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REINJECTION OF FLUIDS INTO A PRODUCING GEOPRESSURED RESERVOIR

Topical Report

By
S. K. Garg

MASTER

October 1979

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Systems, Science and Software
La Jolla, California

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ABSTRACT

A reservoir simulator (MUSHRM) was employed to examine the effects of reinjecting the processed brine on the longterm performance of a representative geopressured reservoir. These calculations indicate that reinjection can be used to substantially increase methane and brine production. The results suggest that power requirements for reinjection pumps can be met by either burning approximately two-thirds of the produced methane (This may in some cases negate the benefits of reinjection as far as methane production is concerned.), or by using the heat of the produced brine (320°F) to generate electric power. Assuming that electric power produced from hot brine is used to reinject the processed fluids, it appears that reinjection is a viable production strategy for increasing methane recovery from some geopressured systems. The attractiveness of reinjection to recover methane increases with increasing formation permeability, and decreasing formation compressibility.

INTRODUCTION

The amount of fluid producible from a geopressured reservoir by primary pressure depletion depends principally on the total compressibility C_T .

$$C_T = \frac{1-\phi}{\phi} C_m + C_f$$

where

C_m = Uniaxial formation compressibility,

C_f = Fluid (water/methane) mixture compressibility, and

ϕ = Formation Porosity.

Formation compressibility C_m of geopressured sands ranges from 10^{-6} to $5 \times 10^{-6} \text{ psi}^{-1}$ (0.145×10^{-10} to $0.725 \times 10^{-10} \text{ cm}^2/\text{dynes}$) (see e.g., Swanson [1] Swanson and Osoba [2]). The production from a geopressured well will decline to zero when the fraction of total fluid produced is $C_T (P_i - P_h - P_f)$ where P_i is the initial reservoir pressure, P_h is the hydrostatic pressure, and P_f is the frictional pressure drop in the production tubing. Assuming an initial reservoir pressure of 11,600 psi (800 bars), an average $(P_h + P_f)$ of 6,600 psi (455 bars), a porosity of 0.2, and an average fluid compressibility C_f equal to $4 \times 10^{-6} \text{ psi}^{-1}$ ($0.59 \times 10^{-10} \text{ cm}^2/\text{dynes}$), the fraction of reservoir fluid producible by pressure depletion ranges

from 4 percent to 12 percent of the total fluid in place. The latter figures are upper limits of the producible resource since declining flow rates will cause abandonment of a well before the production rate reaches zero.

It is thus clear that the energy producible by pressure depletion represents only a very small fraction of the total energy contained in the geopressed fluid. Reinjection of the processed geopressed brines into the producing aquifer (if economically, and technically feasible) can be used to enhance total recoverable energy by maintaining pore pressure. Deep reinjection offers two additional benefits namely (1) disposing of large volumes of waste fluids in an environmentally acceptable manner and (2) alleviating ground surface subsidence. In the following we will only concern ourselves with energy (in particular methane) recovery. It must be recognized at the outset that reinjection presents serious difficulties. First of all, reinjection could only be accomplished after partial depletion of the reservoir, otherwise injection pressure would exceed the reservoir formation fracture pressure. But the depletion would cause reservoir compaction, and hence a reduction in formation permeability. To reinject brine into the formation under the partially depleted conditions, the surface pump must overcome (1) the frictional pressure loss P_f in the injection well (2) the drawdown Δp_w (pressure drop across formation face), and (3) the difference between the reservoir pressure and the hydrostatic pressure. The drawdown, Δp_w , is primarily a function of kh (permeability - thickness product), μ (fluid viscosity), and q (fluid production/injection rate). Not only is this term significant, it is likely to be considerably larger than its production value, due to increase in viscosity

with reduced temperature, as well as reduced permeability with compaction. The result is high surface pump pressure and multiple disposal wells [R. K. Swanson, personal communication, 1979]. The pumping energy required to reinject may render the energetics of the process unfavorable.

The purpose of this study is to investigate, in a quantitative manner, the feasibility of reinjection in geopressed sands. More specifically, we employ the reservoir simulator MUSHRM in its areal mode to examine the effects of reservoir formation permeability and compressibility on the reinjection process. MUSHRM calculations yield the amount of fluids (brine and/or methane) produced (or injected), and also the bottom hole production (or injection) well pressures. Pumping (energy) requirements for a particular bottom hole injection pressure and a given injection rate are calculated by a procedure suggested by R. K. Swanson [personal communication, 1979]. These calculations suggest that energy requirements for pumping can be met either (1) by installing a well-head generator to produce electricity from the hot brines or (2) by burning approximately two-thirds of the produced methane. Since current strategies for exploiting geopressed resources emphasize methane production, it is likely that the first alternative would be the preferred course for supplying pumping energy requirements. The present calculations clearly show that reinjection can be used to significantly enhance methane production; reinjection becomes increasingly attractive with increasing formation permeability and decreasing formation compressibility.

PRODUCTION/INJECTION CALCULATIONS

We consider a representative hypothetical bounded (no mass or energy flux across the boundaries) geopressed sandstone reservoir. The reservoir consists of a rectangular configuration with the following dimensions:

Length	=	2.05 miles (3.3 km)
Width	=	2.05 miles (3.3 km)
Thickness	=	246 feet (75 m)
Average Depth	=	15,585 feet (4.75 km)

A two-dimensional areal representation of the reservoir along with the numerical grid (11 x 11 Zones) is shown in Figure 1. The initial reservoir fluid temperature and pressure are assumed to be 320°F (160°C) and 11,600 psi (800 bars) respectively. The reservoir fluid is, furthermore, taken to be initially single phase hot brine (salinity = 0.05 by mass) saturated with methane (methane mass fraction = 0.005081 ~ 43.57 SCF/STB)*. The reservoir rock is assumed to have the following properties:

ρ_s (rock grain density)	= 164.4 lbm/ft ³ (2.633 gm/cm ³)
C_{vs} (heat capacity of rock grain)	= 0.23 Btu/lbm°F (0.963 x 10 ⁷ ergs/gm°C)

* Standard cubic feet (SCF) and stock tank barrel (STB) denote 1 ft³ of methane and 1 bbl of brine, respectively, at standard conditions (pressure = 1 atm ~ 14.7 psi, Temperature = 60°F). Specific volume of methane at standard conditions = 23.61 SCF/lbm (1.474 m³/kg). Specific volume of brine (salinity = 0.05 by mass) at standard conditions = 2.759 x 10⁻³ STB/lbm (9.670 x 10⁻⁴ m³/kg).

Figure 1

AN AREAL CROSS-SECTION OF THE HYPOTHETICAL BOUNDED RESERVOIR. THE RESERVOIR CROSS-SECTION IS REPRESENTED BY AN 11 x 11 RECTANGULAR MESH ($\Delta x = \Delta y = 984.3 \text{ ft} = 300 \text{ m}$). ○ - PRODUCTION WELL: ● - INJECTION WELLS.

$$K_s \text{ (rock grain thermal conductivity)} = 3.03 \text{ Btu/hr ft}^\circ\text{F} \\ (5.25 \times 10^5 \text{ ergs/sec cm}^\circ\text{C})$$

$$\phi_0 \text{ (initial porosity)} = 0.2$$

The instantaneous porosity (ϕ) and permeability (k) are given by the following relations:

$$\partial\phi/\partial t = (1 - \phi) C_m \partial p/\partial t$$

$$k = k_0 \exp \left[\frac{\phi - \phi_0}{(1 - \phi_0)(1 - \phi)} \right]$$

where

p = fluid pressure

t = time.

k_0 = absolute formation permeability at $\phi = \phi_0$

C_m = uniaxial formation compressibility.

The relative permeabilities (k_{rw} , k_{rg}) are shown as a function of free gas saturation (S_g) in Table 1. The total pore volume, brine in pores, and gas in place are $5.769 \times 10^9 \text{ ft}^3$ ($1.6335 \times 10^8 \text{ m}^3$), $9.641 \times 10^8 \text{ STB}$ ($15.85 \times 10^{10} \text{ kg}$) and $4.214 \times 10^{10} \text{ SCF}$ ($8.094 \times 10^8 \text{ kg}$) respectively.

Table 1
RELATIVE PERMEABILITIES

Free Gas Saturation (S_g)	Liquid Relative Permeability (k_{rw})	Gas Relative Permeability (k_{rg})
0	1	0
0.03	0.92	10^{-4}
0.3	0.2	0.3
0.5	10^{-4}	0.5
1	0	1

The reservoir is produced (by an 8 in (20 cm) diameter single well located at the center of the reservoir in zone $i = 6$, $j = 6$) at a constant rate of 39,400 STB/D (75 kg/s) until the bottom-hole pressure P_w (at datum $Z = -15,585$ feet) falls to 6,600 psi (455 bars $> P_h + P_f$); thereafter the bottom-hole pressure is maintained at 6,600 psi and the fluid production is allowed to decline.* The processed brine (salt mass fraction = 0.05, methane mass fraction = 0, temperature $T = 122^\circ\text{F} = 50^\circ\text{C}$) is reinjected into the geopressed reservoir through two 8 in (20 cm) diameter wells (see Figure 1 for location of reinjection wells). Reinjection rate per well is the lesser of 19,700 STB/D (37.5 kg/s) and the rate corresponding to a bottom-hole pressure P_{iw} of 11,600 psi (800 bars = initial reservoir pressure). In all the examples discussed below, the injection rate was always less than the maximum allowed rate of 19,700 STB/D.

* It is assumed here that two-phase flow occurs in the wellbore, and that sufficient gas percolates through the liquid column to reduce P_h such that $(P_h + P_f) < 6,600$ psi.

A series of three cases was considered to study the sensitivity of the reservoir behavior to variations in formation permeability and uniaxial compressibility (see Table 2). Table 3 shows the fraction of reservoir fluid producible by primary pressure depletion.

Table 2

INITIAL FORMATION PERMEABILITY k_0 AND UNIAXIAL FORMATION COMPRESSIBILITY C_m

CASE	ABSOLUTE FORMATION PERMEABILITY (k_0)	UNIAXIAL FORMATION COMPRESSIBILITY C_m
1	20 md ($20 \times 10^{-11} \text{ cm}^2$)	$5 \times 10^{-6} \text{ psi}^{-1}$ (0.725 x $10^{-10} \text{ cm}^2/\text{dynes}$)
2	10 md ($10 \times 10^{-11} \text{ cm}^2$)	$5 \times 10^{-6} \text{ psi}^{-1}$ (0.725 x $10^{-10} \text{ cm}^2/\text{dynes}$)
3	20 md ($20 \times 10^{-11} \text{ cm}^2$)	10^{-6} psi^{-1} (0.145 x $10^{-10} \text{ cm}^2/\text{dynes}$)

Table 3

FRACTION OF RESERVOIR FLUID PRODUCIBLE BY PRIMARY PRESSURE DEPLETION

<u>CASE</u>	<u>FLUID PRODUCIBLE</u>
1	12 percent
2	12 percent
3	4 percent

Figure 2 gives the bottom-hole pressure for Case 1 (high permeability, high compressibility case). Under primary pressure depletion, the bottom-hole pressure drops to 6,600 psi in a little more than five

Figure 2
BOTTOM-HOLE PRESSURE VERSUS TIME IN THE PRODUCTION WELL
FOR CASE 1 ($k_0 \sim 20$ md; $C_m \sim 5 \times 10^{-6}$ psi $^{-1}$)

years; with reinjection, the bottom-hole pressure can be maintained above 6,600 psi for approximately ten years. The instantaneous fluid production is shown in Figure 3. The fluid production rate, under primary depletion, falls below 5,300 STB/D (10 kg/s) in approximately twelve years; the calculation was terminated at this point. With reinjection, the fluid production can be maintained above 34,000 STB/D (65 kg/s) for thirty-two (time of the present calculation) or more years; significantly, no breakthrough of the cold reinjected fluid occurs during this period. The cumulative methane production with and without reinjection is shown in Figure 4. Reinjection leads to a significantly higher methane recovery over the no-injection case.

In Case 2 (low permeability, high compressibility case), the bottom-hole pressure with and without reinjection is essentially the same, both drop to 6,600 psi in less than one year (see Figure 5). The instantaneous fluid production rate (Figure 6) under primary depletion drops below 5,300 STB/D (10 kg/s) in approximately sixteen years. With reinjection the fluid production stabilizes at about 17,000 STB/D (33 kg/s); no breakthrough of the cold fluid is observed in thirty-two years. Once again, reinjection leads to significantly higher cumulative methane production over the no injection case (see Figure 7).

The bottom-hole pressure in Case 3 (high permeability, low compressibility) under primary depletion falls to 6,600 psi in a little more than one year; with reinjection, the bottom-hole pressure can be maintained over 6,600 psi for approximately three and one-half years (Figure 8). The fluid production rate, under primary depletion, declines to

Figure 3

INSTANTANEOUS FLUID PRODUCTION AND INJECTION RATES FOR
CASE 1 ($k_0 \sim 20$ md; $C_m \sim 5 \times 10^{-6}$ psi $^{-1}$)

Figure 4

CUMULATIVE METHANE PRODUCTION FOR CASE 1
($k_0 \sim 20$ md; $C_m \sim 5 \times 10^{-6}$ psi $^{-1}$)

Figure 5

BOTTOM-HOLE PRESSURE VERSUS TIME IN THE PRODUCTION WELL
FOR CASE 2 ($k_0 \sim 10$ md; $C_m \sim 5 \times 10^{-6}$ psi $^{-1}$)

Figure 6

INSTANTANEOUS FLUID PRODUCTION AND INJECTION RATES FOR
CASE 2 ($k_0 \sim 10$ md; $C_m \sim 5 \times 10^{-6}$ psi $^{-1}$)

Figure 7

CUMULATIVE METHANE PRODUCTION FOR CASE 2
($k_0 \sim 10$ md; $C_m \sim 5 \times 10^{-6}$ psi $^{-1}$)

Figure 8

BOTTOM-HOLE PRESSURE VERSUS TIME IN THE PRODUCTION WELL FOR
CASE 3 ($k_0 \sim 20$ md; $c_m \sim 10^{-6}$ psi $^{-1}$)

5,300 STB/D (10 kg/s) in approximately four years (Figure 9); with reinjection, the production rate can be maintained above 34,000 STB/D (65 kg/s) for thirty-two or more years. Once again, no breakthrough of the cold reinjected fluids occurs in thirty-two years. The cumulative methane production for this case is shown in Figure 10; reinjection yields over ten times the cumulative methane production obtained from primary depletion.

Table 4 summarizes the brine production (injection) and methane production data for all the three cases. In Case 1 (high permeability, high compressibility case), reinjection yields approximately four times the hot brine and methane as those produced by primary depletion. Reinjection appears to be somewhat less attractive in Case 2 (low permeability, high compressibility case); in this instance, reinjection gives only two and one half times the hot brine and methane as those produced by primary depletion. In the latter case, more hot brine (and methane) could be produced by having more reinjection wells; this may, however, be impractical due to the cost of additional reinjection wells. In Case 3 (high permeability, low compressibility case), reinjection leads to most dramatic improvement in reservoir performance; in this case, reinjection yields more than ten times the hot brine and methane as those produced by primary pressure depletion. Generally speaking, reinjection becomes more attractive with increasing formation permeability and decreasing formation compressibility. This is not really surprising in view of the fact that the pressure differential (between production and injection wells) required to maintain a given flow rate in the system

Figure 9

INSTANTANEOUS FLUID PRODUCTION AND INJECTION RATES
FOR CASE 3 ($k_0 \sim 20$ md; $C_m \sim 10^{-6}$ psi $^{-1}$)

Figure 10

CUMULATIVE METHANE PRODUCTION FOR CASE 3
($k_0 \sim 20$ md; $C_m \sim 10^{-6}$ psi $^{-1}$)

Table 4

SUMMARY OF BRINE AND METHANE PRODUCTION WITH AND WITHOUT REINJECTION, AND BRINE REINJECTION

Percentages denote fraction of the total brine (methane) in place.

CASE	PRIMARY PRESSURE DEPLETION			
	Cumulative Brine Produced	Average Brine Production Rate	Cumulative Methane Produced	Average Methane Content of Produced Brine
1 High k High C_m	1.10×10^8 STB $\sim 1.80 \times 10^{10}$ kg (11.4%)	25,000 STB/D for 12 years	4.13×10^9 SCF $\sim 7.94 \times 10^7$ kg (9.8%)	37.5 SCF/STB
2 Low k High C_m	1.00×10^8 STB $\sim 1.65 \times 10^{10}$ kg (10.4%)	17,100 STB/D for 16 years	3.70×10^9 SCF $\sim 7.11 \times 10^7$ kg (8.8%)	37.0 SCF/STB
3 High k Low C_m	3.65×10^7 STB $\sim 6.00 \times 10^9$ kg (3.8%)	25,000 STB/D for 4 years	1.35×10^9 SCF $\sim 2.60 \times 10^7$ kg (3.2%)	37.0 SCF/STB

Table 4 Continued

CASE	WITH REINJECTION					
	Cumulative Brine Produced	Average Brine Production Rate	Cumulative Methane Produced	Average Methane Content of Produced Brine	Cumulative Brine Injected	Average Brine Injection Rate
1 High k High C_m	4.22×10^8 STB $\sim 6.94 \times 10^{10}$ kg (43.8%)	36,100 STB/D for 32 years	1.51×10^{10} SCF $\sim 2.90 \times 10^8$ kg (35.9%)	35.8 SCF/STB	3.68×10^8 STB $\sim 6.05 \times 10^{10}$ kg (38.2%)	31,500 STB/D for 32 years
2 Low k High C_m	2.43×10^8 STB $\sim 4.00 \times 10^{10}$ kg (25.2%)	20,800 STB/D for 32 years	8.91×10^9 SCF $\sim 1.71 \times 10^8$ kg (21.2%)	36.7 SCF/STB	1.86×10^8 STB $\sim 3.05 \times 10^{10}$ kg (19.3%)	15,900 STB/D for 32 years
3 High k Low C_m	4.15×10^8 STB $\sim 6.83 \times 10^{10}$ kg (43.1%)	35,500 STB/D for 32 years	1.44×10^{10} SCF $\sim 2.77 \times 10^8$ kg (34.2%)	34.7 SCF/STB	4.07×10^8 STB $\sim 6.69 \times 10^{10}$ kg (42.2%)	34,800 STB/D for 32 years

declines with increasing permeability. Also it is to be noted that the fraction of fluid producible by primary pressure depletion decreases with decreasing formation compressibility.

"ENERGY COST" OF REINJECTION

In order to assess the feasibility of reinjection, it is necessary to compare the "energy cost" of reinjection with the "energy benefit" associated with the improved reservoir performance. To reinject brine into the formation, the surface pump must overcome the (1) frictional pressure loss P_f in the injection well and (2) the difference between the bottom hole pressure (P_{iw}) in the injection well and the hydrostatic pressure. Thus

$$P_{\text{injection}} = P_{iw} - P_h + P_f$$

For the reinjection cases discussed in the preceeding section, we have

$$P_{iw} = 11,600 \text{ psi (800 bars)}$$

$$P_h = 7,060 \text{ psi (487 bars)}$$

Assuming $P_f \sim 400$ psi, we obtain

$$P_{\text{injection}} = (11,600 - 7,060 + 400) \text{ psi} = 4,940 \text{ psi}$$

The pumping pressure is thus approximately 5000 psi.

We shall now calculate the energy required to pump 10,000 STB/D of brine at a surface pressure of 5,000 psi. (The following calculational procedure is due to R. K. Swanson [personal communication, 1979].) The handbook value for hydraulic horsepower (HHP) to pump 10,000 STB/D at 5,000 psi outlet pressure is:

$$\text{HHP} \approx 123 \times \frac{10,000}{24 \times 60} \sim 850$$

Hydraulic horsepower converts to brake horsepower (BHP) by dividing by the pump efficiency (typically 0.7). Thus

$$\text{BHP} = \frac{850}{0.7} \sim 1200$$

Brake horsepower (BHP) multiplied by 2545 BTU/hr/HP gives the pumping BTU/hr. Therefore,

$$\text{Pumping BTU/hr} = 1200 \times 2545 \sim 3.05 \times 10^6.$$

Pumping BTU/hr converts to fuel BTU/hr by dividing by the engine efficiency (a large gas turbine, for example, may show an efficiency of 28 percent). Thus

$$\text{Fuel BTU/hr} = \frac{3.05 \times 10^6}{0.28} \sim 10.9 \times 10^6$$

Fuel BTU/hr divided by STB/hr yields fuel BTU/STB.

$$\text{Fuel BTU/STB} = \frac{10.9 \times 10^6 \times 24}{10,000} \sim 26,000$$

Fuel BTU/STB converts to SCF gas/STB at the rate of 1000 BTU/SCF. Thus

$$\text{SCF gas/STB} \sim 26.$$

The above calculation indicates that approximately 26 SCF of methane will be required to inject one barrel of brine. In case it is desired to conserve methane, alternate energy sources must be employed to power the injection pumps. One alternative option (if economically

feasible) is to use the produced hot brine to generate electricity which in turn can be utilized to drive the injection pumps. The electric power required to inject 10,000 STB/D at a surface pressure of 5000 psi (assuming an electric drive efficiency of 0.9) is approximately:

$$MW(e) \sim \frac{BHP}{(0.9)} 7.46 \times 10^{-4} \approx \frac{1200}{0.9} 7.46 \times 10^{-4} \sim 1.0$$

Thus 1 MW(e) would be needed to inject 10,000 STB/D. For comparison purposes, we note that as much as 300,000 STB ($T \sim 300^{\circ}F$) of fluids per day would be required to supply one 25 MW(e) power plant [3]. Assuming that the power plant can be scaled down, the latter implies that 12,000 STB of hot brine would be needed to generate 1 MW(e).

Table 5 summarizes the pumping (energy) requirements for the three cases. In Cases 1 and 2, electric power produced from hot brine should be sufficient to reinject the processed fluids; however, for Case 3 electric power generated from hot brine would need to be supplemented by other sources. It should be remarked here that with a slightly increased conversion efficiency (say of the order of 15 percent), even in Case 3 power produced from hot brine should be adequate to operate the injection pumps. In any case, it appears that practically all of the electric power produced from hot brine will be required for reinjecting the processed fluids into the geopressured aquifer.

Provided methane is used to power the injection pumps, for Cases 1 and 2 very little methane (34 percent for Case 1, 10 percent for Case 2) in excess of that produced by primary depletion will be available for sale. The situation is more favorable in Case 3; in this instance reinjection yields over twice the methane produced by pressure depletion. In any event, it is worth emphasizing that substantial amounts of produced methane (approximately two-thirds) will be required to power the reinjection pumps.

Table 5

PUMPING (ENERGY) REQUIREMENTS FOR ELECTRIC AND METHANE DRIVERS

CASE	AVERAGE DAILY BRINE PRODUCTION (STB)	AVERAGE DAILY BRINE INJECTION (STB)	ELECTRIC DRIVE		METHANE DRIVE		
			Power Required Mw(e)	Power Production from Brine Mw(e)	Cumulative Methane Required, SCF	Cumulative Methane Produced, SCF	Methane Available for Sale, SCF
1	36,100	31,500	3.2	3.0	9.57×10^9	1.51×10^{10}	5.53×10^9
2	20,800	15,900	1.6	1.7	4.84×10^9	8.91×10^9	4.07×10^9
3	35,500	34,800	3.5	3.0	1.06×10^{10}	1.44×10^{10}	3.8×10^9

SUMMARY AND CONCLUSIONS

The present calculations indicate that reinjection can be used to substantially increase methane and brine production. The power requirements for reinjection pumps in the cases considered can be met by either burning approximately two-thirds of the produced methane (This may in some cases negate the benefits of reinjection as far as methane production is concerned.), or by using produced brine to generate electric power. Assuming that electric power produced from hot brine is used to reinject the processed fluids, it appears that reinjection is a viable production strategy for increasing methane recovery. The attractiveness of reinjection to recover methane increases with increasing formation permeability, and decreasing formation compressibility.

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