MINISTRY OF EDUCATION OF AZERBAIJAN REPUBLIC

KHAZAR UNIVERSITY

SCHOOL OF PETROLEUM ENGINEERING &APPLIED SCIENCE

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Ph.D. Dissertation

INCREASING OF HYDROCARBON RECOVERY OF NUBIAN RESERVOIR

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BAKU _2007

ABSTRACT

INCREASING OF HYDROCARBON RECOVERY OF NUBIAN RESERVOIR

The present dissertation is devoted to topical research problem-efficiency increasing of Nubian reservoir development with the object of enhancing hydrocarbons recovery.

The urgency target of a dissertation subject is proved and the brief review of research dissertations in the given area is made.

The brief geological and operational characteristic, current development analysis and operating well dissertation conditions of the Nubian reservoir of Bu-Attifel oil field is described.

Practical experience of production process of the long period developed oil and gas fields' shows that at the certain stage of development the most authentic prediction of recoverable reserves can be received by application of evolutionary model.

Using evolutionary approach of modeling the recoverable oil reserves of Nubian reservoir were determined.

Hydrocarbon reserves more precise definition for the target of improvement of the further development of Bu-Attifel oil field Nubian reservoir was carried out.

Based on field data hydrocarbon reserves were recalculated by applying both the volumetric method and mathematical-statistical approach. The results of oil reserves calculations are commensurable with those made in oilfield.

Hydrocarbon reserves calculation by the mathematical-statistical method differs from others by its more precision, less time and labour-consuming.

Based on development performances hydrocarbon recovery factor of the Bu-Attifel oil field Nubian reservoir were predicted.

The problems of improving of development process and stimulation of oil production on considered reservoir were investigated.

Enhancing formation oil recovery methods - such as secondary (water and gas injection) and tertiary (thermal recovery and forced fluid withdrawals etc.) are suggested.

The appropriate recommendations were suggested on the subject of efficiency increasing of Nubian reservoir development with the object of enhancing hydrocarbons recovery further development.

At the end of dissertation, the suitable conclusion was made.

References are given at the end of the dissertation.

The results of the carried out researches can be put into practice at drawing up of the further development program scheduling, hydrocarbon reserves calculation, the analysis and the control of development.

The dissertation includes pages 115, graphs 38, formulas 29, tables 11 and slides on the CD.

CONTENTS

INTRODUCTION

I. Topicality of the Subject. Developed oil industry of the country is required to intensify of oil production by discovering new oil fields, and at the same time. intensifying oil recovery from long-term developed old oil fields. For that it is necessary to increase oil recovery efficiency of Bu-Attifel oil field, one of richest fields of the country. Different ways should be studied to increase oil production in the field. They are:

1. Developing of exploration and drilling in field area;
2. To analyze oil field development process;
3. To specify hydrocarbon reserves;
4. To determine wells interaction;
5. To estimate ultimate oil recovery factor;
6. To design methods of increasing oil recovery factor;
7. To design plan of improving development of investigated oil field.

II. Object of the Dissertation. The present dissertation main aim is based on field development data to revise and analyze reservoir development process in detail. For this purpose, the following problems were considered on this dissertation:

1. General geological, physical and technological field data for the investigated reservoir were gathered, generalized and processed.

2. Geological and operational characteristics, reservoir system physical and chemical properties, development current conditions and well stock operating work were analyzed.

3. Hydrocarbon reserves were revised in detail.

4. Oil recovery factor was predicted and reservoir development efficiency increasing measures were investigated.

5. Recoverable oil reserves were investigated.

6. Based on field production performances and using correlation analysis determination of oil stagnant zones and option of ways involving those into production were provided;

7. Establishment of optimum behavior of producing wells was considered.

8. Problems of improvement of reservoir development process and stimulation of hydrocarbons production rate was investigated.

III. Ways of Solving of Problems.

1. Analysis of field data by using update mathematical and statistical methods;

2. Using the modern computing programs in prognosticating of oil field performances.

IV. **Scientific Novelty.**

1. The oil stagnant zones were defined in development process;

2. To bring the stagnant zones into production the location of new drilling wells were established;

3. Drowned wells production behavior was established.

4. Based on real field data the oil production mathematical model was designed;

5. Using update computer programs oil reserves and oil recovery factor were prognosticated.

V. **Matter of dissertation.**

The dissertation includes introduction, four chapters, conclusion and reference.

In introduction the topicality, object, ways of problems solving and scientific novelty are stated.

In Chapter1 exploration & development history, the brief general field geological & development characteristics of Bu-Attifel (Nubian Sandstones OO Structure) was described. Geological Features (stratigraphy, tectonics, oil, gas and water content, rock properties, drive mechanism etc), reservoir zoning & petrophysical analysis voir further development bringing into development new production wells are sug gested. Applying of evolutionary modelling recoverable oil reserves for Nubian reservoir was computed. The operation conditions of drowned wells of Nubian Reservoir are analyzed. Optimum operating practices of producing wells by the dynamic analysis of the field material are established.

Current water cut of production wells reaches 14.8 %. Water is shown in all wells of a reservoir, in particular, in well OO1.

Results of researches provided show that, it is necessary to pay special attention to prevention of water cutting of well production. One of methods of struggle with water cutting of wells is considered studying of well log and realization on it selective perforating, excluding thus simultaneous shooting water-bearing inter-layers.

In Chapter3 hydrocarbon reserves classification, groups and categories are considered. Based on field data oil reserves were computed by volumetric and mathematical-statistical methods. The results received shows agree with field performances. Using mathematical-statistical approach current and ultimate oil recovery factors were investigated. Current oil recovery factor is 0.3462, and ultimate factor makes 0.36. It dictates the idea to plan the measures for further increasing of the reservoir oil recovery factor.

Chapter4 devoted to the problems of improving of development process and stimulation of oil production on investigated reservoir. Measures of stimulation of oil production and conditions for application of oil recovery methods are described. In particular, enhancing formation oil recovery methods - such as secondary methods (water and gas injection) and tertiary methods, between them thermal recovery methods and forced fluid withdrawals, and so on were sufficiently analyzed. Taking into consideration the specific conditions of Nubian reservoir of Bu-Attifel oil field for stimulation of oil production and enhancing formation oil recovery the appropriate recommendations were suggested.

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At the end of the dissertation considered appropriate conclusions were made and corresponding references were brought.

The Development of the Libyan Petroleum Industry-A Historical Background

Libya is the fourth largest country in Africa with an area of about 1,775,500 km^2 mostly covered by the Sahara desert, with no flowing rivers and scarce vegetation, would probably have not been existing on the economic map of the world, if it had not been for the vast oil reserves which were discovered in the late 1950's and during the 1960's by the international oil companies which determined the locations & the economic map of oil fields as shown on the figures (1, 2).

Beginning of the Exploration Activities

Early exploration activities in Libya were carried out by the Italian Oil Companies during their occupation of the country in the beginning of the 20th century. In 1914 methane gas shows were observed during the drilling of water wells near Tripoli. Prof. Aridito Desio from University of Turin conducted a geological survey in the country during the 1930's for the Italian State Oil Company.

In 1939 a report on the Libyan oil potential was prepared for the Italian Government but these activities came to a halt after the Italians were defeated by the Allies at the end of World War II.

The post-war period did not see any serious exploration activities due to the political uncertainties of the country and the presence of land mines, in addition to the lack of adequate geological studies of the region.

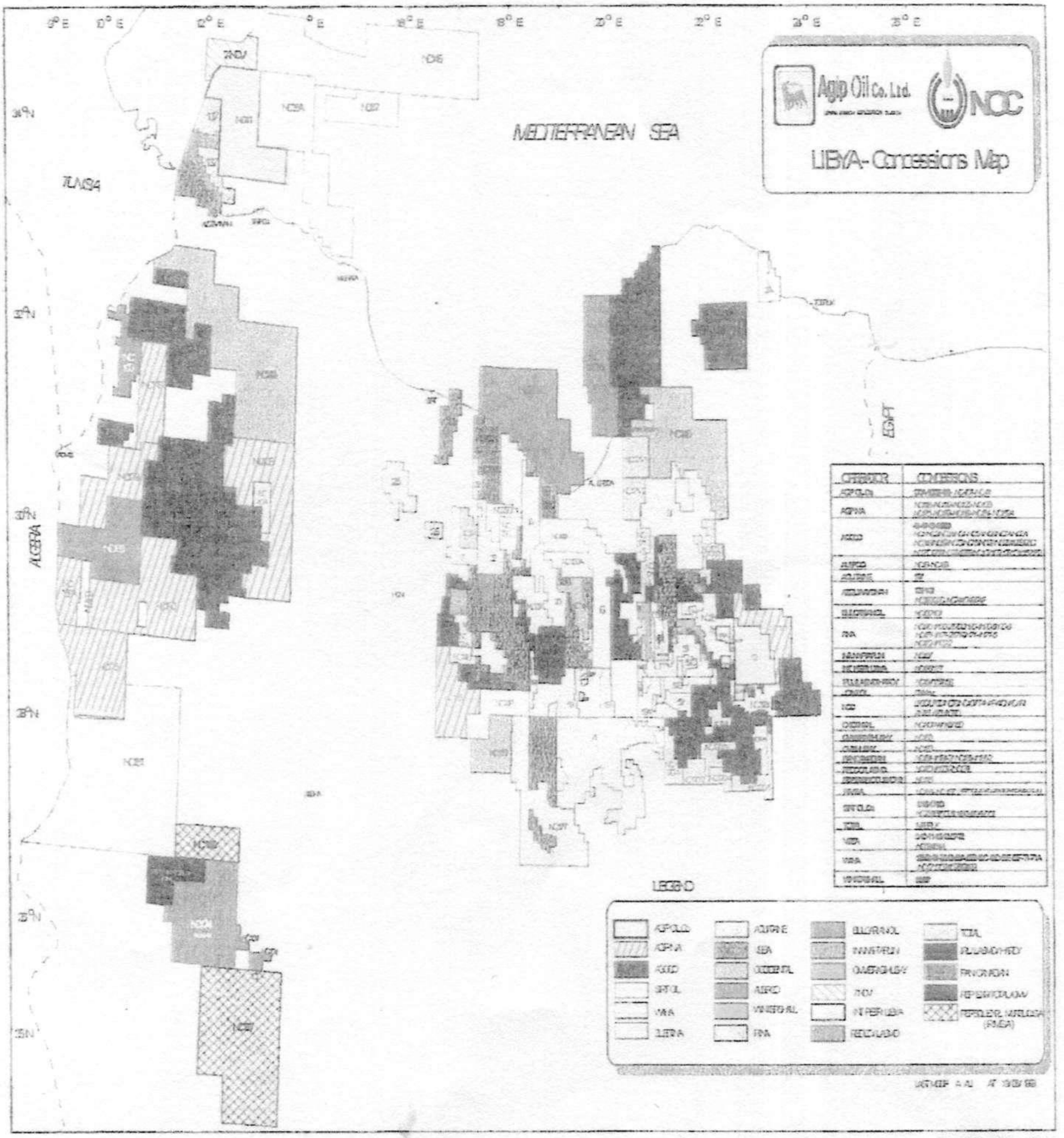


Figure1.General Location Map of
Libian Jamahiria Oil Fields

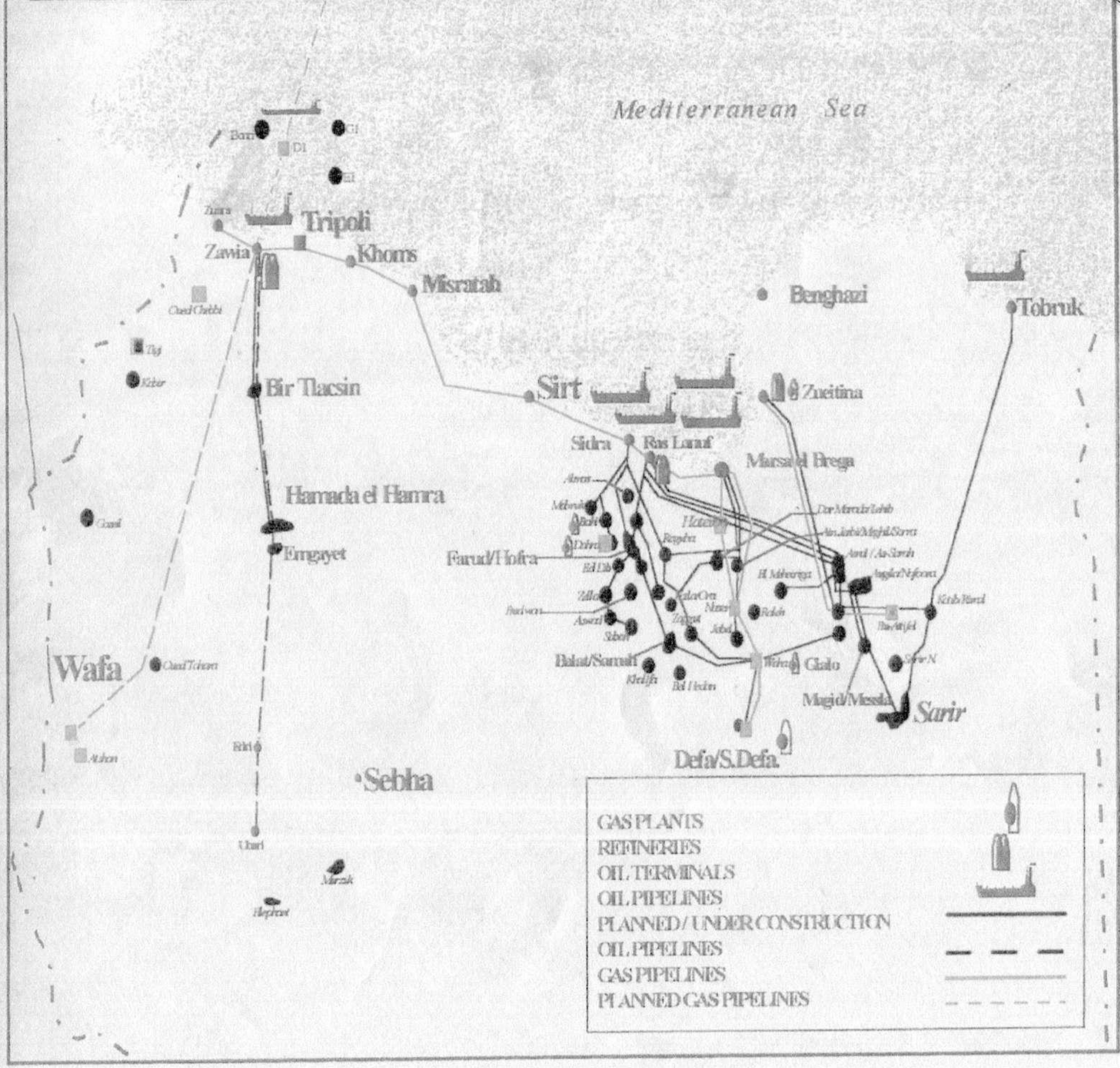


Figure 2.Oil and Gas Objects of Libian Jamahiria

CHAPTER 1

GEOLOGICAL & DEVELOPMENT CHARACTERISTICS OF BU-ATTIFEL OIL FIELD (NUBIAN SANDSTONES OO STRUCTURE)

CONTENTS

CHAPTER 1

GEOLOGICAL & DEVELOPMENT CHARACTERISTICS OF BU-ATTIFEL OIL FIELD (NUBIAN SANDSTONES OO STRUCTURE)

1.1. Geological Characteristics of Bu-Attifel Field (Nubian Sandstones OO Structure)

Reservoir Characteristics

The Bu-Attifel field is one of the richest Libian oil field. It was discovered in the Sirte Basin, about 400 km South-East of Benghazi, in 1967 and oil production targeted in March 1972, at an average depth of 4,200 m s.s.l (subsea level). It 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 and geometrically schematized as a monocline.

The Nubian reservoir depth ranges from 3612 to 3765 m s.s.l and the original oil in place was estimated to be 109.8 MMSTB. In 1992 it was decided to build a new reservoir model able to guide the final development phase.

The problem was the optimization of location and the number of the new wells (oil producers, water and gas injection wells if are necessary) to be determined.

The oil bearing rock (Nubian Sandstone formation of a Top Lower Cretaceous age) is a fine to coarse grained sandstone with interbedded shale and shaly-siltstones.

Its net pay thickness ranges from 75 to 250 m, its inter-granular porosity from 14.1% to 18.5% and its horizontal permeability from a few mD to more than 1,000 mD.

The anisotropy ratio (vertical permeability/horizontal permeability) ranges from 0.48 to 1.23. The water saturation was estimated to be 16%. The initial reservoir pressure was 47.6 MPa and temperature was 115.5°C.

The crude has a 41°API gravity; its base is paraffin (wax content: 36.7%) with an upper pour point of 39°C.

The reservoir oil composition and its main to investigate the feasibility of a tertiary gas injection project to improve the final. The Nubian oil reservoir located in one of the giant oil fields in Libya desert (Libian Arab Jamahiria) which was called Bu-Attifel field (Figure 1.1.1).

OO Field Top Lower Pool Depth Map

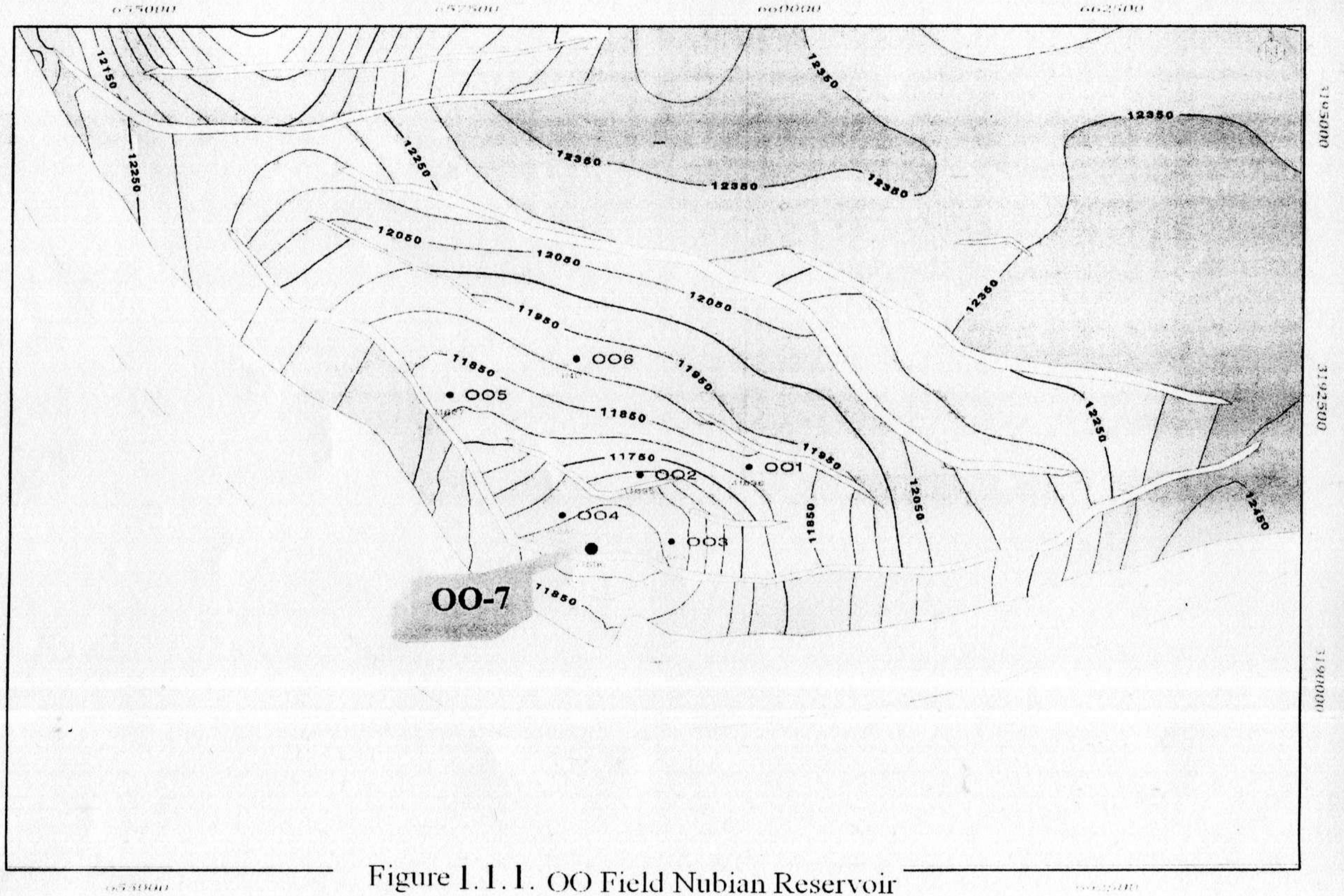


Figure 1.1.1. OO Field Nubian Reservoir

The water injection project was started in 1974. The oil production rate after maintaining an average volume of 24,000 m^3 per day is now decreasing.

It was therefore decided to increase oil recovery factor. At these conditions the oil resulted under-saturated. Volumetric Properties are summarized in Table. 1.1.1

Table 1.1.1

Volumetric Characteristics of Nubian Oil Reservoir

Type Sampling	Subsurface
Reservoir Temperature	115.5°C
Reservoir Pessure	5305.6 PSIG
O. R.V.F. (Bo)	1.4104
Bubble Point Pressure	3440.6 PSIG
Stock Tank Oil Gravity	41 API
Data at Reservoir Pressure Solution Gas (Rs)	731.2 scf/bbl
Reservoir Oil Density	665 kg/m^3
Reservoir Oil Viscosity	0.85 mPa.s

1.1.1. Exploration & Development History

Field History and Description

The Bu-Attifel field was discovered in 1967 in the Sirte Basin by Agip oil company at the end of sixties and put on stream in 1972. about 400 km South-East of Benghazi, with gross pay 250m. The oil bearing area extends for about 60 km. Oil production was started in March 1972 with 14 wells (five of them were located on Nubian Sandstones OO Structure). The reservoir section has an average thickness of 250 m, at an average depth 4205m. It consists of fluvolatile sandstones (Nubian Sandstones OO Structure) Inter-bedded with siltstones and shale's streak which can not be easily correlated over the field. Well recognizable lacustrine shale's are also present, mainly in the Eastern part of the field. The presence considerably affects the vertical communication through 13 geological sandy layers. The field oil gravity 41 API (Nubian reservoir between 37.1-38.8 API) is under-saturated at the initial condition and the saturation pressure varies with depth as well as the solution gas (Tab1.1.1.1 and 1.1.1.2).

Table 1.1.1.1

Average Rock Properties

Average Swi	17%
Sorw	17%
Krw,max (at Sor)	0.35
Krow,max (at Swi)	0.80
Sgc	5%
Sorg	10%
Krg, max	0.55
Krg, max (at Swi)	0.88

Table 1.1.1.2

Reservoir Fluid Properties

Depth, ftssl	12700	14200
Oil gravity, API	41	
Bubble Point Pressure, Psia	6600	5000
Oil FVF, RB/STB	2.7	1.80
Solution GOR, Scf/STB	2900	1300
Oil Viscosity at pb, cp	0.18	0.24
Water FVF,RB/STB	1.05	
Water Viscosity at pb, cp	0.2	

The early phase of liquid production by natural reservoir energy depletion confirmed the total lack of water drive to the limited volume of the bottom aquifer.

After a strong depletion phase, in May 1974 at Bu-Attifel field water injection was set up and started from a row of wells located in the northern flank. Production has increased considerably in the last five years; the feasibility of an EOR tertiary process is being studied to improve the final oil recovery.

Today the technology and economic on the average leaves two barrels of oil in the ground for each barrel recovered world wide.

On the other hand the recovery factor of Bu-Attifel field is around 50% of which consisted around 33.6% of Nubian oil reservoir indicates substantial amount of oil remains in the ground after primary and secondary processes are completed.

Many techniques have been proposed and used to recover the remaining oil. Due to the nature of the reservoir and the current state of economics and technology miscible flooding had been selected to be investigated to improve the oil recovery in Bu-Attifel field.

The thirteen geological layers have been recognized and correlated in the reservoir. The vertical communication between all the layers is going on the western zone of the field. The lacustrine shale's layers, interbedd in the lower barriers in the eastern zone.

An over all plan were developed to study the possibility of implementing miscible flooding in Bu-Attifel field.

The plan consists of three phase's mathematical work, reservoir simulation and plot flooding as shown in the (Figure 1.1.1.1).

About 70 % of the mathematical work has been completed, PTV analysis miscibility pressure between Bu-Attifel crude & co_2 and lean, and swelling tested.

Currently core flooding of composite cores at reservoirs conditions being carried out at the following saturation conditions: initial water saturation, 50% water saturation & residual oil saturation. The natural pressure decline reached its peak in a few years after the reservoir brining into production and secondary gas cap was created.

Water injection was started from a row of wells drilled along Northern border of the field.

An oil field daily production of 150,000–170,000 bopd was maintained fairly constant.

About 30% original oil in place has been recovered and the actual daily injection rate was about 400,000 bwpd.

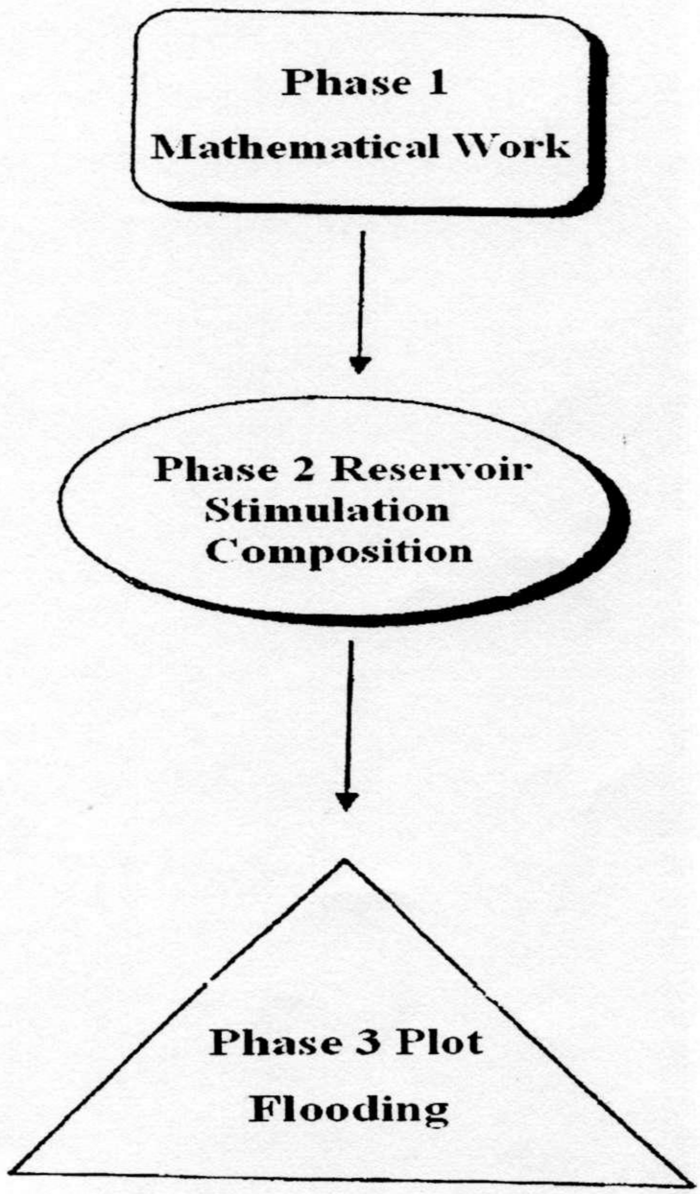


Figure 1.1.1.1 Project Plan of the Field

1.1.2. Rock Samples Studies

Selection of the Rock Samples

Since no core of the reservoir main area (Nubian Sandstone) was available for this study (most of the wells were drilled more than 25 years ago), some cores of a peripheral well, which was recently drilled for another reason, were used.

This non-availability meant that the great care had to be taken over the rock sample selection. A detailed petrography and sediment-logical study was performed in order to recognize the typical facieses of the main reservoir area of the Bu-Attifel field.

The study showed that the less cemented samples tend to show the best permeability. Moreover, a pore network study enables us to conclude the following:

1) Samples with permeability over 100 mD were characterized by well connected, large primary pores and relatively high porosity, with a low content in total authigeneses (quartz overgrowths, kaolinite and chlorite).

2) Samples with permeability ranging from 10 to 100 mD were largely influenced by sediment-logical features such as cross lamination. Along these features, stronger quartz cementation, more abundant pore-filling kaolinite and compaction-enhancing clay drapes were often observed; this deteriorates the pore structure which creates permeability barriers on a micro-scale.

Finally, a routine core analysis study was performed on plugs (5 cm diameter and 5-6 cm length) of the chosen cores and correlations based on hydraulic (flow) units were used to select rock samples in a wide interval of permeability values. (Figure 1.1.2.1) shows the plugs selected for the experiments.

They belong to the most frequent of the flow units occurring in the area designated for the gas injection. After saturating the selected plugs with water, Nuclear Magnetic Resonance Imaging equipment (MRI) was used to evaluate the type of heterogeneity of their internal texture and fluid distribution, without destroying them.

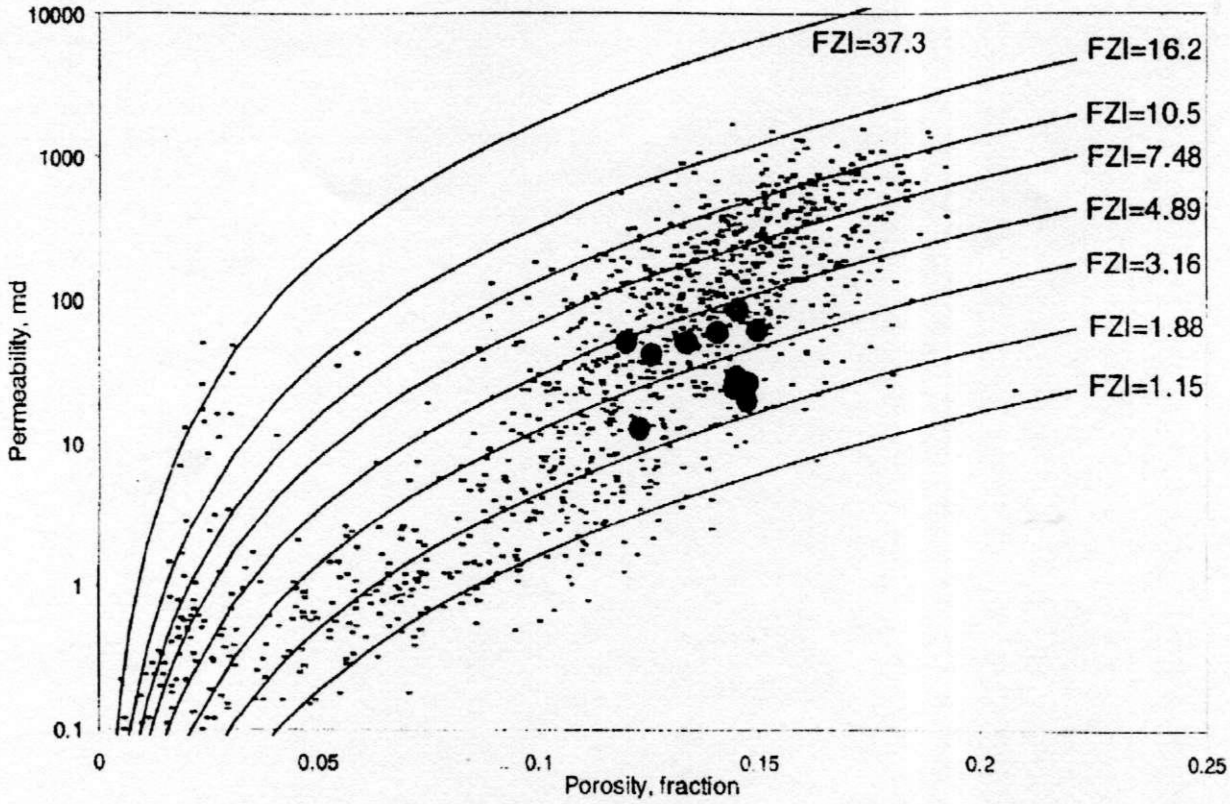


Figure 1.1.2.1 - Rock Samples Selection on the Basis of Hydraulic (Flow) Units

Analysis of the MRI images (the white zones of the images show the greatest water saturation. Water saturation decreases as the colour changes from white to black) highlighted four types of rock samples among the selected plugs:

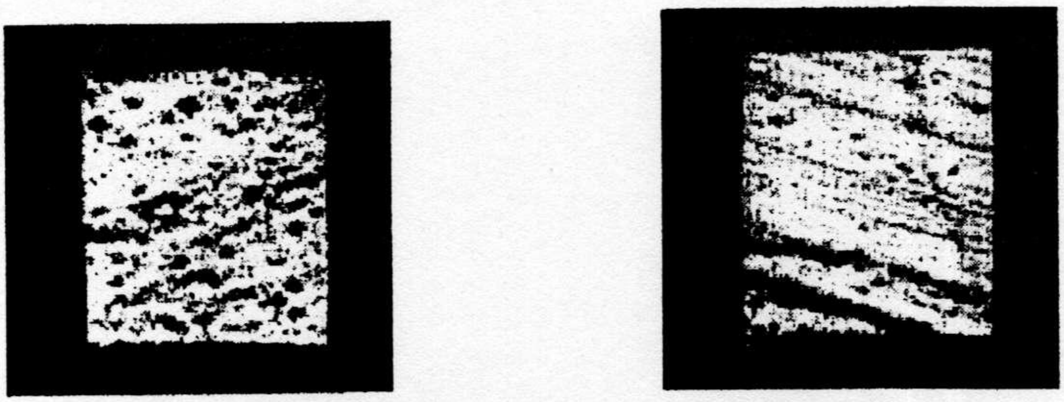
Type 1: Homogeneous Samples with Subrounded Nonporous Zones

The texture observed is probably due to cementation by patchy carbonates, commonly observed in Upper Nubian Sandstones; the other possibility is the presence of large-size quartz grains, but this is less likely, considering the normal grain-size of sandstone (Figure.1.1.2.2).

Type 2: Laminated Samples

The cross lamination, which is either well developed or barely visible, is highlighted by more or less saturated laminae; this is due to a reduction in grain-size and the presence of depositional or digenetic clays which produce a local permeability barrier.

The presence of laminae with very low fluid saturation may be due to the preferential precipitation of carbonate cements along these Laminae. This is also demonstrated by the occurrence of sub-rounded mm-porous zones in the laminae (Figure.1.1.2.2).



Quartz+Heavies	82 %
Feldsparts	0.5 %
Pseudo Matrix	0.5 %
Quartz Overgrowth Occlusive	1.5 %
Quartz Overgrowth Part. Occlusive	3 %
Carbonate Occlusive	1 %
Chlorite	3 %
Kaolinite	8.5 %

Quartz+Heavies	77.5 %
Orthomatrix	1 %
Matrix rim	0.5 %
Quartz Overgrowth Occlusive	2 %
Quartz Overgrowth Part. Occlusive	14.5 %
Kaolinite	4.5 %

Figure 1.1.2.2- MRI Images of Rock Type 1 and 2

Type 3: Homogenous Sample

Only faint depositional structures are present and saturation is fairly homogeneous. The dark, isolated, low saturated structure is probably the clay clasts (Figure.1.1.2.3).

Type 4: Heterogeneous Rock with Crude Lamination

This type of sample is quite common at the basal part of fluvial cycles, where uniformity of grain-size, cementation and occurrence of clay clasts is at a maximum. High porosity zones with very large pores can he isolated into a relatively less porous network with non-porous zones due to clay clasts or cementation (Figure.1.1.2.3). All the samples were water-wet.

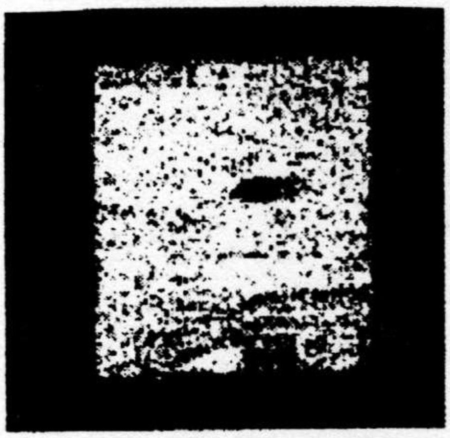


Figure 1.1.2.3- MRI Images of Rock Type 3 and 4

1.1.3 Reservoir Zoning & Petrophysical Analysis

Reservoir zoning was based on core and log data. The interpretation was carried out based on the cluster analysis study that is a useful correlation tool between core facieses and electrofacies.

The interpretative model tuned on the cored wells and then to all the other wells leads to the identification of four main lithofacies: sandstones, silts, shale's and volcanoes.

Thus, on the basis of this model and taking into account the six maim sequence identified by the sedimentological study, 13 layers were identified and correlated through all the wells by a network of 14 geological sections.

The net/gross, porosity and water saturation values were obtained by CPI analysis. Different net pay cases and the cores were made in the fully cored wells. The final cut of values of PHI = 7% and VSH= 15% were adopted.

The resulting net pay varies between 75 and 250 meters. The average porosity was calculated for each layer after verifying the correlation between core and log porosity. Horizontal permeability varies from few mD to more then 1000 mD.

The core data show a good correlation between porosity and permeability.

Oil Displacement Tests Experimental Procedure

All the oil displacements using water was carried out at a high-pressure and high-temperature rig shown in Figure.1.1.3.1. The selected core plugs were washed and saturated with formation water (209 g/l salinity) and brought to irreducible water saturation conditions using a synthetic oil and centrifugation. After MRI analysis all the samples were mounted in a suitable high pressure and high temperature core-holder inserted in a thermostatic air bath, 5—10 pore volumes (PV) of recombined oil were pumped through the plug at a flow rate (which varied according to the petro-physical parameters of the sample) of 2.4-3.2 m/day in order to measure the oil permeability under residual water saturation (Swi).

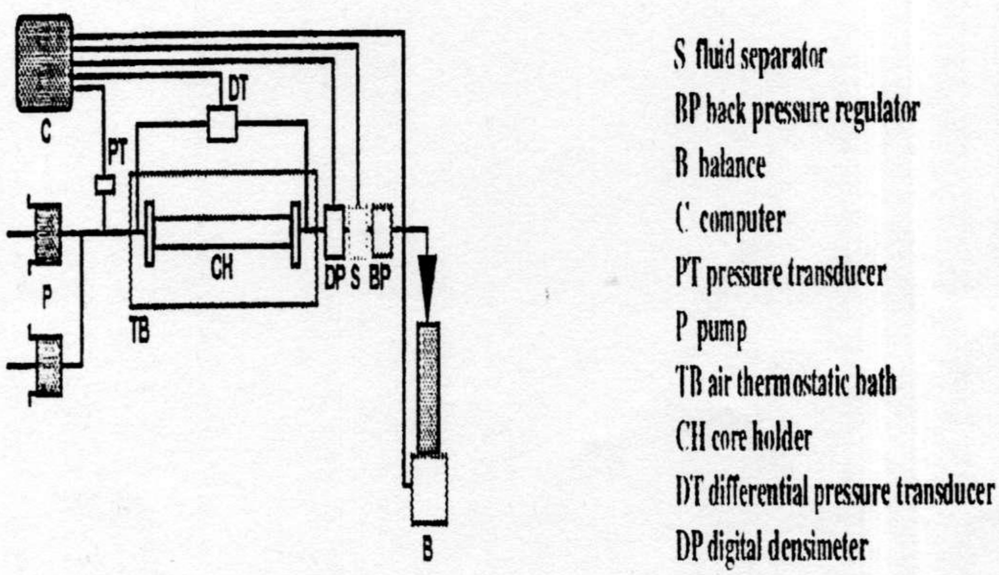


Figure 1.1.3.1 Sketch of the Experimental Flooding Rig

Water Injection

The oil recovery through water intentioned water-oil relative permeability were determined following an unsteady state method, whereby water was injected (10-20PV) at the same flow rate as recombined oil and oil production and pressure drop at the core ends were recorded. The relative permeability values at the end points were directly calculated from experimental data, the relative permeability curves were obtained using a calculation code based on an implicit method developed by Watson.

Flow Regime

All the liquid-liquid displacements were carried out under a capillary regime and in order to simulate the flow rate present in the bulk of the formation as accurately as possible under the current reservoir conditions.

In fact the capillary number (Nb), which is the ratio of viscous forces to capillary forces at pore level, was always less than 10-7. The critical Nb range for the capillary regime was estimated to be less than 10-5, for the water-wet rock. For the gas-liquid displacements, the bond number (Nb), which is the ratio of capillary to gravity forces, was checked.

Its value was very low and this means that the capillary-dominated regime took place for the fluids being studied, interracial tension and density values at reservoir temperature and at different pressures were experimentally determined. Table 1.1.3.1 shows the results obtained.

In particular, the interfacial tension between water-oil, gas-water and gas-oil systems was determined using pendant drop apparatus 12.

Table 1.1.3.1

Interfacial Tension between Different Systems

Pressure (MPa)	Oil		Enriched Gas		Interfacial Tension (mN/m)		
	Density (kg/m^3)	Viscosity (mPa.s)	Density (kg/m^3)	Viscosity (mPa.s)(°)	Oil-Water	Gas-Water	Gas-Oil
47.6	562.5	0.23	297.5	0.0386	24.0	32.3	<0.1(°°)
44.2	557.8	0.22	286.5	0.0367	25.2	33.4	<0.1
41.8	553.4	0.21	-	-	-	34.5	-
41.1	552.1	0.20	275.1	0.0349	27.0		<0.1

The viscosity of the enriched gas was calculated according to the Lohrenz-Bray-Clark correlation (1964) (00) MT values below the current instrumental limits.

PVT Study of Bu-Attifel Crude

A PVT study was carried out on the recombined oil of well OO3. The separator gas of 4117.4 psia was obtained from the gas chromatographic analysis. The separator oil was submitted to a flash test from separator condition to 14.5 psia and 240 °F (115.5°C).

The following standard determination has been carried out at reservoir temperature:

1- constant composition expansion.

2- different vaporization (13 steps below the dew point).

3- flashing of reservoir oil through laboratory separator (4 steps).

4- viscosity of reservoir oil.

Oil Displaced by Water

The scope of this step was to estimate residual oil saturation after the flooding process by using more realistic conditions (reservoir conditions) than possible when the conventional laboratory approach is adopted. The results of five tests are given in Table 1.1.3.2.

Table 1.1.3.2

Results of Oil Displaced by Water

Sample No	Pore volume (ml)	Fluid perme-ability	Swi, %	Sor, %	@Break through ,%	Final, %	Kro, @ Swi	Kro, @ Sor	Capillary number Nc
41	13.4	53	18.3	31.9	43.1	60.85	0.007	0.011	4.33.10
170	15.78	37	10.4	16.6	66.5	81.43	0.4	0.39	3.67.10
34	14.58	39	4.1	20.4	64.4	79.59	0.3	0.16	3.98.10
37	15.37	18.3	16.6	19.9	39.0	76.62	0.062	0.042	3.78.10
63.5	13.10	5.7	7.1	27.8	54.2	70.33	0.95	0.82	4.45.10

The lowest oil recovery, after the water flooding process of sample 41 (Rock Type 2) was due to its rock texture characterized by low permeability layers. These results were compared with those obtained under laboratory conditions in previous petrophysical studies.

As Figure.1.1.3.2 shows, the final oil recovery obtained during tests under reservoir conditions was lower, the main conclusion drawn was that the efficiency of the water-flooding process, simulated under reservoir conditions was poorer than that obtained following the conventional approach.

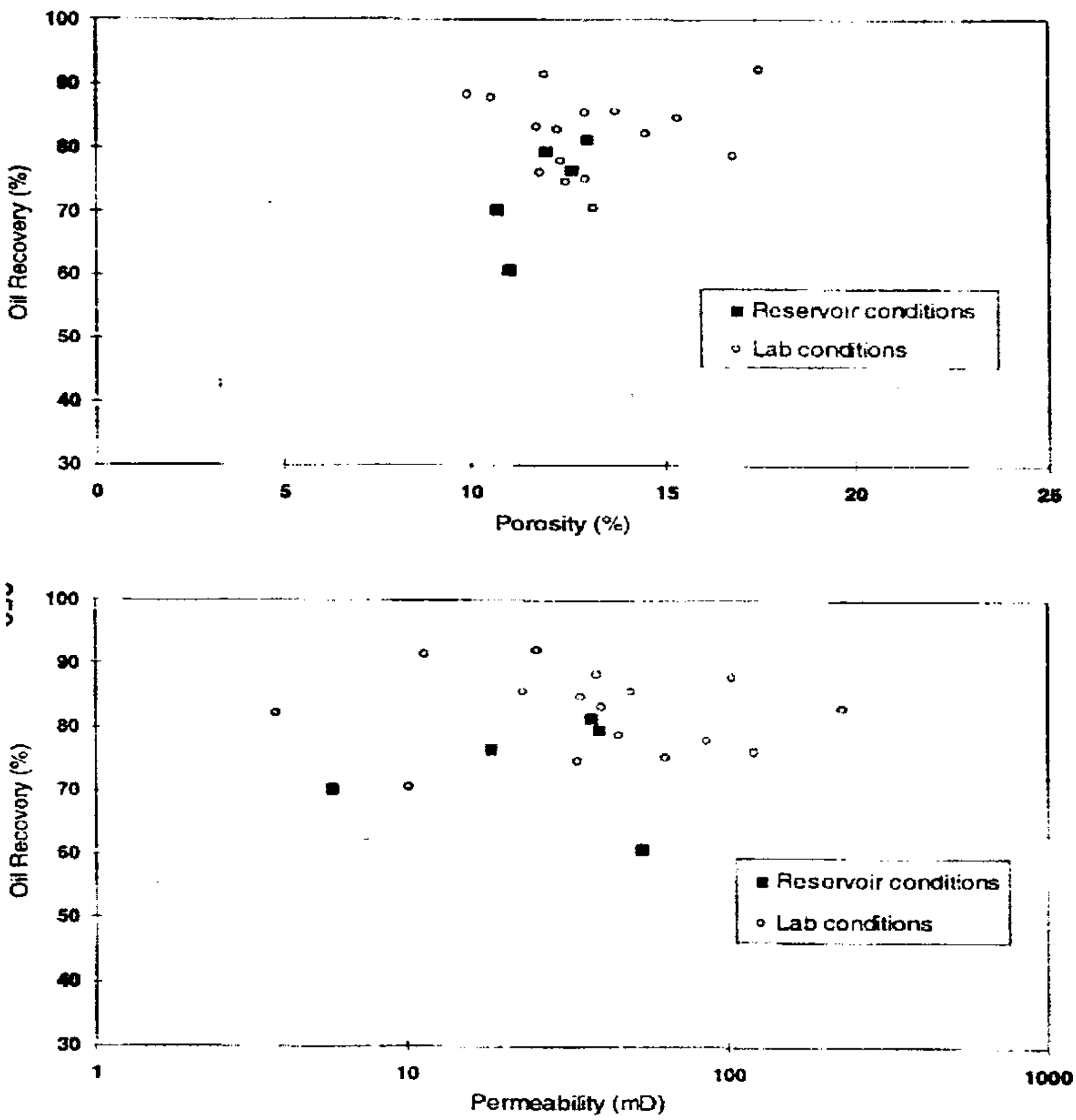


Figure 1.1.3.2 Flow Oil Recovery by Water Flooding vs Porosity & Permeability

The efficiency of the water-flooding process determined under reservoir conditions was lower than that obtained from conventional experiments which are usually carried out in laboratory conditions and with synthetic fluids.

For the water-oil system the peak values of the oil's relative permeability under reservoir conditions were up to 40% lower than those obtained from conventional (laboratory conditions) steady-state methods.

The enriched gas volume needed to recover a unit volume of oil under reservoir conditions was estimated between 2.000 Nm^3/m^3 (minimum oil saturation - Sor) and 300 Nm^3/m^3 (maximum oil saturation - Swi). The highest value of final oil recovery through enriched gas injection was obtained under irreducible water saturation conditions.

CHAPTER 2

DETERMINATION OF OIL STAGNANT ZONES

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CHAPTER 2

DETERMINATION OF OIL STAGNANT ZONES

2.1. The Correlation Analysis on Research of Interaction between Producing Wells

The purpose of the present paragraph is research of problems of enhancing oil recovery from the productive pay combined from non-uniform layers of collectors. The object of research is chosen Nubian reservoir (OO structure) of Bu- Attifel oil field.

Efficiency of process of development can be increased on the basis of the analysis of the current condition of development of a productive formation. Thus revealing of features of development will allow purposefully and with the least expenses to raise productivity of wells and as consequence to enhance oil recovery factor.

The analysis of a development condition of a reservoir includes a sequence of many procedures, following one of another. The considered reservoir is in development sufficient time.

Drilling of wells on a deposit is carried out according to the project of development. However, the most perfect project of development may not provide all features of process of development; it includes only the main principles following from an initial field data. Further specification of this project based on the geological and field information received during development of a deposit is provided. The given work is a basis of such specification.

On the basis of real operational performances areas of the worse filtration are established and ways of control of filtration fluid flow are planned with the purpose of uniform extraction of oil from all volume of a formation, not supposing thus of stagnant zones which to some extent promote decrease of oil recovery factor from a formation.

Now petroleum researchers conduct investigations, one of which directions, consists in application of various mathematical methods for processing the field data with the purpose of reception of a trustworthy information about a productive layer [1,2].

Being guided by it in the given thesis by calculation of factor of correlation between operating wells the degree of their interaction is established and comes to light areas with worse mobility of oil in place, (Figure 2.1.1) shows the schematic development map of Nubian reservoir of Bu-Attifel oil field from which it is visible that by the current moment 7 producing wells are under operation. The area of a deposit is broken by disjunctive dislocations on 5 tectonic blocks, 3 from which are commercially petroliferous.

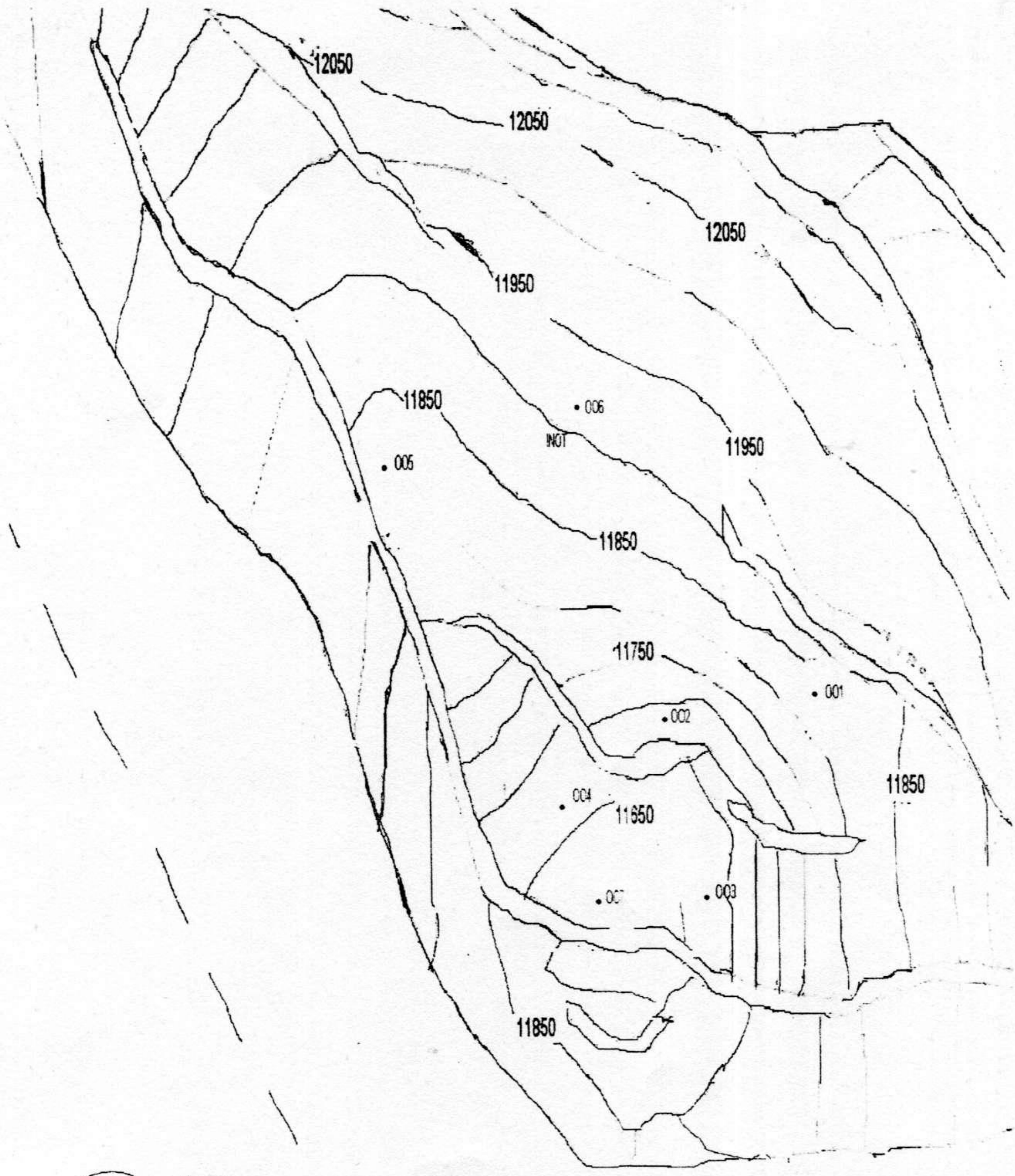
On the tectonic block I producing wells OO3, OO4, OO7 are located.

On the tectonic block II producing wells OO1, OO2, OO5 are located.

On the tectonic block III producing wells OO6 are located.

Preconditions for recovering of oil from all volume of a layer are great, however, for increasing of recovery factor it is necessary to carry out additional researches on the basis of the analysis of the collected field data.

One of works carried out in this direction is the correlation analysis on an establishment of interaction between producing wells drained of this deposit.



Isohipses

11950 Formation Break Lines

OO4-Producing Well

OO8-Projected Well

Figure 2.1.1 Schematic of Nubian Reservoir of Bu-Attifel Oil Field

2.1.1. Application of the Correlation Analysis for Definition of Oil Wells Interaction

Numerous geophysical, geological and field investigations indicate of presence in non-uniform productive pays of significant recoverable oil reserves which is taking place in stagnant and non-uniform drained zones.

The reasons of occurrence of such zones are features of a geological structure, manifestation of initial gradients of pressure and effects of irregularity at a filtration of multiphase flow through porous medium etc.

Existing methods of revealing of such zones, including hydraulic pressure test, tracer fluid injecting, the analysis in comparison of wells production rates do not allow simultaneously estimating influence of all set of wells of examined object from a position of uniform system of interacting elements.

The method developed on the department of "Oil fields Engineering" of Azerbaijan State Oil Academy (ASOA) is deprived the marked lack as allows to establish a degree of interference for any quantity of wells and on any time interval of their work. Here as an initial informative data massive of the time series of wells total liquid, oil and water production rates are used on co-ordination of which changes the degree of interaction of wells is defined.

Poorly drained areas of the productive pay are defined on the basis of the retrospective analysis of tendencies of hydrodynamic redistribution of formation fluid.

For these purpose parameters of communication between oil and water production rates of compared objects are used.

Decisions on regulation of process of development are defined by means of the account of periodicity, stability and the transitive conditions inherent in concrete objects and to formation system as a whole.

Calculations are carried out on the basis of application of rank correlation factor of Spearman when absolute values of analyzed parameters are replaced with sizes of the ranks appropriate to them. It allows raising reliability of results of the analysis of the geological and field information caused by consideration the last, not as quantitative estimations, and as tendencies of their change.

2.1.2. Estimation of Liquid Production Effictiveness in Reservoir Development Process

One of major factors influencing efficiency processes of productive pays development is the regulation of oil flows in formation by changing of quantity of fluid production or water injection.

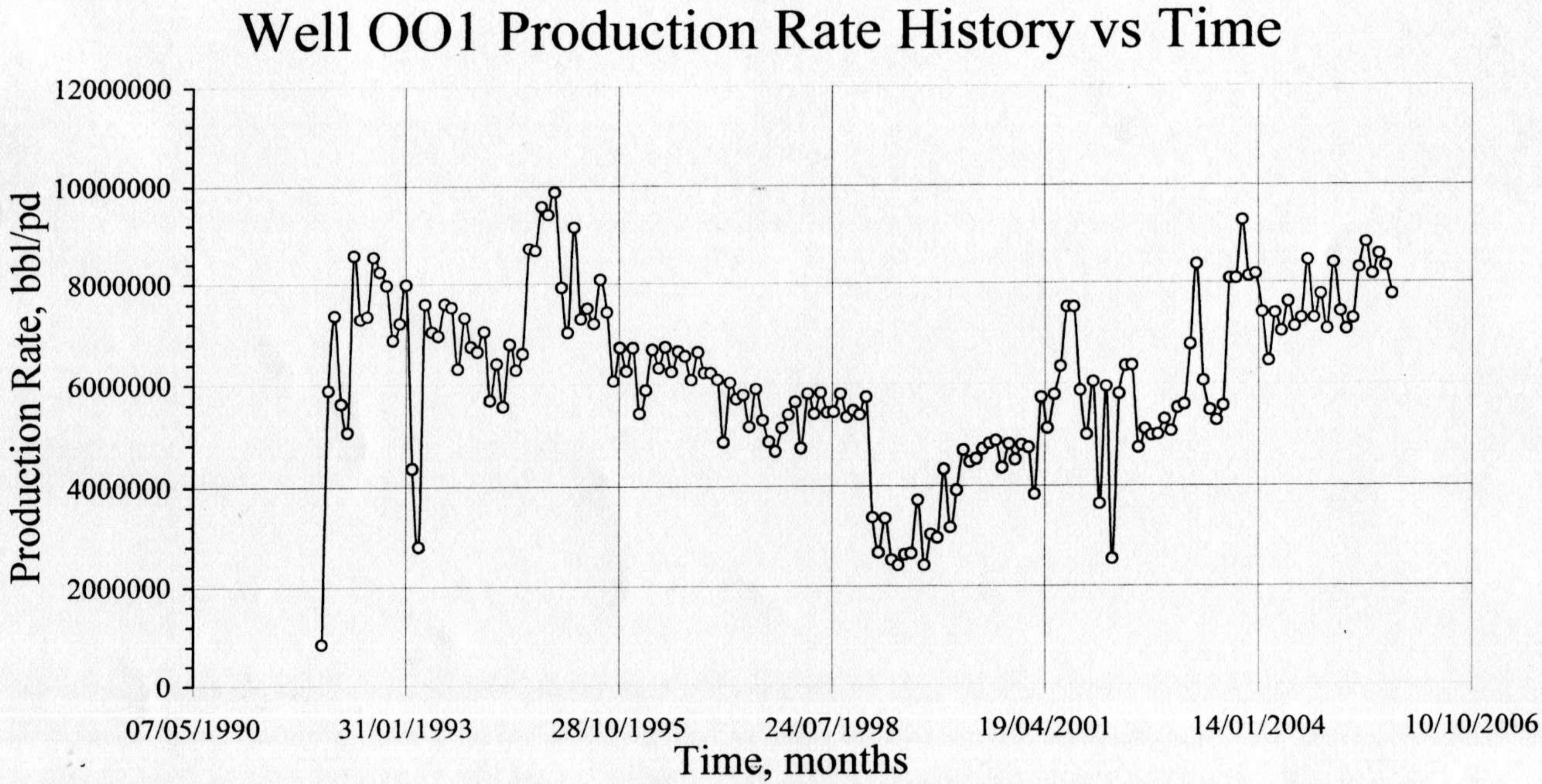
In this connection, definition of water injection directions and knowledge of hydrodynamic communications of wells interaction is necessary.

Water influence by injection it through specially placed on the area injection wells leads to in essential change of fluid flows in a productive formation owing to its efficiency should be estimated in common on group of the producing wells interacting with water injection wells.

Here it is necessary to note that at productive pay development by group of production and water injection wells the preparation of balance relationship between injected water and producing liquid is difficult and not always possible.

Therefore the way of an estimation of a degree of hydrodynamic interaction of wells on their current production rates measurement is offered.

In the Figures 2.1.2.1-2.1.2.6 the production rate monthly dynamics of wells OO1, OO2, OO3, OO4, OO5 and OO7 are introduced.


Well OO1 Production Rate History vs Time
Production Rate, bbl/pd
12000000
10000000
8000000
6000000
4000000
2000000
0
07/05/1990
31/01/1993
28/10/1995
24/07/1998
19/04/2001
14/01/2004
10/10/2006
Time, months
Fig. 2.1.2.1

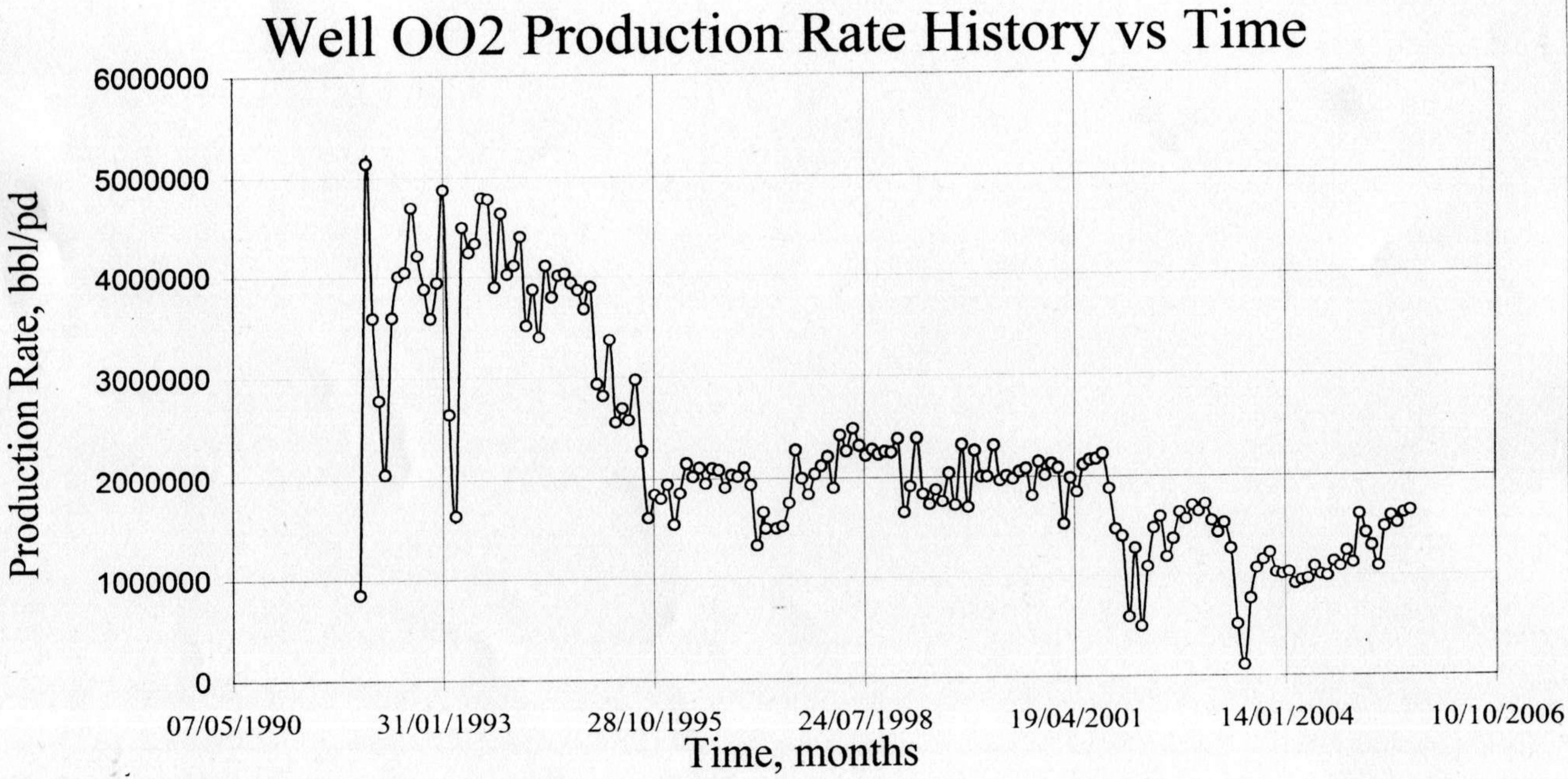
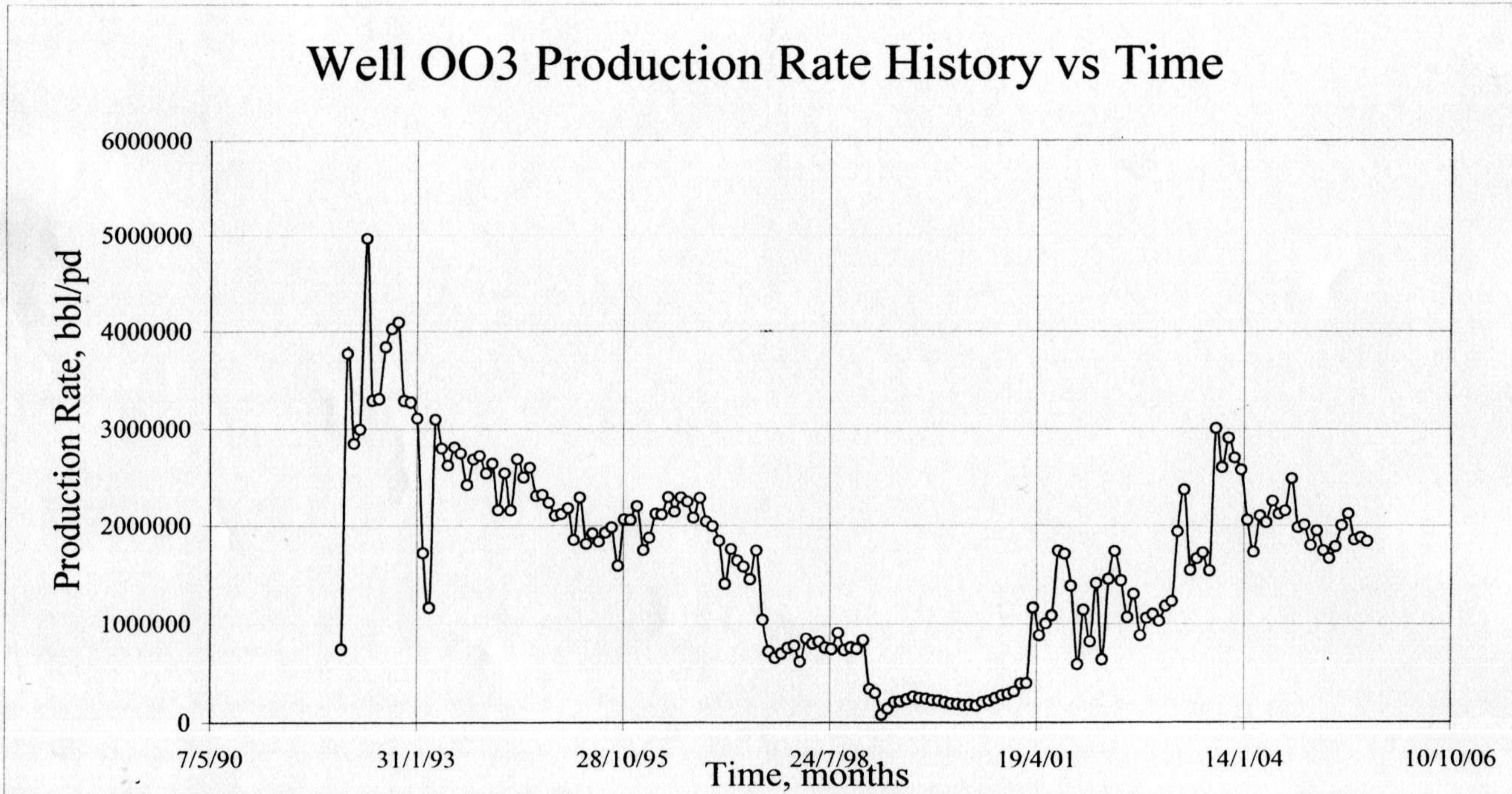
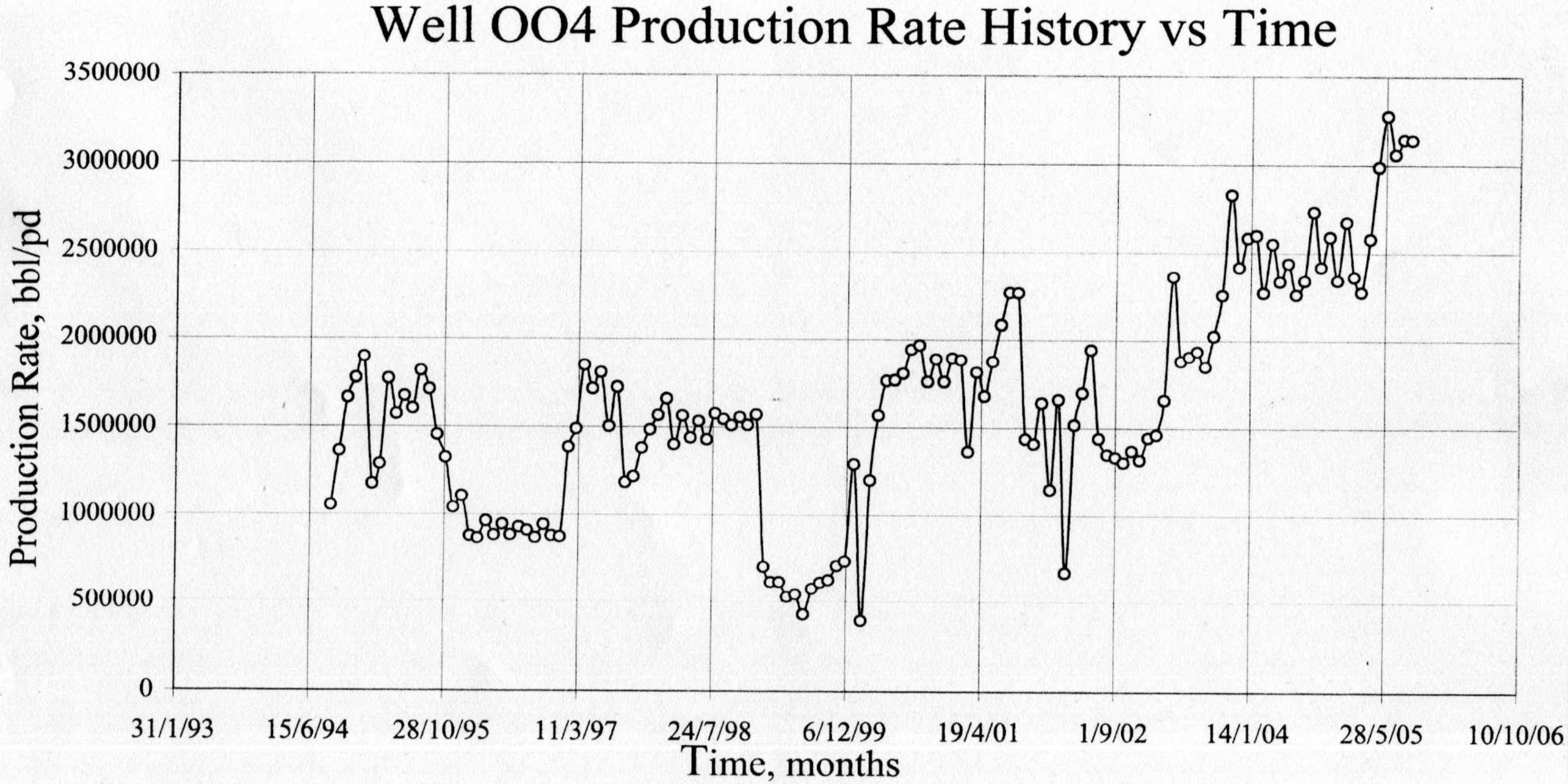

Well OO2 Production Rate History vs Time
Production Rate, bbl/pd
6000000
5000000
4000000
3000000
2000000
1000000
0
07/05/1990
31/01/1993
28/10/1995
24/07/1998
19/04/2001
14/01/2004
10/10/2006
Time, months

Fig. 2.1.2.2


Well OO3 Production Rate History vs Time
Production Rate, bbl/pd
6000000
5000000
4000000
3000000
2000000
1000000
0
7/5/90
31/1/93
28/10/95
24/7/98
19/4/01
14/1/04
10/10/06
Time, months
Fig. 2.1.2.3


Well OO4 Production Rate History vs Time
Production Rate, bbl/pd
3500000
3000000
2500000
2000000
1500000
1000000
500000
0
31/1/93
15/6/94
28/10/95
11/3/97
24/7/98
6/12/99
19/4/01
1/9/02
14/1/04
28/5/05
10/10/06
Time, months
Fig. 2.1.2.4

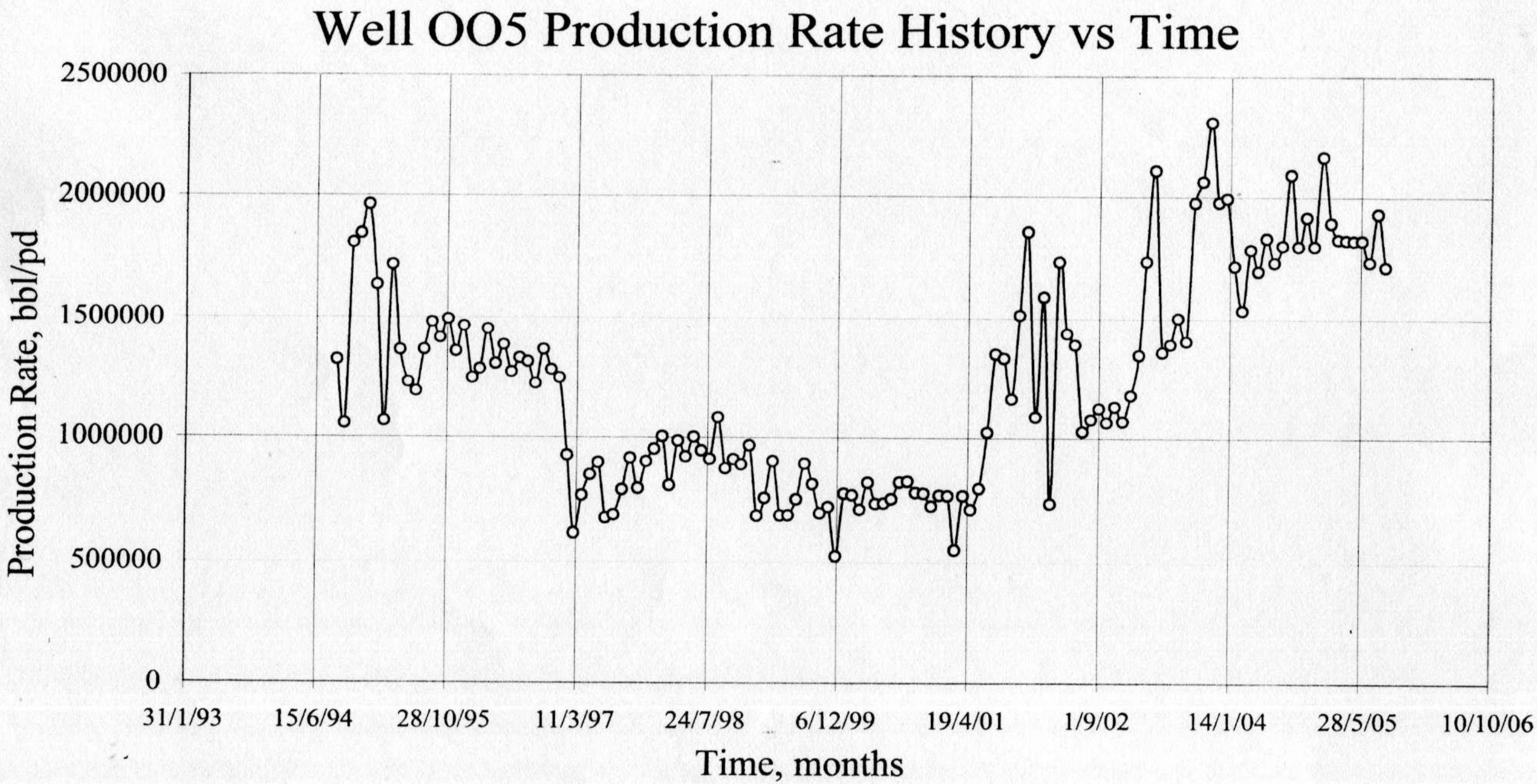
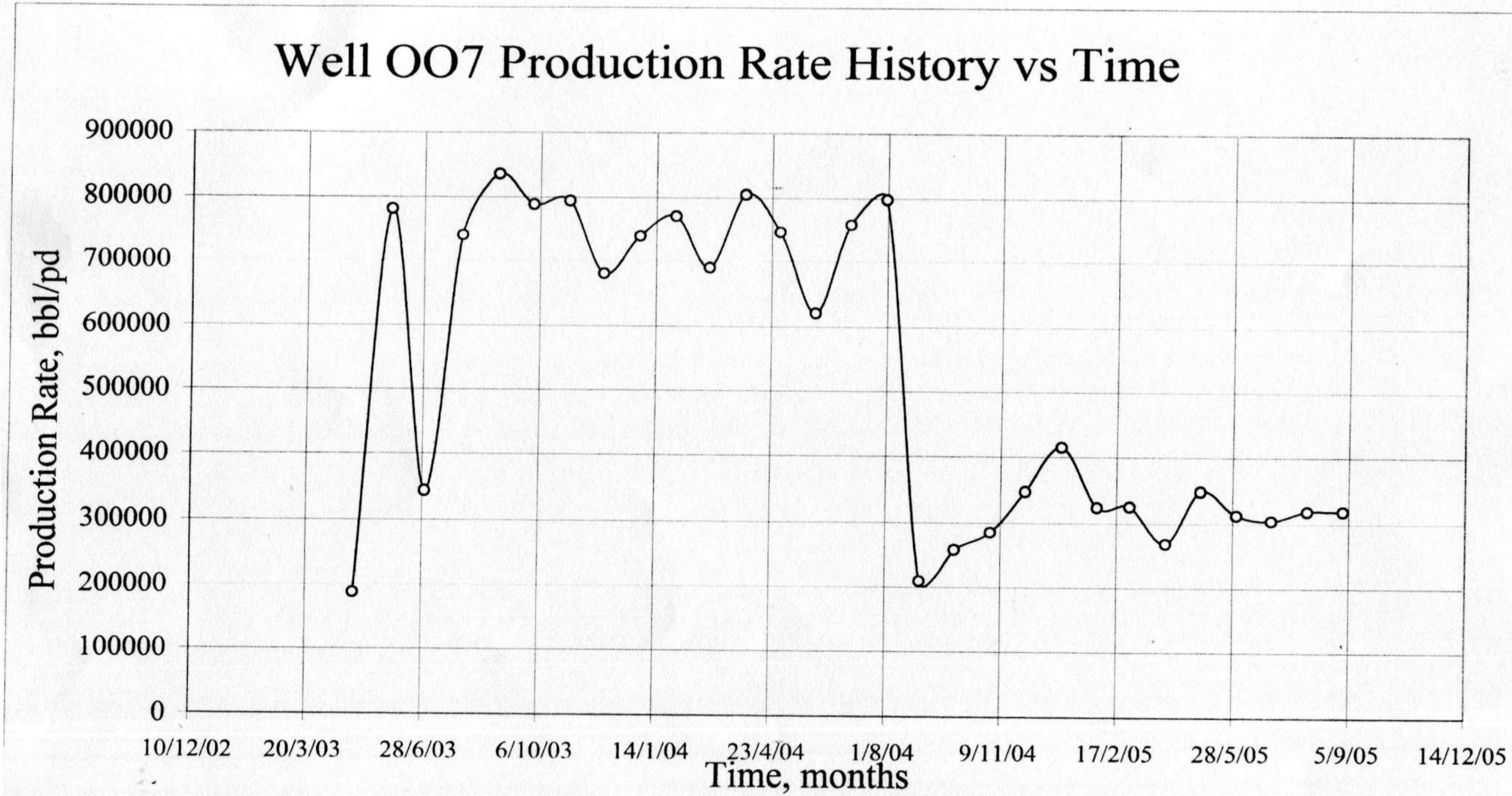

Well OO5 Production Rate History vs Time
Production Rate, bbl/pd
2500000
2000000
1500000
1000000
500000
0
31/1/93
15/6/94
28/10/95
11/3/97
24/7/98
6/12/99
19/4/01
1/9/02
14/1/04
28/5/05
10/10/06
Time, months

Fig. 2.1.2.5


Well OO7 Production Rate History vs Time
Production Rate, bbl/pd
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
10/12/02
20/3/03
28/6/03
6/10/03
14/1/04
23/4/04
1/8/04
9/11/04
17/2/05
28/5/05
5/9/05
14/12/05
Time, months
Fig. 2.1.2.6

Because of that time series of wells production rates have the oscillatory character complicating of an application of known ways of interpretation, the analysis of the field data will be carried out on the basis of multiple factors of correlation.

At interaction of several objects, for the analysis of pair communications between i and j objects in linear systems usually use partial correlation factor $r_{i,j,m}(m=i,j)$ allowing excluding influence of other elements of system to the investigated process. The multiple correlation factors $r_{i,m}(m=i)$ expresses a degree of relationship between one random variable and all others, and its change characterizes change of a degree of cumulative influence on investigated parameter of all other parameters. Without the additional analysis of multiple correlation factors may not be used for a quantitative estimation of a degree of wells hydrodynamic interference, and have qualitative character and allow defining a direction of water flows, to establish the tendency of process development, and to choose ways of regulation of water injection on a productive pay. In a basis of the analysis time series intake rates of injection and production rates separately were taken separately.

The multiple correlation factors of i-well with taking into account its interaction with m surrounded wells is defined from the following relationship:

$$r_{ijm} = (1 - r / r_{ii})^{1/2}, \qquad (2.1.2.1)$$

where R_{ii} - a minor of i-element of a correlation matrix;

R - a determinant of a correlation matrix which is described as

$$R = \det[r_{ij}] \begin{vmatrix} 1 & r_{12} & \dots & r_{1n} \\ r_{i1} & r_{i2} & \dots & r_{in} \\ r_{n1} & r_{n2} & \dots & 1 \end{vmatrix} \qquad (2.1.2.2)$$

Definition of pair multiple correlation factors of two objects i and j in view of their interaction with other objects of examined group from m wells is made under the following formula:

$$r_{ij,m} = r_{ij} / (r_{ii} r_{jj})^{1/2} \qquad , \quad (2.1.2.3)$$

Correlation factor of ranks of Spearman is estimated by the expression

$$r_s = 1 - \frac{6.\sum d^2}{n.(n^2 - 1)}. \qquad (2.1.2.4)$$

where $d = R_X - R_Y$, a difference between ranks of the connected values of x and y (see Tab 2.1.2.1),

R_x – ranks of values X;

R_Y – ranks of values Y;

n – number of pair members of series.

$-1 \leq rs \geq +1$.

Results of calculation of correlation factors of ranks of Spearman are introduced in the Table 2.1.2.1.

Table 2.1.2.1

Calculation results of correlation factors

N	№	X	Y	R_x	R_y	$D=R_x-R_y$	d^2	$\alpha\, d^2$	r_s
10	1	17	75	1	10	-9	81	298	-0.806
	2	22	68	4	8	-4	16		
	3	31	59	7	4	3	9		
	4	27	56	6	2	4	16		
	5	20	61	3	6	-3	9		
	6	18	63	2	7	-5	25		
	7	25	69	5	9	-4	16		
	8	32	60	8	5	3	9		
	9	33	57	9	3	6	36		
	10	35	52	10	1	9	81		

Estimation of the correlation factor value with the help of Student t-test is provided as follows

$$t_f = |r| \sqrt{\frac{n-2}{1-r^2}} \geq t_{st} \qquad (2.1.2.5)$$

t_f - actual value of Student t-test;

t_{st} - critical value of Student t-test for the chosen level of significance (α) and number of degrees of freedom (k=n-2) (Tab2.1.2.2);

r - value of correlation factor;

n - number of pair members of series.

Table 2.1.2.2 introduces the critical values of Student t-test at various significance values.

Table 2.1.2.2

The Critical Values of Student t-Test

(1)	α, %			(2)	α, %		
(k=n-2)	5	1	0,1	(k=n-2)	5	1	0,1
1	12,71	63,66	64,60	18	2,10	2,88	3,92
2	4,30	9,92	31,60	19	2,09	2,86	3,88
3	3,18	5,84	12,92	20	2,09	2,85	3,85
4	2,78	4,60	8,61	21	2,08	2,83	3,82
5	2,57	4,03	6,87	22	2,07	2,82	3,79
6	2,45	3,71	5,96	23	2,07	2,81	3,77
7	2,37	3,50	5,41	24	2,06	2,80	3,75
8	2,31	3,36	5,04	25	2,06	2,79	3,73
9	2,26	3,25	4,78	26	2,06	2,78	3,71
10	2,23	3,17	4,59	27	2,05	2,77	3,69
11	2,20	3,11	4,44	28	2,05	2,76	3,67
12	2,18	3,05	4,32	29	2,05	2,76	3,66
13	2,16	3,01	4,22	30	2,04	2,75	3,65
14	2,14	2,98	4,14	40	2,02	2,70	3,55
15	2,13	2,95	4,07	60	2,00	2,66	3,46
16	2,12	2,92	4,02	120	1,98	2,62	3,37
17	2,11	2,90	3,97	$\propto$	1,96	2,58	3,29
P	0,05	0,01	0,001	-	0,05	0,01	0,001

(1)- Number of degrees of freedom (k=n-2), %

(2)- Number of degrees of freedom (k=n-2), %

The estimation of the correlation factor value is computed by the expression

$$r_{st} = \frac{t}{\sqrt{n-1}}\left(1 - \frac{m}{n-1}\right) \qquad (2.1.2.6)$$

r_{st} - critical value of factor of correlation;

t - critical value of criterion Student for the chosen significance value;

m - criterion of the importance of factor of correlation (criterion Kulbakh);

n - number of pair members of lines.

for α=5 %; t=1,96; m=0,16;

for α=1 %; t=2,58; m=0,69.

Table 2.1.2.3 shows the results of correlation factors calculation between producing wells. Analysis of data given on Table 2.1.2.3 shows that the III block is drained properly, and interference between producing wells is considerable.

Table 2.1.2.3

The Results of Correlation Factors Calculation on Interference between Producing Wells

Blocks	Wells	Correlation Factor	Interaction between Wells
I	OO4 – OO7	-0,396	Bad
I	OO3 – OO7	0,439	Bad
I	OO3 – OO4	0,508	Satisfactory
II	OO1 – OO2	0,603	Good
II	OO1 – OO5	0,789	Good
II	OO2 – OO5	0,955	Good
I&II	OO3 – OO1	-0,493	Bad
I&II	OO4 – OO1	-0,290	Bad
II&III	OO5 – OO6	0,784	Good

Insufficient interaction between operating wells № OO3 – OO1 and OO4– OO1 in I and II blocks should be explained with presence impermeable disjunctive tectonic break between them.

But inadequate interaction between wells № OO3 – OO7 and OO4 – OO7on the I tectonic block should be explained with available dead oil areas between them.

To stimulate of oil production, drilling-in additional development wells on the dead oil areas between these non-interactive wells is suggested. With this purpose drilling-in № OO8 between producing wells № OO3 and OO4, and well № OO10 between producing wells № OO1 and OO5, and well № OO11 between producing wells № OO2 and OO5 is reasonable. To establish oil reservoir boundary it is necessary to drill well number OO9 on the right side of the producing well № OO6. In any case economic efficiency of drilling new producing wells should be considered. In case of non-economic efficiency of drilling new producers it is reasonable to choose wells production stimulation methods for enhanced oil recovery factor. For example, regulation of production wells behaviour, secondary & tertiary enhanced oil recovery methods applying.

As a result of investigations for determining of interaction between producing wells of Nubian oil reservoir of Bu-Attifel field was established:

1. Sufficient interaction between producing wells OO1-OO2, OO1-OO5, OO5-OO2 in the II, and OO5-OO6 in the II and III blocks tectonic blocks is established.
2. Insufficient interaction between producing wells № OO3 – OO1 and OO1 – OO4 on the I and II blocks due the presence of tectonic dislocation between them.
3. Inadequate interference between producing wells OO4-OO7, OO3-OO7 in the tectonic I block should be explained due to presence of stagnant areas between these wells (this is happened with presence of dead oil zones between them) non-conducting surface of tectonic dislocation between these wells.
4. For an intensification of an oil recovery it is offered to drill-in new development wells - № OO8 in the I block; for an establishment of oil pool outline it is advisable

to drill-in well № OO9 in the III tectonic block on the right side of the producing well № OO6 and to drill-in new wells - № OO10, OO11 in the II block

5. To stimulate oil production of new producer № OO8 on the I block and with the purpose of tracking external oil boundary drilling-in well is suggested.

6. Greatly water producing wells could be transferred into water injection wells. Injection wells in this case are additional sources of energy stimulating the oil travel to producing wells.

Thus, it is necessary an economic substantiation of expediency of drilling of new wells; in case of high cost of drilling of new wells it is possible to apply various hydrodynamic methods of influence on stagnant areas of a deposit (for example, regulation of wells' operating practices, application of methods of wells productivity increase and so on). The above-stated technique may be used for further estimation of water injection process, and also periodically for estimation of a hydrodynamic condition of a productive pay.

Studying the conditions of analysis is targeted to influence on the process of development and for increasing the efficiency of development process in an oil deposit.

The conditions of analysis in a deposit of development includes sequence of many procedures which following from one to another.

At the first stage the analysis carries out productive wells in drainage zone, and the result of this research will show the necessity of drilling new wells. The wells in drainage zone shall be calculated by the total of extraction for each well at the moment of research by dividing the received value (flow rate volume) on layer capacity (h), porosity (m), and density of oil (ρ), and ΣQ Cumulative oil production, S- area os the wells under the formula:

$$S = \frac{\Sigma Q}{hm\rho} \qquad (2.1.2.7)$$

The operation drainage is calculated to every area of the wells.

The received value in the plotting scale is for purpose of calculating the radius drainage well under the formula:

$$R = \frac{\Sigma Q}{hm\rho n} \qquad (2.1.2.8)$$

With the help of certain plotting scale the circles on the map of development shows that the analysis of well (OO2-OO5) in the stagnant zone settles down look Figure (2.1.2.7) and between the wells (OO5, OO2, OO7) there is a stagnant area of **oil.**

It is possible in these stagnant zones of development to involve the new wells or allows existing wells to receive additional oil by technological mode of development. In the area of well (OO2-OO5) there is a big site of saturated oil.

The specifications and economic feasibility of these area consequently permit to drill new wells conditionally shall named (OO11) to establish the development well (OO2-OO5) in the block II. With this purpose we shall calculate the factor of mutual correlation between them.

The matter is that the well (OO2) is on the fracture line inside the block III. If the factor of mutual correlation will be low (less than 0.5) of development it means relationship between the wells is bad and the development of various objects, for example the relationship between the wells OO4-OO7, OO3-OO7is bad because it is less than 0.5 and between the wells OO3-OO1, OO4-OO1, is bad too because of the is tectonic line which separates them.

Then the area of drainage well (OO5) considerably increases. For quick involving in operation drainage in stagnant zone it is necessary to drill new well (OO9).

Below the (Rs) of correlation analysis between wells (OO2-OO5) are resulted equal to Rs = 0.45. The analysis of depth (bore-hole) pressure speaks about mediocre communication between wells (OO2-OO5), and shows that for well (OO2) pressure was 5214PSIG and for a well (OO5) it was 5124 PSIG. From here follow that for created oil are convenience conditions for well (OO9) which created congenial conditions of an overflow of oil therefore they are assumed by a fracture line.

Therefore it is necessary to insert the well (OO11) in the middle of a stagnant zone between wells (OO2-OO5) as shown in figure (2.1.2.7). Between wells OO7, OO2, OO5 there are stagnant layers of oil, specification between them in final conducts defining the reliable area of a stagnant zone.

The mutual correlation factor between wells OO6 and OO4 is equal R_S = -0.08889 it leads that communication between them absent for wells OO6 and OO2 R_S =0.195611.

The absence calculations confirm existence of fewer breaks as is specified in Figure (2.1.2.7) and simultaneously show an opportunity of applicability to this method.

The factor of mutual correlation between wells OO4and OO5 is equal Rs = -0.20206: it remarks the absence of communication between them, and given results also corresponds to geological results.

The calculation factor of mutual correlation between wells OO5 and OO7 is carried out in two stages:

1) at initial stage the correlation factor between OO5 and OO7 wells was defined as Rs = 0.1542857.

2) at final stage the correlation factor between OO5 and OO7 wells was determined as Rs =0.628571; it remarks good communications between them.

The calculation factor of mutual correlation between wells OO4 and OO7 was aso carried out in two stages:

1) at initial stage the correlation factor between OO4 and OO7 wells was defined as Rs = 0.11428

2) at final stage the correlation factor between OO4 and OO7 wells was determined as Rs =0.639286; it shows good communications between wells them as they are located in one block. The area of a corresponding stagnant zone is sufficient for drilling-in new development well OO8.

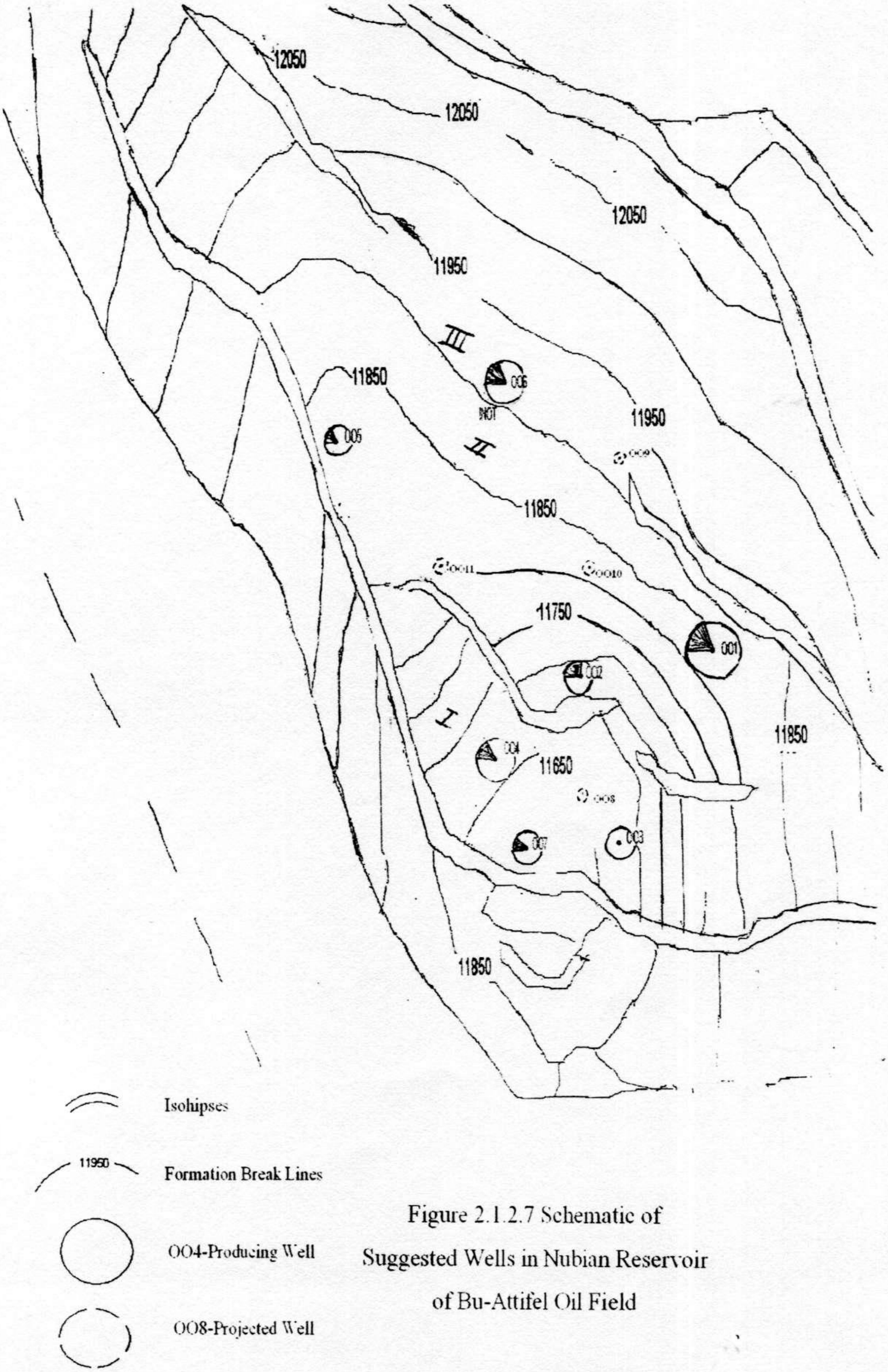


Figure 2.1.2.7 Schematic of Suggested Wells in Nubian Reservoir of Bu-Attifel Oil Field

2.2. Recoverable Oil Reserves Predicted by Applying of Evolutionary Modeling

One of the most widespread and effective way of the analysis the condition and the control of oil reservoirs development is the mathematical modeling of the basic development performances.

In particular, mathematical models of investigation development performances have found wide application in practice allowing on the basis of integrated characteristics to diagnose prominent features of development processes to give qualitative and quantitative prediction of the basic development performances and define their most expedient further decisions.

Practical experience of production process of the long period developed oil and gas fields' shows that at the certain stage of development the most authentic prediction of recoverable reserves can be received by application of evolutionary model.

At such approach the oil pool is considered as the complex system that consist a number of subsystems at which process of growth has an evolutionary character that is defined by set of characteristics of subsystems and a complex of external influences on a whole system.

In oil production processes with such factors there may be change of formation pressure, well stock, well's production water cutting, various kinds of influence on a formation behavior and so on.

Under action of the aforesaid factors, curves of growth of development performances may have the various character determined by a degree of influence of set factors on a process of oil production which may be described based on the evolutionary model as

$$\sum Q = A_0 + Be^{\alpha t}, \qquad (2.2.1)$$

where A, B and α - factors of model at a considered stage of the characteristic of growth, while

$$t \to \infty, \Sigma Q \to A$$

$\sum Q$- cumulative oil production, MMSTB

Procedure of calculations by a method of evolutionary modeling consists of two stages.

At the first investigation stage the analysis of the initial information (an interval of training) will be carried out and the forecast for the subsequent available site curve (an interval of examination) is made.

By the analysis of variance actual and calculated data of selection the most authentic type of model is determined.

At the following stage based on the evolutionary model using the above determined factors further prediction of production and recoverable volume of oil under condition of invariance development system parameters is made.

The offered approach of modeling to oil recovering parameters was applied at the analysis of development of the examined reservoir. As an information data the massive development technological performances were used.

Let us consider applying of evolutionary model for estimation of recordable oil reserves. Existing approaches for this problem are significantly difficult.

The principal difficulty consists in the lack of possibility taking into account all factors influencing to oil reserves. However, further development and development strategy are required knowing of oil reserves.

Evolutionary approach of modeling allows to avoid these difficulties and to get reliable values of oil reserves. The studies were carried out using the following way:

1. On the basis of existing values of production rates cumulative values of oil production for every month were calculated and the cumulative production curve was constructed (figure 2.2.1).
2. On the basis of given values production factors within 143 months were chosen (Tab2.2.1).
3. Further for getting of desirable model of oil production was predicted.
4. The most trustworthy values in the case of close predicting up to 10 months, and also, if there is no changes in the production process, i.e. new wells pattern in production or shutting-in some operating wells.

5. Values of prediction are appreciated.

For Nubian oil reservoir based on 134 months' oil production, the mathematical model of evolutionary of development process was constructed which, in its turn, is described by the equality:

$$\sum Q = A_o + Be^{\alpha t},$$

where: A= 20000000

B=-53822301

α=-0.31772

Based on this model expected values of oil production were determined, where the value of produced oil isn't changed; it shows the value of recoverable oil reserves. For the field investigated we get 20 million barrels of recoverable oil reserves (Table 2.2.1).

Table 2.2.1

Results of Computing on Mathematical Model of Evolutionary Process

Date	Cumulative oil production, ΣQ Mbbl	A	LN(ΣQ-A)	B	α
31.12.1991	27528	20000000	16,79878	-53822301	-0.31772
31.01.1992	189717		16,47636		
29.02.1992	254138		16,35159		
31.03.1992	181318		16,48129		
30.04.1992	168202		16,52049		
31.05.1992	276373		16,25197		
30.06.1992	243071		16,35773		
31.07.1992	237017		16,47658		
31.08.1992	275439		16,25449		
30.09.1992	274604		16,28037		
31.10.1992	257079		16,30296		
30.11.1992	229283		16,38976		
31.12.1992	232586		16,36416		

31.01.1993	257479		16,30193		
28.02.1993	155207		16,65172		
31.03.1993	90235		16,76034		
30.04.1993	253136		16,33368		
31.05.1993	227116		16,37733		
30.06.1993	231920		16,38372		
31.07.1993	245241		16,33301		
31.08.1993	242853		16,33896		
30.09.1993	210521		16,43176		
31.10.1993	236262		16,35521		
30.11.1993	224804		16,39995		
31.12.1993	214467		16,44394		
31.01.1994	227257		16,37699		
28.02.1994	202797		16,47729		
31.03.1994	206784		16,43992		
30.04.1994	185310		16,52334		
31.05.1994	219121		16,39628		
30.06.1994	209701		16,43356		
31.07.1994	213106		16,4103		
31.08.1994	280922		16,23955		
30.09.1994	288805		16,24348		
31.10.1994	308771		16,16001		
30.11.1994	313456		16,17602		
31.12.1994	318520		16,13061		
31.01.1995	255426		16,3687		
28.02.1995	250678		16,379		
31.03.1995	295087		16,19989		
30.04.1995	243051		16,35778		
31.05.1995	242119		16,34078		
30.06.1995	239901		16,36519		
31.07.1995	260551		16,29397		
31.08.1995	239727		16,34908		
30.09.1995	202027		16,45021		
31.10.1995	216839		16,40162		
30.11.1995	208545		16,43609		

31.12.1995	216522		16,40236		
31.01.1996	174575		16,56646		
29.02.1996	202592		16,46344		
31.03.1996	215531		16,40669		
30.04.1996	210706		16,43136		
31.05.1996	217034		16,40116		
30.06.1996	208329		16,43656		
31.07.1996	214345		16,40742		
31.08.1996	211392		16,41426		
30.09.1996	202638		16,4489		
31.10.1996	213816		16,40865		
30.11.1996	207437		16,4385		
31.12.1996	200631		16,4562		
31.01.1997	196286		16,46249		
28.02.1997	172764		16,53434		
31.03.1997	194345		16,4528		
30.04.1997	189910		16,47596		
31.05.1997	186324		16,47044		
30.06.1997	171507		16,52864		
31.07.1997	190311		16,46171		
31.08.1997	170131		16,53593		
30.09.1997	161582		16,54297		
31.10.1997	150450		16,58892		
30.11.1997	170731		16,52681		
31.12.1997	173759		16,49745		
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28.02.1998	168611		16,54198		
31.03.1998	187107		16,46873		
30.04.1998	180278		16,49596		
31.05.1998	187769		16,46728		
30.06.1998	181115		16,49424		
31.07.1998	175493		16,50575		
31.08.1998	187003		16,46896		
30.09.1998	177908		16,50082		
31.10.1998	176440		16,49175		

30.11.1998	179534		16,49749		
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28.02.1999	95203		16,6682		
31.03.1999	108070		16,62791		
30.04.1999	83908		16,67673		
31.05.1999	77853		16,69711		
30.06.1999	87507		16,67053		
31.07.1999	85473		16,66912		
31.08.1999	119957		16,60614		
30.09.1999	80407		16,68367		
31.10.1999	97641		16,64762		
30.11.1999	98463		16,68922		
31.12.1999	139176		16,5701		
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30.04.2000	148551		16,55915		
31.05.2000	145437		16,57363		
30.06.2000	156756		16,54319		
31.07.2000	155174		16,53612		
31.08.2000	156992		16,5324		
30.09.2000	144782		16,57751		
31.10.2000	154861		16,53676		
30.11.2000	149772		16,55679		
31.12.2000	154218		16,53807		
31.01.2001	152467		16,54163		
28.02.2001	136790		16,60534		
31.03.2001	184539		16,47432		
30.04.2001	170267		16,53568		
31.05.2001	186328		16,47043		
30.06.2001	211312		16,43003		
31.07.2001	242444		16,33998		
31.08.2001	242409		16,34006		
30.09.2001	195198		16,46481		

31.10.2001	160740		16,5247		
30.11.2001	201161		16,49726		
31.12.2001	117459		16,65931		
31.01.2002	191547		16,45899		
28.02.2002	90618		16,74288		
31.03.2002	186852		16,56336		
30.04.2002	211605		16,42939		
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31.07.2002	164356		16,5172		
31.08.2002	160149		16,54395		
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28.02.2003	241526		16,40385		
31.03.2003	269852		16,26949		
30.04.2003	201662		16,451		
31.05.2003	176344		16,49297		
30.06.2003	175477		16,50578		
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31.08.2003	260605		16,3047		
30.09.2003	269191		16,29409		
31.10.2003	298948		16,1888		
30.11.2003	270754		16,29015		
31.12.2003	263437		16,28644		
31.01.2004	238873		16,81122		
29.02.2004	222268		16,81122		
31.03.2004	238355		16,81122		
30.04.2004	234179		16,81122		
31.05.2004	245549		16,81122		
30.06.2004	237244		16,81122		
31.07.2004	235051		16,81122		
31.08.2004	272475		16,81122		

30.09.2004	242871		16,81122		
31.10.2004	250384		16,81122		
30.11.2004	235431		16,81122		
31.12.2004	270655		16,81122		
31.01.2005	239248		16,81122		
28.02.2005	252124		16,81122		
31.03.2005	234770		16,81122		
30.04.2005	276552		16,81122		
31.05.2005	284339		16.81122		
30.06.2005	272055		16,81122		
31.07.2005	276417		16,81122		
31.08.2005	268823		16,81122		

It should be remembered that the analysis were provided for the wells existing on the area; if wells number is changed, it would be necessary to do this procedure for changed conditions, if so. Prognosticate should be done from the beginning of wells bringing into production or shutting-in the wells.

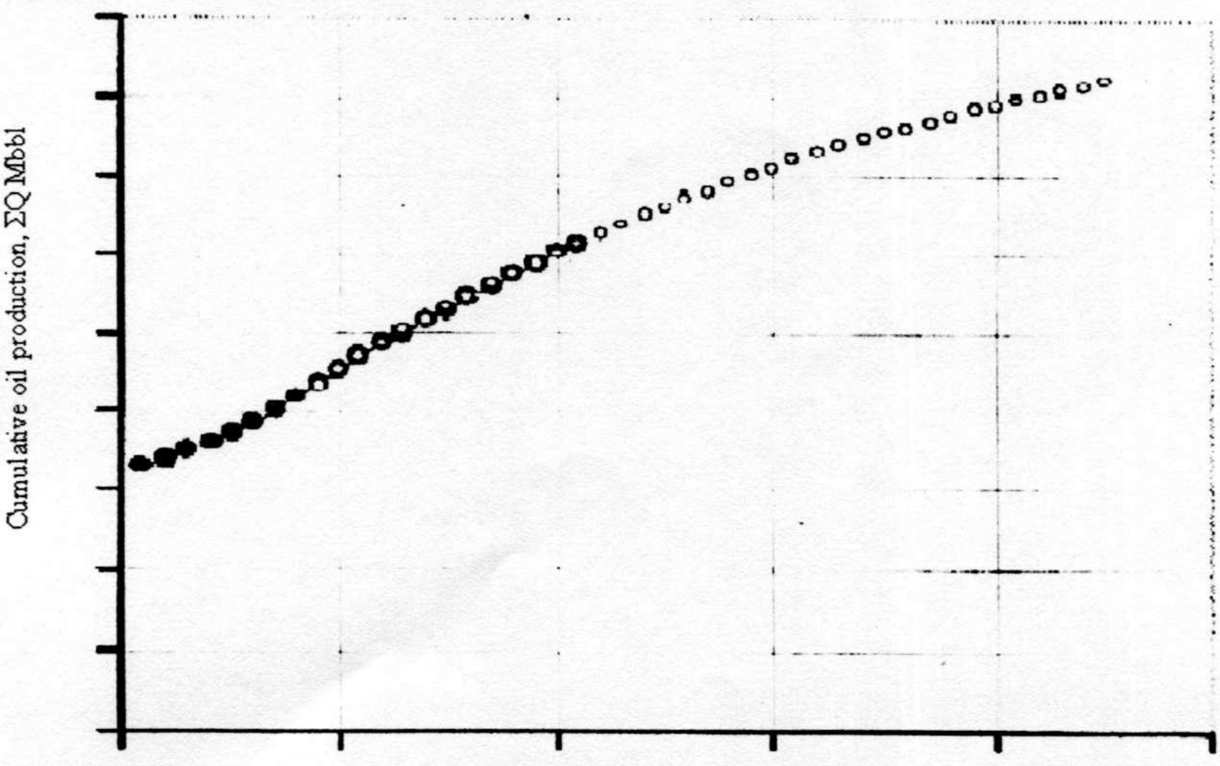


Figure 2.2.1 Cumulative Oil Production vs Time

2.3. Operation Conditions Analysis of Drowned Wells

In the first part of the thesis prospects the development of a researched reservoir as a whole are considered. Areas of a perspective arrangement of wells on a reservoir are specified with the purpose of an additional oil recovery and increase of efficiency its development.

In the given section the operation conditions of drowned wells of Nubian Reservoir of Bu-Attifel oil field is analyzed. Optimum operating practices of producing wells by the dynamic analysis of the field material are established.

The analysis carried out as follows: all wells of a reservoir have grouped in view of operation of the same tectonic block.

By this principle the first group was made with wells OO3, OO4, OO7; the second group includes wells OO1, OO2, OO5, and the third group consists of one well-OO6.

The results of laboratory experiments on displacement of oil by the water, given in [2] have shown that a slope of function $\sum Q = f(t)$, other things being equal, is directly proportional to absolute permeability of reservoir rocks. Applying this principle, it is possible under the analysis of a state of slope of a curve $\sum Q$ - t, constructed according to field data: it is possible to judge an overall performance of wells of an examined reservoir.

Change of wells production rate, in particular, decrease of production rate, may occur due to water cutting of well production, gas liberation from oil, formation damage of bottom-hole zones or due to any internal processes in a bed. For example, it may be caused bed silting-up of bottom-hole zones, increase of water encroachment of bed, increase of a double electric layer at the surface of reservoir rocks etc.

Let's analyze behavior of well in view of the above-stated factors. In our case oil wells produce a single-phase liquid without free gas. So gas doesn't result for decrease of well production. Silting-up, in our case, isn't the reason of well production rate decrease because of oil product doesn't consist of mechanical impurities. As to increase of adsorption layer thickness on the surface of rocks at presence of water, such increase is a few as the formation water is a good conductor. Excluding from consideration all the stated factors we shall consider a degree of water cutting of wells and influence of water on productivity of the wells.

Let's consider the analysis of operation of wells of the first group. Dynamics of process of operation of well OO3 is given as the diagram in figures 2.3.1 and 2.3.2.

In figure 2.3.1 dynamics of cumulative production rate of a liquid (oil + water) versus time is given. On all wells even numbers of figures 2.3.2, 2.3.4, 2.3.6, 2.3.8, 2.3.10 and 2.3.12 correspond to cumulative production rate of a liquid, and on odd numbers of figures 2.3.1, 2.3.3, 2.3.5, 2.3.7, 2.3.9, 2.3.11 to a cumulative oil recovery. Further, the analysis made on a cumulative oil recovery as a function of time $\sum Q=f(t)$. When the tendency of relationship of a cumulative oil recovery and a liquid are identical, the analysis was made on dynamics of an oil production rate.

At strong deviations in both figures made the analysis of divergences. From figure 2.3.1 follows, that up to 143 months of well operation a slope of a curve makes 43°–27°. It is observed rather high water cutting of well production up to 27,6% and rather low values of production rate - 3002 bbls/day.

Since 143 months the slope of a curve began to increase and has made 40°. It shows about increase of productivity of a well. Thus high oil production rates of the order 603-3002 bbls/day are observed, and water cutting of a well has decreased approximately up to 2%. This fact confirms an idea that the decrease of water cutting increases of an oil production rate.

Let's consider work of well OO4, field data of which is given in figures 2.3.3 and 2.3.4. The analysis of a field material shows, that about 56 months of operation a slope of the curve on the diagram has made 26°. At the same period increase of water cut, which reaches the maximum value 42%, is observed. Oil production rates rather high, but by the end of the period it has decreased.

In the period from 56 to 68 months a slope of a curve on the $\sum Q=f(t)$ diagram has made 15°. Water cut is high at the beginning of the period, and then decreases up to 5% on the 68-th month. Within one month the well was shut-in, obviously, actions for restoration of normal work were carried out. It is represented to us that they are connected to restriction of water-inflow. However, this action has not given essential result. It is also traced from $\sum Q=f(t)$ diagram. During 68 months (when the first remedial work on well was made) and up to 89 months (time of the second remedial work) substantial improvement of well operation was not observed. A slope on the diagram has made 33° and maximum water cutting of production was equaled to 27%.

Since 89 months after the second repair the well operation has been improved, that it is visible on increase of a slope on the diagram of $\sum Q=f(t)$ up to 43° and decrease of well production water cut up to 15%. It testifies to efficiency of the carried out the second remedial work.

The further operation of a well occurs at raised oil withdrawals and the slope on the $\sum Q=f(t)$ diagram. Hence, the concept about reduction of water cut has the right to existence and further by development of the reservoir it is necessary to aspire on reduction of water-inflow to well bore. At transition to the second development cycle of the reservoir with water injection it is possible for the first to transfer this well from producing into injection one.

In figures 2.3.5 and 2.3.6 the results of field data analysis of well OO7 are given.

The first 2 months a slope of a curve of $\sum Q=f(t)$ has made 36°. In this period well production rate achieved 1073 bbls/day, and water cut reached up to 3%.

Thus well production rate increased, varying within 1181-400 bbls/day. It is obvious if to reduce water cut it is possible to increase even more oil production rate of a well. A slope of a curve marked on $\sum Q=f(t)$ diagram is increases, too and also makes α =40°-41°.

The character of relationship $\sum Q=f(t)$ shows that the curve to aspire to reduce of production rates. At such continuation of operation of a well there may be decline of well and water breakthrough into the well. It is represented to us, that it would be better to increase a slope of a curve on the diagram of $\sum Q=f(t)$ up to 50° after strong water cutting of well production.

Thus the maximum slope of a curve corresponds to effective operating of well of the given block.

The analysis of the operation conditions of well of the second group. We shall consider behavior of well OO1 introduced in figures 2.3.7 and 2.3.8 In figure 2.3.7 on the diagram of $\sum Q=f(t)$ 4 characteristic sites with the indication of a slope of a curve and durations of operation time of a well on the given flow regime in months are allocated. From curve in fig. 2.3.7 it is visible that it has a little rather direct sites and the slope of each site corresponds to values: $\alpha_1=30^o$, $\alpha_2=36^o$, $\alpha_3=27^o$. Change of value of a slope of a curve occurs due the operation time. It gives evidence that in due course permeability of rock to oil is worsened; the most effective work of a well was observed in the first 16 months.

The next months the slope of the curve has changed accordingly on 13^o and 23^o. From a field data it is possible to establish the reason on which there is a deterioration of permeability (skin-effect) of bottom-hole zone. From the analysis of values of the field data follows that at initial stage of operation of wells their production water cutting has made 1% relative to the cumulative produced liquid.Current water cut of production wells reaches 14,8 %. Water is shown in all wells of a reservoir, in particular, in well OO1.

Dynamics of operation of well OO2 is given in figures 2.3.9 and 2.3.10 From figure 2.3.9 folows, that a slope of a curve of $\sum Q=f(t)$ up to 14th months makes 55^o. Thus the maximum value of production rate reaches 5826 bbl/day, and water cutting of well production has made 31%. Since 15 for 44 months decline of productivity of a well is observed. Thus the slope of a curve has decreased up to 44^o. In this period the oil production rate decreased up to 3094bbl/day and water cutting of well production has decreased to 23%.

Since 44 months and up to 148 months the sharp decrease of productivity of a well up to 1027 bbl/day is observed at lowered water cutting within the limits of 6%.

Dynamics of operation of well OO5 is given in figures 2.3.11 and 2.3.12 From figure 2.3.11 follows, that a slope of a curve of $\sum Q=f(t)$ up to 29th months makes

33°. Thus the maximum value of production rate reaches 1368 bbl/day, and water cutting of well production has made 1,7%. Since 29 for 79 months decline of productivity of a well is observed. Thus the slope of a curve has decreased up to 25°. In this period the oil production rate decreased up to 727 bbl/day and water cutting of well production has decreased from 3 % to 0,1%.

Since 79 months and up to 111 months the sharp increase of productivity of a well up to 2398 bbl/day is observed at lowered water cutting within the limits of 0,1%. It once again confirms an idea on improvement of inflow of oil at lowered water cutting.

The analysis of field data of the wells of the third group. The third group includes well OO6. We shall consider operation of well OO6 is water injection well which was drilled in 2003.

Results of our researches show that it is necessary to pay special attention to prevention of water cutting of well production. One of methods of struggle with water cutting of wells is studying of well log and realization on it selective perforating, excluding thus simultaneous shooting water-bearing inter-layers. In any case, it is necessary to undertake the appropriate measures on control of reservoir development process and prevention of premature water encroachment of a producing formation.

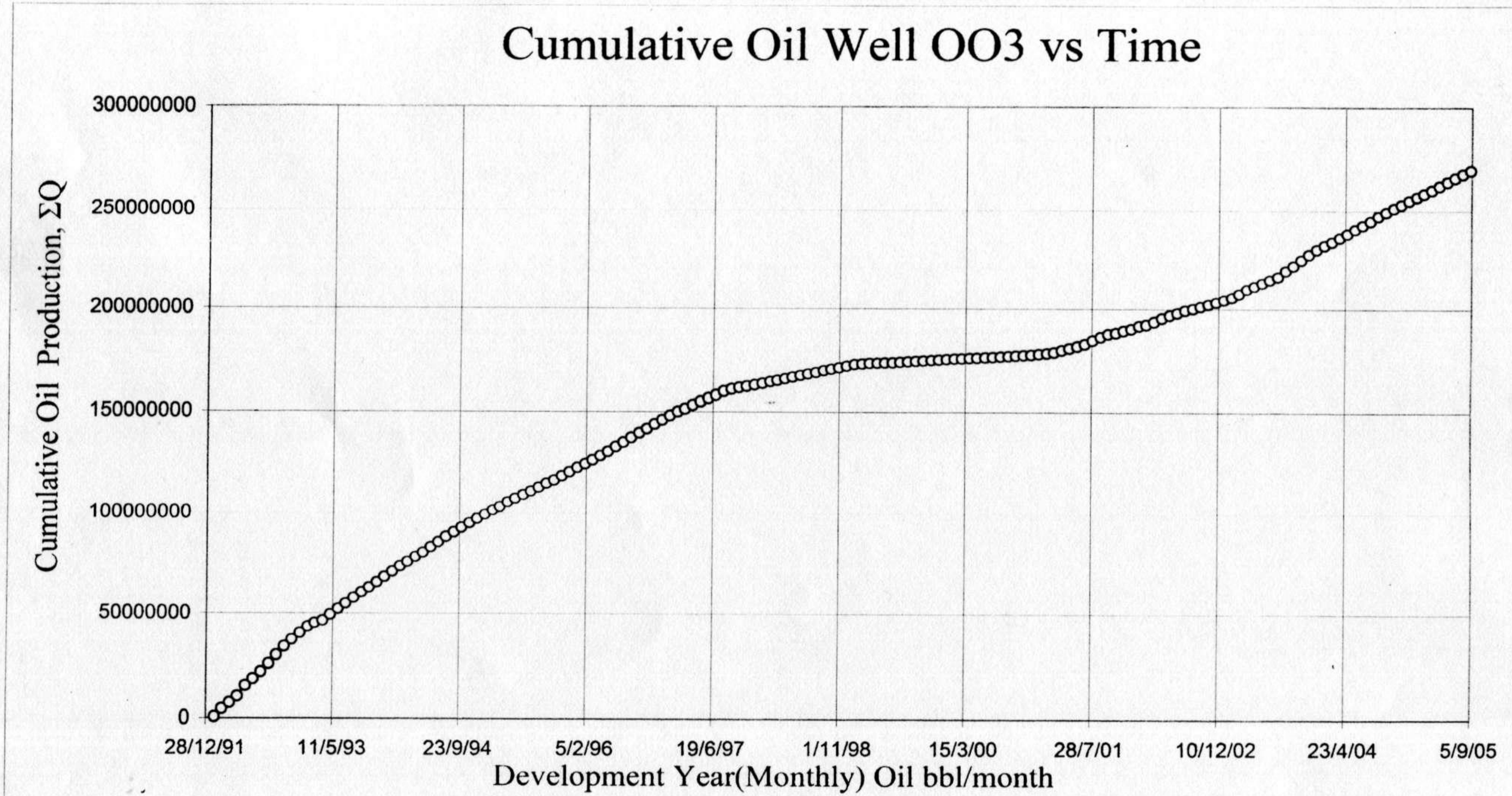
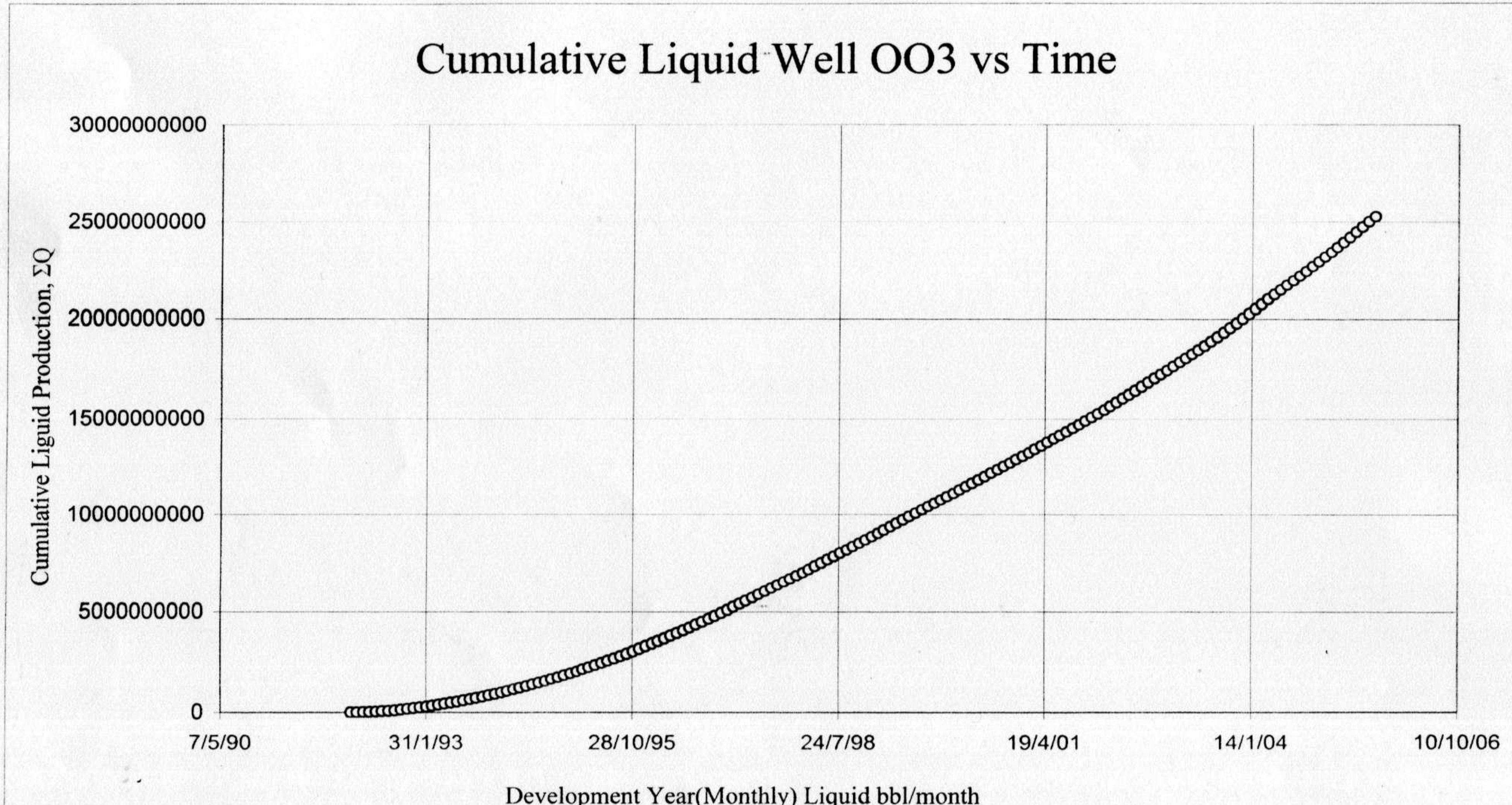

Cumulative Oil Well OO3 vs Time
300000000
250000000
200000000
150000000
100000000
50000000
0
Cumulative Oil Production, ΣQ
28/12/91
11/5/93
23/9/94
5/2/96
19/6/97
1/11/98
15/3/00
28/7/01
10/12/02
23/4/04
5/9/05
Development Year(Monthly) Oil bbl/month

Figure. 2.3.1


Cumulative Liquid Well OO3 vs Time
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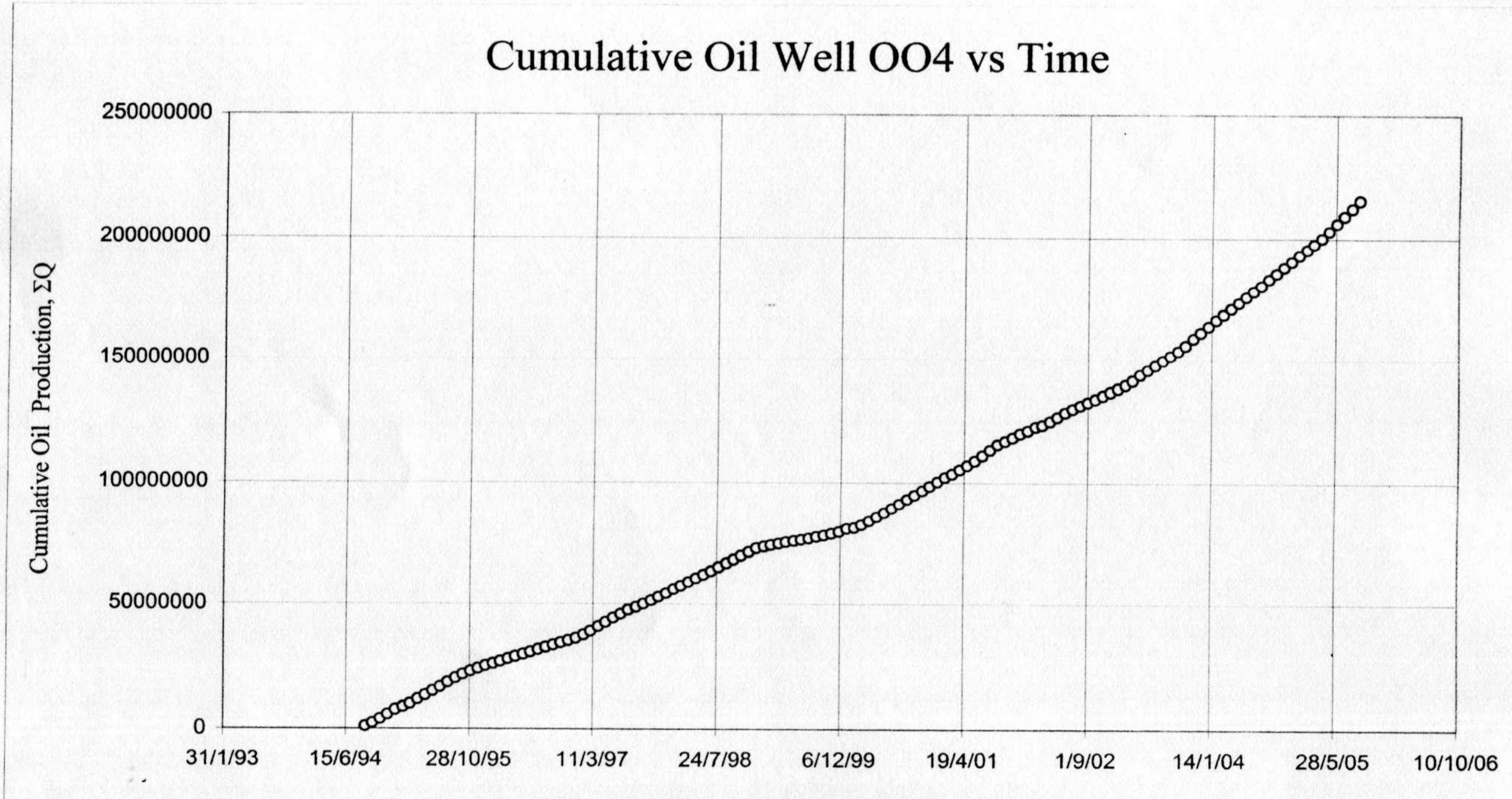
25000000000
20000000000
15000000000
10000000000
5000000000
0
Cumulative Liguid Production, ΣQ
7/5/90
31/1/93
28/10/95
24/7/98
19/4/01
14/1/04
10/10/06
Development Year(Monthly) Liquid bbl/month
Figure. 2.3.2


Cumulative Oil Well OO4 vs Time
Cumulative Oil Production, ΣQ
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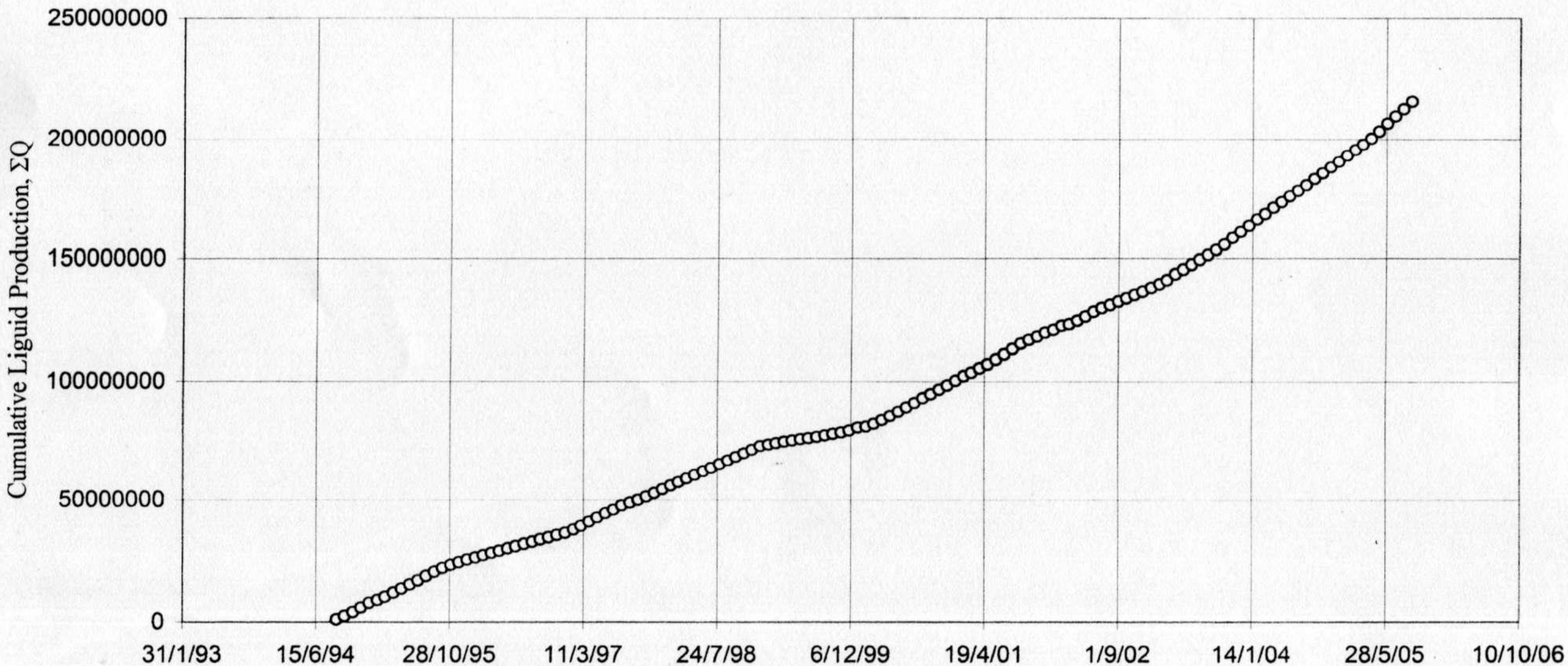
200000000
150000000
100000000
50000000
0
31/1/93
15/6/94
28/10/95
11/3/97
24/7/98
6/12/99
19/4/01
1/9/02
14/1/04
28/5/05
10/10/06
Development Year(Monthly) Oil bbl/month

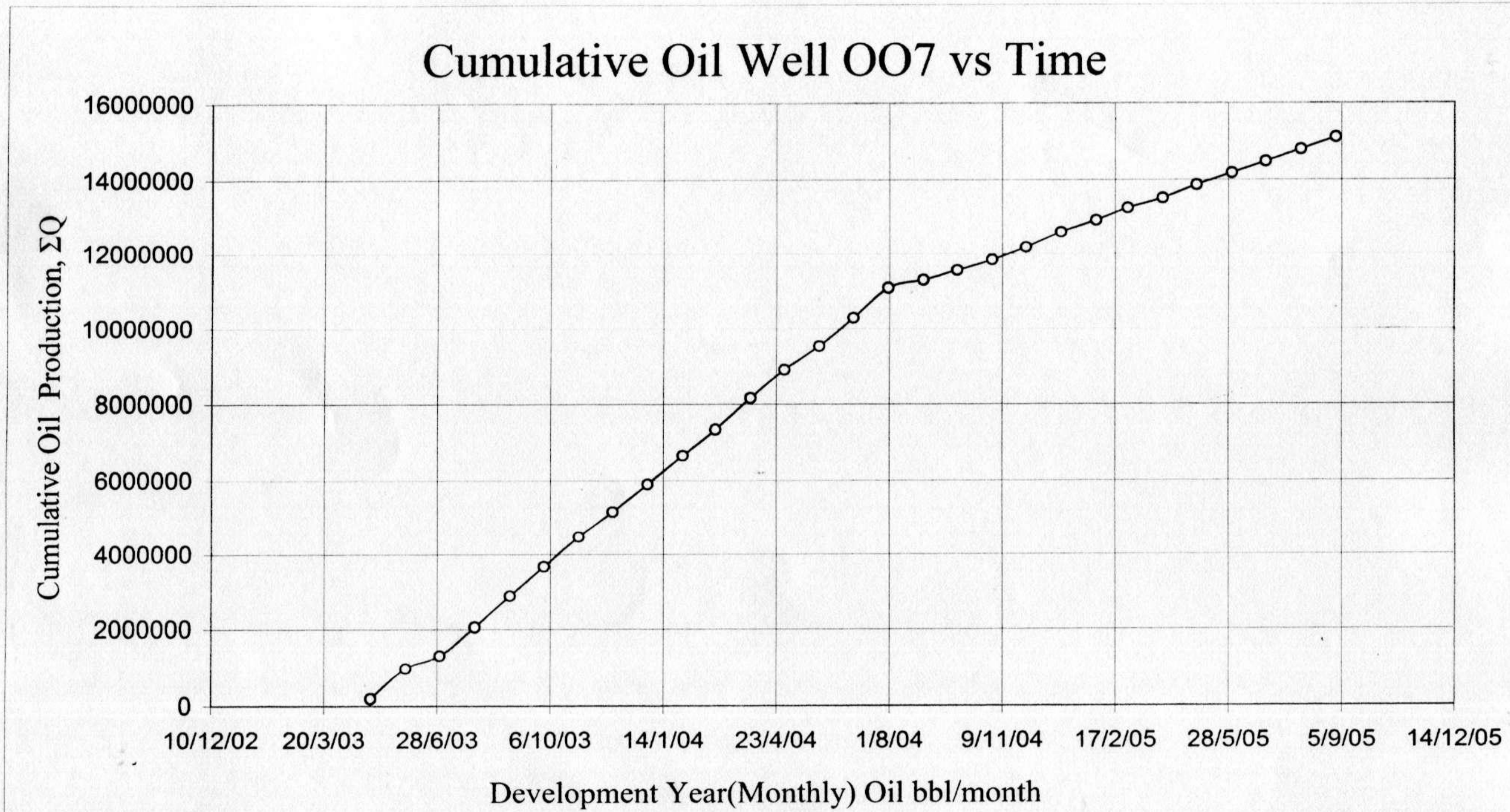
Figure. 2.3.3

Cumulative Liquid Well OO4 vs Time



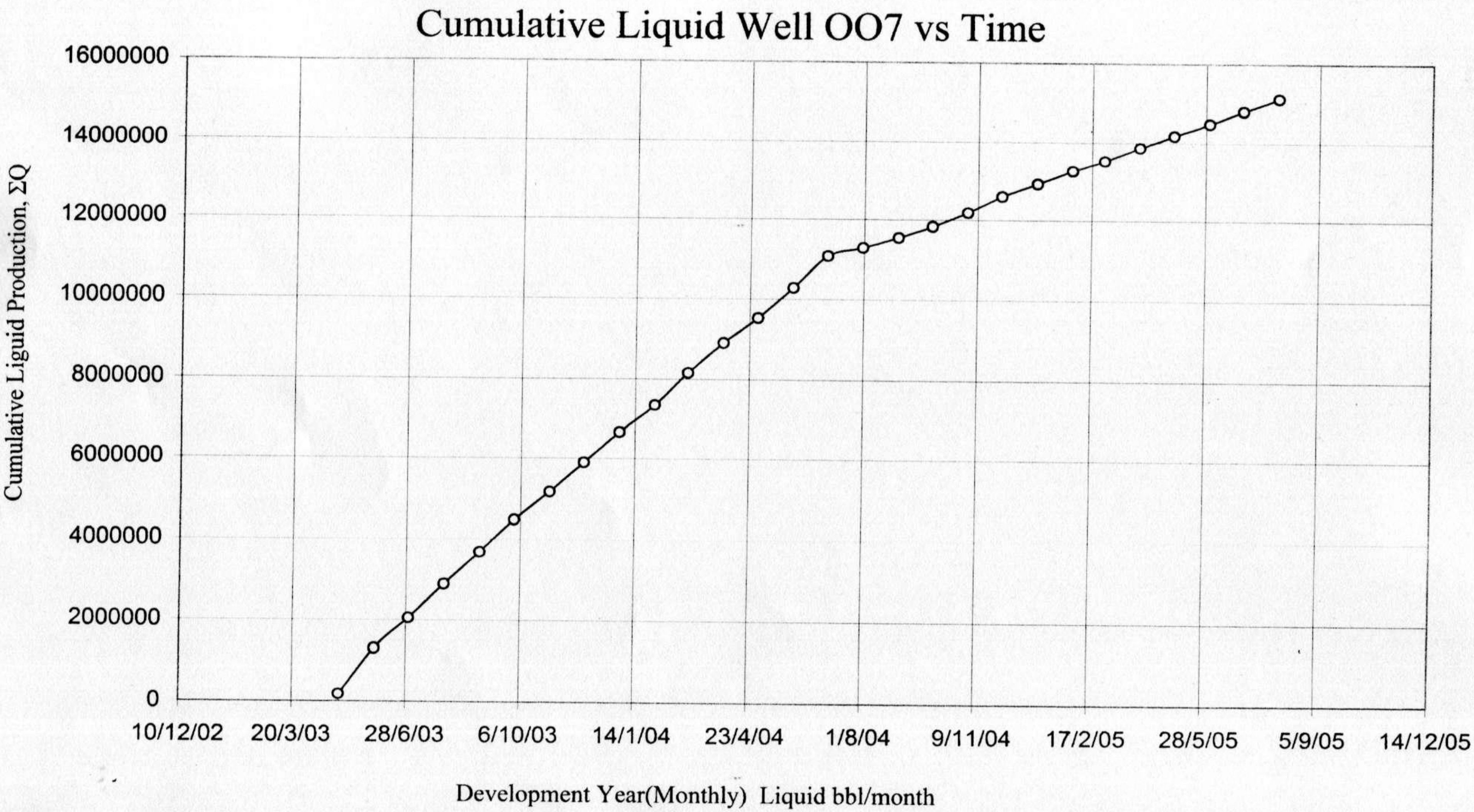
Development Year(Monthly) Liquid bbl/month

Figure. 2.3.4



Cumulative Oil Well OO7 vs Time
16000000
14000000
12000000
10000000
8000000
6000000
4000000
2000000
0
Cumulative Oil Production, ΣQ
10/12/02
20/3/03
28/6/03
6/10/03
14/1/04
23/4/04
1/8/04
9/11/04
17/2/05
28/5/05
5/9/05
14/12/05
Development Year(Monthly) Oil bbl/month

Figure. 2.3.5


Cumulative Liquid Well OO7 vs Time
Cumulative Liguid Production, ΣQ
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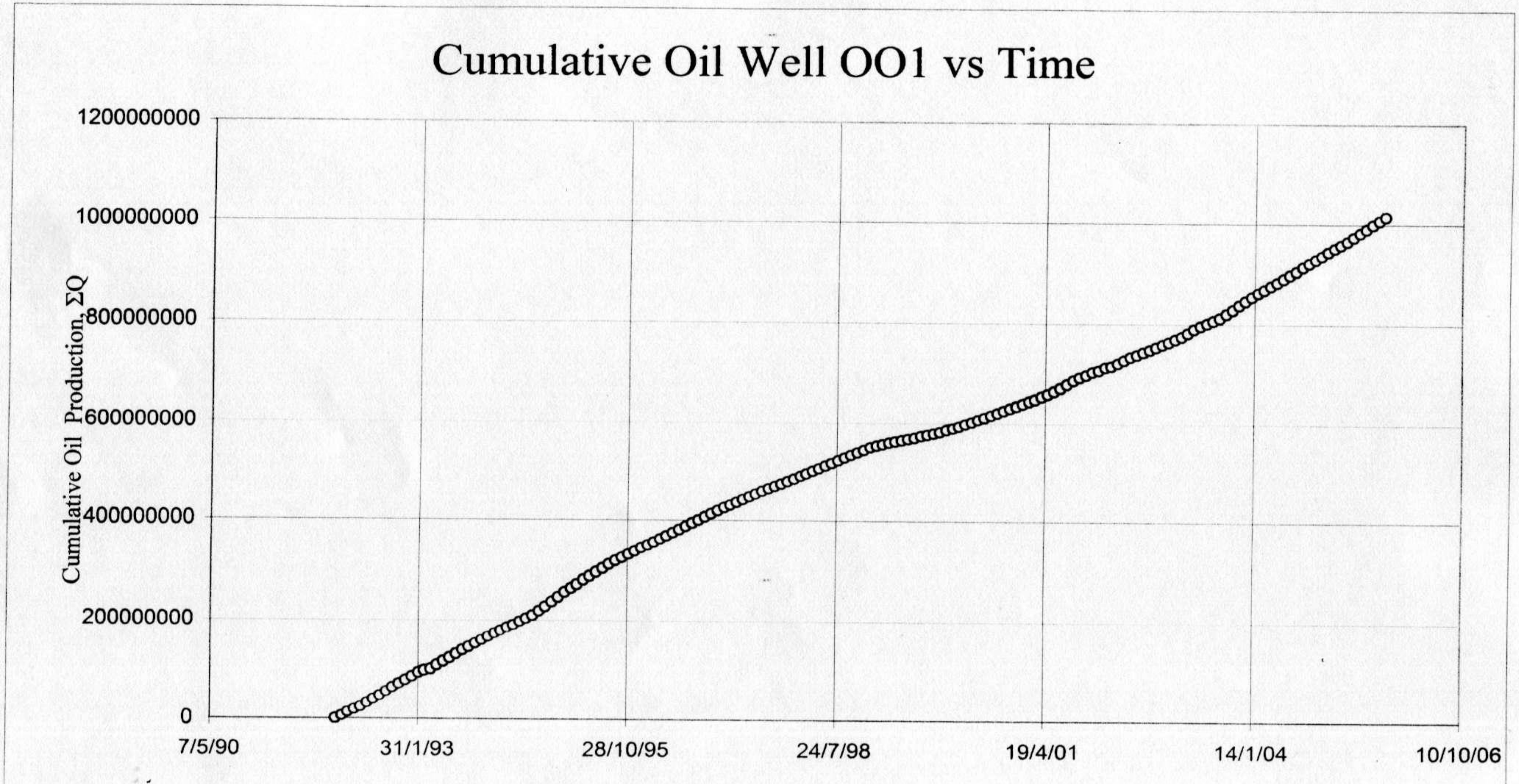
14000000
12000000
10000000
8000000
6000000
4000000
2000000
0
10/12/02
20/3/03
28/6/03
6/10/03
14/1/04
23/4/04
1/8/04
9/11/04
17/2/05
28/5/05
5/9/05
14/12/05
Development Year(Monthly) Liquid bbl/month

Figure. 2.3.6


Cumulative Oil Well OO1 vs Time
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1000000000
800000000
600000000
400000000
200000000
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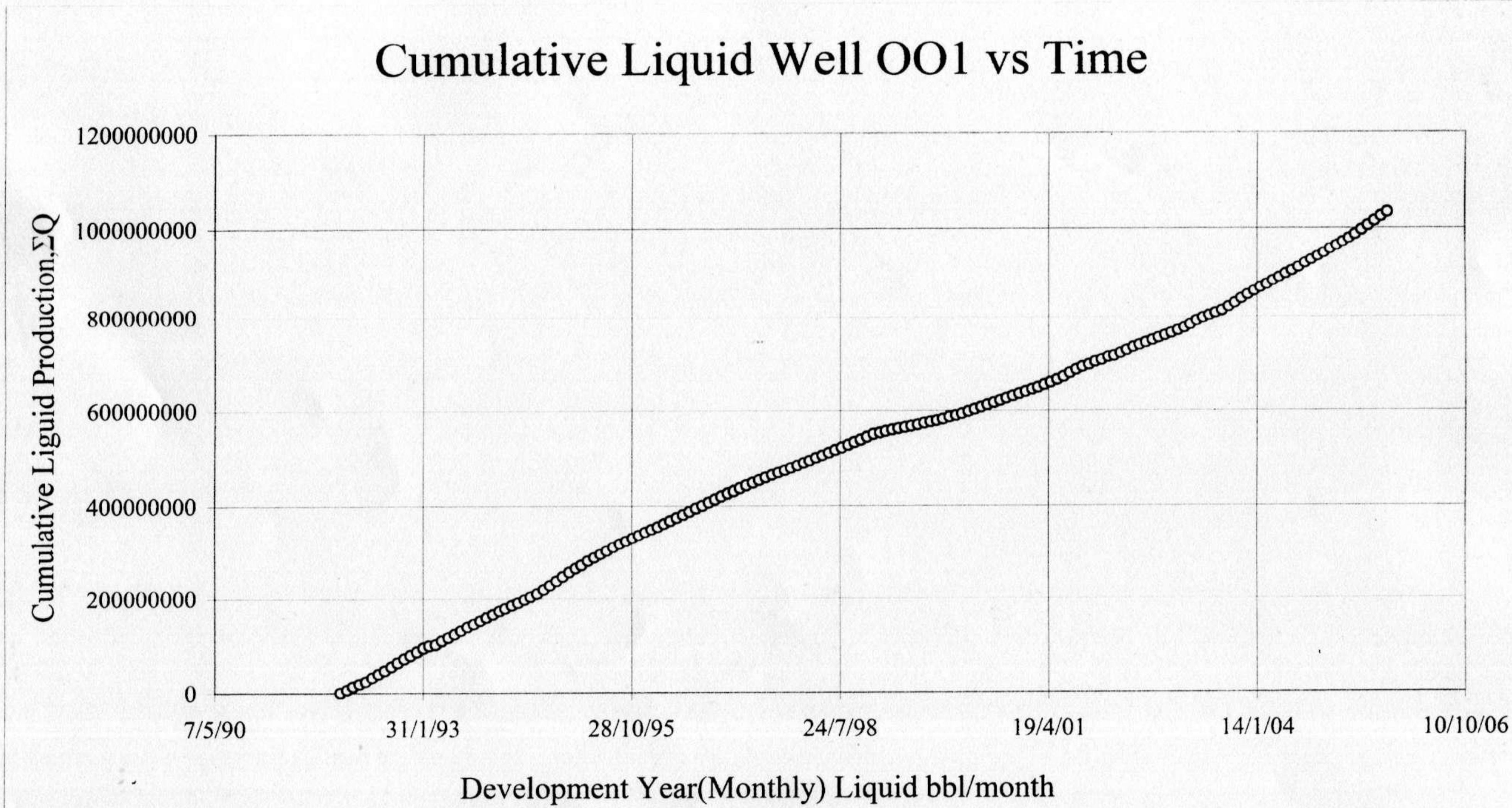
Cumulative Oil Production, ΣQ
7/5/90
31/1/93
28/10/95
24/7/98
19/4/01
14/1/04
10/10/06
Development Year(Monthly) Oil bbl/month
Figure. 2.3.7


Cumulative Liquid Well OO1 vs Time
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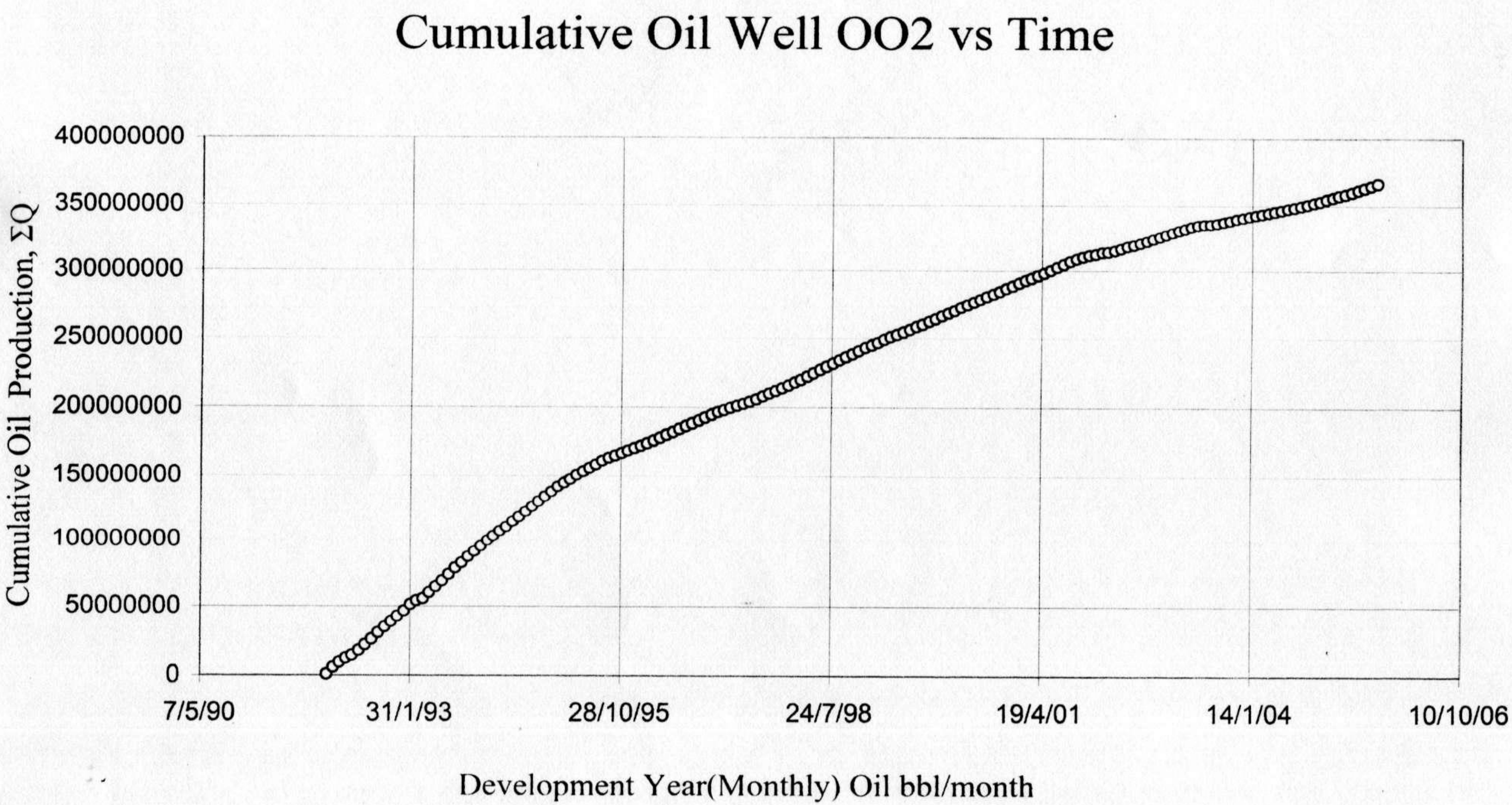
1000000000
800000000
600000000
400000000
200000000
0
Cumulative Liguid Production,ΣQ
7/5/90
31/1/93
28/10/95
24/7/98
19/4/01
14/1/04
10/10/06
Development Year(Monthly) Liquid bbl/month
Figure. 2.3.8



Cumulative Oil Well OO2 vs Time
Cumulative Oil Production, ΣQ
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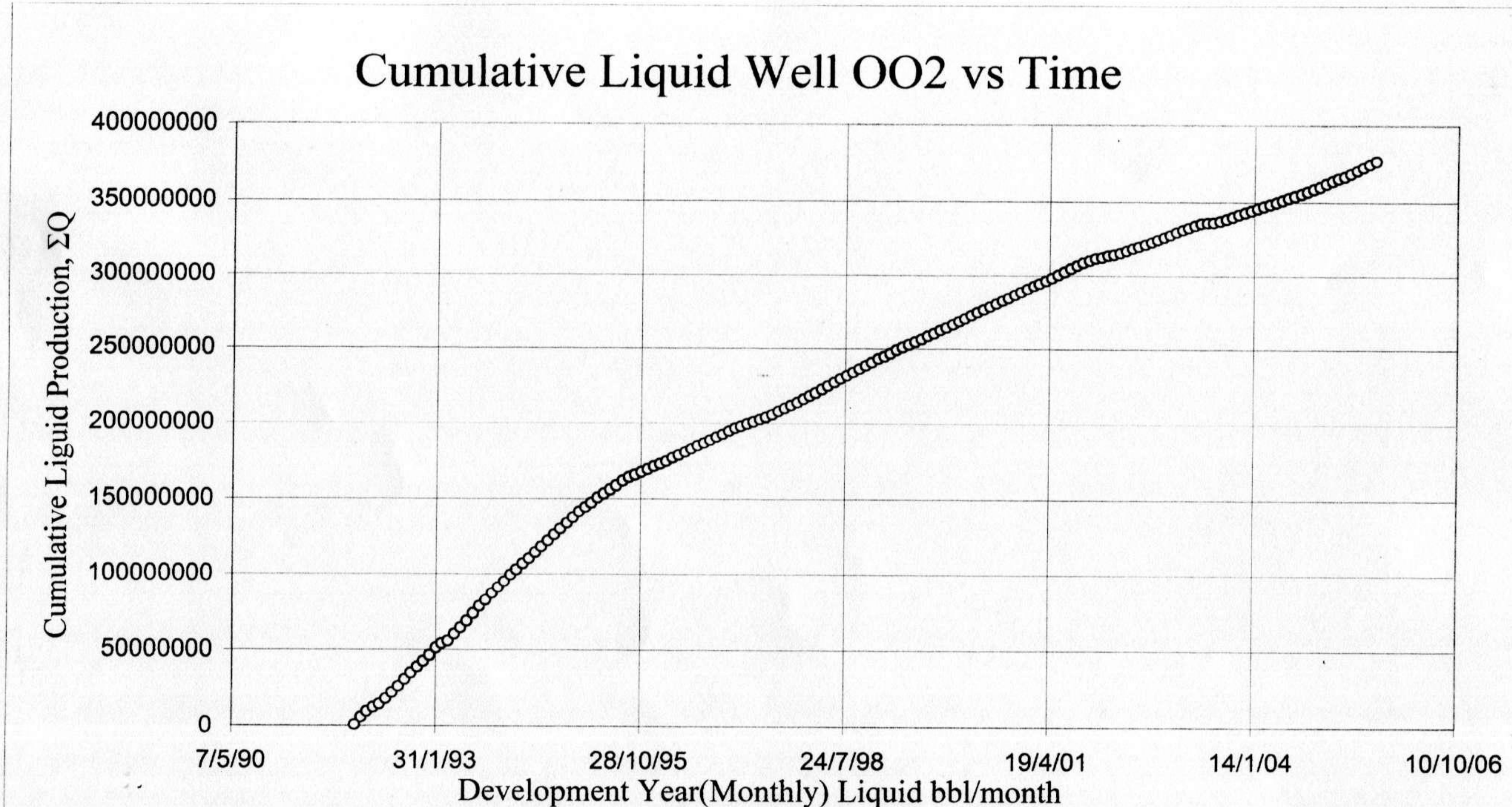
350000000
300000000
250000000
200000000
150000000
100000000
50000000
0
7/5/90
31/1/93
28/10/95
24/7/98
19/4/01
14/1/04
10/10/06
Development Year(Monthly) Oil bbl/month

Figure. 2.3.9


Cumulative Liquid Well OO2 vs Time
Cumulative Liguid Production, ΣQ
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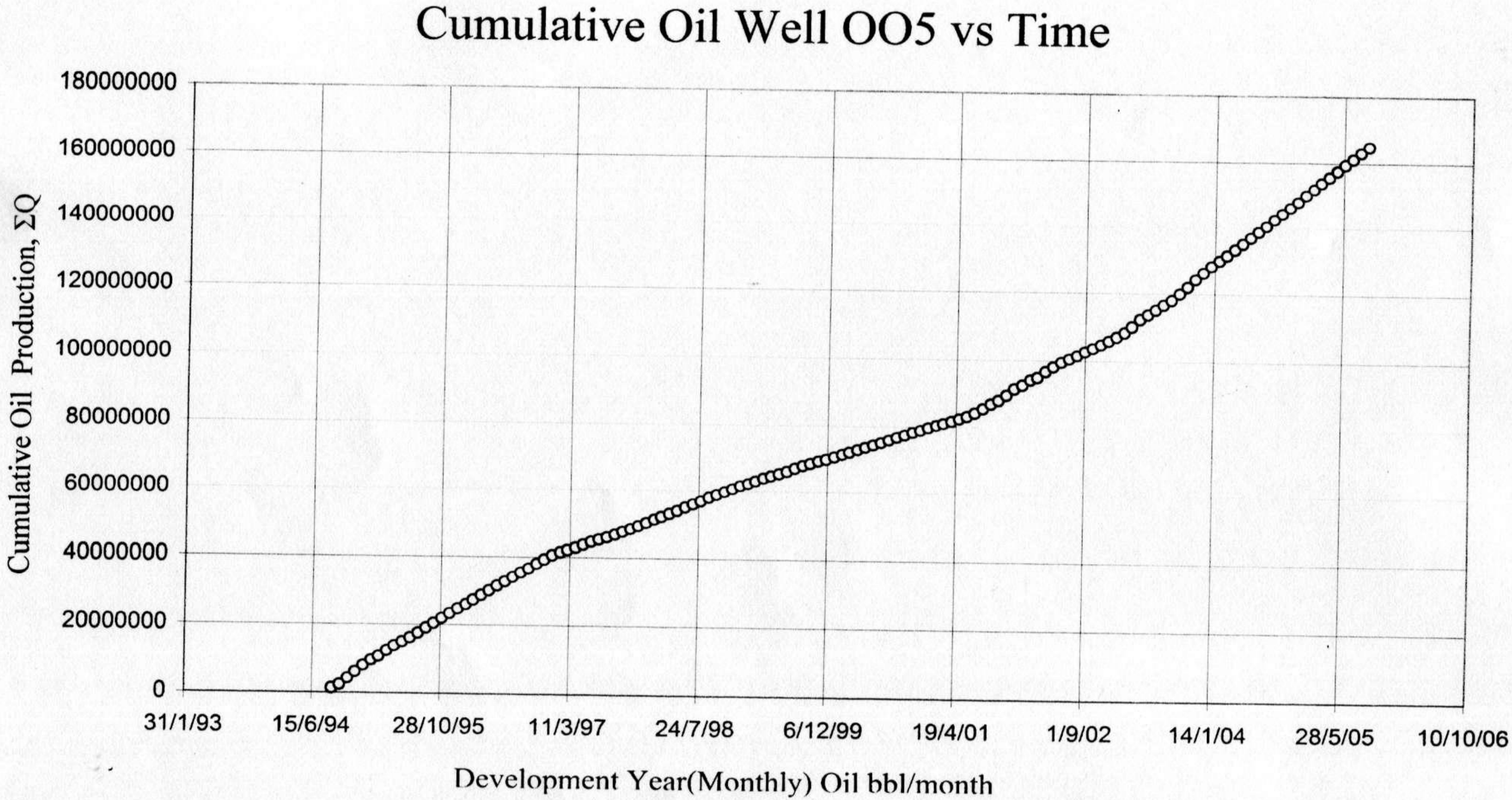
350000000
300000000
250000000
200000000
150000000
100000000
50000000
0
7/5/90
31/1/93
28/10/95
24/7/98
19/4/01
14/1/04
10/10/06
Development Year(Monthly) Liquid bbl/month

Figure. 2.3.10


Cumulative Oil Well OO5 vs Time
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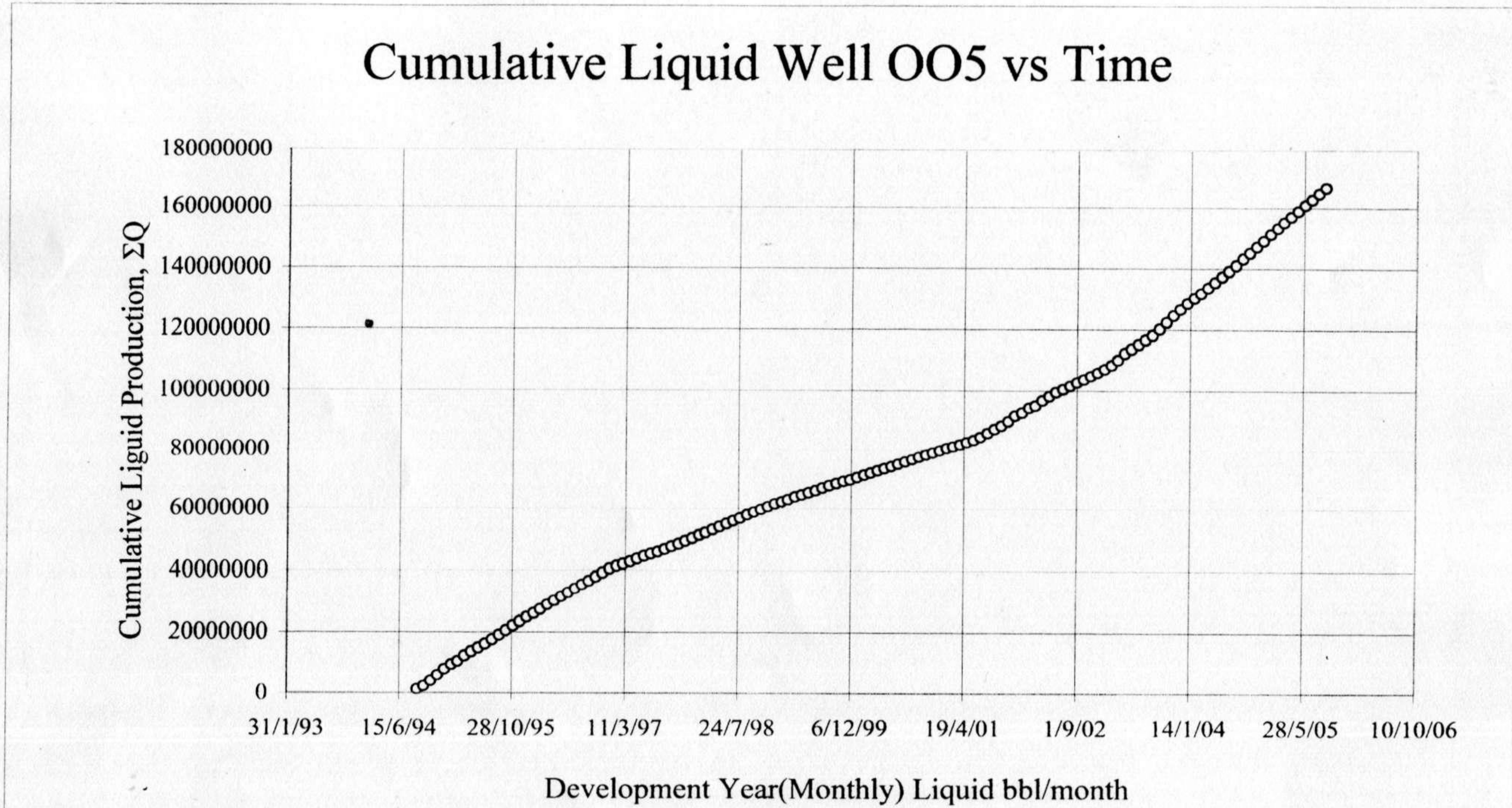
160000000
140000000
120000000
100000000
80000000
60000000
40000000
20000000
0
Cumulative Oil Production, ΣQ
31/1/93
15/6/94
28/10/95
11/3/97
24/7/98
6/12/99
19/4/01
1/9/02
14/1/04
28/5/05
10/10/06
Development Year(Monthly) Oil bbl/month
Figure. 2.3.11


Cumulative Liquid Well OO5 vs Time
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160000000
140000000
120000000
100000000
80000000
60000000
40000000
20000000
0
Cumulative Liguid Production, ΣQ
31/1/93
15/6/94
28/10/95
11/3/97
24/7/98
6/12/99
19/4/01
1/9/02
14/1/04
28/5/05
10/10/06
Development Year(Monthly) Liquid bbl/month
Figure. 2.3.12

CHAPTER 3

REGULATION OF DEVELOPMENT PROCESS

CONTENTS

CHAPTER 3

REGULATION OF DEVELOPMENT PROCESS

3.1. Oil and Combustible Gases Reserves Classification

Calculation of oil and combustible gases reserves is the important economic task.

To calculate oil and combustible gases reserves requires detailed study of geological, physical and thermodynamic conditions of reservoirs.

Only in this case, accuracy of calculated reserves would be raised. Hydrocarbons reserves should be calculated by several methods to get fine results and choose more ones that are exact.

3.1.1. General Information

Oil and combustible gases in most cases contain some pools. The pool can be generally coincided with the one or several reservoirs with a unified hydrodynamic system.

Oil and combustible gases pools are divided into:

a) Oil pools - when the reservoirs contain with that or other quantities of the dissolved gas. Methane content in the gases of these pools reaches 30-50%.

б) Oil and gas pools - when the reservoirs contain oil with the dissolved gas and free gas above oil (gas cap) or when the gas pools are confined (are fringed) with oil fringe.

c) Gas pools - when the reservoirs contain free gas of methane (paraffin) hydrocarbons that do not condense at the formation pressure drop.

As a rule, methane content in the gases of these pools is 94- 98%. Purely gas pools do not produce liquid hydrocarbons (gas condensate).

d) Gas condensate pools – when the reservoirs saturated by paraffin hydrocarbons in composition which there are sufficiently large quantity of heavy hydrocarbons from pentane to more heavy ones (C5+) that condense and evaporating at formation pressure drop. Methane content in these gases, as a rule, makes up 70-90%. Sometimes it can take place and then oil fringe of commercial importance.

e) Gas hydrate pools-when the gases in reservoir's conditions are in solid state. Gas hydrate or solid gas pools are formed under certain pressures in the Earth's crust with low temperature.

For a commercial evaluation of oil and gas fields or separate pools reserves, productive hori-zons and beds configuration and area, also thickness, reservoir properties, oil and gas saturation and operating performances determination are important.

The thickness of productive horizons or separate beds vary from several centimeters up to tens, and sometimes hundreds meters. The following thicknesses of productive beds are distinguished:

1) general thickness of a productive bed including all permeable and impermeable rocks thickness from top (roof) up to bottom (sole).

2) productive (effective) thickness consisting of permeable layers thicknesses.

3) oil- and gas-saturated thickness of the bed including thickness only those layers of rocks which contain oil and gas.

The porosity of productive beds depending on pores connectivity and their oil and gas saturation is divided into three types: absolute, open and effective (available) porosity. At oil and gas reserves calculation open porosity factor is used.

The Regulations by definition of oil and combustible gases fields exploration and study degree, their reserves reference to various categories and also by definition of the oil and gas reserves preparedness degree for the substantiation of oil and gas fields development planning and investing on oil-and gas field facilities and industrial installations them are based on the requirements stated in the document of "Oil and Combustible Gases Reserves Classification".

3.1.2. Groups of Hydrocarbon Reserves

The reserves of oil, combustible gases and accompanying components contained in them on economic view point are divided into two groups which are being the subject to separate the count and taken into account: on (balance) reserves which development are now economically expedient and resources (undeveloped reserves) which development are now unprofitable but which can be considered as the object for commercial development later.

In balance reserves of oil and gas dissolved in it, and also condensate in free gas recoverable reserves are distinguished and taken into account, i.e. the reserves which can be recovered at most full and rational use of up-to date engineering and technology.

Oil, gas and condensate recovery factors are established based on technique and economic calculations tested in practice of oil and gas fields' development.

3.1.3. Oil and Gas Reserves Categories

The reserves of oil, combustible gases and contained in them accompanying components on a degree of study are divided into four categories and which are determined by the following conditions.

Category A – reserves of oil and gases reservoirs (or their parts) is investigated with detail ensuring full determination of the form (configuration) and extension of reservoir, formation oil and gas saturation effective thickness, reservoir properties change character, oil and gas saturation of productive formation, oil, combustible gases and accompanying components contained in them and other parameters qualitative and quantitative composition, as well as formation main features from which conditions, wells productivity, formation pressure, temperature, and permeability, and piezoconductivity of bed and other features of reservoir are depend on. The reserves of the category A are calculated during oil reservoir development.

Category B - reserves of oil or gas reservoirs (or their parts), oil and gas content of which is established on the basis of obtaining commercial oil and combustible gases inflow in wells (commercial oil and gas inflow should be obtained at minimum in two wells) on various hypsometric depth and availability of favorable well logging data of samples. The configuration and extension of reservoir, formation oil and gas saturation effective thickness, character of change of reservoir properties, and oil and gas saturation of productive formations, and other parameters, as well as main features determining reservoir development conditions are approximately investigated but in a sufficient degree for a reservoir development planning; oil, combustible gases and containing in them accompanying components composition at surface and under reservoir conditions are studied in details. On gas reservoir the oil fringe presence is established or its commercial value is determined.

Category C1 - reserves of oil or gas reservoirs (or their parts), oil and gas content of which is established on the basis of obtaining commercial oil and combustible gases inflow in individual wells (the part of wells can be tested by the formation tester) (commercial oil and gas inflow should be obtained at minimum in one well) and favorable well logging data in a number of other wells, as well as reserves of part of reservoir (or tectonic block) adjoining to the areas with reserves of higher categories. Oil and combustible gases occurrence conditions for a given region are established by geological and well logging methods; productive formation properties and other parameters are studied on a test of individual wells or adopted by analogy to a more investigated part of a reservoir and adjacent prospected fields.

Category C2 - reserves of oil or combustible gases which availability are supposed on the basis of favorable geological and well logging data in individual introspected areas, tectonic blocks and in formations of the studied fields, as well as in the new structures within the limits of oil and gas bearing regions outlined by the geological methods tested up for the given region. Unbalanced reserves of the category C2 aren't calculated. The balance reserves of a condensate, helium and other accompanying components, including recoverable reserves, as well as their unbalanced reserves concern to those categories of reserves to which these accompanying components concern. The conditions concerning to oil, combustible gases and containing in them accompanying components reserves of A, B, C1 and C2 categories counted up on separate fields and areas, for assessment of oil- and gas provinces, areas and regions potential capabilities hypothetical (expected) reserves (Group D) are determined on the basis of general geological submissions which are tested by the oil and gas producing organizations. The order of entering, contents and registration of materials on calculation of oil and gas reserves presented on to affirmation in the State Commission are regulated by the directions for use of reserves classification to oil and combustible gases fields.

3.1.4. Computing of Oil Reserves by Volumetric Method

The volume method of oil reserves estimating has received a wide circulation and can be used at any reservoir operation conditions and at any stage of its extent of exploration.

At estimating of oil reserves the following variants of volume method can be applied: basic volume variant, volume-statistical variant, volume-weight variant, hectare variant and isoclines variant. Isoclines variant isn't used in practice.

A basic volume variant is widely used in oil reserves calculation practice.

At use of a volumetric method proceed from the assumption that oil occurs in rock pores which volume can be defined knowing the geometrical sizes of oil-bearing formation and rock porosity.

To calculation of oil reserves the following formula is applied:

$$Q = F\, h\, m\, \beta\, \eta\, \rho\, \theta, \qquad (3.1.4.1)$$

where Q - recoverable reserves of oil, mt; F- oil-bearing area, m^2; h - oil saturation thickness, m; m - rock porosity factor; β - oil saturation factor; η - oil recovery factor; ρ - oil density at surface, mt/m^3; θ - oil shrinkage factor: θ=1/b (b - oil formation volume factor).

Here $b = V_d/V_r$, where V_d –volume of oil at downhole conditions; V_r -volume of oil at surface conditions.

The volume of oil at downhole conditions includes any dissolved gas.

Surface conditions are: 60 degrees F (15.55 °C) and 14.7 psia (1.033 kg/см^2).

b- is determined from PVT measurements on a reservoir fluid sample.

At calculation of oil reserves by a volume method should be submitted:

a) substantiation of the chosen categories of oil reserves with the indication of their borders on the structural map by top of horizon with a designation of testing results or trial operation of wells with conventional symbol (sign);

b) real data on wells about effective thickness of horizon or bed and its porosity and also about technique of reception and substantiation of accepted initial and average values for oil reserves calculation;

c) data on the analyses of oil and oil shrinkage at it recovery on a surface, and also data on the gas-oil ratio (gas factor);

d) real data about formation pressure, bubble-point (saturation) pressure and formation temperature;

e) data on an oil horizon drive, type of a reservoir and its properties.

For computing of initial oil reserves in place formula (3.1.4.1) is written as

$$Q = F\, h\, m\, \beta\, \rho\, \theta\,, \qquad (3.1.4.2)$$

Data for calculation of oil reserves as follows:

F=1,709, 892.2 m^2; h=162.5 m; m=0.16; β=0.84; ρ=0.73 mt/m^3; θ=0.693,

Hence,

Q= 1,709, 892.2x162.5x0.16x0.84x0.73x0.693=18,894,309 mt (or 116.2 MMSTB).

The difference between oil reserves calculated by volumetric method 18,894,309 mt (116.2 MMSTB) and in field conditions 17,853,659 mt (109.8 MMSTB) is 6.4 MMSTB, i.e. 0.94%. It shows the accuracy of oil reserves calculations.

3.2. Calculation of Ultimate Oil Recovery Factor

3.2.1. Calculation of Oil Reserves of Bu-Attifel by Mathematical-Statistical Method

Hydrocarbon reserves calculation by mathematical-statistical method is based on mathematical processing of field data. First in oil industry, V.V. Bilibin introduced oil reserves calculation by statistical method.

By the help of mathematical-statistical method, using production decline curve, it is possible to calculate hydrocarbon reserves with large accuracy.

Construction of different curves with purpose of determining factors influencing to wells and formations production rate it is necessary to use field statistic material concerning all periods of development.

Introducing of statistic methods in most cases requires using field materials concerning middle or declining periods of reservoirs development.

Before using statistic methods, it is necessary to construct special tables in which should be introduced numerical values of function depend on numerical values of argument. Functions presented in such way could be required differentiating or integrating in further operations.

In processing of Tables data it would be required determining argument's intermediate values not shown in the Table (interpolation problem) or argument's out of Tables values (extrapolation problem).

3.2.2. Graphical Construction of Production Curve Based on Field Data Processing

To carry out statistical studies it is required gathering, generalization and systematization of field data. This work is fulfilled for Upper Nubian Sandstone formation of a Lower Cretaceous of Bu-Attifel Field and introduced in Table 3.2.2.1.

Based on data of Table 3.2.2.1 production curve for investigated field was constructed and another Table 3.2.2.2 was drown up.

To plot production curve of Nubian Sandstone formation Table 3.2.2.2 showing cumulative production on reservoir vs development years, were drown up.

Based on data put in Table 3.2.2.2 cumulative oil production vs development years curve $\sum Q = f(t)$ was constructed (Figure 3.2.2.1). As is shown in Figure 3.2.2.1 production curve has linear character with respect to time and is described by expression

$$\sum Q = 8E{+}08t - 7E{+}08 \qquad (3.2.2.1)$$

Table 3.2.2.1& 3.2.2.2

Field data for calculation of oil reserves by statistical method

Development years	Number of development year, t	Cumulative Production of Oil MMSTB	$\frac{t_i}{\sum Q}$	$\frac{t_i}{\sum Q} \cdot t_i$
1	2	3	4	6
1991	29	853368	1.1718E-06	1.1718E-06
1992	30	5.48E+08	3.6496E-09	7.2993E-09
1993	31	1.54E+09	1.9481E-09	5.8442E-09
1994	32	2.52E+09	1.5873E-09	6.3492E-09
1995	33	3.66E+09	1.3661E-09	6.8306E-09
1996	34	4.61E+09	1.3015E-09	7.8091E-09
1997	35	5.46E+09	1.2821E-09	8.9744E-09
1998	36	6.23E+09	1.2841E-09	1.0273E-08
1999	37	6.83E+09	1.3177E-09	1.1859E-08
2000	38	7.37E+09	1.3569E-09	1.3569E-08
2001	39	8.11E+09	1.3564E-09	1.492E-08
2002	40	8.89E+09	1.3498E-09	1.6198E-08
2003	41	9.77E+09	1.3306E-09	1.7298E-08
2004	42	1.09E+10	1.2844E-09	1.7982E-08
2005	43	1.13E+10	1.33E-09	1.9912E-08
	Σ135	Σ8,77E+10		

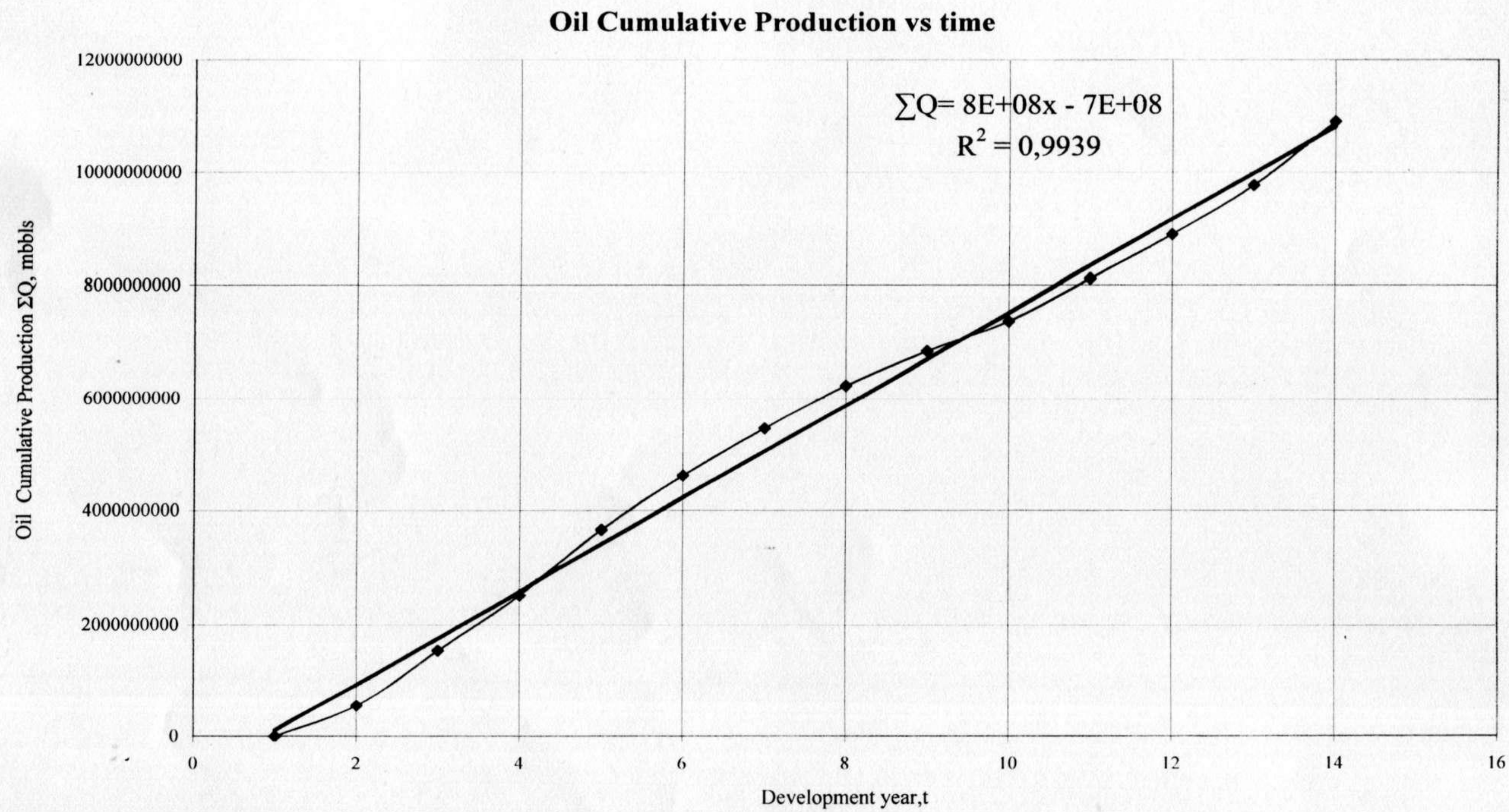

Oil Cumulative Production vs time
∑Q= 8E+08x - 7E+08
R2 = 0,9939
Oil Cumulative Production ΣQ, mbbls
12000000000
10000000000
8000000000
6000000000
4000000000
2000000000
0
0
2
4
6
8
10
12
14
16
Development year,t

Figure.3.2.2.1

To determine oil production for the next years and also cumulative oil production for infinite time period (it means hydrocarbon reserves) based on data put in Table 3.2.2.2 the values of parameter $t/\sum Q$ was calculated and the diagram $t/\sum Q$ vs t was constructed (Figure 3.2.2.2).

As is clear from Table 3.2.2.2 and Figure 3.2.2.2 at the beginning 1991 the value of parameter $t/\sum Q$ increases.

It is required to choose functional relationship for expression $t/\sum Q = f(t)$.

Composition of equation for the curve plotted based on field practical data is called choosing of empirical formula. The curve $t/\sum Q = f(t)$ shown in Figure 3.2.2.2 describes the linear function, which intersects some segment from y-axis and forms some angle with x-axis. Therefore, we can write

$$y = a + bx \qquad (3.2.2.2)$$

So, practically, smoothing of the curve is carried by equation $y = a + bx$. To determine coefficients a and b in equation (3.2.2.1), method of least squares has been used. In a function of $y = a + bx$ as a measure of common error, deviation for all experiments, would be expressed as

$$G = \sum (y - a - bx)^2 = \min. \qquad (3.2.2.3)$$

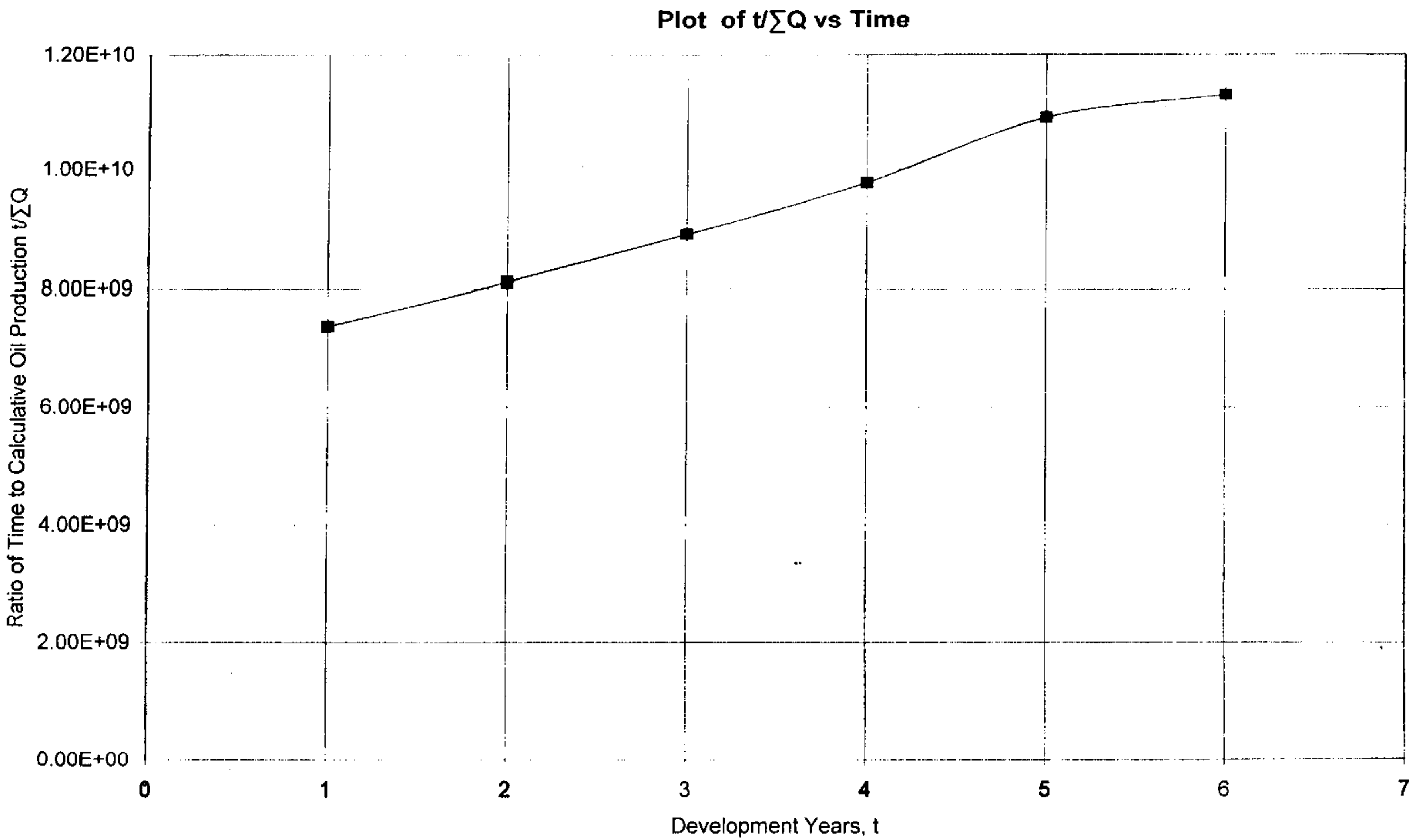
Providing minimum of the sum of all deviations G determining of coefficients values in equation (3.2.2.2) is called the method of least squares.

In a small value of a common error G to calculate constant $b = b^*$ it is required to differentiate it on a and b coefficients provided that

$$\frac{\partial G}{\partial a} = 0 \text{ and } \frac{\partial G}{\partial b} = 0$$

Hence, according to condition (3.2.2.2) system of equation is given Figure 3.2.2.2 (Ratio of Development years to Cumulative Oil Production, t/∑Q vs Time).

$$\left.\begin{aligned} \frac{\partial G}{\partial a} &= 2\sum_{i=1}^{i=n} (y_i - a - bx_i)\cdot(-1) = 0 \\ \frac{\partial G}{\partial b} &= 2\sum_{i=1}^{i=n} (y_i - a - bx_i)\cdot(x_i) = 0 \end{aligned}\right\} \qquad (3.2.2.4)$$



Plot of t/∑Q vs Time
1.20E+10
1.00E+10
8.00E+09
6.00E+09
4.00E+09
2.00E+09
0.00E+00
Ratio of Time to Calculative Oil Production t/∑Q
0
1
2
3
4
5
6
7
Development Years, t

Figure.3.2.2.2

These two conditions allows for determining of coefficients a and b to set up equations systems shown below

$$\left.\begin{aligned}&\sum_{i=1}^{i=n} y_i - na - b\sum_{i=1}^{i=n} x_i = 0\\&\sum_{i=1}^{i=n} x_i y_i - a\sum_{i=1}^{i=n} x_i - b\sum_{i=1}^{i=n} x_i^2 = 0\end{aligned}\right\} \qquad (3.2.2.5)$$

It is not difficult to calculate values of a and b coefficients from equations system (3.2.2.4). For this purpose, to be short, assume that

$$m_1 = \sum_{i=1}^{i=n} x_i; \qquad m_2 = \sum_{i=1}^{i=n} x_i^2;$$

$$q_1 = \sum_{i=1}^{i=n} y_i; \qquad q_2 = \sum_{i=1}^{i=n} x_i \cdot y_i .$$

Then equation system (3.2.2.4) can be written, as

$$\left.\begin{aligned}&m_1 \cdot a + m_2 \cdot b = q_2\\&m_1 \cdot b + na = q_1\end{aligned}\right\} \qquad (3.2.2.6)$$

Solving equation system (3.2.2.5) can be received:

$$\left.\begin{aligned}&a = \frac{m_2 \cdot q_1 - m_1 \cdot q_2}{m_2 \cdot n - m_1^2}\\&b = \frac{q_2 \cdot n - q_1 \cdot m_1}{m_2 \cdot n - m_1^2}\end{aligned}\right\} \qquad (3.2.2.7)$$

There is another approach to the considered method. Equation $y = a + bx$ as a function between two variables x and y being considered linear expression would be written such way that allowed calculating of unknown coefficients a and b. Using the experimental data, depending on these parameters equation system can be written:

$$q_1 = \sum_{i=1}^{i=n} y_i$$

$$\left.\begin{aligned}&y_1 = a + bx_1\\&y_2 = a + bx_2\\&\dots\dots\dots\dots\\&y_n = a + bx_n\end{aligned}\right\} \qquad (3.2.2.8)$$

Having experimental data it is easy to calculate a and b coefficients. However, taking into consideration that parameters x and y were measured by some error, then we believe that those errors influence to a and b coefficients values.

On the contrary, a and b coefficients calculations will be more accuracy with increasing experimental measurements, in other words, with increasing equation numbers.

So errors of separate measurements will compensate each other, and therefore, applying the method of least squares will be more reasonable.

It should be noted if there is not linear relationship between x and y variables, and existed more complicated relationship, solving the problem would be more sophisticated. In practice, in this case, for choosing of mathematical expressions graphical approach is used.

To calculate hydrocarbon reserves of Bu-Attifel (Nubian sandstone formation) field the model shown in [8] has been used:

$$\sum Q = \frac{t}{a+bt}, \qquad (3.2.2.9)$$

If expression (3.2.2.8) being written for the case time approaches to infinite, i.e. $t \to \infty$ we receive:

$$\sum Q \,|_{t\to\infty} = \frac{1}{b}. \qquad (3.2.2.10)$$

In reality, the inverse value of the Y-intercept of the rectilinear constructed between parameter $t/\sum Q$ and time t is characterized the oil reserves in place. From graph shown in Figure 3.2.2.2, we obtain $b = 8{,}4E+09$.

In this case

$$1/b = \frac{1}{8{,}4E-09},$$

$$1/b = 0{,}1190476E+09$$

has been received.

Finally, oil reserves in place calculated by above considered method makes 119.05 MMSTB.

It should be noted that initial oil reserves calculation shows the amount 109.8 MMSTB and our clculations by volumetric method is given 116.2 MMSTB.

3.3. Estimation of Oil Recovery Factor in Nubian Reservoir

3.3.1. General Information

For the oil and gas condensate reservoirs developed long period and a large portion of hydrocarbon reserves which was recovered to increase of the development efficiency for the next period, appropriate corrections should be done in its further development plan.

Further development period is the longest period with worsening of reservoir performances that is characterized by formation pressure declining, decreasing of producers' production rate, water encroachment of pool, liquid hydrocarbons separation, well production problems and their shutdowns for some reason or other; all these problems cause sufficiently declining of recovery rate. Before further development program scheduling the following tasks should be done:

1. As a result of gathering, generalization and processing of field data reservoir development process should be analyzed;
2. Development control information should be analyzed.
3. To increase development efficiency preparing measures of its intensification should be provided.

In the second chapter of this thesis short development analyze was realized. On the third chapter of thesis based on processing field information reservoir hydrocarbon reserves by different methods were calculated.

3.3.2. Estimating the Ultimate Oil Recovery Factor of Nubian Reservoir

Below in Table 3.3.2.1 drown up by field data oil reserves recovery factors of Upper Nubian Sandstone formation Bu-Attifel from beginning of development up to September 2005 are shown.

Table 3.3.2.1

Oil Recovery Field Data

Development Years	Number of Development Year, t	Cumulative Oil Recovery Factor, η	Ratio of Development Year to the Cumulative Oil Recovery Factor, t/η
1	2	3	4
1991	19	0.1947	97.59
1992	20	0.2043	97.90
1993	11	0.2162	101.75
1994	22	0.2283	100.73
1995	23	0.2413	99.47
1996	24	0.2543	98.31
1997	25	0.2659	97.77
1998	26	0.277	97.46
1999	27	0.2885	97.05
2000	28	0.2986	97.13
2001	29	0.3079	97.43
2002	30	0.3167	97.9
2003	31	0.3269	97.88
2004	32	0.3343	98.7
2005	33	0.3466	99.4

Based on information shown on the Table 3.3.2.1 in Microsoft Excel the graph of $\frac{t}{\eta} = f(t)$ function was plotted (Figure 3.3.2.1).

Plot Ratio of t/η vs Time

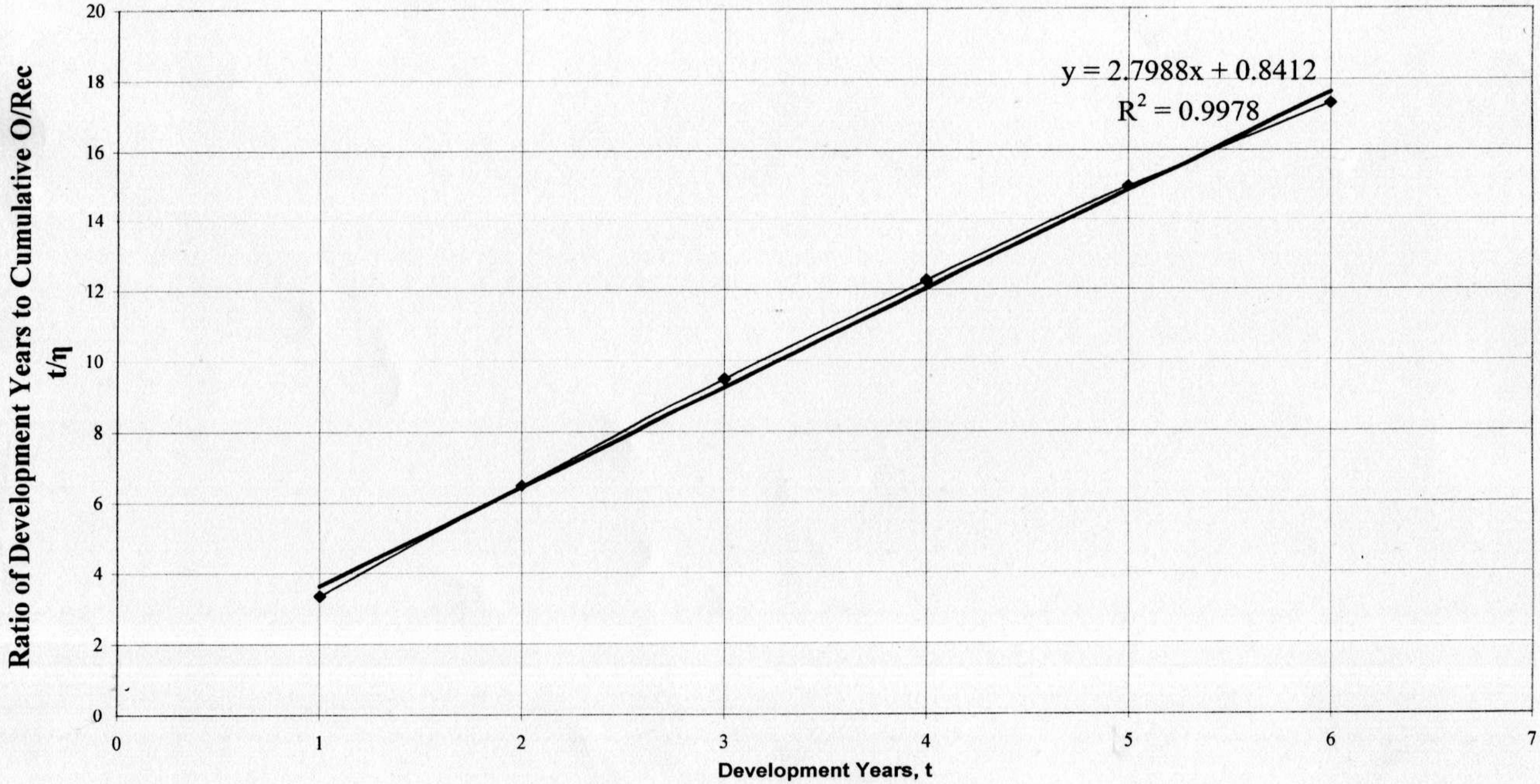


Figure 3.3.2.1

As is clear from Figure 3.3.2.1 plot t/η as a function of t has a rectilinear character and is described as

$$\frac{t}{\eta} = 2.7988t + 0.8412 \qquad (3.3.2.1)$$

Degree of approximation accuracy is $R^2 = 0.9978$.

Dividing of both sides of equation 3.3.2.1 by t, we receive

$$\frac{1}{\eta} = 2.7988 + \frac{0.8412}{t}. \qquad (3.3.2.2)$$

If the expression (3.3.2.1) would be written for the case of $t_{\to\infty}$, then the following expression can be received

$$\frac{1}{\eta}\ |_{t\to 0} = 2.7988. \qquad (3.3.2.3)$$

Hence,

$$\eta = \frac{1}{2.7988.} = 0.357296 \approx 0.36.$$

So, inverse value of a portion of plotted relationship of t/η as a function of time t intersected from y-axis is characterized of ultimate oil recovery factor. From here in becomes clear that ultimate oil recovery factor will be $\eta \approx 0.36$.

It should be noted that in the development program ultimate oil recovery factor was received $\eta = 0.336$.

3.3.3. Estimating of Current Oil Recovery Factor

To predict reservoir current oil recovery factor, information given in the Table 3.3.2.was used.

Based on data shown in the Table 3.3.2.1 the relationship $\eta = f(t)$, the plot oil recovery factor η as a function of development years t was constructed (Figure 3.3.3.1).

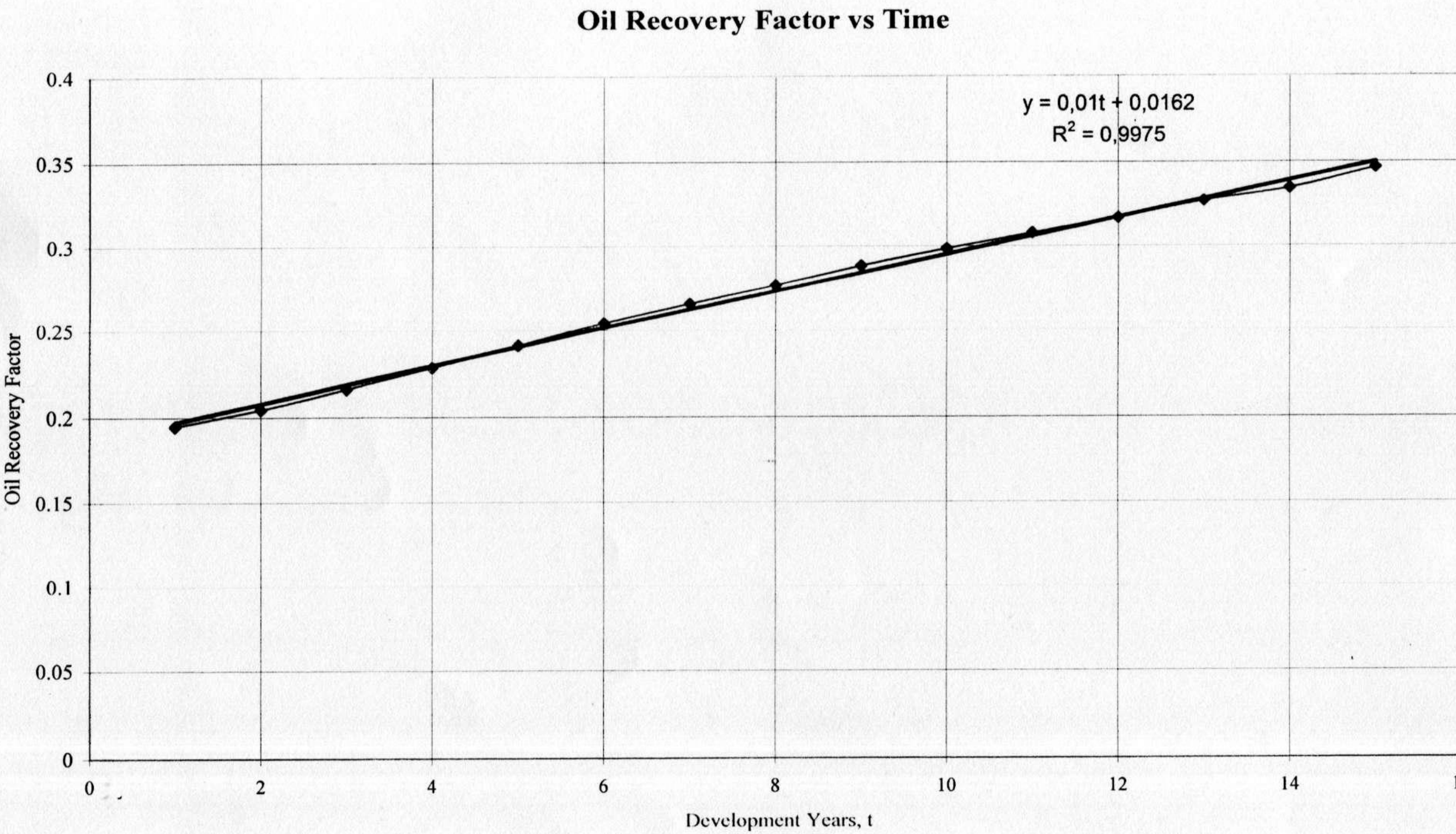

Oil Recovery Factor vs Time
y = 0,01t + 0,0162
R2 = 0,9975
Oil Recovery Factor
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
2
4
6
8
10
12
14
16
Development Years, t

Figure.3.3.3.1

As it is shown in the Figure 3.3.2.1 the curve has linear nature and it could be described by expression

$$y = at + b. \qquad (3.3.3.1)$$

Based on Microsoft Excel program the coefficients of above equation were determined and the ultimate equation was received:

$$\eta = 0.01t + 0.0162 \qquad (3.3.3.2)$$

Reliability factor for this equation is made.

For confirmation of reliability of equation 3.3.3.2 calculation of oil recovery factor on the previous years are needed.

For the 29^{th} (2001) development year it will be:

η = 0.01t+ 0.0162= 0.01x29+0.0162=0.3062.

t=30(2002):

η = 0.01t+ 0.0162=0.01x30+0.0162=0.3162.

t=31 (2003):

η = 0.01t+ 0.0162= 0.01x31+0.0162=0.3262.

t=32 (2004):

η = 0.01t+ 0.0162= 0.01x32+0.0162=0.3362.

t=33 (2005):

η = 0.01t+ 0.0162= 0.01x33+0.0162=0.3462.

Absolute error of calculations is varying within limit less than 1%.

So, oil recovery factors calculated by the equation and real ones are the same.

Therefore, prediction of oil recovery factor for the next development years using expression (3.3.3.2) is reasonable. With this in mind, taking all performances being equal, we also can calculate oil recovery factors for the nearest future development years (Figure 3.3.3.1) using expression (3.3.3.2):

t=34 (2006)

η = 0.01t+ 0.0162= 0.01x34+0.0162=0.3562

t=35 (2007)

η = 0.01t+ 0.0162= 0.01x35+0.0162=0.3662

CHAPTER 4

IMPROVEMENT OF DEVELOPMENT PROCESS AND STIMULATION OF OIL PRODUCTION

CONTENTS

CHAPTER 4

IMPROVEMENT OF DEVELOPMENT PROCESS AND STIMULATION OF OIL PRODUCTION

4.1. Measures of Stimulation of Oil Production

To increase the efficiency of reservoir development, it is required to increase both of wells production rate and development system extension.

For increase wells' production rate, maintaining of the natural filtration features of formation and a number of engineering processes carrying out in wells operating period are needed.

To preserve the formation's natural flow features, it is required to prevent washing liquid filtration into formation and productive pay efficiency exposing in drilling process should be provided. The most widely used wells productivity increasing methods are varieties of hydraulic fracturing of formation, acid and other formation treatment methods, special perforation methods (jet gun, projective gun, heavy-caliber bullet gun, abrasive jet gun etc). and sand bridge removal and so on.

The object of the bottom-hole treatment, both chemically and physically treatment, is increasing of well bottom-hole permeability, additional permeable interlayer and stagnant zones bringing into filtration process and to increase pressure differential on the formation to stimulate oil recovery.

The main wells normal operation troubling processes are water encroachment of pay horizon with further increasing of water production and producing of paraffin-base crude oil (wax content: 36.7% with an upper pour point of 39 °C).

Water-encroached oil-field development could be conducted by two ways:

a) water shutoff in formation;

b) producing of water with oil from wells.

Water isolation of bed should be provided with the purpose of water-encroachment regulation; otherwise, the certain difficulties will be created in development process. After definition of nature of water-encroachment the method of water producing with oil should be chosen.

At present stage the rate of development averages (0.55÷1.2) %, which is very less than it was adopted for onshore oil fields. As is well known for the onshore oil fields with favorable geological properties the rate of development composes more than 6%. So, increasing of the rate of reservoir development is one of the burning topics of the day.

At the same time the special investigations improving water injection and increasing its effectiveness should be provided.

Research of problems of enhancing oil recovery from the productive pay combined from non-uniform layers of collectors by correlation analysis on research of interaction between producing wells should be continued.

Efficiency of process of development can be increased on the basis of the analysis of the current condition of development of a productive formation. Thus revealing of features of development will allow purposefully and with the least expenses to raise productivity of wells and as consequence to enhance oil recovery factor.

Calculations are carried out on the basis of application of rank correlation factor of Spearman when absolute values of analyzed parameters are replaced with sizes of the ranks appropriate to them.

To stimulate of oil production, drilling-in additional development wells on the dead oil areas between these non-interactive wells is suggested.

Procedure of calculations by a method of evolutionary modeling consists of two stages.

At the first investigation stage the analysis of the initial information (an interval of training) will be carried out and the forecast for the subsequent available site curve (an interval of examination) is made.

By the analysis of variance actual and calculated data of selection the most authentic type of model is determined.

At the following stage based on the evolutionary model using the above determined factors further prediction of production and recoverable volume of oil under condition of invariance development system parameters is made.

The volume method of oil reserves estimating has received a wide circulation and can be used at any reservoir operation conditions and at any stage of its extent of exploration.

At estimating of oil reserves the following variants of volume method can be applied: basic volume variant, volume-statistical variant, volume–weight variant, hectare variant and isoclines variant. Isoclines variant isn't used in practice.

To carry out statistical studies it is required gathering, generalization and systematization of field data.

Estimating the ultimate and current oil recovery factor, the absolute error of calculations is varying within limit less than 1%.

With this in mind, taking all performances being equal, we also can calculate oil recovery factors for the nearest future development years.

4.2. Enhancing Formation Oil Recovery Factor

Conditions for application of oil recovery methods what is meant by secondary recovery methods are operations undertaken to extract remaining oil reserves from fields that have been considerably depleted by pervious exploration.

Here depletion refers to the expenditure of the initial reserves of reservoir energy usually accompanied by considerable decline in formation pressure.

The withdrawal of the remaining oil under these conditions encounters certain difficulties as with the decline of reservoir pressure gas is partly released from the oil that as a result of this loss becomes more viscous. Gas liberation from oil which lowers the phase permeability of the rock to oil and the oil pool may be flooded to a greater or lesser extent.

In the great majority of cases the secondary recovery operations used to produce the remaining reserves from depleted or semi-depleted reservoirs consists of displacing the oil by injecting water or gas into the reservoir. Successful application of secondary methods is also favored by: (a) the absence of marked tectonic sub-division of the formation; (b) homogeneous lithological composition and permeability of the reservoir; (c) low oil viscosity. These factors are not always indispensable but if present, they ensure greater efficiency of the process.

The working agent (water or gas) may be injected into different parts of the reservoir depending on its structure, configuration and depth.

In the majority of cases, however, dispersed water and gas injection is applied, the injection wells being spaced as uniformly as possible over the area of the reservoir so as to create a number of local centers of elevated pressure. The unrecovered oil is then displaced towards the surrounding producing wells.

The formation that has been considerably flooded is not favorable to water injection.

If the water content of the rock is already 40-45 percent the water content of the fluid produced reaches 30 percent; in this case continued flooding of the formation greatly increases its phase permeability to water, which naturally reduces efficiency of the process.

Water to oil ratio of 20:1÷25:1 seems to be limit for economic application of water injection. Under these conditions, the water saturation of the rock reaches 70÷75 percent.

Heavy flooding of the formation due to displacement of oil by water in the primary development stage doesn't favor water or gas injection because of the low residual oil content of the formation. Under these conditions, the oil output can only be increased by applying forced fluid withdrawal during the final stages of the producing life of the wells. Thus, the oil-, the water-, and gas saturation of the rocks largely decided the choice of secondary recovery methods.

At present secondary methods are applied to oil fields which contain considerable quantities of unrecovered oil.

A class apart is the production of oil through mine opening, which might constitute the concluding stage of development of the old depleted fields and the principal method of the producing formations with low oil saturation or those which not easily yield their oil.

In order to obtain the greatest possible effect from the planned secondary recovery operations one must be able carefully to assess the oil and water saturation of the producing strata, their permeability and the quality of the oil contained.

Water Injection

At present the most widespread of the secondary methods of oil recovery is pattern flooding of the well when water injected over the entire oil-bearing area of the reservoir.

The main reason why this method is so widely used is the high recovery factor achieved when water is the displacing agent both in the case of natural water drive and when the water injected in the reservoir artificially.

The flood pattern depends upon the array of producing wells. Thus with a square well array the so-called "five spot" system is used the (Figure 4.2.1) in which there is a producing well at the center of a square formed by four injection wells. It will be easily seen that each injection well affects four producing wells so that in the total there is one injection well to each producing well.

A triangular well pattern gives a "seven spot" system (Figure 4.2.2) in which each producing well is at the center of the hexagon formed by six injection wells. Thus, each injection well serves three producing well.

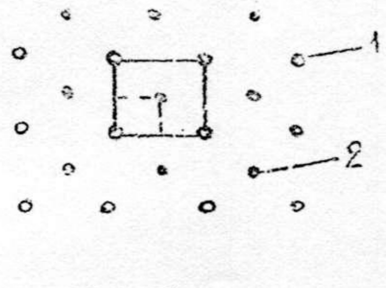


Figure 4.2.1. Five-spot well pattern

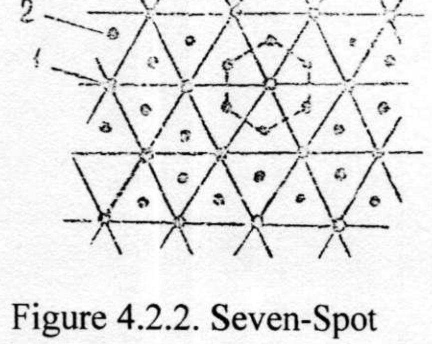


Figure 4.2.2. Seven-Spot well pattern

1- (o) Injection well; 2- (•) Producing well.

It has been demonstrated by experimental work that even with a uniform pattern of closely-spaced wells, complete flooding of the whole area (and so of the volume) of the formation is almost always less than unity. This ratio is called "the flood factor". Adjusting for this factor, the quantity of oil Q_{oil}, which may be recovered from the volume of pore space of the formation to be flooded is:

$$Q_{oil} = A\beta' V , \qquad (4.2.1)$$

where A – flooding factor; β' – pore volume utilization factor (the product of the oil saturation factor and the oil recovery factor $\beta' = \beta\eta$) the flooding factor A depends on the pattern of injection and producing wells and on the quality of oil being displaced. The last is expressed through so-called mobility factor η_m, which is determined as the ratio:

$$\eta_m = \frac{\dfrac{k_w}{\mu_w}}{\dfrac{k_{oil}}{\mu_{oil}}}, \qquad (4.2.2)$$

where k_{oil} and k_w – formation permeability to oil and to water, accordingly; μ_{oil} and μ_m – oil and water viscosity, accordingly.

At the considerable difference between oil and water viscosities the injecting water is thickened with the polymers; this promotes to oil-water contact leveling and mobility factor increase. At the present with this purpose water is treated with the polyacrylamide and micellar solution compositions.

It was established by the experimental studies that for the five-spot well pattern system A is equal;

At $\eta_m = 1$ . . . . $A = 0{,}72$

$\eta_m = 10$ . . . . $A = 0{,}54$

$\eta_m = 0{,}25$ and less . . . . . A approaches to 10

For the seven-spot well pattern system-flooding factor A correspondingly somewhat higher. For the five-spot system the relationship between the quantities of injected water the injection pressure and the distance between wells is given by the following formula:

$$q_w = \frac{\pi k h.\Delta p}{\mu . \ln \frac{R}{2r}}, \qquad (4.3.3)$$

where q_w – quantity of water injected (when the operation has become steady, this is also the output of the producing wells), m^3/day;

k – effective rock permeability, mD;

h – formation thickness, m;

μ – formation fluid viscosity, centipoises;

Δp – overall pressure gradient at the bottom holes of the injected and producing wells, atm;

R – distance between the injection and producing wells, m;

r – effective well radius, m.

Two main periods may be distinguished in a pattern flooding operation: the first is the period of waterless production (until water breaks through into the producing wells) and the second is one during which the producing wells are increasingly flooded.

In favorable conditions oil recovery factor at the first period of water injection makes 30-45%, at the second period 50-80%.

In the former USSR injection of water into oil reservoirs to increase recovery was started in 1943-1944 in the Dossor and Makat oil fields. Later the process was applied in a number of fields in Azerbaijan (Pirallahi Island, Balakhani-Sabunchi-Ramani), Grozneft, Krasnodarneft, Buguruslanneft and elsewhere. In the USA this method is the most widely used of all secondary recovery methods.

Equally with improving of edge water flooding to stimulate of oil production from Nubian reservoir of Bu-Attifel field varieties of a pattern flooding, it should be considered in the near further development program scheduling.

4.3. Gas Injection

Injection of gaseous working agent into an oil reservoir is the oldest effective secondary recovery techniques.

First applied at the beginning of the 20th century in the USA in Marietta County, Ohio. it was so successful that it rapidly becomes widespread under the name of the Marietta method.

The technological are the same as in the case of a water flooding. The working agent is injected through a number of injection wells uniformly distributed over the area of the field and displaces the residual oil towards the surrounding producing wells (Figure 4.3.1).

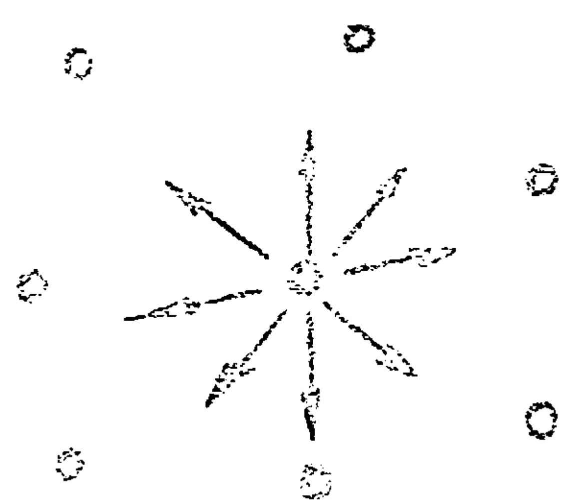


Figure 4.3.1. Gas Injection Pattern

Thus each injection well is a center of higher-pressure in the injection field around it. Such injection fields with four to ten producing wells each may be regarded as separate units in the secondary production of the reservoir.

Depending upon formation permeability and injection pressure the injectability of the wells may differ within wide limits and should be established by tests in each particular case.

It was established from field practice a fairly normal figure is 100-150 m^3 of gas injection per meter formation thickness.

A higher injection rate increases greatly the probability of gas breakthrough.

With this method the specific consumption of working agent may reach 300-1500 m^3 per ton of additional oil production.

The main criterion of the efficiency of the operation is an increase in the rate of oil production that helps to increase whole oil recovery from productive pay.

Practical field data indicate that in individual wells the increase may reach hundreds of percent, although the overall increase in recovery due to gas injection does not exceed 10-30%.

It will be seen that with this method ultimate recovery is lower than that achieved by a water flooding. However, the economic efficiency of process may be fairly high.

Gas and air injection is widely used in many oil fields in the USA.

In the former USSR it is successfully applied in the oil fields of Western Ukraine, Krasnokamsk, Grozneft. Krasnodarneft and Azerbaijan.

Besides of water flooding, as a reserve method, field application of gas injection should be provided for enhancing of ultimate oil recovery factor in Nubian oil reservoir. It is reasonable to envisage this problem in further development program scheduling of investigated reservoir.

The sources of gas injected could serve gas from Libian Jamahiria adjacent oil and natural gas fields.

4.4. Other Secondary Oil Recovery Methods

Various other secondary recovery methods in addition to those described above have been used at different times and under different conditions. Some of these have been or are being tried with varying success in actual field practice, while others are still in the laboratory development stage. These methods are as follows.

Forced fluid withdrawals

Forced fluid withdrawals are applicable for flooded reservoir which has been subjected to natural or artificial flooding. Withdrawal are forced by gradually increasing the output of separate wells by 30 to 50 percent and occasionally as much as by a factor of 2 or 4.

With increased rate of filtration the residual oil accumulations, which were passed by the encroaching water, are steadily scavenged from the stagnation zones, and the overall recovery increases. Forced production should not be applied to flooded marginal wells until the central part of the formation is fully produced. If this were done, the marginal wells could screen off the en
ergy of the encroaching water and considerably impair the operating conditions of the central wells. Field practice indicates that forced fluid withdrawals achieve best results when the well produces 75÷85 percent of water. The efficiency of the method is enhanced by high permeability of the rocks and a high fluid level in the wells.

Forced fluid withdrawal techniques are being successfully applied in many fields of Ichkeriya (Grozneft), Kazakhstan, Russia Federation and Azerbaijan.

The vacuum process

The method consists in reducing the back pressure on the bottom holes of producing wells below the atmospheric pressure, creating thus an increased press which stimulates the influx of fluid and gas to the well. To achieve this, the wellhead is lightly sealed and connected to the intake of a vacuum-compressor or pump and a vacuum of 0.5÷0.6 atm is produced, which corresponds to reducing the pressure on the bottom hole by an amount equivalent to the weight of water column of 5 to 6 meters.

Thermal recovery methods

Increasing the oil recovery by thermal treatment of formation rocks has long been considered by research organizations, both in the former USSR and in other countries. It is known that increasing temperature appreciably reduces the viscosity and surface tension of oils and increases their mobility. Since 50-s of the 20th century experiments have been conducted to introduce heat into oil formation in various ways. Both in the USSR and in the USA attempts have been made to create an artificial traveling combustion focus in the oil formation and generated heat by burning part of the oil.

The bottom-hole zone of injection well is heated by injecting a certain amount of hot water at a temperature of not less than 200°C. After this oil recovery increasing measure the ordinary cold water is injected which displaces from the bottom-hole the hot water, and upon contact with the latter is itself converted into steam which almost completely displaces the oil from the porous collector. The process has not progressed yet beyond the development stage.

In any case thermal bed stimulation methods application in Nubian reservoir which contains paraffin base crude oil will show best results in enhancing of oil recovery factor.

Oil Mining Method

By oil-mining method we understand methods involving the driving of mine openings such as those used in mining solid minerals, and the combination of such opening with wells. This usually includes sinking two mine shafts (the main hoisting shaft and a ventilation shaft); a system of underground galleries or "drifts", horizontal or inclined, which cut up the field into separate drainage sections (usually rectangular), and a number of auxiliary openings such as shaft bottoms, connections, drill chambers, and others (Figure 4.4.1).

The safest and, therefore, the most widely used oil-mining methods are those in which bore holes are drilled from openings above or beneath the producing rocks. In particular, this is the principal method in the Ukhta fields (Komi Autonomous Republic of the Russian Federation).

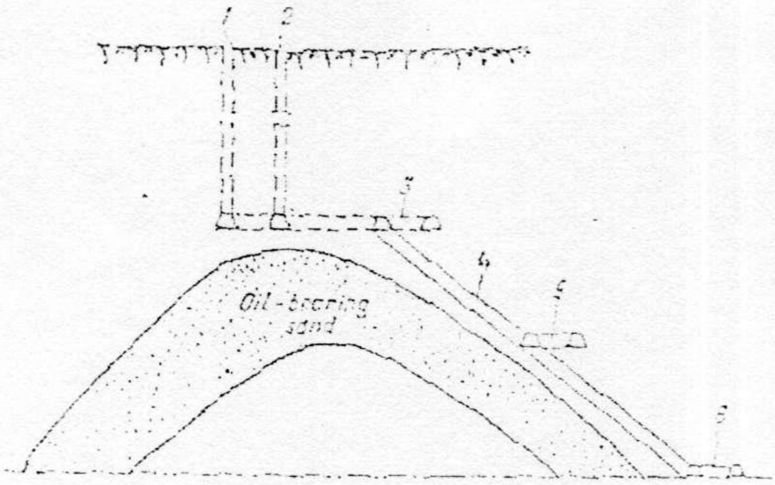


Figure .4.4.1. Sketch of an oil-mining operation of an anticline with mine opening driven above the oil-bearing formation:

1-ventilation shaft; 2- hoisting shaft; 3-main drift; 4- incline; 5,6- sub-drifts.

CONCLUSION

The dissertation includes introduction, four chapters, conclusion and references.

In the Introduction topicality of a subject, the object of the dissertation, ways of solving of problems and scientific novelty of dissertation were considered.

As a result of brief consideration of geological & development characteristics of Bu-Attifel field the following information was given.

1. The Bu-Attifel oil field was discovered in the Sirte Basin, about 400 km South-East of Benghazi, in 1967. It 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.

The Nubian reservoir depth ranges from 3612 to 3765 m s.s.l. (sub-sea level) and the original oil in place was estimated to be (109.8MMSTB). The oil bearing rock-Nubian Sandstone formation of a Top Lower Cretaceous age is a fine to coarse grained sandstone with interbedded shale and shaly-siltstones.

Its net pay thickness ranges from 75 to 250 m, its intergranular porosity from 14.1% to 18.5% and its horizontal permeability from a few mD to more than 1,000 mD. The water saturation was estimated to be 16%. The initial reservoir pressure was 47.6 MPa and temperature was 115.5°C.

The crude has a 41°API gravity; its base is paraffin (wax content: 36.7%) with an upper pour point of 39°C.

The water injection project was started in 1974. The oil production rate after maintaining an average volume of 24.000 m^3 per day is now decreasing. It was therefore decided to increase oil recovery factor.

In connection with this laboratory experiments relative to water flooding were carried out. It was established that water injection effectiveness depends on formation and driven liquids. So, with increasing both of porosity and permeability of rocks and decreasing of oil viscosity, oil recovery factor increases.

2. The early phase of liquid production by natural reservoir energy depletion confirmed the total lack of water drive to the limited volume of the bottom aquifer.

The natural pressure decline reached its peak in a few years after the reservoir brining into production and secondary gas cap was created. Water injection was started from a row of wells drilled along northern border of the field.

3. To get high productivity of wells and increase of oil recovery factor of formation to know the filtration processes is needed. For this purpose investigation of interaction between producing wells using of correlation analysis is provided.

Numerous fields' investigation indicate the presence in non-uniform production pays of significant recoverable oil reserves which is taking place on stagnant zone and non-uniform drained zone.

Stagnant and poorly drained areas were defined in Nubian reservoir by applying correlation analysis.

4. It was established bad interaction between wells OO3-OO7, OO4-OO7 in tectonic block I, between wells OO3 (block I)-OO1 (block II), OO4 (block I)-OO1 (block II).

Satisfactory interaction was established between wells OO3-OO4 (block I), good interaction between wells OO1-OO2, OO1-OO5, OO2-OO5 (block II) and OO5-OO6 (block II&III).

For an intensification of an oil recovery from stagnant and poorly drained zones it is offered to drill-in new development wells - № OO8 in the tectonic block I; for an establishment of oil pool outline it is advisable to drill-in well № OO9 in the tectonic block III, on the right side of the producing well № OO6 to drill-in new wells - № OO10, OO11 in the tectonic block II.

5. To stimulate oil production of new producer № OO8 on the tectonic block I and with the purpose of tracking external oil boundary drilling-in new wells is suggested.

6. Introducing the mathematical models gives possibility to do qualitative and quantities prediction of the basic development performances and defines their most expedient further decisions.

Practical experience of production process of the long period developed oil and gas fields' shows that at the certain stage of development the most authentic prediction of recoverable reserves can be received by application of evolutionary model.

7. Using evolutionary approach of modeling the recoverable oil reserves were determined which makes 20 million barrels.

8. The operation conditions of drowned wells of Nubian reservoir are analyzed. Optimum operating practices of producing wells by the dynamic analysis of the field material are established.

Water is shown in all wells of a reservoir, in particular, in well OO1.

9. Results of researches provided show that it is necessary to pay special attention to prevention of water cutting of well production. One of methods of struggle with water cutting of wells is considered studying of well log and realization on it selective perforating, excluding thus simultaneous shooting water-bearing interlayer. In any case, it is necessary to undertake the appropriate measures on control of reservoir development process and prevention of premature water encroachment of a producing formation.

10. Full information about classification, groups and categories of hydrocarbon reserves were given.

11. Oil reserves in place were calculated by both volumetric and mathematical-statistical method. Volumetric method results Q=18.894,309 mt (or 116.2 MMSTB).The difference between oil reserves calculated by volumetric method 18,894,309 mt (116.2 MMSTB) and in field conditions 17,853,659 mt (109.8 MMSTB) is 6.4 MMSTB, i.e. 0.94%. It shows the accuracy of oil reserves calculations. Oil reserves calculated by mathematical-statistical method result 119.05 MMSTB.

12. Oil reserves calculated by volumetric and mathematical-statistical methods to a certain degree exceed the one calculated by volumetric method. It should be taken into consideration in the further development planning of investigated reservoir.

13. An oil field daily production rate of 150,000—170,000 bopd was maintained fairly constant.

14. Based on field data and using mathematical-statistical model ultimate oil recovery factor was computed. As a result of computations ultimate oil recovery factor $\eta \approx 0.36$ was received.

In 2005 current oil recovery factor makes 0.3462 and daily water injection rate is 12.7 MBWPD.

About 34.70% original oil in place has been recovered to the end of 2005.

15. Problems of improvement of development process and stimulation of oil production from Nubian reservoir, in particular, secondary and tertiary enhancing of oil recovery methods were considered and analyzed.

16. Taking into consideration considerable difference between oil and water viscosities the injecting water should be thickened with the polymers; this promotes to oil-water contact leveling and mobility factor increase. With this purpose water injected water should be treated with the polyacrylamide and micellar solution compositions.

17. Nubian reservoir's oil is a paraffin base crude oil (wax content: 36.7%). With this connection to prevent wax accumulation in tubing application of thermal methods such as heat water and steam injection, and wells' bottom-hole zone thermal treatment are recommended.

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