PRJ, Vol. 7 (January 1995); P. 43–59, 12 FIGS, 4 PLATES.

NAFOORA–AUGILA UNIT: RESERVOIR PERFORMANCE AND THE ROLE OF GRANITE PRODUCTIVITY-A CASE STUDY

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الدور الإنتاجي للجرانيت في حقل النافوره–أوجله المشترك

نوري بالروين و يوسف السنوسي قريو

تراجع الورقة الدور الإنتاجي للجرانيت في حقل النافورة – أوجلة بليبيا.

ينتج الحقل من تراكيب ثلاثة؛ تاقرفت (Tagrifet limestone) والباهي (Bahi sandstone/conglomorate) وصخور القاعدة الغرانيتية (Granite) المتشققة. تعتبر هذه التراكيب الثلاثة المنتجة كمكمن واحد متصل.

بدأ الإنتاج في هذا الحقل سنة 1966 حيث تبع ذلك هبوط حاد في ضغط المكمن وارتفاع في نسبة الغاز إلى نسبة النفط كنتيجة لهبوط الضغط مما حتم استخدام تقنية حقن الماء لإعادة الضغط إلى المستوى المطلوب. جربت هذه العملية بالفعل على جزأ من المكمن، ثم عممت على كل المكمن. حدث نتيجة إلى استخدام هذه التقنية هبوط في انتاجية هذا الحقل الأمر الذي استوجب استخدام تقنية رفع الضغط باستخدام الغاز.

أنتج الحقل أكثر من 900 مليون برميل وكان أغلب الإنتاج من الآبار التي اخترقت تكوين صخور القاعدة الغرانيتية.

ABSTRACT

This paper discusses the role of Granite productivity in the Nafoora–Augila Unit, Nafoora Field, Libya. Three distinct lithologic members, Sandstone, Limestone and Granite constitute an interconnected single reservoir. To date this reservoir has produced more than 900 million barrels of oil. Wells penetrating Granite only have contributed significantly to this field performance. The salient characteristics of the Granite member in this reservoir are discussed along with the overall performance of this prolific reservoir.

INTRODUCTION

This paper reviews the reservoir performance of the Nafoora–Augila Unit in Nafoora Field, Libya. The Nafoora–Augila Unit is one of the largest oil fields in the southeastern part of the prolific Sirte Basin, located about 350 km southeast of Benghazi. The field was discovered in 1965 with the drilling of well G-2 in concession 51, and well D-1 in concession 102. As of November 2, 1971 the two fields were unitized, with the Arabian Gulf Oil Company (AGOCO) as the current operator of the Unit.

Production commenced in July of 1966. Initial production from this field resulted in a rapid decline in reservoir pressure, and a sharp rise in the field gas oil ratio due to the absence of pressure support which led to the decision of maintaining the reservoir pressure by water injection. Therefore, a waterflood pilot was initiated in May of 1969, which was developed into a full scale line-drive water injection by July of 1974. Also, well productivities started to decline and in anticipation of the increased water production due to the implementation of the waterflood, artificial

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lifting by gas lift was initiated early in the life of the field.

The field is productive from three distinct lithological members; the Tagrifet limestone, the Bahi sandstone/conglomorate complex both of Cretaceous age, and the fractured Granite basement of late Precambrian age. The Tagrifet pay is on top of the Bahi, or on top of the Granite where the Bahi is missing. The three oil-bearing horizons constitute a single and interconnected oil reservoir, which is called Tagrifet–Bahi–Granite reservoir (TBG).

The 35.5° API oil of the TBG is undersaturated with an average bubble point pressure of 2465 psig. The initial reservoir pressure is 4272 psig at depth of 8700 feet subsea. The original GOR is 463 Scf/STB. The original oil in place is estimated at 4.3 billion STB with an estimated recoverable reserves of about 1.78 billion STB. As of the end of 1989, 874 million STB of oil, or about 49.1% of the recoverable reserves has been produced.

Both of the sedimentary rocks and the granite are equally important in contributing to the field production. Production from the Granite comes mainly from fractures and possibly from zones of intergranular porosity believed to be associated with fractures. The vast difference between OOIP calculated by material balance and volumetrically calculated OOIP in the sediments (Tagrifet and Bahi) gives credence to the existence of oil in the Granite. The oil productivity of the Granite is further proven by prolific oil production from certain wells that are completed (open-hole) mainly in the Granite.

In relation to the sediments of the Tagrifet limestone and the Bahi sandstone, the Granite has historically been known to be a high rate producer with relatively high cumulative production at locations where the necessary reservoir quality parameters such as fracture-type porosity and good permeability are favorable.

GEOLOGICAL SETTING

The sedimentary rocks of the Nafoora–Augila Unit were deposited over the crest of an extensive Precambrian or early Paleozoic granite high. This regional high encompasses an area greater than a thousand square miles which had topographic relief in excess of two thousand feet in Upper cretaceous time, Fig. 1. During the general subsidence of the Sirte Basin, this large triangular block (as well as all other horst blocks in the basin) subsided more slowly than the areas on the down thrown sides of the faults forming the block. With continued subsidence, the large triangular block began to tilt slightly to the west, and the subsidence and westward tilting have continued to the present. As a result about 8500 feet of sediments were deposited over the highs in Nafoora and Augila Fields.

The Precambrian granite, encountered in Concessions 51 and 102, occurs as a chain of buried hills, uplifted and severely eroded during the hiatus prior to the deposition of, the unconformably overlaying, Cretaceous elastics and carbonates of the Bahi complex and Tagrifet Formation.

The basement rocks in this field are gradations of granophyre, granophyric granite as well as rhyolite. The rock types consist of quartz and alkali feldspars with biotite. Feldspars are granulitized along fractures and or seriticized and kaolinized to varying degrees from few feet to several hundred feet below the igneous suface. The lower areas on the land mass at the time of burial are represented by fresher granites as intense erosion stripped away much of the highly kaolinized upper portions of the granite.

Whether the granite basement is an emplacement mass or the product of granitization of early sediments, in which case grossly correlative log response characteristics might be retained, remains unstudied. That the basement complex has had a long and complex history of repeated periods of deposition and erosion have probably obliterated the evidence beyond recovery.

The granite is estimated to be of Early Paleozoic or late Precambrian (600–1250 million years) age, and it may have been affected by a subsequent hydrothermal tectonic events during the Lower Paleozoic. Porosity in the basement is the result of fracturing and weathering. Porosity distribution is currently not well defined, but production from the Granite indicates a large accumulation of oil. The quality of the basement reservoir is dependent upon fracturing and weathering. Fracture-type porosity with resulting fair to good permeability occurs along fracture zones. Good oil shows throughout zones within the granite also suggest secondary matrix porosity associated with weathering, some of which is probably related to zones of fracturing (Plates 1, 2, 3, and 4). It is probable that deep weathering of the granite took place along joints and fractures. It is likely that these fractures were developed either by stress release with removal of overburden and/or through tectonic forces coincident with movement along the Nafoora fault zone. Therefore, production from the granite is from fractures and zones of intergranular porosity believed to be associated with fractures.

Mudlog "shows" are frequent throughout the intervals of Granite penetration. The deepest such show is down to 10,020 feet, or about 1000 feet below the Granite top in well B-56-51, Fig. 2.

Pressure data, drill stem tests, sidewall cores, logs and several BHTV logs all show a deeply weathered basement complex, with numerous fractures. The basement produced in several wells (D-2, D-9, D-18,

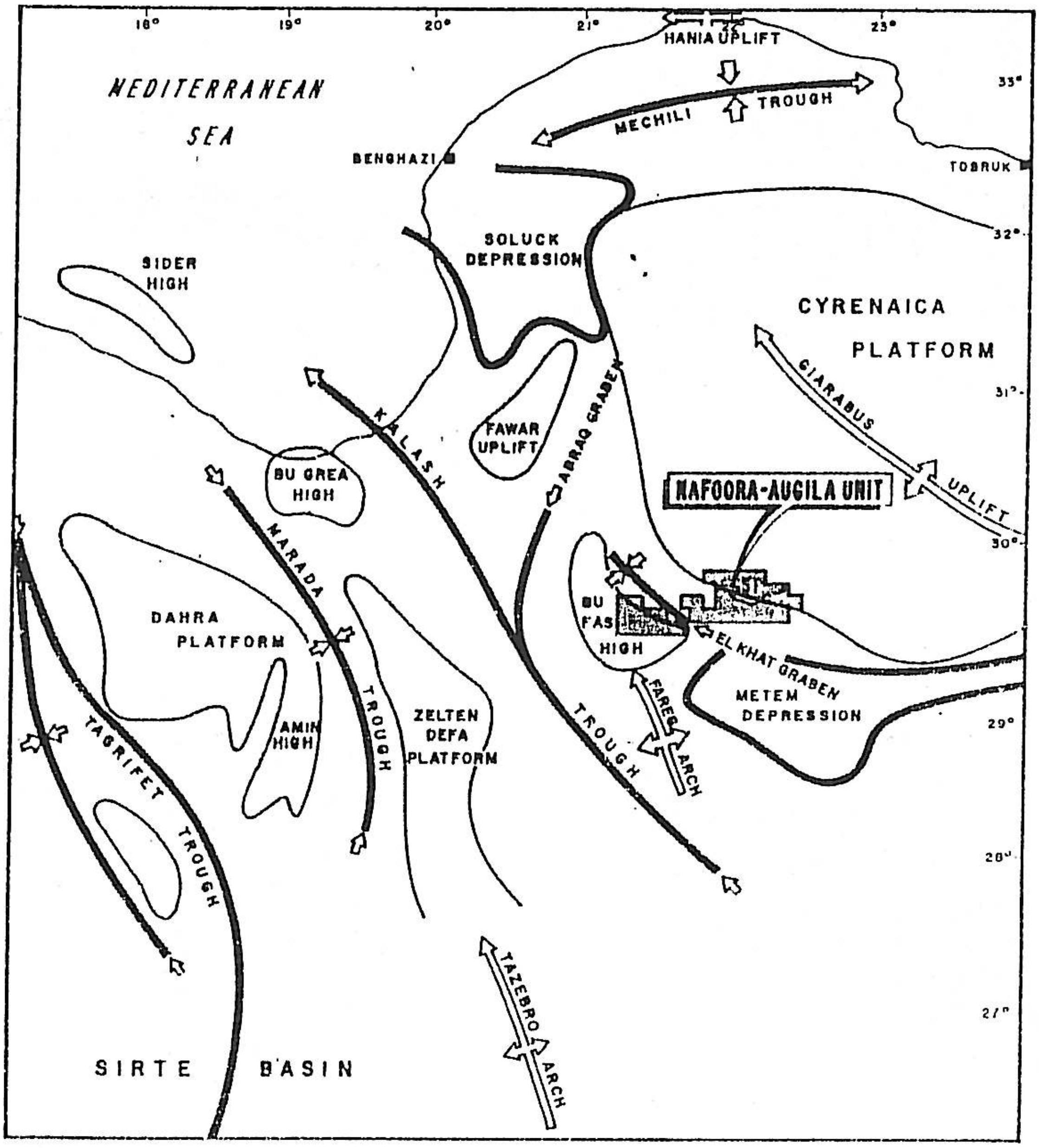

FIG. 1. Nafoora–Augila Unit location map.

D-42, G-13, G-20, G-30, G-54, G-62A, G-68, G-83, G-87, G-88, G-157, G-243, G-251, G-253, and G-254) and it also produces into the over-laying and on-lapping Bahi sands and Tagrifet Carbonates.

DETECTION OF FRACTURES

Fractures were detected with conventional logs. Although the tools do not detect fractures directly, experience gained in the evaluation of this field makes it possible to recognize fractures from the logs. The existence of fluids in the fractures cannot, however, be reliably determined.

The first log to be considered is the drillers log used during drilling of the well. The driller log usually indicates a significant timing decrease in fractured zones. The occurrence of partial loss of mud or drilling fluid is frequent. The following logs were often used for fracture identification:

—Gamma Ray
—Resistivity
—Acoustic
—Density
—PEF
—Natural Gamma Ray Spectrometry

Although not all productive intervals can be clearly picked from the logs, zones of apparent porosity are usually indicated on the Density, Neutron, and Sonic

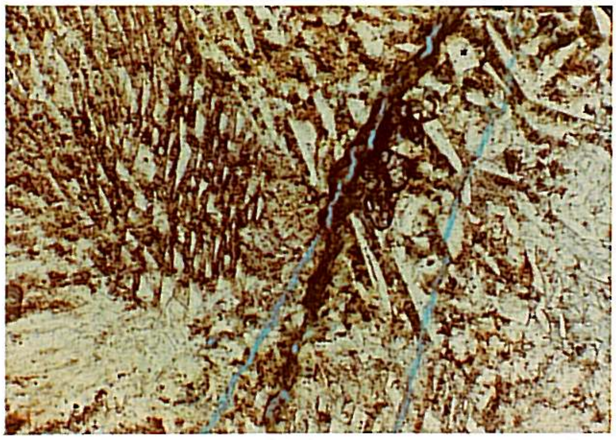

PLATE 1: Well: G253-51; Depth: 9065'; Lithology: Gph; Porosity: 3% est.; Magnification: × 160.

This view exhibits classic graphic texture typical of a granophyte. The graphic texture results from the intergrowth of quartz (clear) and feldspar (turbid, brown, sericitised) as they crystallised from the cooling magma. The granophyte is cut by hairline fractures partially filled with indeterminate, green authigenic clay (probably illite; 7F). Free fracture porosity is highlighted by the blue-dyed resin (8/9D).

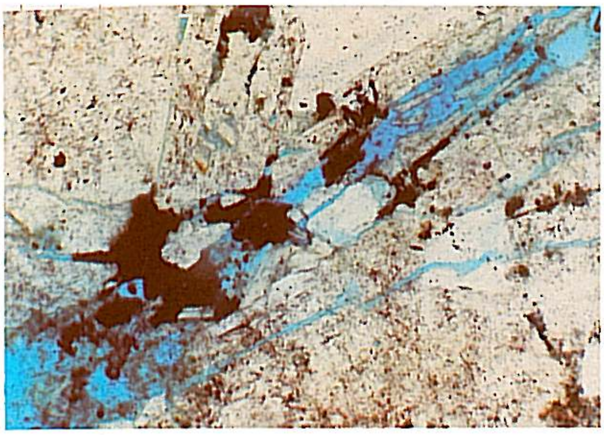

PLATE 2: Well: G2-51; Depth: 8733'; Lithology: HgG; Porosity: 2% est.; Magnification: × 160.

The plate illustrates a part-open, part-cemented fracture cutting a sample of micrographic granite. Free porosity in the fracture is highlighted by blue-dyed resin. The fracture is partially cemented by an opaque mineral (probably pyrite; 5G) and an indeterminate, green, authigenic clay (probably illite; 2J). The relative timing of the pyrite and illite cements cannot be determined from the evidence seen here.

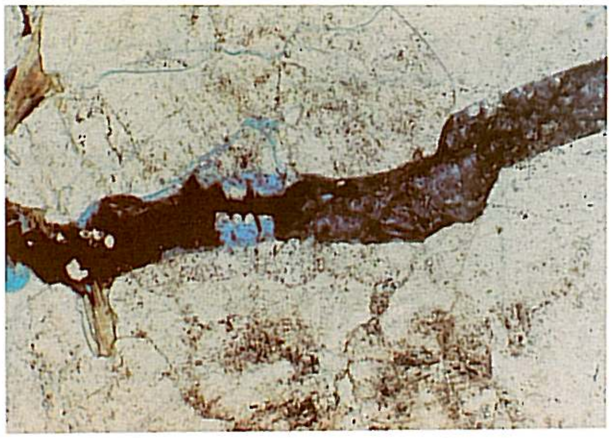

PLATE 3: Well: B2-102; Depth: 8822'6"; Lithology: GR; Porosity: 2% est.; Magnification: × 160.

The fracture illustrated here cross-cutting undeformed granite is partially cemented by blocky ferroan carbonate (blue-stained, probably calcite, e.g. 5F), and also part-filled by bitumen (black, e.g. 12E). Remaining open porosity is shown by the blue-dyed resin (1OE).

PLATE 4: Well: B2-102; Depth: 8822'6"; Lithology: GR; Porosity: 2% est.; Magnification: × 64.

This photomicrograph shows another fracture in the granite illustrated by Plate 73. In particular, it illustrates a hairline fracture part-filled by bitumen (e.g. 5G). Remaining open fracture (13D) porosity and small amounts of leached feldspar porosity is surrounding areas of the wallrock (4E, 5H, etc.) are highlighted by blue-dyed resin.

Logs and possible fractures are generally noted through log characteristics on the acoustic devices, Fig. 3. It is difficult however, to accurately position fractures and it is possible for fractures to remain undetected by the logs.

The Granite sections drilled and logged do exhibit distinctive porous interval responses. These zones of indicated porosity probably reflect well-bore intersections with fracture-planes along which deep solution and chemical "weathering" have induced the channels and void space which make the Granite a functional petroleum reservoir within the Nafoora–Augila Unit.

DRILLING AND COMPLETION

Due to the fact that fractures cannot be precisely identified and to avoid the possibility of cementing off fractures, casing was usually set few feet into the granite and the Granite was completed as an open-hole.

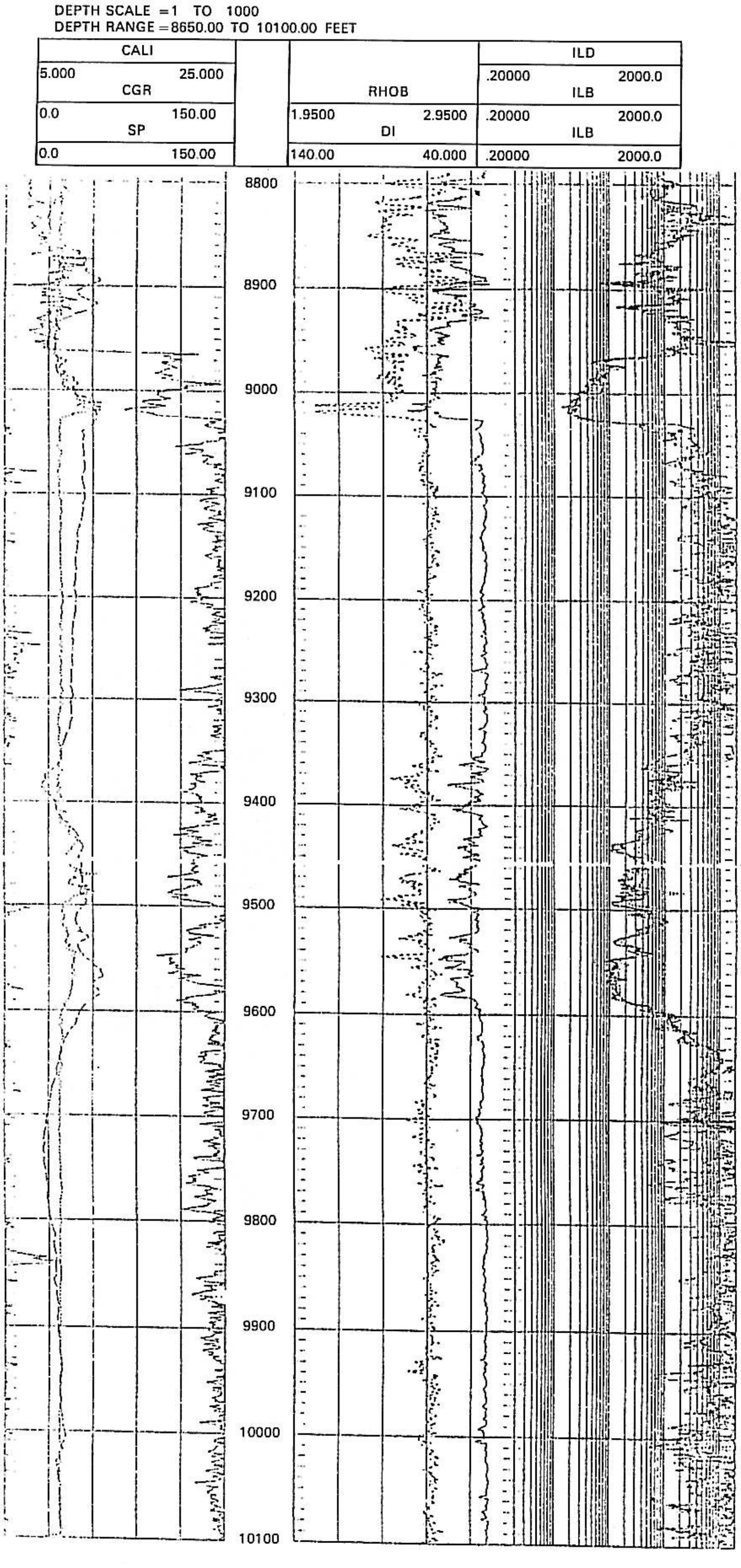

FIG. 2. Well G-56.

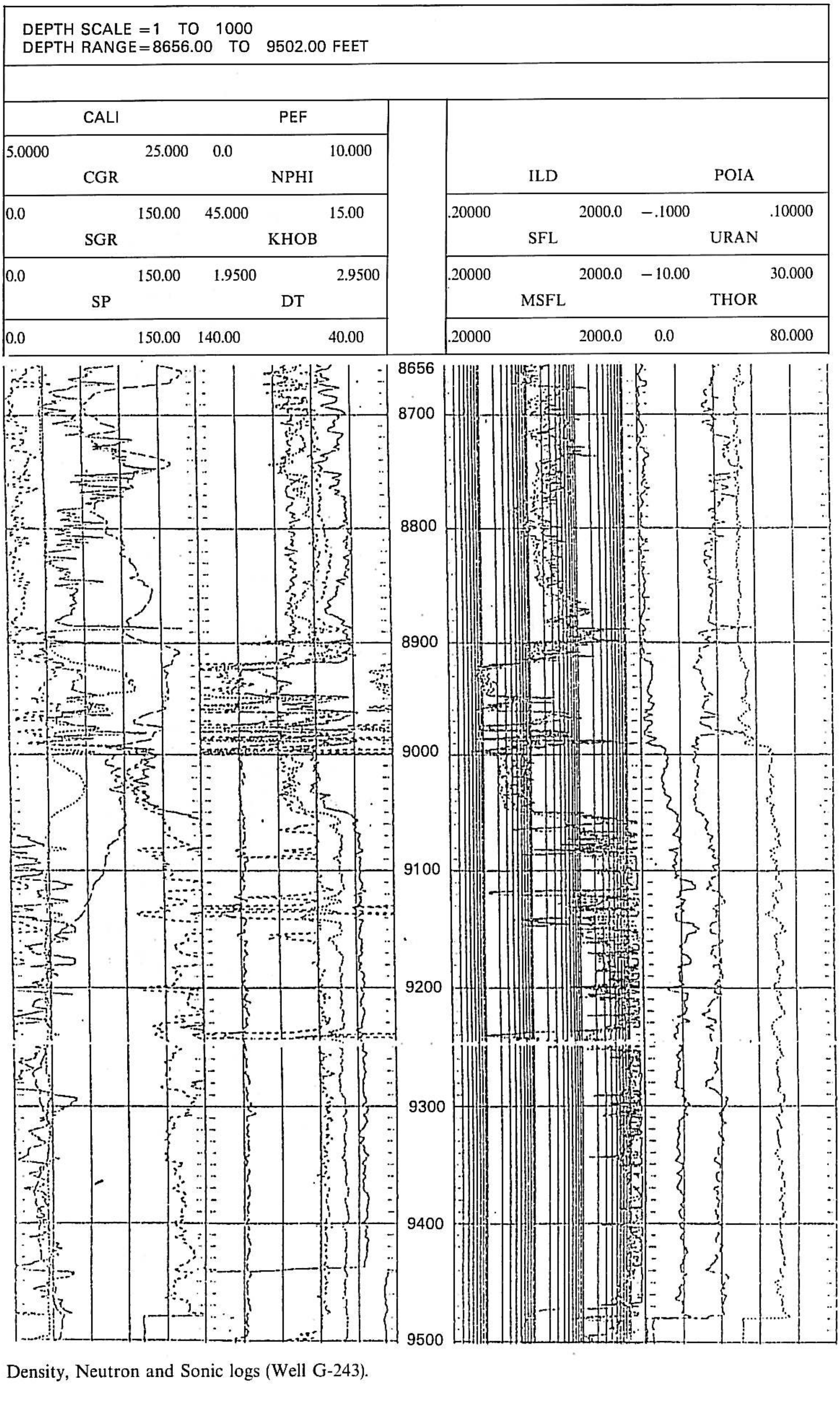

FIG. 3. Density, Neutron and Sonic logs (Well G-243).

RESERVOIR STUDIES

Numerous reservoir studies in the early life of the field were conducted mainly to evaluate the original oil in place, and the natural reservoir drive mechanism. Pressure maintenance by water injection was also investigated in these early studies in order to maintain high production levels, and eventually to improve the ultimate oil recovery.

These early studies concluded that, based on volumetrics and material balanced calculations, the Granite part of the TBG contained about 32% of the total OOIP. The rest of the OOIP was allocated to the sedimentary parts of the TBG.

As the number of drilled wells increased during the initial phases of field development, further reservoir studies continued for the same purpose. In 1971 through the use of a two dimensional areal simulator, the two operators jointly conducted a pre-unitization reservoir study of the TBG, which laid the grounds for the current Nafoora–Augila Unit. Among the conclusions of their study the OOIP was estimated to be 4300 MMSTB, the recovery mechanism was solution gas drive with an estimated recovery factor of 13%, and an ultimate oil recovery by a line-drive waterflood of 41%. The joint study had allocated 37% of the OOIP to the Granite, and 63% to the overlaying sedimentary rocks of the Tagrifet and the Bahi. Hence the current waterflood was implemented on these bases.

In 1982 a reservoir simulation study using a three-dimensional, three-phase model was conducted to provide AGOCO with an overall engineering and operating plan which would maximize oil production from the TBG reservoir. The study assumed that the OOIP within the unit boundaries to be 7000 MMSTB of oil, but did not attribute any of that to the Granite although significant production had come from wells that were completed mainly into the Granite. One of the problems that faced this study was the definition of the bottom layer, which was associated mainly with the granite. Therefore, this layer was omitted; a decision that was not agreeable to the operator.

The additional OOIP, which this study had come up with, was assumed to be attributed to a tight member in the Tagrifet limestone. However, this hypothesis was tested by performing some of the wells into the tight zones only. The completed intervals did not yield any significant amounts of fluids. But these wells were completed into other productive intervals.

Based on the earlier studies and on AGOCO's experience with the history of oil production from water injection into the Granite in many wells, it was agreed that the Granite should be considered as an oil bearing and/or a conduit in some areas of the field. Therefore a new scope of work was defined in order to perform a new study in phases. A consulting firm was contracted to conduct the first phase, which is concerned mainly with the reservoir geology, utilizing all geological, petrophysical, and production information collected since the last study. The main objectives of this study are to develop a better understanding of the reservoir geology of the TBG, to define the Granite as an oil reservoir, and to obtain a model layering consistent with geological layers to be used in the upcoming reservoir simulation study.

RESERVOIR PERFORMANCE

Fig. 4 shows the primary and waterflood performance of the TBG reservoir. The reservoir was initially above the bubble point pressure by about 1800 psi, and did not have any aquifer support. The reservoir primary performance was typical of solution gas drive mechanism, with some contribution from rock and fluid expansion, where the producing GOR had increased from an initial value of 463 scf/STB to a high of about 820 scf/STB after six years of production.

The reservoir production peaked within three years of development to reach 330,000 STB/day of oil. During this period the reservoir pressure had declined from an initial value of 4272 psia to lower than the bubble point pressure, particularly, in the center of the field where most of the profile producers are located. Beginning the middle of 1971, the field production started to decline rapidly concurrent with a continuous increase in the producing GOR.

In 1970, a water injection pilot by dump flooding was started with four wells, while efforts were made to study, design, and construct the surface injection facilities. The waterflood pilot was developed into a major line-drive flood injecting a maximum of 350,000 barrels per day of water by 1974. Prior to the initiation of the water injection water production was insignificant. Within two years of injection the decline in reservoir pressure and the increasing trend in GOR had been arrested. This was also affected by reducing oil production through control of field allowable.

By 1975, the producing GOR had stabilized, while the reservoir pressure continued to increase until it reached a value higher than 3150 psia in September of 1986. However, as the water injection facilities had undergone major revamping efforts, water injection into the TBG was ceased by the end of 1985. Hence the reservoir pressure started to decline but at a lower rate than the initial decline as the field production was curtailed at the same time in compliance with the OPEC quota which was allocated to the Nafoora field.

After the initiation of the waterflood, the water cut increased to 28% and remained constant at about the same value.

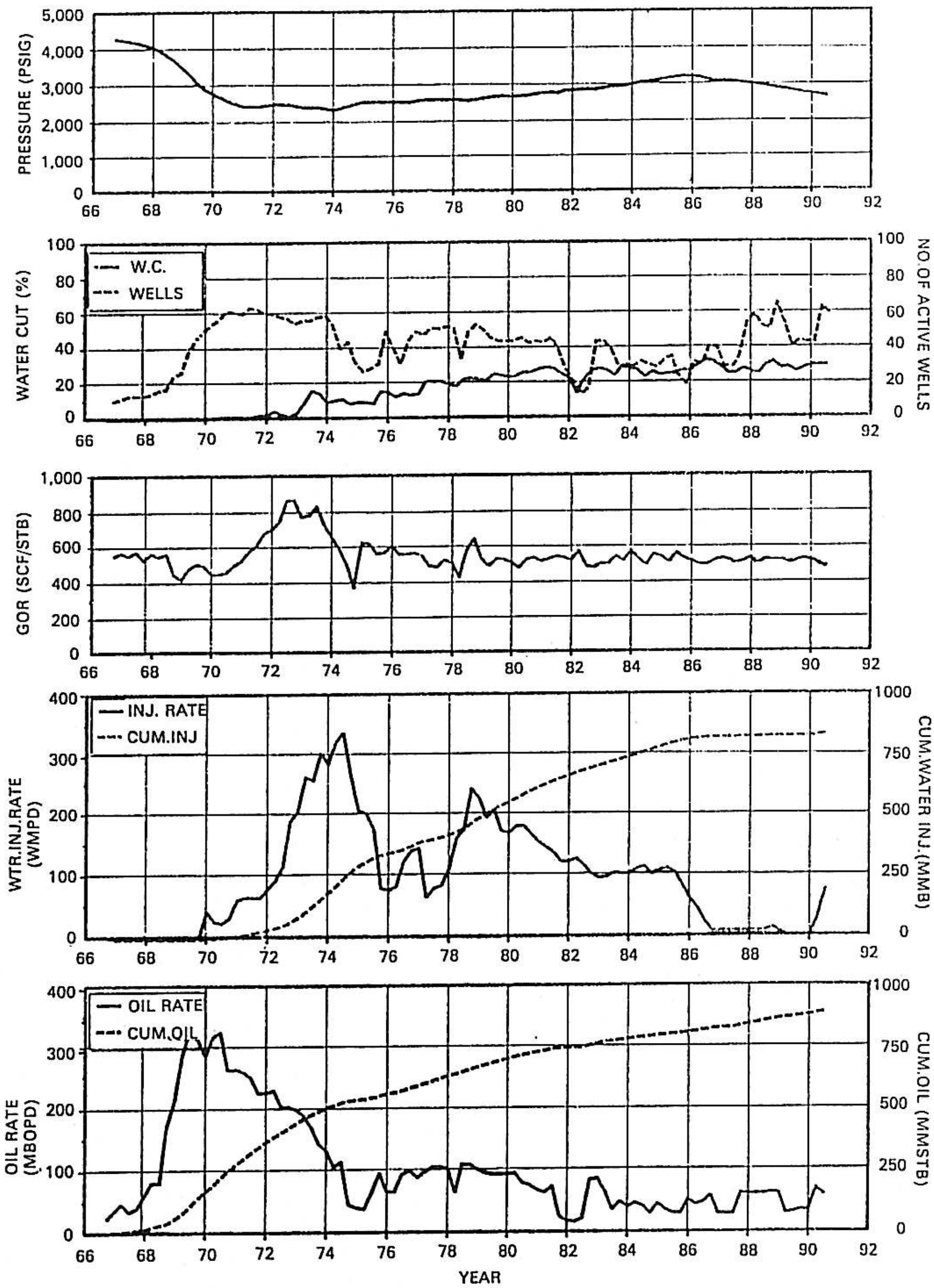

FIG. 4. Nafoora–Augila Unit/TBG Reservoir performance.

During periods of low production from the Unit the number of producing wells varied in an effort to control the level of pressure decline, and to maintain the GOR at an acceptably low values until the surface injection facilities are re-commissioned.

GRANITE OIL PRODUCTION

Indicators for granite production are taken from well completions, production tests, and production logs. Several wells have produced from the Granite, most significantly, wells G-20, G-54, G-62A, G-68, and G-243. Fig. 5 shows the location of these wells, and other wells that are known to have some flow contribution from the Granite.

Well G-20, which completed totally in the granite flowed initially at a rate of 3400 BOPD until it declined to 2000 BOPD as pressure dropped from 4300 to 2600 psi after 6 years of production. During this period it produced 5.5 MMSTB without any water production. It was then converted to an injector. No water production was observed.

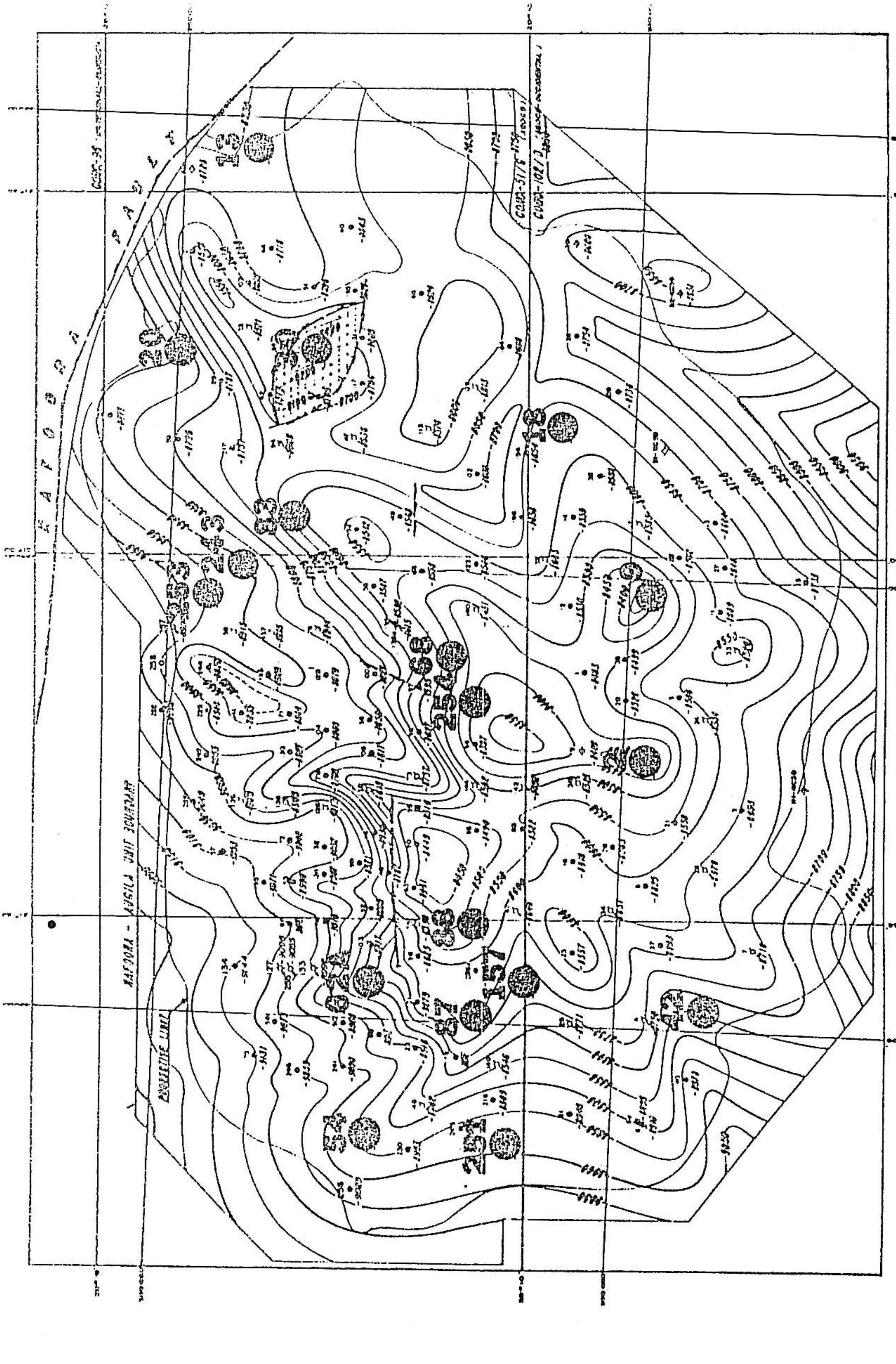

FIG. 5. Nafoora–Augila Unit (Granit STR Top). Well location.

Well G-54 flowed initially at a rate of 6950 BOPD, and declined to 3600 BOPD after four years of production That was caused by both, a drop in the reservoir pressure and an increase in water cut. Fig. 6 illustrates a cross section for this well. During this period it produced 7.3 MM STB before it was converted to an injector. Although this well was completed in the sedimentary rocks as well, production was only from the Granite as revealed from the production logs.

Well G-62a, flowed initially at a rate of 11405 BOPD declined to 7200 BOPD as the reservoir pressure dropped by 1800 psi and water cut increased to 15%. Water production in this well is attributed to water injection in the offset well G103-51 as suggested by the properties of the produced water. Well G-62a produced a total of 15.5 MMSTB before injection was initiated. Even though this well was also completed in the over-laying sediments, flowmeter surveys indicated that approximately 80% of the flow was coming from a set of perforation at the top of the granite.

Well G-68 was completed only in the granite, Figs. 7 and 8. This well flowed initially at a rate of 15750 BOPD, and then declined to 6900 BOPD with a cumulative production of 4.0 MMSTR. The reservoir pressure had also dropped by 1600 psi. The well was kept most of the time shut-in for nearly three years after the water cut increased to 70%. This water production was before the start of water injection in this area. The oil rate had fallen to a low of 1500 BOPD. As the reservoir pressure started to rise in response to waterflooding in the vicinity of well G-68, the water cut dropped to about 25% and the oil rate increased to an average of 5000 BOPD over the following ten years, Fig. 9. Production logs indicated that the flow was coming from several intervals down to 470 feet below the granite top, Fig. 10.

Well G-243, which was put on production in October of 1986, or about 20 years from the start of production from the field, had an initial rate of 4750 BOPD, declined to 1570 BOPD after cumulative production of 1.99 MMSTB. The decline was caused by a drop of 500 psi in the well's bottom-hole

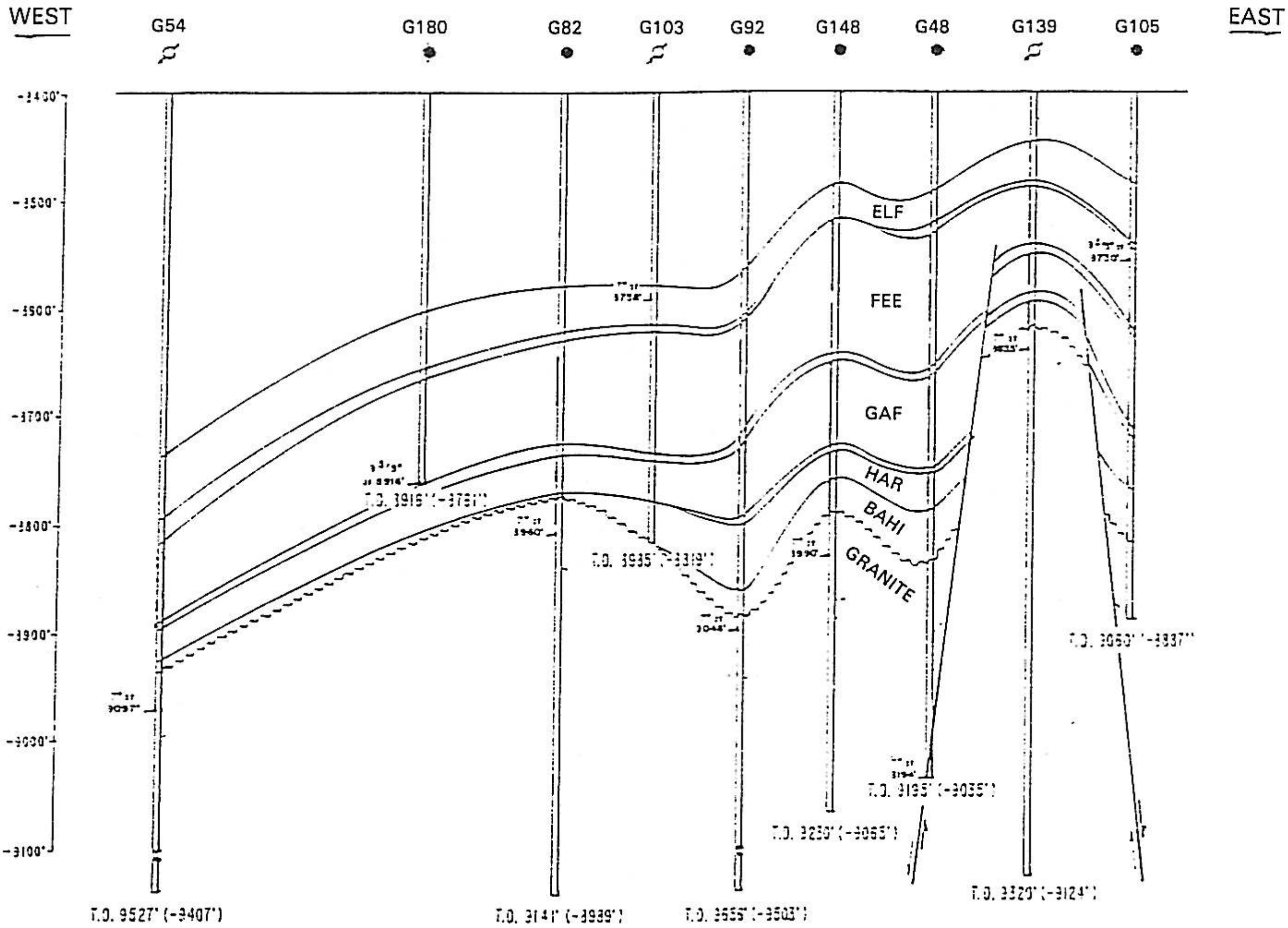

FIG. 6. Nafoora–Augila Unit structure cross section (Wells G54-G62).

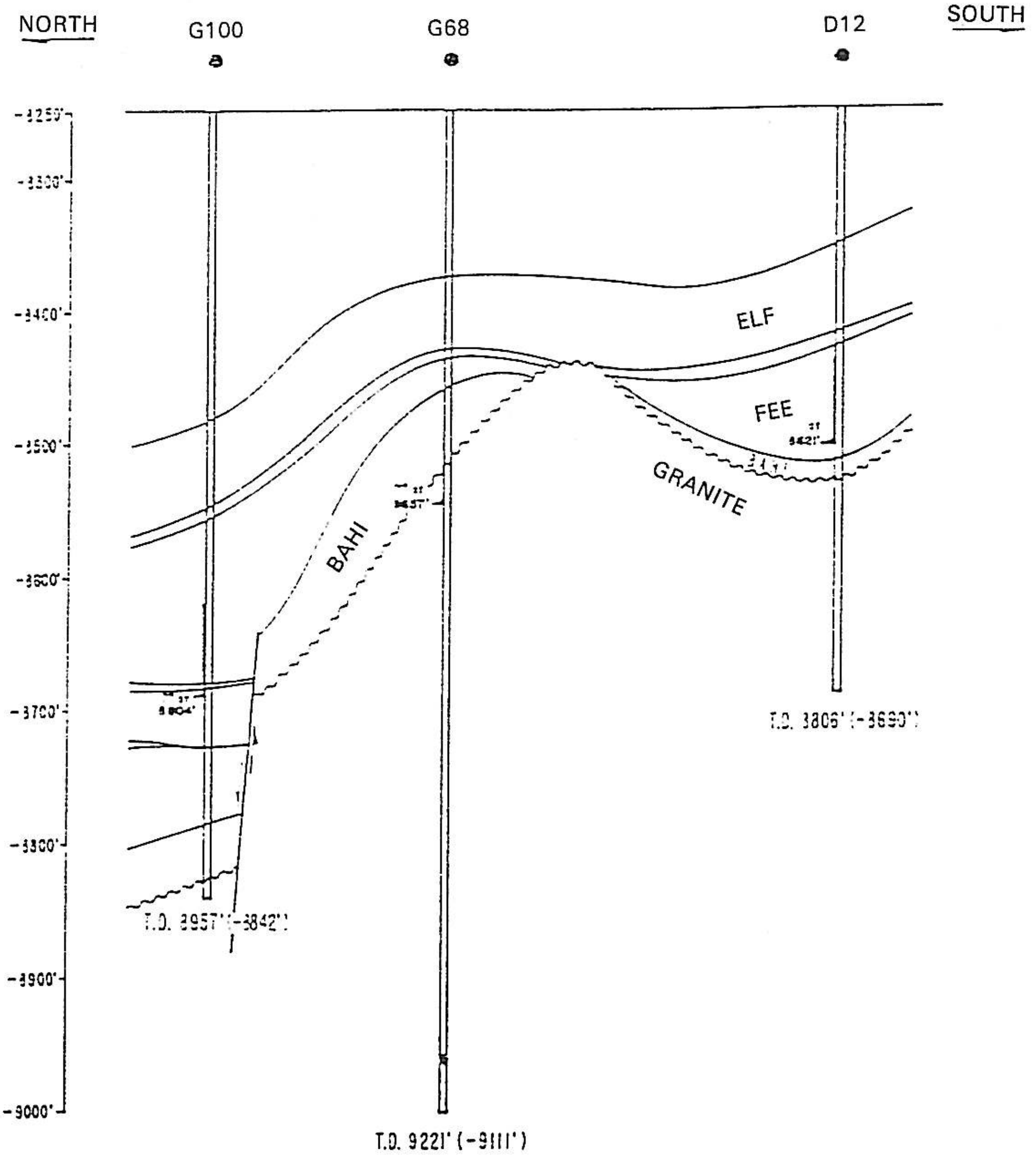

FIG. 7. Nafoora–Augila Unit structure cross-section (Wells G68) North-South.

pressure, which was 2970 psia when the well was first put on production in October of 1986, and an increase in water cut from 7 to 20%, Fig. 11. Production logs indicated that about 80% of the flow was coming from various granite intervals to a depth of 400 feet below the granite top, Fig. 12.

The productivity of these wells is a direct indication of Granite contribution to the field production, while the following is an indirect indication of the role of the granite as an important contributor to oil production:

1. The OOIP calculated by material balance is significantly higher than that obtained by volumetric calculations for the sedimentary rocks of the Tagrifet and the Bahi. The difference is accredited to the Granite.

2. Water cuts were observed to be quite low with reference to the large volumes of injected water in areas where the floodable pay is in very good communication with the granite.

3. A unique characteristic of wells producing exclusively from the granite is the very high salt content of the produced crude oil. This was also observed in some wells which are not known to be producing from the granite. It is believed that this could be as a result of oil being displaced from the granite to the overlaying sediments.

4. There are some wells that penetrated and were completed into the granite were not observed to be

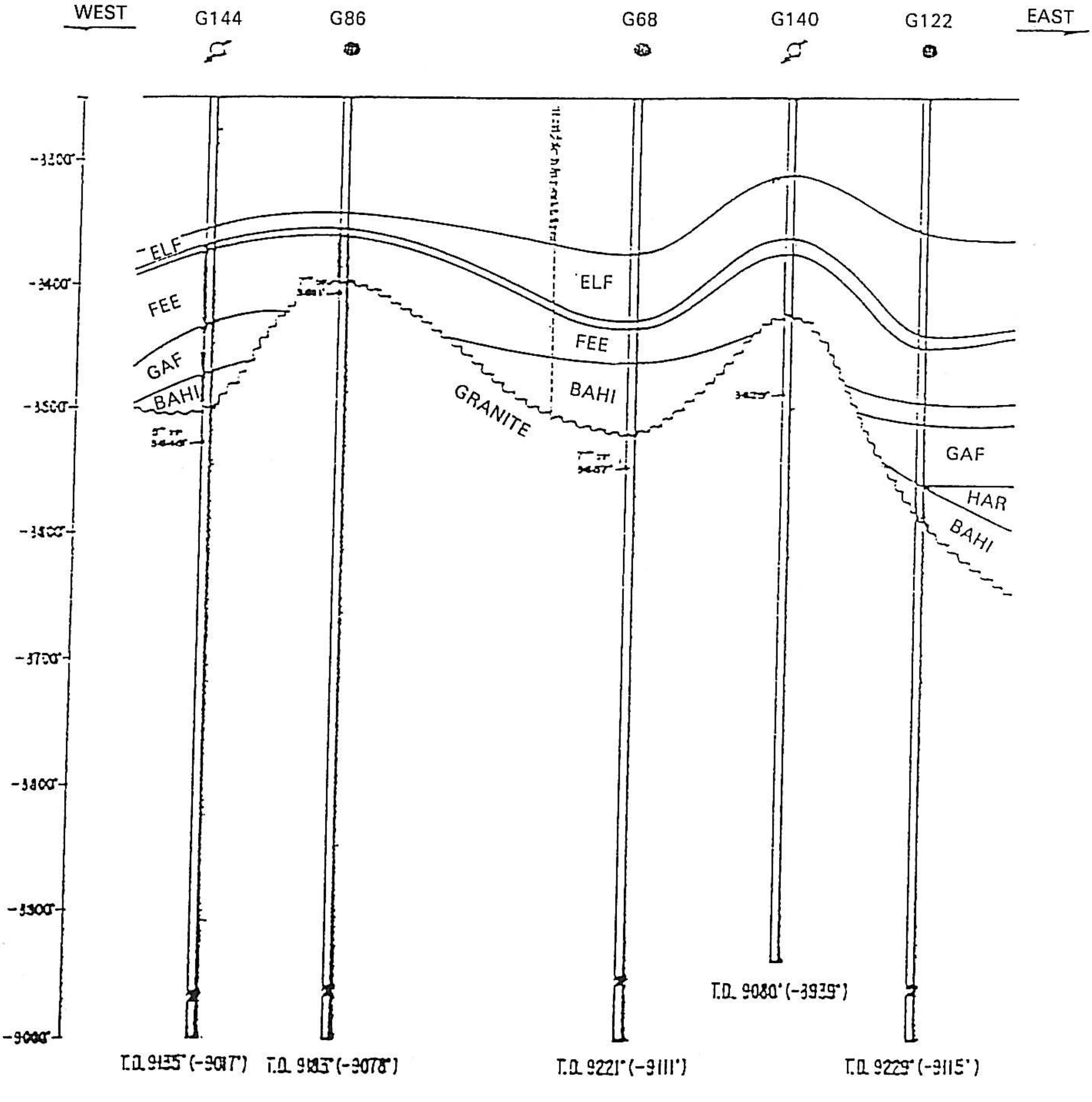

FIG. 8. Nafoora–Augila Unit structure cross-section (Well G-68) West-East.

producing from the granite. This may have been as a result of the fact that in some of these wells fracture intensity is so small that their production could not be detected by the flowmeter, and/or because of the lack of response to acid treatments due to extensive formation damage by drilling fluids, which could have plugged the fractures. Furthermore, exposure of the fractures to cement could cause permanent damage.

WATER PRODUCTION FROM THE GRANITE

Although no definite oil-water contact was established in the TBG reservoir of the Nafoora--Augila Unit, wells G-54 and G-68 starting cutting water after producing about 6.5 and 4.0 million barrels of oil, respectively, and before the start of water injection. This led to the belief that there could be a limited aquifer, but of low permeability, possibly existing

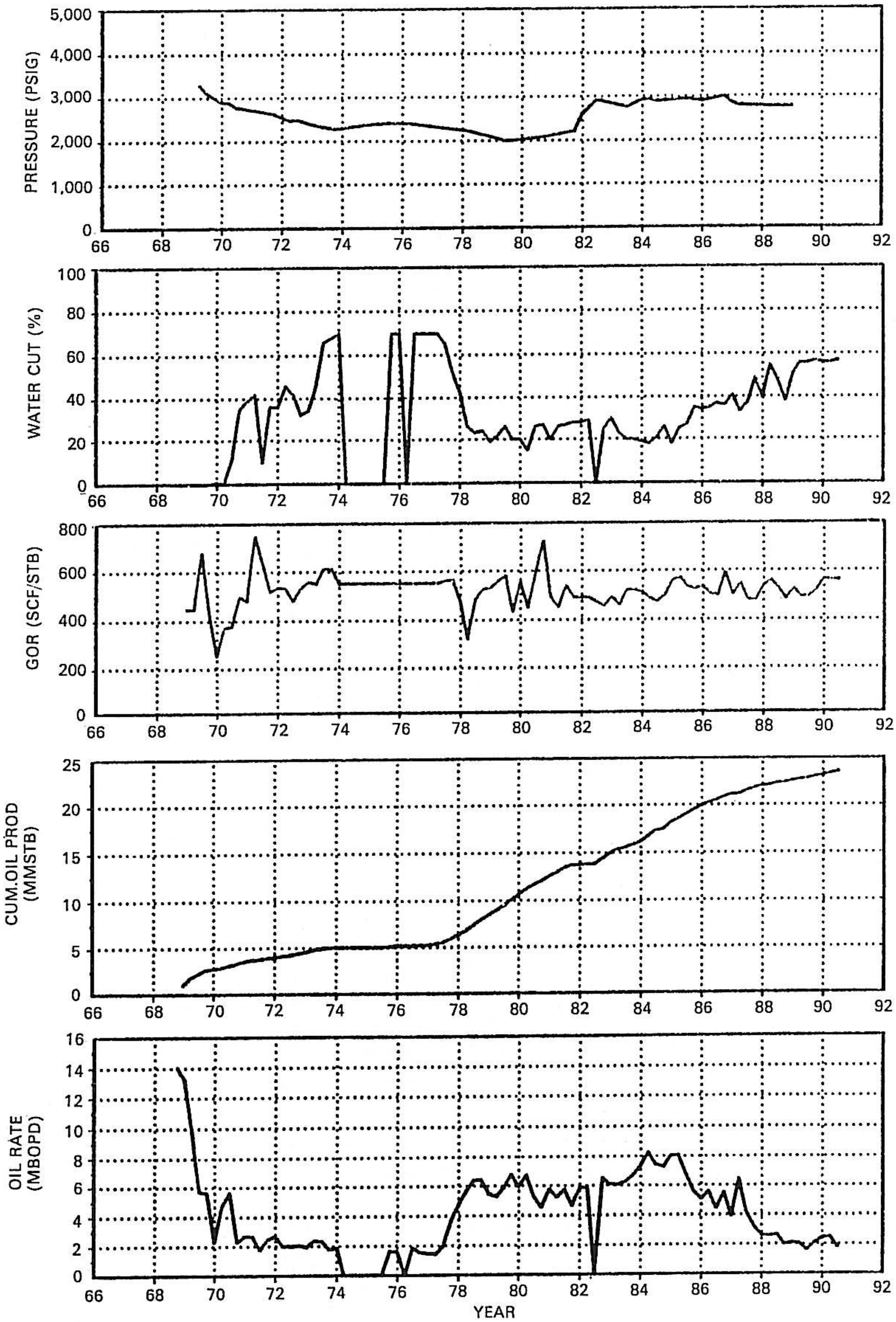

FIG. 9. (G-68) Well performance (Nafoora–Augila Unit).

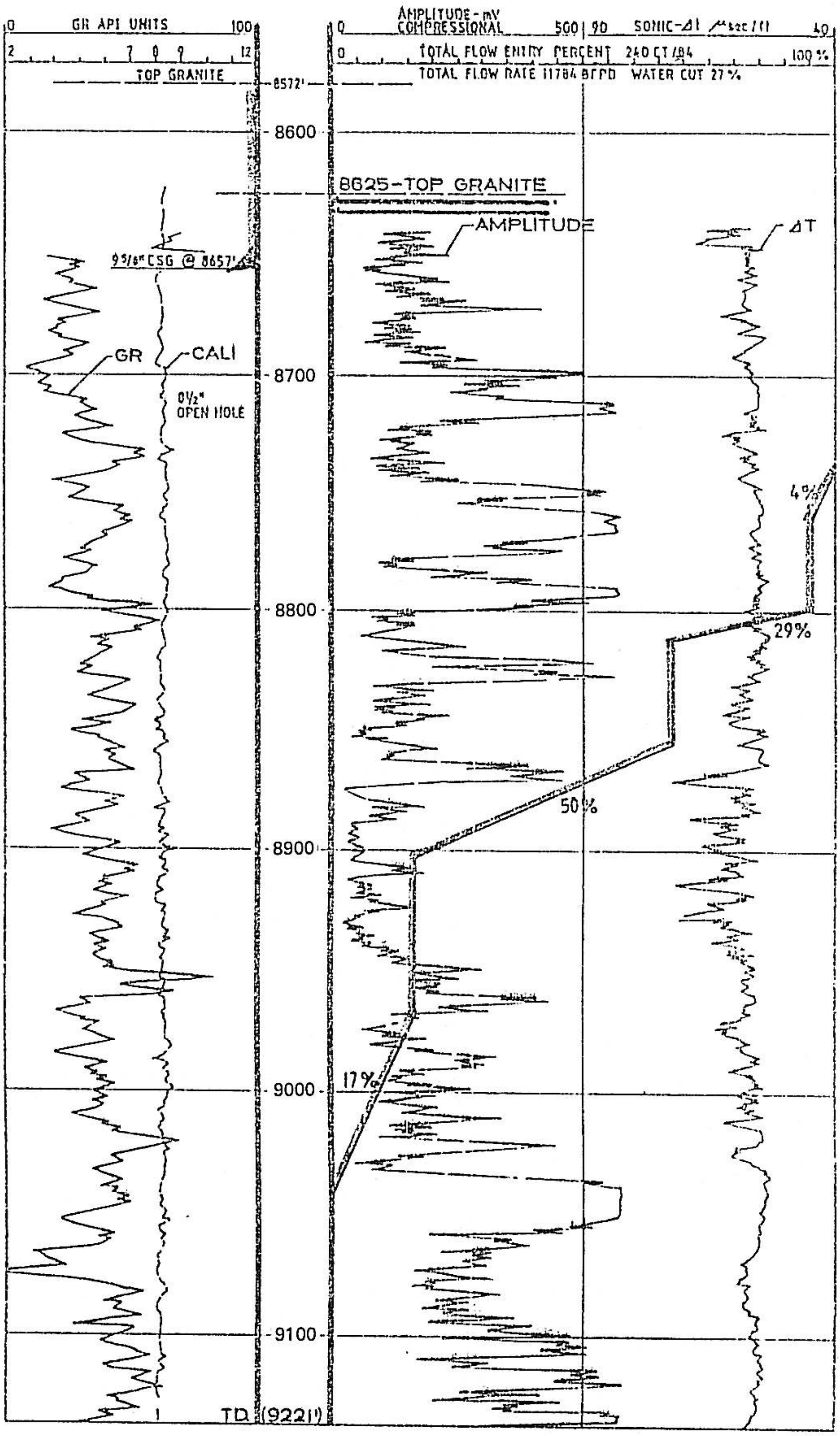

FIG. 10. Production logs (Well G-68).

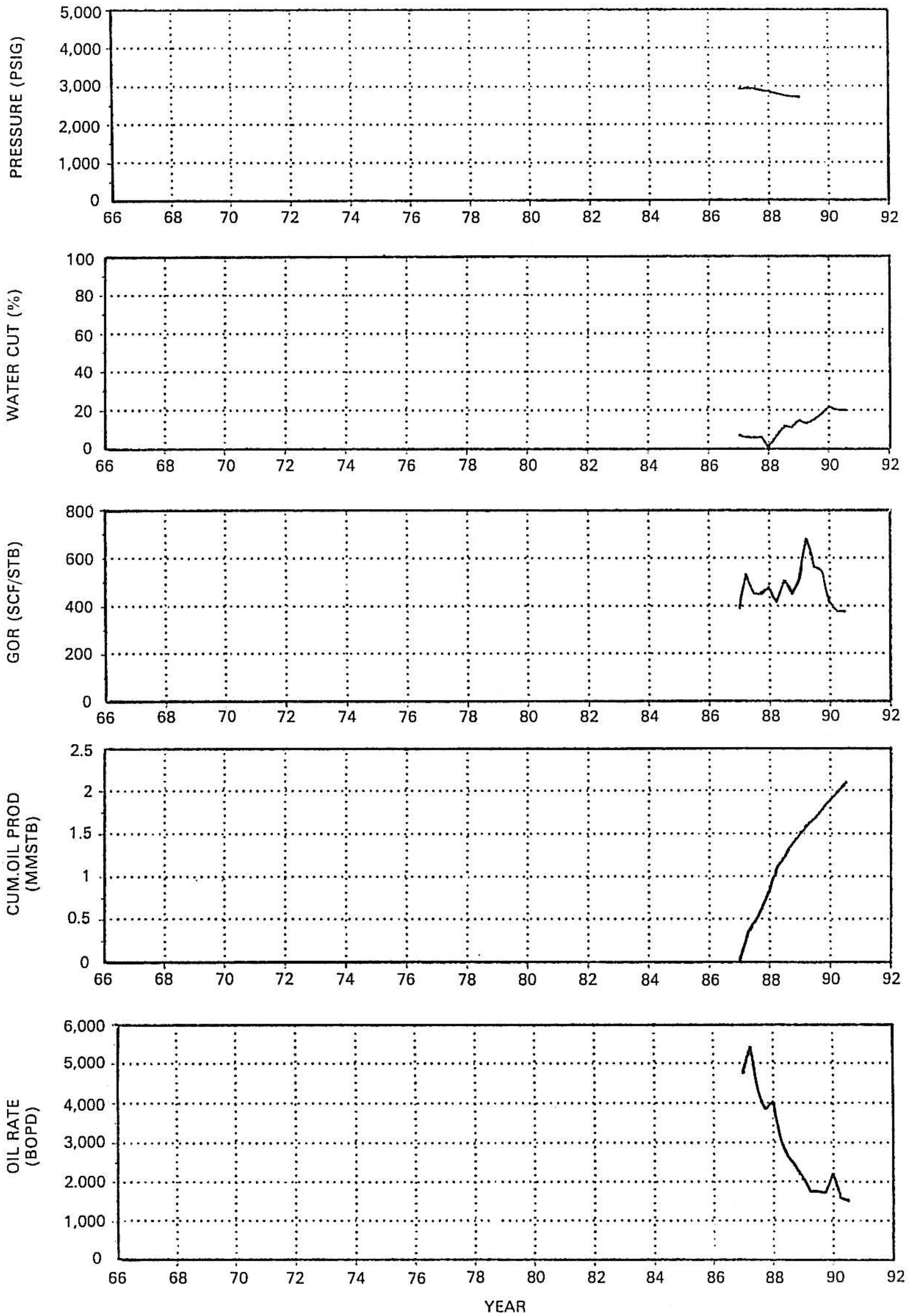

FIG. 11. (G-243) Well performance – Nafoora–Augila Unit.

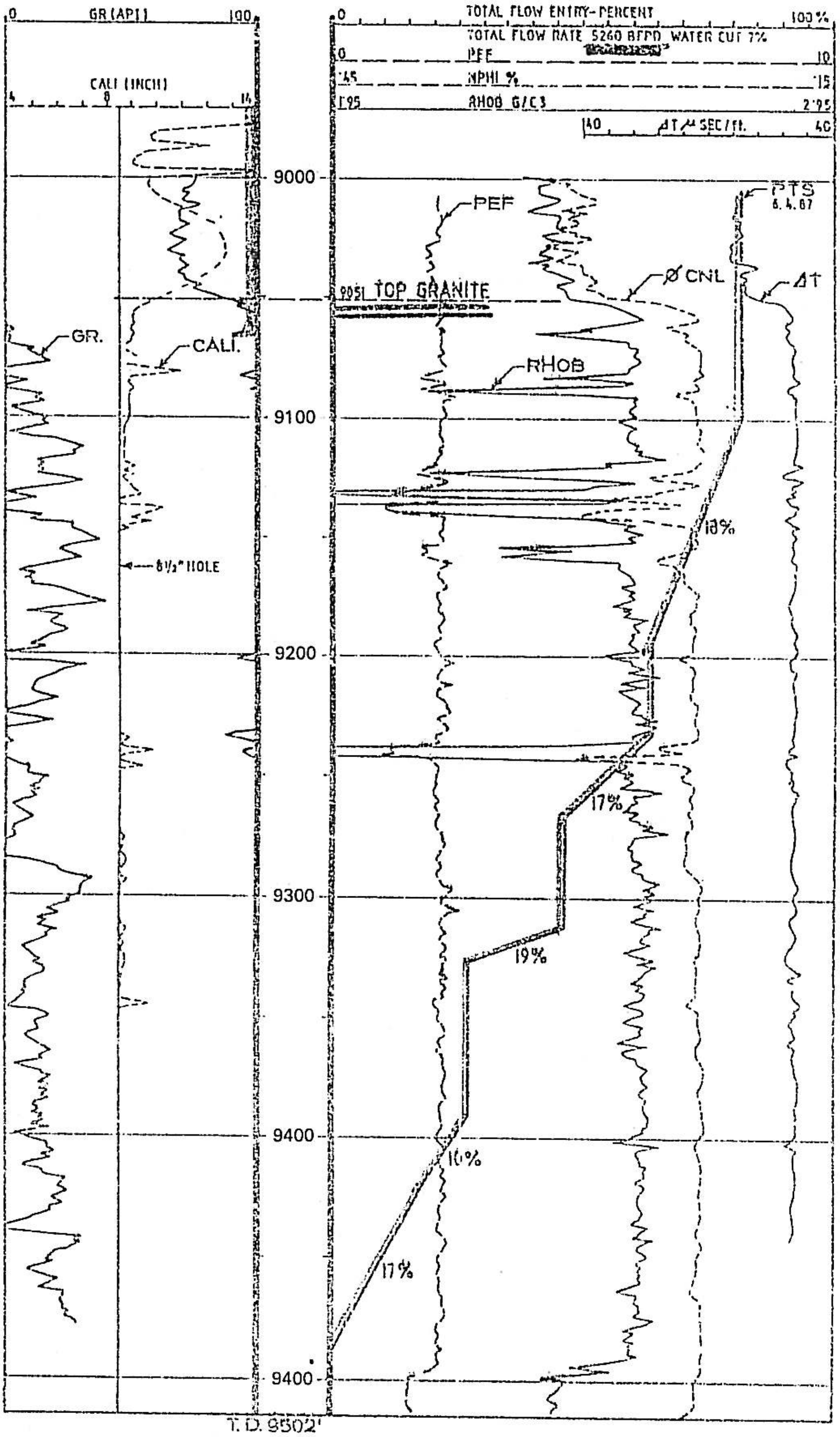

FIG. 12. Production logs (Well-G243).

within the fractured basement. Furthermore, water could have possibly channelled from the overlaying sediments with high initial water saturation.

CONCLUSIONS

- Fractured basement can be productive reservoirs under favorable geological conditions.
- The Granite of Nafoora--Augila Unit was found to be fractured and deeply weathered to as deep as 1000 feet below the Granite surface.
- Fractures can be detected by several Open-Hole logs, partial mud loss and a sudden decrease in drilling time.
- Direct and indirect indicators can be used to verify oil production from the Granite.

ACKNOWLEDGMENT

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