OPERATIONS RESEARCH AND SYSTEMS ANALYSIS OF
GEOPRESSURED/GEOTHERMAL RESOURCES IN TEXAS

MASTER

Final Report

William G. Lesso

C. Dale Zinn

John Cornwell

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Center for Energy Studies
The University of Texas at Austin
Austin, Texas 78712

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SUMMARY

The Department of Energy is actively exploring the use of geopressed, geothermal resources as an alternative source of natural gas and energy for power generation. Bands of this resource are located along the Texas-Louisiana Gulf Coast.

A resource assessment of these "fairways" has been made and reveals that only some of them show potential for commercial development. The major unknowns that influence the prospects for development are the number, size and properties of the reservoirs, and how they are faulted (i.e., how much continuous medium there is between faults).

This GP/GT resource is located at depths in excess of 12,000 feet under extremely high pressure. The water may contain as much as 50 standard cubic feet of dissolved gas per barrel of fluid and have a temperature of 300 - 500°F.

The basic method for producing usable energy from the resource is to remove the dissolved gas from the fluid and convert the heat and pressure energy of the fluid into some usable form. In some cases electric power generation may be possible while in other instances some type of process heat application may be more desirable. Since the energy content of the gas is approximately equal to the thermal and pressure energy of the fluid all of this energy needs to be utilized in order to have an efficient energy production process. A complicating factor is that the geopressed fluids are quite saline and thus present a significant disposal problem.

There are two possible methods of disposal - reinjection into a shallow reservoir, reinjection into the same reservoir. The first

requires less energy, the second helps maintain reservoir pressure and increases overall total product.

A preliminary resource assessment, based on the best available parameters, was made to identify potentially suitable fairways. Of those examined only the Brazoria Fairway in the Frio Formation was able to produce sufficient fluid to meet the minimum requirements. These requirements are based upon the need for a well to produce an initial flow rate of 40,000 bbl/day with a 6% decline rate over a 30 year production period. Next, a development planning analysis was done to determine the number of wells that would have to be drilled in the fairway, considering the probability of success, and the number of drilling rigs available. The results of this analysis provided a time phased scenario and costs of developing the fairway. These were next used in an economic analysis.

The economic analysis was performed to determine the present worth of using the resource under a range of values for the key economic parameters.

The results of this study indicate that the commercial development of the geopressed, geothermal resource is highly dependent upon the pricing of natural gas in the U.S., the development of tax incentives to spur development, and a better understanding of the nature of the resource through additional well tests.

This conclusion is not too surprising when one considers that in order to produce this resource, one must drill a larger than normal diameter well to a substantially greater than normal depth and then dispose of a large quantity of saline water. Also, the reservoir must

be of a large size to support the flow over a rather extensive economic life to justify the investment.

A number of factors such as these cause geopressed wells to be expensive to drill and to operate. Any variation in resource physical parameters from the most optimistic values can have a significant effect on the economic desirability of the project.

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OPERATIONS RESEARCH AND SYSTEMS ANALYSIS OF GEOPRESSURED/GEOTHERMAL RESOURCES IN TEXAS

I. Introduction

The Center for Energy Studies (CES) at the University of Texas at Austin has contracted with the U.S. Department of Energy to perform an operations research and systems analysis of the geopressured-geothermal resources in Texas. This planning support project was initiated in April 1977 under a contract with the then Energy Research and Development Administration (ERDA). Work on this original contract was completed in the fall of 1977 and a report describing the results of this work was published in December 1977.

At that time, detailed information describing the physical properties of the Texas Gulf Coast geopressured resources was not available. In particular, information that is necessary to do meaningful development planning, i.e., size distribution of the reservoir, gas content of the fluids, and formation permeabilities, were obtainable only from general area studies. In fact, prospective resource areas that were selected by the geological researchers were based primarily upon well log information that indicated the existence of thick sandstone formations in the geopressured zone.

Although three formations were identified along the Texas Gulf Coast as having geopressured resource potential, most of the research effort had been concentrated on the Frio formation. Five geopressured prospect areas or fairways were identified. The fairways were characterized by estimates of areal extent, sandstone thickness, and formation

porosity and permeability. No estimates of the reservoir volume that could be produced from one well or the production history of a well were available.

Because of these factors, the first development planning study was based upon the assumption that the sandstones were continuous over the prospect area and that the wells could be drilled close enough together to combine their flows for use by centralized power plants. This assumption resulted in combining the flow from three or more production wells in order to achieve the flow rate necessary to support these central power plants. The total reservoir volume required to support each of these plants was often quite large.

The development scenarios for these Frio prospects were discussed in the final report for this phase of the project.

Since other formations appeared to have potential for development, i.e., the Vicksburg and Wilcox formations, and since basic geological and reservoir research was continuing, the Center for Energy Studies proposed a continuation of the development planning study to construct new development scenarios based upon the additional findings of the basic research groups.

The objective of this project is the preparation and analysis of revised development plans for the Texas Gulf Coast geopressured energy resource.

This report describes the status of the project and reflects the accomplishment of the goals of the project. The first part provides an analysis of the physical parameters of the identified prospect areas for each formation. A development plan based upon a production unit consisting

of a single production well, two disposal wells (one shallow and one deep), a fuel processing plant and a small power plant is formulated for each acceptable fairway. In this context, a geopressured resource fairway is defined as acceptable if its reservoir parameters indicate that it is capable of supporting a minimum of one production well with an initial flow rate of 40,000 bbl/day with a flow decline of no more than 6%/yr for 30 years. Finally, an economic analysis of the development scenario for each acceptable fairway is performed.

A number of qualitative factors such as resource ownership, allowable use of geopressured methane, and rules and regulations regarding fluid production and disposal are likely to have a significant impact on the development of the geopressure resources of Texas. A report describing these factors was prepared by the CES Operations Research team for the Texas Energy Advisory Council. The significant findings of this report to TEAC are summarized in this document and the entire TEAC report is included as Appendix A.

A summary section containing general conclusions is included.

II. Resource Assessment

The portion of this study concerning the assessment of the geopressured-geothermal resources in Texas was partially extracted from existing reports published in 1978 by the Bureau of Economic Geology (BEG) for the State of Texas. The Bureau produced an individual report for the Vicksburg, Wilcox, and Frio Formations along the South Texas coast.

The Vicksburg Formation was described in the BEG report entitled Geothermal Resources, Vicksburg Formation, Texas Gulf Coast.¹ The Vicksburg Formation exists in two sections along the Gulf Coast. The northernmost is located in the southeast corner of Texas, while the southern section is located primarily in Hidalgo County. The report concludes that any potential geopressured-geothermal reservoirs in the formation will be located in the southern section. In addition, the southern section was deemed to have minimal potential due to very low permeability averaging less than one millidarcy and questionable reservoir continuity. Because of this assessment no attempt was made to estimate average resource parameter values for the Vicksburg Formation.

The Wilcox Formation was described in the BEG report entitled Geothermal Resources, Wilcox Group, Texas Gulf Coast.² The Wilcox Formation extends from the Texas-Louisiana border to the Texas-Mexico border parallel to the coast. The formation is located north of the Vicksburg Formation in East Texas while overlapping the Vicksburg Formation in Hidalgo County. The Wilcox Formation was identified to have eight potential geothermal fairways distributed throughout its length. The lack of permeability and porosity information in these fairways has

kept further detailed studies on potential development from being accurately completed. Estimates of the average values of the resource parameters that are important for this development study were obtained from the BEG report² and are summarized in Table 1.

The Frio Formation has been described in the BEG report, Geopressured-Geothermal Fairway Evaluation and Test-Well Site Location, Frio Formation, Texas Gulf Coast.³ The Frio Formation also extends along the entire Texas coast and is situated between the Wilcox corridor and the coast. The Frio Formation has been extensively studied over the past several years, and five potential geopressured-geothermal fairways have been identified. The report analyzed each fairway with particular attention being given to the total sandstone thickness, fluid temperature, and sandstone permeability. Estimates of the average values of the resource parameters were obtained from the BEG report³ and are summarized in Table 1.

Of the five potential fairways identified, only the Brazoria Fairway was judged able to meet all of the specifications for a geothermal prospect set out by the BEG. The Brazoria Fairway contained several hundred feet of sandstone with fluid temperatures greater than 300°F and permeabilities between 40 and 60 millidarcies. The natural gas content of the Brazoria Fairway was estimated to be between 25-45 standard cubic feet per barrel.

The physical data available on the three fairways reported on by BEG was general in form and only specific for certain sites within particular fairways (most notably a portion of the Brazoria Fairway within the Frio Formation). In order to assess the geopressured-

Table 1A

AVERAGE PARAMETERS FOR BASE CASE STUDIES OF THE WILCOX AND FRIO FORMATIONS

Formation Fairway	Porosity (%)	Permeability (md)	Pressure Differential (psi)	Total Formation Thickness (ft)	Areal Fairway Extent (mi ²)
Wilcox					
Colorado	15.	≤2.0	2000.	850.	200.
Duval	15.	≤2.0	2000.	400.	140.
Dewitt	15.	≤2.0	2000.	700.	280.
Liberty	15.	≤2.0	2000.	460.	1200.
Live Oak	15.	≤2.0	2000.	240.	75.
Harris	15.	≤2.0	2000.	3600.	1375.
Webb	15.	≤2.0	2000.	400.	48.
Zapata	15.	≤2.0	2000.	340.	48.
Frio					
Armstrong	15.	2.0	2000.	300.	100.
Brazoria	15.	50.0	2000.	400.	800.
Corpus Christi	15.	2.0	2000.	300.	400.
Hidalgo	15.	≤1.0	2000.	500.	1300.
Matagorda	15.	≤1.0	2000.	300.	300.

geothermal resource on a scale commensurate with the total fairway size, average parameters were used to describe each fairway. By using average data, each fairway could be parametrically studied.

To facilitate in the evaluation of the fairways as possible energy producing resources, a computer code was developed. A code named WELL was designed to study the effect of parametrically varying the important (most sensitive) fairway variables on the reservoir performance. A listing of program WELL is presented in Appendix B.

The overall performance of a fairway is defined by the reservoir's ability to flow, the decay in flow due to reservoir depletion, and the lifetime desired for the project. The major variables to be studied affecting the reservoir's ability to flow are the sandstone permeability, net sandstone thickness (assuming allowance of multiple completions), and the pressure differential between the average reservoir pressure and the bottom hole pressure of the well.

To evaluate the initial flow of the geopresured reservoir, the following simple flow equation is used.³

$$Q = \frac{Kh(P_R - P_B)}{141.2 \mu B \left(\ln \frac{r_e}{r_w} - .75 + S \right)}$$

where:

Q = flow rate (bbl/day)

K = permeability (md)

h = sandstone thickness (feet)

P_R = average reservoir pressure (psi)

P_B = bottom hole flowing pressure (psi)

μ = viscosity of formation water (cp)

B = formation volume factor

r_e = radius of reservoir (feet)

r_w = radius of well (feet)

S = skin factor

Several assumptions are incorporated into the model with the use of this flow equation. The first is that the pressure driving force remains constant throughout the lifetime of the well. This tends to make the results slightly more optimistic. The model does not take into account such factors as rock compaction and pore cementation. Factors such as these were deemed too specific for the scope of the work.

With the initial flow rate calculated, the flow history on the well can be diagrammed as in Figure 1. If the initial flow is greater than 40,000 bbl/day, the well is throttled back to 40,000 bbl/day. This restriction eliminates the problem of dealing with extremely large flow rates which would soon decay to rates unacceptable to the surface equipment. Once natural decay produces a flow less than 40,000 bbl/day, the system is allowed to decay to some minimum value set by economics.

Figure 1

RESERVOIR DECAY CURVES

The depletion rate of a geopressured-geothermal reservoir is a function that is not presently known. It is assumed in this work to be in the range of three to six percent per year. The three percent figure was generally used when assuming reinjection of the spent fluid back into the original formation. The six percent figure assumes reinjection of the spent fluid into a non-producing formation or assumes no reinjection at all. The model initially evaluates whether the fairway can sustain one well with an average flow of 18,500 bbl/day over a 30-year period. This criteria was selected because wells having an initial flow rate of 40,000 bbl/day and operating on a 6%/yr flow decline for 30 years were judged to be the minimum acceptable requirements for a production well. The 18,500 bbl/day value is essentially the average production rate that results from this type of well. A fairway is classified as acceptable for geopressured resource development if the evaluation indicates that it can support one or more of these wells.

If the fairway is initially accepted, then a life history of the fairway production is tabulated. This includes a year-by-year fluid production history as well as a natural gas production history provided the methane content of the geopressured fluid is known. The model evaluates the number of wells required to extract a specified percentage of the fluid in place. It is important to note that the model does not take into account any distribution of the fault block volumes within the fairway. The problem of determining the fault block distribution is addressed in the development planning portion of this report. An example of program WELL's output is given in Figure 2 for a Brazoria Fairway scenario.

CASE NO. 1---W/O REINJECTION-----BASE CASE
INPUT DATA REQUIRED

RESERVOIR DATA

FAULT BLOCK HEIGHT (MI) = 3.0
FAULT BLOCK RADIUS (MI) = 18.0
POROSITY = .150
VISCOSITY OF FORMATION WATER (CP) = .20
PERMEABILITY (MD) = 50.0
FORMATION VOLUME FACTOR = 1.00
PRESSURE DIFFERENTIAL(AVERAGE-BOTTOM HOLE) (PSI) = 2000.0
EFFECTIVE RESERVOIR THICKNESS (FT) = 400.0
EFFECTIVE RESERVOIR RADIUS (FT) = 95000.0

WELL DATA

TARGET WELL LIFETIME (YRS) = 30
ANNUAL PRODUCTION DECAY = .06
FLUID RECOVERY ASSUMED = .050
WELL CAPACITY FACTOR = .850
WELL BORE RADIUS (FT) = .50
SKIN FACTOR = 0.00
MAXIMUM WELL DENSITY (WELLS/SQ. MI) = .50
WELL INTERFERENCE FACTOR = .900

PRELIMINARY RESULTS - FOR MINIMUM PRODUCTION SCENARIO

FAULT BLOCK VOLUME (MI³) = 3053.6
LIQUID VOLUME IN BLOCK (BBLS) = 3.030E+11
MINIMUM LIQUID RECOVERY VOLUME (BBLS) = 1.515E+10
MINIMUM LIQUID RECOVERY BY 1 WELL OVER LIFETIME (BBLS) = 2.033E+08

Figure 2

SAMPLE OUTPUT OF PROGRAM WELL

WELL PRODUCTION SCENARIO

YEAR AVERAGE PRODUCTION (BBL/DAY)

1	40000
2	40000
3	40000
4	40000
5	40000
6	40000
7	40000
8	40000
9	40000
10	40000
11	40000
12	40000
13	40000
14	40000
15	40000
16	40000
17	40000
18	40000
19	40000
20	39720
21	37407
22	35229
23	33177
24	31245
25	29426
26	27712
27	26093
28	24573
29	23147
30	21799

Figure 2 (con't)

PRODUCTION RESULTS

YEAR	LIQUID RECOVERY RATE		TOTAL LIQUID RECOVERED BBLs	TOTAL NATURAL GAS RECOVERED (CU.FT.) ACCORDING TO VOLUMETRIC SOLUBILITY (CU.FT.GAS/38LI LIQ.)				
	BBLG/DAY	BBLs/YR		35.	40.	45.	50.	55.
1	1.499E+06	5.477E+08	5.477E+08	1.917E+10	2.191E+10	2.464E+10	2.738E+10	3.012E+10
2	1.499E+06	5.477E+08	1.095E+09	3.834E+10	4.381E+10	4.929E+10	5.477E+10	6.024E+10
3	1.499E+06	5.477E+08	1.643E+09	5.750E+10	6.572E+10	7.393E+10	8.215E+10	9.036E+10
4	1.499E+06	5.477E+08	2.191E+09	7.667E+10	8.762E+10	9.858E+10	1.095E+11	1.205E+11
5	1.499E+06	5.477E+08	2.738E+09	9.584E+10	1.095E+11	1.232E+11	1.369E+11	1.506E+11
6	1.499E+06	5.477E+08	3.286E+09	1.150E+11	1.314E+11	1.479E+11	1.643E+11	1.807E+11
7	1.499E+06	5.477E+08	3.834E+09	1.342E+11	1.533E+11	1.725E+11	1.917E+11	2.109E+11
8	1.499E+06	5.477E+08	4.381E+09	1.533E+11	1.752E+11	1.972E+11	2.191E+11	2.410E+11
9	1.499E+06	5.477E+08	4.929E+09	1.725E+11	1.972E+11	2.218E+11	2.464E+11	2.711E+11
10	1.499E+06	5.477E+08	5.477E+09	1.917E+11	2.191E+11	2.464E+11	2.738E+11	3.012E+11
11	1.499E+06	5.477E+08	6.024E+09	2.108E+11	2.410E+11	2.711E+11	3.012E+11	3.313E+11
12	1.499E+06	5.477E+08	6.572E+09	2.300E+11	2.629E+11	2.957E+11	3.286E+11	3.615E+11
13	1.499E+06	5.477E+08	7.120E+09	2.492E+11	2.849E+11	3.204E+11	3.560E+11	3.916E+11
14	1.499E+06	5.477E+08	7.667E+09	2.684E+11	3.067E+11	3.450E+11	3.834E+11	4.217E+11
15	1.499E+06	5.477E+08	8.215E+09	2.875E+11	3.286E+11	3.697E+11	4.107E+11	4.519E+11
16	1.499E+06	5.477E+08	8.762E+09	3.067E+11	3.505E+11	3.943E+11	4.381E+11	4.819E+11
17	1.499E+06	5.477E+08	9.310E+09	3.259E+11	3.724E+11	4.198E+11	4.655E+11	5.121E+11
18	1.499E+06	5.477E+08	9.858E+09	3.450E+11	3.943E+11	4.436E+11	4.929E+11	5.422E+11
19	1.499E+06	5.477E+08	1.041E+10	3.642E+11	4.162E+11	4.682E+11	5.203E+11	5.723E+11
20	1.489E+06	5.438E+08	1.095E+10	3.832E+11	4.380E+11	4.927E+11	5.475E+11	6.022E+11
21	1.402E+06	5.122E+08	1.146E+10	4.012E+11	4.585E+11	5.158E+11	5.731E+11	6.304E+11
22	1.321E+06	4.823E+08	1.194E+10	4.190E+11	4.778E+11	5.375E+11	5.972E+11	6.569E+11
23	1.244E+06	4.542E+08	1.240E+10	4.339E+11	4.959E+11	5.579E+11	6.199E+11	6.819E+11
24	1.171E+06	4.278E+08	1.283E+10	4.489E+11	5.130E+11	5.772E+11	6.413E+11	7.054E+11
25	1.103E+06	4.029E+08	1.323E+10	4.630E+11	5.291E+11	5.953E+11	6.614E+11	7.276E+11
26	1.039E+06	3.794E+08	1.361E+10	4.763E+11	5.443E+11	6.124E+11	6.804E+11	7.484E+11
27	9.783E+05	3.573E+08	1.397E+10	4.888E+11	5.586E+11	6.284E+11	6.983E+11	7.681E+11
28	9.213E+05	3.365E+08	1.430E+10	5.006E+11	5.721E+11	6.436E+11	7.151E+11	7.866E+11
29	8.677E+05	3.169E+08	1.462E+10	5.117E+11	5.848E+11	6.578E+11	7.309E+11	8.040E+11
30	8.171E+05	2.985E+08	1.492E+10	5.221E+11	5.967E+11	6.713E+11	7.459E+11	8.205E+11

TOTAL LIQUID VOLUME RECOVERED BY WELL SYSTEM = 1.492E+10 BBLs
TOTAL LIQUID VOLUME AVAILABLE ACCORDING TO PRELIMINARY CALCULATION = 1.515E+10 BBLs
FRACTION RECOVERED = RECOVERED/AVAILABLE = .985
SYSTEM REQUIRED 49 WELLS
WITH A DENSITY OF .03 WELLS/SQ.MI

Figure 2 (con't)

The assessment of the Vicksburg Formation by BEG was that there was little chance of developing the geopressed resources of this formation. Even if optimistic values were used for the important resource parameters, the resource assessment model's results indicate that the formation could not come close to providing the minimum required flow.

The BEG's assessment of the Wilcox Formations' fairways was not so definitive. A summary of the results from the resource assessment code WELL are presented for the eight fairways in Tables 1 through 8. All these cases were run based upon a 30 year production lifetime with a reservoir decay of 6%/yr. For each fairway, the "base" case is listed as case number 1. The base case represents an optimistic set of circumstances. The parametric study which follows elevates the physical parameters to more optimistic values, hence a less probable set of circumstances. The parametric study is performed by varying parameters in reference to the base case. As a result of the resource assessment code, only the Harris Fairway, located near Houston shows an ability to flow. Its ability to support 1061 wells in the base case must be thought of as the maximum since it assumes total continuity of the reservoir sandstones along with the average parameter values throughout. The technical information available on the Harris Fairway is very sparse and thus very little faith can be given to these results for proposed development until better data can be obtained. Obviously the great number of wells which can be supported by the Wilcox Formation in the Harris Fairway is due to its immense areal extent, greater than 1000 mi² rather than its low sandstone permeability, less than 2.0 md or low porosity, less than 15%. The effects of cementation and compaction

Table 1

RESULTS OF PROGRAM WELL: COLORADO FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered	Total Gas Recovered @ 35-ft ³ /bbl
	(%)	(md)	(psi)	(ft)	(%/yr)						(bbl)	(ft ³)
1	15.	2.0	2000.	850.	6.	*Not acceptable, maximum flow 11370. bbl/day						
2	15.	4.0	2000.	850.	6.	"	"	"	"	22714. bbl/day		
3	15.	6.0	2000.	850.	6.	"	"	"	"	34111. bbl/day		
4	15.	8.0	2000.	850.	6.	4.	5.0	.85	.90	33.	5.93(10) ⁹	2.08(10) ¹¹
5	15.	2.0	2000.	1275.	6.	*Not acceptable, maximum flow 17056. bbl/day						
6	15.	2.0	2000.	1700.	6.	"	"	"	"	22741. bbl/day		
7	15.	2.0	2000.	2125.	6.	"	"	"	"	28426. bbl/day		
8	15.	2.0	3000.	850.	6.	"	"	"	"	18056. bbl/day		
9	15.	2.0	4000.	850.	6.	"	"	"	"	22741. bbl/day		

Table 2

RESULTS OF PROGRAM WELL: DUVAL FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	400.	6.	*Not acceptable, maximum flow 5416. bbl/day						
2	15.	4.0	2000.	400.	6.	"	"	"	"	10831. bbl/day		
3	15.	6.0	2000.	400.	6.	"	"	"	"	16247. bbl/day		
4	15.	8.0	2000.	400.	6.	"	"	"	"	21662. bbl/day		
5	15.	2.0	2000.	600.	6.	"	"	"	"	8123. bbl/day		
6	15.	2.0	2000.	800.	6.	"	"	"	"	10831. bbl/day		
7	15.	2.0	2000.	1000.	6.	"	"	"	"	15539. bbl/day		
8	15.	2.0	3000.	400.	6.	"	"	"	"	8123. bbl/day		
9	15.	2.0	4000.	400.	6.	"	"	"	"	10831. bbl/day		

Table 3

RESULTS OF PROGRAM WELL: DEWITT FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	700.	6.	*Not acceptable, maximum flow 9212. bbl/day						
2	15.	4.0	2000.	700.	6.	"	"	"	"	18424. bbl/day		
3	15.	6.0	2000.	700.	6.	"	"	"	"	27637. bbl/day		
4	15.	8.0	2000.	700.	6.	"	"	"	"	36849. bbl/day		
5	15.	2.0	2000.	1050.	6.	"	"	"	"	13818. bbl/day		
6	15.	2.0	2000.	1400.	6.	"	"	"	"	18424. bbl/day		
7	15.	2.0	2000.	1750.	6.	"	"	"	"	23030. bbl/day		
8	15.	2.0	2000.	700.	6.	"	"	"	"	13818. bbl/day		
9	15.	2.0	2000.	700.	6.	"	"	"	"	18424. bbl/day		

Table 4

RESULTS OF PROGRAM WELL: LIBERTY FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	460.	6.	*Not acceptable, maximum flow			6153, bbl/day			
2	15.	4.0	2000.	460.	6.	"	"	"	"	12307, bbl/day		
3	15.	6.0	2000.	460.	6.	"	"	"	"	18460, bbl/day		
4	15.	8.0	2000.	460.	6.	"	"	"	"	24614, bbl/day		
5	15.	2.0	2000.	690.	6.	"	"	"	"	9230, bbl/day		
6	15.	2.0	2000.	920.	6.	"	"	"	"	12307, bbl/day		
7	15.	2.0	2000.	1150.	6.	"	"	"	"	15384, bbl/day		
8	15.	2.0	3000.	460.	6.	"	"	"	"	9230, bbl/day		
9	15.	2.0	4000.	460.	6.	"	"	"	"	12307, bbl/day		

Table 5

RESULTS OF PROGRAM WELL; LIVE OAK FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	240.	6.	*Not acceptable, maximum flow 3356. bbl/day						
2	15.	4.0	2000.	240.	6.	"	"	"	"	6713. bbl/day		
3	15.	6.0	2000.	240.	6.	"	"	"	"	10069. bbl/day		
4	15.	8.0	2000.	240.	6.	"	"	"	"	13426. bbl/day		
5	15.	2.0	2000.	360.	6.	"	"	"	"	5035. bbl/day		
6	15.	2.0	2000.	480.	6.	"	"	"	"	6713. bbl/day		
7	15.	2.0	2000.	600.	6.	"	"	"	"	8391. bbl/day		
8	15.	2.0	3000.	600.	6.	"	"	"	"	5035. bbl/day		
9	15.	2.0	4300.	600.	6.	"	"	"	"	6713. bbl/day		

Table 6

RESULTS OF PROGRAM WELL: HARRIS FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered	Total Gas Recovered @ 35 ft ³ /bbl
	(%)	(md)	(psi)	(ft)	(%/yr)						(bbl)	(ft ³)
1	15.	2.0	2000.	3600.	6.	3.	5.0	.85	.90	1061.	1.86(10) ¹¹	6.50(10) ¹²
2	15.	4.0	2000.	3600.	6.	15.	5.0	.85	.90	690.	1.86(10) ¹¹	6.50(10) ¹²
3	15.	6.0	2000.	3600.	6.	21.	5.0	.85	.90	600.	1.86(10) ¹¹	6.50(10) ¹²
4	15.	8.0	2000.	3600.	6.	26.	5.0	.85	.90	566.	1.86(10) ¹¹	6.50(10) ¹²
5	15.	2.0	2000.	5400.	6.	10.	5.0	.85	.90	1196.	2.79(10) ¹¹	9.76(10) ¹²
6	15.	2.0	2000.	7200.	6.	15.	5.0	.85	.90	1382.	3.72(10) ¹¹	1.30(10) ¹³
7	15.	2.0	2000.	9000.	6.	18.	5.0.	.85	.90	1585.	4.65(10) ¹¹	1.63(10) ¹³
8	20.	2.0	2000.	3600.	6.	3.	5.0	.85	.90	1416.	2.48(10) ¹¹	8.68(10) ¹²
9	25.	2.0	2000.	3600.	6.	3.	5.0	.85	.90	1770.	3.10(10) ¹¹	1.08(10) ¹³
10	30.	2.0	2000.	3600.	6.	3.	5.0	.85	.90	2124.	3.72(10) ¹¹	1.30(10) ¹³
11	15.	2.0	2000.	3600.	6.	3.	10.0	.85	.90	2124.	3.72(10) ¹¹	1.30(10) ¹³
12	15.	2.0	2000.	3600.	6.	3.	15.0	.85	.90	3187.	5.58(10) ¹¹	1.95(10) ¹³
13	15.	2.0	2000.	3600.	6.	3.	20.0	.85	.90	4251.	7.44(10) ¹¹	2.61(10) ¹³
14	15.	2.0	3000.	3600.	6.	10.	5.0	.85	.90	797.	1.86(10) ¹¹	6.50(10) ¹²
15	15.	2.0	4000.	3600.	6.	15.	5.0	.85	.90	690.	1.86(10) ¹¹	6.50(10) ¹²

Table 7

RESULTS OF PROGRAM WELL: WEBB FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	400.	6.	*Not acceptable, maximum flow 5726, bbl/day						
2	15.	4.0	2000.	400.	6.	"	"	"	"	11451, bbl/day		
3	15.	6.0	2000.	400.	6.	"	"	"	"	17177, bbl/day		
4	15.	8.0	2000.	400.	6.	"	"	"	"	22902, bbl/day		
5	15.	2.0	2000.	600.	6.	"	"	"	"	8588, bbl/day		
6	15.	2.0	2000.	800.	6.	"	"	"	"	11451, bbl/day		
7	15.	2.0	2000.	1000.	6.	"	"	"	"	14314, bbl/day		
8	15.	2.0	3000.	400.	6.	"	"	"	"	8588, bbl/day		
9	15.	2.0	4000.	400.	6.	"	"	"	"	11451, bbl/day		

Table 8

RESULTS OF PROGRAM WELL: ZAPATA FAIRWAY, WILCOX FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	340.	6.	*Not acceptable, maximum flow 4867. bbl/day						
2	15.	4.0	2000.	340.	6.	"	"	"	"	9734. bbl/day		
3	15.	6.0	2000.	340.	6.	"	"	"	"	14600. bbl/day		
4	15.	8.0	2000.	340.	6.	"	"	"	"	19467. bbl/day		
5	15.	2.0	2000.	510.	6.	"	"	"	"	7300. bbl/day		
6	15.	2.0	2000.	680.	6.	"	"	"	"	9734. bbl/day		
7	15.	2.0	2000.	850.	6.	"	"	"	"	12167. bbl/day		
8	15.	2.0	3000.	340.	6.	"	"	"	"	7300. bbl/day		
9	15.	2.0	4000.	340.	6.	"	"	"	"	9734. bbl/day		

could significantly reduce the Harris Fairway's ability to flow because of its low permeability and porosity characteristics. With these factors in mind the Harris Fairway was not considered in the development planning portion of this work.

The results of the assessment code on the five Frio Formations are presented in Tables 9 through 13. These cases also used a 30 year production lifetime with a 6%/yr reservoir decay rate. The information describing the Frio Formation is better developed than that describing the Wilcox Formation. Of the five fairways only the base case for the Brazoria Fairway was able to produce above the minimum required volume for the 30 year lifetime. This is primarily due to the permeability averaging 50 md throughout the sandstone formation. For the base case, the fairway could support a maximum of 49 wells over the 30 year lifetime. The total liquid recovered over the lifetime would be nearly 15 billion barrels. This would result in over one-half trillion ft^3 of natural gas if each barrel contained 35 ft^3 natural gas/barrel. The output for this particular scenario was presented earlier as Figure 2.

The study of this fairway shows that different physical circumstances not only change the amount of resources recovered but also the timetable over which they can be recovered. These changes are due to the variation of the production histories.

The assessment code WELL defines the Brazoria Fairway as a possible geopressured-geothermal resource site. The code was also manipulated to study the effects of reinjection and reservoir decay on the Brazoria site. Working on the premise that reinjecting the produced fluid back into the original formation would triple the amount of fluid recovered

Table 9

RESULTS OF PROGRAM WELL: ARMSTRONG FAIRWAY, FRIO FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	2.0	2000.	300.	6.	*Not acceptable, maximum flow 4140. bbl/day						
2	15.	4.0	2000.	300.	6.	"	"	"	"	8295. bbl/day		
3	15.	6.0	2000.	300.	6.	"	"	"	"	12443. bbl/day		
4	15.	8.0	2000.	300.	6.	"	"	"	"	16590. bbl/day		
5	15.	2.0	2000.	450.	6.	"	"	"	"	6221. bbl/day		
6	15.	2.0	2000.	600.	6.	"	"	"	"	8295. bbl/day		
7	15.	2.0	2000.	750.	6.	"	"	"	"	10369. bbl/day		
8	15.	2.0	3000.	300.	6.	"	"	"	"	6221. bbl/day		
9	15.	2.0	4000.	300.	6.	"	"	"	"	8295. bbl/day		

Table 10

RESULTS OF PROGRAM WELL: BRAZORIA FAIRWAY, FRIO FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ .35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	50.	2000.	400.	6.	20.	5.	.85	.90	49.	1.49(10) ¹⁰	5.22(10) ¹¹
2	15.	100.	2000.	400.	6.	No decline	5.	.85	.90	44.	1.48(10) ¹⁰	5.16(10) ¹¹
3	15.	150.	2000.	400.	6.	No decline	5.	.85	.90	44.	1.48(10) ¹⁰	5.16(10) ¹¹
4	15.	200.	2000.	400.	6.	No decline	5.	.85	.90	44.	1.48(10) ¹⁰	5.16(10) ¹¹
5	15.	50.	2000.	600.	6.	27.	5.	.85	.90	68.	2.25(10) ¹⁰	7.87(10) ¹¹
6	15.	50.	2000.	800.	6.	No decline	5.	.85	.90	90.	3.02(10) ¹⁰	1.06(10) ¹²
7	15.	50.	2000.	1000.	6.	No decline	5.	.85	.90	112.	3.76(10) ¹⁰	1.31(10) ¹²
8	20.	50.	2000.	400.	6.	20	5.	.85	.90	65.	1.98(10) ¹⁰	6.93(10) ¹¹
9	25.	50.	2000.	400.	6.	20	5.	.85	.90	82.	2.50(10) ¹⁰	8.74(10) ¹¹
10	30.	50.	2000.	400.	6.	20.	5.	.85	.90	99.	3.01(10) ¹⁰	1.06(10) ¹²
11	15.	50.	2000.	400.	6.	20.	10.	.85	.90	99.	3.01(10) ¹⁰	1.06(10) ¹²
12	15.	50.	2000.	400.	6.	20.	15.	.85	.90	148.	4.51(10) ¹⁰	1.58(10) ¹²
13	15.	50.	2000.	400.	6.	20.	20.	.85	.90	198.	6.03(10) ¹⁰	2.11(10) ¹²
14	15.	50.	3000.	400.	6.	27.	5.	.85	.90	45.	1.49(10) ¹⁰	5.21(10) ¹¹
15	15.	50.	4000.	400.	6.	No decline	5.	.85	.90	44.	1.49(10) ¹⁰	5.16(10) ¹¹

Table 11

RESULTS OF PROGRAM WELL: CORPUS CHRISTI FAIRWAY, FRIO FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity (%)	Permeability (md)	Pressure Differential (psi)	Effective Formation Thickness (ft)	Annual Production Decay (%/yr)	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
1	15.	2.0	2000.	300.	6.	*Not acceptable, maximum flow 3928. bbl/day						
2	15.	4.0	2000.	300.	6.	"	"	"	"	7856. bbl/day		
3	15.	6.0	2000.	300.	6.	"	"	"	"	11785. bbl/day		
4	15.	8.0	2000.	300.	6.	"	"	"	"	15713. bbl/day		
5	15.	2.0	2000.	450.	6.	"	"	"	"	5892. bbl/day		
6	15.	2.0	2000.	600.	6.	"	"	"	"	7856. bbl/day		
7	15.	2.0	2000.	750.	6.	"	"	"	"	3928. bbl/day		
8	15.	2.0	3000.	300.	6.	"	"	"	"	5892. bbl/day		
9	15.	2.0	4000.	300.	6.	"	"	"	"	7856. bbl/day		

Table 12

RESULTS OF PROGRAM WELL: HIDALGO FAIRWAY, FRIO FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	1.0	2000.	500.	6.	*Not acceptable, maximum flow 3072. bbl/day						
2	15.	2.0	2000.	500.	6.	"	"	"	"	6144. bbl/day		
3	15.	3.0	2000.	500.	6.	"	"	"	"	9216. bbl/day		
4	15.	4.0	2000.	500.	6.	"	"	"	"	12287. bbl/day		
5	15.	1.0	2000.	750.	6.	"	"	"	"	4608. bbl/day		
6	15.	1.0	2000.	1000.	6.	"	"	"	"	6144. bbl/day		
7	15.	1.0	2000.	1250.	6.	"	"	"	"	7680. bbl/day		
8	15.	1.0	3000.	500.	6.	"	"	"	"	4608. bbl/day		
9	15.	1.0	4000.	500.	6.	"	"	"	"	6144. bbl/day		

Table 13

RESULTS OF PROGRAM WELL: MATAGORDA FAIRWAY, FRIO FORMATION
(30 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	1.0	2000.	300.	6.	*Not acceptable, maximum flow 1964. bbl/day						
2	15.	2.0	2000.	300.	6.	"	"	"	"	3928.	bbl/day	
3	15.	3.0	2000.	300.	6.	"	"	"	"	5892.	bbl/day	
4	15.	4.0	2000.	300.	6.	"	"	"	"	7856.	bbl/day	
5	15.	1.0	2000.	450.	6.	"	"	"	"	2946.	bbl/day	
6	15.	1.0	2000.	600.	6.	"	"	"	"	3928.	bbl/day	
7	15.	1.0	2000.	750.	6.	"	"	"	"	4910.	bbl/day	
8	15.	1.0	3000.	300.	6.	"	"	"	"	2946.	bbl/day	
9	15.	1.0	4000.	300.	6.	"	"	"	"	3928.	bbl/day	

while doubling the productive lifetime, program WELL was run for the Brazoria Fairway. The results are listed in Table 14. The base case for this scenario is case number 12. Comparing this scenario to the 30 year lifetime decaying at 6%/yr scenario discussed earlier shows that the production did triple while the number of required wells rose from 49 to 116. Similar cases for varying the relationship between production lifetime and reservoir decay rate are presented in Tables 15 and 16. The results for the lower decay rate show that the production level remains constant throughout the 30 year lifetime scenario thus requiring fewer wells to extract the same amount of fluid. For the longer production lifetime, the lower decay rate enables the scenario to maintain a flat production profile for the first 39 years in the base case, thus again requiring fewer wells.

Table 14

RESULTS OF PROGRAM WELL: BRAZORIA FAIRWAY, FRIO FORMATION
(60 yr lifetime, 6%/yr flow decay)

Case	Porosity	Permeability	Pressure Differential	Effective Formation Thickness	Annual Production Decay	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
	(%)	(md)	(psi)	(ft)	(%/yr)							
1	15.	50.	2000.	400.	6.	20.	5.	.85	.9	37.	1.43(10) ¹⁰	5.01(10) ¹¹
2	15.	100.	2000.	400.	6.	32.	5.	.85	.9	29.	1.45(10) ¹⁰	5.07(10) ¹¹
3	15.	150.	2000.	400.	6.	39.	5.	.85	.9	26.	1.45(10) ¹⁰	5.08(10) ¹¹
4	15.	200.	2000.	400.	6.	43.	5.	.85	.9	24.	1.43(10) ¹⁰	5.01(10) ¹¹
5	15.	50.	2000.	600.	6.	27.	5.	.85	.9	49.	2.26(10) ¹⁰	7.79(10) ¹¹
6	15.	50.	2000.	800.	6.	32.	5.	.85	.9	59.	2.95(10) ¹⁰	1.03(10) ¹²
7	15.	50.	2000.	1000.	6.	36.	5.	.85	.9	70.	3.73(10) ¹⁰	1.31(10) ¹²
8	20.	50.	2000.	400.	6.	20.	5.	.85	.9	50.	1.93(10) ¹⁰	6.77(10) ¹¹
9	25.	50.	2000.	400.	6.	20.	5.	.85	.9	64.	2.48(10) ¹⁰	8.66(10) ¹¹
10	30.	50.	2000.	400.	6.	20.	5.	.85	.9	77.	2.98(10) ¹⁰	1.04(10) ¹²
11	15.	50.	2000.	400.	6.	20.	10.	.85	.9	77.	2.98(10) ¹⁰	1.04(10) ¹²
12	15.	50.	2000.	400.	6.	20.	15.	.85	.9	116.	4.49(10) ¹⁰	1.57(10) ¹²
13	15.	50.	2000.	400.	6.	20.	20.	.85	.9	155.	5.99(10) ¹⁰	2.10(10) ¹²
14	15.	50.	3000.	400.	6.	27.	5.	.85	.9	32.	1.45(10) ¹⁰	5.09(10) ¹¹
15	15.	50.	4000.	400.	6.	32.	5.	.85	.9	29.	1.45(10) ¹⁰	5.07(10) ¹¹

Table 15

RESULTS OF PROGRAM WELL: BRAZORIA FAIRWAY, FRIO FORMATION
(30 yr lifetime, 3%/yr flow decay)

Case	Porosity (%)	Permeability (md)	Pressure Differential (psi)	Effective Formation Thickness (ft)	Annual Production Decay (%/yr)	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
1	15.	50.	2000.	400.	3.	No decline	5.	85.	.9	44.	1.48(10) ¹⁰	5.16(10) ¹¹
2	15.	100.	2000.	400.	3.	No decline	5.	85.	.9	44.	1.48(10) ¹⁰	5.16(10) ¹¹
3	15.	150.	2000.	400.	3.	No decline	5.	85.	.9	44.	1.48(10) ¹⁰	5.16(10) ¹¹
4	15.	200.	2000.	400.	3.	No decline	5.	85.	.9	44.	1.48(10) ¹⁰	5.16(10) ¹¹
5	15.	50.	2000.	600.	3.	No decline	5.	85.	.9	67.	2.25(10) ¹⁰	7.86(10) ¹¹
6	15.	50.	2000.	800.	3.	No decline	5.	85.	.9	90.	3.02(10) ¹⁰	1.06(10) ¹²
7	15.	50.	2000.	1000.	3.	No decline	5.	85.	.9	112.	3.76(10) ¹⁰	1.31(10) ¹²
8	20.	50.	2000.	400.	3.	No decline	5.	85.	.9	59.	1.98(10) ¹⁰	6.92(10) ¹¹
9	25.	50.	2000.	400.	3.	No decline	5.	85.	.9	74.	2.48(10) ¹⁰	8.68(10) ¹¹
10	30.	50.	2000.	400.	3.	No decline	5.	85.	.9	90.	3.02(10) ¹⁰	1.06(10) ¹²
11	15.	50.	2000.	400.	3.	No decline	10.	85.	.9	90.	3.02(10) ¹⁰	1.06(10) ¹²
12	15.	50.	2000.	400.	3.	No decline	15.	85.	.9	135.	4.53(10) ¹⁰	1.58(10) ¹²
13	15.	50.	2000.	400.	3.	No decline	20.	85.	.9	180.	6.04(10) ¹⁰	2.11(10) ¹²
14	15.	50.	3000.	400.	3.	No decline	5.	85.	.9	44.	1.48(10) ¹⁰	5.16(10) ¹¹
15	15.	50.	4000.	400.	3.	No decline	5.	85.	.9	44.	1.48(10) ¹⁰	5.16(10) ¹¹

Table 16

RESULTS OF PROGRAM WELL: BRAZORIA FAIRWAY, FRIO FORMATION
(60 yr lifetime, 3%/yr flow decay)

Case	Porosity (%)	Permeability (md)	Pressure Differential (psi)	Effective Formation Thickness (ft)	Annual Production Decay (%/yr)	Initial Year of Flow Decline	Fluid Recovery Assumed (% of in place)	Well Capacity Factor	Well Interference Factor	No. of Wells Required	Total Liquid Recovered (bbl)	Total Gas Recovered @ 35 ft ³ /bbl (ft ³)
1	15.	50.	2000.	400.	3.	39.	5.	.85	.9	24.	1.46(10) ¹⁰	5.09(10) ¹¹
2	15.	100.	2000.	400.	3.	No decline	5.	.85	.9	22.	1.48(10) ¹⁰	5.16(10) ¹¹
3	15.	150.	2000.	400.	3.	No decline	5.	.85	.9	22.	1.48(10) ¹⁰	5.16(10) ¹¹
4	15.	200.	2000.	400.	3.	No decline	5.	.85	.9	22.	1.48(10) ¹⁰	5.16(10) ¹¹
5	15.	50.	2000.	600.	3.	53.	5.	.85	.9	34.	2.25(10) ¹⁰	7.86(10) ¹¹
6	15.	50.	2000.	800.	3.	No decline	5.	.85	.9	44.	2.95(10) ¹⁰	1.03(10) ¹²
7	15.	50.	2000.	1000.	3.	No decline	5.	.85	.9	56.	3.76(10) ¹⁰	1.31(10) ¹²
8	20.	50.	2000.	400.	3.	39.	5.	.85	.9	32.	1.94(10) ¹⁰	6.97(10) ¹¹
9	25.	50.	2000.	400.	3.	39.	5.	.85	.9	41.	2.49(10) ¹⁰	8.70(10) ¹¹
10	30.	50.	2000.	400.	3.	39.	5.	.85	.9	49.	2.97(10) ¹⁰	1.04(10) ¹²
11	15.	50.	2000.	400.	3.	39.	10.	.85	.9	49.	2.97(10) ¹⁰	1.04(10) ¹²
12	15.	50.	2000.	400.	3.	39.	15.	.85	.9	74.	4.49(10) ¹⁰	1.57(10) ¹²
13	15.	50.	2000.	400.	3.	39.	20.	.85	.9	99.	6.00(10) ¹⁰	2.10(10) ¹²
14	15.	50.	3000.	400.	3.	53.	5.	.85	.9	22.	1.45(10) ¹⁰	5.08(10) ¹¹
15	15.	50.	4000.	400.	3.	No decline	5.	.85	.9	22.	1.48(10) ¹⁰	5.16(10) ¹¹

III. Development Planning

The overall result from the resource assessment studies was that only the Brazoria Fairway in the Frio Formation was able to produce geopressured-geothermal fluid above the minimum requirements. The output from the Brazoria runs were fed into a computer code named PRODUCE. PRODUCE is a development planning model which provides a timetable for the drilling of the prospects within the acceptable fairways. A listing of the code is presented in Appendix C.

The code analyzes one fairway at a time and requires as input the number of deep drilling rigs available, the maximum number of prospects to be drilled and an estimate of the probability of finding an acceptable producing well upon well completion.

The number of deep drilling rigs available for the development of the fairway is a user determined variable. The number of rigs assigned to any one fairway may be increased or decreased according to program ambitiousness, initial well success, etc.

The initial case studies assumed that 3 or 4 deep drilling rigs would be available to develop the Brazoria Fairway. This number of rigs was estimated to be about 10% of the total number of rigs along the Texas coast with such deep drilling capability. A flow chart of the development scenario for a single fairway is presented in Figure 2A.

This scenario follows several important rules: 1) The rig which completes a producible well is also assigned to drill that well's shallow reinjection well. 2) If another rig is available at the time of completion of a producible well, it is assigned to drill a deep reinjection well first before being released to a new exploratory drilling assignment.

FIGURE 2A

FLOW CHART FOR EXPLORATORY WELL DRILLING PROGRAM

This scenario minimizes the lag time between completion and the start of production for a producible well. In essence, the scenario randomly searches for producible wells, drills a shallow reinjection well (SRW) and a deep reinjection well (DRW) for each producible well as soon as it can and then releases the rigs for new exploratory drilling.

The initial scenarios outlined in the development planning use drilling times of 4 months for the exploratory and deep reinjection wells while using a 2-month drilling time for the SRW. These times were considered good first estimates for the system; however they can be easily altered by the user.

The maximum number of prospects within a fairway is an output value from the resource assessment code WELL. This maximum number of prospects gives the upper limit to the total number of exploratory wells to be drilled. If the maximum number of prospects were drilled and completed successfully then 100% of the fairway would be producible. Although this result could be attained by the models provided, it would be unrealistic for a number of reasons. First and foremost is the question of reservoir continuity. It is not believed that the formations are continuous enough to allow for 100% of the recoverable resource to be reached. Secondly, the resource assessment program was based on average reservoir properties. Since some of the properties are bound to vary over the fairways' extent, (most likely, permeability, porosity, and sandstone thickness), some reduction in the total number of producible wells to be found must be made. In this study the reduction was made by using a "hit probability" which randomly determined if a just completed exploratory well would be a producible well or a dry hole. The maximum

value of the hit probability would be 1.0. In this case, the upper limit of 100% fairway producibility is realized when the maximum number of prospects are drilled.

Since the fault block size distribution for the fairways studied is not available it is impossible to determine what fraction of the fairway might be producible based on simply having blocks of continuous sandstone large enough to support one well at average properties. This is due to the possibility of having thin sands, locally low permeability, etc. in the fault block. These unknown quantities are the reason for the hit probability being less than 1.0 in this study. The initial choices for the hit probability in this study were .333 (one producible well for every three exploratory wells drilled), .500 (1/2), and .167 (1/6).

The actual sequence of the individual well probabilities comprising the overall fairway hit probability is determined by a reproducible random number generator within the code.

The development planning code itself outputs a drilling timetable for the fairway studied. It provides the sequence of drilling for good wells, well failures, shallow reinjection wells (if required), and deep reinjection wells (if required). A sample output of the example Brazoria Fairway development plan employing three drilling rigs, 49 prospects and a successful hit probability of .333 is given in Figure 3.

A graphical time line history of the number of producing wells during the exploratory time period for the example Brazoria scenario listed in Figure 3 is produced in Figure 4. This producing well history combined with the individual wells production histories evaluated in the resource assessment code WELL provides a time line energy production

FAIRWAY BRAZORIA

NUMBER OF DRILLING RIGS AVAILABLE (NRIGS)= 3
 NUMBER OF PROSPECTS TO BE DRILLED (NDRILL)= 49
 SUCCESS PROBABILITY OF WELL (HITPROB)= .3333

KEY

J =TIME IN YEARS SINCE INITIATION OF PROJECT
 I =TIME IN MONTHS SINCE INITIATION OF PROJECT
 NG(I) =NO. RIGS DRILLING GOOD EXPLORATORY WELLS
 ND(I) =NO. RIGS DRILLING DRY EXPLORATORY WELLS
 NSR(I)=NO. RIGS DRILLING SHALLOW REINJECTION WELLS
 NDR(I)=NO. RIGS DRILLING DEEP REINJECTION WELLS
 NF(I) =NO. RIGS FREE FROM SERVICE
 NS(I) =NO. RIGS SHORT IN PRODUCTION PLAN
 NGC(I)=POINT IN TIME GOOD WELL STARTS PRODUCING
 NDC(I)=POINT IN TIME DRY WELL COMPLETED

STATUS OF RIGS OVER EXPLORATION LIFE OF FAIRWAY

(J)	(I)	NG(I)	ND(I)	NSR(I)	NDR(I)	NF(I)	NS(I)	NGC(I)	NDC(I)
	1	1	2	0	0	0	0	0	0
	2	1	2	0	0	0	0	0	0
	3	1	2	0	0	0	0	0	0
	4	1	2	0	0	0	0	0	0
	5	1	0	1	1	0	0	0	2
	6	1	0	1	1	0	0	0	0
	7	1	1	0	1	0	0	1	0
	8	1	1	0	1	0	0	0	0
	9	0	1	1	1	0	0	0	0
	10	0	1	1	1	0	0	0	0
1	11	0	2	0	1	0	0	1	1
	12	0	2	0	1	0	0	0	0
	13	0	3	0	0	0	0	0	0
	14	0	3	0	0	0	0	0	0
	15	0	3	0	0	0	0	0	2
	16	0	3	0	0	0	0	0	0
	17	0	3	0	0	0	0	0	1
	18	0	3	0	0	0	0	0	0
	19	1	2	0	0	0	0	0	2
	20	1	2	0	0	0	0	0	0
	21	1	2	0	0	0	0	0	1
	22	1	2	0	0	0	0	0	0
2	23	0	1	1	1	0	0	0	1
	24	0	1	1	1	0	0	0	0
	25	2	0	0	1	0	0	1	1
	26	2	0	0	1	0	0	0	0
	27	3	0	0	0	0	0	0	0
	28	3	0	0	0	0	0	0	0
	29	1	0	2	0	0	2	0	0
	30	1	0	2	0	0	2	0	0
	31	0	0	1	2	0	1	2	0
	32	0	0	1	2	0	1	0	0
	33	0	0	0	3	0	0	1	0
	34	0	0	0	3	0	0	0	0
	35	0	2	0	1	0	0	0	0

Figure 3

SAMPLE OUTPUT OF PROGRAM PRODUCE

36	0	2	0	1	0	0	0	0	0	37	0
37	1	2	0	0	0	0	0	0	0	0	0
38	1	2	0	0	0	0	0	0	0	0	0
39	2	1	0	0	0	0	0	0	0	2	0
40	2	1	0	0	0	0	0	0	0	0	0
41	1	1	1	1	0	0	0	1	0	0	0
42	1	1	1	1	0	0	0	1	0	0	0
43	0	0	1	1	2	0	0	0	1	1	0
44	0	0	1	1	2	0	0	0	0	0	0
45	0	1	0	0	2	0	0	0	1	0	0
46	0	1	0	0	2	0	0	0	0	0	0
47	2	1	0	0	0	0	0	0	0	0	0
48	2	1	0	0	0	0	0	0	0	0	0
49	2	1	0	0	0	0	0	0	0	1	0
50	2	1	0	0	0	0	0	0	0	0	0
51	0	1	2	2	0	0	0	2	0	0	0
52	0	1	2	0	0	0	0	2	0	0	0
53	0	1	0	2	0	0	0	0	2	1	0
54	0	1	0	2	0	0	0	0	0	0	0
55	0	1	0	2	0	0	0	0	0	0	0
56	0	1	0	2	0	0	0	0	0	0	0
57	0	3	0	0	0	0	0	0	0	1	0
58	0	3	0	0	0	0	0	0	0	0	0
59	0	3	0	0	0	0	0	0	0	0	0
60	0	3	0	0	0	0	0	0	0	0	0
61	0	3	0	0	0	0	0	0	0	3	0
62	0	3	0	0	0	0	0	0	0	0	0
63	0	3	0	0	0	0	0	0	0	0	0
64	0	3	0	0	0	0	0	0	0	0	0
65	0	3	0	0	0	0	0	0	0	3	0
66	0	3	0	0	0	0	0	0	0	0	0
67	0	3	0	0	0	0	0	0	0	0	0
68	0	3	0	0	0	0	0	0	0	0	0
69	1	2	0	0	0	0	0	0	0	3	0
70	1	2	0	0	0	0	0	0	0	0	0
71	1	2	0	0	0	0	0	0	0	0	0
72	1	2	0	0	0	0	0	0	0	0	0
73	0	1	1	1	1	0	0	0	0	2	0
74	0	1	1	1	1	0	0	0	0	0	0
75	1	1	0	1	1	0	0	0	1	0	0
76	1	1	0	1	1	0	0	0	0	0	0
77	3	0	0	0	0	0	0	0	0	1	0
78	3	0	0	0	0	0	0	0	0	0	0
79	2	0	1	0	0	0	0	1	0	0	0
80	2	0	1	0	0	0	0	1	0	0	0
81	0	0	2	1	1	0	0	2	1	0	0
82	0	0	2	1	1	0	0	2	0	0	0
83	0	0	0	3	3	0	0	0	2	0	0
84	0	0	0	3	3	0	0	0	0	0	0
85	0	1	0	2	2	0	0	0	0	0	0
86	0	1	0	2	2	0	0	0	0	0	0
87	1	2	0	0	0	0	0	0	0	0	0
88	1	2	0	0	0	0	0	0	0	0	0
89	1	2	0	0	0	0	0	0	0	1	0
90	1	2	0	0	0	0	0	0	0	0	0
91	0	1	1	1	1	0	0	0	0	1	0
92	0	1	1	1	1	0	0	0	0	0	0
93	1	1	0	1	1	0	0	0	1	1	0
94	1	1	0	1	1	0	0	0	0	0	0
95	1	1	0	0	0	1	0	0	0	0	0
96	1	1	1	1	1	1	0	0	0	0	0
97	0	0	1	1	1	1	0	0	0	0	0

Figure 3 (cont.)

98	0	0	1	1	1	0	1	0
99	0	0	0	1	2	0	1	0
100	0	0	0	1	2	0	0	0
101	0	0	0	0	3	0	0	0
102	0	0	0	0	3	0	0	0
103	0	0	0	0	3	0	0	0
104	0	0	0	0	3	0	0	0
105	0	0	0	0	0	0	0	0

38

Figure 3 (con't)

TIME LINE FOR WELL PRODUCTION STARTS

FOR BRAZORIA FAIRWAY

history for the exploratory time period. This energy production history for the exploration period of the example Brazoria Fairway is given in Figure 5.

The information contained in the development code PRODUCE enables the producing well history to be evaluated for the life of the fairway. Since each well is assumed to produce for 30 years before extracting its share of the resource, the decommissioning schedule simply follows the same time schedule as the exploration period. A graphical representation of the number of producing wells versus time is presented in Figure 6 for the example Brazoria Fairway. If it were assumed that each well maintained a constant production history throughout its 30 year life, the energy production versus time curve would parallel that of Figure 6. However, maintaining a constant production rate is generally not the case due to the nature of the fairway being studied. This declining production history was demonstrated in the example Brazoria Fairway listed in Figure 2. The well's production begins to decay after 20 years of maintaining the maximum flow of 40,000 bbls/day. This decline in the wells producing capability is demonstrated by comparing the energy production history for the decaying flow case to that of the constant maximum flow case. This comparison is made in Figure 7.

The output from the code PRODUCE which is required for the economic analysis portion of the study is the time history for bringing the producing wells into production.

RECOVERY DURING EXPLORATORY DRILLING PERIOD

FOR THE BRAZORIA FAIRWAY

FIGURE 5

FIGURE 6

NUMBER OF WELLS IN BRAZORIA FAIRWAY vs TIME

FIGURE 7

BRAZORIA FAIRWAY PRODUCTION

IV. Economic Analysis

The effort of the project that has been described to this point has been the assessment of the extent and properties of the geopressured-geothermal resource. Based upon this assessment, various models for developing and using the resource were considered. The development scheme that was adopted for the analysis is a single production well unit. Supporting each production well are two disposal wells (one shallow and one deep) and the required gas separation and fluid reinjection equipment.

This work culminated in an analysis of a development plan that considered the number of drill rigs required, the drilling time, the probability of drilling a successful production well, and the resulting schedule for developing a resource area.

The resource assessment and development planning phases of the project emphasized the technical feasibility of developing the geopressured resource. The completion of these phases made possible the examination of the economic feasibility of developing the resource.

The rationale for conducting an economic analysis of the development plan is to gain insight into what economic conditions must exist in order for the envisioned development to take place. Further, it is instructive to evaluate what are the most important economic factors and how these factors may change in the future.

In order to perform the economic evaluation, an engineering economic project investment analysis program was developed. The criteria of evaluation to be used are the same as that which a private developer would ordinarily choose, net present value and discounted cash flow rate

of return. The complete mathematical model is presented in Appendix D, along with a listing of the computer program. This model was used to determine the net present value for a successful well and an unsuccessful well. This information was then matched with the results from the development planning section in order to perform the economic analysis of the development plan.

Initial Investment. The first step was to consider the major elements of the initial investment and estimate their cost. The cost of the production and disposal wells, the fuel plant, and the power plant make up the bulk of the initial investment.

After Tax Earnings. A basic income equation described in detail in Appendix D was used to calculate the after tax earnings over the economic life of a successful well. This income equation included the initial gas price and escalation rate, initial flow rate and flow decline rate, recovery percentage tax rate, severance tax, royalty rate, depreciation, and various operating costs.

Economic Life. The economic life of a producing unit was determined by calculating the year in which operating revenues are equal to operating costs. This depends upon a number of factors such as initial well flow rate, decline flow rate, and price escalation rate. Details of this calculation are given in Appendix D.

Net Present Value. These three elements, initial investment, after tax earnings, and economic life were combined into a present worth model that was solved using continuous discounting for a range of discount rates.

Input. The base case values of the economic parameters that serve as input to the economic analysis model are given in Table 17.

TABLE 17

ESTIMATED BASE CASE ECONOMIC PARAMETERS (1979)

Investment - Production Well	2,500,000.00
Investment - Deep Disposal Well	2,500,000.00
Investment - Shallow Disposal Well	500,000.00
Investment - Fuel Plant	1,000,000.00
Investment - Power Plant	4,000,000.00
Operating Cost - Fuel Plant	.0585
Operating Cost - Power Plant	.0955
Operating Cost Escalation Factor	.02
Gas Price - \$/MCF	2.00
Price Escalation Factor	.06
Gas Content of Fluid - SCF/BAR	45.00
Initial Flow Rate - Bar./Day	40,000.00
Number of Years to Decline	29.00
Decline Rate	.06
Severance Tax Rate	.075
Royalty Rate	.125

All investment costs are given in 1979 dollars. Operating costs are expressed as a fraction of the capital investment cost and are on an annual basis. The gas price is in 1979 dollars with a price escalation factor applied in the economic model. The decline rate, severance tax rate, and royalty rate are estimated from experience with the oil and gas operations in the state of Texas. Figure 8 illustrates these values as they are used as inputs for the economic analysis computer program.

Results. The results from this analysis shown in Figure 9 for a discount rate of 10% yield as negative net present value and indicate that this is not an economically viable project.

A second economic scenario having lower capital investment costs for the production and deep disposal wells, a lower operating cost escalation factor, and a higher gas price is shown in Figure 10. This scenario was analysed using the economic computer program by beginning with a discount rate of 10% and increasing this rate in 1% increments until the net present value became negative. The results of the analysis

PLEASE ENTER THE FOLLOWING DATA, ONE ITEM PER LINE

INVESTMENT - PRODUCTION WELL
INVESTMENT - DEEP DISPOSAL WELL
INVESTMENT - SHALLOW DISPOSAL WELL
INVESTMENT - FUEL PLANT
INVESTMENT - POWER PLANT
OPERATING COST PERCENTAGE - FUEL PLANT
OPERATING COST PERCENTAGE - POWER PLANT
OPERATING COST ESCALATION FACTOR
GAS PRICE - \$/MCF
PRICE ESCALATION FACTOR
GAS - SF/BAR
INITIAL FLOW RATE - BAR/DAY
NUM OF YRS TO DECLINE
DECLINE RATE
SEVERANCE TAX RATE
ROYALTY RATE

2500000.

2500000.

500000.

1000000.

4000000.

0.0585

0.0955

0.02

2.

0.06

45.

40000.

29.

0.06

0.075

0.125

Figure 8

ECONOMIC SCENARIO NO. 1
(input)

FOR THE FOLLOWING INPUT DATA

INV-PW= 2500000.00
INV-DDW= 2500000.00
INV-SDW= 500000.00
INV-FP 1000000.00
INV-PP= 4000000.00
DC%-FP= .06
DC%-PP= .10
DC ESC= .02
GAS PRICE= 2.00
\$ ESC= .06
GAS SF/B= 45.00
QTY(0)= 40000.00
L1= 29.00
G= .06
SEV TAX= .08
ROY RT= .13

THE FOLLOWING RESULTS WERE OBTAINED:

ANNUAL OPERATING COST= 440500.00
ECONOMIC LIFE= 60.00

R = .10
PVREV = 19864215.24
PVOC = 5460934.96
PVST = 1489816.14
PVDEPR= 1136065.87
PVATE = 5969138.98
NPV = -2770861.02

END - GPST1

Figure 9

ECONOMIC SCENARIO NO. 1
(output)

PLEASE ENTER THE FOLLOWING DATA, ONE ITEM PER LINE

INVESTMENT - PRODUCTION WELL
INVESTMENT - DEEP DISPOSAL WELL
INVESTMENT - SHALLOW DISPOSAL WELL
INVESTMENT - FUEL PLANT
INVESTMENT - POWER PLANT
OPERATING COST PERCENTAGE - FUEL PLANT
OPERATING COST PERCENTAGE - POWER PLANT
OPERATING COST ESCALATION FACTOR
GAS PRICE - \$/MCF
PRICE ESCALATION FACTOR
GAS - \$/BAR
INITIAL FLOW RATE - BAR/DAY
NUM OF YRS TO DECLINE
DECLINE RATE
SEVERANCE TAX RATE
ROYALTY RATE

2000000.

2000000.

500000.

1000000.

3000000.

0.0585

0.0955

0.01

2.5

0.06

45.

40000.

29.

0.06

0.075

0.125

Figure 10

ECONOMIC SCENARIO NO. 2
(input)

of this economic scenario are shown in Figure 11. A discounted cash flow of approximately 11 1/2% is indicated for this scenario.

In order to indicate the sensitivity of the results to the price of gas, three different values were used, i.e., \$2.50, \$4.00, and \$5.50 per Mcf. These results are shown in Figure 12 and indicate that for the current gas price (late 1979) of \$2.50 per Mcf, the net present value of the project is positive only for discount rates of 11 1/2% or less. At a gas price of \$4.00 per Mcf, the critical discount rate (rate of return) was approximately 16%, and only at a gas price of \$5.50 per Mcf did the rate of return rise to approximately 20%.

Therefore, based upon the current best estimates of costs and resource parameters, the current market price for gas does not make the development of the geopressed-geothermal resource economically attractive. A gas price of over \$5.00 per Mcf is required to achieve a rate of return that will likely be required by commercial developers.

As another reference point, resource parameter estimates from the geopressed test well near Alvin, Texas were analyzed. Flow rates from this well may average in the neighborhood of 30,000 barrels of fluid per day and because of relatively high salinity the gas content of the fluid will be approximately 25 scf per barrel. Using these values and a discount rate of 10%, a net present value of $\$4.00 \times 10^6$ was obtained. This result dramatically emphasizes the effect on project economics of a critical resource parameter such as gas content. Further, this result points out the high degree of economic risk associated with the development of this resource.

FOR THE FOLLOWING INPUT DATA

INV-PW= 2000000.00
 INV-DDW= 2000000.00
 INV-SDW= 500000.00
 INV-FP 1000000.00
 INV-PP= 3000000.00
 OC%-FP= .06
 OC%-PP= .10
 OC ESC= .01
 GAS PRICE= 2.50
 \$ ESC= .06
 GAS SF/B= 45.00
 QTY(Q)= 40000.00
 L1= 29.00
 G= .06
 SEV TAX= .08
 ROY RT= .13

THE FOLLOWING RESULTS WERE OBTAINED:

ANNUAL OPERATING COST= 345000.00
 ECONOMIC LIFE= 60.00

R = .10
 PVREV = 24830269.05
 PVOC = 3816019.77
 PVST = 1862270.18
 PVDEPR= 914394.48
 PVATE = 8783970.99
 NPV = 1723970.99

R = .11
 PVREV = 21398398.58
 PVOC = 3441448.30
 PVST = 1604879.89
 PVDEPR= 832199.69
 PVATE = 7511636.55
 NPV = 451636.55

R = .12
 PVREV = 18685757.98
 PVOC = 3132097.03
 PVST = 1401431.85
 PVDEPR= 763318.58
 PVATE = 6510977.78
 NPV = -549022.22

END - GP6T1

Figure 11

ECONOMIC SCENARIO NO. 2
 (output)

Figure 12

PRESENT WORTH OF GEOPRESSURED-GEOTHERMAL WELL

This economic analysis was conducted for the geopressured resources of the Brazoria Fairway and as pointed out in the prior section, the analysis for the other fairways shows even smaller prospects for economic feasibility. Because of this factor, detailed economic investigation of these cases was not conducted.

V. Qualitative Factors Influencing Geopressured-Geothermal Resource Development in Texas

In addition to the physical characteristics of the resource and the economics of resource production, several qualitative factors are likely to have a strong effect on the commercial development of the resource. Among the most important of these factors are 1) resource ownership, 2) allowable use of the dissolved methane, 3) allowing multiple completion of production zones, and 4) regulation of the disposal of geopressured fluids.

In the state of Texas, the onshore geopressured resource areas lie under land that is predominantly owned by private land owners. In this context, in the Spring of 1979, the Texas legislature acted through an amendment to the Geothermal Resources Act to establish geothermal resources as a part of the mineral estate. This situation implies that development of the onshore geopressured resources in Texas will require the acquisition of drilling rights from private mineral rights owners in much the same fashion as that which has existed in the oil and gas industry for years.

Rules and regulations affecting the use of the methane that is recovered from the geopressured fluid could have an important effect on the development of the resource. At this time, it appears that the rules of the Texas Railroad Commission and the rules specified by energy legislation of the federal government will not restrict the use of geopressured methane. The continuation of this situation should have a positive effect on the interest of private industry in the commercial development of the geopressured resource.

Because of the nature of the geopressured formations and the requirement for relatively high production well flow rates, it will probably be necessary to produce fluid from more than one horizon through the same production string. The Texas Railroad Commission is the regulatory agency that has the authority to rule on matters of this type. In general, for oil and gas wells, the rules of the Texas Railroad Commission allow for multiple completions but prohibit production from different horizons via a single production string. This factor has been discussed with the Commission staff and they have agreed to take this matter under consideration in future commission decisions.

Since the development of the geopressured resource requires the production of large volumes of saline water, disposal of this fluid is a significant factor. Because of the properties of this fluid the disposal will probably have to be accomplished by subsurface injection. The Texas Railroad Commission and the Texas Department of Water Resources are the Texas agencies that will be involved with this aspect of geopressured resource development. Additionally, the Environmental Protection Agency (EPA) will have a significant input into the regulation of disposal of these fluids.

Because of the influence of this aspect of the regulatory process, it is important to note that federal laws and regulations concerning hazardous materials have been subject to severe changes which produce a great deal of uncertainty in the regulatory environment. If the regulations governing disposal of these fluids are not compatible with the physical realities of the geopressured resource then development of these resources could be effectively inhibited by the regulatory process.

A more detailed description of these qualitative factors and other related issues is contained in the report "Systems Analysis of the Texas Gulf Coast Geopressured Resources," which was prepared for the Texas Energy Advisory Council (TEAC). This TEAC report is included as Appendix A to this report.

VI. Summary from Texas Energy Advisory Council Report

An integral part of formulating a detailed development strategy for the Texas geopressured resources was the determination of the prospective users of the resource. In addition, the issues concerning the resources as related to the users and developers had to be identified as well as identifying any possible alternative methods for the commercial development of the resource. This part of the development planning work was carried out by the Center for Energy Studies Operations Research team under a contract with the Texas Energy Advisory Council. The results of this work are contained in a report entitled "Systems Analysis of the Texas Gulf Coast Geopressured Resources" which is included as Appendix A of this report.

Appendix A contains an executive summary of the findings of that research effort. Because of this no additional summary is included at this point and the interested reader is referred to Appendix A beginning with page A-4.

The findings of this phase of the research effort were integrated into the development planning and analysis that has been discussed in earlier sections of this report.

VII. Conclusions

From the discussions on resource assessment and development planning and the results of the TEAC sponsored study, one may conclude that several important factors affecting the possible development of the geopressured resource are somewhat uncertain. These factors make it extremely difficult to draw a hard and fast conclusion about the desirability of proceeding with geopressured resource development on a commercial scale.

Because of this difficulty a parametric analysis was performed on the development planning aspects and the economic analysis. This analysis indicates that the commercial development of the geopressured, geothermal resource is highly dependent upon the pricing of natural gas in the U.S., the development of tax incentives to spur development, and a better understanding of the nature of the resource through additional well tests. This conclusion is not too surprising when one considers that in order to produce this resource, one must drill a larger than normal diameter well to a substantial depth and then dispose of a large quantity of saline water. These factors significantly affect the cost of development and difficulty of operation. Additionally, the reservoir must be of a relatively large size in order to support the flow rate over a rather extensive economic life to justify the investment in the project.

A number of factors such as these cause geopressured wells to be expensive to drill and operate. Any variation in resource physical parameters, particularly the gas content of the fluid, from the most optimistic values can have a significant effect on the economic desirability of the project.

In summary, we find that while the geopressed resource may have the potential for producing large quantities of energy, the economics of the situation do not indicate commercial economic feasibility in the near future if the gas prices remain in the \$2/Mcf price range. If gas prices rise to \$5/Mcf, the rate of return on various prospects could be in the range of 20%. This conclusion should not be too surprising at this point in history. The resource that is being considered must be contained in a rather large contiguous volume, with good permeability and porosity, at a high pressure and temperature, with a significant amount of dissolved gas.

One factor that could substantially alter this picture is the future value of the gas that can be produced from the geopressed resource. Significant increases in the price of natural gas that are not accompanied by comparable increases in the cost of production could dramatically enhance the economic outlook for geopressed energy development.

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APPENDIX A

SYSTEMS ANALYSIS OF THE TEXAS GULF COAST GEOPRESSURED RESOURCES

SYSTEMS ANALYSIS OF THE TEXAS
GULF COAST GEOPRESSURED RESOURCES

by

Dr. C. Dale Zinn

Center for Energy Studies

The University of Texas at Austin

Final Report
August 1979

Prepared for: Texas Energy Advisory Council
Energy Development Fund
Project #G-1-2

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DISCLAIMER

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In the interest of timeliness, final editing has not been done by the TEAC staff, but the report is published as submitted by the project investigators.

EXECUTIVE SUMMARY

This report describes the work performed by the Geothermal group within the Center for Energy Studies on the Texas Energy Advisory Council (TEAC) funded portion of the development planning scenario for the Gulf Coast Geothermal/Geopressured Resource.

An integral part of formulating a detailed development strategy was the determination of the prospective users of the resource. In addition, the issues concerning the resources as related to the users had to be identified as well as identifying any possible alternative methods for the commercial development of the resource.

The initial step in identifying the prospective users was to formulate a list of incentives to distribute to interested parties. Following the distribution of the possible incentives, a series of individual meetings between the geothermal team and prospective users were conducted to seek out the individual issues that concern the prospective users. The culmination of this phase of the project came on November 6, 1978 when a group discussion was held in Houston, Texas.

The most important immediate issues affecting the involvement of private industry in the development of geopressured resources are uncertainties regarding the physical characteristics of the resource. The most prominent of these factors are: 1) the size of the zone that is producible from a single well; 2) the sustainable production flow rates; and 3) the methane content of the fluids.

Until more information about these physical factors is available, private industry is not likely to be involved in commercialization activities. This type of information will have to come from a test well

drilling program which will probably have to be financed primarily by the federal government.

Regulatory and legal issues will have a considerable effect upon resource development if the physical characteristics appear to be promising. The most important of these are: 1) resource ownership; 2) allowable use of dissolved methane; 3) allowing multiple completion of production zones; and 4) regulation of the disposal of geopressed fluids.

Economic incentives that are most likely to encourage resource development are tax incentives that can be offered by the federal government. These include: 1) production tax credits; 2) expensing of intangible drilling costs; and 3) depletion allowance for geopressed methane and thermal energy.

The development planning portion of the work was accomplished after assimilation of the latest data concerning the Texas Gulf Coast Geothermal/Geopressed Resource. This information was principally obtained from the Texas Bureau of Economic Geology (BEG). The BEG reports identified thirteen potential Geothermal/Geopressed fairways in Texas. Eight of these fairways are located in the Wilcox Formation. The remaining five are in the Frio Formation.

The physical characteristics of the Wilcox Formation Fairways have not been adequately assessed at this time. The primary parameter missing in the early studies is the sandstones' permeability. If the permeability of the Wilcox Fairways approaches that of the Brazoria Fairway in the Frio Formation, the Wilcox Fairways may be producible.

The Frio Formation Fairways are located closer to the coast than the Wilcox Fairways. The Frio Fairways have been extensively studied,

with most of the attention given to the Brazoria Fairway southwest of Houston. The Brazoria Fairway is the site of the General Crude Oil/Department of Energy (GCO/DOE) Geothermal/Geopressured well. With the exception of the Brazoria Fairway, the physical characteristics of the Frio Fairways appear to be below the minimum criterion established for production. In particular, the permeability often ranges less than 5.0 md for the four fairways.

Computer codes have been created to evaluate the various fairways in both the Wilcox and Frio Formations based upon the latest available data. Using this data, all the fairways, with the exception of Brazoria, fail to satisfy production requirements. The Brazoria Fairway meets all production requirements and the fairway development has been outlined in a followup code. The accuracy of such planning scenarios is dependent on the validity of reservoir physical characteristics incorporated into the codes. When this information becomes available during the testing of the Brazoria well, it will be incorporated into the existing codes.

In conclusion, the various economic and regulatory factors controlling whether the Geothermal/Geopressured resource will become a viable source of energy are secondary to the question of whether the reservoir will be able to produce at all. Preliminary results indicate that only the Brazoria Fairway can meet the minimum physical requirements for production.

The detailed development plan and economic analysis is being prepared as a part of a report to the Division of Geothermal Energy of DOE. This plan will be forwarded to TEAC upon its completion, which is estimated to be early Fall 1979.

I.

INTRODUCTION

The geopressured energy resources of the Texas Gulf Coast have been the subject of considerable research at The University of Texas since 1974. Because of the potential of these resources for making a significant contribution to the energy supply for the State of Texas and for the nation, a systems analysis for the development of these resources was initiated by the U.S. Department of Energy (DOE).

The overall objective of this systems analysis was to produce a coordinated plan for the development of these geopressured resources. An important part of this development planning activity was the determination of 1) who are the likely developers and users of this resource; 2) what issues are important to the industry, users, and governmental agencies that are involved; and 3) what are the viable alternative methods for commercial development of these resources.

In April 1978, the Center for Energy Studies (CES) of The University of Texas at Austin submitted a proposal to the Texas Energy Advisory Council (TEAC) for the support of this resource development planning work. The overall project was funded in the amount of \$50,000 by the TEAC and \$154,919 by DOE. The TEAC part of the project was directed toward the determination of those activities that could have a significant effect upon the commercial development of the Texas geopressured resources. This information was then to be factored into the overall development planning project which was being sponsored by DOE. The final product of these efforts is a detailed plan for the development of the Texas Gulf Coast geopressured resources.

This report describes the work accomplished by the Center for Energy Studies on the TEAC funded portion of the development planning

This report describes the work accomplished by the Center for Energy Studies on the TEAC funded portion of the development planning project. Specifically, emphasis was placed upon the determination of those factors that were most important to the likely developers, users, and regulators of the geopressured energy resources of Texas. This information was utilized in constructing the basic guidelines under which the alternative development plans were constructed. These detailed plans will be described in the final report to DOE which will be published in Fall 1979.

II. DETERMINATION OF INFORMATION AND ACTIVITIES NEEDED FOR DEVELOPMENT OF THE TEXAS GULF COAST GEOPRESSURED RESOURCES

The first step in determining those activities that were likely to have a significant impact upon geopressured resource development was the preparation of a list of possible incentives to be used in initial discussions. This list was compiled from the results of a previous planning study that was sponsored by DOE in 1977. This list was mailed to selected members of the oil and gas industry, electric utility industry, and state agencies during the late summer of 1978. A series of individual meetings was then conducted between this group and Dr. Zinn and Dr. Lesso of the CES research team. At the conclusion of these individual meetings, in early Fall 1978, the research team prepared a document summarizing the comments that had been obtained from these meetings. This summary was circulated to the contributors for their review. A group discussion meeting was held in Houston, Texas on November 6, 1978. This meeting produced a lively interchange of ideas regarding the development of the Texas geopressured resources.

Copies of the initial discussion list and the summary document mentioned earlier are included as Addenda C and D to this report.

III. PROCESSING, ANALYSIS, AND DISSEMINATION OF INFORMATION RELEVANT TO GEOPRESSURED RESOURCE DEVELOPMENT

Using the information obtained from the individual and group meetings described previously, a summary of incentive actions and possible problem areas that could affect geopressured resource development in Texas was compiled by the CES research group. This summary (Addendum D) was circulated to industry and governmental agencies for their review and comment.

The principal result of this activity was the determination that uncertainties regarding the physical characteristics of the geopressured resource are the principal deterrents to private industry participating in the commercial development of the geopressured resource. The most prominent of these physical factors are 1) the size of the reservoir that can be produced from a single well; 2) the production flow rates that can be sustained; and 3) the methane content of the geopressured fluids.

Some information describing these factors can be obtained from geological studies and laboratory investigations; however, the quality of information that is needed to attract direct industry participation probably can be obtained only by a test well drilling program. This type of program is expensive in terms of capital investment requirements, and risky in terms of the results that may be obtained. Therefore, it is the conclusion of the CES research group that private industry is extremely unlikely to participate in the initial test well drilling activity. This effort appears to be an appropriate function of the U.S. Department of Energy which is in fact conducting a drilling program in both Texas and Louisiana for the purpose of obtaining basic data describing the geopressured energy resource.

The test well program can be expected to have a significant impact upon the rate at which geopressed resource development will proceed. If the test results indicate that the resource has the physical characteristics, i.e., sufficient reservoir size, producibility, and methane content, that make commercial development attractive, then private industry is likely to become an active participant in resource evaluation and development activities.

If the geopressed resource does have attractive physical characteristics, then a variety of items that could have significant impact upon commercial development come into play. One of the most prominent of these items is the disposal of the geopressed fluids. Since these fluids are likely to be saline, approximately 20,000-60,000 ppm, disposal will probably have to be accomplished by subsurface injection. This situation could be troublesome from both a physical and regulatory point of view. Physically, acceptable disposal zones will have to be found in close geographical proximity to the production wells, or the spent fluids will have to be returned to the producing zones. If this deep reinjection is required, it will require a considerable amount of energy. From the regulatory standpoint, federal and state laws and regulations will influence the injection process. Because of this it is important to note that federal laws and regulations have been subject to severe changes which produce a great deal of uncertainty in the regulatory environment. As an illustration of this situation, it is possible that the Environmental Protection Agency (EPA) will impose requirements for the location of disposal facilities that will not be compatible with the physical realities of geopressed resource development. The Texas Railroad Commission and the Texas Department of Water Resources are the

Texas agencies that will be involved with this aspect of geopressured resource development.

The possibility that the production of geopressured fluids may cause subsidence is a major factor to be considered. At the present time there does not appear to be a clear consensus as to whether or not subsidence will occur when the geopressured fluids are removed from the production zones. Subsidence monitoring during the test well program should give some insights into the magnitude of this problem.

If subsidence does prove to be a substantial problem, then some form of protection for the potential resource developers and the property owners will probably be required. This may take the form of an "insurance policy" that is provided by the federal government.

The possibility that multiple completions of production zones in a single well may be required to achieve an effective total production volume is another regulatory matter for consideration by the Texas Railroad Commission. In general, for oil and gas wells, the rules of the Texas Railroad Commission allow for multi-completions but prohibit production from different horizons via a single production string. This factor has been discussed with the Commission staff and they have agreed to take this matter under consideration in future commission decisions.

The question of ownership of the geopressured/geothermal resource is a legal issue that may affect resource development. A clarification of this issue via an amendment to the Geothermal Resources Act has been discussed with the staff of the Texas Railroad Commission. A recommendation that this resource be classified as a part of the mineral estate was made law by the Texas legislature during the 1979 session.

The involvement of electrical utilities in geopressured resource development will likely be significantly influenced by regulatory factors. One of the most important of these relates to the use of natural gas as a boiler fuel. The Texas Railroad Commission had held in Docket 600, that the use of natural gas as a boiler fuel would be phased out. A motion was made to reconsider this situation, and during the Spring of 1979 this restriction on using natural gas as a boiler fuel was repealed. This could be a powerful incentive for the involvement of the electrical utilities and for large industrial co-generators.

An additional item affecting electric utility involvement with geopressured resource development is how the costs of geopressured wells and power plant equipment will be allowed to be treated. In general, power plant equipment is depreciated over a long time period while the cost of geopressured wells will likely be treated as a part of the fuel expense. This situation can be both good and bad from the point of view of the utilities and the consumer. Items that can be included in the utility's rate base such as power plant capital costs are generally desirable to the utility because of the long term revenue production. This may not be true in the case of geopressured resource development since uncertainties associated with the life of the resource tend to make an early pay back of capital investment desirable.

On the other hand, the cost of the geopressured production and disposal wells is likely to be a considerable part of the cost of the project. In this event, if the Texas Public Utility Commission allows

this expense to be recovered quickly, this will also be a positive incentive for involvement by the electric utilities. This situation may not be too likely since public utility commissions generally tend to classify costs so that recovery will be over a long period of time in order to create current rates that are as low as possible. The regulatory handling of reservoir drilling and production costs is likely to be a major factor in determining the future structure of the geopressured resource development industry.

IV. SUMMARY OF ACTION ITEMS

This section summarizes those items that are most likely to have an impact on development of the geopressed resources of the Texas Gulf Coast and indicates those entities that will probably be directly involved.

Action Item 1

Completion of drilling and testing of first geopressed test well currently being drilled in Brazoria County, Texas. Agencies involved: DOE, General Crude Oil Company, Texas Railroad Commission, University of Texas geothermal research team. The information obtained from this test well will have a direct influence on the degree of interest of a large segment of the potential commercial developers. If the test results indicate reasonably good values for reservoir volume, fluid production rate, and methane content, then interest on the part of the private sector can be expected to show a significant increase. However, if these initial test results are not favorable, then additional geopressed test well activity in the near future will probably be sponsored exclusively by the federal government.

Action Item 2

Presentation of testing results from first test well. Agencies involved: UT geothermal research team, USGS researchers, other DOE funded research projects. Note: a conference for this purpose is scheduled for Fall 1979.

Action Item 3

Arrange for drilling of additional test wells in Texas resource areas. Agencies involved: DOE, UT geothermal research team, Texas

Railroad Commission, Texas Department of Water Resources, General Land Office (depending upon location). Arrangements for drilling additional test wells can be somewhat complex. Locating sites that are geologically attractive and then obtaining the necessary drilling rights can be a time consuming process. Additionally, finding an operating company that is willing and able to contract with DOE for the drilling of a geopressured test well is not a trivial exercise.

Action Item 4

Resolution of the regulations required for subsurface disposal of used geopressured fluids and the allowable locations for facilities handling geopressured fluids. Agencies involved: Texas Railroad Commission, Texas Department of Water Resources, Federal Environmental Protection Agency, DOE. Proposed regulations by EPA regarding the classification of facilities handling geopressured fluids as hazardous materials handling facilities and a ban on the location of such facilities in wet land areas could pose a significant impediment to the commercial development of the geopressured resource. Since subsurface injection is the most probable method for disposal of the used geopressured fluids, this is a critical item to be resolved for commercial development to occur.

Action Item 5

Resolution of issue of ownership of geopressured resources. Agencies involved: Texas legislature, Texas and Federal courts. During the Spring of 1979, the Texas legislature acted through an amendment to the Geothermal Resources Act to establish geothermal resources as a part of the mineral estate. This should be a useful development; however, it is certainly possible that in some specific cases a resolution of the ownership issue may have to be decided by the courts.

Action Item 6

Resolution of the allowable use of the methane issue. Agencies involved: DOE, U.S. Congress. The action of the Texas Railroad Commission to abandon the phaseout schedule and ban on the use of natural gas as a boiler fuel is likely to have a positive influence on the participation of the electric utilities and large industrial co-generators in geopressured resource development. A similar restriction on the use of natural gas is contained in federal energy legislation. Gas produced from geopressured brine from wells spudded prior to January 1, 1990 is currently excluded from classification as natural gas. The continuation of this situation should have a positive effect on the interest of private industry in the commercial development of the geopressured resource.

Action Item 7

Resolution of the situation concerning the recovery of geopressured energy development costs by the electric utility industry. Agencies involved: Texas Public Utility Commission.

Action Item 8

Resolution of the requirement that different producing horizons must be produced via separate conduits. Agency involved: Texas Railroad Commission. In the case of conventional oil and gas production, the Texas Railroad Commission has generally prohibited the production of separate horizons through the same conduit. Because of the nature of the geopressured formations and the requirement for high flow rates it will probably be necessary to produce fluid from more than one horizon through the same production string. If this is not allowed, then economical production rates may not be attainable.

V.

CONCLUSIONS

The important items associated with the development of the geopressed energy resources appear to fall into three principal categories. These are 1) physical characteristics of the resource; 2) economic incentives; and 3) regulatory factors.

The physical characteristics that appear to be the most important are the size of the reservoir that can be drained by a single production well and the rate of production that can be sustained. Closely associated with these are the methane content of the fluids and the ability to dispose of the fluids by subsurface injection.

Determination of these physical characteristics requires an intensive research and development activity including a test well drilling program. Programs of this type are extremely costly and thus will likely require funding by the U.S. Government or from private sources such as the oil and gas industry.

Because of the dilute nature of this resource in terms of energy concentration, some form of economic incentives are likely to be required to promote development by private industry. Most of these incentives are likely to come in the form of tax provisions. Since the State of Texas does not impose an income tax on corporations, state tax incentives for geopressed resource development may have only a limited effect. Again, more direct forms of incentives such as research and development grants and matching funds for federal government programs may be an effective means for the State of Texas to encourage geopressed resource development.

On the other hand, a variety of tax incentives that could be offered by the federal government could prove to be effective in stimulating

private industry involvement in developing geopressured resources. Among these are: 1) investment tax credits for fuel plant and power plant equipment; 2) intangible drilling expense allowances; 3) depletion allowance for both geopressured methane and thermal energy; and 4) production tax credits.

In the regulatory environment, agencies of the State of Texas have a primary involvement. The Texas Railroad Commission through its regulatory authority over drilling and production is directly involved with geopressured resource development. In a similar fashion, the Texas Department of Water Resources, the Texas Public Utilities Commission, and the General Land Office may be involved through their permitting authority.

The federal government will probably continue to play the major role in research and development activities associated with the geopressured resources. Funding of test well drilling programs and other basic research activities will probably be provided primarily by DOE with some limited support from private industry. If these research and development activities indicate that further development of the resource is attractive, then commercialization activities will probably be carried out by private industry.

In summary, the State of Texas has a long history as a producer of energy. Its regulatory agencies have extensive experience in working with industry so that energy resource development is encouraged while the state and its citizens rights and welfare are protected. If there is no severe disturbance of this situation by federal government action, then the regulatory environment in Texas is such that geopressured energy resource development will not be hindered.

ADDENDUM A

LIKELY DEVELOPERS AND USERS OF GEOPRESSURED ENERGY RESOURCES

LIKELY DEVELOPERS AND USERS OF GEOPRESSURED ENERGY RESOURCES

In Texas, the geopressured resource is located along the Gulf Coast from approximately 150 miles inland to the near offshore. This fact, coupled with the relative difficulty and expense of transporting the geopressured fluid, means that direct use of the resource will likely be confined to the Gulf coastal area. The transportable part of this energy source is created by transforming the thermal energy into electrical energy and by separating the methane gas from the fluids.

These factors, together with the physical factors of resource exploration and production, mean that the likely developers are probably limited to 1) the oil and gas industry, 2) the electric and natural gas utility industries, and 3) large industrial users of process heat and electricity. In the case of the electric utility industry and large industry, the users of the resource are most likely to be located in Texas. However, for gas utility customers, their location will depend upon governmental rulings affecting the markets into which the geopressured methane will be allowed to be sold.

ADDENDUM B

ALTERNATIVE DEVELOPMENT METHODS

ALTERNATIVE DEVELOPMENT METHODS

At the present time, two methods for commercial development seem to be reasonable. These methods are highly dependent upon the location of the resource and the proximity of the producing reservoirs.

If individual reservoirs that are capable of sustaining a production rate of from 20,000 bbls to 40,000 bbls per day for 20 to 30 years are found in reasonable proximity to each other, then a central plant concept can be envisioned. In this sense, reasonable distance means well locations approximately 2 to 3 miles from a central plant site. This central plant would have an electrical generating capacity of approximately 25 to 50 MW and a gas production capacity of approximately 10,000,000 cubic feet per day. This situation would provide some benefit through the economies of scale in the construction of the electric generating and gas processing facilities. In addition, such a facility would probably be of sufficient size to attract a reasonably large industrial plant if the energy resource from the geopressed plant could be made available to it.

On the other hand, if individual reservoirs are not found to be reasonably close together, then a single well development concept will likely be required. In this event, a portable generating unit of approximately 5 MW capacity and a portable gas processing plant will be required. Because of the relatively small amount of energy per well, the utilization of the resource under this scheme will be very site specific. If such sites are located near to existing electric and gas transmission systems, then these products could be distributed fairly easily. However, if these sites are remotely located, then the effective use of these resources is much more difficult.

Other schemes for development of the geopressured resource have been considered. One of these schemes is to produce the fluids for the sole purpose of extracting the methane. Some of the problems associated with this method are: 1) energy conservation laws of the states of Texas and Louisiana, 2) approximately 50% of the energy content of the geopressured fluids is in the temperature and pressure of the fluids, and 3) the energy requirements of fluid disposal by reinjection will probably make this scheme uneconomical.

Another development method centers on the use of the thermal energy in the fluids to provide direct heating or process heat for industry. This is probably a viable alternative only in a few site specific cases. The economics of transporting the thermal energy seem to preclude this option unless the well location happens to be very near to an existing consumer. Also, the amount of thermal energy available from a single well, together with other transportation and logistics problems, makes it unlikely that an industry would relocate to be near the well site.

ADDENDUM C

DISCUSSION LIST

LIST OF POSSIBLE INCENTIVES FOR
DEVELOPMENT OF GEOPRESSURED RESOURCES

Electric Utilities:

1. Guarantee by state utility regulatory agencies that cost of geothermal geopressured facilities can be included in the rate base.
2. Guarantee program backed by federal government that funds spent on geopressured exploration can be recovered either by special tax considerations or by alternative fuel allocations.
3. Special tax credits for investing in geothermal electric generating equipment.
4. Accelerated depreciation of geothermal electric generating equipment.
5. Allocation of a portion of the gas produced for the use of the electric utilities in existing gas fueled generating stations.
6. Research and Development Programs to be funded by federal government or by private research organizations such as EPRI or GRI.
 - A. Develop more efficient energy conversion equipment such as turbine generators and heat exchangers.
 - B. Develop high pressure gas separation equipment.
 - C. Develop efficient methods (including equipment) for reinjection of the geopressured fluids into either shallow or deep formations.

Oil and Gas Industry:

1. Establish a depletion allowance and intangible drilling expense write-off system.
2. Deregulate the price of gas produced from geopressured resources.
3. DOE sponsorships of a test drilling program to determine resource information such as probable size of geopressured reservoirs.
4. Special tax credits based upon production of gas from geopressured resources.
5. Accelerated depreciation of gas processing plant and equipment.

Joint Ventures:

1. Geopressured Demonstration Plant sponsored jointly by DOE/Gulf Coast Utilities/Oil & Gas Industry/EPRI/GRI.
2. Special investment tax credits for developers of geopressured equipment and for purchasers of this equipment.

ADDENDUM D

SUMMARY DOCUMENT

SUMMARY OF COMMENTS AND OPINIONS ON
INCENTIVES TO THE DEVELOPMENT AND USE OF
GEOPRESSURE/GEOTHERMAL RESOURCES IN
THE STATE OF TEXAS

As part of the planning study for the development of geopressure/geothermal resources in Texas, a list of possible incentives to development and use were prepared (see attachment). These were sent mainly to members of the GP/GT advisory board for comment. Following this, representatives of the various organizations were visited and interviewed. After providing an overview and update on the project, these general questions were asked:

- a) Which incentive listed is most important to your organization?
- b) Which incentive(s) would you add to the list?
- c) At what point would your organization become active in the development and/or use of GP/GT?

The organizations visited were the electric utilities mainly along the Gulf Coast, oil/gas producers, and pipeline companies.

The following represents a compilation and summary of the interviews as interpreted by the project team members. As such it does reflect their observations and opinions as to the position on this matter on the part of the organizations interviewed.

Utilities

An overall assessment of the attitude of the electric utilities is one of mild to extreme conservatism. They all said they would be willing to operate in any of three positions: a) drill the wells, produce the energy and generate electricity, b) buy the resources from a

producer (fuel supplier) and produce electricity, c) let others produce the resources, generate the electricity and they would just buy the power to put in their system. Initially, the last position was somewhat of the preferred one although they all had fuel producing subsidiaries.

One consideration in a utility being producer of GP/GT energy and generator of electricity is that the second part of this operation is under the jurisdiction of the State Public Utility Commission. There is some concern as to what can be put into the rate base and at what cost the "fuel" part of the utility charges the "electric" part of the utility.

One utility expressed a willingness to try to produce electricity from even a single well (2 to 5MW) as a demonstration under the right conditions. The "bottom line" in all of our discussions was ECONOMICS. This attitude on the part of the utilities is understandable when one considers that they are a regulated monopoly. This puts them in a slightly schizophrenic position. The public is asking for reduced costs and expecting innovative approaches on the part of the utilities, yet by charter they are restricted to operate in a "safe, conservative" manner. They are not in the "risk venture" business as, for example, are the oil companies.

With regard to the incentives there was not clear consensus as to the most important. They felt the incentives would be good but they were not sure the use of GP/GT energy would be economically feasible.

The idea of joint ventures with the U.S. Government was not attractive unless the mix of funding was such that most of it was put up by the government. (A 50-50 partnership was viewed as one having all the hassle of government rules and regulations, and interference, and costing twice what it would if the utilities did it alone).

The incentives of tax credits would mainly be attractive if they were tax rebates, i.e., a direct reduction of taxes. This was one of the unexpected factors brought out, which in retrospect, should have been expected. Many utilities have major building programs underway. As such, they are accumulating large investment tax credits. Therefore, reductions of taxable income are not of immediate benefit.

The incentive of having access to the dissolved methane as a boiler fuel was interesting, but not considered a major factor. Since the Texas Railroad Commission has issued Docket 600 directing the phasing out of natural gas as a boiler fuel, most of the utilities have established a multi-year plan to comply and these have now been underway for several years. Therefore, many existing plants are being converted or retired. It would allow for a stretching out of those plants which cannot be converted. However, this was viewed as an uncertain variable: will there be enough dissolved gas? how long will it last? will they be allowed to use it? would it be more valuable sold for another use? Some of the utilities still have favorable gas contracts so that the dissolved gas would not be economical at the present estimated costs to produce it.

The major "missing" incentive was: LESS RULES AND REGULATIONS.
(Enough said).

The utilities and the producers all expressed a concern about the size of the reservoirs. Since this is a low quality energy source, there must be a sufficiently large reservoir per well (drainage area) to guarantee an economic life for the electrical generating plant. (This could be as short as 15 years, to as much as 30 years. An estimate of the drainage value is between 0.2 and 1.0 cubic miles).

Some of the possible GP/GT formations may have many layers of producing zones. This may be a way to achieve an effective total volume, but would require multiple completions from a single well. In general, for oil and gas wells, the rules of the Texas Railroad Commission do not allow for multiple completions. This factor has been discussed with the Texas Railroad Commission, and they have agreed to study the matter in regard to geopressured/geothermal reservoirs.

Another potential obstacle to the utilities, producers, and transmission companies is the question of how to obtain the "right-of-way" for the GP/GT pipelines from the wells to the generating facilities. Would the present condemnation procedures apply? Other legal problems concern who owns the resource, the land estate or the mineral estate? Would existing oil and gas leases automatically include GP/GT? Since large drainage areas are required, will there be special unitization rules established? These questions are also in the domain of the Railroad Commission.

Another concern of the utilities is the size of the electrical generating plants. Our preliminary analysis suggests that a typical

installation would have three to six wells tied together to produce 25 to 50 MW. Because of well spacing, this is about the limit of transport without excessive heat and pressure loss. The well spacing in turn, is dictated by the required drainage area. Also, there is a requirement that the wells flow continuously, making the electric generating plant essentially a base load plant. Normally only large size plants, 350 MW and larger are used as base load, because of the economics of scale. The use of plants one-tenth this size may result in a cost penalty.

Also, the size of the utilities with regard to generating capacity and service area will influence the interest in GP/GT. A large load, compact metropolitan area is less likely to use this resource than smaller, large rural area utilities. In the latter case, with a large transmitting network, there may be side advantages in having small "lumps" of capacity through the service area. This would reduce line losses and provide more system stability.

In summary, the general position of the utilities with regard to GP/GT can best be classified as "guarded." They do not anticipate any active involvement until more information on formation properties is obtained. Current economic analysis is such that the uncertainties make them feel that this energy source is too risky.

Oil and Gas Industry

The exploration and production components of the oil and gas industry have extensive experience in "risk venture" business. The general response of this segment of the industry was that while incentives such

as deregulated gas prices, allowance of intangible drilling costs as expense items for federal income tax purposes, and production tax credits were interesting, these items could not be considered sufficient to stimulate active development of the geopressured resource. The primary reasons given for this are the uncertainty that exists as to the size of a geopressured zone that can be produced from a single well bore, and the gas content of the geopressured fluids. The effect of salinity on the gas content of these fluids appears to be an item of considerable concern.

The current DOE test well program and laboratory research on the effect of salinity on dissolved gas content should provide useful insights into these two factors. When more information of this type is available, then the economic incentive would become more important in terms of making geopressured development projects competitive with other projects that are available for investment by the oil and gas industry.

The oil/gas producers also feel they have more than enough other prospects for their investment dollars. To them GP/GT is a low quality energy fuel and the effort to extract it may not be worth the cost. Market sources also may present problems to the development of the resource. GP/GT cannot be stored once extracted (except for the dissolved gas). Its use to generate electricity was also questioned. As one person stated, "Don't the utilities now dump hot water at 350°F from current steam turbines?"

There was a consensus that the proper government role was to drill the first few exploratory wells, determine reservoir size and properties and in general reduce the zone of uncertainty about this resource.

Transmission Pipe Line Companies

The gas transmission phase of the business is related to the electric utility industry in that it is a regulated industry. One of the production incentives on the list, deregulation of the well head price of gas produced from geopressured aquifers, could have an effect on the desirability of acquiring this gas by a gas transmission company. This could occur if regulatory agencies require that incremental rather than average pricing rules be applied to gas that is sold by the transmission company. Another factor of significant interest to the gas transmission industry is what portion of their involvement in the development of geopressured gas supplies will be allowed to be included in their rate base. Past experience with rulings of regulatory agencies has left them somewhat uncertain and concerned as to the effect of their involvement in projects that are not strictly within their normal operations routine.

Texas Railroad Commission

As mentioned previously, several issues were raised that are under the jurisdiction of the Texas Railroad Commission. These were discussed with the chairman of the commission and he requested that we formally ask the commission in writing to take these issues under consideration. This has been done. These issues are: use of GP/GT gas as a boiler fuel and multiple completion from a single well.

State of Louisiana Study

At the completion of this round of interviews and discussions, we met with our counterparts in Louisiana to exchange information on what

we had found. The Louisiana group will try to interview some of their contacts in the petro-chemical industry to see what their interest is. Also, they are developing an economic evaluation model incorporating risk. We plan to extend our planning models to include more details and perform sensitivity analysis. The Louisiana group plans to hold a meeting in early October to consider the legal aspects of the GP/GT resources. We plan to hold an early November meeting of all interested parties.

An interesting idea was brought up in our discussions. There may be some benefit in developing a simple sequential decision making model (stochastic decision tree) to determine the probable consequences of proceeding (and to what step) or stopping the effort, based on each successive result obtained.

In summary, a wide range of interest in the geopressured energy resource was exhibited by all participants. However, to some degree, all participants expressed that a lack of knowledge about key physical parameters of the resource, i.e., reservoir volume, recoverability, gas content, were primary factors that were inhibiting their direct participation in the development of these resources.

APPENDIX B

LISTING OF PROGRAM WELL

```

PROGRAM WELL (INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)      B-2
DIMENSION TOT(60),TOTY(60),TOTR(60),QBBL(60),GAS(5,60),TITLE(4)
DIMENSION FAIR(4)
COMMON/AA/MAXQ,THICK,DELP,VISWAT,VOLFF,RRES,RWELL,S,PERM
COMMON/BB/TOTR,GAS,NLIFE
COMMON/CC/QBBL
REAL MINR,MINP,INTFACT,LIQREC,LIQVOL,MINPA,MINRA,MAXQ,MINPRO,
      LIQLEFT
C  READ IN BASE CASE PARAMETERS
  READ(5,499)(TITLE(I),I=1,2)
  READ(5,500) NLIFE
  KASE=0
  IA=IB=IC=ID=IE=0
  READ (5,499)(FAIR(I),I=1,2)
  READ(5,501) FBV,FBR,MINR,MINP,DENS,CAPF,VISWAT,VOLFF,
      RWELL,S,PERM,THICK,DELP,RRES,INTFACT,MINPRO,
      DEPL
  TITLE(3)=10HBASE CASE
  TITLE(4)=10H
  PERMA=PERM
  THICKA=THICK
  MINPA=MINP
  MINRA=MINR
  DELPA=DELP
10 CONTINUE
C  PRINT OUT CASE PARAMETERS
  KASE=KASE+1
  WRITE(6,600)
  WRITE(6,612) FAIR(1),FAIR(2)
  WRITE(6,601) KASE,TITLE(1),TITLE(2),TITLE(3),TITLE(4)
  WRITE(6,602) FBV,FBR,MINP,VISWAT,PERM,VOLFF,DELP,THICK,RRES
  WRITE(6,603) NLIFE,DEPL,MINR,CAPF,RWELL,SKINF,DENS,INTFACT
C  PERFORM PRELIMINARY CALCULATION
  FBVOL=3.1416*FBR*FBR*FBV
  SANDVOL=3.1416*RRES*RRES*THICK
  LIQVOL=SANDVOL*MINP/5.615
  LIQREC=LIQVOL*MINR
  SUMQ=MINPRO*365.25*NLIFE
  NW=1
  IF(SUMQ.GT.LIQREC) GO TO 8000
110 X=NW*40000.*365.25*NLIFE
  IF(X.LT.LIQREC) 120,130
120 NW=NW+1
  GO TO 110
130 NW=NW-1
  AREA=3.1416*FBR*FBR
  DENSITY=NW/AREA
  IF(DENSITY.GT.DENS) WRITE(6,9002) DENSITY,DENS
C  PRINT OUT PRELIMINARY RESULTS
  WRITE(6,610)
  WRITE(6,611) FBVOL,LIQVOL,LIQREC,SUMQ
C  MODEL ASSUMES CONSTANT DELP OVER LIFETIME OF WELL
C  PERFORM WELL PRODUCTION CALCULATION
C  CALL SUBROUTINE FOR WELL FLOW RATE CALCULATION
135 CONTINUE
  CALL WELLO
  IF(MAXQ.LT.40000.) GO TO 8003
C  CALCULATE TOTAL RECOVERY

```

```

C WELL FLOW IS CAPPED AT 40000 BBLs/DAY UNTIL NATURAL DEPLETION
C YIELDS A LOWER FLOW RATE
B-3
  QBBL(1)=40000.
  TOT(1)=NW*QBBL(1)*CAPF*INTFACT
  TOTY(1)=TOT(1)*365.25
  TOTR(1)=TOTY(1)
  DO 160 I=2,NLIFE
  MAXQ=MAXQ*EXP(-DEPL)
  IF(MAXQ.LT.40000.) 140,145
140 QBBL(I)=MAXQ
  GO TO 150
145 QBBL(I)=40000.
150 CONTINUE
  TOT(I)=NW*QBBL(I)*CAPF*INTFACT
  TOTY(I)=TOT(I)*365.25
  TOTR(I)=TOTR(I-1)+TOTY(I)
160 CONTINUE
  IF(TOTR(NLIFE).GT.LIQREC) GO TO 8002
  LIQLEFT=LIQREC-TOTR(NLIFE)
  SCHECK=40000*365.25*NLIFE
  IF(LIQLEFT.GT.SCHECK) 163,165
163 NW=NW+1
  GO TO 135
165 CONTINUE
  FRAC=TOTR(NLIFE)/LIQREC
C EVALUATE AMOUNT OF GAS RECOVERED
C CALL SUBROUTINE FOR GAS RECOVERY CALCULATION
  CALL GASQ
C PRINT OUT PRODUCTION RESULTS
  WRITE(6,600)
  WRITE(6,604)
  DO 167 I=1,NLIFE
167 WRITE(6,605) I,QBBL(I)
  WRITE(6,600)
  WRITE(6,606)
  DO 170 I=1,NLIFE
170 WRITE(6,607) I,TOT(I),TOTY(I),TOTR(I),(GAS(J,I),J=1,5)
  WRITE(6,608) TOTR(NLIFE),LIQREC,FRAC
  WRITE(6,609) NW,DENSITY
C FINISHED CASE CALCULATION START VARIATION IN PARAMETERS
190 CONTINUE
  IF(IA.EQ.3) GO TO 200
  PERM=PERM+PERMA
  IA=IA+1
  TITLE(3)=10HVARY PERM
  GO TO 10
200 PERM=PERMA
  IF(IB.EQ.3) GO TO 220
  THICK=THICK+.50*THICKA
  IB=IB+1
  TITLE(3)=10HVARY THICK
  GO TO 10
220 THICK=THICKA
  IF(IC.EQ.3) GO TO 230
  MINP=MINP+.05
  IC=IC+1
  TITLE(3)=10HVARY MINP
  GO TO 10

```

```

230 MINP=MINPA
  IF(ID.EQ.3) GO TO 240
  MINR=MINR+.05
  ID=ID+1
  TITLE(3)=10HVARY MINR
  GO TO 10
240 MINR=MINRA
  IF(IE.EQ.2) GO TO 250
  DELP=DELP+.50*DELPA
  IE=IE+1
  TITLE(3)=10HVARY DELP
  GO TO 10
250 DELP=DELPA
  GO TO 9050
8000 WRITE(6,9001)
  GO TO 8050
8002 WRITE(6,9004) TOTR(NLIFE),LIQREC
  GO TO 8050
8003 WRITE(6,9005) MAXQ
8050 CONTINUE
  GO TO 190
9050 CONTINUE
499 FORMAT(8A10)
500 FORMAT(16I5)
501 FORMAT(8F10.4)
600 FORMAT(1H1)
601 FORMAT( 5X*CASE NO.*I3*---*4A10/SX*INPUT DATA REQUIRED*
  Q//7X*RESERVOIR DATA*/)
602 FORMAT(7X*FAULT BLOCK HEIGHT (MI) ==F5.1/
  Q7X*FAULT BLOCK RADIUS (MI) ==F5.1/
  Q7X*POROSITY ==F5.3/
  Q7X*VISCOSITY OF FORMATION WATER (CP) ==F5.2/
  Q7X*PERMEABILITY (MD) ==F5.1/
  Q7X*FORMATION VOLUME FACTOR ==F5.2/
  Q7X*PRESSURE DIFFERENTIAL(AVERAGE-BOTTOM HOLE) (PSI) ==F8.1/
  Q7X*EFFECTIVE RESERVOIR THICKNESS (FT) ==F7.1/
  Q7X*EFFECTIVE RESERVOIR RADIUS (FT) ==F8.1/)
603 FORMAT( 7X*WELL DATA*/)
  Q7X*TARGET WELL LIFETIME (YRS) ==I3/
  Q7X*ANNUAL PRODUCTION DECAY ==F4.2/
  Q7X*FLUID RECOVERY ASSUMED ==F5.3/
  Q7X*WELL CAPACITY FACTOR ==F5.3/
  Q7X*WELL BORE RADIUS (FT) ==F5.2/
  Q7X*SKIN FACTOR ==F5.2 /
  Q7X*MAXIMUM WELL DENSITY (WELLS/SQ. MI) ==F5.2/
  Q7X*WELL INTERFERENCE FACTOR ==F5.3/)
604 FORMAT(/5X*WELL PRODUCTION SCENARIO*/
  Q7X*YEAR*5X*AVERAGE PRODUCTION (BBL/DAY)*/)
605 FORMAT(7X,I4,I0X,F10.0)
606 FORMAT(/5X*PRODUCTION RESULTS*/)
  Q 5X*YEAR*3X*LIQUID*20X*TOTAL LIQUID*6X*TOTAL NATURAL GAS RECOVERED
  Q (CU.FT.) ACCORDING TO*/12X*RECOVERY RATE*13X*RECOVERED*9X*VOLUMET
  QRIC SOLUBILITY (CU.FT.GAS/BBL LIQ.)*12X*BBL/DAY*5X*BBL/YR*
  Q6X*BBL*17X*35.*10X*40.*10X*45.*10X*50.*10X*55.*/)
607 FORMAT(5X,I4,3(3XE10.3),5X,5(3X,E10.3))
608 FORMAT(5/5X*TOTAL LIQUID VOLUME RECOVERED BY WELL SYSTEM ==E10.3
  Q* BBL*/5X*TOTAL LIQUID VOLUME AVAILABLE ACCORDING TO PRELIMINARY
  QCALCULATION ==E10.3* BBL*/5X*FRACTION RECOVERED = RECOVERED/AVAIL

```

```

TABLE =*F5.3)
609 FORMAT( 5X*SYSTEM REQUIRED *I4* WELLS*/ 5X*WITH A DENSITY OF*F5.2
  Q* WELLS/SQ.MI*/)
610 FORMAT( //5X*PRELIMINARY RESULTS - FOR MINIMUM PRODUCTION SCENARIO
  Q*/)
611 FORMAT(5X*FAULT BLOCK VOLUME (MI3) =*F10.1/
  Q5X*LIQUID VOLUME IN BLOCK (BBLS) =*E10.3/
  Q5X*MINIMUM LIQUID RECOVERY VOLUME (3BLS) =*E10.3/
  Q5X*MINIMUM LIQUID RECOVERY BY 1 WELL OVER LIFETIME (BBLS) =*E10.3)
612 FORMAT(5X,*FAIRWAY STUDIED -- *2A10/)
9001 FORMAT(/5X*---ABORT---THIS PRODUCTION SCHEME IS TO AGGRESSIVE *
  Q*FOR THIS REERVOIR*/)
9002 FORMAT( /5X*---CAUTION---WELL DENSITY OF *F5.2/19X
  Q*IS GREATER THAN TARGET VALUE OF*F5.2/ )
9003 FORMAT(/5X*---ERROR---ERROR IN PRESSURE DATA INPUT*/19X
  Q*RESULTS IN NEGATIVE DELP*/)
9004 FORMAT(/5X*---ERROR---SECOND CHECK ON PRODUCTION SCHEME*
  Q/11X*THIS SCENARIO PRODUCES*E10.3* BBLS WHICH IS MORE THAN*/
  Q11X* THE*E10.3* BBLS AVAILABLE*/)
9005 FORMAT(/5X*---ABORT---THE MAXIMUM FLOW RATE CALCULATED IS*
  QF7.0* BBLS/DAY*/11X*WHICH IS LESS THAN THE REQUIRED 40000 BBLS/DAY
  Q*/)
  END

```


SUBROUTINE WELLO

COMMON/AA/MAXQ,THICK,DELP,VISNAT,VOLFF,RRES,RWELL,S,PERM B-6

REAL MAXQ

C WELL FLOW RATE EQUATION TAKEN FROM

C J.S. DOE REPORT ORD/4891-4

C MAXQ IS EVALUATED IN BBL/DAY

MAXQ=PERM*THICK*DELP/(141.2*VISNAT*VOLFF*(ALOG(RRES/RWELL)

Q=.75+S))

RETURN

END

```
SUBROUTINE GASQ
  DIMENSION TOTR(60),GAS(5,60)
  COMMON/BB/TOTR,GAS,NLIFE
C  CALCULATE THE AMOUNT OF NATURAL GAS EXTRACTED FROM
C  THE FLUID FOR VARIOUS VOLUMETRIC SOLUBILITIES
  DO 10 I=1,NLIFE
  DO 10 J=1,5
    GAS(J,I)=(35.+(J-1)*5.)*TOTR(I)
10 CONTINUE
  RETURN
  END
```

APPENDIX C

LISTING OF PROGRAM PRODUCE

```

PROGRAM PRODUCE (INPUT,OUTPUT,PUNCH,TAPE1=INPUT,TAPE2=OUTPUT,
QTAPE3=PUNCH)
C-2
DIMENSION NG(2000),ND(2000),NSR(2000),NDR(2000),NF(2000),NS(2000)
DIMENSION NGE(2000),NDE(2000),NGC(2000),NDC(2000)
DIMENSION NAME(2),H(3),N(3)
DO 47 K=1,3

```

```

47 H(K)=N(K)=0

```

```

C READ IN THE FOLLOWING INITIAL PARAMETERS,
C FAIRWAY NAME, NAME(1),NAME(2)
C NUMBER OF DRILLING RIGS AVAILABLE, NRIGS
C NUMBER OF PROSPECTS TO BE DRILLED WITHIN FAIRWAY, NDRILL
C SUCCESS PROBABILITY OF WELL, HITPROB
C READ(1,400) NAME(1),NAME(2)
C READ(1,401) NRIGS,NDRILL,HITPROB
C NDRILL, THE NUMBER OF PROSPECTS TO BE EXPLORED IS A PREDETERMINED
C FIGURE. THE TWO VARIABLES IN THE PROGRAM ARE NRIGS AND HITPROB.
C SET UP ARRAYS OF VALUES TO USE IN A PARAMETRIC STUDY OF THE SYSTEM.
C BOTH NRIGS AND HITPROB ARE INCREASED AND DECREASED BY 50 PERCENT
C TO YIELD NINE DISTINCT CASES.
C NOTE THAT NRIGS MUST BE ROUNDED OFF TO AN INTEGER AND HITPROB
C CANNOT BE GREATER THAN 1.0

```

```

H(1)=HITPROB
H(2)=HITPROB*0.5
H(3)=HITPROB*1.5
IF(H(3).GT.1.0) H(3)=1.0

```

```

N(1)=NRIGS
N(2)=NRIGS*0.5
N(3)=NRIGS*1.5
DO 2000 MA=1,3
HITPROB=H(MA)
DO 2001 MB=1,3
NRIGS=N(MB)

```

```

C INITIALIZE VARIABLES
C IP=NO. OF MONTHS REQUIRED TO DRILL EXPLORATORY GEOTHERMAL WELL
C IS=NO. OF MONTHS REQUIRED TO DRILL A SHALLOW REINJECTION WELL
C ID=NO. OF MONTHS REQUIRED TO DRILL A DEEP REINJECTION WELL

```

```

IP=4
ID=4
IS=2
IFLAG=0
ILAST=0
NCHECK=0

```

```

DO 2 K=1,2000

```

```

NGE(K)=NDE(K)=0

```

```

2 NG(K)=ND(K)=NSR(K)=NDR(K)=NF(K)=NS(K)=NGC(K)=NDC(K)=0

```

```

I=1

```

```

NF(I)=NRIGS

```

```

5 CONTINUE

```

```

C CHECK FOR COMPLETION OF FAIRWAY DEVELOPMENT

```

```

IF(NS(I).EQ.0) 6,520

```

```

6 IF(ILAST.GE.10) GO TO 1000

```

```

IF(IFLAG.EQ.1) ILAST=ILAST+1

```

```

IF(NF(I).EQ.0) 7,9

```

```

7 I=I+1

```

```

GO TO 5

```

```

9 CONTINUE

```

```

NCHECK=NCHECK+NF(I)

```

```

IF(NCHECK.EQ.NDRILL) 10,11

```

```

10 IFLAG=1
   GO TO 13
11 IF(NCHECK.GT.NDRILL) 12,13
12 JX=NF(I)-(NCHECK-NDRILL)
   IFLAG=1
   GO TO 14
13 CONTINUE
   JX=NF(I)
14 CONTINUE
   IF(JX.LE.0) 500,17
17 CONTINUE
C   USE RANDOM NUMBER GENERATOR TO ESTABLISH SEQUENCE OF GOOD/BAD WELLS
   DO 26 J=1,JX
   R=RANF(0)
   IF(R.LE.HITPROB) 15,20
15 NGE(I)=NGE(I)+1
   GO TO 25
20 NDE(I)=NDE(I)+1
25 CONTINUE
26 CONTINUE
   IF(NGE(I).GT.0) 27,50
27 CONTINUE
C   DRILL GOOD EXPLORATORY WELLS
   NF(I)=NF(I)-NGE(I)
   NW=NGE(I)
   JA=I+IP-1
   DO 30 J=I,JA
30 NG(J)=NW+NG(J)
C   DRILL SHALLOW REINJECTION WELLS
   JB=JA+1
   JC=JB+IS-1
   DO 35 J=JB,JC
35 NSR(J)=NW+NSR(J)
   NGC(JC+1)=NGC(JC+1)+NW
   NF(JC+1)=NF(JC+1)+NW
50 CONTINUE
   IF(NDE(I).GT.0) 60,100
C   DRILL DRY EXPLORATORY WELLS
60 JA=I+IP-1
   NF(I)=NF(I)-NDE(I)
   NW=NDE(I)
   DO 65 J=I,JA
65 ND(J)=NW+ND(J)
   NDC(JA+1)=NDC(JA+1)+NW
   NF(JA+1)=NF(JA+1)+NW
   IF(NGE(I).EQ.0) GO TO 500
   IF(NF(I+IP).GE.NGE(I)) 70,80
C   DRILL ALL THE DEEP REINJECTION WELLS THAT ARE REQUIRED
70 NW=NGE(I)
   JA=I+IP-1
   NF(JA+1)=NF(JA+1)-NGE(I)
   JB=I+IP
   JC=JB+ID-1
   DO 75 J=JB,JC
75 NDR(J)=NW+NDR(J)
   NF(JC+1)=NF(JC+1)+NW
   GO TO 500
80 CONTINUE

```

C-4

```

C   DRILL AS MANY DEEP REINJECTION WELLS AS POSSIBLE WITH EXISTING
C   FREE RIGS
      JA=I+IP-1
      NW=NF(JA+1)
      NF(JA+1)=0
      JB=I+IP
      JC=JB+ID-1
      DO 85 J=JB,JC
85   NDR(J)=NW+NDR(J)
      NF(JC+1)=NF(JC+1)+NW
      IE=I+IP
C   EVALUATE THE NUMBER OF RIGS SHORT
      NS(IE)=NGE(I)-NW
      GO TO 500
100  IF(NGE(I).GT.0) 105,500
105  IE=I+IP
      NS(IE)=NGE(I)+NS(IE)
      GO TO 500
500  CONTINUE
      I=I+1
C   EVALUATE THE NEXT MONTHS RIG AVAILABILITY
      NF(I)=NF(I)+NF(I-1)
      NS(I)=NS(I)+NS(I-1)
      GO TO 5
520  CONTINUE
530  CONTINUE
C   COMPLETE DRILLING OF ANY REQUIRED DEEP REINJECTION WELLS BEFORE
C   ANY NEW EXPLORATORY WELLS ARE DRILLED.
      IF(NF(I).GE.NS(I)) 600,650
600  CONTINUE
      NF(I)=NF(I)-NS(I)
      NW=NS(I)
      NS(I)=0
      JA=I
      JB=I+ID-1
      DO 605 J=JA,JB
605  NDR(J)=NDR(J)+NW
      NF(JB+1)=NF(JB+1)+NW
      GO TO 5
650  CONTINUE
      NW=NF(I)
      NS(I)=NS(I)-NW
      NF(I)=0
      JA=I
      JB=I+ID-1
      DO 655 J=JA,JB
655  NDR(J)=NDR(J)+NW
      NF(JB+1)=NF(JB+1)+NW
      I=I+1
      NS(I)=NS(I)+NS(I-1)
      GO TO 530
1000 CONTINUE
C   PRINT OUT RESULTS FOR EACH CASE
      WRITE(2,8000)NAME(1),NAME(2),NRIGS,NDRILL,HITPROB
      WRITE(2,8001)
      WRITE(2,8002)
      IEND=I+1
      J=0

```

```

M=0
DO 1100 I=1,IEND
M=M+1
IF(M,EQ,12) GO TO 1050
WRITE(2,6000)I,NG(I),ND(I),NSR(I),NDR(I),NF(I),NS(I),NGC(I),NDC(I)
GO TO 1075
1050 J=J+1
M=0
WRITE(2,6001)J,I,NG(I),ND(I),NSR(I),NDR(I),NF(I),NS(I),NGC(I),NDC(I)
1075 CONTINUE
1100 CONTINUE
2001 CONTINUE
2000 CONTINUE
4000 FORMAT(2A10)
4001 FORMAT(2I5,F5.0)
6000 FORMAT(4X,9I8)
6001 FORMAT(4X,I3,I5,8I8)
8000 FORMAT(1H1,3/,4X*FAIRWAY *2A10//
Q4X*NUMBER OF DRILLING RIGS AVAILABLE (NRIGS)=*I5/
Q4X*NUMBER OF PROSPECTS TO BE DRILLED (NDRILL)=*I5/
Q4X*SUCCESS PROBABILITY OF WELL (HITPROB)=*F6.4//)
8001 FORMAT(4X*KEY*/
Q4X*J      =TIME IN YEARS SINCE INITIATION OF PROJECT*/
Q4X*I      =TIME IN MONTHS SINCE INITIATION OF PROJECT*/
Q4X*NG(I)  =NO. RIGS DRILLING GOOD EXPLORATORY WELLS*/
Q4X*ND(I)  =NO. RIGS DRILLING DRY EXPLORATORY WELLS*/
Q4X*NSR(I) =NO. RIGS DRILLING SHALLOW REINJECTION WELLS*/
Q4X*NDR(I) =NO. RIGS DRILLING DEEP REINJECTION WELLS*/
Q4X*NF(I)  =NO. RIGS FREE FROM SERVICE*/
Q4X*NS(I)  =NO. RIGS SHORT IN PRODUCTION PLAN*/
Q4X*NGC(I) =POINT IN TIME GOOD WELL STARTS PRODUCING*/
Q4X*NDC(I) =POINT IN TIME DRY WELL COMPLETED*//)
8002 FORMAT(4X*STATUS OF RIGS OVER EXPLORATION LIFE OF FAIRWAY*//4X
Q* (J) (I) NG(I) ND(I) NSR(I) NDR(I) NF(I) NS(I) NGC(I)
Q) NDC(I) */)
END

```

APPENDIX D

DESCRIPTION OF THE ECONOMIC MODEL

Mathematical Description of the Economic Model

The analysis will start with the development of the net present value of a successful well and the net present value of an unsuccessful well.

Net Present Value (NPV) - Successful Well

$$NPV = PW(ATE) - I_0$$

$PW(ATE)$ = Present Worth of After Tax Earnings

I_0 = Initial Investment

Initial Investment

$$I_0 = I_{PW} + I_{DDW} + I_{SDW} + I_{FP} + I_{PP}$$

I_{PW} = Investment, Production Well

I_{DDW} = Investment, Deep Disposal Well

I_{SDW} = Investment, Shallow Disposal Well

I_{FP} = Investment, Fuel Plant

I_{PP} = Investment, Power Plant

Note: The first three items are divided into two categories for tax purposes: Tangible and Intangible. The tangible portion (approximately 1/3) is subject to depreciation. The intangible portion (approximately 2/3) is "expensed" at the time of occurrence.

Revenue

$$\begin{aligned} \text{REV}_t &= P_0 e^{\lambda t} Q_0 && \text{if } 0 \leq t \leq L_1 \\ &= P_0 e^{\lambda t} Q_0 e^{-g(t - L_1)} && \text{if } L_1 \leq t \leq L_2 \end{aligned}$$

P_0 = Initial Price (1979)

λ = Price Increase Rate

Q_0 = Initial Flow Rate (= 40,000 bbl/day)

L_1 = Time Under Constant Flow Rate

g = Flow Decline Rate

L_2 = Economic Life of Project

Initial Price

$$P_0 = P/\text{MSCF} * \text{MSCF}/\text{bbl} * f_r$$

f_r = Recovery Percentage

After Tax Earnings

$$\text{ATE} = \text{Net Income} - \text{Taxes}$$

$$\text{NI} = \text{Net Revenue} - \text{Operating Costs} - \text{Severance Taxes}$$

$$\text{TAXES} = (\text{Tax Rate}) * (\text{Taxable Income})$$

$$\text{NET REV} = \text{Gross Revenue} - \text{Royalties}$$

$$\text{O.C.} = (\% I_{FP} + \% I_{PP}) e^{\rho t}$$

$$\text{TI} = \text{NI} - \text{Allowances}$$

$$\text{ALL} = \text{DEPR} + \text{DEPL ALLOW}$$

$$\text{SEVTAX} = \% \text{REV}$$

$$\text{DEPR} = \left[\frac{1}{3} I_{PW} + \frac{1}{3} I_{DDW} + \frac{1}{3} I_{SDW} + I_{FP} + I_{PP} \right] / L_2$$

$$L_2 = \text{Economic Life}$$

(Note: Depletion allowance will not be included at this time).

$$\text{ATE} = \text{NR} - \text{OC} - \text{ST} - t_r(\text{TI})$$

$$= \text{NR} - \text{OC} - \text{ST} - t_r(\text{NR} - \text{OC} - \text{ST} - \text{DEPR} - \text{DA})$$

$$= (1 - t_r)\text{NR} - (1 - t_r)\text{OC} - (1 - t_r)\text{ST} + t_r(\text{DEPR}) + t_r(\text{DA})$$

Economic Life

$$L_2: \text{REV}_{L_2} = \text{OC}_{L_2}$$

$$P_0 e^{\lambda t_2} Q_0 e^{-g(L_2 - L_1)} = \text{OC}_0 e^{\rho L_2}$$

$$P_0 Q_0 e^{[-g(L_2 - L_1) + \lambda L_2]} = \text{OC}_0 e^{\rho L_2}$$

$$\frac{P_0 Q_0}{\text{OC}_0} = e^{[\rho L_2 + g(L_2 - L_1) - \lambda L_2]}$$

$$\frac{P_0 Q_0}{\text{OC}_0} = e^{[L_2(\rho + g - \lambda) - L_1 g]}$$

Taking Logs:

$$\ln(P_0) + \ln(Q_0) - \ln(OC_0) = L_2(\rho + g - \lambda) - L_1 g$$

$$L_2 = \frac{\ln(P_0) + \ln(Q_0) - \ln(OC_0) + L_1 g}{\rho + g - \lambda}$$

Present Worths

$$PW(REV) = \int_0^{L_1} p_0 e^{\lambda t} Q_0 e^{-rt} dt + \int_{L_1}^{L_2} p_0 e^{\lambda t} Q_0 e^{-g(t-L_1)} e^{-rt} dt$$

r = discount rate

$$\begin{aligned} PW(REV) &= \frac{p_0 Q_0}{(r - \lambda)} \left[1 - e^{-(r-\lambda)L_1} \right] \\ &\quad + \frac{p_0 Q_0 e^{gL_1}}{(r - \lambda + g)} \left[e^{-(r - \lambda + g)L_1} - e^{-(r - \lambda + g)L_2} \right] \end{aligned}$$

$$\begin{aligned} PW(OC) &= \int_0^{L_2} OC_0 e^{\rho t} e^{-rt} dt \\ &= \frac{OC_0}{(r-\rho)} \left[1 - e^{-(r-\rho)L_2} \right] \end{aligned}$$

$$PW(ST) = \% PW(REV)$$

$$\begin{aligned} PW(DEPR) &= \int_0^L DEPR e^{-rt} dt \\ &= \frac{DEPR}{r} \left[1 - e^{-rL_2} \right] \end{aligned}$$

```
PROGRAM GPGT1(TTY,TAPE5=TTY,TAPE6=TTY)
```

```
COMMON X(16),XNPV(20)
```

```
WRITE(6,1)
```

```
FORMAT(*PLEASE ENTER THE FOLLOWING DATA, ONE ITEM PER LINE*,/,5X
```

```
+ ,*INVESTMENT = PRODUCTION WELL*,/,5X,*INVESTMENT = DEEP DISPOSAL  
+ L WELL*,/,5X,*INVESTMENT = SHALLOW DISPOSAL WELL*,/,5X,  
+ *INVESTMENT = FUEL PLANT*,/,5X,*INVESTMENT = POWER PLANT*,/,  
+ 5X,*OPERATING COST PERCENTAGE = FUEL PLANT*,/,5X,  
+ *OPERATING COST PERCENTAGE = POWER PLANT*,/,5X,*OPERATING *,  
+ *COST ESCALATION FACTOR*,/,5X,*GAS PRICE = $/MCF*,/,5X,  
+ *PRICE ESCALATION FACTOR*,/,5X,*GAS = SF/BAR*,/,5X,  
+ *INITIAL FLOW RATE = BAR/DAY*,/,5X,*NUM OF YRS TO DECLINE*,/,  
+ 5X,*DECLINE RATE*,/,5X,*SEVERANCE TAX RATE*,/,5X,*ROYALTY RATE*)
```

```
DO 2 I=1,16
```

```
READ(5,3) X(I)
```

```
FORMAT(F15.0)
```

```
WRITE(6,4) X
```

```
FORMAT(/,* FOR THE FOLLOWING INPUT DATA*,/,5X,*INV=PW*,F12.2,
```

```
+/,5X,*INV=DDW*,F12.2,/,5X,*INV=SDW*,F12.2,/,5X,*INV=FP*,  
+ F12.2,/,5X,*INV=PP*,F12.2,/,5X,*OC=FP*,F12.2,/,5X,  
+ *OC=PP*,F12.2,/,5X,*OC ESC*,F12.2,/,5X,*GAS PRICE*,F12.2  
+ ,/,5X,*$ ESC*,F12.2,/,5X,*GAS SF/B*,F12.2,/,5X,*QTY(0)*,  
+ F12.2,/,5X,*L1= *,F12.2,/,5X,*G= *,F12.2,/,5X,*SEV TAX*  
+ ,F12.2,/,5X,*ROY RT*,F12.2,/,*THE FOLLOWING RESULTS WERE*,  
+ * OBTAINED:*,/)
```

```
CALL NPV
```

```
END
```

```
SUBROUTINE NPV
```

```
COMMON X(16),XNPV(20)
```

```
OC=X(6)*X(4)+X(7)*X(5)
```

```
XL2=(ALOG(0.75*X(9)*X(11))+ALOG(365.*X(12))-ALOG(OC)+X(13)*
```

```
+ X(14))/(X(8)-X(10)+X(14))
```

```
IF(XL2.GT.60.) XL2=60.
```

```
WRITE(6,2) OC,XL2
```

```
FORMAT(/,*ANNUAL OPERATING COST*,F12.2,/,*ECONOMIC LIFE*  
+ ,F12.2,/,)
```

```
R=0.09
```

```
DO 3 IR=1,20
```

```
R=R+0.01
```

```
PVREV=(1.-EXP(-(R-X(10))*X(13)))/(R-X(10))
```

```
F2=EXP(X(14)*X(13))*(EXP(-(R+X(14)-X(10))*X(13))
```

```
+ -EXP(-(R+X(14)-X(10))*XL2))/(R+X(14)-X(10))
```

```
PVREV=PVREV+F2
```

```
PVREV=PVREV*(X(9)*X(11)*X(12)*365.*0.00075)
```

```
PVOC=OC*(1.-EXP(-(R-X(8))*XL2))/(R-X(8))
```

```
PVST=X(15)*PVREV
```

```
DEPR=((X(1)+X(2)+X(3))/3.)*X(4)+X(5))/XL2
```

```
PVDEPR=DEPR*(1.-EXP(-(R+X(14)-X(10))*XL2))/R
```

```
PVATE=0.52*(1.-X(16))*PVREV-0.52*PVOC-0.52*PVST+0.48*PVDEPR
```

```
XNPV(IR)=PVATE-0.52*2.*(X(1)+X(2)+X(3))/3.-(X(1)+X(2)+X(3))/3.
```

```
+ -X(4)-X(5)
```

```
WRITE(6,4) R,PVREV,PVOC,PVST,PVDEPR,PVATE,XNPV(IR)
```

```
FORMAT(/,*R *,F12.2,/,*PVREV *,F12.2,/,*PVOC *,F12.2,
```

```
+ ,/*PVST *,F12.2,/,*PVDEPR*,F12.2,/,*PVATE *,F12.2,/,
```

```
+ *NPV *,F12.2,/,)
```

```
IF(XNPV(IR).LT.0.) RETURN
```

```
CONTINUE
```

```
RETURN
```

```
END
```