GEOPRESSURED BRINES

UNCONVENTIONAL GAS SOURCES

NATIONAL PETROLEUM COUNCIL • JUNE 1980

John F Bookout, Chairman—Committee on Unconventional Gas Sources

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PREFACE

By letter dated June 20, 1978, the National Petroleum Council, an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of potential natural gas recovery from Devonian Shale, coal seams, geopressured brines, and tight gas reservoirs. In requesting the study, the Secretary stated that:

> ...Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for cost and recovery of unconventional gas and should consider how government policy can improve the outlook. (See Appendix A for complete text of the Secretary's letter and a further description of the National Petroleum Council.)

To aid it in responding to this request, the National Petroleum Council established a Committee on Unconventional Gas Sources under the chairmanship of John F. Bookout, President and Chief Executive Officer, Shell Oil Company. R. Dobie Langenkamp, Deputy Assistant Secretary for Resource Development & Operations, Resource Applications, U.S. Department of Energy, served as Government Cochairman of the Committee. A Coordinating Subcommittee and four task groups, by source, were formed to assist the Committee. The Geopressured Brines Task Group was chaired by Thomas W. Stoy, Jr., Union Oil Company of California, and cochaired by Don C. Ward of the Department of Energy. (Rosters of the study groups responsible for this volume are included in Appendix B.)

The National Petroleum Council's report on Unconventional Gas Sources is being issued in five volumes:

- Volume I - Executive Summary
- Volume II - Coal Seams
- Volume III - Devonian Shale
- Volume IV - Geopressured Brines ✓
- Volume V - Tight Gas Reservoirs. ✓

The Coal Seams, Devonian Shale, and Geopressured Brines volumes are being issued in June 1980 with the Executive Summary and Tight Gas Reservoirs volumes being issued in late 1980.

For each source, reserve additions and producing rates are calculated at five gas prices, three rates of return, and at least two levels of technology. Constant January 1, 1979, dollars were used in all analyses. The report presents estimates of what could happen under certain technical and economic circumstances and is not intended to represent a forecast of what will occur.

BACKGROUND AND CONCLUSIONS

BACKGROUND

The phrase "geopressured reservoir" means that the pressure of fluid in pores in the reservoir is greater than the hydrostatic pressure of a column of brine from the surface to the reservoir depth (0.465 pounds per square inch [psi] per foot of depth). The fluid in the pores can be oil, gas, brine, or a combination of them. If the mobile fluid is oil or gas, the reservoir is classified as a geopressured oil or gas reservoir. If no free gas or oil is present in the pores, the reservoir is classified as a geopressured brine reservoir.

This study addresses only geopressured brine reservoirs. By definition, such reservoirs contain no free oil or natural gas. However, the brine is assumed to be at saturation with natural gas in solution.

This study also addresses only sandstone reservoirs of Tertiary age in the Texas and Louisiana Gulf Coast onshore area. This additional constraint has been adopted by virtually all studies of potential energy production from geopressured brine reservoirs because the amount of existing data from this area is much greater than for other identified geopressured reservoir areas.

The large existing data base for Tertiary sandstone reservoirs in the Gulf Coast area results from more than 10,000 penetrations to explore for and develop prolific geopressured oil and gas reservoirs. This data base has provided knowledge of:

- Temperature as a function of depth and location
- Reservoir pressure as a function of depth and location
- Sandstone thickness and porosity as a function of depth and location
- The range of permeability as a function of geography, formation age, and depth of burial
- Drilling, surface facility, and operating costs for both production wells and brine disposal wells.

The existing data are comprehensive in relation to exploring for and producing geopressured oil and gas reservoirs. However, several factors which are critically important to the production of geopressured brine reservoirs to recover methane from solution have minimal significance to the search for oil and gas. These factors or areas of uncertainty that must be resolved by future work are:

- The thickness and areal extent of continuous, high permeability sandstone reservoirs

- The amount of natural gas and minerals in solution in the brine

- The system compressibility that controls the producible fraction of the brine in place.

The National Petroleum Council study is an engineering appraisal of 11 geopressured brine prospects in the Gulf Coast. The appraisal is based upon the known data and what the NPC study participants believe to be reasonable estimates for the value of the unknown data.

CONCLUSIONS

It is possible to develop commercial production of gas from geopressured brines at gas prices ranging from $4.00 to $9.00 per thousand cubic feet (MCF) with a 10 percent rate of return (ROR) from selected areas of the Gulf Coast. For a maximum gas price of $9.00 per MCF and a 10 percent ROR, the projected gas production would be 81 million cubic feet per day (MMCF/D) by the year 2000 for the most optimistic case. The ultimate gas recovery for this case would be 568 billion cubic feet.

Large-scale gas production is highly unlikely prior to the year 2000 for the following reasons:

- The extremely high capital investment and operating expense per unit of gas production leaves little margin for dry holes or poor reservoir performance.

- The low solubility of gas in brine makes the value of each barrel of brine very low (5¢ to 45¢ per barrel). This in turn requires that each well be capable of producing at high rates for many years.

- The low recovery efficiency of approximately 3 percent of the gas in place and the highly faulted nature of the geopressured sands greatly limit the size of the resource available for exploitation.

- The existence of numerous elements of mechanical and geological risk makes large-scale gas production unlikely.

FINDINGS

STUDY OBJECTIVES

The objectives of the NPC Geopressured Brines analysis were as follows:

- To examine the regional geology and identify prospects for development in the Tertiary trend of the Texas-Louisiana Gulf Coast
- To study these prospects in detail to estimate the following:
  - Reservoir performance
  - Drilling programs
  - Production and water disposal methods
  - Geothermal and hydraulic energy potential
  - Producing rates and recoverable reserves
  - Detailed estimates of costs and the economics of field development
- Based upon the study of these prospects, to predict the addition of ultimate recovery and production rate by year to the year 2000 as a function of gas price for a base case discounted cash flow rate of return of 10 percent and example cases of 15 and 20 percent
- To report on environmental and legal considerations
- To determine the potential for technical improvements
- To comment on critical technical factors, risk, and uncertainty.

REGIONAL GEOLOGY

The major potential areas of interest for geothermal, geopressure energy are located along the northwestern rim of the Gulf of Mexico in southern Louisiana and Texas (see Figure C-1 in Appendix C). The southern Louisiana and Texas geopressured trend, in which the potential areas occur, ranges in width from 50 to 70 miles northward from the coast. The prospects are all Tertiary in age and are part of a fluvial deltaic and marine depositional system. During early Tertiary time (Eocene and Oligocene), the primary area of deposition occurred along the Texas coastal area. This depocenter shifted into Louisiana during the later Tertiary Miocene and ever, the actual sand thickness that could be considered prospective is in the order of 500 to 1,000 feet.

The Texas Oligocene Frio prospects were delineated in a regional assessment reported by the Bureau of Economic Geology.[1] Of the six best Frio prospects identified in the study, the study participants eliminated four on the basis that reservoir conditions would preclude developing commercial gas production within the $9.00 per MCF price limitation. The two remaining best Frio prospects were included in this study.

It should be pointed out, however, that this Frio study was limited to depths that would have reservoir temperatures greater than 300°F, and that studies in progress of areas with lesser temperatures will no doubt identify additional prospects.

Other Texas prospects in the Oligocene Vicksburg and Eocene Wilcox have also been evaluated.[2] Two of the Wilcox prospects which the study participants believed to be the most promising of this Vicksburg – Wilcox study were evaluated in this report.

The investigation of the geothermal, geopressure resource of southern Louisiana sands was initiated in 1975 as a result of an Energy Research and Development Administration (ERDA) contract with the Petroleum Engineering Department at Louisiana State University (LSU), Baton Rouge.[3] As a result of that work, 63 prospective areas were found, and after preliminary ranking, the five most promising prospects were mapped and studied in detail. The study indicated that the better prospects were generally located in the western half of southern Louisiana.[4] Poorer sand development in the eastern half was the reason LSU downgraded the prospects in that area.

Data on these prospects in Texas and Louisiana are listed in Table D-1 in Appendix D. These 11 prospects have estimated total gas in place of 6.7 trillion cubic feet.

Although these prospects represent only a fraction of the total resource, the study participants selected them for analysis because they represent the largest and most promising reservoirs identified by Department of Energy (DOE)-sponsored studies. If development of the geopressured brine resource is to occur, it will probably be started in these areas.

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[1]Bebout, Dorfman, and Agagu, 1975; Bebout, Loucks, Bosch, and Dorfman, 1976; Bebout, Loucks, and Gregory, 1978.

[2]Unpublished report by Bebout, Gregory, Loucks, and Weise.

[3]Hawkins, 1975; Bassiouni and Bernard, 1978.

[4]These are identified in the September 1979 DOE publication entitled "Geopressured Geothermal Reservoirs."

There are, of course, geopressured formations in other parts of the United States in addition to these Tertiary age deposits along the Gulf Coast. In the deep Mississippi Salt basin (of Mississippi and Alabama), the Smackover and adjacent formations are geopressured. These are highly faulted; one well could drain only a limited volume. Deep formations in the San Joaquin basin in California and the Arkoma basin of Arkansas and Oklahoma are sometimes geopressured. However, these formations are generally of low permeability. The Wind River, Piceance, Green River, Uinta, and Big Horn basins of Montana, Wyoming, Colorado, and Utah contain geopressured formations. These are usually of extremely low permeability. The major aquifer in this area of the United States is the Mississippian (Mission Canyon) formation. This aquifer is not geopressured. The Tuscaloosa-Woodbine formation along the Gulf Coast is often geopressured. In some cases, this formation is highly permeable. However, it is usually highly faulted. Thus, individual accumulations of brine would usually be too small to be of interest for geopressured brine production. Other small geopressured accumulations are found in Michigan and Arizona. Figure 1 shows the location of geopressured brine formations in the United States.

It is the opinion of the geologists participating in this study that the geopressured formations along the Gulf Coast form by far the largest and most likely to be commercial target of all the geopressured formations in the United States.

This study was also confined to onshore geopressured deposits. Although the geopressured resource is known to extend into the offshore, drilling and operating costs are so much higher offshore than onshore that onshore development would certainly proceed first. From the results of this study's economic analyses, it appears doubtful that any offshore development of geopressured brine reservoirs could be carried out for the $9.00 per MCF maximum price examined in this report. (See Appendix C for details on regional geology and prospect evaluation.)

RESERVOIR PERFORMANCE

Unsteady-state reservoir models were developed for each prospect using the geologic and reservoir data from Table D-1. Production/pressure performance for each prospect was predicted using the following criteria:

- Maximum brine production rates of 30,000, 50,000, and 70,000 barrels per day (B/D) per well
- Maximum well life of 25 years
- Single- and multiple-well development.

(See Appendix D for a complete discussion of reservoir engineering.)

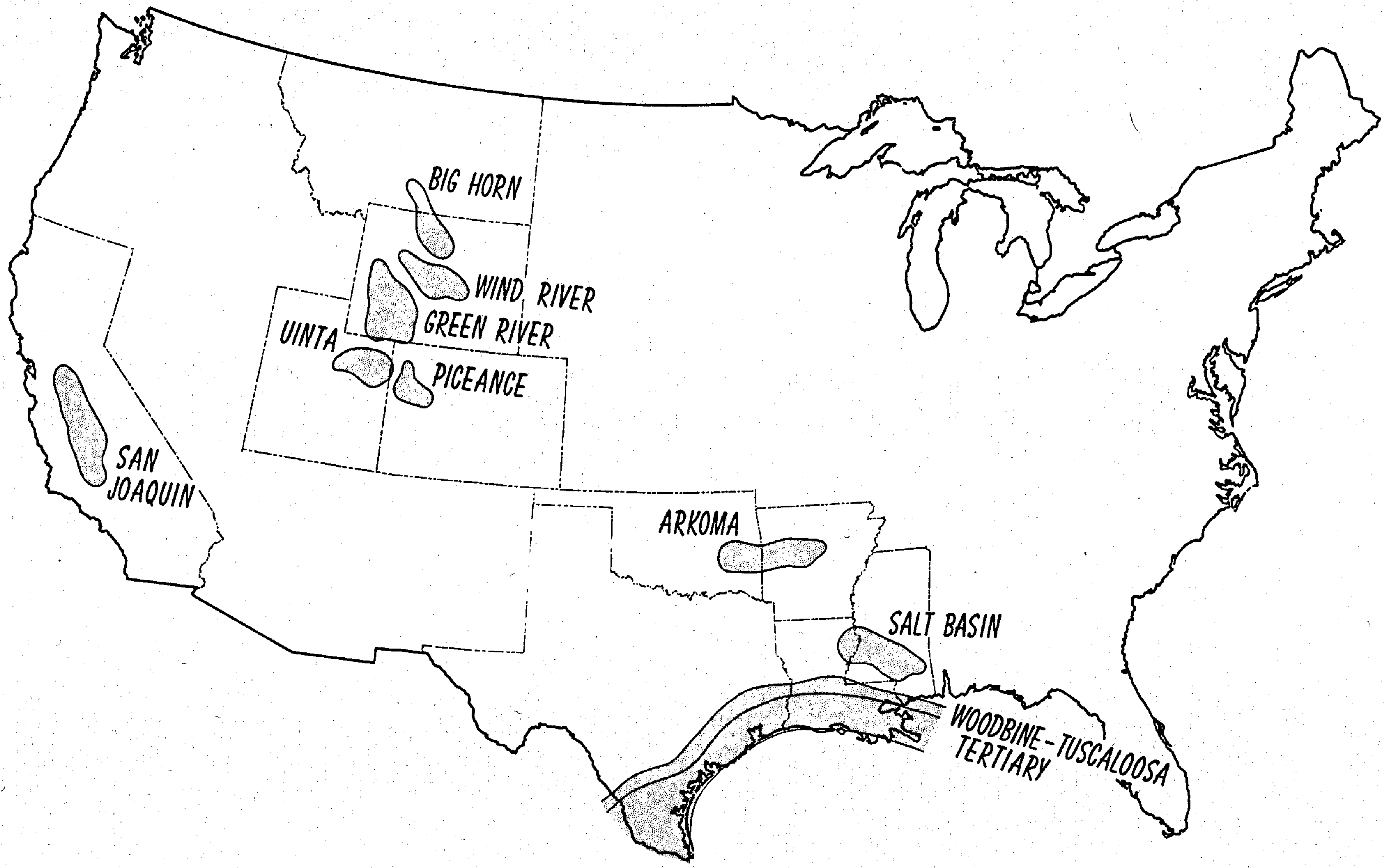

Figure 1. United States Geopressured Brine Formations.

DRILLING PROGRAMS

Individual detailed development well programs and cost estimates were made for two prospects in Louisiana with depths of 13,500 and 17,700 feet, respectively, and for two prospects in Texas with depths of 13,500 and 16,500 feet, respectively. These cost estimates were extrapolated to other prospects.

The drilling programs are quite similar to conventional oil and gas drilling with the exception that the geopressured brine programs require larger diameter (5 1/2-inch) tubing in order to accommodate the high volume water production contemplated.

Drilling costs vary from $166 per foot for the shallower wells (about 12,000 feet) to $272 per foot for the deeper wells (17,000 feet). These costs, which are approximately 25 percent higher than conventional drilling costs, result from the larger tubing, casing, and related equipment requirements. (See Appendix E for details on drilling and well costs.)

PRODUCTION AND WATER DISPOSAL FACILITIES

Production facilities would consist of large-capacity gas/water separators, gas compression facilities, water holding tanks and treating facilities, water injection pumps, and multiple, shallow, high-rate water disposal wells. Fuel would be obtained from natural gas production. Gas would be delivered to the purchaser at the well site at 800 pounds per square inch gauge (psig).

Because of the distance of 2 miles or more between wells, each well would require separate production, water disposal, and sales facilities. (See Appendix F for detailed descriptions of production and water disposal facilities.)

WATER DISPOSAL METHODS

Three methods for water disposal were investigated:

- Disposal into brine aquifers using shallow disposal wells
- Pressure maintenance by disposal of brine into the producing horizon
- Transportation via pipeline and disposal into the Gulf of Mexico.

Disposal into shallow brine aquifers was selected for the following reasons:

- It is the conventional method of disposal used on the Gulf Coast.
- It is environmentally acceptable.

- Its fuel requirements are economical -- 2 cubic feet per barrel injected.

(See Appendix F for a discussion and costs of subsurface water disposal.)

Pressure maintenance or partial pressure maintenance into the producing reservoirs is not feasible for the following reasons:

- Injection pressures are high.

- Fuel requirements consume a substantial part of the recoverable gas (50 percent or more).

- The cost of injection wells and high-pressure injection pumps increases the investment operating costs and the required gas price beyond the $9.00 per MCF upper limit for this study.

(See Appendix G for a discussion and costs of pressure maintenance.)

Disposal of the waste water into the Gulf of Mexico is not a viable alternative because of the environmentally objectionable, highly dissolved solid content of the produced brine and the high cost of pipelines and facilities for the widely spaced brine wells. (See Appendix F for facility costs and Appendix I for the operating expense of water disposal into the Gulf of Mexico.)

ARTIFICIAL LIFT

The use of artificial lift for brine production is not feasible. The high fuel requirements and pump capacity limitations result in marginal economics at best, using a gas price of up to $9.00 per MCF. (See Appendix F for the costs of artificial lift.)

GEOTHERMAL POTENTIAL

Opportunity for the conversion of geothermal energy to electricity is limited. For a 10 percent ROR in geothermal equipment, the following criteria must be met:

- Minimum brine production rates of 40,000 B/D per well

- Minimum surface flowing temperature of 270°F or higher

- Minimum life of constant production of 10 years with no decline.

Of the 11 prospects examined in detail, only five would meet the minimum requirements. These five prospects, if developed, would generate a total of 19.1 megawatts (mW) of power from eight separate well locations.

This report does not examine the possibility of using the geothermal energy for projects such as space heating or low-grade industrial heat. In any case, the use of heat energy would not have wide application because of the marsh location of many of the prospects. (See Appendix H for a detailed discussion of geothermal potential.)

HYDRAULIC POTENTIAL

Wellhead pressure declines immediately from its initial level and is very short-lived, thereby creating a high rate of amortization and obsolescence for investment in facilities for utilization of hydraulic energy. For this reason, conversion of hydraulic energy into electric energy for sale or into mechanical energy for lease operation has only minor potential within the margin of error of this evaluation and was not considered in the economic evaluations. (See Appendix H for a detailed discussion of hydraulic potential.)

PRODUCING RATES AND RECOVERABLE RESERVES

Four separate cases were used to estimate future production and recoverable reserves from the 11 identified prospects:

- Most Optimistic Case
  - 50,000 B/D per well maximum initial rate. Solution gas/water ratio from Table D-1.
- Upper Median Case
  - 30,000 B/D per well maximum initial rate. Solution gas/water ratio from Table D-1.
- Lower Median Case
  - 50,000 B/D per well maximum initial rate. Solution gas/water ratio equals half the amount listed in Table D-1.
- Minimum Case
  - 30,000 B/D per well maximum initial rate. Solution gas/water ratio equals half the amount listed in Table D-1.

Although five of the 11 prospects are estimated to be capable of higher maximum flow rates, projects were limited to 50,000 B/D because:

- Flow rates in excess of 50,000 B/D show early decline for most prospects.

- High tubing velocity in excess of 25 feet per second would be expected to result in serious downhole corrosion and erosion problems.

The 30,000 B/D maximum flow rates per well were used as sensitivity runs to account for less than the expected values of permeability x thickness from Table D-1.

The lower median and minimum case sensitivity projections using one-half of the solution gas per barrel of brine estimated in Table D-1 have been supported by recent production tests conducted at Austin Bayou in Texas and Fairfax Foster Sutter No. 2 and Beulah Simon No. 2 in Louisiana. Higher-than-anticipated concentrations of dissolved solids in the brines were observed and reported in dissolved gas/water ratios of approximately 25, 22.5, and 22.6 cubic feet per barrel. These values are substantially less than projections based upon estimated water salinities in Table D-1.

Gas reserves per well were estimated for all cases assuming the wells produced to depletion by natural flow or had a 25-year maximum life.

Recovery factors as a fraction of original gas in place for the 11 identified prospects ranged from a low of 1.4 percent at the Candelaria Prospect to a high of 4.9 percent at the Rockefeller Refuge Prospect.

The predicted recovery factors from the model studies are based upon the known compressibility of brine for the temperature and pressure of each reservoir (values are near 2.2×10^{-6} psi^{-1}), an assumed rock pore volume compressibility of 5.0×10^{-6} psi^{-1}, and an assumed critical gas saturation of 3 percent of pore volume. For all prospects, the model studies revealed that buildup of free gas due to pressure reduction reached a maximum of less than 1 percent of pore volume. Since this maximum is less than the 3 percent required for the gas to move, free gas flow cannot occur. Vertical gas flow cannot create a gas cap, and the ratio of produced gas to produced water declines throughout the life of each well.

Rock compressibility has a significant effect on recovery efficiency, and the value chosen by the study participants is believed to be reasonable and possibly optimistic. Recent laboratory tests by the University of Texas on geopressured sandstone cores indicate that rock compressibility could be as low as 1.8×10^{-6}. Further, the NPC believes that the 3 percent critical gas saturation used in the model studies, which is based upon extensive reservoir engineering experience, is reasonable. (See Appendix D for further discussion of reservoir performance.)

ECONOMICS

The discounted cash flow rate of return on the 11 prospects studied was calculated with the following economic assumptions:

- Investments
  - Land acquisition at $20 per acre
  - Geophysical at 1 mile grid per prospect, $8,000 per mile
  - Well cost (Appendix E)
  - Facility cost including water disposal (Appendix F)
  - Geothermal, where appropriate (Appendix H)
- Revenue
  - Gas, varied from $2.50 to $9.00 per MCF
  - Electric power correlated with gas price for gas used to generate electric power, as follows:

    $2.50/MCF gas = 4.5¢ per kilowatt-hour (kWh)

    $9.00/MCF gas = 13.3¢ per kWh
- Expense
  - Gas operations, $320,000 per year per well plus 2.9¢ per barrel variable (Appendix I)
  - Geothermal, 0.5¢ per kWh
  - Royalty, 1/6
- Taxes
  - 46% federal income tax rate
  - 2% state income tax rate
  - 10% tax credit for tangibles
  - Intangibles -- expensed
  - Additional energy -- 10% on tangibles

(See Appendix J for detailed data and calculation results for the 11 prospects studied.)

POTENTIAL FOR TECHNICAL IMPROVEMENTS

The potential for technical improvements would be expected to parallel the experience of conventional deep gas well drilling. Whether or not deeper drilling would enlarge the resource is geologically uncertain. For the prospects evaluated, the small amount of usable geothermal energy contained in the brine negates the potential benefits of technical improvements that may be expected in geothermal energy development.

PROJECTIONS OF FUTURE GAS PRODUCTION AND RESERVES TO THE YEAR 2000

Based on the results of the economic study of these 11 prospects, a development program was projected incorporating a rising scale of gas prices which accommodated the 10 percent rate of return criterion. By this procedure, the best economic prospects were drilled first. After these economic prospects had been developed, it was assumed that future undesignated prospects would be developed comparable to the last economic prospect drilled.

The rate of development of the prospects in the most optimistic case is based upon the following:

- The development of the 11 identified prospects from 1979 to 1985 is in reasonable conformance with the DOE Designed Well Test Series schedule.
- The massive geophysical, geological, and leasing effort required by industry to program exploration and development of unidentified prospects will be triggered only by demonstrated success of the DOE tests.
- The initial well drilled on each prospect would require a minimum of one year of testing and reservoir evaluation before scheduling additional drilling on that prospect.
- Prospect evaluation and development will be slow because most prospects studied would support only one or two producing wells.

The results of this most optimistic case, together with the upper median, lower median, and minimum cases, are presented in Figures 2 and 3 and Tables 1 through 4. The undesignated prospects represent an important part of the projections. Of the 96 wells drilled in the most optimistic case, 70 of the wells were drilled on undesignated prospects. The reserve projection for this case of 568 billion cubic feet includes 350 billion cubic feet from undesignated prospects.

For a maximum gas price of $9.00 per MCF and a 10 percent ROR, the projected gas production would be 81 MMCF/D by the year 2000 for

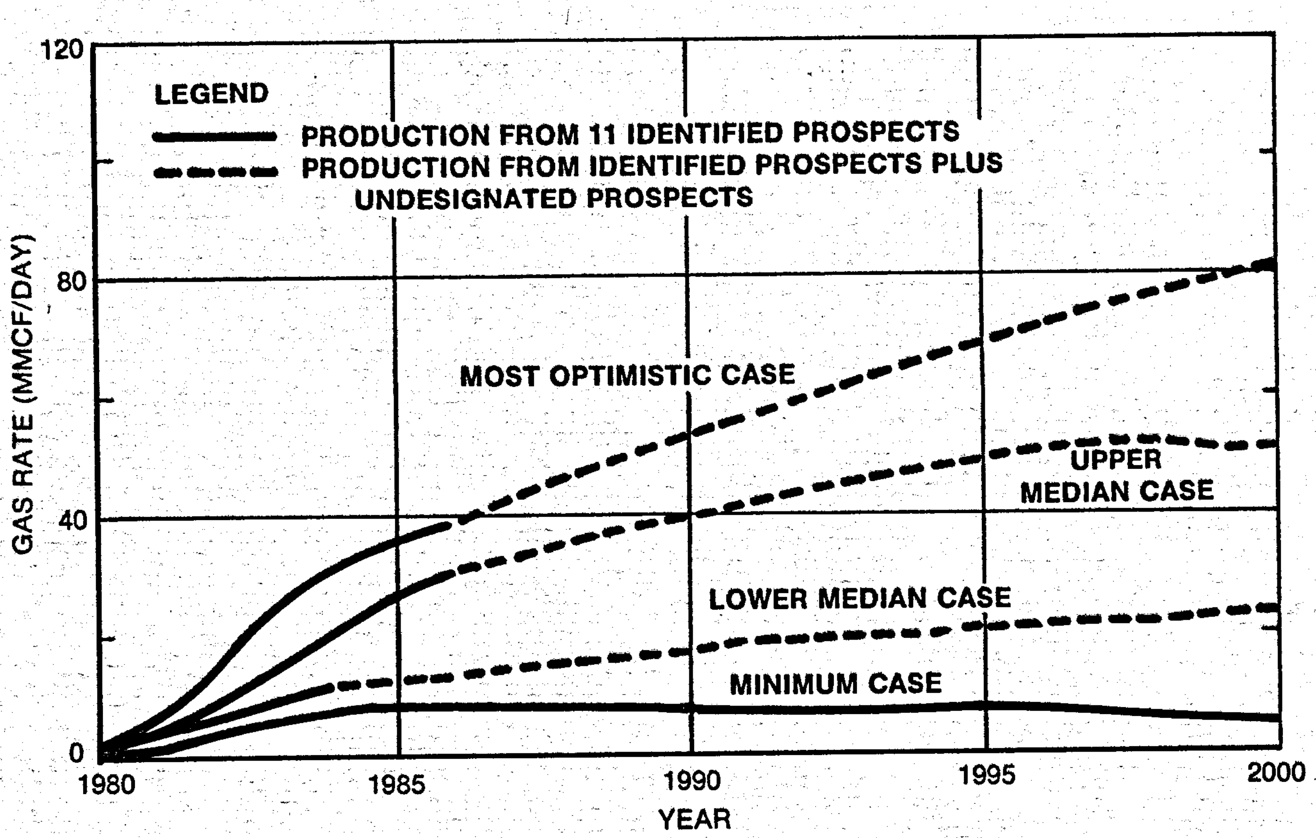

Figure 2. Sales Gas vs. Time (10% ROR).

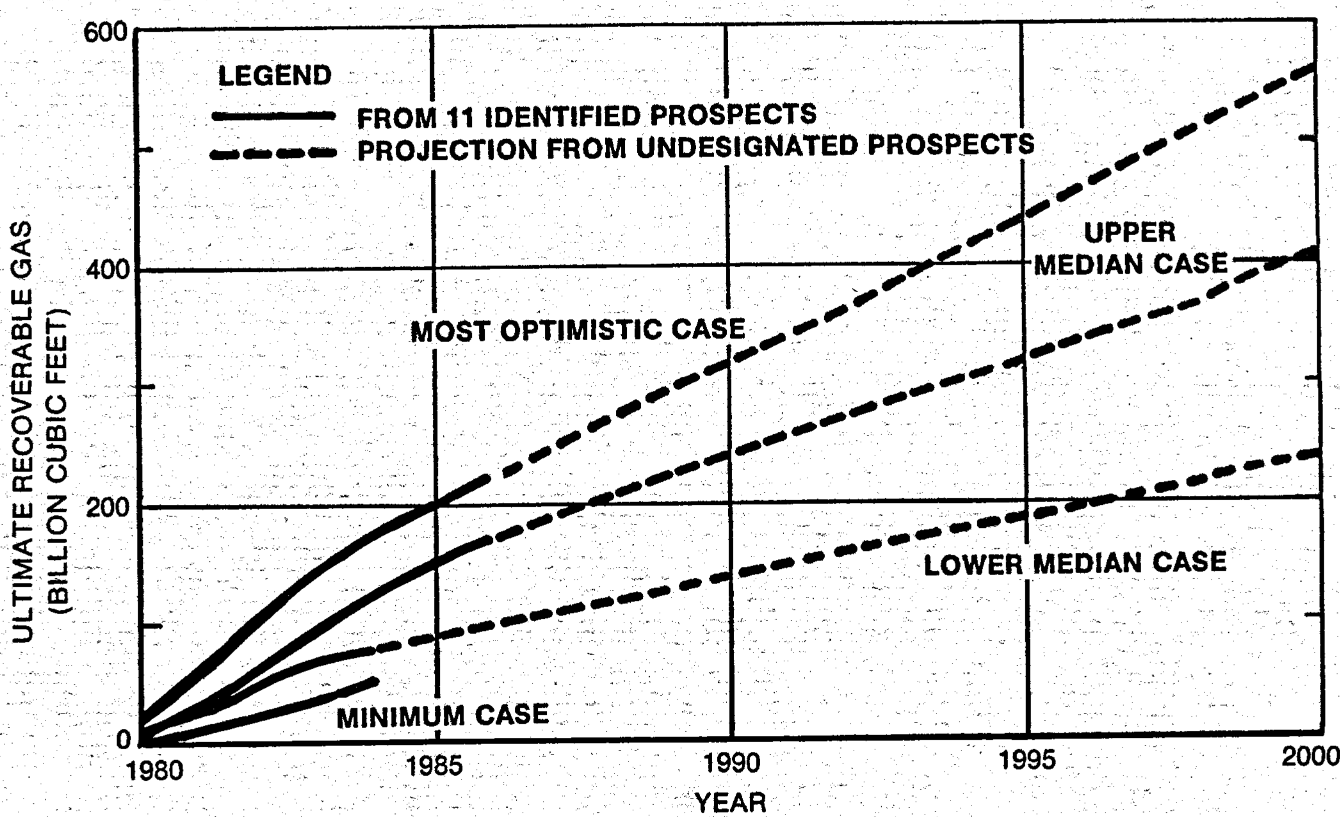

Figure 3. Ultimate Recoverable Gas vs. Time (10% ROR).

TABLE 1

Drilling, Production, and Reserve Schedule
10 Percent ROR, Most Optimistic Case
(Constant 1979 Dollars)

Development				Production		Reserves				
Year	Prospect	No. Wells Drilled	Cum. Wells Drilled	Year	Initial Gas Rate (MMCF/D)	Reserves Added (BCF)	Cum. Reserve Additions (BCF)	Max. Price ($/MCF)	Power Added (mW)	Cum. Power (mW)
1979	Austin Bayou	1	1	1980	1.9	12	12	4.00	2.7	2.7
1980	Rockefeller Refuge	1		1981	2.5	21			2.9	
	LaFourche Crossing	1	3		1.8	15	48	4.00	1.3	6.9
1981	Rockefeller Refuge	2		1982	5.0	35		5.00	5.8	
	LaFourche Crossing	1			1.8	4				
	SE Pecan Island West	1	7		1.6	13	100	5.00	2.3	15.0
1982	Rockefeller Refuge	3		1983	7.2	26			2.8	
	SE Pecan Island East	1			1.6	7				
	Atchafalaya Bay East	1	12		1.3	10	143	6.00	1.3	19.1
1983	Atchafalaya Bay East	1		1984	1.4	6		8.00	None	
	Atchafalaya Bay West	1			1.0	9				
	Johnson's Bayou	1			0.9	8				
	Clinton				1.3	4				
	Eagle Lake	1	17		1.4	3	173	8.00	None	19.1
1984	Atchafalaya Bay West	1		1985	1.1	3		8.00		
	Johnson's Bayou	4	22		3.6	20	196	8.00	None	19.1
1985	Candelaria	1			0.8	6				
	Johnson's Bayou	3	26	1986	2.7	16	218	8.00	None	19.1
1986	Undesignated*	5	31	1987	4.5	25	243	9.00	None	19.1
1987	Undesignated*	5	36	1988	4.5	25	268	9.00	None	19.1
1988	Undesignated*	5	41	1989	4.5	25	293	9.00	None	19.1
1989 through 1999	Undesignated*	5/yr	96	1990	4.5/yr	25/yr	568	9.00	None	19.1
						568				

*Undesignated prospects assumed to be identical to Johnson's Bayou prospect (Computer Run L24).
This case would require the drilling of 70 wells to develop 350 billion cubic feet of reserves on undesignated prospects.

TABLE 2

Drilling, Production, and Reserve Schedule
10 Percent ROR, Upper Median Case
(Constant 1979 Dollars)

Development				Production		Reserves				
Year	Prospect	No. Wells Drilled	Cum. Wells Drilled	Year	Initial Gas Rate (MMCF/D)	Reserves Added (BCF)	Cum. Reserve Additions (BCF)	Max. Price ($/MCF)	Power Added (mW)	Cum. Power (mW)
1979	Austin Bayou	1	1	1980	1.1	9.4	9.4	5.00	None	None
1980	Rockefeller Refuge	1		1981	1.5	8.5				
	LaFourche Crossing	1	3		1.1	8.6	26.5	5.00	None	None
1981	Rockefeller Refuge	2		1982	3.0	17				
	LaFourche Crossing	1			1.1	8.6				
	SE Pecan Island West	1	7		1.0	6.6	58.7	6.00	None	None
1982	Rockefeller Refuge	2		1983	3.0	17				
	SE Pecan Island East	1			1.0	6.4				
	SE Pecan Island West	1			1.0	6.6				
	Atchafalaya Bay East	1	12		0.8	3.7	92.4	7.00	None	None
1983	Rockefeller Refuge	2		1984	3.0	17				
	Atchafalaya Bay East	2			1.6	7.4				
	Candelaria	1			0.8	6.0				
	Clinton	1	18		0.8	3.6	126.4	8.00	None	None
1984	Rockefeller Refuge	2		1985	3.0	17				
	Atchafalaya Bay East	1			0.8	3.7				
	Atchafalaya Bay West	1			0.7	3.7				
	Eagle Lake	1	23		0.8	2.7	153.5	9.00	None	None
1985	Rockefeller Refuge	1		1986	1.2	8.5				
	Atchafalaya Bay West	3	27		1.8	11.1	173.1	9.00	None	None
1986	Undesignated*	4	31	1987	2.4	16.4	189.5	9.00	None	None
1987	Undesignated*	4	35	1988	2.4	16.4	205.9	9.00	None	None
1988	Undesignated*	4	39	1989	2.4	16.4	222.3	9.00	None	None
1989 through 1999	Undesignated*	4/yr	83	1990	2.4/yr	15.4/yr	402.7	9.00	None	None
						402.7				

*Undesignated prospects assumed to be identical to Atchafalaya Bay West prospect (Computer Run L19). This case would require the drilling of 56 wells to develop 229.6 billion cubic feet of reserves on undesignated prospects.

TABLE 3

Drilling, Production, and Reserve Schedule
10 Percent ROR, Lower Median Case
(Constant 1979 Dollars)

Development				Production		Reserves				
Year	Prospect	No. Wells Drilled	Cum. Wells Drilled	Year	Initial Gas Rate (MMCF/D)	Reserves Added (BCF)	Cum. Reserve Additions (BCF)	Max. Price ($/MCF)	Power Added (mW)	Cum. Power (mW)
1979	Austin Bayou	1	1	1980	1.0	7	7.0	5.00	2.7	2.7
1980	Rockefeller Refuge	1		1981	1.2	11			2.9	
	LaFourche Crossing	1	3		0.9	8	26.0	6.00	1.3	6.9
1981	Rockefeller Refuge	1		1982	1.3	11			2.9	
	LaFourche Crossing	1			1.1	3				
	SE Pecan Island West	1	6		0.8	7	47.0	8.00	2.3	12.1
1982	Rockefeller Refuge	2		1983	2.5	17			5.7	
	Atchafalaya Bay West	1	9		0.7	5	69.0	8.00	1.3	19.1
1983	Rockefeller Refuge	2	11	1984	2.3	8	77.0	8.00	None	19.1
1984	Undesignated*	2	13	1985	1.4	10	87.0	9.00	None	19.1
1985	Undesignated*	2	15	1986	1.4	10	97.0	9.00	None	19.1
1986	Undesignated*	2	17	1987	1.4	10	107.0	9.00	None	19.1
1987	Undesignated*	2	19	1988	1.4	10	117.0	9.00	None	19.1
1988	Undesignated*	2	21	1989	1.4	10	127.0	9.00	None	19.1
1989 through 1999	Undesignated*	2/yr	43	1990	1.4/yr	10/yr	237.0	9.00	None	19.1
						237				

*Undesignated prospects assumed to be identical to Atchafalaya Bay West prospect using solution gas in Table D-1 x .5 (Computer Run L11).

This case would require the drilling of 32 wells to develop 160 billion cubic feet of reserves on undesignated prospects.

TABLE 4

Drilling, Production, and Reserve Schedule
10 Percent ROR, Minimum Case
(Constant 1979 Dollars)

Development				Production		Reserves				
Year	Prospect	No. Wells Drilled	Cum. Wells Drilled	Year	Initial Gas Rate (MMCF/D)	Reserves Added (BCF)	Cum. Reserve Additions (BCF)	Max. Price ($/MCF)	Power Added (mW)	Cum. Power (mW)
1979	Austin Bayou	1	1	1980	0.6	5	5	10.00	None	None
1980	Rockefeller Refuge	1	2	1981	0.7	4.5	9.5	8.00	None	None
1981	Rockefeller Refuge	3	5	1982	2.2	13.5	23	8.00	None	None
1982	Rockefeller Refuge	3	8	1983	2.2	13.5	36.5	8.00	None	None
1983	Rockefeller Refuge	3	11	1984	2.2	13.5	50	8.00	None	None
						50				

the most optimistic case. The ultimate gas recovery for this case would be 568 billion cubic feet.

ENVIRONMENTAL CONSIDERATIONS

Production from geopressured brine reservoirs would have an impact on the environment similar to conventional gas production with two possible exceptions: large volume geopressured water production could result in land subsidence and/or in increased tectonic activity along growth faults. Either of these events could result in the early abandonment of a project. (See Appendix K for a further discussion of environmental considerations.)

LEGAL CONSIDERATIONS

No case law in Texas or Louisiana deals specifically with questions relating to ownership and the right to produce geothermal energy. It appears to be the consensus of those who have speculated on these questions that in Louisiana the present owners of mineral interests or leases may neither own nor have the right to produce geothermal energy. Those who have speculated on what the future holds in Texas with respect to such questions are even less certain in their prognostications. (See Appendix L for a summary of the arguments prevailing in the current legal literature.)

Aside from the question of ownership and operating rights, other legal problems can be foreseen. If the surface owner is determined to be owner of the geothermal energy, those rights may conflict with the rights of the mineral owner, as for example in those instances in which the energy of a gas reservoir is affected by the production of geopressured brine, or in which the geopressured brine contains methane. Conversely, if it is determined that the owner of the minerals owns the geothermal energy, extensive use of the surface which may be required may conflict with the surface owner's rights.

With the current state of the jurisprudence, it would seem that the operator would conclude agreements with both the mineral and surface owner in order to develop geothermal energy.

Since very large areas may be affected by the production of geothermal energy, leasing of small tracts may prove onerous and the unitization status of Louisiana and Texas does not offer a complete solution. Under Louisiana's Geothermal Energy Resources Act, geothermal energy falls under the existing Louisiana Conservation Act, which provides for units that are comprised of an area which can be efficiently and economically drained by one well. The act also authorizes pool-wide units upon agreement of 75 percent of the working interest and royalty owners. The operator of a unit appears to be limited in recoupment of development and operating costs to whatever production may be secured. If a large area and many tracts are involved, the risk that the operator must bear may be prohibitive.

Texas does not have compulsory unitization, but rather relies on spacing orders of the Railroad Commission which, in effect, requires an operator to have control of or participation by working interest owners within minimum prescribed areas.

It appears that, under the prevailing systems of both states respecting pooling, voluntary unit operations will be required and the risk-taker will have to obtain ownership rights of significant size within the pooled area to justify the exploration and development of geothermal resources.

Notwithstanding the resolutions by the courts with respect to ownership and operating rights under existing titles, it would appear that new and innovative legislation will be needed in order to reduce the leasing problems inherent in developing geothermal energy.

CRITICAL TECHNICAL FACTORS, RISK, AND UNCERTAINTY

Geologic

The known geologic factors have been defined for the 11 identified prospects by the geology and engineering departments of LSU and Texas University.

In addition, the Southeast Pecan Island prospect was intensively analyzed by the study participants. Geologic uncertainties which remain include unidentified fault barriers and degree of sand continuity over the very large drainage areas required for economic development. Other engineering and geologic factors which have uncertainty include:

- Net sand thickness
- Permeability
- Rock compressibility
- Water salinity
- Degree of gas saturation
- Permeability reduction with pressure reduction.

Each of the 11 prospects was analyzed using a Monte Carlo model to determine its chance for a 10, 15, and 20 percent ROR as a function of gas price. (See Appendix M for details of the Monte Carlo simulation.)

This risk analysis indicates that three prospects (Johnson's Bayou, Rockefeller Refuge, and Austin Bayou) have a 75 percent chance of obtaining a 10 percent ROR at gas prices of $9.00 per MCF or less, and seven of the 11 prospects have a 50 percent chance of obtaining a 10 percent ROR using the same price criteria (Atchafalaya Bay East, Johnson's Bayou, LaFourche Crossing, Rockefeller Refuge, Southeast Pecan Island West, and Austin Bayou).

This analysis indicates that the three best prospects are Rockefeller Refuge, Johnson's Bayou, and Austin Bayou.

Mechanical Risks

Mechanical problems can seriously affect the longevity of production and the economics of a geopressured brine project. No production experience exists for a high volume geopressured brine well. If and to what extent sand production will become a problem at these high rates is unknown. In addition, recent tests by the DOE at the Fairfax Foster Sutter No. 2 well in Louisiana and the Pleasant Bayou No. 2 well at Austin Bayou in Texas indicate the potential for serious downhole corrosion and scaling problems because of dissolved carbon dioxide. The presence of carbon dioxide in the dissolved gas depressed the pH of the brine to levels of 6 or less. Because of the high rates of production required, treatment to prevent downhole corrosion would be extremely difficult, if not impossible.

APPENDICES

APPENDIX A

Request Letter
and
Description of the
National Petroleum Council

Department of Energy
Washington, D.C. 20585

June 20, 1978

Dear Mr. Chandler:

An objective of the energy supply initiatives of the President's energy policy is to promote domestic energy production from unconventional sources as well as from conventional sources. One of the areas to be encouraged is the recovery of natural gas from unconventional sources.

In the past, the National Petroleum Council has provided the Department of the Interior with appraisals on the extent and recovery of the Nation's oil and gas resources through such studies as Future Petroleum Provinces, U. S. Energy Outlook, Ocean Petroleum Resources, and Enhanced Oil Recovery.

Therefore, the National Petroleum Council is requested to prepare, as an early and important part of its new relationship with the Department of Energy, a study on unconventional sources of natural gas to include deep geopressured zones, Devonian shale, tight gas sands, and coal seams. Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for costs and recovery of unconventional gas and should consider how Government policy can improve the outlook.

For the purpose of this study, I will designate the Deputy Assistant Secretary for Policy and Evaluation to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger

James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum Council
1625 K Street, N. W.
Washington, D.C. 20006

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- Petroleum Resources Under the Ocean Floor (1969, 1971)
  Law of the Sea (1973)
  Ocean Petroleum Resources (1974, 1975)
- Environmental Conservation -- The Oil and Gas Industries (1971, 1972)
- U.S. Energy Outlook (1971, 1972)
- Emergency Preparedness for Interruption of Petroleum Imports into the United States (1973, 1974)
- Petroleum Storage for National Security (1975)
- Potential for Energy Conservation in the United States: 1974-1978 (1974)
  Potential for Energy Conservation in the United States: 1979-1985 (1975)
- Enhanced Oil Recovery (1976)

* Materials and Manpower Requirements (1979)

* Petroleum Storage & Transportation Capacities (1979).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B
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APPENDIX C

Regional Geology and Prospect Evaluation

REGIONAL GEOLOGY AND PROSPECT EVALUATION

The major potential areas of interest for geothermal, geopressure energy are located along the northwestern rim of the Gulf of Mexico in southern Louisiana and Texas (Figure C-1). Much is known about the Tertiary sandstone reservoirs in these areas from more than 10,000 penetrations to explore for and develop prolific geopressured oil and gas reservoirs (Figure C-2).

REGIONAL GEOLOGY

The southern Louisiana and Texas geopressured trend, in which the potential areas occur, ranges in width from 50 to 70 miles northward from the coast. The prospects identified to date are all Tertiary in age and are part of a fluvial deltaic and marine depositional system. During early Tertiary time (Eocene and Oligocene) the primary area of deposition occurred along the Texas coastal area. This depocenter shifted into Louisiana during later Tertiary Miocene and Pliocene time. In this depositional environment, wedges of sands and clays thickened to the south as the result of contemporaneous movement along growth faults and the underlying salt. Total sediment thickness, including shales and sands along this trend, are reported up to 50,000 feet; however, the actual sand thickness that could be considered prospective is in the order of 500 to 1,000 feet. Other water-bearing sands are present in the geopressured intervals, but because of discontinuities (i.e., faulting, stratigraphic variations), low temperatures and pressures, and poor permeabilities and porosities, their contribution to a geothermal, geopressure brine gas recovery project would not be significant.

The Texas Oligocene Frio prospects were delineated in a regional assessment reported by the Bureau of Economic Geology.[1] Other prospects in the Oligocene Vicksburg and Eocene Wilcox have also been evaluated.[2] Broad regional studies of the Texas trends were followed by detailed local investigations resulting in a Frio site selection in the Brazoria Fairway; this prospect is currently being drilled.

The investigation of the geothermal, geopressured resource of southern Louisiana sands was initiated in 1975 as the result of an

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[1]Bebout, Dorfman, and Agagu, 1975; Bebout, Loucks, Bosch, and Dorfman, 1976; Bebout, Loucks, and Gregory, 1978.

[2]Unpublished report by Bebout, Gregory, Loucks, and Weise.

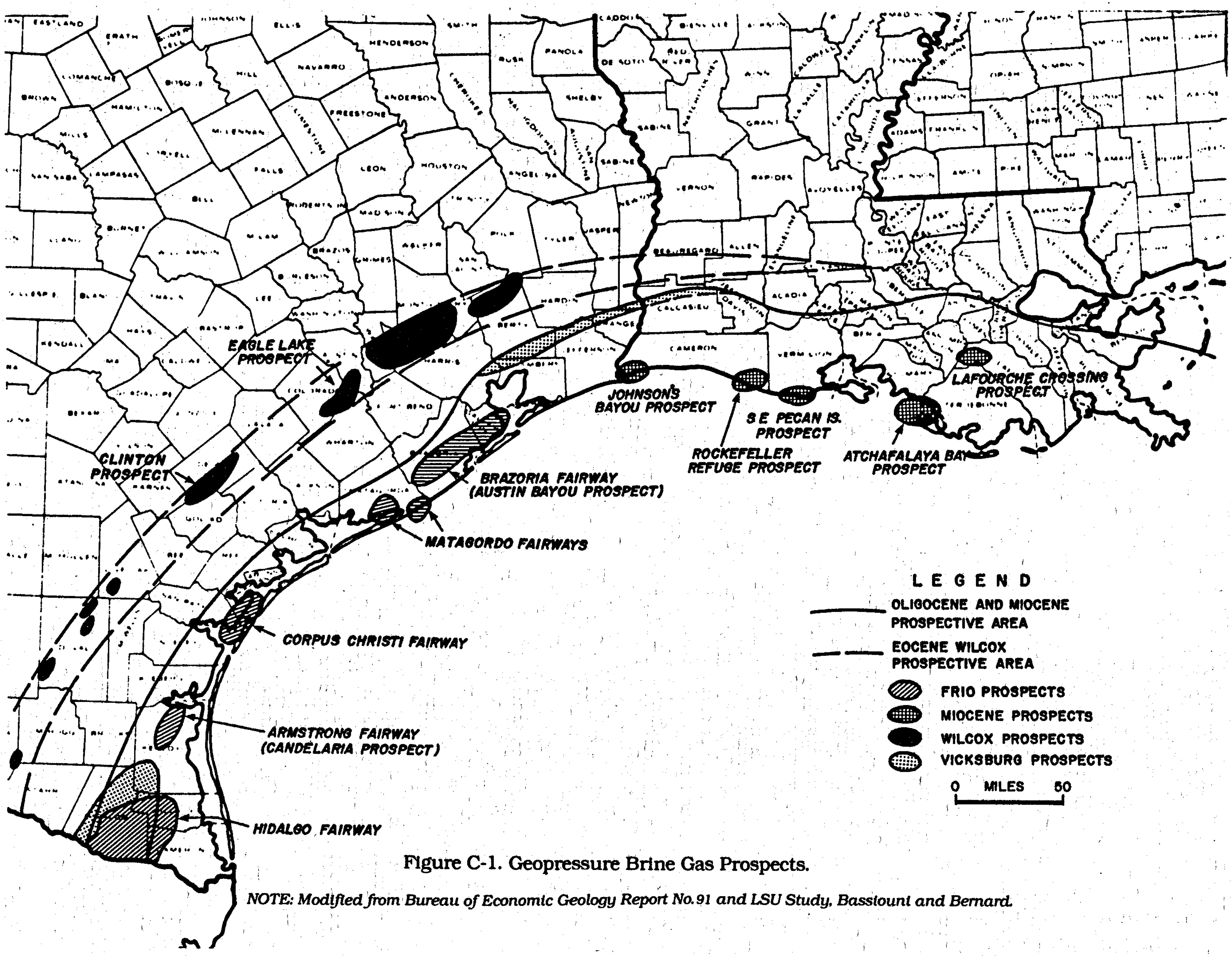

Figure C-1. Geopressure Brine Gas Prospects.

NOTE: Modified from Bureau of Economic Geology Report No. 91 and LSU Study, Bassiouni and Bernard.

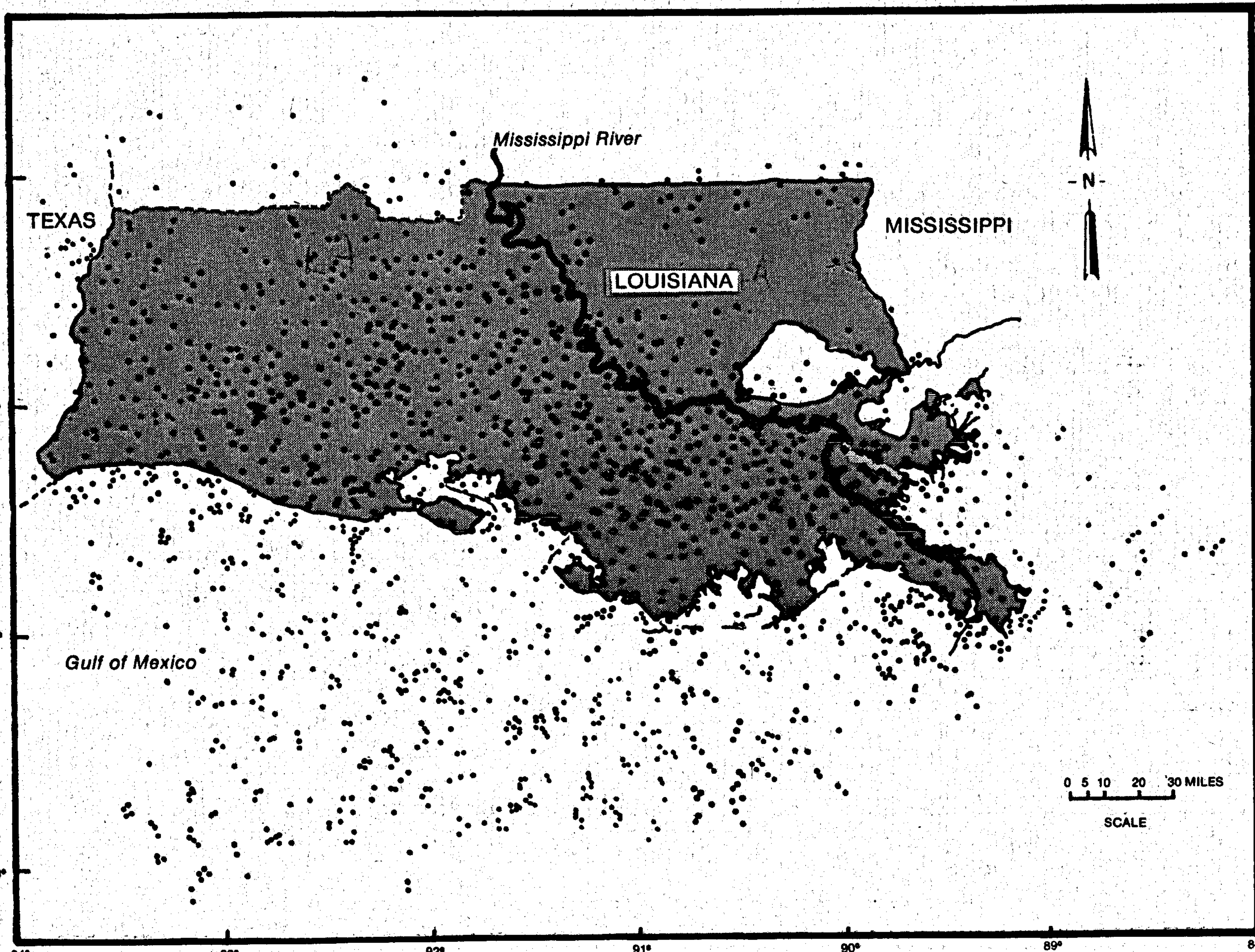

Figure C-2. Location of Study Area and Well Control Used for Estimation of Resource Base.

ERDA contract with the Petroleum Engineering Department at Louisiana State University (LSU), Baton Rouge.[3] As a result of that work, 63 prospective areas were found, and after preliminary ranking, five of the most promising prospects were mapped and studied in detail. The study indicated that the better prospects were generally located in the western half of southern Louisiana. Poorer sand development in the eastern half was the reason LSU downgraded the prospects in that area.

Geopressures in the Texas prospects range in depth from 10,500 to 12,000 feet, and in Louisiana from 8,740 to 14,500 feet. Temperatures are generally higher in the Texas sediments (in the order of 300°F). In Louisiana, temperatures range from 230°F to 320°F. Net sands thickness in one of the better Texas Frio prospects at Brazoria ranges from 100 to 1,000 feet. In Louisiana, the Miocene sand thickness in one of the better prospects is in the same range. Other data regarding the various prospects in both Texas and Louisiana analyzed in this report are listed in Table D-1 in Appendix D.

PROSPECT EVALUATION -- SOUTHEAST PECAN ISLAND

For this study, what was perceived to be one of the best prospects was analyzed in significant detail. Two independent approaches were used in evaluating the Pecan Island prospect. The area was selected by LSU as one of the top prospects identified in their study and has been the subject of a detailed study by that group. About the time results of the LSU study on this prospect were published by Bassiouni and Bernard in October 1978 (but without the benefit of this published information), the area was identified by the NPC study participants and tentatively selected as a project area. Final selection of the area for the project was made because it contains a large volume of thick, correlative sand zones with high pressures and temperatures located in a relatively unfaulted area.

The prospect is located in the southern part of Vermilion Parish along the geopressure trend of southern Louisiana. It is an interfield area bounded by Pecan Island field to the northwest, the Freshwater Bayou gas field to the north, and the Vermilion Area Block 16 field to the south. The fields are separate structural entities and are separated from the project area by bounding down to the south faults (Figure C-3). The limiting fault to the north (Fault A) has a throw of 700 feet; to the south the project area is limited by Fault B with a throw of 300 feet. These faults are the typical east-west striking down to the south growth faults, and based on pressure and geologic information, are considered to be sealing. Several minor nonsealing faults are present within the prospect.

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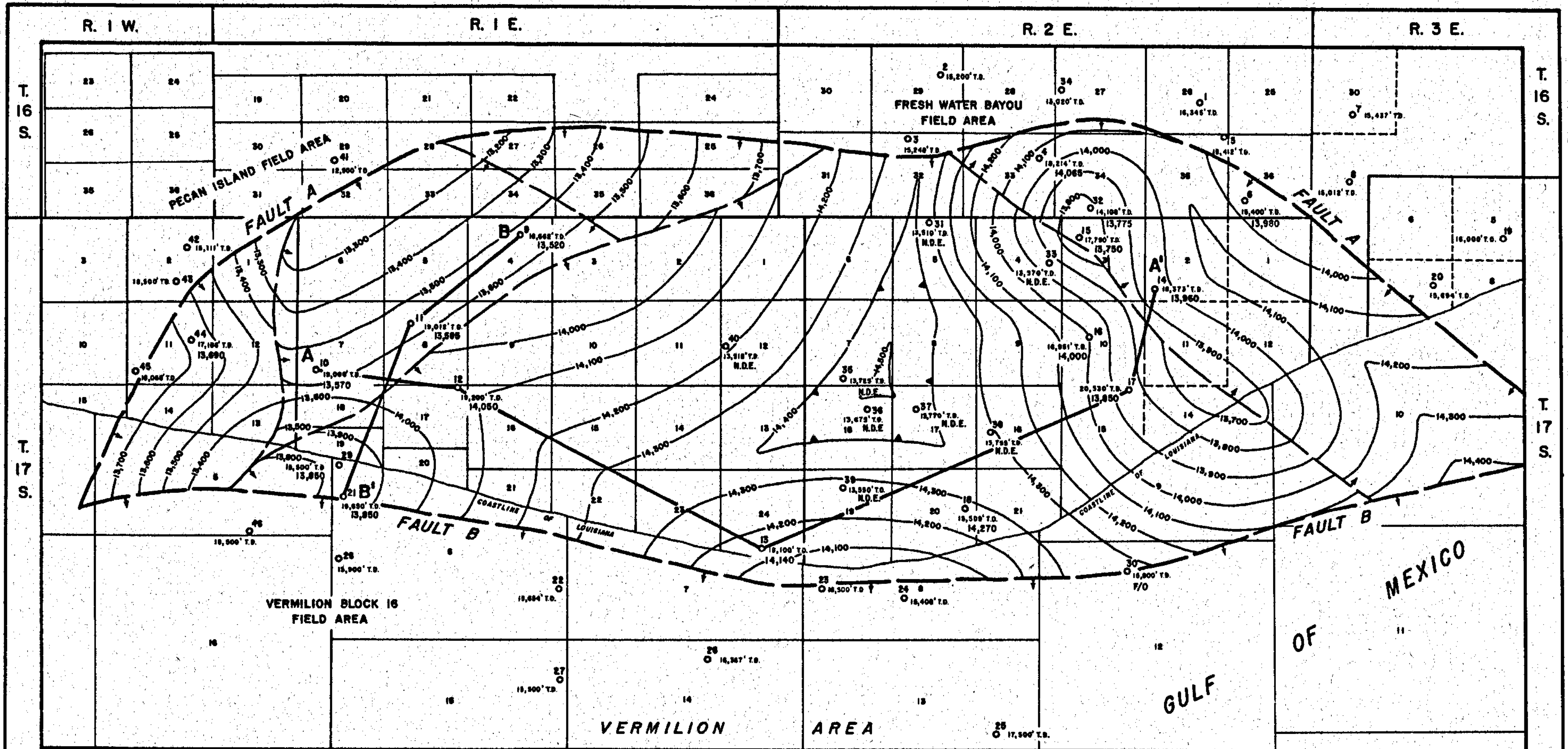
[3] Hawkins, 1975; Bassiouni and Bernard, 1978.



DEPARTMENT OF ENERGY
CONTRACT NO. Ey-76-S005-4889

SOUTHEAST PECAN ISLAND GEOPRESSURE ENERGY PROSPECT
VERMILION PARISH, LOUISIANA

Figure C-3. Structure Map (Top Stratigraphic Interval A).

Contour Interval: 100'

EXPLANATION

O39	Well Location & Identification Number
13,585	Top of Stratigraphic Interval "A"
19,200' T.D.	Total Depth
N.D.E.	Not Deep Enough
F/O	Faulted Out
A-A'	Location East-West Stratigraphic Section Plate 13
B-B'	Location North-South Stratigraphic Section Plate 14

SCALE – FEET
4000 0 4000 8000

R. 1 W. R. 1 E. R. 2 E. R. 3 E.

The LSU group divided the prospective Miocene sands into three stratigraphic intervals, as shown in Figure C-4. Isopach and structure maps were constructed on all zones; however, only the structure map on the top (or upper) Interval A and the composite sand isopach of all three intervals are included in this report (Figure C-5). A list of the wells used in this study is shown in Table C-1.

The Miocene sediments in the Southeast Pecan Island prospect consist of alternating sands and shales. The sands are predominantly fine-grained, silty sands which in some areas grade into fine-grained, clean sands. The gross sand zones can be correlated over the entire area; however, individual sand bodies are not continuous and do not form a uniform blanket. Thickness variations of the individual sand bodies within the three intervals mapped are common, and in some instances the sands disappear completely.

An independent evaluation by the NPC study participants of the sands in this area indicated that the Q and R Sands (equivalent to the upper two sand bodies in Stratigraphic Interval B of the LSU study) appeared to have the best continuity. A structure map on the top of the Q Sand (Figure C-6) indicates the same approximate outline but at a slightly lower elevation. Figure C-7 shows the correlative nature of the sand, the continuous nature of the gross zone, but the poor correlation of thinner individual sand units. A composite isopach of the two sand bodies (Figure C-8) shows a thick net sand, up to 900 feet in the western portion of the prospect, thinning to approximately 150 feet to the east. Permeability, porosity, salinity, pressure, temperature, and methane gas data were based on the LSU group findings and on data supplied by various study participants. These data are tabulated below:

Porosity:	20 percent
Permeability:	10 millidarcies (md) (2 md - 50 md)
Salinity:	100,000 parts per million
Temperature:	300°F
Pressure:	13,500 pounds per square inch
Dissolved Gas:	35 standard cubic feet per barrel

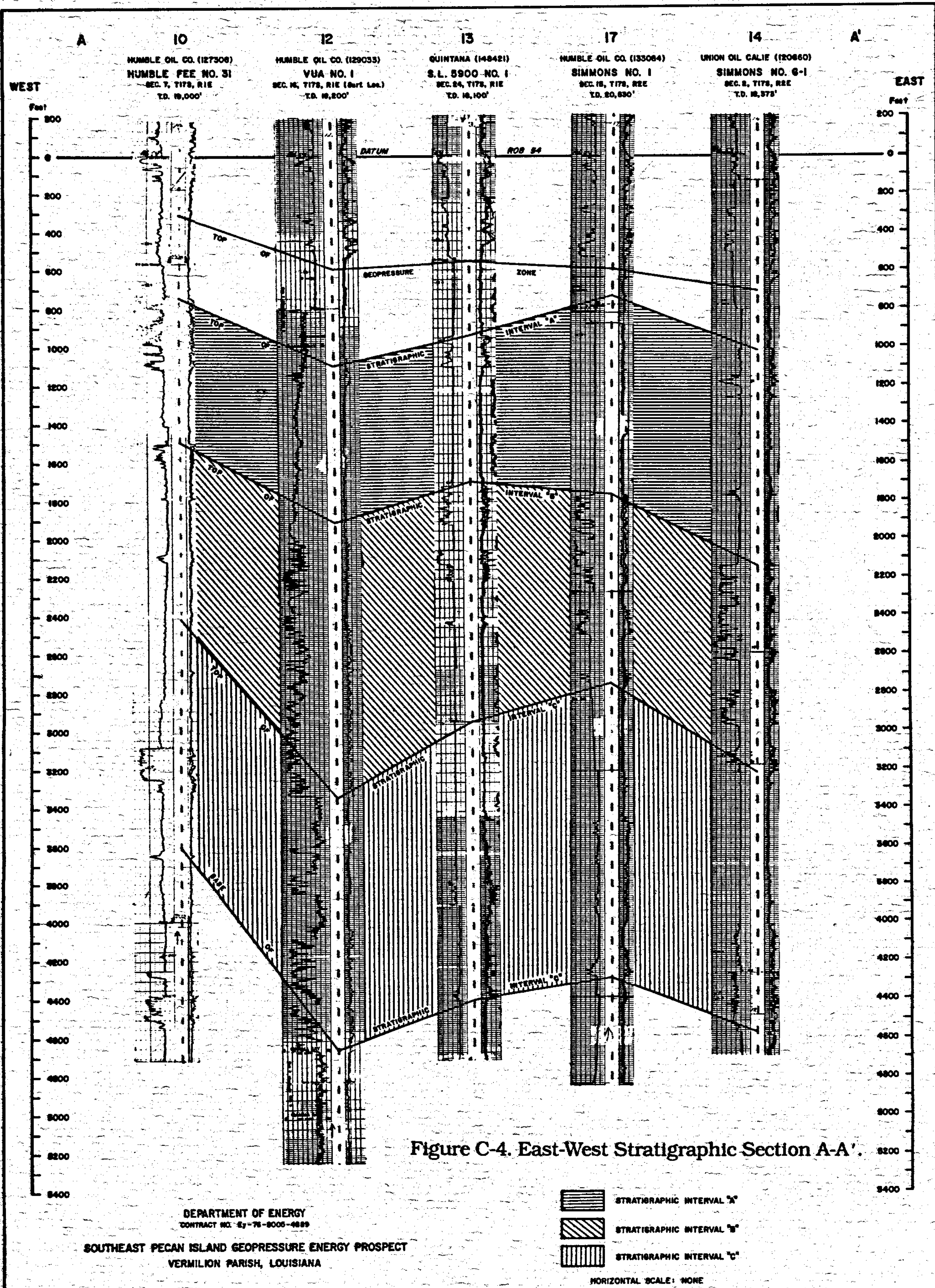
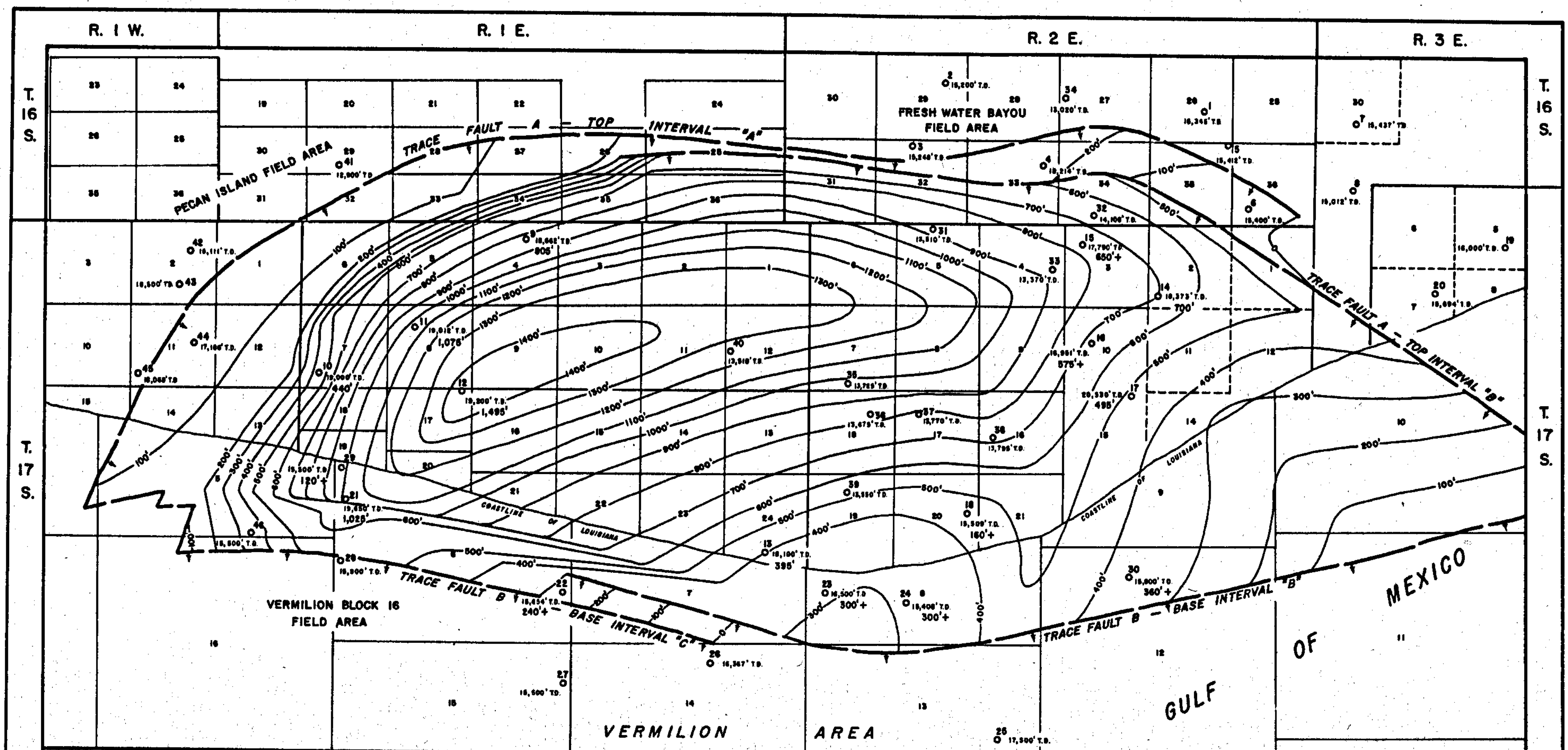


Figure C-4. East-West Stratigraphic Section A-A'.



DEPARTMENT OF ENERGY
CONTRACT NO. Ey-76-S005-4889

SOUTHEAST PECAN ISLAND GEOPRESSURE ENERGY PROSPECT
VERMILION PARISH, LOUISIANA

Figure C-5. Composite Net Sand Isopach Map (Total Stratigraphic Intervals A, B, and C).

EXPLANATION

o 18	Well Location & Identification Number
160'+	Actual Sand Value (Entire Interval Not Penetrated)
395'	Total Sand Value
15,550' T.D.	Total Depth

SCALE – FEET
4000 0 4000 8000

R. 1 W. R. 1 E. R. 2 E. R. 3 E.

TABLE C-1

Wells Used in the Southeast Pecan Island Prospect Evaluation
Vermilion Parish

Map No.	Well Identification
1.	Stone Oil Corp. (148544)* Audubon Soc.-Simmons #2 Sec. 26, T16S, R2E (No Log) T.D. 16,345'
2.	J. P. Owen (88319) La. Furs #G1 Sec. 29, T16S, R2E T.D. 15,200'
3.	Union Oil Co. of Calif. (84876) La. Furs #J2 Sec. 32, T16S, R2E T.D. 15,248'
4.	Union Oil of Calif. (133365) La. Furs #C12 Sec. 33, T16S, R2E T.D. 18,214'
5.	Signal Petro. (146080) Simmons #2 Sec. 35, T16S, R2E T.D. 15,412'
6.	Tidewater Oil (73745) McIlhenny #B-1 Sec. 36, T16S, R7E T.D. 15,400'
7.	Consolidated Gas (127279) Nicks Lake #1 Sec. 30, T16S, R3E T.D. 15,437'
8.	Pan Am (100857) National Audubon Soc. #1 Sec. 31, T16S, R3E T.D. 15,012'
9.	Humble Oil (93647) Humble Fee #23 Sec. 4, T17S, R1E T.D. 18,662'
10.	Humble Oil (127308) Humble Fee #31 Sec. 7, T17S, R1E T.D. 19,000'
11.	Humble Oil Co. (121502) Humble Fee #26 Sec. 8, T17S, R1E T.D. 19,012'
12.	Humble Oil (129033) VUA #1 Sec. 16, T17S, R1E (Surf. loc.) T.D. 19,200'
13.	Quintana (148421) S. L. 5900 #1 Sec. 24, T17S, R1E T.D. 18,100'
14.	Union Oil Calif. (120860) Simmons #G-1 Sec. 2, T17S, R2E T.D. 18,373'
15.	Union Texas (142442) La. Furs #1 Sec. 3, T17S, R2E T.D. 17,790'
16.	Sinclair Oil (74698) McIlhenny #1 Sec. 10, T17S, R2E T.D. 16,951'

*Conservation Department serial number.

TABLE C-1 (continued)

Map No.	Well Identification
17.	Humble Oil (133084)* Simmons #1 Sec. 15, T17S, R2E T.D. 20,530'
18.	Kilroy Co. of Texas (90820) McIlhenny Est. #C-1 Sec. 20, T17S, R2E T.D. 15,509'
19.	A. H. Bruner (81603) National Audubon Soc. #1 Sec. 4, T17S, R3E T.D. 16,000'
20.	Kilroy Co. of Texas (9631) White #B-1 Sec. 5, T17S, R3E T.D. 15,694'
21.	Ocean Drlg. (136970) S. L. 3843 #3 Vermilion Blk. 6 T.D. 19,650'
22.	Ocean Drlg. (95463) S. L. 3843 #1 Vermilion Blk. 6 T.D. 15,654'
23.	Humble Oil (76450) S. L. 3510 #1 Vermilion Blk. 8 T.D. 16,500'
24.	Ocean Drlg. (93061) S. L. 3844 #1 Vermilion Blk. 8 T. D. 15,408'
25.	Exchange Oil (141332) S. L. 5907 #1 Vermilion Blk. 8 T.D. 17,500'

Map No.	Well Identification
26.	Amoco (139360) S. L. 861 #7 Vermilion Blk. 14 T.D. 16,367'
27.	Pan Am (108990) S. L. 862 #5 Vermilion Blk. 15 T.D. 15,500'
28.	Ocean Drlg. (101098) S. L. 3843 #2 Vermilion Blk. 6 T.D. 15,900'
29.	Humble Oil & Refg. Co. (78653) S. L. 3512 #1 Vermilion Blk. 6 T.D. 15,500'
30.	Ocean Drlg. (95464) S. L. 3846 #1 Vermilion Blk. 12 T.D. 15,800'
31.	J. P. Owen et al (94232) La. Furs "J" #2 Sec. 5, T17S, R2E T.D. 13,510'
32.	Union Oil Co. of Calif. (60511) La. Furs "C" #9 Sec. 34, T16S, R2E T.D. 14,108'
33.	Union Oil of Calif. (108171) La. Furs "C" #11 Sec. 4, T17S, R2E T.D. 13,370'
34.	Humble Oil & Refg. Co. (42877) La. Furs. "H" #1 Sec. 27, T16S, R2E T.D. 13,020'

*Conservation Department serial number.

TABLE C-1 (Continued)

Map No.	Well Identification
35.	Diversa, Inc. (89333)* Humble Oil #1 Sec. 7, T17S, R2E T.D. 13,725'
36.	Monterey (82823) McIlhenny Est. #1 Sec. 18, T17S, R2E T.D. 13,675'
37.	Union Texas Natural Gas (87876) McIlhenny #1 Sec. 17, T17S, R2E T.D. 13,770'
38.	Kilroy Co. of Texas (85802) Vermilion Ph. Sch. Brd. #1 Sec. 16, T17S, R2E T.D. 13,755'
39.	Union Oil of Calif. (80830) McIlhenny Est. #A-1 Sec. 19, T17S, R2E T.D. 13,550'
40.	Wacker Oil Co. (86638) La. Furs #1 Sec. 12, T17S, R1E T.D. 13,518'
41.	Exxon Corp. (142426) Exxon Fee #46 Sec. 29, T16S, R1E T.D. 12,900'
42.	Exxon Corp. (118835) Exxon Fee #25 Sec. 2, T17S, R1W T.D. 15,111'
43.	Exxon Corp. (122939) Exxon Fee #29 Sec. 2, T17S, R1W T.D. 18,500'
44.	Exxon Corp. (124819) Exxon Fee #32 Sec. 11, T17S, R1W T.D. 17,186'
45.	Exxon Corp. (128788) Exxon Fee #35 Sec. 11, T17S, R1W T.D. 18,068'
46.	ODECO (89558) S. L. 3762 #1 Vermilion Blk. 5 T.D. 15,500'

*Conservation Department serial number.

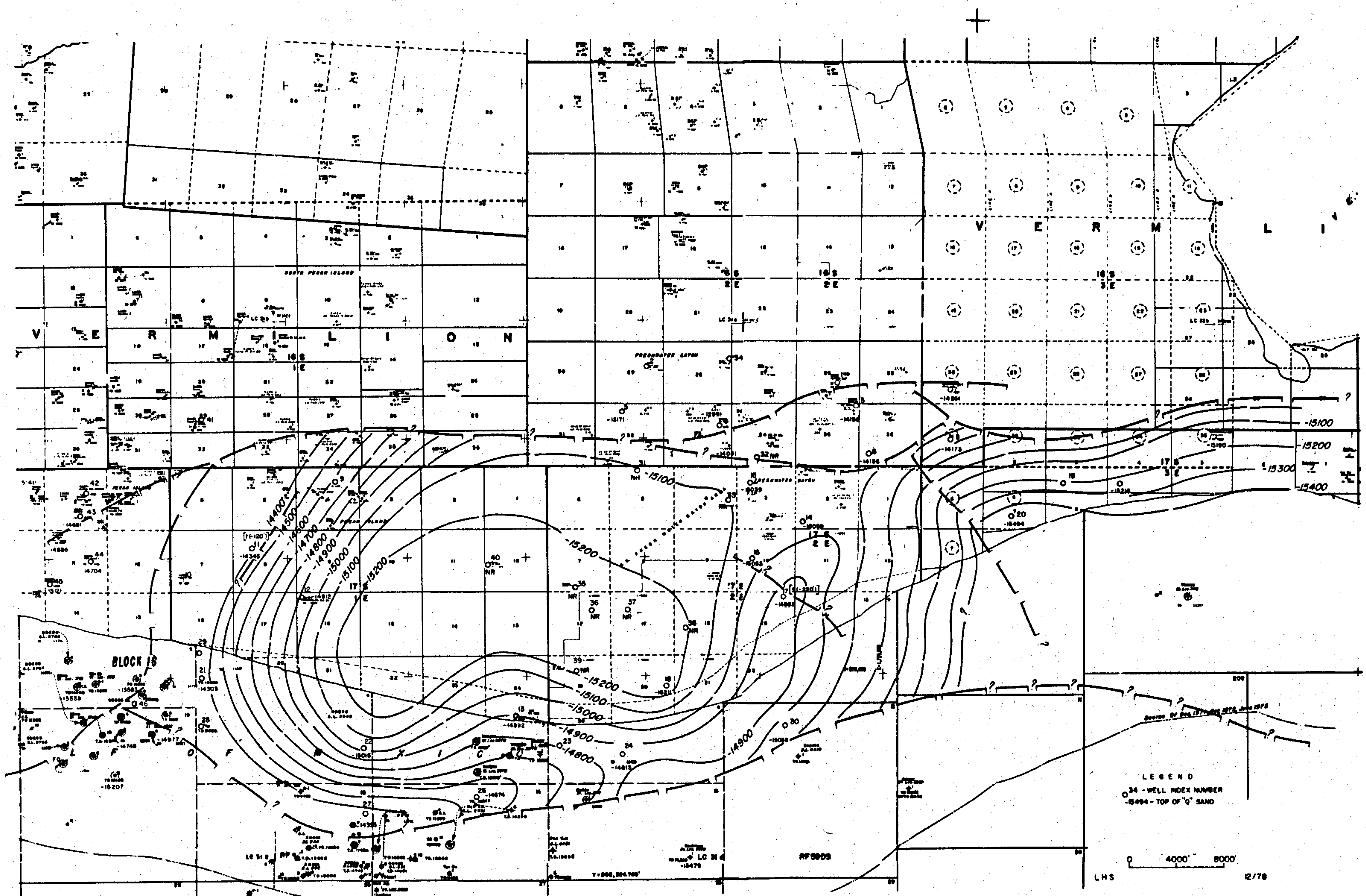
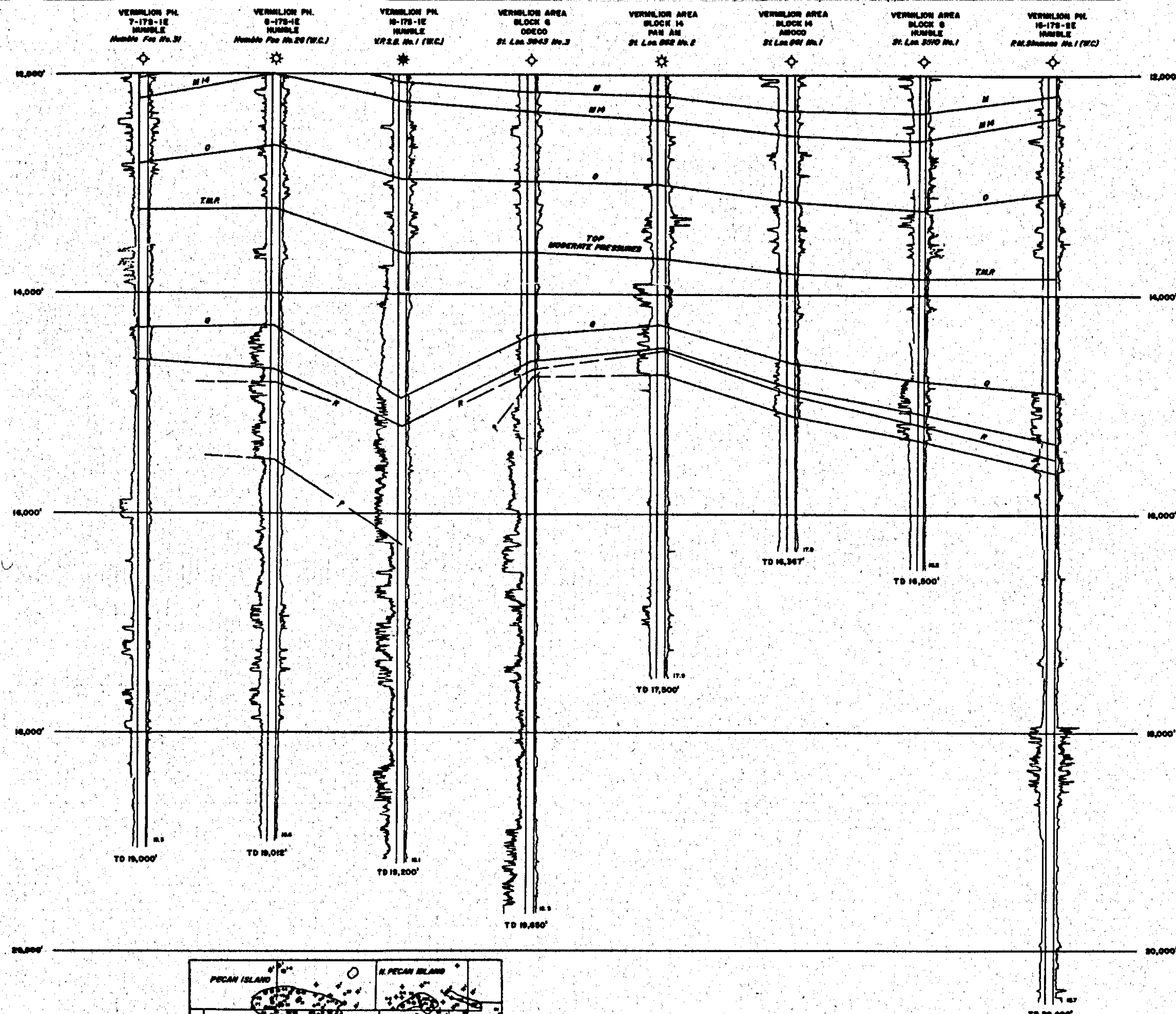


Figure C-6. SE Pecan Island Area Structure Map.



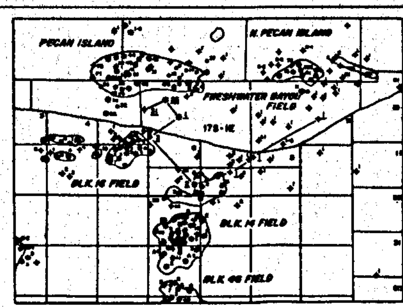


Figure C-7. SE Pecan Island Area Structural Cross Section - Vermilion, Louisiana.

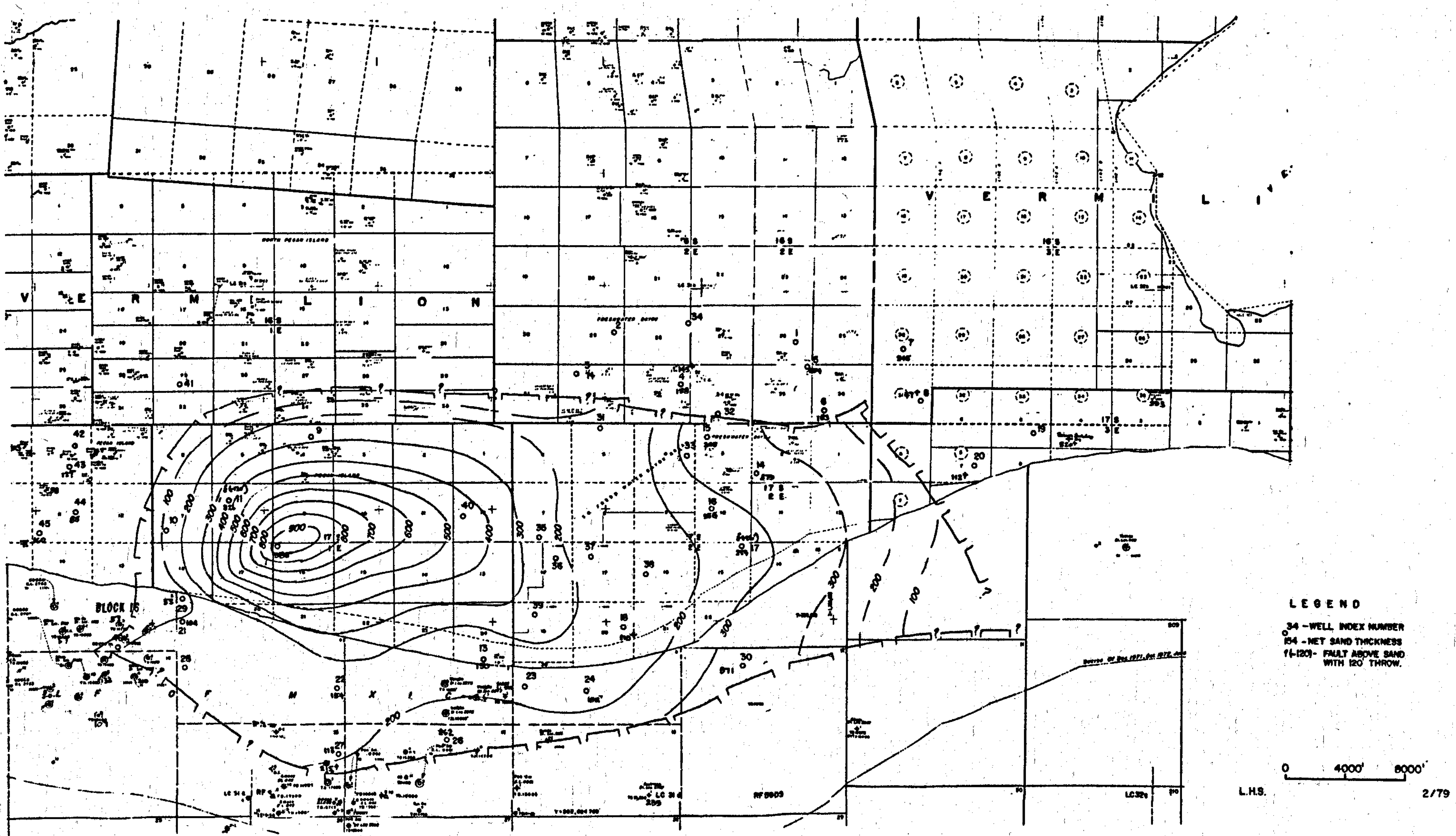


Figure C-8. SE Pecan Island Area Net Sand Isopach (Q and R Sand Combined).

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Loucks, R. G., "Geothermal Resources, Vicksburg Formation, Texas Gulf Coast," Bureau of Economic Geology, University of Texas at Austin, 1978.

<u>Proceedings, Third Geopressured Geothermal Energy Conference</u>, University of Southwestern Louisiana, Lafayette, Louisiana, November 16-18, 1977, Vols. 1-3.

APPENDIX D
Reservoir Engineering

RESERVOIR ENGINEERING

DESCRIPTION OF COMPUTER MODEL

Evaluation of the brine- and gas-producing potential of the Texas and Louisiana geopressured geothermal prospects was performed utilizing a one-dimensional, radial flow, "tank" model. The model was designed to maintain a volumetric balance over each time step of the calculation procedure to assure representative pressure/production behavior. The model accounted for gas liberation in the reservoir, water production, and expansion of free gas, water, and the reservoir rock. An iterative procedure employing small time steps was employed to calculate instantaneous flow rates and pressures assuming pseudosteady-state flow in a bounded, finite drainage area, slightly compressible, radial flow system. The calculation procedure continued until flow to a given wellhead pressure could no longer be maintained or until a specified number of time steps had been executed.

Computational procedures were included for both single-phase and two-phase radial flow through porous media. In all cases, the aquifer water was assumed to be saturated with dissolved gas at initial reservoir conditions of temperature, pressure, and salinity with no free gas phase initially present. The period of single-phase flow would then exist from initial conditions until the liberated gas reached the equilibrium saturation. In all production cases evaluated, the free gas saturation remained well below the assumed equilibrium saturation of 3 percent throughout the natural flow period. Free gas saturation was less than 1 percent in every case evaluated and usually remained below 1/2 percent over 25 years. Since equilibrium gas saturation was never met, two-phase flow was not considered by the model. Likewise, since free gas saturation remained low throughout the natural flow period, reduction of water permeability due to gas saturation was minor and was not included in the computations.

The computer model also considered well bore hydraulics. Since there are a number of possible tubing sizes which might normally be utilized in such producing wells, computer runs were made on one of the prospects using tubing sizes of 4 1/2, 5 1/2, and 7 inches. From those runs it was estimated that 4 1/2-inch tubing would place unacceptable constraints on daily production rates while 7-inch tubing would probably not be required at desired and sustainable producing rates. It was decided, therefore, that the subsequent computer runs on all other prospects would consider only 5 1/2-inch production tubing.

RESERVOIR PROPERTIES OF TEXAS AND LOUISIANA PROSPECTS

To predict the pressure and production schedules for the Texas and Louisiana geopressured prospects through the use of a computer model and to complete the economic evaluation of these prospects, it was necessary to derive a number of descriptive reservoir parameters for use in these analyses. Parameters utilized for prospects in this study are summarized in Table D-1. Fluid properties such as water viscosity, water density, and water formation volume factor were determined from correlations commonly utilized in the petroleum industry.

Dissolved Gas Content

Determination of the dissolved methane content of the reservoir brines was based on the experimental data of Culberson and McKetta[1] and Sultanov, Skripka, and Namiot.[2] These researchers examined methane solubility in pure water as a function of temperature and pressure. Additional research, including a recent study by Haas,[3] has indicated that dissolved salts reduce methane solubility in water and that the reduction is in the order of 15 to 20 percent at 50,000 parts per million NaCl and 30 to 40 percent at 100,000 parts per million NaCl. Haas' empirical relations for methane solubility in pure water were also in quite close agreement with those of the two previously mentioned studies over the range of pressures and temperatures of interest in the present study. For the computer model runs on each prospect, the initial dissolved gas content of the water was specified in the input data and was then automatically adjusted by the model in accordance with the experimental data as the reservoir pressure was lowered.

System Compressibility

The fraction of water in place which can be produced by depressuring an aquifer by natural flow is primarily dependent on the compressibility of the system. This compressibility is the sum of physical phenomena which contribute to maintaining pressure as water is withdrawn from the reservoir. The space vacated by produced water is filled by a combination of:

- Water expansion (Item 1)
- Rock expansion manifested as a decrease in effective porosity (Item 2)

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[1]Culberson, O. L., and McKetta, J. J., "Phase Equilibria in Hydrocarbon Water Systems III -- the Solubility of Methane in Water at Pressures to 10,000 psia," Transactions AIME 192, 1951, pp. 223-226.

[2]Sultanov, R. G.; Skripka, V. G.; and Namiot, A. Y., "Solubility of Methane in Water at High Temperatures and Pressures," Gazovaia Promyshlennost, Vol. 17, 1972, pp. 6-7. (in Russian)

[3]Haas, J. L., Jr., An Empirical Equation with Tables of Smoothed Solubilities of Methane in Water and Aqueous Sodium Chloride Solutions up to 25 Weight Percent, 360°C, and 138 MPa, U.S. Geological Survey, Reston, Virginia, 1978. Open-File Report No. 78-1004.

TABLE D-1

PROSPECT EVALUATION SUMMARY

Prospect Name	Location (Parish or County)	Physiography	Geological Zone	Top of Geopressure (Feet)	Bottom of Sand Interval (Feet)	Bulk Volume ($Ft^3 \times 10^9$)	Area (sq. miles)	Average Thickness (Feet)	Net Sand Thickness at Recommended Well Site (Feet)	Average Depth (Feet)	Average Temperature (°F) *	Average Pressure (psi)	Average Permeability (md)	Average Porosity (%)	Average Salinity (ppm)	Dissolved Methane Content (SCF/bbl)
I. Louisiana																
Atchafalaya Bay	St. Mary & Terrebonne	Marsh & Bay	Miocene													
East				11,675	15,500	496	56	320	340	15,200	270	12,160	20	26	107,000	29
West				11,120	14,600	555	90	220	600	13,300	240	10,640	30	26	107,000	23
Johnson's Bayou	Cameron	Marsh & Gulf	Miocene	8,740	13,500	1,600	46	1,250	1,550	11,400	230	9,500	100	31	95,000	20
LaFourche Crossing	LaFourche & Terrebonne	Land	Miocene	13,850	17,000	332	33	360	650	15,000	270	12,900	20	25	45,000	36
Rockefeller Refuge	Cameron	Marsh & Gulf	Miocene	14,500	17,500	946	78	435	1,400	16,500	320	14,200	20	23	56,000	51
S.E. Pecan Island East	Vermillion	Marsh & Gulf	Miocene	13,700	16,500	152	22	250	380	15,563	300	13,500	10	20	100,000	35
West				13,400	17,700	351	46	275	980	15,565	300	13,500	10	20	100,000	35
II. Texas																
Austin Bayou	Brazoria	Land & Marsh	Frio	12,000	17,000	360	18	715	900	14,500	315	11,600	20	16	60,000	40
Candelaria	Kenedy	Land	Frio	10,700	13,500	588	44	480	700	12,000	275	9,750	5	15	75,000	28
Clinton	DeWitt	Land	Wilcox	10,500	12,000	222	11	700	700	11,500	275	8,250	20	16	60,000	28
Eagle Lake	Colorado	Land	Wilcox	12,000	12,900	160	10	575	575	12,450	315	9,335	20	13	90,000	30

*Temperatures determined from well logs corrected for mud circulation.

- Gas evolved from solution in the reservoir water with depressuring (Item 3)

- Water migrating into the reservoir pore space from shales surrounding and interbedded with the reservoir rock (Item 4)

- Decrease in effective porosity caused by subsidence (Item 5).

Items 3, 4, and 5 usually contribute little to maintenance of pressure in moderate depth, normally pressured aquifers, and these aquifers are usually stimulated considering only Items 1 and 2. Adequate compressibility data are available for water, but data for rock compressibility in the geopressured range are sparse. The available data indicate somewhat higher rock compressibility in geopressured reservoirs than in normally pressured reservoirs, but present data is not sufficient for accurately estimating representative values for a particular reservoir. Although a wide range of rock compressibility values has appeared in the literature on geopressured aquifers, some have been purely speculative. In the absence of more definitive data, therefore, a rock pore volume compressibility value of 5.0×10^{-6} psi^{-1} was used in the NPC study.

Item 3 can be significant if the aquifer water is saturated with gas at original conditions and depressuring is carried to a level well below original. The effect of Item 3 was included in the NPC study, while possible pressure maintenance by Items 4 and 5 was not included.

There are different opinions regarding the importance of Item 4 in maintaining pressure. Shales have some permeability, but in normally pressured reservoirs, this permeability is so small that it can be neglected. Abnormally pressured shales tend to have more permeability because high fluid pressure has prevented overburden stresses from squeezing water from the pore structure to the extent that this occurs in normal pressure environments. With higher permeability in abnormally pressured shales and with large pressure gradients which will occur as these reservoirs are produced, some water will migrate into the reservoir sands from shales in immediate proximity to the reservoir rock. One author has attributed significant pressure maintenance to this source in analyzing the depletion of abnormally pressured gas reservoirs.[4]

Pressure maintenance from decreases in effective porosity due to subsidence have been reported for a number of fields including Wilmington and several Venezuelan fields. Reservoir rock subsidence is attributable to rearrangement and to crushing of sand grains. These factors would tend to decrease well productivity and, in severe instances, could cause casing failure.

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[4]Wallace, W. E., "Water Production from Abnormally Pressured Gas Reservoirs in South Louisiana, Part II," Proceedings of the Second Symposium on Abnormal Subsurface Pressure, Louisiana State University, Baton Rouge, Louisiana, January 30, 1970.

There are, therefore, major uncertainties regarding system compressibility. More laboratory and field data are needed to assess the effect of the various components of system compressibility on geopressured aquifer performance. Based on currently available data, however, it is felt that the system compressibility value utilized in this study is reasonable.

Other Reservoir Parameters

Other reservoir and fluid descriptive properties for the Texas and Louisiana geopressured prospects were determined from evaluation reports prepared for the U.S. Department of Energy, Division of Geothermal Energy, by researchers at Louisiana State University (LSU)[5] and the University of Texas.[6,7,8,9] These researchers utilized, as their primary source of data, well logs from wells within the prospects and in the immediate surrounding area, analyzing and correlating the logs to develop geologic information in the form of cross sections, structural maps, and isopach maps. Other prospect information, such as reservoir temperature, pressure, salinity, porosity, and permeability, were developed using well logs, cores, and data from drilling reports.

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[5]Bernard, W. J., Evaluation of Five Potential Geopressure Geothermal Test Sites in Southern Louisiana, Petroleum Engineering Department, Louisiana State University, Baton Rouge, February 1979. Contract Study EY-76-S-05-4889 prepared for U.S. Department of Energy, Division of Geothermal Energy.

[6]Bebout, D. G.; Loucks, R. G.; and Gregory, A. R., Geopressured Geothermal Fairway Evaluation and Test-Well Site Location, Frio Formation, Texas Gulf Coast, Bureau of Economic Geology, University of Texas at Austin, January 1978. Contract Study EY-76-S-05-4891-4 prepared for U.S. Department of Energy, Division of Geothermal Energy.

[7]Bebout, D. G.; Gavenda, V. J.; and Gregory, A. R., Geothermal Resources, Wilcox Group, Texas Gulf Coast, Bureau of Economic Geology, University of Texas at Austin, January 1978. Contract Study EY-76-S-05-4891-3 prepared for U.S. Department of Energy, Division of Geothermal Energy.

[8]Bebout, D. G.; Gregory, A. R.; Loucks, R. G.; and Weise, B. R., A Prospectus, Geopressured Geothermal Prospects and Test-Well Sites, Wilcox Group and Frio Formation, Texas Gulf Coast, Bureau of Economic Geology, University of Texas at Austin, December 1978. Prepared for U.S. Department of Energy, Division of Geothermal Energy.

[9]Loucks, R. G., Geothermal Resources, Vicksburg Formation, Texas Gulf Coast, Bureau of Economic Geology, University of Texas at Austin, January 1978. Contract Study EY-76-S-05-4891-2 prepared for U.S. Department of Energy, Division of Geothermal Energy.

For each of the Louisiana prospects, the LSU evaluation report provides a general description of the prospect with regard to its surface geographic location, a geologic description of the prospect area, and a general stratigraphic description of the geopressured sediments in the prospect. The LSU evaluation report also specifies, for each prospect, its net sand volume, areal extent, top and bottom of sand interval, and average depth as these parameters were determined from structure and isopach maps and geologic cross sections.

Additionally, LSU researchers determined from net sand isopach maps the sand thickness at a site which was recommended as the location for a test well in each prospect area. That thickness was utilized as the net sand thickness in all single-producing-well computer model prediction runs in the NPC study. Where prediction involved the development of the prospect with more than one producing well, the sand thickness used in the model was the average net sand thickness determined by dividing the reservoir bulk volume by the area of the prospect.

Data values estimated from conventional well logs for each of the Louisiana prospects included average salinity, average pressure, top of geopressure, and average temperature. Pressures were estimated from shale resistivity indications on the well logs. Temperature readings from logs were corrected to undisturbed reservoir temperatures, to account for mud circulation effects, using a generally accepted American Association of Petroleum Geologists (AAPG) correction relationship. Other data values estimated from well logs and/or sidewall cores included average permeability and porosity. Permeability values cited by the LSU reports were considered to be high for use as average values over the total net sand thickness and were adjusted downward by the study participants, based on oil and gas production experience in the areas.

For all Louisiana prospects with the exception of Southeast Pecan Island, data values determined by LSU researchers as described above were utilized in the computer model runs. In the case of the Southeast Pecan Island prospect, however, a separate examination was performed by the geologists participating in the NPC study. Values used in the Pecan Island computer runs for reservoir bulk volume, areal extent, top and bottom of sand interval, average depth, and expected thickness at the recommended test well site were determined from geologic maps prepared by the study participants. Other values used in the Pecan Island model runs were either taken directly from the LSU report or were adjusted somewhat to account for the difference in average depth between the two geologic models.

Four Texas prospects for which sufficient data were available in the University of Texas evaluation report were examined using the computer model to estimate their brine- and gas-producing potentials. The University of Texas report was broken down into several parts, each covering a separate geologic formation: one part covered the Frio prospects, while another covered Wilcox Group prospects, and a third discussed prospects in the Vicksburg Formation. Geologic structure and isopach maps were not included in the Texas report and properties were, therefore, necessarily drawn from textual information, data tables, and geologic cross sections included in the report. Of the Texas sites, the Austin Bayou, Frio Formation prospect received the most extensive coverage, while information on the other Texas prospects was presented in less detail.

In several cases, prospect bulk volumes were reduced from the values given in the University of Texas reports to exclude from the reservoir volume those sands which were indicated by the evaluation reports to be of very low permeability or not within the geopressured zone. Consequently, it was necessary to alter the average reservoir properties of the prospects to conform with the change in average depth of the reservoirs. Since the tabulated data were often presented as a range of values over an interval of depth, it was generally possible to interpolate within the given range to the new average depth.

Data values presented in the Texas reports were generally developed by means of the same analytical procedures described above for the Louisiana prospects using well logs, cores, and drilling report information. As in the case of the Louisiana prospects, permeability values presented in the Texas evaluation reports were considered by NPC study participants to be too high to be applied as average permeability values over the entire net sand thickness. Permeabilities were therefore decreased in accordance with the experience of study participants familiar with the prospect areas.

PRODUCTION EVALUATION OF LOUISIANA PROSPECTS

Five Louisiana geopressured brine prospects were evaluated by computer model for this study. The aquifer properties utilized in the computer model for each of the prospects were summarized in Table D-1. Most of the properties listed were taken directly from data presented in the evaluation of the five possible test sites prepared by LSU staff members. Parameters utilized in modeling the Southeast Pecan Island prospect, however, were determined from industry data and from the geologic interpretation by the geologists participating in the NPC study. In the case of several of the prospects, the dissolved natural gas content of the brine was changed somewhat from the LSU data (usually in the direction of a higher gas content), to reflect the probable saturated gas content at reservoir temperature, pressure, and water salinity. All computer runs considered only a production tubing size of 5 1/2 inches and a rock pore volume compressibility of 5.0×10^{-6} psi^{-1}.

The computer model was run to determine, for each of the prospects, its brine- and gas-producing capability at initial rates of 30, 50, and 70 MB/D per well for single-well and multiple-well configurations; this process involved 61 model runs. Table D-2 lists summary information for each of the prospects. The production

TABLE D-2

Louisiana Geopressure-Geothermal Prospect Production Summary

Prospect	Brine Production Rate (B/D)	Computer Run Number	Number of Producing Wells	Length of Constant Flow Period (Years)	Total Gas Produced Per Well During Natural Flow Period* (BCF)	Gas Produced as Percentage of Original Gas In Place
Atchafalaya Bay East	70,000	L1	1	0	11.42	1.8
	50,000	L2	1	7	11.27	1.8*
		L3	2	3	8.73	2.7
	30,000	L4	1	25+	7.69	1.2
		L5	2	22	7.37	2.3
		L6	4	11	5.37	3.3
		L7	6	7	3.80	3.6
		L8	8	6	2.85	3.6
		L9	10	4	2.28	3.6
Atchafalaya Bay West	70,000	L10	1	0	10.55	1.8
	50,000	L11	1	17	9.81	1.7*
		L12	2	0	6.40	2.2
	30,000	L13	1	25+	6.19	1.1
		L14	2	18	5.77	2.0
		L15	4	9	4.11	2.8
		L16	6	6	2.95	3.0
Johnson's Bayou	70,000	L17	1	25+	12.70	0.7*
		L18	2	19	12.19	1.4
		L19	4	9	10.15	2.3
		L20	6	6	8.11	2.8

*Natural flow period of 25 years or less if aquifer pressure depletes sooner.

TABLE D-2 (continued)

Prospect	Brine Production Rate (B/D)	Computer Run Number	Number of Producing Wells	Length of Constant Flow Period (Years)	Total Gas Produced Per Well During Natural Flow Period* (BCF)	Gas Produced as Percentage of Original Gas In Place
Johnson's Bayou	50,000	L21	1	25+	9.15	0.5
		L22	2	25+	8.93	1.0
		L23	6	17	7.61	2.6
		L24	8	13	6.29	2.9
		L25	14	7	3.61	2.9
	30,000	L26	1	25+	5.53	0.3
		L27	2	25+	5.46	0.6
		L28	12	19	4.21	2.9
		L29	14	16	3.60	2.9
		L30	18	12	2.81	2.9
		L31	24	9	2.10	2.9
		L32	30	7	1.69	2.9
LaFourche Crossing	70,000	L33	1	3	17.16	3.2
	50,000	L34	1	18	15.56	2.9*
		L35	2	6	10.44	3.9
	30,000	L36	1	25+	9.93	1.8
		L37	2	21	9.18	3.4
		L38	4	10	5.73	4.2
		L39	6	7	3.84	4.3
		L40	8	5	2.88	4.3
Rockefeller Refuge	70,000	L41	1	25+	31.34	1.7*
		L42	2	4	25.90	2.8

*Natural flow period of 25 years or less if aquifer pressure depletes sooner.

TABLE D-2 (continued)

Prospect	Brine Production Rate (B/D)	Computer Run Number	Number of Producing Wells	Length of Constant Flow Period (Years)	Total Gas Produced Per Well During Natural Flow Period* (BCF)	Gas Produced as Percentage of Original Gas In Place
Rockefeller Refuge	50,000	L43	1	25+	22.68	1.2*
		L44	2	25+	21.99	2.4
		L45	4	13	18.45	4.0
		L46	6	8	14.39	4.6
		L47	8	6	11.29	4.8
	30,000	L48	1	25+	13.78	0.7
		L49	10	14	9.02	4.8
		L50	14	10	6.48	4.9
		L51	20	7	4.54	4.9
SE Pecan Island East	70,000	L52	1	0	7.28	4.0
	50,000	L53	1	1	7.27	4.0
	30,000	L54	1	12	6.95	3.8
		L55	2	4	3.87	4.3
SE Pecan Island West	70,000	L56	1	2	14.44	3.5
	50,000	L57	1	15	13.53	3.2
		L58	2	0	7.33	3.5
	30,000	L59	1	25+	9.03	2.2
		L60	2	10	7.07	3.4
		L61	4	5	4.42	4.2

*Natural flow period of 25 years or less if aquifer pressure depletes sooner.

rate, computer run number, number of producing wells, and length of the constant flow period are given. Table D-2 also lists, for each of these cases, the total gas produced per well during 25 years of natural flow (or until the end of the natural flow period if pressure depletion occurred in less than 25 years) and that total production as a percentage of the original gas in place. In each of the single-well production cases, the net sand thickness used in the model was the expected thickness at the recommended well site as determined from net sand isopach maps. In each of the multiple-well production cases, the average net sand thickness, as determined from the values for bulk volume and areal extent, was used in the computer model.

PRODUCTION EVALUATION OF TEXAS PROSPECTS

Four Texas geopressured brine prospects were evaluated by computer model for this study. The aquifer properties utilized in the computer model for each of the prospects were summarized in Table D-1. These properties were derived primarily from research reports on the prospects prepared by the Bureau of Economic Geology at the University of Texas at Austin. A small amount of additional industry data was also available and was utilized in the determination of reservoir properties, as was the input of several NPC study participants who are familiar with the prospect areas. The dissolved natural gas content of the geopressured brine was adjusted to reflect saturation conditions at the temperature, pressure, and salinity of the individual prospect reservoirs. As was the case in the previous evaluation of the Louisiana prospects, only 5 1/2-inch production tubing and rock pore volume compressibility of 5 x 10^{-6} psi^{-1} were considered in the model runs.

The computer model was run to determine the brine- and gas-producing capabilities of each of the prospects over 25 years at initial producing rates of 30, 50, and 70 MB/D per well for single-well and multiple-well configurations; this process involved 16 model runs. Table D-3 lists summary information for each of the prospects. The production rate, computer run number, number of producing wells, and length of the constant flow period are given as well as the total gas produced per well during a natural flow period of 25 years or less if pressure depletion occurred sooner. Gas production, as a percentage of original gas in place at saturated conditions, is also provided in Table D-3. For the single-well production cases, the net sand thickness used in the model was the expected thickness at the recommended well site as determined from net sand isopach maps. In the multiple-well production cases, the net sand thickness utilized in the computer run was the average net sand thickness as determined from values given for bulk volume and areal extent.

TABLE D-3

Texas Geopressure-Geothermal Prospect Production Summary

Prospect	Brine Production Rate (B/D)	Computer Run Number	Number of Producing Wells	Length of Constant Flow Period (Years)	Total Gas Produced Per Well During Natural Flow Period* (BCF)	Gas Produced as Percentage of Original Gas In Place
Austin Bayou	70,000	T1	1	2	13.70	3.5
	50,000	T2	1	12	13.24	3.4
		T3	2	5	7.25	3.8
	30,000	T4	1	25+	9.99	2.6
		T5	2	14	7.22	3.7
		T6	4	7	3.62	3.7
Candelaria	70,000	T7	1	0	6.72	1.6
	50,000		1	0	6.72	1.6
	30,000	T8	1	9	6.56	1.5
		T9	2	0	4.31	2.0
Clinton	70,000	T10	1	0	3.95	2.3
	50,000	T11	1	1	3.94	2.3
	30,000	T12	1	8	3.92	2.3
		T13	2	4	1.96	2.3
Eagle Lake	70,000	T14	1	0	2.96	2.8
	50,000	T15	1	1	2.95	2.8
	30,000	T16	1	6	2.95	2.8

*Natural flow period of 25 years or less if aquifer pressure depletes sooner.

APPENDIX E
Drilling and Well Costs

TABLE E-1

Producing Well Cost Summary
(Constant 1979 Dollars)

Louisiana Prospects	Total Depth	Total Well Cost	Cost/ Foot
Atchafalaya Bay			
East	15,500 Ft	$3,500,000	$225
West	14,600	3,200,000	220
Johnson's Bayou	13,500	2,670,000	198
LaFourche Crossing	17,000	4,100,000	242
Rockefeller Refuge	17,500	4,250,000	242
SE Pecan Island			
East	16,500	4,000,000	242
West	17,700	4,290,000	242
Texas Prospects			
Austin Bayou	17,000	4,630,000	272
Candelaria	13,500	2,280,000	169
Clinton	12,000	2,000,000	166
Eagle Lake	12,900	2,200,000	170

TABLE E-2

Drilling Programs and Cost Estimates
(Constant 1979 Dollars)

Johnson's Bayou Prospect, Louisiana

Top Geopressure	8,700 Ft	
Total Depth	13,500	
Tangibles		
26" Conductor		$ 10,000
20" Surface Casing	1,800 Ft	80,000
13 3/8" Intermediate	8,700	310,000
9 5/8" Production	13,500	410,000
5 1/2" Tubing	9,000	150,000
Xmas Tree		150,000
Subtotal		$1,110,000
Intangibles		
Location and Move		$ 100,000
Rig 50 Days, $7,000/Day		350,000
Mud		200,000
Logging and Perforating		130,000
Bits		80,000
Rental Equipment		20,000
Fuel and Water		20,000
Trucking		20,000
Coring		20,000
Geology and Engineering		50,000
Well Supplies		25,000
Cementing		100,000
Subtotal		$1,115,000
Contingency (20% of Total)		445,000
Total		$2,670,000

TABLE E-2 (continued)

Southeast Pecan Island Prospect West, Louisiana

Top Geopressure	13,400 Ft	
Total Depth	17,700	
Tangibles		
26" Conductor		$ 10,000
13 3/8" Surface Casing	3,000 Ft	100,000
9 5/8" Intermediate	13,400	535,000
7" Liner	17,500	50,000
5 1/2" Tubing	15,000	200,000
Xmas Tree		150,000
Subtotal		$1,045,000
Intangibles		
Location and Move		$ 100,000
Rig 100 Days, $7,000/Day		700,000
Mud		400,000
Logging and Perforating		350,000
Bits		100,000
Rental Equipment		100,000
Fuel and Water		50,000
Trucking		50,000
Coring		40,000
Geology and Engineering		225,000
Well Supplies		40,000
Compl. and Spec. Services		150,000
Cementing		225,000
Subtotal		$2,530,000
Contingency (20% of Total)		715,000
Total		$4,290,000

TABLE E-2 (continued)

Austin Bayou Prospect, Texas

Top Geopressure	10,200 Ft	
Total Depth	16,500	
Tangibles		
26" Conductor		$ 10,000
20" Surface Casing	1,300 Ft	50,000
13 5/8" Intermediate	8,500	295,000
9 5/8" Production	14,500	495,000
7" Liner	16,500	60,000
5 1/2" Tubing	15,000	200,000
Xmas Tree		150,000
Subtotal		$ 1,260,00
Intangibles		
Location and Move		$ 200,000
Rig 140 Days, $7,200/Day		1,008,000
Mud		400,000
Logging and Perforating		250,000
Bits		50,000
Rental Equipment		50,000
Fuel and Water		125,000
Trucking		60,000
Coring		25,000
Geology and Engineering		150,000
Well Supplies		30,000
Compl. and Spec. Services		100,000
Cementing		150,000
Subtotal		$2,598,000
Contingency (20% of Total)		772,000
Total		$4,630,000

TABLE E-2 (continued)

Candelaria Prospect, Texas

Top Geopressure	10,700 Ft	
Total Depth	13,500	
Tangibles		
13 3/8" Surface Casing	2,000 Ft	$ 50,000
9 5/8" Production Casing	10,700	240,000
7" liner	3,000	60,000
5 1/2" Tubing	10,500	130,000
Xmas Tree		150,000
Subtotal		$ 630,000
Intangibles		
Location and Move		$ 100,000
Rig 80 Days, $5,000/Day		400,000
Mud		200,000
Logging and Perforating		130,000
Bits		30,000
Rental Equipment		40,000
Fuel and Water		100,000
Trucking		20,000
Coring		20,000
Geology and Engineering		65,000
Well Supplies		35,000
Compl. and Spec. Services		60,000
Cementing		70,000
Subtotal		$1,270,000
Contingency (20% of Total)		380,000
Total		$2,280,000

APPENDIX F

Production and Water Disposal Facilities

PRODUCTION AND WATER DISPOSAL FACILITIES

DESCRIPTION OF FACILITIES

For a typical geopressured brines project, production facilities would consist of large-capacity gas/water separators; gas compression facilities; water holding tanks and treating facilities; water injection pumps; and multiple, shallow, high-rate water disposal wells. Fuel would be obtained from natural gas production. Gas would be delivered to the purchaser at the well site at 800 pounds per square inch gauge (psig). Because of the distance of 2 miles or more between wells, each well would require separate production, water disposal, and sales facilities. Detailed schematics of production and water disposal facilities are presented in Figures F-1 through F-3. Cost estimates for these facilities, excluding those for geothermal, are shown in Table F-1 and Figure F-4.

PRODUCTION METHODS -- ARTIFICIAL LIFT

The use of artificial lift for brine production was determined not to be feasible. The high fuel requirements and pump capacity limitations result in marginal economics at best, using a gas price of up to $9.00 per MCF. Table F-2 presents artificial lift cost data.

WATER DISPOSAL METHODS

Three methods for water disposal were investigated:

- Disposal into brine aquifers using shallow disposal wells
- Pressure maintenance by disposal of brine into the producing horizon (See Appendix G for complete discussion)
- Transportation via pipeline and disposal into the Gulf of Mexico. (See Table F-3 for cost estimates)

Disposal into shallow brine aquifers was selected for the following reasons:

- It is the conventional method of disposal used on the Gulf Coast.
- It is environmentally acceptable.
- Its fuel requirements are economical -- 2 cubic feet per barrel injected.

SUBSURFACE WATER DISPOSAL FACILITY REQUIREMENTS AND COSTS

For this study, one prospect was examined in significant detail to determine the facility requirements and costs associated with water disposal into shallow brine aquifers.

Prospect, Location, Terrain

The prospect selected was Southeast Pecan Island. The prospect is located in southern Louisiana in a marsh-type environment.

Production Rate

Three production rates were considered as typical cases. Rates of 20,000, 40,000, and 60,000 B/D were given as standard disposal quantities. It was assumed that the salt water would be relatively free of hydrocarbons but would have normal characteristics concerning corrosion and treating requirements prior to injection.

Well Depth

The average salt water disposal depth for this area is approximately 2,000 feet. However, injection quantities are usually much less than 20,000 barrels of water per day per well. Injection well depth was lowered to 3,500 feet to ensure that cost estimates would include an allowance to drill through clean sands in the 50-foot thickness range. This would allow the well bore to take the required 20,000 barrels of water per day as well as leave higher sands as possible recompletion candidates.

Disposal Pressure

Based upon the physical piping layout, distances from pumps to injection wellheads, and injection well conditions, disposal pressures would range from 150 to 300 psig.

Well-Cost Estimate

Well depth was assumed to be 3,500 feet. A casing program including 13 3/8-inch casing set through the fresh water sands, 10 3/4-inch casing set as total depth, and 7-inch casing set as the injection string was chosen to accommodate high injection rates. The completion would include gravel packing and a screen/liner assembly. The total cost includes all wellhead equipment and safety and control devices required for an injection well location.

Surface Facility Cost -- Structure

A concrete platform was selected for marsh-type terrain. The cost included installation labor and transportation to the proposed location. The cost of possible dredging to the location was not included; a more definite area would have to be defined to estimate dredging costs. Living quarters and communications equipment were also not included; the general location of the prospect suggests that daylight manned operations would be normal, with callouts at night for equipment shutdown situations. If living quarters were considered essential, platform size would have to be increased to accommodate the building.

Surface Facility Cost -- Storage

The most successful salt water disposal tank structures have been welded steel tanks coated internally with coal tar epoxy. The typical facilities include a 1,500-2,000 barrel separation and settling tank. Produced sand can be jetted from this vessel to a small wash tank. Chemicals can be added from the mix tank to clean the sand prior to final discharge. Salt water could flow from the settling tank into a larger holding tank. Retention time is the major consideration when sizing the separation and settling tank. The holding tank should be sized to accommodate anticipated pump rates. In some instances it may be desirable to have 100 percent duplication of both the settling tank and storage tank. This would occur if no downtime could be tolerated during cleanout operations or tank maintenance. Duplicate tanks were not included in cost estimates for the three cases. Continuous operations would require not only duplicate vessels but also the additional platform necessary to contain them.

Surface Facility Cost -- Pumps

For ease of comparison and simplification, identical pumps were selected for each production rate case. For the purposes of this study, all cost estimates were based upon an Oilwell A-368 plunger pump driven by a Waukesha 2895 engine. A more detailed study would likely reveal that fewer and larger pumps would be more practical in the 60,000 B/D case. Each case allows one unit as a standby for routine maintenance as well as unanticipated pump downtime.

Fuel Usage

Fuel requirements are based upon the following relationships:

(1) $$\text{Horsepower} = \frac{(\text{B/D})\ (\text{discharge pressure})}{53{,}760\ (\text{pump efficiency})}$$

(2) $$\text{Btu/Day} - (\text{horsepower})(24)(8{,}000)$$

These relationships result in a fuel usage of approximately 1.5 cubic feet of gas for each barrel of water disposal.

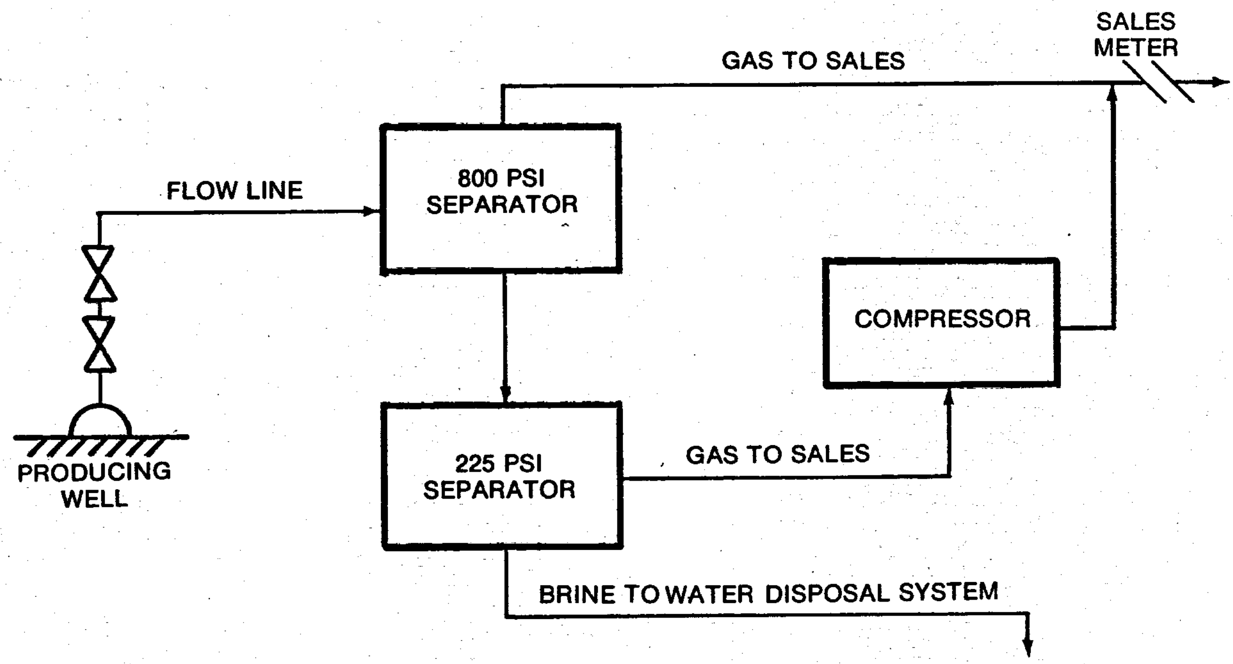

Figure F-1. Production Facility (No Geothermal).

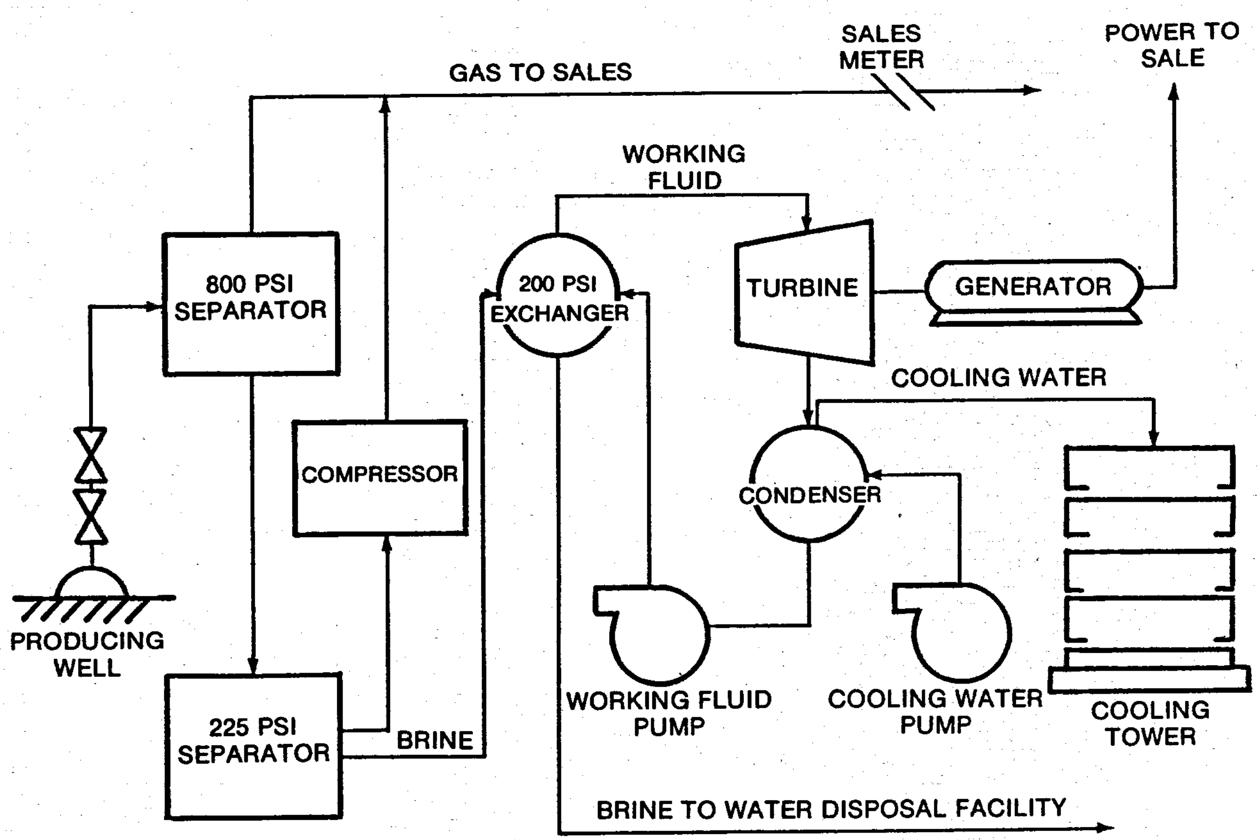

Figure F-2. Production Facility (Including Geothermal).

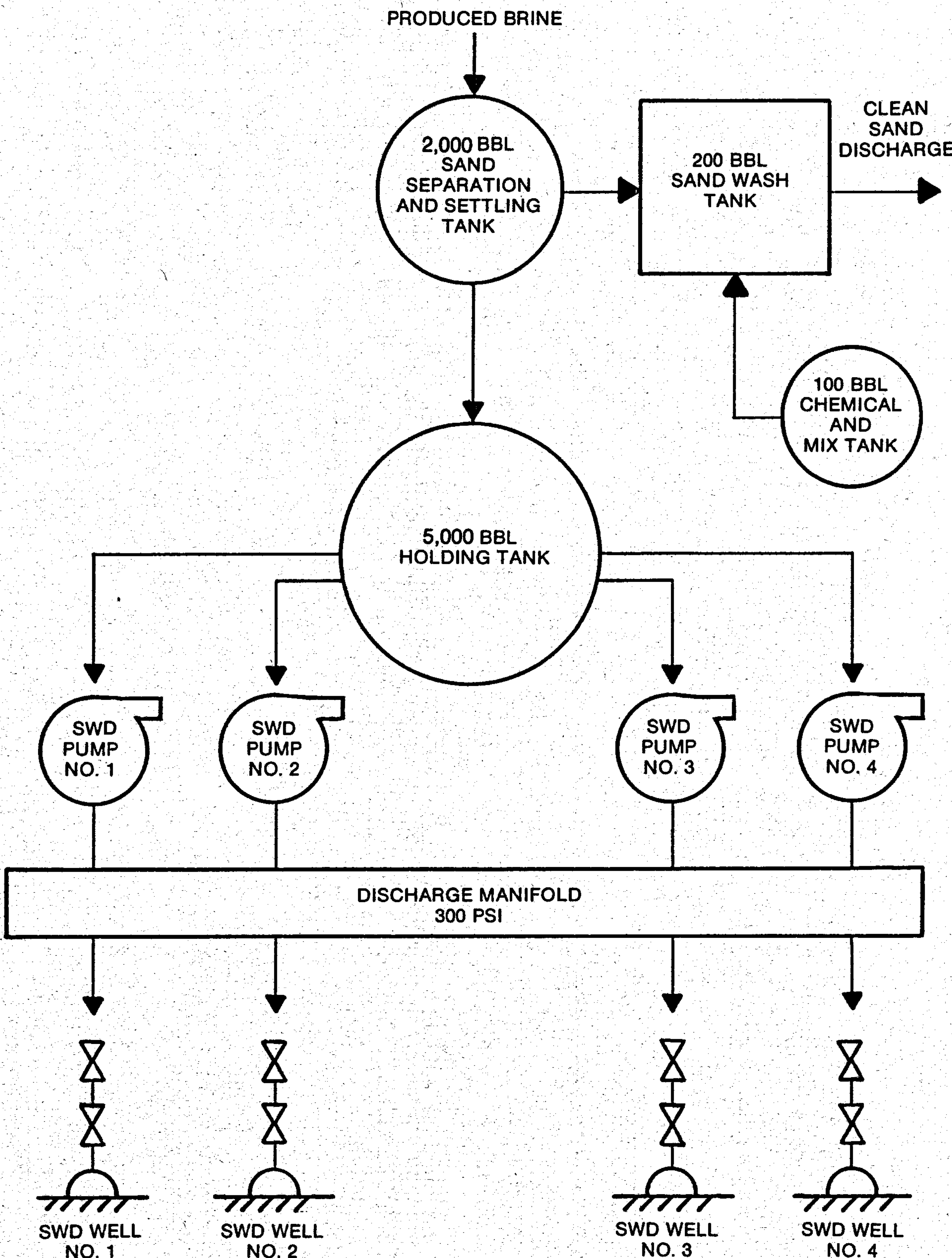

Figure F-3. Subsurface Water Disposal Facility (60,000 B/D Capacity Louisiana; 30,000 B/D Capacity Texas).

TABLE F-1

Production and Subsurface Water Disposal Facility Cost Estimates
(Constant 1979 Dollars)

Louisiana Prospects	20,000 B/D	40,000 B/D	60,000 B/D
Location	$ 250,000	$ 250,000	$ 250,000
Separators, Tanks and Pumps	960,000	1,400,000	1,900,000
Labor	240,000	280,000	325,000
Transportation	10,000	15,000	20,000
Piping, Valves, & Fittings	30,000	50,000	60,000
Gas Compression	100,000	100,000	200,000
Disposal Wells*	600,000	900,000	1,200,000
Subtotal	$2,190,000	$2,995,000	$3,955,000
Contingency (10%)	220,000	295,000	395,000
Total	$2,410,000	$3,290,000	$4,350,000

Texas Prospects	20,000 B/D	40,000 B/D	60,000 B/D
Location	$ 100,000	$ 100,000	$ 100,000
Separators, Tanks and Pumps	960,000	1,400,000	1,900,000
Labor	240,000	280,000	325,000
Transportation	10,000	15,000	20,000
Piping, Valves, & Fittings	30,000	50,000	60,000
Gas Compression	100,000	100,000	200,000
Disposal Wells†	900,000	1,500,000	2,100,000
Subtotal	$2,340,000	$3,445,000	$4,705,000
Contingency (10%)	230,000	345,000	465,000
Total	$2,570,000	$3,790,000	$5,170,000

*20,000 B/D/well; $300,000/well; 1 standby well.
†10,000 B/D/well; $300,000/well; 1 standby well.

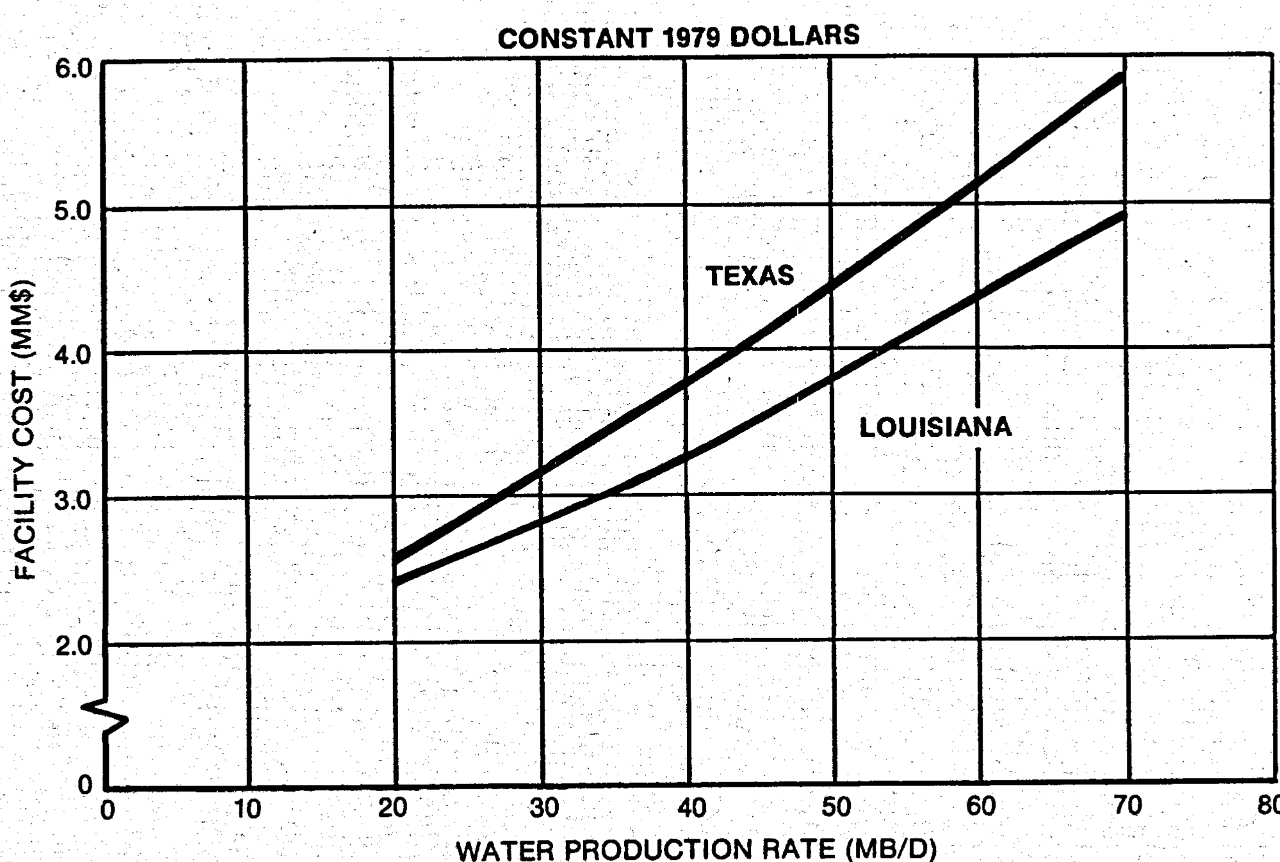

Figure F-4. Facility Cost vs. Water Production Rate.

TABLE F-2

Artificial Lift*
(Constant 1979 Dollars)

Lift Depth (Feet)	Maximum Water Rate (B/D)	Prod. Gas (MCF/D)	Fuel Gas (MCF/D)	Sales Gas (MMCF/D)	Oper. Cost ($/Day)	Oper. Cost ($/MCF)
3,670	20,000	400	230	170	1,200	7.05
4,550	15,000	300	220	20	900	11.25
8,180	10,000	200	215	--		

*Assumptions:

Casing: 9-5/8"
Maximum hp: 1,020
Fuel: 200 MCF/D for lift plus
1.5 cu ft/bbl for water disposal

TABLE F-3

Production and Water Disposal Facility Cost Estimates
(Discharge into Gulf of Mexico)
(Constant 1979 Dollars)

Rate	50,000 B/D
Location	$ 250,000
Separators & Tanks	500,000
Labor	200,000
Transportation	10,000
Piping & Valves	40,000
Gas Compression	100,000
Pumps	400,000
5 Miles 10" Line	2,000,000
Subtotal	$3,500,000
Contingency (10%)	350,000
Total	$3,850,000

APPENDIX G

Pressure Maintenance

PRESSURE MAINTENANCE

It was found that pressure maintenance or partial pressure maintenance into the producing reservoirs is not feasible for the following reasons:

- Injection pressures are high.
- Fuel requirements consume a substantial part of the recoverable gas (50 percent or more).
- The cost of injection wells and high-pressure injection pumps increases the investment operating costs and the required gas price beyond the $9.00 per MCF upper limit for this study.

PARTIAL PRESSURE MAINTENANCE EVALUATION

In order to evaluate the overall potential of pressure maintenance, calculations were made regarding partial pressure maintenance for the Southeast Pecan Island and Johnson's Bayou prospects. Production and pressure data generated by the computer model are described in Appendix D. Additional calculations were made to estimate pressures to be encountered in reinjecting the produced volumes of water; these data provide a basis for estimating horsepower and fuel requirements for pressure maintenance. Tables G-1 and G-2 summarize pressure maintenance and investment data for the two injection-well cases for these prospects at a production rate of 50,000 B/D.

Reinjection was examined utilizing from one to four injection wells per producer. In accordance with study participant judgment, only 5 1/2-inch tubing was considered in the injection wells. For the pressure maintenance cases examined, the data in Tables G-3 and G-4 include, at the specified rates: tubing friction pressure drop, injection sandface pressure, and injection wellhead pressure. Calculation methodology is described in this appendix. Table G-3 summarizes injection data for the Pecan Island production case presented in Computer Run L57 and Table G-4 summarizes that for the Johnson's Bayou production case of Run L23.

Water properties at injection conditions were estimated from correlations. At a water salinity of 100,000 ppm NaCl, brine viscosity at approximately 150°F injection temperature was estimated to be 0.48 centipoise (cp) and brine density was estimated to be 8.95 pounds per gallon. Water viscosity utilized in the computer production model was a function of temperature; for Pecan Island it was 0.22 cp and for Johnson's Bayou it was 0.27 cp.

TABLE G-1

SE Pecan Island West Pressure Maintenance Data

Production Rate	50,000 B/D
Injection Rate	50,000 B/D
Average Reservoir Pressure at Onset of Pressure Maintenance	10,506 psi
Producing Solution Gas/Water Ratio	31 cu ft/bbl
At Injection Rate of 25,000 B/D/Well:	
Surface Pressure	6,700 psi
Sandface Pressure	13,360 psi
Fuel Requirements	27 cu ft/bbl
Investment (Constant 1979 Dollars):	
2 Injection Wells	$ 8,940,000
Pumps (10 Operating, 2 Standby)	5,400,000
Tanks	100,000
Injection Line	634,000
Total	$15,074,000
Operating Expense	$ 320,000/year
plus	5¢/bbl
Sales Gas	4 cu ft/bbl
	200 MCF/D

TABLE G-2

Johnson's Bayou Pressure Maintenance Data

Production Rate	50,000 B/D
Injection Rate	50,000 B/D
Average Reservoir Pressure at Onset of Pressure Maintenance	6,760 psi
Producing Solution Gas/Water Ratio	17 cu ft/bbl

At Injection Rate of 25,000 B/D/Well:

Surface Pressure	2,010 psi
Sandface Pressure	6,885 psi
Fuel Requirements	10 cu ft/bbl

Investment (Constant 1979 Dollars):

2 Injection Wells	$ 5,300,000
Pumps (6 Operating, 2 Standby)	3,600,000
Tanks	100,000
Injection Line	634,000
Total	$ 9,634,000

Operating Expense	$ 320,000/year
plus	5¢/bbl
Sales Gas	7 cu ft/bbl
	350 MCF/D

TABLE G-3

Pressure Maintenance

Case: Production Wells at Recommended Well Site, SE Pecan Island West

Computer Run: L57

Total Injection Rate	50,000 B/D
Average Reservoir Pressure at Onset of Pressure Maintenance	10,506 psi
Average Reservoir Productivity Index	32.6 B/D/psi
Producing Gas/Water Ratio at Onset of Pressure Maintenance	31 cu ft/bbl

Injection Case:

1 Injection Well

Rate (B/D/well)	50,000
ΔP_f (tubing)* (psi)	2,259
Sandface Pressure (psi)	14,886
Wellhead Pressure (psi)	9,903

2 Injection Wells

Rate (B/D/well)	25,000
ΔP_f (tubing) (psi)	582
Sandface Pressure (psi)	13,360
Wellhead Pressure (psi)	6,700

3 Injection Wells

Rate (B/D/well)	16,666
ΔP_f (tubing) (psi)	270
Sandface Pressure (psi)	12,696
Wellhead Pressure (psi)	5,724

4 Injection Wells

Rate (B/D/well)	12,500
ΔP_f(tubing) (psi)	154
Sandface Pressure (psi)	12,235
Wellhead Pressure (psi)	5,147

*Δp_f(tubing) = tubing friction pressure drop.

TABLE G-4

Pressure Maintenance

Case: Production and Injection Wells at Average Sand Thickness Locations, Johnson's Bayou

Computer Run: L23

Total Injection Rate	50,000 B/D
Average Reservoir Pressure at Onset of Pressure Maintenance	6,760 psi
Average Reservoir Productivity Index	355 B/D/psi
Producing Gas/Water Ratio at Onset of Pressure Maintenance	17 cu Ft/bbl

Injection Case:

1 Injection Well	
Rate (B/D/well)	50,000
Δp_f (tubing)* (psi)	1,655
Sandface Pressure (psi)	7,010
Wellhead Pressure (psi)	3,364
2 Injection Wells	
Rate (B/D/well)	25,000
Δp_f (tubing) (psi)	426
Sandface Pressure (psi)	6,885
Wellhead Pressure (psi)	2,010
3 Injection Wells	
Rate (B/D/well)	16,667
Δp_f (tubing) (psi)	195
Sandface Pressure (psi)	6,843
Wellhead Pressure (psi)	1,737
4 Injection Wells	
Rate (B/D/well)	12,500
Δp_f(tubing) (psi)	113
Sandface Pressure (psi)	6,822
Wellhead Pressure (psi)	1,634

*Δp_f(tubing) = tubing friction pressure drop.

Calculation Methodology

The injectivity index (I) was estimated by adjusting the productivity index (J) computed by the computer model for the increase in water viscosity (μ) at lower temperature and for a decrease in net sand thickness (h) where necessary:

$$I = J \left(\frac{\mu_p}{\mu_i}\right)\left(\frac{h_i}{h_p}\right) \quad \text{bbl/day/psi}$$

The subscripts p and i refer to the production and injection cases, respectively. As indicated in the previous discussion, for Pecan Island $(\mu_p/\mu_i) = \frac{0.22}{0.48} = 0.46$ while (h_i/h_p) varied from 1 to approximately 1/2 due to the wide variation in net sand thickness. For Johnson's Bayou $(\mu_p/\mu_i) = 0.56$ and $(h_i/h_p) = 1.0$ since the average sand thickness was utilized in both production and injection wells.

Excess pressure above reservoir pressure $(P_s - P_f)$ which causes a given injection rate was then estimated for the injection wells from the definition of injectivity index:

$$I = \frac{\text{Injection rate (B/D)}}{P_s - P_f \text{ (psi)}}$$

where the injectivity index and the injection rate per well are known. The sandface pressure, P_s, was then calculated as average reservoir pressure (from computer output) plus excess pressure.

Injection wellhead pressure, P_{wh}, is related to sandface pressure by the relationship:

$$P_{wh} = P_s + \Delta P_f \text{ (tubing)} - \text{fluid static head (psi)}$$

WATER INJECTION FACILITY REQUIREMENTS AND COSTS

For this study, estimates were made of the cost of injecting salt water at rates of 20,000 B/D and 40,000 B/D. Injection pressures of 2,000 to 6,000 psig in 1,000 psi increments were examined. The salt water would require pipeline transport 1 mile to the disposal location. It was assumed that the facilities described in the Subsurface Water Disposal Facility Requirements and Cost section of Appendix F would be utilized to transfer the salt water through the 1-mile line to the disposal location.

Production Rates

Two salt water injection rates, of 10,000 B/D and 20,000 B/D, were selected as typical disposal rates.

Disposal Pressures

Rates of 2,000 to 6,000 psig in 1,000 psi increments were examined. These pressures were assumed to be wellhead injection pressures. All pump sizing and piping were based upon the pressures measured at the wellhead.

Surface Facility Cost -- Pumps

Oilwell Quintuplex plunger pumps were selected as examples for the purposes of cost estimating. Models B-528 and B-538 powered by Waukesha L-7042 engines could be utilized throughout the pressure range. Pump plunger substitution and varying the revolutions per minute allowed covering the entire line of applications with the two pump units. Injection pump data are listed in Tables G-5 and G-6.

TABLE G-5

Injection Pumps
(10,000 B/D)
(Constant 1979 Dollars)

Injection Pressure (psig)	Pump Type and Number	Fuel Usage (Btu/D)	Pump Cost
2,000	Oilwell 538 Quintuplex 1 Operating 1 Standby	96×10^6 (9.6 cu ft/bbl)	$ 800,000
3,000	Oilwell 538 Quintuplex 1 Operating 1 Standby	120×10^6 (12 cu ft/bbl)	800,000
4,000	Oilwell 528 Quintuplex 2 Operating 1 Standby	188×10^6 (19 cu ft/bbl)	1,350,000
5,000	Oilwell 528 Quintuplex 2 Operating 1 Standby	215×10^6 (21 cu ft/bbl)	1,350,000
6,000	Oilwell 528 Quintuplex 2 Operating 1 Standby	241×10^6 (24 cu ft/bbl)	1,350,000

TABLE G-6

Injection Pumps
(20,000 B/D)
(Constant 1979 Dollars)

Injection Pressure (psig)	Pump Type and Number	Fuel Usage (Btu/D)	Pump Cost
2,000	Oilwell 538 Quintuplex		
	2 Operating	192×10^6	$1,350,000
	1 Standby	(9.6 cu ft/bbl)	
3,000	Oilwell 538 Quintuplex		
	2 Operating	240×10^6	1,350,000
	1 Standby	(12 cu ft/bbl)	
4,000	Oilwell 528 Quintuplex		
	4 Operating	376×10^6	2,250,000
	1 Standby	(19 cu ft/bbl)	
5,000	Oilwell 528 Quintuplex		
	4 Operating	430×10^6	2,250,000
	1 Standby	(21 cu ft/bbl)	
6,000	Oilwell 528 Quintuplex		
	4 Operating	482×10^6	2,250,000
	1 Standby	(24 cu ft/bbl)	

Surface Facility Cost -- Platform

If the disposal location is assumed to be 1 mile from the salt water handling facility, it would be most practical to utilize the pumps described in Appendix F to transfer the salt water at low pressure to a holding tank located at the point of injection. From the holding tank the salt water could be injected at high pressure by pumps as described in this discussion. To transport salt water at high pressure through the 1-mile line for injection would require much more horsepower as well as fuel. In this discussion it is assumed that the high-pressure pumps would be located at the injection site. This would require a platform containing pumps and a holding tank similar to the platform described in Appendix F for a 20,000 to 40,000 B/D facility. In any case, locating the injection pumps as close as practical to the disposal site will conserve both horsepower and fuel.

Fuel Usage

Fuel consumption was calculated using a rate of 8,000 Btu per horsepower per hour or 8 standard cubic feet per horsepower per hour. The varied fuel rates from identical machines are a function of actual revolutions per minute and applied loading when plunger sizes are changed.

Flowline Cost

The flowline sizing was based upon a maximum velocity of 10 feet per second and minimizing the pressure drop to the disposal location. The pressure drop was held to 30 psig for the line. As described above, the flowline costs are based upon low-pressure (less than 2,000 psig) service to the injection site where high-pressure pumps would raise the salt water pressure for injection. Flowline cost estimates are as follows:

- 20,000 barrels per day
  - Size = 6 inch O.D. Schedule 80 Minimum Pressure Drop @ 300 GPM = 0.5 psi/100 feet
  - Cost = $ 634,000
- 40,000 barrels per day
  - Size = 8 inch O.D. Schedule 80 Minimum Pressure Drop @ 600 GPM = 0.5 psi/100 feet
  - Cost = $ 898,000

APPENDIX H

Geothermal and Hydraulic Energy Assessment

GEOTHERMAL AND HYDRAULIC ENERGY ASSESSMENT

CONCLUSIONS

Potential geothermal and hydraulic power production from geopressured reservoirs has been reported to be of great magnitude.[1] However, calculations using reasonable estimates for reservoir parameters reveal a potential for the generation of only limited amounts of cost-competitive energy. Brine production rates per well must be in the 50,000 B/D range which, over a 20-year well life, would drain a reservoir with a surface area of 10 to 40 square miles.[2] As a consequence, power plants are limited to single well sites and no economies of scale are possible. Because of these limitations, the cost of electricity generated from the geothermal portion of the resource for the cases examined is estimated to be from 100 to 150 percent of the cost of new generation from conventional sources (Table H-1). The cost of power from the hydraulic portion of the resource is estimated to be only 40 to 70 percent of that from conventional sources, but the hydraulic resource is of limited magnitude and would be rapidly depleted.

DISCUSSION

Geothermal Energy Assessment

The incremental economics of geothermal power production from individual geopressured brine wells was assessed for three representative temperature and well-rate cases. The power cost estimates for actual reservoirs shown in Table H-1 were then derived by the same procedures. The power generating facility in these cases does not bear any of the cost of exploration, drilling, fluid disposal, or overhead. Tables H-2 and H-3 show the cost of power calculated on the basis of: (1) 1979 dollars; (2) 15 percent ROR; (3) 85 percent capacity factor; and (4) operating expenses of $44,000 per year per mW of capacity (1/2¢ per kWh at 100 percent capacity factor). These calculations were made for both flashed steam and binary conversion systems. Figures H-1 and H-2 are schematics of these systems.

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[1]House, P.A., et al., "Potential Power Generation and Gas Production from Gulf Coast Geopressure Reservoirs," Lawrence Livermore Laboratory, 1975.

[2]Whitehead, W.R., and McMullan, J.H., "Economics of Electrical Energy Production from Geopressured Aquifers in South Louisiana," 1976.

TABLE H-1

Cost of Electricity Generated From Geothermal Energy in
Geopressured Brine Reservoirs*
(Constant 1979 Dollars)

Louisiana Prospects	Reservoir Life (Years)	Water Rate (B/D)	Flow Temp. (°F)	Output (mW)	Inv. (mW)	10% ROR Power Cost (¢/kWh)
Atchafalaya Bay						
East	7	50,000	266	1.3	3,730	6.79
West		50,000	236	None	None	None
Johnson's Bayou		50,000	226	None	None	None
LaFourche Crossing	20	50,000	266	1.3	3,730	4.75
Rockefeller Refuge	15	50,000	316	2.88	5,610	3.65
SE Pecan Island						
East		30,000	296	None	None	None
West	20	50,000	296	2.29	4,950	3.73
Texas Prospects						
Austin Bayou		30,000	310	None	None	None
	12	50,000	310	2.71	5,430	3.98
Candelaria		30,000	270	None	None	None
Clinton		30,000	270	None	None	None
Eagle Lake		30,000	270	None	None	None

*For comparison, gas price vs. electric power cost is shown below:

Gas Price ($/MCF)	Electricity Value (¢/kWh)
$2.00	4.0
2.50	4.5
3.50	6.0
5.00	8.0
7.00	10.7
9.00	13.3

The $2.00/MCF gas price vs. 4.0¢/kWh electric power price is based upon current conditions. The correlations between higher gas prices and electric power prices are based upon the assumption that 1/3 of electric power prices is directly related to fuel costs, and 2/3 of the cost is based upon capital investment and operating expense.

TABLE H-2

Plant Investment and Cost of Electricity for Geothermal Energy Recovery

	Net Power (mW)	Investment ($/kW)	Cost of Power (¢/kWh)	Cost of Power ($/MMBtu)
Case 1 (290°F wellhead, 60,000 B/D)				
Binary	2.65	2,049	4.96	14.50
Steam	1.27	2,079	5.02	14.70
Case 2 (284°F wellhead, 40,000 B/D)				
Binary	1.61	2,447	5.83	17.05
Steam	0.79	2,447	5.83	17.05
Case 3 (282°F wellhead, 20,000 B/D)				
Binary	0.78	3,173	7.40	21.63
Steam	0.37	3,048	7.15	20.98

Further details on the calculations upon which the costs in Table H-2 are based are shown in Table H-3. In addition to the assumptions mentioned above, these costs are based on certain tax assumptions which are given in Table H-11. The capital costs are basically derived from recent (spring 1979) firm quotes for similar equipment, corrected to mid-1979 dollars. A 15 percent contingency has also been included in the figures. Site preparation costs are assumed to be borne by the methane production facility.

These capital costs are very high compared to conventional generating facilities primarily because of the relatively small scale of the geothermal plants in the cases evaluated. With the possible exception of the binary turbine, all of the equipment is proven, conventional, and available. The 1979 cost of new generation from conventional sources is in the range of 4 to 5¢ per kWh.[3] On this basis, Case 1 is just barely competitive. Generation costs for the other cases (lower temperatures and flow rates) are not competitive with power from conventional sources.

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[3]"Economic Analyses of Geothermal Energy Development in Southern California," Draft report under Stanford Research Institute Project ECU 5013, November 1976.

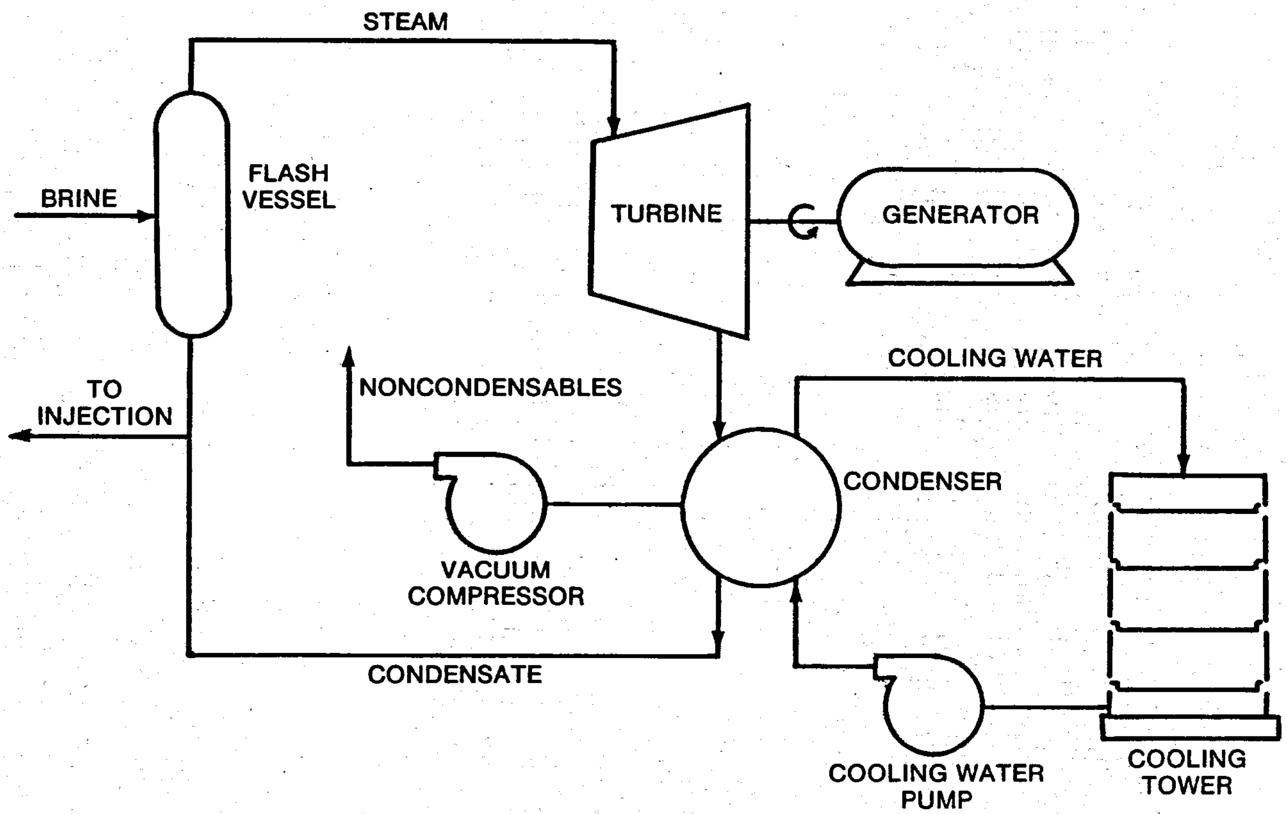

Figure H-1. Flashed Steam Schematic.

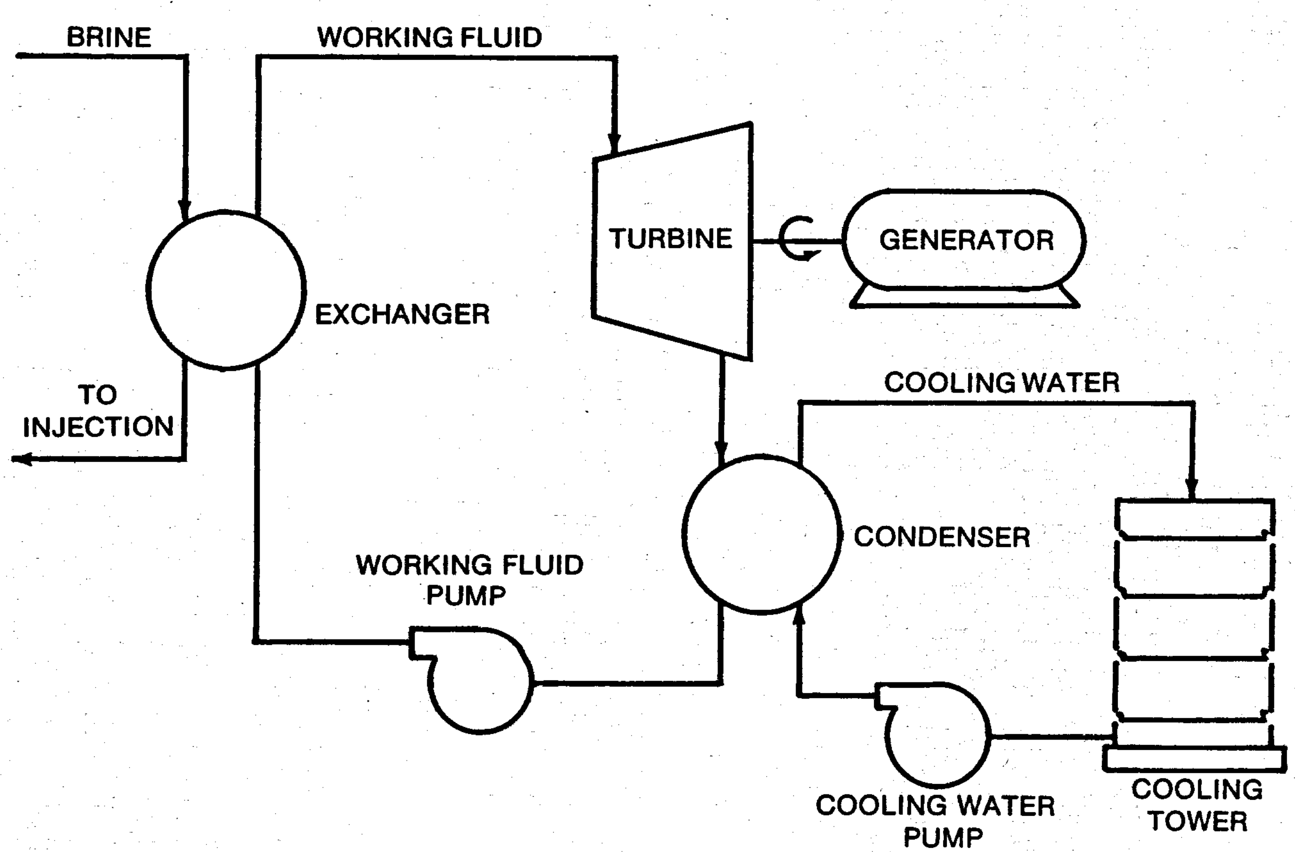

Figure H-2. Binary Cycle Schematic.

TABLE H-3

Cost of Electricity From Geothermal Energy in Geopressured Brine Resources
(Constant 1979 Dollars)

	Case 1		Case 2		Case 3	
	Binary	Steam	Binary	Steam	Binary	Steam
Temperature (°F)	290	290	284	284	282	282
Working Fluid	Isobutane		Isobutane		Isobutane	
Brine Rate (B/D)	60,000	60,000	40,000	40,000	20,000	20,000
(Lb/hr)	917,700	917,700	614,100	614,100	307,400	307,400
Optimum Flash Pressure (psia)		30		28		28
Gross Power (mW)	3.31	1.35	2.02	0.84	0.98	0.40
(Btu/lb Brine)	12.3	5.0	11.3	4.7	10.9	4.4
Net Power (mW)	2.65	1.27	1.61	0.79	0.78	0.37
(Btu/lb Brine)	9.9	4.7	9.0	4.4	8.7	4.1
Heat Exchanger Area (Ft^2)	5,000	5,000	4,000	4,000	3,000	3,000
Operating Expense ($/yr)	116,000	55,000	70,000	35,000	34,000	16,000
Investment ($)	5,429,000	2,646,000	3,940,000	1,924,000	2,471,000	1,136,000
($/kW)	2,049	2,079	2,447	2,447	3,173	3,048
Cost of Power (¢/kWh)*	4.96	5.02	5.83	5.83	7.40	7.15
($/MMBtu)	14.50	14.70	17.05	17.05	21.63	20.98

*Assumptions:

15 percent ROR, 85 percent capacity factor
1/2 ¢/kWh operating expense based on 100 percent capacity factor.

The cost of power varies with flow rate for the two systems, as is shown in Figure H-3. The cost calculations show that the binary cycle system is slightly superior to the flashed steam at 60,000 B/D; both cost the same at 40,000 B/D; and the flashed steam is somewhat more economical at 20,000 B/D. Other geothermal economic studies have shown significant cost advantages for binary cycle systems, especially in the 300°F or less temperature range. However, small (less than 10 mW) binary turbine-generators are relatively more expensive than small steam turbines. This has shifted the binary cycle power plant investment cost into the same range as flashed steam systems. For the 20,000 B/D case, the inelastic cost of the very small binary turbine has resulted in a higher investment than for the flashed steam system.

Potential Technological Advances

There is unproven, but theoretically possible, geothermal energy recovery technology which might be more efficient and less expensive than that presently available. A total flow impulse turbine, as proposed by the Lawrence Livermore Laboratory, may approach the efficiency of binary cycle systems.[4] A reasonable cost estimate for a total-flow type power generation system would be comparable to that of a flashed steam system for the same brine flow rate. For comparison, the above assumptions were applied to the three cases investigated. The results are summarized in Table H-4.

Potential Economies of Scale for Geothermal Power Production

Despite the potential economies of scale of using 10-20 mW geothermal power plants (vs. the 1-3 mW units used in this analysis), they are more than offset by the added cost of the brine gathering and brine disposal systems for multiple-well facilities. The investment for the 290°F wellhead, 60,000 B/D, 2.65 mW binary cycle single-well facility was estimated at $2,049 per kW, or $5.4 million. A plant using the brine from five wells of this size would generate approximately 13.25 mW and cost about $1,320 per kW, or $17.5 million. The economy-of-scale savings are especially large for the binary turbine-generator unit, which drops from $440 per kW to only $170 per kW for the larger plant. However, each well would have to drain a large area. Assuming a five spot well spacing with 16 square miles per well, 16 miles of production lines

[4]Austin, A.L., "Prospects for Advances in Energy Conversion Technologies for Geothermal Energy Development," Lawrence Livermore Laboratory, 1975.

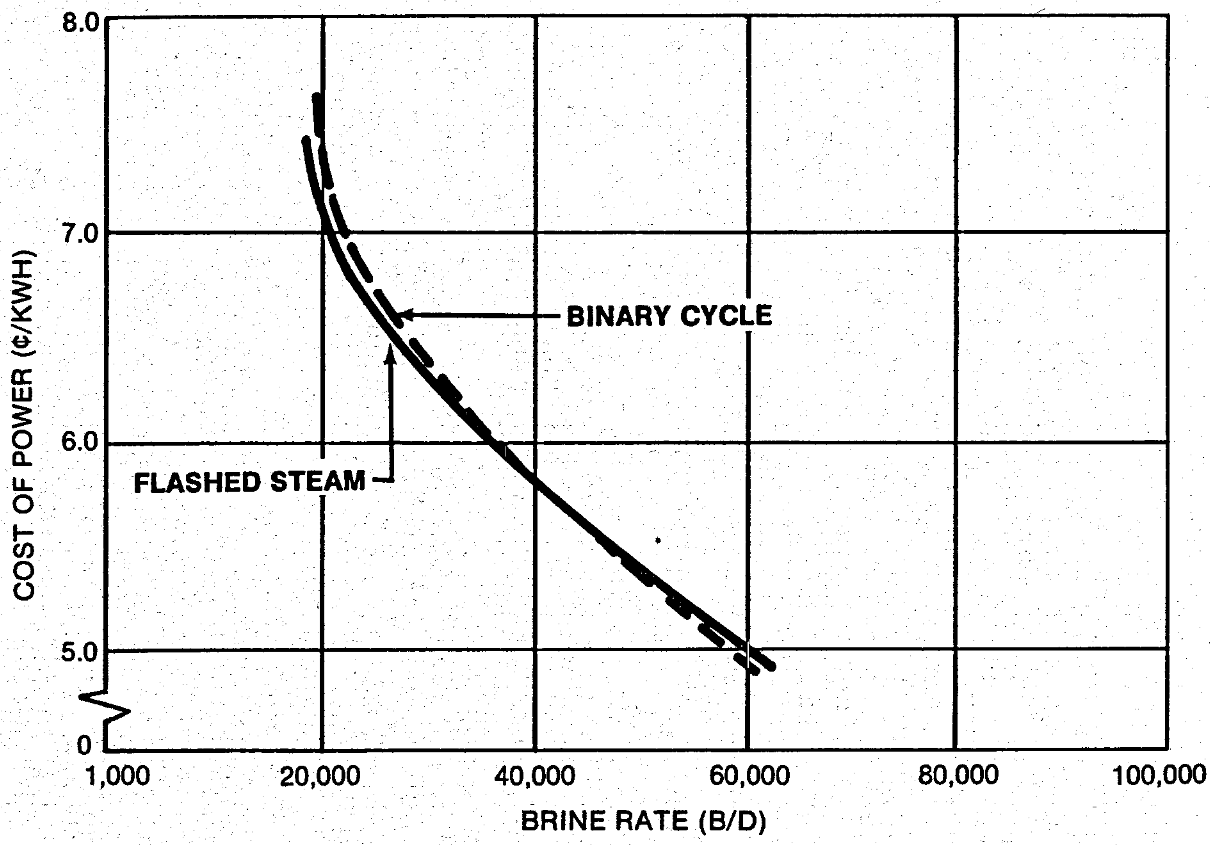

Figure H-3. Cost Comparison of Flashed Steam vs. Binary.*

*SOURCE: Table H-3.

TABLE H-4

Potential Economics of Total Flow Impulse Turbines for Geothermal Energy Recovery

(Based on Brine Conditions, Economic Assumptions, and Net Power of Binary Cycle Systems from Table H-3)

	Net Power (mW)	Total Cost (MM$)	Cost ($/kW)	Cost of Power (¢/kWh - 1979 Dollars)
Case 1 (290°F wellhead, 60,000 B/D)	2.65	2.64	996	2.68
Case 2 (284°F wellhead, 40,000 B/D)	1.61	1.92	1,192	3.10
Case 3 (282°F wellhead, 20,000 B/D)	0.76	1.14	1,500	3.69

These figures are quite attractive when compared with the current 1979 cost of new generation by conventional means.

are needed. Pipe diameter is dependent on the flow rate, length, and head loss:

$$D^5 = \frac{gpm^2 \times 1\ ft}{1{,}000 \times h \times mi}$$

where h = head loss in psi/per mile

For h = 10 psi per mile, the incoming brine lines would be 18 inches in diameter.

Hopefully, reinjection is in shallower formations with thick, permeable sand layers, and these wells will not need to be as widely spaced. Assuming four injection wells and only 2 miles' separation between injections, 5.7 miles of outgoing pipe are needed. For h = 10 psi per mile, the injection lines will be 20 inches in diameter. Estimating the installed cost of insulated pipe to be $5.00 per in.-ft, the total pipe costs $10.6 million, which would bring the cost of the entire facility to $28.1 million, or $2,120 per kW. Reducing the spacing between injection wells to 1 mile only drops the total cost to $2,010 per kW. No significant savings are possible unless the production well spacings can be reduced.

Hydraulic Energy Assessment

The economics of electricity generation from the hydraulic energy in geopressured brine reservoirs were assessed for two cases of single wells which flowed 50,000 and 75,000 B/D, respectively. The first case is based on the aquifer properties of Southeast Pecan Island West, and the second case represents a higher flow rate but shorter life aquifer. The produced brine initially reaches the wellhead with a considerable hydraulic head. During the life of the well, the pressure declines steadily, with pressure maintenance eventually required to maintain a constant production rate. Power may be generated by flowing the brine in reverse through a five-stage centrifugal pump which acts as a turbine. The output was assumed to drive other pumps directly and would thus not require a generator. The optimum turbine size is a function of the initial flow rate, the decline rate, the required rate of return, and the relationship between net power production and the hydraulic turbine cost. The optimized results shown in Table H-5 suggest that the cost of power from this source is competitive with power from conventional sources.

These calculations are made on the same basis as the geothermal energy assessment cases. The capital estimates shown here are quite speculative, but even at a 50 percent higher investment, the cost of power is less than 3¢ per kWh for both cases. Full power under Cases 1 and 2 is only available for the first seven and two years, respectively. After that, the available horsepower declines quite rapidly due to the declining reservoir pressure (See Table H-11).

TABLE H-5

Economics of Power Generation from Hydraulic Energy of Geopressured Brine Reservoirs

	Case 1	Case 2
Initial Flow Rate (B/D)	50,000	75,000
Initial Flow Rate (Gallons per Minute [gpm])	1,458	2,187
Life (Years)	16	10
Initial Net Power (hp)	1,100	1,300
Investment ($/kW)	453	412
Cost of Power (¢/kWh)	1.72	2.05
Cost of Power ($/MMBtu)	5.00	6.00

Potential Technological Advances

The five-stage centrifugal pump used for the hydraulic power generation cases was assumed to have a 70 percent efficiency. The maximum obtainable efficiency with a turbine designed specifically for this process is probably no more than 90 percent. In all likelihood, however, such a turbine would also be significantly more expensive than a centrifugal pump. Thus, prospects for advances in hydraulic energy recovery appear limited.

METHODOLOGY AND SUPPORTING DATA

Geothermal Energy Assessment

Costing

Cost Calculation Equation. Binary Turbine and Generator.

$$\$ = 725{,}000\ (\text{mW})^{0.4}$$

(Based on conversations with an Elliott Company representative.)

Cost Calculation Equation. Steam Turbine and Generator.

$$\$ = 320{,}000\ (\frac{Pf}{P}\ x\ mW)^{0.7}$$

where P_f = 95 psia

(Based on recent [spring 1979] firm quotes for turbine generators in the 1-10 mW size range.)

Cost Calculation Equation. Condensers and Heat Exchangers.

$$\$\ ft^2 = C_f\ e^{.4383\ \ln\ (P_s)\ -\ 0.1297}$$

where P_s = shell side pressures

For shell side pressures $\leq$ 50 psia, let P_s = 50. C_f is a correction factor based on contracted prices and inflation. C_f = 2.16. (Taken from "Resource Utilization Efficiency Improvement of Geothermal Binary Cycles," K. E. Starling et al., 1978.)

Cost Calculation Equation. Cooling Tower.

$$\$ = 889\ (gpm)^{0.6}$$

The exponential is from "Process Plant Estimating Evaluation and Control," K. E. Guthrie, Page 341, 1974. The constant is based on recent firm quotes corrected for inflation to mid-1979 dollars.

Cost Calculation Equation. Vacuum Compressor.

$$\$ = 1{,}580\ (hp)^{0.8}$$

The exponential is from Guthrie, Page 165. The constant is based on recent firm quotes corrected for inflation to mid-1979 dollars.

Cost Calculation Equation. Recycle Pumps and Drivers.

Prices are taken from "Capital Cost Estimating" by K. E. Guthrie, Page 126 of the March 24, 1969, issue of Chemical Engineering. The prices have been adjusted to reflect recent firm quotes and are corrected for inflation by applying a correction factor of 9.6.

Facility Cost Calculation Procedure. The total plant cost is the sum of the following: (1) total cost of major equipment (turbine plus generator, exchangers, condensers, cooling tower, vacuum compressor, and main pumps and drivers); (2) miscellaneous equipment, construction, and engineering; and (3) 15 percent contingency. The miscellaneous amount is based on the following power law expression:

$$\$ = 1{,}790{,}000 \left(\frac{kW}{2{,}500}\right)^{0.7}$$

The base case parameters noted below were used to calculate the cost of the major equipment of a 2.5 mW flashed steam facility.

Flow Rate (lb/hr)	263,000
Enthalpy (Btu/lb)	500
Flash Pressure (psia)	95
Gross Power (kW)	2,500
Net Power (kW)	2,445.8
Vacuum Compressor (hp)	7.9
Cooling Water (lb/hr)	1,100,000
Cooling Water (gpm)	2,196
Condenser (lb/hr)	1,046,000
Cooling Water Pumps (ΔP x gpm)	66,000
Total Major Equipment	$ 895,000
Misc. Equipment & Construction (2 x Major Equipment)	$1,790,000
15 Percent Contingency	$ 403,000
Total Plant Cost	$3,088,000

Calculations by this method are in agreement with actual plant costs in the 1-10 mW range.

Two times that cost was then set as the constant for the power law equation. In the case of a 2.5 mW plant, the gross power capacity term is one and the cost of the remaining equipment, construction and engineering equals the constant or two times the major equipment. Other size plants will have higher or lower miscellaneous costs than this plant, as determined by their gross power capacity. For example, in Table H-8 for Case 1, 30 psia flash pressure, the remaining miscellaneous equipment and construction cost is calculated as follows:

$$\$ = 1{,}790{,}000\left(\frac{1{,}351.9}{2{,}500.0}\right)^{0.7}$$

$$= 1{,}790{,}000\ (.65)$$

$$= 1{,}164{,}000$$

Binary Cycle Cost Calculations

Selection of the Working Fluid. Starling et al.[5,6,7] found that the minimum plant cost at a wellhead temperature of 300°F was with a 50/50 mixture of isobutane/isopentane. However, their cost equations result in an estimated 1979 cost of $1,000,000 for a gross 30 mW turbine generator set. Elliott Company has estimated that small (1 to 5 mW) binary turbine-generators will cost from $840,000 to $990,000. For the low end of this range, turbine-generator costs will be well over 50 percent of the major equipment cost. Thus, cost equations indicate that to minimize the investment, binary turbine efficiency must be at the maximum. Starling has shown that the most energy efficient working fluid at 300°F is isobutane. Therefore, at 300°F, isobutane is the fluid of choice for small binary cycle units. At lower temperatures, propane/isobutane mixtures are probably slightly more efficient. However, 100 percent isobutane was assumed to be the working fluid for this study. The following values for isobutane are obtained from Starling et al.:

Temp. (°F)	Gross Power (Btu/lb Brine)	Net Power (Btu/lb Brine)
300	14.1	11.4
350	23.0	18.4
400	30.7	24.1

[5]Starling, K.E., et al., "Resource Utilization Efficiency Improvement of Geothermal Binary Cycles, Phase I," University of Oklahoma, 1976.

[6]Starling, K.E., et al., "Resource Utilization Efficiency Improvement of Geothermal Binary Cycles, Phase II," 1976.

[7]Starling, K.E., et al., "Resource Utilization Efficiency Improvement of Geothermal Binary Cycles, Phase III," Final Report, 1978.

Net and gross power at other temperatures were obtained by extrapolation of these values. Similarly, the material balance data in Table H-6 for 2.5 mW net isobutane binary cycle units at 300°F and 350°F were used to size equipment for the binary cases evaluated in this study. The data from Table H-6 are plotted in Figures H-4 through H-8. These curves are used to size the equipment for the binary cycle cases that are evaluated in this report.

Binary Cycle Equipment Sizing Procedure. For a given wellhead temperature, the major equipment can be sized using the curves in Figures H-4 through H-8.

- Binary Turbine Generator. The size of the binary turbine-generator set is obtained using Figure H-4, as follows:

$$\text{Power mW} = \text{gross Btu/lb brine} \times \text{brine rate } \frac{\text{lb}}{\text{hr}} \times 2.93 \times 10^{-7}\ \frac{\text{mW}}{\text{Btu}}$$

TABLE H-6

Material Balance Data

	Temperature (°F)		
	300	350	400
Isobutane/Brine Ratio (Lb/lb Brine)	0.728	1.048	1.34
Exchanger Heat Load (Btu/lb Brine)	114.4	154.7	199.7
Exchanger Transfer Coeff (Btu/hr Ft^2°F)	104.7	104.7	104.7
Exchanger Shell Side Pressure (psia)	300	450	550
Exchanger Log (Mean ΔT)	38	46	54
Cooling Water/Brine Ratio (Lb/lb Brine)	5.89	7.33	9.19
Condenser Heat Load (Btu/lb Brine)	100.3	131.7	163.1
Condenser Transfer Coeff (Btu/hr Ft^2°F)	129.7	129.7	129.7
Condenser Shell Side Pressure (psia)	82	84	86
Condenser Log (Mean ΔT)	20	25	30
Condenser Outlet Isobutane Temp. (°F)	110	112	115
Working Fluid Pump ΔP (psi)	235	385	485
Cooling Water Pump ΔP (psi)	30	30	30

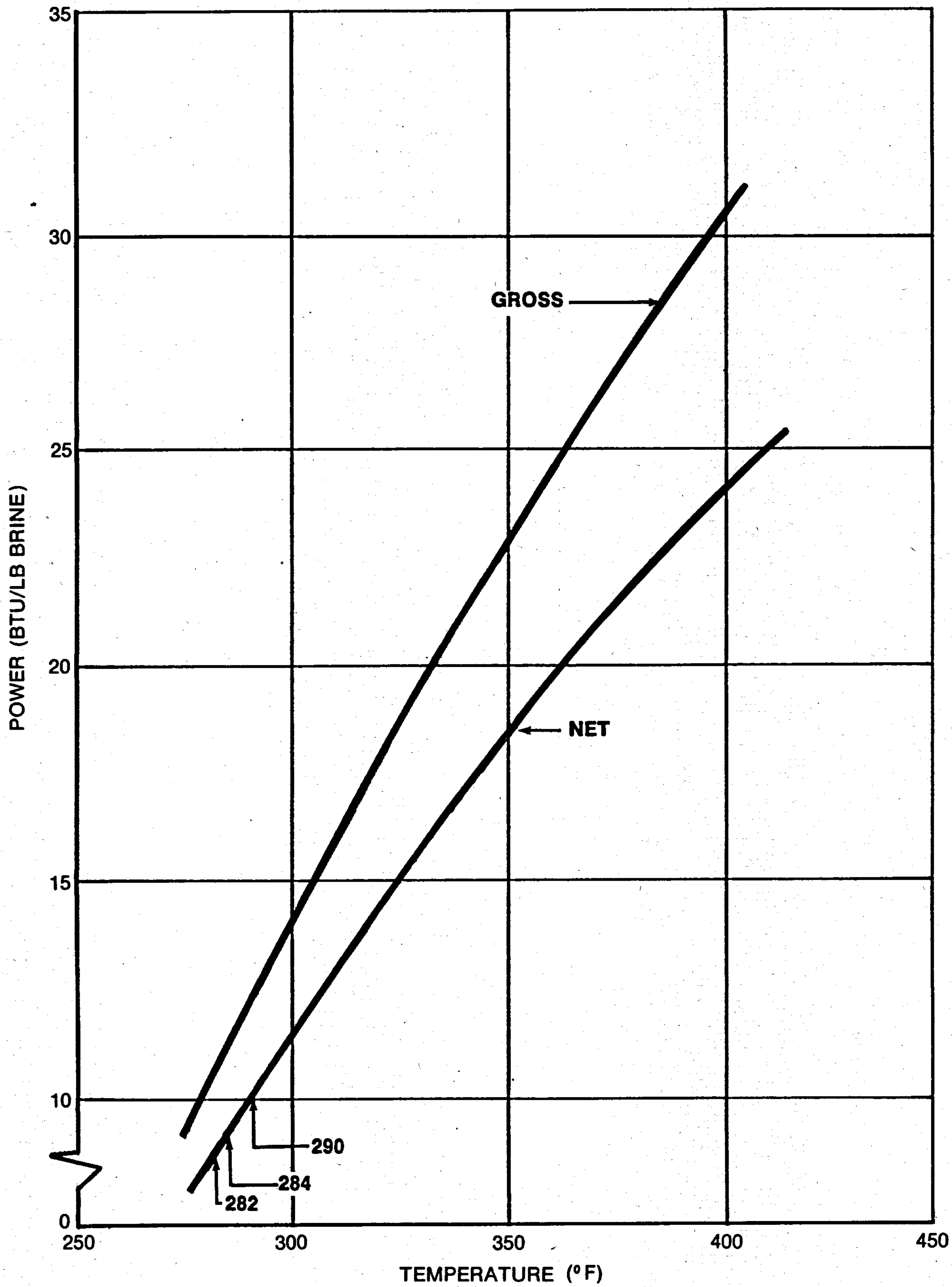

Figure H-4. Power vs. Temperature.

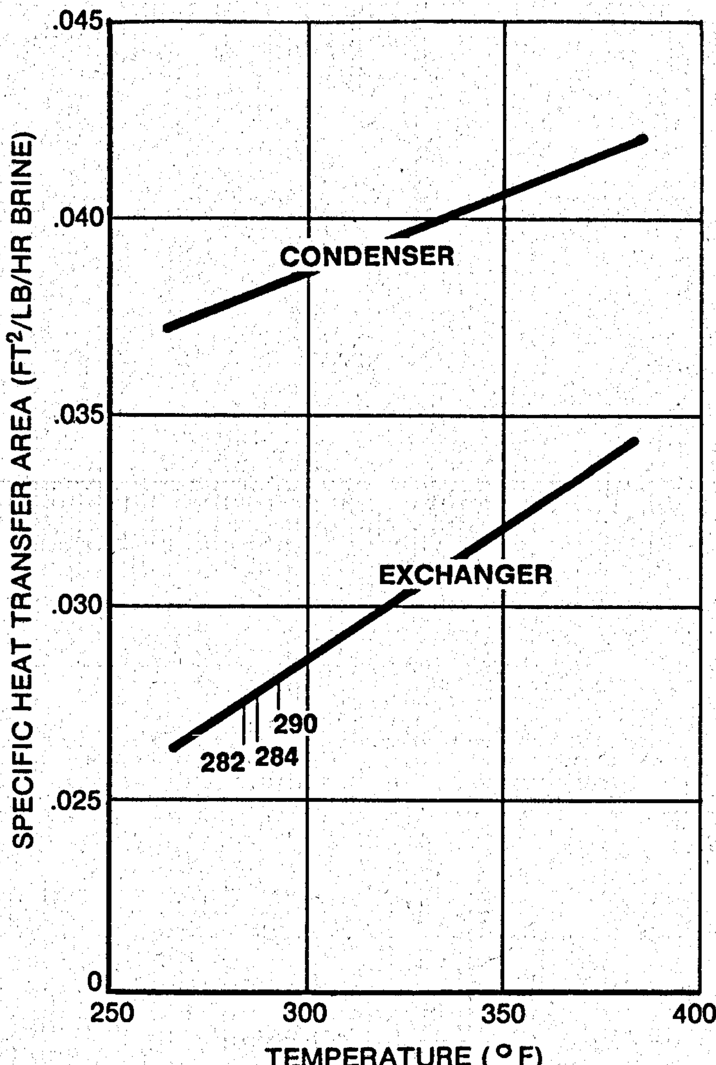

Figure H-5. Specific Heat Transfer Area vs. Temperature.

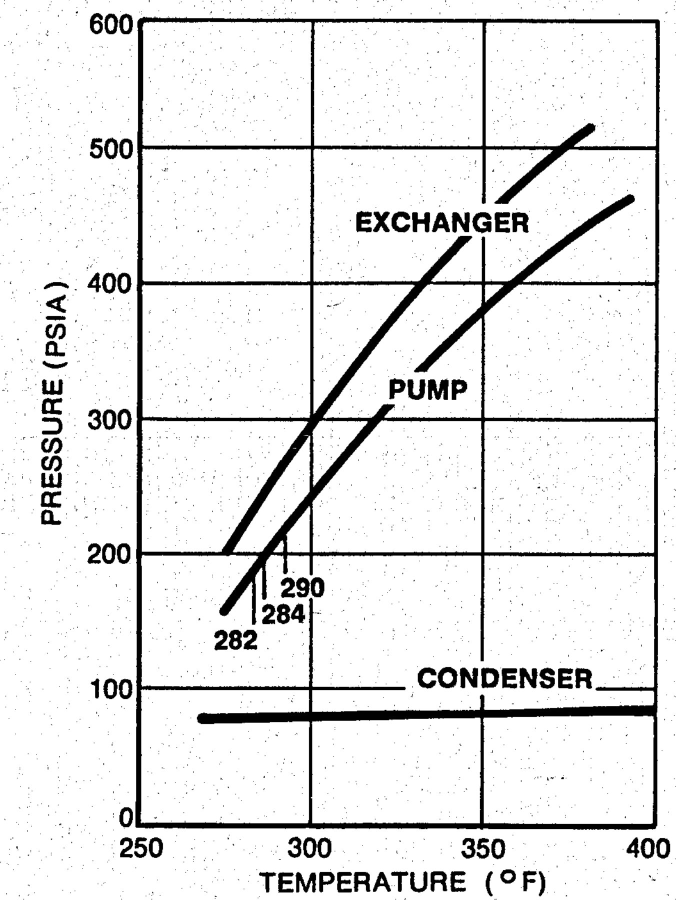

Figure H-6. Exchanger and Condenser Shell Side Pressure, and Working Fluid Pump ΔP vs. Temperature.

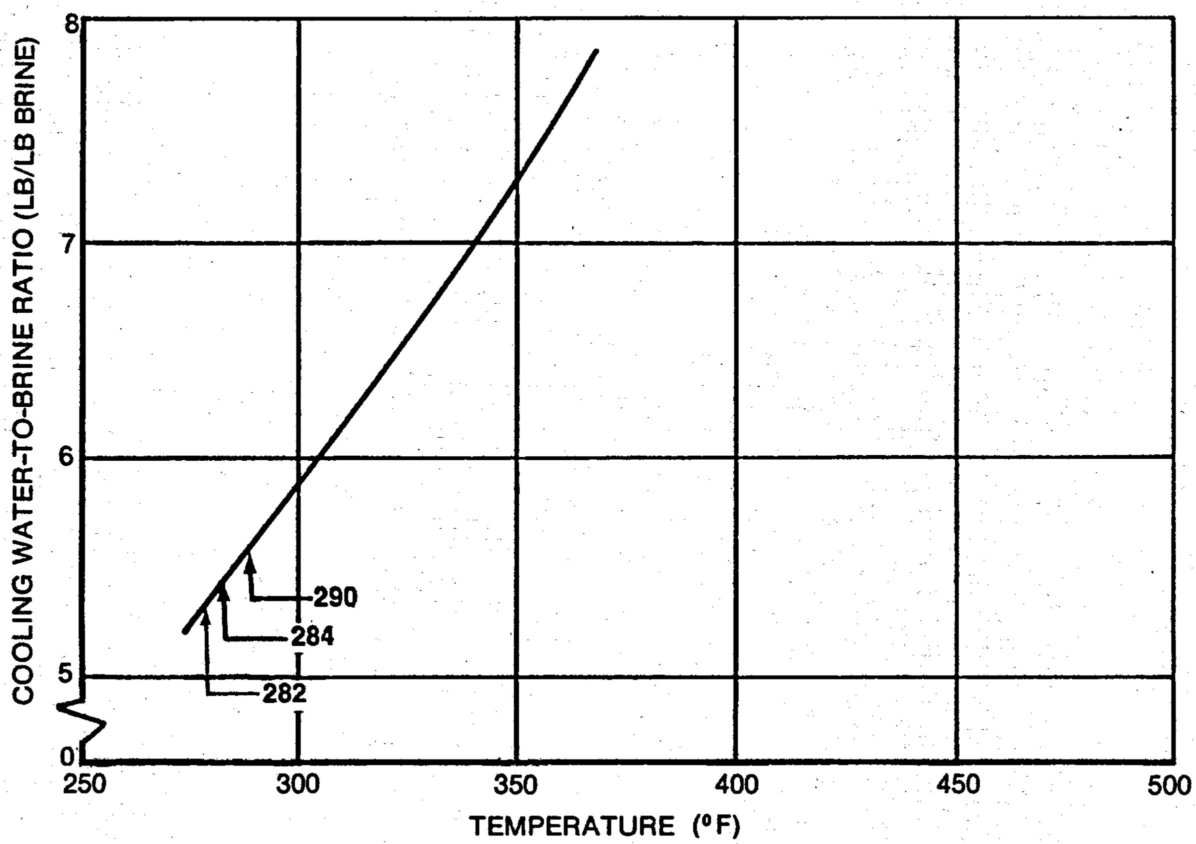

Figure H-7. Cooling Water-to-Brine Ratio vs. Temperature.

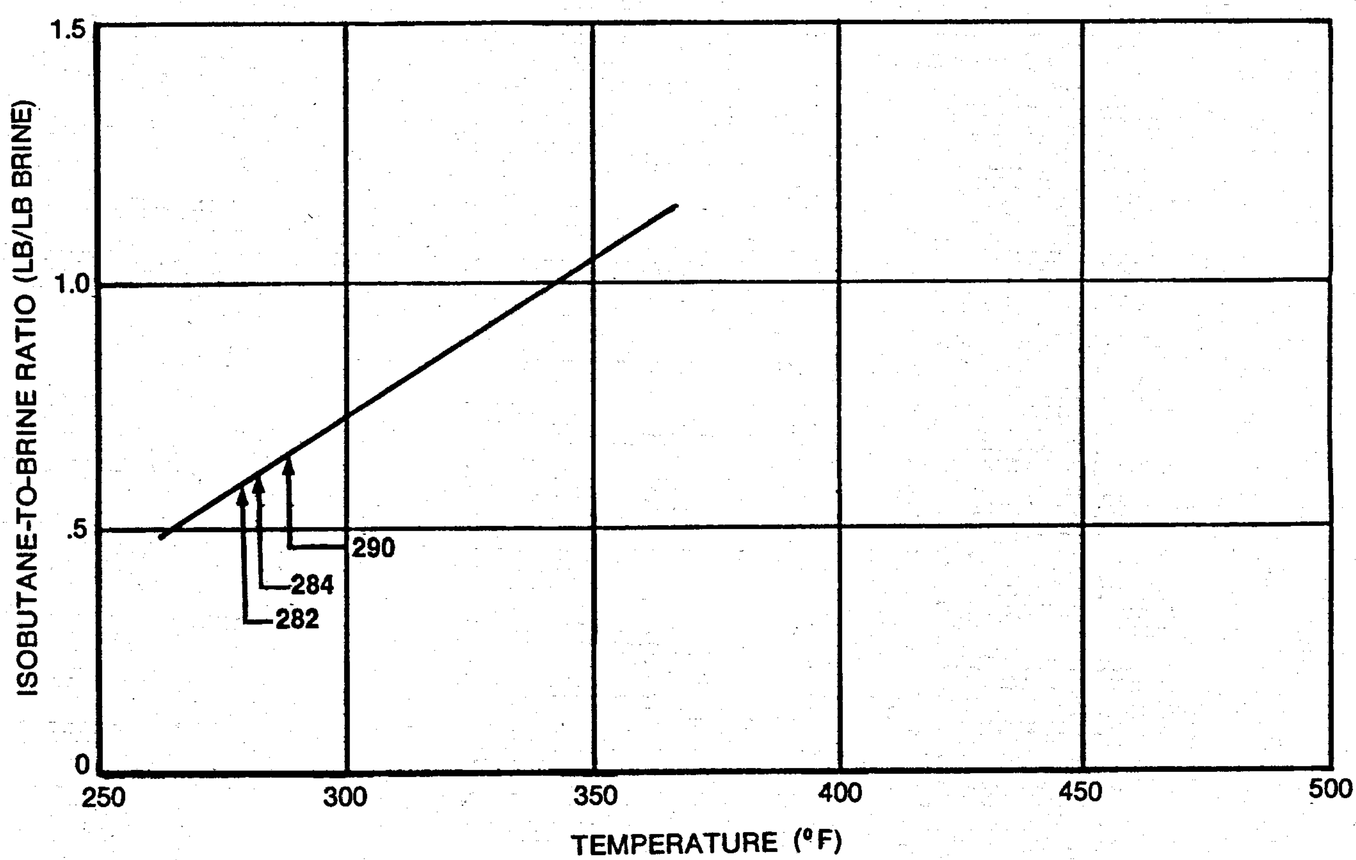

Figure H-8. Isobutane-to-Brine Ratio vs. Temperature.

The flow rates are converted from barrels per day to pounds per hour by using the correlations developed by Dittman.[8] A reservoir of 10 wt % total dissolved solids (TDS) in the brine has been assumed for all cases. The cost of the binary turbine-generator set can now be calculated using the cost equations.[9]

- Heat Exchangers. The standard shell and tube heat exchangers are sized from Figure H-5, which shows specific heat transfer area (ft^2/lb/hr brine) vs. wellhead temperature. The curve was derived from the ratio of the heat load (Btu/lb brine) over the heat transfer rate (Btu/hr/ft^2 x log mean T °F).

$$\text{Exchanger ft}^2 = \text{Specific heat transfer area } \frac{\text{ft}^2}{\text{lb/hr}} \times \text{brine rate lb/hr}$$

- Condenser. The condenser, which is sized in the same manner as the heat exchangers, is also assumed to be of standard shell and tube construction. The exchanger and condenser costs in \$/ft^2 are then calculated from the cost equation.[9] The shell side pressure (P_s) is obtained from Figure H-6.

- Cooling tower. For a given wellhead temperature, the cooling tower is sized from Figure H-7, as follows:

$$\text{Cooling water rate (gpm)} = \frac{\text{cooling water-to-brine ratio x brine rate}}{\text{8.35 lb/gal x 60 min/hr}}$$

- Working Fluid Pump. The working fluid pump is sized by multiplying the pressure head required (Figure H-6) by the working fluid rate. This rate is calculated as follows:

$$\text{Working fluid rate (gpm)} = \frac{\text{i-}C_4\text{-to-brine ratio x brine rate}}{\text{i-}C_4\text{ density lb/gal x 60 min/hr}}$$

The isobutane-to-brine ratio is determined from Figure H-8. The isobutane density is for the condenser outlet temperature.

- Cooling Water Pump. The cooling water pump is sized by multiplying the pressure head required (30 psi) by the cooling water rate as calculated above for the cooling tower.

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[8] Dittman, G.L., "Calculation of Brine Properties," Lawrence Livermore Laboratory, 1977.

[9] Cost equations in this section are those noted earlier in the Cost Calculation Equations section.

Results. The results of the binary cycle sizing and costing calculations are shown in Table H-7.

Flashed Steam Cost Calculations

The material balances in Table H-8 for the flashed steam cost calculations were generated by flashed steam computer models. The total plant cost was then calculated at various flash pressures to determine the economic optimum for each case. These results are presented in Tables H-8 through H-10. The investment cost as a function of flash pressure has been plotted in Figure H-9.

Economic Sensitivity Analysis

The effect of changes in ROR, capital investment, capacity factor, and operating expense on power price was investigated for Case 1 (290°F wellhead and 60,000 B/D brine rate). To summarize, every 1.0 percent increase in ROR or investment resulted in a 0.9 percent increase in the price of electricity. A 1.0 percent increase in operating expense resulted in a 0.1 percent power price increase. A 1.0 percent decrease in capacity factor near the base case value resulted in a 1.0 percent increase in power price. The calculations were made using an economic analysis computer program. The range of variables examined and the fixed assumptions are shown in Table H-11. Figures H-10 and H-11 are examples of the type of information available for the case. This is followed by Table H-12, which presents a condensed summary of the output for a single set of calculations.

Finally, all of the sensitivity analyses for the case are summarized in the "spider diagram" of Figure H-12. With this diagram, the effect of percentage changes in the variables investigated on the cost of power, can be seen. The steeper the slope of a curve, the more sensitive the cost of power to changes in that variable. From this it can be concluded that variations in the operating expense are relatively unimportant, but that variations in the required ROR, the size of the investment, and the capacity factor have pronounced effects on the cost of power. The conclusions would be similar for Cases 2 and 3 and the flashed steam facilities.

Hydraulic Energy Assessment

Costing

Cost Calculation Procedure. The data for these two hydraulic power generation cases were based on the aquifer properties of Southeast Pecan Island West. The pressure decline rate and available horsepower are shown in Table H-13. To find the minimum cost of power, a variety of pump sizes were investigated for each case. Total installed capital cost was assumed to be three times the hydraulic turbine cost. The cost of power for each pump size was then determined with the economics program. These results are plotted for the higher flow rate case in Figures H-13 and H-14. These curves indicate that the optimum turbine size varies with the required ROR but not with changes in the capacity factor. The most economical pump size was found to be 1,100 hp for Case 1 and 1,300 hp for Case 2. The optimal results are summarized in Table H-14. The effects of investment, ROR, capacity factor, and operating expense were again investigated in the sensitivity analysis. These results are summarized in the spider diagram of Figure H-15 which indicates that costs are most sensitive to capacity factor with a 1 percent change in that variable near the base value, resulting in a 1.0 percent change in the cost of power. The other variables are less sensitive, with a 1.0 percent change in investment, ROR, and operating expense resulting in a 0.65 percent, 0.45 percent, and 0.35 percent change in the cost of power, respectively. Table H-15 contains a condensed summary of the output from Case 1.

<u>Sizing and Cost Calculation</u>. Power generation equation:

$$hp = .000017 \times Q \times \eta \times (\Delta P)$$

where Q = flow rate (B/D)

η = efficiency (.70)

ΔP = available pressure (psia)

hp = available horsepower at the shaft

Hydraulic turbine cost equation:

$$\$ = 10{,}250\ (hp)^{0.42}$$

(Source: Discussions with Pacific Pumps, a division of Dresser Industries, Inc.)

The turbine is assumed to be a multistage centrifugal pump with flow reversed and horsepower available at the shaft to drive process equipment.

TABLE H-7

Binary Cycle Cases
Cost Calculation Summary

	Case 1	Case 2	Case 3
Wellhead Temperature	(290°F)	(284°F)	(282°F)
Working Fluid	Isobutane	Isobutane	Isobutane
Brine Rate (B/D)	60,000	40,000	20,000
(Lb/hr)	917,700	614,100	307,400
Gross Power (kW)	3,307	2,024	982
(Btu/lb brine)	12.3	11.25	10.9
Net Power (kW)	2,649	1,610	779
(Btu/lb Brine)	9.85	8.95	8.65
Heat Exchanger Area (Ft^2)	25,740	16,980	8,450
Condenser Area (Ft^2)	35,100	23,370	11,670
Working Fluid Pump (ΔP * gpm)	479,500	277,400	132,400
Cooling Water Pump (ΔP * gpm)	308,300	200,400	99,400
Cooling Water (gpm)	10,280	6,680	3,310
Costs (Thousand Constant 1979 Dollars)			
Heat Exchanger	561	354	174
Turbine and Generator	1,170	961	720
Condenser	370	246	123
Cooling Tower	227	175	115
Working Fluid Pump	130	82	47
Cooling Water Pump	86	64	39
Total Major Equipment	2,544	1,882	1,218
Remaining Eqpt. & Constr.	2,177	1,544	931
Contingency (15%)	708	514	322
Total Cost	5,429	3,940	2,471
Investment/Net kW	2,049	2,447	3,173

TABLE H-8

Flashed Steam Material Balances and
Cost Optimization Calculation Summary

CASE 1*

Flash Pressure (psia)	20	25	28	30†	32	35	40
Gross Power (kW)	1,739.6	1,560.0	1,444.5	1,351.9	1,269.0	1,131.9	906.9
Net Power (kW)	1,640.5	1,471.6	1,361.5	1,272.5	1,192.8	1,060.3	842.3
Cooling Water (gpm)	2,724	2,200	1,937	1,760	1,610	1,383	1,050
Condenser (MMBtu/hr)	52.241	42.411	37.411	33.727	30.787	26.443	20.027
(Ft^2)	18,660	15,150	13,360	12,050	11,000	9,440	7,150
Cooling Water Pump (P * gpm)	82,000	66,000	58,000	53,000	48,000	41,500	31,500
Costs (Thousand Constant 1979 Dollars)							
Turbine and Generator	1,403	1,112	974	886	810	702	548
Cooling Tower	102	90	83	79	75	68	58
Condenser	196	160	141	127	116	99	75
Vacuum Compressor	20	20	20	20	20	20	20
Cooling Water Pumps	34	30	28	25	24	21	19
Total Major Equipment	1,755	1,412	1,246	1,137	1,045	910	720
Remaining Eqpt. & Constr.	1,389	1,287	1,219	1,164	1,114	1,028	881
Contingency (15%)	472	405	370	345	324	291	240
Total Plant Cost	3,616	3,104	2,835	2,646	2,483	2,229	1,841
Cost/Net kW	2,205	2,109	2,083	2,079	2,082	2,102	2,186

*Case 1: 290°F; 259.3 Btu/lb; 60,000 B/D.

†Optimum.

TABLE H-9

Flashed Steam Material Balances and
Cost Optimization Calculation Summary

CASE 2*

Flash Pressure (psia)	25	28†	30	32	35
Gross Power (kW)	921.6	838.1	773.0	714.0	618.5
Net Power (kW)	865.9	786.1	723.3	666.5	574.1
Cooling Water (gpm)	1,300	1,120	1,005	904	754
Condenser (MMBtu/hr)	24.899	21,487	20.144	17.292	14.411
(Ft^2)	8,890	7,670	7,190	6,180	5,150
Cooling Water Pump ($\Delta P \cdot$ gpm)	39,000	33,600	30,200	27,100	22,600
Costs (Thousand Constant 1979 Dollars)					
Turbine and Generator	769	665	596	541	460
Cooling Tower	66	60	55	53	47
Condenser	94	81	75	65	54
Vacuum Compressor	15	15	15	15	15
Cooling Water Pumps	20	19	18	17	16
Total Major Equipment	964	840	759	691	592
Remaining Eqpt. & Constr.	890	833	787	745	673
Contingency (15%)	278	251	232	215	190
Total Plant Cost	2,132	1,924	1,778	1,651	1,455
Cost/Net kW	2,462	2,447	2,458	2,478	2,533

*Case 2: 284°F; 253.2 Btu/lb; 40,000 B/D.

†Optimum.

TABLE H-10

Flashed Steam Material Balances and Cost Optimization Calculation Summary

CASE 3*

Flash Pressure (psia)	20	25	28†	30	32
Gross Power (kW)	508.4	440.3	397.5	364.4	334.3
Net Power (kW)	477.5	413.1	372.0	340.1	311.1
Cooling Water (gpm)	795	621	532	474	423
Condenser (MMBtu/hr)	15.253	11.892	10.186	9.069	8.089
(Ft^2)	5,450	4,250	3,640	3,240	2,890
Cooling Water Pump (ΔP * gpm)	23,800	18,600	16,000	14,200	12,700
Costs (Thousand Constant 1979 Dollars)					
Turbine and Generator	593	459	395	353	318
Cooling Tower	49	42	38	35.5	33
Condenser	57	45	38	33.5	30
Vacuum Compressor	8	8	8	8	8
Cooling Water Pumps	16	14	13	12	12
Total Major Equipment	723	568	492	442	401
Remaining Eqpt. & Constr.	587	531	494	465	438
Contingency (15%)	196	165	150	136	126
Total Plant Cost	1,506	1,264	1,136	1,045	965
Cost/Net kW	3,156	3,059	3,048	3,067	3,102

*Case 3: 282°F; 251.1 Btu/lb; 20,000 B/D.

†Optimum.

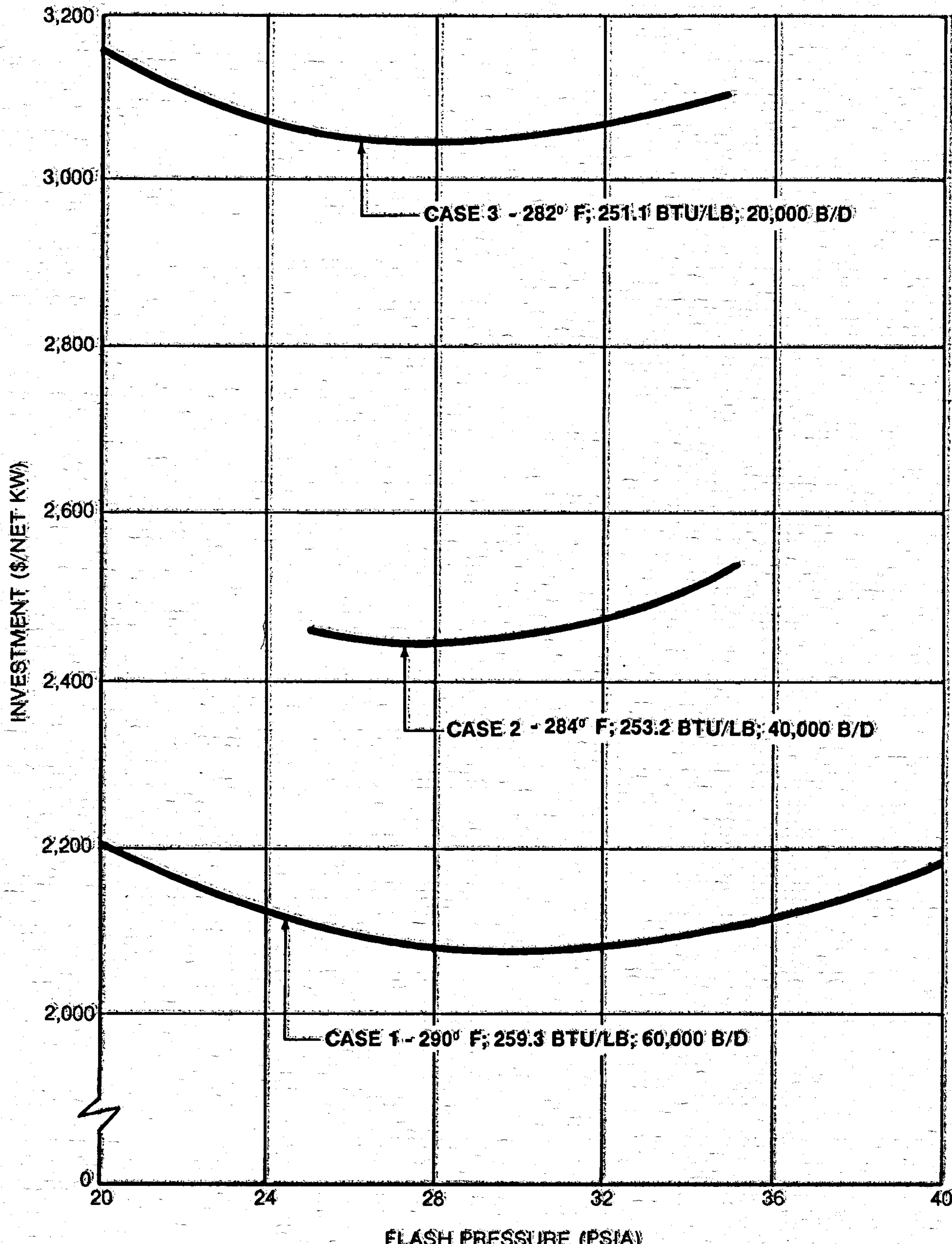

Figure H-9. Steam Flash Optimization Investment vs. Flash Pressure.

TABLE H-11

Sensitivity Analysis Variables*
(Constant 1979 Dollars)

ROR (Percent)	Capacity Factor (Percent)	Operating Expense (¢/kWh Capacity)	Investment ($/kW)
5	65	0.25	1,025
10	80	0.375	1,537
15	85	0.50	2,049
20	100	1.0	3,074

*Tax assumptions:

20 percent investment tax credit
15 percent depletion allowance
50 percent tax rate
Sum-of-years-digits depreciation
over the 20-year life of the facility

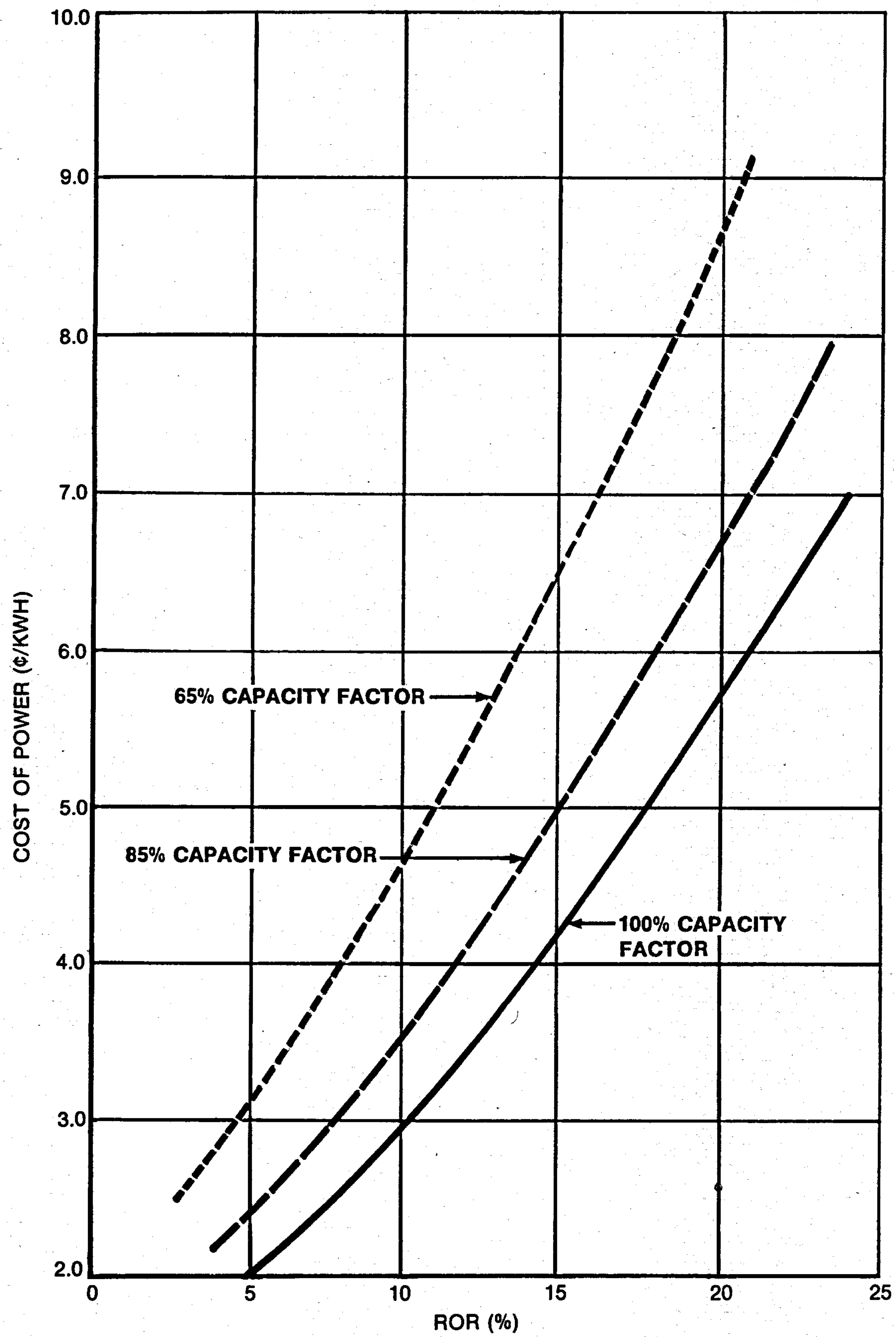

Figure H-10. Cost of Power vs. ROR (Example Based on Case 1, 290° F, 60,000 B/D Binary Cycle).

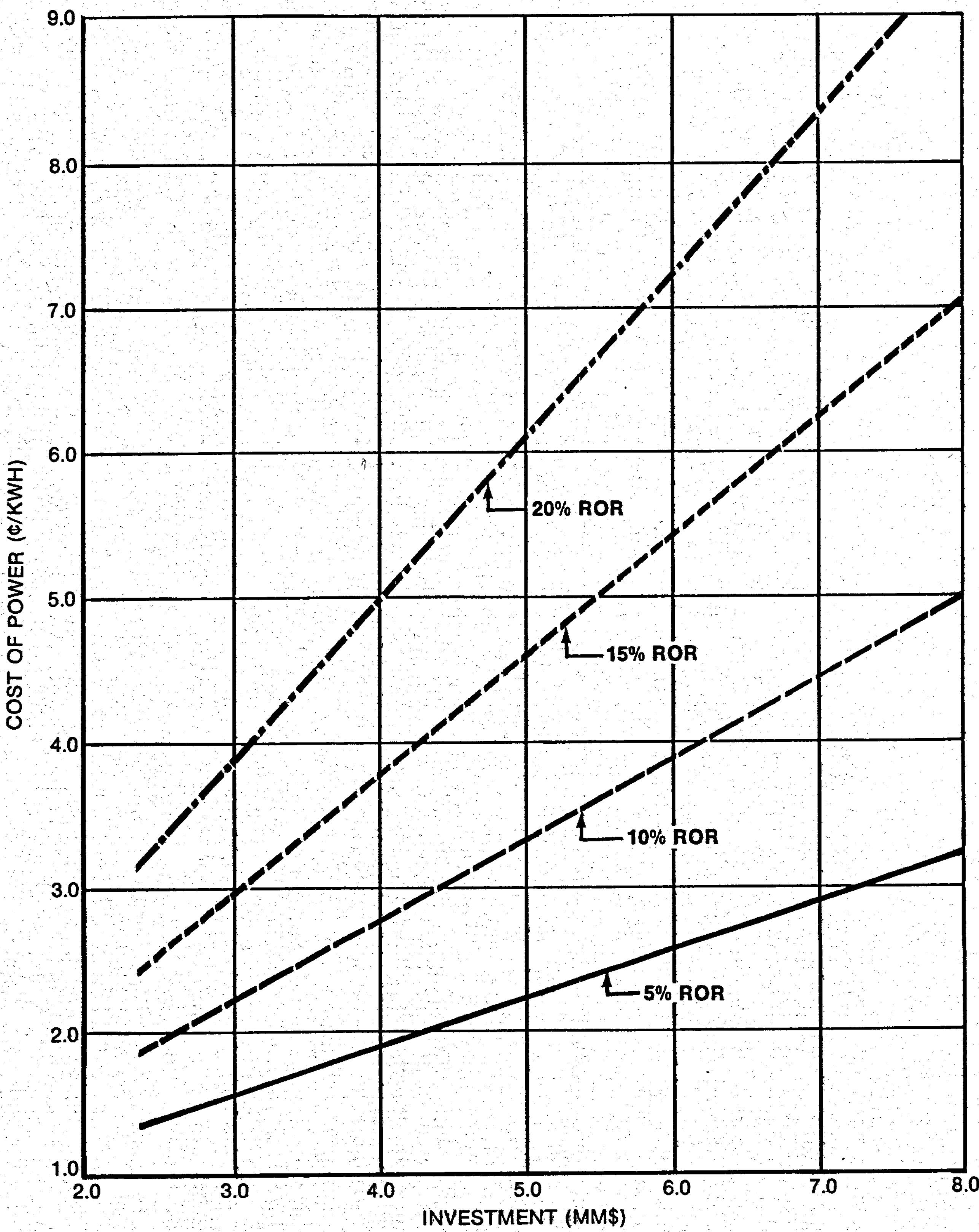

Figure H-11. Cost of Power vs. Investment (Example Based on Case 1, 290° F, 60,000 B/D Binary Cycle).

TABLE H-12

Economic Analysis: Case Summary
Binary Cycle Facility
(Thousand Constant 1979 Dollars)

(For 290°F, 60,000 B/D, 15% ROR, 85% Capacity Factor,
1/2 ¢/kWh Operating Expense/Cost of Power 4.96 ¢/kWh)

Year	Investment	Revenue	Depr.	Depl.	Oper. Exp.	Net Taxable Income	Tax Credits	U.S. Tax	Net Cash Flow
1	5,429	0	0	0	0	0	1,086	-1,086	-4,343
2	0	979	517	147	116	199	0	99	763
3	0	979	491	147	116	225	0	112	750
4	0	979	465	147	116	250	0	125	737
5	0	979	439	147	116	276	0	138	724
6	0	979	414	147	116	302	0	151	712
7	0	979	388	147	116	328	0	164	699
8	0	979	362	147	116	354	0	177	686
9	0	979	336	147	116	380	0	190	673
10	0	979	310	147	116	406	0	203	660
11	0	979	284	147	116	431	0	216	647
12	0	979	259	147	116	457	0	229	634
13	0	979	233	147	116	483	0	242	621
14	0	979	207	147	116	509	0	254	608
15	0	979	181	147	116	535	0	267	595
16	0	979	155	147	116	561	0	280	582
17	0	979	129	147	116	587	0	293	569
18	0	979	103	147	116	612	0	306	556
19	0	979	78	147	116	638	0	319	543
20	0	979	52	147	116	664	0	332	531
21	0	979	26	147	116	690	0	345	518
Total*	5,429	19,573	5,429	2,936	2,320	8,887	1,086	3,358	8,465

*Totals may not add as a result of rounding.

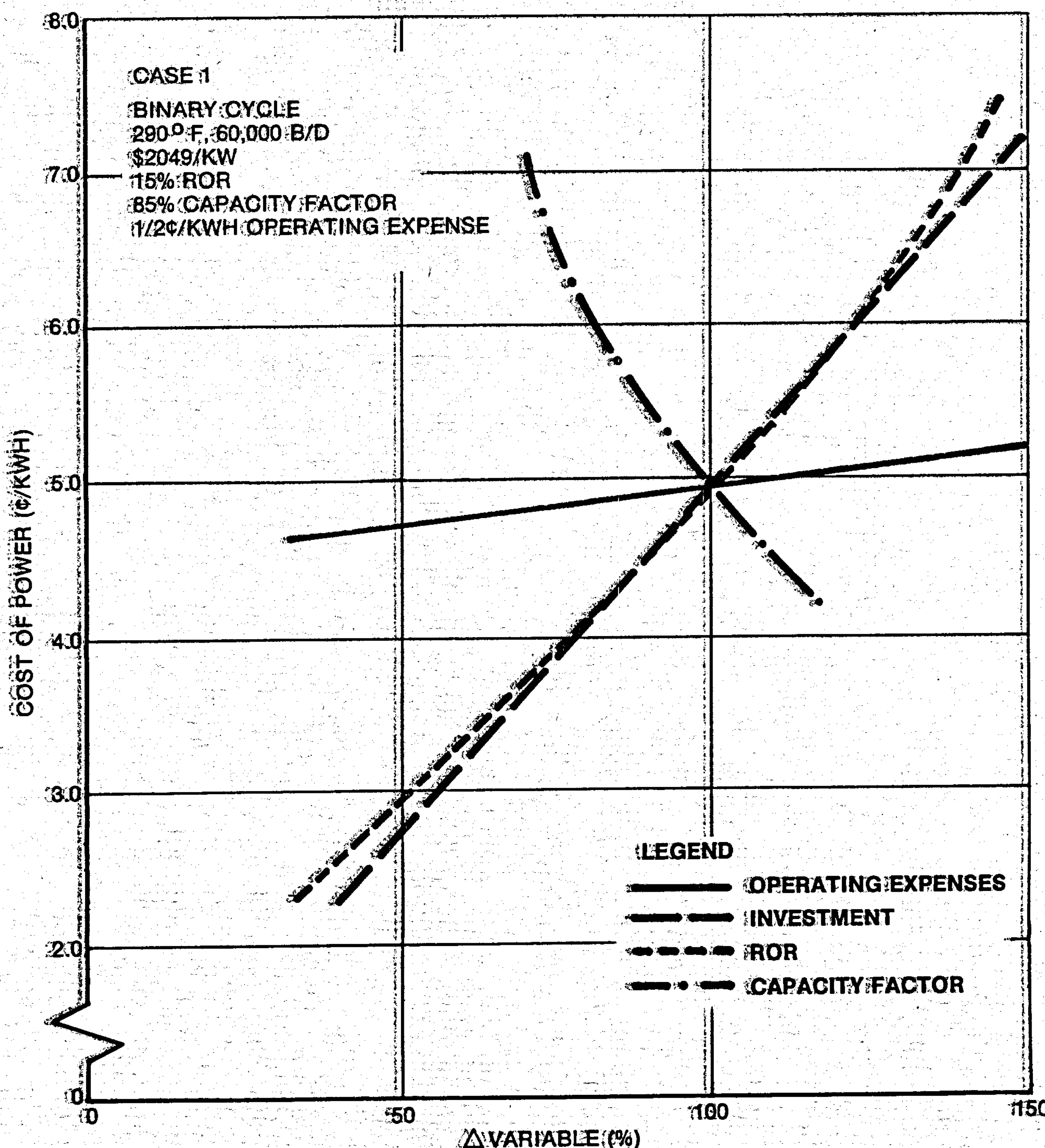

Figure H-12. Sensitivity Analysis Summary Cost of Power vs. Δ Variable.

TABLE H-13

Hydraulic Pressure Decline Rates

	Case 1 (50,000 B/D)			Case 2 (75,000 B/D)		
	Available		M mWh/yr @ 85%	Available		M mWh/yr @ 85%
Year	Δ P	hp	Capacity Factor	Δ P	hp	Capacity Factor
1	3,064	1,823	18.220	1,775	1,584	15.831
2	2,865	1,705	17.041	1,594	1,423	14.222
3	2,666	1,586	15.851	1,414	1,262	12.613
4	2,467	1,468	14.672	1,234	1,101	11.004
5	2,269	1,305	13.043	1,054	941	9.405
6	2,070	1,232	12.313	874	780	7.796
7	1,873	1,114	11.134	695	620	6.197
8	1,675	997	9.965	515	460	4.598
9	1,478	879	8.785	336	300	2.998
10	1,282	763	7.626	156	139	1.389
11	1,086	646	6.456			
12	890	530	5.297			
13	695	413	4.118			
14	500	298	1.819			
15	306	182	1.819			
16	113	67	0.670			

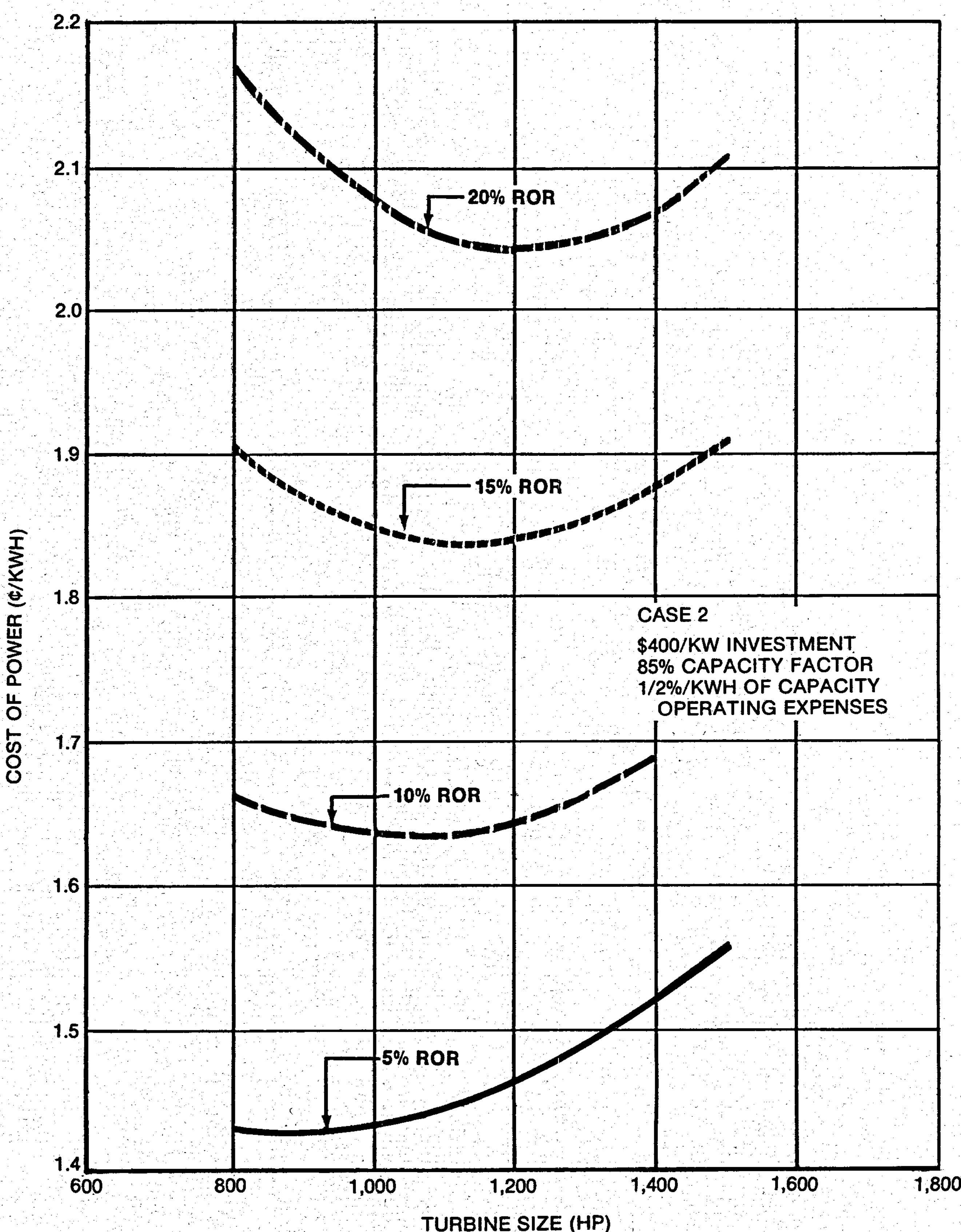

Figure H-13. Cost of Power vs. Hydraulic Turbine Capacity.

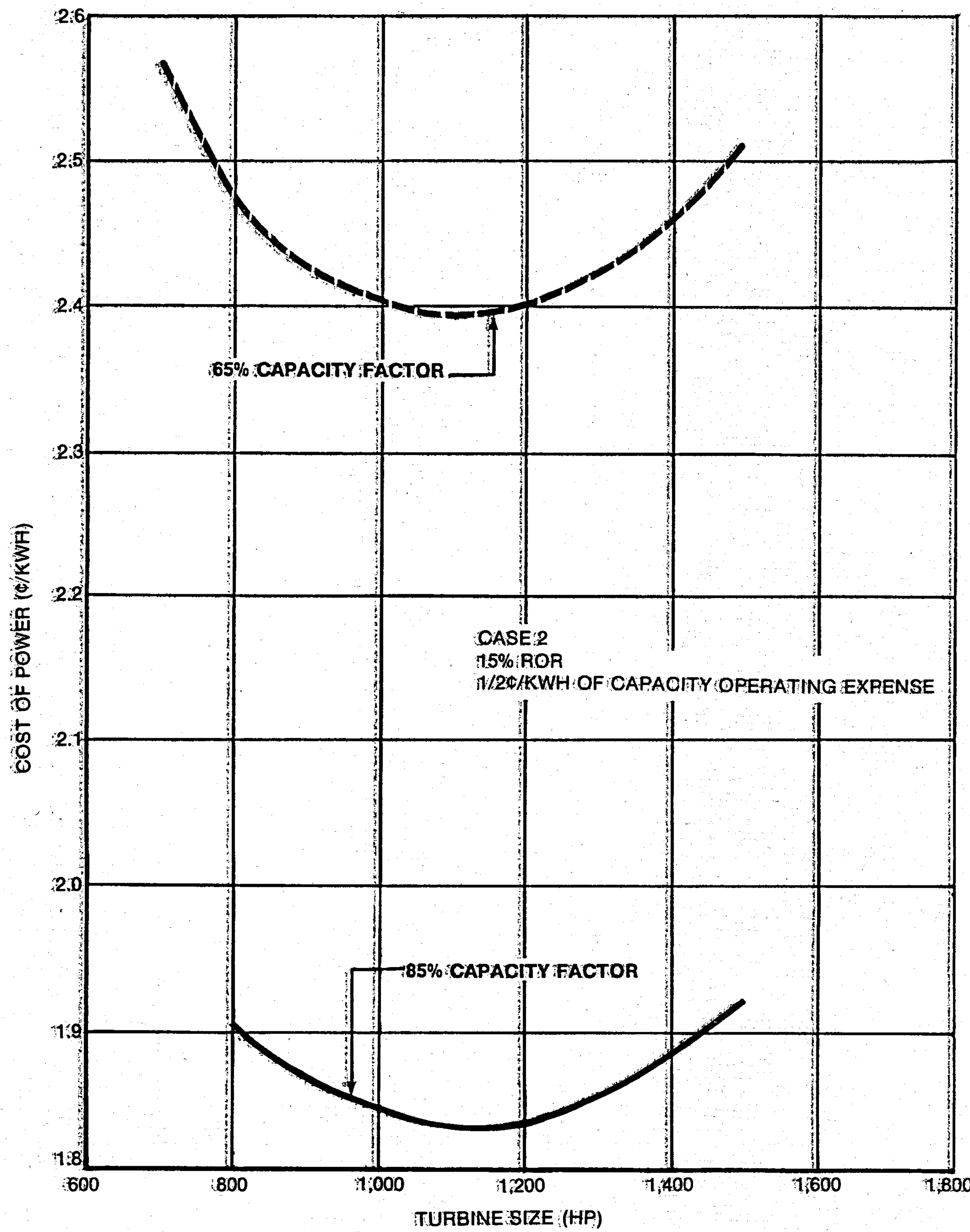

Figure H-14. Cost of Power vs. Turbine Size.

TABLE H-14

Hydraulic Energy Assessment Results

	Case 1	Case 2
Flow (B/D)	50,000	75,000
Well Life with $\Delta P > 0$ (yr)	16	10
Turbine Operating Conditions		
Design ΔP (psi)	1,850	1,460
Design hp (hp)	1,100	1,300
(Btu/lb brine)	6.5	5.2
Required Area (Ft^2)	200	250
Costs (Thousand Constant 1979 Dollars)		
Turbine	194	208
Misc. Eqpt. & Constr.	388	417
Contingency (15%)	87	94
Total Cost	669	719
Operating Expense (M $/year)	64	76
Cost of Power* (¢/kWh)	1.72	2.05
Equivalent ($/MMBtu)	5.00	6.00

*Assumptions:

15 percent ROR
85 percent capacity factor
1/2 ¢/kWh operating expense based on 100 percent capacity factor

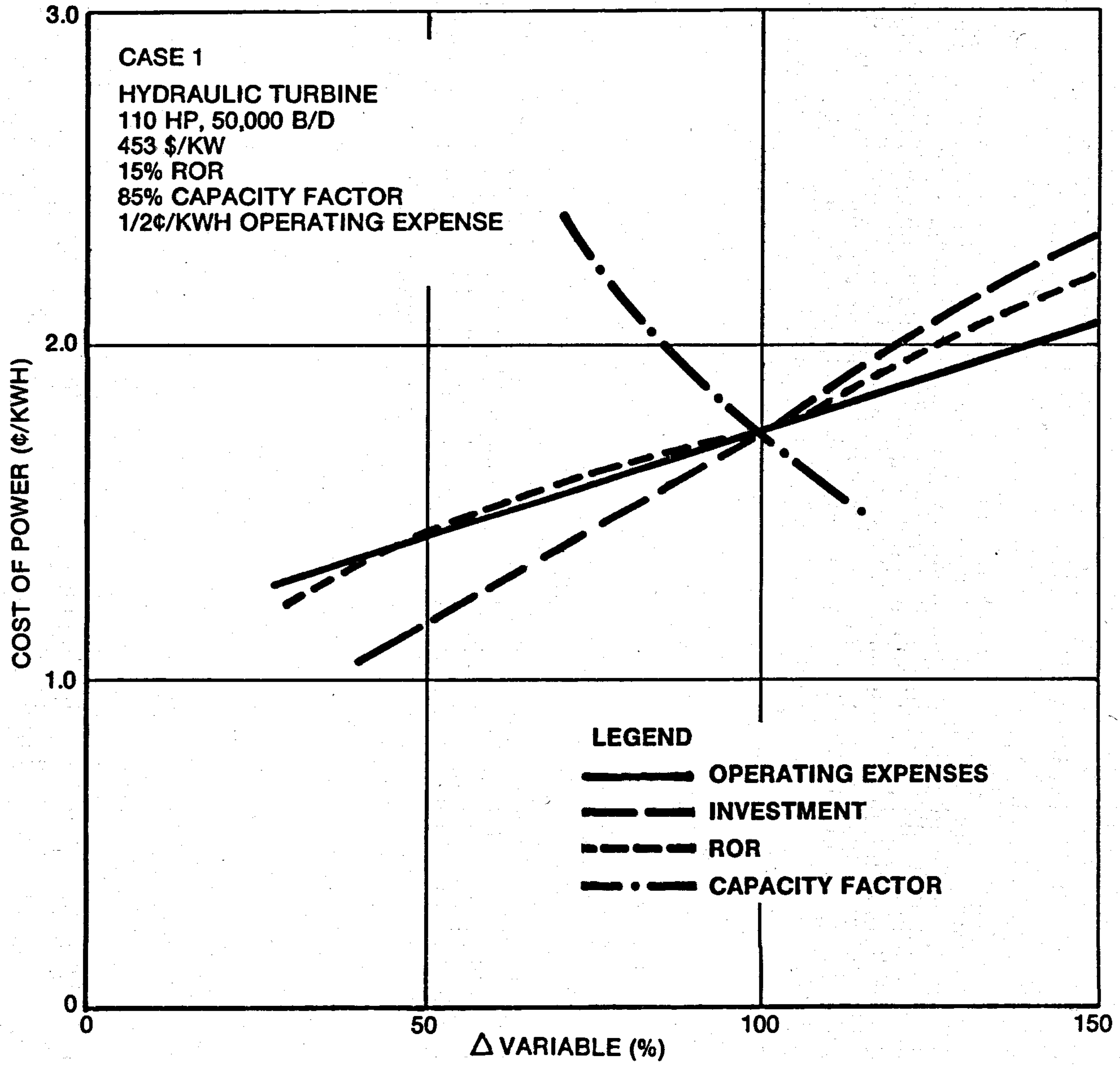

Figure H-15. Hydraulic Power Sensitivity Analysis Summary Cost of Power vs. Δ Variable.

TABLE H-15

Economic Analysis: Case Summary
Hydraulic Power Generation
(Thousand Constant 1979 Dollars)

CASE 1

(For 50,000 B/D, 15% ROR, 85% Capacity Factor,
1/2 ¢/kWh Operating Expense/Cost of Power 1.72 ¢/kWh)

Year	Investment	Revenue	Depr.	Depl.	Oper. Exp.	Net Taxable Income	Tax Credits	U.S. Tax	Net Cash Flow
1	669	0	0	0	0	0	134	-134	-535
2	0	190	79	23	65	0	0	12	113
3	0	190	74	26	65	23	0	13	112
4	0	190	69	28	65	26	0	14	111
5	0	190	64	28	65	28	0	16	109
6	0	190	59	28	65	33	0	19	106
7	0	190	54	28	65	37	0	21	104
8	0	190	49	28	65	42	0	24	101
9	0	172	44	26	65	47	0	19	89
10	0	152	39	23	65	37	0	12	74
11	0	132	34	16	65	25	0	8	59
12	0	111	30	9	65	16	0	4	42
13	0	91	25	1	65	9	0	1	26
14	0	71	20	0	65	1	0	-7	13
15	0	51	15	0	65	-13	0	-14	1
16	0	0	15	0	0	-28	0	-3	3
17	0	0	0	0	0	0	0	0	0
Total*	669	2,107	669	265	905	283	134	5	528

*Totals may not add as a result of rounding.

APPENDIX I
Operating Expense

TABLE I-1

Operating Expense
(Gas Production and Subsurface Water Disposal)
(Constant 1979 Dollars)

Fixed Cost	$/Year
Labor	$100,000
Transportation	40,000
Special Tests	50,000
Laboratory	25,000
Field Supervision	50,000
Subtotal	$265,000
Overhead (20%)	55,000
Total	$320,000/yr

Variable Cost	¢/Bbl
Producing Well Repair	1.00
Disposal Well Repair	.33
Pump Maintenance	.50
Chemical	.30
Well Treating	.30
Subtotal	2.43
Overhead (20%)	.47
Total	2.90¢/bbl
Geothermal	0.5¢/kWh

TABLE I-2

Operating Expense
(Gas Production and Gulf of Mexico Disposal)
(Constant 1979 Dollars)

Fixed Cost	$/Year
Labor	$100,000
Transportation	40,000
Special Tests	50,000
Laboratory	25,000
Subtotal	$215,000
Overhead (20%)	45,000
Total	$260,000/yr

Variable Cost	¢/Bbl
Producing Well Repair	1.00
Pump Maintenance	.25
Subtotal	1.25
Overhead (20%)	.25
Total	1.50¢/bbl
Geothermal	0.5¢/kWh

APPENDIX J
Economic Evaluation

ECONOMIC EVALUATION

ECONOMIC EVALUATION PARAMETERS

A standard set of economic parameters was employed in the NPC's analyses of four unconventional gas sources, as follows:

- Basis
  - January 1, 1979, dollars held constant
- Desired Output
  - Additions to ultimate recovery, by year, to the year 2000 as a function of gas price and state of technology
  - Production rates, by year, to the year 2000
- Gas Price
  - Price at point of sale. All capital to that point, such as compression and gathering lines, should be included in the evaluation.
  - The lowest gas price to be considered is that which gives a 10 percent ROR, after tax, for best prospect, taking risk into account. The upper limit is $9.00 per MCF for 1,000 Btu per cubic foot of gas. Final calculations should be made for $2.50, $3.50, $5.00, $7.00, and $9.00 per MCF.
- Cases
  - Current technology -- likely to evolve and improve during normal operations; this is the base case.
  - Improved technology -- effect and timing to be determined for each gas source based on analysis of problems and improvements likely with large industry/government research, development, and testing programs.
- Other Parameters
  - Royalty -- to be chosen as typical for each area; generally to be in the range of 1/8 to 1/6
  - Taxes -- 46% federal income tax rate

    2% state income tax rate

    8% (of producer revenue) production, severance, and property tax

10% federal investment tax credit on tangible equipment

10% additional energy property tax credit on tangible equipment used to produce gas from geopressured brines and placed in service in the period September 30, 1978, to January 1, 1983[1]

- Depletion allowance -- statutory rates to be compared with 50 percent of net income and cost depletion in customary computation

- Statutory depletion allowance of 10 percent on value of gas produced from geopressured brine wells drilled in the period September 30, 1978, to January 1, 1984[1]

- Statutory depletion allowance on value of hot water produced if used for geothermal purposes, as follows:

1979, 1980	22%
1981	20%
1982	18%
1983	16%
1984 and thereafter	15%

- Overhead -- 10 percent of invested capital
  20 percent of direct operating expense

- Treatment of costs for tax purposes

  - Expense intangible drilling and development costs

  - Capitalize tangible equipment and write off by most favorable treatment under current tax laws and regulations

  - Treat leasehold and exploration costs in most favorable manner permitted by current tax laws and regulations

- Treatment of dry hole costs and other risks. Burden successful wells with their share of dry hole costs, unsuccessful exploration, leasehold, and other nonrecoverable costs.

- Rates of return (ROR)

  - Base case 10 percent, after tax

  - Also, compute additions to ultimate recovery for 15 and 20 percent ROR for example cases

[1]Assumed to continue to the year 2000.

- Inflation rate (for the purposes of computing taxes) is 8 percent.

- Uncertainty in estimates -- for the final report, show the band of uncertainty around curves of additions to ultimate recovery vs. time, and around curves of possible production rate vs. time.

ECONOMIC CALCULATIONS -- 11 IDENTIFIED PROSPECTS

Discounted cash flow rates of return were calculated for each of the 11 identified prospects based on the economic assumptions listed in the Economics subsection of this volume's Findings section. The economic data used for the seven Louisiana prospects are listed in Table J-1; the data for the four Texas prospects are listed in Table J-2.

The after-tax rate of return vs. gas price resulting from the economic calculations for the seven computer runs on the Texas prospects is shown in Figures J-1 through J-7. The same information for the 23 computer runs on the Louisiana prospects is shown in Figures J-8 through J-30.

For the 11 prospects, gas rates and reserves vs. gas prices were calculated for the four production cases examined (Most Optimistic, Upper Median, Lower Median, and Minimum). The results at 10, 15, and 20 percent ROR are listed in Tables J-3 through J-5. Gas price calculations were made at the three examined rates of return and are given for the four production cases in Table J-6.

TABLE J-1

Economic Data - Louisiana Prospects
(Constant 1979 Dollars)

Prospect	Run No.	Water Rate (MB/D)	Drainage Area (Acres)	Land Inv. (M $)	Geophysics Cost (M $)	Well Cost (M $)	Facility Cost (M $)	Flow Temp. (°F)	Geothermal Inv. (M $)	Sol. Gas (Cu Ft/Bbl)	Sales Gas/Well (MCF/D)	Power Output (kWh/Bbl)	Operating Expense: Gas (M $/Yr)	Operating Expense: Variable and Geothermal (¢/Bbl)	No. of Wells	Daily Rate (MCF/D)	Sales Gas (BCF)	Elect. Power (kW)
Atchafalaya Bay East	L2	50	30,000	600	400	3,500	3,800	266	3,730	29	1,350	0.62	320	3.2	1	1,350	10.4	1.3
	L3	50	17,000	400	200	3,500	3,800	266	None	29	1,350	None	320	2.9	2	2,700	16.0	None
	L6	30	9,000	200	100	3,500	2,800	266	None	29	810	None	320	2.9	4	3,240	19.6	None
West	L11	50	21,000	530	400	3,200	3,800	236	None	23	1,050	None	320	2.9	1	1,050	8.9	None
	L12	50	21,000	700	200	3,200	3,800	236	None	23	1,050	None	320	2.9	2	2,100	11.6	None
	L15	30	14,000	350	100	3,200	2,800	236	None	23	630	None	320	2.9	4	2,520	14.8	None
Johnson's Bayou	L18	70	14,000	350	200	2,670	4,900	226	None	20	1,260	None	320	2.9	4	5,040	43.2	None
	L19	70	7,000	180	100	2,670	4,900	226	None	20	1,260	None	320	2.9	6	7,560	53.4	None
	L22	50	14,000	350	200	2,670	3,800	226	None	20	900	None	320	2.9	2	1,800	15.6	None
	L24	50	4,000	100	50	2,670	3,800	226	None	20	900	None	320	2.9	8	7,200	44.0	None
	L28	30	3,000	75	30	2,670	2,800	226	None	20	540	None	320	2.9	12	6,480	44.4	None
LaFourche Crossing	L34	50	12,000	300	400	4,100	3,800	266	3,730	38	1,800	0.62	320	3.2	1	1,800	14.6	1.3
	L35	50	10,000	250	200	4,100	3,800	266	None	38	1,800	None	320	2.9	2	3,600	19.4	None
	L37	30	10,000	250	200	4,100	2,800	266	None	38	1,080	None	320	2.9	2	2,160	17.2	None
Rockefeller Refuge	L44	50	25,000	600	200	4,250	3,800	316	5,610	51	2,450	1.38	320	3.6	2	4,900	42.0	5.8
	L45	50	12,000	300	100	4,250	3,800	316	5,610	51	2,450	1.38	320	3.6	4	9,800	70.0	11.5
	L46	50	9,000	225	70	4,250	3,800	316	None	51	2,450	None	320	2.9	6	14,700	81.6	None
	L49	30	5,000	125	40	4,250	2,800	316	None	51	1,470	None	320	2.9	10	14,700	85.0	None
SE Pecan Island East	L53	50	9,000	230	200	4,000	3,800	296	None	35	1,650	None	320	2.9	1	1,650	6.7	None
	L54	30	9,000	230	200	4,000	2,800	296	None	35	990	None	320	2.9	1	990	6.4	None
West	L57	50	8,000	200	200	4,290	3,800	296	4,950	35	1,650	1.10	320	3.4	1	1,650	12.6	2.29
	L59	30	8,000	200	200	4,290	2,800	296	None	35	990	None	320	2.9	1	990	8.5	None
	L60	30	8,000	200	100	4,290	2,800	296	None	35	990	None	320	2.9	2	1,980	13.2	None

TABLE J-2

Economic Data - Texas Prospects
(Constant 1979 Dollars)

Prospect	Run No.	Water Rate (MB/D)	Drainage Area (Acres)	Land Inv. (M $)	Geophysics Cost (M $)	Well Cost (M $)	Facility Cost (M $)	Flow Temp. (°F)	Geothermal Inv. (M $)	Sol. Gas (Cu Ft/Bbl)	Sales Gas/Well (MCF/D)	Power Output (kWh/Bbl)	Operating Expense: Gas (M $/YR)	Operating Expense: Variable and Geothermal (¢/Bbl)	No. of Wells	Daily Rate (MCF/D)	Sales Gas (BCF)	Elect. Power (kW)
Austin Bayou	T2	50	9,000	230	200	4,630	4,500	310	5,430	40	1,900	1.3	280	3.5	1	1,900	12.4	2,171
	T4	30	9,000	230	200	4,630	3,200	310	None	40	1,140	None	280	2.9	1	1,140	9.4	None
Candelaria	T8	30	19,000	480	400	2,280	3,200	270	None	28	780	None	280	2.9	1	780	6.0	None
Clinton	T11	50	7,000	170	100	2,000	4,500	270	None	28	1,300	None	280	2.9	1	1,300	3.6	None
	T12	30	7,000	170	100	2,000	3,200	270	None	28	780	None	280	2.9	1	780	3.6	None
Eagle Lake	T15	50	6,000	150	100	2,200	4,500	270	None	30	1,400	None	280	2.9	1	1,400	2.7	None
	T16	30	6,000	150	100	2,200	3,200	270	None	30	840	None	280	2.9	1	840	2.7	None

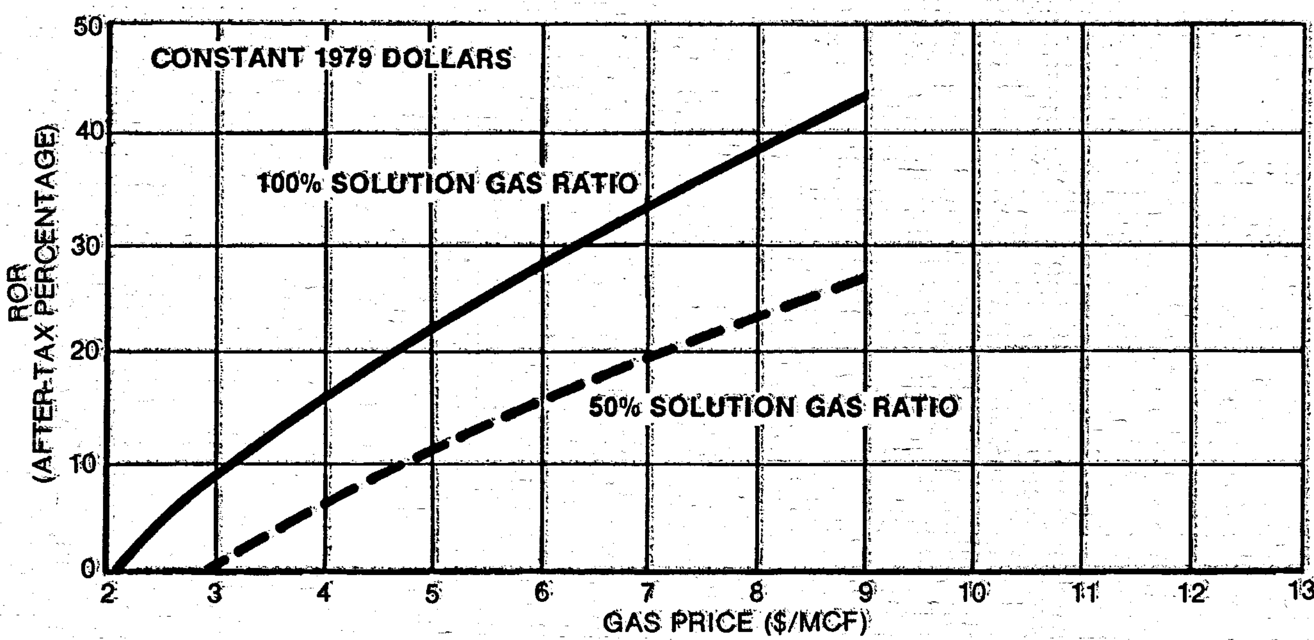

Figure J-1. Austin Bayou Run T2.

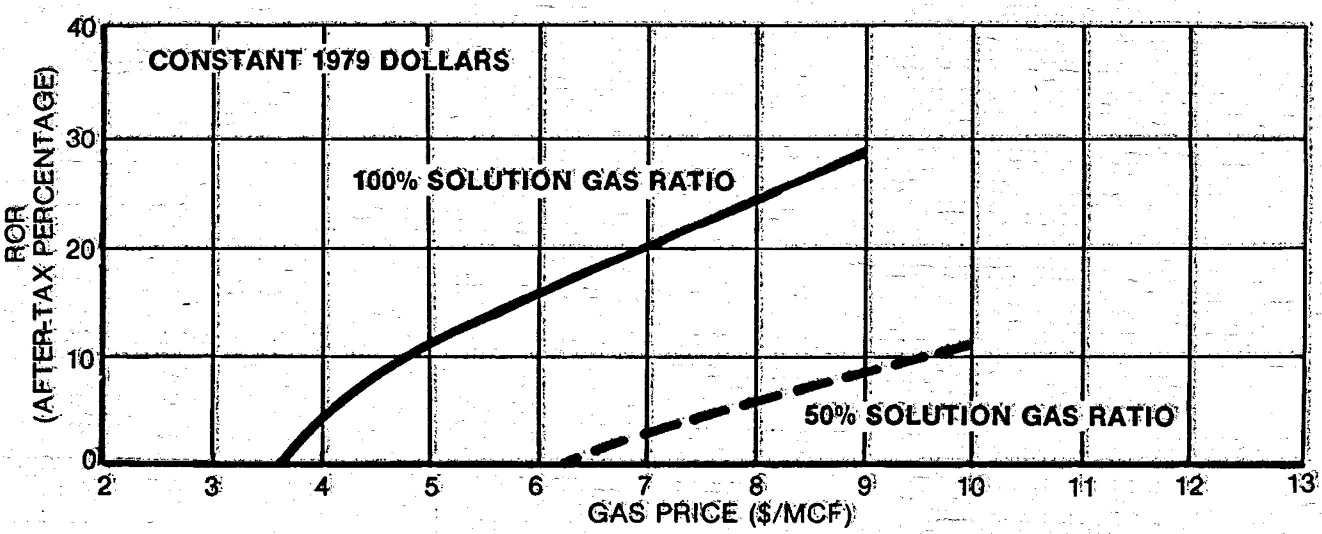

Figure J-2. Austin Bayou Run T4.

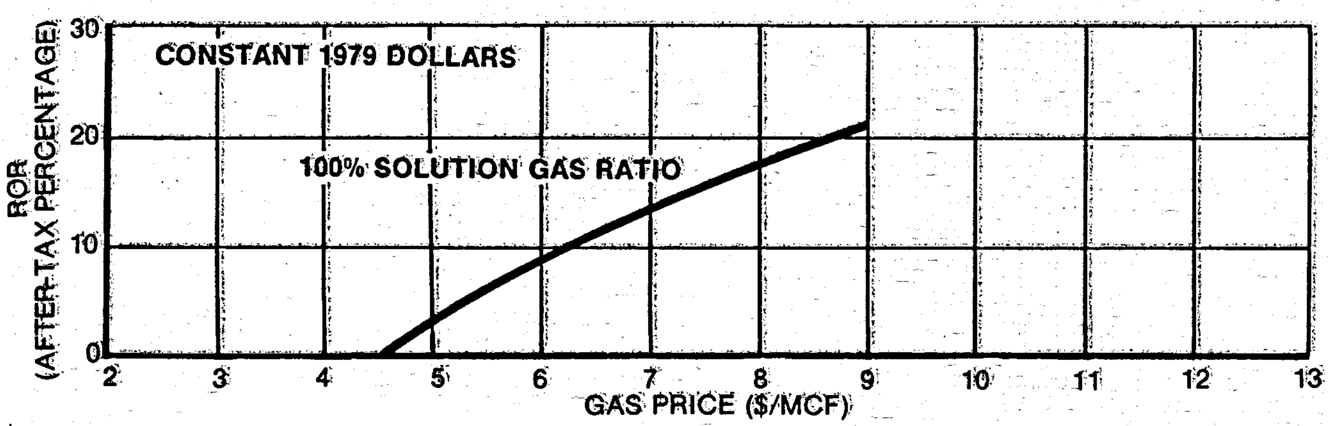

Figure J-3. Candelaria Run T8.

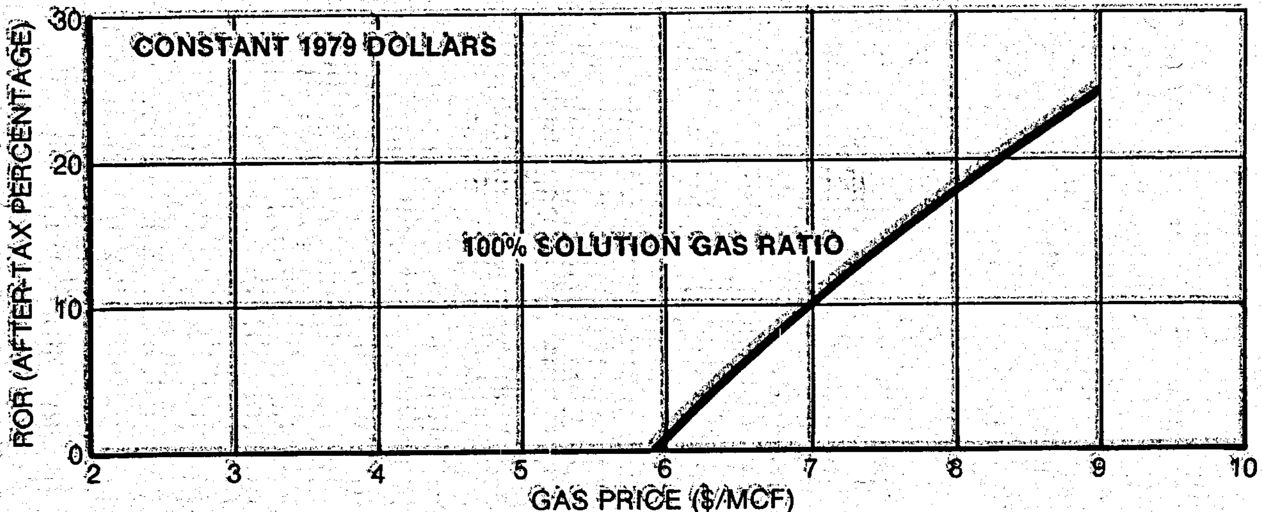

Figure J-4. Clinton Run T11.

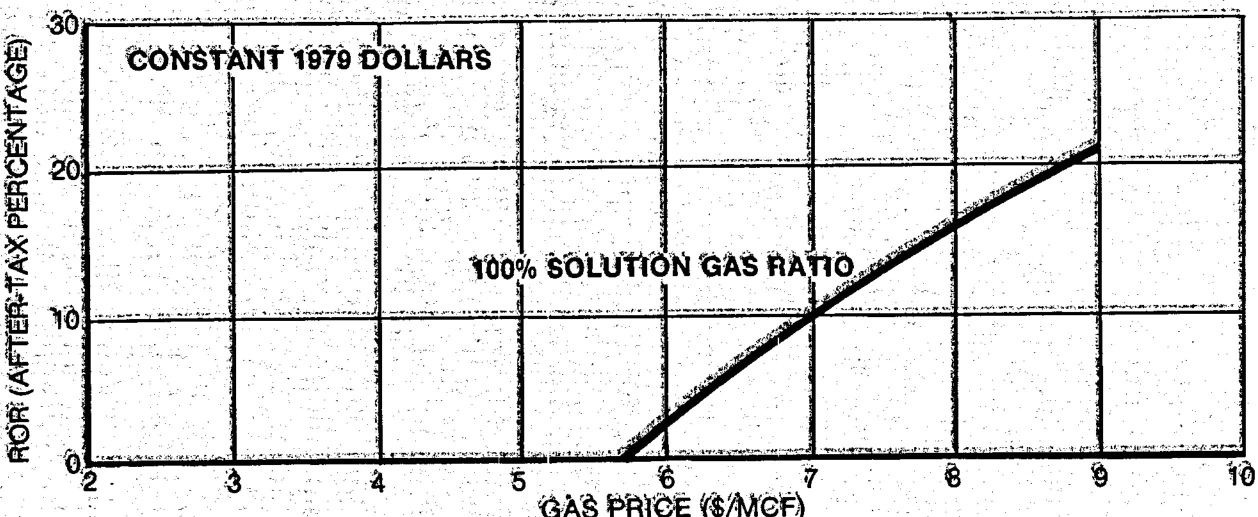

Figure J-5. Clinton Run T12.

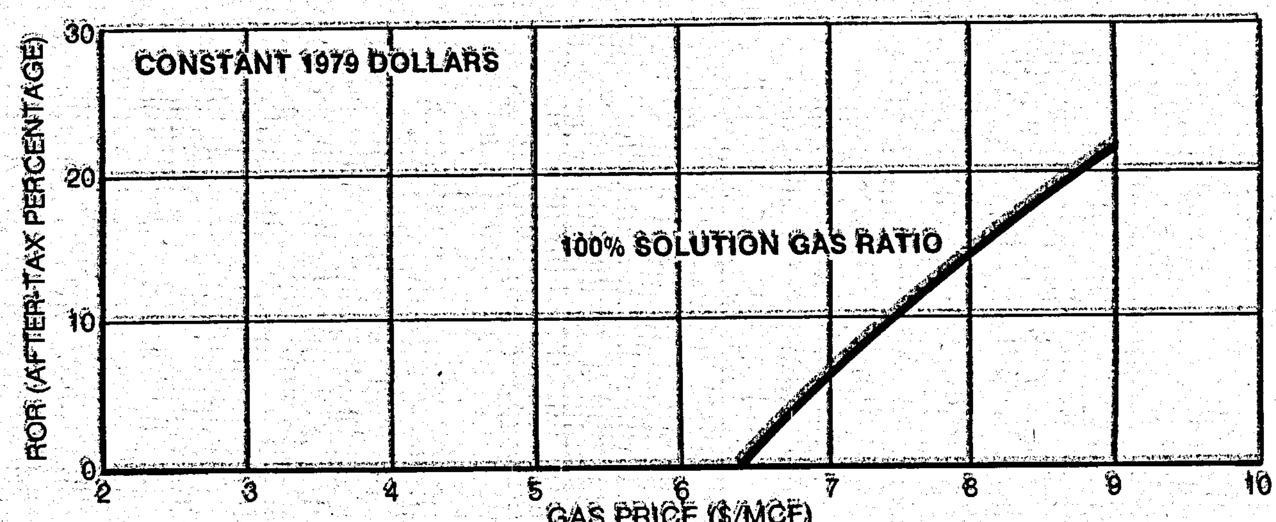

Figure J-6. Eagle Lake Run T15.

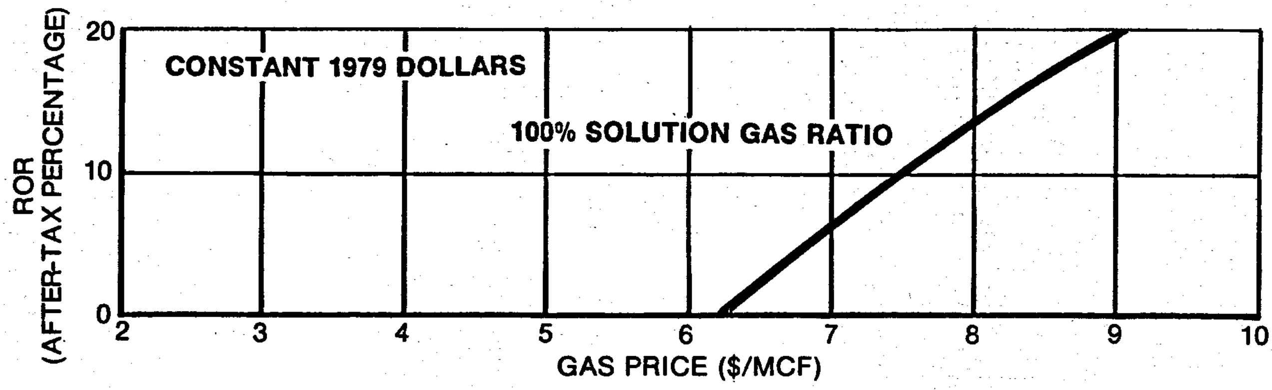

Figure J-7. Eagle Lake Run T16.

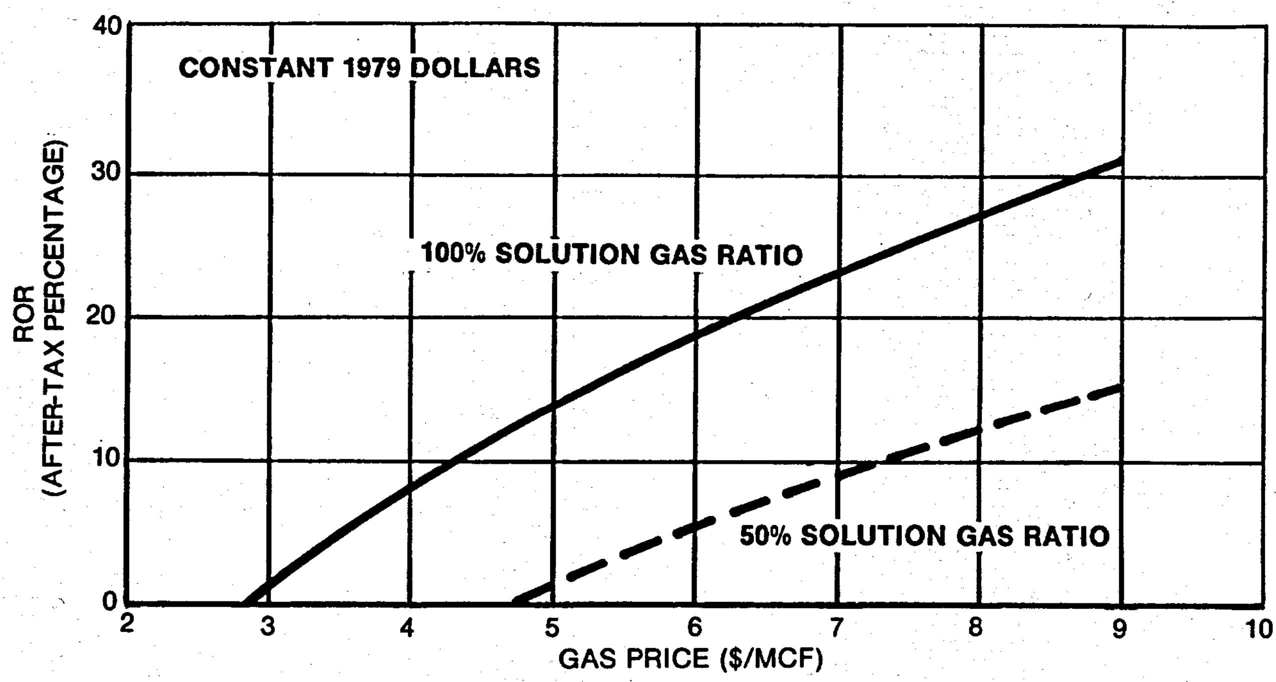

Figure J-8. Atchafalaya Bay East Run L2.

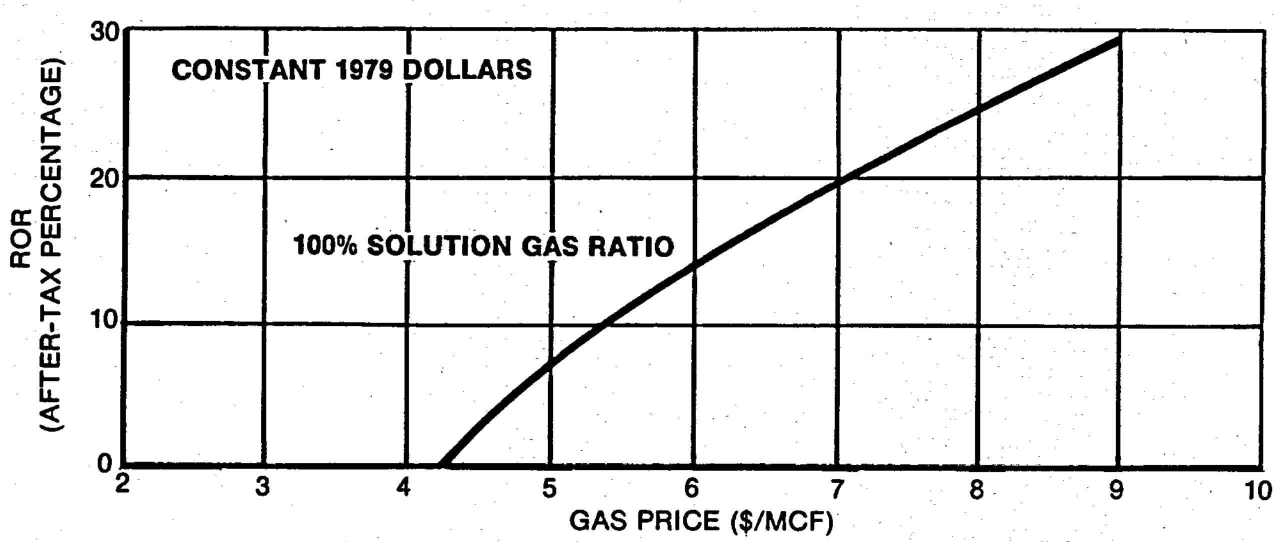

Figure J-9. Atchafalaya Bay East Run L3.

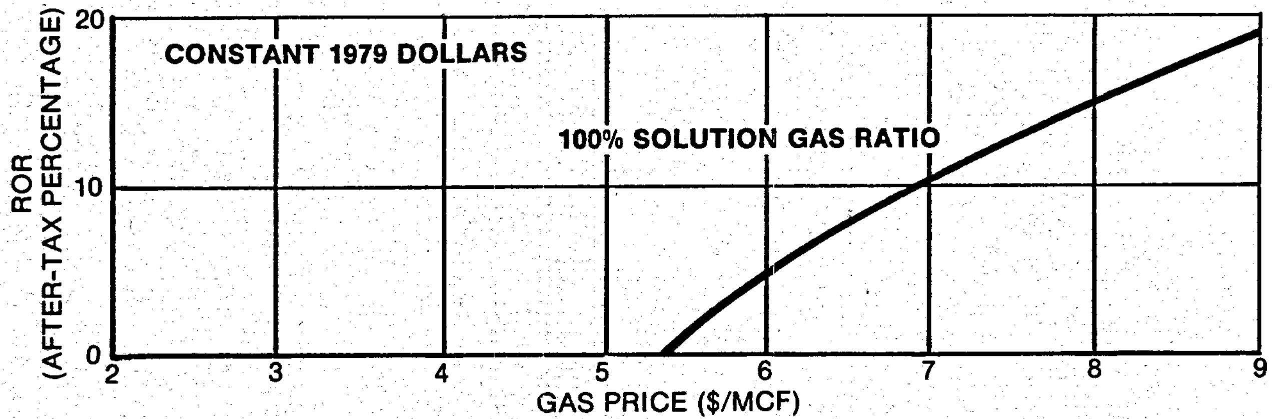

Figure J-10. Atchafalaya Bay East Run L6.

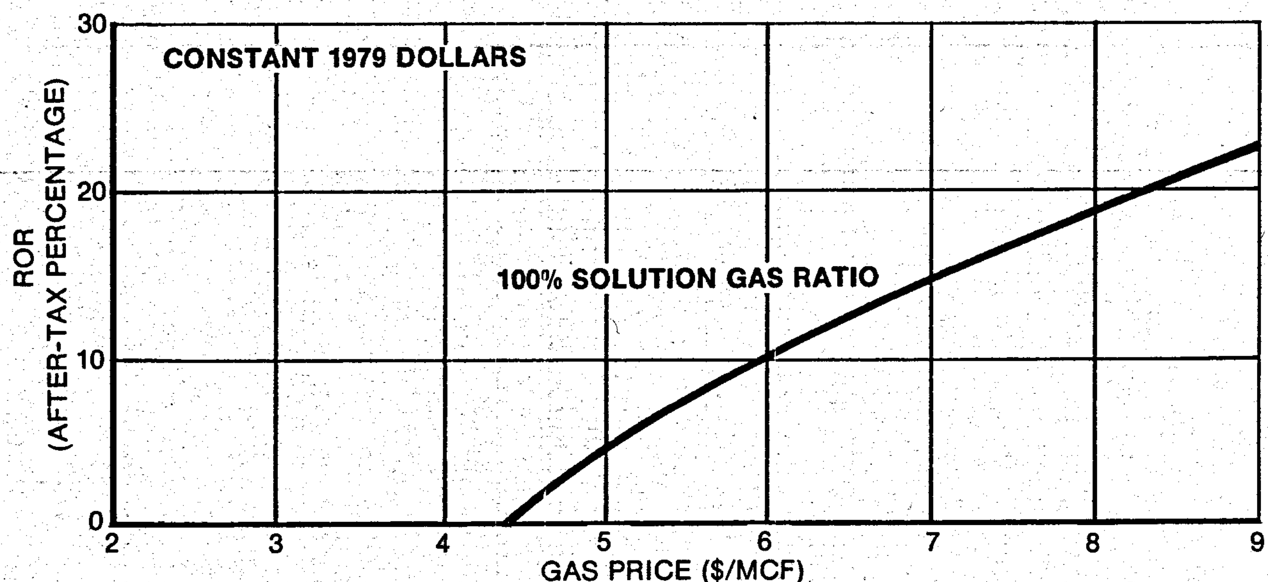

Figure J-11. Atchafalaya Bay West Run L11.

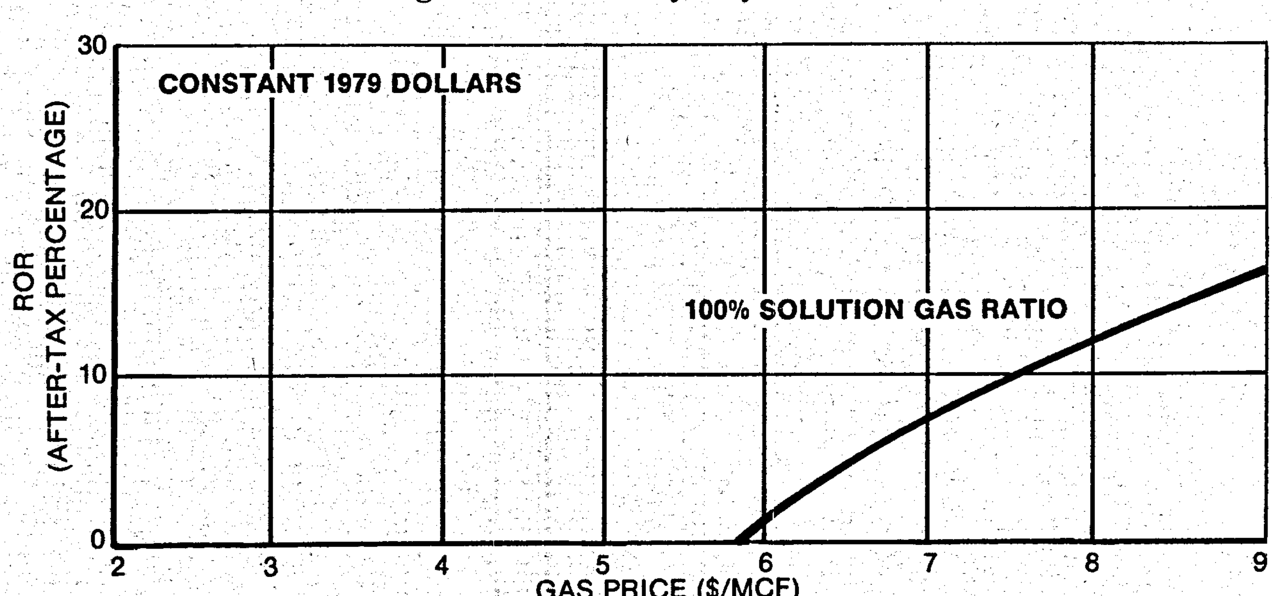

Figure J-12. Atchafalaya Bay West Run L12.

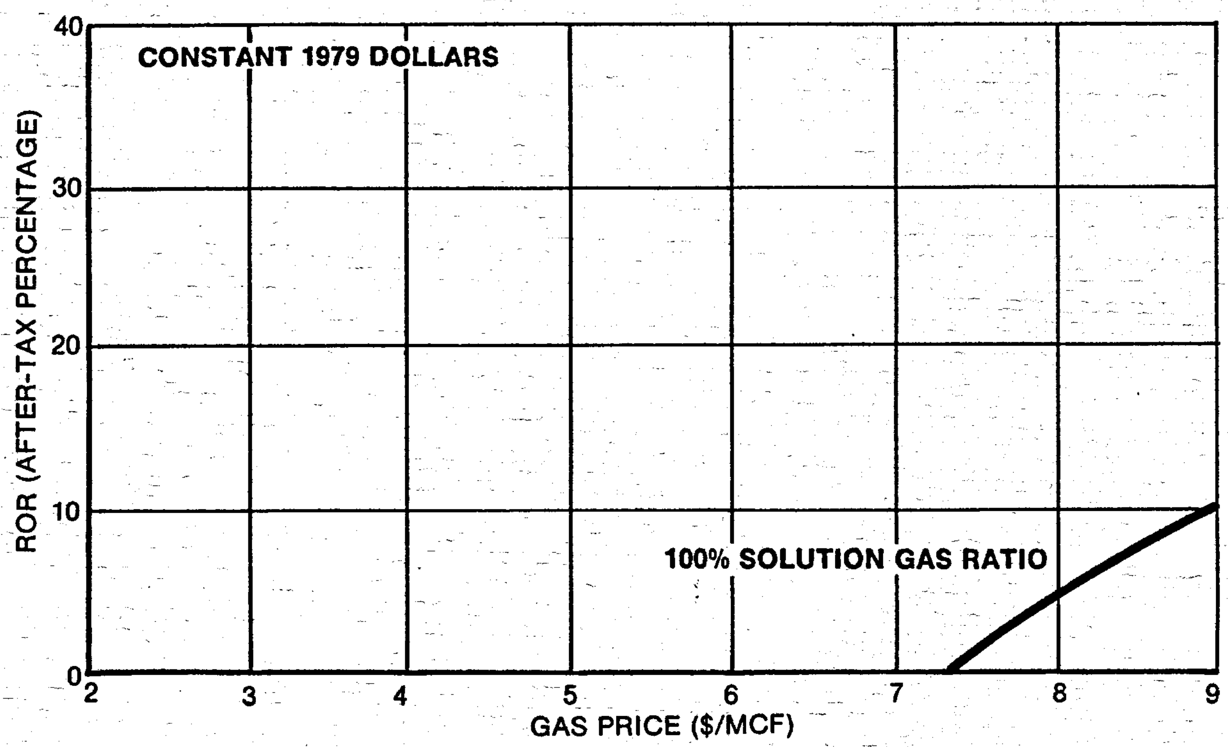

Figure J-13. Atchafalaya Bay West Run L15.

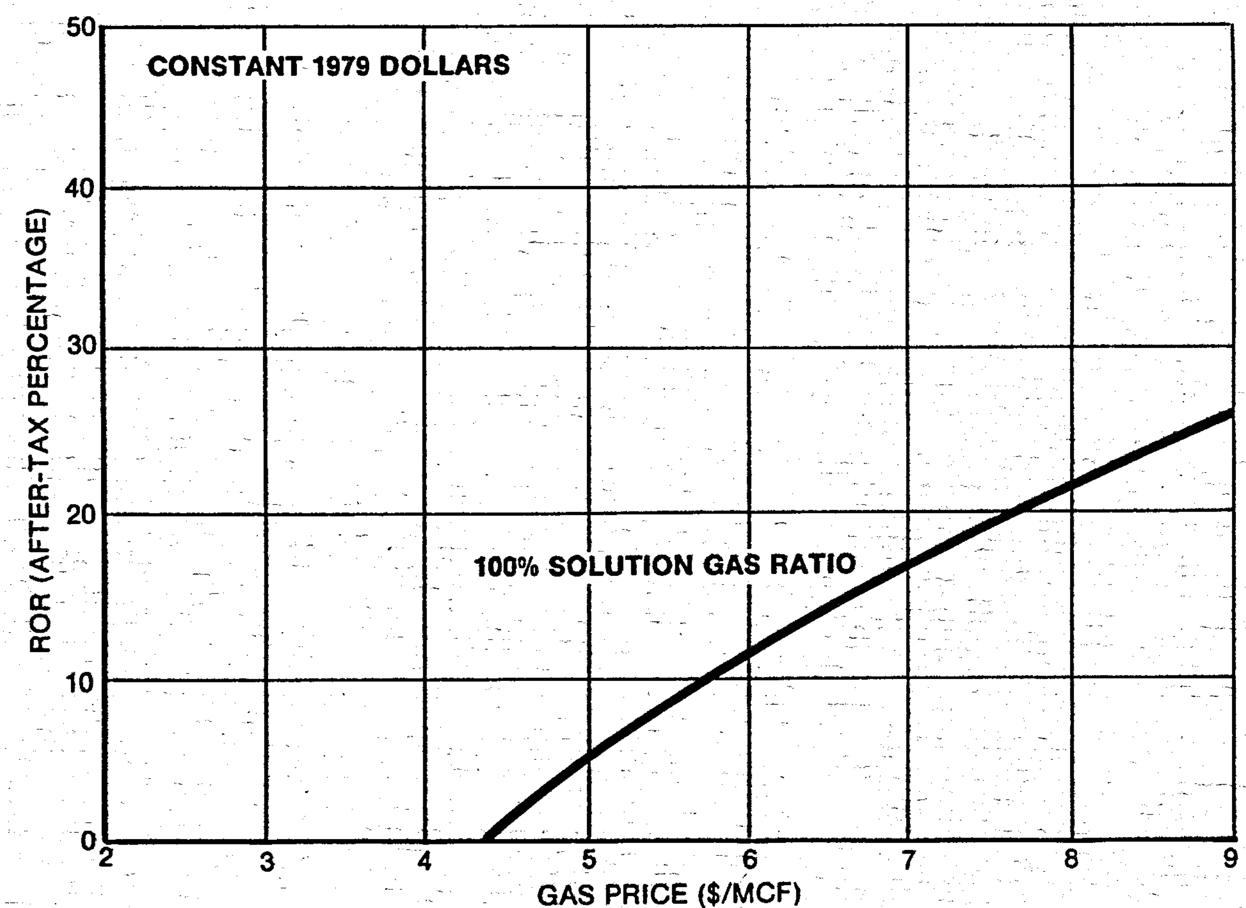

Figure J-14. Johnson's Bayou Run L18.

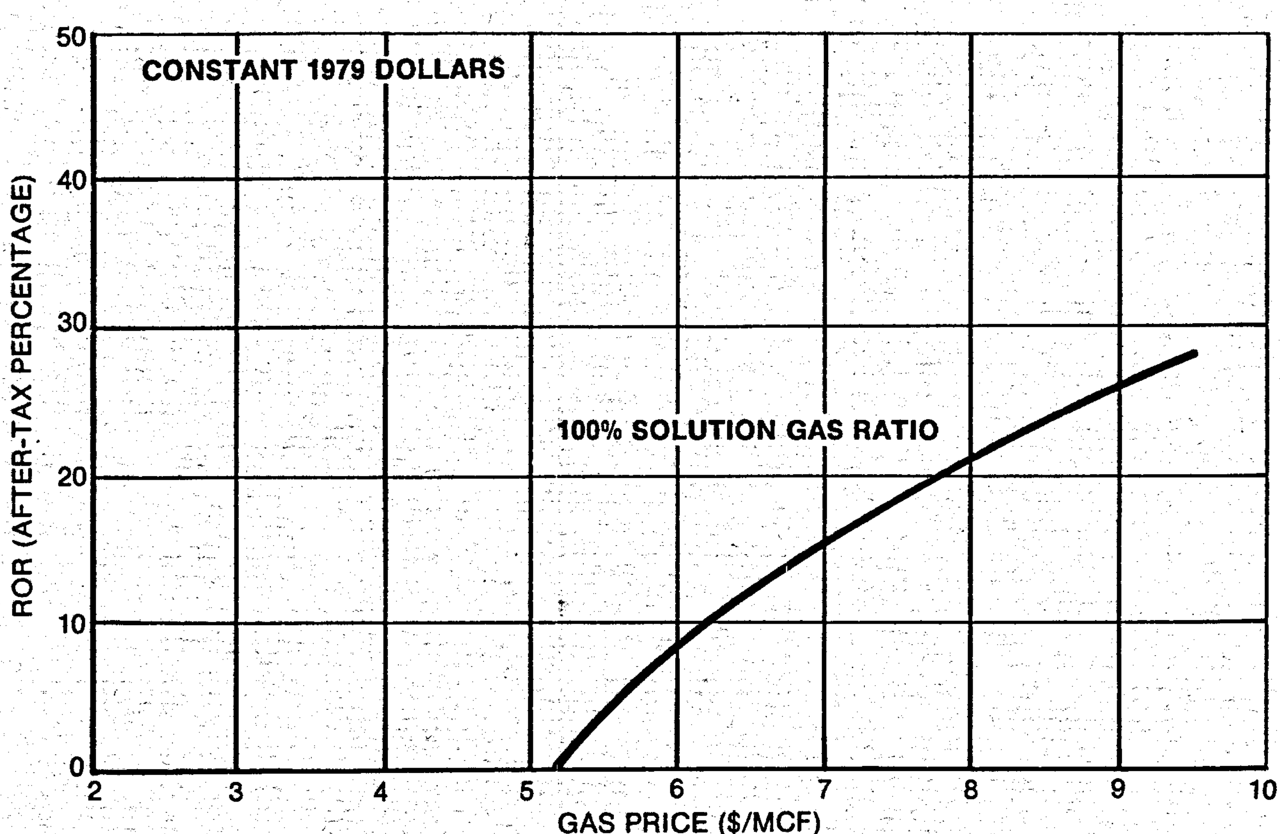

Figure J-15. Johnson's Bayou Run L19.

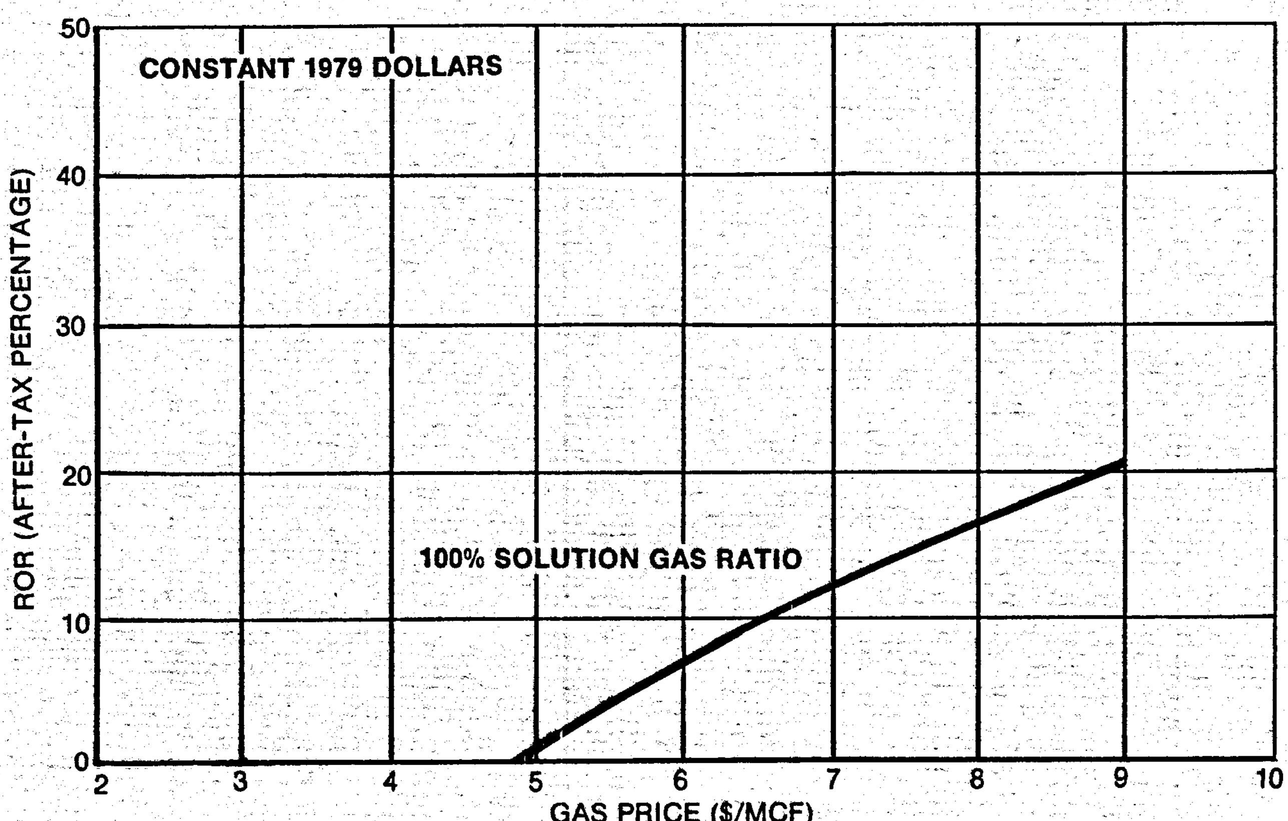

Figure J-16. Johnson's Bayou Run L22.

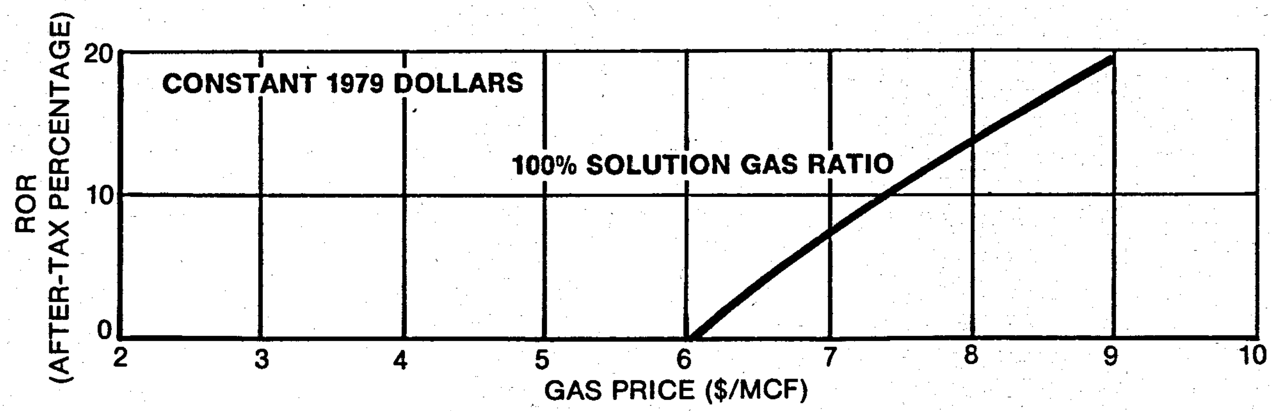

Figure J-17. Johnson's Bayou Run L24.

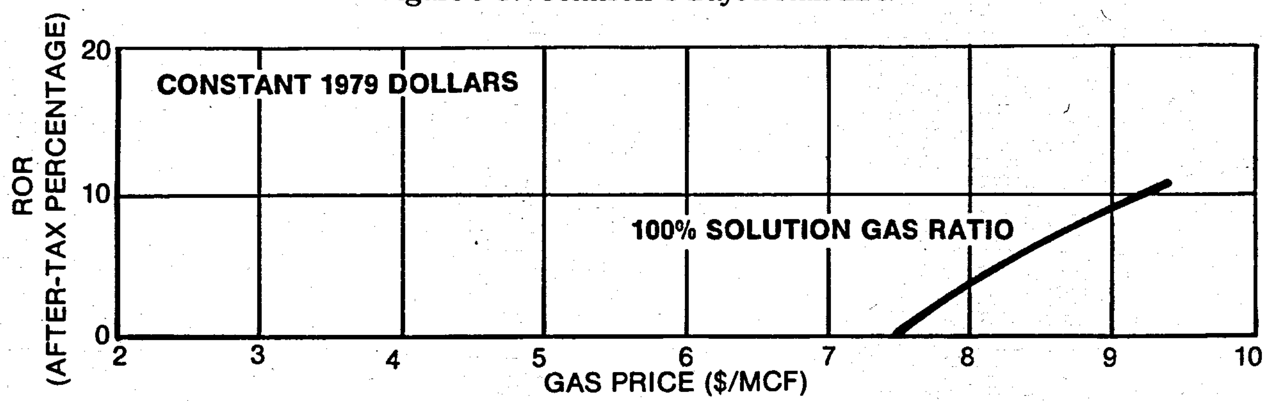

Figure J-18. Johnson's Bayou Run L28.

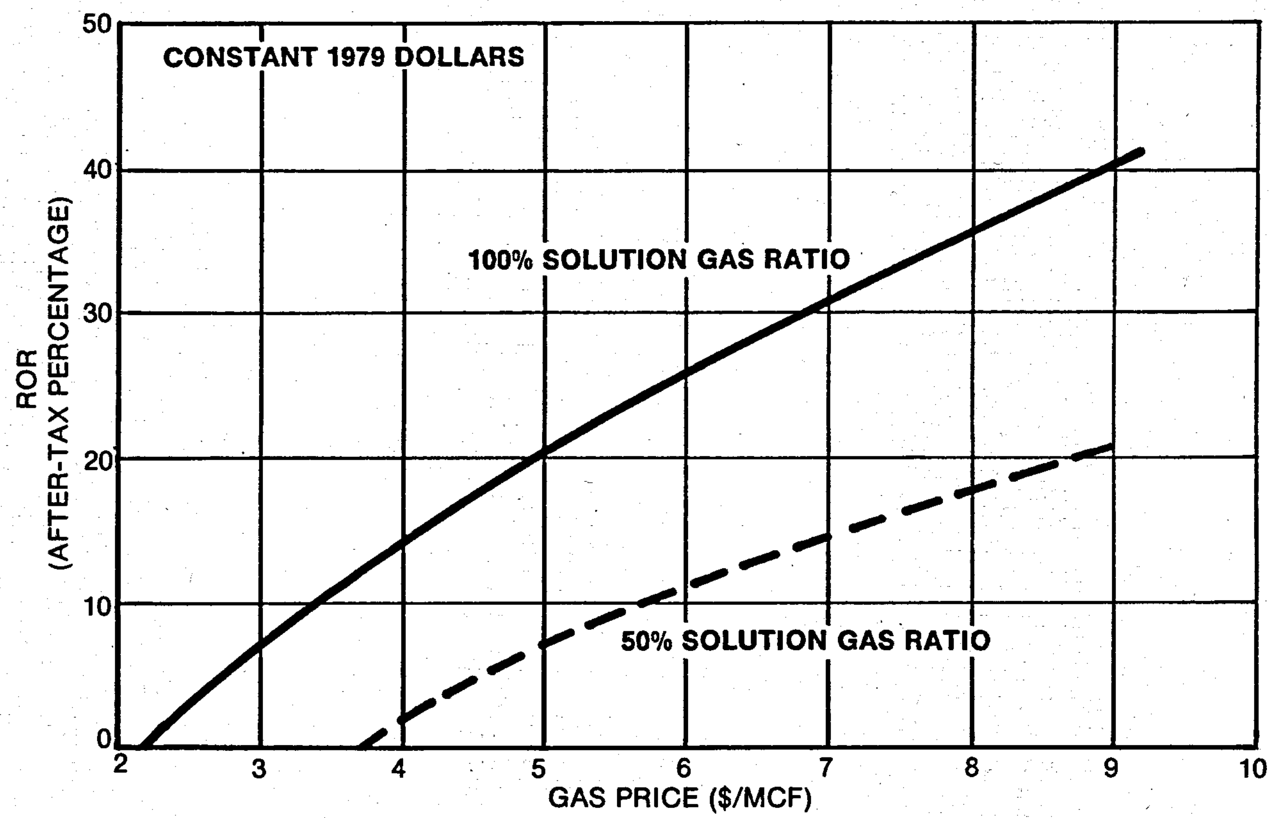

Figure J-19. LaFourche Crossing Run L34.

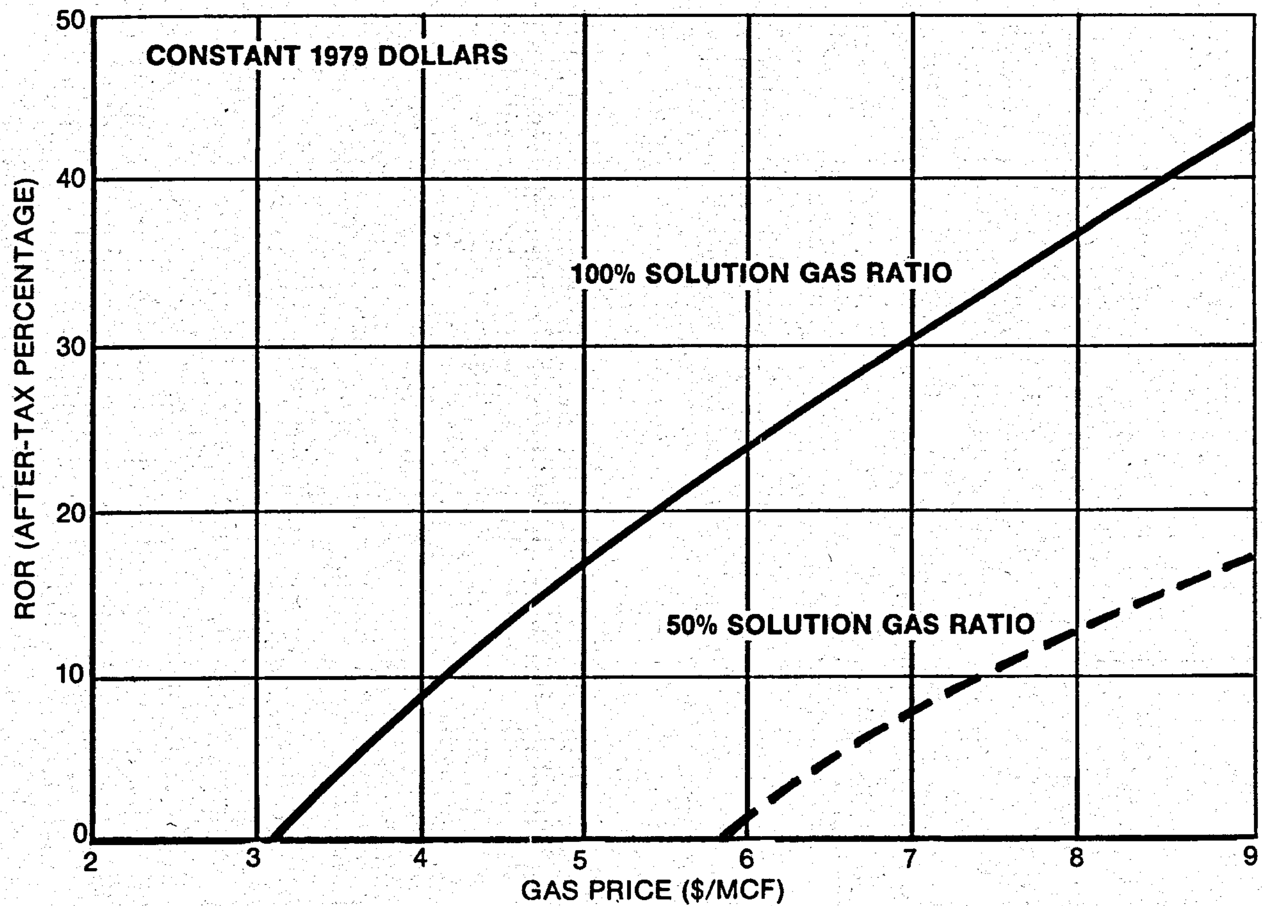

Figure J-20. LaFourche Crossing Run L35.

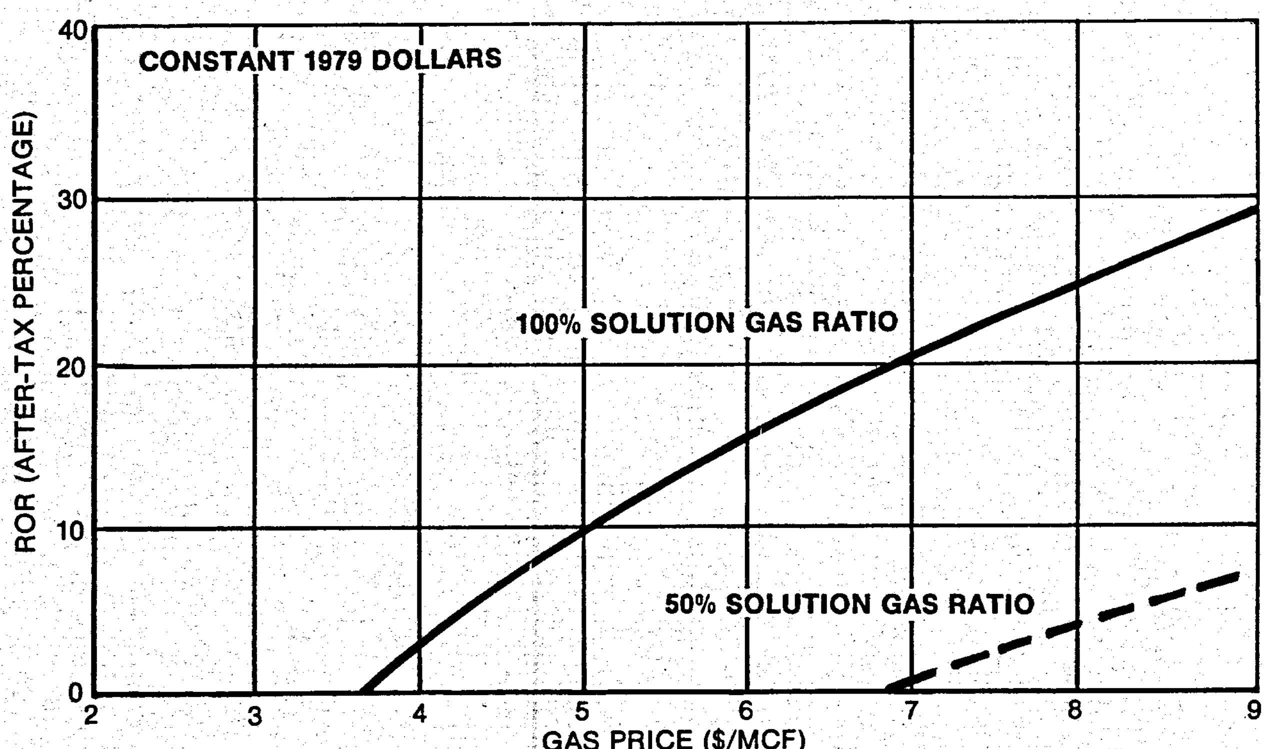

Figure J-21. LaFourche Crossing Run L37.

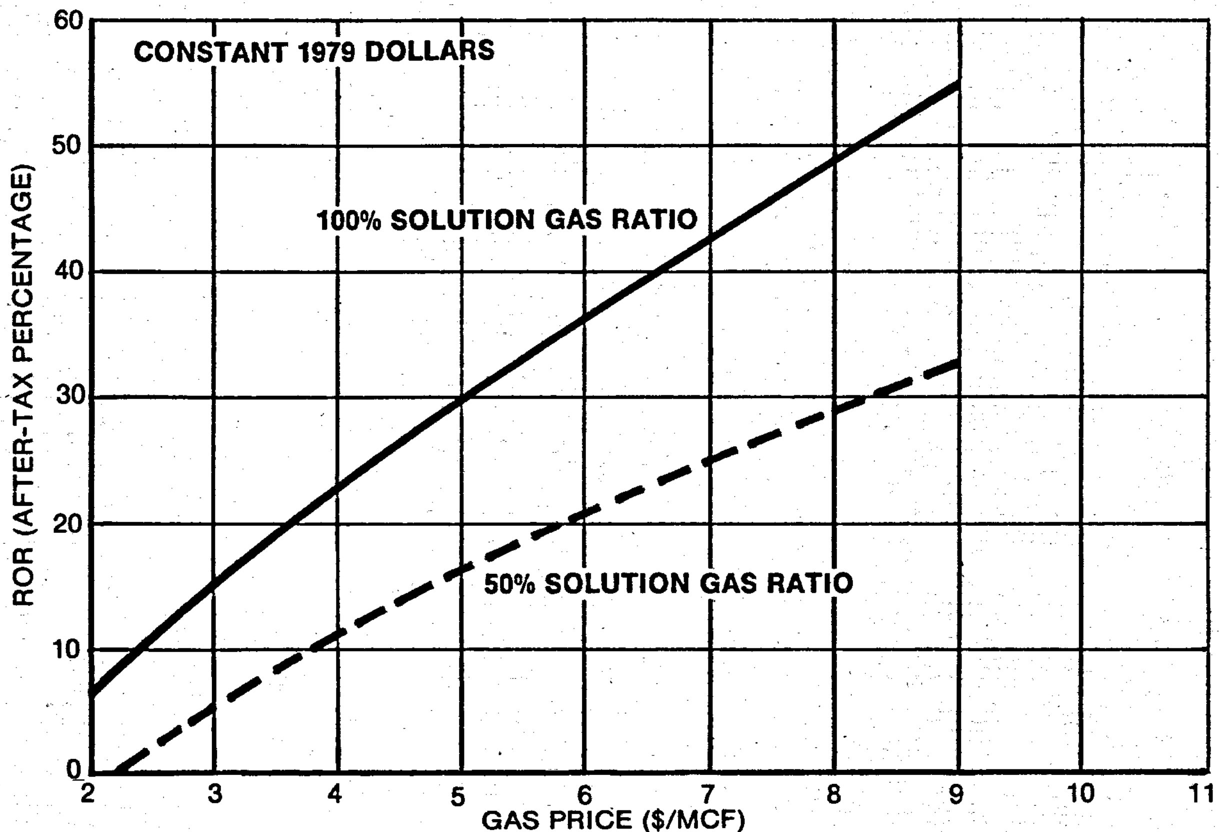

Figure J-22. Rockefeller Refuge Run L44.

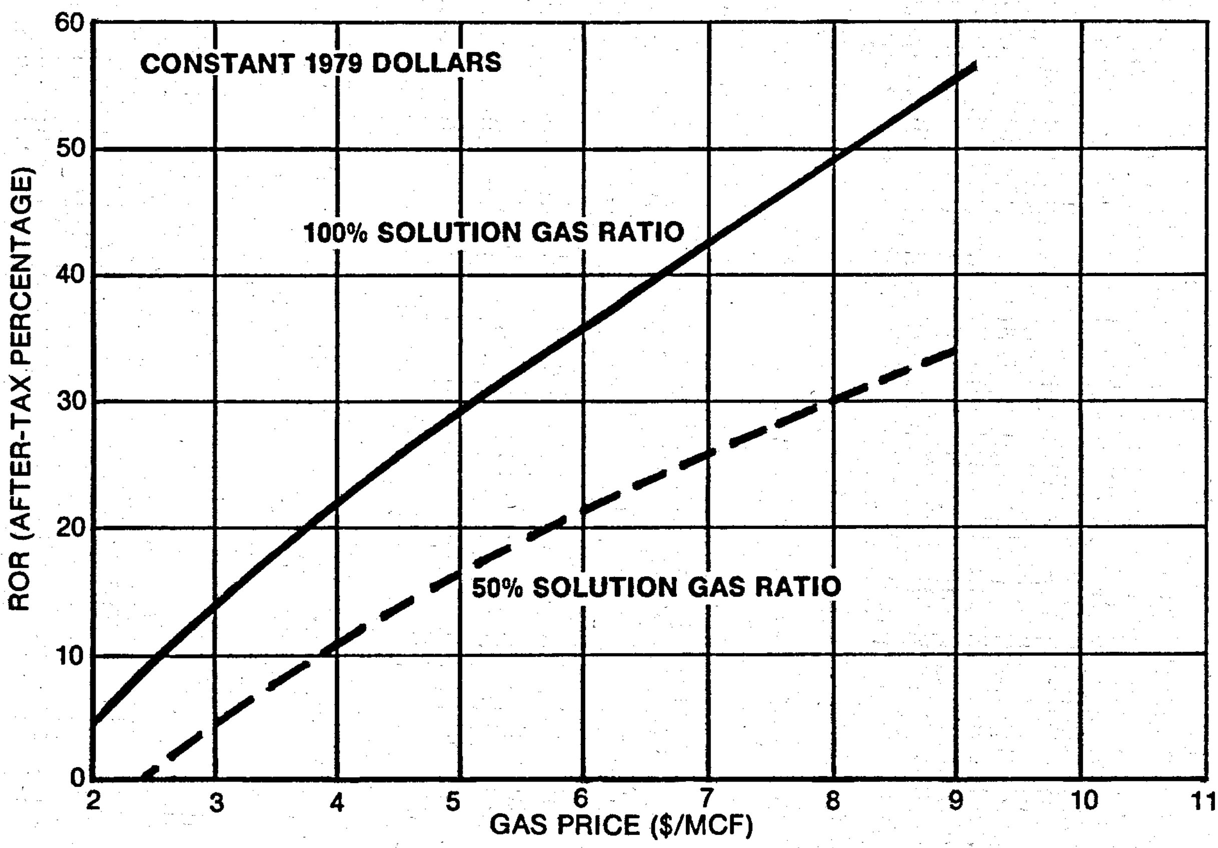

Figure J-23. Rockefeller Refuge Run L45.

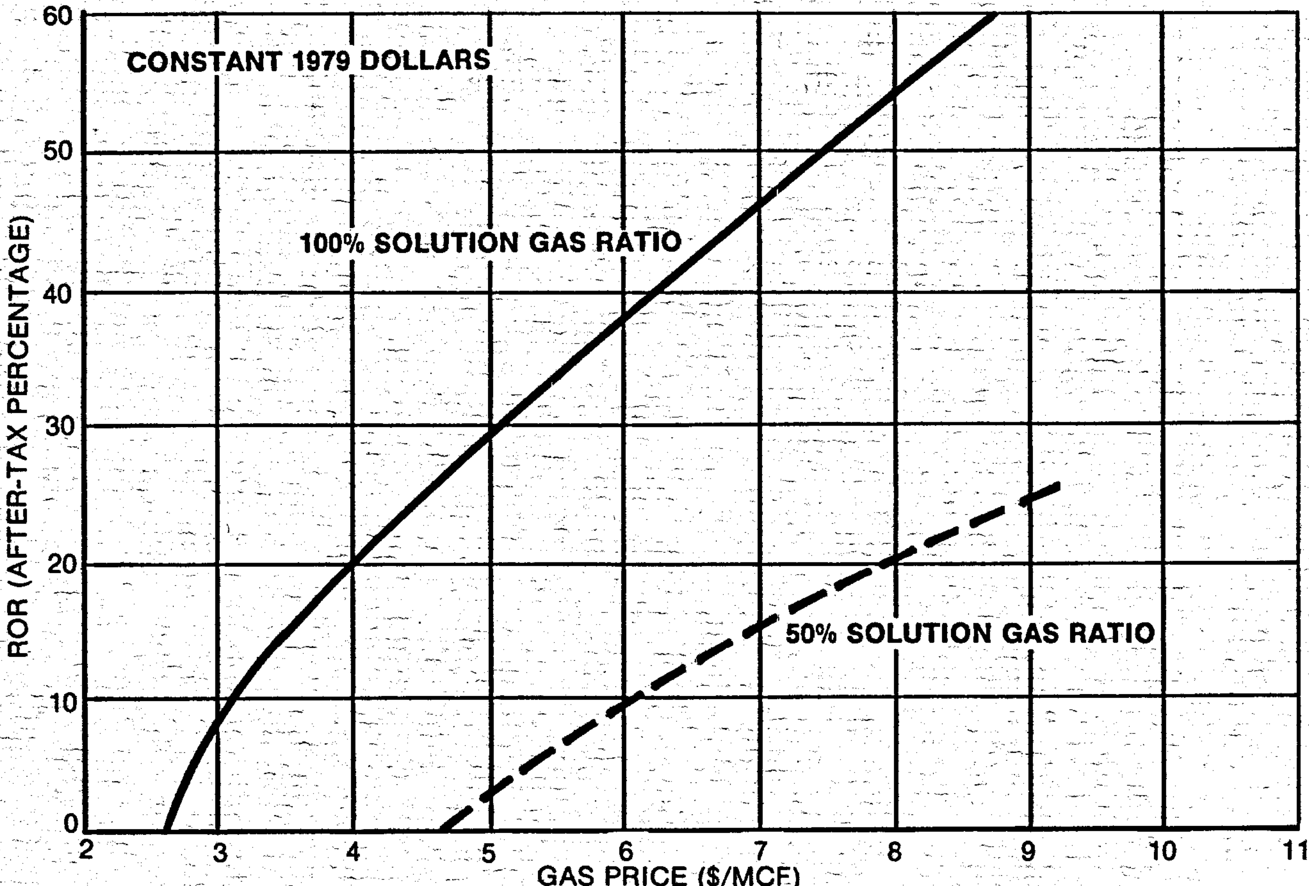

Figure J-24. Rockefeller Refuge Run L46.

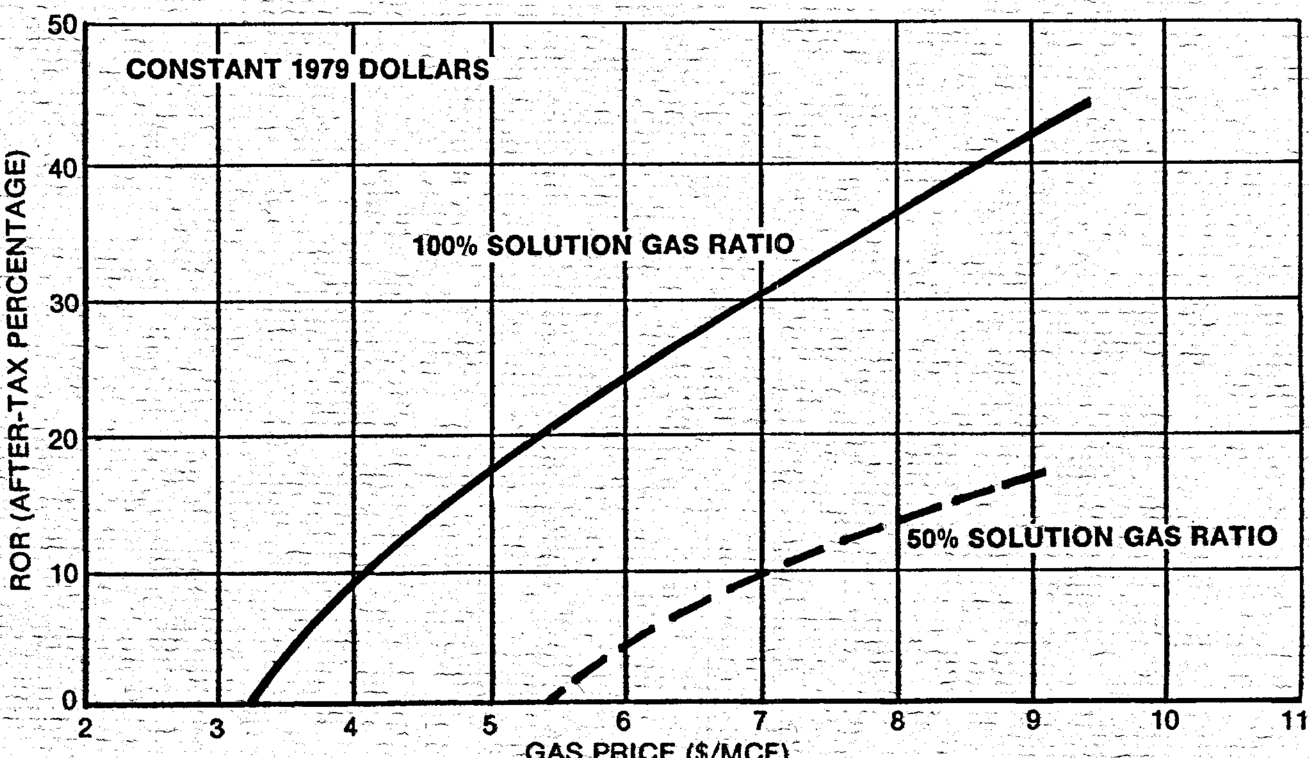

Figure J-25. Rockefeller Refuge Run L49.

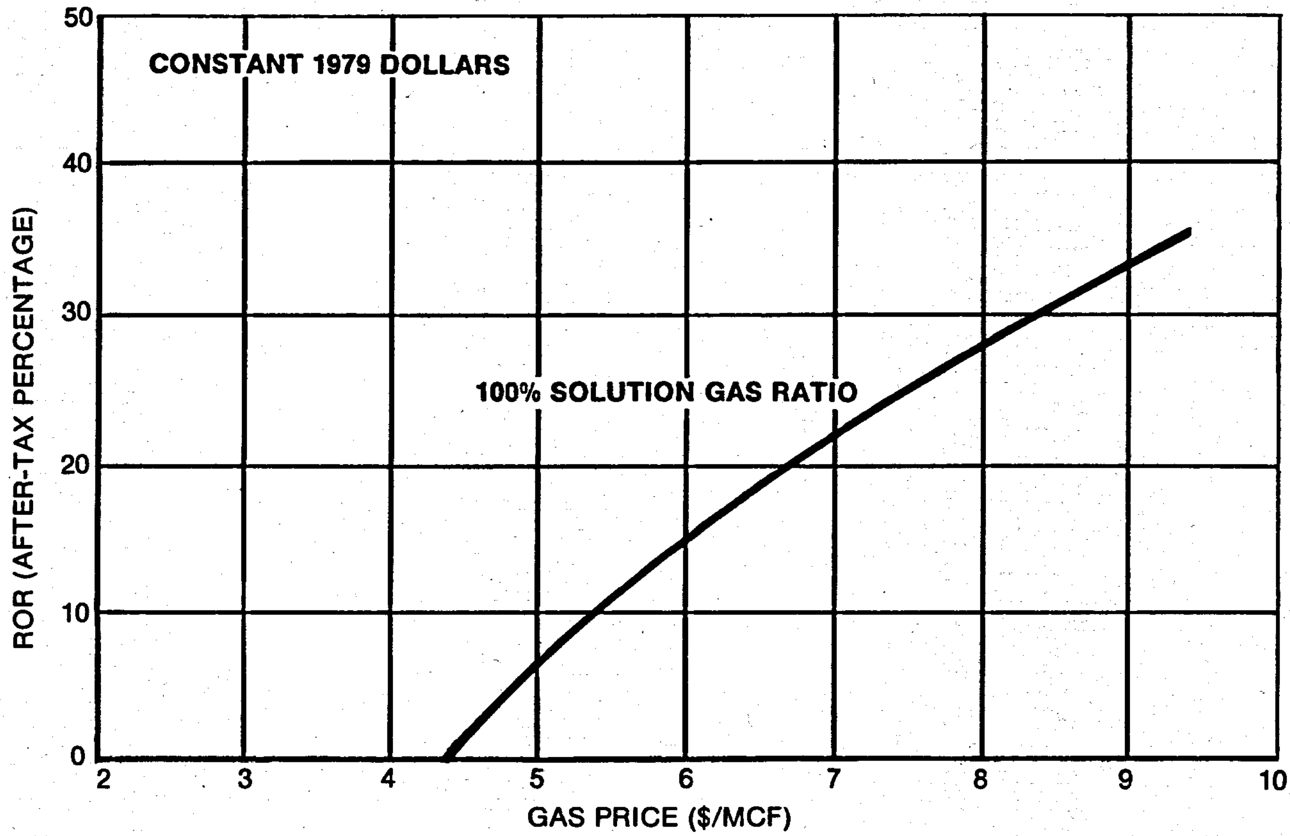

Figure J-26. SE Pecan Island East Run L53.

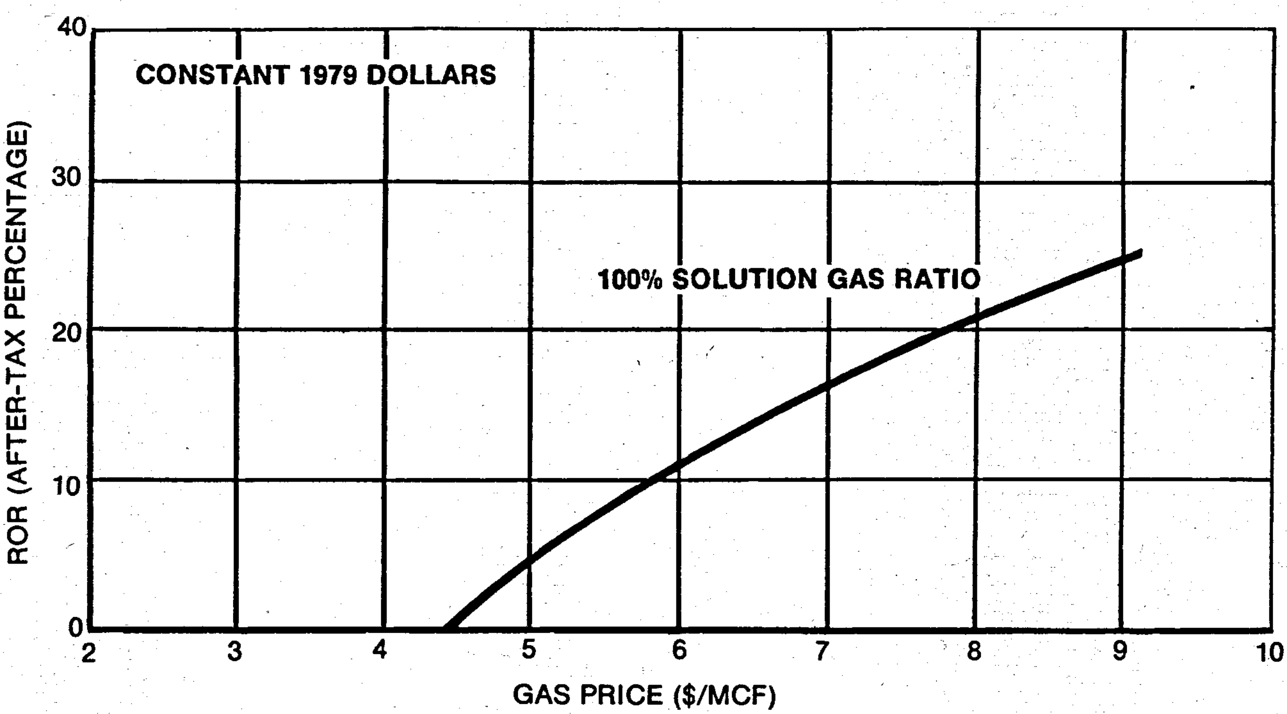

Figure J-27. SE Pecan Island East Run L54.

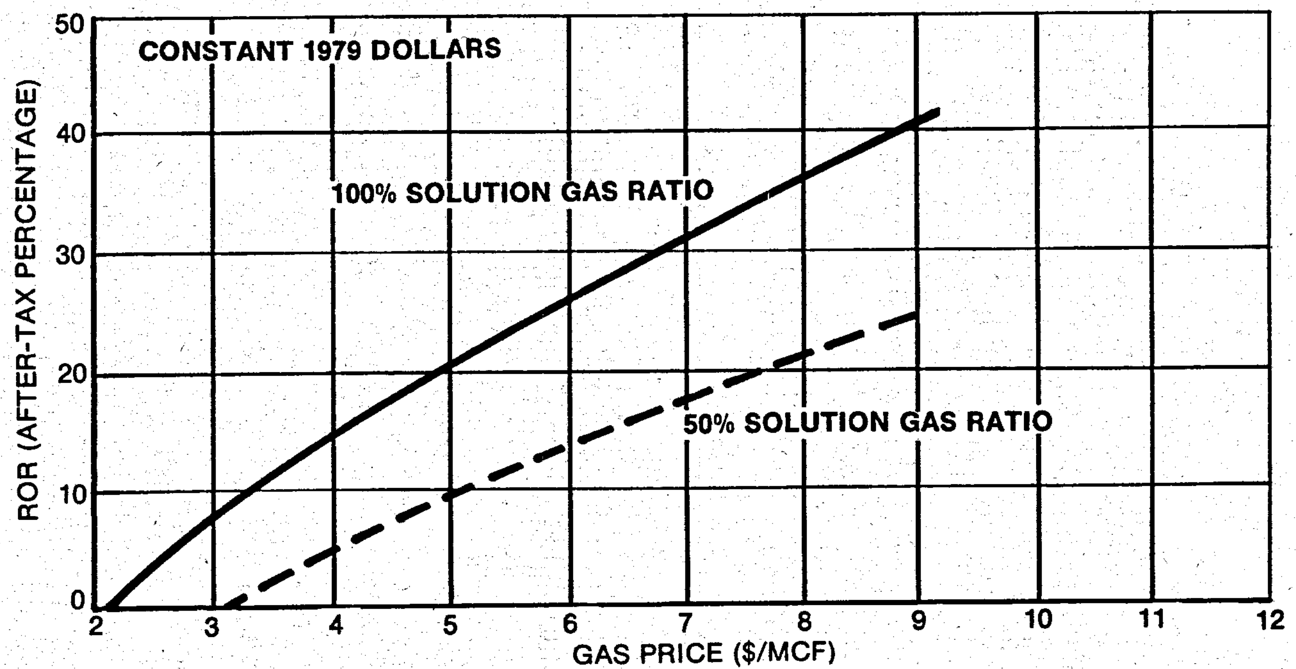

Figure J-28. SE Pecan Island West Run L57.

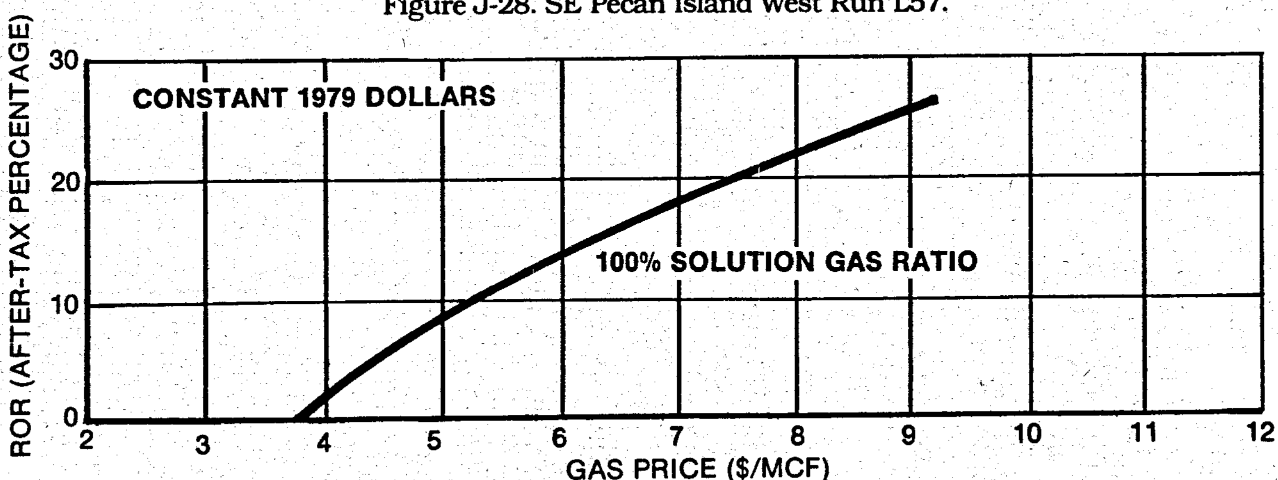

Figure J-29. SE Pecan Island West Run L59.

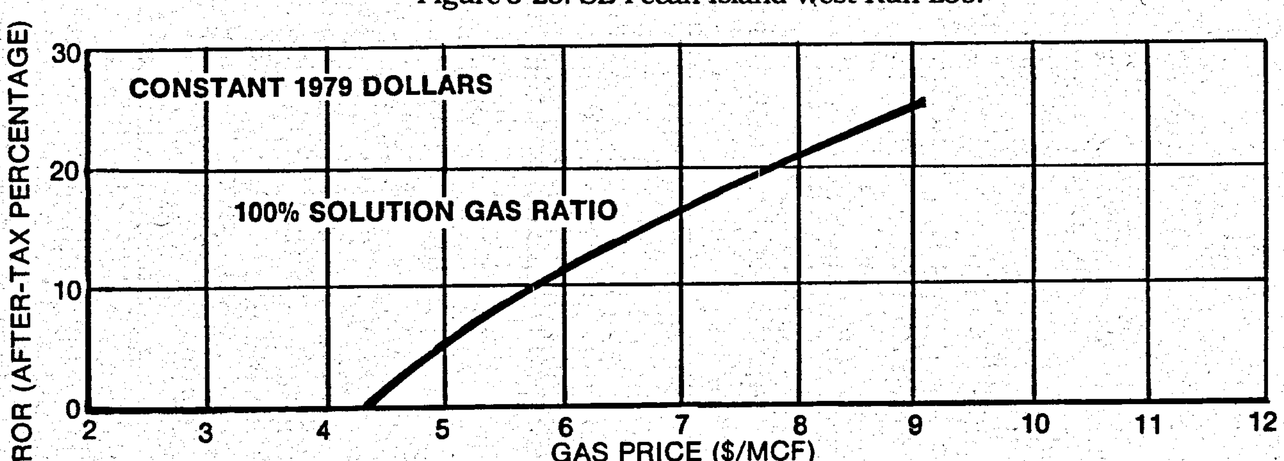

Figure J-30. SE Pecan Island West Run L60.

TABLE J-3

Eleven Identified Prospects -- Rate of Return vs. Gas Price
(10 Percent Rate of Return)
(Constant 1979 Dollars)

Most Optimistic Case (Maximum Rate 50,000 B/D; Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
2.50	2	4.9	42	5.8
3.00	4	9.8	70	11.5
4.00	9	20.0	122	17.8
5.00	11	23.1	136	19.1
6.00	14	27.1	158	19.1
7.00	16	30.2	178	19.1
8.00	25	38.9	218	19.1
9.00	25	38.9	218	19.1

Upper Median Case (Maximum Rate 30,000 B/D; Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
4.00	None	None	None	None
5.00	13	18	111	None
6.00	16	21	131	None
7.00	20	24	152	None
8.00	22	26	158	None
9.00	27	29	173	None

Lower Median Case (Maximum Rate 50,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
3.00	None	None	None	None
4.00	4	5.0	39	11.5
5.00	6	6.0	53	13.8
6.00	9	10.0	69	16.5
7.00	9	--	--	17.8
8.00	11	11.8	77	19.1
9.00	11	11.8	77	19.1

Minimum Case (Maximum Rate 30,000 B/D; 50 Percent Solution Ratio From Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
8.00	10	7.3	45	--
9.00	10	7.3	45	--
10.00	11	7.9	50	--

TABLE J-4

Eleven Identified Prospects -- Rate of Return vs. Gas Price
(15 Percent Rate of Return)
(Constant 1979 Dollars)

Most Optimistic Case (Maximum Rate 50,000 B/D; Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
3.00	None	None	None	None
4.00	5	11.7	82	13.8
5.00	10	22.1	126	17.4
6.00	11	23.4	136	19.1
7.00	13	26.4	149	19.1
8.00	17	30.5	178	19.1
9.00	25	38.4	212	19.1

Upper Median Case (Maximum Rate 30,000 B/D; Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
5.00	10	14.7	85	--
6.00	13	18.0	112	--
7.00	16	21.0	131.2	--
8.00	21	24.3	142.0	--
9.00	23	25.9	148.3	--

Lower Median Case (Maximum Rate 50,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
5.00	4	4.9	39	11.5
6.00	5	5.7	46	14.2
7.00	8	8.9	61	16.5
8.00	9	9.8	69	17.8
9.00	11	11.6	77	19.1

Minimum Case (Maximum Rate 30,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
9.00	10	7.3	49	--

TABLE J-5

Eleven Identified Prospects -- Rate of Return vs. Gas Price
(20 Percent Rate of Return)
(Constant 1979 Dollars)

Most Optimistic Case (Maximum Rate 50,000 B/D; Solution Ratio from Tables J-1 and J-2)

Gas Price ($/MCF)	No. Wells	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)
4.00	4	9.8	70	11.5
5.00	8	18.2	107	16.5
6.00	10	22.1	126	16.5
7.00	11	23.1	131	19.1
8.00	12	24.5	137	19.1
9.00	14	26.8	150	19.1

Upper Median Case (Maximum Rate 30,000 B/D; Solution Ratio from Tables J-1 and J-2)

6.00	10	14.7	85	--
7.00	13	18.0	112	--
8.00	16	21.0	131	--
9.00	17	21.8	137	--

Lower Median Case (Maximum Rate 50,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

6.00	4	4.9	39	11.5
7.00	5	5.7	46	14.2
8.00	8	8.9	61	16.5
9.00	9	9.8	69	17.8

Minimum Case (Maximum Rate 30,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

9.00	None	None	None	None

TABLE J-6

Eleven Identified Prospects -- Rate of Return vs. Gas Price
(Constant 1979 Dollars)

Most Optimistic Case
(Maximum Rate 50,000 B/D; Solution Ratio from Tables J-1 and J-2)

Run No.	Prospect	Gas Price ($/MCF) 10% ROR	15% ROR	20% ROR	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)	No. Wells	Orig. GIP (BCF)	Recovery (%)
L44	Rockefeller Refuge	2.50	3.10	3.70	4.9	42	5.8	2		
L45	Rockefeller Refuge	2.60	3.10	3.70	9.8	70	11.5	4		
L46	Rockefeller Refuge	3.20	3.60	4.10	14.7	82	None	6	1,890	4.3
L34	LaFourche Crossing	3.50	4.30	5.20	1.8	15	1.3	1		
L35	LaFourche Crossing	4.30	4.90	5.60	3.6	19	None	2	536	3.5
L57	SE Pecan Island West	3.40	4.10	5.00	1.6	13	2.3	1	411	3.1
L2	Atchafalaya Bay East	4.40	5.40	6.50	1.3	10	1.3	1		
L3	Atchafalaya Bay East	5.50	6.40	7.20	2.7	16	None	2	634	2.5
L53	SE Pecan Island East	5.40	6.30	6.90	1.6	7	None	1	182	3.8
L11	Atchafalaya Bay West	6.00	7.20	8.40	1.0	9	None	1		
L12	Atchafalaya Bay West	7.50	8.60	--	2.1	12	None	2	586	2.0
L22	Johnson's Bayou	6.70	7.90	--	1.8	16	None	2		
L24	Johnson's Bayou	7.40	8.20	--	7.2	44	None	8	1,814	2.4
T2	Austin Bayou	3.20	3.90	4.70	1.9	12	2.7	1	391	3.0
T11	Clinton	7.00	7.70	8.40	1.3	4	--	1	171	2.3
T15	Eagle Lake	7.90	8.60	--	1.4	3	--	1	106	2.8
T8	Candelaria	6.40	7.40	9.00	0.8	6	--	1	420	1.4
					38.9	218	19.1	26	7,141	3.05

TABLE J-6 (continued)

Upper Median Case
(Maximum Rate 30,000 B/D; Solution Ratio from Tables J-1 and J-2)

Run No.	Prospect	Gas Price ($/MCF) 10% ROR	15% ROR	20% ROR	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)	No. Wells	Orig. GIP (BCF)	Recovery (%)
L49	Rockefeller Refuge	4.10	4.70	5.40	14.7	85	--	10	1,890	4.5
L37	LaFourche Crossing	5.00	6.00	7.00	2.2	17.2	--	2	536	3.2
L54	SE Pecan Island East	5.90	6.80	8.00	1.0	6.4	--	1	182	3.5
L60	SE Pecan Island West	5.90	6.90	8.00	2.0	13.2	--	2	411	3.2
T4	Austin Bayou	4.90	6.00	7.00	1.1	9.4	--	1	391	2.3
T8	Candelaria	6.40	7.60	9.00	0.8	6.0	--	1	420	1.4
L6	Atchafalaya Bay East	7.00	8.00	--	3.2	14.8	--	4	634	2.3
T12	Clinton	7.10	8.10	--	0.8	3.6	--	1	171	2.1
T16	Eagle Lake	7.50	8.50	--	0.8	2.7	--	1	106	2.5
L15	Atchafalaya Bay West	9.00	--	--	2.5	14.8	--	4	586	2.5
					29.1	173.1		27	5,327	3.2

TABLE J-6 (continued)

Lower Median Case
(Maximum Rate 50,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

Run No.	Prospect	Gas Price ($/MCF) 10% ROR	15% ROR	20% ROR	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)	No. Wells	Orig.* GIP (BCF)	Recovery (%)
L44	Rockefeller Refuge	3.80	4.80	5.90	2.5	22	5.8	2	--	--
L45	Rockefeller Refuge	3.80	4.80	5.80	4.9	39	11.5	4	--	--
L46	Rockefeller Refuge	6.00	7.00	8.00	7.3	47	--	6	945	4.9
L34	LaFourche Crossing	6.00	7.30	8.80	0.9	8	1.3	1	--	--
L35	LaFourche Crossing	7.40	8.40	--	2.0	11	--	2	268	4.1
L51	SE Pecan Island West	5.00	6.30	7.70	0.8	7	2.3	1	205	3.4
L2	Atchafalaya Bay East	7.30	9.00	--	0.7	5.0	1.3	1	317	2.1
T2	Austin Bayou	4.70	5.70	6.80	1.0	7.0	2.7	1	195	3.6
					11.8	77	19.1	11	1,930	4.0

*50 percent solution ratio from Tables J-1 and J-2.

TABLE J-6 (continued)

Minimum Case
(Maximum Rate 30,000 B/D; 50 Percent Solution Ratio from Tables J-1 and J-2)

Run No.	Prospect	Gas Price ($/MCF) 10% ROR	15% ROR	20% ROR	Initial Gas Rate (MMCF/D)	Gas Reserves (BCF)	Electric Power (mW)	No. Wells	Orig.* GIP (BCF)	Recovery (%)
L49	Rockefeller Refuge	7.20	8.30	10.00	7.3	45	--	10	945	4.8
T4	Austin Bayou	10.00	--	--	0.6	5	--	1	195	2.6
					7.9	50		11	1,140	4.4

*50 percent solution ratio from Tables J-1 and J-2.

APPENDIX K

Environmental Considerations

ENVIRONMENTAL CONSIDERATIONS

Production from geopressured-brine reservoirs would have an impact on the environment similar to conventional gas production with two possible exceptions: large volume geopressured water production could result in land subsidence and/or in increased tectonic activity along growth faults. Either of these events could result in the early abandonment of a project.

The environmental aspects of large-scale gas recovery from geopressured and hydropressured aquifers were reported to the Department of Energy by the Supply-Technical Advisory Task Force on Nonconventional Natural Gas Resources. The environmental section of their report is reproduced in this appendix. In addition, a listing of potential impacts was prepared by the Gulf Coast Regional Vice-President of the Sierra Club, who was an NPC study participant. This list appears in the following section of this appendix.

POTENTIAL IMPACTS

It appears that the potential direct adverse impacts, both short-term and long-term, are in the following areas:

- Water pollution, involving both surface and ground. This area includes migration to or impact on hazardous waste storage reservoirs, of which both Texas and Louisiana have quite a number.
- Air pollution.
- Noise pollution.
- Subsidence.
- Induced seismicity, including fault activation.
- Aesthetic considerations.
- Land use, including archaeological sites.
- Vegetation, including consideration of endangered species.
- Fish and wildlife and their habitat, including consideration of endangered species.
- Cultural patterns.

These direct impacts are of concern both during development and during utilization of the resource.

Potential adverse indirect impacts, as well as adverse secondary impacts, should also be considered.

ENVIRONMENTAL ASPECTS OF LARGE SCALE GAS RECOVERY FROM GEOPRESSURE AND HYDROPRESSURE AQUIFERS[1]

Introduction

This section is concerned with the various environmental problems that probably will arise with the development of any large scale gas recovery program from either geopressured or hydropressured aquifers along the Miocene trend of southern Louisiana.

Environmental Aspects

When consideration is given to large scale gas recovery from these aquifers it probably should be envisioned as a series of smaller scale projects. Our focus will be on one of these "smaller projects" which typically could be expected to produce some 50 million cubic feet of methane associated with upwards of one million barrels of brine per day.[2] The production, processing, and disposing of these large volumes of brine from such a project will result in several problems from an environmental standpoint. The two most significant problems will be: (1) the possible subsidence of the land surface in the immediate vicinity of the producing wells, and (2) the disposal of the large volume of produced brine. Lesser environmental problems may be thermal pollution, air pollution, noise, and land use considerations.

With the removal of large volumes of water from either a geopressured or hydropressured aquifer over an extended period of time, there is a strong probability that the area around the project will experience considerable subsidence. Surface subsidence has been a problem in many areas where large volumes of water (or oil) have been removed. This can be particularly troublesome in low relief, low elevation coastal areas -- typical of the Miocene Belt of southern Louisiana. Subsidence of any appreciable degree in these swampy, coastal areas could be extremely bothersome, even in an undeveloped region.

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[1]National Gas Survey, Report to the Federal Energy Regulatory Commission by the Supply-Technical Advisory Task Force on Nonconventional Natural Gas Reources, Sub-Task Force 1 -- Gas Dissolved in Water, DOE/FERC-0029, March 1979.

[2]Largest project from National Petroleum Council study is Johnson's Bayou, with 400,000 barrels of water per day from eight wells.

This geographic area (the Miocene trend of southern Louisiana) is thought to be aseismic; however, the removal of large volumes of water, with the resultant drastic reduction of reservoir pressures, conceivably could activate some of the growth faults in these aquifers. Subsequently, it is also possible that such fault movements could result in surface adjustments. Damage due to such movements would probably be limited to the immediate area where the projected fault plane(s) intersect the surface.

Concerning the disposal of large volumes of brine, the easiest disposal method would be to discharge to nearby surface waters or into the Gulf of Mexico. This undoubtedly would be the most advantageous from an operating and economic standpoint. This disposal method, however, would raise environmental problems associated with the difference in composition of the produced brine and the receiving water. There is also the probability that the temperature of the disposed brine will be considerably higher than that of the receiving water, thus resulting in "thermal pollution." Strong objections could be expected from both commercial and sport fishermen, as well as regulatory authorities.

A second and a more environmentally acceptable disposal method would be to inject the brine into shallower, normal pressured aquifers with a series of disposal wells.[3] From an operating and economic standpoint this has great disadvantages. A high capacity disposal well may handle as much as 10,000 barrels per day with suitable high pressure pumps. Thus, a project such as this would require a large network of active disposal wells (plus stand-by or reserve wells) with the associated surface installations, including high-pressure pumps which would be required to effect satisfactory injection rates.

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[3]These aquifers are normal pressured brine aquifers underlying fresh-water zones.

APPENDIX L
Legal Considerations

LEGAL CONSIDERATIONS

DISCUSSION

This appendix will focus on the legal problems incident to the ownership of or the right to exploit hot, highly pressured aquifers existing under the Gulf Coast of Louisiana and Texas which contain a wet steam source with significant amounts of methane existing in solution. Therefore, all references to geothermal energy used hereafter in this paper should be understood to denote hot, high-pressured water containing significant amounts of methane, and not hot, dry steam or an anhydrous hot rock strata.

In the absence of case law in Texas or Louisiana establishing ownership of geothermal energy as incident to any particular type of interest in property, one must examine the ownership concepts applicable to the various interests and determine which interest in property would seem most likely to be vested with ownership of geothermal energy.

Public Ownership vs. Private Ownership

At the outset, one must decide whether geothermal energy lies within the public domain or the private domain. Without exploring the issue in detail, one may feel reasonably confident that neither Texas nor Louisiana would assert ownership in its sovereign capacity as against those parties already possessing ownership rights in the property.

In Texas, the state owns "the water of the ordinary ... underflow ... of every flowing river, natural stream and lake ...." See TEX. WATER CODE ANN. §5.021(a). The ownership of underground water, defined as essentially percolating subsurface water and excluding subterranean streams and the underflow of rivers, is recognized as being vested in the owner of the land and his lessees and assigns. TEX. WATER CODE ANN. §52.002. Geopressured waters, being essentially stabilized in porous strata, are not likely to be considered a defined underground stream. Further, no cases have arisen wherein the boundaries of an underground stream have been shown so as to vest ownership in the state.[1] Though the geothermal waters do not technically fit within the definition of "underground water" for purposes of Article §52.002 of the Texas Water Code so as to vest ownership in the landowner, it is much more probable that such would be the result rather than a judicial determination that such waters are vested in the state.

In Louisiana, running water[2] and the sea[3] are considered as belonging to the state. However, Adams vs. Grigsby, 152 So. 2d (619) (La. App. 2d Cir. 1963), in determining the ownership of subterranean waters, held that the right to appropriate underground water is an integral part of the ownership of the land. Further, the Louisiana Geothermal Energy Resources Act of 1975, in extending the provisions of the Louisiana Conservation Act to all geothermal operations, including provisions for unitization of mineral interests and allocation of production among the various property owners, strongly implies that the right to exploit geothermal energy is vested in the owner of the land under which it is found.[4] Thus, though the exploration and production of geothermal energy is subject to extensive regulation by the state, the right to exploit geothermal energy in Louisiana and the right to own the resource in Texas in all probability will be held to be possessed by the owner of the land.

Of course, the ownership of certain lands lies within the public domain. Further, certain of the lands conveyed by the state or federal sovereign are subject to statutory reservation.[5]

Surface Owner vs. Mineral Owner

In large part, the issue of ownership of the geothermal energy will be between the owner of the surface estate and the owner of the subsurface (or mineral) estate.[6] Of course, when the land is owned in fee and has not been severed horizontally into the surface and mineral estates, or otherwise burdened, there is no question as to identity of the party or parties possessing the right to exploit the geothermal energy.

TEXAS

There is a substantial volume of case law in Texas construing the scope of a conveyance of "oil, gas and all other minerals." The term "other minerals" does not include substances which, though technically a mineral, are not rare or exceptional in nature, and which exist as outcroppings or components of the surface and are so closely related physically to the surface as to be part of it. Thus, sand, gravel, limestone, and caliche would not be encompassed in a grant or reservation of "oil, gas and other minerals." Heinatz vs. Allen, 217 S.W. 2d 994 (Tex. Sup. 1949); San Jacinto Sand Co. vs. Southwestern Bell Telephone Co., 426 S.W. 2d 338 (Tex. Civ. App. 1968).

The basic test by which Texas courts must analyze the scope of the conveyance of "oil, gas and other minerals" was established in Acker vs. Guinn[7] (hereinafter referred to as the Acker case) and extended in Reed vs. Wylie[8] (hereinafter referred to as the Reed case). In holding that iron ore was not part of the "oil, gas and other minerals" conveyed in a 1941 deed, the Supreme Court in the Acker case reasoned that the parties to a mineral lease or deed usually think of the mineral estate as including valuable substances that are removed from the ground by means of wells or mine shafts, and though this mineral estate is dominant and its owner is entitled to make reasonable use of the surface for the production of minerals, in the absence of the express contrary intention, a grant or reservation of "minerals" or "mineral rights" should not be construed to include a substance that must be removed by methods that will, in effect, consume or deplete the surface estate.

The Acker case was followed by Williford vs. Spies,[9] Dubois vs. Jacobs[10] and Reed vs. Wylie.[11] A divided Supreme Court in the Reed case, in affirming the judgment of the Court of Civil Appeals remanding the case to trial court for determination of the fact issue as to the coal and lignite in question, reaffirmed the Acker decision, and stated:

> Acker vs. Guinn stands for the rule that a substance is not a 'mineral' if substantial quantities of that substance be so near the surface that the production will entail the stripping away and substantial destruction of the surface. That being the circumstance, and there being no contrary affirmative expression in the instrument, it controls the construction of the instrument as to the same substance at all depths.
>
> ... the surface owner must prove that, as of the date of the instrument being construed, if the substance near the surface had been extracted, that extraction would necessarily have consumed or depleted the land surface.

Therefore, a surface owner could argue for an extension of the general intent theory[12] of Acker and Reed. This argument would cite the myriad burdensome structures that would be necessary to harness and exploit the hot, highly pressured water and the possible subsidence and faulting of the surface as not within the "general intent" of the parties to the original instrument of conveyance. Acker would then apply, and a court would classify the geothermal resource as incident to the surface estate.

However, such an argument would not be a logical extension of the Acker doctrine. First of all, the fact that exploitation of "minerals" by the mineral interest owner might interfere with the surface owner's enjoyment of his estate should not be equated with a "consumption or depletion of the surface" within the meaning of Acker. Acker, Reed, Williford,[13] and Dubois[14] all dealt with a substance which was located so near to the surface as to constitute the surface itself. The methane located in the geothermal resource cannot logically be considered to be in this physical posture. Therefore, the argument that the surface owner had established "ownership" of the geothermal resource by virtue of the Acker doctrine would not appear to be convincing.

A second argument a surface owner could assert would be based upon Robinson vs. Robbins Petroleum, 501 S.W. 2d 865 (Tex. Sup. 1973) (hereinafter referred to as the Robinson case). The court in the Robinson case, in finding that the lessee had no implied right to use or increase the burden on the surface estate for the benefit of other lands and holding that the surface owner was entitled to damages for the proportion of that water produced from the leased land which was consumed (injected for water flood project) for production of oil for lands outside the lease, stated:

> It has been decided that water is part of the surface estate according to the ordinary and normal use of the words conveying or reserving minerals. Sun Oil Company vs. Whitaker, 483 S.W. 2d 808 (Tex. 1972). ... we are not attracted to a rule that would classify water according to a mineral contained in solution.[15]

The surface owner could assert ownership of the geothermal resource as incident to his ownership of the water itself. However, it should be noted that in this case the Supreme Court, in dicta, stated:

> If a mineral in solution or suspension were of such value or character as to justify production of the water for the extraction and use of the mineral content, we would have a different case. The substance extracted might well be the property of the mineral owner, and he might be entitled to use the water for purposes of production of the mineral.[16]

Assuming the presence of sufficient concentrations of methane within the geothermal water as to make the methane commercially valuable in and of itself, the mineral interest owner could validly assert its ownership of this "mineral" by virtue of its fee interest in the mineral estate. Because of the physical inconsistencies between the substances considered in the Acker line of cases and the geopressured reservoirs involved in this fact situation as noted above, the Acker doctrine would not be construed so as to deny ownership of the "mineral" in the mineral interest owner. Furthermore, the rationale employed in the general intent test would seem to favor the mineral interest owner. Since exploitation of the geothermal resource would involve the drilling of wells much in the same manner as oil and gas are exploited, this method of exploitation would seem to fall within the general intent of the parties[17] that the mineral owner was granted an estate in the valuable substances usually removed from the ground by means of wells or mineshafts.[18]

The type of physical destruction or consumption of the surface estate found to be a paramount consideration in the Acker line of cases is not present in geothermal operations. Rather, the issue is more properly categorized under the rubric of excessive use or interference with the surface estate. By virtue of the classification of the interest of the mineral owner or lessee as the dominant estate and the interest of the surface owner or lessor as the servient estate, the mineral interest owner has the implied legal right to use however much of the surface estate as is reasonably necessary to its operations. Humble Oil & Refining Company vs. Williams, 420 S.W. 2d 133 (Tex. 1967), held that a cause of action for damages exists on behalf of the surface owner if the lessee's use of the surface is negligent or if such use is not "reasonably necessary" to the lessee's operations. The Supreme Court in Getty Oil Company vs. Jones, 470 S.W. 2d 618 (Tex. 1971), however, found that if the lessee's use substantially interferes with a pre-existing use by the surface owner[19] and reasonable alternatives are available to the lessee, reasonable usage of the surface estate by the lessee may require adoption of a less injurious alternative by the lessee. Sun Oil Company vs. Whitaker, 483 S.W. 2d 808 (Tex. 1972), in holding that the lessee had the right to free use of so much of the fresh water underlying the lease (for a water flood project) as was reasonably necessary to produce oil from its oil wells, limited the Getty Oil Company vs. Jones decision to situations in which there are reasonable alternative methods available to the lessee on the leased premises (emphasis added) to accomplish the purposes of the lease.

Once a court finds that ownership of the geothermal resource lies incident to the mineral estate, the lessor cannot readily assert a cause of action for interference with his enjoyment of the surface estate. The production, gathering, and processing equipment that will probably be required to efficiently exploit the geothermal resource may exceed that burden placed upon the surface estate incident to exploration and production of oil and gas. However, as stated in Sun Oil Company vs. Whitaker,

> The rights implied from the grant are implied by law in all conveyances of the mineral estate and, absent an express limitation thereon, are not to be altered by evidence that the parties to a particular instrument of conveyance did not intend the legal consequences of the grant.[20]

Finally, Kenney vs. Texas Gulf Sulphur Co., 351 S.W. 2d 612 (Tex. Civ. App. - Waco 1961, writ ref'd.) relieved the lessee from liability for damages when a reasonably necessary method of extraction of minerals caused surface subsidence.[21]

In summary, the existence of commercial quantities of methane found in the geothermal resource will probably vest title as to such methane in the mineral interest owner. Further, in order to produce the methane to which the mineral interest owner is entitled, the hot, high-pressured water will also have to be produced. Whether the mineral interest owner would be entitled to all of the benefits resulting from the exploitation of this by-product is a moot question. However, this analysis has been predicated upon the existence of commercially valuable methane in sufficient quantities as to justify development of the geothermal resource. It might seem inequitable to deny the owner of the subsurface water any of the benefits resulting from exploitation of the subsurface water for its energy potential aside from the exploitation of its methane content, but a court may find it difficult to differentiate such exploitation of the hot, high-pressured water from the lessee's right under Sun Oil Company vs. Whitaker to use such amounts of the subsurface water as are necessary to the enjoyment of the mineral estate.[22]

LOUISIANA

The courts in Louisiana, in determining whether a servitude or lease gives to its owner the right to exploit a specific mineral, have employed a number of judicial canons in a consistent manner. This approach has favored more of a determination of the specific intent of the parties than the general intent test used in Texas.

The canons of contractual construction in Louisiana differ in some ways from those used in Texas courts. The doctrine of ejusdem generis[23] is applied in Louisiana, while it was specifically rejected by the Texas Supreme Court in the Acker case. The Texas courts have not allowed extrinsic evidence to be admitted as to the intent of the parties at the time of the conveyance in the Acker line of cases, whereas, the Louisiana courts admit evidence as to the circumstances existing at the time of the contract and the situation of the parties at that time.[24] In addition, Civil Code Article 753 requires that burdens on the land be narrowly construed. See Delahoussaye vs. Landry, 3 La. Ann. 549 (1848).

The application of the Louisiana canons of contractual construction and the existing Civil Code legal presumptions would probably result in a determination that the right to exploit the geothermal energy for its heat and pressure is not included as right incident to a mineral servitude or lease.[25] It would be difficult for a court using these constructional devices to find that the parties to such instruments intended or even contemplated the exploitation of a substance which may have not been known to exist at the time of execution or which even now cannot be shown to be clearly capable of commercial exploitation.[26]

Absent these judicial considerations, the servitude owner or lessee would seem to have available a logical argument to the effect that because methane is but "natural gas" dissolved in geopressured water, the servitude owner or lessee has the right to produce such gas,[27] regardless of manner in which it must be produced. This contention is more persuasive than the argument available to the lessee attempting to claim the right to strip mine lignite; however, even a narrow application of the legal doctrines consistently applied in the Holloway, Delahoussaye, and similar cases would make it difficult for a lessee to successfully prove that the parties "intended" to convey the right to exploit methane.

CONCLUSION

An analysis of case law in Texas indicates that ownership of geothermal energy as defined in the introductory paragraph of this appendix would probably vest in the mineral interest owner as opposed to the surface owner. A similar analysis of Louisiana case law indicates that present mineral servitude owners and lessees probably do not possess the right to exploit the geothermal energy.

Obviously, with no jurisdictional cases existing which are determinative of the issue, litigation will be necessary to resolve the issue; furthermore, resolution of this issue will certainly not eliminate all of the producer's problems. Very substantial legal problems relating to the operation of a viable geothermal project will remain.

Any analysis of ownership of geothermal resources must make mention of Geothermal Kinetics, Inc. vs. Union Oil Company of California, 141 Cal. Rptr. 879 (1978). In this case involving ownership of geothermal resources existing in a form differing from that analyzed in this appendix, namely steam, a California District Court of Appeals, in affirming the trial court, held that a general grant of "all minerals, in, on or under" the property conveyed in a 1951 deed included a grant of geothermal resources, including steam therefrom.

In an analysis which recognized and applied the doctrines and rationales used in the Texas cases analyzed herein, the court made the following points:

1. A grant should be construed to convey the broadest possible estate, and the general intent of the parties was to grant the owner of the mineral estate the right to extract valuable resources from the earth. Therefore, the geothermal resources should follow the mineral estate.

2. Production of energy from geothermal energy by means of wells is analogous to production of energy from other minerals such as oil and natural gas.

3. Recognizing the general intent test established in Acker vs. Guinn, the court noted that the trial court found that the exploitation of geothermal resources does not substantially destroy the surface of the property.

Using language and rationale very similar to that employed by the Supreme Court of Texas in the Acker line of cases, the court stated:

> The parties to the 1951 grant had a general intention to convey those commercially valuable, underground, physical resources of the

> property. They expected that the enjoyment of this interest would not destroy the surface estate and would involve resources distinct from the surface soil. In the absence of any expressed specific intent to the contrary, the scope of the mineral estate, as indicated by the parties' general intentions and expectations, includes the geothermal resources underlying the property."

In addition to holding that the geothermal resources are part of the mineral estate, the court concluded that geothermal water also was a part of the mineral estate. In recognizing that some states, including Texas, have held that the ownership of subsurface water is vested in the surface estate, the court distinguished such subsurface water from the water and steam components of geothermal resources. Recognizing that there is a geologic basis for distinguishing the ground water system which originates from and is replenished by rainfall from the geothermal water system which is cut off from such waters by a thick mineral cap, and noting that the rationale for recognizing the rights of the surface estate to the ground water system is largely inapplicable in the case of geothermal water, the court concluded that geothermal water is a mineral and thus not a part of the waters included in the surface estate. It is apparent that, in large part, the court was attempting to avoid a fragmentation of the ownership or exploitation rights relating to geothermal resources based upon the physical type of geothermal energy. Hopefully, such an approach, whether resulting in full ownership in the surface owner or mineral interest owner, will be followed by courts in Louisiana and Texas.

NOTES

[1]Comment, "Geothermal Resource Development in Texas," 29 BAYLOR L. REV. 993 (1977).

[2]R.S. 9:1101

[3]R.S. 49:3

[4]Harrell, Hill, Pike, and Wilkins, Legal Problems Inherent in the Development of Geopressured and Geothermal Resources in Louisiana, Final Report prepared for U.S. Department of Energy (1978). (Referred to hereinafter as Harrell).

[5]The question of ownership of geothermal resources arose in the case of United States vs. Union Oil Company of California, 549 F. 2d 1271 (9th Cir. 1973), wherein the Ninth Circuit Court of Appeals, in reversing the lower court decision, held that the United States, in a reservation of coal and other minerals, did by such reservation retain ownership in the geothermal resource. However, the decision was based upon statutory construction of the Stock Raising Homestead Act, 43 U.S.C.A. §299 (1970), using its legislative history. Thus, this decision is of little value in determining the public ownership vs. private ownership issue, or in the surface owner vs. mineral owner issue.

[6]A few comments concerning the nature of the landowner's interest in oil and gas in place beneath his land should be made at this juncture. Despite the variation in the classification schemes employed by the various authorities in this area of law, one can validly classify the landowner's interest under either an ownership in place theory or a non-ownership (or exclusive right) theory. Texas courts, in adhering to the ownership in place theory, hold that the landowner has title to the underlying oil and gas to the same extent as he owns any other underlying minerals and that the interest in oil and gas is a real interest subject to ownership, severance, and sale while embedded in the sands or rocks beneath the surface. See Stephens County vs. Mid-Kansas Oil and Gas Co., 113 Tex. 160, 254 S.W. 290, 29 A.L.R 566 (1923). Thus, since the landowner in Texas is deemed to have fee simple title to all minerals, including oil and gas, which underlie the surface, he may effect a horizontal severance by conveyance or reservation of the mineral interest fee simple. Similarly, under the typical oil and gas lease providing for a fixed term and so long thereafter as production continues, a fee simple determinable is created in the lessee. See Stephens County, supra.

Louisiana courts, on the other hand, follow the non-ownership theory and hold that minerals are insusceptible of ownership apart from the land until reduced to possession. Article 6 of the Louisiana Mineral Code (R.S. 31:6) provides that "the landowner has the exclusive right to explore and develop his property for the production of such minerals (i.e. minerals occurring naturally in liquid or gaseous form or elements or compounds in solution, emulsion or association with such mineral) and to reduce them to possession and ownership. Thus, a grant, reservation, or lease of oil and gas carries only the right to extract such minerals from the soil. The basic mineral rights that may be created by a landowner are the mineral servitude, the mineral royalty, and the mineral lease. R.S. 31:16.

[7]Acker vs. Guinn, 451 S.W. 2d 549, aff'd., 464 S.W. 2d 348 (Tex. Sup. 1971).

[8]Reed vs. Wylie, 554 S.W. 2d 169 (Tex. Sup. 1977).

[9]Williford vs. Spies, 530 S.W. 2d 217 (Tex. Civ. App. 1975), held that a reservation of an interest in oil, gas, and other minerals did not include coal and lignite that would (emphasis added) be mined and recovered by open pit or strip mining methods.

[10]Dubois vs. Jacobs, 551 S.W. 2d 147 (Tex. Civ. App. 1977), held that a reservation of a royalty interest in oil, gas, and/or other minerals did not reserve any substance that must (emphasis added) be produced by methods which will in effect consume or deplete the surface estate.

[11]Note 10, *supra*.

[12]The phrase "general intent theory" is merely a convenient device for referring to the rationale of the court in Acker that the general intent of the parties was not to include a substance that must be removed by methods that will, in effect, consume or deplete the surface estate.

[13]Note 11, *supra*.

[14]Note 12, *supra*.

[15]Robinson, at 867. However, the mineral referred to in the instant case was salt.

[16]*Id.*, at 867.

[17]Comment, Note 1, *supra* at 1007.

[18]See Reed vs. Wylie, Note 10, *supra*.

[19]The surface owner had previously installed a self-propelled irrigation system requiring an operating clearance of 7 feet. Though two other lessees had found methods to develop their interests which did not interfere with the irrigation system, Getty drilled two interfering wells and installed pumping units requiring clearance substantially in excess of 7 feet.

[20]Sun Oil Company vs. Whitaker, 483 S.W. 2d (Tex. 1972), at 811.

[21]The court recognized that subsidence is a necessary and inevitable result of use of the Frasch Process, the only commercially known method of producing sulphur in the region of the Gulf Coast, and noted that the plaintiff's right to have her land free of subsidence was one of the rights disposed of by her predecessor in title, when the lease was made.

[22]Of course, the implied right of use of the surface estate has always been construed in a situation wherein the surface use was necessary to assist in recovering the mineral being exploited. In this case, besides having this quality, the surface use would result in a by-product possessing commercial value as an energy source in itself.

[23]The rule of <u>ejusdem generis</u> is a rule of construction to aid in ascertaining the meaning of a statute or written instrument whereby an enumeration of specific substances or things followed by a more general word or phrase is to be held to refer to things or substances of a like nature or kind.

[24]<u>Holloway Gravel vs. McKowen</u>, 200 La. 917, 9 So. 2d 222 (1942). The Supreme Court, in holding that a reservation of "all the minerals, oil, and gas," did not include the right to mine gravel deposits, employed those concepts in limiting the scope of the term "mineral." A similar approach was taken in <u>River Rouge Minerals, Inc. vs. Energies Resources of Minnesota</u>, 331 So. 2d 878 (La. App. 2d Cir. 1976), writs denied 337 So. 2d 221, (1976), in which case the court used the principles followed in the <u>Holloway</u> case to find that the strip mining of lignite was not included within the terms of an "oil, gas and all other minerals" lease. In addition to noting that the strip mining of the lignite would render that portion of the surface unusable for other purposes, and that the lease did not contain provisions appropriate for strip mining, the court concluded that it was unlikely the parties would have included lignite within the meaning of "other minerals" at the time the lease was executed.

[25]<u>Harrel</u>, 6, <u>supra</u> at 67.

[26]<u>Id.</u>, at 67.

[27]In <u>Reich vs. Commissioner of Internal Revenue</u> (1969), 52 T.C. 700, affd. (9th Cir. 1972) 454 F. 2d 1157, the Tax Court concluded that geothermal steam produced from the geysers in California was a gas for purposes of the oil and gas depletion allowance in the Internal Revenue Code. However, this decision, based upon statutory construction, would have little or no precedential value in resolving the issues posed in this appendix.

APPENDIX M
Risk Analysis

MONTE CARLO SIMULATION OF ELEVEN GULF COAST PROSPECTS

This appendix presents results of the Monte Carlo simulation of gas production from 11 geopressured brine prospects studied by the National Petroleum Council. The objective of these simulations was to define gas prices needed to provide economically feasible rates of return (ROR) on investments in these risky ventures.

Because the chance for project failure (defined as a negative ROR) was high, in many cases the average prospect ROR's were not meaningful. Therefore, this report presents curves which show the probability that a given prospect will achieve specified minimum ROR goals. Results are in the form of plots of the chances that an investment in a given prospect will achieve at least zero percent ROR (success), 10 percent, 15 percent, or 20 percent ROR.

Monte Carlo Program

This project used the Bonner and Moore "Planning and Analysis of Uncertain Situation" (PAUS) computer program. Figure M-1 is a schematic diagram of the Monte Carlo simulation scheme for the Southeast Pecan Island prospect which was initially studied in detail. In general terms, the Monte Carlo method uses probability distributions of uncertain factors to generate a likely range of project economics. The method works as follows. First, a specific number is drawn at random from the overall range of values for each important factor. These random draws are combined into a single economic valuation with its resulting return on investment. This process is repeated hundreds or thousands of times. The final result (in this case a rate of return) is saved from each run. The PAUS output is a plot of the distribution of these ROR's biased by the systematic selection from among the range of possible input variables.

Simulation of Geologic Input Variables

In order to run a Monte Carlo simulation, the range of each input factor must be known. A commonly used method is to make three estimates for each factor. Project geologists are asked for "optimistic" (high), "pessimistic" (low), and "most likely" (mode) values for the important variables.

Table M-1 presents the National Petroleum Council study participant estimates of the likely value ranges for geologic variables in the 11 geopressured brine gas prospects. These values were arrived at after very careful analysis of each prospect by expert geologists in the area. These estimates are the low, most likely, and high parameters described above. A single run consists of 1,000 random draws from the resulting beta distributions. Table M-2 lists the average and standard deviation for geologic variables after 1,000 Monte Carlo trials.

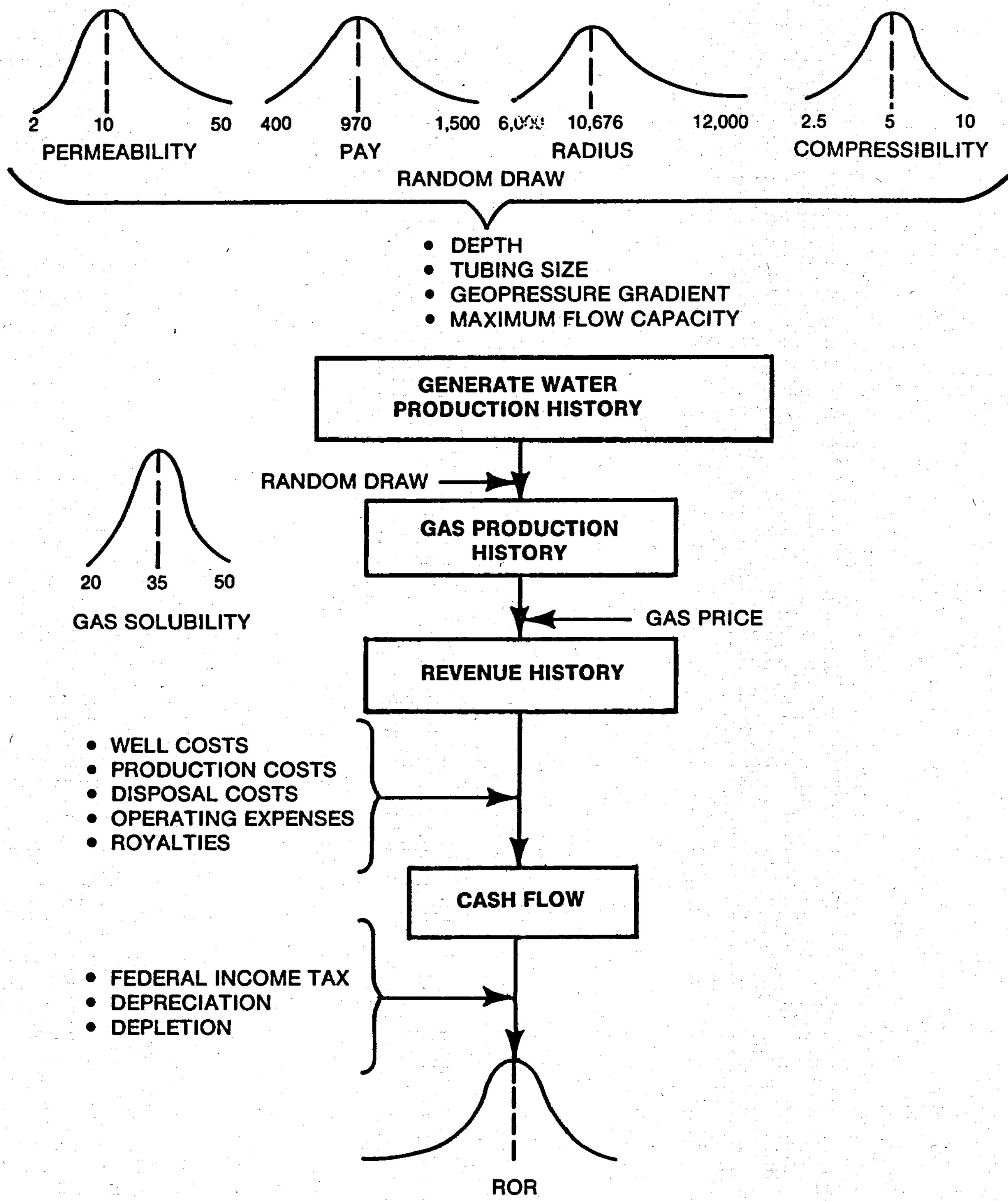


Figure M-1. Geopressured Gas Prospect, "Monte Carlo" Simulation.

TABLE M-1

Geopressure Gas Simulation Geologic Factors

Prospect	Net Pay Low (Feet)	Net Pay Likely (Feet)	Net Pay High (Feet)	Permeability Low (md)	Permeability Likely (md)	Permeability High (md)	Drainage Radius Low (Feet)	Drainage Radius Likely (Feet)	Drainage Radius High (Feet)	Rock Compressibility Low ($x 10^{-6}$)	Rock Compressibility Likely ($x 10^{-6}$)	Rock Compressibility High ($x 10^{-6}$)	Gas Solubility Low (.4) (Cu Ft/Bbl)	Gas Solubility Likely (0.8) (Cu Ft/Bbl)	Gas Solubility High (1.2) (Cu Ft/Bbl)
Atchafalaya Bay															
East	100	320	340	5	20	95	3,000	7,900	21,000	2.5	5.0	10.0	12	23	35
West	50	220	600	10	30	100	3,000	7,140	17,000	2.5	5.0	10.0	9	18	28
Johnson's Bayou	500	1,250	1,550	50	100	300	3,000	7,350	18,000	2.5	5.0	10.0	12	23	35
LaFourche Crossing	100	360	650	5	20	70	3,000	6,180	12,750	2.5	5.0	10.0	15	30	46
Rockefeller Refuge	200	435	1,400	10	20	80	3,000	6,600	14,666	2.5	5.0	10.0	20	41	61
SE Pecan Island															
East	100	250	380	5	10	50	3,000	5,700	11,000	2.5	5.0	10.0	14	28	42
West	100	275	980	5	10	50	3,000	6,500	14,000	2.5	5.0	10.0	14	28	42
Austin Bayou	100	715	900	5	20	60	3,000	5,700	11,000	2.5	5.0	10.0	16	32	48
Candelaria	100	480	700	1	5	60	3,000	6,930	16,000	2.5	5.0	10.0	11	22	34
Clinton	--	700	--	5	20	100	3,000	5,500	10,000	2.5	5.0	10.0	11	22	34
Eagle Lake	--	575	--	5	20	500	3,000	5,300	9,500	2.5	5.0	10.0	12	24	36

TABLE M-2

Geopressure Gas Simulation Averages and Standard Deviations for Geologic Factors

Prospect	Pay Thickness (Feet) Avg.	Pay Thickness (Feet) Std.	Permeability (md) Avg.	Permeability (md) Std.	Radius Geom. (Feet) Avg.	Radius Geom. (Feet) Std.	Compressibility 1/psi x 10^{-6} Avg.	Compressibility 1/psi x 10^{-6} Std.	Gas Solubility (Cu Ft/Bbl) Avg.	Gas Solubility (Cu Ft/Bbl) Std.
Atchafalaya Bay										
East	283	39	30	15	9,340	2,957	5.4	1.2	23	4
West	252	91	38	15	8,150	2,300	5.4	1.2	18	3
Johnson's Bayou	1,170	175	124	42	8,460	2,465	5.4	1.2	23	4
LaFourche Crossing	362	92	26	11	6,785	1,600	5.4	1.2	30	5
Rockefeller Refuge	552	197	28	12	7,392	1,918	5.4	1.2	41	7
SE Pecan Island										
East	245	47	16	7	6,166	1,316	5.4	1.2	28	5
West	360	145	16	7	7,211	1,809	5.4	1.2	28	5
Austin Bayou	639	133	24	9	6,166	1,316	5.4	1.2	32	5
Candelaria	450	100	14	10	7,840	2,137	5.4	1.2	22	4
Clinton	700	--	32	15	5,790	1,172	5.4	1.2	22	4
Eagle Lake	575	--	80	77	5,576	1,088	5.4	1.2	24	4

PAUS output includes plots of the frequency distributions of all geologic input variables as well as the resulting distribution of project ROR's. For the sake of brevity, this report presents only curves which summarize the result of changing gas prices from $2.00 per MCF through $16.00 per MCF.

Likely Success or Failure of a Given Prospect

Figure M-2 illustrates a typical output from a successful prospect.

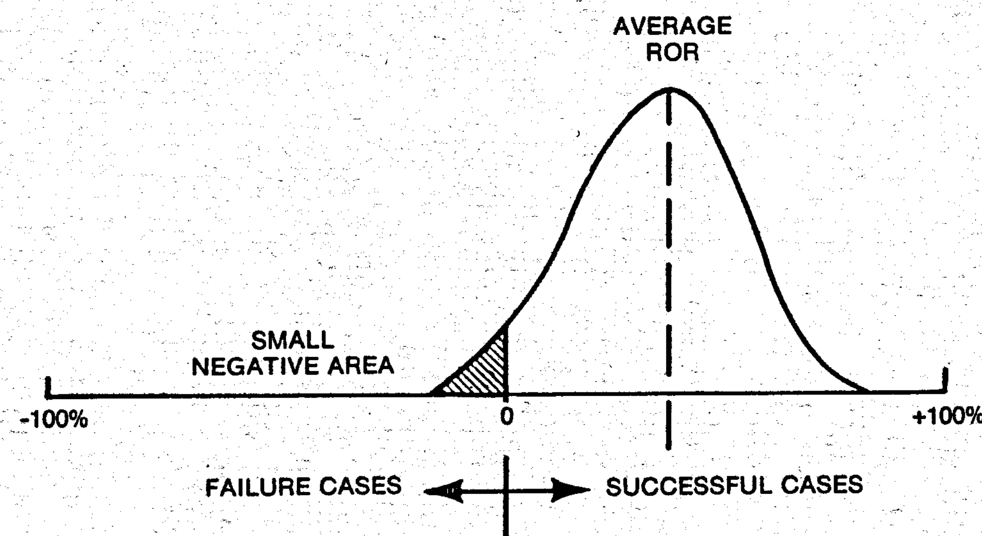


Figure M-2. ROR Distribution, Largely Successful Prospect.

In general terms, the frequency distribution of ROR's is a bell-shaped curve with the average prospect ROR located near the peak or most likely value. The tails of the curve represent the probably extreme ranges of project outcomes. On the left, the pessimistic outcomes combine to give low, sometimes negative (meaningless) ROR's.

For the purposes of this discussion a negative ROR is called a "failure" (shaded area). Obviously one would not choose to participate in a prospect likely to result in a net loss. The relative size of the shaded area determines the chances for a failure to occur. In Figure M-2 the large part of the ROR curve on the positive side indicates high probability for success.

Figure M-3 illustrates the ROR distribution for a prospect which is likely to fail.

In this case, random draws in the Monte Carlo simulation resulted in many combinations of low values for geologic variables. When this occurs (and especially at low gas prices) the project

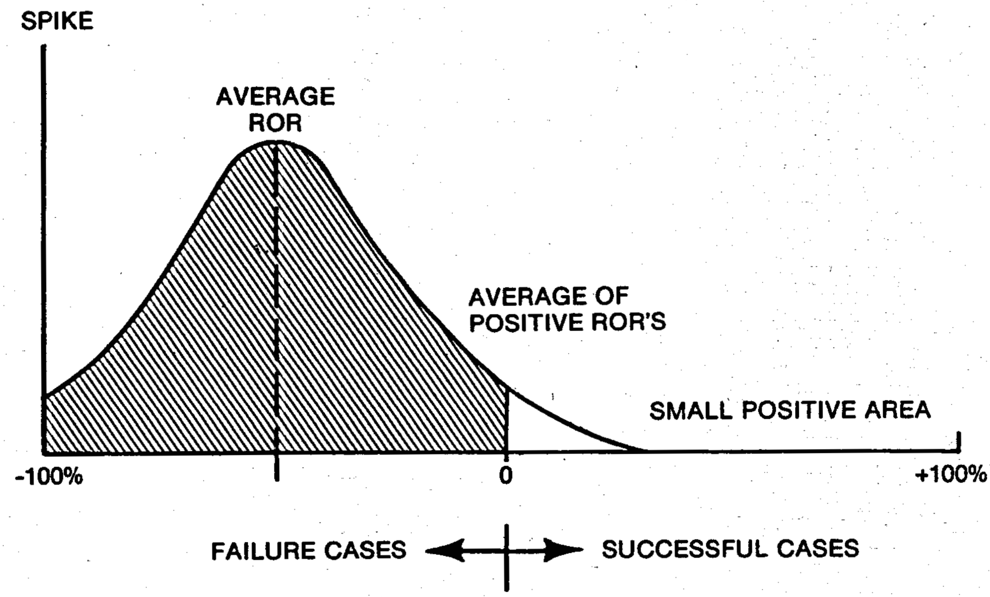


Figure M-3. ROR Distribution,Prospect Likely to Fail.

loses money with a negative ROR. The shaded area (representing chances for failure) becomes large and, as the left tail approaches -100%, the ROR program blows up. This results in a "spike," or meaningless ROR values, all plotted at -100%. When negative ROR's occur, the average project ROR's are not meaningful. This happened often in the prospects in this report.

Monte Carlo Simulation Results

Simulation runs were made to determine gas prices which would result in 10, 15, and 20 percent ROR's. However, the above discussion explains why average ROR's are often not meaningful. For this reason it was decided to rephrase the results in the following form.

The probability of achieving at least a given minimum percentage ROR as a goal was computed; this eliminates the need to consider or average meaningless negative ROR's. As a cutoff reference point, a project was arbitrarily defined as a "success" when it achieved at least a positive ROR. This is the same as calling for at least a positive undiscounted cash flow sometime within the life of the project. In addition, simulations were run to find and plot the chances that each prospect will achieve goals of at least 10, 15, or 20 percent ROR.

Simulations for all 11 prospects were run at prices ranging from $2.00 per MCF to $16.00 per MCF. Figures M-4 through M-14 present the resulting plots of the chance for achieving the given ROR goals vs. gas prices.

For the purposes of illustration, Figure M-4 is discussed in detail. This figure presents the results of the East Atchafalaya

Bay prospect. The four curves labeled zero percent, 10, 15, and 20 percent ROR represent minimum returns on investment goals. Each curve presents the chance that the prospect will achieve the given goal as a function of gas price. The 50/50 chance is shown as a broken line across the center of the figure.

To find the minimum price required for 50/50 chance of success, simply draw a vertical line downward from the point at which the zero percent curve crosses the 50/50 line. This corresponds to gas prices of about $7.50 per MCF. Similarly, a 50/50 chance for at least a 10 percent ROR requires about $9.20 per MCF of gas.

Finally, in order to show how ROR's behave around a particular goal, Figure M-15 was included. This is a simulation print plot of the distribution of ROR's for the 1,000 cases at $9.20 per MCF of gas for this prospect.

This plot shows the frequencies at which various ROR's occur in 1,000 Monte Carlo simulations selling gas at $9.20 per MCF. The vertical axis is the count (out of 1,000 trials) of outcomes in each ROR interval. For example, Interval 1 is 0-2 percent ROR, Interval 2 is 2-4 percent ROR, etc.

The spike on the left side of Figure M-15 is the number of failure cases all plotted at an ROR equal to zero percent. This spike shows that there is about a one in three chance (36.8 percent) for failure (zero or negative ROR) of this prospect even at $9.20 per MCF of gas. The remaining intervals show approximately bell-shaped distribution of positive ROR's peaking somewhere around the 14-16 percent ROR interval.

The table on the right side of Figure M-15 gives interval frequencies and cumulative percentages. For example, next to Interval 6 (lower limit = 10 percent) a cumulative percentage of 50.4 is seen. This gives a 50/50 chance for at least a 10 percent ROR corresponding to one point on the 10 percent ROR curve shown in Figure M-4.

Other points on this figure can be found in a similar fashion. This type of ROR plot shows the entire range of possible outcomes for a prospect at one price. However, it is not practical to reproduce this figure for all possible prices and every prospect. For this reason it was decided to present the plotted results as was done in Figures M-4 through M-14.

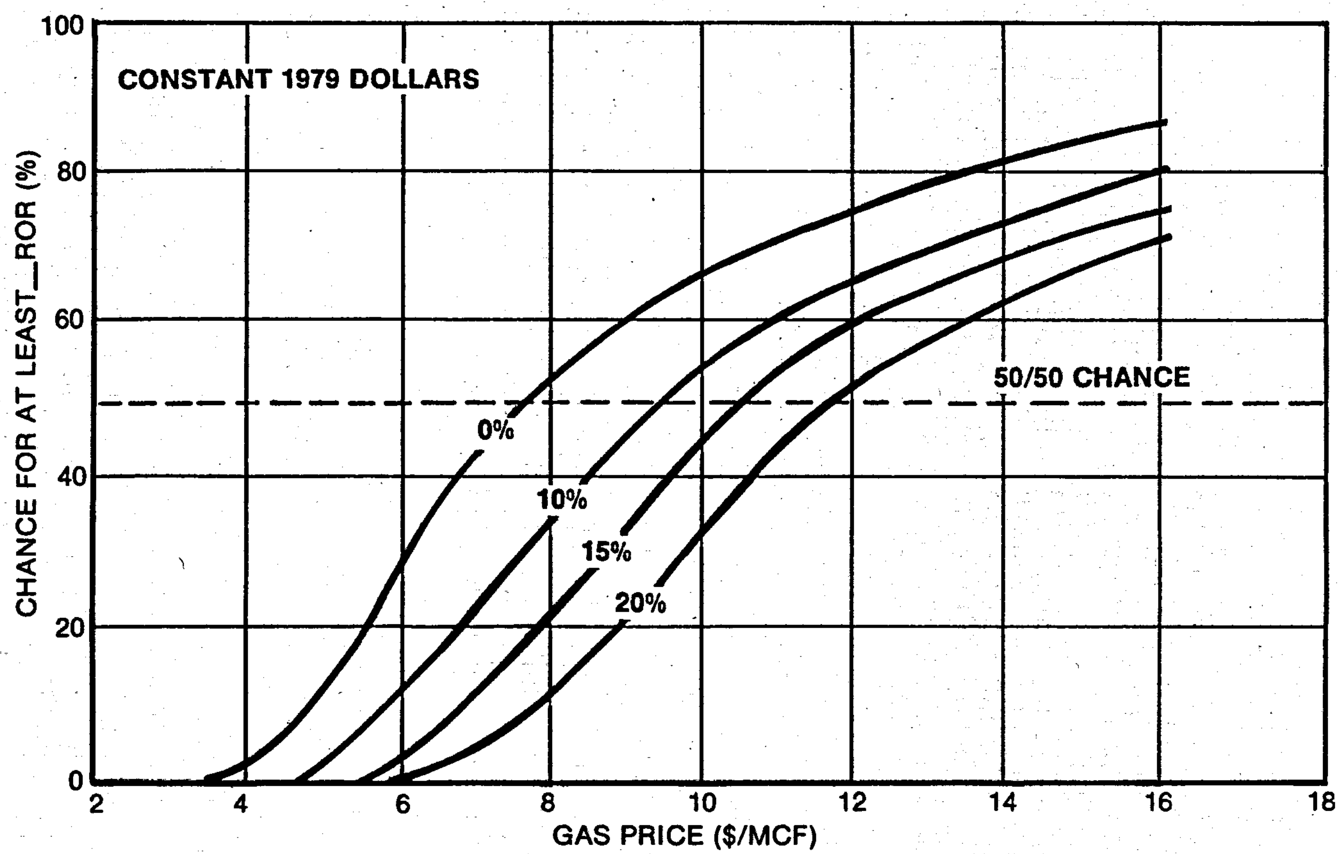


Figure M-4. Atchafalaya Bay East Prospect.

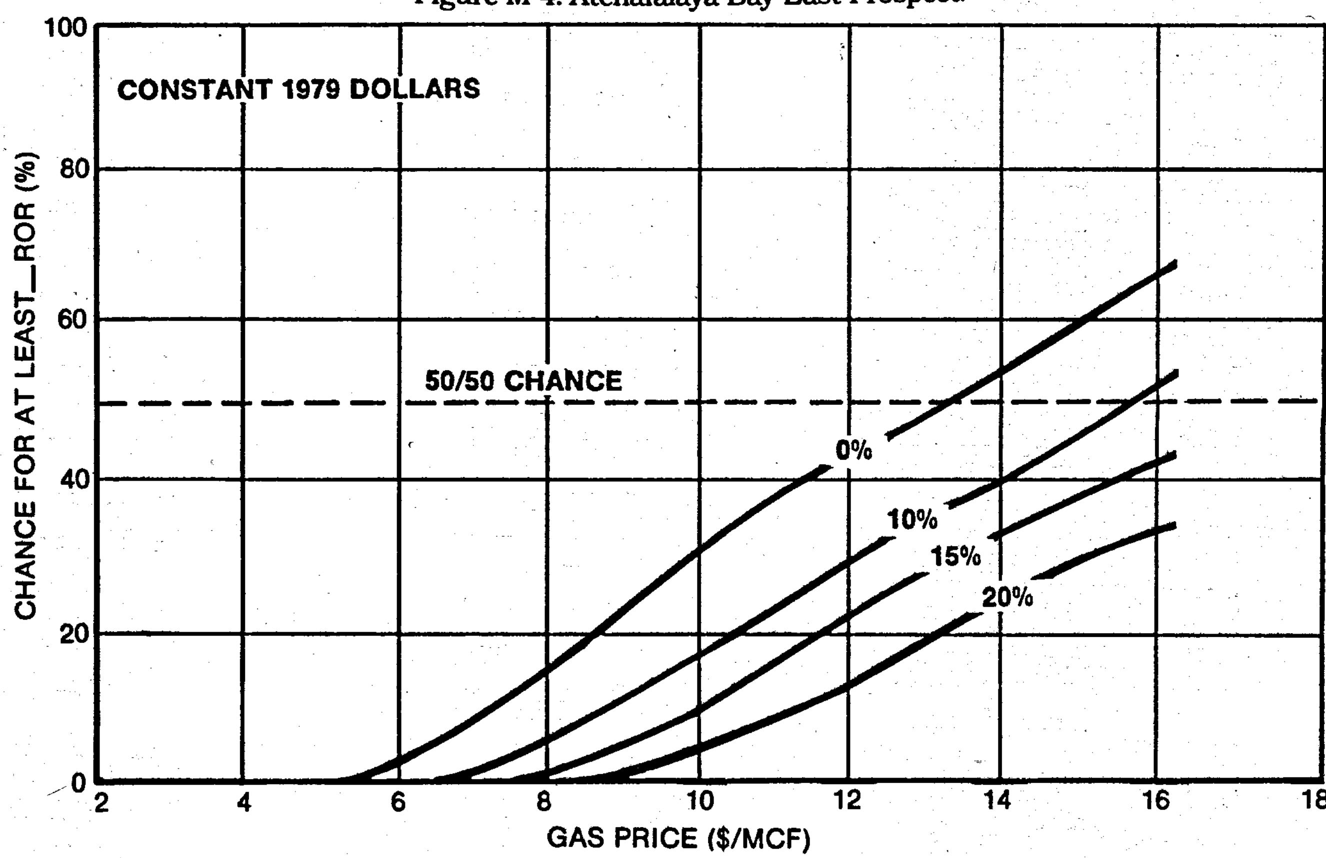


Figure M-5. Atchafalaya Bay West Prospect.

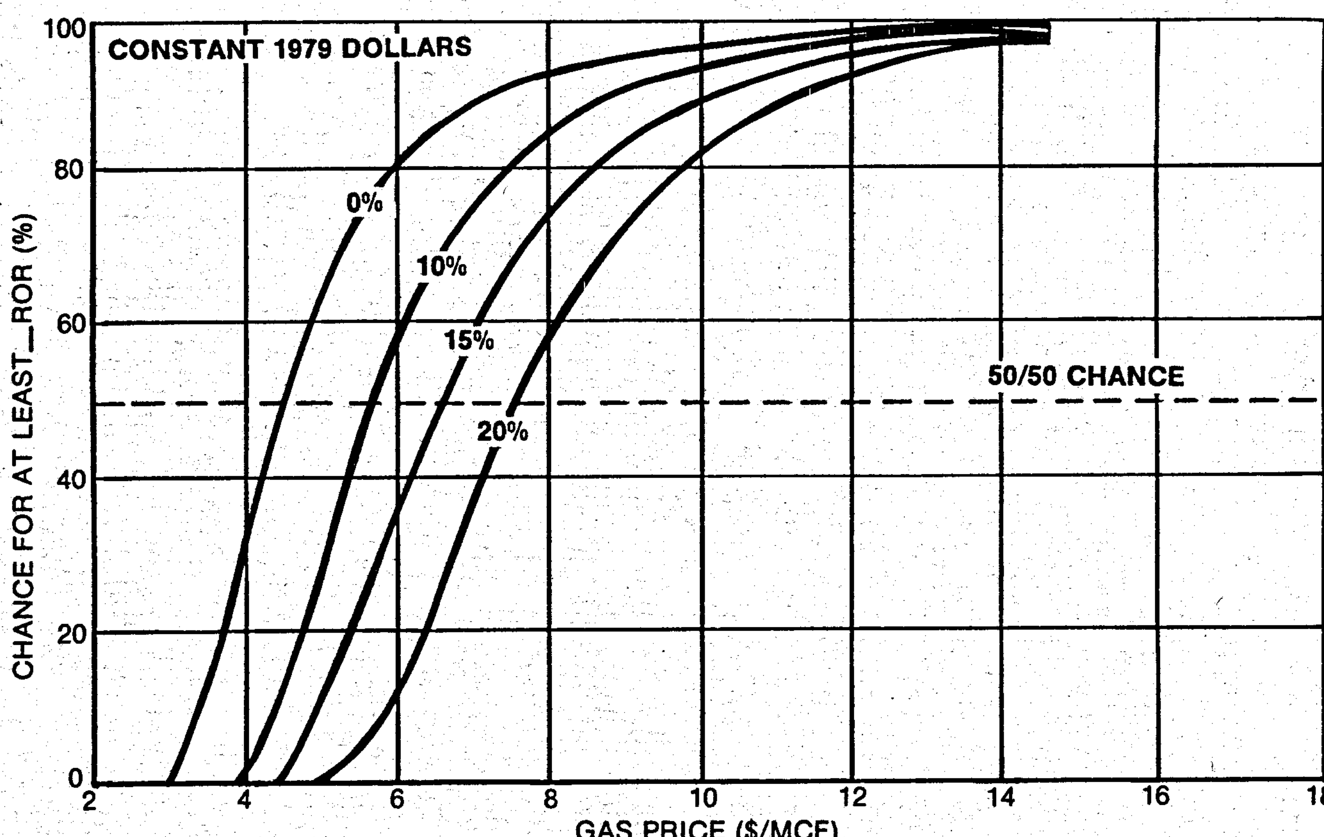


Figure M-6. Johnson's Bayou Prospect.

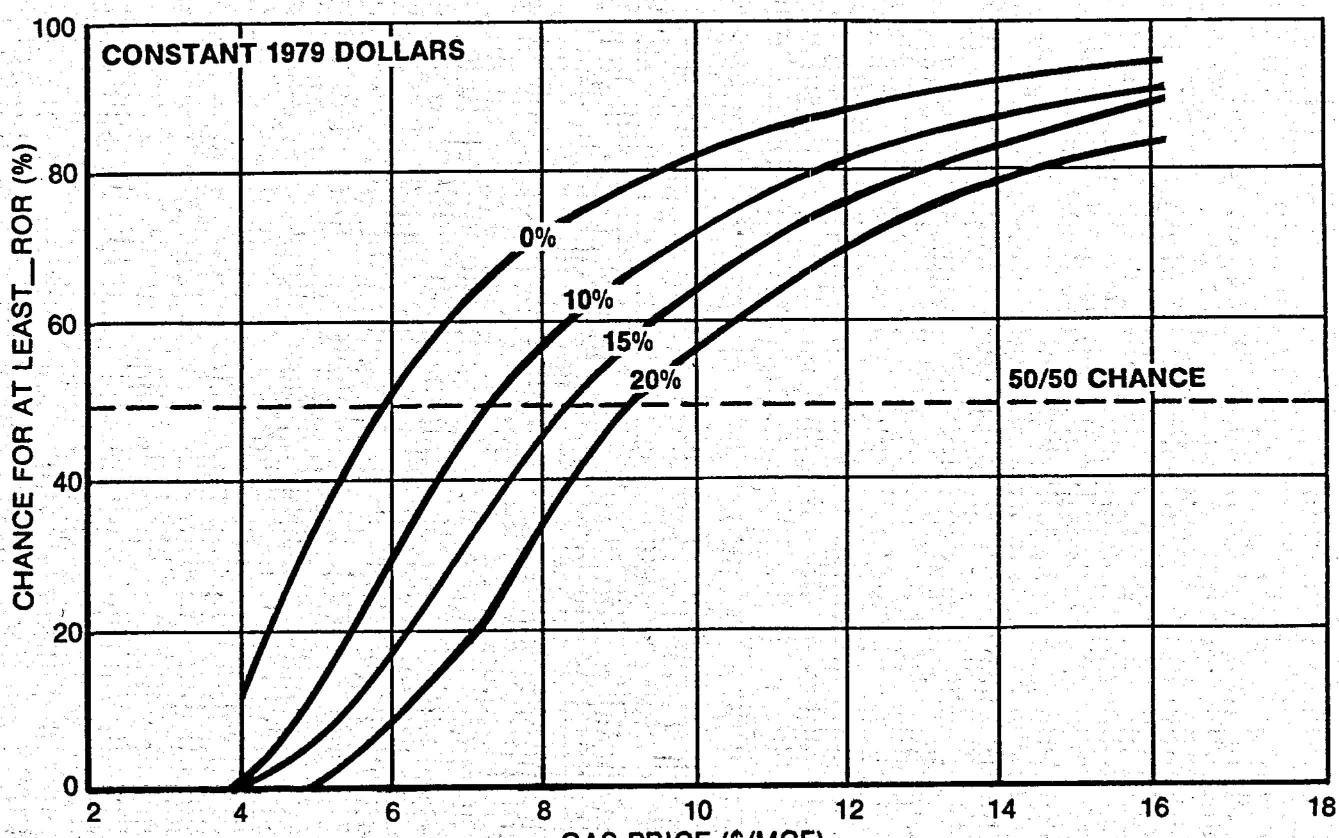


Figure M-7. LaFourche Crossing Prospect.

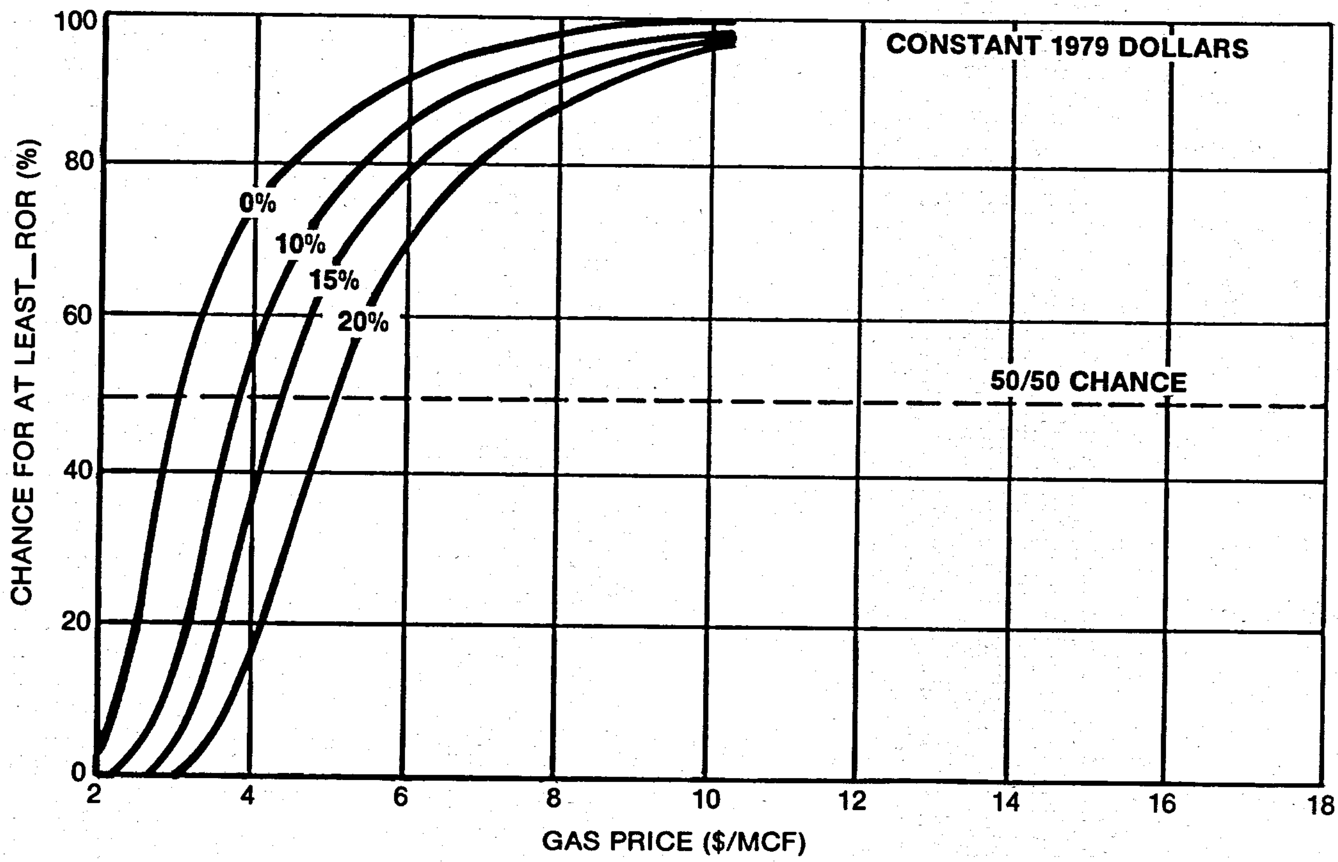


Figure M-8. Rockefeller Refuge Prospect.

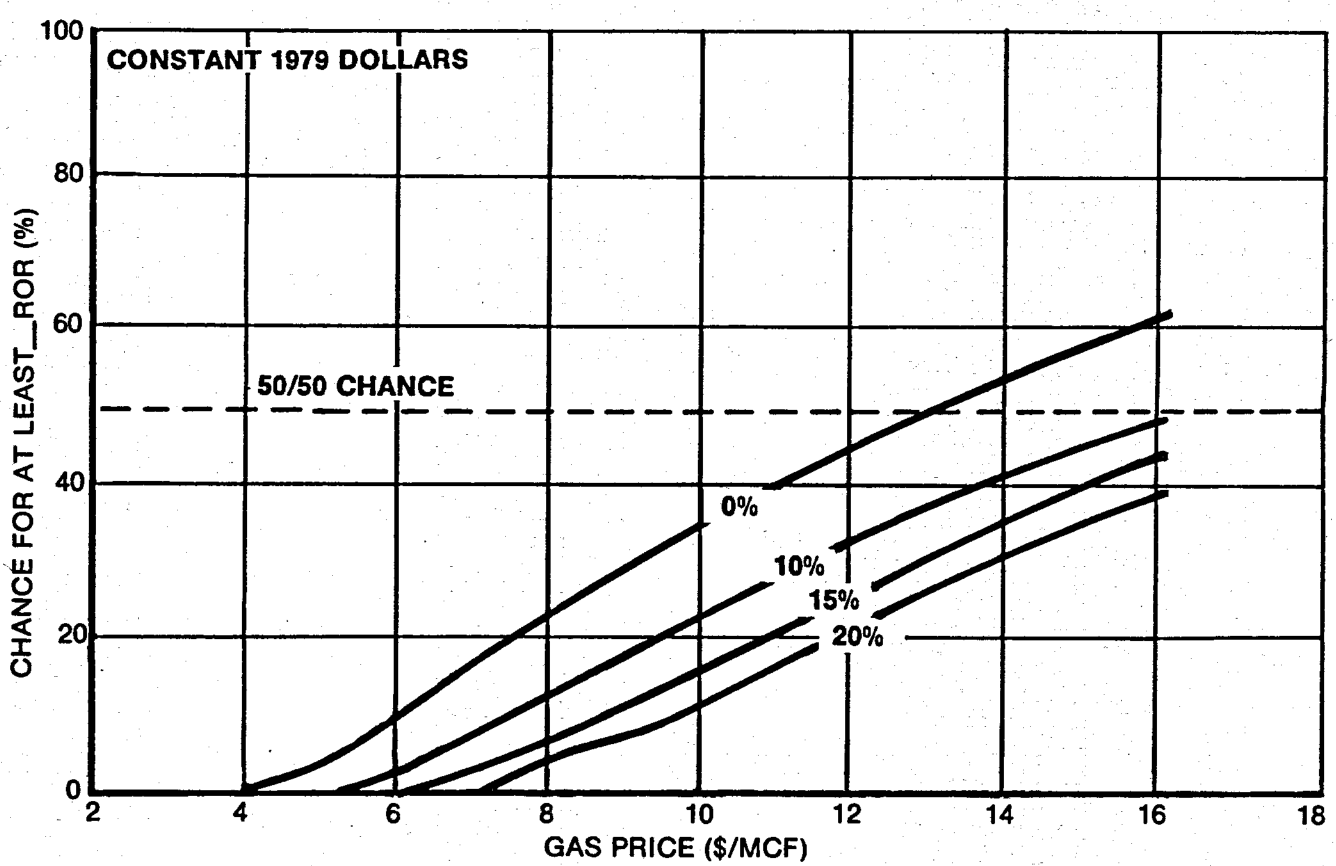


Figure M-9. SE Pecan Island East Prospect.

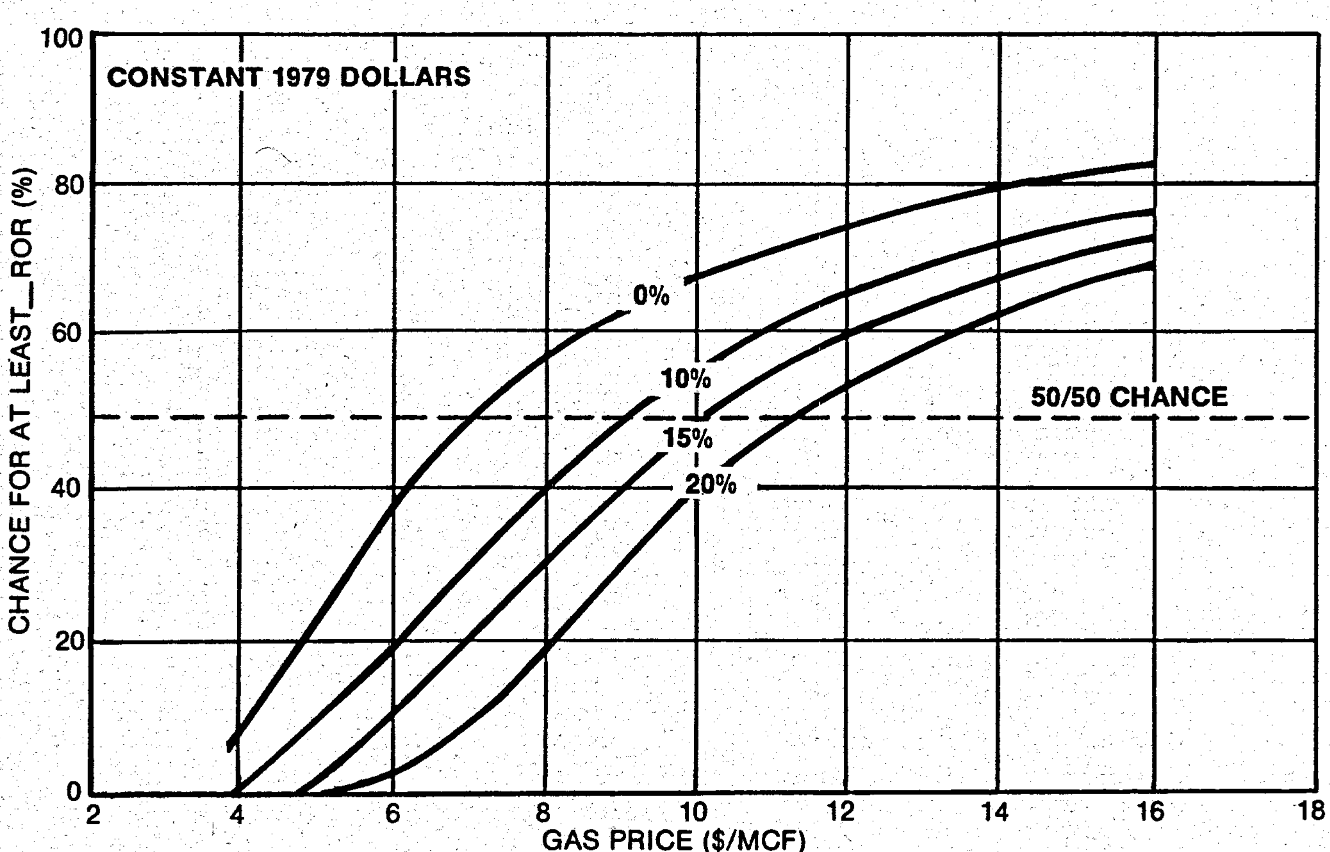


Figure M-10. SE Pecan Island West Prospect.

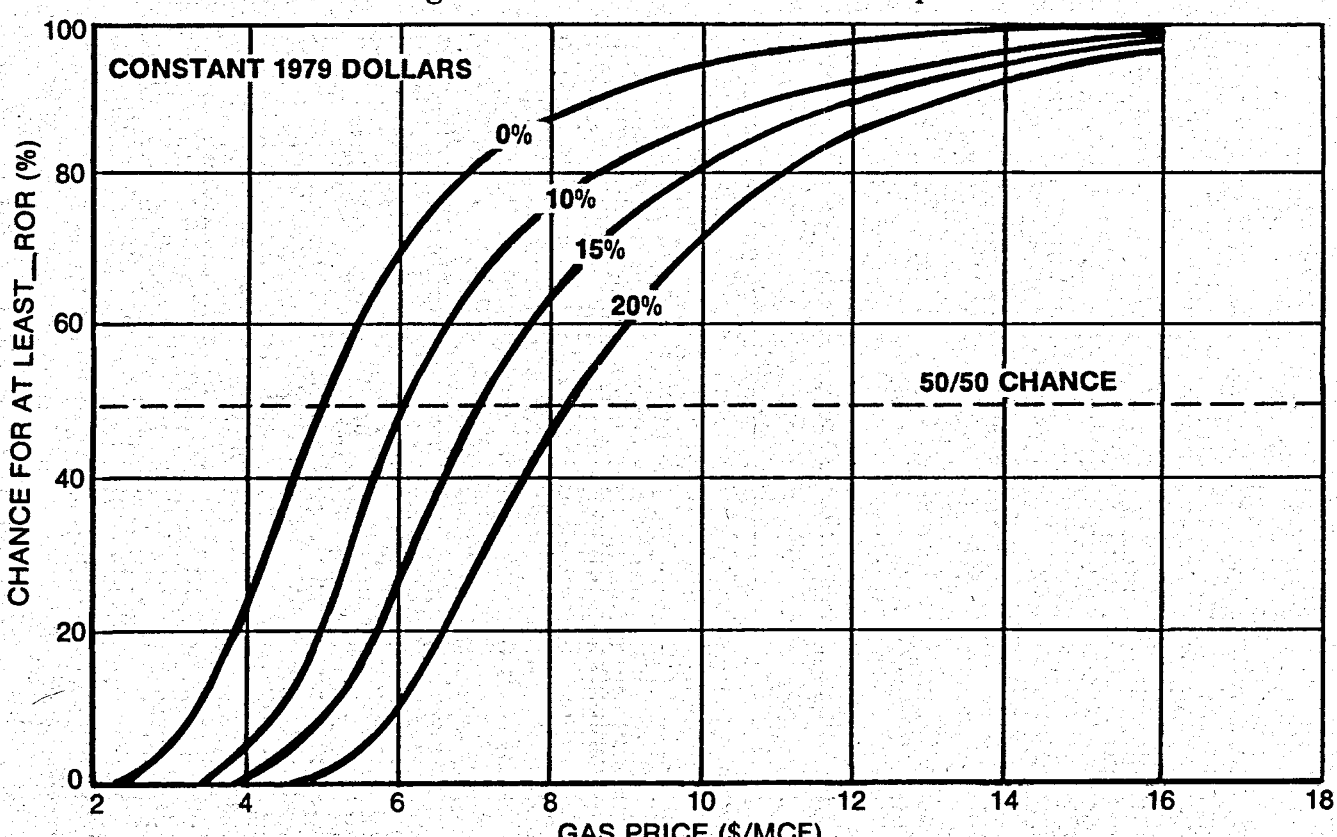


Figure M-11. Austin Bayou Prospect.

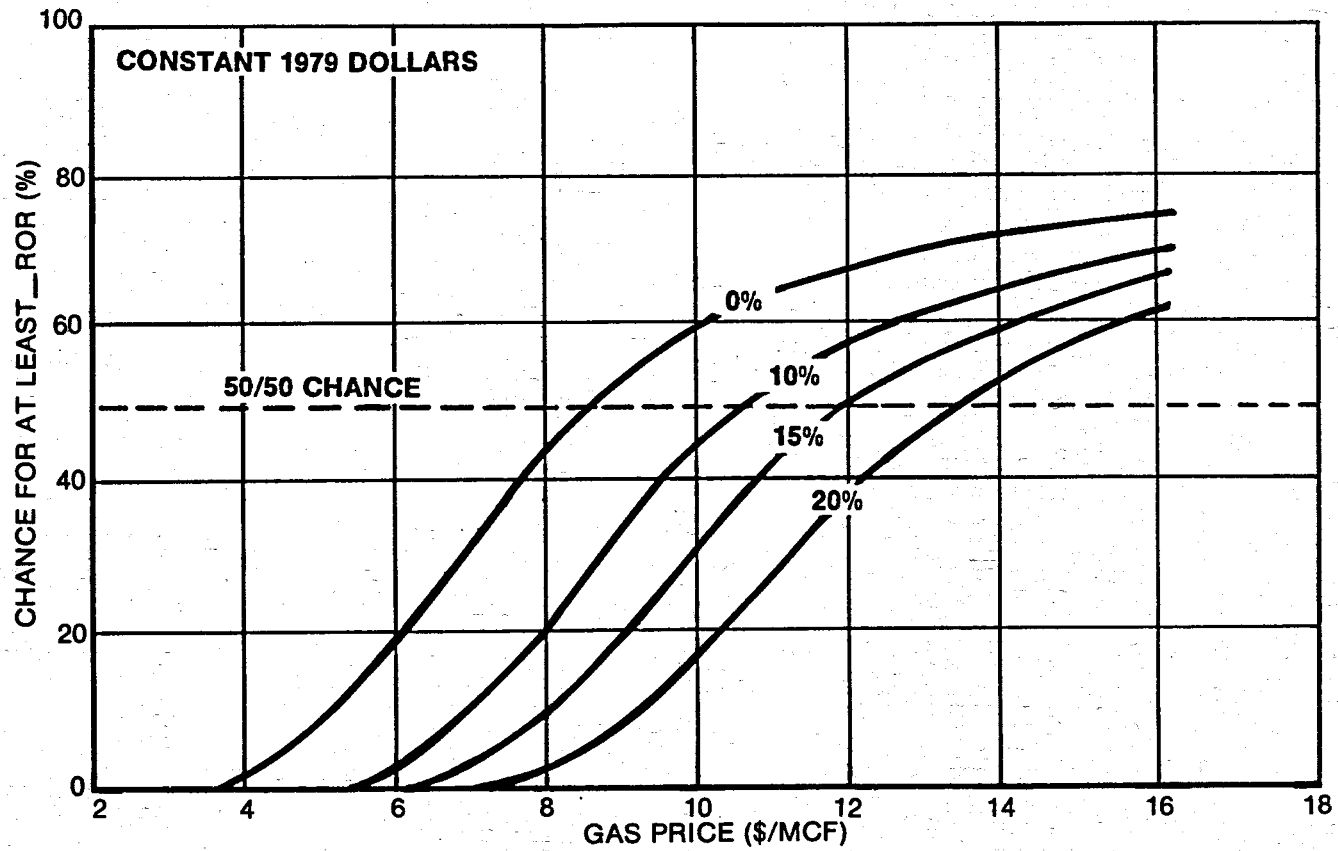


Figure M-12. Candelaria Prospect.

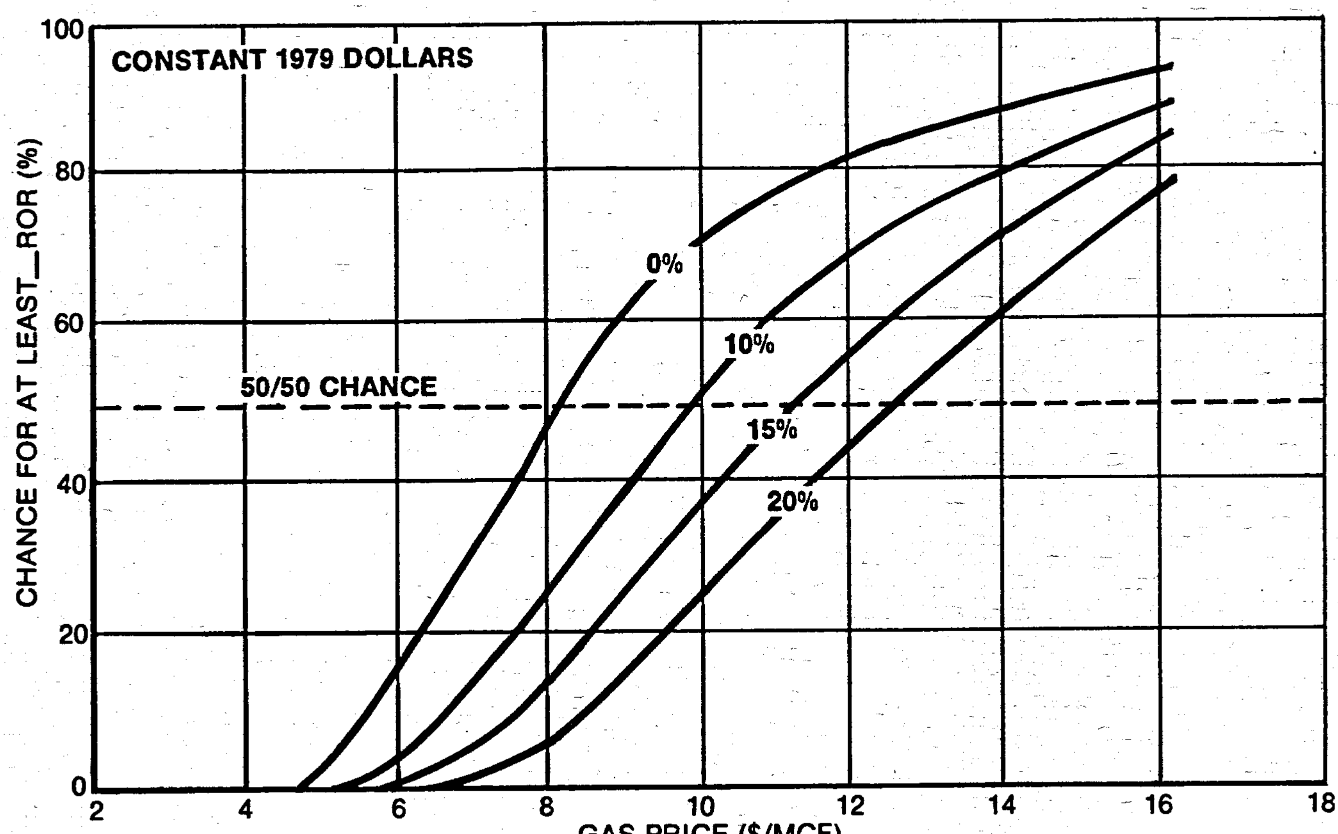


Figure M-13. Clinton Prospect.

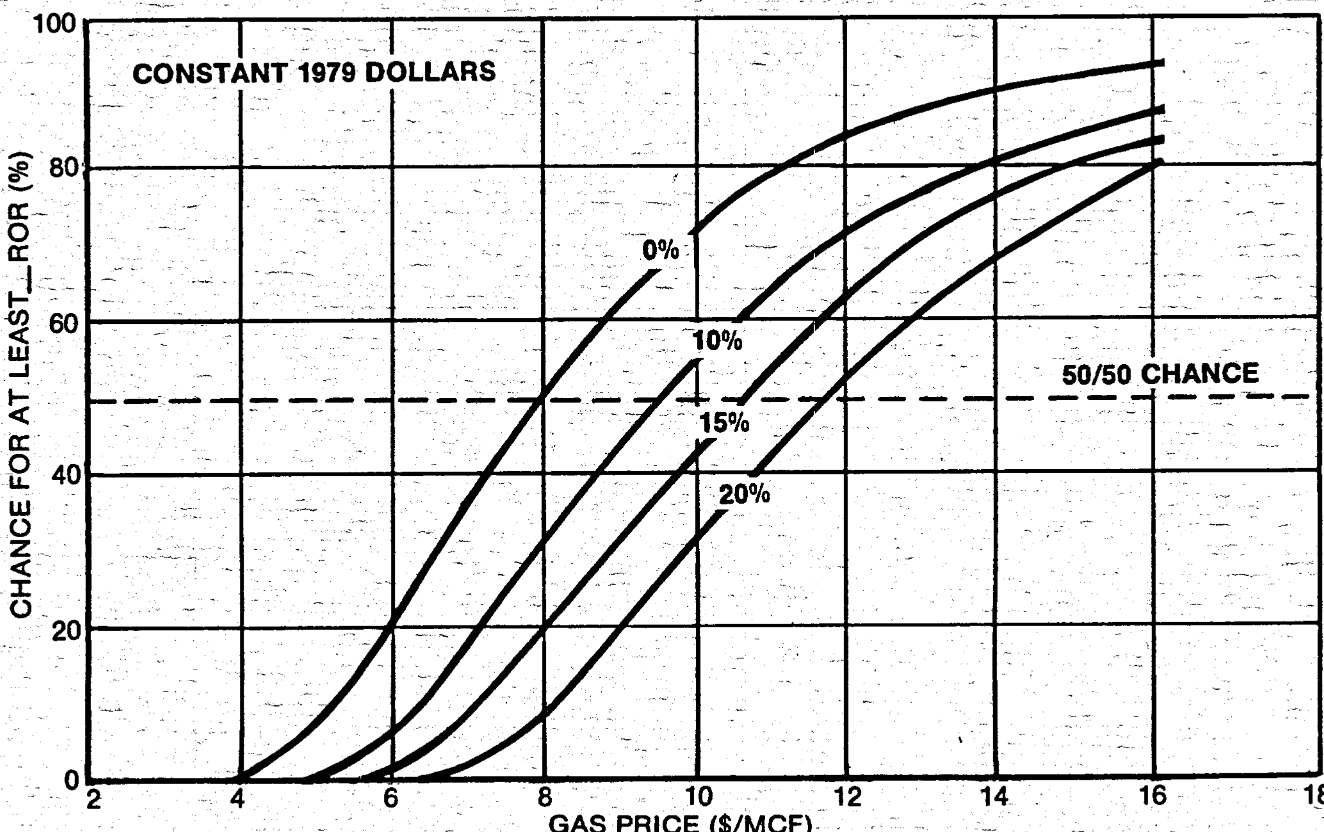
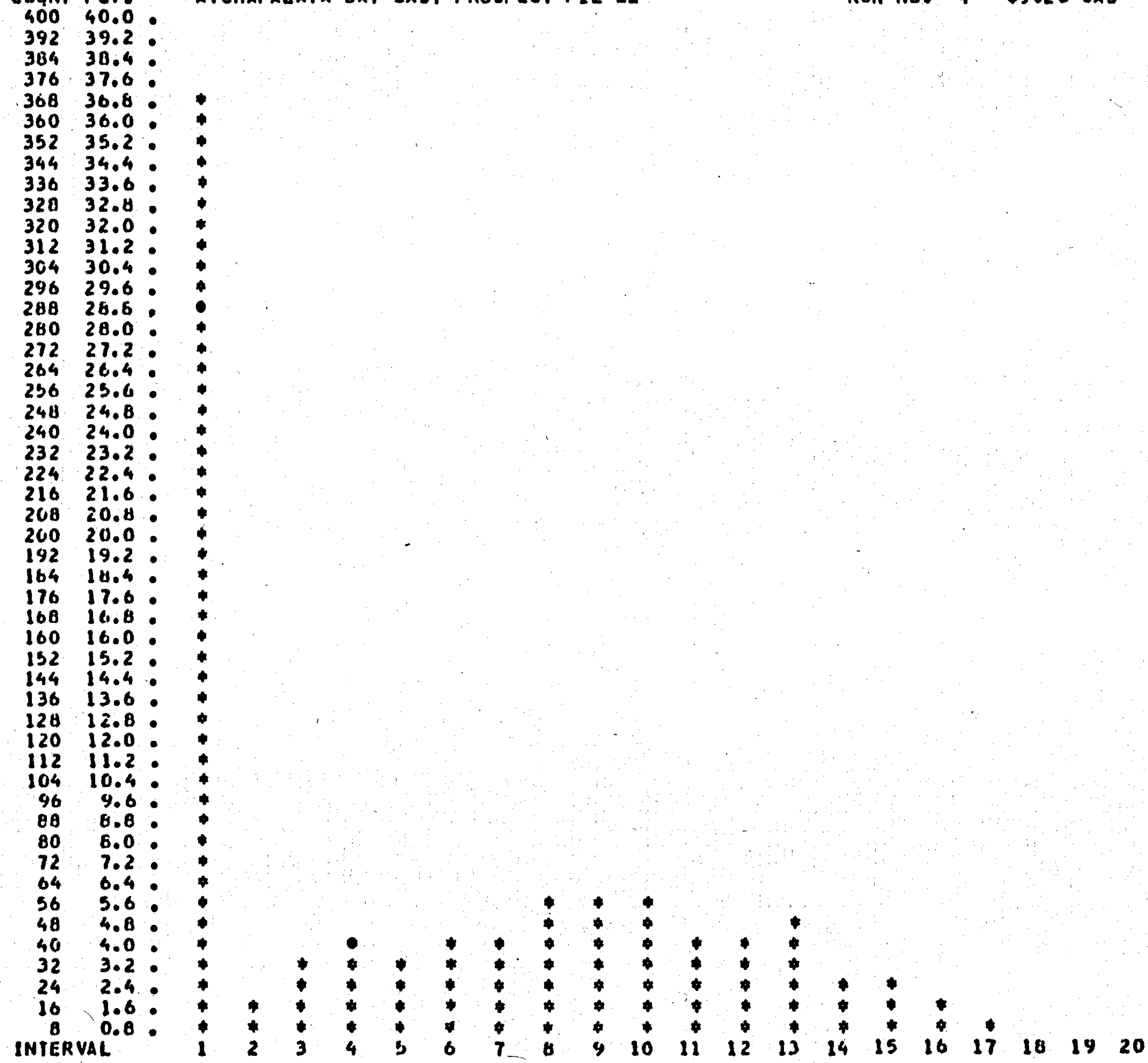


Figure M-14. Eagle Lake Prospect.

ATCHAFALAYA BAY EAST PROSPECT-P12 L2 RUN NO. 4 $9.20 GAS

PAGE 12
FINAL RUN



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RATE OF RETURN
VARIABLE ROR
FREQUENCY PLOT

****

MEAN = 10.9361
STD. DEV. = 10.5594

CONF MEAN = .654476 (.95)
CONF STDEV = 4.14074 (.95)

COEF SKEW = .450029
COEF KURT = 2.60025

MIN. VALUE = .0
MAX. VALUE = 41.4956

UNDERFLOW = 0 (0.0 PCT.)
OVERFLOW = 1 (0.10 PCT.)

INTERVAL NO.	LIMIT	FR. PCT.	CUM. PCT.
1	.0	37.3	0.0
2	2.00000	2.3	37.3
3	4.00000	3.4	39.6
4	6.00000	4.0	43.0
5	8.00000	3.4	47.0
6	10.0000	4.3	50.4
7	12.0000	4.1	54.7
8	14.0000	6.3	58.8
9	16.0000	5.6	65.1
10	18.0000	5.8	70.7
11	20.0000	4.3	76.5
12	22.0000	4.7	80.8
13	24.0000	5.0	85.5
14	26.0000	2.4	90.5
15	28.0000	3.1	92.9
16	30.0000	1.6	96.0
17	32.0000	1.5	97.6
18	34.0000	0.4	99.1
19	36.0000	0.4	99.5
20	38.0000	0.0	99.9
	40.0000		99.9

Figure M-15. Sample Simulation Plot.