
C      FLOW(I)=FLOW0
10    TEMP(I)=TEMP0
C
C      SET UP VALUES FOR CALCULATION
C
C      NDAYS=N*365
C      AREASF=AREA*43560.
C      RESQ=AREASF/(3.14159*FLOAT(NWELLS))
C      RESQ=AREASF/3.14159
C      RE=SQRT(RESQ)
C      PERMK=PERM/1000.
C      RW=DORE/24.
C      DENS=0.94+0.76654*SALINE/(1.+SALINE)
C      DENS=1.
C      TEMP1=RW*RW*PORE*COMPR
C      TEMP2=3.14159*RESQ*THICK*PORE*COMPR
C      TEMP3=14.22*PERMK/TEMP1
C      TEMP4=1./(14.16*THICK*PERMK)
C      TEMP14=7.08*PERMK*THICK
C      TEMP5=(ALOG(RE/RW)-.75)/TEMP14
C      TEMP6=5.615/TEMP2
C      TEMP9=(ALOG(RESQ/(RW*D))-1.5)/TEMP14
C      TEMP11=(ALOG(RESQ*RE/(D*D*RW))-2.25)/TEMP14
C      TEMP13=(ALOG(RESQ*RESQ/(RW*(D*3)*SQRT(2.)))-3.)/TEMP14
C      DO 12 I=1,N
12    FLOW(I)=FLOW(I)/FLOAT(NWELLS)
C
C      CALCULATE READJUSTMENT TIME
C
C      TS=0.04*VISC(TEMP0)*COMPR*PORE*RESQ/PERMK
C      TS=INT(TS)
C      DPHEAD=PRESS0-DEPTH*DENS*62.321/144.
C      FACTOR = 1.
C
C      GO TO ASSIGNED RESERVOIR TYPE MODEL.
C
C      GO TO (15,140,15),ITYPE
C      SINGLE WELL IN THE CENTER OF AQUIFER OR OF N EQUALLY-SPACED
C      WELLS, EACH HAS AREA EQUAL TO TOTAL AREA DIVIDED BY N
C
C      COMPUTE THE FLOWING HEAD PRESSURE FOR EACH DAY, WHEN
C      PRESSURE .LE. THE MIN. OPERATING PRESSURE, FLOW RATE WILL BE
C      CUT BACK TO INCREASE PRESSURE.
C

```

```

15 NYEAR=NDWN/365
   IPRO=NDWN-NYEAR*365+1
   TS=TS+IPRO
   FLOWD=FLOWO*FACTOR
   FLOWBY=FLOWD
   Q=0
   NYSET=0
   JYEAR=365
   ICHNGE=0
   IFCHNG=0
   DO 110 J=IPRO,NBAYS
   IF(NYEAR.NE.0)GO TO 30
   T=TEMP(1)
   GO TO 35
30 T=TEMP(NYEAR+1)
35 JYEAR=JYEAR-1
   TEMP7=VISC(T)
   Q=Q+FLOWD
   IF(J.GE.TS)GO TO 40

C
C   TIME IS LESS THAN READJUSTMENT TIME
C
C   PF=BPHEAD-TEMP4*TEMP7*FLOWD*ALOG(TEMP3*J/TEMP7)-DPFL(FLOWD)
C
C   CALCULATE BOTTOM HOLE PRESSURE
C
C   PBOT=PF+(PRESSO-BPHEAD)+DPFL(FLOWD)
C   IF(PF.GT.PMIN)GO TO 45
C   FACTOR = FACTOR * .9
C   GO TO 15

C
C   TIME IS GREATER THAN TS, ENTERING SEMI-STEADY STATE
C
C   40 PF=BPHEAD-TEMP6*Q-TEMP5*TEMP7*FLOWD-DPFL(FLOWD)
C
C   CALCULATE BOTTOM HOLE PRESSURE
C
C   PBOT=PF+(PRESSO-BPHEAD)+DPFL(FLOWD)
C   IF( PF.GT.PMIN)GO TO 45
C   ICHNGE=1

C
C   IF PRESSURE DROPPED BELOW THE MIN. OPERATING PRESSURE,
C   CUT BACK 20 PERCENT
C
C   Q=Q-FLOWD
C   FLOWD=0.8*FLOWD

C
C   SET FLAG TO INDICATE THE DATE ON WHICH FLOW HAS BEEN CHANGED.
C
C   GO TO 40

C
C   RESTORE THE YEARLY VALUES
C

```



```

45 IF (ICHNGE .EQ. 0) GO TO 46
   IFCHNG=IFCHNG+1
   IF (IFCHNG .GT. 20) WRITE(4,48) NSETDM,NYEAR
48 FORMAT(1H,'NUMBER OF FLOWCHANGES EXCEEDED',I4,'IN SUBROUTINE',
+       'RESERV IN YEAR ',I4,'. ANSWERS IN OUTPUT ARE NOT',
+       'CORRECT.')
   IF (IFCHNG .GT. 20) IFCHNG=20
   ICHNGE=0
   NSET(IFCHNG) = 365-JYEAR-1
   FLOWC(IFCHNG) = FLOWD
C   WRITE(4,665) IFCHNG,NSET(IFCHNG),IFCHNG,FLOWC(IFCHNG)
665 FORMAT(1H,'NSET(',I4,')= ',G15.7,'FLOWC(',I4,') = ',G15.7)
46 IF(JYEAR.NE.0)GO TO 110
   IF(IFCHNG.EQ.0)GO TO 108
   NSET(IFCHNG+1) = 365
   FLOW(NYEAR+1) = FLOWBY + NSET(1)
   DO 47 II=1,IFCHNG
   FLOW(NYEAR+1) = FLOW(NYEAR+1) + FLOWC(II) * (NSET(II+1)
+     - NSET(II))
47 CONTINUE
   FLOW(NYEAR+1) = FLOW(NYEAR+1) / 365.
   GO TO 109
108 FLOW(NYEAR+1)=FLOWD
109 JYEAR=365
   IFCHNG=0
   FLOWBY=FLOWD
   NYEAR=NYEAR+1
   PRESS(NYEAR)=PF
   PRESSB(NYEAR)=PBOT
C   WRITE(4,552)
552 FORMAT(1H,2X,'YEAR',4X,5X,'FLOW')
C   DO 100 JJ=1,N
C 100 WRITE(4,551) JJ,FLOW(JJ)
551 FORMAT(1H,2X,I4,4X,G15.7)
110 CONTINUE
   GO TO 184
C
C   THIS SECTION MODELS MULTI-WELL SYSTEMS AS A CLUSTER IN
C   A BOUNDED RADIAL AQUIFER, WITH D IS THE DISTANCE BETWEEN WELLS
C
140 K=NUWELLS-1
   NYSET=0
   IF(NUWELLS.GT.4)WRITE(4,902)
   IF(NUWELLS.GT.4) STOP
902 FORMAT(1H0,'TOO MANY WELLS WERE ATTEMPTED FOR THE CLUSTERED WELL
+     CASE.'/USE 2, 3, OR 4 WELLS')
   NYEAR=0
   JYEAR=365
   Q=0.
   DO 180 J=1,NDAYS
   IF(J.EQ.1)FLOWD=FLOW(1)
   IF(NYEAR.NE.0)GO TO 145

```

```

      T=TEMP(1)
      GO TO 150
145 T=TEMP(NYEAR)
150 JYEAR=JYEAR-1
      Q=Q+FLOWD
      TEMP7=VISC(T)

C
C      SELECT WELL MODEL
C
      GO TO (155,160,165),K

C
C      TWO WELLS IN A CLUSTER MODEL
C
155 PF=-2*(TEMP6*Q)-TEMP9*TEMP7*FLOWD
      ASSIGN 155 TO JUMP
      GO TO 170

C
C      THREE WELLS IN A CLUSTER
C
160 PF=-3*(TEMP6*Q)-TEMP11*TEMP7*FLOWD
      ASSIGN 160 TO JUMP
      GO TO 170

C
C      FOUR WELLS IN A CLUSTER
C
165 PF=-4*(TEMP6*Q)-TEMP13*TEMP7*FLOWD
      ASSIGN 165 TO JUMP
170 PF=PF+DPHEAD-DPFL(FLOWD)

C
C      CALCULATE BOTTOM HOLE PRESSURE
C
      PBOT=PF+(PRESSO-DPHEAD)+DPFL(FLOWD)
      IF(PF.GT.PMIN)GO TO 175

C
C      IF PRESSURE DROPPED BELOW THE MIN. OPERATION PRESSURE,
C      CUT BACK TO 80 PERCENT FLOW
C
      Q=Q-FLOWD
      FLOWD=0.8*FLOWD
      FLOWD=FLOWD-20000.
      SET FLAG TO INDICATE THE DATE FLOW HAS BEEN CHANGED.

C
      NYSET=365-JYEAR-1
      GO TO JUMP,(155,160,165)

C
C      RESTORE YEARLY VALUES
C
175 IF(JYEAR.NE.0)GO TO 180
      IF(NYSET.EQ.0)GO TO 172
      IF(NYEAR.NE.0)GO TO 171
      FLOW(1)=FLOW(1)+NYSET+FLOWD*(365-NYSET)
      FLOW(1)=FLOW(1)/365.
      GO TO 173
171 FLOW(NYEAR+1)=FLOW(NYEAR)+NYSET+FLOWD*(365-NYSET)
      FLOW(NYEAR+1)=FLOW(NYEAR+1)/365.
      GO TO 173

```

```

172 FLOW(NYEAR+1)=FLOW
173 NYSET=0
      JYEAR=365
      NYEAR=NYEAR+1
      PRESS(NYEAR)=PF
      PRESS(NYEAR)=PBOT
180 CONTINUE
184 CONTINUE
      DO 185 J=1,N
185 FLOW(J)=FLOW(J)+FLOAT(NWELLS)
C      Q=Q+FLOAT(NWELLS)
C      RESQ=RESQ+FLOAT(NWELLS)
C      RE=RE+FLOAT(NWELLS)
      RETURN
      END

```

```

      FUNCTION VISC(T)
C
C      THIS FUNCTION CALCULATES THE VISCOSITY OF WATER BY A LOG-LOG LINEAR
C      INTERPOLATION. IT IS MOST ACCURATE BETWEEN 150 AND 400 DEGREES F.
C
      VLOG=-0.36653-1.21964*(ALOG(T)-2.17609)
      VISC=10.0**VLOG
      VISC=.3
      RETURN
      END

```

SOLUTE

Function SOLUTE is a subprogram which computes the quantity of methane dissolved in a geopressured brine (assuming the brine is saturated with methane), given the temperature, pressure and salinity of brine. SOLUTE is called at two points in GPPROG: first from MAIN to determine the amount of methane retained by the brine leaving the separators prior to re-injection (CH4SEP), and second from PROCES to determine the amount of methane contained in the brine as it enters the well bore (SMCH4). PROCES then calculates the methane recovery rate by multiplying the difference between these methane contents by the brine flow rate. Note that as the reservoir depletes over the life of the project, both the brine flow rate

and the methane content of the brine entering the well bore may decline, resulting in a reduction in the methane recovery rate with time.

The computation of the methane content of the brine is performed according to the calculation procedure described in detail in Appendix 3, "Correlation of Methane-Brine Solubility Data." The current version of SOLUTE is based only upon a correlation of the data of O'Sullivan and Smith⁴ which covered the following ranges of the independent variables: temperature 52.5, 102.5, and 125°C; pressure, from 100 to 600 atm; salinity, 0, 1, and 4 molality. The fifty data points of O'Sullivan and Smith were computed by SOLUTE with an average absolute deviation of 1.6%. It is considered that extrapolation beyond the pressure and salinity range of the original data is sound because the correlation procedure was based on fundamental thermodynamic relationships. However, because of the relatively narrow temperature range of the O'Sullivan and Smith data, and because a minimum in solubility occurred within this range, extrapolations much beyond the temperature range of these data are not recommended.

It is planned that SOLUTE will be revised in the future to incorporate the results of applying the correlation procedure to all available published data so that the routine will be of maximum utility over as wide a range of the independent variables as possible.

For ease of programming and of implementing revisions later, SOLUTE is highly modularized into function subprograms, each accomplishing a specific subtask. These function subprograms are listed below with a brief description of their purpose and methodology.

PSH20	calculates the saturation vapor pressure of water in atmospheres using Antoine's equation, given the temperature in degrees Celsius.
PHIH20	calculates the fugacity coefficient of pure water vapor given the temperature in degrees Celsius and the pressure in atmospheres. The original version merely returned 1.0 for this value, but the current version uses the Redlich-Kwong equation of state.
VPMH20	calculates the molar volume of liquid water (cc/g-mol) temperature in degrees Celsius and the pressure in atmospheres. The current version merely returns 18.0 for this quantity.
HCH4	calculates Henry's law constant for methane in pure water at zero pressure, given the temperature in degrees Celsius. The units of Henry's law are atm ⁻¹ . In the current version, this computation is made using the equation which was fit to the O'Sullivan and Smith data as described in Appendix 1.

- VDPINT calculates the correction to Henry's law constant for pressure, following the procedure described in Appendix 1. The current version utilizes parameters determined from the O'Sullivan and Smith data.
- PHICH4 calculates the fugacity coefficient for methane in a vapor mixture of methane and water, given the temperature in degrees Celsius; pressure in atmospheres; and water content of the vapor as mol fraction. The current version uses the Redlich-Kwong equation of state for methane-water mixtures.
- PHECH4 calculates the fugacity coefficient for pure methane vapor given the temperature in degrees Celsius, and the pressure in atmospheres. The equation of state used is that of Starling and Han.⁵ This function is not used by SOLUTE in the current version, as it does not permit calculation for methane-water vapor mixtures, as does PHICH4.
- SLTOUT calculates the salting out coefficient for methane in brine solutions, given the temperature in degrees Celsius, pressure in atmospheres, and salinity as molality of the brine. This coefficient is used to correct the methane solubility of pure water for the salinity of the brine. The equation and procedure is described in Appendix 1, and the current version is based upon the O'Sullivan and Smith data.

Input: TO (temperature, F), PO (pressure, psia), and SALNTY (lbs salt per 1000 lb water).

Output: SMCH4 (methane content, SCF per bbl), and XCH4 (methane content, mol. fraction).

FUNCTION SOLUTE(TO,PO,SALNTY,SMCH4,XCH4)

```

C
C THIS ROUTINE CALCULATES THE SOLUBILITY OF METHANE IN SALT WATER
C AS A FUNCTION OF TEMPERATURE, PRESSURE, AND SALINITY.
C THE EQUATION WAS FITTED USING DATA FROM O'SULLIVAN AND SMITH
C (J. PHYS. CHEM., VOL. 74, NO. 7 (1970), PP. 1460-1466)
C   R = 22.4 * 1000. / 273.15
C FIRST CONVERT TEMPERATURE TO DEGREES CENTIGRADE, PRESSURE TO
C ATMOSPHERES, SALINITY TO MOLALITY
C
C   T = (TO+40.)/1.8-40.
C   P = PO/14.696
C   SALTML = SALNTY*1000./58.44
C
C CALCULATE MOL FRACTION OF H2O IN LIQUID (NEGLECTING CH4
C CONTENT)
C
C   XM20 = (1000.)/18./((1000./18.+SALTML))

```

```

C
C CALCULATE MOL FRACTION H2O IN VAPOR IN EQUILIBRIUM WITH
C LIQUID
C ASSUME IDEAL SOLUTION IN BOTH PASSES
C
  YH2O = XH2O * PSH2O(T) *
  + EXP(VPHH2O(T,P) * (P-PSH2O(T)) / (R * (T+273.15)))
  + / (P*PHIH2O(T,P))
C
C COMPUTE MOL FRACTION CH4 IN VAPOR
C
  YCH4 = 1 - YH2O
C
C COMPUTE FUGACITY OF CH4 ASSUMING IDEAL SOLUTION
C
  FUGCH4 = YCH4 * P * PHICH4(T,P)
C
C COMPUTE MOL FRACTION CH4 IN PURE WATER
C
  XCH4 = FUGCH4 / (HCH4(T) * EXP(VDPINT(T,P) / (R * (T+273.15))))
C
C CORRECT XCH4 FOR SALT CONTENT OF WATER BASED ON SALTING-OUT COEFF.
C
  XCH4 = XCH4 * 10.**(-SALTNL*SLTOUT(T,P,SALTNL))
C
C COMPUTE SCF PER BBL CH4 IN LIQUID ASSUMING VOLUME OF LIQUID
C IS THAT OF WATER
C
  SOLUTE = XCH4 / (XH2O*18.) * 0.33*42.*359.
  RETURN
  END

```

```

FUNCTION PSH2O(TC)
  DATA ANTA,ANTB,ANTC/18.3036,3816.44,-46.13/
  T = TC + 273.15
  PSH2O = EXP(ANTA-ANTB/(T+ANTC))
  PSH2O = PSH2O/760.
  RETURN
  END

```

```

FUNCTION PHIH2O(T,P)
  PHIH2O=1.0
  RETURN
  END

```

```

FUNCTION VPHH2O(T,P)
  VPHH2O=18.
  RETURN
  END

```

```

FUNCTION HCH4(T)
DT1 = 102.5 - 51.5
DT2 = 125.0 - 102.5
DH1 = 11.001 - 10.905
DH2 = 10.943 - 11.001
D = -DT1 * DT2**2 - DT2 * DT1**2
DNB = -DH1 * DT2**2 - DH2 * DT1**2
DHC = -DT1 * DH2 + DT2 * DH1
HB = DNB/D
HC = DHC/D
HCH4 = EXP(11.001 + HB * (T-102.5) + HC * (T-102.5)**2)
RETURN
END

```

```

FUNCTION VDPINT(T,P)

```

```

C
C THIS FUNCTION CALCULATES THE VALUE OF THE INTEGRAL OF V/RTDP
C FOR METHANE AT INFINITE DILUTION IN WATER BETWEEN THE LIMITS
C OF PSH20 AND P. THIS FACTOR IS USED AS A CORRECTION IN THE
C HENRY'S LAW CALCULATION A LA KRICHEVSKY-KASARNOVSKY ,
C SEE PAGE 357 IN PRAUSNITZ.
C COMPUTE DIFFERENCES FROM DATA IN ARTICLE TO BE USED IN QUADRATIC FIT
C NOTE THAT CONSTANTS ARE MULTIPLIED BY RT TO GET BACK TO V
C

```

```

R = 22.4 * 1000. / 273.15
DT1 = 102.5 - 51.5
DT2 = 125.0 - 102.5
BB1 = 1.647*R*(102.5 + 273.15) - 1.393*R*(51.5 + 273.15)
BB2 = 1.905*R*(125. + 273.15) - 1.647*R*(102.5+273.15)
BC1 = -3.94 * R*(102.5 + 273.5) - 0.0
BC2 = -5.99*R*(125.+273.15) + 3.94 * R*(102.5 + 273.15)

```

```

C
C COMPUTE DETERMINANTS
C

```

```

B = -(DT1) * DT2**2 - DT2 * DT1**2
BBB = -(BB1) * DT2**2 - BB2 * DT1**2
DBC = -(DT1) * BB2 + DT2 * BB1
BCB = -DC1 * DT2**2 - DC2 * DT1**2
BCC = -DT1 * DC2 + DT2 * DC1

```

```

C
C COMPUTE COEFFICIENTS
C

```

```

BB = BBB/B
BC = DBC/B
CB = DCB/D
CC = BCC/D

```

```

C
C NOW COMPUTE COEFFICIENTS IN EQUATION FOR INTEGRAL OF VDP
C

```

```

BRT = 1.647*R*(102.5+273.15) + BB * (T-102.5) + BC * (T-102.5)**2
BRT = BRT*1.E-3
CRT = -3.94*R*(102.5+273.15) + CB * (T-102.5) + CC * (T-102.5)**2
CRT = CRT * 1.E-7

```

```

C
C  FINALLY CALCULATE THE VALUE OF THE INTEGRAL OF VDP USING COEFFICIENTS
C  CORRECTED FOR TEMPERATURE DEPENDENCE
C  NOTE THAT THE VALUE OF C FROM TABLES IN ARTICLE ALREADY INCLUDED
C  THE DIVISION BY 2.0 WHICH OCCURS WHEN INTEGRATION TAKES PLACE
C
      VDPINT = BRT * P + CRT * P**2
      RETURN
      END

```

```

      FUNCTION PHICH4(TCENT,PATH)
C  THIS FUNCTION COMPUTES THE FUGACITY COEFFICIENT OF METHANE
C  USING THE REDLICH-KWONG EQUATION OF STATE. REFERENCE
C  IS PP 152-157 IN PRAUSNITZ, "MOLECULAR THERMODYNAMICS
C  OF FLUID PHASE EQUILIBRIA".
C
C  PARAMETERS FOR METHANE SUPPLIED IN DATA STATEMENT
C
      DATA OMEGAA,OMEGAB,TC,PC/0.4278,0.0867,190.60,45.40/
C  CONVERT TEMPERATURE TO KELVIN COPY PRESSURE AND CALCULATE R
      T=TCENT + 273.15
      P = PATH
      R = 22.4*1000./273.15
C  COMPUTE SOME FACTORS TO BE USED LATER
      RT=R*T
      RTDP=RT/P
      RT15 = R * T ** 1.5
C  COMPUTE DIMENSIONLESS PARAMETERS A AND B FOR REDLICH-KWONG
C  EQUATION OF STATE
      A = OMEGAA * R**2 * TC**2.5 / PC
      B = OMEGAB * R * TC / PC
C  FIRST MUST SOLVE EQUATION OF STATE BY TRIAL AND ERROR FOR
C  SPECIFIC VOLUME, V
C  SET FIRST GUESS OF Z, COMPRESSIBILITY FACTOR, = 1.0
C  AND CALCULATE V
      Z = 1.0
      V1 = Z * RTDP
      IF (V1 .LE. B) V1 = B * 5.
C  BEGIN ITERATION LOOP
      DO 10 J=1,50
C  COMPUTE NEW Z BY SUBSTITUTING CURRENT V, INTO REDLICH
C  KWONG EQUATION
      F = V1/(V1-B) - A/(RT15*(V1+B)) - Z
      DFDV = - B/(V1-B)**2 + A/(RT15*(V1+B)**2) - 1./RTDP
      V2 = V1 - F/DFDV
      DO 3 J=1,10
      TEST = (V2-V1)/V1
      IF (ABS(TEST) .GT. 0.2 .OR. V2 .LT. B) V2 = (V1+V2)/2.
      IF (ABS(TEST) .GT. 0.2 .OR. V2 .LT. B) GO TO 3
      GO TO 4

```



```

3 CONTINUE
4 Z = V2/RTBP
  V3 = V1
  V1 = V2
  V = V2
  IF (ABS(TEST) .LE. .00001) GO TO 20
10 CONTINUE
C WRITE FAILURE TO CONVERGE MESSAGE
  WRITE(4,100) T,P
100 FORMAT('FUNCTION PHICH4 FAILED TO CONVERGE IN 50 ITERATIONS'
+         ', FOR T = ',G15.7,' AND P = ',G15.7,' ATM')
C FINALLY, COMPUTE FUGACITY COEFFICIENT BASED ON REDLICH-KUONG
C EQUATION OF STATE
20 PHICH4 = ALOG(V/(V-B)) + B/(V-B) -2.0 * A/(RT15 * B)
+         * ALOG((V+B)/V) + A*B/(RT15*B**2) *
+         (ALOG((V+B)/V) - B/(V+B)) - ALOG(V/RTBP)
  PHICH4 = EXP(PHICH4)
  RETURN
END

FUNCTION PHECH4(TCENT,PATN)
  DIMENSION AT(11),BT(11)
C THIS FUNCTION CALCULATES THE FUGACITY COEFFICIENT OF PURE METHANE VAP
C BASED ON THE "NEW" EQUATION OF STATE PUBLISHED BY STARLING AND HAN,
C HYDROCARBON PROCESSING, MAY, 1972
C
  DATA AT/0.443690,1.28438,0.356306,0.544979,0.528629,0.484011,
1 0.070523,0.504087,0.030745,0.073283,0.006450/
  DATA BT/0.115449,-0.920731,1.70871,-0.270896,0.349261,0.754130,
+ -0.044448,1.32245,0.179433,0.463492,-0.022143/
  DATA RHOC,TC,ACENTF/0.6274,343.57,0.013/
C CONVERT TEMP AND PRESS, AND CALCULATE R AND RT
  T = (TCENT + 273.15)*1.8
  P = PATN * 14.696
  R = 359. * 14.696/492.
  RT = R*T
C COMPUTE PARAMETERS TO BE USED IN EQUATIONS
  B = (AT(1) + BT(1) * ACENTF)/RHOC
  A = (AT(2) + BT(2) * ACENTF)/RHOC*R*TC
  C = (AT(3) + BT(3) * ACENTF)/RHOC*R*TC**3
  BAH = (AT(4) + BT(4)*ACENTF)/RHOC**2
  BSHALL = (AT(5) + BT(5)*ACENTF)/RHOC**2
  ASHALL = (AT(6) + BT(6)*ACENTF)/RHOC**2*R*TC
  ALPHA = (AT(7) + BT(7) * ACENTF)/RHOC**3
  CSHALL = (AT(8) + BT(8) *ACENTF)/RHOC**2*R*TC**3
  B = (AT(9) +BT(9) *ACENTF)/RHOC*R*TC**4
  BSHALL = (AT(10) + BT(10) * ACENTF)/RHOC**2*R*TC**2
  E = (AT(11) +BT(11) * ACENTF*EXP(-3.8*ACENTF))/RHOC*R*TC**5
C SOLVE THE EQUATION OF STATE FOR GAS DENSITY, USING NEWTON'S METHOD
C GET FIRST GUESS FROM IDEAL GAS LAW
  RH02= P/RT
  DO 10 J = 1,50
  RH0 = RH02

```

```

C  COMPUTE TERMS IN THE EQUATION
    F1 = RT*RHO/P
    F2 = (B*RT-A-C/T**2+D/T**3-E/T**4)/P*RHO**2
    F3 = (BSMALL*RT-ASMALL-DSMALL/T)*RHO**3/P
    F4 = ALPHA*(ASMALL + DSMALL/T)*RHO**6/P
    F5 = CSMALL * RHO**2/T**2/P
    F6 = 1. + GAM*RHO**2
    F7 = EXP(-GAM*RHO**2)
C  COMPUTE FUNCTION WHICH SHOULD BE FORCED TO ZERO
    F = -1. + F1 + F2 + F3 + F4 + F5*F6*F7
C  COMPUTE DERIVATIVES OF TERMS WITH RESPECT TO RHO
    DF1DR0 = F1/RHO
    DF2DR0 = 2.*F2/RHO
    DF3DR0 = 3.*F3/RHO
    DF4DR0 = 6. * F4/RHO
    DF5DR0 = 2.0*F5/RHO
    DF6DR0 = 2. * GAM*RHO
    DF7DR0 = F7*(-DF6DR0)
C  COMPUTE DERIVATIVE OF TOTAL FUNCTION
    DFDHR0 = DF1DR0 +DF2DR0 + DF3DR0 + DF4DR0 + DF5DR0*F6*F7 +
    + F5*DF6DR0*F7 + F5*F6*DF7DR0
C  APPLY NEWTON'S METHOD TO GET NEXT GUESS OF RHO
    RHO2 = RHO - F/DFDRHO
    DO 5 I = 1,20
    TEST = (RHO2 - RHO)/RHO
C  LIMIT CHANGE IN RHO
    IF(ABS(TEST).GT.0.2.OR.RHO2.LE.0.) RHO2 = (RHO2 + RHO) * 0.5
    IF(ABS(TEST).LE.0.2.AND.RHO2.GT.0.) GO TO 51
    5 CONTINUE
C  TEST FOR CONVERGENCE
    51 IF(ABS(TEST).LE..00001) GO TO 20
    10 CONTINUE
C  WRITE MESSAGE FOR NON CONVERGENCE
    WRITE (4,100) RHO2,RHO
100 FORMAT (' FUNCTION PHICH4 DID NOT CONVERGE WITHIN 50 ITERATIONS/
    + THE FINAL COMPUTED VALUES OF VAPOR DENSITY WERE' ,G15.7,G15.7)
20 RTLN = RT*ALOG(RHO*RT) + DF2DR0*P + DF3DR0*P/2. + DF4DR0*P/5.
    + CSMALL/GAM/T**2*(1.-(1.-0.5*GAM*RHO**2 - GAM**2*RHO**4)*F7)
C  COMPUTE PHI = F/P
    PNECH4 = EXP(RTLN/RT)/P
    RETURN
    END

```

```

FUNCTION SLTOUT(T,P,SALTML)
C THIS FUNCTION COMPUTES THE SALTING-OUT COEFFICIENT FOR METHANE BY
C AN EMPIRICAL FIT OF THE SALTING-OUT COEFFICIENTS PRESENTED IN THE
C O'SULLIVAN PAPER. THE EFFECT OF PRESSURE WAS FOUND TO BE NEGLI
C GIBLE, SO IT IS NOT INCLUDED.
C SINCE THE COEFFICIENT DOESN'T VARY MUCH IN THE RANGE OF THE
C DATA OF THE PAPER, IT MAY BE REASONABLE TO EXTRAPOLATE
C OUTSIDE THE TEMPERATURE AND PRESSURE RANGE OF THE PAPER
C
C FIRST, COMPUTE DELTA TEMPERATURES FROM THE EXPERIMENTAL DATA
  DT1 = 102.5 - 51.5
  DT2 = 125. - 102.5
C NOW GET THE DETERMINANT OF TEMPERATURES FOR USE IN A QUADRATIC FIT
  D = -DT1*DT2**2 - DT2*DT1**2
C GET DELTAS OF THE SALTING OUT COEFFICIENTS AT ONE MOLALITY
C AND AT FOUR MOLALITY FROM EXPERIMENTAL DATA
  DSM11 = 0.114 - 0.127
  DSM21 = 0.122 - 0.114
  DSM14 = 0.107 - 0.114
  DSM24 = 0.117 - 0.107
C GET DETERMINANTS FOR TEMPERATURE DEPENDENCE
C EQUATION USED IS SLTOUT = A + B(T-T2) + C(T-T2)**2
  DSMB1 = -DSM11 * DT2**2 - DSM21 * DT1**2
  DSMC1 = -DT1 * DSM21 + DT2 * DSM11
  DSMB4 = -DSM14 * DT2**2 - DSM24 * DT1**2
  DSMC4 = -DT1 * DSM24 + DT2 * DSM14
C NOW SOLVE FOR TEMPERATURE COEFFICIENTS AT BOTH ONE AND FOUR MOLALITY
  SMB1 = DSMB1/D
  SMB4 = DSMB4/D
  SNC1 = DSMC1/D
  SMC4 = DSMC4/D
C GET LINEAR SLOPES OF COEFFICIENTS VS MOLALITY
  SMBSLP = (SMB4 - SMB1)/(4. - 1.)
  SNCSLP = (SMC4 - SNC1)/(4. - 1.)
  SLTSLP = (.107 - .114)/(4. - 1.)
C FINALLY, SUBSTITUTE GIVEN T,P, AND SALTML INTO RESULTING EQUATION
C TO GET PREDICTED SALTING-OUT COEFFICIENT
  SLTOUT = 0.114 + SLTSLP*(SALTML - 1.) + (SMB1 + SMBSLP*
    * (SALTML - 1.))*(T-102.5) + (SNC1 + SNCSLP*(SALTML -1.))
    * (T - 102.5)**2
  RETURN
  END

```

DEPREC

This subroutine computes the annual depreciation of the investment over the depreciable life of the project. One of four depreciation schedules may be used in a given simulation. These are the standard methods, identified as: 1) Straight-line, 2) Sum-of-the-years-digits, 3) Declining Balance, and 4) Double Declining Balance. The first two methods are applied to the investment net of scrap value.

Input: Depreciable investment, depreciation life, and scrap value.

Output: Depreciation for each year in dollars.

```

SUBROUTINE DEPREC(INVD,DEP,SCRAP)
REAL INVD(1)
INTEGER START
DIMENSION DEP(1),SCRAP(1)
COMMON /BLK1/RATE,TDNFW,DISCFA,UCRET,SUMWC,PRICE(50),TAXRAT,
+       FRLEAS,PDIFF(50)
COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERN,RECOV,D,
+       SMCH4,CH4SEP
COMMON/BLK3/N,M,IDEPTP,IPTYPE,ITXTYP,IPRTYP,ITYPE,TEMPO,PRESSO,
+       NWELLS,BORE,DPIPE,COMPR,FLOWO
COMMON /BLK4/PMIN,START,TBCF,F,XCH4,CH4MIN,NDUN,NDSP

C
C THIS SUBROUTINE CALCULATES THE DEPRECIATION OF
C DEPRECIABLE CAPITAL INVESTMENT
C
C FIRST DECIDE WHICH TYPE OF DEPRECIATION TO USE
C
C   GO TO (10,20,30,40), IDEPTP
C
C 10 CONTINUE
C
C STRAIGHT-LINE DEPRECIATION
C
C   XM=M
C   DO 11 J=1,M
C 11 DEP(J)=0.
C   DO 13 J=1,M
C   NYD=J + M - 1
C   IF(NYD.GT.N)NYD=N
C   DO 12 I=J,NYD
C
C PROGRAM IS PATCHED SO THAT ONLY 1 INVESTMENT WORKS
C WITH SCRAP AT END OF PROJECT LIFE (N).
C
C   SAVE=(INVD(J)-SCRAP(N))/XM
C   IF (SAVE .LT. 0.) SAVE=0.
C 12 DEP(I) = DEP(I) + SAVE
C 13 CONTINUE
C   RETURN

```

```

C
C 20 CONTINUE
C
C SUM-OF-THE-YEARS-DIGITS DEPRECIATION
C
      MSUM=0
      DO 21 J=1,N
21  MSUM=MSUM+J
      XMSUM=MSUM
      DO 22 J=1,N
22  DEP(J)=0.
      DO 24 J=1,N
      NYD=J+M-1
      IF(NYD.GT.N)NYD=N
      DO 23 I=J,NYD
      K=NYD-I+1
      XK=K
C
C PROGRAM IS PATCHED SO THAT ONLY 1 INVESTMENT WORKS
C WITH SCRAP AT END OF PROJECT LIFE(M).
C
      SAVE=(INVD(J)-SCRAP(N))*XK/XMSUM
      IF (SAVE .LT. 0.) SAVE=0.
23  DEP(I)=DEP(I)+SAVE
24  CONTINUE
      RETURN
C
C
C 30 CONTINUE
C
C DECLINING BALANCE DEPRECIATION
C
      DO 31 J=1,N
31  DEP(J)=0.
      R=1./(FLOAT(M))
      DO 33 J=1,N
      PSUM=INVD(J)
      NYD=J+M-1
      IF(NYD.GT.N)NYD=N
      DO 32 I=J,NYD
      K=I-J+1
      P=INVD(J)*((1.0-R)**K)
      DEP(I)=DEP(I)+PSUM-P
32  PSUM=P
33  CONTINUE
      RETURN
C
C 40 CONTINUE

```

```

C
C  DOUBLE DECLINING BALANCE DEPRECIATION
C
      DO 41 J=1,N
41  DEP(J)=0.
      R=2./(FLOAT(M))
      DO 43 J=1,N
      PSUM=INVD(J)
      NYD=J+M-1
      IF(NYD.GT.N)NYD=N
      DO 42 I=J,NYD
      K=I-J+1
      P=INVD(J)*((1.0-R)**K)
      DEP(I)=DEP(I)+PSUM-P
42  PSUM=P
43  CONTINUE
      RETURN
C
C  END OF SUBROUTINE
C
      END

```

TAXES

This subroutine, along with TAXCAL, computes and totals the annual taxes of the venture. Federal income taxes are computed first after adjusting profits for: losses incurred in the previous years; the prior year's state taxes and severance taxes; and depletion, which is computed at 10% of gross income but limited to 65% of taxable income. Depletion exceeding the limit is carried forward against future taxable income. State income taxes are computed after adjusting profits for losses incurred in the previous year and the previous year's federal income tax payments. Severance taxes are then computed as product of gas production in MSCF/day and the severance tax rate is \$/MSCF. This is then converted to an annual amount.

Input: Profits before taxes, in dollars, gas production in MSCF/day, and the severance tax rate in \$/MSCF.

Output: Total taxes for each year.

```

SUBROUTINE TAXES(PBT, FLOW, TAX, GAS, TURBO, THERM, REV)
DIMENSION FLOW(1), PBT(1), TAX(1)
DIMENSION GAS( 1), TURBO( 1), THERM( 1)
DIMENSION REV(1)

```

```

COMMON /BLK1/RATE,TBPU,DISCFA,UCRET,SUNWC,PRICE(50),TAXRAT,
+ FRLEAS,PDIFF(50)
COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
+ SNCH4,CH4SEP
COMMON/BLK3/N,N,IDEPTP,IPTYPE,IIXTYP,IPRTYP,IITYPE,TEMPO,PRESSO,
+ NWELLS,BORE,DPIPE,COMPR,FLOWO
COMMON /BLK4/PMIN,START,TDCF,F,XCH4,CH4MIN,NDUN,NDSP

COMMON /BLK6/NFTB,RATEF(10),TINTF(10),NSTTB,RATEST(10),TINST(10),
+ RATES,TAXCRB,IOS,TCRR,FTXAD,STXAD,SVTXAD
COMMON /BLK7/TAXF(50),TAXST(50),TAXO7(50),GRUADF,GRUFLN,GRWFCI,
+ CNSTPR,XLOSS(50),DEPL(50)
NAMelist/TEST1/RATEST,RATES,NSTTB,TINST,SVTXAD,TXPRFT,NFTB,RATEF,
+ STXAD,TINTF,FTXAD,DEPL,XLOSS

C
C SET FIRST YEAR'S DEPLETION CARRYOVER EQUAL TO ZERO
C
  DEPL(1)=0.
  DO 100 I=1,N

C
C COPY GROSS PROFIT INTO THIS YEAR'S PROFIT
C
  TXPRFT = PBT(I)

C
C CARRYOVER LAST YEAR'S LOSS INTO THIS YEAR'S PROFIT
C
  IF (I .NE. 1 .AND. XLOSS(I-1) .LT. 0.0) TXPRFT = PBT(I)
  + XLOSS(I-1)
  XLOSS(I) = 0.0

C
C IF GROSS PROFITS ARE LESS THAN OR EQUAL TO ZERO, THEN
C STATE AND FEDERAL TAX ARE ZERO.
C
  IF (TXPRFT .LE. 0.) XLOSS(I)=TXPRFT

C
C ADJUST GROSS PROFIT FOR LAST YEAR'S STATE TAX DEDUCTIONS
C BEFORE CALCULATING FEDERAL INCOME TAX
C
  10 IF (I .NE. 1) TXPRFT = TXPRFT - TAXST(I-1) - TAXO7(I-1)

C
C COMPUTE DEPLETION AS TEN PERCENT OF GROSS INCOME
C
  DEPL(I) = 0.10 * REV(I) + DEPL(I)

C
C COMPUTE LIMITATION ON DEPLETION - SIXTY-FIVE PERCENT OF TAXABLE
C INCOME
C
  DLIMIT = 0.65 * TXPRFT

```

```

C
C IF TAXABLE PROFIT IS ZERO AFTER STATE DEDUCTIONS, THERE IS NO
C FEDERAL TAX AND DEPLETION FOR THIS YEAR MUST BE CARRIED OVER
C TO NEXT YEAR.
C
    IF (TXPRFT .GT. 0.0) GO TO 45
    TAXF(I) = 0.0
    DEPL(I+1) = DEPL(I)
    GO TO 50
C
C DEDUCT DEPLETION FROM TAXABLE INCOME UP TO THE LEGAL LIMIT,
C CARRYOVER ANY AMOUNT OVER THE LEGAL LIMIT TO BE DEDUCTED NEXT YEAR
C
45 DEPL(I+1) = 0.
    IF (DEPL(I) .GT. DLIMIT) TXPRFT = TXPRFT - DLIMIT
    IF (DEPL(I) .GT. DLIMIT)
    +   DEPL(I+1) = DEPL(I) - DLIMIT
    IF (DEPL(I) .LE. DLIMIT) TXPRFT = TXPRFT - DEPL(I)
    CALL TAXCAL(NFTB,RATEF,TXPRFT,TINTF,TAXF(I),FTXAD)
C
C IF LAST YEAR HAD A LOSS OR A LOSS CARRYOVER, ADJUST GROSS
C PROFIT BY DEDUCTING IT BEFORE CALCULATING STATE TAX
C THIS YEAR
C ADJUST GROSS PROFIT FOR LAST YEAR'S FEDERAL TAX DEDUCTIONS
C BEFORE CALCULATING STATE CORPORATE TAX
C
50 TXPRFT = PBT(I)
    IF (I .NE. 1 .AND. XLOSS(I-1) .LT. 0.0)
    +   TXPRFT = TXPRFT + XLOSS(I-1)
    IF (I .NE. 1) TXPRFT = TXPRFT - TAXF(I-1)
    CALL TAXCAL(NSTB,RATEST,TXPRFT,INST,TAXST(I),STXAD)
C
C IF AFTER ADJUSTING GROSS PROFIT FOR FEDERAL TAX
C DEDUCTIONS AND LOSS CARRYOVER, IT IS LESS THAN ZERO,
C THEN STATE TAX IS ZERO
C
    IF (TXPRFT .LE. 0.0) TAXST(I) = 0.0
C
C CALCULATES SEVERANCE TAX
C
20 TAX07(I) = RATES * GAS(I) * 365.E-6 * SVTXAD
    TAX(I) = TAXF(I) + TAXST(I) + TAX07(I)
C IF (I .NE. 7 .AND. I .NE. 8 .AND. I .NE. 9) GO TO 100
C WRITE(4,TEST1)
C WRITE(4,500)
C 500 FORMAT(1H ,6X,'GAS',16X,'TAX',16X,'TAXF',17X,'TAX07',17X,'TAXST',
C +   7X,'PBT')
C DO 1111 II=1,N
C1111 WRITE(4,135)GAS(II),TAX(II),TAXF(II),TAX07(II),TAXST(II),PBT(II)
135 FORMAT(1H ,G15.7,4X,G15.7,4X,G15.7,4X,G15.7,4X,G15.7,4X,G15.7)
100 CONTINUE
    RETURN
    END

```


TAXCAL

This subroutine computes income taxes due the federal government and the state government for each year. The current tax tables for the two income taxes are used to compute taxes.

Input: Federal tax rates, specific by income interval and the income intervals; state income tax rates specific by income interval and the income intervals; and taxable income.

Output: Annual Income Tax.

```

SUBROUTINE TAXCAL(M,RATE,PROFIT,TAXINT,TAX,ADJVAL)
  DIMENSION RATE(1),TAXINT(1)
  IF (PROFIT.GT.TAXINT(1))GO TO 10
  TAX=PROFIT*RATE(1)
  RETURN
10 N=M-1
  DO 20 I=2,N
    IF (I.NE.2)GO TO 15
    TAX=TAXINT(1)*RATE(1)*ADJVAL
15 IF (PROFIT.GT.TAXINT(I))GO TO 20
    TAX=TAX+(PROFIT-TAXINT(I-1))*RATE(I)*ADJVAL
    RETURN
20 TAX=TAX+(TAXINT(I)-TAXINT(I-1))*RATE(I)*ADJVAL
    TAX=TAX+(PROFIT-TAXINT(N))*RATE(N)*ADJVAL
    RETURN
  END

```

INVESC, QUEUE, DEQUE and DOWN

These four subroutines operate as a unit with INVESC as the main subroutine of the group. The purpose of INVESC is to compute the investment tax credit available during each year of project life. The credit is computed as 10% of depreciable investment and may not exceed the tax liability on \$25,000 plus 50% of the liability over \$25,000. The credit exceeding the limit may be carried forward for not more than seven years. QUEUE, DEQUE and DOWN are used to age each credit and establish a queue to assure that the oldest credit is used first to maximize credit against taxes over the life of the project.

Input: Depreciable investment each year.

Output: Annual investment tax credit against current tax liability.

```

SUBROUTINE INVESC(INV,INVD,INVND,INVCRT,TAX)
REAL INV(1),INVD(1),INVND(1),INVCRT(1),TAX(1)
COMMON/BLK3/N,M,IDEPT,IPRTYP,ITXTYP,ITYPE,TEMPO,PRESSO,
+      MWELLS,BORE,DPIPE,COMPR,FLOWO
COMMON /BLK6/NFTB,RATEF(10),TINTF(10),NSTTB,RATEST(10),TINST(10),
+      RATES,TAXCRB,IQS,TCRR,FTXAD,STXAD,SVTXAD
DIMENSION STACK(20),ISTACK(20)
DATA IB,IE,IEMPTY/7,7,0/
DO 100 I=1,N
  INVCRT(I)=0.
C
C TAXCRB IS THE TAX LIABILITY BRACKET
C
  IF(TAX(I).GT.TAXCRB)GO TO 10
  CRMAX=TAX(I)
  GO TO 15
10  CRMAX=TAXCRB+(TAX(I)-TAXCRB)/2.
C
C TCRR IS THE PERCENT OF DEPRECIABLE INVESTMENT USED
C FOR INV. CREDIT
C
  15 CRED=INVD(I)*TCRR
  CALL QUEUE(IB,IE,IQS,IEMPTY,STACK,ISTACK,CRED)
  20 CONTINUE
  IF(IEMPTY.EQ.0)GO TO 100
  X=INVCRT(I)+STACK(IB)
  IF(X.GT.CRMAX)GO TO 25
  INVCRT(I)=X
  CALL DEQUE(IB,IE,IQS,IEMPTY,STACK)
  GO TO 20
  25 INVCRT(I)=CRMAX
  IF(ISTACK(IB).EQ.0)GO TO 30
  STACK(IB)=X-CRMAX
  28 CALL DOWN(IB,IE,IQS,IEMPTY,ISTACK)
  GO TO 100
  30 CALL DEQUE(IB,IE,IQS,IEMPTY,STACK)
  GO TO 28
100 CONTINUE
  RETURN
  END

```

```

SUBROUTINE QUEUE(IB,IE,IQS,IEMPTY,STACK,ISTACK,X)
DIMENSION STACK(1),ISTACK(1)
IF(IEMPTY.NE.0)GO TO 10
C
C EMPTY QUEUE

```

```

C      IEMPTY=1
      IE=1
      IB=1
      GO TO 22
10 IF (IE-IB)15,20,30
C
C      CHECK IF QUEUE FULL
C
15 IF (IB-IE-1)25,25,20
C
C      PARTIALLY FULL
C
20 IE=IE+1
22 STACK(IE)=X
   ISTACK(IE)=IQS
   RETURN
C
C      QUEUE FULL
C
25 WRITE(4,900)
900 FORMAT(1X,'QUEUE IS FULL')
   RETURN
C
C      THE QUEUE IS 1 BIGGER THAN THE NO. OF YEARS
C      THAT CREDIT CAN BE CARRIED OVER
C
30 IF (IQS-IE+IB)25,25,35
C
C      PARTIALLY FULL
C
C
C      TEST IF IE AT END OF QUEUE, IF SO, WRAP AROUND
C
35 IF (IE.NE.(IQS+1))GO TO 20
   IE=1
   GO TO 22
END

```

```

SUBROUTINE DEQUE(IB,IE,IQS,IEMPTY,STACK)
  DIMENSION STACK(1)

```

```

C
C      TEST IF QUEUE EMPTY
C
      IF (IEMPTY.NE.0)GO TO 10
      WRITE(4,900)
900 FORMAT(10X,'QUEUE IS EMPTY')
      RETURN

```

```

10 IF(IE-IB)25,20,30
20 IEMPTY=0
   RETURN
25 IB=IB-1
   RETURN
30 IB=IB+1
   RETURN
END

```

```

SUBROUTINE DOWN(IB,IE,IQS,IEMPTY,ISTACK)
DIMENSION ISTACK(1)
ISIZE=IQS+1
IF(IE-IB)10,25,30
10 DO 15 I=1,IE
15 ISTACK(I)=ISTACK(I)-1
   DO 20 I=IB,ISIZE
20 ISTACK(I)=ISTACK(I)-1
   RETURN
25 IF(IEMPTY.EQ.1)GO TO 30
   WRITE(4,900)
900 FORMAT(10X,'QUEUE IS EMPTY')
   STOP
30 DO 35 I=IB,IE
35 ISTACK(I)=ISTACK(I)-1
   RETURN
END

```

WKGCAP

This subroutine computes the initial working capital of the project and each year's increase or decrease in working capital. The operating definition of working capital for the simulation is current assets less current liabilities. A gas industry average ratio of working capital to cash operating costs of .048 is used to compute the working capital for each year and new working capital is the difference from the previous year.

Input: Annual operating costs.

Output: The annual change in working capital.

```

SUBROUTINE WKGCAP(FLOW,REV,OPCOST,INV,WC,DEP)
DIMENSION FLOW(1),REV(1),WC(1),DEP(1)
REAL INV(1),OPCOST(1)
COMMON /BLK1/RATE,TBMPV,DISCFA,UCRET,SUMVC,PRICE(50),TAXRAT,
+       FRLEAS,PDIFF(50)
COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
+       SNCH4,CH4SEP
COMMON/BLK3/N,M,IDEPT,IPTYPE,ITXTYP,IPRTYP,ITYPE,TEMPO,PRESS0,
+       MWELLS,BORE,DPIPE,COMPR,FLOWO
COMMON/BLK5/NDINV1(50),NDINV2(50),NDINV3(50),NDINV4(50),NDINV5(50)
+       ,NDINV6(50),NDINV7(50),DINV1(50),DINV2(50)

```

```

C
C THIS SUBROUTINE CALCULATES THE NEW WORKING CAPITAL REQUIRED
C EACH YEAR BY TAKING 4.8 PERCENT OF THE OPERATION AND
C MAINTENANCE COSTS BASED ON INDUSTRY AVERAGES
C SO FAR THIS INCLUDES THE WELL AND GAS SEPARATION PROCESS ONLY
C
      TEMP1=0.
      DO 1 I=1,N
C
C WORKING CAPITAL IS ASSUMED TO BE 4.8 PERCENT OF THE OPERATING COSTS
C
      TEMP2=0.048*(OPCOST(I)-DEP(I))
      WC(I)=TEMP2-TEMP1
      TEMP1=TEMP2
1 CONTINUE
      RETURN
      END

```

MONTE

This subroutine is used to make probabilistic simulations of reservoir performance. In addition to the uncertainty associated with reservoir parameters derived from resource assessment studies, there is little known about the distributions of these parameters. Consequently, a triangular distribution (depicted below) that is completely described by three values is used for all parameters that are simulated in a probabilistic mode.

The three values are:

- P Pessimistic value--the smallest value that an expert thinks the parameter can take on.
- ML Most likely--estimate or best guess at value.
- O Optimistic value--highest value parameter can take on.

Like any distribution, the area, $1/2(\overline{PO}) \cdot h$, is equal to one. A random number from a uniform distribution with a limit of 0 and 1 can be mapped into the triangular distribution to produce a random value of the parameter between p and o. When a number of input parameters are probabilistic, the resulting computed values, such as methane in solution or revenue, have a distribution that is not necessarily triangular. Multiple simulations allow the analyst to obtain from the model:

1. The average or expected value of the output variable,
2. The minimal order statistic,
3. The maximal order statistic,
4. A probabilistic interval estimate.

Input: Pessimistic value, most likely value, optimistic value, and a random number seed.

Output: A random value of the parameter with entry values.

```

SUBROUTINE MONTE(P,RML,Q,X,ISEED)
C * THIS SUBROUTINE IS USED TO MAKE PROBABILISTIC SIMULATIONS
C * OF RESERVOIR PERFORMANCE **
C * A TRIANGULAR DISTRIBUTION IS USED FOR ALL PARAMETERS THAT ARE
C * SIMULATED IN A PROBABILISTIC MODE **
C * INPUT ARE PESSIMISTIC VALUE, MOST LIKELY VALUE,
C * OPTIMISTIC VALUE AND A RANDOM NUMBER SEED **
C * VALUE RETURNED IS A RANDOM VALUE
C * OF THE PARAMETER WITH ENTRY VALUES **
H=2./(Q-P)
TANP=H/(RML-P)
TANQ=H/(Q-RML)
AREAP=0.5*(RML-P)*H
IS=ISEED
CALL GSUBS(IS,1,R)
IF(R.GT.AREAP)GO TO 10
X=P+SQRT(2.*R/TANP)
GO TO 20
10 X=Q-SQRT(2.*(1.-R)/TANQ)
20 RETURN
END

```

PROCES

This subroutine computes the physical output of natural gas from the separation plant, and, when incorporated, the electrical output of an electric generation plant, using the thermal and kinetic energy of the resource. If a fixed amount of methane in solution is assumed, based upon resource assessment estimates, a 70% recovery efficiency in separation is assumed. When methane solubility is computed using SOLUTE, the methane recovered is computed as the difference between methane in solution at well head in SCF and the methane in solution in the separator outlet water.

Input: Annual flow of fluid in bbl/day, temperature, pressure, salinity, recovery rate, and methane in solution in the separator outlet water.

Output: Production of gas for each year of the project in MSCF/day.

```

SUBROUTINE PROCES(FLOW,PRESS,TEMP,GAS,TURBO,THERM)
DIMENSION FLOW(1),PRESS(1),TEMP(1),GAS(1),TURBO(1),THERM(1)
INTEGER START
COMMON /BLK1/RATE,TDWPW,DISCFA,WCRET,SUMWC,PRICE(50),TAXRAT,
+      FRLEAS,PDIFF(50)
COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
+      SMCH4,CH4SEP
COMMON/BLK3/N,N,IDEPTP,IPTYPE,ITXTYP,IPRTYP,ITYPE,TEMPO,PRESSO,
+      NWELLS,BORE,DPIPE,CONPR,FLOWO
COMMON /BLK4/PHIN,START,TDCF,F,XCH4,CH4MIN,NDWN,NBSP

C
C  SO FAR THIS PROCESS ROUTINE DOES NOT MODEL THE KINETIC AND
C  THERMAL ENERGIES OF THE RESERVOIR.
C  METHANE GAS IS IN 1000 STD. CU. FT./DAY
C

  IY=NDSP/365
  FX=(365.+FLOAT(IY)-FLOAT(NDSP)/365.)/365.
  DO 100 I=1,N
    TURBO(I)=0.
    THERM(I)=0.
    GAS(I)=0.
    IF (I .LT. IY-1) GO TO 100
    IF (I .GT. IY-1) FX=1
    IF (SMCH4 .NE. 0.) GAS(I)=F*SMCH4*FLOW(I)/1000.*FX
    IF (SMCH4 .EQ. 0.) GAS(I)=(SOLUTE(TEMP(I),PRESS(I),SALINE,
+      SMCH4,XCH4)-CH4SEP)*FLOW(I)/1000.*FX
100  CONTINUE
    RETURN
  END

```

ITERAT

This subroutine, through iteration, finds the value of a parameter that causes the net present value to approximate zero. The subroutine currently solves for one of five parameters. These are: the rate of return, the price of methane, the tax rate, the minimum methane solubility, or the minimum area of the reservoir. For the rate of return and methane solubility the values are incremented, utilizing linear interpolation to accelerate convergence, until the net present value is .00001 or less. The number of iterations is limited to 20 times, with a test to identify conditions which are unlikely to allow convergence. In order to find the critical value for the area of the reservoir, the driving subroutine RESERV must be re-executed with each new incremental value of the area. This is due to the fact that the reservoir's production characteristics are determined, in part, by the area parameter.

In the case of price and taxes, the critical value actually solved for is not the price or tax rate itself but rather an adjustment factor. The price of the methane is not single valued but rather has a different value each year of the project life. In the model the assumed price for each year is taken from an econometric forecast. There are four options that may be pursued when the price of methane is considered the unknown parameter. First, the assumed growth pattern in the model may be accepted and increased or decreased linearly until the net present value is zero. Second, the absolute price increase or decrease necessary each year can be computed with the 1985 price as a base price. Third, the necessary compound rate of growth of the price beginning with the 1985 base price can be computed. Last, a critical constant or level price can be computed in the case of constant dollar analysis.

As for the taxes, only one tax can be treated at a time in solving for a critical adjustment factor. For severance taxes the adjustment applies only to the single rate of taxation per mcf of gas. For the state income and federal income taxes the critical adjustment factor is applied to each tax rate by income bracket.

Input: the value of the critical parameter which is to be adjusted is passed to subroutine ITERAT.

Output: the value of the critical parameter which results from forcing NPV to zero.


```

SUBROUTINE ITERAT(/X2/,IMAX)
COMMON /BLK1/RATE,TDNPW,DISCFA,UCRET,SUNWC,PRICE(50),TAXRAT,
+ FRLEAS,PDIFF(50)
COMMON/BLK3/M,M,IDEPTP,IPTYPE,ITXTYP,IPRTYP,ITYPE,TEMPO,PRESS0,
+ MWELLS,BORE,DPIPE,COMPR,FLOW0
COMMON /BLK6/NFTB,RATEF(10),TINTF(10),NSTTB,RATEST(10),TINST(10),
+ RATES,TAXCRB,IQS,TCRR,FTXAD,STXAD,SVTXAD
COMMON /BLK7/TAXF(50),TAXST(50),TAXO7(50),GRUABF,GRUFLN,GRUFCI,
+ CNSTPR,XLOSS(50),DEPL(50)
COMMON /BLK8/FLOW(50),REV(50),REVGAS(50),REVPRE(50),REVTEM(50),
+ OPCOST(50),OPCGAS(50),OPCPRE(50),OPCTEN(50),PBT(50),
+ TAX(50),UC(50),INV(50),INVCRT(50),DEP(60),SCRAP(50),
+ INVD(50),INVND(50),CASH(50),DCF(50),DISFAC(50),
+ GAS(50),TURBO(50),THERM(50),OPCWEL(50),PAT(50)
COMMON/BLK9/PRESS(50),PRESSB(50)
NAMELIST/BUG/X1,TDNPW,TDNPL,SLOPE,TEST

C
C
IF (IPTYPE .NE. 2) GO TO 15
DO 10 I=1,M

C
C IF SOLVING FOR PRICE OF METHANE, SET UP PRICE VECTOR
C DEPENDING ON IPRTYP
C
IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 1)
+ PDIFF(I) = PRICE(I) - PRICE(1)
IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 2)
+ PRICE(I) = PRICE(1) + (I-1) * X2
IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 3)
+ PRICE(I) = PRICE(1) * X2 ** (I-1)
IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 4) PDIFF(I) = PRICE(I)
10 CONTINUE
15 CONTINUE
CALL DISC(FLOW,REV,REVGAS,REVPRE,REVTEM,OPCOST,OPCGAS,OPCPRE,
+ OPCTEN,PBT,PAT,TAX,UC,INV,INVCRT,DEP,SCRAP,INVD,
+ INVND,CASH,DCF,DISFAC,GAS,TURBO,THERM,OPCWEL)
XI=X2
TDNPL=TDNPW
X2 = XI *1.01

C
C BEGIN ITERATION
C ON EACH ITERATION, XI IS THE OLDER VALUE AND X2 IS THE NEWEST
C VALUE.
C IMAX IS THE MAXIMUM NUMBER OF ITERATIONS ALLOWED FOR
C CONVERGENCE.
C
DO 30 J=1,IMAX
IF (IPTYPE .NE. 2) GO TO 25

C
C IF SOLVING FOR PRICE OF METHANE, ADJUST THE PRICE VECTOR
C USING LATEST ITERATION VALUE AND APPROPRIATE FORMULA DEPENDING
C ON IPRTYP.

```

```

      DO 20 I=1,N
      IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 1)
      +      PRICE(I) = PDIFF(I) * X2 + PRICE(1)
      IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 2)
      +      PRICE(I) = PRICE(1) + (I-1) * X2
      IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 3)
      +      PRICE(I) = PRICE(1) * X2 ** (I-1)
      IF (IPTYPE .EQ. 2 .AND. IPRTYP .EQ. 4) PRICE(I) = PDIFF(I) * X2
20 CONTINUE
25 CONTINUE

C
C IF SOLVING FOR THE AREA OF THE RESERVOIR, CALL RESERVE TO
C RECOMPUTE FLOW USING LATEST ITERATED VALUE FOR AREA
C IF ARE SOLVING FOR AREA OF RESERVOIR OR MINIMUM METHANE
C SOLUBILITY, CALL PROCES AND INVEST TO RECOMPUTE
C GAS AND INVESTMENT COSTS WITH LATEST ITERATED VALUE FOR AREA OR
C MINIMUM METHANE SOLUBILITY
C
      IF (IPTYPE .EQ. 6) CALL RESERV(FLOW,PRESS,PRESSB,TEMP)
      IF (IPTYPE .EQ. 6 .OR. IPTYPE .EQ. 5)
      +      CALL PROCES(FLOW,PRESSB,TEMP,GAS,TURBO,THERM)
      IF (IPTYPE .EQ. 6 .OR. IPTYPE .EQ. 5) CALL INVEST
      CALL DISC(FLOW,REV,REVGAS,REVPRE,REVTEN,OPCOST,OPCGAS,OPCPRE,
      +      OPCTEN,PBT,PAT,TAX,UC,INV,INVCRT,DEP,SCRAP,INVD,
      +      INVND,CASH,BCF,DISFAC,GAS,TURBO,THERM,OPCUEL)

C
C TEST TO DETERMINE CONVERGENCE
C
      TEST = ABS((X2-X1)/X2)
      IF (TEST .LT. 0.00001) GO TO 40

C
C CHECK FOR FUNCTION THAT IS UNLIKELY TO CONVERGE AND QUIT AND
C WRITE OUT MESSAGE IF IT IS NOT MAKING PROGRESS
C
      TEST2 = ABS((TDNPW-TDNPL)/TDNPW)
      IF (TEST2 .LE. 1.E-4) GO TO 31

C
C LINEARLY INTERPOLATE TO MAKE TDNPW EQUAL ZERO.
C
      SLOPE = (TDNPW-TDNPL)/(X2-X1)
      X = X1-TDNPL/SLOPE
      IF (IPTYPE .NE. 2 .AND. X .LE. 0.) X = X1/2.
C
      WRITE(4,9999) X2,X1,TDNPW,TDNPL,SLOPE,TEST,X
      X1=X2
      X2=X
      TDNPL=TDNPW
9999 FORMAT(' X2 = ',G15.7,' X1 = ',G15.7,' TDNPW = ',G15.7/
      +      ' TDNPL = ',G15.7,' SLOPE = ',G15.7,' TEST = ',G15.7,
      +      ' X = ',G15.7)
30 CONTINUE

C
C WRITE FAILURE TO CONVERGE MESSAGE.

```

C

```

WRITE(4,333) IMAX
333 FORMAT(1H0,'IN SUBROUTINE ITERAT TBNPU DID NOT CONVERGE IN ',
+      14,' ITERATIONS')
31 WRITE (4,998) J,TBNPU
998 FORMAT(' SUBROUTINE ITERAT AFTER ',15,' ITERATIONS WAS',
+      ' MAKING LITTLE PROGRESS. NPV = ',G15.7)
40 CONTINUE
RETURN
END

```

INVEST

This subroutine establishes the operating costs and investment structure on an annual basis. The operating costs and investment are input values based upon a specific production configuration designed to produce and process 40,000 bbl/day of geopressured brine. The operating costs are reduced using the "six-tenths rule." This is expressed as:

$$\text{Cost} \text{---} \text{Input cost} * \left(\frac{\text{flow rate}}{40,000 \text{ bbl/day}} \right) .6$$

The costs are then converted to a per barrel basis by dividing by the daily flow rate of fluid. There are three categories of costs: 1) General operating and maintenance, 2) Well operation and maintenance, and 3) Power Cost.

Investment in the project has two components: drilling investment and plant investment. The investment is segregated into depreciable and nondepreciable investment by adding the plant to one-third of the drilling investment for the depreciable portion. The balance of the drilling cost is intangible and treated as an expense in the first year of operation. Investment values are scaled as the operating costs are, utilizing the "six-tenths rule."

Input: General operating and maintenance cost; well operation and maintenance cost and power cost all in \$/day; drilling cost and plant cost; and the base flow rate and the computed production rate each year in bbl/day.

Output: Depreciable investment and nondepreciable investment in millions of dollars; three operating costs in \$/bbl.

```

SUBROUTINE INVEST
REAL NDINV1,NDINV2,NDINV3,NDINV4,NDINV5,NDINV6,NDINV7
REAL INV,INVD,INVND
COMMON/BLK3/N,N,IDEPT,IPRTP,ITXTYP,IPRTYP,IITYPE,TEMPO,PRESSO,
+      MUWELLS,BORE,DPIPE,COMPR,FLOWO
COMMON/BLK5/NDINV1(50),NDINV2(50),NDINV3(50),NDINV4(50),NDINV5(50)
+      ,NDINV6(50),NDINV7(50),DINV1(50),BINV2(50)
COMMON /BLK8/FLOW(50),REV(50),REVGAS(50),REVPRE(50),REVTEM(50),
+      OPCOST(50),OPCGAS(50),OPCPRE(50),OPCTEN(50),PBT(50),
+      TAX(50),WC(50),INV(50),INVCRT(50),DEP(60),SCRAP(50),
+      INVD(50),INVND(50),CASH(50),DCF(50),DISFAC,GAS(50),
+      TURBO(50),THERM(50),OPCWEL(50),PAT(50)
COMMON /BLK10/ BNDNV1(50),BNDNV2(50),BNDNV3(50),BBINV2(50),
+      BINVD(50),BINVD(50),BSCRAP(50),BFLOW
C      INPUT VALUES OF NDINV1,NDINV2,NDINV3 AND DINV2 ( $/DAY )
C      OF THE SUPERFICIAL PLANT
C
C      NDINV1      GENERAL OPERATION AND MAINTENANCE, NOT INCLUDING
C                  POWER COST ON GAS SEPARATION PLANT, NON-DEPRECIABLE,
C      NDINV2      WELL OPERATION AND MAINTENANCE, NON-DEPRECIABLE
C                  INVESTMENT, PER BBL
C      NDINV3      POWER COST ASSOCIATED WITH GAS SEPARATION PLANT,
C                  NON-DEPRECIABLE,PER BBL
C      NDINV4      CONTRACTOR'S FEE, NON-DEPRECIABLE
C      NDINV5      ENGINEERS' FEE, NON-DEPRECIABLE
C      NDINV6      TAX ASSOCIATED WITH EQUIPMENT PURCHASING, DEPRECIABLE
C      NDINV7      CONTINGENCY, NON-DEPRECIABLE
C      DINV1       CAPITAL INVESTMENT, SUCH AS DRILLING COST
C      DINV2       CAPITAL DEPRECIATION, PER BBL
C      INVD        CAPITAL INVESTMENT SUCH AS EQUIPMENT PURCHASING
C      INVND       NON-DEPRECIABLE INVESTMENT FOR YEAR 1, IN MILLION $
C      BFLOW
C
C      NEW COST ARE COMPUTED BY SIX-TENTHS RULE, BASED ON CURRENT
C      FLOW RATE/BASE INPUT FLOW RATE(BFLOW)
C
C      DO 1011 I=1,N
C      RST=(FLOW(I)/BFLOW)**0.6/FLOW(I)
C      NDINV1(I)=BNDNV1(I)*RST
C      NDINV2(I)=BNDNV2(I)*RST
C      NDINV3(I)=BNDNV3(I)*RST
C      BINV2(I)=BBINV2(I)*RST
1011 CONTINUE
C      DO 1401 I=1,N
C      INV(I)=BINVD(I)+(DINV1(I)/3.)+NDINV6(I)
C      INVND(I)=BINVD(I)+NDINV5(I)+NDINV7(I)+NDINV4(I) +
C      +      ((DINV1(I) * 2.)/3.)
C      CONVERT TO MILLION DOLLARS, AND ADJUST INVESTMENT BY .6 RULE
C      ADJFAC = (FLOWO/BFLOW)**.6
C      INV(I)=INV(I)*1.E-6*ADJFAC
C      INVND(I)=INVND(I)*1.E-6*ADJFAC

```

```

C THE PROGRAM IS PATCHED UP HERE SO THAT 1 INVESTMENT IS SCRAPPED AT
C END OF PROJECT RUN (N). TWO INVESTMENTS WILL NOT WORK AND AN
C INVESTMENT SCRAPPED DURING THE MIDDLE OF THE PROJECT RUN WILL NOT
C WORK.
      IF(INVD(I) .NE. 0) SCRAP(N)=INVD(I)*.2
1401 CONTINUE
C
C ALSO ADD DEPRECIABLE AND NON-DEPRECIABLE VESTMENTS TO GET TOTAL IN
C INVESTMENT FOR EACH YEAR
C
      DO 66 I=1,N
66 INV(I)=INVD(I)+INVND(I)
      RETURN
      END

```

CSHFLW

This subroutine computes the current dollar income generated in the operation of the well and separation plant. Total revenue, operating costs, and depreciation are obtained by calling subroutines REVENU, DEPREC, and COSTS. Profits before taxes are computed as revenue less operating costs, depreciation and nondepreciable investment. Total taxes, investment tax credit, and new working capital are then obtained by calling subroutines TAXES, INVESC and WKGCAP. Finally the cash flow for each year is computed as: cash = Revenue + Investment Tax Credit - taxes - new working capital - investment - cash operating costs.

Input: The output of the subroutines identified above.

Output: The current dollar cash flow for each year of project life.

```

SUBROUTINE CSHFLW(FLOW,REV,REVGAS,REVPRE,REVTEN,OPCOST,OPCGAS,
+               OPCPRE,OPCTEN,PBT,PAT,TAX,UC,INV,INVCRT,
+               DEP,SCRAP,INVD,INVND,CASH,GAS,TURBO,THERM,
+               OPCUEL)
  DIMENSION CASH(1),REV(1),REVGAS(1),REVPRE(1),REVTEN(1),PBT(1)
  DIMENSION PAT(1),TAX(1),UC(1),DEP(1),SCRAP(1),FLOW(1)
  DIMENSION GAS( 1),TURBO( 1),THERM( 1)
  REAL NDINV1,NDINV2,NDINV3,NDINV4,NDINV5,NDINV6,NDINV7
  INTEGER START
  REAL INV(1),INVCRT(1),INVD(1),INVND(1)
  REAL OPCOST(1),OPCGAS(1),OPCPRE(1),OPCTEN(1),OPCUEL(1)
  COMMON /BLK1/RATE,TDNPU,DISCFA,UCRET,SUMWC,PRICE(50),TAXRAT,
+         FRLEAS,PDIFF(50)

```

```

COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
+      SMCH4,CH4SEP
COMMON/BLK3/N,M,IDEPT,IPRTP,ITXTYP,IPRTYP,IITYPE,TEMPO,PRESSO,
+      NWELLS,BORE,DPIPE,CONPR,FLOWO
COMMON /BLK4/PHIN,START,TBCF,F,XCH4,CH4MIN,NDWN,NBSP

COMMON/BLK5/NDINV1(50),NDINV2(50),NDINV3(50),NDINV4(50),NDINV5(50)
+      ,NDINV6(50),NDINV7(50),DINV1(50),DINV2(50)
C
C FIRST, CALCULATE THE REVENUES FOR EACH YEAR BY CALLING S/R REVENU
C
C      CALL REVENU(REV,REVGAS,REVPRE,REVTEN,SCRAP,GAS,TURBO,THERM,FLOW)
C
C NOW CALCULATE DEPRECIATION FOR EACH YEAR BY CALLING SUBROUTINE DEPREC
C
C      CALL DEPREC(INVD,DEP,SCRAP)
C
C NOW CALCULATE THE OPERATING COSTS FOR EACH YEAR BY CALLING S/R COSTS
C
C      CALL COSTS(OPCOST,OPCGAS,OPCPRE,OPCTEN,FLOW,GAS,TURBO,THERM,DEP
+      ,OPCUEL)
C
C NOW CALCULATE BEFORE-TAX PROFIT FOR EACH YEAR
C
C      DO 1 J=1,N
C      1 PBT(J) = REV(J) - (OPCOST(J) + INVND(J))
C NOW CALCULATE TAXES FOR EACH YEAR BY CALLING SUBROUTINE TAXES
C
C      CALL TAXES(PBT,FLOW,TAX,GAS,TURBO,THERM,REV)
C
C NOW CALCULATE AFTER-TAX PROFIT FOR EACH YEAR
C
C      DO 2 J=1,N
C      2 PAT(J)=PBT(J)-TAX(J)
C
C NOW CALCULATE INVESTMENT CREDIT FOR EACH YEAR BY CALLING S/R INVESC
C
C      CALL INVESC(INV,INVD,INVND,INVCRT,TAX)
C
C NOW CALCULATE NEW WORKING CAPITAL FOR EACH YEAR BY CALLING S/R WKGCAP
C
C      CALL WKGCAP(FLOW,REV,OPCOST,INV,WC,DEP)
C
C FINALLY, CALCULATE THE CASH FLOW (NON-DISCOUNTED) FOR EACH YEAR
C
C      DO 3 J=1,N
C      3 CASH(J)=REV(J)-TAX(J)-INV(J)+INVCRT(J)-WC(J)-OPCGAS(J)-OPCPRE(J)
C      +      -OPCTEN(J)-OPCUEL(J)
C
C END OF CALCULATION
C
C      RETURN
C      END

```

DISC

This subroutine computes the discount factors for a continuous cash flow for each year. The discount factor equation used for the cash flow is:

$$\text{discount factor} = (e^r - 1/r)/e^{rt}$$

At the end of the project the working capital is returned at shutdown and is discounted using the standard term equation:

$$\text{discount factor} = 1/e^{rt}$$

The sum of the discounted cash flow for each year and end of project discounted working capital is the net present value of project.

Input: Annual cash flow, the discount rate, and the return of working capital at project end.

Output: Total net present value, annual discounted cash flow, annual discount factor, and the discounted return of working capital.

SUBROUTINE DISC

1 (FLOW, REV, REVGAS, REVPRE, REVTEM, OPCOST, OPCGAS, OPCPRE, OPCTEM, PBT, PAT,
2, TAX, WC, INV, INVCRT, DEP, SCRAP, INVD, INVND, CASH, DCF, DISFAC, GAS, TURBO,
3 THERM, OPCUEL)

DIMENSION CASH(1), DCF(1), DISFAC(1), WC(1), GAS(1), TURBO(1), THERM(1)

DIMENSION REV(1), REVGAS(1), REVPRE(1), REVTEM(1), PBT(1), PAT(1)

DIMENSION TAX(1), DEP(1), SCRAP(1), FLOW(1)

REAL NDINV1, NDINV2, NDINV3, NDINV4, NDINV5, NDINV6, NDINV7

REAL INV(1), INVCRT(1), INVD(1), INVND(1)

REAL OPCOST(1), OPCGAS(1), OPCPRE(1), OPCTEM(1), OPCUEL(1)

INTEGER START

COMMON /BLK1/ RATE, TNPV, DISCFA, UCRET, SUMWC, PRICE(50), TAXRAT,
+ FRLEAS, PDIFF(50)

COMMON /BLK2/ DEPTH, SALINE, THICK, AREA, SATRN, PORE, PERM, RECOV, B,
+ SMCH4, CH4SEP

COMMON /BLK3/ N, N, IDEPT, IPTYPE, ITXTYP, IPRTYP, ITYPE, TEMPO, PRESSO,
+ MWELLS, BORE, DPIPE, COMPR, FLOWO

COMMON /BLK4/ PHIN, START, TDCF, F, XCH4, CH4MIN, NDWN, NDBP

COMMON /BLK5/ NDINV1(50), NDINV2(50), NDINV3(50), NDINV4(50), NDINV5(50),
+ NDINV6(50), NDINV7(50), DINV1(50), DINV2(50)

C

C THIS SUBROUTINE CALCULATES THE TOTAL NET PRESENT VALUE OVER A
C PROJECT'S LIFE

C

C

C

C

C

C

C

C

C

C

C

C

C

FIRST, CALL CSHFLW TO CALCULATE UNDISCOUNTED CASH FLOW

CALL CSHFLW(FLOW, REV, REVGAS, REVPRE, REVTEM, OPCOST, OPCGAS, OPCPRE,
+ OPCTEM, PBT, PAT, TAX, WC, INV, INVCRT, DEP, SCRAP, INVD,
+ INVND, CASH, GAS, TURBO, THERM, OPCUEL)

```

C
C SECOND, CALCULATE THE DISCOUNT FACTORS FOR EACH YEAR
C
      DO 1 J=1,N
      XJ=FLOAT(J)
      1 DISFAC(J)=((EXP(RATE)-1.)/RATE)/(EXP(RATE*XJ))
C
C NOW CALCULATE THE DISCOUNTED CASH FLOW FOR EACH YEAR
C
      DO 2 J=1,N
      2 DCF(J)=CASH(J)*DISFAC(J)
C
C NOW DISCOUNT THE RETURN OF WORKING CAPITAL AT THE PROJECT'S END
C
      XN=N
      DISCFA=EXP(-XN*RATE)
      SUMUC=0.
      DO 3 J=1,N
      3 SUMUC=SUMUC+WC(J)
      WCRET=SUMUC*DISCFA
C
C NOW ADD UP ALL THE DISCOUNTED CASH FLOWS TO GET
C TOTAL NET PRESENT VALUE
C
      TDCF=0.
      TDNPW=WCRET
      DO 4 J=1,N
      TDCF=TDCF+DCF(J)
      4 TDNPW=TDNPW+DCF(J)
C
C END OF ROUTINE
C
      RETURN
      END

```

REVENUE

This subroutine computes the total revenue of the project in current dollars for each year of project life. Since the kinetic and thermal energy are not being converted currently, there is no income originating from this source although there are variables provided for this purpose. The revenue from the natural gas is computed as the product of gas production and the current year price. Royalties, currently 8%, are then subtracted to provide net revenue to the venture. In the terminal year of the project, the scrap value of the equipment is returned to the venture as a revenue.

Input: Annual gas production in bbl/day, annual price of gas in \$MSCF, the scrap value of the investment, and the royalty rate in percentage terms.

Output: Total revenue for each year and revenue components when the surface configuration includes electric generation.

```

SUBROUTINE REVENU (REV,REVGAS,REVPRE,REVTEN,SCRAP,GAS,TURBO,THERM,
+               FLOW)
  DIMENSION REV(1),REVGAS(1),REVPRE(1),REVTEN(1),FLOW(1)
  DIMENSION GAS( 1),TURBO( 1),THERM( 1),SCRAP(1)
  COMMON /BLK1/RATE,TDNFW,DISCFA,WCRET,SUNWC,PRICE(50),TAXRAT,
+        FRLEAS,PDIFF(50)
  COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
+        SMCH4,CH4SEP
  COMMON/BLK3/N,M,IDEPTP,IPTYPE,ITXTYP,IPRTYP,ITYPE,TEMPO,PRESSO,
+        NWELLS,BORE,DPIPE,COMPR,FLOWO
  COMMON /BLK4/PMIN,START,TDCF,F,XCH4,CH4MIN,NDWN,NDSP

C
C   SO FAR THIS DOES NOT TAKE INTO ACCOUNT THE KINETIC
C   AND THERMAL ENERGIES POTENTIAL.
C
  DO 1 I=1,N
C
C   FRLEAS IS THE FRACTION OF THE REVENUE THAT GOES TO THE LESSOR.
C   IT IS SUBTRACTED OFF OF THE TOP OF THE GAS REVENUE.
C
    REVGAS(I)=GAS(I)*PRICE(I)*365./10**6 * (1.0 - FRLEAS)
C    XJ=FLOAT(I)
C    REVGAS(I)=REVGAS(I)*(EXP(.08*(XJ-1.)))
    REVPRE(I)=0.
    REVTEN(I)=0.
    REV(I)=REVGAS(I)+REVPRE(I)+REVTEN(I)+SCRAP(I)
1  CONTINUE
  RETURN
  END

```

COSTS

This subroutine computes cash operating costs of the separation plant and the well maintenance in current year dollars using unit costs in \$/bbl. In the event that production drops below 40,000 bbl/day the unit costs are reduced using the six-tenths rule explained in the description of subroutine INVEST. Gas operating cost is the product of fluid production in bbl/day and the cost of general operation and maintenance and power costs in \$/bbl. Well operating costs are computed as the product of fluid production in bbl/day and well operating cost in \$/bbl. These values are then totaled and converted to an annual value of costs. Depreciation charged for the year is then added to provide the yearly accounting cost

to charge against revenue for computing profits. There is provision made for computing electric generating cost in the future.

Input: General operation and maintenance cost in \$/bbl, power cost for disposal in \$/bbl, well operation and maintenance in \$/bbl, and depreciation in \$/yr.

Output: Total operating costs, gas operating costs, and well operating costs all in \$/yr.

```

SUBROUTINE COSTS(OPCOST,OPCGAS,OPCPRE,OPCTEM,FLOW,GAS,TURBO,THERM,
+               DEP,OPCWEL)
REAL NDINV1,NDINV2,NDINV3,NDINV4,NDINV5,NDINV6,NDINV7
DIMENSION GAS( 1),TURBO( 1),THERM( 1),FLOW(1),DEP(1)
REAL OPCOST( 1),OPCGAS( 1),OPCPRE( 1),OPCTEM( 1),OPCWEL(1)
COMMON /BLK1/RATE,TDNPU,DISCFA,UCRET,SUMUC,PRICE(50),TAXRAT,
+       FRLEAS,PDIFF(50)
COMMON /BLK2/DEPTH,SALINE,THICK,AREA,SATRN,PORE,PERM,RECOV,D,
+       SNCH4,CH4SEP
COMMON/BLK3/N,N,IDEPT,IPRTP,ITXTYP,IPRTYP,IITYPE,TEMPO,PRESSO,
+       NWELLS,BORE,DPIPE,COMPR,FLOWO
COMMON /BLK4/PHIN,START,IDCF,F,XCH4,CH4MIN,NDWN,NDSP

COMMON/BLK5/NDINV1(50),NDINV2(50),NDINV3(50),NDINV4(50),NDINV5(50)
+       ,NDINV6(50),NDINV7(50),DINV1(50),DINV2(50)

C
C SO FAR, THIS SUBROUTINE COMPUTES OPERATING COST ON GAS SEPARATION
C PLANT ONLY
C
DO 1 I=1,N
  OPCGAS(I)=(NDINV1(I)+NDINV3(I))*FLOW(I)*365./10**6
C  XJ=FLOAT(I)
C  OPCGAS(I)=OPCGAS(I)*(EXP(.08*(XJ-1.)))
  OPCPRE(I)=0.
  OPCTEM(I)=0.
  OPCWEL(I)=NDINV2(I)*FLOW(I)*365./10**6
C  OPCWEL(I)=OPCWEL(I)*(EXP(.08*(XJ-1.)))
  OPCOST(I)=OPCGAS(I)+OPCPRE(I)+OPCTEM(I)+OPCWEL(I)
  OPCOST(I)=OPCOST(I)+DEP(I)
1 CONTINUE
RETURN
END

```

OUTPUT

OUTPUT, as the name implies, controls the format and content of the results of any specific simulation. Information from the MAIN subroutine determines the content produced from OUTPUT, and the format for engineering results and economic results are standardized in OUTPUT for any simulation.

References

1. Chase Econometrics Associates, Inc., Long Term Macroeconomic Forecast, 1979 (Bala Cynwyd, Pa.: Chase Econometrics Association, Inc., Feb. 1979).
2. DOW Chemical Company, "A study of phase 'O' plan for the production of electric power from U.S. Gulf Coast geopressured geothermal waters," Proceedings: Second Geopressured Geothermal Energy Conference; Volume IV, Surface Technology and Resource Utilization (Austin, Texas: Center for Energy Studies, the University of Texas at Austin, 1976).
3. Kuuskraa, V. A., et al., Enhanced Recovery of Unconventional Gas, Vol. 2, Chapter Six (Springfield, Va.: National Technical Information Service, 1978).
4. O'Sullivan, Thomas D., and Norman O. Smith, "The solubility and partial molar volume of nitrogen and methane in water and in aqueous sodium chloride from 50° to 125° and 100 to 600 atm," Journal of Physical Chemistry (1970), pp. 1460-1466.
5. Starling, K. E., and M. S. Han, "Thermo data refined for LPG," Hydrocarbon Processing (May 1972), vol. 51, no. 5, pp. 129-131.
6. U.S. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies, 1977 (Washington, D.C.: Energy Information Administration, Office of Energy Data, Dept. of Energy, Dec. 1978).

C. APPLICATION OF THE TECHNOECONOMIC MODEL TO HIGH-POTENTIAL PROSPECTS IN LOUISIANA

In order to evaluate the potential commercial viability of Louisiana's geopressured resource, the systems analysis team at LSU decided that a site-specific evaluation of the high-potential prospect sites reported by Bernard¹ would be the best approach in view of the limited regional resource assessment data available. Accordingly, the five prospects identified in Bernard's report as best candidates for an exploratory test-well were submitted to a series of case studies using the technoeconomic model. Since one of the prospects, Atchafalaya Bay, was split by a major fault into an east and west area, there were actually six prospects evaluated. The results of these studies are summarized in this section; they are presented in more detail in a paper entitled "A Report of the Economic Analyses Completed to Date of the Most Promising Geopressured Energy Prospects in Louisiana," in Appendix 2 of this report. This paper was presented at the Fourth Geopressured-Geothermal Conference at the University of Texas at Austin, in October 1979.

Using the reservoir parameters for each prospect site supplied in Bernard's report, the case studies were conducted to estimate the expected economic profitability for each prospect in the same way that a private business would consider the prospect for a commercial venture. For each prospect, the specific venture simulated was a single well drilled to accommodate a 5.5-inch diameter producing string delivering initially 40,000 bbl/day of brine and its associated dissolved methane. (Once the well head pressure declines to 500 psi, the production rate is reduced by the model in 20% increments as needed to maintain a minimum well head pressure of 500 psi thereafter.) Besides a producing well, the venture includes two 20,000 bbl/day shallow disposal wells and the necessary surface equipment to separate the evolved gas and the pumps required to reinject the brine. No investment

for generation of electricity from the thermal and/or pressure energy of the brine was included, as this was not considered reasonable for inclusion in a base case analysis by an industrial firm. It requires utilization of a specific technology, conversion of low grade thermal energy to electricity, which is not in standard use for industrial profit-making ventures, and it also requires a higher certainty than is known now that multiple geopressured wells in a small region will be feasible. At any time it becomes warranted by expectations, an incremental venture analysis on this additional investment for electric power generation could be made. Magma Power Company has indicated that it has designed a small secondary fluid (isobutane and/or propane) power generation unit for use in this situation, called magma max (9 megawatts and 2 megawatts), but the investment cost is reported to be rather high at this time, about \$1,400/kilowatt.²

Total investment costs estimated for the single well venture were \$6,900,000, and total operating costs were \$.043 per barrel in 1985, which was chosen as the initial year for a typical project life. These cost estimates were based upon well costs and equipment costs estimated by Dow Chemical Company in a proposal to DOE in 1976, and the costs were converted to 1985 dollars using factors from the Chase Econometric Forecasts published in 1979. Income credited to the venture was the value of the methane produced from the separators, which in the base case was \$6.17 per MSCF in 1985, increasing to \$22.14 per MSCF by 2004.

In general, the results of each case study of a prospect determined either (1) the DCFRR (discounted cash flow rate of return), (2) NPV (net present value) computed using a 15% after-tax rate of return, or (3) the value of some parameter, such as gas price or federal tax rate, which was required to provide a 15% rate of return. (More detailed descriptions of the case studies and of the input data are included in the paper in Appendix 2.) A summary of the major conclusions reached from the case studies follows.

(1) Of the six high potential prospects, using the forecast methane prices, only two prospects, Rockefeller Refuge and Southeast Pecan Island, provided a return in excess of 15% on the investment for an initial single producing well assumed to be drilled in a contiguous reservoir of area equal to the entire prospect area. The other prospects returned only about 11% on the investment, which is less than the minimum return

normally required for commercial investments to be considered attractive.

(2) Sensitivity studies revealed that for the reservoir parameter ranges of these prospects, the primary requirements for a 15% return on investment are a reservoir volume of at least one cubic mile (which insures 40,000 bbl/day brine production for the project life) and a methane recovery ratio of 26 SCF per bbl (which insures adequate income over the project life).

(3) All six prospects provided a reservoir volume of one cubic mile or greater (assuming the reservoirs to be contiguous), but the ones which did not yield a 15% return did not provide a methane recovery of 26 SCF per bbl because of the high salinities and relatively low temperatures predicted for the reservoirs.

(4) It was found that methane price growth rates of 10% per year (instead of the forecast 7.5% per year) would result in all of the prospects equalling or exceeding a 15% rate of return.

(5) When 1979 constant dollars were used instead of 1985-2004 forecast dollars, the DCFRR of each prospect was consistently 10% lower. Since an average forecast inflation rate of only 4.5% was used for the 1985-2004 period, the remaining 5.5% difference was a result of the relatively high rate of increase in methane prices (6.5% per year) for the period.

In summary, yields from the high potential prospects recommended by Bernard appear to range from a less than attractive 11% DCFRR to a very attractive 20% DCFRR. However, by assuming larger values for either the methane price annual growth rate or the methane content of the brine, both of which fall within the range of current uncertainty, all five prospects would meet at least a 15% DCFRR. It is important to realize, however, that by no means could a single well venture ever be considered extremely attractive (that is, a DCFRR in the range of 50%), because this would require either substantially higher prices for methane relative to other costs than currently envisioned or substantially higher methane solubilities than appears reasonable at this time. The uncertainties still associated with the probability of finding contiguous reservoirs of one cubic mile and higher, and the uncertainties connected with sustainable brine flow rates, brine salinities, and methane content, force the private investor to hold back action until test well results are obtained to dispel these uncertainties in one way or the other.

References

1. Bernard, W. J., "Evaluation of five potential geopressure geothermal test sites in southern Louisiana." Prepared for DOE contract no. EY-76-S-05-4889. (Baton Rouge, La.: Petroleum Engineering Department, LSU, June 1979)
2. C.K. GeoEnergy Corp., "Minutes for the site selection working subgroup, DOE/Industry Geopressured Geothermal Resource Development Program," held in New Orleans, La., Mar. 17, 1980. (Las Vegas, Nev.: Clay Durham, C.K. GeoEnergy Corp., May 1980)

D. DEVELOPMENT OF A CORRELATION PROCEDURE FOR METHANE SOLUBILITIES IN GEOPRESSURED BRINES

One of the recurring points of discussion at geopressured-geothermal meetings and conferences has been the question of the amount of methane contained in the geopressured brine. There are two aspects to the question: first, what is the maximum, or saturation, amount of methane which the brine can contain at a given total pressure, temperature and salinity; and second, whether the typical geopressured brine is saturated or undersaturated. The first question is being addressed by two currently active DOE-sponsored projects, conducted by C. W. Blount (USGS) and J. M. Prausnitz (Univ. of California), aimed at extending the range of experimentally determined methane solubility into the pressure and temperature regions expected for geopressured brines. The second question will be answered only by field data accumulated from test wells and wells of opportunity. Until such time that enough field data is accumulated, it has become standard procedure to assume that the geopressured brines are indeed saturated with methane.

In order to provide the LSU technoeconomic model with a method of predicting (calculating) the expected methane content of a geopressured brine, it was decided to develop a computer subroutine, SOLUTE, to compute the solubility of methane in brine based upon a correlation of available literature data. At present, the literature data consist of publications by Culberson and McKetta,¹ Price,⁴ Sultanov,⁵ O'Sullivan and Smith,³ and Haas.² The first three papers named reported data only for methane-water, whereas the O'Sullivan and Smith paper included data for methane in both pure water and also in a 4 m NaCl solution. The last paper develops a calculation equation based on the Culberson and McKetta data plus an assumed salting out coefficient.

Development of subroutine SOLUTE necessitated a correlation of the data available in equation form to permit calculation of the saturation

amount of methane in a brine as a function of temperature, pressure, and salinity. Preferably the correlation procedure should be based on theoretical, fundamental relationships, rather than empirical equations.

Accordingly, a project was undertaken to develop such a correlation procedure. It was decided to perform the necessary analysis and apply the resulting methodology first to the data reported by O'Sullivan and Smith, and then later to incorporate the data reported by the other authors, and eventually also to include the data being obtained by Blount and by Prausnitz. The results of developing the methodology and applying it to the O'Sullivan and Smith data were reported at the Sea Island, Georgia, Engineering Foundation Conference in January 1980. This complete paper is reproduced and included in this report as Appendix 3.

Briefly, an equation was developed to correlate the effect of temperature, pressure, and salinity upon Henry's law constant for methane in brine solutions. The equation contains eleven parameters, which were evaluated by fitting the equation to the data of O'Sullivan and Smith. These data consisted of fifty data points over a pressure range of 100 to 600 atmospheres, at temperatures of 51.5, 102.5 and 125°C, and at sodium chloride contents of 0, 1, and 4 molal. The resulting correlation of Henry's law constant was combined with a Redlich-Kwong equation of state for water-methane vapor mixtures into subroutine SOLUTE, which calculates solubility values which agree with the O'Sullivan and Smith experimental solubilities, with an average absolute deviation of 1.60%. These results indicate that the correlation procedure appears capable of representing methane-brine solubility data quite well, and the next step in this work is to combine all the data from the several investigators to provide a comprehensive accurate tool for predicting methane solubility at geopressured conditions.

References

1. Culberson, O. L., and J. J. McKetta, "Phase equilibria in hydrocarbon-water systems," Petroleum Transactions, AIME, Vol. 192 (1951), pp. 356-361.
2. Haas, John L., Jr., "An empirical equation with tables of smoothed solubilities of methane in water and aqueous sodium chloride solutions up to 25 wt percent, 360°C, and 138 MPa," U.S. Department of the Interior Geological Survey Open File Report No. 78-1004. (Reston, Va.: U.S. Geological Survey, 1978)

3. O'Sullivan, Thomas D., and Norman O. Smith, "The solubility and partial molar volume of nitrogen and methane in water and aqueous sodium chloride from 50 to 125°C and 100 to 600 atm," Journal of Physical Chemistry (1970), pp. 1460-1466.
4. Price, Leigh D., "Aqueous solubility of methane at elevated pressures and temperatures," American Association of Petroleum Geologists Bulletin, Vol. 63 (1979), pp. 1527-1533.
5. Sultanov, R. G., V. G. Skripka, and A-Yu Namiot, "Solubility of methane in water at high temperatures and pressures," Gasovia Promyshlennost, Vol. 17, No. 5 (1972), pp. 6-7.

E. RESULTS OF SENSITIVITY STUDIES AND THE
ANALYSIS OF ALTERNATIVE PROPOSALS
FOR GEOPRESSURED DEVELOPMENT

These studies were undertaken in order to determine if additional information about the economics of reservoir performance under set geologic conditions could be obtained. It was hoped that relevant general information could be developed that would be of value in a site evaluation process. Further, the study of alternate technologies economics was done as exploratory work to determine the economic significance of the possibilities. A detailed discussion of these studies is given in Appendices 4 and 5. Only the results and conclusions are reported here.

Sensitivity

The sensitivity studies showed:

- That all Net Present Value (NPV) curves when plotted against a given parameter have the same basic shape.
- That a reservoir volume of one cubic mile appears to be critical for sustained 40,000 bbl/day flow over the project life.
- That certain threshold values for geologic parameters appear to limit economic feasibility. That is, regardless of how attractive the other parameters are, economic feasibility would be improbable below these threshold values.

Alternate Technologies

- Whenever recovery of mechanical and thermal energy has been found to be marginal and therefore not commercially attractive, such recovery may be justified for the purpose of saving the costs of reinjection. In such cases the NPV of the purchased reinjection energy provides

an upper limit to the capital investment which can be put into a process to recover mechanical and thermal energy.

- That surface disposal of fluid, which would eliminate costs of drilling and operating disposal wells, would have a significant effect on the economics in every use.
- That alternate fluid use, when the fluid would have some value, would make the projects much more attractive economically.
- That if free gas from the aquifer can be recovered it can significantly affect the economics of the projects.

F. AN ANALYSIS OF LEGAL AND INSTITUTIONAL
IMPEDIMENTS TO THE DEVELOPMENT OF THE
GEOPRESSURED RESOURCE IN LOUISIANA

Introduction

In 1978 a study of the legal problems inherent in the development of the geopressured-geothermal resource in Louisiana was prepared by LSU under the auspices of the Department of Energy.* Following publication and distribution of that report and in connection with the present project, a conference was held at LSU at which persons representing a wide spectrum of interests considered the report; evaluated the problems identified in it, as well as concerns not expressly addressed by it; and shared their perceptions of possible legal and institutional impediments to the development of the resource.** Since that time discussions have been held with representatives of some of those companies engaged in the Wells of Opportunity program of the Department of Energy, and with lawyers and others interested in the development of the resource as to the legal and institutional impediments they expected to encounter or had encountered in the leasing of the resource, the exploration, drilling or production of geopressured wells, and the utilization of their products. This report reflects the information obtained from such sources and from additional research conducted as a consequence of those investigations. To a large degree, matters discussed and conclusions in the 1978 report were confirmed, although

*Thomas A. Harrell, John M. Hill, Ralph W. Pike, and Bert Wilkins, Jr., Legal Problems Inherent in the Development of Geopressured and Geothermal Resources in Louisiana, No. ORO-5257-IT. (Springfield, Va.: National Technical Information Service, 1978)

**The participants consisted of representatives of oil and gas companies, landowners, institutional representatives, academicians and representatives of governmental agencies.

some additional problems that are mentioned below have come to light.

General Observations

Certain general observations as to the consensus of those who have considered the matter and contributed their ideas concerning the general state of geopressured-geothermal resource development might be useful before considering specific problems facing the developer.

Little support was found for tax credits, guaranteed loan programs, or similar economic incentives. The view seems to be that incentives of this nature will not materially affect industry's present decision not to enter upon commercial development of the resource. The only action of this kind that might contribute to earlier or greater industry participation would be to free geopressured methane from any artificial price restraints or cost limitations upon its users so that it can bring the best price possible in the market. The consensus of those persons with whom the matter was discussed is that the resource cannot pass the "risk versus the rate of return" analysis used by industry in the allocation of capital resources because of perceived technological risks and uncertainties, and that tax credits, loan guarantees and similar economic incentives simply would not have enough effect upon that analysis to vary the end result.

The technological uncertainties restraining commercial development are well known. However, it might be useful to note those that were most frequently mentioned.

Geological

Concerns as to methane content, reservoir size, reservoir life, deliverability, the ability of shallower sands to accept large quantities of disposal waters, and uncertainties as to the ability of geologists and engineers to predict fault block or reservoir size.

Engineering

These primarily center upon problems associated with "scaling up" existing drilling and producing practices to produce large quantities of hot fluids from highly pressured zones, and concern as to the ability of existing technology to handle corrosive and heat-induced problems within

acceptable economic parameters.

Environmental

The risks of blow-outs, adverse consequences from the disposal of large quantities of waste water, and subsidence, with their correlative effect upon the ability to continue production, also appear to be of major concern.

Particular Legal Problems

Ownership of the Resource

Much interest continues to be exhibited in the question of whether the right to develop the geopressured-geothermal resource and utilize its heat, pressure and methane is vested in the "surface" owner or the owner of the "mineral" estate, in those cases where rights to minerals have been sold or reserved by the landowner. While the question is of undeniable relevance where such a severance exists, it does not appear to be nearly as important in Louisiana as is the case in Texas. Under Louisiana law, any severance of the minerals from the land actually creates a servitude giving the mineral owner the right to drill for, develop and produce the minerals.* Such a servitude terminates as a matter of law if the rights of the mineral owner are not exercised during any continuous ten-year period by drilling or production.** As a consequence, the severance of minerals from land is not encountered with the same degree of frequency in Louisiana as is the case in other states. Unless there has either been considerable mineral development within the immediate vicinity of a geopressured deposit, or unless there have been numerous recent property transfers in which the sellers reserved minerals, it is unlikely the geopressured resource developer will encounter large areas where the problem exists.

While it has been postulated that in Louisiana the ordinary mineral rights transfer does not convey the right to develop, exploit or produce a

*Louisiana Mineral Code, Articles 16 and 21. See also: Footnote 38 to Chapter IV of Harrell et al.

**Louisiana Mineral Code, Articles 27-29.

geopressured resource, and that it should remain vested in the landowner,* the correctness of this premise has been rendered more doubtful by the recent case of Allison v. Continental Group, involving a lignite reservation.** At the time of preparation of this report the case was pending before the Louisiana Supreme Court.*** A decision is expected within the next months. While the case will undoubtedly be helpful in clarifying the question, it probably will not give a definite answer to it. If the geopressured resource is proven to be economically valuable, litigation will undoubtedly be required to finally resolve the issue.

If one concludes the resource is "owned" either by a mineral owner or by a surface owner, or for that matter, if there are ordinary oil and gas leases covering lands, a determination that the right to exploit the resource is vested in either the mineral owner or landowner will not eliminate the problems associated with the division. In most cases the prospective geopressured resource developer will still have to contract both with persons having an interest in the land and with those owning the operating rights to either the resource or oil and gas. For example, if the mineral owner has the authority to develop and produce the geopressured resource underlying a particular tract of land, those rights will not, in the opinion

*Harrell et al., Ch. IV.

**379 So. 2d 1117 (La. C.A. 2d, 1979). The case involves several questions among which are: 1) whether a sale of timber lands reserving "all mineral rights" included the right to mine lignite when, at the time of the sale, although known to be present in the area, lignite was not considered as a substance of any value, and 2) if so, whether the producing of oil and gas interrupts the prescription of such right and maintains that right beyond ten years from the date of the sale. The opinion of the Court of Appeal was that the right to mine lignite was reserved and preserved. It based this decision largely upon its interpretation of the particular negotiations of the parties and it is not clear as to the first question whether the court believed those negotiations indicated an intent not to exclude the substance or an intent to include it. In other words, the opinion does not clearly indicate whether the court held that, absent a contrary intention, unknown and unmineable substances are included in the term "minerals" and the parties must evidence an intent to limit the usage of the term in a given case to exclude a particular substance, or whether the contrary is the point of departure for the case.

***Writs have been granted by the court although this has not been yet officially reported.

of the author, permit the use of the premises to conduct operations on other lands adjacent thereto.* If centralized collection of the geopressured water and its disposal from a number of wells is necessary for the efficient and economic operation of the project, consent of the surface owner will undoubtedly be required for such combined actions. The same problem will exist if surface facilities such as pipelines, generating plants, or electric gathering lines are required to serve several sources. On the other hand, if the right to the resource is vested in the surface owner, the presence of outstanding oil and gas rights may create difficulties. Claims that geopressured production or the disposal of waste water will injure existing or possible oil and gas reservoirs production, or future unexpected discovery of such reservoirs by oil and gas lessees, or by the geopressured resource lessee in drilling geopressured wells, may cause serious problems to the developer. Royalties or non-participating mineral interests in amounts that exceed the amount of royalty that the project can economically bear may also present difficulties.

The Effect of Unitization

There appears to be little doubt that the effective, efficient and orderly development of geopressured resources will require some form of unitization. Furthermore, the fact that in Louisiana unitization is expected almost as a matter of course in oil and gas development should make it almost certain such unitization will take place for the geopressured resource. The law authorizes the Louisiana Commission of Conservation to establish for each geopressured well a unit encompassing the area that the well can

*The mineral owner has all rights over the property reasonably necessary to explore for and extract minerals from the lands covered by the grant. Louisiana Mineral Code Art. 21. There has never been any thought that such an owner may use the land to extract minerals from other lands. This has been somewhat obscured in oil and gas matters because unitization fictitiously attributes unit production to each tract in the unit as though the well were located upon it, and because oil and gas leases customarily confer such rights upon the lessee as a matter of contract.

efficiently and economically drain.* Any developer who expects to drill a well must then, as a practical matter, have under lease an area adequate to encompass the prospective unit the well will give rise to, or have agreements with the other property owners or lessees within that area for the joint drilling and operation of the well. In default of this, he will be required to bear all of the cost and take the entire risk of the venture but receive only a part of the benefits.** Economic considerations may preclude drilling unless all or nearly all of the prospective unit is under the developer's control. Furthermore, unitization vests each owner of mineral rights in the unit with an undivided interest in the production from the unit well.*** If a prospective developer wishes to utilize the geopressured resource for a specialized or particular purpose, subsequent inclusion of a unit of land the developer does not control may well result in the products of the well being owned in indivision by persons who may not be willing to devote them to the same purpose or who may demand unreasonable compensation for the right to do so.****

The Geopressured Lease

It is generally assumed that private leasing will be the model for development of the resource. The principal problems facing the drafter in devising an acceptable lease can be characterized under three basic headings:

(1) Identifying the Substances Covered by the Lease. Most geopressured-geothermal reservoir leases now in existence attempt to differentiate the resource from other minerals which may be found under the property, notably oil and gas, and limit the lessee's rights to the production

*Louisiana RS 30:801 extends, by reference, the provisions of the Louisiana Conservation act (Louisiana RS 30:1 et seq) to geopressured wells. RS 30:8 and 9 provide for such unitization by the Commissioner of Conservation for oil and gas wells.

**Harrell et al., p. 188 et seq.

***Id.

****Desomeaux v. Inexco Oil Co., 277 So. 2d 218 (La. C.A. 1173), Hardy v. Union Producing Co., 207 La 137, 20 So. 2d 734 (1945).

of the geopressured resource.* Such an approach requires the lease to define the resource and distinguish it from "conventional" oil and gas. It then becomes necessary to distinguish geopressured methane from gas found in conventional deposits. Existing leases appear to use one of two approaches to do this. Some define the geopressured resource as consisting of water and all substances produced therewith excluding hydrocarbons that are not in solution in the reservoir. The difficulty with this is that it may exclude from the definition of the resource methane or other hydrocarbons disseminated in the water although not in solution. The second approach has been to exclude all oil and gas producible in paying quantities, even though they may come from the geopressured source. The difficulty with this is that, if methane is found in sufficient quantities to be produced economically without regard to the heat or pressure of the water in which it is found, it, too, would appear to be entirely excluded from such a lease. This would eliminate one of the very values the parties are looking for. Some accommodation to the realities of the resource might be possible by combining the two methods and excluding hydrocarbons that are both (a) not in solution and (b) accumulated in discrete reservoirs economically producible by themselves.

Another problem implicit in both forms of lease is caused by a failure to take into account the possibility that a geopressured well may produce substances that are both included and excluded under their terms. Under the terms of some of the leases that were examined, it appears the lessor could easily contend that the lessee is required to deliver the excluded hydrocarbons to the lessor entirely free of cost.

(2) Royalties. A second area of concern is in determining the amount and method of calculating royalties. The royalties stipulated in existing geopressured leases appear to range from one-tenth to one-sixth of the value of the resource produced. It is highly possible that royalties of this

*Although no commercial production of the resource has yet occurred there has been some isolated leasing. Also, persons acting under contract with the Department of Energy in its Wells of Opportunity program have leased a few areas.

magnitude may render uneconomic most geopressured development.* Furthermore, such royalty provisions may prove to be seriously deficient if the heat and pressure energy of the resource are utilized. The most reasonable method of calculating a royalty for these components would appear to be one based upon the energy that is converted to some useful purpose. If the resource is used to generate electricity, then the method used in the Western states for royalties on geothermal energy might be adopted by relating the royalty to the amount or value of the electricity generated. If the pressure and heat are used for other purposes, such as process or plant heat, the most reasonable way to calculate a royalty might be to base it upon some fraction of the value of the energy ultimately so used. In any event, the failure to take these uncertainties into account and merely providing a royalty based upon the "market value" or "gross value" of the product may prove to be highly unsatisfactory.

(3) The Term of the Lease. Most existing geopressured-geothermal leases appear to be modifications of oil and gas lease forms in common usage. These leases have a relatively short primary term in which the lessee must obtain production.** After the primary term, if production ceases for any cause, the time permitted the lessee to restore production is quite restricted, 60 to 90 days being the norm. If large areas of the land have to be maintained under lease while geopressured development is occurring, if the complexity and magnitude of such operations require much longer periods for decision making, and, perhaps, if longer periods during which production is not occurring are encountered, then adopting the oil and gas leases as a model may place the lessee in an extremely precarious position once operations are commenced.

*It may in fact be said that this question is actually central to the legal problems facing the geopressured resource developer. If the economic returns from development will support the division of benefits and allocation of risks to the same extent, and in the same manner, as a conventional oil and gas venture, it would appear that generally there would be no greater impediment to one than the other, and the problems facing the geopressured resource developer will largely be the same as those facing the developer of conventional hydrocarbons.

**Primary terms of more than five years are becoming quite rare and a three-year term is not at all unusual.

Pragmatic Barriers to Leasing

The legal problems involved in leasing the geopressured resource, particularly those created by attempting to distinguish geopressured methane from "conventional" natural gas, present difficult lease drafting problems. The necessity for making this distinction arises from the belief that conventional oil and gas reservoirs may exist in conjunction with the geopressured formations. There is evidence that this belief may pose a much more pragmatic obstacle to leasing the geopressured-geothermal resource than mere problems of lease draftsmanship, particularly if one assumes that the economics of development are such that cash bonuses, delay rentals, or royalties equivalent to those ordinarily given in South Louisiana in an oil and gas lease would be prohibitive to the geopressured resource developer.

It is not apparent that as much eagerness to lease the geopressured sites will be present as is ordinarily the case with oil and gas if the geopressured operations offer only modest returns. There is a universally held belief that lessors receive extremely high returns from oil and gas development. As a result, one seldom encounters landowners who are unwilling to lease their lands for such purpose. It is true that unrealistic expectations as to cash bonus, delay rentals, or royalties sometimes may make leasing difficult, but negotiations generally begin with a landowner and lessee who both actively desire to lease the land. Whether this will be true with the geopressured resource is by no means certain. If the returns to the landowner from a geopressured resource are modest, if the risk of injury from blowouts or the escape of salt water are perceived (correctly or not) to be serious, and if surface facilities are more burdensome than is the case with oil and gas, then developers may encounter persons who are simply not interested in leasing upon any terms that might be reasonably justified by the economics of the venture.

The isolated leasing of the resource that has occurred so far also indicates there may be a problem with landowner fears that production of vast quantities of salt water from a geopressured reservoir may injure unknown, and as yet undiscovered, deposits of oil and gas in the same formations by dissipating the reservoir energy necessary to produce

them.* Furthermore if the land has speculative oil and gas value, a landowner may be reluctant to lease land to a geopressured resource developer for less cash than the amount for which he believes he may some day sell an oil and gas lease, since a geopressured-geothermal well will prove or disprove that value. Since the deposits that appear most attractive for geopressured development are found in those blocks of sand having the greatest areal extent, a developer may have to satisfy the lessor of a fact which is for practical purposes unprovable, that no conventional oil and gas deposits exist in the same formations.

Nor is the belief that oil or gas may be encountered in a geopressured formation limited to landowners. Few prospective geopressured resource developers expressed a willingness to drill wells to the depth of the geopressured-geothermal formations under leases which preclude them from operating or producing conventional oil and gas deposits if they are found. This may place the lessee in the dilemma of wanting to acquire the right to develop conventional oil and gas but being unable to pay what it takes to acquire such rights.

It is a simple matter to combine the right to produce conventional oil and gas and the geopressured resource in a single lease and even to limit the rights of the lessee to the particular geopressured strata or horizons to which the wells will be drilled, if a landowner believes conventional gas or oil may occur at other depths, and if the geopressured resource developer is willing to drill through such formations without the right to produce those zones. Royalties may also be graduated according to the gas-water content of the production, starting with a fairly nominal royalty for high water ratios and ultimately reaching a royalty that would be appropriate for conventional oil and gas development if the amount of gas produced is equivalent to what is found in conventional reservoirs. In fact, there are positive benefits from this to the lessee as it may permit

*The implications of this, in terms of the correlative rights of a geopressured resource developer and a conventional oil and gas developer to produce from the same formation using essentially the same source of reservoir energy are unknown. The Commissioner of Conservation would appear to have authority to prohibit production of one resource if to do so would cause undue waste of the other. See: RS 30:2, and 30:802.

him to offer what may appear to be fairly small royalties at the lower end of the scale but to balance them with royalties that appear to be thoroughly conventional if conventional deposits of oil and gas are discovered. This kind of lease may encourage landowners who are unaware of the nature of the geopressured resource and unfamiliar with its parameters to be more willing to lease. However, it leaves unresolved the question of how much bonus or other cash rental may have to be paid.

Conclusions

The analysis of legal and institutional impediments to the development of the geopressured-geothermal resource in Louisiana yields the following conclusions:

- The principal barriers to the active development of the resource appear to be based upon technological rather than legal or institutional considerations.
- The uncertainty as to the ownership of the resource, whether landowners or mineral owners, should not of itself pose a major problem. The existence of outstanding oil and gas interests or the severance of the geopressured-geothermal resources from the land, or from other mineral interests, will require, for effective development of the resource, negotiation and agreement with the owners of all such interests and the land itself.
- The probability of unitization of the resource will require effective control over the entire area that a well is expected to drain, and uncertainties as to the size of that area may require leasing of larger tracts than may ultimately prove to be required. While in itself causing no unusual legal problems this may increase the cost of the project and magnify the number of other problems encountered in leasing.
- Existing legal institutions are adequate to permit preparation of geopressured-geothermal leases, but they will require careful and intelligent draftsmanship. Existing models used for conventional oil and gas development may prove to be highly deficient if used indiscriminately for the leasing of the geopressured-geothermal resource.

- The critical impediment to the leasing of the resource may prove to be economic if: (a) either the lessor or lessee believes conventional oil and gas deposits may exist under the land, above or in the geopressure-geothermal formations, and (b) the economics of the geopressured-geothermal resource will not permit payment of cash consideration (in the form of bonuses and rentals) and royalties commensurate with those suitable for oil and gas development.

G. DISPOSAL OF FLUIDS FROM GEOPRESSURED AQUIFERS

Rationale

During the first year of the project, the systems analysis team judged disposal of the fluids from geopressured sites to be a key issue in development of the resource. Part of the group's concern stems from the lack of attention given to the feasibility, costs and impacts of either surface disposal or subsurface injection, especially in view of the large scale of disposal operations from geopressured aquifers. Proceedings from a Workshop on Disposal of Geopressured Fluids held at LSU accompany this report as an Addendum. A brief summary of the proceedings follows.

In the case of subsurface disposal, it seems that both industry representatives and researchers have relied heavily on oil and gas field experience to carry over to the geopressured situation, when, from all available evidence, geopressured wells' disposal operations may differ significantly. Certainly, the total volumes to be disposed of will be uniquely high if anticipated production rates are achieved. Knutson and Boardman's 1978 review⁵ of Gulf Coast oil and gas field disposal operations highlights this point very clearly. The review shows that while individual wells have sustained high injection rates over time in Gulf Coast operation, these are exceptions. In contrast, geopressured subsurface disposal operations will have to depend on consistently reliable, high injection rate wells for tens of years in order to keep disposal costs within a reasonable range. Furthermore, the most likely disposal zone, -2,000 to -5,000 feet, is deeper than usual oilfield practice. This deeper interval is established partly by the need for adequately large sandstone formations, and partly because of federal regulations which will prohibit disposal above the base of slightly saline water (10,000 mg/l total dissolved solids). Finally, the geochemistry of geopressured fluids will differ from that of the brines usually produced with oil and conventional gas. As Kharaka et

al. point out,³ the solution chemistry and temperature of geopressured fluids give them significantly different corrosion and scale-formation properties than oil and gas field brines. Conventional wisdom has it that industrial waste disposal experience is vast in regard to corrosion and scaling. However, the anticipated volumes in the case of geopressured fluids are so much larger than in industrial waste disposal that uncertainties about handling corrosive fluids are valid.

The issues in the case of surface disposal are quite different, although large-scale, surface disposal of geopressured fluids in closed systems (i.e., pipelines) into the open Gulf waters should utilize routine practice. The uncertainties center on whether such large-scale surface disposal would be permitted at all. Recent developments in the Strategic Petroleum Reserve program, such as the permitting of surface disposal of brines from the Bryan Mound site in Texas, may indicate a willingness on the part of federal authorities to permit large-scale surface disposal activities. Certainly, surface disposal from geopressured sites within economic distance from deep Gulf waters is preferable from the standpoint of costs (see Lehr's discussion of this for the Strategic Petroleum Reserve Program).⁶

In any case, the surface disposal option will be available only at those sites within economic distance from deep Gulf waters. (Dames and Moore¹ suggest 20 feet for large-scale brine disposal if at all.) Thus the only other alternative for many sites will be subsurface disposal. Given this situation, and considering the factors mentioned above, the systems analysis group concentrated exclusively on identifying those potential impediments to development of the resource posed by subsurface disposal, particularly hydrogeologic, operational, and economic problems.

Approach

The approach used by the systems analysis group to identify these problems and to outline possible solutions and research and development needs was to invite industry and academic specialists in the field to address specific subjects in a group discussion format. This appeared to be the best approach for an initial inquiry in that it allowed for brainstorming by experts on an essentially new topic. Confidence in the results of such an effort rests largely, we think, on the completeness of the group

assembled in terms of expertise and interests, as well as on working out an effective structure for facilitating the exchange of information and ideas.

To this end, the systems analysis group held the Workshop on Subsurface Disposal of Geopressured Fluids at LSU in March 1979. The Workshop Proceedings accompanies this report and will be referred to frequently in the following summary. Approximately 75 people attended the workshop, which was entirely invitational. They included representatives of: 1) industries with an interest in geopressured resource development; 2) industries experienced in subsurface disposal of oilfield and industrial fluid wastes; 3) state and federal regulatory agencies; 4) the Strategic Petroleum Reserve Program; 5) researchers in the geopressured resources area or in the appropriate disciplines (geology, geochemistry, hydrology, petroleum and chemical engineering, etc.). Many of the participants (see the list at the end of the appended Proceedings) were recognized experts in their fields and one-fourth were new to the consideration of geopressured resource development. This allowed for fresh insights into the areas covered and much productive questioning of assumptions.

The workshop was co-sponsored by the Louisiana Department of Natural Resources and Louisiana State University. However, a concerted effort was made to invite representatives of Texas interests and to deal with geographic differences in regulatory matters and experience (see the program in the accompanying Proceedings).

The workshop took place in a highly structured setting which, we think, facilitated focusing clearly on specific topics. There were concurrent discussion sections but no concurrent presentations. Discussions of potential problems and possible solutions took place for the following subjects: hydrogeologic concerns, operational factors, fluid/formation compatibility, and fluid migration. Participants were provided with background papers^{2,3,4} on the geochemistry of geopressured fluids prior to the workshop and with lists of discussion topics at registration (Appendix B of the Proceedings). Leaders of each discussion section reported the results of their group's work to the entire workshop group at the end of each of the four sessions, and a critique of the workshop was given by two people with different perspectives: Jay Lehr, Executive Director of the National Waterwell Association as the outside expert; and Darrell Greenwell, DOE, Dallas,

as the knowledgeable "insider."

Regulatory considerations were presented in the introductory portion of the workshop but only to give some framework to the discussions of technical topics; regulation of subsurface disposal was not a matter for specific attention.

Interest in the workshop was high both before the meeting and afterward. The invited participants seemed appreciative of the opportunity to get together to discuss this topic and frequently commented that such an opportunity was long overdue. The results of the workshop have been reported in presentations at the Fourth United States Gulf Coast Geopressured-Geothermal Energy Conference: Research and Development, at Austin, Texas (October 1979) and at the Engineering Foundation Conference: Geotechnical and Environmental Aspects of Geopressure Energy, at Sea Island, Georgia (January 1980). These papers are reproduced in Appendices 6 and 7 of this report. Participants attending both meetings expressed considerable interest in the topic and in receiving the Proceedings; the distribution list for the Proceedings includes over 250 people, 75 of whom attended the meetings.

In general, we think the workshop achieved its goals: to review potential hydrogeologic and operational concerns; to focus on those that could impede development of the resource; to make recommendations as to research and development of the resource; and to make recommendations as to research and development needs. As the first attempt to deal with these topics, we think the workshop provided many "leads" which should be pursued. There was a remarkable amount of consensus on many topics. These opinions need to be reviewed, but we have a high degree of confidence in them as an initial, informed assessment of the issues. We do not think that such a meeting needs to be repeated until considerable field experience is available.

Conclusions

The conclusions of the workshop participants are reported in full and summarized in the accompanying Proceedings. A brief summary is given here.

- Economics. The workshop participants agreed that the economics of subsurface disposal is the crucial issue. They observed with respect to nearly every potential problem that the technology exists to correct or alleviate operational problems but at costs that may be prohibitive.
- Disposal Formation Volume, Continuity and Permeability. There was general agreement that disposal formations of adequate volume, continuity, porosity and permeability are available in the most likely disposal zones, -2,000 to -5,000 feet. It was noted, however, that continuity and permeability in these sands are highly variable laterally as well as with depth. For this reason and because of the large scale of disposal from a geopressured operation, detailed site specific studies should be performed.
- Fault Activation and Seismicity. There was no consensus as to the probability of triggering either abrupt or gradual stress release by subsurface disposal of large quantities of fluids. In general, the group did not express much concern about the problem because they noted the geology in the Gulf Coast is very different from the geologic setting in documented cases of injection-induced earth movement. However, enough uncertainty was felt to exist, because of the uniquely large scale of geopressure disposal, to warrant monitoring for earth movement.
- Fluid/Formation Compatibility. While the group agreed that fluid/fluid and fluid/formation incompatibility was possible, even likely, in disposal from geopressured operations, they observed that these problems could be alleviated through appropriate chemical and mechanical treatment. The key issue is the cost of producing an acceptable quality effluent and not the technical feasibility of doing so.
- Scaling and Corrosion. The workshop participants agreed that geopressured fluids are likely to present corrosion and scaling problems but that these could be alleviated through appropriate chemical and mechanical treatment. Again, the group agreed that the crux of this problem is the economics of treatment, not lack of experience and technical expertise. It was suggested that temperature cycling during processing could be an additional mechanism (i.e., not usually employed) for precipitation of substances with inverse solubilities. Special studies of these are recommended.
- Back-up Disposal System. A geopressured site's disposal system will have to have some excess capacity, it was agreed, and the amount required would be an important factor in the economics of the disposal operation. The extent of the back-up system, the group noted, will depend on how much fluid treatment is planned (on the premise that a high quality effluent would reduce down-time for remedial action) and on whether production would have to be sustained or could be interrupted.
- Fluid Migration. In general, the workshop participants agreed on a low probability of injected fluids' migrating into hydrocarbon producing zones, or to the surface. A number of reasons were cited to support this conclusion (see a detailed discussion in the attached Proceedings). However, monitoring for fluid migration is

recommended because of the large volume of fluids to be injected. The group expressed concern about the costs of complying with environmental regulations concerning fluid migration. The provision in the proposed EPA regulations (FR, April 20, 1979) thought to be most onerous is the "area of review" requirement: review of wells in a minimum of one-fourth mile from each disposal well and remedial action if they are improperly plugged.

Recommendations

The workshop participants made a number of recommendations on the design and operation of actual subsurface disposal systems for geopressured wells. These are given in detail in the attached Proceedings. The theme common to most of these recommendations is that, because of the large volumes to be processed and injected, considerably more care than is standard practice should be given to data collection and testing before the disposal system goes into full operation. Similarly, operational procedures should be carefully monitored, and monitoring should take place for environmental impacts (earth movement and fluid migration). A number of these recommendations were incorporated into the disposal system testing program proposed by the Louisiana Department of Natural Resources for the Lafourche Crossing test well.

The workshop groups' recommendations regarding research and development studies were as follows:

- A detailed economic study of subsurface disposal activity so that areas where costs should be reduced can be identified.
- Research on the solubilities of the slightly soluble salts to determine the effects of temperature cycling.
- Site-specific hydrogeologic assessments but not a regional study of the -2,000 to -5,000 foot interval.

To these, the systems analysts group recommends adding:

- Compilation and analysis of all field data from test wells relating to subsurface disposal problems so that a record of experience in disposing of geopressure and fluids can be started.

References

1. Dames & Moore Consultants, "Napoleonville Dome brine injection feasibility and environmental assessment report, Preliminary Draft." Prepared for DOE Contract E1-77-C-01-8789. (Atlanta, Ga.: Dames and Moore, Oct. 10, 1978).
2. Kharaka, Yousif K., et al., "Chemistry of waters in the geopressured zone from coastal Louisiana--implications for the geothermal development.: Geothermal Resources Council, Transactions, Vol. 2 (July 1978), pp. 371-374.
3. Kharaka, Yousif K., et al., "Corrosion and scale-formation properties of geopressured geothermal waters from the northern Gulf of Mexico basin," Proceedings, Society of Petroleum Engineers (SPE) of AIME, International Symposium on Oilfield and Geothermal Chemistry, Houston, Texas, January 22-24, 1979.
4. Kharaka, Yousif K., et al., "Geochemistry of geopressured-geothermal waters from the Frio Clay in the Gulf Coast region of Texas," Geology, Vol. 5 (April 1977), pp. 241-244.
5. Knutson, C. F., and C. R. Boardman, "An assessment of subsurface salt water disposal experience on the Texas and Louisiana Gulf Coast for application to disposal of salt water from geopressured-geothermal wells," Topical Report, prepared for DOE under Contract No. EY-77-C-08-1531 (Las Vegas, Nev.: C.K. GeoEnergy Corp., August 4, 1978).
6. Lehr, Jay H., "Hydrogeologic feasibility analysis of the utilization of deep well disposal technology for the removal of brine produced by the development and use of storage facilities at Bryan Mound near Freeport, Texas," report to the Dallas, Texas, Office of the Environmental Protection Agency, August 16, 1978.
7. Newchurch, E. J., et al., A Plan for the Long Term Environmental Assessment of Geopressured Resource Development in the Louisiana Gulf Coast Region, prepared for Lawrence Livermore Laboratory for DOE under Order No. 8316603. (Baton Rouge, La.: Institute for Environmental Studies, Louisiana State University, July 1978)

H. AN OVERVIEW OF THE PROBLEMS OF SUBSIDENCE
ASSOCIATED WITH DEVELOPMENT OF
GEOPRESSURED-GEOTHERMAL RESOURCES IN LOUISIANA

The subsidence of the surface of the earth attendant to the extraction of geopressured brines presents what is potentially the most serious environmental problem in developing this resource in Louisiana. The essence of the phenomenon is reduction of the vertical distance between the bottom of the producing formation and the surface of the earth above it.

The geopressured state of the brines comprises much of their value, but is also the condition which creates the possibility of subsidence. The fact that the interstitial fluids in geopressured formations bear more than their "share" of the weight of the overburden places their importance in maintaining the formation structure above that of fluids in "normally" pressured formations. The possibility of surface reflection of reservoir compaction is exacerbated by the facts that the fluids in geopressured formations will be withdrawn at a very high rate (40,000 bbl/day per well), and the formations under consideration are extensive in area (from 20 mi² at the Sweet Lake to 103 mi² at the Atchafalaya Bay).

On the other hand, excepting the site-specific characteristics of the overburden, it is primarily the depth of production that will mitigate these effects. For the sites under investigation, this ranges from 11,000 feet at Atchafalaya Bay to 14,000 feet at Lafourche Crossing, Southeast Pecan Island, and Sweet Lake.

Although the depth of production may be a buffer against the surface effects of compaction, it also introduces considerable uncertainty into the calculation of the effects. Subsidence resulting from the "normal" compaction of sediments, and that attendant to the production of groundwater, oil and gas from shallower horizons has a much longer record of research than does deep production. Subsidence associated with production of groundwater

has been studied in Baton Rouge and Texas.¹⁴ But it must be noted that, though production levels approximate those for geopressured resources, it is from relatively shallow formations (2,000 feet to 2,800 feet in the case of Baton Rouge). Subsidence resulting from the production of oil and gas is also well documented, from the extremes of the phenomenon (such as a 30-foot vertical surface drop in Southern California), to studies of individual fields of regional significance.⁴ But in this case also, though oil and gas are produced at levels exceeding that of groundwater, production at the depth of 14,000 feet is the exception, rather than the rule. This reduces the value of these studies as direct analogs.

Study of the literature pertaining to subsidence associated with geopressured resource exploitation divides itself into three categories:

- 1) Information from actual experience with subsidence,
- 2) Models and calculations being applied to the geopressured-geothermal case for measurement and estimation of subsidence,
- 3) Analysis of the problem of uncertainty in the prediction of subsidence from large productions at deep levels.

An overview of the material on these topics is presented below. It is confined to the materials listed in the bibliography and does not represent a comprehensive treatment.

Information from Available Evidence

In all formations where there is liquid and/or gas in the interstitial spaces between rock grains, the liquid or gas bears some of the pressure exerted on the formation as a whole by the material between it and the surface. If that fluid or gas is withdrawn from the formation, rearrangement of the structural support will take place. This can include the compaction of the formation due to: 1) reduction in volume from withdrawal of the fluid itself, and 2) compaction of the sediments themselves, as each grain equilibrates the new stress conditions. Added to this is the effect identified as "compaction of the included and surrounding shales" that give up water to the reservoir as the fluids are withdrawn.⁷ Taken together,

these effects (and possibly others) lead to the reduction of the vertical distance between the bottom and top of the producing formation.

While reduction of reservoir height in itself has little effect beyond influencing production characteristics of the formation, when that movement is communicated to the surface it can have substantial impact. The mechanism of that communication is a function of the characteristics of the sedimentary column between the formation and the surface. For subsidence to be reflected, the overburden must lack compensating internal self support and be of such a nature as to easily deform downward to supply a constant load to the underlying formation. The bounds of the area of subsidence from compaction in one reservoir may be set by the location of faults surrounding the formation and overburden.¹³

The factors which enter the calculation of compaction of the reservoir itself and reflection of that in the surface are in Table 1, "Factors Tending to Influence Geopressured/Geothermal Subsidence." From that, it is apparent that many of the characteristics which we seek in a formation as favorable for production are the same factors that lead to a higher probability of surface subsidence. In some cases, factors which would mitigate surface subsidence would also make the reservoir practically useless for production. These include small reservoir size, low pressure, low porosity, and high consolidation and cementation. Some other factors which help surface stability, such as igneous or metamorphic rock formations, or older sediments, simply are not present in prospect areas. Sediments older than Miocene are present only at the Sweet Lake prospect, which is composed of the only slightly older Oligocene sediments.)

Though surface subsidence from deep production of oil and gas is generally unknown, in the major fields of the northern Gulf the absence of occurrences does not justify the conclusion that it will not occur. The lack of evidence may be attributed (at least in part) to inadequate field data.¹¹ Assuming that compaction of the geopressured reservoir will occur over time with the production of 40,000 bbl/day per well over a field that may have many wells, the central question then turns to the mechanics of communication of this compaction to the surface.

TABLE 1

FACTORS TENDING TO INFLUENCE GEOPRESSURED SUBSIDENCE
(After Atherton, 1976, cited in White¹³)

Factor Type [(+) = major factor] [(-) = minor factor]	Factors which Con- tribute to Subsidence Susceptibility	Factors which Con- tribute to Surface Stability
1. Reservoir fluid		
(+) Phase	All liquid	Vapor-liquid mix
Pressure	Geopressured	Low (less than hydro- static)
Density	High	Low
(-) Dissolved solids		
(-) Temperature		
2. Production fluid		
(+) Volume	Large	Small
(+) Fluid level ^a	Large drops, long time, extensive area	No drops
(+) Pore pressure ^a	Large drops, long time, extensive area	No drops
Formation flashing	None	Extensive, continual flashing
3. Geohydrology		
Natural recharge ^a	Low rates	High rates
4. Reservoir material		
(+) Type	Sedimentary	Igneous or metamorphic
Grain size	Coarse	—
Grain shape	Angular	Round
Porosity - primary	25-40%	Very low
Porosity - secondary	High	Low
(+) Consolidation and cementation	Unconsolidated and uncemented	Consolidated and cemented
(+) Preconsolidation ^b	None	Much
Hydrothermal altera- tion	Present	Absent
Admixed clay content (sorting) ^c	—	—
Admixed mineral con- tent	High mica, montmorillo- nite clays	None
Age	Miocene or younger	Older than Miocene
(+) Thickness (in communication)	Great vertical sections	Small vertical sections
(+) Deformation properties ^d	Highly deformable	Slightly deformable

TABLE 1 (cont'd)

Factor Type [(+) = major factor] [(-) = minor factor]	Factors which Con- tribute to Subsidence Susceptibility	Factors which Con- tribute to Surface Stability
5. Associated material type Occurrence	Clays, siltstones, shales Many thin strata of large total vertical thickness interbedded with reservoir materials, but not impair- ing communication between them	Volcanic flows and shallow intrusions
6. Width/thickness ratio ^e	Large	Small
7. Overburden		
(+) Thickness	Small, less than 3000'	Great
(+) Competence	Incompetent, unconsoli- dated	Competent, consoli- dated
(+) Deformation properties ^f	Highly deformable	Slightly deformable
Density	High	Low
8. Site geology, Structure		
Folding	Gentle, broad synclinal	Sharp, anticlinal
Flank dips	Less than 25°	Greater than 25°
Faulting	Normal, graben blocks	Reverse or thrust
Fracturing	Much, recent	Little, old, sealed
Regional stresses	Tensional	Compressional
Stratigraphy	—	—

^aDepends upon formational properties, which may be studied by preliminary well tests.

^bPreconsolidated materials have previously experienced pressure loads.

^cIf high pressures did not always accompany the presence of admixed clays in geopressed areas, they would be preconsolidated.

^dElastic contents, compaction coefficient, yield stress, etc.

^eOf the production zone.

^fCan the overburden materials possibly respond more slowly than the producing material below?

Of the factors controlling the response of the overburden, its thickness is of primary importance. The structural resistance of a disc or slab to bending is proportional to the cube of its thickness.¹³ This obviously makes the geopressured situation where production is at great depth favorable to surface stability.

Other factors governing the overburden's response to reservoir compaction include lateral expression through movements along growth faults, expansion of the material in the overburden resulting from a reduction of supporting pressure from below, and "dissipation effects," such as caving and other rearrangement of material in the overburden, which would compensate for the reduction of reservoir height. Cementation and other factors which determine the structural strength of the overburden may also play a role in "bridging" where vertical movement in the sedimentary column is insulated by the absorption of stress in a horizon of high resistance to bending.

Opinions differ in applying these principles to the analysis of responses of sediments in the Gulf basin. However, it is clear that, as stated by Lofgren:¹¹

With the tremendous weight of the overburden and the low strength of Gulf Coast sediments, it is unlikely that compaction would not be projected to the surface due to bridging action in the overburden, except for very narrow fields.

It has further been found that the chances of adverse effects from subsidence are roughly equal in the six prospect areas under investigation for geopressured resources exploitation in Louisiana.⁷ The effects, however, would vary between the sites due to features of topography, location, land use, and biological environment.

Fault activation and seismicity are also within the potential effects of substantial pressure drawdown in a reservoir. Although the northern Gulf in general, particularly in the prospect areas, is laced with faults (running generally east-west, parallel to the coast), the Gulf is considered a "tectonically relaxed area." Tectonically-induced stress is small, and usually released at a slow, even rate across the basin.

Because of this stability, the chances of seismic activity as a result of development of geopressed resources in Louisiana are small.⁷

Measurement and Estimation of Subsidence

As noted above, the apparent absence of subsidence related to deep production of oil and gas may be the result of a paucity of field data. The recommendation by the Institute for Environmental Studies in its Plan for the Long Term Environmental Assessment of Geopressed Resource Development in the Louisiana Gulf Coast Region is that attempts be made to monitor possible subsidence by high precision levelling on an annual basis tied to the existing inland and tidal benchmarks, as well as with tiltmeters in selected areas.

In this process, natural subsidence must be removed from the estimation. Attributed to its macroscopic components, natural subsidence across south Louisiana has been calculated as:

- 1) Due to eustatic sea level rise (0.32'/century),
- 2) Due to basement sinking (0.07'/century),
- 3) Compaction of Pleistocene sediments (0.39'/century)

for a total of 0.78'/century. This is an average rate across the Gulf Coast of Louisiana and is subject to substantial variation as the regions grade from the relatively stable western portion of the coast to the southeastern area around the "birdfoot" delta, where subsidence is greatest. Further refinement will be necessary to eliminate the possible effects of local, man-made subsidence due to the production of ground water or oil and gas from shallower formations in the area bounded by the same fault system. In the case of the prospect areas, all except Sweet Lake have producing oil and gas formations wholly or partially within them.

Estimation of the degree of reservoir compaction and the extent to which that will be communicated to the surface in the absence of a full evidentiary record of deep brine production is a speculative proposition. The formula for estimation relied upon by the Texas group was developed by Geertsma. This formula applies to a reservoir being produced through a single well. Other assumptions are that:

- 1) the reservoir is disc shaped,
- 2) there is a uniform reduction in pressure throughout the reservoir,
- 3) deformation is homogeneous with respect to the reservoir and its surroundings.

The Geertsma formula¹³ is:

$$u_z(r,0) = -2 c_m (1 - v) \Delta_p H A(\rho, \eta)$$

where: u_z = vertical displacement, z = vertical coordinate
 r = radius from the vertical axis through the nucleus
 c_m = uniaxial compaction coefficient
 v = Poisson's ratio
 Δ_p = pore (reservoir) pressure reduction
 H = height of the production interval
 $A = R \int_0^\infty J_0(\alpha R) J_0(\alpha r) e^{-D\alpha} d\alpha$ for ranges of values ρ and η
 $\rho = r/R$
 $\eta = D/R$
 R = reservoir radius
 D = depth of burial

and
$$c_m = \frac{1}{3} \frac{(1 + v)}{(1 - v)} (1 - \beta) c_b$$

where: c_m = uniaxial compaction coefficient
 v = Poisson's ratio
 c_r = rock matrix compressibility
 c_b = rock bulk compressibility
 $\beta = c_r/c_b$

With the assumptions placed on the equation, it is of only the broadest indicative value when confronted with the realities of irregularly shaped reservoirs, where pressure reduction is very unlikely to be uniform (especially in the case of field development involving more than one well), and deformation will probably not be homogeneous. Additionally,

the presence of shale beds within and surrounding the producing formation may further offset the calculation. It should be noted though, that shales at these depths will not compact to nearly the same degree that sands will.

Calculations for a test well in Louisiana using this method yielded the results in Table 2:⁷

TABLE 2

Reservoir Radius (miles)	Estimated Pressure Decline (psi)	Estimated Subsidence (inches)
For 20,000 bbl/day Production for 3 years		
2	354	3.16
4	88	1.24
6	39	1.70
For 40,000 bbl/day Production for 3 years		
2	709	16.08
4	177	2.49
6	78	3.43

In the estimation associated with 40,000 bbl/day production from one well, the extent of subsidence would be sufficient to inundate much of the affected area.

It is clear from the results of the estimation that using the Geertsma formula would have a dramatic effect on the feasibility of development. The problem of accuracy in the prediction of subsidence was demonstrated in the case of the Wilmington oil field in California, where subsidence prediction models were unsuccessful until the field had subsided almost thirty feet, 65-70% of its probable ultimate subsidence.¹³ As a result of findings like this, it is estimated that models associated with subsidence from geopressured production would be good if they came within 100% of the actual vertical drop at the surface. The real difficulty

is that the 16.08" estimation may be 100% too high, but it may also be 100% too low.

In summation, it is the uncertainty of potentially substantial environmental effects that is the most distinguishing characteristic of the subsidence problem. Second would be the extreme difficulty of mitigating these effects. The analogs which do exist for prediction (production from shallow formations) are poor, because the greatest mitigating factor (depth) is of an entirely different magnitude. Reliance on the absence of evidence of subsidence attendant to deep production of oil and gas is bad because of the scant attention paid in the past to the collection of field data, and the fact that much of the area in which deep production has occurred was already under water or marsh, thus obscuring the effects. Clearly, production experience on a small scale will be required to forecast with any accuracy the response to production of an entire field.

References

1. Adams, R. D., et al., Barataria Basin: Geologic Processes and Framework. (Baton Rouge, La.: Center for Wetland Resources, Louisiana State University, 1976)
2. Donaldson, E. C., "Subsurface disposal of brines from geopressured reservoirs." Unpublished typescript. U.S. Department of Energy, Bartlesville Energy Technology Center, 1979.
3. Dunrud, R. C., and F. W. Osterwald, Effects of Coal Mine Subsidence in Western Powder River Basin, Wyoming. U.S. Geological Survey, Open-File Report 78-473, 1978.
4. Earth Science Associates, "Chocolate Bayou." (Draft). An unpublished typescript forwarded under letter from John E. Noble (Lawrence Berkeley Laboratory) to Ralph W. Pike (LSU) dated October 31, 1978.
5. Hahn, W. F., and R. E. Smith, "Programmatic and technical aspects of subsurface brine disposal: experiences of the Strategic Petroleum Reserve (SPR)." Unpublished typescript, 1979.
6. Institute for Environmental Studies, A Plan for the Long Term Environmental Assessment of Geopressured Resources in the Louisiana Gulf Coast Region. (Baton Rouge, La.: Institute for Environmental Studies, Louisiana State University, 1978)
7. Institute for Environmental Studies, A Preliminary Environmental Assessment of Selected Geopressured Geothermal Prospect Areas: Louisiana Gulf Coast Region. Vols. I and II. (Baton Rouge, La.: Institute for Environmental Studies, Louisiana State University, 1978)

8. Kharaka, Y. K., P. M. Brown, and W. W. Carothers, "Chemistry of waters in the geopressed zone from coastal Louisiana--implications of geothermal development." Geothermal Resources Council, Transactions, Vol. 2 (July 1978), pp. 371-374.
9. Kharaka, Y. K., P. M. Brown, and M. S. Lico, "Corrosion and scale formation properties of geopressed geothermal brines from the northern Gulf of Mexico basin." Society of Petroleum Engineers of AIME, International Symposium on Oilfield and Geothermal Chemistry, SPE 7866. Houston, Texas, January 22-24, 1979, pp. 55-60.
10. Kharaka, Y. K., E. Callender, and R. H. Wallace, "Geochemistry of geopressed geothermal waters from the Frio Clay in the Gulf Coast region of Texas." Geology, Vol. 5 (April 1977), pp. 241-244.
11. Lofgren, B. E., Background Studies for Appraising Subsidence in Texas Gulf Coast Region. U.S. Geological Survey, Open-File Report 77-412, 1977.
12. Phillips, S. L., T. A. Fair, F. B. Henderson III, and S. R. Schwartz, Review of Geothermal Subsidence. (Berkeley, Cal.: Lawrence Berkeley Laboratory, University of California, 1975)
13. White, W. A., M. McGraw, and T. C. Gustavson, Environmental Analysis of Geopressed-Geothermal Prospect Areas, Brazoria and Kenedy Counties, Texas. (Austin, Tex.: Bureau of Economic Geology, University of Texas at Austin, 1978)
14. Wintz, W. A., Jr., R. G. Kazmann, and C. G. Smith, Jr., Subsidence and Ground-Water Offtake in the Baton Rouge Area. Bulletin 6. (Baton Rouge, La.: Louisiana Water Resources Research Institute, Louisiana State University, 1970)
15. U.S. Department of Energy and Comision Federal de Electricidad. Mexican-American Cooperative Program at the Cerro Prieto Geothermal Field. (Springfield, Va.: National Technical Information Service, 1977)

I. SUMMARY OF THE SOCIO-ECONOMIC IMPACTS
OF GEOPRESSURED-GEOTHERMAL ENERGY
DEVELOPMENT IN COASTAL LOUISIANA

The major goal of the socio-economic impact portion of the overall project was to provide an overview of the potential social, demographic, and economic impacts to the six Louisiana parishes containing the proposed geopressured-geothermal sites. Those factors which determine the impact of such development may be grouped into two broad categories--"site-specific factors" (social, demographic and economic characteristics of the area surrounding the site), and "technology-specific factors" (basically, the scale of the facility). For a full treatment of the material, see Appendix 8, of which the following is a summary.

A variety of different indicators for representing the socio-economic environment of the host areas were selected. These were grouped into five basic categories. These were labeled (representative variables follow each label in parentheses): population size and composition (population size, population density, percent of population urban); labor force characteristics (total unemployed, percent of labor force black); economic characteristics (per capita income, percent of families below poverty level); educational characteristics (percent completing high school, median years school completed); and health services (per capita hospital beds and physicians). The parish was selected as the unit of analysis and data were assembled for a baseline profile for each of the six parishes.

Examination of these baseline data profiles for the six parishes revealed fairly consistent similarities. All parishes except one were below the state averages in population density and percent urban population, and all had lower proportions of black residents. Too, all but one parish (Calcasieu) had lower unemployment rates and lower educational attainment levels than the average for the entire state. Further, most parishes were

below state levels in terms of poverty and median incomes. Finally, medical facilities were also less adequate than those in the remainder of the state. The two parishes which were most inconsistent with this pattern were Calcasieu, which contains the Lake Charles Standard Metropolitan Statistical Area, and Cameron, clearly the most rural of the group.

An analysis of the possible range of development for the geopressured-geothermal energy resource for the site parishes resulted in the construction of two development scenarios. Two major influences guided this phase of the operation: the technology of geopressured-geothermal energy development considered generally, and a realistic assessment of potential levels of development based upon the resources at the particular site in question. The first of these scenarios (our "minimum" model) consisted of a single well with two disposal wells and a gas separation plant. The second model (the "maximum") simply expanded the first operation to include ten wells with twenty disposal wells. For each, estimates of the timetable of development and levels of manpower were derived. These were then used to estimate both the short-term impact and the long-term impact of each level of development on the host areas.

For the level of development specified in the "minimum" model for the geopressured-geothermal resource, both the short-term and the long-term impacts on the host areas will be minimal. The highest level of employment for this model will be only about 40 and this level will be maintained for only a short period of time. In the short term, then, the only influences will be some additional employment opportunities and perhaps some additional demand for housing and other goods and services. For the long term, these effects will be even further circumscribed since the operational phase of the resource development will involve far fewer employees.

A look at the "maximum" alternative reveals two differences between it and the "minimum" development scenario. Not only is the magnitude of the "maximum" model greater (as measured by the number of additional jobs generated--an average of 75 as compared to 40 workers), but it also occurs over a much longer period of time (14-16 months as compared to 6 months in the "minimum" case). Given the fact that the resource capacities of the host areas are the same in both cases, it should be expected that the impacts will be greater so long as the magnitude of the "technology-specific" influences is greater. So, for the short term at least, far greater impacts

on the host areas are anticipated for the "maximum" development alternative. However, after the construction phase of this alternative has been completed, impacts will be similar in nature to those postulated for the "minimum" model since the operational phases of the two models have similar parameters.

In summary, our analysis of the impacts of two possible scenarios of development for the geopressured-geothermal energy resource on six sites in coastal Louisiana revealed that, for the long term, these influences will be small for both the alternatives. For the short term, particularly for the "maximum" model in the smaller, more rural parishes (particularly Cameron Parish), the impacts are likely to be greater. These, however, will lessen over time.

IV

CONCLUSIONS AND RECOMMENDATIONS

The major findings of the systems analysis project and recommendations for future work on geopressured resources are summarized in this section. For clarity, the conclusions and recommendations are grouped under subheadings which identify the subject area.

Resource Assessment

Conclusions

- The site specific assessments which have been completed by Bernard and those soon to be completed by Bassiouni provide an excellent basis for a priori evaluation of typical Louisiana high-potential prospects, subject to the acknowledged uncertainties which exist. The use of Monte Carlo methods in future analyses of these prospects should help to determine in a quantitative manner the probabilities associated with the calculated rates of return.
- The regional assessments which are being performed by Bebout et al. will provide a comprehensive base for evaluation of the entire Louisiana geopressured resource potential.
- The test well program and the Wells of Opportunity program will provide the best source of "hard" data on specific prospects to confirm the validity of studies made based on resource assessments alone.

Recommendations

- The work which has been done to develop subroutine SOLUTE for predicting methane contents of saturated brines should be continued and expanded. The correlating technique which was developed should

be applied to all available data, including the most recent results of Blount et al. and that currently under way by Prausnitz et al. This will provide the best possible method for computing methane content for saturated brines over as wide a range of the independent variables as possible.

- The "hard" data collected from test well draw-down studies should be analyzed using the reservoir simulator of Intercomp, Inc., Houston, Texas, for which a DOE contract has been awarded. The simulator should also be used before the well testing takes place to predict expected behavior of the test well based on a priori estimated parameters, and thereby evaluate critically the proposed draw-down schedule.

Commercial Viability of High-Potential Louisiana Prospects

Conclusions

- Analyses of these prospects based on methane recovery alone have shown that the essential requirements for a commercially attractive venture, a 15% rate of return after taxes, are: a reservoir volume of at least one cubic mile of contiguous sandstone, and a methane recovery of at least 26 scf/bbl of brine.
- Only two of the six prospects studied met the methane recovery requirement of 26 scf/bbl, whereas all six met the contiguous reservoir requirement. The four prospects which are predicted to provide less than 26 scf/bbl yielded an average return of approximately 11.5%.
- There is, however, substantial uncertainty connected with both the predicted contiguous reservoir volume and the methane recovery from the geopressured brines. It appears likely that some reservoirs will not be completely contiguous because of as yet undetected minor faults. The prediction of the salinity of a reservoir and the calculation of the methane content based upon assuming a saturated solution are both subject to substantial uncertainty.
- Should the price growth rate of methane in the future be 9-10% per year instead of the forecast 6.5% used in these base studies, the rate of return on all the prospects studied would exceed 15%.

- When a geopressured resource venture is viewed as an option to be considered after an oil or gas well has failed to produce, preliminary economics for the incremental (piggy-back) venture are substantially more attractive than for the stand-alone geopressured venture. A rate of return of 15% or better was indicated for all the prospects studied (see Appendix 2).

Recommendations

- The site-specific analyses should be continued, using additional high-potential prospects recently reported by Bassiouni et al.
- The Monte Carlo option for the technoeconomic model should be completed and applied to all prospects for which resource assessments are complete. The results of these analyses will provide information about the probabilities associated with the rates of return for each prospect.
- Once the regional resource assessment work is completed (Bebout et al.), the technoeconomic model, including the Monte Carlo option, should be used to assess the commercial viability of the total resource in order to provide a comprehensive evaluation of the Louisiana geopressured resource.
- For specific situations of interest to industry, such as for a sugar refinery or some other process industry which utilizes low level heat energy, site-specific evaluations should be made with the technoeconomic model which include recovery of the heat energy as well as the methane content of the brine.
- Whenever each test well is completed and reservoir performance tests are made which determine more specifically the reservoir parameters, the technoeconomic model should be used to compute commercial viability for each test well reservoir. Such evaluations will provide the most accurate analyses which can be made for specific prospects.
- Additional studies of imaginative alternative ventures, such as the piggy-back and the surface disposal cases, should be pursued in an effort to identify all the various situations in which the geopressured resource can be a commercially viable venture.

The Potential for Commercial Development
in Louisiana

Conclusions

- Ignoring the uncertainties, and considering the case where only methane is recovered from a geopressured well, it appears that a satisfactory rate of return, i.e., 15%, is achievable from a stand-alone geopressured well drilled in an identified high-potential prospect area. There is no indication, however, that this return would be extremely attractive, e.g., above 40%, unless there is an unforeseen escalation of methane prices.
- Of the uncertainties which are associated with geopressured ventures, several are crucial, namely: reservoir continuity, sandstone permeability, and methane recoverability. Qualitatively, the combined risk is at least as high as the finding risk in oil and gas exploration. Since the return on a successful oil and gas well is much higher than that of a geopressured well, industry will continue to prefer oil and gas exploration ventures until the uncertainties of the geopressured ventures are reduced, presumably by the test well results.

Recommendations

- In view of the vital role the test well program must play in reducing the crucial uncertainties which are a barrier to commercial development of the geopressured resource in Louisiana, the systems analysis project should place emphasis on evaluation of the test well results and interpretation and extrapolation of their significance with respect to confirming or denying the potential commercial viability of the resource.

Alternate Technology

Recommendations

- Work should be initiated to develop a better understanding of the various alternate surface systems which could be employed to extract methane from the brine, to recover the thermal energy for site-specific process use, to recover the thermal energy for electrical

generation, and to utilize the pressure energy to reinject the brine. A good bit of work has already been reported by various investigators in each of these areas, but it is important that site-specific analyses be made which incorporate these alternate technologies when appropriate to a particular location, so that the commercial viability of a specific prospect can be evaluated under circumstances which are most favorable to its development.

Legal and Institutional Analysis

Conclusions

- The uncertainty as to the ownership of the resource is not a major problem in Louisiana.
- Preparation of geopressured-geothermal leases will require careful draftsmanship. Existing models from conventional oil and gas development are likely to be highly deficient for leasing of the geopressured-geothermal resource.
- A critical impediment to leasing of the resource may arise if either the lessor or lessee believes conventional oil and gas deposits may exist under the land under consideration for geopressured-geothermal leasing and if the economics of the geopressured-geothermal resource will not permit payment of cash bonuses and rentals and/or royalties commensurate with those suitable for oil and gas development.

Recommendations

- There is no need for further analysis and research into the legal and institutional aspects of the geopressured-geothermal resource development at this time.
- As soon as new information becomes available (as a result of the Wells of Opportunity program and the test well drilling program) which substantially reduces the uncertainties connected with the key elements necessary for successful private exploitation of the resource, renewed study of the legal and institutional problems, in particular the preparation of geopressured-geothermal leases, is recommended.

- Meanwhile, results from current activity authorized by DOE regarding the drafting of geopressured test well leases should be used as a bellwether to forecast whether the concerns which have been presented here regarding the possible difficulties of developing geopressured-geothermal leases are indeed valid.

Subsurface Disposal

Conclusions

- Both the necessary technology and appropriate underground formations for disposal are considered to be available and adequate for successful subsurface reinjection.
- The probability of a catastrophic occurrence, such as undesirable fluid migration, well plugging, or induced seismicity, is considered to be low enough to present no a priori deterrent to geopressured resource development.
- The crucial issue, which will be resolved only by actual well experience, is whether the costs of disposal prove to be excessive as a result of operational problems caused by scaling, corrosion, fluid incompatibilities, etc.

Recommendations

- The uncertainties associated with the costs of large-scale disposal from geopressured sites and with potential catastrophic problems make it important in early wells to monitor earth movement, test for fluid incompatibilities, conduct site-specific studies of the aquifer characteristics, and in general evaluate critically the disposal operation and its costs.
- In order to anticipate fluid incompatibility problems, fundamental research is needed, both experimental and theoretical, in water chemistry and chemical equilibria of geopressured brines.

Socio-Economic Impacts

Conclusions

- Based on analyses of six prospect areas at both a minimum and a maximum level of anticipated geopressed resource development, long-range impacts are estimated to be minimal.
- For the short term, however, the impact of the maximum level of development in a small parish such as Cameron will be somewhat greater than minimal, but it will lessen over time.

Recommendations

- There is no need for further socio-economic impact analysis at this time. Should the estimates of the magnitudes of the minimum and maximum levels of development activity change, a revision of the analyses may be indicated.

APPENDIX 1

A DESCRIPTION OF THE TECHNOECONOMICAL MODEL USED TO ANALYZE THE DEVELOPMENT POTENTIAL OF LOUISIANA GEOPRESSURED ENERGY PROSPECTS

By:

Fred M. Wrighton
Office of Advanced Studies and Research
Louisiana State University

Adrain E. Johnson, Jr.
Department of Chemical Engineering
Louisiana State University

Thomas G. Ray
Department of Industrial Engineering
Louisiana State University

A paper presented at The Fourth United States Gulf
Coast Geopressured/Geothermal Energy Conference:
Research and Development, at Austin, Texas

October 31, 1979

INTRODUCTION

The Geopressure/Geothermal Technoeconomic Site Simulation Model (GPPROG) is designed to achieve the objective of providing a comprehensive set of parameters and economic data that will allow the scientific and economic analysts to evaluate the commercial viability of a specific site. By using averages of key technical and economic parameters it will be possible to provide estimates of total economic resource recovery available in Louisiana. A simulator model cannot be detailed from its inception but can be comprehensive. The comprehensive character has been included throughout its development by the liberal application of abstraction. As the O. R. project has progressed, more and more of the abstraction has been replaced with real world detailed algorithms. This has been accomplished, as will be seen, by a modular development of the model with each module existing initially as an abstraction with form and substance added through time with the detailed analysis of the task of the module.

In addition to refining the model in terms of the detail included in each of the subroutines, the model has also undergone an evolutionary process in terms of analytical flexibility. Use of the model over the year has led to the identification of several solution options useful to the analyst. The initial objective was to solve for the net present value of the investment and operation of the development, with other economic parameters as given. The next logical stage was to incorporate an interactive procedure to solve for the internal rate of return that produced a

net present value of zero. Four other solution options have been added that use zero net present value as the solution criteria. The other values that can be solved for are 1) the vector of the price of methane; 2) the tax rate; 3) minimum methane solubility; and 4) the minimum area of the reservoir. With all of the existing options there are 192 different ways to simulate a given prospect. Obviously, some combinations of the options are more relevant than others so that the set of different runs of use in our analysis is much smaller than the potential.

In this author's view, the best way to familiarize someone with a simulation model is to begin with the basic assumptions and parameters inherent in the model. It is then easy to move to an explanation of the technical structure of the model and some typical execution flow charts.

ECONOMIC ASSUMPTIONS

The basic framework of analysis is a single well development consisting of one producing well, two disposal wells and a separation plant. The specifics of the facility are described in the cost assumptions. The planning horizon of our analysis is the period 1985 to the year 2004, 20 years. Since all of the cost estimates used have their origin in pre-1979 interviews and literature, an inflation adjustment is used to bring the figures to a 1985 basis. The inflation adjustment for investment was accomplished using a weighted value of two components of the GNP Price Deflator - 1) Fixed Investment, Nonresidential, Structures; and 2) Fixed Investment, Nonresidential, Equipment. The weights were ninety percent for equipment and ten percent for structures. All forecasted values were obtained from the most recent long term standard forecast prepared by

Chase Econometrics, Inc. The GNP Implicit Price Deflator was used to adjust operating costs. The investment cost estimates that follow will be given in both the original dated estimate and the 1985 value.

Drilling Costs

Drilling costs are based on "A Study of Phase 'O' Plan for the Production of Electric Power from U. S. Gulf Coast Geopressured Geothermal Waters," by the DOW Chemical Company, found in Proceedings: Second Geopressured Geothermal Energy Conference; Volume IV, Surface Technology and Resource Utilization - Center for Energy Studies, The University of Texas at Austin (1976).

One Source Well	\$ 1,925,000
7" Bore @ 16,000"	

Two Disposal Wells	<u>1,200,000</u>
7" Bore @ 6,000"	\$ 3,125,000

This 1976 estimate has been price adjusted to a 1985 value of \$5,934,375.

Plant Costs

Plant costs were obtained from the same source as the drilling costs and represent a gas-water separation plant that does not include the process of separating the liquids from the gas. It is assumed that separation of the liquids would take place in a central facility operated by the company that buys the methane. The plant configuration and cost is as follows:

First Stage Separator (2000 PSI)	\$ 95,000
Second Stage Separator (300 PSI)	6,000
Third Stage Separator (150 PSI)	5,000
Disposal Pumps (Two - 30x300 PSIA Head)	135,000
Collection Piping	73,000
Disposal Piping	<u>195,000</u>
Total:	\$ 509,000

This 1976 value was price adjusted to a 1985 value of \$966,591.

Depreciation

The term of depreciation is assumed to be ten years for the total investment. This is based on the presumption that Internal Revenue regulations will change before 1985 in industry's favor. As for the drilling investment, two-thirds is expensed in the first year and one-third is depreciated. Four standard methods of depreciation are optional in the model but typically it is assumed that one of the accelerated methods will be used. Scrap value of the investment is assumed to be 20% of the initial investment.

Working Capital

Working capital presents a cash drain in any operation to the extent that it increases. For the purposes of this simulation working capital is defined as current assets minus current liabilities. Since it would entail considerable effort to prepare detailed financial statements to generate figures for working capital, it was decided to estimate it using an industry average. The financial condition of domestic interstate natural gas pipeline companies for the year 1977 was obtained from Statistics of Interstate Natural Gas Pipeline Companies - 1977, U. S. Department of Energy, Energy Information Administration, Office of Energy Data, Washington, D. C., December 1978. Working capital for all classes A and B pipelines for December 31, 1977 was \$843 million. Operation and maintenance expenses for the year ended December 31, 1977 was \$17,596 million. The ratio of working capital to operation and maintenance expenses is .048. Working capital in the model is computed as 4.8% of operating and maintenance expenses each year. The increase in working capital each year is

a negative cash flow and at project termination the accumulated working capital represents a cash return.

Taxes

Income taxes are levied both by the federal government and the State of Louisiana. Federal income taxes are computed against net profit at 20% on the first \$25,000; 22% on income between \$25,000 and \$50,000; and 46% on income exceeding \$50,000. Corporate income tax in Louisiana is levied against federally defined taxable income at 4% of income to \$25,000; 5% on income between \$25,000 and \$49,999; 6% on income of \$50,000 to \$99,999; 7% on income of \$100,000 to \$199,999; and 8% on income exceeding \$200,000. State severance taxes are calculated at 7¢ per MCF on all methane gas that is produced. Depletion allowance in this analysis is treated as an accounting adjustment affecting taxes and is not reflected in the before taxes profit. The production of natural gas from geopressured brines constitutes an exception to the repeal of the oil depletion allowance passed in 1975. Ten percent of gross income is allowed for depletion with the limitation that the deduction may not exceed 65% of taxable income. The excess which is disallowed for one tax year because of the limitation is carried over to following years.

A standard investment tax credit of 10% against the tax liability is provided for in the model for all depreciable investment. The credit is not allowed to exceed the tax liability. Any excess is carried forward to the legal limit of seven years. There is a special investment tax credit of an additional 10% allowed for investments made in "alternative energy property" which includes that equipment which is used to exploit geopressured and geothermal resources. To be eligible for this credit,

construction must be initiated before December 31, 1982. Since this model covers the period 1985-2004, this additional credit was not included.

Operating Costs

Operating costs are incorporated in the model in three categories - 1) general operation and maintenance costs; 2) well operating and maintenance costs; and 3) power costs for reinjection. The basis for the operating costs estimates is a separation plant with a processing capacity under normal conditions of 40,000 barrels of water daily. The costs are on a per barrel basis to accomodate variable levels of production. General operation and maintenance costs and well operating and maintenance costs were obtained from Enhanced Recovery of Unconventional Gas, Vol. 2 Chapter six, V. A. Kuuskraa, et al., (NTIS, 1978). The well operating costs were downgraded slightly to take account of the fact that Kuuskraa's plant configuration included four reinjection wells, while this model uses two. Power costs were derived from a theoretical calculation of the horsepower required to drive the pumps for reinjection. This was then converted to electric power requirements. Current electric prices then provided a cost estimate for reinjection of 40,000 barreld of water daily. These operating costs then are as follows:

General Operation and Maintenance	\$.015/Barrel
Well Operation and Maintenance	.0082/Barrel
Power Costs	.008/Barrel

These costs are all in 1978 dollars and are price adjusted over the life of the project using the GNP price deflator. The forecasted values of this index are from a Chase Econometrics long-term forecast with a linear regression used to extrapolate beyond the forecast horizon.

Prices

Perhaps the most important of all assumptions is the anticipated pattern of gas prices in future. The nature of the objectives of the systems analysis requires that the problem be coped with and it is in several ways as will be seen later in this paper. There is a scarcity, if not an absolute void, of forecasts that are industry based. Company forecasts are considered private so again as in other cases we turned to an econometric forecast. The forecast available extended ten years into the future and the balance of the project term was estimated with a linear regression. In lieu of specifying the entire price vector, I will provide the end points. The assumed price in 1985 is \$6.17/MCF and rises over the twenty-year period to a value in the vicinity of \$20.MCF.

Royalty Payments

Royalty payments to the lessor are assumed to be 8% of the gas produced. Although this is below current oil and gas royalties, we feel that the nature of the operation would allow a value of this level to be negotiated.

STRUCTURE OF THE MODEL

The Techno-economic model consists of a main program and twenty-eight subroutines and functions. The main program in this case can be considered an executive program since its execution determines the subroutine call schedule for any particular run. The analyst must specify a number of decision parameters prior to execution or the model will use default values or values retained in the data set from previous execution. Certain of these parameters must be established for any execution. For example, the simulation must either be Monte Carlo or deterministic, the discount rate must be established and the type of depreciation schedule must be selected. Then the problem type must be established, the options being to 1) solve for the rate of return; 2) find the discounted net present value; 3) solve for the minimum methane in solution; 4) solve for the minimum size of the reservoir in area; 5) solve for the price of methane; or 6) solve for the tax rate. In all the cases, with the exception of solving for minimum methane solubility, the analyst must either specify methane content or elect to solve for methane content within the model. If the price is solved for as a critical value, then the user must select from four options of how to create a price vector. These options are 1) adjust the existing forecast price vector; 2) estimate a linear function between price and time; 3) estimate a compound interest function between price and time or 4) solve for a constant or average price. If the tax rate is the critical value sought, then the user must choose among adjusting 1) the federal income tax; 2) the State income tax; or 3) the severance tax. Once a set of options is selected then a hypothetical site or one of the Louisiana prospects is

then used for the base geologic data base.

Figure 1 contains a list of the subroutines and functions that comprise the models classified as to whether they are engineering, statistical and Input/Output, or economic. Most of the subroutines perform the function that their name implies. Some explanation is warranted, however, especially among those classified as engineering.

RESERV is the heart of the model since pressure levels and flow rates are computed by that subroutine using theoretical equations for a bounded circular aquifer. PROCES determines the gas volumes that are associated with the flow volumes determined by RESERV. VISC is a function that computes the viscosity of the fluid for utilization as an input in RESERV. SOLUTE and all the remaining engineering functions are used to compute the methane in solution in the brine. The MAIN program has already been described and MONTE is a statistical subroutine that accepts as input a triangular distribution of a variable and outputs a random value from the distribution. ITERAT, as its name implies, is a statistical subroutine that iterates the solution variable to identify the critical value. OUTPUT defines the format for printing the results of the simulation. Without enumerating the economic subroutines they compute, given the results of the engineering subroutines, the investment, revenue, costs, depreciation, taxes, investment tax credits, working capital and finally, the discounted cash flow of the development. The total model requires 1225 source statements and about seven cpu seconds for execution. The lengthy execution time can be attributed to the fact that the reservoir subroutine models the performance of the reservoir on a daily basis.

Figure 2 illustrates the subroutine call schedule for computing the

net present value of a site. The flow is clear in that control moves from MAIN to the engineering subroutines, then to the specification of the required investment. The discounting subroutine requires the output of CSHFLW which computes current dollar cash flow for each year using the components of the standard cash flow equation generated by the balance of the economic subroutines. The call schedule for solving for critical values shown in Figure 3 is identical with the previous one, with the inclusion of ITERAT between DISC and OUTPUT. The call schedule for a Monte Carlo simulation shown in Figure 4 places subroutine MONTE after MAIN to convert the input values to randomly generated values from the appropriate distribution.

The techno-economic model then takes geologic input data such as area, thickness, depth, porosity, permeability and compressibility, couples it with a basic set of economic assumptions and produces detailed technical and economic characteristics of a specific site. These details include flow rates, pressures, temperatures, gas production, revenues, operating costs and the components of the cash flow equation for each year. Then depending on the option selected, a critical value may or may not be reported.

APPENDIX 2

A REPORT OF THE ECONOMIC ANALYSES COMPLETED TO DATE OF THE MOST PROMISING GEOPRESSURED ENERGY PROSPECTS IN LOUISIANA

By:

Adrain E. Johnson, Jr.
Department of Chemical Engineering
Louisiana State University

Fred M. Wrighton
Office of Advanced Studies and Research
Louisiana State University

Thomas G. Ray
Department of Industrial Engineering
Louisiana State University

A paper presented at The Fourth United States Gulf
Coast Geopressured/Geothermal Energy Conference:
Research and Development, at Austin, Texas

October 31, 1979

I. Introduction

The results reported in this paper are a series of site-specific economic case studies which were performed for the five high potential geopressured prospect areas in south Louisiana identified in Bill Bernard's 1979 report.¹ The objective of these studies was to evaluate these prospects from a potential business investor's point of view, using net present value (NPV) and discounted cash flow rate of return (DCFRR) criteria applied to each prospect. Each case study was a complete run, using the techno-economic model described in the paper by F. M. Wrighton and A. E. Johnson.² In these runs, the best available estimates of reservoir parameters for each prospect supplied in Bernard's report were used for input data. Later studies are planned in which the evaluations will utilize a Monte Carlo technique, so that uncertainties in input data will be included in the analysis, producing probability distributions instead of single values for the output quantities of each case study.

As was explained in the paper by Wrighton and Johnson, it was intended that these site-specific analyses reflect as closely as possible the expected situation for each site, assuming that a typical commercial venture were to begin in 1985. Accordingly, costs and prices used as input data were adjusted to 1985 and later years using forecasts and GNP price deflator tables from 1978 Chase Econometrics Forecast.³ In recognition, however, that many studies of this type are made using "constant dollar"

costs and prices (ignoring both future inflation and future relative price changes) some site specific studies were also made in which 1979 costs and 1979 prices (held constant into the future) were used. Results from both types of studies are presented in this paper.

II. Input Data Common to All Sites

The economic data used in the studies were common to all prospects; that is, investment costs, operating costs, and methane prices were identical for the different prospects. The 1985 costs and forecasted prices are summarized in Table I. In Table II are the 1979 costs and prices used for the "constant dollar" studies. Note that in both cases the costs include allowance for drilling and operating two disposal wells at 20,000 bbl/day of water flow for each producing well (nominal flow of 40,000 bbl/day).

III. Site-Specific Input Data

The site-specific input data consisted mainly of the parameters which define each reservoir, viz., area, sand thickness, temperature, pressure, permeability, porosity, salinity, etc. These are presented in Table III for each prospect. Note that there were in reality six site-specific prospects, since the Atchafalaya Bay prospect is divided into the Atchafalaya Bay East and West prospects by a major northeast-southwest trending fault.

The general philosophy in assigning reservoir parameters was to use the average values of salinity, permeability, and porosity

recommended for each prospect from Bernard's report. Temperature and pressure values, on the other hand, were those Bernard predicted for the specific test well site he recommended. Wells subsequent to the first well in a prospect may exhibit different temperature and pressure values, but it was not deemed a useful or meaningful exercise to attempt to predict this variation. The remaining parameters, area, sand thickness and compressibility, determine the brine flow pattern which can be produced by a well. A series of runs was made for each prospect in which first the entire prospect area was used, followed by runs using $1/2$, $1/4$, $1/8$, etc. of the total area. As will be explained, this practice established both an upper limit of performance for each prospect and also a minimum contiguous area (volume) required for acceptable performance. The thickness of sand used was the maximum thickness of a single sand zone predicted for the proposed well site. As described by Bernard,¹ "there are no blanket sands, and it is difficult to correlate a given sand member over a large distance;" therefore, this choice of thickness must be considered optimistic, since the thickest sand member is not likely to extend over the entire prospect. However, the procedure followed in which smaller areas were investigated permitted a determination of the minimum area (volume) required for acceptable performance. On the other hand, these results may be conservative as they do not consider the possibility of multiple sand completion (which is speculative at this point) nor do they consider the possibility of completion at a different

(higher) level once the brine flow from the initial sand drops off.

IV Methane Content of Brines

As was explained in the paper by Wrighton and Johnson,² the techno-economic model developed for this work includes a computer subroutine SOLUTE which calculated the dissolved methane in a brine at equilibrium for a given (NaCl) salinity, temperature, and pressure. To write subroutine SOLUTE it was first necessary to develop a thermodynamically sound correlation of the experimental data presented in a paper by O'Sullivan and Smith, 1970.⁴ The data reported in this paper covered ranges of 1500 to 7500 psia, 0 - 233 ppm salt, and 51.5 to 125 Celsius. The correlation reproduces the original data with an accuracy of $\pm 0.5\%$. Because of the sound theoretical basis of the pressure correlation, subroutine SOLUTE can extrapolate the effect of pressure quite accurately up to the geopressured range. Similarly, extrapolation of the salinity effect can also be expected to give good accuracy. Extrapolation of the temperature effect, however, is completely empirical because the required thermodynamic parameters were unavailable; therefore, methane solubilities calculated by subroutine SOLUTE may not be very accurate for temperatures much outside the range of the reported data. Fortunately, the pressures, temperatures, and salinities of the Louisiana geopressured brines studied to date are generally within the ranges in which the subroutine can be expected to

produce accurate solubility predictions. Accordingly, subroutine SOLUTE was used in all studies reported here to calculate the dissolved methane content of the geopressured brines, based on temperatures, pressures, and salinities predicted in Bernard's report.¹ (It is expected that the data reported by Blount⁵ at this conference will be useful for improving the range of applicability of the correlation equation.)

It is important to recognize that subroutine SOLUTE calculates the dissolved methane in a brine at equilibrium with pure free methane at the temperature and pressure of the system. Clearly, this methane content represents an upper limit to that actually contained in the brine, as it does not consider the effect of other gases present, such as CO_2 , nor of other salts in the brine, nor of an under-saturation situation. In all studies reported here it was implicitly assumed that the brine in situ contains this amount of methane before well flow begins. Since for a producing well there is a pressure drop from the reservoir limits to the well bore, the reservoir model in this work considers that the methane content of the brine entering the well bore always corresponds to the pressure at the well bore entrance, not the original reservoir pressure. Thus, the model assumes that free methane is formed as the pressure drops in the brine flowing toward the well bore, and that this free methane does not flow but remains in place. As has been pointed out by Hawkins,⁶ this situation occurs as long as the free methane content is below the 'critical gas saturation point'

(approximately 10 volume per cent for the methane-water system). The reservoir model used here does not allow for any free methane gas flow into the well bore. Free methane gas flow could occur only if the original free gas content of a reservoir were high, or if the pressure in the brine at the well bore were to drop low enough, neither of which was considered likely. Consequently, in each case study reported here, the methane content of the brine entering the well bore drops as well production proceeds because of the decrease in methane solubility due to the drop in pressure of the brine entering the well bore.

V. Case Study Results

For the purpose of analyzing the economic potential of each of the six prospects (considering Atchafalaya Bay East and West as two prospects), the following sequence of case studies were made:

(1) Base Cases

Description:

Initially, base case runs were made for each prospect with the techno-economic computer model, using 1985 as the first major project year and extending twenty years into the future. Each base case assumed a single well was drilled at the proposed test well site; the reservoir section of the model produced a well operations history (based on the input site-specific parameters from Bernard¹); the economic portion

of the model calculated a cash flow history for the well (using the costs and prices predicted from the Chase Econometric Forecast³); the report writer section produced detailed output of both the financial and the physical parameters for the entire life of the project. As already explained, the reservoir area was taken to be the entire area of the prospect for these first base case runs. Since the wells were considered to contain a 5.5-inch tubing and a 9-inch bottom well bore, each well was subjected to a maximum brine flow rate of 40,000 bbl/day and a minimum well-head pressure of 500 psia. Two base cases were run for each prospect, one using 15 percent as the discount rate (cost of capital) and a second using 20 percent. The results of these twelve base case runs are summarized in Table IV.

Analysis

At 15 percent discount rate, the NPV (net present value) entries in Table IV for four of the prospects (Lafourche Crossing, Johnson's Bayou, Atchafalaya Bay East and West) were all significantly negative, ranging from $-\$1.5 \times 10^6$ to $-\$2.2 \times 10^6$. The NPV for the remaining two prospects (Southeast Pecan Island and Rockefeller Refuge) were $\$1.3 \times 10^6$ and $\$3.0 \times 10^6$, respectively. At 20 percent discount rate, NPV for all six prospects were negative, although that of the

Rockefeller Refuge was barely so ($-\$0.16 \times 10^6$).

Overall these base case results are somewhat less than encouraging, as they indicate that four of the six prospects are not acceptable, i.e., they do not provide a 15% return on investment for a single well drilled at the recommended site, assuming a completely contiguous sand of maximum thickness extending over the entire prospect.

These base cases do show that there are definite, significant differences in the profitability potential of the six prospects, which clearly must have been a result of the differences in reservoir performance, since the investments, costs, and prices did not differ from prospect to prospect. Some of these differences can be seen from the entries in Table IV, such as reservoir area, thickness, and volume (the latter ranged from 0.94 cu. mi. for Lafourche Crossing to 13.5 cu. mi. for Johnson's Bayou), and methane gas recovered (ranging from 20.4 cu. ft./bbl for Atchafayala Bay East to 31.4 cu. ft./bbl for Rockefeller Refuge).

(2) Cases to Determine Critical Values of Parameters

Description:

Once the single well base cases were completed and analyzed, a series of runs were made to solve for the critical value of various parameters which would result in a zero NPV value. The parameters chosen for

these runs were: discount rate, percent; methane recovered, std. cu. ft./bbl; methane price adjustment factor, and federal tax adjustment factor. In each of these runs all input data were kept at the values used in the base case runs except the particular parameter whose critical value was determined by the search routine ITERAT included in the techno-economic model package. Actually, as with the base case runs, two sets of runs were made for each prospect, one for a 15% discount rate and one for a 20% discount rate. The 15% discount rate runs are summarized in Table V, and the 20% discount rate runs are summarized in Table VI. (The runs solving for the critical discount rate are included in Table V).

Analysis

The runs solving for the critical discount rate show that the prospects range in profitability from 11.8 percent return on investment for the Lafourche Crossing site to 19.7 percent for Rockefeller Refuge. Note that the four non-acceptable prospects all gave about the same rate of return (11.8-12.5%).

When a critical methane recovery was solved for, it was found that for all prospects except the Lafourche Crossing site, a value of about 25.5-26.0 std. cu. ft. per bbl would result in a 15% rate return, whereas the Lafourche Crossing site required 29.5 std.

cu. ft./bbl.methane to be recovered to provide a 15% rate of return. For achieving a 20% rate of return, the Lafourche Crossing site requires 35.5 SCF/bbl, whereas the other five require 32.4 SCF/bbl.

These results are easily interpreted by recognizing that all of the prospects except Lafourche Crossing resulted in 40,000 bbl/day of brine flow for the entire project life. Since the income generated from methane sales is directly proportional to the product of brine flow and methane content of the brine, and since most operating costs are directly proportional to brine flow, it is clear that for reservoirs which produce at 40,000 bbl/day constant brine rate, the critical value of methane content required for the investment to give a particular rate of return should be approximately the same, in this case 26 SCF/bbl for a 15% rate of return. Since the Lafourche Crossing prospect did not maintain 40,000 bbl/day of brine flow for the life of the project (the average flow was 31,600), the critical methane content required for it to provide a given rate of return was correspondingly higher than that of the other prospects.

The essential differences between the base case results of the six prospects can now be summarized:
Both Rockefeller Refuge and Southeast Pecan Island

delivered 40,000 bbl/day of brine for the life of the project and recovered well in excess of 26 SCF/bbl of methane, so that they both exceeded a 15% rate of return using the projected 1985 costs and prices of the base case. Of the remaining four prospects, all but Lafourche Crossing delivered 40,000 bbl/day of brine flow for the life of the project, but since the methane recovered from the brine (calculated by subroutine SOLUTE) averaged about 21 SCF/bbl, the rate of return achieved was only 12 percent. For Lafourche Crossing, both the brine flow rate and the methane recovered were less than 40,000 bbl/day and 26 SCF/bbl, respectively, resulting in only 11.8 percent rate of return.

Turning to the federal tax rate, the runs in Table V solving for an adjustment factor required to give a 15% rate of return, showed that even a zero federal tax rate would not result in a 15% rate of return for the Atchafalaya Bay East Prospect, and that the other three non-acceptable prospects required substantial tax reductions.

Finally, the runs solving for a methane price growth factor showed that for a 20% rate of return a compounded yearly growth rate of 14-15% is required for the four less attractive prospects, and for a 15% rate of return a compounded yearly growth rate of 9-10% is required. These growth rates, although higher than

the forecasted growth rate of 6.5% are not inconceivable, considering the uncertainties connected with the prediction of future energy costs.

(3) Multiple Well Case Studies (sensitivity to reservoir volume)

Description

The next series of case studies was made to exhibit the effect of using smaller reservoir areas (hence, volumes) than the total fault-bounded areas used in the base case studies. For each prospect, runs were made using 1/2, 1/4, and 1/8 of the original base case areas, leaving all other input parameters constant. These results are summarized in Table VII. These runs may be viewed in two ways: (1) considering the prospects to consist of a contiguous sand throughout, the runs represent the performance of each well in a multiple well field, drilled at approximately the same time; (2) considering the prospects to be subdivided because of minor faults into smaller areas, these runs represent the performance of a single well drilled into a contiguous reservoir within the prospect smaller in area than the area bounded by the major faults of the prospect.

Analysis

The significance of these studies can best be seen

from the graphs plotted in Figures 1 and 2. In Figure 1 the NPV for all six prospects is plotted vs. the volume of the reservoir in cu. mi. All prospects give curves of similar shape, i.e., as the reservoir volume increases from zero, the NPV increases from the initial value of $-\$6,900,966$ (the total investment cost associated with a single well) rapidly at first and then levels off to essentially a constant value at a sufficiently high volume. For a large enough volume, every prospect will produce 40,000 bbl/day for the entire project life, and the well bore pressure will be very close to the original reservoir pressure, thereby providing the maximum methane recoverable for that prospect. The curves for the different prospects level out at positive or negative values corresponding to the maximum methane solubility attained by each prospect, which is governed by the original reservoir pressure, temperature, and salt content. As was pointed out, four of the prospects do not reach a zero NPV because the methane solubility does not reach approximately 26.0/bbl, whereas two prospects level out at positive values because their calculated methane solubility was greater than 26.0 SCF/bbl.

It is interesting that all six curves change from a region of steeply ascending slope to one of moderate to zero slope at about the same reservoir volume, namely

one cu. mi., showing that if a reservoir volume is less than one cu. mi. it is not likely that any prospect with reservoir parameters like these six will be profitable. Since the reservoir parameters of these six prospects did vary considerably from each other, this conclusion seems likely to apply generally for all potential south Louisiana prospects.

In Figure 2, the average brine flow rate for the 20-year life of the prospect is plotted vs. volume of reservoir. In this graph, the data points were close enough together on the scale of the graph to permit plotting only one curve to represent all six prospects. Here we find that the one cu. mi. breakpoint is very sharply defined, as it is the volume required to permit an average of 40,000 bbl/day flow rate for the project life, and average flow rate drops off almost linearly to zero as reservoir volume drops to zero. Clearly, although it is not absolutely necessary that flow rate average 40,000 bbl/day in order for a prospect to be profitable, the rate of decline of flow rate with reservoir volume is so rapid, that for practical purposes, one cu. mi. reservoir volume (leading to 40,000 bbl/day average brine flow rate), is a solid rule-of-thumb requirement for profitability for all six of these prospects.

(4) Constant 1979 Dollar Case Studies

Description

As previously pointed out, most studies of this type have been made with constant dollar prices and operating costs. In Table VIII are the results of constant dollar runs made on the six prospects, using the cost and price schedules from Table II. Using a 1979 price of \$3.50 per MSCF for methane, the base cases are all negative at 15% discount rate on capital, with the four lower potential prospects more negative than the two "better" prospects, Rockefeller Refuge and Southeast Pecan Island. The DCFRR for the four lower potential prospects ranged from 1.16% to 2.45%; for the two better prospects it was 7.07% and 9.38%. Finally, the methane price required for a 15% rate of return was from \$6.17 to \$6.76 for the four lower potential prospects, but was \$4.45 and \$4.96 for the two better prospects. If the only difference between the constant dollar runs and those of the 1985-2004 runs were that a constant inflation rate were applied each year to all cost and prices, then it is clear that the DCFRR would differ by merely the inflation rate. That is, if a constant dollar run showed a DCFRR of 10%, and the inflation rate were 5%, then the corresponding 1985-2004 run would give a DCFRR of 15%.

This is not, however, the only difference in the two sets of runs. Different rates of growth for the various prices and costs can be seen from the information in Tables I and II. Methane prices increase by about 10% yearly from 1979 to 1985, then by about 6.5% through 2004. Other prices do not increase as much; e.g., investment costs increase 7.5% yearly between 1979 and 1985, and general operations costs increase only 4.5% between 1979 and 2004. Thus the 1985-2004 base cases reflect the different growth rates forecast for the various prices and costs, with methane prices rising relatively steeply compared to others in the base case.

Taking this into consideration, we find that the difference in the DCFRR for the 1979 constant dollar runs and those of the 1985-2004 runs is approximately 10% for each prospect study. This is not due, however, solely to inflation, but part of it is due to the forecasted relatively high increase in methane prices compared to the other costs. Therefore, based on these forecasted prices and costs, the profitability of the six prospects will be better for a well drilled in 1985 than it would be for a well drilled in 1979, because of the forecasted higher growth of methane prices compared to other prices and costs.

(5) "Piggy Back" Case Studies

Description

A few case studies were made recently for each prospect, assuming that a geopressured well was developed after first drilling a natural gas well and finding it to be a dry hole. Estimates of the total investment cost required to convert the dry hole gas well into a geopressured well were made, using cost estimates from a proposal by Grury Federal, Inc.⁷ for a well of opportunity. Since the tubing was assumed to be only 3.5 inch diameter, the flow rates were limited to a maximum of 25,000 bbl/day in these runs. The results of these initial "Piggy Back" runs (for a geopressured well drilled only after first finding a dry hole) are presented in Table IX.

Analysis

These runs are only preliminary, as the various cost estimates used need to be refined and discussed with industrial experts before they can be considered valid, but they do point up the possibility that the "piggy back" concept shows promise. All six prospects yielded a DCFRR of approximately 15% or better, even though the maximum flow rate was limited to 25,000 bbl/day. The methane recovered from the worst case, Atchafalaya Bay West, averaged only 20.9 SCF/bbl, so

that the minimum requirements for the "piggy back" concept appear to be less. Additional sensitivity studies will be made in the future to evaluate the concept more rigorously than was done in these preliminary runs.

VI. Conclusions

The more important findings from the case studies reported here are summarized below:

1. Of the six prospects studied, single wells (assumed to be drilled in a contiguous reservoir of area equal to the entire prospect area) meet a 15% discount rate profitability requirement only for the Rockefeller Refuge and Southeast Pecan Island prospects, using prices and costs forecasts for 1985-2004.
2. Sensitivity studies on all six prospects reveal the following requirements for profitability for the 1985-2004 case studies:
 - + Reservoir volumes of one cu. mi. are required for average brine flow to equal 40,000 bbl/day. The steep decline of average brine flow as reservoir volume is decreased below one cu. mi. makes one cu. mi. a minimum requirement for profitability.
 - + At 40,000 bbl/day average brine flow rate, methane recovery must equal 26 SCF/bbl to yield at least a 15% after tax return on the investment.
3. Methane price annual growth rates of 10% (instead of the forecasted 6.5%) would result in all six of the prospects

equalling or exceeding a 15% rate of return for the single well base case.

4. A comparison between 1985-2004 studies and constant dollar 1979 studies shows that each prospect gives a DCFRR for 1985-2004 approximately equal to that for 1979 plus 10%. This is not due merely to the average cost inflation (4.5% year), but is also caused by the higher growth rate forecast for methane prices (6.5% year).
5. A set of preliminary "piggy back" runs to investigate the profitability of converting a dry-hole natural gas well to a geopressured well show that the reduced investment costs chargeable to the geopressured venture can increase the profitability picture substantially, even though such wells might be limited to 25,000 bbl/day brine flow rates.

TABLE I
SUMMARY OF INVESTMENTS AND COSTS
FOR 1985-2004 PROJECT LIFE *

DRILLING COSTS (1985)	\$ 5,934,375	
PLANT COSTS (1985)	966,591	
TOTAL INVESTMENT (1985)	6,900,966	
OPERATING COSTS (PER BARREL)	<u>1985</u>	<u>2004</u>
GENERAL OPERATION AND MAINTENANCE	\$.021	.05
WELL OPERATION AND MAINTENANCE	.011	.027
POWER COST	.011	.027
METHANE PRICE(PER MCF)	\$ 6.17	22.14

* BASED ON 1978 CHASE ECONOMETRIC FORECASTS

TABLE II
SUMMARY OF INVESTMENTS AND COSTS
FOR 1979 "CONSTANT DOLLAR" PROJECT

DRILLING COSTS	\$ 3,834,375
PLANT COSTS	624,523
TOTAL INVESTMENT	4,458,918
OPERATING COSTS (PER BARREL)	
GENERAL OPERATION AND MAINTENANCE	\$.016
WELL OPERATION AND MAINTENANCE	.0089
POWER COST	.0087
METHANE PRICE (PER MCF)	3.50

TABLE III
RESERVOIR PARAMETERS FOR SIX HIGH POTENTIAL
GEOPRESSURED PROSPECTS IN LOUISIANA

<u>Reservoir Parameter</u>	<u>LaFourche Crossing (LFC)</u>	<u>Atchafalaya Bay East (ABE)</u>	<u>Atchafalaya Bay West (ABW)</u>	<u>Johnson's Bayou (JBY)</u>	<u>Rockefeller Refuge (RRF)</u>	<u>Southeast Pecan Island (SPI)</u>
Depth, ft.	17000	14500	14600	13200	17300	17700
Press., psia	14600	11600	11700	11000	14900	14400
Temp., Deg. F.	244	236	209	231	293	271
Salinity, ppm	45	107	107	95	56	70
Thickness, ft.	150	340	400	1550	570	350
Area, acres	21120	35840	57600	29440	49920	42880
Volume, cu. mi.	0.94	6.82	6.82	13.5	8.42	4.44
Permeability, md.	25	95	95	300	80	98
Porosity, vol. fr.	0.94	0.26	0.26	0.31	0.23	0.23
Compressibility	1×10^{-5}	1×10^{-5}	1×10^{-5}	1×10^{-5}	1×10^{-5}	1×10^{-5}

TABLE IV
SUMMARY OF RESULTS OF
BASE CASE RUNS FOR EACH PROSPECT

<u>Parameter or Calculated Result</u>	<u>LaFourche Crossing(LFC)</u>	<u>Atchafalaya Bay East (ABE)</u>	<u>Atchafalaya Bay West (ABW)</u>	<u>Johnson's Bayou (JBY)</u>	<u>Rockefeller Refuge (RFR)</u>	<u>Southeast Pecan Island (SPI)</u>
Area, acres	21120	35840	57600	29440	44920	42880
Sand thickness, ft.	150	340	400	1550	570	350
Volume, cu. mi.	0.94	3.61	6.82	13.5	8.42	4.44
Discount rate, %	15 , 20	15 , 20	15 , 20	15 , 20	15 , 20	15 , 20
Average Brine Flow, Bbl/day	31600	40000	40000	40000	40000	40000
Methane Recovered SCF/Bbl	24.0	20.4	21.1	22.0	31.4	27.9
Methane Recovered MMSCF	5540.3	5951	6161.2	6412.3	9163	8739.6
Brine Recovered, %	3.75	1.19	0.64	0.26	0.58	1.09
NPV, MM\$	-1-1.61 , -3.25	-2.16 , -3.95	-1.51 , -3.74	-1.51 , -3.48	+3.00 , -0.16	+1.33 , -1.32

Table V

SUMMARY OF RESULTS OF CRITICAL PARAMETER RUNS

(using 15% rate of return on capital)

<u>Parameter or Calculated Result</u>	<u>LaFourche Crossing (LFC)</u>				<u>Atchafalaya Bay East (ABE)</u>				<u>Atchafalaya Bay West (ABW)</u>			
Area, acres	21120	21120	21120	21120	35840	35840	35840	35840	57600	57600	57600	57600
Sand thickness, ft.	150	150	150	150	340	340	340	340	400	400	400	400
Volume, cu. mi.	0.94	0.94	0.94	0.94	3.61	3.61	3.61	3.61	6.82	6.82	6.82	6.82
Discount rate, %	11.8**	15.0	15.0	15.0	11.3**	15.0	15.0	15.0	11.9**	15.0	15.0	15.0
Average Brine Flow Bbl/day	31600	31600	31600	31600	40000	40000	40000	40000	40000	40000	40000	40000
Methane Recovered SCF/Bbl	24.0	29.5**	24.0	24.0	20.4	26.0**	20.4	20.4	21.1	26.0**	21.1	21.1
Methane Recovered MM SCF	5540	6817	5540	5540	5951	7595	5951	5951	6161	7592	6161	6161
Brine Recovered, %	3.75	3.75	3.75	3.75	1.19	1.19	1.19	1.19	0.64	0.64	0.64	0.64
NPV, MM\$	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.08	0.0	0.0	0.0	0.0
Methane Price growth rate, %	6.5	6.5	9.8**	6.5	6.5	6.5	10.2**	6.5	6.5	6.5	9.7**	6.5
Federal Tax adjust. factor	1.0	1.0	1.0	0.28**	1.0	1.0	1.0	0.0**	1.0	1.0	1.0	0.18**

** Denotes parameter chosen as critical parameter for this run

Table V (continued)

SUMMARY OF RESULTS OF CRITICAL PARAMETER RUNS

(using 15% rate of return on capital)

<u>Parameter or Calculated Result</u>	<u>Johnson's Bayou (JBY)</u>				<u>Rockefeller Refuge (RRF)</u>				<u>Southeast Pecan Island (SPI)</u>			
Area, acres	29440	29440	29440	29440	49920	49920	49920	49920	42880	42880	42880	42880
Sand thickness, ft.	1550	1550	1550	1550	570	570	570	570	350	350	350	350
Volume, cu.mi.	13.5	13.5	13.5	13.5	8.42	8.42	8.42	8.42	4.44	4.44	4.44	4.44
Discount rate, %	12.5**	15.0	15.0	15.0	19.7**	15.0	15.0	15.0	17.7**	15.0	15.0	15.0
Average Brine Flow Bbl/day	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000
Methane Recovered SCF/Bbl	22.0	26.1**	22.0	22.0	31.4	25.6**	31.4	31.4	27.9	25.3**	27.9	27.9
Methane Recovered MM SCF	6412	7621	6412	6412	9163	8354	9163	9163	8116	7385	8116	8116
Brine Recovered, %	0.26	0.26	0.26	0.26	0.58	0.58	0.58	0.58	1.09	1.09	1.09	1.09
NPV MM\$	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methane Price growth rate, %	6.5	6.5	9.1**	6.5	6.5	6.5	2.9**	6.5	6.5	6.5	4.9**	6.5
Federal Tax adjust. factor	1.0	1.0	1.0	0.39**	1.0	1.0	1.0	1.55**	1.0	1.0	1.0	1.31**

** Denotes parameter chosen as critical parameter for this run

Table VI

SUMMARY OF RESULTS OF CRITICAL PARAMETER RUNS

(using 20% rate of return on capital)

<u>Parameter or Calculated result</u>	<u>LaFourche Crossing (LFC)</u>			<u>Atchafalaya Bay East (ABE)</u>			<u>Atchafalaya Bay West (ABW)</u>		
Area, acres	21120	21120	21120	35840	35840	35840	57600	57600	57600
Sand thickness, ft.	150	150	150	340	340	340	400	400	400
Volume, cu. mi.	0.94	0.94	0.94	3.61	3.61	3.61	6.82	6.82	6.82
Discount rate, %	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Average Brine Flow Bbl/day	31600	31600	31600	40000	40000	40000	40000	40000	40000
Methane recovered SCF/Bbl	35.5**	24.0	24.0	32.4**	20.4	20.4	32.4**	21.1	21.1
Methane recovered MM SCF	8193	5540	5540	9466	5951	5951	9466	6161	6161
Brine recovered, %	3.75	3.75	3.75	1.19	1.19	1.19	0.64	0.64	0.64
NPV, MM\$	0.0	0.0	-1.89	0.0	0.0	-2.78	0.0	0.0	-2.46
Methane price comp. int. growth rate, %	6.5	14.8**	6.5	6.5	15.2**	6.5	6.5	12.5**	6.5
Federal tax adj. factor	1.0	1.0	0.0**	1.0	1.0	0.0**	1.0	1.0	0.0**

**** Denotes parameter chosen to be critical parameter on this run**

Table VI (continued)

SUMMARY OF RESULTS OF CRITICAL PARAMETER RUNS

(using 20% rate of return on capital)

<u>Parameter or Calculated result</u>	<u>Johnson's Bayou (JBY)</u>			<u>Rockefeller Refuge (RRF)</u>			<u>Southeast Pecan Island (SPI)</u>		
Area, acres	29440	29440	29440	49930	49920	49920	42880	42880	42880
Sand thickness, ft.	1550	1550	1550	570	570	570	350	350	350
Volume, cu.mi.	13.5	13.5	13.5	8.42	8.42	8.42	4.44	4.44	4.44
Discount rate, %	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Average Brine Flow Bbl/day	40000	40000	40000	40000	40000	40000	40000	40000	40000
Methane Recovered SCF/Bbl	32.4**	22.0	22.0	32.2**	31.4	31.4	32.4**	27.9	27.9
Methane Recovered MM SCF	9466	6412	6412	9388	9163	9163	9467	8155	8155
Brine recovered, %	0.26	0.26	0.26	0.58	0.58	0.58	1.09	1.09	1.09
NPV, MM\$	0.0	0.0	-2.06	0.0	0.0	0.0	0.0	0.0	0.0
Methane Price comp. int. growth rate, %	6.5	14.1**	6.5	6.5	7.3**	6.5	6.5	9.5**	6.5
Federal Tax adj. factor	1.0	1.0	0.0**	1.0	1.0	0.95**	1.0	1.0	0.49**

** Denotes parameter chosen to be critical parameter on this run

Table VII**SUMMARY OF RESULTS FOR MULTIPLE WELL CASES**

Parameter or Calculated Result	LFC			ABE			ABW		
Area, acres	10560	5280	2640	17920	8960	4480	28800	14400	7200
Sand thickness, ft.	150	150	150	340	340	340	400	400	400
Volume, cu. mi.	0.47	0.23	0.12	1.80	0.90	0.45	3.41	1.70	0.85
Discount rate %	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Average Brine Flow Bbl/day	23400	13900	7100	40000	36990	20300	40000	40000	36400
Methane Recovered SCF/BB1	23.4	22.9	22.6	19.7	18.3	17.0	20.7	20.0	18.5
Methane Recovered MM SCF	4001	2320	1175	5738	4942	2529	6044	5828	4008
Brine Recovered, %	5.57	6.59	6.77	2.37	4.39	4.83	1.26	2.51	4.57
NPV MM\$	-3.06	-4.92	-7.31	-2.40	-3.05	-4.90	-1.99	-2.23	-2.95

Table VII**SUMMARY OF RESULTS FOR MULTIPLE WELL CASES (continued)**

<u>Parameter of Calculated Result</u>	<u>JBY</u>				<u>RRF</u>				<u>SPI</u>		
Area, acres	14720	7360	3680	1840	24960	12480	6240	3120	21440	10720	5360
Sand thickness, ft.	1550	1550	1550	1550	570	570	570	570	350	350	350
Volume, cu. mi.	6.75	3.38	1.69	0.84	4.21	2.11	1.05	0.53	2.22	1.11	0.56
Discount rate, %	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Average Brine Flow Bbl/day	40000	40000	40000	39900	40000	40000	40000	40000	40000	40000	25582
Methane Recovered SCF/Bbl	21.8	20.8	20.1	19.3	30.8	29.6	27.6	24.7	27.0	25.3	22.9
Methane Recovered MM SCF	6360	6068	6050	5622	8988	8655	8643	5649	7884	7316	4278
Brine Recovered, %	0.53	1.05	2.11	4.20	1.16	2.30	4.60	6.91	2.18	4.36	6.23
NPV, MM\$	-1.56	-1.68	-1.91	-2.36	+2.80	+2.43	+1.74	-0.35	+1.03	+0.49	-1.44

Table VIII

SUMMARY OF RESULTS FOR RUNS BASED ON CONSTANT 1979 DOLLARS

<u>Parameter or Calculated result</u>	<u>LaFourche Crossing (LFC)</u>			<u>Atchafalaya Bay East (ABE)</u>			<u>Atchafalaya Bay West (ABW)</u>		
Area, acres	21120	21120	21120	35840	35840	35840	57600	57600	57600
Sand thickness, ft.	150	150	150	340	340	340	400	400	400
Volume, cu.mi.	0.94	0.94	0.94	3.61	3.61	3.61	6.82	6.82	6.82
Discount rate, %	15.0	1.58**	15.0	15.0	1.16**	15.0	15.0	1.78**	15.0
Average Brine Flow Bbl/day	31600	31600	31600	40000	40000	40000	40000	40000	40000
Methane recovered SCF/Bbl	24.0	24.0	24.0	20.4	20.4	20.4	21.1	21.1	21.1
Methane recovered MM SCF	5540	5540	5540	5951	5951	5951	6161	6161	6161
Brine recovered, %	3.75	3.75	3.75	1.19	1.19	1.19	0.64	0.64	0.64
NPV, MM\$	-3.15	0.0	0.0	-3.72	0.0	0.0	-3.59	0.0	0.0
Methane Constant Dollar Price	3.50	3.50	6.17**	3.50	3.50	6.76**	3.50	3.50	6.58**

** Denotes parameter chosen as critical parameter

Table VIII (continued)

SUMMARY OF RESULTS OF RUNS BASED ON CONSTANT 1979 DOLLARS

<u>Parameter or Calculated result</u>	<u>Johnson's Bayou (JBY)</u>			<u>Rockefeller Refuge (RRF)</u>			<u>Southeast Pecan Island (SPI)</u>		
Area, acres	29440	29440	29440	49920	49920	49920	42880	42880	42880
Sand thickness, ft.	1550	1550	1550	570	570	570	350	350	350
Volume, cu. mi.	13.5	13.5	13.5	8.42	8.42	8.42	4.44	4.44	4.44
Discount rate, %	15.0	2.45**	15.0	15.0	9.33**	15.0	15.0	7.07**	15.0
Average Brine Flow Bbl/day	40000	40000	40000	40000	40000	40000	40000	40000	40000
Methane recovered SCF/Bbl	22.0	22.0	22.0	31.4	31.4	31.4	27.9	27.9	27.9
Methane recovered MM SCF	6412	6412	6412	9163	9163	9163	8155	8155	8155
Brine recovered, %	0.26	0.26	0.26	0.58	0.58	0.58	1.09	1.09	1.09
NPV, MM\$	-3.42	0.0	0.0	-1.53	0.0	0.0	-2.13	0.0	0.0
Methane Constant Dollar Price	3.50	3.50	6.36**	3.50	3.50	4.45**	3.50	3.50	4.95**

** Denotes parameter chosen as critical parameter

TABLE IX
SUMMARY OF RESULTS OF RUNS BASED ON "PIGGY BACK" CONCEPT

Parameters or Calculated result	Lafourche Crossing		Atchafalaya Bay East (ABE)		Atchafalaya Bay West (ABW)		Johnson's Payou (JRY)		Rockefeller Refuge (RRF)		Southeast Pecan Is. (SP)	
Area, acres	21120	21120	35840	35840	57600	57600	29440	29440	49920	49920	42880	42880
Sand thickness, ft.	150	150	150	150	340	340	1550	1550	570	570	350	350
Volumes, cu. mi.	.094	.094	3.61	3.61	6.82	6.82	13.5	13.5	8.42	8.42	4.44	4.44
Discount rate, %	15.0	20.0**	15.0	14.9**	15.0	14.7**	15.0	15.3**	15.0	24.6**	15.0	21.6**
Average Brine Flow, bbl/day	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000
Methane recovered SCF/bbl	26.1	26.1	21.5	21.5	20.9	20.9	22.1	22.1	32.0	32.0	28.9	28.9
Methane recovered MM SCF	4756	4756	3922	3922	3818	3818	4024	4024	5829	5829	5230	5230
Brine recovered, %	3.00	3.00	0.39	0.39	0.74	0.74	0.17	0.17	0.36	0.36	0.68	0.68
NPV MM\$	+1.42	0.0	-0.04	0.0	-0.19	0.0	+0.10	0.0	+2.99	0.0	1.95	0.0

** Denotes parameter chosen as critical parameter.

Figure 1

EFFECT OF RESERVOIR SIZE ON NPV OF SINGLE WELL(using 15% rate of return on capital)

Figure 2

EFFECT OF RESERVOIR SIZE ON AVERAGE BRINE FLOW RATE

REFERENCES

1. Bernard, W. J., "Evaluation of Five Potential Geopressure-Geothermal Test Sites in Southern Louisiana," prepared for D.O.E., Contract No. EY-76-S-05-4889, June 1979.
2. Wrighton, F. M., and Johnson, A. E., Jr., "A Description of the Techo-Economic Model Used to Analyze the Development of Potential of Louisiana Geopressured Energy Prospects," Proceedings: Fourth United States Gulf Coast Geopressured-Geothermal Energy Conference: Research and Development, October 29-31, 1979, published by Center for Energy Studies, University of Texas at Austin.
3. Chase Econometric Associates, Inc., Macroeconomic Forecasts, 1978, published by Chase Econometric Associates, Inc., 1 Chase Manhattan Plaza, New York, New York 10015.
4. O'Sullivan, Thomas D., and Smith, Norman O., "The Solubility and Partial Molar Volume of Nitrogen and Methane in Water and in Aqueous Sodium Chloride from 50 to 125° and 100 to 600 Atm," The Journal of Physical Chemistry 1970, pp. 1460-1466.
5. Blount, Charles W., "Methane Solubility in Aqueous NaCl Solutions at Elevated Temperatures and Pressures," Proceedings: Fourth United States Gulf Coast Geopressured-Geothermal Energy Conference: Research and Development, October 29-31, 1979, published by Center for Energy Studies, University of Texas at Austin.
6. Hawkins, Murray F., and Craft, B. C., Applied Petroleum Reservoir Engineering, Prentice-Hall, Inc., Englewood Cliffs, New Jersey, 1959.
7. Grury Federal, Inc., Proposal to Department of Energy to complete No. 1 Tenneco Fee "N," July 1979.

APPENDIX 3

THE CORRELATION OF METHANE-BRINE SOLUBILITY DATA

By:

Adrain E. Johnson, Jr.
Department of Chemical Engineering
Louisiana State University

A paper presented at the Engineering Foundation
Conference on Geopressured-Geothermal Energy at
Sea Island, Georgia

January 1980

THE CORRELATION OF METHANE-BRINE SOLUBILITY DATA

I. INTRODUCTION

In planning the development of the LSU techno-economic computer model for use in site-specific analyses of geopressed prospects, it was decided that it was essential that the package include a subprogram which would compute the maximum (saturated) amount of methane which can be dissolved in a brine solution, given the salinity of the brine and its temperature and pressure. This subprogram (later named SOLUTE) is used in the techno-economic model to calculate the methane content of a brine entering a well bore and the methane content of the depressured, cooled brine leaving the surface separators. The methane recovered per barrel of brine is then calculated from the difference.

To develop subroutine SOLUTE clearly what was required was a correlation of available experimental data on methane solubility in brine solutions at various temperatures and pressures. Such a correlation will be of maximum utility if it is based as much as possible upon equations developed from fundamental thermodynamic vapor-liquid equilibrium relationships rather than upon an empirical equation relating the three independent variables to methane solubility. The use of fundamental equations for correlating experimental data insures that (1) the best possible fit of the data is obtained (using the fewest parameters), (2) physically meaningful parameters are determined (which often can be checked for accuracy and consistency by independent analysis), and (3) extrapolation beyond the range of the experimental data can be expected generally to give good results. In this paper the equations used in this analysis are developed, and the results of correlating some published literature data using these equations are presented.

II. DEVELOPMENT OF EQUATIONS AND METHODOLOGY

A. Fundamental equations

The starting point for development of vapor-liquid equilibria equations is the statement that for each component in a system, the liquid phase fugacity must equal the vapor phase fugacity at equilibrium:

$$(f_i^V)_{T,P} = (f_i^L)_{T,P} \quad (1)$$

The standard expressions for vapor phase and liquid phase component fugacities are:

JOHNSON, Adrain E., Jr., Professor, Department of Chemical Engineering,
Louisiana State University, Baton Rouge, Louisiana 70803

A. E. Johnson, Jr.

$$(f_i^V)_{T,P} = (\phi_i)_{y_i,T,P} y_i P \quad (2)$$

$$\text{and } (f_i^L)_{T,P} = (\gamma_i)_{x_i,T,P} x_i (f_i^0)_{T,P} \quad (3)$$

where $(\phi_i)_{y_i,T,P}$ is the fugacity coefficient of component i in the vapor phase at mol fraction y_i and the T and P of the system

$(\gamma_i)_{x_i,T,P}$ is the activity coefficient of component i in the liquid phase at mol fraction x_i and at the T and P of the system

$(f_i^0)_{T,P}$ is the fugacity of component i at its reference state. (Clearly the numerical value of γ_i depends upon the reference state chosen for component i .)

The usual reference state chosen for a component is the fugacity of the pure liquid component at the temperature and pressure of the system.

However, when the component of interest is a gas (i.e., T is much larger than T_c , the critical temperature of the component,) there is no physical meaning to this reference state, and it is convenient to choose the infinite dilution condition as the reference state.

$$(f_i^0)_{T,P} = (f_i^\infty, \text{solvent})_{T,P} \quad (4)$$

Substitution into equation (1) of equations (2), (3) and (4) results in:

$$(\phi_i)_{y_i,T,P} y_i P = (\gamma_i^*)_{x_i,T,P} x_i (f_i^\infty, \text{solvent})_{T,P} \quad (5)$$

where $(\gamma_i^*)_{x_i,T,P}$ is the activity coefficient of component i when the reference state is chosen as the infinite dilution condition. (The value of γ_i^* becomes 1.0 as x_i approaches zero.)

For sparingly soluble gases, such as the methane-brine system, the activity coefficient of the methane in solution is constant over the relatively narrow range of gas solubility encountered, so that Henry's law constant can be employed.:

$$(\gamma_i^*)_{x_i,T,P} (f_i^\infty, \text{solvent})_{T,P} = (H_i)_{T,P} \quad (6)$$

substitution into equation (5) gives

$$(f_i^V)_{T,P} y_i = (\phi_i)_{y_i,T,P} y_i P = (H_i)_{T,P} x_i \quad (7)$$

From equation (7), we see that the usual vapor-liquid equilibrium data collected for the methane-brine system (x_i , T, P , salinity) can be used to calculate Henry's law constant for each data point:

$$\frac{(f_i^V)}{x_i} \bigg|_{T,P,Y_i} = \frac{(\phi_i^V)_{T,P,Y_i} P}{x_i} = (H_i)_{T,P, \text{salinity}} \quad (8)$$

Equation (8) provides a fundamental basis for correlating the experimental data. Assuming that ϕ_i^V and y_i can be calculated for the methane in the vapor phase, then a value of $(H_i)_{T,P, \text{salinity}}$ can be calculated for each experimental data point. (Calculation of ϕ_i^V and y_i will be discussed in a later section.) These experimentally determined Henry's law constants can be correlated as described in the following sections to provide an equation for predicting Henry's law constant for a given temperature, pressure and salinity, with which the methane solubility, x_i , can be predicted from equation (8).

B. Effect of pressure on Henry's law constant

The effect of pressure on Henry's law constant has been shown to be:

$$\frac{\partial \ln (H_i)_{T,P}}{\partial P} = \frac{(\bar{v}_i^\infty)_{T,P}}{RT} \quad (9)$$

where $(\bar{v}_i^\infty)_{T,P}$ is the partial molar volume of the gas (methane) in the solvent i (brine) at infinite dilution. Integration of equation (9) between the limits of zero and P gives

$$(H_i)_{T,P} = (H_i^0)_T e^{\frac{1}{RT} \int_0^P (\bar{v}_i^\infty)_{T,P} dP} \quad (10)$$

where $(H_i^0)_T$ is the value of Henry's law constant at zero pressure.

It is reasonable to consider that $(\bar{v}_i^\infty)_{T,P}$ varies linearly with pressure over the range of interest:

$$(\bar{v}_i^\infty)_{T,P} = (b_i)_T + (2c_i)_T P \quad (11)$$

Substitution in to equation (10) and integrating gives

$$(H_i)_{T,P} = (H_i^0)_T e^{\left[\frac{1}{RT} (b_i)_T P + (c_i)_T P^2 \right]} \quad (12)$$

or

$$\begin{aligned} \ln (H_i)_{T,P} &= \ln (f_i^V/x_i)_{T,P} \\ &= (a_i)_T + \frac{1}{RT} \left[(b_i)_T P + (c_i)_T P^2 \right] \quad (13) \end{aligned}$$

where $(a_i)_T = \ln (H_i^0)_T$, Henry's law constant for methane in a brine solution at zero pressure and at temperature T

$(b_i)_T =$ partial molar volume of methane in a brine at infinite dilution, at zero pressure, and at temperature T

$(c_i)_T =$ coefficient for linear pressure dependence of partial molar volume of methane in a brine at infinite dilution and temperature T.

Equation (13) can be used as the basis for correlating constant temperature and constant salinity methane solubility data. The value of f_i^V for methane can be calculated, as shown later, with an accurate equation of state for methane-water mixtures, then the quantity $\ln (f_i^V/x_i)_T, P, Y_i$ plotted vs. P, and the values of $a_i, b_i,$ and c_i determined from a statistical regression of the data. Since b_i and c_i are parameters which correlate partial molar volume of the methane at infinite dilution with total pressure, the results can be evaluated for consistent behavior and compared with expected values determined from independent sources. Once the parameters have been determined they can be used to predict values of methane solubility at any desired pressure by substitution into equation (13) and solving for x_i . Since equation (13) accounts only for the effect of pressure, additional terms must be developed to include the effect of temperature and salinity.

C. Effect of Temperature on Henry's Law Constant

It has been shown² that the effect of temperature on Henry's law constant is given by:

$$\frac{\partial [\ln (H_i)_T, P]}{\partial [1/T]} = \frac{\Delta \bar{h}_i}{R} \quad (14)$$

Where $\Delta \bar{h}_i$ is the partial molar enthalpy change of solution of the methane in the brine. This relationship is not quite as useful as equation (9) for the effect of pressure because less is known in general about the behavior of $\Delta \bar{h}_i$, for comparison purposes. One approach, however, is to consider the variation of parameters a, b, and c from equation (13) as a function of temperature. It seems reasonable that both b and c should exhibit monotonic behavior and that both are likely to be only slightly sensitive to temperature, (unless T approaches T_c of the water). Parameter a ($\ln H_i^0$), however, should also obey equation (14) above. Experimentally, methane solubilities have been found to pass through a minimum with temperature³. Accordingly, parameter a ($\ln H_i^0$) can be expected to pass through a maximum, but parameters b and c are expected to behave monotonically with only slight sensitivity to temperature.

In order for parameter a to pass through a maximum, clearly $\Delta \bar{h}_i$ must pass through zero at the temperature at which the maximum occurs and must have a positive slope vs T (negative slope vs $1/T$). If we assume a simple linear relationship with temperature for $\Delta \bar{h}_i$ ($\Delta \bar{h}_i = a_T' + a_T'' T$) and for parameters b and c , the following relationship results for correlating the data for a specific brine with both temperature and pressure:

$$\begin{aligned} \frac{\ln (f_i^V)_{T,P}}{x_i} &= \ln (H_i)_{T,P} \\ &= a_0 + \frac{a_T'}{R} \left(\frac{1}{T} - \frac{1}{T_0} \right) - \frac{a_T''}{R} \ln \left(\frac{T}{T_0} \right) + \frac{1}{RT} [b_0 + b_T' (T - T_0)]P \\ &\quad + \frac{1}{RT} [c_0 + c_T' (T - T_0)] P^2 \end{aligned} \quad (15)$$

Where a_0 , b_0 , and c_0 , are the values of a , b , and c at a reference temperature T_0 and a_T' , a_T'' , b_T' , and c_T' are parameters which express the temperature dependency of the parameters a , b , and c .

D. Effect of Brine Salinity on Henry's Law Constant

Equation (15) relates the Henry's law constant of methane dissolved in a brine of a specific salinity with the variables T and P . To account for the effect of the salt content of the brine upon the methane solubility, there is no derived thermodynamic relationship equivalent to equation (9) for the pressure effect or equation (14) for the temperature effect. Instead, a semi-empirical relationship has been used by researchers for correlating solubility data for systems containing dissolved salts⁵. This relationship utilizes a "salting-out" coefficient:

$$(x_i)_{T,P,m} = (x_i^0)_{T,P} 10^{\bar{m}(k)}_{T,m} \quad (16)$$

where $(x_i^0)_{T,P}$ = solubility (mol fraction) of methane in pure water at the stated temperature and pressure

$(x_i)_{T,P,m}$ = solubility of methane in a brine (NaCl) solution of molality m at the stated temperature and pressure

m = molality of the brine solution (g moles / 1000 g water)

$(k)_{T,m}$ = salting out coefficient of methane in brine solutions. (For most systems k is found to

be slightly dependent upon $\bar{T}$, less dependent upon m , and independent of P .)

From equation (8), we see that the solubility of the methane is determined by two quantities, $(H_i)_{T,P,m}$ and $(f_i^V)_{T,P,y_i}$. It is clear that the salting-out coefficient defined in equation (16) actually is a correction to the value of Henry's law constant, $(H_i)_{T,P,m}$, to account for the change in the activity of the methane in the liquid phase due to the presence of the salt. In those cases in which the water content of the vapor mixture is quite small the value of (f_i^V) , the fugacity of methane in the vapor, does not change when salt is added to the liquid phase, so that equation (16) holds true. When, however, the temperature is high and the total pressure is low, the water content of the vapor will be substantial, and equation (16) should be replaced by the more correct equation:

$$(H_i)_{T,P,m} = (H_i^0)_{T,P} 10^{-m(k)}_{T,m} \quad (16a)$$

or

$$\ln (H_i)_{T,P,m} = \ln (H_i^0)_{T,P} - 2.3026m(k)_{T,m} \quad (16b)$$

Since k is expected to be only slightly dependent upon T and m , a linear relationship is suggested, which results in the following equation for k :

$$(k)_{T,m} = k_0 + k_m m + (k_T + k_{T,m})(T - T_0) \quad (17)$$

where k_0 = salting-out coefficient at reference temperature T_0 extrapolated to zero salt content.

k_m = parameter for linear effect of salt molality on salting-out coefficient

k_T = parameter for linear effect of temperature on salting-out coefficient

$k_{T,m}$ = parameter for interactive effect of temperature and salt molality on salting-out coefficient.

E. Recommended Correlation Equation:

Equations (16b) and (17) can be combined with equation (15) to give the following equation for correlating Henry's law constant for methane in pure water and brine solutions:

$$\begin{aligned}
 \ln(H_i)_{T,P,m} = \frac{(f_i^V)_{T,P}}{x_i} = & a_0 + \frac{a'_T}{R} \left(\frac{1}{T} - \frac{1}{T_0} \right) - \frac{a''_T}{R} \ln \left(\frac{T}{T_0} \right) \\
 & + \frac{1}{RT} [(b_0 + b'_T(T-T_0))P + (c_0 + c'_T(T-T_0))P^2] \\
 & + 2.3026 m [k_0 + k_m m + (k_T + k_{T,m} m)(T-T_0)]
 \end{aligned}
 \tag{18}$$

This equation contains a total of eleven parameters to be determined from the experimental data, but because it is based as much as possible on fundamental thermodynamic relationships involving parameters which are physically meaningful, it should be capable of correlating data over wide ranges of the independent variables with good accuracy. Were a completely empirical, statistical correlation used instead, it would probably require more parameters for equivalent accuracy and would be unlikely to provide good extrapolation effectiveness. It is useful to remember that the terms in equation (18) involving the 'a' parameters correlate the Henry's law constant for methane in pure water at zero pressure with temperature, the terms involving the 'b' and 'c' parameters correct the Henry's law constant to pressure P by integration of the partial molal volume of methane in pure water, and the terms involving the 'k' parameters correct the Henry's law constant for the presence of salt in solution by means of the salting-out coefficient. One important characteristic of equation (18) is that data for only the methane-pure water system are used to determine the 'a' 'b' and 'c' parameters, whereas data for methane-brine systems are used to determine the 'k' parameters.

F. Calculation of the Vapor Phase Fugacity of the Methane

The methane dissolved in a brine solution can be predicted by using equation (18) to calculate the value of Henry's law constant for the methane-brine system, then substituting into equation (8) and solving for x_i , the mol fraction methane in the brine:

$$(x_i)_{T,P,m} = \frac{(H_i)_{T,P,m}}{(f_i^V)_{T,P,y_i}} \tag{19}$$

Clearly, to do this it is necessary to calculate f_i^V , the fugacity of the methane in the vapor in equilibrium with the brine. It is also necessary to calculate f_i^V when equation (8) is used to calculate experimental Henry's law constants from methane solubility data. The procedure for this calculation is described in this section.

To calculate the fugacity of the methane in the vapor, it is necessary to evaluate y_i and ϕ_i , the mol fraction methane in the vapor and its fugacity coefficient. In the most general case, this means simultaneously solving the vapor-liquid equilibrium relationships for both methane and water. However, an important simplifying assumption can be made which permits decoupling the computation of y_{H_2O} and y_{CH_4} .

for the methane-brine system: the mol fraction of methane in the liquid phase is, in fact, very small, (much less than 0.01), so that in calculating the liquid phase fugacity of water, the effect of the methane upon both the activity coefficient and the mol fraction of the water can be neglected. The simplified vapor-liquid equilibrium equation for water becomes:

$$(f_{H_2O}^V)_{T,P,y} = (f_{H_2O}^L)_{T,P,m} \quad (20)$$

or

$$(\phi_{H_2O})_{T,P,y} y_{H_2O} P = x_{H_2O} (f_{H_2O}^0)_{T,P}$$

where

x_{H_2O} = mol fraction of water in the brine
(neglecting any methane dissolved in the brine)

$(f_{H_2O}^0)_{T,P}$ = fugacity of pure water at the temperature and pressure of the system, atm

P = total Pressure, atm

y_{H_2O} = mol fraction water in the vapor phase

$(\phi_{H_2O})_{T,P,y}$ = fugacity coefficient of water in the vapor phase

Solving equation (20) for y_{H_2O} and making the usual substitutions for $f_{H_2O}^0$ gives:

$$y_{H_2O} = \frac{x_{H_2O} (\phi_{H_2O}^S)_T P_{H_2O}^S (\phi_{H_2O})_{T,P}}{(\phi_{H_2O})_{T,P,y} P} \quad (21)$$

where

$(\phi_{H_2O}^S)_T$ = fugacity coefficient for saturated pure water vapor at temperature T

$(P_{H_2O}^S)_T$ = vapor pressure of pure water at temperature T , atm

$(\phi_{H_2O})_{T,P}$ = Poynting correction factor for pure water to correct its fugacity from saturation pressure to pressure P at temperature T

$$= e^{\left[\frac{1}{RT} v_{H_2O}^L (P - P_{H_2O}^S) \right]}$$

$$(\phi_{\text{H}_2\text{O}})_{T,P,y} = \text{fugacity coefficient for water vapor in methane mixture of composition } y_{\text{H}_2\text{O}} \text{ at temperature } T \text{ and } P$$

Examination of equation (21) shows that with $x_{\text{H}_2\text{O}}$ known, the remaining three terms in the numerator can be calculated using an equation for pure water vapor pressure, and equations of state for pure water liquid and vapor phases. The fugacity coefficient in the denominator can be calculated from an equation of state for water-methane vapor mixtures, but an iterative procedure is necessary, since $y_{\text{H}_2\text{O}}$ is required to calculate $\phi_{\text{H}_2\text{O}}$.

Only $y_{\text{H}_2\text{O}}$ is calculated from equation (21); y_{CH_4} is evaluated simply as $y_{\text{H}_2\text{O}} (1 - y_{\text{H}_2\text{O}})$, and $(\phi_i)_{T,P,y}$, the fugacity coefficient of the methane in the vapor phase, can be calculated using the same equation of state for water-methane vapor mixtures which was used to compute the fugacity coefficient of the water in the vapor phase. Finally, the fugacity of the methane in the vapor phase is calculated by:

$$(f_i^v)_{T,P,y} = (\phi_i)_{T,P,y} y_i P \quad (22)$$

This calculated fugacity can be used either in equation (19) to predict the methane dissolved in the liquid phase, or in equation (8) to calculate the experimental Henry's law constant from actual solubility data.

III APPLICATION TO THE DATA OF O'SULLIVAN AND SMITH

At the time the foregoing analysis was developed, it was decided to apply the procedures and methodology to the data reported by O'Sullivan and Smith⁴ first. These data appear to be very consistent over the range of the variables studied, and O'Sullivan and Smith had used a procedure for data analysis similar to but less comprehensive than that recommended here. After testing the correlation procedure with the O'Sullivan and Smith data, then all published data would be evaluated next in order to assimilate together in one correlation all data whose parameters prove to be consistent in behavior and compatible with physical parameters determined from independent sources.

Accordingly, in this paper only the data of O'Sullivan and Smith have been analyzed. Other published data will be analyzed and reported on in the future. For this initial analysis the following choices were made for physical properties; The Redlich-Kwong equation of state for mixtures⁵ was used for computing vapor phase fugacities for methane and water; Antoine's equation⁶ was used for computing water vapor pressures; for calculating the Poynting factor for water, the molar volume was taken as 18 cc/g-mol and the fugacity coefficient of the saturated water vapor was taken as 1.0. These choices were deemed accurate enough because the temperature and pressure ranges of the data were such that the value of $y_{\text{H}_2\text{O}}$ was always quite small, so that y_i , the mol fraction methane in the vapor phase, was almost 1.0 and

insensitive to the relative accuracy of y_{H_2O} . Also, the Redlich-Kwong equation provides very good accuracy for the computation of ϕ_i , the fugacity coefficient of methane, as long as there is little water vapor present in the mixture. (It is planned to replace all of the above-mentioned approximations with more accurate computational procedures in the future.)

The original data of O'Sullivan and Smith are reproduced in Table 1 along with the computed $\ln$ of Henry's law constant (parameter a) for each data point. The results of correlating Henry's law constant are summarized in a series of graphs. In Figures 1 - 3 $\ln$ of Henry's law constant is plotted vs. pressure for the methane-pure water system at the three temperatures investigated by O'Sullivan and Smith. On each graph the equations which correlate the data are given, with the associated parameter values indicated. In Figure 4, the $\ln$ of Henry's law constant extrapolated to zero pressure for the methane-pure water system is plotted vs. temperature, with the correlating equation and the associated parameter values indicated. In Figure 5 parameter 'b', the partial molar volume of methane in pure water at infinite dilution and zero pressure, is plotted vs. temperature, with the correlating equation and the associated parameter values indicated. In Figure 6 parameter 'c' is plotted vs. temperature, with the correlating equation and the associated parameter values indicated.

From this set of figures it can be seen that, in general, the expected relationships were found to hold true for the methane-pure water system. From Figure 4 it is seen that parameter a ($\ln(H_i^0)$) passed through a maximum in this temperature range. By fitting the three points to the recommended form, equation (14), a value of 27.2 cal/mol-K was determined for the slope of the partial molar heat of solution ($\Delta\bar{h}_i$) of methane vs. temperature, and a temperature of 361.5 K (88.5 C) was found to be the point at which the maximum value of $\ln(H_i^0)$ was reached (the temperature at which $\Delta\bar{h}_i$ equals zero). For convenience, this temperature was chosen as the reference temperature T^0 for parameters a , b , and c in the final correlating equation. From Figure 5, the effect of temperature on parameter b , the partial molar volume of methane, was found to be linear, giving a value of 49.9 cc/g-mol at the chosen reference temperature of 88.5 C and a slope of 0.3414 cc/g-mol-K. The positive slope with temperature was expected, but its magnitude seems large. The partial molar volume varied from 37.28 to 62.37 cc/g-mol over the temperature range of the data (51.5 C to 125 C). As pointed out by O'Sullivan and Smith⁴, values of 40.0 to 41.4 cc/g-mol have been reported by others in this temperature range, which is qualitative agreement with these results.

From Figure 6, the effect of temperature upon parameter c (which expresses the pressure dependence of the partial molar volume of the methane) is also found to be approximately linear within the range of these data. The value of c becomes increasingly negative at higher temperatures. This behavior is qualitatively reasonable, although there are no independent data available for comparison. The salting-out coefficients calculated for the two brines at each of the three temperatures are given in Table 2. As was pointed out by O'Sullivan and Smith⁴, the individual salting-out coefficients exhibited

TABLE I
EXPERIMENTAL SOLUBILITY DATA AND COMPUTED HENRY'S LAW CONSTANTS
FOR METHANE-BRINE SYSTEM
(Data from O'Sullivan and Smith⁴)

T C	NaCl Conc. Molality	P atm	x _i Mol Fraction	y _{H₂O} * Mol Fraction	f _i ^v ** atm	Ln(H _i)*** [parameter 'a']
51.5	0	100	.001427	.002968	88.24	11.03219
51.5	0	200	.002279	.003123	162.9	11.17728
51.5	0	300	.00287	.003582	236.4	11.31910
51.5	0	400	.00334	.003933	316.1	11.45743
51.5	0	500	.00373	.004162	406.1	11.59799
51.5	0	600	.00409	.004300	509.4	11.73248
51.5	1	100	.001076	.002915	88.24	11.31456
51.5	1	200	.001695	.003067	162.9	11.47339
51.5	1	300	.002138	.003518	236.4	11.61360
51.5	1	400	.00250	.003862	316.1	11.74768
51.5	1	500	.00279	.004087	406.1	11.88843
51.5	1	600	.00307	.004223	509.5	12.01942
51.5	4	200	.000805	.002911	163.0	12.21814
51.5	4	300	.000997	.003338	236.5	12.37666
51.5	4	400	.001154	.003665	316.2	12.52093
51.5	4	500	.001303	.003878	406.2	12.65001
51.5	4	600	.001444	.004006	509.6	12.77389
102.5	0	101	.001355	.01891	92.88	11.13526
102.5	0	201	.002205	.01564	178.7	11.30289
102.5	0	302	.00287	.01558	266.0	11.43684
102.5	0	403	.00333	.01588	359.5	11.58936
102.5	0	503	.00385	.01609	461.9	11.69513
102.5	0	604	.00419	.01615	578.5	11.83546
102.5	1	201	.001693	.01536	178.8	11.56739
102.5	1	302	.002219	.01530	266.0	11.69438
102.5	1	403	.00257	.01559	359.6	11.84871
102.5	1	503	.00289	.01579	462.1	11.98223

A.E. Johnson, Jr.

TABLE I
(continued)

T C	NaCl Conc. Molality	P atm	x_i Mol Fraction	$y_{H_2O}^*$ Mol Fraction	f_i^v ** atm	$\ln(H_i)^{***}$ [parameter 'a']
102.5	1	604	.00320	.01585	578.6	12.10530
102.5	4	201	.000826	.01457	178.9	12.28584
102.5	4	302	.001079	.01450	266.3	12.41618
102.5	4	403	.001211	.01477	359.8	12.60197
102.5	4	503	.001319	.01496	462.5	12.76743
102.5	4	604	.001433	.01501	579.1	12.90949
125	0	103	.001434	.03645	94.55	11.09637
125	0	204	.002321	.02838	184.3	11.28214
125	0	305	.00296	.02705	275.4	11.44067
125	0	405	.00343	.02681	371.8	11.59359
125	0	507	.00396	.02667	480.2	11.70577
125	0	608	.00430	.02644	600.4	11.84678
125	1	103	.001058	.03579	94.61	11.40113
125	1	204	.001752	.002786	184.4	11.56390
125	1	305	.002223	.002655	275.5	11.72750
125	1	405	.00260	.002631	372.0	11.87113
125	1	507	.00294	.002616	480.5	12.00408
125	1	608	.00325	.002594	600.7	13.76196
125	4	204	.000825	.02641	184.6	12.31847
125	4	305	.001005	.02515	275.9	12.52274
125	4	405	.001164	.02491	372.5	12.67613
125	4	507	.001322	.02476	481.1	12.80470
125	4	608	.001438	.02454	601.5	12.94396

* computed from equation (21)

** computed from Redlich-Kwong equation of state⁶

*** computed from equation (8)

Figure 1
Henry's Law Constant vs. Pressure
For Methane-Pure Water
at 51.5 C (324.5 K)
 (From Data of O'Sullivan and Smith⁴)

Figure 2
Henry's Law Constant vs. Pressure
For Methane-Pure Water
at 102.5 C (275.5 K)
(From Data of O'Sullivan and Smith⁴)

Figure 3
Henry's Law Constant vs. Pressure
For Methane-Pure Water
at 125 C (398 K)
 (From Data of O'Sullivan and Smith⁴)

Figure 4
Henry's Law Constant at
Zero Pressure vs. Temperature
For Methane-Pure Water
 (From Data of O'Sullivan and Smith⁴)

Figure 5
Parameter b (Partial Molar Volume at
Zero Pressure and Infinite Dilution) vs. Temperature
For Methane-Pure Water
 (From Data of O'Sullivan and Smith⁴)

Figure 6
Parameter c vs. Temperature
For Methane-Pure Water
 (From Data of O'Sullivan and Smith⁴)

TABLE II

SALTING-OUT COEFFICIENTS FOR
METHANE-BRINE SYSTEM *
(from data of O'Sullivan and Smith⁴)

1 Molal NaCl Brine (0.0552 mol fraction)

<u>P, atm.</u>	<u>T=324.5 K (51.5C)</u>	<u>T=375.5 K (102.5C)</u>	<u>T=298 K (125C)</u>
101	0.1226	----	----
201	0.1286	0.1144	0.1224
302	0.1279	0.1118	0.1246
403	0.1258	0.1126	0.1205
503	0.1261	0.1247	0.1296
604	0.1246	0.1172	0.1218
Average over P	0.126	0.114	0.122

4 Molal NaCl Brine (0.1895 mol fraction)

<u>P, atm.</u>	<u>T=324.5 K (51.5C)</u>	<u>T=375.5 K (102.5C)</u>	<u>T=398 K (125.C)</u>
103	----	----	----
204	0.1130	0.1067	0.1125
305	0.1148	0.1063	0.1175
405	0.1154	0.1099	0.1175
507	0.1142	0.1164	0.1193
608	0.1131	0.1166	0.1191
Average over P	0.114	0.112	0.117

*Calculated from equation (16b)

TABLE III

PARAMETERS FOR EQUATION TO CORRELATE
HENRY'S LAW CONSTANT
FOR METHANE-BRINE SYSTEM*

(Determined from Data of O'Sullivan and Smith⁴)

Parameter	Value	
T_0	361.5 K	[for parameters a, b & c]
$a_0 (\text{Ln}H_i^0)$	10.972	
a'_T	-9840 cal/g-mol	
a''_T	+27.22 cal/g-mol-K	
b_0	49.98 cm ³ /g-mol	
b'_T	0.3417 cm ³ /g-mol-K	
c_0	-0.01132 cm ³ /g-mol-atm	
c'_T	-.000306 cm ³ /g-mol-atm-K	
T_{0k}	375.5 K	[for parameter k]
k_0	0.114	
k_m	-.000667	
k_T	-.000255** .000356***	
$k_{T,m}$	.000719** .0000444***	

** For $T < 375.5$ K

*** For $T > 375.5$ K

* The equation is:

$$\begin{aligned} \text{Ln}(H_i)_{T,P,m} = & a_0 + \frac{a'_T}{R} \left(\frac{1}{T} - \frac{1}{T_0} \right) - \frac{a''_T}{R} \text{Ln} \left(\frac{T}{T_0} \right) \\ & + \frac{1}{RT} [(b_0 + b'_T (T - T_0)) P + (c_0 + c'_T (T - T_0)) P^2] \\ & + 2.3026m [k_0 + k_m^m + (k_T + k_{T,m}^m) (T - T_{0k})] \end{aligned}$$

TABLE IV

COMPARISON OF CALCULATED SOLUBILITIES WITH EXPERIMENTAL
DATA POINTS FOR METHANE-BRINE SYSTEM

(From Data of O'Sullivan and Smith⁴)

T K	atm	PURE WATER		1 m NaCl BRINE		4 m NaCl BRINE	
		x_i (Data) mol fr.	x_i (Calc.) mol fr.	x_i (Data) mol fr.	x_i (Calc.) mol fr.	x_i (Data) mol fr.	x_i (Calc.) mol fr.
324.5	100	.001427	.001432	.001076	.001069	---	---
324.5	200	.002279	.002299	.001695	.001716	.000805	.000807
324.5	300	.002870	.002903	.002138	.002167	.000997	.001016
324.5	400	.003340	.003379	.002500	.002522	.001154	.001182
324.5	500	.003730	.003779	.002790	.002821	.001303	.001322
324.5	600	.004090	.004127	.003070	.003081	.001444	.001444
375.5	101	.001355	.001345	---	---	---	---
375.5	201	.002205	.002205	.001693	.001696	.000826	.000786
375.5	302	.002870	.002819	.002219	.002168	.001079	.001004
375.5	403	.003330	.003307	.002570	.002544	.001211	.001179
375.5	503	.003850	.003733	.002890	.002871	.001319	.001331
375.5	604	.004190	.004146	.003200	.003189	.001433	.001478
398	103	.001434	.001428	.001058	.001078	---	---
398	204	.002321	.002343	.001752	.001769	.000825	.000798
398	305	.002960	.002988	.002222	.002256	.001005	.001017
398	405	.003430	.003494	.002600	.002638	.001164	.001189
398	507	.003960	.003952	.002940	.002984	.001322	.001345
398	608	.004300	.004393	.003250	.003317	.001438	.001495

*Calculated by first solving for H_i^L using equation (18) and then
solving for x_i using equation (19). Average absolute deviation is 1.60 %.

no pressure effect, so that equation (17) should be applicable to the data of Table 2. However, inspection of the data in Table 2 shows that for both brines the salting-out coefficients appear to pass through a minimum within the temperature range of the data. Consequently, two sets of 'k' parameters were computed, one set for use with temperatures below 102.5 C and the other for temperatures above 102.5 C. These parameters values are given in Table 2. Since the total variation of the salting-out coefficient was very slight over the range of the O'Sullivan and Smith data, this seemed a reasonable approach, but extrapolation far beyond the temperature range of these data is clearly not warranted. It is hoped that this somewhat anomolous behavior of the salting-out coefficient can be resolved when other published data are evaluated.

The complete set of parameters for equation (18) which were determined from the O'Sullivan and Smith data are given in Table 3. Methane solubilities computed by subroutine SOLUTE using these parameters are compared to the original data in Table 4. The agreement is seen to be very good, (average deviation = 1.60%) although it should be remembered that the salting-out coefficient was forced to fit the three temperatures by using two sets of 'k' parameters.

Literature Cited:

1. Prausnitz, J.M., Molecular Thermodynamics of Fluid-Phase Equilibrium, Prentice-Hall, 1969, pp 356-361.
2. Prausnitz, J.M., *ibid.*, pp 362-365.
3. Culberson, L., and McKetta, J.J., Jr., "Phase Equilibria in Hydrocarbon-Water Systems," Petroleum Transactions, AIME, 1951, pp 223-226
4. O'Sullivan, Thomas D., and Smith, Norman O., "The Solubility and Partial Molar Volume of Nitrogen and Methane in Water and Aqueous Sodium Chloride from 50 to 125° and 100 to 600 Atm," The Journal of Physical Chemistry, 1970, pp 1460 - 1466.
5. Morrison, T.J., "The Salting-out of Non-Electrolytes," Part I and II, Journal of Chem. Soc., pp 3814 - 3822.
6. Prausnitz, J.M. *ibid.*, pp 152 -157.
7. Reid, Robert C., Prausnitz, John M., and Sherwood, Thomas K., The Properties of Gases and Liquids, McGraw Hill, Third Edition, 1977, p. 629.

APPENDIX 4

SENSITIVITY OF THE ECONOMICS OF A GEOPRESSURED ENERGY PROSPECT TO VARIATIONS IN GEOLOGIC PARAMETERS

By:

**Thomas G. Ray
Department of Industrial Engineering
Louisiana State University**

**Adrain E. Johnson, Jr.
Department of Chemical Engineering
Louisiana State University**

**A paper presented at The Fourth United States Gulf
Coast Geopressured/Geothermal Energy Conference:
Research and Development, at Austin, Texas**

October 31, 1979

SENSITIVITY OF THE ECONOMICS OF A GEOPRESSURED ENERGY
PROSPECT TO VARIATIONS IN GEOLOGIC PARAMETERS

by

Thomas G. Ray, Associate Professor
Department of Industrial Engineering
Louisiana State University

and

Adrain Johnson, Professor
Department of Chemical Engineering
Louisiana State University

INTRODUCTION

The study of the possibility of the recovery of energy from underground aquifers in the Gulf Coast area has led to various conclusions [1, 2]. In this paper we wish to look further at the possibility of such recovery in the light of the contributions made by those who did the initial work.

Purpose. The purpose of the study was to determine the relative importance of certain geologic parameters. It was believed that a knowledge of this information would be useful in specifying the information that is most critical to the analysis of prospective investments in the area. It could be used in the determination of the most productive areas in which governmental agencies interested in furthering the development of this possible resource could spend research funds optimally. It would further be of value in the research effort directed toward the analysis of specific sites in the Louisiana Gulf Coast area.

Approach. Our approach will be to analyze the outcome of various possible occurrences by using a model for predicting a measure of merit given a set

of hypothetical inputs. This was done as a sensitivity analysis.

Sensitivity Analysis. Sensitivity analysis is a process of analyzing the effects of possible values of parameters of a study upon some measure of effectiveness chosen to represent system performance. This analysis is done to obtain information as to which parameters (or variables) have the most significant effect upon a system measure of merit or effectiveness.

Such analysis is done when there is a requirement for knowledge as to the relative importance of various parameters. It is accomplished by choosing some base case for analysis and then varying the parameters one at a time so that the distinctive effect of the change of the single parameter can be noted. In order to accomplish this, a model of the situation which can be manipulated mathematically, must exist.

Justification for Sensitivity Analysis

Sensitivity analysis is done for the purpose of furthering the knowledge about the manner in which certain parameters or variables interact. Although previous sensitivity analysis studies have been done for geopressed prospects, none have been done with a model such as that used for this study.

Geologic Parameters of the Study

We have chosen to study the effects of porosity, permeability, compressibility, geometry, and total volume of a hypothetical prospect upon its performance.

These four parameters were chosen because it was believed that they would provide an adequate basis for initial analysis. It is intended that this initial study be a point of departure for a much more extensive study.

Further, it was believed that information gained from this initial analysis would provide direction as to the most productive possibilities for further study.

METHODOLOGY FOR THE STUDY

Model Used for Analysis. The model used for sensitivity analysis in this paper was that described by Wrighton and Johnson [3]. It uses as a reservoir model a bounded radial aquifer. The model assumes that the solution is saturated with methane at the given temperature and pressure of the reservoir. It accounts for methane loss as pressure drops under the assumption that the solution contains the maximum dissolved methane content. The model incorporates tax effects. In our analysis the model was used to evaluate alternative data inputs in terms of net present value.

Model Inputs

Base Case. The base case data was shown in Table 1. Economic data inputs are also shown in Table 1. It should be noted that certain inputs in the base case data might be very optimistic. It is not the intent of the authors to imply that these values are representative.

The reservoir volume used in the base case was one cubic mile. Doscher, et al. [1] feel that such a case is highly unlikely. Randolph [2] however, used a larger reservoir volume for his base case.

Most other values are in the range of what has been termed probable for certain Gulf Coast sites.

Parameter Variations. An initial run was made using the base case. The model output resulting from the run is as shown in Table 2. Study of this output reveals three interesting observations. First, that the

volume of the fluid produced held constant for the first thirteen years of production before it began to drop. The bottom hole pressure drops off over the life of the project thereby allowing the methane content of the solution to drop considerably. Thirdly, the ratio of total revenue to total operating expenses increases. This later fact is due to the rapidly increasing price of gas due to both inflation and real price increases.

Another point of interest from the output is that roughly 5% of the fluid was recovered from the aquifer. It is also noted that for this situation the net present value is one hundred and ninety thousand dollars. Subsequently runs were made varying the following over the ranges indicated: porosity: .20 to .30; permeability: 25 to 500 md; compressibility: 10×10^{-6} to 20×10^{-6} ; volume: 0.5 to 1.0 cubic miles; thickness: 50 to 2400 feet. The results of the variations are shown in terms of their effect upon net present value in figures 1 through figure 3.

Conclusions

Study of the output from the program for the cases analyzed reveals that the NPV curves have the same basic shape for the plot of NPV versus any of the geologic parameters. The geologic parameters are essentially shape parameters for the NPV curve. The more favorable the set of parameters the more rapidly the plot of NPV versus a single parameter changes to make the alternative approach its maximum possible value of the present value of the maximum recovery from the given aquifer at the constrained flow rate of 40,000 BBLs/day. It appears that threshold values for economic feasibility can be determined for a given parameter by allowing all other parameters to be highly favorable and then decreasing the parameter of

where its slope becomes the greatest as the point at which the NPV curves has zero present value for a given interest rate.

For the case analyzed it appears that these threshold values appear to be approximately one cubic mile for reservoir volume, 10 millidarcies for permeability and .08 for porosity. No determination was made for compressibility.

Figure 1

GRAPHS OF NPV VS THICKNESS FOR SELECTED VOLUMES

Figure 2

GRAPHS OF NPV VS POROSITY FOR SELECTED VALUES OF PERMEABILITY

Figure 3

GRAPHS OF NPV VS POROSITY FOR SELECTED VALUES OF PERMEABILITY

BASE CASE INPUT DATA

RESERVOIR PROPERTIES

DEPTH 17,000 FT.
THICKNESS 300 FT.
AREA 11,264 ACRES
POROSITY 0.20
PERMEABILITY 25 MD.
COMPRESSIBILITY 10×10^{-6}
PRESSURE 14,600 PSI
TEMPERATURE 244 F

WELL DATA

RADIUS 4.5 IN.
CASING SIZE 5.5 IN. I.D.
PRODUCTION RATE 40,000 BBL/DAY MAX.
WELL HEAD PRESSURE 500 PSI MIN.

ECONOMIC DATA

WELL COST INCLUDING 2 DISPOSAL WELLS
\$5.9 MILLION
GAS PLANT COST \$1.0 MILLION
OPERATING COST \$0.043-0.104 /BBL

Table 1

COMPILATION OF RESERVOIR STATISTICS OVER THE PROJECT LIFE.

WELL SYSTEM IS A SINGLE WELL IN THE
MIDDLE OF A RESERVOIR OF 11264.00 ACRES

CUBIC VOLUME OF RESERVOIR IS 1.00 CUBIC MILES

<u>YEAR</u>	<u>FLOW, BBLs/DAY</u>	<u>WELL-HEAD PRESSURE, PSI</u>	<u>BOTTOM-HOLE PRESSURE, PSI</u>	<u>GAS PRODUCED MSCF/DAY</u>	<u>GAS RECOVERED CU. FT./BBL</u>	<u>GAS REVENUE</u>	<u>TOTAL OP. COST, \$/MCF</u>
1985	40000.	4043.	12138.	1169.	29.21	2.421	0.988
1986	40000.	3764.	11859.	1149.	28.73	2.536	0.910
1987	40000.	3486.	11581.	1130.	28.26	2.627	0.908
1988	40000.	3207.	11302.	1112.	27.79	2.796	0.922
1989	40000.	2929.	11024.	1093.	27.33	2.944	0.928
1990	40000.	2650.	10745.	1075.	26.88	3.098	0.937
1991	40000.	2372.	10467.	1057.	26.43	3.259	0.948
1992	40000.	2093.	10188.	1040.	25.99	3.432	0.960
1993	40000.	1815.	9910.	1022.	25.55	3.607	0.976
1994	40000.	1537.	9631.	1005.	25.11	3.795	0.993
1995	40000.	1258.	9353.	987.	24.68	3.991	1.018
1996	40000.	980.	9074.	970.	24.25	4.195	1.080
1997	40000.	701.	8796.	953.	23.82	4.408	1.151
1998	37764.	1130.	8970.	910.	24.09	4.506	1.220
1999	32000.	908.	8748.	760.	23.74	4.026	1.336
2000	32000.	685.	8525.	749.	23.40	4.247	1.473
2001	30913.	986.	8660.	730.	23.61	4.428	1.549
2002	25600.	808.	8481.	597.	23.33	3.877	1.771
2003	25600.	630.	8303.	590.	23.05	4.100	1.878
2004	24211.	851.	8415.	562.	23.23	4.181	1.996
<hr/>							
AVG.	36404.	1842.	9808.	933.	25.42	72.473	23.908
TOTAL	0.2658E+09 BBLs			6810.68 MCF		3.624	1.195

PERCENT OF FLUID RECOVERED FROM RESERVOIR 5.068664

TOTAL DISCOUNTED NET PRESENT VALUE = \$ 0.190940

Table 2

BIBLIOGRAPHY

1. "Methane from Geopressured Aquifers Studies," Oil and Gas Journal by Doscher, T. M., et al., April 9, 1979.
2. Natural Gas from Geopressured Aquifers?, by P. Randolph. SPE Paper #6826 presented at 52d Annual Fall Technical Conference of SPE of AIIME, Denver, Colorado, October 9-12, 1977.
3. Wrighton, F. M., and Johnson, Adrain E., A Description of the Techno-economical Model Used to Analyze the Development Potential of Louisiana Geopressured Energy Prospects, presented at 4th U. S. Gulf Coast Conference on Geopressured/Geothermal Energy: Research and Development, October 31, 1979.

APPENDIX 5

ECONOMICS OF ALTERNATIVE GEOPRESSURED TECHNOLOGIES

By:

**Fred M. Wrighton
Energy Programs Office
Louisiana State University**

**Thomas G. Ray
Department of Industrial Engineering
Louisiana State University**

**A paper presented at the Engineering Foundation
Conference on Geopressured-Geothermal Energy at
Sea Island, Georgia**

January 1980

ECONOMICS OF ALTERNATIVE GEOPRESSURED TECHNOLOGIES

Most individuals involved in research concerning the development of Geopressured/Geothermal resources readily concede that existing and new technologies are a very important element in this type of venture. The application of existing technologies and development or investigation of new technologies is motivated by the anticipated economic value of the results. This is clear from such examples as improved secondary recovery techniques, offshore drilling, and deep drilling, that have resulted from the increasing value of the resource to be acquired. This paper describes in brief form the assumptions used in the LSU Techno-economic site simulation model and results of alternative scenario simulations for surface and subsurface technologies.

Analytical Model

The analysis that follows utilizes the LSU Techno economic Geopressured Reservoir Simulation Model. The model simulates a single production well development with a production capacity of 40,000 barrels a day. The brine produced is processed in a gas separation plant and the fluid is then disposed of in a shallow aquifer (about 6,000') through two disposal wells. The planning horizon of the analysis is the period 1985 to the year 2004, a period of 20 years. Since the cost estimates used have their origin in pre-1980 interviews and literature, an inflation adjustment was used to bring the figures to a 1985 basis. The inflation adjustment for investment was accomplished using a weighted value of two components of the GNP Price Deflator --1.) Fixed Structures and 2.) Fixed Equipment. The weights were ninety percent for equipment and ten percent for structures. All forecasted values were obtained from the most recent long term standard forecast prepared by Chase Econometrics, Inc. The GNP Implicit Price Deflator was used to adjust operating costs. The investment cost and operating cost assumptions are reported in their project life values.

Drilling and Plant Cost Estimates

Drilling costs were obtained from a study conducted by the Dow Chemical Company in 1976. The drilling configuration in that study included one source well with a seven inch bore at 16,000 feet and two disposal wells with a seven inch bore at 6,000 feet. The total drilling

WRIGHTON, Fred M., Energy Programs Office, Louisiana State University
Baton Rouge, Louisiana 70803

RAY, Thomas G., Department of Industrial Engineering, Louisiana State
University, Baton Rouge, Louisiana 70803

cost for this configuration was \$6,125,625 with the majority of the costs in the production well. The plant cost were derived from the individual component estimates for separators and piping found in the same Dow study that provided drilling costs. The estimate of the cost of the plant to separate gas from brine was \$834,000.

Depreciation, Taxes and Revenues

Depreciation is computed over a ten year life utilizing the sum-of-the-years-digits methods. New working capital requirements are computed each year as a proportion of operating costs and any increase or decrease from the previous year is subtracted or added to the cash flow.

Taxes represent a cash drain and the full complement is included in the model using the appropriate tax schedules. Taxes included are federal income, state income, and severance. Tax provisions for depletion allowance and investment tax credit are included with the prevailing limitations and carry-over rules. Operating costs are computed as a function of the flow rate of the production well. They are differentiated into three main categories 1) general operation and maintenance, 2.1¢/barrel, 2) well operation and maintenance, 1.1¢/barrel, and 3) power costs for reinjection, 1.1¢/barrel.

Perhaps the most important of all assumptions is the anticipated pattern of gas prices in the future. The nature of the objectives of our systems analysis required that the problem of future prices be addressed. Industry and organizational forecasts are considered proprietary so as in other cases an econometric forecast from Chase Econometrics was used. The assumed price in 1985 is \$6.17/MCF rising over the twenty year period of analysis to over \$20/MCF.

Base Case Discussion and Evaluation

There are five prospective geopressured reservoirs that have been identified in Louisiana which are currently under study using the LSU model. For the purposes of this analysis, it was decided that a hypothetical reservoir would be most appropriate. The geologic parameters of this hypothetical reservoir are within the range of estimates made for the five prospects described by Bernard [1]. The base case reservoir properties, well data and major economic assumptions are found in Table 1.

A major assumption in the reservoir properties is that the combination of the area and thickness parameters produce a reservoir volume of one (1) cubic mile. The combination of the reservoir properties and well data produces an initial flow rate that is limited to 40,000 BBL/Day. With time, as production continues, the well head pressure declines, when it drops below 500 psi the production rate is decreased until the pressure rises above 500 psi. The twenty year production characteristics of the simulated base case are illustrated in Table 2. The rate of production begins at 40,000 BBL/Day which is maintained until 1998 when it becomes necessary to reduce the rate until end of project when the production is 24,211 BBL/Day. The bottom hole pressure declines from 12,138 psi to 8,415 over the period. The decline in the bottom hole pressure accounts for the decline in the gas recovered per bbl from 29.21 cubic feet to 23.23 cubic feet. The methane in solution is computed through a series of subroutines developed by Johnson [2].

TABLE 1

BASE CASE INPUT DATA

RESERVOIR PROPERTIES

DEPTH 17,000 Ft.
THICKNESS 300 Ft.
AREA 11,264 Acres
POROSITY 0.20
PERMEABILITY 25 md
COMPRESSIBILITY 10×10^{-6}
PRESSURE 14,600
TEMPERATURE 244 F

WELL DATA

RADIUS 4.5
CASING SIZE 5.5 in. I.D.
PRODUCTION RATE 40,000 bbl/day max.
WELL HEAD PRESSURE 500 psi Min.

ECONOMIC DATA

Well cost including 2 disposal wells
\$6.2 million

Gas Plant Cost \$.83 million

Operating Cost \$0.043-0.104/bbl

Table 2

Production Characteristics of the Base Case

Year	Flow, bbls/day	Well-Head Pressure, psi	Bottom-Hole Pressure, psi	Gas Produced MSCF/day	Gas Recovered Cu. Ft./bbl
1985	40000.	4043.	12138.	1169.	29.21
1986	40000.	3764.	11859.	1149.	28.73
1987	40000.	3486.	11581.	1130.	28.26
1988	40000.	3207.	11302.	1112.	27.79
1989	40000.	2929.	11024.	1093.	27.33
1990	40000.	2650.	10745.	1075.	26.88
1991	40000.	2372.	10467.	1057.	26.43
1992	40000.	2093.	10188.	1040.	25.99
1993	40000.	1815.	9910.	1022.	25.55
1994	40000.	1537.	9631.	1005.	25.11
1995	40000.	1258.	9353.	987.	24.68
1996	40000.	980.	9074.	970.	24.25
1997	40000.	701.	8796.	953.	23.82
1998	37764.	1130.	8970.	910.	24.09

Wrighton

Table 2 continued

Production Characteristics of the Base Case

Year	Flow, bbls day	Well-Head Pressure, psi	Bottom-Hole Pressure, psi	Gas Produced MSCF/day	Gas Recovered Cu. Ft./bbl
1999	32000.	908.	8748.	760.	23.74
2000	32000.	685.	8525.	749.	23.40
2001	30913	986.	8660.	730.	23.61
2002	25600.	808.	8481.	597.	23.33
2003	25600.	630.	8303.	590.	23.05
2004	24211.	851.	8415.	562.	23.23

Surface Disposal

Another alternative depends on the physical location of the production well and the ability to overcome environmental regulatory agency objections to particular disposal techniques. Here it is evident that an offshore installation and offshore disposal directly into the Gulf of the fluid produced by the well is being described. This is not without precedent and there is currently disposal of heavy concentrations of brine in the Gulf from salt domes in Louisiana. Disposal in the Gulf yields a major economic impact on the geopressure venture. A significant reason is the elimination of the drilling expense for two disposal wells. A substantial impact on the net present value arises from the fact that this is a first year expenditure. The case is now one in which there are no power costs for pumping and no disposal drilling investment. The latter amounts to \$2,279,000. This causes an increase in net present value over the base case of \$2,082,224 and over the no power case of \$1,389,853. This requires some explanation, since the first year cash flow was a drilling cost, the net loss in the first year declined because two-thirds of the drilling investment is expensed. Carry over provisions in the tax law reduce tax liabilities through the carry over of losses in previous years. The reduction in the loss in the first year of the project initiate tax liabilities much earlier than in the base case.

Alternate Fluid Use

The last alternative is to not only reduce disposal costs but perhaps instead to make a revenue producer of the fluid. Once again the physical location of the production unit would be crucial to the alternative. Oil and gas production companies currently use water flooding as a production technique to enhance recovery. The value of the water to the oil and gas company is implicit in the drilling expense required to acquire the water. It is not completely improbable that a geopressure geothermal production unit could sell the produced fluid to another operator. In fact, one oil and gas company now operates a water production unit, stripping 10 cubic feet per barrel of methane from the fluid prior to using it for reservoir flooding. Rather than speculate on the price that might be obtained for the fluid, it is believed sufficient to simply indicate that the net present value would rise above the base case value with no disposal expense.

Economics of Subsurface Technology

Subsurface technology is more difficult to evaluate because of remaining uncertainties about the resource and the performance of a geopressured reservoir under production conditions. One specific possibility that should be explored in future tests is that of the production of free gas in the aquifer. Total free gas in the formation is the resultant gas freed from the solution as a result of the pressure drops.

For the base case problem the maximum free gas is the difference between the gas recovered in the first and last years of the project life ($29.21 - 23.23 = 5.98$ scf/BBL). The total formation fluid content is 5.24×10^9 barrels. The formation free gas would then be 3.14×10^{10} scf or 3.14×10^7 mcf. Some portion of this gas might be produced over the

Wrighton

life of the project as a result of its migration in the formation.

The possibility of recovering free gas from the aquifer raises the question as to how this gas might be produced in time and how much volume and value it might represent. The most desirable production pattern from the point of view of economics is at a constant rate over the period. Since the free gas occurs as a result of the pressure drop in the reservoir through fluid production this is a very improbable case. A more likely time pattern of free gas production would be little if any initially, with an increasing production of free gas during the last years of the project life.

If 5% of the free gas were produced it would amount to an additional 1.570 billion cu. ft. or a 23% increase in total production. A conservative estimate of the value of the gas can be obtained by using the end of project life gas price of \$22/MSCF and assuming all the additional gas was produced in the twentieth year. The net present value (at a discount rate of 15%) of the additional gas is \$1,855 million. A potential increase in the project net present value of this magnitude could easily determine the feasibility of a project. Only through production testing, however, will an assessment of the potential for free gas production through migration to the well bore be made.

Conclusions

This paper has been a preliminary economic evaluation of the economics of alternate technologies for enhancing the feasibility of gas recovery from the GP/GT resources. It pointed out several variations for consideration for the surface technology and lumped all subsurface alternatives that may exist into a consideration of free gas production. Since no production information exists for the performance of the GT/GP aquifers under assumed operating condition, much of what might happen appears to be conjecture. However, this analysis points out definite possibilities exist if technologies can be advanced, within the limits of the indicated economic justification.

¹ Bernard, W. J. "Evaluation of Five Potential Geopressure/Geothermal Test Sites in Southern Louisiana, Petroleum Engineering Department, Louisiana State University, 1979

² Johnson, Jr. A.E., "The Calculations of Methane Solubility for Salt Water Solutions." Louisiana State University. Paper presented at Engineering Foundation Conference, Geotechnical and Environmental Aspects of Geopressured Energy, Sea Island Georgia, January 13-18, 1980

APPENDIX 6

SUBSURFACE DISPOSAL OF GEOPRESSURED FLUIDS: POTENTIAL GEOLOGIC AND OPERATIONAL PROBLEMS WITH RECOMMENDATIONS FOR DISPOSAL SYSTEM TESTING

By:

Ann L. Bachman
Office of Energy Programs
Louisiana State University

Charles G. Smith
Consulting Geologist
Baton Rouge, Louisiana

A paper presented at The Fourth United States Gulf
Coast Geopressured/Geothermal Energy Conference:
Research and Development, at Austin, Texas

October 31, 1979

**SUBSURFACE DISPOSAL OF GEOPRESSURED FLUIDS:
POTENTIAL GEOLOGIC AND OPERATIONAL
PROBLEMS WITH RECOMMENDATIONS
FOR DISPOSAL SYSTEM TESTING**

**Ann L. Bachman, Office of Energy Programs
Louisiana State University, Baton Rouge**

**C. G. Smith, Consulting Geologist
Baton Rouge, Louisiana**

INTRODUCTION

Development of any geopressure prospect will involve a resource assessment, production, marketing the products, and disposal of the effluents. Of these, the disposal activity has received the least attention although it is critical to the success of the entire venture. Geopressured energy investigations are not unique in this regard. They share with other kinds of development the fact that at the point disposal is required, what was once a product has become a valueless waste. Contributing to this lack of attention in the geopressure case has been reliance on the considerable experience in oil and gas field brine disposal in the Gulf Coast.

There are unique features about disposal in geopressure operations, however, that require special attention. Certainly the total volumes to be disposed of are uniquely large, given anticipated rates of production. A recent review of oilfield brine disposal in the Gulf Coast confirms this point [13]. The study shows that while individual wells sustain

high injection rates over long periods of time, they are exceptions. Subsurface disposal on the scale anticipated in the geopressure case has not been required in Gulf Coast conventional hydrocarbon production.

Without either an analysis of the potential problems of geopressure fluid injection, or a useful analagous situation, it is impossible to determine which aspects, if any, could seriously impede commercial development of the resource. Similarly, in trying to weigh impacts from failure of a subsurface disposal system vis-a-vis other impacts [17, 18] the authors found it impossible to estimate the probability of occurrence of disposal problems that would lead to adverse environmental effects. For example, how likely is it that injected geopressured fluids will remain isolated from fresh water aquifers given the high injection rates and large total volumes we want to achieve?

To help answer these kinds of questions, a Workshop was held at Louisiana State University on March 6 and 7, 1979. The LSU Workshop was the first to specifically address, in a group discussion format, the potential geologic and operational problems of subsurface injection of geopressured fluids. The 70 participants represented a wide range of expertise and included the major industry representatives and researchers in the geopressure field, as well as people representing the Strategic Petroleum Reserve Program and industrial and oilfield disposal operations. This paper summarizes the results of the Workshop (the Proceedings [1], which is in press, gives a full report on the meetings; the Workshop program is appended for reference). Unless referenced, the conclusions and recommendations reported in the subsequent sections were made during the discussion periods at the Workshop. The paper also shows how the results of the

Workshop contributed to the development of a disposal system testing program for the proposed test well near Lafourche Crossing, Louisiana.

The Workshop was restricted to subsurface disposal so did not include any discussion on surface disposal operations. It is thought that while some geopressure prospect areas would be within economic distance of the open Gulf for surface disposal, if it were permitted, many would not. Thus, subsurface disposal would be the only alternative in many prospects, and therefore critical to the success of development of those areas. Within this context, the Workshop participants discussed potential hydrogeologic and fluid/formation compatibility problems, operational factors, and the probability of fluid migration from the intended injection zone.

HYDROGEOLOGIC AND FLUID/FORMATION COMPATIBILITY CONSIDERATIONS

Disposal Sandstone Volume and Continuity

A successful geopressure disposal operation requires a porous, permeable formation of wide areal extent at depths below the base of fresh and slightly saline water (10,000 mg/l total dissolved solids). Furthermore, a zone of low permeability, such as shale, must overlie the injection zone to prevent the vertical migration of the injected fluid or formation waters. In the Gulf Coast, with the average deep occurrence of fresh water at -2,000 feet, the Miocene sands in the interval -2,000 to -5,000 feet is the most likely disposal formation [22]. Oil and gas field brine disposal is generally within this zone or shallower [13]. In the Strategic Petroleum Reserve Program injection is below -5,000 feet, but for reasons relating more to ease of permitting and lack of data on the prior use of

shallower reservoirs than to hydrogeologic considerations [7].

There was a general consensus among the Workshop participants that the sand volumes required for geopressured fluid disposal would be available within the -2,000 to -5,000 foot interval. The distribution of sandstone in this interval shows somewhat higher net sand thickness in south Louisiana than in the Texas Gulf Coast region [22]. It was pointed out, however, that the sandstones are interrupted frequently by shale layers. While these provide the necessary barriers to vertical migration, they may also vertically compartmentalize the disposal aquifers. For example, it was reported at the Workshop that for the Brazoria County, Texas test well, a total of 2,000 feet of sand is available for disposal between -2,000 and -7,000 feet. However, most of the individual sand bodies are only 10-30 feet thick.

The disposal sandstones, it was noted, may also be compartmentalized by faulting. The opinion was offered that this would have a minor effect on injectivity rates in general, if all other factors are favorable. Furthermore, it was pointed out that while the incidence of faulting becomes more complex with depth, in the Gulf Coast many of the faults die out below the first major sand series.

The injectivity of a disposal zone depends partly on permeability. Several discussants pointed out that permeability is highly variable laterally as well as with depth, so that an individual disposal aquifer may not be at all homogeneous with respect to permeability.

These considerations led the Workshop participants to recommend site specific studies of the lateral continuity and permeability of the disposal sandstones. It was agreed that an understanding of the hydraulics of a particular disposal aquifer is critical to the success of an operation on

as large a scale as that anticipated in the geopressure case; and that the existing tools for this kind of analysis are adequate. It was stressed that, unlike the usual oilfield practice, extensive site specific studies should be made prior to the start of injection and the design of the entire disposal system. It was suggested that a regional study of sandstone volume in the most likely disposal interval is not necessary because in such a study, the potential for disposal would be evaluated in many areas that are out of the question for geopressure energy production[22]. Also, the variability of the most important parameters is on too small a scale for interpretation by a regional study.

Fault Activation, Seismicity and Subsidence

Several cases of fault activation as a result of injection of fluids have been documented. In the Baldwin Hills area of Los Angeles in 1963, increased injection of oilfield brines is believed to have triggered movement along a fault plane. This movement broke a dam, causing loss of life and property [8]. Similarly, in the Rangely, Colorado oilfield, injection of fluids is thought to have caused slippage of rocks which resulted in earth tremors [4, 21]. Because these cases are well-documented examples of movement along established faults due to the injection of fluids, the high volume, high injection rate operations in geopressure disposal should be approached with some caution [3].

The Workshop participants did not reach a consensus on the probability of these kinds of events occurring, although they agreed that monitoring for earth movement was recommended. Several discussants emphasized the fact that above approximately -8 000 feet, rocks in the Gulf Coast are

unconsolidated and thus strain is released gradually rather than abruptly. However, it was also pointed out that geopressure disposal operations could lubricate faults and cause slippage, if not seismicity. In either event, damage at the surface could result, and fault slippage could aid in the migration of fluids upward into fresh water aquifers.

Several cases of subsidence due to deep oil and gas withdrawals have been documented in the Gulf Coast [5]. The lack of cases, however, may reflect the fact that surface elevation change isn't routinely monitored during oil and gas field operations, rather than the absence of subsidence. A great deal of concern has been expressed on the issue because of the destructive effects of surface subsidence in the Gulf Coast environment [6]. The Workshop participants also observed that compaction at depth could damage the casing and completion of disposal wells (and production wells). No consensus was reached on the probability that subsidence would occur, but it was agreed that surface subsidence should be monitored.

Compatibility Problems

The injected fluid in a disposal operation may be incompatible with either the interstitial fluid in the disposal formation or with the formation rocks. In the first case, the problem is usually evidenced by plugging at the wellbore or in the formation because of precipitation of minerals when the two fluids mix. Clay hydration is the most common mechanism for plugging when the injected fluid is incompatible with the formation rocks. A common Gulf Coast clay, montmorillonite, has the base ion-exchange and hydration properties that cause swelling when they come in contact with water [3]. The Workshop participants suggested that an

additional type of incompatibility could be of concern: Incompatibility between the produced fluids from different formations when mixed for purposes of disposal. It was pointed out that in a disposal system as large as that anticipated in geopressured resource development, the highest degree of flexibility is desirable.

It was also suggested that temperature cycling might be an additional mechanism for precipitation of substances with inverse (to temperature) solubilities, such as calcium sulfate and calcium carbonate. In geopressure operations, the fluid temperature could cycle from high in the producing well, to somewhat lower temperatures on the surface, to moderate-high temperature in the disposal zone. The discussants agreed that research should be conducted on the solubilities of the slightly soluble salts in order to investigate this problem.

There was a consensus among the discussants that fluid/fluid incompatibility is not a serious problem because it can be remedied by the use of buffer fluids, although some concern was expressed about whether large sections, 200 feet thick, for example, can be adequately protected with buffers. It was agreed, however, that large volume injection situations like that expected in geopressure disposal warrant a thorough analysis of the potential problems prior to injection. This would require site specific data on the chemical and physical properties of the geopressured and native fluids, as well as data on the changes in solution composition, temperature, and pressure that would occur during processing.

In the case of fluid/formation incompatibility, the discussants pointed out that clay hydration should not occur if the injected fluids contain more than 20,000 ppm total dissolved solids. However, it was agreed that this

problem should also be investigated in advance of actual disposal at a site, and that this would require coring the disposal zones. In addition, some concern was expressed about damage to the formation sandstones and subsequent plugging due to the high projected velocity of injection.

OPERATIONAL FACTORS

The Gulf Coast geopressured fluids appear to contain those elements that contribute to corrosion and scaling [10, 12]. Total dissolved solids content in Louisiana geopressure fluid samples ranges from 22,000 to 275,000 mg/l [10], for example. It has been suggested that samples from Gulf Coast wells showing lower salinities are not representative because they have been diluted by condensed water vapor produced with natural gas [12]. The carbonates and sulfates of calcium, strontium and barium may also contribute to scaling in geopressure fluid processing [11]. Erosion may become a problem if dissolved solids precipitate or if sand is produced from the geopressured formations. While not strictly related to disposal, suspended solids in the waste stream could foul the injection pumps and plug the wellbore and the disposal formation.

These problems are not unique to geopressure operations. They have been successfully dealt with in the oil and gas industry by combinations of chemical treatment, sedimentation, filtration and aeration. There are special concerns in the geopressure case, however. Relative to oil and gas field brine disposal, the temperature of the geopressured fluids will be higher, the total volume processed will be much larger, and flow is expected to be at consistently high rates and under greater pressure. The Workshop participants agreed that these are the unique and critical

factors in the operational problems of geopressure disposal, and that the consequences of the large scale of operation are evidenced most in the economics of treatment and disposal. For example, there was a consensus that the technology and experience for handling corrosion, scaling and erosion problems are available, and that the economics of producing an acceptable quality effluent for surface processing and disposal is the real problem. A detailed economic assessment of treatment is recommended; hopefully it will show high economies of scale.

Another way in which the scale of geopressure operations affects the economics of the disposal activity concerns the back-up disposal system. An extensive back-up disposal system would be critical to the economics of disposal. It was suggested that the size of the back-up system will depend in part on how much fluid treatment is planned, on the premise that a high quality effluent will reduce down-time for remedial action such as well workovers. Another important factor is how sustained production should be, assuming that holding ponds of sufficient capacity will not be available for continued production in the event of disposal well failure. Several discussants pointed out that a sustained flow is necessary if electric generation or process heat uses are part of the operation. Others thought that producing wells should not be shut in frequently because the well casing would be subject to undue stress as a result of thermal shock. It was agreed that the economics of energy production vis-a-vis treatment costs and the costs of back-up disposal capacity is key, and that these relationships should be thoroughly studied.

The following additional conclusions were made:

1. Suspended solids should be thoroughly filtered from the waste stream to avoid erosion and plugging problems.
In the Strategic Petroleum Reserve Program, suspended solids concentrations as little as 2 ppm were found to be very damaging in the disposal wells.
2. Human error, such as introduction of suspended solids into the waste stream and bacteriological contamination of the formation, can cause serious injectivity problems. Therefore, operational procedures should be very closely controlled.
3. The ability to predict chemical precipitation is very important in planning the appropriate fluid treatment. Existing models should be improved and applied to site specific situations of chemistry and temperature.
4. Closed systems for surface handling of fluids are preferable to open systems (i.e., aeration completes oxidation and solids are filtered from the waste stream) because they cost less, are simpler to operate, and produce an effluent as near to what was originally withdrawn as possible. Closed systems are recommended for geopressure operations in which fluid handling is at a minimum (i.e., methane recovery alone) since it is difficult to prevent all exposure to the atmosphere with more complex processing.

5. Site specific hydrogeologic surveys and injectivity tests should be made in advance of disposal to determine aquifer capacity and pressure interference between wells.
6. Large-size equipment and well casings, and possibly piping of non-standard configurations may be required in geopressure operations and may not be readily available.

FLUID MIGRATION

The objective of both federal and state regulations on the injection of wastes is to protect fresh water aquifers and the surface environment from the contamination that would result from migration of the injected fluids or displaced native fluids. In the geopressure case, the anticipated large scale of injection has underlined this concern. To assess the problem, the Workshop participants reviewed: (1) reported cases of injected fluid reaching the surface in Gulf Coast disposal operations; (2) the mechanisms for migration away from the intended disposal zone; and (3) the effect of federal regulations on injection of geopressured fluids.

In Louisiana, only a few cases of fluid migration from an injection well to the surface through an abandoned well have been reported. Several of these occurred because injection was taking place too close to the flanks of salt domes [2] . The Workshop participants agreed that it is unlikely that geopressure wells will be located adjacent to these or other structures because the objective is to find large systems to produce, not "traps." Louisiana regulations on disposal wells [15] have been amended recently, reducing the potential for such situations to occur.

Both Texas and Louisiana have the problem of numerous wells drilled before effective state regulation that are improperly plugged or unplugged [2, 19] . These can and do act as conduits to the surface for injected fluids or displaced native fluids. One Workshop participant pointed out that uncased and unplugged holes did not stay open long in the Gulf Coast because clays flow into the uncased hole and seal it. The "natural" clay plugs can have lower permeability than concrete, it was noted.

The Railroad Commission of Texas, which regulates subsurface disposal in the state, uses a rule of thumb on allowable injection pressures (1/2 pound per foot of depth) to avoid some of these problems [19] . In general, the subject of overpressuring a disposal aquifer: The likelihood, the consequences, and the measures for control, was emphasized in the Workshop discussions on fluid migration. The general conclusion of the group was that overpressuring is unlikely and can be avoided through prior testing of the disposal formation and through monitoring.

First, it was noted that while overpressuring does cause fracturing in the Gulf Coast, the fractures probably do not extend close to the surface because of the unconsolidated nature of the sands. Second, it was observed that confinement of the injected fluids to a particular formation (and from less saline ones) does not require absolute isolation in the sense of impermeable barriers such as facies changes and faults. Rather, effective confinement can take place in a large system in the Gulf Coast in which the natural Gulfward and downdip movement of fresh water serves to isolate the injected fluids. These systems are available [22] and should be sought for large volume disposal. In such a system, a large amount of

native fluid would be displaced near the wellbore but there would not be sufficient movement of the native fluid out in the formation.

Finally, adequate prior planning for the disposal system and monitoring during injection are effective means for avoiding fluid migration problems, it was agreed. Disposal wells should be cored to assess the potential for clay hydration which would quickly plug a formation and lead to overpressuring. Pressure interference between wells can be simulated for different configurations of well placement[3] with a final well configuration chosen to minimize interference. A fracture pressure gradient should be calculated for the disposal zone on the basis of injectivity tests and hydrogeologic assessments, and the injection pressure at the surface controlled accordingly to avoid pressure build-up. Certainly, good cement bonds in the disposal well casings are vital, and injection pressures in the casing annulus should be monitored.

While there was a consensus that there are no serious hydrogeologic and operational constraints with respect to the fluid migration problem, it was also agreed that the regulatory and legal aspects are of considerable concern. State regulation of disposal of geopressed fluids [16] is not expected to be onerous; but compliance with the proposed federal regulations on injection wells[20] could be costly. The federal regulations will require that the public records of plugging and abandonment of existing wells will have to be examined, within a certain radius (the "zone of endangering influence") of a disposal operation, and improperly abandoned wells replugged by the permit applicant. The radius is to be determined by the states and may be set according to a consistent formula or may be fixed (but not less than 1/4 mile).

Because the federal regulations require only examination of the public record of plugging and abandonment, the number of abandoned wells the geopressure operator must deal with will be smaller than the number of wells actually present within the radius established for the particular disposal system. However, if any leakage occurs, the operator will have to replug the faulty well. In either case, the Workshop participants thought that there could be a conflict with property law: Could a geopressure operator legally go onto another's property (presumably outside the geopressure unit) and re-enter and replug a well?

Present or future uses of formations adjacent to the geopressure disposal zones, or the disposal zones themselves, need to be considered, as well. The specific case of fluid migration into a productive hydrocarbon zone as a result of geopressure disposal activities was not thought to be a problem by the Workshop participants. Neither the Louisiana nor the Texas regulatory agency representatives anticipated difficulties of this kind or could cite any examples [2, 19]. It was pointed out, however, that a geopressure disposal zone is likely to be pressured-up, if not overpressured, and that future oil and gas operators should be apprised of this. A related, if not so easily resolved, problem faces the operator interested in producing water for methane extraction from the hydropressure zones (i.e., the shallower zones of hydrostatic water pressure). A considerable amount of interest in this kind of operation has been expressed by industry [9]. The possibility exists that Gulf Coast sandstones in the interval -2,000 to -5,000 feet could be attractive both for waste disposal and as an energy resource.

AN EXAMPLE DISPOSAL SYSTEM TESTING PROGRAM

Hydrogeologic and operational tests of a disposal system prior to full-scale use (or design in the case of a multiple well situation) is vital to the success of a geopressure operation, especially because of the uniquely high total volume and injection rates anticipated. This was a major conclusion of the Workshop participants who suggested a number of specific tests to reduce the likelihood of certain problems arising. The following discussion describes the disposal system testing program for the proposed Lafourche Crossing, Louisiana test well [14], and relates the elements of the test program to the Workshop conclusions.

Disposal well testing for the Lafourche Crossing program is designed to: (1) test the efficiency of each disposal well before disposal begins; (2) insure that the injected fluid and the native fluid in the formation are compatible; (3) monitor the operation of the wells during disposal; and (4) assess any long-term problems that may develop in injecting large quantities of geopressed fluids. The Lafourche Crossing test will require two gravel-packed disposal wells to handle the anticipated flow rates with adequate back-up capacity. The wells will be completed in massive sands between -3,000 and -6,000 feet.

Logging Program

The proposed logging program is designed to establish the correlation of aquifers at the site and to provide data on formation shaliness and porosity. The log suite will include a Gamma Ray-Induction Survey and a sonic formation density log. Log interpretations will be augmented by conventional and sidewall cores taken from the proposed disposal

aquifers and their confining clays. Conventional core samples will be used for evaluating fluid/formation compatibility and formation parameters such as porosity and permeability. Based on results of these data, disposal formations of adequate volume (i.e., thickness and apparent lateral extent) will be selected for completion.

Injectivity Tests

While the availability of an adequate thickness of disposal sands is reasonably assured for the test situation, the performance of the disposal system (the well, the disposal aquifer, the native and produced fluids) remains uncertain before an injection history is established. Therefore, each disposal well will be tested to ascertain performance characteristics and to project long-term disposal system performance. The disposal well flow tests described below are adapted from test procedures established for high-volume salt water disposal wells by the engineering firm, Louis Records and Associates, Lafayette, Louisiana.

The disposal zones will be drilled with polymer muds to minimize formation damage and reduce development time. The well will be completed with gravel pack and stainless steel, wire-wrapped, rod-base screen. Upon completion, 4,000 barrels of native fluid will be pumped from the disposal well, using a nitrogen gas-lift process. A bottom-hole pressure bomb will be utilized to record pressures during production and until pressure has recovered following the test. A sample of the formation water will be taken at the end of the production test to be analyzed in fluid compatibility tests. An injectivity test will also be performed on each well using the produced water, which will be stored in tanks and reinjected

after filtration.

The record of the pressure changes with time developed during these tests will be evaluated to establish the well's injectivity index, which is an indication of the maximum flow rate the well can sustain. Also, these data will permit determinations of kh (reservoir thickness $\times$ permeability) and Z (skin effects) values. Finally, the pressure data will be analyzed to determine if flow boundaries are detectable nearby which would limit the flow rate to the well, and which would suggest that the volume of the disposal aquifer may be more limited than geologic data alone would indicate.

Long Term Monitoring

Surface pressure and injection rates will be monitored in each well during the life of the disposal operation. At injection start-up, the pressure and flow rate will be monitored continuously until the equilibrium pressure is reached. Additional measurements of pressure will be taken as production/injection flow rates increase to insure that the injectivity index of the wells is maintained and to evaluate aquifer performance to determine the proximity of any no-flow boundaries. In general, the duration and intensity of monitoring will depend on the record of well performance. However, a minimum program will require that injection pressure be monitored continuously and that the long-term pressure trend be evaluated weekly.

CONCLUSION

The participants at the LSU Workshop disagreed on a number of points

regarding subsurface disposal of geopressured fluids. There were also several areas of concern, the likelihood of subsidence and fault activation, for example, on which they could offer no additional information. However, a consensus was reached on some of the most important issues of injection in the geopressure case, thereby providing a significant contribution toward distinguishing the real problems from the non-problems.

The Workshop participants agreed that the technology is available for dealing with compatibility and operational problems. This idea was expressed explicitly as well in the frequent references to the experience with disposal of oil and gas field brines and in the Strategic Petroleum Reserve Program. It was also stressed, with regard to every major discussion topic, that the large scale of geopressured disposal operations: the huge total volumes anticipated and the high injectivity rates that we hope can be sustained for long periods of time is unique to the development of geopressured resources.

This conclusion seems contradictory at first, to the idea that experience in oilfield brine disposal proves that technological solutions to potential problems are already at hand. However, it was evident in the discussion sessions that the participants think that most of the operating and hydrogeologic problems facing the geopressure operator will differ in scale, not in kind, from those facing the conventional oil and gas operator.

Thus, the real problems, the Workshop participants agreed, concerned the economics of disposal. Compatible fluids, consistently high injection rates, and an adequate back-up disposal system can be obtained at a price; the question is, at what price? It was the consensus of the group that

an economic evaluation should be made of the disposal activity with the results dictating which aspects should receive more attention. In this way, those areas will be addressed where there is the greatest potential for reducing the costs of disposal. Much can also be learned from testing programs such as the one described above for the Lafourche Crossing disposal wells.

REFERENCES

1. Bachman, A. L. Editor, Proceedings: Workshop on Subsurface Disposal of Geopressed Fluids, (Baton Rouge, Louisiana: Energy Programs Office, Louisiana State University, in press).
2. Bates, Robert, "Fluid Migration: The Louisiana Experience," in Proceedings: Workshop on Subsurface Disposal of Geopressed Fluids, A. L. Bachman, Editor, (Baton Rouge, Louisiana: Energy Programs Office, Louisiana State University, in press).
3. Donaldson, Erle C., "Subsurface Disposal of Brines from Geopressed Reservoirs," in Proceedings: Workshop on Subsurface Disposal of Geopressed Fluids, A. L. Bachman, Editor, (Baton Rouge, Louisiana: Energy Programs Office, Louisiana State University, in press).
4. Evans, D. M., "The Denver Area Earthquakes and the Rocky Mountain Arsenal Disposal Well," Mountain Geologist, Vol. 3, No. 1, 1966, pp. 23-26.
5. Grimsrud, G. Paul, et al., Areas of Ground Subsidence Due to Geofluid Withdrawal, Prepared for Lawrence Berkeley Laboratory under DOE Contract No. W-7405-ENG-48, (Palo Alto, California: Systems Control, Inc., August 1978).
6. Gustavson, Thomas C., and Kreitlet, Charles W., Geothermal Resources of the Texas Gulf Coast: Environmental Concerns Arising from the Production and Disposal of Geothermal Waters, Geological Circular 76-7, (Austin, Texas: Bureau of Economic Geology, 1976).
7. Hahn, William J., and Smith, Richard E., "Programmatic and Technical Aspects of Subsurface Brine Disposal. Experiences of the Strategic Petroleum Reserve (SPR)" in Proceedings: Workshop on Subsurface Disposal of Geopressed Fluids, A. L. Bachman, Editor, (Baton Rouge, Louisiana: Energy Programs Office, Louisiana State University, in press).
8. Hamilton, D. H., and Meehan, R. L., "Ground Rupture in the Baldwin Hills," Science, Vol. 172, No. 3981, April 23, 1971, pp. 333-344.
9. Johnson, Adrain E., et al., Systems Analysis of Geopressed Resource Development in Louisiana: Final Report, Prepared for Louisiana Department of Natural Resources under Contract No. 11-01-03-03-78-29, (Baton Rouge: Energy Programs Office, Louisiana State University, in press).

10. Kharaka, Yousif K., et al., "Chemistry of Waters in the Geopressured Zone from Coastal Louisiana--Implications for the Geothermal Development," Geothermal Resources Council, Transactions, Vol. 2, July 1978, pp. 371-374.
11. Kharaka, Yousif K., et al., "Corrosion and Scale-Formation Properties of Geopressured Geothermal Waters from the northern Gulf of Mexico Basin, in Proceedings, Society of Petroleum Engineers (SPE) of AIME International Symposium on Oilfield and Geothermal Chemistry, Houston, Texas, January 22-24, 1969.
12. Kharaka, Yousif K., et al., "Geochemistry of geopressured geothermal waters from the Frio clay in the Gulf Coast region of Texas," Geology, Vol. 5, pp. 241-244.
13. Knutson, C. F., and Boardman, C. R., An Assessment of Subsurface Salt Water Disposal Experience on the Texas and Louisiana Gulf Coast for Application to Disposal of Salt Water from Geopressured Geothermal Wells: Topical Report, Prepared for DOE under Contract No. EY-77-C-08-1531, (Las Vegas, Nevada: C. K. GooEnergy Corp., August 4, 1978).
14. Louisiana Department of Natural Resources, A Proposal for Drilling and Testing the Lafourche Crossing Geopressured-Geothermal Prospects, Louisiana, submitted to U. S. Department of Energy.
15. Louisiana Department of Natural Resources, Office of Conservation, State-Wide Order No. 29-B Governing the Drilling for and Production of Oil and Gas in the State of Louisiana, (Baton Rouge: Department of Natural Resources, 1974).
16. Louisiana Department of Natural Resources, Office of Conservation, Statewide Order No. 29-P, Governing the Drilling for and Production of Geothermal Resources in the State of Louisiana, (Baton Rouge: Department of Natural Resources, 1978).
17. Newchurch, E. J., et al., A Plan for the Long Term Environmental Assessment of Geopressured Resource Development in the Louisiana Gulf Coast Region, Prepared for Lawrence Livermore Laboratory for DOE under Order No. 8316603, (Baton Rouge: Institute for Environmental Studies, Louisiana State University, July 1978).
18. Newchurch, E. J., et al., A Preliminary Environmental Assessment of Selected Geopressured-Geothermal Prospect Areas: Louisiana Gulf Coast Region, Prepared for DOE under Contract No. ET-78-S-05-5862.
19. Singletary, George, "Fluid Migration: The Texas Experience," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, A. L. Bachman, Editor, (Baton Rouge: Energy Programs Office, Louisiana State University, in press).

20. U. S. Environmental Protection Agency, Proposed Regulations, State Underground Water Source Protection Programs, (Federal Register, Vol. 44, No. 78, April 30, 1979).
21. Van Poolen, H. K., and Hoover, O. B., "Waste Disposal and Earthquakes at the Rocky Mountain Arsenal, Derby, Colorado," Journal of Petroleum Technology, Vol. 21, Sept., 1969, pp. 983-993.
22. Wallace, Raymond H., "Gulf Coast Geopressured-Geothermal Resources as Related to Hydrogeologic Characteristics of the Subsurface System for Disposal of Spent Brines," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, A. L. Bachman, Editor, (Baton Rouge: Energy Programs Office, Louisiana State University, in press).

WORKSHOP ON SUBSURFACE DISPOSAL OF
GEOPRESSURED FLUIDS, GULF COAST

Tuesday, March 6 - Wednesday, March 7, 1979

Speaker

Discussion Leader

INTRODUCTION 9:00 a.m. - 10:00 a.m., Tuesday, March 6

Workshop Goals

Ann Bachman
Louisiana State University

Regulatory Framework

George Singletary
Texas Railroad Commission

William Deville
La. Dept. of Natural Resources

Larry Browning
U. S. Environmental
Protection Agency

Developmental Scenarios

Charles Smith
Consulting Geologist

SESSION I: HYDROGEOLOGIC FACTORS 10:00 a.m. - 12:20 p.m.

Hydrogeology of Disposal
Aquifers in the Gulf Coast

Raymond Wallace
U.S. Geological Survey

Discussion 10:30 - 12:00
Group A

Charles Groat
La. Geological Survey

Group B

Robert Louks
Texas Bureau of
Economic Geology

Discussion Summary
12:00 - 12:20

Charles Groat
Robert Louks

SpeakerDiscussion LeaderSESSION II: OPERATIONAL FACTORS 2:00 p.m. - 5:00 p.m.

Industry Experience

H. C. Corbell
Marathon Oil Company

Strategic Petroleum
Reserve Program
Experience

William Hahn
Richard Smith
U. S. Dept. of Energy

Discussion 3:00 - 4:15

Group A

Larry Owen
Lawrence Livermore
Laboratory

Group B

Jay Lehr
National Water Well
Association

Discussion Summary
4:15 - 4:40

Jay Lehr
Larry Owen

SESSION III: FLUID/FORMATION COMPATIBILITY - 8:15 a.m. - 10:30 a.m.
Wednesday, March 7Fluid/Formation
Compatibility

Erle Donaldson
DOE, Bartlesville

Discussion 8:50 - 10:10

Group A

R. M. Lasater
Halliburton Services

Group B

Ken Davis
Ken Davis Assoc.

Discussion Summary
10:10 - 10:30

Ken Davis
R. M. Lasater

SpeakerDiscussion LeaderSESSION IV: FLUID MIGRATION 10:30 a.m. - 12:00 noon

Leakage Through Abandoned
Wells; Interference with
Oil and Gas Production

Robert Bates
La. Dept. of Natural
Resources

George Singletary
Texas Railroad
Commission

Discussion 11:00 - 12:00

Group A

Robert Bates

Group B

George Singletary

Discussion Summary
12:00 - 12:20

Robert Bates
George Singletary

WORKSHOP CRITIQUE 12:20 noon - 12:40 p.m.

Jay Lehr
National Water Well
Association

Darrell Greenwell
Dept. of Energy
Dallas, Texas

APPENDIX 7

SUBSURFACE DISPOSAL: HYDROGEOLOGIC AND OPERATIONAL CONCERNS

By:

Ann L. Bachman
Energy Programs Office
Louisiana State University

Charles G. Smith
Consulting Geologist
Baton Rouge, Louisiana

A paper presented at the Engineering Foundation
Conference on Geopressured-Geothermal Energy at
Sea Island, Georgia

January 1980

SUBSURFACE DISPOSAL: HYDROGEOLOGIC AND OPERATIONAL CONCERNS

A. L. Bachman and C. G. Smith

INTRODUCTION

This paper presents the results of an invitational workshop on subsurface disposal of geopressured fluids that was held at Louisiana State University in March 1979.¹ Workshop participants included industry representatives and researchers in the geopressure field, as well as individuals with experience in disposal in the Strategic Petroleum Reserve (SPR) Program and in industrial and oil-field operations. The LSU Workshop provided the first opportunity for such a group to discuss the potential geologic and operational problems of geopressure injection activities.

An exchange of ideas and information on these topics is long overdue partly because geopressured energy development shares with other kinds of resource development the fact that at the point disposal is required, what was once a product has become a valueless waste. However, subsurface disposal of geopressured fluids is likely to be the only disposal alternative at many sites and is therefore critical to the development of those prospects. Furthermore, there are unique features about disposal in geopressure operations that require special attention. Certainly fluid production per well is expected to be uniquely large, and total volumes for disposal will be huge in comparison to oil and gas field experience.² Geopressured fluids will also be higher in temperature than brines in conventional hydrocarbon operations.³

Given these differences, the data available from oil and gas operations does not suffice in assessing potential disposal problems either technically or as possible impediments to timely commercialization of the resource. The LSU Workshop produced an overview of some of these problems and outlined solutions to them in the areas of hydrogeology, fluid-formation compatibility, operational problems and the potential for fluid migration. Oilfield and SPR experience with brine injection was used to suggest areas of concern and possible solutions, always applying these insights, however, to the unique features of injection in the geopressure case. In fact, there was a large degree of consensus among the Workshop participants that the high volume, high temperature nature of geopressure disposal is of critical importance in assessing potential problems.

Ann L. Bachman is a Senior Research Associate with the Energy Programs Office, Louisiana State University. Charles G. Smith is a consulting geologist in Baton Rouge, Louisiana

A geopressure subsurface disposal operation requires a porous, permeable formation of wide areal extent at depths below the base of fresh and slightly saline water (10,000 mg/l total dissolved solids). Furthermore, a zone of low permeability such as shale must overlie the injection zone to prevent vertical migration of the injected fluid or formation waters. With the average deep occurrence of fresh water in the Gulf Coast at -2,000 feet, the Miocene sands in the interval -2,000 to -5,000 feet is the most likely disposal formation.⁴ Oil and gas field brine disposal is generally within this zone or shallower.⁵ In the Strategic Petroleum Reserve Program, injection is below -5,000 feet but for reasons relating more to the ease of permitting and lack of data on the prior⁶ uses of shallower reservoirs than to hydrogeologic considerations.

The Workshop participants were in agreement concerning the availability of adequate disposal sands in the Gulf Coast for injection on the large scale anticipated in geopressure energy development. Sandstones with the required volume, porosity and permeability are plentiful within the -2,000 to -5,000 foot interval although compartmentalizing due to faulting is likely. However, it was the general consensus of the group that this will have a minor effect on injectivity rates if all other factors (sand volumes, permeability, etc.) are favorable. This assessment is due primarily to the expectation that geopressure injection systems will not be developed in geologically complex areas. Where large displacements in the Miocene sands do create no-flow barriers, they should divide the sands into such large blocks that the volume will still be adequate.

Variability in the major hydrogeologic parameters is great enough, the group agreed, to require site specific studies of lateral continuity and permeability. In fact, the Workshop participants suggested that in an operation on as large a scale as geopressure resource development, prior investigation of the hydraulics of a particular disposal aquifer is critical to the success of the operation and should be done in more detail than is usually the case in oil and gas field practice.

A regional study of sandstone volume in the Miocene sands is not necessary, the group suggested. In such a study, the potential for disposal would be evaluated in many areas that are out of the question for geopressure resource production. Also, the variability of the most important parameters is on too small a scale for useful interpretation by a regional study.

Several cases of fault activation as a result of injection of fluids have been documented. In the Baldwin Hills area of Los Angeles, increased injection of brines for oil recovery, and waste disposal is thought to have triggered surface faulting.⁷ Similarly, injection of fluids in the Rangely, Colorado oilfield is thought to have caused slippage of faults resulting in earth tremors.⁸ Although there was no consensus among the Workshop participants about the probability of fault activation or seismicity occurring as a result of geopressured fluid injection, the group agreed that there is cause for concern if not alarm. On the plus side of the question, it was noted that the geology of the Gulf Coast is very different than the geology of the regions with documented cases. In the Gulf

Coast there is no significant history of seismicity; strain tends to be released gradually rather than abruptly. On the other hand, it was pointed out that the geopressure case will be a much higher volume, higher injection rate operation compared with the Rangeley and Baldwin Hills examples. As a precaution, the group recommended that geopressure operators monitor earth movement in conjunction with the injection history during disposal operations.

FLUID/FORMATION COMPATIBILITY

Fluid/fluid compatibility was a major topic for discussion at the LSU Workshop because of the assumption that the relatively shallow disposal formation waters and the deep geopressured fluids will differ significantly in solution composition and temperature. In fact, Hanor reports in his recent investigation of this question in the south Louisiana region that significant differences in salinity and in dissolved Ca, Sr, Fe and SO_4 do exist between waters of the two zones. He concluded that the probability is therefore high that sulfates and carbonates of Ca, Sr, and Ba, and Fe carbonates will precipitate if these waters are mixed. This could cause plugging at the wellbore or in the formation.

There was a consensus among the Workshop participants that achieving fluid/fluid compatibility in the geopressure case presents no special technical problems because incompatibility conditions can be corrected through the use of buffer fluids. It was agreed, however, that large volume injection situations like that expected in geopressured fluid disposal warrant a thorough analysis of the potential problems prior to injection. This will require site specific data on the chemical and physical properties of the geopressured and disposal zone fluids, as well as data on the changes in solution composition, temperature and pressure expected to occur during processing.

The fluid/formation compatibility problem of most concern is clay hydration. Montmorillonite, a common Gulf Coast clay, has the base ion exchange and hydration properties that cause swelling, upon contact with water.¹⁰ However, several Workshop participants noted that clay hydration should not occur if the injected fluids contain more than 20,000 mg/l total dissolved solids, and that Kharaka's investigations show Gulf Coast geopressure waters to be generally above that concentration.¹¹ Again, the group agreed that the problem should be investigated in advance of actual disposal at a site and that this will require coring the disposal zone.

OPERATIONAL FACTORS

Kharaka's research also shows that the scaling and corrosion properties of geopressured fluids are different than those of oil and gas field brines. The higher salinities, calcium concentrations and temperatures are of concern in terms of corrosion, although the absence of dissolved oxygen and sulfate reducing bacteria from the fluids and the high pH values will slow corrosion. Scale formation could be problematic because carbonates of Ca, Sr and Ba, and sulfate

of Ba may precipitate as temperatures change during production and processing.¹² Erosion may also be a more serious problem than in conventional oil and gas production if sand is produced with the geopressured fluids or if precipitation occurs, because of the higher flow rates expected and the lack of oil carry over. All of these processes affect the disposal activity because suspended solids in the waste stream could foul the injection pumps and plug the disposal wellbore and formation.

The Workshop participants noted that while scale formation, corrosion and erosion may be more serious in the geopressure case, they are not unique and have been successfully dealt with in oil and gas field operations through combinations of chemical treatment, sedimentation, filtration and aeration. It was pointed out that the ability to predict chemical precipitation is very important, in planning the appropriate fluid treatment and that existing models should be improved and applied in the site specific situations. There was a consensus that the real problem facing the geopressure operator in this regard, however, is the economics of producing an acceptable quality effluent when such large amounts of waste fluids must be handled. The group recommended detailed economic assessments of surface treatment.

Another way in which the scale of geopressure operations affects the economics of disposal is through the design of the back-up disposal system. An extensive back-up system would be critical to the economics of disposal. It was suggested that the size of the back-up system will depend in part on how much fluid treatment is planned on the premise that a high quality effluent will reduce downtime in the primary disposal system. Another decision factor is how desirable it is to maintain production, assuming that holding ponds of sufficient capacity are not feasible for continued production in the event of disposal well failure. Several Workshop participants pointed out that a sustained flow is necessary if electricity generation or process heat uses are part of the operation. Others thought that producing wells should not be shut in frequently because the well casing would be subjected to undue stress due to thermal shock. It was agreed that the economics of energy production vis-a-vis treatment costs and the costs of back-up disposal capacity are key relationships and should be thoroughly studied.

The following additional points were made about operating a geopressure disposal system:

1. Suspended solids should be thoroughly filtered from the waste stream to avoid erosion and plugging problems. In the SPR program, suspended solids concentrations as low as 2 ppm were found to be very damaging to the disposal wells.
2. Human error such as introduction of suspended solids into the waste stream and bacteriological contamination of the formation can cause serious injectivity problems. Therefore, operational procedures should be very closely controlled.
3. Closed systems for surface handling of fluids are

preferable to open systems in which aeration completes oxidation and solids are filtered from the waste stream. Closed systems cost less, are simpler to operate, and produce an effluent as near to what was originally withdrawn as possible. Closed systems are recommended for geopressure operations in which fluid handling is at a minimum (i.e., methane recovery alone) since it is difficult to prevent all exposure to the atmosphere with more complex processing.

FLUID MIGRATION

The objective of both federal and state regulations on the injection of wastes is to protect fresh water aquifers and the surface environment from the contamination that would result from migration of the injected fluids or displaced native fluids. In the geopressure case, the anticipated large scale of injection has underlined this concern. To assess the problem, the Workshop participants reviewed: (1) reported cases of injected fluid reaching the surface in Gulf Coast disposal operations; (2) the mechanisms for migration away from the intended disposal zone; and (3) the effect of federal regulations on injection in the geopressure case.

In Louisiana, only a few cases of fluid migration from an injection well to the surface through an abandoned well have been reported. Several of these occurred because injection was taking place too close to the flanks of salt domes.¹³ The Workshop participants agreed that it is unlikely that geopressure wells will be located adjacent to these or other structures because the objective is to find large systems to produce, not "traps."

Both Texas and Louisiana have the problem of numerous wells drilled before effective state regulation that are improperly plugged or unplugged.¹⁴ These can and do act as conduits to the surface for injected fluids or displaced native fluids. One Workshop participant pointed out that uncased and unplugged holes did not stay open long in the Gulf Coast because clays flow into the uncased hole and seal it. The "natural" clay plugs can have lower permeability than concrete, it was noted.

The Railroad Commission of Texas, which regulates subsurface disposal in the state, uses a rule of thumb on allowable injection pressures to avoid some of these problems.¹⁵ In general, the subject of overpressuring a disposal aquifer was emphasized in the Workshop discussions of fluid migration. The general conclusion of the group was that overpressuring is unlikely and can be avoided through prior testing of the disposal formation and thorough monitoring.

First, it was noted that while overpressuring does cause fracturing in the Gulf Coast, the fractures probably do not extend close to the surface because of the unconsolidated nature of the sands. Second, it was observed that confinement of the injected fluids to a particular formation (and from less saline ones) does not require absolute isolation in the sense of impermeable barriers such as facies changes and faults. Rather, effective confinement can take place in a large system in the Gulf Coast because the natural Gulfward and downdip movement of fresh water serves to

isolate the injected fluids. In such a system, a large amount of native fluid would be displaced near the wellbore but there would not be sufficient movement of the native fluid out in formation.

Finally, adequate prior planning for the disposal system and monitoring during injection are effective means for avoiding fluid migration problems, it was agreed. Disposal wells should be cored to assess the potential for clay hydration which would quickly plug a formation and lead to overpressuring. Pressure interference between wells can be simulated for different configurations of well placement¹⁶ with a final well configuration chosen to minimize interference. A fracture pressure gradient should be calculated for the disposal zone on the basis of injectivity tests and hydrogeologic assessments, and the injection pressure at the surface controlled accordingly to avoid pressure build-up. Certainly, good cement bonds in the disposal well casings are vital, and injection pressures in the casing annulus should be monitored.

It was pointed out by several Workshop participants that present and future uses of formations adjacent to the geopressure disposal zones, or the disposal zones themselves, need to be protected as well. The specific case of fluid migration into a productive hydrocarbon zone as a result of geopressure disposal activities was not thought to be a problem by the group. Neither the Louisiana nor the Texas regulatory agency representative anticipated difficulties of this kind or could cite any examples.¹⁷ It was pointed out, however, that a geopressure disposal zone was likely to be pressured-up, if not overpressured, and that future oil and gas operators should be apprised of this. A related, if not so easily resolved, problem faces the operator interested in producing water for methane extraction from the hydropressure zone (i.e., the shallower zones of hydrostatic water pressure). The possibility exists that Gulf Coast sandstones in the interval -2,000 to -5,000 feet could be attractive both for waste disposal and as an energy resource.

CONCLUSION

The participants in the LSU Workshop showed a high degree of consensus on several important issues. First, the group agreed that the technology is available for dealing with the compatibility and operational problems of subsurface disposal. This idea was expressed explicitly as well as in the frequent references to the experience with disposal of oilfield brines and in the SPR Program. Second, the group agreed that the large scale of geopressured disposal operations--the huge total volumes anticipated and the high injectivity rates that we hope can be sustained for long periods--is unique to the development of geopressured resources and the key factor in assessing potential problems. There was a general consensus that the hydrogeologic and operating problems facing the geopressure operator will differ in scale and not in kind from those dealt with routinely in conventional oil and gas field disposal systems.

Thus, the real problems, the Workshop participants agreed, concern the economics of disposal. Compatible fluids, consistently high injection rates, and adequate back-up disposal system can be obtained but at a price we may not be able to afford. It was

therefore the consensus of the group that detailed economic evaluations of the disposal activity should be made to identify those areas with the greatest potential for cost reduction. 244

NOTES

¹A full report of the Workshop can be found in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, Ann L. Bachman, editor, Energy Programs Office, Louisiana State University, March 1980.

²See C. F. Knutson and C. R. Boardman, An Assessment of Subsurface Salt Water and Disposal Experience on the Texas and Louisiana Gulf Coast for Application to Disposal from Geopressured Geothermal Wells: Topical Report, Prepared for DOE under contract No. EY-77-C-08-1531, C. K. GeoEnergy Corp., Las Vegas, Nevada, August 1978.

³Yousif K. Kharaka, et al., "Corrosion and Scale-Formation Prospects of Geopressured Geothermal Waters from the Northern Gulf of Mexico Basin," in Proceedings, Society of Petroleum Engineers (SPE) of AIME International Symposium on Oilfield and Geothermal Chemistry, Houston, Texas, January 22-24, 1979.

⁴Raymond H. Wallace, "Gulf Coast Geopressured-Geothermal Resources as Related to Hydrogeologic Characteristics of the Subsurface System for Disposal of Spent Brines," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, Ann L. Bachman, editor, Energy Programs Office, Louisiana State University, March 1980.

⁵Knutson and Boardman.

⁶William J. Hahn and Richard E. Smith, "Programmatic and Technical Aspects of Subsurface Brine Disposal: Experiences of the Strategic Petroleum Reserve (SPR)," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, Ann L. Bachman, editor, Energy Programs Office, Louisiana State University, March 1980.

⁷D. H. Hamilton and R. L. Meehan, "Ground Rupture in the Baldwin Hills," Science 172 (April 23, 1971): 333-344.

⁸H. K. Van Poolen and O. B. Hoover, "Waste Disposal and Earthquakes at the Rocky Mountain Arsenal, Derby, Colorado," Journal of Petroleum Technology, 21 (September 1969): 983-993.

⁹Jeffrey S. Hanor, A Report on the Salinity and Geochemistry of Shallow Groundwaters in South Louisiana and their Potential for Reacting with Injected Geothermal Wastes: Part 1: Observations, Conclusions, and Suggestions for Further Study, Prepared for Interagency Agreement No. 110103017903 of Louisiana Department of Natural Resources and Louisiana State University, Department of Geology, Louisiana State University.

¹⁰Erle C. Donaldson, "Subsurface Disposal of Brines from Geopressured Reservoirs," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, Ann L. Bachman, editor, Energy Programs Office, Louisiana State University, March 1980.

¹¹Yousif K. Kharaka, et al. "Chemistry of Waters in the Geopressured Zone from Coastal Louisiana: Implications for the Geothermal Development," Geothermal Resources Council, Transactions 2 (July 1978): 371-374; and Karaka, et al. "Geochemistry of Geopressured Geothermal Waters from the Frio Clay in the Gulf Coast Region of Texas," Geology 5, 241-244.

¹²Kharaka, "Corrosion and Scale-Formation Properties."

¹³Robert Bates, "Fluid Migration: The Louisiana Experience," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, Ann L. Bachman, editor, Energy Programs Office, Louisiana State University, March 1980.

¹⁴Bates; and George Singletary, "Fluid Migration: The Texas Experience," in Proceedings: Workshop on Subsurface Disposal of Geopressured Fluids, Ann L. Bachman, editor, Energy Programs Office, Louisiana State University, March 1980.

¹⁵Singletary.

¹⁶Donaldson.

¹⁷Bates and Singletary.

APPENDIX 8

ASSESSING THE SOCIO-ECONOMIC IMPACT OF GEOPRESSURED/GEOTHERMAL ENERGY DEVELOPMENT IN COASTAL LOUISIANA: A PRELIMINARY REPORT

By:

Michael D. Grimes
Department of Sociology
Louisiana State University

Deborah L. Saucier
Energy Programs Office
Louisiana State University

A paper presented at The Fourth United States Gulf
Coast Geopressured/Geothermal Energy Conference:
Research and Development, at Austin, Texas

October 31, 1979

ASSESSING THE SOCIO-ECONOMIC IMPACT OF GEOPRESSURED/GEOTHERMAL
ENERGY DEVELOPMENT IN COASTAL LOUISIANA: A PRELIMINARY REPORT

Michael D. Grimes, Department of Sociology,
Louisiana State University
Baton Rouge

Deborah L. Saucier, Energy Programs Office,
Louisiana State University
Baton Rouge

A crucial consideration in geopressured/geothermal (hereafter noted as GP/GT) energy development is the impact of the development upon the area surrounding the site. While attention in the past focused almost exclusively on a cost-benefit analysis of purely economic factors, it has become increasingly apparent that such a focus is too narrow and that other factors deserve scrutiny as well (Leopold, et al., 1971). Perhaps foremost among these other factors are the environmental effects of development.¹ With the passage of the Environmental Policy Act in 1969, the federal government gave formal recognition to the importance of environmental considerations in developmental decision-making as the:

...objective of the act... (was) to build into agency decision-making process an appropriate and careful consideration of the environmental aspects of proposed action. (Council on Environmental Quality, 1971:1399).

One outgrowth of this act and the administrative guidelines detailing its role in the process of development is the environmental impact statement. Such a statement is a:

...detailed assessment of the effect of a proposed development on the environment and thus its ecological, separate from its monetary, benefits and costs. (Leopold, et al., 1971:1).

Included as well in this act is the extension of the parameters of impact assessment to include the socio-economic as well as the physical environment (Council on Environmental Quality, 1971). The purpose of this paper is to consider the potential socio-economic impacts of GP/GT energy development in coastal Louisiana.

Establishing Procedures

While the Environmental Quality Act was clear in its provision for the assessment of environmental impacts, it was rather ambiguous in terms of just how these assessments were to be made (Gillette, 1971:1130). In response to this ambiguity, several efforts have attempted to systematize the form and procedures for impact assessment (Leopold, et al., 1971; Potter, 1978).² One scheme proposed that a "complete environmental impact statement" consists of four basic items:

1. A complete analysis of the need for the proposed action...
2. An informative description of the environment to be involved, including a careful consideration of the boundaries of a project...
3. A discussion of the pertinent details of the proposed action...
4. An assessment of the probable impacts of the variety of specific aspects of the proposed action upon the variety of existing environmental elements and factors (Leopold, et al., 1971:4).

We are primarily interested here in the last three of these items, particularly items two and four.

Socio-Economic Impact Assessment. As noted above, our primary interest is in the area of the environment commonly known as the "socio-economic" environment. As Stenehjem and Allen (1978:215) explain:

Local socio-economic impacts result from economic, institutional, and social changes following the siting, construction, and operation of energy facilities. The interdependencies among labor supply, local public capital, and the availability of accessible sources of goods and services circumscribe the most important spheres of socioeconomic impact.

These authors also state that the factors which determine the impact of energy development at the local level may be grouped into two broad categories: those associated with the host county (which they call "site specific" factors) and those associated with the scale of the facility (technology-specific" factors) (Stenehjem and Allen, 1978:216). These two categories of influence will form the basis for our analysis and discussion below.

Representing the Socio-Economic Environment. While, as noted above, both the rationale and procedures for environmental impact assessment have been established, there is less clear agreement on few guidelines for selecting aspects of the socio-economic environment for analysis.³ For any unit of analysis, a myriad of variables is available from secondary sources for use in characterizing this environment. The problem then, becomes (1) is there a parsimonious sub-set of these variables which can be used to represent this environment; and (2) how may such variables be selected? Researchers in community and urban ecology have begun to use the technique of factor analysis in an attempt to answer these questions (Berry and Kasarda, 1978). This technique mathematically examines the interrelationships among a group of variables and represents their common

variance by means of a smaller set of "dimensions" (Fructer, 1954; Rummel, 1967). These "summary" variables may then be either used collectively as a surrogate for the entire group of variables or they may be used as a means for selecting from the group of variables a sub-set to represent the total set. Application of such procedures to a variety of different geo-political units (such as cities, SMSA's and counties) has generally isolated the following set of dimensions: population size and composition, age structure of the population, general social educational and economic structure of the population, and employment status of the population. We made use of these findings as guidelines for the selection of the variables to be used in this analysis.

A comparison between these findings and those used in the particular context of socio-economic impact assessment reveals considerable overlap.⁴ Thus, the selection of a particular sub-set of variables to represent the socio-economic environments of the five (5) potential development sites in coastal Louisiana was guided by several influences: (1) the research on community/urban structure; (2) socio-economic impact assessment research; (3) the particular character of this research problem (i.e., coastal Louisiana); and (4) the nature of available data resources. The variables selected are presented in Table One.

Units of Analysis and Comparison Strategy. An important decision facing the socio-economic impact analyst is the choice of a unit of analysis. In this context, when compared to some of the other "impacts" of GP/GT energy development (i.e., disposal problems, subsidence) socio-economic impacts are a bit more difficult to localize. An additional

Table 1

**DIMENSIONS OF THE SOCIOECONOMIC ENVIRONMENT
AND THE VARIABLES SELECTED**

- o Population Size and Composition**
 - Population size and composition
 - Changes in population
 - Population density
 - Percent of urban population
 - Percent of Black population
- o Labor Force Characteristics**
 - Most recent unemployment rate
 - Trends in unemployment
 - Occupational distribution
- o Economic Characteristics**
 - Per capita income
 - Percent of families below low income level
 - Median earnings for selected occupational groups
- o Educational Characteristics**
 - Percent of persons 25 years of age and older completing four years of high school or more
 - Percent of persons 25 years of age and older completing less than 5 years of schooling
 - Median years of school completed
- o Health Services**
 - Hospital beds, per capita
 - Number of physicians, per 10,000 population

constraint is that gathering the types of information necessary to make such assessments is very expensive. The tendency, then, has been to make use of existing data. A major source for data of this variety is information collected by local, state and national governmental bodies in the normal course of their operations. However, these data often use units of analysis which do not coincide perfectly with the parameters of the impact problem. The result is that choice of a unit of analysis will be the result of the interaction between an "ideal" impact area defined by the researcher and the geo-political boundary units used by existing data sources. In this particular instance, the most likely unit of analysis is the county (or county equivalent). Among the most salient reasons for this choice are: (1) the county is the one unit below the level of the state for which a wide variety of comparable measures are available; (2) the use of the county allows the inclusion of both urban and rural areas; and (3) the use of either larger (state-level) or smaller (city-level) units of analysis (especially in this context) are less appropriate (cf Ronjean et al., 1969). In this analysis, we will make use of the county equivalent in Louisiana, the parish. Comparisons will be made between the six site parishes and two larger units of analysis--the state planning districts⁵ and the state as a whole--on a variety of different socio-economic indicators to establish a baseline reference for each target site. The locations of these sites and units of analysis are presented in Table Two.

Baseline Socio-Economic Profiles

This section of the paper presents profiles for each of the five

Table 2
POTENTIAL GEOPRESSURED SITES : LOUISIANA GULF COAST

Table 3
BASELINE SOCIOECONOMIC INDICATORS FOR SITE PARISHES,
PLANNING DISTRICTS AND STATE

	LOUISIANA	DISTRICT 3	LAFOURCHE	TERREBONNE	DISTRICT 4	ST.MARY	VERMILION	DISTRICT 5	CALCASIEU	CAMERON
POPULATION	3,966,168	270,393	76,903	89,438	514,288	61,699	46,972	247,150	157,730	9,528
POPULATION DENSITY	85	79	63	60	117	97	37	47	137	6
% URBAN	66.1		39	52.6		65.3	38.4		74.6	----
% POPULATION CHANGE 1960-1970	8.8	13.7	11.5	17.6	9.5	1.6	9.1	9.0	8.5	16.3
% BLACK	29.2	23.7	11.5	18.1	26.9	28.6	13.6	20.9	21.8	6.9
% TOTAL UNEMPLOYED	7.0	8.1	5.7	5.7	6.7	6.1	6.6	8.7	8.0	7.4
% BLACK LABOR FORCE	26.1	21.3	10.9	16.3	22.4	25.1	13.1	18.0	18.7	8.0
% BLACK UNEMPLOYED	11.1	12.8	14.3	12.1	10.9	12.9	12.1	12.0	12.5	20.2
INCREASE IN NON-FARM EMPLOYMENT 1971-1976	15.0		27.0	35.0		32.0	36.0		23.0	5.0
MEDIAN SCHOOL YEARS	10.8		8.5	9.8		9.9	8.3		11.7	9.4
% POPULATION WITH 5 YEARS OF SCHOOL,	13.1		23.7	18.9		17.6	25.3		11.8	14.8
% POPULATION WITH 4 YEARS HIGH SCHOOL	42.2		31.3	35.6		37.3	27.6		48.3	32.4
PER CAPITA INCOME	\$5,910		5,683	6,474		6,246	5,116		6,223	5,345
% FAMILIES BELOW POVERTY LEVEL	21.6		15.6	15.6		19.0	25.2		16.6	16.7
PUBLIC ASSISTANCE PER CAPITA	\$ 115	72	56	58	158	90	97	87	76	31
* HOSPITAL BEDS PER 1,000	5.08	3.5	4.0	4.2	4.37	3.7	5.3	4.73	5.03	2.83
* PHYSICIANS PER 10,000	13	5.0	8.0	7.0	9.0	7.0	6.0	9.0	12.0	3.0

target sites in coastal Louisiana using the indicators presented above (see Table Three). Potential socio-economic impacts will then be assessed using the baseline profiles as reference points.

Lafourche. Of the 6-parish study area, Lafourche Parish has the highest percentage of surface area taken up by surface water bodies. While the total surface area of the parish is 1,388,387 acres, almost 75% of that is underdeveloped swamps, marshes, and water surfaces; agricultural land use accounts for 8.6%.

Residential, commercial and industrial land use account for only 8% of total land use; of this, 86% or 92,000 acres is utilized for oil and gas extraction (Land Use Data Analysis System, State Planning Office, Louisiana, 1975).

Although only a relatively small percentage of the parish's total surface area is developed, the parish has maintained a steady growth in population. The 1970 census recorded the parish population at 68,941. By 1976 the census revised estimates indicated the population had increased to 74,955; an 8.7% increase. Population projections prepared by Louisiana Tech for 1978, predict a population of 76,903, reflecting an overall increase from 1970-1978 of 11.5% (Denton, 1979). Although this is somewhat better than the 13.7% increase predicted for the district as a whole, it is still well above the 8.8% increase estimated for the state.

Lafourche Parish is approximately 39% urban, with a population density of 63 persons per square mile. The largest town in the Parish, Thibodaux, has a population of less than 18,000 (City and County Data Book, 1977). Population distribution in the parish is somewhat below that of the state and the district. Blacks represent only 11.5% of the parish population, in comparison to 23.7% of the district, and 29.2%

of the state population.

In the area of unemployment, the parish has reported unemployment rates well below those for the state during the last five years. The parish unemployment rate for 1978 was 5.7%, somewhat below the 7% statewide unemployment rate, and the 8.15% district unemployment rate (Louisiana Manpower Information Report, 1979). Black unemployment rates are much higher in relation to their representation in the parish labor force. Although Blacks comprise only 10.9% of the parish labor force, they face an unemployment rate of 14.3% (Louisiana Manpower Information Report, 1979). Statewide, Blacks represent 26% of the labor force, with an 11.1% unemployment rate.

During the period 1971-1976, over 3,500 non-farm jobs were added in the parish, showing a 27% increase (O'Boyle, 1978). For 1978, the parish labor force totaled over 32,600 persons engaged in non-farm employment. Major employment areas were: manufacturing, specifically food products and sugar refining, transportation and retail trade. Major occupational distributions within the labor force were: professional/technical - 21%; craftsmen/foremen - 16.3%; and blue collar, 21.7% (Louisiana Manpower Information Report, 1979). Farm employment comprised 3.6% of the total labor force. Farm employment which had experienced increases from 1970-1975 began to decline in 1975, and reached its lowest point in 10 years in 1978 (Bureau of Economic Analysis, 1978).

Although the parish has relatively low unemployment rates and steady growth in non-farm employment, Lafourche is slightly below district and state per capita income levels. Per capita income for the parish, for 1977, was \$5,684 as compared with the statewide per capita of \$5,910 and

the district per capita of \$5,826. The percent change in per capita income for the parish during the period 1969 to 1977 was still above the overall percent change for the state (Survey of Current Business, 1979).

According to the 1970 census, 15.6% of the parish families were classified as being below the poverty level. As such, the parish compared favorably to the statewide rate of 21.6% (City and County Data Book, 1977) . Public assistance payments made to parish residents has increased from 1970-1977. The 1977 level of public assistance was \$4,249 or \$56.00 per capita (Bureau of Economic Analysis, 1978).

In the area of education, the parish is somewhat below the statewide median number of school years completed. The parish reported for the 1970 census, that the median number of school years completed in the parish was 8.5, slightly below the statewide median of 10.8 years. At the same time, 27.3% of the parish residents had less than 5 years of schooling, while 31.3% had completed four years of high school.

Medical services offered to parish residents compare quite favorably with those offered throughout the district as a whole, but are slightly below the statewide average. For 1978, the parish had 4.0 hospital beds per 1,000 population, as compared with the district figure of 3.5 beds, and the statewide average of 5.08 beds per 1,000 population. By 1978, the parish had 8 physicians per 10,000 population. (Louisiana State Board of Medical Examiners, 1974-1978)

Terrebonne Parish. Terrebonne Parish is the easternmost parish in the six-parish study area and is the largest in terms of total acreage. Of the 1,470,885 acres which make up the parish, 58% is land area and

44% is classified as wetlands, with another 41% streams, bays, estuaries and waterways. The northern portion of the parish is dominated by alluvial levee systems which provide the higher land elevations and are therefore the location of the major agricultural and residential development in the parish. The wetlands adjacent to the levee systems are typically cypress-tupelo gum swamps. The western portion of the parish is predominantly marsh, which accounts for over 44% of the total land area in the parish. In the central portion of the parish, Bayou Terrebonne, the major waterway, branches out and forms five distributive channels, each of which have formed individual levee systems where separate communities have developed over time. Like many of the parishes in the coastal zone region, Terrebonne Parish has only a small percentage of its total land area in residential, commercial and/or industrial use - only 6.5% of the parish's land area is developed; another 3.7% is devoted to agriculture, and 6.4% is utilized for oil and gas extraction (Land Use Data Analysis System, State Planning Office, 1975).

The lack of sizeable land areas for development has not constrained population growth in the parish. The 1970 census placed the parish population at 76,049; by 1976, census estimates had increased that figure to 85,591, reflecting a 12.5% increase. Current population projections by Louisiana Tech forecasts the parish population to be over 89,000 in 1978, showing a net increase from 1970-1978 of 17.6%. This is well above the projected 13.7% for the planning district and 8.8% projected overall increase for the state. The parish is just over 52% urban (City and County Data Book, 1977), with approximately 60 persons per square mile. The city of Houma, which is the only incorporated community in

the parish (Burk and Associates, 1977), has an estimated 1978 population of over 30,000 (Denton, 1979), which is approximately 75% of the total urban population. Population distribution in the parish is somewhat below state and district averages. Blacks represent only 18% of the parish population, although they make up 24% of the district population and 29.2% of the state population.

During the last 5 years, Terrebonne Parish has reported unemployment rates below both state and district levels. For 1978, the unemployment rate in the parish was only 5.7%, as compared with 7% unemployment rate for the state and 8.1% for the district (Louisiana Manpower Information Report, 1979).

Here, too, unemployment rates are higher for Blacks. Although they make up only 16.3% of the total labor force, Blacks in Terrebonne Parish face unemployment rates of 12.1%. District figures are likewise high, showing 12.8% unemployment for Blacks, while the state reported an overall 11.1% unemployment rate for Blacks.

Over the last five years, Terrebonne Parish has experienced a very favorable increase in non-farm employment. From 1971-1976, over 8,000 new jobs were added, reflecting a 39% increase in non-farm employment. In 1977, the parish reported almost 36,000 persons engaged in non-farm employment. Farm employment has likewise seen a slight increase, adding approximately 200 jobs over the last five years (Louisiana Manpower Information Report, 1979). Primary employment in the parish was in the areas of: oil and gas extraction and field services; manufacturing, primarily food products, transportation and public utilities and wholesale trade and services (City and County Data Book, 1977). Of those non-farm jobs

held in 1978, 22% were classified as professional/technical; 15.7% were craftsmen/foremen; and another 22% were blue collar. Of the total labor force in the parish, only 1.9% were classified as farm workers. However, farm employment has shown modest increases from 1977 and 1978 (Louisiana Manpower Information Report, 1979).

Per capita income for the parish was well above state and district figures. The per capita income for the parish for 1977 was \$6,474, as compared with the district's per capita income of \$5,826 and the statewide per capita income of \$5,910. The percentage of parish families below the poverty level in 1970 was 15.6%, well below the 21.6% reported for the state. Public assistance payments, both federal and state, provided to parish residents have been increasing from 1970 to 1977. The current level of public assistance provided to parish residents is \$4.976 million (Bureau of Economic Analysis, 1977).

In the area of education, the median number of school years completed by parish residents was 9.6 years, somewhat lower than the 10.8 years statewide. Although only 18.9% of the parish residents have less than 5 years of school, 35.6% of the 1970 population had more than 4 years of high school.

Medical care available to the parish residents was comparable to that offered by other parishes in the planning district, but somewhat below the statewide level. The number of hospital beds per 1,000 population was 4.2 in 1978; statewide, the figure was 5.08 beds per 1,000 population. A steady increase in the number of physicians in the parish has been noted from 1974-1978, reaching a total of 7 physicians per 10,000 population (Louisiana State Board of Medical Examiners, 1974-1978).

St. Mary Parish. Although St. Mary Parish covers approximately 986,000 acres, swamp and marshland account for almost 47% of the total surface area. For much of the year, water is either on or just below the surface of these marshlands. Natural levee ridges, formed by successive deltaic sedimentation, make up only one-third of the parish's land area and provide the higher land areas needed for agricultural and residential use. The most notable topographic features of the parish are the salt domes which occur on the western and southern tips of the parish.

Since wetlands comprise almost half of the parish's total surface area, there is little land suitable for residential and agricultural use other than the high elevations of these natural levee ridges and salt domes. Residential, commercial and industrial land use account for only 73,000 acres, or 7.4% of total surface area, while agricultural land use accounts for 8.7%. By contrast, over 247,000 acres in the parish are classified as wetlands, salt flats and sand beaches (Land Use Data Analysis System, State Planning Office, Louisiana, 1975). The scarcity of land suitable for development may be one of the factors which have contributed to the relatively small population growth in the parish. According to the 1970 census, there were 60,752 persons in the parish. Census Bureau estimates for 1976 indicate the parish population had increased to 61,794, reflecting an increase of 1,042 additional persons. Recent population estimates prepared by Louisiana Tech University, project that the 1978 population showed a slight decrease from 1976 figures (Denton, 1979). If the projections prove accurate, the parish would have a net overall increase from 1970 to 1978 of only 1.6%. This figure falls far below the estimated 9% population increase projected for the planning district

and the 8.8% overall increase projected for the state.

The parish is 65% urban and relatively densely populated, with almost 100 persons per square mile (City and County Data Book, 1977), ranking it third within the 8-parish planning district. Population percentages for Blacks approximate state and district figures. Blacks represent 28.6% of the parish population, as compared to 29.2% of the state and 26.9% of the planning district (Louisiana Manpower Information Report, 1979).

Unemployment has been consistently below the statewide unemployment rates for the past five years. The 5% unemployment rate reported by the parish is well below the 7% statewide figure, and the 6.7% district average. Unemployment rates are higher, however, for Blacks and reflect similarly higher state and district rates. Blacks make up 25% of the parish labor force, but have a 12.8% unemployment rate. This is in comparison to the 11.1% unemployment rate for Blacks statewide, and 22.4% unemployment for Blacks in the district as a whole (Louisiana Manpower Information Report, 1979).

From 1971 to 1976, over 6,000 non-farm jobs were added in the parish, reflecting a 32% growth rate (O'Boyle, 1978). In 1978, the parish reported over 27,000 persons engaged in non-farm employment. Major employment sectors were: mining, including oil and gas extraction; wholesale and retail trade; services; and transportation and public utilities. During this same period, farm employment has experienced a slight decrease in employment, from a high in 1972 of 1570 employees, to the current figure of 1025 (Bureau of Economic Analysis, 1977). The parish has experienced a steady increase in per capita income from 1969 to 1977. Per capita income in the parish was \$2,660 in 1969; by 1977 it had increased

to \$6,240, an increase of over 130% (Survey of Current Business, 1979). The parish did have 19% of its families below the poverty level, according to the 1970 census. Although this is still below the 21.5% reported statewide and 28.7% reported for the district as a whole (City and County Data Book, 1977). Public assistance payments, both federal and state, were on the increase from 1971 to 1976. For 1977, public assistance payments were slightly less than those for 1976, going from 6.1 million in 1976 to 5.5 million in 1977. However, St. Mary Parish still ranks second within the study area in terms of public assistance payments computed by per capita. In 1977 these payments totaled \$90 per capita for the parish (Bureau of Economic Analysis, 1978).

In the area of education, with respect to the median number of school years completed, St. Mary Parish is slightly above the district average, yet is slightly below the statewide average. For the 1970 census, St. Mary Parish reported that the median number of school years completed by its residents was 9.9. This is somewhat higher than the district average of 8.7 years, but lower than the statewide average of 10.8 school years completed. The census also reported that 17.6% of the parish had less than five years of school, while 37.3% had more than 4 years of high school.

Medical facilities offered to parish residents are somewhat below district levels, as well as the statewide average. For 1978, the parish had 228 hospital beds, which averaged 3.70 beds per 1,000 population. This is in comparison to the district rate of 4.37 beds per 1,000 population and the overall state average of 5.08 beds per 1,000 population. The number of physicians in the parish has increased during the past five

years and now stands at 7 physicians per 10,000 population (Louisiana State Board of Medical Examiners, 1974-1978)

Vermilion Parish. Vermilion Parish is situated in the southwestern portion of the state and acts as the boundary between the southeastern and southwestern portions of the coastal region. Vermilion parish is part of the Deltaic Plain, formed by the periodic changes in the course of the Mississippi River over some 8,000 years. The northern portion of the parish lies within the upland terrace or prairie region, while the southernmost portion of the parish is predominantly marshland. By reclaiming much of this marshland for agricultural use, the parish has been able to utilize a greater portion of its total surface area for agricultural use. In fact, over 31% of the parish's 1,380,000 acres is utilized for agricultural production, making the parish one of the largest agricultural parishes in the state (Bobo, 1977). Residential, commercial and industrial use constitute only .8% of the land area, while wetlands comprise 21% of the surface area, with surface water bodies constituting 45% of the parish (Land Use Data Analysis System, State Planning Office, 1975).

Population in the parish has been steadily growing since 1970. Census figures for that year show that the parish population has reached 43,071. By 1976, revised census estimates indicated a population at 46,156, showing a modest gain of 4.8%. Recent population projections by Louisiana Tech University estimate the parish population for 1978 at 46,972, showing an overall increase from 1970-1978 of 9.1%. This is slightly above the 8.8% population increase projected for the state, and only slightly below the 9.5% increase projected for the district as a whole (Denton, 1979).

Vermilion parish is approximately 38% urban, with a population density of 37 persons per square mile, with a population density of 37 persons per square mile, making it the least densely populated parish in the planning district (City and County Data Book, 1977). Population distribution within the parish is significantly below the state and district averages. Blacks constitute only 13.6% of the parish population, as compared with 29.2% for the state and 26.9% for the district (Louisiana Manpower Information Report, 1979).

As many of the parishes already studied have shown, Vermilion Parish has relatively low unemployment rates for the last five years (Department of Employment Security, 1974-1978).

For 1978, the unemployment rate in the parish, which was reported at 6.6%, was somewhat lower than the 7% reported statewide. Within the 8-parish planning district, Vermilion has the third highest unemployment rate (Louisiana Manpower Information Report, 1979). Unemployment rates, however, are higher for Blacks in the parish. Blacks represent 13.1% of the parish labor force, and face unemployment rate of 12.1%. This is only slightly higher than the statewide unemployment rate for Blacks of 11.1% but slightly higher than the district rate of 10.9% (Louisiana Manpower Information Report, 1979).

The parish made respectable gains in the area of non-farm employment during the period 1971-1976, showing an increase of over 2,200 jobs, and reflecting a 32% increase (O'Boyle, 1978). In 1978, the parish reported over 16,000 persons engaged in non-farm employment. Of this, 19% were classified as professional/technical; 14% craftsmen/foremen; and 19% blue collar.

In addition, 2,000 persons were engaged in agricultural work. This is the highest farm employment rate within the study area, and emphasizes the major role agriculture plays in the parish. Mining, including oil and gas extraction, manufacturing and retail trade are also important areas of employment within the parish (City and County Data Book, 1977).

Given the parish's low unemployment rates and steady increase in jobs, per capita income in the parish has shown a 128% increase for the period 1969-1977. The 1977 parish statistics show that Vermilion ranked 27th among the 64 in the level of per capita income. The 1977 per capita income for the parish was \$5,116, only slightly below the statewide per capita of \$5,910 (Survey of Current Business, 1979).

According to the 1970 census, over 25% of the families in Vermilion Parish were below the poverty level. Public assistance, both federal and state, totaled 4.93 million in 1977, showing a slight decrease from 1975-1976 figures. Nevertheless, the parish still had the highest public assistance payments per capita of the other parishes in the study area. Federal and state public assistance payments in Vermilion Parish amounted to \$97 per capita for 1977 (Bureau of Economic Analysis, 1978).

In terms of education, the parish reported for the 1970 census that the median number of school years completed by parish residents was 8.3, as compared with the state's 10.8 and the district average of 7.7 years. At the same time, 25.3% of the parish had completed less than 5 years of schooling, while 27.6% completed four years of high school or more.

In the area of community service, the parish ranks third in the planning district in relation to the number of hospital beds per 1,000 population. For 1978, the parish had 249 hospital beds. This averages 5.30 beds per 1,000 population. This is well above the district rate of

4.3 beds per 1,000 population. The number of physicians in the parish has increased over the last five years, and now totals 5 physicians per 10,000 population (Louisiana State Board of Medical Examiners, 1974-1978)

Calcasieu Parish. Calcasieu Parish is situated in the southwestern portion of the State, to the north of Cameron Parish. Although it does not share the coastline with the other parishes in the study area, it is included in the state's coastal zone management region. Like Cameron Parish, Calcasieu is located on the Chenier Plain and shows the same unique geographical features of that region. Although Calcasieu Parish has no swamps, it does have rather extensive wetlands. Of the parish's total surface area of 702,000 acres, over 117,000 acres or 16%, are classified as wetlands (Land Use Data Analysis System, State Planning Office, 1975). Residential, commercial and industrial land use accounts for only about 8% of the total area, while agricultural land use accounts for 356,174 acres, or almost 50.7% of the total surface area.

Population in the parish is the largest in the study area, owing to the fact that the Lake Charles SMSA is located here. In 1970 the parish had a total population of 145,416. By 1976, the population was estimated at 154,174. Louisiana Tech University projections estimated the parish population to be 157,730 in 1978, an increase of 8.5% for 1970-1978 (Denton, 1979). Even though the parish has the largest population so far studied, the percentage increase projected for the parish is still below the percentage increases projected for both state and district.

Given the parish's population and inclusion of the Lake Charles SMSA within the parish, it is not surprising that Calcasieu is about 75% urban, and relatively densely populated, with 137 people per square mile

(City and County Data Book, 1977). Population distribution in the parish is comparable with both state and district figures. In 1978, Blacks represented 21.8% of the parish population, while they constituted 29.2% of the state and 20.9% of the district population (Louisiana Manpower Information Report, 1979).

Unlike the parishes previously studied, Calcasieu has experienced unemployment rates consistently above the state average for the last five years. While the 1978 unemployment rate for the state was 7%, Calcasieu Parish reported an unemployment rate of 8.1%. This does, however, fall below the district unemployment rate of 8.7% for 1978. Here, too, unemployment rates for Blacks are slightly higher than the statewide rates, but comparable to the district unemployment rate for Blacks. The 1978 unemployment rate for Blacks, who constitute 18.7% of the parish labor force, was 12.5%. During this same year, the district unemployment rate for Blacks was 12.6%, while the state unemployment rate was 11.1% for Blacks (Louisiana Manpower Information Report, 1979).

During the period 1971-1976, over 8,500 non-farm jobs were added to the parish, reflecting an increase of 23% (O'Boyle, 1978). The total parish labor force for 1978 numbered 59,571 in non-farm employment; another 926 persons were engaged in farm work (Louisiana Manpower Information Report, 1979).

Major employment sectors in the parish are: manufacturing - primarily chemicals and petroleum refining - retail trade and services (City and County Data Book, 1977).

Calcasieu Parish ranks ninth in the state in relation to per capita income. Per capita income for 1977 was \$6,223, an increase of 109% from

the 1969 figure of \$2,973 (Survey of Current Business, 1979). This is well above the statewide per capita income of \$5,910 and the district level of \$4,911.

For the 1970 census, the parish reported that 16.6% of its families were below the poverty level (City and County Data Book, 1977). Public assistance payments, both federal and state, to parish residents totaled 11.8 million for 1977, slightly below the 1976 figure. Public assistance payments for 1977 amounted to \$76 per capita (Bureau of Economic Analysis, 1978).

In relation to the educational level of parish residents, the median number of school years for Calcasieu Parish was 11.7, in contrast to the statewide median number of school years of 10.8. Of the total parish population, 11.8% have less than 5 years of school, and only 4.8% have more than four years of high school.

With respect to the level of medical facilities in the parish, in 1978, there were 5.03 hospital beds per 1,000 population, as compared to 4.73 beds per 1,000 population for the district, and the statewide average of 5.08 beds per 1,000 population. In 1978, there were 11 physicians per 10,000 population (Louisiana State Board of Medical Examiners, 1974 - 1978).

Cameron Parish. Cameron Parish covers over 1,350,000 acres and is one of the five largest parishes in the State of Louisiana. Land use patterns reflect the predominance of marshes, swamps and other water bodies in the parish. Wetlands comprise over 62% of the parish; water surfaces, such as bays, estuaries, and lakes account for another 28.5%, leaving only 8.7% for agricultural use and a scant .8% for residential, commercial and industrial use (Land Use Data Analysis System, State

Planning Office, 1975).

The scarcity of land available for development does not seem to be a factor limiting population growth in the parish. In 1970, the parish population was 8,194. By 1976, the Census Bureau estimated that the population had grown to 9,103, showing a full 11% increase. Louisiana Tech University population projections forecast a continued increase in the population, bringing it to 9,528 by 1978 (Denton, 1970). If the population reached this projected level, it would reflect a net increase of more than 16% from 1970 to 1978, well above both the 9% population change projected for the district, and the 8.8% projected overall statewide population increase.

According to the 1970 census, Cameron Parish is the least densely populated parish in the state, with only 6 persons per square mile (City and County Data Book, 1977). Population distribution within the parish is likewise very low. Blacks represent only 6.6% of the parish population, in contrast to 29.2% of the state population and 20.9% of the district population. As such, Cameron Parish has the smallest Black population within the six-parish study area and the three planning districts (Louisiana Manpower Information Report, 1979).

In the area of unemployment, Cameron Parish reported unemployment rates below the statewide rates for 1974 through 1977. However, for 1978, Cameron had a 7.4% unemployment rate, topping the 7% unemployment rate for the state. This is still below the district average of 8.7% (Louisiana Manpower Information Report, 1979). Unemployment rates for Blacks in the parish are significantly higher and disproportionate to the number of Blacks in the parish. During 1978, Blacks represented 8% of the labor force, yet had an unemployment rate of over 20% statewide.

Blacks represented 26.9% of the total labor force, with an 11.1% unemployment rate. Blacks fared better in the planning district as a whole, where they made up 18% of the district labor force and had an unemployment rate of 12% (Louisiana Manpower Information Report, 1979). In all, the parish has the smallest Black labor force, with the highest unemployment rate for Blacks, within the six-parish study area, and the three planning districts.

From 1971 to 1976, only 118 non-farm jobs were added to the parish, reflecting only a 5% increase for that period (O'Boyle, 1978). Farm employment fared better, as total employment for 1978 was over 3,775 persons, slightly above the 1977 figure of 3,650 (Bureau of Economic Analysis, 1978).

Per capita income for the parish has been steadily increasing from 1969 to 1977. From a per capita income level of \$2,624 in 1969, the 1977 per capita income of \$5,343 reflected a 103% increase.

The 1970 census indicated that 16.7% of the parish families were below the poverty level. This is still well below the 21.6% of families statewide reported to be below the poverty level (City and County Data Book, 1977). For the last five years, public assistance, both federal and state, has been on a slight decline. Total public assistance in 1977, which amounted to 2.85 million, was somewhat below the 1976 figure of 3.14 million. When computed on a per capita basis, Cameron Parish has the lowest level of public assistance payments, providing \$31 per person in the parish.

In the area of education, the 1970 census reported that for the parish residents, the median number of school years completed was 9.4.

as compared with the statewide average of 10.8. The census also reported that 14.8% of the parish residents had received less than five years of schooling, while 32.4% had four years of high school.

Medical facilities available to parish residents are somewhat below the statewide average for the number of hospital beds per 1,000 population. In 1978, the parish had 27 hospital beds, or 2.82 beds per 1,000 population, in comparison to the statewide average of 5.08 beds per 1,000 persons. The number of physicians in the parish has remained fairly constant for the last five years, and remains at three physicians per 10,000 population (Louisiana State Board of Medical Examiners, 1974-1978).

Summary of Baseline Data Profiles. For the most part, the six parishes in the study area have great similarities in regard to population levels, population density and urban/rural divisions. The one exception is Camero Parish, which has no "urban" population. With only six persons per square mile, it is also the least densely populated parish in the study area and state as a whole.

Calcasieu Parish is the only parish with a Standard Metropolitan Statistical Area included within its area.

Racial distributions are either below or approximate the distribution within the state. Here again, Cameron is the exception. The parish has the smallest Black population in the study area and the second lowest in the state as a whole.

In the area of unemployment, all parishes, with the exception of Calcasieu, reported unemployment rates well below the 7% statewide unemployment rate, for the last five years. Calcasieu Parish was the

only one to top this mark, registering an unemployment rate of 8.1% for 1978. Within the study area, Black unemployment was, however, significantly higher than that reported statewide. Interestingly, Cameron Parish, with the lowest percent Black population, had the highest unemployment rate - 20.2% among Blacks, as compared with the 11.1% statewide.

In terms of education, all of the parishes, except Calcasieu, were below the statewide education levels, with lower median number of school years completed, more persons 25 years and older completing less than five years of schooling, and fewer persons 25 years and older completing four years of high school or more.

Medical facilities offered to parish residents were generally below average. Calcasieu Parish had the greatest number of physicians per 10,000 population. In terms of hospital beds, Calcasieu Parish also leads the other parishes with 5.03 beds per 1,000 population, closely approximating the statewide average of 5.08 beds per 1,000 population.

All except one of the six parishes reported lower numbers of families below the poverty level than that of the state as a whole. Of the six parishes, only Vermilion, with 25% of its families below the poverty level, was higher than the 21.6% statewide average. Vermilion is also highest among the six parishes in regard to public assistance payments. For 1977, Vermilion expended \$97 per capita on public assistance payments to parish residents, closely approaching the \$115 per capita spent by the state.

Five of the six parishes had percentage increases in non-farm employment greater than the statewide increase of 15% (O'Boyle, 1978).

Only Cameron Parish with 5% increase in non-farm employment, was below the state's 15% growth level.

Only two of the six parishes (St. Mary and Terrebonne) had per capita income above state per capita level of \$5,910. The remaining parishes were just slightly below the state per capita levels. Median earnings in these six parishes for the most part reflect the industrial character of the labor force in the study area. The three top occupational distributions were: professional/managerial; craftsmen/foremen; and laborers. Calcasieu Parish had the highest median earnings at \$7,551. The influence of the Lake Charles SMSA is clearly seen. Lafourche had the highest median earnings for farm laborers within the study area. It may then be possible to assume that a skilled labor force, capable of performing functions associated with drilling and operating geopressured wells, does exist within the study area, and can be utilized when necessary.

MEASURING THE POTENTIAL SOCIOECONOMIC IMPACT OF GP/GT ENERGY DEVELOPMENT

Scenarios of Energy Development. Turning now to the "technological" side of the impact assessment, scenarios were constructed using data from the techno-economic case studies to represent, for purposes of the socioeconomic impact analysis, potential development alternatives. Two major influences guided the construction of these models. The first was the technology of GP/GT energy development considered generally. The second was a realistic assessment of potential levels of development based upon the resources at the particular sites in question. The results of the interaction between these two factors were two models which represent the ends of a continuum of potential GP/GT energy development in coastal

Louisiana.

The first of these models, called the "minimum model," consists of a single well with two disposal wells and a gas separation plant. The second model, our "maximum model," expands the first to include ten wells (with twenty disposal wells and a gas separation plant). Figure One highlights the timetables and levels of manpower involved from the beginning of the construction phase to production status for each of these models. Data derived from these models will comprise the "technology-specific" parameters for the impact assessment discussed below.

Identifying Potential Impacts. Just what the specific impacts the development of GP/GT energy on the scale suggested by the scenarios presented above will be depends heavily upon the parameters of the question. For example, we will not attempt to deal here with such issues as the contribution which the development will make to the total energy needs of the region (or to the society as a whole for that matter). Aside from the fact that answers to this question remain tentative at this point, this is not the focus of our effort. Our major interest in this paper is the impact which GP/GT energy development will have on quite a narrowly prescribed area--in this instance, the county or counties which contain the proposed development site, and on only one of several potential environments--the socioeconomic. In this light, such impacts may be viewed, at least tentatively, using a calculus of gain or loss for the host community.⁶ However, the decision as to whether a given impact is a gain or a loss depends upon several considerations. Importantly, impacts may have either short- or long-term influence (and these may be different for each). Too, potential impact depends also upon the

Table 4

SOME POTENTIAL SOCIOECONOMIC IMPACTS
OF GP/GT ENERGY DEVELOPMENT AT THE LOCAL LEVEL

- o Jobs
 - New
 - Improved
- o Money to Local Private Economy
 - Wages
 - Royalties
- o Money to Local Public Economy
 - Sales Tax
 - Real estate tax
- o Demands for Increased or New Municipal Services
 - Education
 - Utilities (water, sewer)
 - Health services
 - Transportation (roads, mass transit)
 - Public safety (police and fire protection)
 - Welfare services
- o Demographic Effects
 - Growth of population
 - Change in age distribution
- o Sociocultural Changes

magnitude of the influence compared to the host community's capacity to respond. Here, obviously a large host community with established institutional structures will respond differently from a smaller community with more nascent structures. With these facts in mind, several potential impacts are presented in Table Four. The next section will consider the possible influences of these impacts on the socioeconomic structures of site parishes in coastal Louisiana.⁷

ASSESSMENT OF POTENTIAL SOCIOECONOMIC EFFECTS

Analysis of the potential socioeconomic effects of GP/GT energy development will be divided into short-term and long-term effects for each of the two development models. Here we designate as short-term effects those impacts on the socioeconomic structure of the host parish caused by an increase in local demands for goods and services in conjunction with GP/GT energy development activities. In the "minimum" model this development period is only about six months in duration, while for the "maximum" model, the period extends to about 14-16 months. An example of a short-term effect might be an increased demand for local employees during the construction phase of development. Long-term effects, on the other hand, are those influences on the local socioeconomic structure which will remain after the developmental phase of the project. Using this same commodity, labor, a long-term effect would be the number of permanent jobs which the development of these resources created.

The Effects of the "Minimum" Model. Referring to Figure One, it can be seen that initially about fifteen employees will be necessary

Figure 1

during the first four months of development in any of the host parishes. This figure will increase to about 40 employees during the fourth month, and will then fall to about five employees only as construction ends and production begins. Employment will then remain at this level for the duration of the production period.⁸ Given the population composition of even the smallest of the host parishes, the addition of such a small number temporarily and an even smaller number over the long run will have little, if any effect on any of the indicators for this dimension of the socioeconomic structure. As indicated in Table Three, population sizes in all but one of the parishes (Cameron) are such that these negligible contributions are virtually meaningless. Even for Cameron Parish, these effects will be small either in the short- or the long-term for the "minimum" model of development.

This same situation holds true for the labor force characteristics of the host parishes. Because of the nature of this particular technology,⁹ many of the few additional jobs which the "minimum" level of development will generate will be filled by outsiders, leaving only a few minimum-skill-level jobs for locals. Thus, no appreciable effects for either the short-term or the long-term will be felt by either the total work force of the host parishes or particular segments of this work force.

Generally, there are two major ways in which GP/GT development might influence the educational characteristics of the population. The first is through heavy in-migration of persons with higher levels of education than the host population. The second is through greater demands on the educational system brought about by dependents of these same migrants. In both the short and the long run, however, the levels of impact stimulated by the "minimum" model don't seem to satisfy either of these

conditions for influence. Even to the extent that, in the short run, dependents of workers during the construction phase of development do attend local educational institutions, not much noticeable influence is anticipated.

Turning now to the economic characteristics of the host parishes, again there are several ways in which the GP/GT energy development may impact the host parishes. The expenditures of wages and salaries in the local economy is one way. With average salaries of about \$15,000 per worker, certainly some influence on the local economy will be felt. This will only be true, however, if workers, even for the brief period they are working on a particular site, take up residence in the host parishes and/or otherwise spend their paychecks there. Given the proximity of several of the host parishes to metropolitan areas outside their boundaries, however, many of these benefits may not filter into the local economy. Even those revenues which do enter the local economy will be short-lived since in the long run the work force will shrink to six workers only. Another manner of influence is through the royalties paid to local landowners. These could, according to one source, amount to about a quarter million dollars per well per year.¹⁰ However, because the mechanism by which these dollars reach the local economy is not so direct as with wages and salaries, it is difficult to speculate on the direct effects of these revenues on the economic structure of the host parishes. Certainly, if they are "invested" in some manner in the local scene, their impacts will be felt, both in the short and the long run.

The last area of concern here is the health services of the host parishes. Again, despite the fact that several of the host parishes rank low on such indicators of this dimension as hospital beds and

physicians, it is difficult to foresee a situation in which the development per se, would have a great influence on these facilities. The proximity of these sites to metropolitan areas with better-equipped facilities and available emergency transfer vehicles (both land and air) lessens greatly the dependence on as well as the influence on local health care facilities.

In short, it appears that both the short- and the long-term effects of the development of GP/GT energy resources along the lines suggested by the "minimum" model seem almost inconsequential for the socio-economic structures of almost all of the six host parishes in coastal Louisiana.

The Effects of the "Maximum" Model. The "maximum" model differs from the "minimum" model both in terms of numbers of additional workers and length of developmental time. Here, we are talking about the employment of from fifty to 100 employees for a period of time from 14 to 16 months. The impacts of this increase in scale should certainly have different impacts than for the "minimum" model, even though the long-range employment falls to the same level approximately as in that case.

In terms of population composition, since most of the employees are temporary, short-term effects are likely to be greater than over the long-term. Given the extended amount of time which the workers will be involved in the construction operation, some no doubt, will elect to relocate in the host parish during their work there. This fact could increase demands for housing, create opportunities for service-type businesses, and otherwise stimulate growth in the host parish. Whether this additional stimulation would encourage population growth to greater levels than currently exist (from a low of 1.6 percent between 1970 and

1978 in St. Mary to a high of 17.6 percent in Terrebonne Parish) for parishes that are growing, is hard to say, since much of this growth has no doubt been the result of the expansion of oil and gas exploration in these areas. At any rate, it would, because of its low initial population, also affect the growth rate in Cameron Parish. The occupational opportunities, unless developed in other spheres, will disappear, causing out-migration, and either halt or certainly limit the rate of growth.

The "maximum" model should, in the short-term at least, have an impact on the labor force characteristics of the host parishes, by providing additional employment opportunities to some of the unemployed or under-employed host parish residents. Some of this will be due to the fact that other workers from outside the parish will be unwilling to relocate to the parish in order to work. Other effects will stem from service jobs created by the increased activity in the host parish. While these effects may not be demonstrable, given the gross employment statistics available (i.e., percents of total employed), the addition of a hundred or so jobs will, no doubt, influence the labor force. This will be particularly true for the smaller parishes. However, given the temporary nature of this stimulus, the effects should be rather short-lived, and many of these jobs will disappear as the construction phase of the development operation begins to wind down and the employees (and those who provide services for them) move on to other areas.

The same kind of parabolic influence could affect the educational characteristics of the population of the host parish. Although for most

of the host parishes with larger populations, such effects will be negligible, for the smaller ones, such as Cameron Parish (population 9,528), measurable effects could result. The influx of new residents with school-age children could place stress on the educational facilities in such a sparsely populated area. Of course, this "demand" for educational facilities will only last as long as the construction phase of the development continues, and out-migration and a slackening in demand should accompany the completion of that phase of the operation.

The economic characteristics of the host parishes should also feel the impact of GP/GT development, certainly in the short run and maybe in the long run as well. Multiplying the effects of the "minimum" model by ten generates quite an input into local economies, again depending heavily upon the size of the host parish and existing levels of development. Given the longer developmental period for the "maximum" model, a more constant flow of both wage and salary dollars and royalty revenues into the local economies of the host parishes is likely. Thus, a greater proliferation of service-oriented businesses is likely, as well as revenues to the public sector through sales taxes. Some land owners, given the estimates of royalties, are likely to receive rather large amounts of money from these developments. Some of these revenues, no doubt, will be circulated in the local economies, thereby boosting the indicators used to characterize them. While the wage and salary dollars will disappear as the construction of these facilities ends, the royalty dollars will continue to flow to the land owners at least, and perhaps to the local economy as well. With this situation, it is much more difficult to predict the long term effects of GP/GT energy development on the economic structures

of these host parishes.

Greater impacts on local health services are also likely, at least in the short run, with the "maximum" model. Again, these will be short-term impacts and will depend heavily upon the size and nature of the existing facilities as well as the distance to metropolitan health care resources. With the possibility of dependents moving to the area following the workers, even greater potential impacts seem likely, despite the qualifications noted with regard to this area in the "minimum" model. These effects, like the others, will tend to lessen over time and a condition of underutilization could result if rapid expansion of these services follows the increase in demand in the short-run.

In comparison to the impacts for the "minimum" model, the short-term effects for the "maximum" model, particularly for the smaller parishes, such as Cameron Parish, are likely to be of greater magnitude. With the exception of this parish, the long-term effects are less noteworthy, except for the potentially tremendous economic impact of the royalties from GP/GT development.

CONCLUSIONS

In summary, we agree with Stenehjem and Allen (1978) that is the interaction between the scale of the energy development and the characteristics of the host parishes which influence the nature of socioeconomic impacts to the host areas. This seems true despite the fact that the scale of our models of GP/GT energy development does not compare favorably with other, more extensive forms of energy development such as coal extraction or nuclear power development. However, even for the rather

small scale of our energy development, we found potentials for impact at least for our "maximum" model of GP/GT energy development. Too, these impacts tended to be greater for host parishes with smaller, less well-developed socioeconomic infrastructures. And, while our analysis did not reveal a single parish whose socioeconomic infrastructure could not support the projected level of development with existing socioeconomic resources, it seems obvious from our analysis that for the six-site parishes in coastal Louisiana, the ability to absorb these impacts with few detrimental effects to the socioeconomic structure of the parish did vary from moderate to high in five of the cases, to rather low in terms of one parish.

SOME LIMITATIONS

Consumers of socioeconomic impact assessment should be reminded that in addition to the difficulties in predicting the impacts of previously undeveloped energy resources, the methods and procedures of the assessment itself generate potential problems of interpretation. Several of these problems are highlighted below.

Boundary overlap. One of the most difficult problems facing the impact analyst is that of boundaries. Because of the expense of data gathering, studies of socioeconomic impact generally make use of data gathered by local, state or national governmental bodies for the purpose of administering the area. These data are organized according to geopolitical boundaries (i. e., city, SMSA, county, etc.). However, these may not coincide with the analyst's perceptions of the impact area drawn from the technology of the particular form of energy development. Many

studies use the county as the unit of analysis, while the impacts of GP/GT energy development are likely to be felt over a much broader (or, in some cases, depending on the level of development, an even smaller) area. As an example of this problem, in this study one site was included within the boundaries of two parishes. The data on the socioeconomic indicators, wherever, were available only for each county. Such problems can cause difficulties in interpretation.

Representing the Socioeconomic Environment. As discussed earlier in the paper, there are a wide variety of different variables available for representing the socioeconomic environment. To date, less than complete agreement exists as to just which variables to use. Perusal of the variables employed in the different models extant in the field amply demonstrates this problem. The analyst must pick and choose from among these variables those which he feels best represent this environment. The ambiguity of available theoretical guidelines only adds to the impact analyst's frustrations. This situation also hampers efforts to compare different impact studies.

The Indicator Source Problem. Most impact assessments make use of data gathered by a variety of different sources, each operating under different constraints, with different goals and means. For example a municipality does not have the expertise and resources which the U.S. Bureau of the Census can marshal in a data-gathering effort. Yet municipalities must gather information relevant to their needs. Thus, the scope and accuracy of data-gathering will vary according to the source and purpose (s) for which the data were gathered. The researcher must exercise caution when attempting to use indicators from different sources in an impact assessment.

The "Age" of Data. Since the socioeconomic analyst must often use data previously gathered, another salient concern is that the data on important indicators are outdated. This is particularly true when using census data, the bulk of which is gathered in ten-year intervals. This problem becomes even greater during the end of the ten-year cycle. The current rapid rates of growth in the sunbelt states exacerbates the problem even more. In some instances this problem may be overcome by using data from other sources or projection devices. However, for some key indicators of socioeconomic structure, there may be no substitute. Thus, efforts to compare or estimate effects of different impacts are greatly hampered by this problem.

To summarize, the very nature of socioeconomic impact assessment generates problems of interpretation which circumscribe the accuracy of the assessment. An awareness of these problems is essential for a correct appraisal of efforts to assess proposed impacts of energy-related development.

FOOTNOTES

1. Schnaiberg (1973) details the shift in public opinion in America from an orientation directed primarily toward the maximization of production and economic expansion to one which emphasizes the primacy of concern with the environment. One of the results of such a shift in his scheme is governmental action of the sort which resulted in the Environmental Policy Act and other federal actions emphasizing the importance of concern with possible negative environmental impacts of development.
2. However, the controversy over the act and its provisions has not ended. For example, Greenberg and Hordon (1974) raise several significant questions about both the act itself and its subsequent application which call into serious question some of the manifestations of the decision.
3. There is, however no paucity of "models" available for use in this area. A recent source (Texas General Land Office, 1979) identified thirteen extant models. This source also noted a set of twenty-three factors "normally considered in an impact assessment." These factors also served as inputs into variable selection for this project.
4. This should come as no surprise to researchers engaged in either area of concern since impact assessment takes as a primary goal the determination of the effects of development on the host area. It follows that the impact analyst should center his interest on the salient structural parameters of the area in question, hence on the "ecological" structure of the area
5. Similar to the lack of fit between the "county" unit and the impact area, the boundaries of the state planning districts and the impact areas also do not coincide. The state planning district were set up primarily as a facilitative device for planning and coordination. They are represented (State of Louisiana Executive Order 27) as units which reflect "natural, social and economic groupings of parishes which reflect a community of interests." The degree to which they do so is certainly subject to debate. What seems immediately clear, however, is that they are too large and diverse for use as the primary unit of analysis here. However, they are useful for comparative purposes since they do comprise to some indeterminate degree more homogeneous units than does the state as a whole.

6. At the outset, it should be noted that it is often difficult to characterize outputs unambiguously as gains or losses. What may be a gain in one sense (i.e., an increase in available jobs) may prove to have loss potential as well (i.e., greater strain on municipal service levels). However, this approach seems more viable than a tortuous mapping of potential losses and gains for each output.
7. Our analysis will not consider each of these indicators. The scale of development suggested by our models is small, relative to the ability of the host parishes to support it. Thus, while increased demands for municipal services are commonly felt in some energy development situations, they will not be greatly stimulated in this situation. We also will not consider changes in the age distribution or sociocultural changes for the same reason.
8. These estimates were provided by Dr. Fred Wrighton, Office of Energy Coordination, Louisiana State University, Baton Rouge.
9. Typically, a drilling contractor will import the entire operation, including equipment and crew, to a drilling site. In some cases, they may even live on the drilling site as well.
10. A Report of the Economic Analyses Completed to Date of the Most Promising Geopressured Energy Prospects in Louisiana, by Adrain E. Johnson, Jr., Office of Energy Coordination, Louisiana State University, Baton Rouge.