Analyzing the Continuous Gas Injection as a tool for EOR

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ABSTRACT

Gas injection into the omo/efe reservoirs was initiated in April 2008 to maintain reservoir pressure and enhance oil production. This was a result of a study that showed recovery from gas injection to be superior (Recovery Factor 60%) to water injection (R.F. 54%) or a combination of gas and water injection (R.F. 52%). Economic indicators also favored gas injection. Also, the rock and fluid properties coupled with the produced GOR performance indicated that the reservoirs are under the influence of Gravity Segregation which enhances recovery by gas injection.

A reservoir engineering study was carried out to determine the optimum injectivity that would arrest the declining pressure and bring it up to a level that would keep the wells flowing. Facilities engineering design of the compressors and pipelines was carried out. In April 2008, a 120 MMCF/D gas injection plant was installed and commissioned. In June 2012 additional gas (50 MMCF/D) was made available to the Gas Injection Plant through an 18 inch, 17 mile gas pipeline from the nearby fields to increase the amount of gas being injected. The gas injection program has been effective in arresting the declining reservoir pressures. While oil producibility has increased actual production has been less than anticipated due to OPEC quota. The gas injection program has also reduced the volume of gas being flared thus enabling MPN to partially comply with the 'No gas flare' Decree 99.

Keywords: Pressure, Gas injection, Field, Permeability, Porosity, Wells, Reservoir and Gravity segregation.

INTRODUCTION

Gas injection into the xyz fields is concentrated in three m1, m2 and m3 reservoirs. Figures 1, 2 and 3 show the reservoir structural maps of these reservoirs.

M1 reservoir was put on production in June 1999 while production in m2 and m3 reservoirs commenced in November 2000. Rapid declining reservoir pressures in these reservoirs triggered off studies on how best to arrest the pressure decline and ensure continuous oil production.

Accordingly, pressure maintenance by gas injection was identified as the most suitable means of managing the reservoirs. In April 2008, the 120 MMCF/D capacity mX gas injection plant was installed and commissioned to compress associated gas gathered from nearby WW fields for injection into m1 and m2 gas injection reservoirs. The gas injection consists of five low-pressure Solar Centaur Turbine/centrifugal compressor, two high-pressure Solar Centaur Turbine/Ingersol Rand reciprocating compressors, two Solar Centaur Turbine/Power Generation units and a gas dehydration system. The centrifugal compressors take in produced gas at 45 psi and discharge at 1000 psi while the reciprocating compressors take in the compressed gas at 1000 psi and discharge at 3400 psi. In June 2012 a 50

MMCFD capacity Inim-Asabo gas line was installed and commissioned to bring additional produced gas from Enang fields for injection at the Asabo/Ekpe complex.

Gas injection in these reservoirs has been effective in arresting declining pressures, boosting production and replacing voidage. A total of 122 BCF of produced gas has been injected and stored into these reservoirs as at December 2005.

XY GAS INJECTION RESERVOIRS

A. **Geology and Reservoir Characteristics**

The omo/efe field is a highly faulted east-west trending anticline. The field is bounded in the north, east and west by large growth fruits and in the south by a large down to the north growth fault and an oil-water contact. It is further subdivided by minor faults into fault blocks A, B, and C. The reservoir rock consists of numerous sand and shale layers. The average net sand to gross oil column ratio is 0.48 indicating that the gross reservoir volume contains slightly more shale than sand.

Initially, the m1 reservoir oil was gas-saturated, with a saturation pressure of 2515 psig. Three pressure systems exist two in the A/B area and the third in the C-area. The C-area wells are completed in sand layers which are poorly developed in the A/B area. However, adequate connectivity exists in the system to permit the flow of reservoir fluids from system to system.

The field is a faulted rollover anticline with an eastern and western culmination. The field was discovered by Well 1 in December 1982 and appraised by Well 2 which discovered the m2 and m3 reservoirs. These are the two gas injection reservoirs in the field. Seven wells were drilled into these two reservoirs. These reservoirs have thick pay columns ranging from 500-550 feet with an average net to gross of 0.90 - 0.96. Both reservoirs are relatively clean with thick unconsolidated pays.

At time of discovery, the m1 reservoirs were gas- saturated. The saturation pressures were 3375 and 3614 psig in m2 and m3 reservoirs, respectively. Laboratory tests indicated good vertical and horizontal permeabilities, low oil viscosity, low interstitial water saturation and high relative permeability to oil. The production performances of the reservoirs show the GOR decreasing with time indicating gravity segregation.

B. Production History and Performance Prior to Gas Injection

Sixteen wells have so far been drilled into the reservoir. Production started in June 2000 from 8 wells in the A and B clusters (crest of the structure) while production commenced in the eastern part (C-cluster) in September 2005 from 4 wells.

After two years of production, the crestal wells in the A/B cluster started to cusp gas due to the formation and expansion of a secondary gas cap. These wells have been either shut in due to excess gas production or have had their oil rate drastically reduced to conserve reservoir energy. After several years, the gas-oil-ratio of several wells decreased indicating gravity segregation. Water influx has been very limited in the down dip wells of the A/B cluster but relatively more active in the C-cluster wells. The composite drive mechanism in the reservoir is that of gravity drainage with partial water drive.

With only 19% of the STOIIP produced, the As reservoir pressure dropped by 25% from an initial value of 2515 psig to 1890 psig. By the end of 2007, the wells were dying (Figure 4) and could not flow naturally. It became evident the water influx into the reservoir was not sufficient to support the pressure. Consequently, pressure maintenance by gas injection was initiated in order to arrest the declining pressure and increase oil production.

Production started in the m2 reservoir in November 2002 and peaked at 42,000 BOPD in September 2003. After two years of production, the oil rate started to drop and by 2006 the wells were dying because

of low pressures. Figure 5 shows the reservoir performance curve. The reservoir pressure declined by 37% from an initial pressure of 3375 psig to 2112 psig with 40% of the STOIIP produced. A redrill in 2006, to optimise production, found 65 feet of secondary gas cap at the top of the reservoir. Thus, the drive mechanism was predominantly gravity segregation assisted by dissolved gas drive and partial water drive support. These supports did not exert enough energy to cause the wells to flow naturally and sufficiently. Additional energy was thus required in the reservoir to produce the remaining reserves. Reservoir performance reviews indicate there is more oil yet to be recovered. As such geologic description and reservoir simulation studies were planned for the reservoir.

Production started in m3 reservoir in November 2000 from 3 wells and peaked at 27000 BOPD in June 2002. The oil rate later dropped gradually and by the end of 2007, the wells died because of low pressure. The produced GOR declined with time thus confirming gravity segregation in the reservoir. The reservoir pressure dropped from an initial value of 3614 psig to a pressure of 2214 psig by the end of 2007. This is a drop of over 38% for the production of only 35% of the STOIIP. Figure 6 shows the reservoir performance history. A decline curve analysis had indicated that there was good quantity of oil yet to be recovered.

Gas injection was therefore initiated in these two reservoirs to provide the needed energy and to optimise oil production. This was based on a study which identified gas injection as the most suitable means of managing the reservoir. The study found pressure maintenance by gas injection to yield a higher ultimate oil recovery. A summary of the results is shown in Table 1.

C. Performance History of the Gas Injection Reservoirs

By 2006 there were substantial pressure drops in the reservoirs, the oil rates dropped to very low levels that caused the wells to die. It therefore became necessary to initiate a pressure maintenance program to arrest the declining pressure, keep the wells flowing and boost production.

The 80 MMCF/D capacity gas injection plant is located at a nearby field and compresses associated gas gathered from WW fields for re-injection. Crestal gas injection started in April 2008 in m1, m2 , m3 reservoirs and three months later in m2 reservoir. The total gas available for compression was 45 MMCFD or 56% of the installed compressor capacity. At an operating efficiency of about 80%, only 36 MMCFD was actually utilized and 30 MMCFD was injected.

A review of the gas injection performance in 2011 indicated that a total gas supply of 45 MMCFD was insufficient to ensure effective pressure maintenance program. Consequently, the zym gas line was installed and commissioned in June 2014. The new gas line, with a design capacity of 50 MMCFD, brings additional produced gas from nearby fields for injection into omo/efe fields, thereby ensuring a more effective pressure maintenance program.

By, the declining pressures were arrested and the reservoir pressures stabilised (See Figures 7 through 9). Performance of the reservoirs after the commissioning of the zym gas line has stabilised. The injection rate has gradually been increased to average 49 MMCFD in 2017 and the reservoir pressures have been building up. The oil recovery has also improved. The oil rate rose by 28% in m1 by 114% in m2 and by 267% in m3 reservoir.

The historical gas injection rate is shown in Figure 10. Prior to the commissioning of the xym gas line, about 25 - 32 MMCFD was being injected. Though pressure decline was substantially reduced, the reservoir voidage replacement was not fully achieved mainly because of insufficient injected gas coupled with mechanical problems. As the increase in net voidage became appreciable, the reservoir pressure

dropped and edge water encroached. This was evident in the C-block of the m1 reservoir as the water-oil-ratio started to increase.

Since the commissioning of the gas line, sufficient gas is now being injected into the reservoirs. The net voidage and the reservoir pressure have improved significantly in all the injection reservoirs.

Figures 11-13 show the not voidage of the injection reservoirs. The plots indicate that replacement is much higher than withdrawal in the m2 and m3reservoirs. This implies that the withdrawals from these reservoirs are not at the optimal rates. Consequently, in 2017 efforts were stepped up to increase productibility of all the wells. Problem wells were worked over in order to maximise production from each well. Improvement in the net voidages was not appreciable mainly because of production restrictions imposed by government on the fields. As a result, reservoir replacement has continued to increase. Accelerated production, coupled with increased gas injection remains the optimal means of depleting the reserves within the useful life of the installed facilities, especially in omo/efe field. In-house study has indicated that reserves in the field would last for another 45 years if production is restricted to 17 TBD. A reservoir simulation study will be embarked upon after the completion of a geologic description of the reservoirs to find ways of further accelerating the depletion of the reserves.

The composition of the injected gas shown in Table 2 has remained fairly constant.

Future Plan

The future plan for the Gas injection reservoirs will include a comprehensive 3-D simulation study of the reservoirs. The study will utilise the pressure, production and injection data gathered over the years. The study is expected to confirm the STOIIP, determine the water influx volume, ensure continued pressure maintenance and optimize oil production as well as suggest the most effective gas storage strategy. The study will highlight the optimal locations for in-fill wells for accelerated oil production.

A geologic reservoir description of the reservoir will soon be undertaken by our Reservoir Management team. This study will provide the needed geologic input into the simulation studies. The geologic description is designed to characterize the different sand bodies that constitute the reservoir thereby describing the reservoir quantitatively and qualitatively. The geologic study will also highlight the sand bodies that have not been drained or swept by the gas injection. It will complement the results of the reservoir simulation study and help spot the optimal locations of the in-fill wells.

CONCLUSIONS

1. Continuous gas injection has arrested initial rapid pressure decline and has substantially increased oil recovery.

2. Increased gas injection has also resulted in more gas storage and a reduction in flared gas volume thereby making it possible for MPN to partially comply with the 'No gas flare' decree.

Gas injection has accelerated the depletion of reserves in the injection reservoirs.

Further reservoir description and simulation studies will detail ways of fully exploiting these reservoirs

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TABLE 1 - SUMMARYS FOR
VARIOUS PRESSURE MAINTENANCE TECHNIQUES

REVENUE OPTIONS	ULTIMATE RECOVERY (%)			FACILITIES INVEST.COST ($MM)	INCREMENTAL COST ($/BBL)	INCREMENTAL GOVT. REVENUE ($MM)
	M1 m1	m2 m2	m3 m3			
GAS INJECTION	56.2	55.9	64.7	63.3	0.79	1728
	45.3	54.0	62.8	53.3	0.98	1210
WATER INJECTION WITH LIFT	43.8	55.9	54.3	84.5	1.51	1100

GAS INJECTION WILL RESULT IN FEWER WELL FLOW PROBLEMS, LESS OIL-WATER

SOURCE: ASABO/EKPE FLUID INJECTION STUDY,

TABLE 2- COMPOSITION OF INJECTION GAS

GAS ANALYSIS DATE

GAS ANALYSIS

DATE

COMPOSITION MOLE%	2002 MOLE%	2005 MOLE%	2007
NITROGEN	0.01	0.01	0.03
CARBON DIOXIDE	1.41	2.35	1.78
METHANE	86.04	84.59	84.06
ETHANE	6.54	6.90	6.53
PROPANE	3.22	3.60	4.14
1-BUTANE	0.74	0.73	0.89
N-BUTANE	0.95	0.95	1.26
1-PENTANE	0.34	0.31	0.61
N-PENTANE	0.24	0.22	0.31
N-HEXANE	0.22	0.18	0.26
N-HEPTANE+	0.29	0.16	0.14

TOTAL	**100.0**	**100.0**	**100.0**
MOLECULAR WEIGHT	**19.75**	**19.95**	**20.35**
GRAVITY (AIR= 1.0)	**0.68**	**0.69**	**0.70**
MOLECULAR WEIGHT C7+	**109.4**	**104.6**	**104.0**

FIG. 1

ASABO II – VI
RESERVOIR
STRUCTURE MAP

☐ LOCATION OF PROPOSED WELL

● PRODUCING WELL

⚑ GAS INJECTION WELL

FIG. 2

EKPE FIELD
4X - 2 RESERVOIR

☐ LOCATION OF PROPOSED WELL

● 4-X2 PRODUCING WELL

⚑ GAS INJECTION WELL
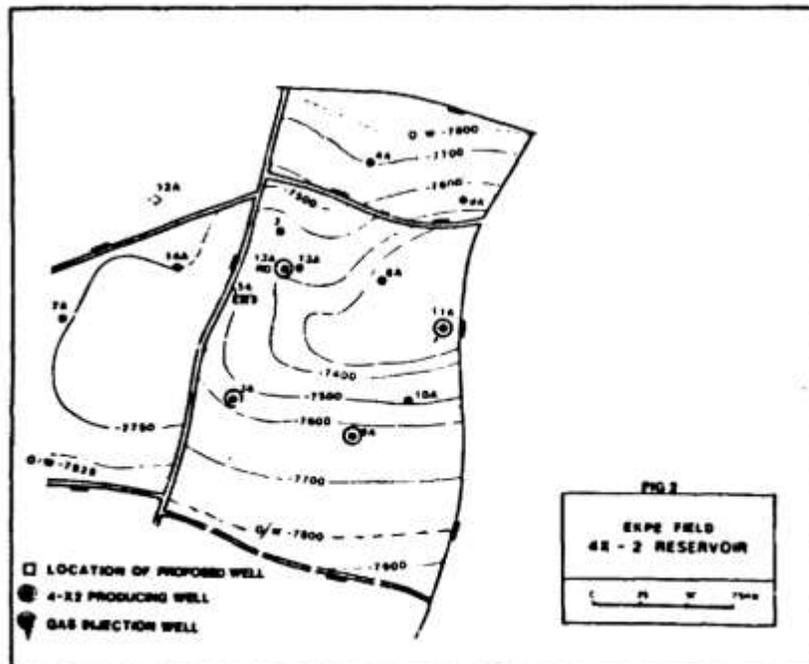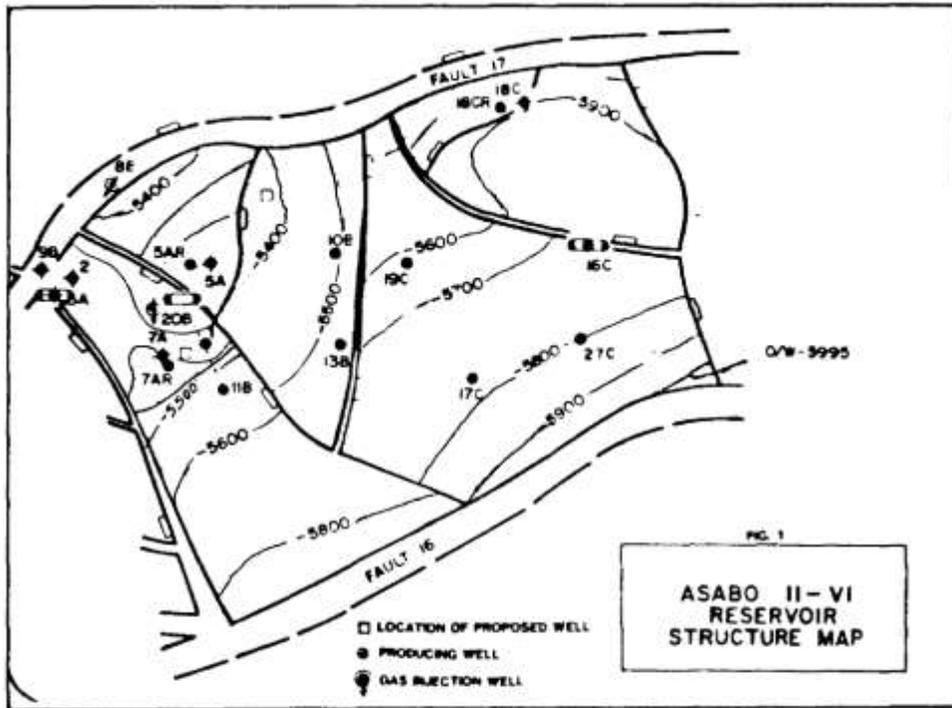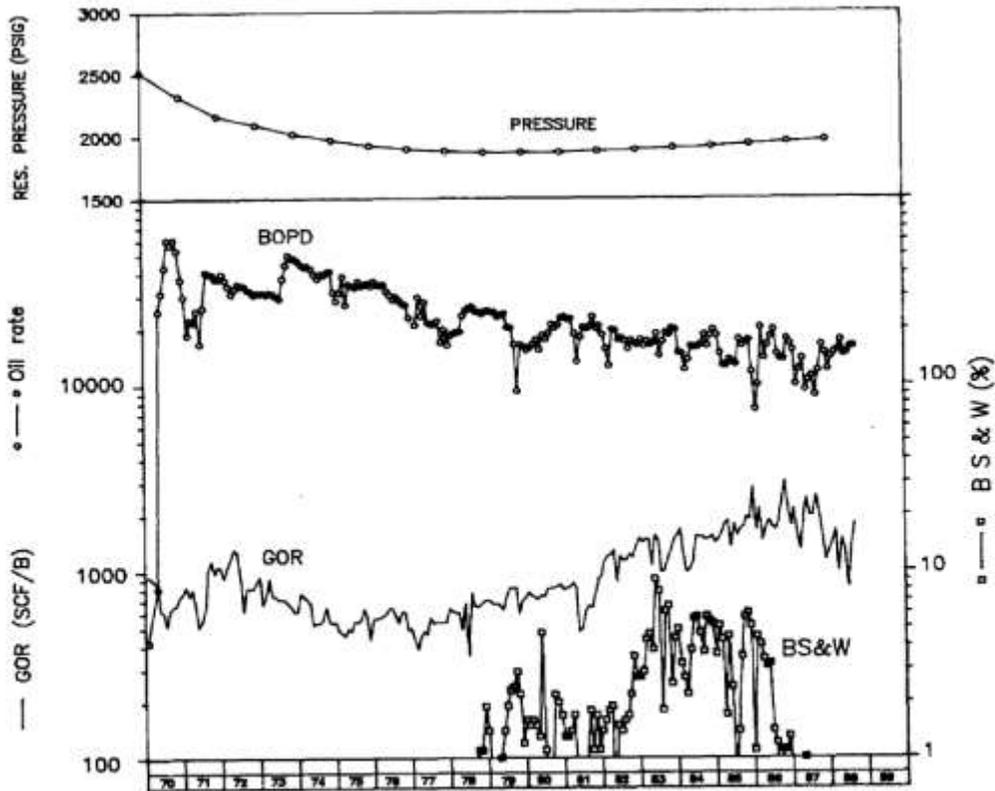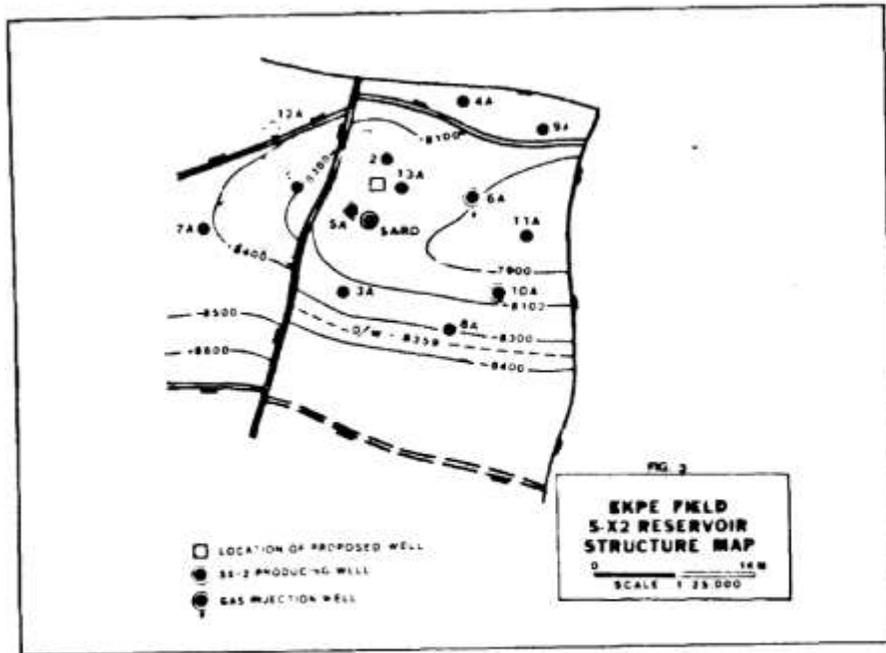
Fig. 4 — Asabo 11–V1 reservoir performance history.
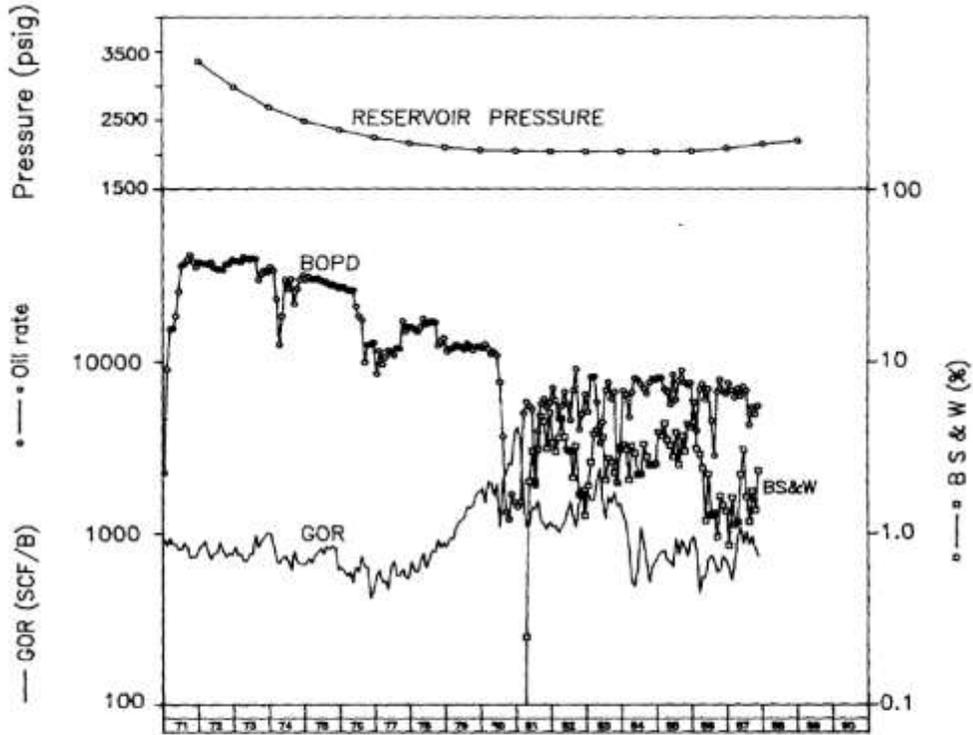
Fig. 5 – Ekpe 4–X2 reservoir performance history.
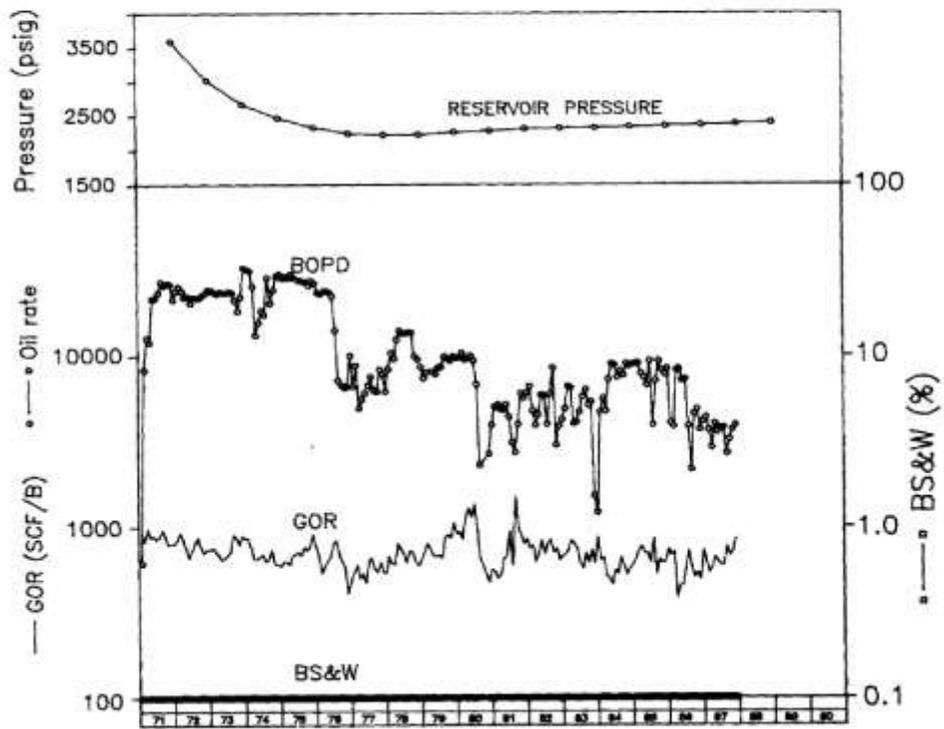
Fig. 6 – Ekpe 5–X2 reservoir performance history.
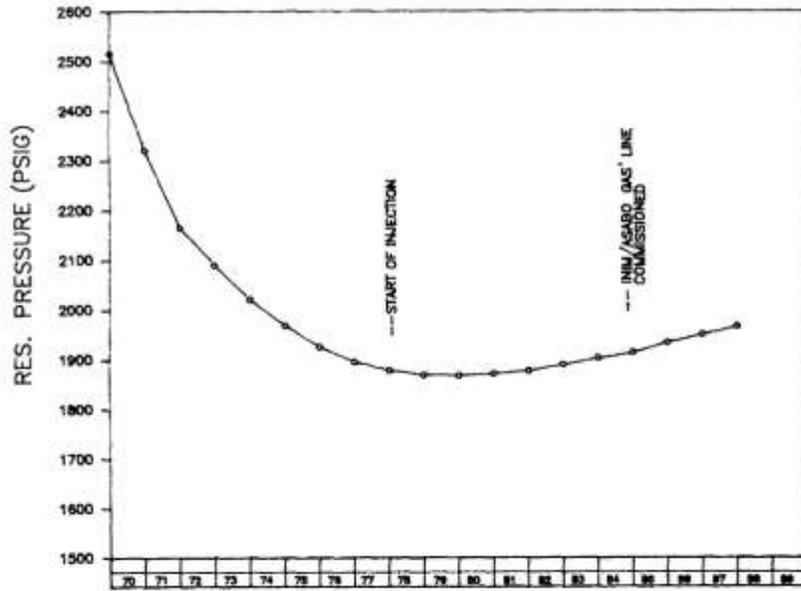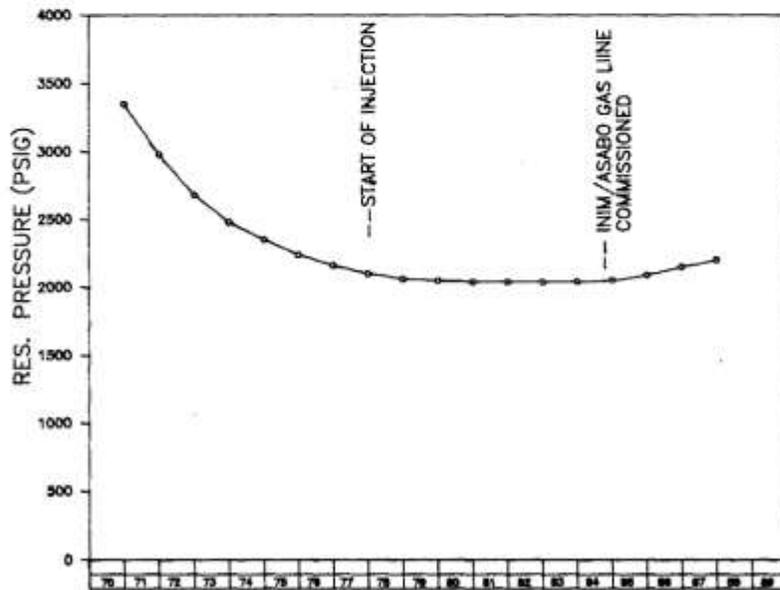
Fig. 7 — Asabo 11–V1 reservoir pressure curve.

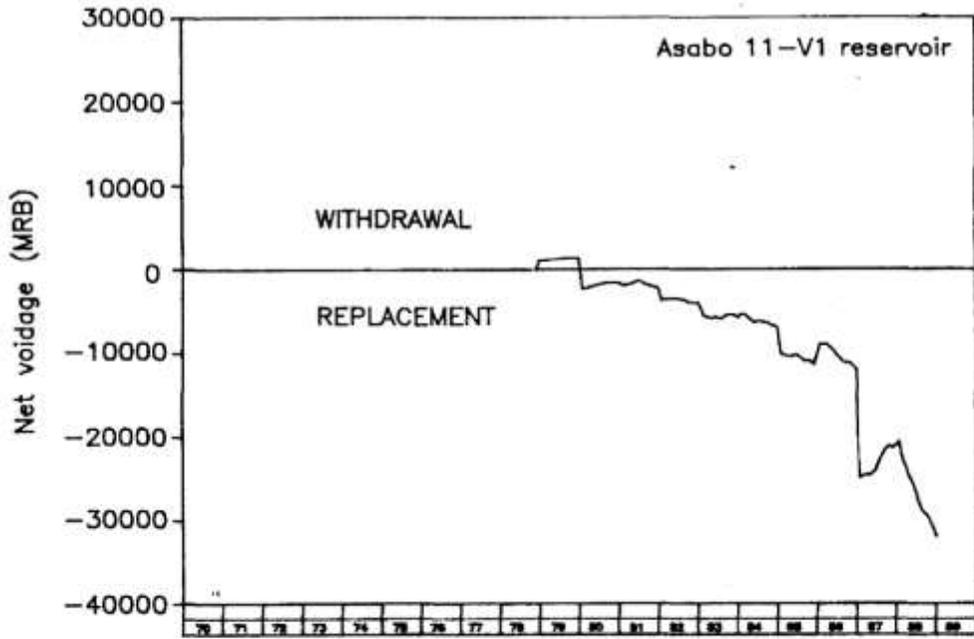Fig. 8 — Ekpe 4–X2 reservoir pressure curve.

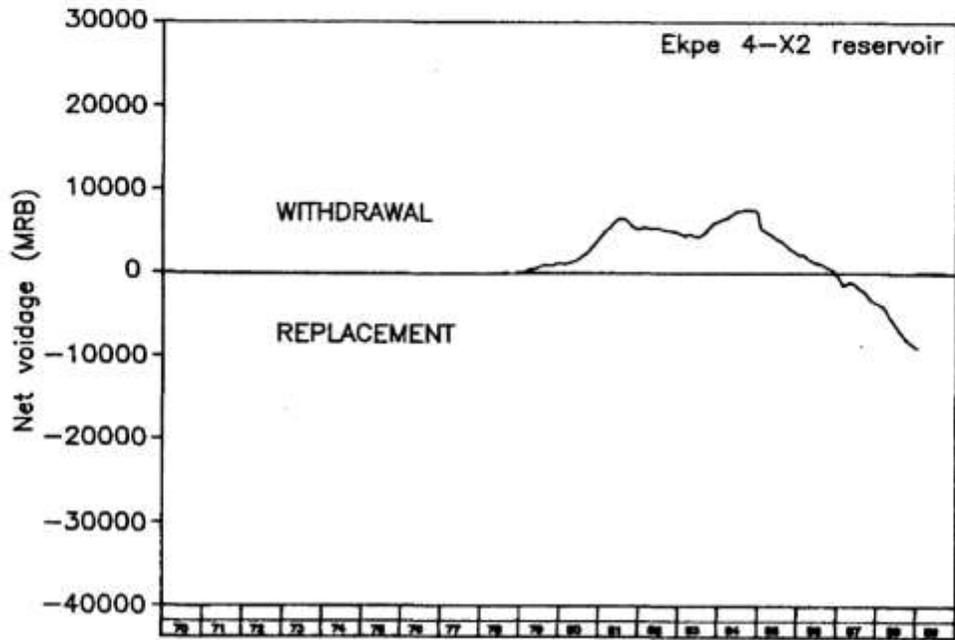Fig. 11 — Effect of gas injection on net reservoir voidage.
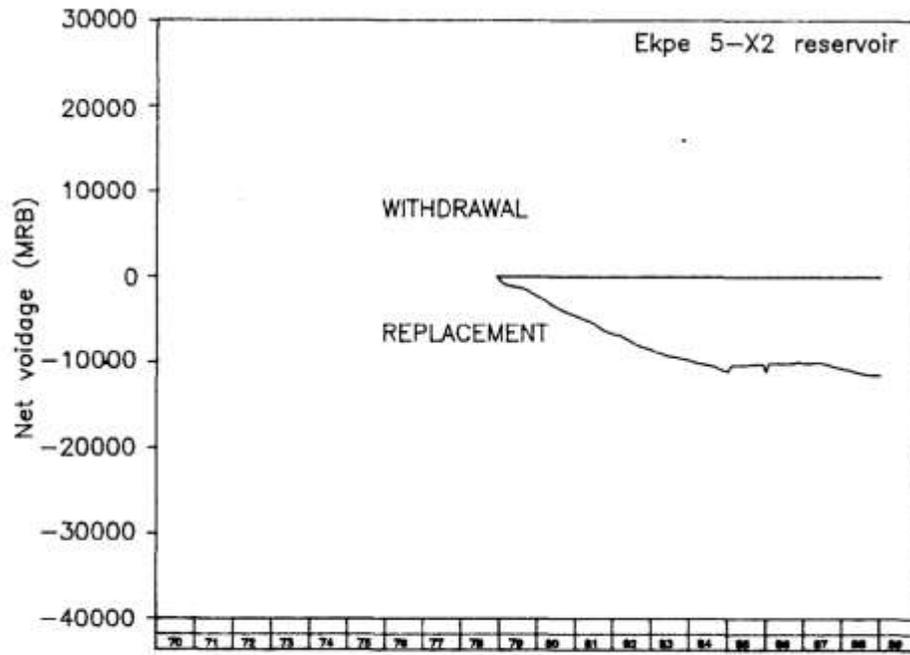

Fig. 12 — Effect of gas injection on net reservoir voidage.

Fig. 13 — Effect of gas injection on net reservoir voidage.