BC/14802-8 Vol III

IMPROVED RECOVERY FROM GULF OF MEXICO RESERVOIRS

Volume IV (of 4) - Comparison of Methane, Nitrogen and Flue Gas for Attic Oil Recovery

(Task 7, Simulate Gas Injection Processes Using N2, Flue Gas, and CO2 (Subtask 7.1, 7.2), Task 9, Perform Laboratory Research on Gas Injection Processes (Subtask 9.1, 9.2, 9.3)

Grant Number: DE-FG22-95BC14802

Louisiana State University
Department of Petroleum Engineering
Baton Rouge, LA 70803-6417

Award Date: February 14, 1995
Completion Date: October 13, 1995
Total Government Award: $1,266,667.00

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Final Report: Covering February 14, 1995 - October 13, 1996

Report Date: January 13, 1997

US/DOE Patent Clearance is <u>not</u> required prior to publication of this document.

Grant Number DE-FG22-95BC14802

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Volume IV - Comparison of Methane, Nitrogen and Flue Gas for Attic Oil Recovery

by Joanne Wolcott and Sara Shayegi

Abstract

Gas injection for attic oil recovery was modeled in vertical sandpacks to compare the process performance characteristics of three gases, namely methane, nitrogen and flue gas. All of the gases tested recovered the same amount of oil over two cycles of gas injection. Nitrogen and flue gas recovered oil more rapidly than methane because a large portion of the methane slug dissolved in the oil phase and less free gas was available for oil displacement. The total gas utilization for two cycles of gas injection was somewhat better for nitrogen as compared to methane and flue gas. The lower nitrogen utilization was ascribed to the lower compressibility of nitrogen.

Executive Summary

Gas injection for attic oil recovery was modeled in sandpacks to compare the process performance characteristics of three gases, namely methane, nitrogen and flue gas. Flue (or engine exhaust) gas is a product of combustion, and is primarily nitrogen mixed with 10-20% CO_2. The sandpacks were mounted vertically, and had ports located at both ends and midway between the ends. The pack was initially saturated with water and then flushed with a live oil from top to bottom until no additional water was produced. After the oil flush, water was injected into the bottom of the pack and oil was produced from the center port to simulate primary oil production in a bottom water-drive reservoir. The attic oil recovery process was initiated by injecting gas into the center port. As gas was injected, water was produced from the bottom of the pack to maintain the pack at the desired pressure. After gas injection, the pack was shut-in for ten days to allow time for gas to migrate upward and displace oil downward. When the pack was reopened for production, water was injected into the bottom of the pack while oil was produced from the center port. After oil production ceased, a second cycle of gas was injected and the pack was again shut-in for five days. A third cycle of nitrogen was injected using the same procedure as described for the second cycle. The packs were maintained at 1000 psig and 140 ^{o}F during the entire experimental procedure. All of the experiments were performed under similar conditions to facilitate comparisons.

The ultimate oil recovery after two cycles of gas injection was the same for all of the gases tested. Injection of extra gas and allowing a longer period for gravity segregation did not significantly reduce the residual oil saturation. Nitrogen and flue gas recovered oil more rapidly than methane. The low first cycle recovery with methane was attributed to over 30% of the first cycle methane slug becoming dissolved in the oil phase, while no nitrogen and only 11% of the first cycle flue gas slug was dissolved. Dissolved gas occupied significantly less pore space than the free gas so less attic oil was displaced. Methane and the CO_2 in flue gas will dissolve in reservoir oil if the oil is not initially saturated with respect to gas, or if the reservoir pressure increases due to gas injection.

The total gas utilization for two cycles of gas injection was somewhat better for nitrogen as compared to methane and flue gas. The lower nitrogen utilization was ascribed to the lower compressibility of nitrogen as compared to methane and the CO_2 in flue gas, and the inadvertent injection of a slightly larger gas slug in the second flue gas cycle. Based on gas compressibilities, nitrogen would be less expensive to employ for attic oil recovery than methane or flue gas if the gas prices per Mscf of gas injected were equal.

INTRODUCTION

In inclined, water-drive reservoirs, substantial quantities of oil may be located updip from the structurally highest producing well. Most of this updip or "attic" oil will remain unrecovered at the end of primary production. Sidetracking or drilling new wells to recover attic oil is usually uneconomic due to the limited amount of oil-in-place and difficulties in adequately defining reservoir boundaries. In many cases, gas injection is the only viable option for the recovery of attic oil.

Gas injection for attic oil recovery was initially implemented in 1950 in the West Hackberry Field in south Louisiana.[1] Since that time, the process has been employed in numerous reservoirs, primarily those located around salt domes. The flanks of salt domes are a highly-faulted area which results in small reservoirs containing only one or a limited number of wells. In addition, these reservoirs characteristically have steep dip angles and active water drives.

The attic oil recovery process depends on the gravity segregation of gas and oil. A slug of gas is injected into the reservoir, then the well is shut-in, and sufficient time is allowed for gas to migrate updip and displace oil down towards the production well. Finally, production is resumed and the displaced oil is produced. This cycle of injection, shut-in period, and production may be repeated until oil production reaches its economic limit. The process is usually implemented as a single-well injection/production process, however it is also possible to use separate wells for injection and production.

Although gas injection for attic oil recovery has been successfully applied in numerous fields,[1-4] the literature on the process is sparse. The primary sources for process guidelines are two reports issued by Combs and Knezek[1] and by Morse and Strickland.[5] The most critical process parameters, as defined by these authors, are the gas volume injected and the gas injection rate. If the volume of gas injected is too large or if gas is injected too rapidly, oil and gas may be pushed downdip of the production well. When oil is displaced below the original oil/water contact, some oil will be permanently lost as a residual saturation in the water zone. If gas migrates downdip of the production well, some gas will also be lost as a residual saturation. This lost gas will not be available for recycling into the well and, additionally, will not be able to contribute to oil recovery.

Combs and Knezek[1] assumed that the maximum rate at which a gas could be injected without fingering downdip was limited by the gas segregation rate, and derived an equation based on an idealized one-well reservoir. The maximum injection rate is given the equation

$$q_{s(max)} = 3x10^{-4} klh\,(\sin\alpha)\left(\frac{\gamma_o - \gamma_g}{\mu_{os} B_o}\right)$$

where $q_{s(max)}$ is the maximum segregation rate in terms of the oil flow rate in STB/D. The other terms are defined in the NOMENCLATURE section of this report.

Morse and Strickland[2] used computer simulation to evaluate critical process parameters. They found that gas migration was strongly affected by the gas injection rate in reservoirs above bubble point pressure, but was independent of gas injection rate in reservoirs below bubble point pressure where a gas cap had formed during initial production. In either case, the gas volume injected was a critical

parameter. They proposed that the maximum volume of gas that could be injected without displacing oil below the original oil/water contact was equal to the reservoir volume of water that could be moved from the watered-out zone (above the original oil/water contact) into the water zone (below the initial oil/water contact).

In the past, methane has usually been employed as the injection gas, although the use of air,[6] and liquid solutions that generate nitrogen gas *in-situ*[7] have been mentioned in the literature. In addition, Magnie and Terry[8] proposed the use of a special gas mixture that is generated by the combustion of coal and contains 10.5% hydrogen, 22.0% carbon monoxide, 5.7% carbon dioxide, 58.8% nitrogen, and 3% methane. This gas mixture can be used to estimate the size of the attic as based on the composition of the recovered gas and the solubility capacity of each gas in the oil, besides recovering oil from the attic. The only comparison of the effectiveness of different injection gases was made by Harvey.[9] He compared the migration rates of methane and nitrogen using a mathematical model. The results of the computations suggested that the segregation rate for methane was only slightly higher than for nitrogen under most of the conditions considered in the study.

The study outlined in this report was performed to compare the process performance characteristics of three gases, namely methane, nitrogen and flue gas. Flue (or engine exhaust) gas is a product of combustion, and is primarily nitrogen mixed with about 10-20% CO_2. Gas injection for attic oil recovery was modeled in sandpacks using live oil at 1000 psig and 140 °F. All of the experiments were performed under similar conditions to facilitate comparisons.

EXPERIMENTAL MATERIALS AND METHODS

The apparatus employed in the experiments is depicted in Figure 1. Two sandpacks were used in the study. The sandpacks were housed in cylindrical, stainless steel core holders that were mounted vertically, and had ports located at both ends and midway between the ends. Sandpack A was used in the methane, nitrogen and second flue gas experiments; sandpack B was used for the first flue gas experiment. Both sandpacks were 0.25 feet in diameter; sandpack A was 9.5 feet long, and sandpack B was 9.67 feet long. The sandpacks were prepared by pouring Ottawa sand (F-95 grade) into distilled, deoxygenated water contained in the coreholder. The holder was vibrated to insure a tight, uniform pack. The sand temperature was controlled by circulating heated fluid through brass tubing coiled around the coreholder, and the system was insulated to minimize heat losses. Ruska pumps were used to inject oil, water and gas into the sandpack. Water was injected directly into the sandpack, while transfer vessels were used to inject oil and gas. The sandpack outlet was connected to a sight glass for visual observation of produced fluids at core pressure, and a back pressure regulator was used to maintain the desired core pressure. Pressures at the injection and production ports were monitored using digital meters and Bourdon tube gauges, and a digital meter was used to measure the pressure drop across the sandpack. Produced fluids were routed into a separator which was maintained at atmospheric pressure. Oil and water were collected and measured in the separator burette, while gas was routed to a gasometer. The sand porosity was estimated to be 36% by averaging values obtained from smaller packs prepared in the same fashion.

At the beginning of each experiment, the absolute permeability of the sandpack was determined by pumping water at a constant flow rate and pressure drop across the pack. The absolute permeability was measured at operating conditions of 1000 psig and 140 °F, and these conditions were maintained throughout the entire experiment. The water-saturated pack was flushed with oil by injecting oil into

the top of the pack and producing water from the bottom. This process was continued until the water-cut was less than 5%. After the sandpack was saturated with oil, water was injected into the bottom of the pack and oil was produced from the center port to model water-drive production from a well located in the center of an inclined reservoir as depicted in Figure 2. Water displacement was continued until the oil-cut was less than 5% to establish a residual oil saturation in the bottom portion of the pack. Water and oil were injected at a rate of 160 cc/hr. The water was distilled water that was deoxygenated by boiling. The oil was a live oil prepared by mixing crude obtained from the South Marsh 73 Field (B65G Reservoir) with excess methane in a transfer vessel maintained at sandpack conditions. The stock-tank oil density and viscosity at 75 °F were 0.856 g/cc and 12.37 cp respectively. The solution gas-oil ratio (GOR) of the live oil used in runs 1-7 was 45 scf/STB; the solution GOR of the live oil used in runs 8 and 9 was 58.9 scf/STB. An unreasonably long time was required for the oil to become completely saturated with methane gas because the available equipment was not designed for efficient mixing. Because of limited storage capacity for live crude and scheduling requirements, it was not possible to wait the required length of time for complete saturation of the oil with methane. Therefore, experiments were conducted with undersaturated oil. Production from the live oil transfer vessel was monitored using a sight glass. Excess gas was routed away from the sandpack so that only liquid was introduced into the sand.

The attic oil recovery process was initiated by injecting gas into the center port of the sandpack. Three different injection gases were used: nitrogen, methane and flue gas. The flue gas was prepared by mixing 15 vol% CO_2 with nitrogen at 1000 psi and 140 °F. (Note: this is equivalent to mixing about 20 vol% CO_2 with nitrogen at standard conditions since CO_2 is more compressible than N_2.) All of the gases used in the study had purities of 99.5% or better. The gas slug volume used in the first cycle was designed to be 70% of the movable water volume. The movable water volume was assumed to be equal to the volume of oil displaced by water during the waterflood. The gas slug used in the second cycle was one-half the size of the first cycle slug. Sandpack conditions at the initiation of gas injection and gas slug sizes in terms of pore volume at operating conditions and cubic feet at standard conditions are given in Table 1.

As gas was injected, water was produced from the bottom of the pack to maintain the desired pressure. Gas was injected at a rate of about 170 cc/hr. The sight glass at the bottom of the sandpack was monitored, and only brine was displaced out of the pack. After gas injection, the sandpack was shut-in for ten days to allow time for gas to migrate upward and displace oil downward. When the sandpack was reopened for production, water was injected into the bottom of the pack while oil was produced from the center port. The water injection rate was 96 cm^3/hr. Oil production was terminated when the water-cut reached 95%. After oil production ceased, a second cycle of gas was injected and the pack was shut-in for 5 days. After the shut-in period, oil was produced in the same manner as described for the first cycle. A third cycle of nitrogen injection was performed using the same procedure as described for the second cycle. The experimental results are presented in Table 2.

EXPERIMENTAL RESULTS AND DISCUSSION

The results of the first flue gas experiment (runs 5 and 6) could not be directly compared with those of nitrogen and methane because waterflood oil recovery results indicated that channels had formed in sandpack B. The waterflood oil recovery for the first flue gas experiment was 35.8% IOIP which was considerably lower than the waterflood oil recoveries of 48.5% IOIP and 43.8% IOIP obtained

in the nitrogen and methane experiments respectively. The lower waterflood oil recovery in sandpack B was indicative of poor sweep efficiency which suggested that channeling was more prevalent in sandpack B. Because the results of the first flue gas experiment were questionable, a second flue gas experiment (runs 8 and 9) was conducted in the same pack that had been used for the nitrogen and methane experiments. The waterflood oil recovery for the second flue gas experiment was 45.5% IOIP, a value close to those obtained in the nitrogen and methane experiments.

The ultimate oil recovery after two cycles of gas injection was the same for nitrogen, methane and flue gas. At the end of second cycle production, the residual oil saturations, S_{org}, for all three experiments were 16%. However, nitrogen and flue gas recovered significantly more oil in the first cycle of gas injection as compared to methane. This difference was attributed to the fact that the live oil used in the experiments was not completely saturated with methane, and 30% of the first cycle methane slug dissolved in the oil phase. No nitrogen and only 11% of the first cycle flue gas slug dissolved in the oil phase. The dissolved methane occupied significantly less pore space than the free gas so less attic oil was displaced. In contrast, methane recovered significantly more oil in the second cycle of gas injection as compared to nitrogen or flue gas. This was not unexpected since the second cycle target oil saturation was higher for methane than for nitrogen or flue gas.

The gas utilization factor, the volume of gas injected in terms of Mscf per STB of oil recovered, is used to assess process efficiency. Although all of the gases recovered equal quantities of oil after two cycles of gas injection, the total nitrogen utilization, 0.476 Mscf/STB, was somewhat better than that of methane, 0.575 Mscf/STB, and flue gas, 0.563 Mscf/STB (Table 2). Methane and the CO_2 in flue gas are more compressible than nitrogen; thus, a smaller volume of nitrogen at standard conditions occupied the same pore space at experimental conditions as methane and flue gas. The inadvertent injection of a slightly larger gas slug in the second cycle of the flue gas experiment also contributed to the higher flue gas utilization. Based on the gas compressibilities, nitrogen would be less expensive to employ for attic oil recovery than methane or flue gas if the gas prices per Mscf of gas injected were equal.

A third cycle of nitrogen gas was injected to determine if additional benefits could be gained by continued nitrogen injection. The gas slug size and shut-in period were the same as used in the second cycle. Unlike the previous cycles, a large quantity of free gas and water were produced prior to production of a small amount of oil; about 76% of the injected gas slug was recovered during the production stage. As the quantity of oil recovered was low, only 3.2% in terms of waterflood residual oil, and the gas utilization was high, 3.36 Mscf/STB, the third cycle was considered to be unnecessary for adequate oil recovery and wasteful of gas resources.

As mentioned earlier, some of the injected gas dissolved in the oil phase during the methane and flue gas experiments. The dissolution of methane and flue gas in the oil was confirmed by sight glass observations and measurements of the produced fluid GOR. No free gas was observed in the sight glass connected to the sandpack outlet during the first or second cycle production stage of any experiment. In addition, the gas-oil ratios remained constant throughout all of the first cycle production periods, and only increased slightly near the end of second cycle production. Although little or no free gas was produced in any experiment, solution gas was produced as shown by the GORs of the produced fluids in Table 2.

The producing GOR for all three cycles of the nitrogen experiment was 45 scf/STB, the same as the solution GOR of the live oil initially injected into the sandpack. Thus, little or no, nitrogen dissolved in the oil under the conditions of the experiment. In contrast, the producing GORs for the first and second cycles of the methane experiment were 122 and 158 scf/STB respectively, while the producing GORs for the first and second cycles of the flue experiment were 85 and 134 scf/STB respectively. The live oil used in the flue gas experiment contained more methane, 58 scf/STB, than the oil used in the nitrogen and flue gas experiments. The differences in the first and second cycle GORs of the methane and flue gas experiments were attributed to additional gas dissolving in oil over time. The second cycle GOR for the methane experiment, 158 scf/STB, was close to the solution GOR of 160 scf/STB estimated for oil saturated with methane at experimental conditions using Standing's correlation.[10] Apparently, an extended length of time was required for equilibration of gas and oil in the sandpack environment.

Material balance calculations revealed that a total of 28% of the injected methane and 14% of the injected flue gas volume at standard conditions had dissolved in the oil phase by the beginning of second cycle production. As CO_2 comprised 20 vol% of the total flue gas slug at standard conditions and CO_2 was the only component of flue gas that dissolved in the oil under the conditions of the experiment, the amount of flue gas that dissolved was equivalent to 70% of the injected CO_2. Methane would be expected to dissolve in reservoir oil if the oil was initially undersaturated with respect to methane, or if the reservoir pressure increased due to gas injection. CO_2 is more soluble in oil than methane, but the total amount of flue gas that could dissolve in oil would be limited by its low CO_2 concentration.

The higher quantity of dissolved gas in the methane and flue gas experiments could affect the oil recovery process in several ways. An increase in the amount of dissolved gas would reduce the density and viscosity of the oil and swell the oil. In addition, there would be less free gas available to displace oil. The methane experiment was analyzed to determine the impact of each of these factors on oil recovery. The effects of dissolved CO_2 would be similar to those described for methane.

As indicated in the maximum injection rate equation, the oil segregation rate is directly proportional to the density difference between the oil and gas, and inversely proportional to the oil viscosity. The estimated live oil viscosities and densities for methane-oil ratios of interest are listed in Table 3. Since the change in viscosity outweighed the change in density, the overall effect of added solution gas would be an increase in the gas-oil segregation rate. However, as little, or no, free gas was produced during any of the experiments, sufficient time was apparently allowed for segregation, and the amount of oil produced in these experiments was not limited by the segregation rate. It is likely that the viscosity effect would become more noticeable as the time allowed for segregation is reduced. In the field, where shorter shut-in periods would be more economically attractive, an increase in the segregation rate would have greater importance.

The increase in oil volume due to dissolved gas was small as indicated by the change in formation volume factors, B_o, shown in Table 3. In run #1, the solution GOR changed from 45 to 122 scf/STB after gas injection. This change in solution GOR caused the oil saturation after first cycle gas injection, S_{orw}, to change from 0.444 to 0.457, an increase of 2.8%. The loss of free gas induced by this same change in solution GOR was considerably larger. In run #1, 3.23 scf methane were injected into a sandpack containing live oil with a solution GOR of 45 scf/STB. The fraction of pore space

occupied by the gas slug at run conditions and assuming that none of the gas became dissolved in the oil was estimated to be 0.293 PV. When the solution GOR of the oil phase increased from 45 to 122 scf/STB, the fraction of pore space occupied by the free gas was reduced to 0.200 PV, a decrease of 32%.

It was evident from experimental results and observations that the gas slug sizes and shut-in periods used in these experiments were excessive. Consequently, the indicators of process performance, namely the measured oil recovery efficiencies and gas utilization factors, were not sensitive to factors that caused small to moderate changes in the gas slug size or gravity drainage rate. It is likely that larger differences would have been observed in the experimental results if the gas slug size and shut-in periods were minimized; however, sufficient information was not available to accurately predict optimum slug sizes or shut-in periods. In addition, it is anticipated that reservoir pressure would dramatically affect process performance, but only one reservoir pressure was examined in this study. Further experiments are needed to provide a more complete comparison of the injection gases examined in this study under different conditions of reservoir pressure, solution gas content, gas slug size, and time allowed for gravity drainage.

CONCLUSIONS

1. The ultimate oil recovery after two cycles of gas injection was the same for nitrogen, methane and flue gas, under the conditions of the study. Injection of extra gas and allowing a longer period for gravity segregation did not significantly reduce the residual oil saturation.

2. Nitrogen and flue gas recovered oil more rapidly than methane, under the experimental conditions of the study. The low first cycle oil recovery with methane was attributed to the fact that over 30% of the first cycle methane slug dissolved in the oil phase, while no nitrogen and only 11% of the first cycle flue gas slug dissolved in the oil phase.

3. The total gas utilization over the first and second cycles was somewhat better for nitrogen as compared to methane and flue gas. The higher methane and flue gas utilizations were ascribed to the higher compressibilities of methane and the CO_2 in flue gas as compared to nitrogen, and the inadvertent injection of a slightly larger gas slug in the second flue gas cycle.

4. Methane and the CO_2 in flue gas dissolved in oil under the conditions of the experiment. These gases would be expected to dissolve in oil that was not initially saturated with respect to gas or if the reservoir pressure increased due to gas injection. The dissolved gas occupied significantly less pore space than the free gas so less attic oil was displaced.

5. It was evident from experimental results and observations that the amount of gas injected and the time allowed for gas-oil segregation in this study were excessive. Consequently, the measured oil recovery efficiencies and gas utilizations were not very sensitive to factors that could become important if the gas slug size and shut-in time were minimized.

NOMENCLATURE

B_o oil formation volume factor, reservoir bbl/STB
E_{rw} fraction of initial oil-in-place recovered by initial water influx

E_{rg} fraction of waterflood residual oil recovered by gas injection
GOR gas-oil ratio, scf/STB
h effective thickness of formation, ft
IOIP initial oil-in-place, bbl
k absolute permeability, md
L width of reservoir along strike, ft
PV pore volume
S_{gr} residual gas saturation after oil production
S_{oi} initial oil saturation
S_{org} residual oil saturation after gas injection
S_{orw} residual oil saturation after initial water influx
STB stock-tank barrel
V_{pr} fraction of pore volume occupied by gas at reservoir conditions
α dip of sand, degrees
γ_o, γ_g specific gravity of oil and gas, dimensionless
μ_{os} viscosity of saturated oil at reservoir conditions, cp

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TABLE 1
DESCRIPTION OF GAS SLUG AND SANDPACK CONDITIONS

			Sand	PV	Gas Volume		Perm	S_{oi}	S_{orw}	E_{rw}
Run #	Cycle	Gas	Pack	cm^3	V_{pR}	scf	(darcy)	%	%	%
1	1	CH_4	A	4760	0.293	3.2	2.4	86.1	44.4	48.4
2	2	CH_4	A		0.146	1.6				
3	1	N_2	A	4760	0.293	3.0	2.6	83.1	46.7	43.8
4	2	N_2	A		0.146	1.5				
7	3	N_2	A		0.146	1.5				
5	1	Flue	B	4987	0.280	3.1	2.6	85.1	54.6	35.8
6	2	Flue	B		0.140	1.6				
8	1	Flue	A	4760	0.293	3.1	2.7	81.2	44.3	45.5
9	2	Flue	A		0.159	1.7				

TABLE 2
EXPERIMENTAL RESULTS

			GOR	S_{gr}	S_{org}	E_{rg}		Utilization, Mscf/STB	
Run #	Cycle	Gas	scf/STB	%	%	Cycle	Total	Cycle	Total
1	1	CH_4	122	20	29	34.5		0.705	
2	2	CH_4	158	32	16	29.0	64.0	0.420	0.575
3	1	N_2	45	29	25	46.0		0.459	
4	2	N_2	45	44	16	20.6	66.6[a]	0.513	0.476[a]
7	3	N_2	45	47	14	3.2	69.6[b]	3.360	1.606[b]
5	1	Flue	63	25	38	29.6		0.622	
6	2	Flue	100	35	28	19.3	48.9	0.475	0.564
8	1	Flue	85[c]	23	23	47.9		0.495	
9	2	Flue	134[c]	31	16	17.1	65.0	0.755	0.563

a. Total value for first and second cycles.

b. Total value for all three cycles.

c. The solution GOR of the live oil used in the second flue gas experiment (runs 8 and 9) was 58.9 scf/STB. The live oil used in the other experiments had a solution GOR of 45 scf/STB.

TABLE 3
OIL PROPERTIES FOR VARIOUS METHANE/OIL RATIOS

GOR	Density	Viscosity	B_o
scf/STB	g/cm^3	cp	res bbl/STB
0	0.82	3.8	1.04
45	0.82	2.9	1.05
122	0.80	2.0	1.08
158	0.80	1.9	1.09

Density and viscosity values for gas-free oil were measured at 65 °C (149 °F) and atmospheric pressure. All other density and viscosity values were estimated for run conditions of 1000 psig and 140 °F.[10]

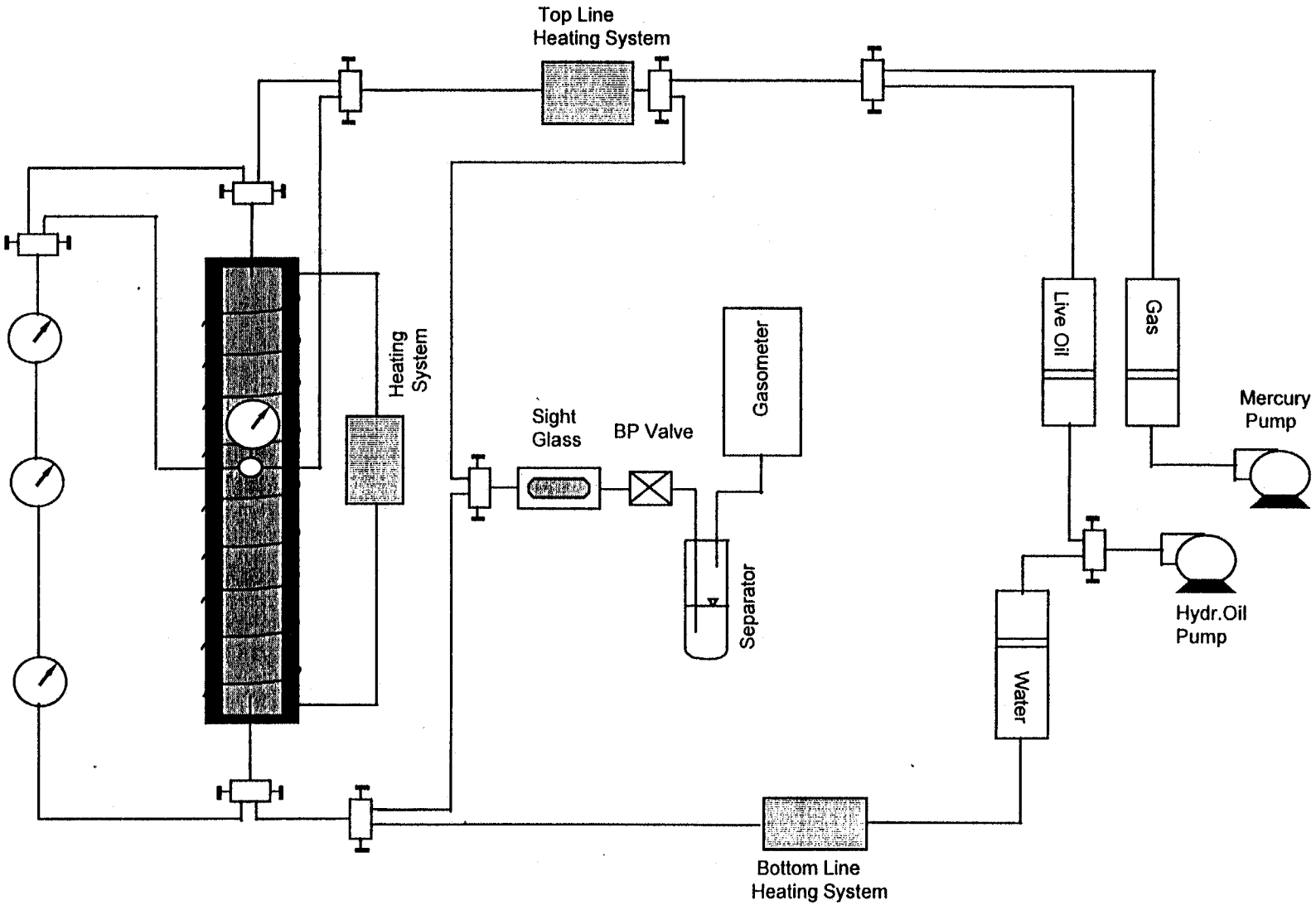

Fig. 1 EXPERIMENTAL APPARATUS

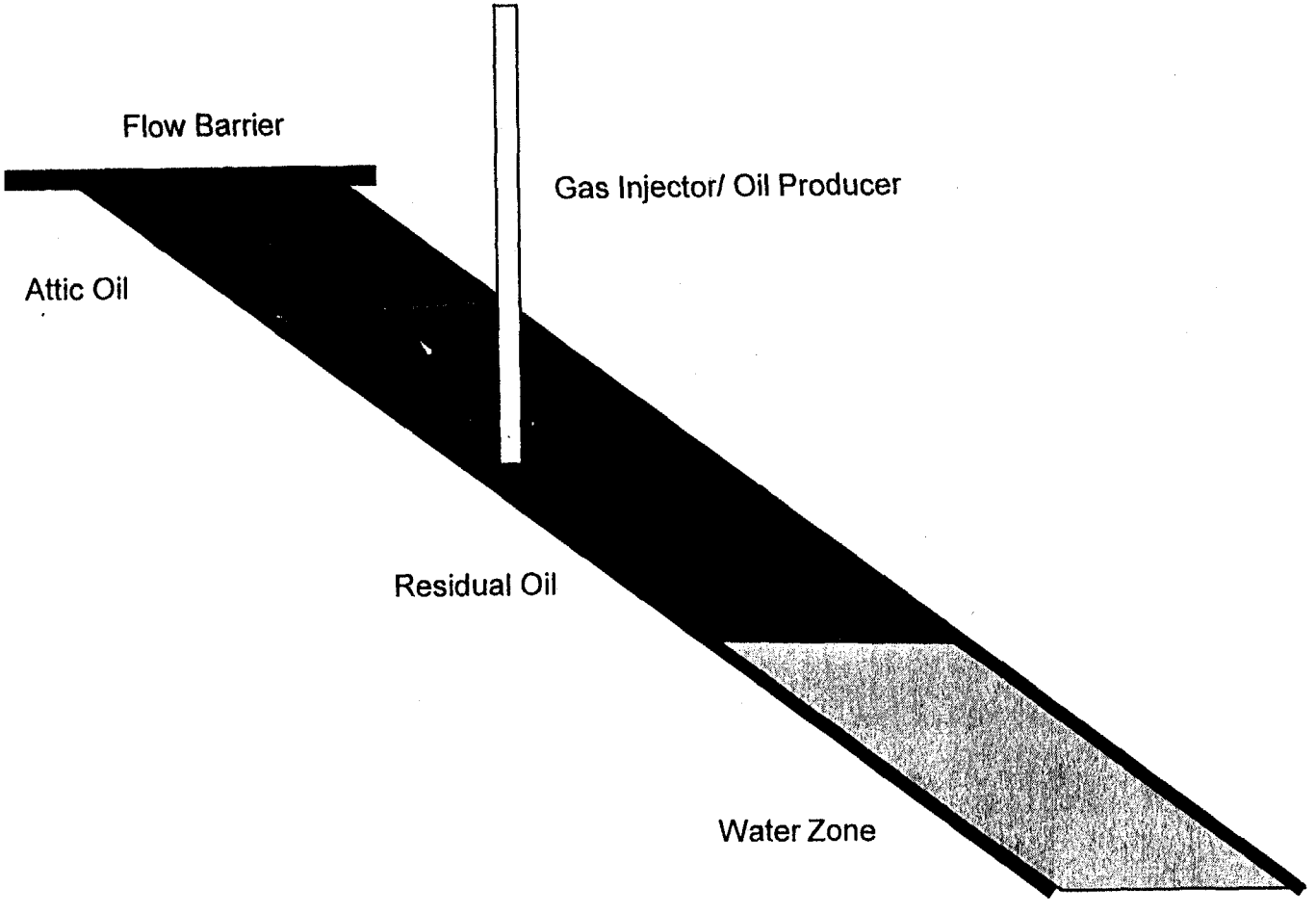

Fig. 2 RESERVOIR CONTAINING ATTIC OIL