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**POTENTIAL POWER GENERATION AND GAS
PRODUCTION FROM GULF COAST
GEOPRESSURE RESERVOIRS**

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POTENTIAL POWER GENERATION AND GAS PRODUCTION FROM GULF COAST GEOPRESSURED RESERVOIRS

Abstract

Extensive onshore and offshore geopressured water reservoirs are found in the Texas and Louisiana Gulf Coast region. Energy in these reservoirs is present as natural gas in solution, as thermal energy, and as hydraulic energy. Reservoir depths generally vary from 5000 to 20,000 ft, with corresponding temperatures from below 200 to above 300°F. For the purposes of this study the resource was divided into three classes depending on depth, with corresponding temperatures, pressures, and gas concentrations. Natural gas is presumed to be present at saturation levels in each class of reservoir.

Total-flow, flashed-steam, and binary-cycle thermal energy conversion systems were investigated. The total-flow system was selected for incorporation into a detailed power-plant systems analysis. Power-plant net power output as a function of

wellhead pressure was determined for the two disposal methods (surface and injection) of the wastewater. The peak power output for each class of reservoir and disposal method was selected as the operating points to be used in the economic analysis. The range of output of electricity and gas from 7-in.-nominal production wells is from 0.36 MW and 6.4 scf/sec for the shallow reservoir with fluid disposal by injection to 6.2 MW and 39.9 scf/sec for the deepest reservoir with surface disposal.

Economic analysis indicates that the relatively shallow reservoirs would not be profitable for combined gas production and electrical power generation, but might be profitable for gas production alone. Deeper reservoirs would be profitable for combined gas production and power generation. The deepest reservoir, without gas, would be marginally profitable for electrical generation alone.

Introduction

Power production from geothermal energy is a commercial success at The Geysers in California. This resource is in the form of dry steam. Two other fundamental categories of geothermal energy are hot dry rock and hot water or brine. The geopressure energy resource located in the Texas and Louisiana Gulf Coast area falls into the hot-water (i.e., thermal) category, but it also has energy in two other forms: geohydraulic and natural gas in solution.

Geopressured aquifers are anomalous in the sense that their fluid pressure is higher than the hydrostatic pressure. A geopressured reservoir generally consists of alternate layers of sandstone and shale. As a result of gradual subsidence and isolation, via growth faults, trapped fluid has prevented full compaction of the formation. Thus the fluid is required to support a substantial portion of the overburden weight. As a result, the pore pressure

is at a value between hydrostatic and geostatic. A geopressured well is expected to be capable of producing high water flow rates even at wellhead pressures of up to several thousand pounds per square inch.

The function of a geopressure surface plant would be to recover natural gas as it comes out of solution and to produce electrical power from the hydraulic and thermal energy contained in the water. If reinjection of the water into normally pressured sand bodies is required for

disposal, the surface plant would also include the necessary pumping equipment to provide a closed system with an array of production and injection wells.

The purpose of this study is to provide a brief description of the resource geology, an estimate of recoverable energy, an engineering evaluation of the net power and gas production under a variety of operating conditions, an economic analysis, and a discussion of the steps required for developing the resource.

Resource Geology

GENERAL REMARKS

The geopressured geothermal energy resource in the Gulf of Mexico Basin is in a thick, young (Neogene, Upper Tertiary) sequence of poorly consolidated sandstones and shales. It is known that in many places these sediments have abnormally high pore pressures and temperatures above those expected from normal geothermal gradients. Similar occurrences of abnormally pressured fluid-bearing rocks are known in geologically similar areas in other parts of the world.

The deposits west and southward from the Mississippi Delta are mainly sand, clay and shale, siltstone, and sandstone. Intensive oil and gas exploration and development in the area, including several hundred thousand oil and gas wells and associated tests, have accumulated a large store of stratigraphic and structural information. However, because of the difficulty of drilling and testing through the geopressured formations, there is a lack

of certain critical detailed information that is needed in the evaluation of the geopressured resource.

The structure of the area is characterized by gentle basinward dips and by belts of normal faults generally parallel to the present shoreline, with major vertical displacement down toward the coast. These "growth faults" exhibit thickening of the sedimentary section on the down-thrown side, due to continued movement during sedimentary deposition.

THE GEOPRESSURED ZONES

The geopressured zones have been mapped by Jones¹ as a somewhat discontinuous area centered on the Gulf Coast shore, extending up to 100 miles both shoreward and seaward, and ranging from the Mississippi Delta to the northeast part of Mexico (Fig. 1).

Sandstones and sands, the potential producing aquifers, constitute less than half of the stratigraphic section. Detailed stratigraphic studies by Atwater,²

Fig. 1. Geopressured zones in northern Gulf of Mexico Basin. (Source: Jones.¹)

Fisher,³ and others demonstrate that the thicker delta-front and offshore bar sands were progressively deposited in more basin-

ward positions as these deposits gradually built up in an offshore direction (Fig. 2). For this reason the age of the sands and

Fig. 2. Geologic cross section showing the distribution of sediment types and the effects of regional normal faults (southeast Louisiana). (Source: Jones.¹)

sandstones decreases in a basinward direction. Thick sandstone sections are separated by even thicker shale sections, and the thick sandy sections appear cyclically in a vertical section. Individual sandy sections may be as much as 5000 ft thick, but more commonly they are about 1300 ft thick.

Within geopressured aquifers there is progressive freshening of the water with

depth below the pressure seal. Some salinities are reported to be below 1000 ppm. The progressive freshening in geopressured aquifers is believed to be due to the progressive dehydration of clays with increase in depth and temperature and the expulsion of the water into the aquifer. The existence of very fresh water would depend on a high ratio of clay (shale) to sandstone in the aquifer.

Estimation of the Resource Magnitude

The magnitude of the geopressure energy resource in the Texas and Louisiana Gulf Coast region was roughly estimated on the basis of the following:

1. Estimation of the total in-place water.
2. Classification of the resource into three basic reservoir and well types.
3. Estimation of the total available gas production and electrical energy for each reservoir class.

ESTIMATION OF TOTAL IN-PLACE WATER

Figure 1 shows three shaded geopressure zones representing 5000-ft intervals in depth. In this study the zones (and the

reservoirs contained in the zones) have been labeled I, II, and III (see Table 1). The zone areas listed in Table 1 were determined from Fig. 1. The narrow offshore strip extending from the Texas portion of the resource was excluded from the area determination since its existence is not as well substantiated as that of other areas. It should be noted that 34% of the calculated resource is offshore; this could present important constraints for economic electric power generation.

The next step was to estimate the fraction of the area listed in Table 1 that would be underlain by geopressured reservoirs suitable for development. A value of 0.05 was chosen on the basis of a similar ratio of productive to unproductive

Table 1. Geopressure zone areas and estimated exploitable in-place water volume.

Zone	Depth (10 ³ ft)	Texas area (mi ²)	Louisiana area (mi ²)	Total area (mi ²)	Exploitable water (10 ¹³ ft ³)
I	5-10	15,500	7,300	22,800	1.78
II	10-15	9,200	21,400	30,600	2.38
III	15-20	--	5,700	5,700	0.44

areas for oil and gas wells in Gulf Coast sandstone reservoirs. Other factors that make a small fraction seem reasonable are described in the following quotation from Kaufman⁴:

The geopressed zones are not continuous over the region but exist in lenses, blocks, and partitioned volumes, a result of the particular sequence of causative processes.... A geopressed zone suitable for power production from the hot high-pressure water would be one which contained a large volume of connected sandstones. Major water production from associated shales would occur only if the shale sections were thin and interbedded with the sands.... Such large volume reservoirs may be limited in number because geopressed zones usually contain much more shale than sandstone and the sands may be of limited thickness and/or area extent. Such cases do exist, however, as indicated by the known cases of large water production.

Representative values for the sandstone-to-shale ratio and for the sandstone permeability within a geopressure reservoir are 0.56 and 0.20, respectively. The estimated exploitable in-place water, listed in the last column of Table 1, was calculated from the areas listed in Table 1 and the 0.05, 0.56, and 0.20 factors.

RESERVOIR AND WELL PARAMETERS

Representative well depths and reservoir temperatures and pressures were selected for each geopressure zone (see Table 2). The selection was based on examination of the well logs and the geopressed-aquifer temperature and pressure data of Jones.¹

It is generally believed that the geopressed waters will be saturated with natural gas. Saturation values for natural gas dissolved in water have been determined in the laboratory by Culberson and McKetta.⁵ Their data and representative reservoir fluid temperature and pressure values were used to estimate the quantity of gas per barrel of fluid (see Table 2).

ESTIMATE OF AVAILABLE GAS PRODUCTION AND ELECTRICAL ENERGY

The upper bound for in-place natural gas is determined by multiplying the water volumes given in Table 1 by the gas saturation values given in Table 2.

The potential electrical energy was calculated from the mass flow rate, net thermal power (turbine output minus cooling-system requirements), and hydraulic power

Table 2. Representative parameters for wells and reservoirs.

Reservoir class	Well depth (ft)	Fluid temperature (°F)	Fluid pressure (psi)	Natural gas in solution at saturation (scf/bbl)
I	8,500	200	5,100	19
II	13,000	250	9,100	30
III	16,000	300	12,800	44

Table 3. Available gas production and electricity generation.

Reservoir class	In-place water (10 ¹⁵ lb)	Recoverable natural gas ^a (10 ¹³ scf × R)	Recoverable electrical energy ^a (10 ⁴ MW-yr × R)
I	1.07	6.02	10.2
II	1.40	12.7	37.4
III	0.25	3.45	12.3
Total		22.2	59.9

^aThe term R is the recovery factor: the fraction of in-place fluid that can be brought to the surface and utilized.

(see Appendix A). Values were selected from the operating points for the case of noninjection of the wastewater. Hence they represent an upper bound. A value of only half the hydraulic power was used, on the assumption that the eventual loss of excess wellhead pressure (caused by a decline in reservoir pressure) defines the useful life of the reservoir. The potential electrical energy is thus 9.52, 26.7, and 49.1 × 10⁻¹¹ MW-yr/lb reservoir water for the Class I, II, and III reservoirs, respectively. The quantity of water present was determined from the volume values in Table 1 and the specific weights of water corresponding to the reservoir temperatures (see Table 3). The total calculated amounts of elec-

trical energy and gas are shown in Table 3.

As indicated in Table 3, in order to calculate the available gas and energy, the in-place potential must be multiplied by a recovery factor R, which is the fraction of in-place fluid that can be brought to the surface and utilized. The recovery factor R depends on many parameters, such as compressive energy in the water, effect of compaction, water coming out of the shale, gas drive, solution drive, and method of production, including the production rate and the possibility of reinjection. Estimates range from a few percent, to 100% (R = 0.02 to 1.0) of the sandstone water if it is driven by the shale water.

Power Generation and Gas Recovery

COMBINATIONS STUDIED

Net power production was calculated for 12 different configurations. The combinations were made from: (1) three basic reservoir types, (2) injection versus no injection, and (3) total-flow energy conversion versus binary-cycle energy conversion. Profitability was also studied (Section VI) for reservoir fluids without

natural gas. A comparison was made between the total-flow and flashed-steam systems. There are many other factors that could be varied, such as production- and injection-well diameters, less-than-saturated values of natural gas in solution, formation pressure as a function of time, formation permeabilities, efficien-

cies of conversion and of pumping machinery. For the purposes of this study we have attempted, in general, to assign realistic values to the parameters that are held constant. In the production well flow-rate and hydraulic power calculations, the initial reservoir pressure was assumed to remain constant. With large reservoirs, compared to the number of production wells, and a finite power-plant lifetime, this assumption might be reasonably valid. For a fully developed reservoir with a planned production lifetime the reservoir pressure would decline with time. A thorough study with site-specific data will have to be made for each commercial power plant in order to predict the reservoir pressure over the expected plant lifetime.

The physical properties of pure water were used throughout the analysis.

FLUID PRODUCTION

The first step in the preliminary investigation of geopressure power plants is to calculate the expected well characteristics of flow rate versus wellhead pressure. The model for the calculations is shown in Fig. 3. Production-well casing with a 7-in. outside diameter is considered⁶ to be the largest practical size for deep wells drilled into the unpredictable geopressure formations.

With the high flow rates and wellhead pressures required for a geopressure power plant, the flow can be considered, without any significant loss in accuracy, to be isothermal, turbulent fluid flow. The few degrees of temperature loss that would occur from heat transfer are essentially balanced by the heat from fluid friction.

Fig. 3. Production-well model.

Since the wellhead pressures are far above the vapor pressure of the water at these temperatures, the water flow is single phase. Furthermore, as the relative volume of gas coming out of solution on the way to the wellhead is small in comparison to the water volume, its effect on the flow rate can be ignored.

The wellhead pressure is lower than the reservoir pressure because of the drawdown pressure loss between the reservoir and the bottom of the wellbore, fluid friction in the well casing, and the well-column hydrostatic head. It is assumed that the surface run of pipe from the production wells to the power plant can be made of a diameter large enough for the surface pressure loss to be negligible in comparison to that occurring in the wells.

Details of the calculational procedure are contained in Appendix B. Results of the calculated well production rate versus wellhead pressure are shown in Fig. 4.

Fig. 4. Calculated well production rate as a function of wellhead pressure for three types of geopressured wells; Curve A, class I, 8,500 ft; Curve B, class II, 13,000 ft; Curve C, class III, 16,000 ft.

FLUID INJECTION

The wastewater rejected from the power plant after the extraction of gas and energy must be disposed of. The injection of water into normally pressured sand formations appears to be a practical way of disposal in cases where salinity is too high for useful purposes. These formations are deeper in zones where the geopressure formations are also deeper. Therefore, in this study, we have assumed injection-well depths of 5000, 6000, and 7500 ft for corresponding production-well depths of 8500, 13,000, and 16,000 ft. The model used for calculating fluid-injection power requirements is shown in Fig. 5.

It is assumed that the surface run of pipe from the power plant to the injection wells can be made of a diameter large

Fig. 5. Injection-well model.

enough for the surface pressure loss to be negligible in comparison to that occurring in the wells.

A typical saline-water pressure gradient from the surface to a normally pressured sand reservoir in the Gulf Coast area is 0.465 psi/ft. The hydrostatic pressure gradient of 113°F water rejected from the power plant, if fresh water, would be 0.429 psi/ft. Therefore, some work is required to inject relatively fresh water into the ground for all flow rates. In this study, pump power was calculated based on fresh water and, thus, is an upper bound. For the more probable case of saline water injection, required pump power would decrease with increasing salinity.

A pump efficiency of 70% (representative of multistage pumps working against a large head) was used in the calculations. The pump head is composed of the hydrostatic head difference between the reservoir and the well, the well-bore fluid-

Fig. 6. Pump power requirements versus flow rate for three injection wells at different depths.

friction head loss, and the head loss between the well-bore bottom and the formation. The latter head loss dominates because larger casing is used for injection (9.62 in.) than for production (7 in.). This large casing is practical because the well is shallower and leads to normally pressured formations.

Details of the calculations are contained in Appendix C. The injection-well pump power requirements versus flow rate for 113°F water are shown in Fig. 6. (The power is shown in horsepower to acknowledge direct coupling between the hydraulic or thermal conversion devices and the pump.)

GAS RECOVERY AND HYDRAULIC POWER

The upper limit of dissolved natural gas to be expected in a geopressured reservoir is represented by the curves of Fig. 7. The curves were plotted from data published by Culberson and McKetta⁵ and

Fig. 7. Solubility of methane in water (plotted from data in Ref. 5).

show solubility of methane in cubic feet per barrel of fresh water.

When geopressured wells are produced, the pressure drop will release some gas from solution between the reservoir and the wellhead. The first major item of equipment in any type of surface power plant will thus be a separator to separate the gas from the water. Following the separator will be a hydraulic turbine (see Fig. 8). The source of energy to drive the turbine is the pressure reduction with flow from the wellhead pressure to the water saturation pressure for the temperature involved. Power from the hydraulic turbine is determined by*

$$W_h = 1.70 \times 10^{-5} Q_{fp} \eta_h (P_{wh} + 14.7 - p_g) \quad (1)$$

The first gas separator is a simple drum that allows entrained gas bubbles to rise to the liquid surface. Gas is withdrawn from the drum top, and liquid is with-

*The symbols and units for all calculations in this report are listed in Appendix D.

Fig. 8. Total-flow power plant.

drawn from the bottom. The liquid level is controlled by adjustment of the gas flow rate. This first gas-separator drum could also be designed as a sand trap to allow entrained particulate matter to settle out.

The hydraulic turbine may require up to three stages for the higher pressure wells and must be built from corrosion-resistant materials. Impulse stages with a high head capability, such as the Pelton wheel, are

Fig. 9. Flashed-steam power plant.

envisioned, with provision in the cases for the removal of natural gas that has come out of solution. A 90% conversion efficiency, realistic for Pelton wheels, was used in this study. The first stages will require a case design that can withstand high internal pressures. Scaling in the hydraulic turbine should be minimal because the temperatures are low (200 to 300°F), conditions are essentially isothermal, and no flashing of the water occurs.

The second gas separator in the system (Fig. 8) will need to be a desorption tower to bring the dissolved gas close to its equilibrium concentration at the water saturation pressure and temperature (a simple spray tower will probably be adequate).

THERMAL ENERGY CONVERSION SYSTEMS

Power may be generated from thermal energy in the water by any of three systems: total flow, flashed steam, and the binary cycle (see Figs. 8, 9, and 10). In the total-flow concept,⁷ power is produced by expansion of the entire well output of low-quality (two-phase) steam to the condenser pressure. Steam expansion can be accomplished by means of a specialized impulse turbine⁷ or positive-displacement expander. Ideal available energy is represented by an isentropic expansion of water from the inlet saturation pressure to the expander exit pressure. A conservative efficiency estimate at this stage of development for a total-flow turbine with relatively-low-temperature saturated-water input might be 54%. However, the development of a positive-displacement machine, or combinations of machines (hybrids) specifically designed for these low-temperature

wellhead conditions could provide higher conversion efficiencies.

In Fig. 11, curve A shows the work output that can be obtained with a 54%-efficient total-flow turbine at various inlet water temperatures. Curve B is the work output calculated for an optimum single-stage flashed-steam system with an 80%-efficient steam turbine. In this system, the steam is throttled within the separator from the inlet pressure down to the outlet pressure. The turbine inlet pressure in this idealized example was assumed to be the same as the separator outlet pressure. Work output was then calculated by taking 0.8 times the isentropic work in expansion of the saturated vapor to the condenser pressure. It can be shown that an optimized two-stage flashed-steam system with 80%-efficient turbines will yield efficiencies very close to the 54%-efficient total-flow turbine. For purposes of this study it was considered reasonable to assume that 54% of the available thermal energy was an attainable efficiency for any one of the three basic systems. The total-flow system only was selected for detailed analysis. The binary-cycle system was not analyzed in detail except with respect to its effect on gas recovery and injection-well pump power requirements.

Thermal power output is a function of the mass flow rate and enthalpy change (ideal enthalpy change times the expander efficiency):

$$W_t = \frac{\dot{m}_1 \Delta H_s (778) \eta_e}{550} \quad (2)$$

With expander inlet temperatures of 200, 250, and 300°F, and with a 120°F exit temperature, the power output W_t becomes

Fig. 10. Binary system, Case A: Injection-well driving pressure requirement exceeds production-wellhead pressure, Case B: Production-wellhead pressure exceeds injection-well driving pressure requirement.

Fig. 11. Steam turbine systems for use with hot-saturated-water input. Curve A: total-flow turbine with a 54% overall efficiency; curve B: single-stage flashed-steam system at optimum pressure with an 80%-efficient turbine. Exhaust temperature, 120°F.

3.90 $\dot{m}_1$, 9.83 $\dot{m}_1$, and 18.1 $\dot{m}_1$, respectively. Cooling-tower power must be subtracted from the expander output to obtain the net power available from thermal energy. In this study we have calculated cooling-tower power requirements based on the total-flow system and have assumed, for comparisons of gas recovery and injection-well pump power only, that the power requirement is also representative of the binary-cycle system. To evaluate the cooling-tower system we must first establish the thermodynamic state points in the system. State points 1, 2, and 3 are shown in Fig. 8. Point 1 is the saturated-liquid inlet to the expander, and point 2 is the expander exhaust. Points 3_l and 3_g are the liquid and vapor outlets from the separator. Values of temperature, pressure, enthalpy, and quality are listed in Table 4. The mass flow rate of vapor going to the condenser, $\dot{m}_{3g}$, is equal to $\dot{m}_1 X_3$. Power estimates for the cooling tower were based on a dry-bulb temperature of 92°F, a wet-bulb temperature of 79°F, and a cold-water approach to wet-bulb temperature of 8°F. For a forced-draft cooling tower, power estimates are 7.27 $\dot{m}_{3g}$ for the fan horsepower and 6.47 $\dot{m}_{3g}$ for the pump horsepower.

THE BINARY SYSTEM

The binary system could be used to recover thermal energy in a mode of operation similar to that of the total-flow or flashed-steam system. A hydraulic turbine is used to reduce the wellhead pressure to near the saturation value, and a heat exchanger is then used to extract thermal energy from the water. Full gas recovery would then be practical since the final water pressure would be near ambient prior to injection or surface disposal. On the basis of the equal-efficiency premise of this study, the plant electrical output and gas production would be the same as for the total-flow system.

There is another mode of operation for the binary system, however, which is illustrated in Fig. 10. In this system the purpose is to lower the injection-well power requirement. Case A of the figure illustrates the configuration needed for high flow rates, when the production-wellhead pressure is lower than the required injection-wellhead pressure. A pump is required to make up the deficit in pressure. Case B illustrates the configuration needed for lower flow rates, when

Table 4. Thermodynamic data for reservoirs.

Reservoir class	T ₁ (°F)	P ₁ (psia)	H ₁ (Btu/lb)	T ₂ (°F)	P ₂ (psia)	H ₂ (Btu/lb)	X ₂	T ₃ (°F)	P ₃ (psia)	X ₃
I	200	11.5	168.0	120	1.69	165.2	0.0754	113	1.39	0.0818
II	250	29.8	218.5	120	1.69	211.5	0.120	113	1.39	0.127
III	300	67.0	269.6	120	1.69	256.7	0.165	113	1.39	0.171

the production-wellhead pressure exceeds the injection-wellhead pressure requirement. A hydraulic turbine is used to convert the excess energy into electricity. In both cases final gas recovery takes place where the water temperature and pressure are at their lowest point. The injection volumetric flow rate is lower than the production volumetric flow rate because of the temperature reduction:

$$Q_{fbi} = \frac{\gamma_p}{\gamma_i} Q_{fp} \quad \text{or} \quad Q_{fbi} = \frac{\dot{m}(15,389)}{\gamma_i} \quad (3)$$

$$= 249.42 \dot{m} \text{ for } 120^\circ\text{F water.}$$

The injection-well pump power is determined by the equation

$$W_{bp} = \frac{Q_{fbi}(144)(\Delta P_{dd} + \Delta P_f + P_r - P_c - P_{wh})}{550\eta_p(15,389)}$$

$$= 2.43 \times 10^{-5} Q_{fbi}$$

$$\times (\Delta P_{dd} + \Delta P_f + P_r - P_c - P_{wh}) \quad (4)$$

for $\eta_p = 0.70$. The required injection-well pressure is

$$P_{bp} = \Delta P_{dd} + \Delta P_f - P_r - P_c \quad (5)$$

Therefore

$$W_{bp} = 2.43 \times 10^{-5} Q_{fbi} (P_{bp} - P_{wh}) \quad (6)$$

for $P_{bp} > P_{wh}$.

The pressure-loss terms ΔP_{dd} and ΔP_f are evaluated using methods described in Appendix B. When the production wellhead

Fig. 12. Performance characteristics of an 8500-ft geopressured well producing 200°F water. Curve A: total-flow expander-cooling-tower requirements; curve B: injection pump power requirement; curve C: hydraulic turbine. Reservoir pressure, 5100 psi; 7-in. production-well casing; 9.625-in. injection-well casing; injection-well depth, 5000 ft.

Fig. 13. Performance characteristics of a 13,000-ft geopressured well producing 250°F water. Curve A: total-flow expander-cooling-tower requirements; curve B: injection pump power requirement; curve C: hydraulic turbine. Reservoir pressure, 9100 psi; 7-in. production-well casing, 9.625-in. injection-well casing; injection-well depth, 6000 ft.

pressure exceeds the injection-well pressure requirement, the hydraulic power is determined by

$$W_{bh} = 1.53 \times 10^{-5} Q_{fb1} (P_{wh} - P_{bp}) \quad (7)$$

for $P_{wh} > P_{bp}$.

The net power output for the binary system is composed of the net thermal power minus the pump power or plus the hydraulic turbine power, depending on the mode of operation.

COMPUTED RESULTS

Results of the various power and gas production calculations are listed in Appendix A. Selected results are shown in Figs. 12 through 22. The thermal and hydraulic shaft power was converted to electrical power assuming a 97%-efficient generator.

In Figs. 12, 13, and 14 the production-well flow rate, net thermal power (turbine output minus cooling-tower power requirements), hydraulic power, and injection-well power requirements are plotted as a function of wellhead pressure. In all three cases a comparison between the thermal and hydraulic power shows that hydraulic power accounts for about half the power output at mid-wellhead pressures. In Figs. 15, 16, and 17 the curves have been combined to show the net power output for two basic modes of operation. Curves A are for the case where the wastewater can be used or disposed of on the surface. Curves B are for the case where the wastewater must be injected into the ground. The operating points used in the economic evaluation were

Fig. 14. Performance characteristics of a 16,000-ft geopressured well producing 300°F water. Curve A: total-flow expander-cooling-tower requirements; curve B: injection pump power requirement; curve C: hydraulic turbine. Reservoir pressure, 12,800 psi; 7-in. production-well casing; 9.625-in. injection-well casing; injection-well depth, 7500 ft.

Fig. 15. Power output from an 8500-ft geopressured well producing 200°F water. Curve A: hydraulic and thermal; curve B: hydraulic and thermal-injection power. Reservoir pressure, 5100 psi; 7-in. production-well casing; 9.625-in. injection-well casing; injection-well depth, 5000 ft.

Fig. 16. Power output from a 13,000-ft geopressed well producing 250°F water. Curve A: hydraulic and thermal; curve B: hydraulic and thermal-injection power. Reservoir pressure, 9100 psi; 7-in. production-well casing; 9.652-in. injection-well casing; injection-well depth, 6000 ft.

selected at essentially the peak of the net-power-output curves.

In Fig. 18 the net power output without injection is shown as a function of production-wellhead pressure for the three reservoir classes. Figure 19 illustrates

Fig. 17. Power output from a 16,000-ft geopressed well producing 300°F water. Curve A: hydraulic and thermal; curve B: hydraulic and thermal-injection power. Reservoir pressure, 12,800 psi; 7-in. production-well casing; 9.625-in. injection-well casing; injection-well depth, 7500 ft.

Fig. 18. Hydraulic plus thermal power output for three types of geopressed wells (7-in. production-well casing; 0.02 friction factor); Curve A, depth 8,500 ft, temperature 200°F, pressure 5,100 psi; Curve B, depth 13,000 ft, temperature 250°F, pressure 9,100 psi; Curve C, depth 1,600 ft, temperature 300°F, pressure 12,800 psi.

Fig. 19. Hydraulic plus thermal minus injection power output for three types of geopressed wells (7-in. production-well casing; 9.625-in. injection-well casing; 0.02 friction factor); Curve A, production-well depth 8,500 ft, temperature 200°F, pressure 5,100 psi, injection-well 5,000 ft; Curve B, production-well depth 13,000 ft, temperature 250°F, pressure 9,100 psi, injection-well depth 6,000 ft; Curve C, production-well depth 16,000 ft, temperature 300°F, pressure 12,800 psi, injection-well depth 7,500 ft.

Fig. 20. Net power and gas production from an 8500-ft geopressured well producing 200°F water saturated with natural gas. Curve A: Gas production, total-flow system; curves B: gas production, binary system, with an injection pump (B₁) and with a hydraulic turbine (B₂); curve C: total-flow thermal and hydraulic minus injection power; curves D: binary-system net power with an injection pump (D₁) and with a hydraulic turbine (D₂). Reservoir pressure, 5100 psi; injection-well depth, 5000 ft; 7-in. production-well casing, 9.625-in. injection-well casing.

Fig. 21. Net power and gas production from a 13,000-ft geopressured well producing 250°F water saturated with natural gas. Curve A: gas production, total-flow system; curves B: gas production, binary system, with an injection pump (B₁) and with a hydraulic turbine (B₂); curve C: total-flow thermal and hydraulic, minus injection pump requirements; curves D: binary-system net power with an injection pump (D₁) and with a hydraulic turbine (D₂). Reservoir pressure, 9100 psi; 7-in. production-well casing; 9.625-in. injection-well casing; injection-well depth, 6000 ft.

Fig. 22. Net power and gas production from a 16,000-ft geopressured well producing 300°F water saturated with natural gas. Curve A: gas production, total-flow system; curves B: gas production, binary system, with an injection pump (B₁) and with a hydraulic turbine (B₂); curve C: total-flow thermal and hydraulic, minus injection requirements; curves D: binary-system net power with an injection pump (D₁) and with a hydraulic turbine (D₂). Reservoir pressure, 12,800 psi; 7-in. production-well casing; 9.625-in. injection-well casing; injection-well depth, 7500 ft.

the net power output for the three reservoir classes when injection is required. In both Figs. 18 and 19 the advantage of the deeper, hotter reservoirs is apparent. In Figs. 20, 21, and 22 the binary and total-flow system power and gas production performances are compared for each of the three basic reservoir types. Some advantage in binary-system power production is apparent, particularly for the class I reservoir (Fig. 20). This advantage is of

smaller economic value than the increased gas production of the total-flow system.

Maximum-power-output operating points were selected for use in the evaluation of the economics of geopressure power generation and gas production. The single production and injection well power and gas output values are listed in Table 5. In the profitability section, a 15-pair production/injection well array is the model with an assumed 80% load factor.

Table 5. Operating points for single production/injection well.

Reservoir class	Disposal method	Wellhead pressure (psi)	Flow rate (10^3 bbl/day)	Electrical output (kW)	Gas production (10^3 scf/day)
I	Injection	1150	30.3	359	555
I	Surface	700	47.9	748	877
II	Injection	2400	54.6	1974	1571
II	Surface	1800	66.4	2794	1909
III	Injection	3600	74.5	4952	3025
III	Surface	2800	84.9	6178	3446

Chemistry Problems

BACKGROUND STATEMENTS

The information in this section is of necessity a generalization because of the wide variation to be expected in the quantity and chemical nature of the total dissolved solids within the resource.

For example, Jones¹ observed a variation of more than an order of magnitude in total dissolved solids (14,000 to 175,000 mg/liter) in Texas and Louisiana geopressured aquifers. As a result, the scaling

and corrosion problems are site specific, and a detailed assessment must await data from flowing test wells. It is expected, however, that a considerable amount of the brine chemistry work in progress in the Imperial Valley of California will be applicable to the geopressured resource.

Three problems that frequently occur in geothermal wells and power plants are scaling, corrosion, and erosion.

Facilities for the recovery of methane and the generation of electric power from

geopressured resources face materials problems similar to those encountered in other geothermal development. The combinations are, however, somewhat less severe because the temperatures are lower and sulfides are generally lacking in the brines. A high partial pressure of carbon dioxide is present in some cases and would increase corrosion problems.

SCALING

Geothermal and geopressured hot-water systems are generally saturated with silica at the temperature of the reservoir. Fournier and Rowe⁸ note that the amount of silica in solution is governed by the solubility of quartz at depth. Scale formation from well fluids results from supersaturation caused by cooling or flashing of steam.

Since the pressure and temperature changes that occur in the power plant are rapid and the precipitation of quartz and other crystalline silica phases is quite slow, deposition of scale is controlled by the solubility of amorphous silica. For example, when reservoir temperatures are on the order of 390°F, the precipitation of silica begins at approximately 120°F in the absence of flashing. Where flashing occurs, as in the expander, the silica precipitates because water is lost as vapor and the silica concentration in the remaining water increases. The total quantity of silica that can be expected to precipitate out of fluid from a 390°F source on flashing and cooling to 100°F is approximately 0.08 lb/bbl. Deposition is most likely to occur in the expander and throughout the cooling and reinjection system.

CORROSION AND EROSION

The physicochemical environment for materials in the gas recovery and energy conversion of the geopressured resource could give rise to numerous corrosion and erosion problems. An analysis of reported studies⁹ on materials exposure to various geothermal waters and streams indicates that corrosion and erosion problems in most surface equipment can be minimized to an acceptable level. The solution depends largely on clearly identifying the physicochemical conditions of the fluid in a proposed system, on proper engineering to minimize the conditions that lead to excessive damage, and on careful selection of materials. Conventional casing materials should be satisfactory for the boreholes and for a number of surface components. For other, more critical, components such materials as the more corrosion-resistant stainless steels, titanium alloys, nickel-chromium-molybdenum alloys, and tantalum and the cheaper, but still quite corrosion-resistant, copper and aluminum alloys may all be considered as potential candidates. Their relative costs, their relative susceptibility to the various types of corrosion and erosion, their interaction with respect to galvanic attack, and their response to inhibitors and to cathodic protection must all be considered.

Corrosion by the brine will depend on the nature and concentration of dissolved salts and gases, the temperature, the pH, and the amount of oxygen that has been admitted. Erosion and accelerated corrosion may result from entrained particulate matter (coming from either the sand or precipitated solids) or from cavita-

tion. The formation of scale deposits by the precipitation of silicates, carbonates, and sulfates frequently leads to improved corrosion resistance, especially when the scale becomes mechanically interlocked or chemically interacted with the less tenacious films containing the lower valence states Fe^{2+} and Cu^+ . The pH and temperature are important factors that influence such deposition.

Corrosion problems should be controllable if there is adequate information on the operating conditions and the physico-chemical characteristics of the fluids. Some screening tests will probably have to be made. Undoubtedly, further economic advantages would be realized with the development of low-cost alloys selected or tailored for resistance to corrosion by geothermal and geopressured fluids. It is premature to specify materials, since the future operating conditions are not well established and the composition of the fluids varies over a wide range. This range of compositions, however, is not too

different from that found in seawater and brine from presently operating geothermal sources. Thus we can assume that useful information on materials and engineering to guide us in the preliminary designs and test runs can be extracted from experiences reported on materials exposed to other saline environments.

Geothermal or geopressured wells are normally completed in formations that produce some quantity of sand. The quantity is generally large during the initial well flow and decreases with time to some smaller, nonzero, value. Erosion of well-head valves and fittings has been a problem at Cerro Prieto¹⁰ and other locations during initial well production.

The most serious problem caused by entrained particles is that they increase corrosion, as mentioned earlier. Control of particulate matter can be accomplished by careful system design, by using traps and erosion-resistant configurations, and by management of wells to avoid shutdowns and restarts.

Profitability Analysis

A brief study was made to explore the potential profitability of the three geopressure-resource categories. The study was for a plant started in 1975 and completed in 1981. Well costs dominate the system costs and were taken from current field estimates.* Plant costs were scaled from various sources, such as existing geothermal operations¹² and various reports¹³ and proposals.^{14,15} All costs were indexed

to 1975 and escalated to a 1981 plant completion date. Optimal power-plant operating points developed earlier in this report were used in this study.

*Dorfman¹¹ estimates a cost of \$1 million for a 15,000-ft-deep geopressured well. This is approximately \$67 per foot for drilling, casing, and completing a well. Estimates varying from \$750,000 to \$1,250,000 have been made by other experts.

ASSUMPTIONS

An array of 15 production wells (and 15 injection wells when used) with a centrally located power plant was assumed. A 500-ft-thick sandstone reservoir having a porosity of 20%, covering 300 square miles, and allowing a minimum recovery factor of 6% was assumed. These assumptions ensure a plant life of 20 years. The 1981 costs were determined by using an 8% per year escalation during construction. The annual operating cost was taken to be 8% of well costs and 2% of plant costs.

The prices for gas and electricity used were commensurate with an oil price of \$10 per barrel: \$2 per 1000 scf and 30 mills per kilowatt-hour. An annual royalty of 12.5% of sales and a plant load factor of 80% were also used. Additional assumptions were a federal income tax rate of 48%, no

depletion allowance, and internal financing.

CAPITAL COSTS

The major elements of the system are production wells, methane-extraction equipment, power plant, and injection wells. A breakdown of these costs is given in Appendix E along with a breakdown of total capital costs for the two operating modes: electricity and gas production and electricity production only. Note that well costs constitute approximately half the total system costs.

PROFITABILITY

A 15% minimum return after tax is probably reasonable if the field has been proved. Straight-line depreciation and a

Table 6. Typical calculations for class III reservoir with injection required.

Gross sales income (\$2.00 and 30 mills)		\$42,169,160
Less royalty (12.5% gross)	\$ 5,271,145	
Less annual operating costs	5,000,000	
Gross profit		31,898,015
Less depreciation ^a	4,770,850	
Net profit before federal income tax		27,127,165
Less federal income tax (48%)	13,021,039	
Net profit after federal income tax		14,106,126
Add depreciation	4,770,850	
Annual cash flow		18,876,975
1981 plant cost		95,417,000
Investment return criteria:		
Plant lifetime	20 yr	
Net payback period	5.05 yr	
Net present value @ 15%	\$22,740,249	
Internal rate of return	19.2%	

^a Straight-line depreciation over 20 years.

20-year plant life were used. Table 6 shows a typical calculation, and Table 7 is a summary of return criteria for the various resource conditions. Figures 23 and 24 show the internal rate of return for various combinations of electricity and gas rates.

SUMMARY

The class III resource exceeds the minimal profitability criteria both with and without a requirement for waste-fluid

injection. The class II resource exceeds the criteria without injection but would require higher gas or electricity prices with injection. The class I resource is unprofitable, except possibly as a gas well if injection were not required. The methane yield for this class could be raised by operating at higher mass flow rates than those selected for optimal power output. These conclusions depend on predictions of reservoir extent, methane saturation, and production rates that have not been verified by actual testing. If the reservoir fluid does not contain substantial amounts of methane in solution, electrical generation alone would be marginally feasible in the class III resource without injection at 40 mills/kW-hr or at 63 mills/kW-hr with injection.

Fig. 23. Internal rate of return for electricity plus gas for the three classes of resource.

Fig. 24. Internal rate of return for electricity only.

Table 7. Summary of profitability criteria.

Parameter	Class I ^a		Class II ^b		Class III ^c	
	Injection	No injection	Injection	No injection	Injection	No injection
Fifteen-well annual output ^d :						
Electrical output (MW)	4.3	9.0	24.1	33.7	59.7	74.4
Gas production (10 ⁹ scf)	2.4	3.8	6.9	8.4	13.2	15.1
Gas and Electricity ^e :						
Plant cost (\$1000)	41,309	32,222	66,699	55,178	95,417	81,080
Net payback period (yr)	18.3	7.4	7.7	4.8	5.0	3.6
Net present value @ 15% (\$1000)	(-)	(-)	(-)	16,865	22,740	60,968
Internal rate of return (%)	1	13	12	20	19	28
Electricity only ^f :						
Plant cost (\$1000)	38,684	28,065	61,950	48,846	89,899	73,710
Net payback period (yr)	19.34	34.3	26.1	12.8	13.4	8.3
Net present value @ 15% (\$1000)	(-)	(-)	(-)	(-)	(-)	(-)
Internal rate of return (%)	(-)	(-)	(-)	0.05	0.04	0.10

^aFluid temperature 200°F.

^bFluid temperature 250°F.

^cFluid temperature 300°F.

^dAssuming a 0.8 plant load factor.

^eAssuming a gas price of \$2 per 1000 scf and an electricity price of 30 mills per kilowatt-hour.

^fAssuming an electricity price of 30 mills per kilowatt-hour.

Conclusions

Development of power and gas production from the Gulf Coast geopressure resource is technically feasible, though only marginally economic. The profitability of a geopressure-resource development depends on the reservoir production potential, the future price of gas and electricity, and the future costs of power plants and wells. Our analysis indicates that natural gas must be present at near saturation levels for the class II and class III reservoirs to be economically feasible as producers of

electrical power and gas. The class I reservoir does not appear to be economically feasible for the production of both electrical power and gas. It might be economical as a gas well only. A class III reservoir is the only one that would be even marginally profitable for electrical power generation alone, if natural gas were not present. Development leading to higher thermal conversion efficiencies will improve profitability and thus effectively make more of the resource available.

Discussion

Key questions that will need answers in the future are (1) verification of the presence of natural gas, (2) ability of the wells to maintain high flow rates for long periods of time, (3) ability to solve formation sand-control problems at high flow rates, (4) the relative amount of subsidence, and (5) recovery factors. A sufficient number of large reservoirs (about 30 cubic miles each or larger) will have to be located, in areas where development would be environmentally acceptable, in order to justify a large research and development program.

Hardware development will be required for both the hydraulic and thermal energy conversion machinery. The hydraulic turbine may require several stages for the higher pressure wells and must be designed to withstand high internal pressures. Provision will have to be made for removing natural gas between stages.

Thermal energy conversion systems operating in the range of 250 to 350°F

will also require development. The systems utilizing the geothermal fluid directly (i.e., the total-flow and flashed-steam systems) will have to operate with low pressures and high specific volumes. This will require large sizes of pipe and equipment and careful design in order to minimize pressure drops in the system. Corrosion and scaling problems, which will be more severe in the thermal energy conversion part of the system, will have to be addressed when site-specific data are available. The binary-cycle system may not be practical for the higher salinity waters unless heat-exchanger scale deposition can be minimized by chemical or mechanical means.

Portions of the geopressure resource with high-salinity waters may not be economical to develop because of adverse effects of dissolved solids on the thermal energy content of the fluid ($\Delta H/lb$ available to the expander), the solubility of natural gas, and power-plant costs.

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Appendix A

Summary of Power-Generation and Gas-Production Calculations

Table A1. Calculated operating parameters for total-flow and binary systems (8500-ft production well, 5000-ft injection well).^a

Well-head parameters			Total-flow system									Binary system					
P_{wh} (psig)	Q_{fp} (bbl/day)	$\dot{a}$ (lb/sec)	W_t (hp)	W_c (hp)	$W_t - W_c$ (hp)	$W_t - W_c$ (kW)	W_h (hp)	$W_t - W_c + W_h$ (kW)	W_p (hp)	$W_t - W_c + W_h - W_p$ (kW)	V_g (10^3 scf/day)	P_{bp} (psil)	W_{bp} (hp)	W_{bh} (hp)	$W_t - W_c - W_{bp}$ (kW)	$W_t - W_c + W_{bh}$ (kW)	V_{bg} (10^3 scf/day)
20	67,230	263	1024	295	729	527	24	544	1467	-548	1231	1025	160	-	-664	-	1218
100	65,210	255	994	287	707	511	103	586	1385	-446	1194	997	1384	-	-519	-	1150
200	62,600	245	954	275	679	491	195	631	1284	-324	1147	961	1128	-	-349	-	1056
300	59,910	234	913	263	649	470	278	671	1183	-210	1097	924	885	-	-189	-	964
400	57,100	223	870	251	619	448	352	702	1082	-103	1046	886	657	-	-41	-	892
500	54,170	212	825	238	587	425	417	726	983	-5	992	846	444	-	94	-	815
600	51,110	200	779	225	554	401	472	742	884	84	936	806	249	-	215	-	734
700	47,880	187	730	210	519	375	515	748	786	163	877	763	72	-	322	-	660
800	44,460	174	677	195	482	349	546	744	689	231	814	718	-	54	-	388	608
900	40,820	160	622	179	443	320	564	728	593	287	748	671	-	139	-	421	567
1000	36,900	144	562	162	400	289	566	699	497	329	676	621	-	208	-	440	516
1100	32,620	128	497	143	354	256	551	654	403	354	598	568	-	259	-	443	478
1150	30,320	118	462	133	329	238	535	624	357	359	555	539	-	276	-	437	447
1200	27,870	109	425	123	302	218	513	589	310	359	510	509	-	287	-	426	416
1300	22,450	88	342	99	243	176	448	499	219	337	408	443	-	287	-	383	342
1400	15,930	62	243	70	173	125	342	372	129	276	292	365	-	246	-	303	252
1500	7,150	28	109	31	78	56	165	175	43	143	131	264	-	132	-	151	118
1552	0	0	0	0	0	0	0	0	0	0	0	0	-	0	-	0	0

^aSee Appendix D for symbol definitions.

Table A2. Calculated operating parameters for total-flow and binary systems (13,000-ft production well, 6000-ft injection well).^a

Well-head parameters			Total-flow system										Binary system					
P_{wh} (psig)	Q_{sp} (bbl/day)	$\dot{A}$ (lb/sec)	W_c (hp)	W_e (hp)	$W_t - W_c$ (hp)	$W_t - W_c$ (kW)	W_h (hp)	$W_t - W_c + W_h$ (hp)	W_p (hp)	$W_t - W_c + W_h - W_p$ (hp)	$W_t - W_c + W_h - W_p$ (kW)	V_g (10 ³ acf/day)	P_{bp} (psia)	W_{pb} (hp)	W_{bh} (hp)	$W_t - W_c - W_{bp}$ (hp)	$W_t - W_c - W_{bh}$ (hp)	V_{bg} (10 ³ acf/day)
40	93,060	356	3496	620	2877	2080	36	2215	2500	244	2676	2676	1439	3016	-	-165	-	2667
200	90,930	348	3416	605	2811	2032	257	2218	2392	438	2615	2615	1406	2542	-	141	-	2495
400	88,220	337	3314	587	2727	1972	519	2347	2255	669	2537	2537	1365	1973	-	503	-	2296
600	85,420	327	3209	569	2640	1909	764	2462	2120	884	2457	2457	1323	1431	-	844	-	2143
800	82,530	315	3101	549	2551	1844	991	2561	1985	1084	2373	2373	1280	918	-	1161	-	1969
1000	79,540	304	2988	530	2459	1778	1199	2644	1850	1268	2287	2287	1236	434	-	1454	-	1822
1200	76,450	292	2872	509	2363	1709	1386	2711	1716	1434	2199	2199	1191	-	11	-	1716	1687
1400	73,230	280	2751	488	2264	1637	1552	2759	1582	1581	2106	2106	1144	-	273	-	1834	1630
1600	69,880	267	2625	465	2160	1562	1694	2787	1449	1708	2010	2010	1096	-	514	-	1933	1575
1800	66,370	254	2493	442	2052	1483	1812	2794	1318	1813	1909	1909	1046	-	730	-	2011	1508
2000	62,680	240	2355	417	1938	1401	1904	2777	1186	1894	1803	1803	995	-	919	-	2065	1436
2200	58,780	225	2208	391	1817	1314	1965	2734	1056	1949	1691	1691	941	-	1079	-	2094	1364
2400	54,630	209	2052	364	1689	1221	1993	2662	925	1974	1571	1571	885	-	1207	-	2094	1283
2600	50,170	192	1885	334	1551	1121	1984	2556	796	1964	1442	1442	825	-	1299	-	2060	1196
2800	45,320	173	1703	302	1401	1013	1931	2409	666	1914	1303	1303	761	-	1348	-	1987	1094
3000	39,960	153	1501	266	1235	893	1825	2213	537	1813	1149	1149	692	-	1345	-	1866	979
3200	33,890	130	1273	226	1047	757	1651	1951	408	1648	974	974	615	-	1278	-	1681	843
3400	26,690	102	1003	178	825	596	1382	1596	278	1389	767	767	526	-	1119	-	1405	679
3600	17,330	66	651	115	536	387	951	1075	145	976	498	498	415	-	805	-	970	451
3792	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

^aSee Appendix D for symbol definitions.

Table A3. Calculated operating parameters for total-flow and binary systems (16,000-ft production well, 7500-ft injection well).^a

Well-head parameters			Total-flow system										Binary system					
P_{wh} (psig)	Q_{fp} (bbl/day)	$\dot{a}$ (lb/sec)	W_t (hp)	W_c (hp)	$W_t - W_c$ (hp)	$W_t - W_c$ (kW)	W_h (hp)	$W_t - W_c + W_h$ (kW)	W_p (hp)	$W_t - W_c + W_h - W_p$ (kW)	V_g (10^3 scf/day)	P_{bp} (psi)	W_{bp} (hp)	W_{bh} (hp)	$W_t - W_c - W_{bp}$ (kW)	$W_t - W_c + W_{bh}$ (kW)	V_{bg} (10^3 scf/day)	
80	113,390	422	7642	990	6652	4809	48	4844	3388	2322	4604	1842	4509	-	1453	-	4572	
400	110,410	411	7440	964	6476	4682	587	5107	3214	2715	4483	1791	3467	-	2102	-	4229	
800	106,560	397	7181	930	6251	4519	1219	5401	2999	3169	4327	1727	2228	-	2861	-	3847	
1200	102,570	382	6913	896	6017	4350	1801	5653	2783	3581	4164	1661	1067	-	3557	-	3514	
1600	98,430	367	6634	859	5774	4175	2331	5860	2569	3941	3996	1593	-	10	-	4182	3237	
2000	94,120	350	6343	822	5521	3992	2805	6019	2358	4265	3821	1524	-	637	-	4452	3095	
2400	89,600	334	6039	782	5256	3800	3219	6127	2147	4530	3638	1452	-	1207	-	4673	2971	
2800	84,860	316	5719	741	4978	3599	3567	6178	1937	4737	3446	1378	-	1714	-	4838	2838	
3200	79,850	297	5381	697	4684	3386	3845	6167	1728	4880	3242	1301	-	2154	-	4944	2699	
3600	74,510	277	5022	651	4371	3160	4045	6084	1521	4952	3025	1222	-	2518	-	4981	2532	
4000	68,790	256	4636	601	4035	2917	4155	5921	1314	4943	2793	1137	-	2798	-	4940	2369	
4400	62,570	233	4217	546	3671	2654	4162	5663	1109	4838	2541	1048	-	2980	-	4808	2184	
4800	55,710	207	3754	486	3268	2363	4047	5289	904	4616	2262	952	-	3046	-	4565	1970	
5200	47,950	179	3231	419	2813	2033	3776	4764	699	4243	1946	847	-	2965	-	4177	1717	
5600	38,790	144	2614	339	2275	1645	3292	4026	493	3659	1575	728	-	2685	-	3587	1414	
6000	27,020	101	1821	236	1585	1146	2459	2924	280	2716	1097	581	-	2081	-	2650	1005	
6400	5,464	20	368	48	320	232	531	615	35	590	221	333	-	471	-	572	210	
6433	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

^aSee Appendix D for symbol definitions.

Appendix B

Fluid-Flow Calculations

The production-well model used in calculating fluid flow is shown in Fig. 3 of the text. The symbols and units used in the calculations presented here are defined in Appendix D.

The production-wellhead pressure P_{wh} is obtained as follows:

$$P_{wh} = P_r - P_c - \Delta P_{dd} - \Delta P_f. \quad (B.1)$$

The drawdown pressure loss (ΔP_{dd}) between the basic reservoir pressure and the wellbore bottom is calculated from a formula by Muscat^{B1}:

$$\Delta P_{dd} = \frac{Q_{fp} \mu \beta \ln(r_e/r_w)}{0.007082Kh}. \quad (B.2)$$

The values used for the various factors are as follows: $\beta = 1$, $r_e/r_w = 500$, $h = 500$ ft, and $K = 100$ millidarcies (typical geopressure sandstone permeability). By substitution into Eq. (B.2), we obtain

$$\Delta P_{dd} = 0.01755\mu Q_{fp}. \quad (B.3)$$

The term β in Eq. (B.2) is a factor used to correct for the change in specific volume between the reservoir and the wellhead. Since water is relatively incompressible, a value of unity may be used. In retrospect, the r_e/r_w ratio of 500 probably should be larger. Fortunately, since the equation uses the logarithm of the ratio

and the pipe fluid-friction pressure drop (ΔP_f) predominates at high flow rates, the effect of a small r_e/r_w ratio is not serious.

The pipe fluid-friction pressure drop is determined by the turbulent-flow head-loss equation^{B2}:

$$\Delta P_f = (fHV^2/2gD)(\gamma/144). \quad (B.4)$$

By continuity, $Q = VA$, $V = Q/A$, and

$$V = 4Q/\pi D^2. \quad (B.5)$$

By substitution of Eq. (B.5) into Eq. (B.4), using $f = 0.02$, $D = 0.4933$ ft, the ΔP_f relationship becomes

$$\Delta P_f = 5.052 \times 10^{-13} H \gamma Q_{fp}^2. \quad (B.6)$$

The well-fluid-column hydrostatic pressure P_c is simply

$$P_c = \gamma H/144. \quad (B.7)$$

Substitution of Eqs. (B.3), (B.6), and (B.7) into Eq. (B.1) results in

$$P_{wh} = P_r - \frac{\gamma H}{144} - 0.01755\mu Q_{fp} - 5.052 \times 10^{-13} (H \gamma Q_{fp}^2). \quad (B.8)$$

By rearranging Eq. (B.8) and solving for Q_{fp} , we obtain

$$Q_{fp} = \frac{-0.01755\mu + \left\{ (0.01755\mu)^2 - 2.021 \times 10^{-12} (H \gamma) [P_{wh} + (H \gamma/144) - P_r] \right\}^{1/2}}{10.104 \times 10^{-13} (H \gamma)} \quad (B.9)$$

Thus with reservoir values of H and P_r , and fluid properties of μ and γ , the flow rate Q_{fp} can be determined as a function of P_{wh} .

Results of the production calculations for corresponding operating points of Table 5 in the text are listed in Table B1.

Table B1. Examples of flow-rate calculations.

P_r (psi)	P_c (psi)	P_{wh} (psi)	Q_{fp} (bbl/day)	ΔP_{dd} (psi)	ΔP_f (psi)
5,100	3548	1150	30,310	165	237
5,100	3548	700	47,880	260	592
9,100	5308	2400	54,630	240	1153
9,100	5308	1800	66,370	291	1701
12,800	6367	3600	74,510	262	2572
12,800	6367	2800	84,860	298	3336

References

- B1. M. Muscat, Physical Principles of Oil Production (McGraw-Hill Book Company, Inc., New York, 1949).
- B2. J. K. Vennard, Elementary Fluid Mechanics (John Wiley & Sons, Inc., New York, 1954).

Appendix C

Fluid-Injection Power Calculations

The model used for calculating the fluid-injection power requirements is shown in Fig. 5 of the text. The symbols and units used in the calculations presented here are defined in Appendix D.

The volumetric injection flow rate Q_{fi} is reduced from the production flow rate Q_{fp} because of the temperature reduction and the reduced mass flow rate. Only the liquid portion from the separator downstream from the total-flow expander is injected (see point 3l in Fig. 8 of the text):

$$Q_{fi} = (1 - X_3) \left(\frac{\dot{m}}{\gamma} \right) 15,390. \quad (C.1)$$

The pump power is determined by

$$W_p = \frac{144 Q_{fi}}{(15,390)(550)\eta_p}$$

$$(-P_i + P_r + 14.7 - P_c + \Delta P_{dd} + \Delta P_f). \quad (C.2)$$

By substituting Eq. (C.1) into Eq. (C.2), we obtain

$$W_p = \frac{(1 - X_3)144\dot{m}}{550\eta_p\gamma}$$

$$(-P_i + P_r + 14.7 - P_c + \Delta P_{dd} + \Delta P_f). \quad (C.3)$$

Table C1. Values of the parameters needed to calculate P_c , ΔP_{dd} , and ΔP_f .

Parameter	Value
Pipe inside diameter D (ft)	0.729
Formation zone thickness h (ft)	500
Temperature T (°F)	113
Specific weight γ (lb/ft ³)	61.8
Moody friction factor f	0.02
Viscosity μ (cP)	0.586
Pump efficiency η_p	0.7
Pump inlet pressure P_i (psia)	1.4
r_e/r_w	500
Permeability (millidarcies)	85 ^a

^aSlightly lower than the production permeability to allow for some "plugging."

The quantities P_c , ΔP_{dd} , and ΔP_f are determined by the methods outlined in Appendix B. Table C1 lists the values of the various parameters needed.

Examples of the pump-power calculations for the three nominal operating points that require injection (see Table 5 in text) are shown in Table C2.

Table C2. Examples of injection pump power.

H (ft)	Q_{fi} (bbl/day)	P_r (psi)	P_c (psi)	ΔP_f (psi)	ΔP_{dd} (psi)	W_p (hp)
5000	27,120	2325	2145	16.3	328	357
6000	45,480	2790	2574	54.8	550	925
7500	57,390	3488	3217	109	694	1521

Appendix D

Symbol Names and Units

Symbol	Definition	Unit
A	Area	ft ²
D	Pipe inside diameter	ft
f	Moody friction factor	dimensionless
g	Dimensional constant	32.2ft-lb _m /sec ² -lb _f
h	Formation zone thickness	ft
H	Enthalpy	Btu/lb
H	Depth to well bottom	ft
K	Permeability	Millidarcies
$\dot{m}$, $\dot{m}_1$	Well flow rate	lb/sec
P _{bp}	Binary pump pressure	psi
P _c	Hydrostatic pressure	psi
P _i	Pump inlet pressure	psi
P _p	Pump pressure	psi
P _r	Reservoir pressure	psi
P _s	Water saturation pressure	psi
P _{wh}	Production-wellhead pressure	psi
Q	Flow rate	ft ³ /sec
Q _{fp}	Production-well flow rate	bb1/sec
Q _{fi}	Injection-well flow rate	bb1/sec
Q _{fbi}	Binary injection flow rate	bb1/sec
r _e	Undisturbed reservoir radius	ft
r _w	Well-casing outside radius	ft
T	Temperature	°F
T _r	Reservoir temperature	°F
V	Velocity	ft/sec
V _g	Gas production	scf/day
V _{bg}	Binary gas production	scf/day
W _{bh}	Binary hydraulic power	hp
W _{bp}	Binary pump power	hp
W _c	Cooling-system power	hp
W _h	Hydraulic turbine power	hp
W _p	Injection pump power	hp
W _t	Expander power	hp
X	Steam quality	dimensionless

Symbol	Definition	Unit
β	Volumetric correction factor	dimensionless
γ	Specific weight	lb/ft ³
γ_i	Injection fluid specific weight	lb/ft ³
γ_p	Production fluid specific weight	lb/ft ³
ΔH_s	Constant entropy enthalpy change	Btu/lb
ΔP_f	Pipe fluid-friction pressure loss	psi
ΔP_{dd}	Drawdown pressure loss (formation to wellbore)	psi
η_e	Expander efficiency	dimensionless
η_h	Hydraulic turbine efficiency	dimensionless
η_p	Pump efficiency	dimensionless
μ	Viscosity	cP

Appendix E
Capital and Total Cost Breakdowns

Table E1. Capital cost breakdown.^a

Cost	Class I resource ^b		Class II resource ^c		Class III resource ^d	
	Injection	No injection	Injection	No injection	Injection	No injection
Production-well costs:						
Land and site	1,000	1,000	1,000	1,000	1,000	1,000
Production wells	8,505	8,505	13,005	13,005	16,005	16,005
Well contingency @ 10%	850	850	1,300	1,300	1,600	1,600
Wellhead equipment	635	635	635	635	635	635
Collection piping	2,175	2,175	2,175	2,175	2,175	2,175
Engineering and management	658	658	906	906	1,071	1,071
Total	13,823	13,823	19,021	19,021	22,486	22,486
Methane-extraction costs:						
Equipment costs	1,612	2,554	2,917	3,889	3,889	4,527
Engineering and management	161	255	292	389	339	453
Total	1,773	2,809	3,209	4,278	3,728	4,980
Power-plant costs-- total-flow expander:						
Powerhouse	310	490	1,377	1,673	3,370	3,838
Expander and generator	388	612	1,721	2,091	4,213	4,798
Separator	313	496	859	1,044	1,534	1,748
Condenser	392	620	1,074	1,306	1,918	2,185

^aAll costs are in thousands of dollars.^bFluid temperature 200°F.^cFluid temperature 250°F.^dFluid temperature 300°F.

Table E1. Capital cost breakdown.^a (Continued)

Cost	Class I resource ^b		Class II resource ^c		Class III resource ^d	
	Injection	No injection	Injection	No injection	Injection	No injection
Cooling tower	899	1,426	2,468	2,995	4,420	5,010
Electrical plant equipment	93	147	413	502	1,011	1,152
Engineering and management	240	379	791	961	1,646	1,873
Total	2,635	4,170	8,703	10,572	18,112	20,604
Power-plant costs-- hydraulic turbine:						
Power house	359	346	1,337	1,337	2,714	2,394
Turbine and generator	449	432	1,621	1,520	3,392	2,992
Electrical plant equipment	107	104	401	365	814	718
Engineering and management	92	88	336	310	692	610
Total	1,007	907	3,695	3,411	7,612	6,714
Injection-well costs:						
Injection-well	5,000	0	6,000	0	7,500	0
Well contingency @ 10%	500	0	600	0	750	0
Wellhead equipment	635	0	635	0	635	0
Disposal piping	2,175	0	2,175	0	2,175	0
Injection pumps and motors	275	0	532	0	876	0
Engineering and management	413	0	497	0	597	0
Total	8,673	0	10,439	0	12,533	0

^aAll costs are in thousands of dollars.^bFluid temperature 200°F.^cFluid temperature 250°F.^dFluid temperature 300°F.

Table E2. Total cost breakdown.^a

Cost	Class I resource ^b		Class II resource ^c		Class III resource ^d	
	Injection	No injection	Injection	No injection	Injection	No injection
Gas and electricity:						
Production wells	13,823	13,823	19,021	19,021	22,486	22,486
Injection wells	8,673	0	10,439	0	12,533	0
Methane extraction	1,773	2,809	3,209	4,278	3,728	4,980
Power plant: total flow	2,635	4,170	8,703	10,572	18,112	20,604
Power plant: hydraulic	<u>1,007</u>	<u>970</u>	<u>3,695</u>	<u>3,411</u>	<u>7,612</u>	<u>6,714</u>
Total (1975)	27,911	21,772	45,067	37,282	64,471	54,784
Interest during construction	6,699	5,225	10,816	8,948	15,473	13,148
Escalation during construction	<u>6,699</u>	<u>5,225</u>	<u>10,816</u>	<u>8,948</u>	<u>15,473</u>	<u>13,148</u>
Total (1981)	41,309	32,222	66,699	55,178	95,417	81,080
Annual operating costs	2,809	1,862	3,935	2,792	5,000	3,616
Electricity only:						
Production wells	13,823	13,823	19,021	19,021	22,486	22,486
Injection wells	8,673	0	10,439	0	12,533	0
Power plant: total flow	2,635	4,170	8,703	10,572	18,112	20,604
Power plant: hydraulic	<u>1,007</u>	<u>970</u>	<u>3,695</u>	<u>3,411</u>	<u>7,612</u>	<u>6,714</u>
Total (1975)	26,138	18,963	41,858	33,004	60,743	49,804
Interest during construction	6,273	4,551	10,046	7,921	14,578	11,953
Escalation during construction	<u>6,273</u>	<u>4,551</u>	<u>10,046</u>	<u>7,921</u>	<u>14,578</u>	<u>11,953</u>
Total (1981)	38,684	28,065	61,950	48,846	89,899	73,710
Annual operating costs	2,735	1,790	3,840	2,677	4,926	3,464

^aAll costs are in thousands of dollars.^bFluid temperature 200°F.^cFluid temperature 250°F.^dFluid temperature 300°F.