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PAPER

100,000 QUADS OF NATURAL GAS?

By

William M. Brown

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100,000 QUADS OF NATURAL GAS?

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William M. Brown

SUMMARY

Of the various possible unconventional natural gas resources that have been examined, the most recent, and by far the largest, is that which is dissolved in the hot salt water within the "geopressurized" zones of the Gulf Coast. Recent assessments have estimated that the amount of gas contained in these waters, underlying about 150,000 square miles of Texas and Louisiana--both onshore and offshore--is between 60,000 and 100,000 quads. One quad is roughly a trillion cubic feet and currently is worth about \$2 billion at uncontrolled prices. In addition to the natural gas there is a huge potential for producing electric power from the heat content of the fluid, as well as other potential uses for hot water. The net value of this geothermal heat may be about half that of the natural gas. The major problems associated with commercial production of the fluids from these zones and the extraction of energy from the heat and pressure of the fluid are discussed and the long-term potential is estimated. It appears likely that commercial production will depend upon the existence of uncontrolled prices for natural gas and the satisfactory resolution of various legal, environmental, and institutional problems, all of which are likely to require considerable effort. However, the immense size of the potential resource, which rivals that of U.S. coal deposits in its energy content, appears likely to create a growing demand for such development, especially if fossil fuel prices and/or U.S. dependence upon OPEC increases in the near future.

The conditions which have created this resource in the Gulf region are not geologically unique. Consequently, a crude or "ball-park" estimate is given that the world's resources of a similar nature may be ten or twenty times as much as that of the zones analyzed in this paper--and should include basins off California and Alaska.

Although the production potential from the Gulf Coast zones might be accurately estimated after a decade or so of active research and development, at present the long-term potential appears to be between 4 percent and 50 percent of the fluid within the reservoirs which are eventually developed. During the last year a modest research and development program (4 million dollars requested for fiscal '77) to analyze and estimate the practical potential in the Gulf region has been funded by the Energy Research and Development Administration (ERDA).

Although the costs of production of gas and electric power from this resource may not be cheap, the principal reservoirs should be relatively easy to locate in the onshore Gulf region because of the existing data available from the vast number of wells which have already been

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drilled in the area. One of the principal economic benefits that might result if the development of this resource proceeds is its potential for placing a ceiling upon the future price of fossil fuels in the U.S.; this ceiling is expected to be about \$2.00 per million BTU (in \$1976)--although many factors could move this estimate up or down in the near future. Over the longer term the actual cost of production (in constant dollars) appears likely to decline as a result of technological progress.

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100,000 QUADS OF NATURAL GAS?

Introduction

A somewhat surprising and perhaps even awesome development among the potential energy alternatives for the United States has been quietly maturing away from public view and may within the next few years--or less--start to blossom into one of the largest energy projects in the world, perhaps the largest. The story has some strange antecedents and a few complications but it appears to be both promising and exciting and, in my judgment, deserves much more attention than it has received to date.

I will begin by "letting the cat out of the bag." It now appears that the resource base* of natural gas within the U.S. is probably greater, in terms of energy content, than that of coal, with which the U.S. is unusually well endowed. The U.S. Geological Survey's 1973 estimate of U.S. total coal resources (including lignite) was 3,224,372 million tons (Reference 1, p. 137). At an average of 20 million BTU per ton, this gives about 65,000 quads (1 quad = 1 quadrillion BTUs = 10^{15} BTU) as our coal resource base--about 40 percent of which is classified as identified resources; the remainder is hypothetical. The long term recoverability of coal is estimated at roughly 50 percent of the total, but this judgment eventually will be dependent on many variables (economics, environment, etc.). In any event the coal resource base is huge in comparison to the current U.S. rate of energy consumption, about 80 quads annually. How, therefore, can the natural gas resource base be comparable or even be greater? The resolution of this question, addressed in this paper, is related to one of the several unconventional sources of natural gas.**

The story starts with the renewed search for geothermal energy which was induced by the recent energy crisis. In classifying the nation's (or the world's) geothermal energy resources, it has been customary to list:

1. Steam reservoirs,
2. Hydrothermal (hot water, above 200 °C) reservoirs, and
3. Hot-dry-rock subsurface "outcroppings"

as the more important potential sources and then to add for the sake of completeness:

* The resource base means the total amount of the resource in the ground whether it is now feasible to extract it or not.

** Unconventional potential natural gas sources which are not discussed in this paper include coal formations, tight sand formations in Rocky Mountain basins, and certain shale formations--all of which are presently being examined for their commercial potential.

4. Geopressurized zones, and
5. Molten magma sources.

The listing is roughly in the order of the anticipated commercial feasibility or development expressed by various analysts during recent years.

In most summaries of the nation's energy potential prior to 1975 (e.g., Ford Foundation study, FEA's 1974 report on Project Independence, etc.), the U.S. geothermal potential appears to be included almost by way of being polite to a new or "orphan" technology; therefore it is not unusual to find that energy analysts have generally dismissed any geothermal resources beyond the more familiar ones, such as 1 and 2 above, even though there are far greater quantities of energy associated with 3, 4 and 5 (this 5th item is essentially an inexhaustible energy source if one probes deeply enough into the earth, but technologically it appears to be quite difficult even for shallow intrusions)--indeed the last three on the above list have not even been included in most of the projections I have seen. At Hudson, we, too, were "guilty" (in Chapter 3 of TNTY*) of omitting data on item 4 (geopressurized zones), giving only a passing reference acknowledging its existence.

But recently an article in Science (February 13, 1976) entitled "Natural Gas: U.S. Has It If the Price is Right," stimulated a new examination of the "slighted" geopressurized zones. The article reminded me that this particular resource might not only furnish electric power but that these zones contained hot water with dissolved methane**--the principal constituent of natural gas--and that the quantity might be quite large. Indeed, Science gave several different estimates for the resource base, the highest of which was 1400×10^{12} cubic meters of methane within the onshore aquifers of the Gulf Coast region of the U.S. (The U.S. Geological Survey estimate--discussed later--is about 50 percent less.)

That volume of methane became more impressive when translated into more familiar energy units. It turned out to be approximately 52,000 quads.

A number like this is obviously worth a deeper look in order to get a better picture of the practical potential. At current free market prices 1-quad of natural gas is worth roughly \$2 billion and under two Gulf Coast states--Texas and Louisiana--there may be 52,000 quads.

* TNTY: The Next 200 Years, by Herman Kahn, William Brown, and Leon Martel (New York: William Morrow & Co., Inc., 1976).

** Methane (CH_4) is the simplest natural hydrocarbon. Because natural gas from Texas and Louisiana is more than 95 percent methane, the two terms can almost be used interchangeably for most of the issues discussed in this paper.

In this paper I will attempt to portray an accurate picture of the potential resource base associated with the hot water reservoirs within the geopressurized zones of the Gulf Coast and of the problems associated with its commercial extraction and utilization. The total resource base, I will show, for the Texas and Louisiana portion of the Gulf Coast, has been estimated by two competent sources to lie between 60,000 and 105,000 quads, for the natural gas alone. Moreover, as far as I know, these are the only two studied estimates that have been published recently, neither of which claims to be highly reliable. At this time the eventual recoverability is highly uncertain but probably lies in the range of 4 percent to 50 percent of the methane within the reservoirs which are eventually developed. Whether the reservoirs which are developed will include most of the resource base will be uncertain until both economic and technological feasibility are assessed--a process which has already begun--and the inevitable institutional and environmental problems are resolved.

The Resource Base

For millions of years rivers draining a large part of the U.S. continent have been depositing sediments into the Gulf of Mexico, gradually shifting the coastline further towards the sea. This has resulted in huge deposits of interbedded sand and clay of widely varying dimensions, separated by large shale wedges. These formations have become growth-faulted (see Figure 1) as a result of continued deposition and changing geological forces during the recent Cenozoic era (the last 70 million years).

As a consequence, as drilling experience near the Gulf Coast has demonstrated, within these sediments are large aquifers in which the salt water is at normal hydropressure down to some level called the top of the geopressure zone (roughly around 10,000 feet, but with substantial variance). Below this level the pressure in the aquifers rises rapidly until it reaches nearly lithostatic pressures--about twice that of normal hydropressure. Below this transition zone are the hot geopressurized aquifers whose waters help to support the weight of the overburden and which, therefore, permit the porosity of the sediments to be substantially greater than that which would otherwise be found at the same depth (see Figure 2). Some of the important geological characteristics of these formations are shown in Figures 3, 4 and 5.

Over time, the organic content of the subsiding sediments were gradually subjected to increasing temperatures from the geothermal heat flow and as a result were converted to petroleum hydrocarbons. In this manner, according to accepted theory of the origin of petroleum, nature provides a giant "pressure-cooker" which cracks the organic matter increasingly into simpler hydrocarbons as the temperature increases until, eventually, little is left except methane wherever the temperature has exceeded 150 °C. Consequently, as Professor Paul H. Jones (L.S.U.) stated in reference to the Gulf region:

Figure 1

GROWTH FAULT DEVELOPMENT INTERPRETED FROM A SEISMIC SECTION
AND SHOWN SEQUENTIALLY BY DIAGRAMS

(SD is sand, SH is shale)

Source: D. G. Bebout in Reference 6

Figure 2

POROSITY-DEPTH RELATIONSHIP

Relation of porosity to depth of burial in sand beds and in shale beds of Cenozoic age in the hydropressure zone and in the geopressure zone in the Gulf basin.

Source: P. H. Jones in Reference 2.

Figure 3

THICKNESS OF CENOZOIC DEPOSITS IN THE GULF COAST GEOSYNCLINE

Source: P. H. Jones in Reference 2.

Figure 4

GEOLOGIC DIP SECTION ACROSS SOUTH TEXAS COASTAL PLAIN, SHOWING
GROWTH-FAULT SYSTEMS IN MAJOR CENOZOIC DELTA DEPOSITS AND
THEIR RELATION TO THE TOP OF THE GEOPRESSURE ZONE

Source: P. H. Jones in Reference 2.

Figure 5

PRINCIPAL REGIONAL NORMAL FAULTS IN NEOGENE DEPOSITS
OF THE GULF COAST GEOSYNCLINE

Source: P. H. Jones in Reference 2.

Wherever methane gas is associated with reservoir waters those waters are saturated in dissolved methane. Saturated formation waters associated with more than 8,000 producing gas reservoirs in the geopressure zone of the Gulf coast occur in a depth range from about 9,000 to 22,000 ft. (Reference 3)

Evidently, natural gas reservoirs are formed within the geopressurized zones whenever more methane has accumulated than the water could dissolve. The high water pressure in these geopressure zones tended to cause extraordinary trouble to wildcatters during the '50s. Drilling through the caprock to these waters frequently caused their wells to blow out. Consequently, this water was considered a great nuisance; this led to widespread acceptance of an "impenetrables clause" in drilling contracts--one which protected the driller from financial responsibility if the well was blown out by the pressurized water (Jones in Reference 2). During the '60s, however, improvements in drilling technology overcame this problem and the geopressure zones are no longer considered hazardous.

Because the water in the geopressure zones has until very recently been considered a nuisance at best, no one has, as yet, even attempted to measure its methane content.* The general belief on theoretical grounds that the geopressurized waters are saturated with methane is bolstered by existence of thousands of producing gas reservoirs, which indicate that there is often an excess of methane, and by the fact that all measurements of waters in the shallower hydropressure zones (into which the geopressured waters gradually leak over time) have been found to be methane saturated.

The recent increased interest in geothermal energy sources has led to new investigations of the potential of the Gulf Coast geopressured waters. The interest in this region probably has grown slowly for several reasons. First because the technology of extracting energy commercially from mineralized hydrothermal reservoirs had not been developed in the U.S. and second, because the temperatures in these geopressure zones were considerably lower than those which could be found at the same depths elsewhere. Only recently have sufficient funds become available even to study the alternative seriously.** The few studies made since the 1973 energy crisis have suggested that the amount of natural gas available as a "byproduct" would offset to some extent the lower water temperatures and, indeed, might make this region more commercial than competing nonmethanated hydrothermal reservoirs. A study to estimate the size of the resource base was first published, as far as I can determine, by the U.S.G.S. in 1975 (Reference 4). Although this is a preliminary estimate, the results clearly suggest an immense energy potential. Also, the hardware now being developed for the exploitation of the hydrothermal zones in California might also be adapted to extract electrical

* Except possibly for unpublicized measurements by private companies.

** Even ERDA's budget request for fiscal 1977 was only \$4.2 million, but that is up from \$.25 million for fiscal 1976; I have heard, informally, from ERDA, that this request was very recently changed to \$6.1 million.

energy from the Gulf zones. Finally, at controlled prices of natural gas (currently 52 cents per MCF--1,000 cu. ft.--at the wellhead for interstate delivery), the economic incentive has been much too small.

An assessment of the energy potential and other physical data of this Gulf Coast region is given in a U.S. Geological Survey publication (Papadopoulos, et al., in Reference 4). Their assessment is based on an examination of data from 193 existing wells.* The authors divide the onshore areas of Texas and Louisiana into 21 subareas, each of which is treated as a separate reservoir (see Figure 6) and calculate the average value of the important parameters. They estimate that these reservoirs contain 24,000 quads of methane (see Table 1) in addition to 43,000 quads of heat and about 220 quads of mechanical (pressure) energy. Moreover, the authors indicate that this estimate ignores other potential but less accessible sources (e.g., offshore reservoirs, deeper sands). They estimate, however, that "the potential of these additional geopressurized reservoirs is about $1\frac{1}{2}$ to $2\frac{1}{2}$ times that of those assessed in this study." Their total estimated methane resource base therefore is between 60,000 to 84,000 quads; the heat content of the water is between 100,000 and 150,000 quads.

Professor Jones, who is considered to be the nation's foremost expert on the geology of this region, has examined the above calculations, and concluded that the simplifying assumptions are frequently erroneous, up to a factor of 2--mostly on the conservative side. He estimates a resource base of approximately 52,000 quads of methane as associated with the waters within the sandbeds and a total of 105,000 quads of methane for these beds plus the waters available from the associated geopressured shale formations (Reference 3). Overall, his estimate is about 50 percent higher than that of the U.S.G.S.

Extracting the Energy

Suitable Reservoirs

Although the U.S.G.S. assessment seems, at first glance, to suggest that there are about 21 major geopressurized reservoirs in the Texas and Louisiana onshore region (Figure 6 and Table 1), that is a deliberately gross oversimplification. The known geology of the region suggests the existence of a great many more reservoirs than that, possibly thousands or even tens of thousands--although, on the other hand, it is probable that the major reservoirs might be a very small fraction of the total number and nevertheless contain the bulk of the geothermal fluid. Initial attempts at commercial extraction would be expected, naturally, to begin exploitation through the larger reservoirs (say, 200 square miles or more in area, with several sand beds at various depths).

Jones, for example, presents some more detailed geological data on conditions to be expected in the subarea, designated DT-2 by the U.S.G.S., which indicates the existence of more than 5,000 feet of accumulated sand

*The authors estimate that over 300,000 wells have been drilled onshore within this region.

Figure 6

LOCATION MAP SHOWING THE EXTENT OF THE ASSESSED GEOPRESSURED ZONES AND THEIR DIVISION INTO SUBAREAS (AT₁, BT₁, AND SO ON)

Source: S. S. Papadopoulos et al., Reference 4.

Table 1

ASSESSMENT OF THE "FLUID RESOURCE BASE"

Reservoir	Volume of water in storage	Thermal energy	Methane Energy*		Mechanical energy
			Volume	Thermal equivalent	
	10^{12} m^3	10^{20} J	10^{12} std. m^3	10^{20} J	10^{20} J
AT ₁	4.91	32.4	54.0	20.4	0.1
ATL ₂	11.80	66.1	99.4	37.5	0.2
BT ₁	8.81	53.8	83.7	31.6	0.2
BT ₂	3.14	17.0	23.6	8.9	0.1
CT ₁	4.62	28.5	41.1	15.5	0.1
DT ₁	2.39	14.3	21.7	8.2	0.1
DT ₂	2.56	15.6	23.5	8.9	0.1
DT ₃	4.04	22.3	32.3	12.2	0.1
DIL ₄	2.55	13.1	18.6	7.0	0.1
DL ₅	3.82	23.4	30.6	11.5	0.2
DL ₆	2.06	12.2	17.1	6.5	0.1
ET ₁	2.69	16.3	23.7	8.9	0.1
ET ₂	0.99	5.9	9.3	3.5	0.0
ET ₃	4.28	22.6	33.4	12.6	0.1
ETL ₄	1.73	8.9	11.6	4.4	0.1
EL ₅	3.75	23.6	30.0	11.3	0.1
EL ₆	4.61	27.7	35.5	13.4	0.2
EL ₇	3.70	19.6	31.5	11.9	0.1
FT ₁	1.02	6.3	10.4	3.9	0.0
FL ₂	2.25	12.6	16.4	6.2	0.1
FL ₃	2.67	14.9	21.9	8.3	0.1
Totals:	78.39	457.6	669.3	252.6	2.3

*Note: J = Joule, $10^{20} \text{ J} \approx 95 \text{ quads}$.

Source: S. S. Papadopoulos, et al. in Reference 4.

beds. Within this zone, which has an overall area of about 2,000 square miles, he estimates that there exists about 1,200 quads of methane (Reference 3). This calculation is reproduced in Table 2. He does not, of course, claim that the DT-2 area is one continuous reservoir throughout.

Nevertheless, enough hard geological information is available to lead those who have been studying the area to expect to find a number of very large reservoirs. This Gulf region may be the most explored area in the world; data is available from the 300,000 wells which have been drilled into it. Much if not most of this well-data is available and can be computerized to yield the desired information--a project currently underway in ERDA's program (Reference 2, p. 362). Professor Myron Dorfman of the University of Texas concluded from early findings that:

Some of the sand bodies contained in these deep intervals appear to have volumes considerably in excess of four cubic miles and average porosity values range between 20% and 25% in most areas. (Reference 5, p. 15)

A large reservoir is especially desirable for an early demonstration project since it will improve the chances for successfully developing the current ERDA program, which ultimately hopes to determine an optimum way to extract energy from this resource. It visualizes eventually the possibility of large electric power plants, large quantities of natural gas, and possibly the development of alternative uses for the hot water as an important working fluid for industrial and commercial uses. Most importantly, a large reservoir will guarantee a lifetime greater than (perhaps very much greater than) 20 years to make commercial investments attractive. If these large reservoirs can be made commercially successful, then over time they will indicate more and more clearly the degree to which smaller ones might be profitably exploited.

Anticipated Well Production

Part of the problem is a need to understand the rate at which a well can be expected to produce the geothermal fluid. This result depends upon a number of parameters, such as depth, well-diameter, pressure, permeability, etc. The theoretical results are illustrated in Figure 7 for one set of parameters, varying only the product of permeability (k) and sand depth (h). This figure suggests that 60,000 bbls/day are likely to be produced even if it is desirable to maintain wellhead pressures of 2,000 psi or greater. A 7" rather than 5½" production tubing could increase this rate to over 100,000 bbls/day. The possibility that such large extraction rates can be attained is one of the important reasons for desiring a large reservoir. It should be noted also that the above example is based upon a rather modest well depth of 13,000 feet. Eventually wells over 18,000 feet in depth may be preferred, despite greater costs, because of the higher temperature and methane solubility, as well as the additional sands that can be tapped (see Table 2).

Table 2

DATA ON SUB-AREA DT₂ (OF TABLE 1)
 TOTAL AREA = 5,155 km² (1,980 mi²)

Depth	ΔP	Pressure ^{1/}	Temp ^{2/}	Gas in ^{3/} Solution	Sandbed ^{4/} Porosity	Cum Thick Sand	Vol. of Water per mi ² cu ft x 10 ⁶	Water	Gas in Solution
ft x 10 ³	psi/ft	psi x 10 ³	°F	scf/bbl	%	ft		bbl/mi ² x 10 ⁶	scf/mi ² x 10 ¹⁰
8	0.55	4.8 ³	194	18.8	?	-	-	-	-
9	0.60	5.4	199	20.0	27.0	200	1,505	268	0.537
10	0.70	7.0	212	23.7	30.0	300	2,509	448	1.061
11	0.75	8.2	237	27.9	32.5	400	3,624	647	1.805
12	0.80	9.6	261	32.1	34.0	500	4,739	846	2.716
13	0.85	11.0	285	39.0	36.96	600	5,182	1,103	4.305
14	0.90	12.6	307	46.8	35.13	600	5,876	1,049	4.910
15	0.92	13.8	331	55.0	33.30	600	5,570	994	5.470
16	0.95	15.2	354	64.0	31.47	500	4,386	783	5.013
17	0.95	16.1	376	73.0	29.64	400	3,305	590	4.308
18	0.96	17.2	397	82.0	27.71	300	2,317	413	3.393
19	0.97	18.4	414	92.0	25.98	400	2,897	517	4.759
20	0.97	19.4	434	103.0	24.15	500	3,366	601	6.191
21	0.97	20.3	450	114.0	22.32	500	3,111	555	6.333
22	0.97	21.3	466	125.0	20.49	400	2,284	408	5.100
23	0.98	22.5	480	137.0	18.66	300	1,560	278	3.817
24	0.98	23.5	500	150.0	16.83	200	938	137	2.513
25	0.98	24.5	520	164.0	15.0	100	418	74	1.224
								TOTAL	63.846

1/ Timko and Fertl, 1972, World Oil, pt. 6, fig. 30

2/ Hilchie, depth-temperature data, Jackson County, Texas, corr. by AAPG

3/ Culberson and McKetta, 1951; curves extrapolated by Jones, 1976

4/ Stuart, 1970, fig. 5

Source: Reference 3.

Figure 7

FLOWING WELLHEAD PRESSURE AS A FUNCTION OF RATE FOR VARIABLE PERMEABILITY-THICKNESS CONDITIONS (5½" TUBING)

Source: Reference 7.

Wells at a relatively shallow depth may be preferred during the next decade or so, during which time alternative designs for power plants should be tested and demonstrated. The technology for simply producing the water and separating the methane is on hand today. For sufficiently productive wells the value of the gas alone might provide an early way to begin commercialization of the resource--especially as the water at depths from 10,000 to 14,000 feet is less desirable for power production because of its lower temperature (e.g., 212 to 307 °F in the DT-2 zones--Table 2). Nevertheless this 10-14,000 feet zone might be able to produce 100,000 bbls/day yielding (at 30 SCF/BBL) 3 million cfd, roughly worth \$6,000/day at \$2/MCF.* A 14,000 foot well with 7" casing would cost a little less than \$2,000,000 in Nueces County, Texas, according to a late 1975 estimate by the Dow Chemical Company's Oil & Gas Division (in Reference 7). This and other cost data for wells appear in Table 3. There would be other expenses (methane separator, fluid reinjection, etc.) which might add up to another \$1 to \$2 million, and of course, there is always the possibility of "dry holes." An estimate of 1/3 dry holes was used by Dow in making conservative cost estimates (Reference 10).

If the natural flow of water from a well is marginal because of low permeability, the well can be stimulated to maximize its productivity, principally through the use of hydraulic fracturing. For deep (18,000 feet) wells hydraulic fracturing is not normally applied, because at this depth the standard propping agents (which hold the fracture open) may be unable to withstand the pressure; however, the outlook is favorable that propping agents of sufficient strength will soon become available that could triple the productivity of a well (Reference 7, pp. 54-6).

Economic Considerations in the Energy Extraction

The energy from these geothermal pressurized fluids comes in three forms: the hydraulic energy, from a wellhead pressure up to about half the bottom pressure (see Figure 8), the heat content of the fluid, and the methane. According to the U.S.G.S. assessment (Table 1) these energies exist approximately in the ratio of 1:200:110. However, during the extraction process most of the hydraulic energy will probably be sacrificed in exchange for a more rapid flow rate. In any event the two principal energy sources are the hot water and methane.

If, in fact, the hot water is used for electric power production, then engineers expect to convert less than 10 percent of its energy (heat content above 15 °C) to electricity.

*
 BBL: barrel
 SCF: standard cubic feet
 cfd: cubic feet per day
 MCF: thousand cubic feet.

Table 3

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

AFE NO. _____

Well Name GEOTHERMAL WELL NO. 3 Area or Field Wildcat

Location _____

Nueces County, TexasWork To Be Performed Drill, Test and CompleteProposed Depth 14,000' Objective Formation _____

<u>INTANGIBLE COSTS:</u>	<u>Estimated Cost Dry Hole</u>	<u>Estimated Cost Completion</u>
Stake Location	\$ 500	\$ --
Right of Way Cost and Surface Damage, Clean-up	20,000	--
Clear Right of Way, Construct Road and Location	50,000	--
Contract Drilling Cost -- Ft. @ \$ -- Ft.	--	--
Rig Time - Daywork with Drill Pipe <u>50/18</u> days @ \$ <u>4600</u> day	230,000	82,800
Rig Time - Daywork without Drill Pipe -- days @ \$ -- day	--	--
Hauling or Boat Rental	11,500	3,500
Mud and Chemicals	105,000	10,000
Cement, Cementing and Tools	35,000	10,000
Acid, Service and Tools Stimulation	--	50,000
Logging - Open Hole	65,000	--
Logging - Cased Hole	--	10,000
Perforating	--	10,000
Coring and Core Analysis	10,000	--
Mud Logging	22,000	--
Formation Testing - Open Hole and Casing	10,000	10,000
Floating Equipment, Centralizers, Scratchers	2,000	1,000
Bits, Permanent Packer and Rentals	100,000	34,000
Company Supervision and/or Consultant	22,000	7,000
Miscellaneous Services and Supplies, Bridge Plugs, Retainers, Fishing Tools, etc., Contingencies	105,000	33,000
Move-in, rig-up, rig down	50,000	--
Total Intangible Costs	\$ 838,000	\$ 261,300

AFE NO. _____

THE DOW CHEMICAL COMPANY
OIL AND GAS DIVISION
AUTHORITY FOR EXPENDITURE

Well Name GEO THERMAL WELL NO. 3

<u>TANGIBLE COSTS:</u>	Estimated Cost Dry Hole	Estimated Cost Completion
Conductor Casing <u>100</u> Ft. of <u>20</u> O.D. @ \$ _____ /Ft.	\$ 3,000	\$ --
Surface Casing <u>2500</u> Ft. of <u>13-3/8</u> O.D. @ \$ _____ /Ft.	48,000	--
Protection Casing <u>10,000</u> Ft. of <u>9-5/8</u> O.D. @ \$ _____ /Ft.	240,000	--
Production String <u>14,000</u> Ft. of <u>7</u> O.D. @ \$ _____ /Ft.	--	385,000
Tubing <u>14,000</u> Ft. of <u>5 1/2</u> O.D. @ \$ _____ /Ft.	--	275,000
Well Head Assembly _____	20,000	120,000
Retrievable Packers, Liners, Special Hole Equipment _____	--	10,000
Surface Production Facilities:		
Tanks, Treater, Heater, Separator _____		
Flow Lines, Connections _____		
Related Contract Labor, etc. _____		

Total Tangible Costs	\$ 311,000	\$ 515,000
Total Tangible & Intangible	\$ 1,149,000	\$ 776,300
TOTAL WELL COST	\$ 1,925,300	

Prepared By J. E. Thomas Approved By _____
Date 12/22/75 Date _____

<u>Joint Owners</u>	<u>Approved</u>	<u>Date Approved</u>
_____	By _____	_____
_____	By _____	_____
_____	By _____	_____
_____	By _____	_____

Figure 8

CHANGES IN PRESSURE GRADIENTS WITH DEPTH IN DEPOSITS
PENETRATED BY AN OFFSHORE LOUISIANA WELL

Source: P. H. Jones in Reference 2.

The efficiency theoretically attainable for the conversion of geothermal heat to electric power is temperature dependent and limited by the second law of thermodynamics. Thus if the fluid from the well emerges at 150 °C, the maximum theoretical efficiency would be about 26 percent and in practice is likely to be roughly a third of that, about 8 percent--although with advances in technology it might be increased to 10 or 11 percent by the end of the century. The U.S.G.S. uses a representative conversion factor of 8 percent for fluids between 150 °C and 200 °C (Reference 4, p. 107).

Burning methane to produce power with existing technology would convert about 35 percent of its energy into electricity. Therefore the available energy ratio, of hot water to natural gas, in electric power equivalents becomes 20:38.5 or roughly 1:2 after assuming a 10 percent conversion efficiency for the heat content. That is, the methane has about 2/3 of the value in this relationship. Economically the value of the methane should be even more than 2/3 of the total because the capital investment required to produce power by burning methane is considerably less than any projected for producing power from the geothermal waters.

Some attention has been given to the economics of power production from the geopressurized fluids during the last two years (References 2, 4, and 11) all of which tend to suggest that the outcome may depend upon uncertainties such as conversion efficiencies, temperatures, methane content, flow rates, number of dry holes, reinjection requirements, alternative uses of the hot water, etc. However, the value of the methane alone in terms of free market prices, generally taken to be about \$2/MCF, suggests that extraction of the gas alone might justify early commercial development and that uses for the hot water could follow as they became practical. The historical approach has instead emphasized the conversion of the heat of the water into electric power, with the income from the natural gas used to offset some of the costs--an approach which still dominates the published literature and ERDA's formal program. However, there are occasional hints in conference discussions that the commercially-oriented participants consider the gas to be the major potential asset (e.g., Reference 2, pp. 299, 307). A typical calculation that illustrates the historical approach is given in Table 4.

During the last two years, increasing thought has been given to other uses of the hot water resource than just conversion to electric power--and also to the possibility of multiple uses which could include electric power production. For example, early analyses have found that the hot water might have relatively greater value in (a) pulp and paper mills, and (b) sugar refineries, especially if plants were engineered to utilize this resource (G. D. Hornburg, in Reference 2). This result emerged despite some conservative values in the calculation (e.g., \$1 per million BTU as the value of the usable heat energy). In addition, the authors of that study found a large potential for the use of geothermal waters in petroleum refining (about .4 quad/yr.) and also stated that:

Table 4

ESTIMATED CAPITAL AND UNIT COSTS--1980 BASIS

Item	Hildalgo County			Jones No. 2		
	Isobutane	Steam - 1 Stage	Steam - 2 Stage	Isobutane	Steam - 1 Stage	Steam - 2 Stage
Wells	\$ 10,100,000	10,100,000	10,100,000	25,000,000	24,400,000	24,400,000
Collection & disposal piping	\$ 240,000	240,000	240,000	470,000	470,000	470,000
Methane extraction	\$ 27,000	27,000	27,000	49,000	49,000	49,000
Dehydration	\$ 60,000	60,000	60,000	112,000	112,000	112,000
Cooling and separation	\$ 881,000	881,000	881,000	1,856,000	1,856,000	1,856,000
Methane pipeline & compressor	\$ 4,979,000	4,979,000	4,979,000	6,157,000	6,157,000	6,157,000
Flash chamber & separator	\$ --	46,000	129,000	--	102,000	286,000
Heat exchange boiler & separator	\$ 3,797,000	--	--	10,310,000	--	--
Settling pond	\$ 31,000	--	--	83,000	--	--
Turbine-generator	\$ 4,498,000	4,026,000	6,844,000	12,134,000	10,968,000	18,646,000
Condenser	\$ 3,576,000	1,894,000	2,312,000	9,710,000	5,143,000	6,274,000
Cooling tower	\$ 804,000	611,000	745,000	2,183,000	1,659,000	2,024,000
Step-up transformer	\$ 202,000	115,000	195,000	549,000	313,000	532,000
General site development	\$ 357,000	357,000	357,000	400,000	400,000	400,000
Land	\$ --	--	--	--	--	--
Total estimated capital cost(1974)	\$ 29,552,000	23,336,000	26,869,000	69,013,000	51,629,000	61,206,000
TEC(1980) at 5%/yr inflation(1.27)	\$ 37,531,000	29,637,000	34,124,000	87,646,000	65,569,000	77,732,000
Kw capacity	Kw 25,280	14,410	24,500	68,660	39,110	66,500
Unit capital cost	\$/Kw 1,485	2,057	1,393	1,276	1,676	1,169
Annual cost of ROI, depr., mtce, oper.	\$ 13,886,000	10,966,000	12,626,000	32,429,000	24,260,000	28,761,000
Annual royalty for energy	\$ 122,000	122,000	122,000	330,000	330,000	330,000
Total annual cost (1980)	\$ 14,008,000	11,088,000	12,748,000	32,759,000	24,590,000	29,091,000
Annual credit for methane	\$ 5,600,000	5,600,000	5,600,000	15,200,000	15,200,000	15,200,000
Annual credit for condensate	\$ --	62,000	78,000	--	168,000	212,000
Net annual cost (1980)	\$ 8,408,000	5,426,000	7,070,000	17,559,000	9,222,000	13,679,000
Kwh/yr at 90% load capacity	Kwh/yr 1.938×10^6	1.105×10^6	1.879×10^6	5.265×10^6	2.999×10^6	5.099×10^6
Unit power cost (1980)	Mills/Kwh 43.4	49.1	37.6	33.3	30.7	26.8

Source: Reference 10.

Analysis of the processes used in the industrial organic chemicals group showed that acetic acid, acetic anhydride, ethyl alcohol, and isopropyl alcohol can be produced with almost all the energy needed being supplied by low level geothermal....

Similar analysis of the industrial inorganic chemicals group revealed that sulfur, bromine, aluminum sulfate and alums could be produced with energy supplied by low level geothermal sources....

Other potential uses of the geothermal waters (listed in Reference 5) are:

- District heating and cooling
- Cold storage and frozen foods
- Desalinization of water
- Air reduction and liquefaction
- Lumber and concrete block curing
- Injection for secondary recovery of petroleum
- Make-up water for coal slurry pipeline
- Make-up water for power plant cooling lakes

and in coordination with other uses:

- Frost protection for crops
- Greenhouse heating or cooling
- Rice and grain drying.

Clearly, the list of potential uses will grow as the anticipated flow of geothermal waters from the onshore reservoirs becomes more imminent and may include year-round warm water swimming pools, health spas, and possibly marine aquaculture as an end use. Of course it is not yet clear whether all such uses would add up to a multi-billion dollar annual market; this won't be known until many years have passed.

Most of the economic analysis that has appeared in the literature is, I believe, somewhat conservative and "rigid." This last adjective implies that such analysis gives no credit to man's ingenuity in reducing costs within present, let alone future, technology. It gives no credit for future dual purpose uses of the geothermal fluids--e.g., for industrial, recreation, health, agri- or aqua-culture developments, to name a few categories.

It makes no allowances for the adaptation of existing oil and gas wells which are nearly depleted and could be converted to water wells. It makes no allowances for the utility of hundreds of "dry" wells which are abandoned each year in this region in unsuccessful attempts to develop oil and gas fields. It makes no allowance for potential "infant industry" assistance from the government. It ignores the obvious fact that the initial sites chosen for development are likely to be much above average in their potential benefit/cost ratio.

It gives no credit for dual purpose exploration: that is, a wild-catter could look for natural gas pockets, realizing that if he fails to find the gas reservoir (as happens perhaps 80-90 percent of the time) then he might have perhaps a 50 percent chance of finding geothermal waters with dissolved methane in quantities sufficient to recover much of his investment--perhaps in sufficient quantities to develop that reservoir commercially and make a profit. A somewhat analogous actual situation was reported by Jones (Reference 2, p. 308):

An oil company was pumping water from 9,000 feet for refracturing a deeper oil reservoir and the water well was being pumped at the rate of 900 gallons per minute and was found to yield 400,000 standard cubic feet of gas per day. The company asked...for a ruling on whether this was a gas well or water well and what to do about the gas.

Such considerations can greatly affect (i.e., reduce) the cost of producing the energy of these reservoirs. But this can occur only after entrepreneurs have sufficient incentives to start the exploitation of these zones. The relevant rules must be made sufficiently explicit and attractive for investors to take the required risks.

One of the major possible economic consequences of this potential resource is that it could place a lid on fossil fuel prices. Natural gas in very large quantities profitably obtained from these zones at \$2/MCF would establish a ceiling on gas (and probably oil) prices that the U.S. obtains from foreign as well as domestic sources. Indeed, if the commercially recoverable energy from this resource is established and is found to be huge, it can be expected to have a strong effect upon long term contractual prices for all fossil fuels--perhaps upon other competitive energy sources too. Needless to say, a ceiling price on fossil fuels--especially one that could be expected to shrink gradually over time (in constant dollars) in response to technological advances, economies of scale, and innovative utilization of the total resource--should be highly desirable to all of the countries dependent on imported fuels and constantly threatened with rising, perhaps rapidly rising, prices.

During the next decade or two the economic leverage that this resource could provide in stabilizing energy prices could be much more important than the actual energy produced. Over the longer term it could greatly increase the nation's energy reserve, which would also be in the form of the finest natural fossil fuel available. This reserve would permit a more orderly transition to the eventual use of the inexhaustible fusion, fission, solar, and geothermal sources of energy.

Another, somewhat controversial, concept for the relatively efficient exploitation of the methane resource has been suggested by Professor Jones. He believes that by the time a small fraction of the water is drawn from a reservoir (say 4 percent) the drop in reservoir pressure will cause much of the methane to come out of solution and move upward through the reservoir until it is trapped in the highest part of the zone, thereby forming a gas cap. By appropriate monitoring with

geological instruments the new gas cap will be revealed, after which it can be tapped directly. The dispute about this possibility involves some technical questions related to the difficulty that gas bubbles might experience in moving through the sandstone formations and collecting in commercial quantities within limited time spans (decades). If this debate cannot be resolved through theoretical study, it will be resolved empirically once the use of these reservoirs becomes a commercial reality. If Jones' concept should prove viable, it would greatly reduce the cost of extracting the natural gas.

The amount of geopressurized water that can be economically extracted from a large reservoir is very uncertain--as indicated earlier. It appears, first, that about 4 percent or 5 percent of the water in the sand formations is about the minimum expectation since this is the amount that must flow out just to relieve the excess pressures (above normal hydrostatic). Secondly, a number of geologists have stated that they expect an influx of water from the nearby shales as the water pressure drops in the sands. This might more than double the amount of producible water. Finally, and perhaps most important, is the compressibility of the shale and sand strata. There is no doubt that the sand and shale beds are undercompacted and that the water bears a large part of the load. The data from core measurements are shown in Figure 2. Consequently, as the waters are withdrawn the resulting compression of the sand and shale beds within the aquifers could serve to further increase the production--by more than a factor of three according to Professor William J. Bernard of Louisiana State University (Reference 2, p. 167). Thus it seems that at least the large reservoirs may be somewhat likened to a huge water-logged "sponge" under great pressure. As the fluids are withdrawn, the weight of the overburden squeezes the sponge. Ultimately, when the porosity has been reduced to that which is normal for aquifers which are not geopressurized, the process would stop and the natural flow of the water will have stopped. By then, however, a large fraction of the resource base would have been produced. After that time other technological approaches would be needed if still more fluid is desired--for example, as technological innovations for secondary and tertiary recovery have been developed to produce additional oil from depleted reservoirs--but that problem we leave for the distant future.

Legal, Institutional and Environmental Considerations

In recent years industrial development has become increasingly complex--especially when numerous regulatory agencies are involved and the jurisdictional responsibilities are overlapping and unclear, if not sometimes actually contradictory.

To achieve commercial development, the geopressurized resources of the Gulf Coast will have to run this gauntlet. In the first place there is the question as to whether the resource should be classified as a water resource, a mineral resource, a hydrocarbon resource, or a geothermal resource. Different agencies on the federal and state levels

will be involved depending upon the classification, which may be difficult to establish firmly and quickly. Moreover, the rights of private property owners will be strongly affected by future legal interpretations and the "losers" can be expected to fight for more favorable ones.

It is unfortunate, in one sense, that the legal situation has not already been made clear. If this had been accomplished, development could then proceed, whoever the owners are, at a more or less optimum rate of commercialization. If, as seems likely, legal matters remain obscure or undefined for several years, then we can expect a battle whose intensity will tend to correlate with the changing estimated value of the resource--which appears likely to become enormous. Thus, there may be "interesting" times ahead in determining ownership as well as the appropriate jurisdictional authorities, applicable tax measures, royalties, depletion allowances, and/or special development incentives at both state and federal levels.

What the country needs is a rapid determination of the commercial potential of this energy resource. If it turns out to be very large, then Project Independence would be given a big boost. What the country will get is now uncertain, but at least over the near term it is apt to involve some immense and complicated political struggles. Until these are settled, it is unlikely that much commercial activity will occur, however promising the initial assessments or exploratory efforts prove to be.

The two major environmental problems associated with this resource are: (a) disposal of the large quantities of hot or warm mineralized salt waters and (b) the possibility of land subsidence, especially of uneven subsidence, or of subsidence near developed urban centers close to the shores. The first of these (disposal) is amenable to several solutions including reinjection of the waters to less deep (3,000-7,000 ft.) aquifers or channeling them to the sea in appropriate regions (perhaps with a number of beneficial uses along the way).

The subsidence problem is potentially more serious, although the extent to which it might result in damage to property or a potential hazard in the form of earthquakes is not yet known. Indeed the gradual subsidence of the land over the reservoirs being tapped is desirable in one major respect--that is, it appears to be the simplest way to assure the production of a substantial fraction of the fluids contained in the reservoirs. To the extent that the subsidence is gradual and uniform, or not excessively irregular, very little of the potential onshore area involved (about 40,000 square miles) should be seriously affected. Quakes may or may not be serious if they occur, depending on number, magnitude, and location. For the Gulf Coast area there is no historical record of any major earthquakes and most structures are not built to anticipate earthquake effects. Huge quantities of fresh water withdrawn from shallow aquifers have already created substantial subsidence effects in the Houston area, and other regions, without unduly serious consequences (Reference 2, p. 312). However, the possibility of earthquakes can fire the public imagination and might readily be used by the anti-growth movement as a ploy to discourage development, even if a careful study by a blue ribbon panel had concluded that the dangers were minimal and very improbable.

Earthquakes have been experienced in an extremely large range of sizes. They tend to be large in the tectonically active regions of the world (e.g., near the Pacific Coast); the Gulf Coast, however, is not one of them; it is geologically quiet. In recent years it has even begun to appear technically feasible to create a protracted series of mini-quakes deliberately in order to avoid the damage which a large one might cause through its sudden, relatively large, ground displacements. The principal technique is that of injecting water into the stressed area that acts as a lubricant to induce earth slippage by many small increments rather than to allow the stresses to build up to the point where sudden relief occurs, causing a large earthquake. The mini-quakes would be expected to be felt as tremors but would not be destructive.

The land under the Gulf Coast, as we have seen, contains an unusually large amount of fluid and porous rock and therefore would tend to give way relatively readily under stresses. Consequently, the probability that more than mini-quakes would occur from exploitation of the geopressure zones may be quite small. Earthquakes with destructive potential, if they occur at all, are likely to be associated with existing growth-faults which have formed during the recent geological era; these are illustrated in Figure 1.

Microquakes are small tremors resulting from smaller ground motions of either natural or manmade origin but are not noticeable except by delicate instruments. Although the land subsidence resulting from large scale extraction of the geopressured fluid mainly may create a large number of microquakes and some mini-quakes, potentially damaging larger ones could occur by slippage along the growth-faults. Although the risks do not appear to be large, the possibility of such "small" earthquakes cannot be ignored, especially where such faults exist in or near the more populated areas. Such earthquakes, if they occurred, would probably be caused by the tendency of the rock along the fault zones to lock up as the pressure was gradually reduced by withdrawal of fluid, with a potential for a subsequent sudden release.

In 1964, for example, four earthquakes were experienced in east Texas (3.3 to 4.4 on the Richter scale), the largest of which was equivalent in effect to a small buried nuclear detonation (about the energy yield of the Hiroshima weapon). Evidently they arose from the slippage of one of the faults near the boundary of the Miocene deposits (Figure 5) that had been in a locked state for some time (Reference 2, p. 314). Hundreds of microquakes too small to be felt except by instruments were recorded during the next several months. From this evidence it is necessary to conclude that some earthquakes in the size range mentioned above might eventually result from the large scale development of this resource. Although the damage potential of such earthquakes may not be large, especially with careful planning and monitoring, they cannot be ignored. Until further investigation and testing is done, it will not be possible to make an unambiguous evaluation of the hazard. Perhaps, as with so many other phenomena, ambiguity will always be present to an annoying degree.

It appears that the subsidence effects will need to be closely monitored if the geopressurized zones are developed. During the early decades--before too much fluid is removed--judicious selections of the reservoirs, coupled with monitoring, should produce data from which better judgments can be made. If more or less slow uniform subsidence can be expected, in part through an appropriate sequence and rate of reservoir development, then the problem of quakes may prove to be manageable, that is, they might occur essentially as micro- or mini-quakes without causing measureable damage. However, wherever subsidence causes or is believed to be able to cause significant damage, then political decisions will be required to balance the costs and benefits of continuing the program within the affected areas.

Ultimately, if no better procedure is found, one possible solution to both the reinjection and subsidence problems may be to draw the fluid from a well, remove the heat and the gas, and then pump the spent water down a second well back to the original formation. A plan for sequential fluid removal in which some wells are producers and others are reinjectors--perhaps with former producing wells becoming reinjection wells later in their life cycle, in order to avoid the expense of drilling new ones merely for injection--may prove to be economically sound. Of course this approach, which requires powerful large volume pumps to work against the high geopressures, would be more costly than one which allows the land to subside and might only be practical at prices for the natural gas higher than \$2/MCF; this would have to be assessed.

Early in the development of the resource, it might be necessary to avoid taking more than a small fraction of the fluid from some of the reservoirs to prevent substantial subsidence; over time a system might develop which would specify different land utilization categories; for example:

A-Zones: Those with no subsidence restrictions. These would include most of the offshore reservoirs plus, perhaps, some onshore ones in rural areas where subsidence effects would be much less threatening or costly--and with provisions for compensation in event of damage.

B-Zones: Those which required reinjection of the spent fluid to the original formations after a pre-specified level of subsidence was reached. (Perhaps several classes of B-Zones related to the estimated local potential hazards.)

In commercial practice the cost of production in many of such B-Zones might not be significantly greater than that of the A-Zones, if a plan can be devised in which the investment in an installation could be recouped before reinjection into the geopressure reservoir is required to begin, say 20 years later. It appears reasonable to expect that, with appropriate design of extractive systems, large reservoirs could produce fluid in commercial quantities for 100 years or more, during which time

many of the problems which appear difficult today would undoubtedly have been resolved through experience, ingenuity, and technological progress.

Another important factor in the resolution of these problems will be the variation in the price of natural gas over time (in real terms). Because natural gas is the premium fossil fuel, it can be expected, before long, to be priced accordingly. Today, to compete properly with imported crude oil, that would mean about \$2.50/MCF. At this price the extraction of energy from the geopressured zones might be quite attractive, once the legal and institutional problems have been resolved. The higher the real price of fuels becomes in the world market, the more we can expect pressure to grow for the development of the geopressurized resource.

ERDA's Program

The effort underway in Texas and Louisiana to study, develop, and demonstrate the feasibility of utilizing the geopressure resources is in its infancy. ERDA budgeted about \$0.9 million in fiscal 1975, a mere \$.25 million in 1976, has asked for \$.5 million during the transition quarter, and now wants \$6.1 million for fiscal 1977. Besides conceptual studies and geological investigations based on existing well data, contracts have been let to test an existing well (in Louisiana) that penetrates into the geopressure zone and for a program for site selection and the drilling of a new well in Texas.

The Texas Program is being managed by the University of Texas' Center for Energy Studies under the leadership of Dr. Myron H. Dorfman. The recommendation of this group is for a tightly coordinated demonstration program which could lead to a rapid utilization of the resource. It would require the expenditure of over \$50 million in a 6-year period. Their proposal is outlined in Table 5.

The major energy companies are involved only indirectly in the program, mostly as observers, consultants, and suppliers of data. At one energy conference a remark was made "that in about 5 years we could know as much about geothermal resources in this area as the oil companies knew 5 years earlier." Whether valid or not, this remark suggests that an old-fashioned approach based upon a free market and a clarified legal situation might be a more effective one than the long torturous one down which we seem to be headed.

Other Geopressurized Zones

This paper estimates somewhat optimistically that the resource base of the Gulf Coast geopressurized zone might have ultimate potential sales of \$100 trillion (1976 dollars) in methane alone and about half that much in the heat content of the fluid. Although it appears unlikely today that as much as 50 percent of the total resource base will be extracted, even over the long run, judgment is clearly clouded by our inability to

Table 5

**COST ESTIMATES
FOR A PROPOSED DEMONSTRATION PROGRAM**

ACTIVITY	Fiscal YEAR	1976 (Year 1)	1977 (Year 2)	1978 (Year 3)	1979 (Year 4)	1980 (Year 5)	1981 (Year 6)	TOTALS
1. Pathway Review, Target Selection		275						275
2. Environmental Baseline, Report		200	140					340
3. Site Specific Geology, Geophysics		125	150					275
4. Drill Test Wells		100	4330					4430
5. Effluent Disposal for Test Wells		100	3000					3100
6. Legal, Institutional, Social								
a) Legal		120	58					178
b) Social and Institutional		56	108					164
7. Rock Mechanics Research		126	94					220
8. Geopressured Fluid Sampling in Existing Wells		1000	1000	2000				4000
9. Reservoir Simulation Research		125	125					250
10. Supporting Research and Technology- Utilization		130	130	80				340
11. Preliminary Test Facility								
a) Design Facility and Test Program		120						120
b) Fabricate, Install Test Facility		25	175					200
c) Fabricate, Install Fuel Facility		70	487					557
d) Operate Test Facility			10	14				24
12. Well Production Tests								
a) Operations			50	120	80			250
b) Royalty Payments			5	12	8			25
13. Major Test Facility								
a) Design, Construction Management		50	100	300				450
b) Fabrication, Installation, Construct			250	3700				3950
c) Fabricate, Test by Pilot Plant Modules			150	350	40			590
d) Operations - Overhead				100	250	250		600
TOTAL ACTIVITY PRIOR TO PILOT PLANT		2497	10412	6676	428	250	250	20513
14. Pilot Power Plant								
A. Design & Procurement								
i) Conceptual Design (Power/Fuel Plant)				500				500
ii) Purchase Turbine/Generator Sets				350	760	2000	350	3460
iii) Well Design (field)				100				100
iv) Purchase Methane Separators, Compressors, Glycol Dehydrators				30	70	70	30	200
v) Detailed Design, Construction Management				300	450	600		1850
B. Construction, Testing								
i) Step-out Drilling of Field				3400	7800	3400		14600
ii) Land Purchase/site Development					140			140
iii) Procure Electrical Equipment				50	190	100	50	390
iv) Purchase Cooling Tower, Condenser, C.I. Pumps				100	300	400	100	900
v) Fuel Plant Equipment Procurement				100	200	600	100	1000
vi) Fuel Plant Construction						2570		2570
vii) Power Plant Construction						1000	3680	4680
viii) Operational Testing							200	200
TOTAL: POWER/FUEL PLANT		0	0	4930	10320	10740	4510	30500
TOTAL: ACTIVITY PRIOR TO PILOT PLANT		2497	10412	6676	428	250	250	20513
15. Management/Coordination		250	250	250	250	250	250	1500
TOTAL: Estimated Project Cost		2747	10662	11856	10998	11240	5010	52513

*Currently funded for fiscal 1976; not included in totals.

Numbers in thousands of dollars.

Source: Reference 5.

project long term demand or technological progress with much accuracy. In any event even assuming, relatively conservatively, that from 10 percent to 20 percent of the resource may be economically extracted over time, at today's market prices (\$2 million BTU for methane) this would imply an ultimate market potential of roughly 15 to 60 trillion dollars. But this is only for the Gulf Coast. There are many known geopressurized zones in the world that can also be investigated and appear likely to contain methane dissolved in hot water. Jones (Reference 2, p. 91) stated that:

All the tertiary oil-producing basins of the world are geopressurized. They exhibit the same general geothermal gradient characteristics....

...in some 28 countries around the world....

The implications of the above quotation are that the kind of potential that exists in the Gulf Coast geopressured zones also exists in many other basins in the world. According to Jones* they also exist off California and Alaska. Indeed Jones believes that a crude "ball-park estimate" of the global resource base would be 10 to 20 times that of the Gulf Coast region,* placing the very long term world market potential in the neighborhood of 1,000 trillion dollars, even if most of the resource were left in the ground. That is, of a global resource base of roughly 1 to 2 million quads of methane and an additional 2 to 4 million quads of heat content in the waters, we are assuming that $\frac{1}{2}$ million quads are eventually recoverable, in methane or methane equivalents (4 quads of heat are assumed equivalent to 1 quad of methane), or between $\frac{1}{6}$ and $\frac{1}{3}$ of the total. This much energy is expected to be greater than the total world requirements for the next 200 years--estimated to be 0.4 million quads in Chapter III of The Next 200 Years.

*Personal Communication.

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WILLIAM M. BROWN
Professional Staff, Hudson Institute

Dr. William M. Brown is a physicist with a Ph.D. degree (1959) in theoretical physics from the University of California in Los Angeles. He has taught physics at UCLA and at the South Dakota School of Mines and Technology.

Before joining the Institute staff Dr. Brown was first a resident consultant and later a senior scientist on the staff of RAND Corporation. His principal efforts there were directed to the study of national security problems as they related to strategic defense, arms control and damage limiting systems--including civil defense and recovery from nuclear attacks.

At the Hudson Institute Dr. Brown has directed and supported major studies for the Department of Defense, the Department of the Interior, the Energy Research and Development Administration, and the Federal Energy Administration. For the Pentagon his work has centered about the effects of nuclear weapons, the optimization of strategic systems for active and passive defense, arms control, and nuclear testing. In recent years his interests and investigations have been related to energy, resource, and environmental problems and their implications for the near and long term future within alternative scenarios for political and social developments. His interest in these matters has culminated in several studies and a book The Next 200 Years, jointly authored with Herman Kahn and Leon Martel.

He also has been deeply involved recently as one of Hudson's project leaders on a projective study for NASA on the potential of space developments over the next two centuries.