The energy potential of geothermal waters in the geopressed reservoirs of the Gulf Coast ultimately depends on the yield of wells tapping these reservoirs. An analysis is made to determine possible well yields in a geopressed reservoir in Hidalgo County, Texas. The reservoir lies beneath an area 16 kilometres (10 miles) wide and 48 kilometres (30 miles) long, with the long axis extending northeast-southwest parallel to and east of the McAllen fault. The average pressure-to-depth ratio in the reservoir is 17 kilonewtons per square metre per metre (0.75 pound per square inch per foot). The average temperature of the water is 135°C (275°F), and the average salinity is about 25,000 milligrams per litre. On the basis of solubility data, the average methane content is estimated to be 4.8 standard cubic metres per cubic metre (standard cubic feet per cubic foot).

Based on an idealized model of the reservoir, the results of the analysis indicate that a single 0.23-metre (0.75-foot) diameter well at the center of the reservoir could sustain a flow rate of 0.31 cubic metre per second (11 cubic feet per second) for 20 years. The total production rate from the reservoir could be increased to 2.7 cubic metres per second (95 cubic feet per second) for the 20-year period by assuming that a minimum flow rate of 0.15 cubic metre per second (5.3 cubic feet per second) per well is satisfactory and by developing the reservoir with 18 wells at optimum spacing. Estimates of subsidence under the 18-well production scheme indicate that the average subsidence over the reservoir area would be about 1 metre (3 feet) at the end of the 20-year production period. In the immediate vicinity of a centrally located well, subsidence would be about 2 metres (6 feet). The thermal, mechanical, and methane energy contained in the waters produced with the 18-well development scheme is equivalent to $11.32 \times 10^{17}$ joules ($10.73 \times 10^{14}$ British thermal units). The thermal and mechanical energy components of this total could be converted to 94 megawatts (estimated) of electrical power over the 20-year production period.

In addition to this analysis of a geopressed reservoir, the sensitivity of well yields to hydrogeologic factors is examined. It is concluded that the most important hydrogeologic factor in the development of geopressed reservoirs is the transmissivity. The results of calculations made for this sensitivity determination are presented graphically and can be used to make quick estimates of the yield of wells tapping geopressed reservoirs.
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Jones (1969, 1970) and Wallace (1970) have discussed and attempted to explain subsurface geologic conditions that combine to produce geopressured-geothermal reservoirs.

Unlike other geothermal areas that are being considered for the development of energy, the energy potential of waters in the geopressured-geothermal areas of the Gulf Coast is not limited to thermal energy. The abnormally high fluid pressures that have resulted from the compartmentalization of the sand and shale beds that contain these hot waters are a potential source for the development of mechanical (hydraulic) energy. In addition, dissolved natural gas, primarily methane, contributes significantly to the energy potential of these waters. Estimates of the magnitude of the energy contained in geopressed reservoirs have been presented by several investigators (Herrin, 1973; Myers et al., 1973; Dorfman and Kehle, 1974).

The feasibility of recovering energy from geopressed reservoirs and the rate at which this energy could be recovered ultimately depends on the yield of wells tapping these reservoirs. The yield of wells, in turn, is controlled by the hydrogeologic properties of the reservoir sands and confining shale beds and by the chemistry of the stored waters. Previous studies of the potential use of geopressed reservoirs for electrical power generation have considered only the yield of a single well or a cluster of wells at a specific site within a reservoir (Parmigiano, 1973; Wilson et al., 1974). Development of an entire reservoir with several appropriately spaced wells has not been considered. Also, these studies have not taken into account the contribution of water from storage in the confining shale beds.

The purpose of this paper is to analyze, on the basis of only hydrogeologic factors, a "typical" geopressed reservoir of the Gulf Coast in order to obtain estimates of (1) possible well yields and (2) the energy potential of the reservoir. The yield of individual wells and the total production rate from the reservoir with wells placed at optimum well spacing will be examined. Also, the effects of leakage from storage in the confining shale beds will be considered.

A second objective of this paper is to determine the sensitivity of well yields to well spacing or reservoir size and to hydrogeologic factors. The variation of well yields with well spacing will be examined for various values of aquifer and confining bed parameters within a range that can be expected in the Gulf Coast geopressed reservoirs.

The units of the International System (SI system) followed by their equivalents in the English System are used throughout this paper. To maintain uniformity, SI units were inserted in quoted material that is originally in other units. Such insertions are clearly indicated wherever they occur. Factors for converting SI units to English units and to other units commonly used in ground-water and petroleum literature are given in Table 1.

To select a "typical" reservoir that is representative of the conditions that exist in the geopressed zones of the Gulf Coast, the advice of Paul H. Jones (oral communication, March 1974), former project chief of the U.S. Geological Survey's "Gulf Basin Hydrology Project", was sought. At his recommendation, a geopressed reservoir in Hidalgo County, Texas, (fig. 1) was selected for analysis. Preliminary examination of the available data indicated that the data were insufficient or lacked the detail needed for analysis of the reservoir by digital simulation. Therefore, it was decided to make a simplified analysis based on an idealized model of the reservoir, using analytical well-flow equations and average values of the reservoir properties. On the basis of
available data and his knowledge of the hydrogeology of the Gulf Coast geopressed zones, Jones (written communication, May 1974) provided the following estimates of the average values of the data needed for a simplified analysis.
a) The main sand unit has good area continuity in a belt about [16 kilometres] 10 miles wide and [48 kilometres] 30 miles long, the long axis parallel to the McAllen fault. The boundaries are the presence of fault-controlled sediment facies, and not strictly the faults, as the aquifers can be continuous across faults in this area.

b) The northern boundary is about [64 kilometres] 40 miles from the Rio Grande. The aquifer zone (main sand unit) continues to the north, but the upper part is not geopressed.

c) The thickness of the main sand unit ranges from about [610 to about 2,000 metres] 2,000 to about 6,500 feet and the cumulative thickness of sand beds in the unit is generally greater than 35 percent. The average unit thickness is about [910 metres] 3,000 feet, and the average cumulative thickness of sand beds is about [370 metres] 1,200 feet.

Figure 1. Location of geopressed reservoir selected for analysis; main sand unit estimated to have good continuity over the shaded area.
The thickness of shale above the unit is [300 to 610 metres] 1,000 to 2,000 feet; below, the shale is thousands of [metres] feet thick.

d) The average elevation of the top of the unit is [2,400 metres] 8,000 feet below sea level.
e) The pressure in the unit ranges from [14 kilonewtons per square metre per metre (kN/m²/m)] 0.6 pounds per square inch per foot (psi/ft). The average is [17 kN/m²/m] 0.75 psi/ft. The sands above the unit are hydrostatic, that is, less than [11 kN/m²/m] 0.5 psi/ft, and below the main unit the pressure is in excess of [20 kN/m²/m] 0.9 psi/ft.
f) The temperature ranges to above 150°C [300°F], the average temperature is about 135°C [275°F].
g) The salinity ranges from less than 5,000 milligrams per liter (mg/l) to about 60,000 mg/l. Some of the most massive sands have water with a salinity of less than 10,000 mg/l. The average salinity probably falls between 20,000 and 25,000 mg/l.
h) The estimated horizontal permeability of the main sand unit ranges from about [2 × 10⁻¹⁴ to 1 × 10⁻¹² metres square (m²)] 20 to 1,000 millidarcy (md), being least near the boundaries (tops and bottoms) of sand beds, and decreasing upward in the zone of pressure relief (drainage into the overlying hydropressure zone). At the top of this zone, in hydrocarbon productive areas, the sand permeability is often reported as less than [2 × 10⁻¹⁴ m] 20 md. Shale permeability in the geopressed zone is highly dependent on the geostatic ratio and related porosity. It is probably two or more orders of magnitude greater than in normally compacted shale at the same depth. Coupled with the very large gradients in head that can be generated by fluid discharge from adjacent sand-bed aquifers, the relatively large shale permeability may account for appreciable shale water influx.

On the basis of these data, the selected geopressed reservoir was idealized and a reservoir model that lends itself to a simplified analysis was developed.

Reservoir Properties

AREAL EXTENT AND BOUNDARIES. The reservoir was assumed to lie beneath a rectangular area 16 kilometres (km) or 10 miles (mi) wide and 100 km (62.5 mi) long, with the long axis extending parallel to and east of the McAllen fault from a point 36 km (22.5 mi) southwest of the Rio Grande to a point 64 km (40 mi) northeast of the Rio Grande (fig. 1). The boundaries of this rectangular area were assumed to be impermeable. Development of the reservoir was assumed to be limited to the 16 by 48 km (10 by 30 mi) area adjacent to the Rio Grande over which the reservoir sands have good areal continuity.

THICKNESS AND DEPTH. The idealized reservoir was assumed to consist of a single sand aquifer underlain and overlain by two single shale confining beds. The thickness of the sand aquifer was assumed to be 370 metres (m) or 1,200 feet (ft), equal to the average cumulative sand thickness of the reservoir. Both of the confining shale beds were assumed to be 610 m (2,000 ft) thick (fig. 2). The top of the sand aquifer was assumed to lie at a depth of 2,700 m (8,900 ft) below land surface.

PRESSURE AND HYDRAULIC HEAD. The average pressure-to-depth ratio of 17 kN/m²/m (0.75 psi/ft) was assumed to occur at the midpoint of the sand
The hydraulic head within the sand aquifer was calculated from this pressure-to-depth ratio as 2,400 m (7,870 ft) above land surface. Above the upper confining shale bed the pressure was assumed to be hydrostatic, corresponding to a hydraulic head of zero metres (feet) above land surface. The hydraulic gradient was assumed to vary uniformly from this zero at the top of the upper confining bed to 2,400 m (7,870 ft) at the top of the sand aquifer. The same hydraulic gradient was assumed also to occur in the lower confining shale bed (fig. 2).
TRANSMISSIVITY AND STORAGE COEFFICIENT OF SAND AQUIFER. The sand aquifer was assumed to have an intrinsic permeability of $10^{-13}$ m$^2$ (100 md) and a specific storage of $3.3 \times 10^{-6}$ m$^{-1}$ ($10^{-4}$ ft$^{-1}$). These values resulted in a calculated transmissivity for the sand aquifer of 0.0016 metres square per second (m$^2$/s) or 0.017 feet square per second (ft$^2$/s) and a storage coefficient of 0.0012.

HYDRAULIC CONDUCTIVITY AND SPECIFIC STORAGE OF CONFINING SHALE BEDS. The intrinsic permeability of both the upper and lower shale beds were assumed to be $10^{-18}$ m$^2$ (0.0001 md), resulting in a hydraulic conductivity of $4.4 \times 10^{-12}$ metres per second (m/s) or $1.4 \times 10^{-11}$ feet per second (ft/s). This value of permeability is two to three orders of magnitude higher than the permeability of normally compacted shale beds. However, shale beds within the geopressed zone are undercompacted, resulting in permeabilities larger than those of compacted shale beds. Furthermore, under actual reservoir conditions of interbedded shale and sand beds, several shale beds would be draining from both sides to adjacent sand beds that are being developed, contributing a much larger rate of flow to the sand beds than the shale beds of the idealized reservoir model, which consists of only two beds, each draining only on one side. Thus, it is believed by the author that for the analysis in this study, which is based on the conceptual model, the assumed shale bed permeability is reasonable. To account for the compressibility of these undercompacted shale beds a relatively high "short-term" specific storage of $3.3 \times 10^{-4}$ m$^{-1}$ ($10^{-4}$ ft$^{-1}$) was assumed.

Note that the properties of both the upper and lower confining shale beds were assumed to be identical. For the short periods of time (20 years) that will be considered in the analysis of well yields, head changes in the confining beds occur only within a few tens of metres (feet) from the confining bed-aquifer boundaries. Since the confining shale beds are known to be thicker than a few tens of metres (feet), their actual thickness and the fact that this thickness was assumed to be identical will not affect the results of the analysis. It was further assumed that under undeveloped conditions the vertical flow in the reservoir is steady and that, therefore, the product of hydraulic conductivity and hydraulic gradient (the specific discharge) should be the same for both the upper and lower confining beds. Since the assumed values for these two parameters are judgmental estimates of possible average values, for convenience they were assumed to be identical in the upper and lower confining beds. The specific storage, another judgmental estimate, was also assumed to be identical for convenience. The effect of assuming these parameters to be identical on the results of the analysis would probably not be any greater than the effects of other assumptions made in formulating the idealized reservoir mode.

**Water Properties**

TEMPERATURE AND SALINITY. The geothermal waters stored in the reservoir were assumed to have an average temperature of 135°C (275°F) and an average salinity of 25,000 mg/l.

KINEMATIC VISCOSITY. The kinematic viscosity of fresh water at the assumed average reservoir temperature and pressure is $2.2 \times 10^{-7}$ m$^2$/s or $2.4 \times 10^{-6}$ ft$^2$/s (Meyer et al., 1968). This value of the kinematic viscosity, without correction for salinity, was used in the calculations of transmissivity and hydraulic conductivity and of the Reynolds number needed in the determination of pipe friction losses.

DENSITY. The density of the water at saturation pressure and at the average reservoir temperature and salinity was calculated from data given by Haas (1970) as 948 kilograms per cubic metre (km/m$^3$) or 59.2 pounds per cubic foot.
Ib/ft³. This value of density was used in the analysis without correction for pressure effects.

METHANE CONTENT. Although the dissolved gas content of waters from geopressed zones has not been measured, on the basis of data from normally pressured zones these waters were assumed to be methane-saturated. Curves of methane solubility in fresh water presented by Culberson and McKetta (1951) were extended and modified to correct for salinity. Using an extension of the solubility table from O'Sullivan and Smith (1970), the methane content was determined to be 4.8 standard cubic metres per cubic metre (standard cubic feet per cubic foot).

ANALYSIS

Well Yields and Total Production Rates

The well-flow equation used to determine possible well yields from the idealized geopressed reservoir is the "modified leaky aquifer" equation presented by Hantush (1960). The equation, which describes the drawdown (head decline) distribution, s, around a well producing at a constant flow rate, Q, from an infinite confined aquifer, allows for the effects of leakage from storage in both the upper and lower confining beds. The equation has the form

\[ s = \frac{Q}{4\pi T} H(u, \beta) \]

where
\[ u = \frac{r^2S}{4Tt} \]
\[ \beta = \frac{r\lambda/4}{1} \]
\[ \lambda = \left(\frac{K'S_s'/TS}{10K'}\right)^{1/4} + \left(\frac{K''S_s''/TS}{10K''}\right)^{1/4} \]

and in which \( H(u, \beta) \) is a tabulated function (Hantush, 1960; 1961), \( r \) is distance from well, \( T \) and \( S \) are the transmissivity and storage coefficient of the aquifer, \( t \) is time since production started, and \( K', S_s' \) and \( K'', S_s'' \) are the hydraulic conductivity and specific storage of the upper and lower confining beds, respectively. The equation is valid for "relatively small times" of \( t \) less than both \((b')^2S_s'/10K'\) and \((b'')^2S_s''/10K''\). For the confining shale bed properties used in the analysis this "relatively small time" covers a period as long as 90,000 (!) years. To apply the above equation, which is for an infinite aquifer, to a bounded aquifer, the method of images (Ferris et al., 1962) was used.

The wells tapping the reservoir were assumed to have a diameter of 0.23 m (0.75 ft) and to completely penetrate the sand aquifer, that is, to have a depth of 3,080 m (10,100 ft). The production period for the wells was assumed to be 20 years. It was further assumed that to produce mechanical (hydraulic) energy the well-head pressure should not decline below a minimum value of 14 meganewtons per square metre (MN/m²), or 2,000 psi, at the end of the 20-year production period. This minimum well-head pressure corresponds to a hydraulic head of about 1,500 m (4,920 ft). Thus, the maximum allowable drawdown at the end of the 20-year production period was assumed to be 900 m (2,950 ft).

The total drawdown in a well consists of the formation loss at the well-face, that is, the head decline due to the flow within the sand aquifer, as calculated by equation 1 and the method of images, plus the head loss due to pipe friction in the well casing. The head loss, \( h_i \), due to pipe friction was calculated using the Darcy-Weisbach equation (Streeter, 1962), which in terms of flow rate, \( Q \), well radius \( r_w \), and well depth, \( L \), is expressed as

\[ h_i = \frac{Q^2L}{4\pi^2r_w^5g} \]
where $g$ is a gravitational acceleration and $f$ is a friction factor that depends on the Reynold's number. For a given well diameter and kinematic viscosity, the Reynold's number, and consequently the friction factor, depends on the flow rate. Therefore, to calculate the friction factor for the various flow rates that were considered in the analysis, a plot of the variation of the friction factor with the Reynold's number (fig. 3) was prepared by assuming a roughness coefficient of $1.65 \times 10^{-5}$ m ($5.40 \times 10^{-5}$ ft) for the well casing and interpolating in a Moody diagram (Streeter, 1962).

Within the 16 by 48 km (10 by 30 mi) area of the reservoir to which development was assumed to be limited, wells were placed at an optimum spacing in terms of maximizing the total production rate from the reservoir for a given number of wells. That is, a well was placed in the center of the area, then the area was divided into two and a well was placed at the center of each of the two subareas. Thus, the number of wells was increased by dividing the reservoir area into equal subareas per well. For each well configuration, the flow rate that will result in a total well drawdown (formation loss plus pipe-friction loss) of 900 m (2,950 ft) at the end of the 20-year production period was calculated. The results of these calculations are shown on figure 4. Note that as the number of wells in the reservoir increases, the flow rate per well decreases, but the total production rate from the reservoir increases.

The flow rate of a single well at the center of the area to be developed is 0.31 cubic metres per second (m$^3$/s), or 11.0 cubic feet per second (ft$^3$/s). For two wells at optimum spacing, the flow rate per well decreases only slightly to 0.30 m$^3$/s (10.6 ft$^3$/s), but the total production rate increases to 0.60 m$^3$/s (21.2 ft$^3$/s). If a flow rate of about 0.3 m$^3$/s (11 ft$^3$/s) is economical, that is, if it results in a

![Figure 3. Variation of friction factor with Reynold's number.](image)
benefit-cost ratio larger than unity, the net benefits to be derived by developing the reservoir with two wells would be about twice the net benefits to be derived from a single-well development. As the number of wells increases, the net benefits will also increase but at a gradually slower and slower rate until a point of maximum net benefits is reached. Thereafter, an increase in the number of wells will cause a decrease in the net benefits.

As the above discussion indicates, a development plan for recovering energy from geopressed reservoirs cannot be selected on the basis of only hydrogeologic factors. Economic and environmental factors have to be considered and will probably govern the selection of the development plan. An optimum development plan would be one that maximizes economic benefits while it minimizes the environmental effects of the development.

In the absence of economic and environmental studies, which are beyond the scope of this paper, it was assumed that 0.15 m$^3$/s (5.3 ft$^3$/s) would be a satisfactory flow rate per well, as also suggested by Parmigiano (1973). At this specified flow rate, 18 wells (fig. 4) could be placed in the reservoir to produce at a total rate of 2.7 m$^3$/s (95 ft$^3$/s) for the 20-year production period. A possible well configuration and the area of influence of a centrally located well are shown on figure 5.
Figure 6 shows the variation of the drawdown and hydraulic head over the 20-year production period in the centrally located well shown on figure 5. The drawdown distribution around the same well, at the end of the 20-year production period, is shown on figure 7.

The analysis presented above has considered only single wells at optimum spacing in terms of maximizing the total production from the reservoir with a given number of wells. Economic studies might indicate that clusters of wells at each of the locations considered for a single well would be preferable. As
Figure 6. Variation of drawdown and hydraulic head in the centrally located well shown on figure 5 over the production period.

*Includes 110 metres (360 feet) of pipe friction losses.

Figure 7. Drawdown distribution within the area of influence of the centrally located well shown on figure 5 at the end of the production period.
stated earlier, a single well at the center of the reservoir could produce at a flow rate of 0.31 m$^3$/s (11.0 ft$^3$/s). If two wells are placed at this same location the flow rate per well is reduced, but not to one-half of that of a single well, since pipe friction losses are also reduced. Under this scheme the flow rate per well is 0.23 m$^3$/s (8.1 ft$^3$/s) and the total production rate is 0.46 m$^3$/s (16.2 ft$^3$/s). The benefits to be derived from the additional 0.15 m$^3$/s (5.3 ft$^3$/s) of the total production have to be weighed against the cost of the additional well and the cost of increasing the capacity of the surface facilities. The net benefits from these two wells at the same location should also be compared with the net benefits of two wells at optimum spacing, which, as also stated earlier, have a flow rate of 0.30 m$^3$/s (10.6 ft$^3$/s) and a total production rate of 0.60 m$^3$/s (21.2 ft$^3$/s).

In general, a given number of wells at optimum spacing would result in a total production rate larger than that of the same number of wells placed in clusters. However, whether this larger production rate is desirable or not cannot be determined without considering economic, environmental, and all other factors that might affect the development of the reservoir.

Under the assumed 18-well development plan and for the assumed reservoir parameters, drawdowns are considerable throughout the reservoir area (fig. 7). These large drawdowns cause a steep hydraulic gradient across the confining bed-aquifer boundaries and, consequently, a large contribution of water from storage in the confining shale beds. The volume of leakage $V_L$, that is, the volume of water contributed from storage in the confining beds, was calculated from the following equation (Hantush, 1960)

$$V_L = V \left[ 1 - \frac{2}{\sqrt{\eta \pi t}} + \frac{1}{\eta t} [1 - e^{\eta t} \text{erfc}(\sqrt{\eta t})] \right].$$  \hspace{1cm} (3)

where

- $\eta = T \xi S$
- $V = Qt =$ volume of produced water

and in which the exponential function $e^x$ and the complimentary error function $\text{erfc}(x)$ are tabulated functions (Dwight, 1958). Other symbols are as previously defined. Although Hantush (1960) presents this equation for aquifers of infinite extent, it can be shown that the equation is equally applicable to bounded aquifers without modification.

The variation of the volume of leakage-to-volume produced ratio with time, as calculated by equation 3, is shown on figure 8. Note that 55 percent of the volume produced over the 20-year production period is derived from storage in the confining shale beds.

As a result of this leakage from storage, the confining shale beds will be compacting. A certain amount of elastic compression will also occur within the sand aquifer in response to the large drawdowns. A rough estimate of possible average subsidence over the reservoir area is obtained by assuming that the compaction of the shale beds plus the compression of the sand beds is transmitted to the surface without reduction. The average subsidence due to the compaction of the confining shale beds was estimated by dividing the calculated volume of leakage by the area of the reservoir.
The average subsidence due to the compression of the sand aquifer was estimated by first calculating the average drawdown over the reservoir area using the following equation:

\[
\text{Average Drawdown} = \frac{\text{Volume produced} - \text{Volume of leakage}}{\text{Reservoir area} \times \text{Storage coefficient}}
\] (4)

The fraction of the storage coefficient due to the compressibility of water was then calculated assuming a porosity of 0.20 for the sand aquifer. (See Jacob, 1950, for definition of storage coefficient in terms of aquifer and water compressibility.) This fraction was subtracted from the storage coefficient to obtain the fraction due to aquifer compressibility, and the average subsidence due to the compression of the sand aquifer was calculated by multiplying this latter fraction with the average drawdown.

The results of these calculations are shown on figure 9. The estimated average subsidence at the end of the 20-year production period is about 1 m (3 ft). The distribution of subsidence around a centrally located well would be similar to the drawdown distribution shown on figure 7. By comparing the average drawdown with the drawdown in the immediate vicinity of the well, the possible subsidence near the well is estimated to be 2 m (6 ft).

Note that these are rough estimates of subsidence based on an idealized model of the reservoir. Actual subsidence in a reservoir consisting of interbedded sand and shale strata could be greater than these estimates. Although an attempt has been made to compensate for this possibility by assuming relatively high values of hydraulic conductivity and specific storage for the confining shale beds, the resulting estimates of subsidence could still be...
in error. However, the intent has been to draw attention to the fact that in any future studies of the possible development of geopressed reservoirs consideration needs to be given to environmental factors.

**Energy Potential of the Reservoir**

The energy potential of geopressed reservoirs depends on the amounts of water that can be produced from these reservoirs. Having determined the possible well yields and total production rates for the reservoir considered in this paper, the energy contained in the water produced can also be determined. The energy recovered with the assumed 18-well development scheme was calculated as follows.

The thermal energy in the water produced under this scheme was assumed equal to the heat content above 20°C (68°F) and calculated to be $7.94 \times 10^{17}$ joules (J) or $7.53 \times 10^{14}$ British thermal units (Btu).

To calculate the mechanical energy, the average operating head during the 20-year production period was estimated to be 1,750 m (5,740 ft) from the time-drawdown variation in the wells (fig. 6). The mechanical energy that can be produced with this average operating head is $0.28 \times 10^{17}$ J ($0.26 \times 10^{14}$ Btu).

The volume of methane that can be recovered from the produced water was calculated to be $8.19 \times 10^9$ standard m$^3$ ($2.89 \times 10^1$ standard ft$^3$) by simply multiplying the volume of water with the assumed methane content. To provide a basis of comparison with the other two sources of energy and to estimate the total recovered energy, this volume of methane can be expressed as thermal energy by assuming a heat equivalent of $3.77 \times 10^7$ J/standard m$^3$ ($1,010$ Btu/standard ft$^3$). Thus, the thermal equivalent of the recovered methane was calculated to be $3.10 \times 10^{17}$ J ($2.94 \times 10^{14}$ Btu.)

![Graph](image-url)

*Figure 9. Variation of estimated average subsidence over the production period.*
The total energy recovered, that is, the sum of these three sources, is \(11.32 \times 10^7\) J \((10.73 \times 10^{14}\) Btu\), or \(6.3 \times 10^6\) J \((6.0 \times 10^{13}\) Btu\) per well. This estimated energy is energy at the well head. Although methane is a resource that can be directly marketed, the thermal and mechanical energy will probably have to be converted to a more readily usable form of energy such as electricity. Additional large energy losses will result from this conversion.

The electrical power that can be produced over the 20-year production period from the thermal and mechanical energy components of the energy recovered at the well head can be estimated by assuming that the efficiency of converting thermal and mechanical energy to electrical energy is 5 and 70 percent, respectively. Thus, the power that can be produced with the 18-well development scheme is estimated to be 94 megawatts (MW), or 5.2 MW per well.

In the preceding analysis the well yields and the energy recoverable from a geopressed reservoir of the Gulf Coast were examined. The reservoir was referred to as typical and assumed to be representative of conditions in the geopressed zones of the Gulf Coast. Of the data used in the analysis, data on the hydrogeologic parameters of the reservoir were the least reliable. Questions might arise as to whether the assumed parameters are representative of the Gulf Coast geopressed reservoirs. To provide a basis for estimating well yields in reservoirs having parameters other than those assumed in the previous analysis and to determine the sensitivity of well yields to hydrogeologic parameters, the flow rate of wells was examined for a range of values of the parameters.

Examination of equation 1 indicates that, for a given drawdown and production period, the hydrogeologic parameters that affect the flow rate of a well are the transmissivity and the storage coefficient of the aquifer and the product of the hydraulic conductivity and specific storage of the confining beds. In a bounded aquifer, which requires the use of the method of images, the flow rate is also affected by the size of the aquifer. If wells in a large aquifer are placed on a square grid pattern, each well produces from the center of a square having the dimensions of the well spacing. The sides of this square act as impermeable boundaries, and therefore the flow rate of the well is affected by the size of the square, that is, the well spacing.

The flow rates of wells were calculated for different values of these four parameters: (1) transmissivity, \(T\); (2) storage coefficient, \(S\), (3) the product \(K'S_s'\) of the hydraulic conductivity and specific storage of the confining beds; and (4) the well spacing. As explained above, the well spacing can also be regarded as being the size of a square reservoir. The results of these calculations are shown on figures 10 through 13. The production period for these calculations was assumed to be 20 years, and a well diameter of 0.23 m (0.75 ft) was assumed. However, note that in these figures the results are given in terms of the flow rate per unit formation drawdown, that is, total drawdown less pipe friction losses. The well diameter is critical in the determination of pipe friction losses, but it has a negligible effect on the formation drawdown. Therefore, these figures can also be used to estimate the yield of wells having a different diameter.

As expected, figures 10 through 13 show that the flow rate per unit formation drawdown increases with all four of the parameters that were considered. The following conclusions, regarding the sensitivity of flow rates to hydraulic parameters, are drawn from a study of these figures.

1. At small well spacing, the flow rate is insensitive to the transmissivity of the aquifer and depends mainly on the storage coefficient and the confining-bed parameters.
Figure 10. Variation of the flow rate per unit 20-year formation drawdown with well spacing for hydraulic parameters of confining beds; $K'S_d$: $0.0 s^{-1}$.

* Does not include pipe friction losses in well.

Figure 11. Variation of the flow rate per unit 20-year formation drawdown with well spacing for hydraulic parameters of confining beds, $K'S_d$: $1.4 \times 10^{-18} s^{-1}$.

* Does not include pipe friction losses in well.
Figure 12. Variation of the flow rate per unit 20-year formation drawdown with well spacing for hydraulic parameters of confining beds, \( K'S' \): \( 1.4 \times 10^{-15} \text{ m}^{-1} \).

Figure 13. Variation of the flow rate per unit 20-year formation drawdown with well spacing for hydraulic parameters of confining beds, \( K'S' \): \( 1.4 \times 10^{-14} \text{ m}^{-1} \).
2. With increasing well spacing, the flow rate increases and becomes less sensitive to storage coefficient and confining-bed parameters and more dependent on transmissivity. As well spacing continues to increase, a maximum flow rate, which is mainly dependent on transmissivity, is reached. Thereafter, the flow rate remains constant regardless of well spacing.

3. The flow rate becomes less sensitive to confining-bed parameters as storage coefficient increases.

Assuming the reservoirs are larger than some minimum size, it is concluded that transmissivity is the most important hydrogeologic factor in the development of geopressed reservoirs. As stated in the second conclusion, the maximum flow rate per unit drawdown that can be obtained from a reservoir would depend on transmissivity. If the transmissivity of a geopressed reservoir is less than that needed to obtain an economic flow rate per unit drawdown, the reservoir could not be developed regardless of its size or the magnitude of the other hydrogeologic parameters.

ACKNOWLEDGMENT

The assistance provided by the staff of the U.S. Geological Surveys "Gulf Basin Hydrogeology Project", particularly Messrs. Paul H. Jones and Raymond H. Wallace Jr., respectively former and present chiefs of the project, in furnishing data and in answering the author's many questions on the geology of the Gulf Coast is gratefully acknowledged.

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