038 BU ATTIFEL FIELD, LIBYA — GAS INJECTION PROJECT, LABORATORY APPROACH

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Abstract

Bu Attifel field, discovered in 1967, is a giant oil reservoir located in the Sirte Basin of the Libyan desert. It produces volatile oil (41°API) from continental sandstones, 4200 m s.s.l. deep. The crude is paraffinic with a wax content of 36.7% and a high pour point temperature (39°C).

A pressure maintenance project by water injection started in 1974 with 9 injectors, increased to 17 later on. The current oil rate is 23,000 m³/day and the average water cut is some 29%. The final recovery is expected to be about 50%.

Since the water production considerably increased in the last five years, the feasibility of an EOR tertiary process is under study to improve the final oil recovery. Up to now the miscibility of three different gases (carbon dioxide, lean gas and enriched gas) with the reservoir oil was evaluated through lab experiments performed at the average reservoir temperature (145°C). At current reservoir pressure (about 40.5 MPa) the lean gas enriched with liquefied petroleum gas (LPG), according to the ratio of 290.3 m³/MSm³, resulted the most efficient solvent and was selected for future field application.

Introduction

Bu Attifel field is located in the Sirte Basin, about 400 km SE of Benghazi. It was discovered in 1967 and went on stream in 1972. The present oil rate, 20,000 m³/day flowing from 35 wells, is steadily decreasing from an average plateau of 23,800 m³/day maintained until 1993. A peak of 27,000 m³/day was recorded in 1990-92 after an infill drilling campaign. Up to now the cumulative oil production amounts at some 33% of the original oil in place (OOIP), and the expected final recovery is estimated at about 50%.

A water injection project started in 1974 with 9 injectors (*Ref.1* and *Ref.2*) for pressure maintenance purpose. A daily rate of 55,600 m³ of water is presently injected through 17 wells, and the field water cut has already reached 29%.

The rate decline and mature status of the field led Agip Oil's management to investigate the feasibility of a tertiary gas injection project to improve the final oil recovery. Carbon dioxide, lean gas and enriched gas were tested with the aim of finding out the most efficient solvent, miscible with the oil at the current reservoir conditions.

Reservoir Characteristics

The reservoir is a West to East elongated horst, approximately 17 km long and 2+4 km wide, limited on all sides by faults and with a low dip of 5° to the North. Its OOIP is estimated at some 620 Mm³.

The oil production comes from the Upper Nubian sandstones, a formation of a Lower Cretaceous age whose depth goes from 3886 to 4336 m s.s.l.

The oil bearing rock is a fine to coarse grained sandstone with interbedded shale and shaly-siltstones; it ranges in net thickness from 75 to 250 m. The porosity (8%÷16%) is intergranular and was preserved at rather good value by a syntaxial siliceous cementation which reduced the effect the compaction after the deposition. The horizontal permeability spans from a few md to more than 1000 md, and the k_v/k_h ratio ranges from 0.48 to 1.23. The initial water saturation, which correlates quite well with the local porosity, averages 16%.

At discovery, a bubble point variation with the depth was recognized, but the oil resulted undersaturated at the initial pressure (47.6 MPa) through all the field. The basic volumetric properties and an average composition are listed in **Tab. 1** and **Tab. 2**, respectively.

The stock-tank crude has a 41°API gravity; its base is paraffinic at high wax content (36.7%) with an Upper Pour Point of 39°C.

Representative gas and oil samples for the study were collected at the separator of the well A-17 (perforated interval: 4137-4232 m). They were recombined according to a gas-oil ratio of 245 Sm³/m³ to obtain a system saturated at 40.5 MPa at 145°C, i. e. at the current field conditions. In fact, a partial reservoir voidage lowered the initial pressure below the original average bubble point.

Experimental procedures

The effect of each selected gas, when contacting the reservoir oil, was investigated both at static and dynamic conditions.

In the first case, the volumetric behavior of several gas/oil mixtures, representing a wide range of different "injected gas-oil ratios" (IGOR, defined as the volume of gas - referred to standard conditions - added to a unit volume of reservoir oil at the original bubble point), was studied in a double windowed PVT cell. Each mixture was expanded at constant composition for measuring its saturation pressure and its "swelling factor". This last parameter was defined as *"the volume of the system at a given pressure divided by the volume of the reservoir oil at the original saturation pressure"*. Furthermore, each system was identified as "oil" or "condensate", according to the volumetric behavior observed when the pressure was lowered below the saturation point.

The dynamic experiments were performed in a slim tube equipment (Fig. 1), for finding out either the Minimum Miscibility Pressure (MMP) (Ref.3) or the Minimum Miscibility Enrichment (MME) (Ref.4). The slim tube had a cross-sectional area of 38 mm² and a length of 18.23 m; the pore volume of the filling sand was 322 cm³ and the absolute permeability to air 3.95 μm².

The rig consisted of two pumps for displacing either the stock-tank or the reservoir oil held in two high pressure vessels. In the thermostatic air bath were put:

- a high pressure bottle filled with gas;
- the slim tube;
- an optical cell to check the colour variations and the refraction index of the effluent;
- a high pressure densimeter to measure the density of the produced fluid.

Gas and liquid phases were separated in a vessel, working at 15°C and atmospheric pressure. A mass-flowmeter continuously recorded the flow rate of the separated gas, whose chemical composition (up to C₈) was analysed every half an hour by a gas chromatograph set on line. The liquid samples were collected in glass bottles and weighed, because the high pour of the crude point did not allow any reliable volume measurements.

All the tests were carried out at a displacement velocity of 5.0 m/day (equivalent rate: 3.9 cm³/h), and at least 1.2 pore volume of gas was always injected during each experiments.

Phase behavior of oil/carbon dioxide mixtures

Fig. 2A shows the volumetric behavior of the reservoir oil swollen with CO₂ at different IGORs. The system behaved like an "oil" for IGOR up to 124.6 Sm³/m³ (corresponding saturation pressure: 42.9 MPa). Above it, for IGOR of 173.8 Sm³/m³ (corresponding saturation pressure: 43.8 MPa), the system appeared as a "condensate". The interval enclosed between these two values is the "critical point" zone, which was not investigated.

Five tests at 145°C and 53, 49.1, 42.9, 41.4 and 39.3 MPa were run to find out the MMP. The resulting value was very close to 42.9 MPa, as shown by the plot of the oil recovered (93.6, 93.0, 92.9, 88.2, 81.1% of OOIP, respectively) at CO₂ breakthrough vs. pressure (Fig. 3). For pressures beyond this value, the injectant and the oil develop a multicontact miscibility, below it they are immiscible. The MMP found lies inside the transition zone between the "oil" and "condensate" systems outlined with the swelling tests.

It is quite interesting to notice that the CO₂ density (615÷720 kg/m³) resulted always greater than that of the reservoir oil (530÷540 kg/m³).

In the interval 41.4÷49.1 MPa, i.e. around the MMP, the CO₂ stripping of the intermediate oil components destabilized the heavy paraffin fractions (C₂₅+C₆₀), and caused a wax precipitation. At 42.9 MPa a drastic permeability reduction of the sand inside the slim tube was noticed, as well as the upstream section of the equipment resulted plugged. The appearance of a solid phase was also observed during the oil swelling tests.

Phase behavior of oil/lean gas mixtures

The composition of the lean gas, sampled at the Oil Center, is listed in **Tab. 2**. Four tests at 145°C and 56.9, 53.0, 47.5 and 41.4 MPa were performed to determine the MMP. The oil recovered at lean gas breakthrough was 94.2, 93.4, 89.3 and 46.5% of OOIP, respectively. The plot of these data vs. pressure (**Fig. 4**) gave a MMP value of 48.1 MPa, which is higher even than the original reservoir pressure. The miscible process was identified as vaporizing gas drive (*Ref. 5*).

In the interval 47.5÷41.4 MPa, well below the MMP, precipitation of heavy paraffins ($C_{30}+C_{60}$) was still observed. However, the phenomenon was less severe than that recorded during the CO_2 displacements. In fact, at 41.4 MPa the precipitated waxes caused a permeability reduction only in the inlet part of the slim tube and a partial plugging of the upstream section of the equipment.

The swelling tests (**Fig. 2B**) showed that the systems oil/lean gas behaved as "oil" up to an IGOR of 159.7 Sm^3/m^3 (corresponding saturation pressure: 50.6 MPa). Above it, for IGOR of 189.3 Sm^3/m^3 (corresponding saturation pressure: 51.9 MPa), the system appeared as "condensate".

It is interesting to notice that for the lean gas, too, the MMP value is very close to the transition zone.

Lean gas enrichment with LPG

Because the lean gas miscibility was attained at too high pressure, it was decided to investigate to what extent it should be enriched with LPG (MME) to obtain a multicontact miscibility. In fact, the good production of LPG at Bu Attifel Oil Center would potentially permit this enhancement.

The experiments were run with the equipment and according to the lab procedures employed during the MMP displacements, but for the pressure kept constant at 41.4 MPa to maintain the oil always in single liquid phase. Four injectant mixtures, prepared according to different "liquid gas ratios" (LGR, defined as the LPG volume - referred at the sampling conditions 23°C and 1.3 MPa - added to $10^6 Sm^3$ of lean gas) were tested, namely 250, 710, 1000, 1670 m^3/MSm^3 .

The results of all these tests were compared with those of the lean gas displacement (LGR=0) performed at the same conditions. The trend analysis of the separated gas composition and the effluent density helped considerably the interpretation. For example, the oil displacement became "piston like" passing from the lean gas to the richest injectant (LGR=1670 m^3/MSm^3), as shown by the trend of methane concentration in **Fig. 5**. The same conclusion is attainable also looking at the density (**Fig. 6A**), whose trend becomes more and more smooth as the injectant is enriched.

The most probable displacement mechanism was a condensing/vaporizing gas drive, with the condensing process prevailing as the gas was enriched (*Ref. 5*).

The MME was quantitatively evaluated plotting the oil recovered at gas breakthrough vs. LGR (**Fig. 6B**). It resulted 290.3 m^3/MSm^3 at 145°C and 41.4 MPa (**Fig. 6C**). The injectant composition, measured after the LPG solubilization in a correspondent volume of lean gas, is reported in **Tab. 2**.

Unlike the two other solvents, the enriched gas did not destabilize the paraffins of the reservoir oil, even in the case of miscible displacement.

Phase behavior of oil/enriched gas mixtures

Fig. 2C shows the volumetric behavior of the reservoir oil swollen with enriched gas (LGR=290.3 m^3/MSm^3) at different IGORs. The transition zone between "oil" and "condensate" occurred only at high pressure. In fact, the system behaved like a liquid for IGORs up to 178.3 Sm^3/m^3 (corresponding saturation pressure: 47.2 MPa), and like a gas for an IGOR of 189.8 Sm^3/m^3 (corresponding saturation pressure: 47.6 MPa). The phase transition took place after a minimum change in the system composition, as proved by the following table which reports the chemical analysis of the two mixtures, compared with the original oil and MME gas compositions.

IGOR (Sm^3/m^3)	Moles (%)									
	CO_2	N_2	C1	C2	C3	C4	C5	C6	C7	C8+
178.3	3.30	0.52	67.95	9.40	3.17	2.11	1.42	1.81	1.49	8.83
189.8	3.30	0.52	68.15	9.43	3.18	2.13	1.42	1.81	1.47	8.59
Original Oil	3.06	0.47	61.97	8.72	2.86	1.76	1.30	1.99	1.94	15.93
MME Gas	3.58	0.58	75.28	10.21	3.48	2.41	1.42	1.44	0.86	0.74

Conclusions

A large laboratory program, including PVT studies, swelling tests, slim tube displacements, was carried out to find the most efficient solvent to enhance the final oil recovery of Bu Attifel Field (Libya) through a tertiary miscible gas injection project.

The behavior at reservoir temperature (145°C) of three injectants, potentially available in the area, was investigated, namely:

1. **Carbon dioxide**, which does not appear as the most suitable solvent for field applications. In fact, it developed miscibility, even though at a pressure level (42.9 MPa) a little higher than the current reservoir pressure (40.5 MPa), with precipitation of heavy paraffins noticed both during the displacements in slim tube and the swelling tests. Moreover, a large corrosion took place in some parts of the lab equipment. The handling of these problems at field scale should affect considerably the operating costs.
2. **Lean gas**, which is still an inadequate solvent because becomes miscible only at 48.1 MPa, a pressure even higher than the original one (47.6 MPa). Moreover, paraffin precipitation and corrosion were again noticed during the experiments.
3. **Enriched gas** obtained vaporizing LPG, available on the field, in the lean gas. With an enrichment of $290.3 \text{ m}^3/\text{MSm}^3$ miscibility was attained by condensing/vaporizing gas drive. Unlike the two other solvents, neither paraffin precipitation nor corrosion occurred in all the tests, therefore this injectant was retained for future field applications.

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Tab. 1 - Characteristics of reservoir oil

Reservoir temperature	: 144.5 °C
Reservoir pressure	: 47.57 MPa abs.
Bubble point pressure	: 40.46 MPa abs.

Data at reservoir pressure

Solution gas (Rs)	: 393.5 Sm ³ /m ³
O.R.V.F. (Bo)	: 2.2623
Reservoir oil density	: 543 kg/m ³
Reservoir oil viscosity	: 0.21 mPa·s

Data at bubble point pressure

Solution gas (Rs)	: 393.5 Sm ³ /m ³
O.R.V.F. (Bo)	: 2.3264
Reservoir oil density	: 528 kg/m ³
Reservoir oil viscosity	: 0.17 mPa·s

Separator test (5.99 MPa abs.- 69 °C)

First stage separator GOR	: 266.9 Sm ³ /m ³
O.F.V.F.	: 2.047
Stock-tank oil gravity	: 40.9 °API

Tab. 2 - Chemical compositions (% mol.)

Components	Reservoir oil	Lean gas	Liquefied Petroleum Gas	Enriched gas (LGR = 290.3 m ³ /MSm ³)
<i>Nitrogen</i>	0.47	0.62	0.01	0.58
<i>Carbon dioxide</i>	3.06	3.76	0.70	3.58
<i>Hydrogen sulfide</i>	-	-	-	-
<i>Methane</i>	61.97	79.51	5.41	75.28
<i>Ethane</i>	8.72	10.43	6.51	10.21
<i>Propane</i>	2.86	3.13	9.29	3.48
<i>I-Butane</i>	0.66	0.63	5.50	0.92
<i>N-Butane</i>	1.10	0.92	10.81	1.49
<i>I-Pentane</i>	0.58	0.29	7.34	0.69
<i>N-Pentane</i>	0.72	0.28	8.19	0.73
<i>Hexanes</i>	1.99	0.27	20.80	1.44
<i>Heptanes</i>	1.94	0.09	13.63	0.86
<i>Octanes (plus)</i>	1.90	0.07	7.00	0.47
<i>Nonanes</i>	1.21	-	2.87	0.16
<i>Decanes</i>	1.16	-	1.22	0.07
<i>Undecanes</i>	0.74	-	0.40	0.02
<i>Dodecanes</i>	0.70	-	0.19	0.01
<i>Tridecanes plus</i>	10.22	-	0.13	0.01

FIG. 1 - SCHEME OF THE OIL DISPLACEMENT APPARATUS

FIG.2 - SWELLING FACTORS OF DIFFERENT GAS/OIL SYSTEMS FOR SEVERAL INJECTION G.O.R. (Nm³/Nm³)

FIG.3 - MMP OF CARBON DIOXIDE WITH BU ATTIFEL OIL

FIG.4 - MMP OF LEAN GAS WITH BU ATTIFEL OIL

FIG.5 - SEPARATOR GAS COMPOSITION (METHANE CONCENTRATION TREND) FOR DIFFERENT L.G.R.

FIG.6 - EFFLUENT DENSITY, OIL RECOVERY AND M.M.C. DETERMINATION