Dhodak Field: A Case History of First and the Largest Condensate Discovery of Pakistan*

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Abstract

Dhodak condensate and gas field is located in the rugged terrain of the eastern Sulaiman Range, about 80 km north of Dera Ghazi Khan in the Punjab province. The field was discovered in December, 1976 through the drilling of Dhodak well # 1 where condensate/gas was tested in the Pab Sandstone of Cretaceous age. Sandstone of Lower Ranikot Formation (Paleocene) was also proved to be hydrocarbon bearing during the course of further appraisal. Development and Production license was granted to Oil & Gas Development Corporation over an area of 41.92 square kilometers by the Government of Pakistan. To date, a total of eight wells have been drilled and seven wells are gas/condensate producers. Recent volumetric estimates for total wet GIIP are 1076 BSCF and total recoverable reserves are 611 BSCF of gas and 40 MMSTB of condensate. Gas processing plant was set up near Dhodak which started production in December, 1994. Present average daily production of condensate, gas, and LPG is 2600 barrels, 42 MMSCFT, and 180 metric tons respectively. Production is constrained due to the processing capacity of the plant.

Exploration and drilling history, complexities of petrophysics, reservoir geology, and challenges of development planning of the Dhodak Field are presented. This paper also summarizes the reservoir management strategy developed on the basis of compositional modeling and history matching with special emphasis on problems related to condensate recovery in the clastic reservoirs of Pab and Lower Ranikot.

Introduction

Dhodak Field is the northern most culmination of the Sufaid Koh anticlinorium, situated on the eastern margin of Sulaiman Range, about 80 km north of Dera Ghazi Khan city (Figure 1). The area has been under active exploration since the early seventies. The first gas discovery in the Sufaid Koh area was made by OGDC at Rodho in 1974. OGDC explorationists then looked for a deeper prospect near Rodho hoping to find liquid hydrocarbon accumulation. The Dhodak structure was selected for this purpose and consequently, the first condensate discovery of Pakistan was made there in 1976 from the Lower Ranikot of Paleocene and Pab Sandstone of Cretaceous age. With this discovery, the Lower Ranikot and Pab Sandstone were established as gas/condensate reservoirs in the Sulaiman Range. Since the Dhodak discovery in

1976, seven more wells have been drilled and the average daily production of the field is 42 MMSCFT gas, 2600 barrels condensate, and 180 tons of LPG.

This paper being the case history of Dhodak Field is required to encompass every aspect of development phase along with the exploration history. The first part of the paper describes the exploration history, petrophysics, and reservoir geology of the field. The second part of the paper attempts to summarize the essential reservoir engineering aspects along with the development optimization considerations. The paper also very briefly reviews the existing surface facilities at Dhodak Field. The paper concludes with some inferences from the exploration and development history of this field.

Exploration History

Exploration activities in the eastern Sulaiman Range date back to 1925 when Burmah Oil Company started some geological studies. Then in late fifties Pakistan Shell Oil Company and a joint venture of PPL and POL conducted geological surveys. OGDC started its exploration activities in Dhodak and surrounding areas in 1968 by conducting a geological survey which resulted in the delineation of four culminations. Further detailed geological mapping was again conducted over Dhodak structure in 1973 and Dhodak well # 1 was proposed on the basis of this surface geological information (Figure 2 and Figure 3). Seismic data could not be acquired at that time due to rugged terrain and lack of proper equipment.

Drilling of Dhodak-1 started in June, 1975. At the depth of 1945 meters while drilling in the Lower Ranikot sands, a strong kick was observed which could not be controlled and resulted in a blowout and burning of the rig. Drilling was resumed in the same hole in August 1976 and the same well was completed as a gas/condensate producer in the Pab Sandstone of Cretaceous age. Two appraisal wells were subsequently drilled and 24 fold seismic survey was also conducted using dynamite source and helicopters. Data quality was not good and several reprocessing attempts were made without any significant improvement. After reprocessing, seismic interpretation was again undertaken by a consultant in 1986-87 mainly focusing on the axial part and faults.

A geological mapping exercise was also undertaken on the request of seismic interpreters to supplement the interpretation, particularly on throw and trend of the major longitudinal fault running parallel to the axis. In the light of these later seismic interpretations and results of drilling, the subsurface structural picture of Dhodak changed significantly from the one at the time of discovery. There were many more faults mapped at the Paleocene and Cretaceous levels (Figure 4). To date 08 wells have been drilled and 07 wells are condensate/gas producers, except well # 4 which turned out to be dry.

Stratigraphy

The Dhodak Field is located on the eastern margin of the Sulaiman fold and thrust belt just adjacent to Middle Indus Basin where rocks from Cambrian to Oligocene are present. However, the basement gets deeper towards the foldbelt and wells drilled in the eastern portion of the foldbelt have not penetrated below the Triassic sequence. The deepest well in Dhodak has penetrated a succession from Oligocene Nari Formation to Parh Limestone of Cretaceous age. The general stratigraphic sequence encountered in Dhodak is given in Figure 5.

In Dhodak, Cretaceous is represented by Parh, Mughalkot, and Pab formations representing thin carbonate ramp deposits at the base, then deeper water deposits of Mughalkot and finally on-lapped by the clastics of the Pab Formation. Mughalkot is the basinal equivalent of the Pab Formation. Clastics of Lower Ranikot (Paleocene) although very similar to Pab, have been deposited on the eroded surface of Pab sandstone. Shales and carbonates of the Dunghan Formation mark an overall backstepping during a marine transgression. Marine conditions persisted throughout Eocene depositing shales and carbonates of Ghazij and Kirthar formations. Nari Formation of Oligocene age, comprising glauconitic sandstone and fluvial clastics is present on top of the Kirthar Formation. Siwalik rocks of Miocene to Quaternary age are mapped on both flanks of the Dhodak structure.

Structure

The Dhodak structure is an asymmetrical anticline with a steeper eastern limb which is disturbed by a west verging back thrust. Maximum dips on the eastern flank are 60° while the western flank is gentler with maximum dips reaching up to 26°. In the most recent seismic interpretation by 551, the subsurface structure is more complex than mapped earlier seismically or geologically (Figure 6). The structure is compartmentalized by four major east-west trending normal faults. Most prominent of these faults is the one just north of Dhodak well No.3 and has up to 350 meters throw. By virtue of this fault, the Pab reservoir is wet in Dhodak well No.3. Several longitudinal north-south trending faults are also mapped and most of these are minor thrusts in nature. These longitudinal faults appear to be older and related to an initial thrusting phase as they have been displaced by transverse faults developed during a later trans-tensional wrenching phase. Structural relief of the Dhodak structure at the Pab and Lower Ranikot level is more than 900 meters but the structure is not filled to the spill. The same is also true for other adjoining structures. This indicates that an initial structuring produced the available trap which was charged with hydrocarbons and sealed by the Ghazij Shales. The later phase of structuring may have initiated a breach of this top seal allowing hydrocarbons to migrate out of the trap.

Depth values on the structure contour map increase abruptly in the area around Dhodak Well No.4 on the western flank but no structural disturbance is mapped on the seismic sections. According to the latest geological interpretation by 551, the Dunghan Limestone appears to be penetrated twice and the Dunghan and Upper Ranikot sequence below 1677 meters subsea is a repeat sequence caused by a thrust fault cutting the well at 1677 meters subsea depth near the base of the Upper Ranikot Formation (Figure 7). This interpretation honors the 'hard' data as depicted by well logs, well cuttings, and cores but is not necessarily reflected by the 'soft' seismic interpretation as Dhodak well No.4 does not fall on any of the seismic line. Two structural cross-sections across the Dhodak structure are given in Figure 8 and Figure 9.

Petrophysics

A typical logging suite consisting of DLL-MSFL-SP-GR, LDL-CNL-GR, BHC-GR, and BGT-SHDT was acquired in Dhodak wells 2 to 7. FMS log was only conducted in well No.7. The Dhodak reservoirs are very complex from a petrophysical point of view. A differentiation between two formation fluids (water and gas) is not possible due to the low chloride contents of formation water, complex mineralogy, and pore structures. The presence of ankerite also affects the deep resistivity curve, therefore, water saturation computation becomes unrealistic.

An analysis of produced water from a number of samples suggested that formation water in the reservoir was fresh and its salinity ranged from 1000 to 4000 ppm. This value did not truly represent the reservoir, as log interpretations using this value would give Sw ~ 100% throughout the whole reservoir. However using Picket cross plot technique (porosity vs resistivity) a more reliable value for formation water resistivity (Rw = 0.38 ohm-m at 75°F) was calculated and used in the log evaluation. Evaluation results show the presence of relatively high water volumes over major parts of the reservoirs. The reservoir heterogeneities, presence of thin clay beds, and the presence of silty sands, did not allow the use of Sw values to identify the exact gas-water contacts or separate the transition zone trends from normal irreducible water trends.

Analysis of RFT data (from well No.6) is also inconclusive in marking the exact water contact. The RFT has 22 good pressure points between 2196 meter to 2511 meter depth in zones 2 and 3 of the Lower Ranikot and zones 3, 4, 5, and 6 of the Pab reservoir. The data is plotted in Figure 10, where a linear regression through good pressure points indicates a gas gradient of 0.082 psi/ ft. But the final two good points (at 2508.5 and 2511 meters) fall off to the right of the gas gradient line making the interpretation inconclusive. However, we can say there is at least gas-down-to 2462 meters (1771 meters subsea depth) and it can also be suggested that a transition zone exists between gas and heavier hydrocarbons in the interval between 2462 to 2508 meters depth. DST data from well No.3 provides further information. The deepest tested gas was from Pab zone-2 with the lowest perforations at 1810 meters subsea depth. This value has been used in volumetric calculation of gas-in-place of the Dhodak Field.

For the calculation of reservoir parameters and net pay summaries, the petrophysical cut-offs used were: porosity 7%, permeability 0.1 mD, and shale volume 35%. The water saturation cut-offs were ignored. Porosities in both reservoirs range from 8 to 14% and generally decrease with depth. Log derived and core porosities show a reasonable match with a maximum difference of not more than 2 %. Water saturations range from 20 % to 55 % in all wells except well No.3 where they are in the range of 48 to 80 %. Shale volume ranges from 2 % to 23 %. The Lower Ranikot is shalier than the Pab with Pab-l and Pab-2 as the most clean zones and L. Ranikot-l and 3 as the shaliest zones. Matrix permeability ranges from 0.12 mD (Pab zone-8) to 24 mD (Ranikot zone-2).

Reservoir Description

Pab Sandstone: The Pab reservoir consists of interbedded sandstones, shales, and siltstones. The sandstones range from quartz arenites to subarkoses and are brown to white in color. Detrital quartz is a dominant component with feldspars. Lithoclasts of chert and mica schist are also rarely present. Sorting of the sands ranges from poor to moderate and grains generally are sub-rounded to subangular. Cementing material is dominantly siliceous. Shales and siltstones are gray to dark gray in color, hard, and fissile. Several, 3 to 5 meter thick fining upward cycles are present representing different lithofacies. At further small scale, bundle beds are observed within the cross-stratified sand beds. These indicate the deposition of the Pab sandstone in the form of point bars, by tidal channels on a coastal tide dominated shoreline.

The thickness of the Pab reservoir ranges between 315 to 325 meters and has been divided into eight zones which more or less correspond to different depositional cycles. Each depositional cycle represents one point bar sand body. Zone thickness ranges between 20 to 60 meters (Figure 11).

Lower Ranikot: The Lower Ranikot reservoir is also clastic, consisting of sandstones, shales, and siltstones. Its basal part is similar to the Pab but differs considerably in the upper and middle part.

In the lower part, sandstones are greenish gray sublitharenites with detrital monocrystalline quartz as a dominant component. Volcanic lithoclasts are also common. Cements are generally siliceous. A prominent white cryptocrystalline marker is present all over the field at the base of the Lower Ranikot and is very helpful in marking the top of the Pab Sandstone. Lower Ranikot and Pab reservoirs represent a fining upward transgressive sequence relating to the regional marine incursion during late Cretaceous and Tertiary times.

Thickness of the Lower Ranikot ranges between 148 to 170 meters in the Dhodak Field. Several shale markers are identified within the Lower Ranikot which extends all over the field. This reservoir has been divided into 3 zones of 40 to 70 meters thickness (Figure 11).

Fractures: Fracture log (FMS) was conducted on Dhodak well No.7. If we compare fractured intervals with PLT data, it becomes very obvious that increase in fracture spacing corresponds to inflow recorded on the PLT log (Figure 12). This also explains the marked difference observed between core and well test build-up permeabilities. Mud losses are seen to be related to the presence of fractures in well No.7. This relationship of heavy mud losses and fractures is noted in all other wells and points towards the well distributed fractures in the field.

Drilling Operations and Problems

From drilling operations point of view, Dhodak proved to be a difficult structure. Rugged terrain, scarcity of water, and local tribal culture, made the logistic support very difficult. Then during drilling, severe mud losses, in-flow of formation fluids, and caving of shaly intervals were very frequently encountered.

Complete and partial mud losses were frequently encountered in the rubbly limestone member of the Ghazij Formation, Lower Ranikot, and Pab Sandstone. In a few wells while drilling in rubbly limestone, mud losses were so severe the problematic interval had to be blind drilled i.e. without returns. Whenever mud weight was lowered to control the losses, wells started to flow and vice versa. Therefore, a very delicate balance of mud weight had to be maintained.

Caving and tight spots were encountered in the shales of Sirki, Ghazij, and Upper Ranikot.

In the first three wells of Dhodak (drilled in late seventies), the following casing sizes were used: 16¾", 11¾", 8¾", and 5½". Typical well design in later Dhodak wells (from Well No.4 to 8) consisted of four stage drilling. The 20" casing was set within the Pirkoh Limestone. The

13⅜" casing was set after drilling the shale/limestone sequence of the Kirthar Formation. A 9⅝" casing shoe was set near top of the Lower Ranikot after drilling the Ghazij, Dunghan, and Upper Ranikot. The reservoir sections of Lower Ranikot and Pab sandstone were drilled with an 8½" bit and cased with 7" casing.

Average depth of Dhodak wells is 2300 meters with the exception of wells # 2 and 3 which were drilled to a depth of 3000 meters. The time taken to drill each of the first four wells was 12 months whereas the next four wells were drilled in 4 months. This improvement was the result of experience in handling different hole problems gained during drilling of the earlier four wells.

Reservoir Pressure and Temperature Analysis

Determination of reservoir pressure and temperature required a review of all the well test data, DST results, and RFT analysis. For volumetric purposes, the reservoir datum depth for the Dhodak Field was selected to approximate the centroid depth in the hydrocarbon zone. In the Dhodak reservoirs, the centroid depth was selected to be the top of the Lower Ranikot Layer R3 interval. For the eight Dhodak wells available, the average lower Ranikot R3 depth was 1618 meters TVSS.

A total of 27 pressure measurements (including 11 pressure measurements from the well DK-6 RFT results), were plotted against subsea reservoir depths. A wet gas gradient of 0.08 psi/ft, determined from the fluid analysis was applied to best fit the available data. As evident from Figure 13, the pressure determination is strongly influenced by the RFT results from well DK-6. However, this best fit relationship also relates to pressure measurements obtained from wells DK-l, DK-5, DK-6, and DK-7.

The initial reservoir pressure at the reservoir datum depth of 1618 meters TVSS is determined to be 3210 psia. When corrected to datum conditions, no significant pressure variation exists vertically through the Lower Ranikot and Pab reservoir layers, indicating pressure communication between these layers. It is also assumed that no significant pressure variation exists areally across the Dhodak Field.

Of the 14 temperature measurements as function of subsea reservoir depth, a geothermal gradient of 0.053°F/meter was applied to best fit the available data. As evident from Figure 14, the temperature determination is not clearly correlated. Hence, a preferred initial temperature of 259°F was applied to coincide with the PVT laboratory analysis for well DK-5.

Historical Production and Pressure Data

The Dhodak Field came on production in late November 1994. Stable production started in December 1994. The well stream production rates, on a monthly basis, and reservoir pressures are provided in Table 1.

Reservoir Fluid Characterization

Several modifications to the original Redlich-Kwong EOS were made to allow Dhodak fluid characterization. The PVT sample from Dhodak well DK-5 was considered to be the most representative of the available fluid samples, since it did not suffer from the reduced heavy end characterization of the sample from well DK-1, or the uncertainties in dew point determination from the sample in well DK-3.

The selected sample was characterized by using Zudkevitch-Joffe-Redlich-Kwong (ZJRK). Both constant volume depletion data and constant composition expansion data were used as input in the data matching procedure. The well stream compositions derived from each of the selected samples were input up to C_{11}. The heavy end components beyond C_{12} were grouped as C_{12+}, giving 14 components for each reservoir sample. Regression was used to match the ZJRK EOS to the experimental data by varying the Omega's and binary interaction coefficients of the pseudo-components.

Careful analysis of PVT results reveals that:

- There is no indication of compositional variation, neither laterally, nor vertically, or as a function of depth in the Lower Ranikot and Pab reservoirs. This in turn suggests that the gases in the Lower Ranikot and Pab reservoirs have the same primary origin. The differences in compositions of these gases are attributed to differences in sampling pressure and temperature combined with variable drawdown effects. Figure 15 compares compositional analysis of samples from the Dhodak reservoirs.
- The presence of the same original fluid in the Lower Ranikot and Pab formations across the field also suggest that the main field faults are not sealing.
- The reservoir was discovered at the dew point pressure, PVT study indicates the unlikeliness of liquid to drop out during equilibration and its accumulation on the flanks of the field as oil rims, over geologic time (see Figure 16).
- A single PVT description realistically simulates the Dhodak horizon (see Figure 17).
- The initial wet gas formation volume factor (Bgwet) is 0.00576 v/v (E = 173.5 v/v).
- The initial dry gas volume factor (Bgdry) is 0.00606 v/v (E = 164.9 v/v).
- The initial Condensate Gas Ratio is 51.5 b/MMScf (GOR = 19411 scf/b).

The water analysis reports from Core Laboratories provided a specific gravity for water of 1.010, to 1.02 at 60°F, along with the water formation volume factor as 1.0001 rb/stb, water density as 62.36 lb/ft^3, and water viscosity as 0.35 cP.

Estimates of GIIP

Deterministic estimates of gas and condensate initially in place were derived by integrating the seismic depth maps and petrophysical averages for each reservoir zone utilizing the Equivalent Oil Column Method. The gas expansion factor(s) and the condensate gas ratio were derived from the PVT analysis and used to convert reservoir volumes to volumes at standard conditions. Volumetric reserves were computed for each reservoir zone. The GIIP estimated by OGDC professionals in an in-house exercise are listed in Table 2.

Prior to the latest study (1998) based on the dynamic data, the GIIP estimates by several independent consultants were in conformity. Table 3 presents a comparison of GIIP by various consultants.

The basic uncertainty associated with the calculation of GIIP was connate water saturation as determined by petrophysical analysis. Owing to this uncertainty, OGDC decided to adopt the phased development strategy prior to the availability of dynamic data. After 3.5 years of Dhodak production, the material balance was carried out to validate the volumetric estimates of gas in place, and to indicate the drive mechanism in the Dhodak reservoirs. The Havlena-Odeh and Fetkovich-Meitzen material balance techniques were used (see Figure 19).

The principal parameters determined by the Havlena-Odeh technique were the water influx to match the observed reservoir pressure decline. This technique provided an initial volumetric estimate of 1076.8 Bcf, with an active aquifer. The extrapolated line Figure 20 shows the "depletion line" to the 1076.8 Bcf volumetrics and the effects of water influx are apparent.

In order to validate the Havlena-Odeh material balance, the analysis technique of Bruns-Fetkovich-Meitzen was used. The depletion material balance was first solved to determine the apparent gas initially in-place. Using the water influx parameters determined from Havlena-Odeh analysis, the relationship between apparent GIIP and the Bruns-Fetkovich parameter conforms to the 1076.8 BCF in place (see Figure 21):

In addition to routine material balance techniques a full field reservoir simulation model was constructed to match the production history. The reservoir pressure, gas, condensate, and water production rates were matched. The match was accomplished by changing the capillary pressure values in the model. As a response to the history match results, the following changes were made to the geological model to have a revised volumetric estimate:

i) Revision in the connate water saturations.
ii) Reduction in the transition zones of DK # 7 and 8.
iii) Modeling DK # 3 in the separate pool with longer gas column and higher water saturations.

The saturation maps were revised to refine the estimate of GIIP for the Dhodak reservoirs. A detailed profile of original water saturation as function of depth for all producers in the Dhodak Field is shown in Figure 18. The revised connate water saturation compared with the original Sw is as under Table 4.

Based on the refinements made in the geological and reservoir model the wet gas in place was calculated as 1076.7 BCF, out of which 715.2 BCF in the Lower Ranikot and 316.5 BCF in the Pab reservoir.

Well Deliverability Analysis

Gas well deliverability analysis was performed on all producing Dhodak wells. Dhodak wells have been completed with 3½" tubing for commingled production from both the reservoirs. The absolute open flow (AOF) well potential, the performance coefficient 'C' (MSCF/d-psia^{2n}) and the exponent 'n' were calculated from flow after flow or isochronal testing on wells. The deliverability analysis of Dhodak wells is presented in Table 5.

The values of exponent 'n' in the above table reveal that the gas flow in all Dhodak wells is turbulent. However, the degree of turbulence varies from well to well. The significance of acid stimulation and additional perforation is also evident from the AOF values in the above table. The AOF potentials for the wells mentioned in the above table indicate a gas potential of about 90 MMscf/d with around 5200 bbls of condensate for the entire duration of contractual requirement.

Surface Facilities Review

Dhodak is the only field in the country which has the processing facilities in the field enabling operator to market the petroleum products. The well site and test facilities are located at the field and processing facilities are located at Kot Qaisrani. The well site facilities are connected to the process facility by a 12 inch, 24 kilometer high pressure pipeline that is insulated and buried below ground. The existing gas process facility was designed to process 56 MMscfd of raw gas and generate 47 MMscfd of lean gas and 2600 bpd of hydrocarbon liquids. Production records indicate that the plant has achieved its objectives slightly more than the forecast. Facilities currently available in the Dhodak Field are as follows:

i) Flow Line Gathering Network

Each well is connected to the centrally located production manifold with its own separate 4 inch flow line. The production manifold includes a "group" and "test" header that permits wells to be placed on test or directed in to the 12" pipeline which connects manifold to the gas processing plant.

ii) The Gas Processing Facilities

The gas processing facilities have been provided for 54 MMscfd wet gas. The major components of gas process facility include:

- Gas - liquid separation to remove free liquid accumulations condensed in the pipeline during transport.
- Mol Sieves for gas dehydration, a turbo expander to maximize hydrocarbon liquid recovery.
- De-Ethanizer and De-Butanizer towers to produce LPG and lean sale gas.
- Condensate fractionation tower to produce motor gasoline, kerosene, high speed diesel, and diesel fuel oil
- LPG storage tanks and atmospheric storage tanks for the stabilized liquid products and their associated loading facilities.

iii) Slug Catcher

A slug catcher with a capacity of about 1500 barrels is available, to handle liquid production.

Reservoir Modeling

In order to assess the potential for condensate banking, to determine the effect on well productivity, and to assess the water movement on field scale, radial models of wells DK-3, DK-6 and DK-8 along with the cross-sectional models of wells DK-5 and DK-6 were built. A full field simulation model utilizing 5600 (20 x 28 x 10) grid cells was used to model the Dhodak reservoirs. No simulation cells were set inactive, reflecting the good communications anticipated across the field faults. The Carter-Tracy aquifer modeling technique was used to model the aquifer in the Dhodak reservoirs. The reservoir pressure, gas rate, and condensate rate was matched with historical production history by changing the capillary pressures transmissibilities along faults and permeabilities around the wells. The history match plots are attached as Figure 22, Figure 23, Figure 24, Figure 25, Figure 26, Figure 27, and Figure 28.

The reservoir model, modified as a result of the history match concluded the following.

i. The total wet gas in place is 1079 BCF, which matches with the revised material balance.
ii. Presence of a very active water drive is evident.
iii. There is a little liquid drop out in the reservoir during future depletion.

Table 6 presents a comparison of wet gas in place both calculated with and without dynamic data.

Development Optimization

The phased development strategy was adopted while developing Dhodak Field due to uncertainties in the reserves estimates. The existing processing facilities were designed to process 56 MMscfd of raw gas. The history matched reservoir model was used for a development optimization study. The prediction runs considered as part of the development optimization study were designed to accelerate production whilst maximizing ultimate recovery. A base case considered the current reservoir off take strategy, with production at the existing facility limit of the 54 MMscfd wet gas. The maximum rate achievable by the reservoir whilst meeting a contractual 15 year plateau obligation was sought and individual well rates optimized. The following were the major considerations in addition to recovery optimization during the study:

- Merits of gas recycling.
- Merits of well head compression.
- Merits of water shut-off.

The results of production optimization study are summarized in Table 7.

As a result of development optimization study it has been concluded that:

i) The ultimate gas, condensate, and LPG recovery may reach to 611 Bsdf, 29.8 million barrels, and 11 million metric tons, respectively.

ii) Economic benefits from the field could be doubled if the wet gas production rate could be increased to the available well deliverability rate. Accordingly the second train of processing facilities would be required to have an optimized field development.

iii) The study suggests that gas recycling has little impact on condensate recovery because there is no liquid drop out in the reservoir based on the expected depletion scenario at PVT analysis.

i) Flow Line Gathering Network

In order to increase the well head deliverability the tubing head pressure needed to be reduced to 500 Psi from existing pressure of 1350 Psi. The compositional network simulation allows two alternate operating scenarios to handle the problem of lowered pressure and increased deliverability.

a) **Option-1**: Loop the existing 12 inch pipeline with 16 inch line. Transport 95 MMscfd of "raw" gas to the processing plant, arriving at approximately 250 Psi. Compress the gas in two stages from 245 Psi to 1230 psi (approximately 10,000 hp).

b) **Option-2**: Install a single stage compressor (approximately 8500 hp) at the production manifold to raise the pressure from 400 Psi to approximately 1500 Psi. Transport the gas and free liquids in the existing 12 inch pipeline arriving at the plant inlet at approximately 1250 Psi.

Option-2 is judged financially superior to Option-1, since it requires less investment on compression.

ii) Gas Processing Facilities

By raising the pressure of the produced gas at the production manifold it is possible to maintain the current operating conditions at the plant inlet. By maintaining the operating conditions at the plant inlet, the design efficiency will remain unchanged. However, the problem of processing an incremental 41 MMscfd of "raw" gas must still be dealt with.

iii) Slug Catchers

Considering the slug size and the speed of the slug, the Slug Catcher vessel needed to be replaced with a vessel which is 8' x 6" x 40" to provide more liquid capacity.

A second train for condensate processing to sell petroleum products would be required.

Inferences

Our understanding of the Dhodak Field in the perspective of its production and pressure history combined with geological, petrophysical, and core analysis data, present development strategies and future development options can lead to the following inferences:

- In the Dhodak Field, the Lower Ranikot and Pab Sandstones were established as the first gas/condensate reservoirs in the Sulaiman Range.
- Total wet GIIP of the field is estimated to be 1076 Bscf. Recoverable reserves of gas and condensate are: 611 Bscf and 29.8 MMstb barrels, respectively.
- Recovery optimisation and economics suggest the present raw gas facility should be increased to deliver 90 MMscfd sale gas.
- The gas recycling has little impact on the condensate recovery.
- The straight depletion production strategy with the provision of water disposal facilities looks to be the most attractive option, in view of the recovery optimization. However, a careful economic evaluation needs to be done to compare the benefits of this strategy with the water shut-off one.
- The prediction runs show that optimal reservoir depletion for Dhodak depends largely on the aquifer response which in particular should be monitored.

Issues

- The amendments in Gas Sale Agreements (GSA) and Gas Prices Agreements (GPA) would be critical issues to be resolved before making decisions on additional investment.

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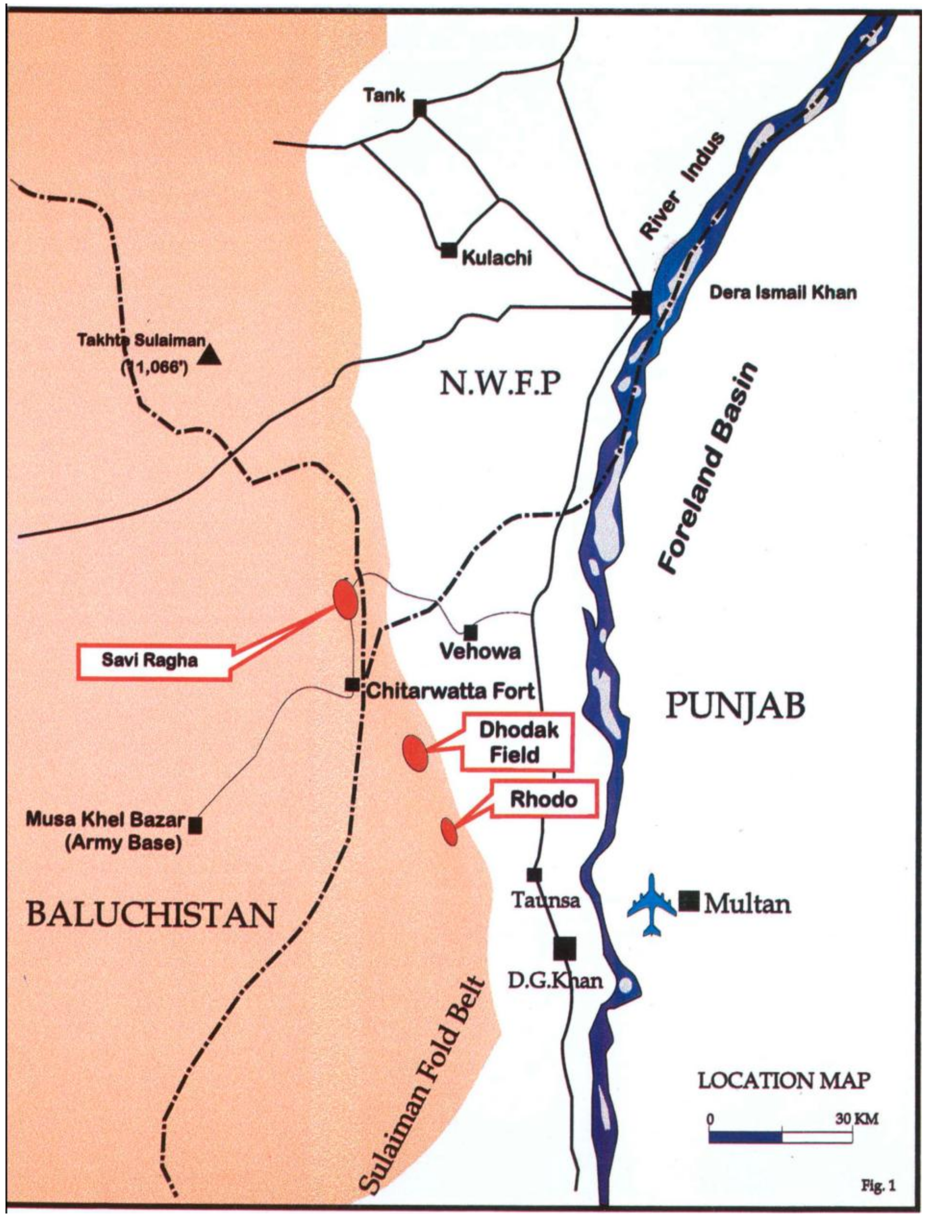

Figure 1. Geographic Location of Dhodak Field.

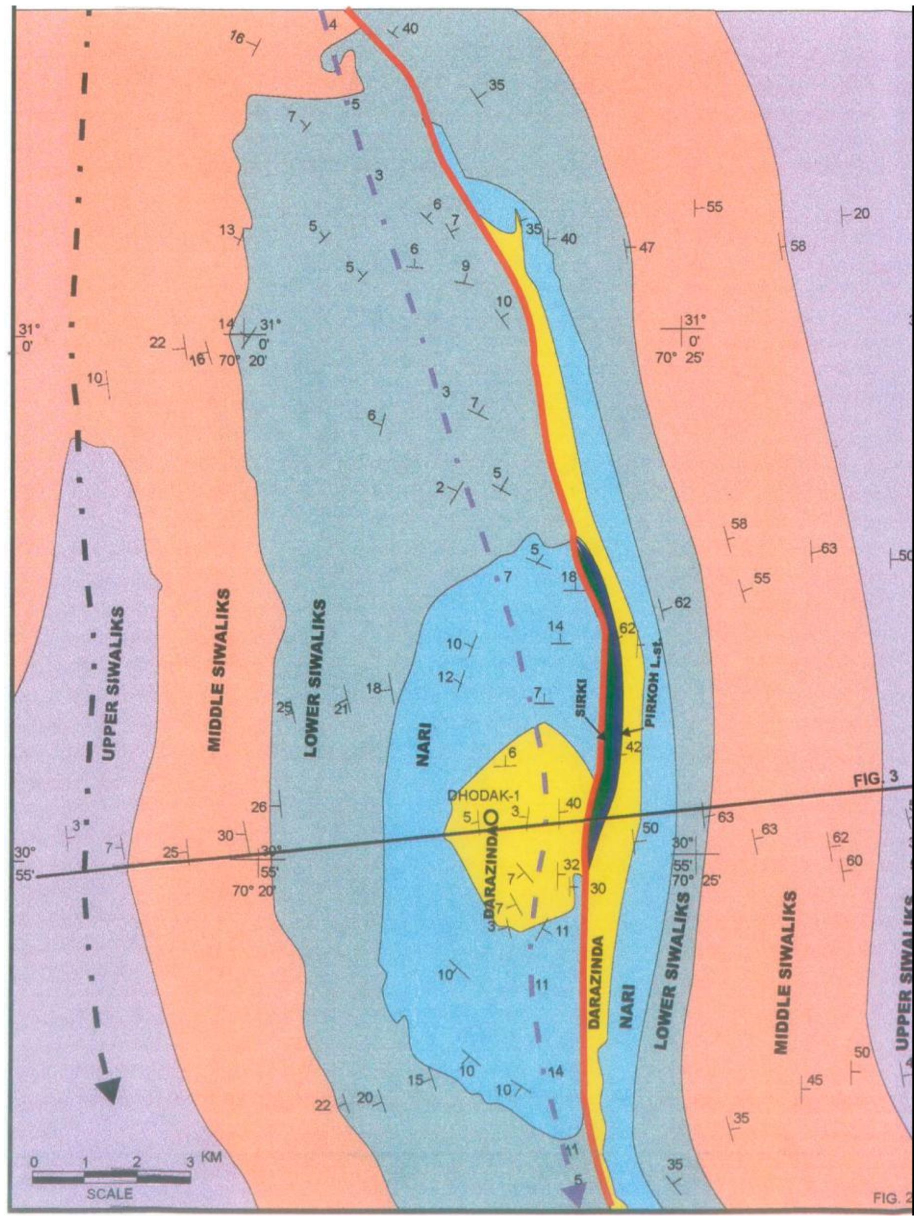

Figure 2. Geologic Map of Dhodak Anticline.

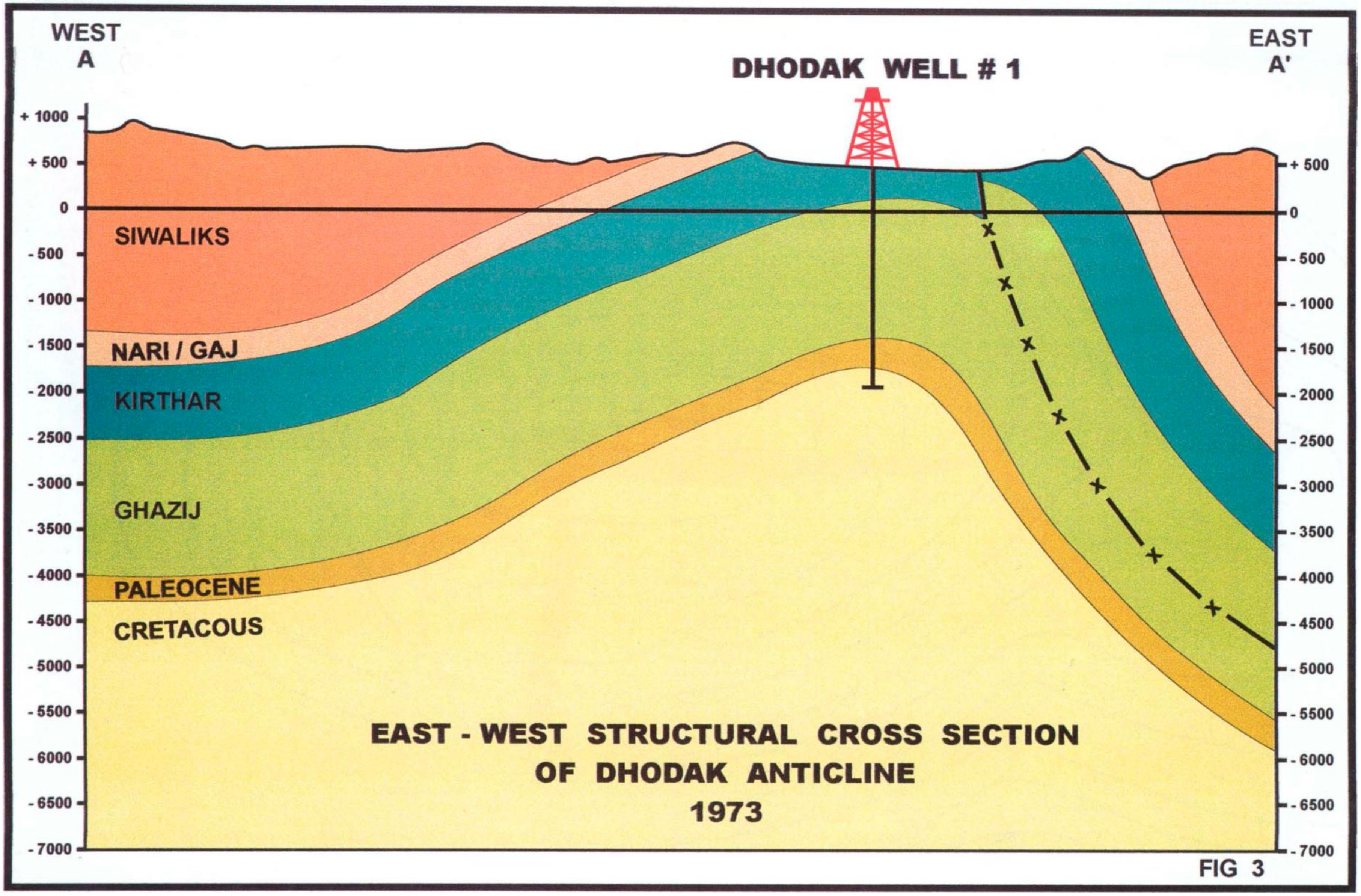

Figure 3. East-West Structural Cross Section of Dhodak Anticline, 1973.

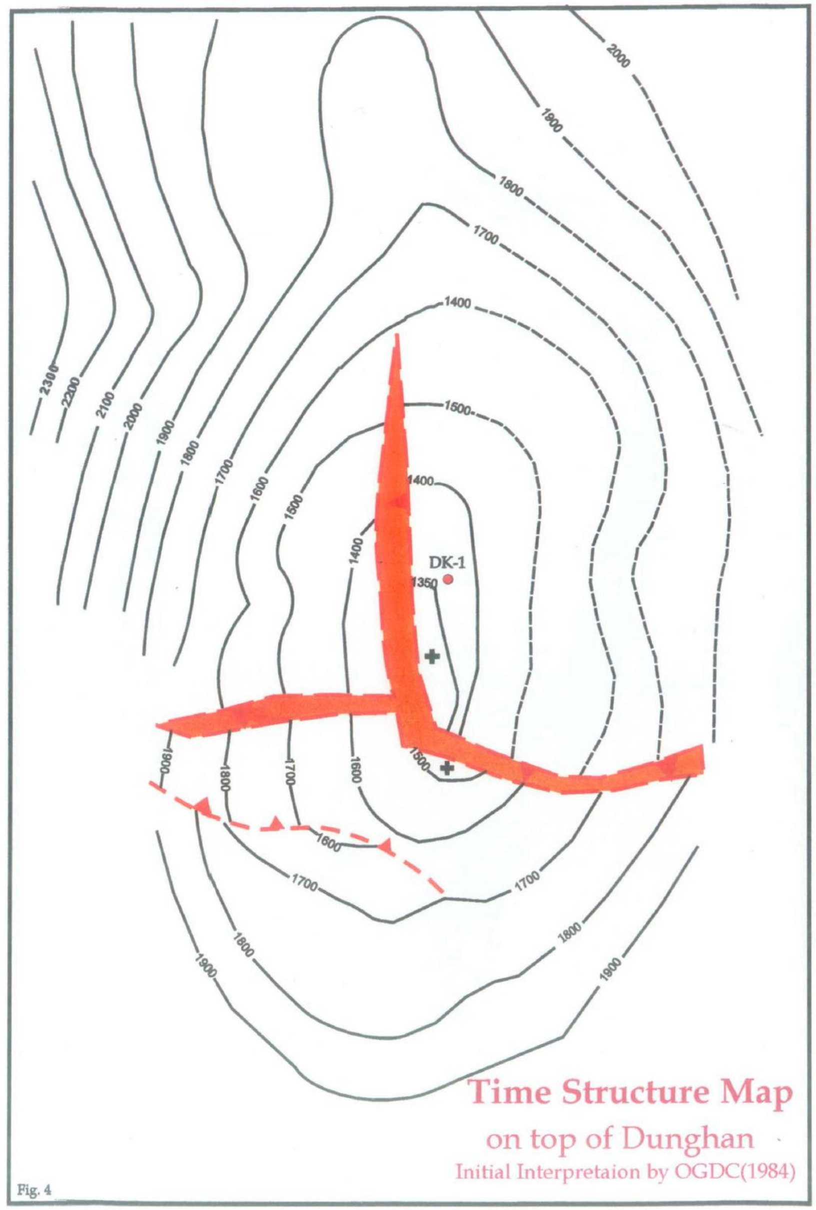

Figure 4. Time Structure Map on Top of Dunghan.

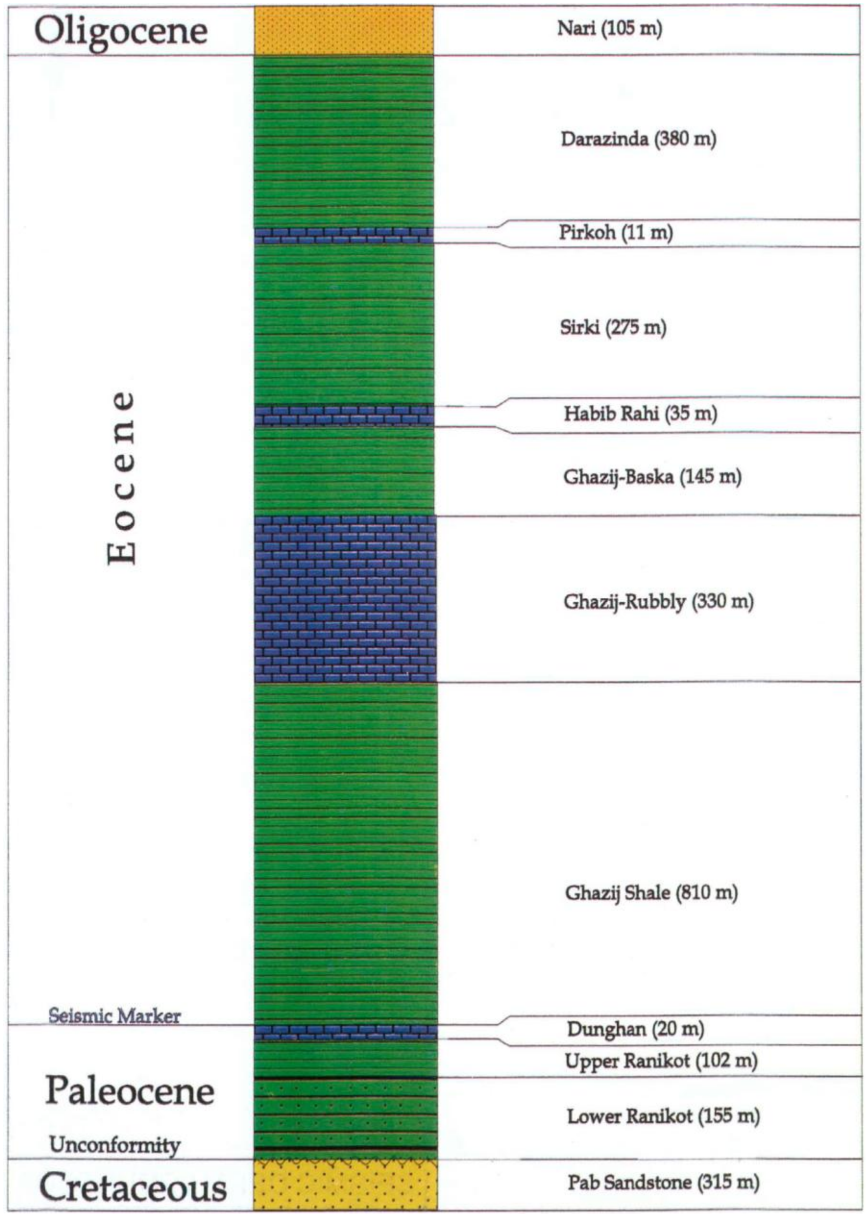

Figure 5. Stratigraphic Succession in Dhodak Field.

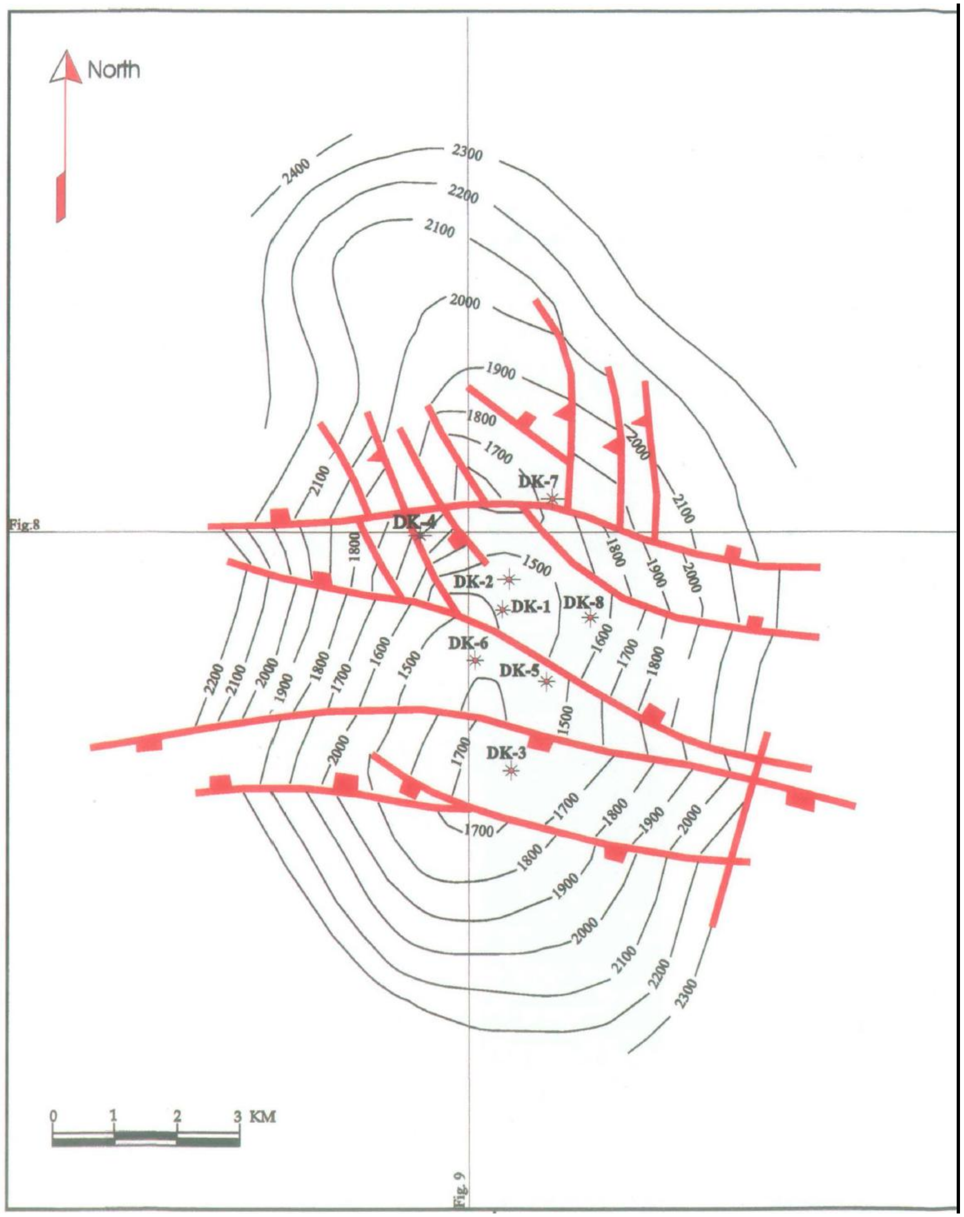

Figure 6. Seismic Depth Contour Map on Top of Lower Ranikot by S.S.I., 1998.

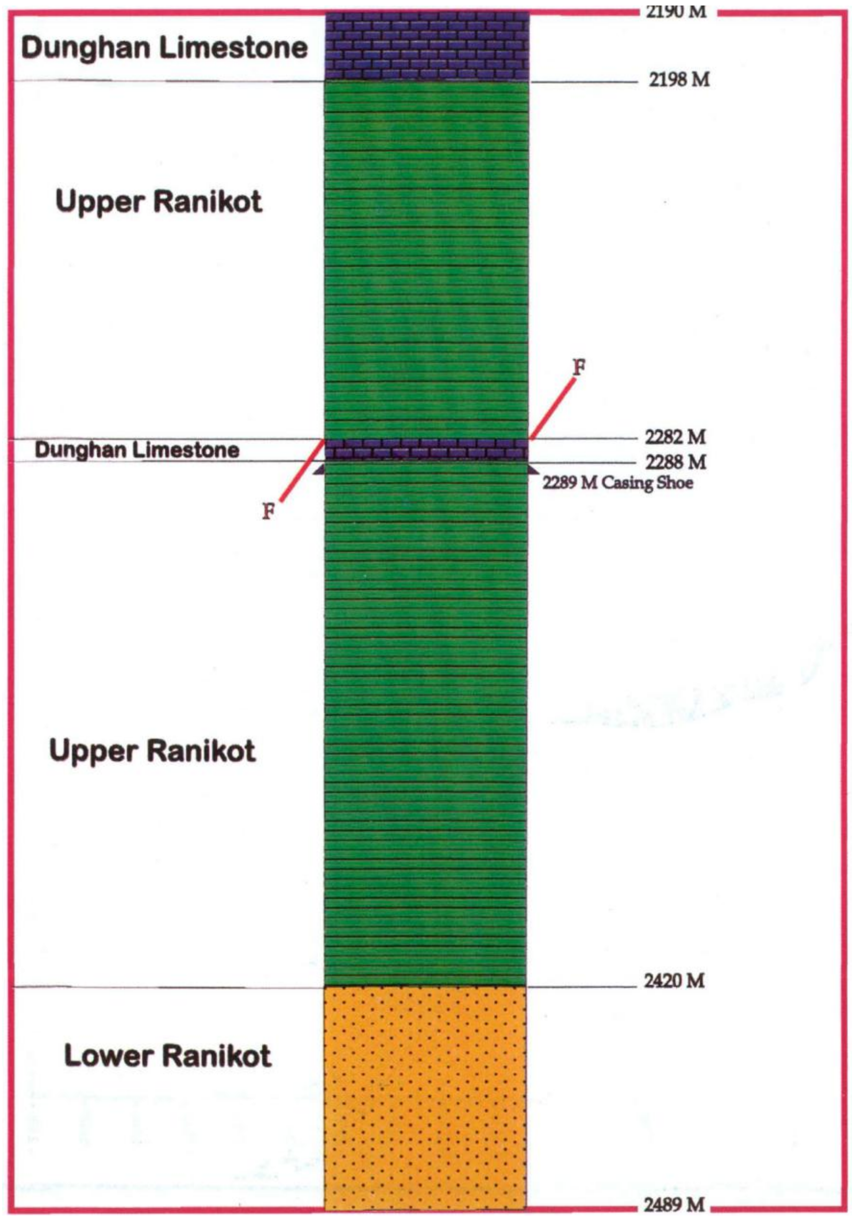

Figure 7. Dhodak Well No. 4 – Repetition of Upper Ranikot.

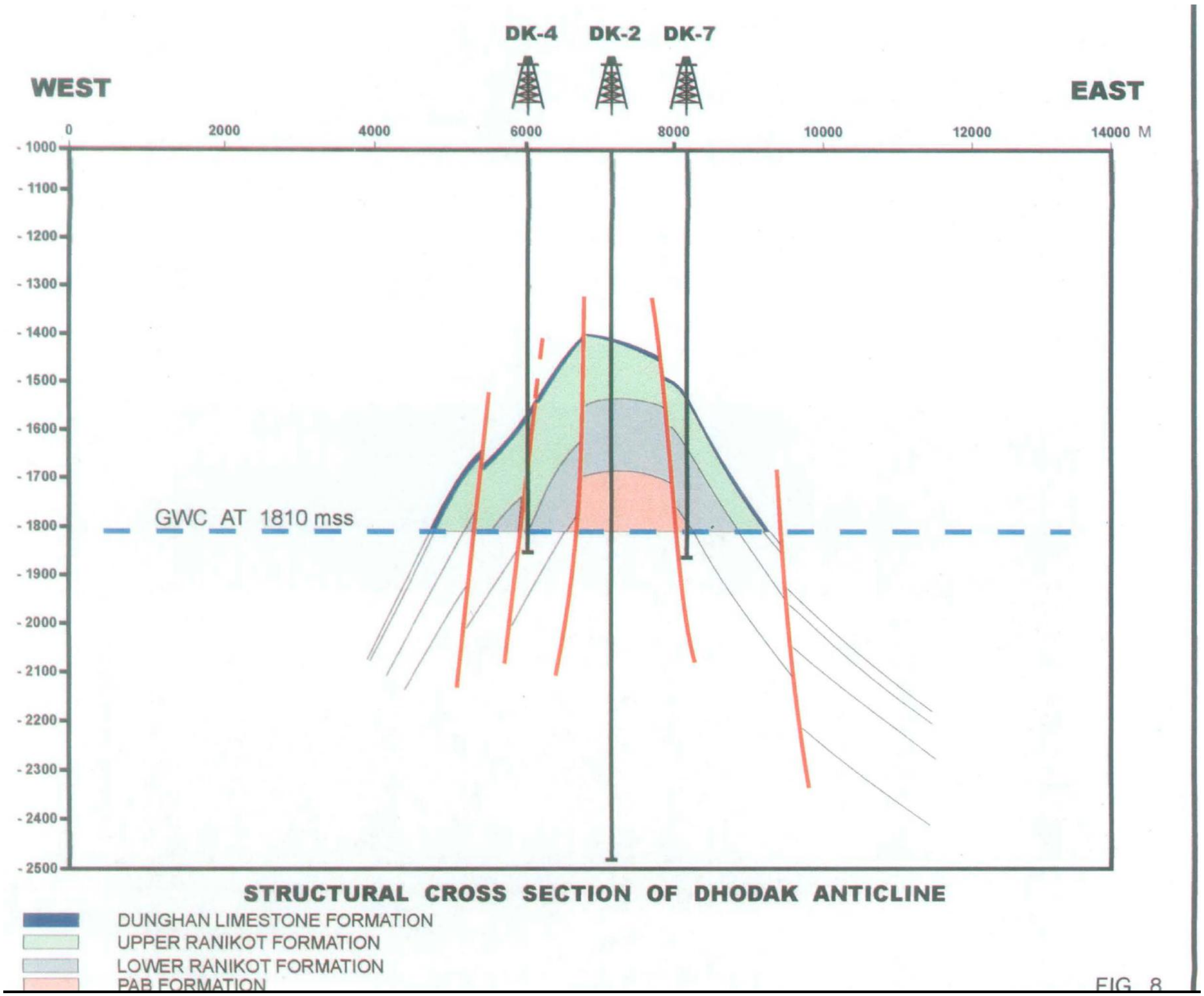

Figure 8. West-East Structural Cross Section of Dhodak Anticline.

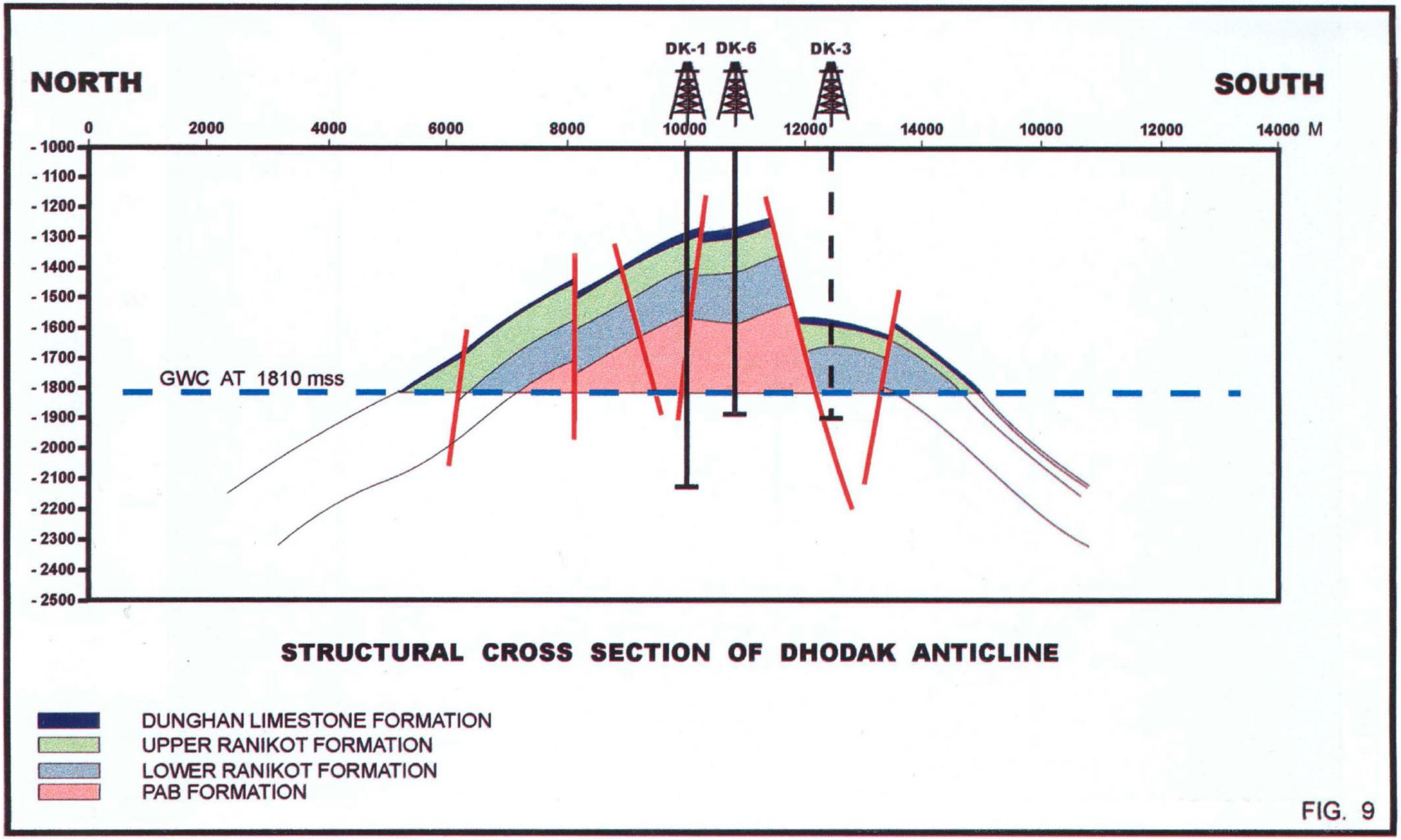

Figure 9. North-South Structural Cross Section of Dhodak Anticline.

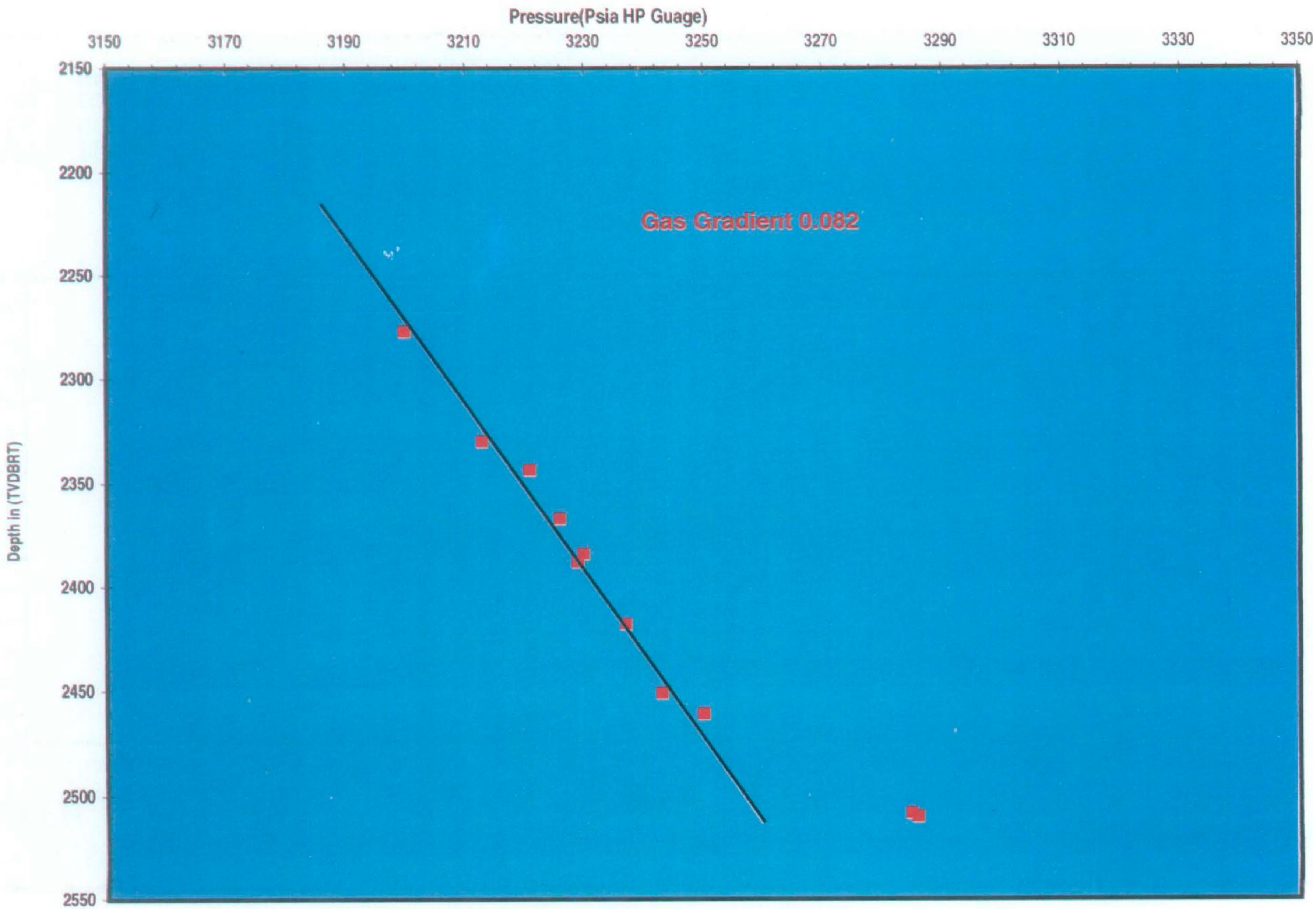

Figure 10. RFT Data from Dhodak Well No. 6.

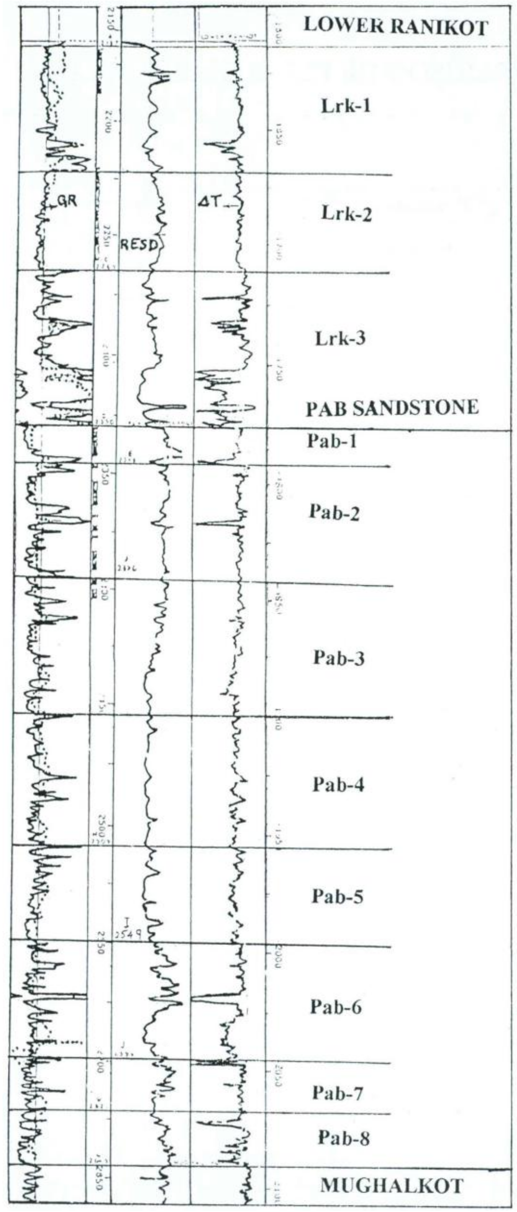

Figure 11. Reservoir Zonation in L. Ranikot and Pab Sandstone.

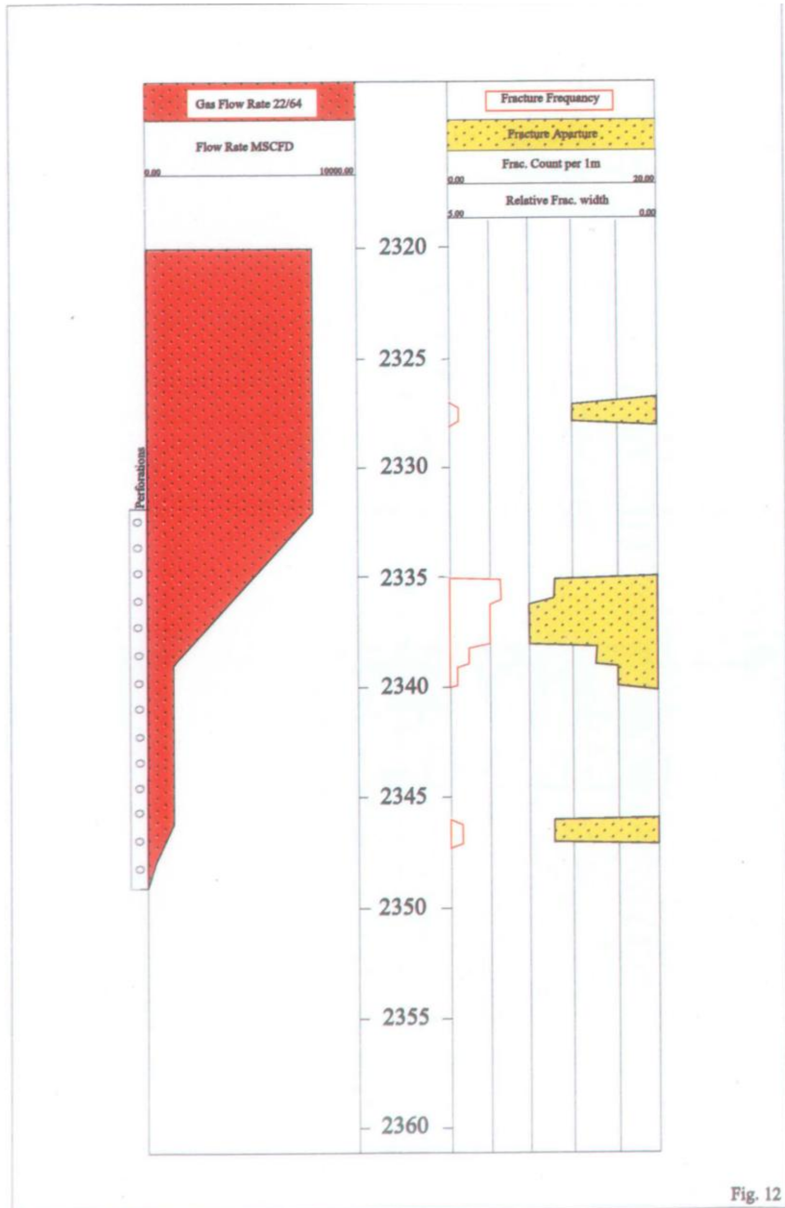

Figure 12. Dhodak Well No. 7 – Comparison of PLT and Fracture Log.

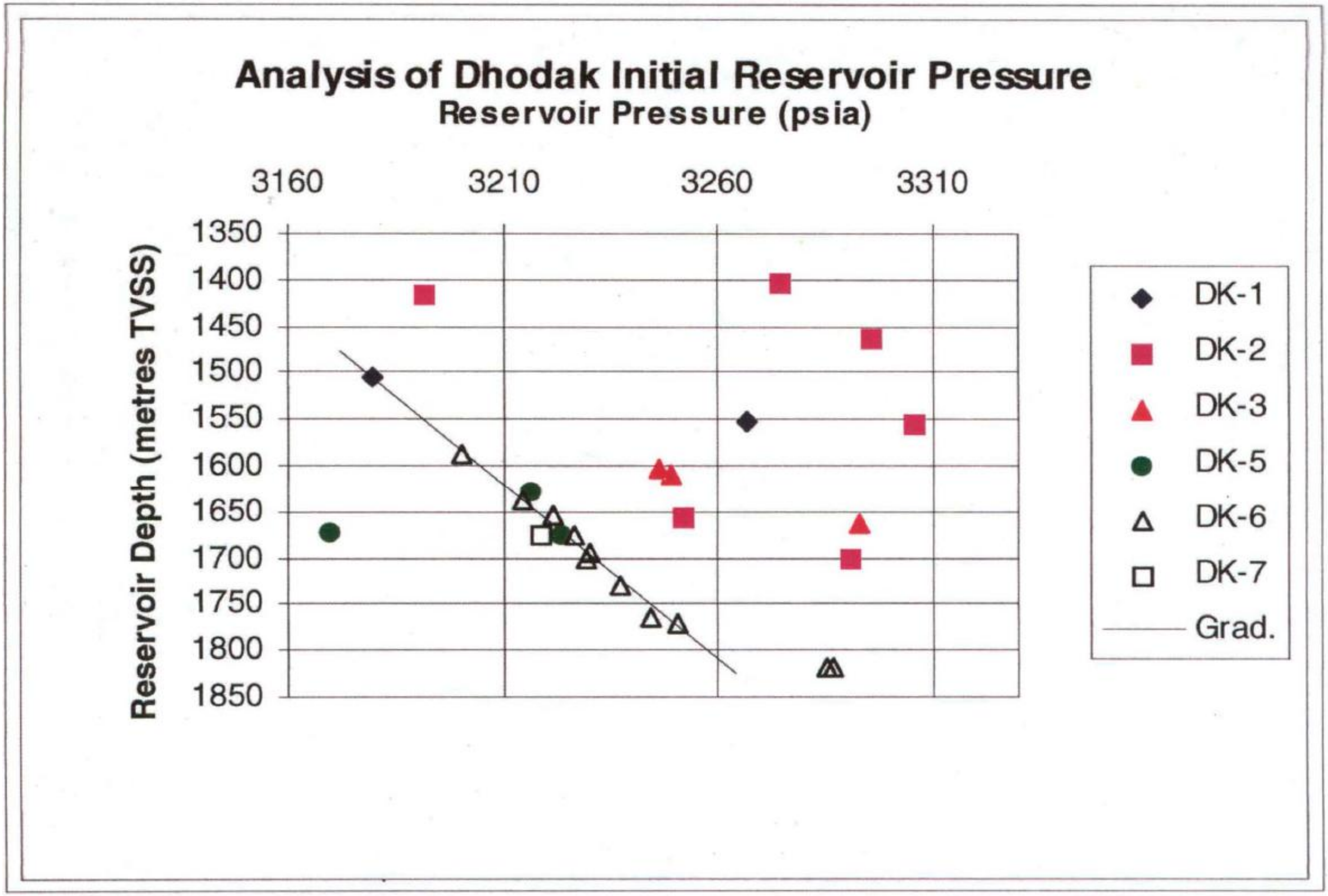

Figure 13. Analysis of Dhodak Initial Reservoir Pressure.

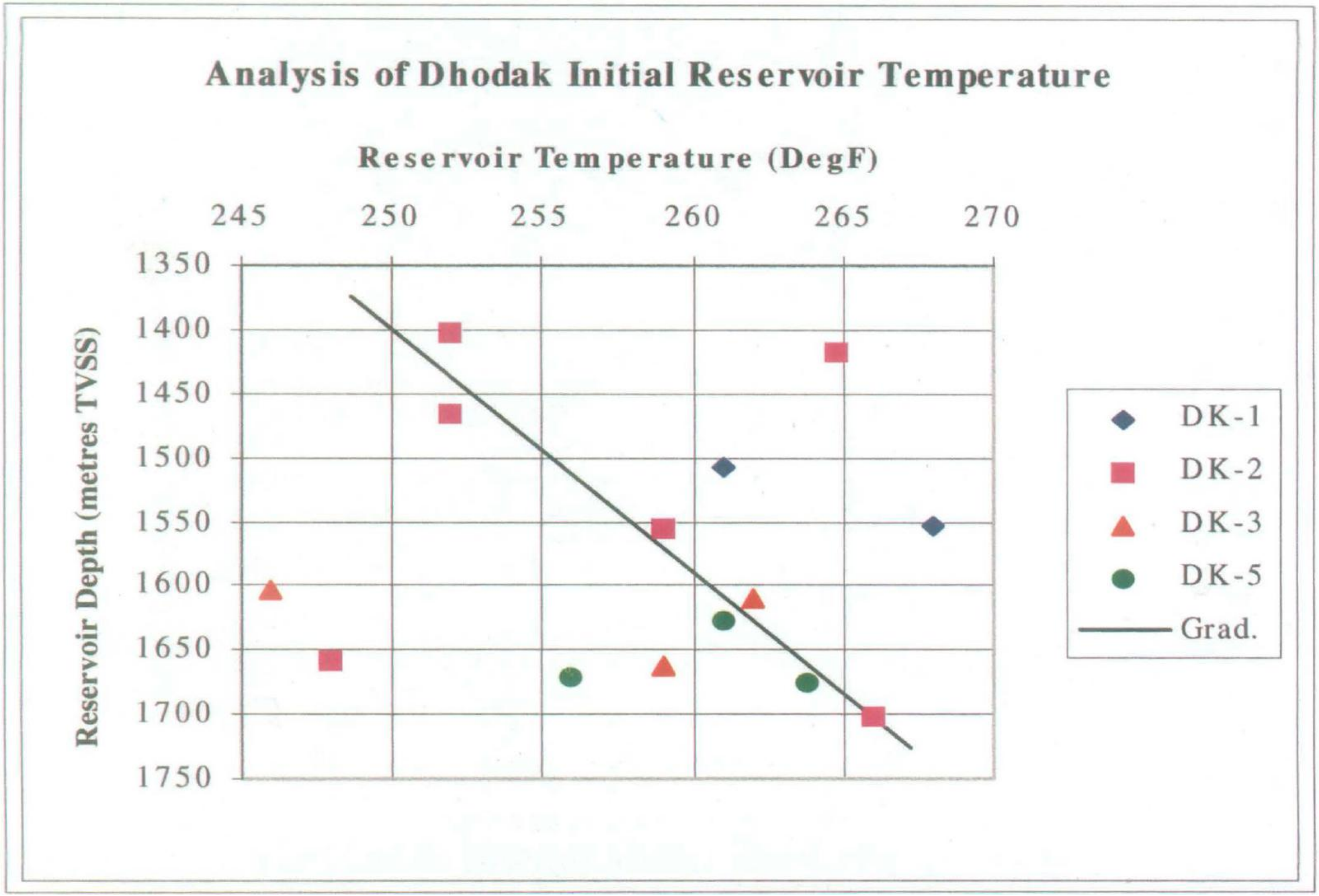

Figure 14. Analysis of Dhodak Initial Reservoir Temperature.

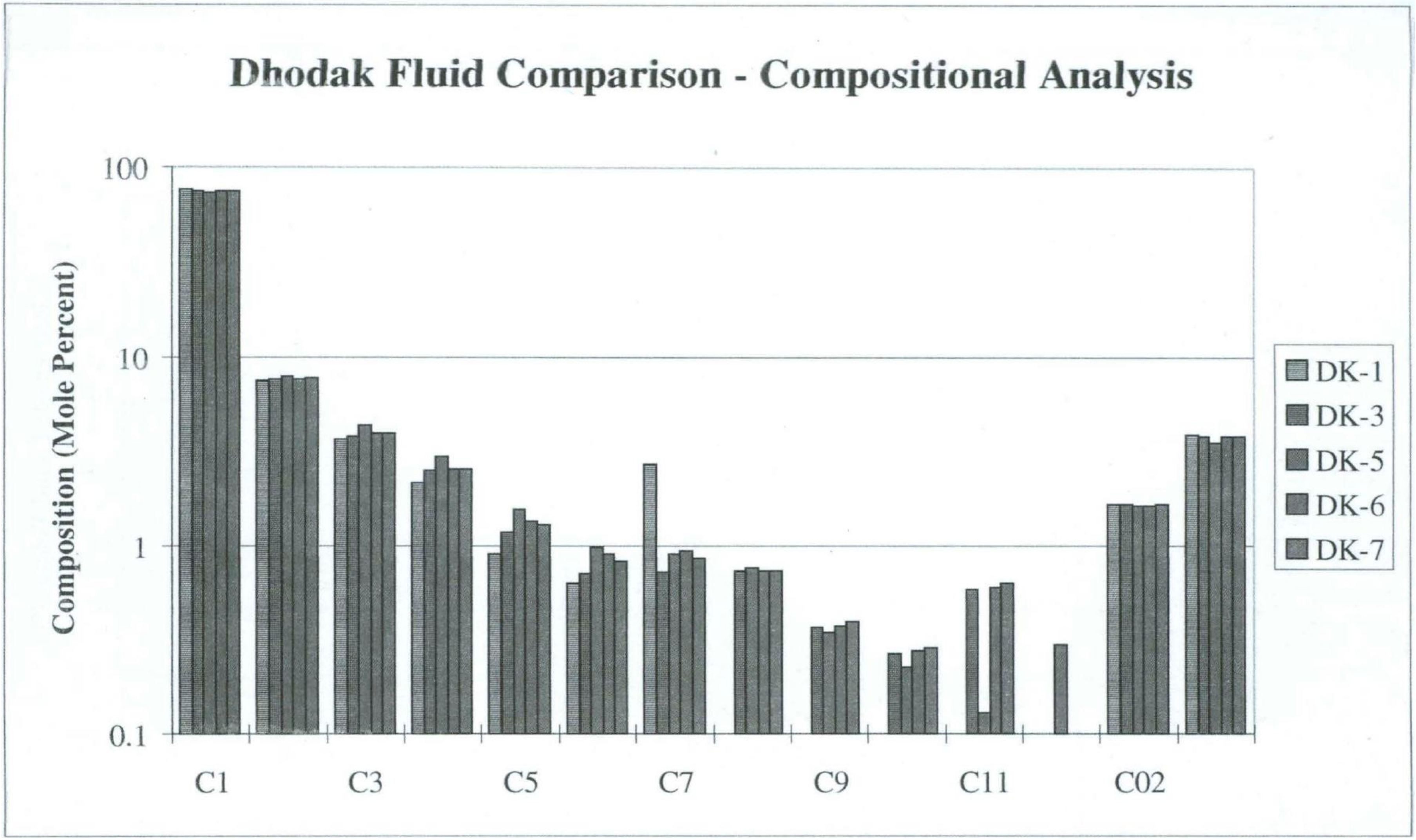

Figure 15. Dhodak Fluid Comparison – Compositional Analysis.

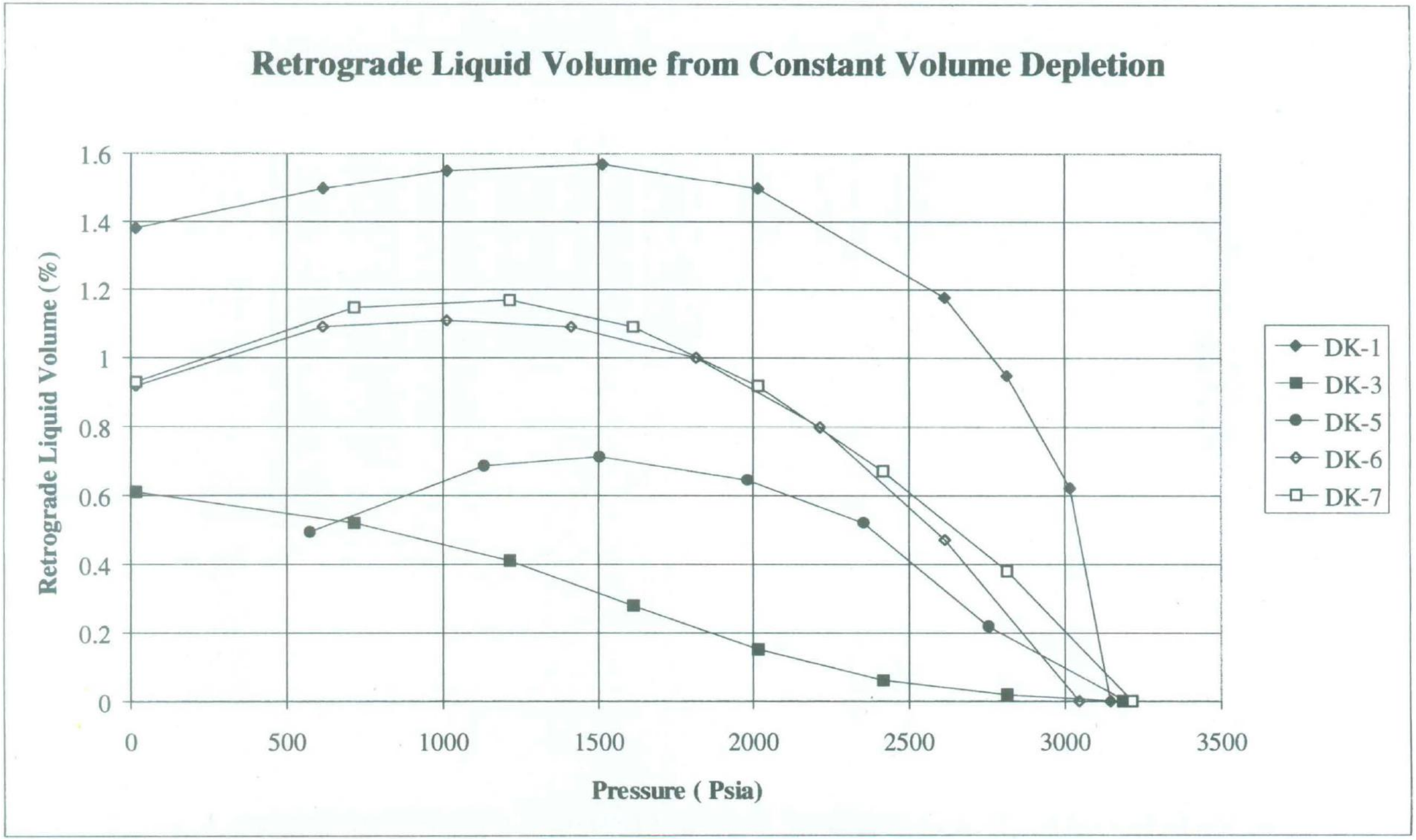

Figure 16. Dhodak Fluid Comparison – Retrograde Liquid Volume.

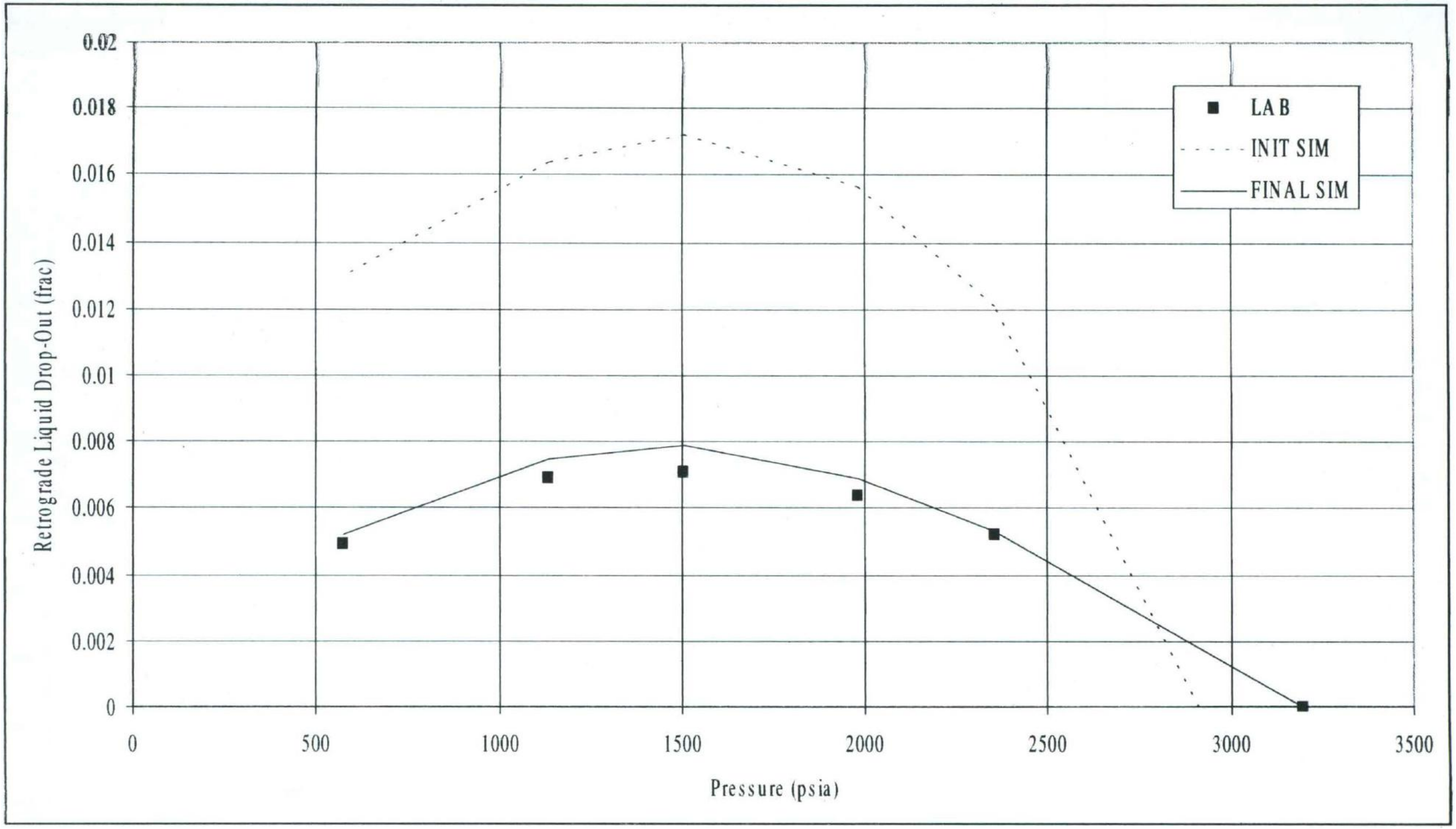

Figure 17. Liquid Drop-Out Match for Control Volume Depletion.

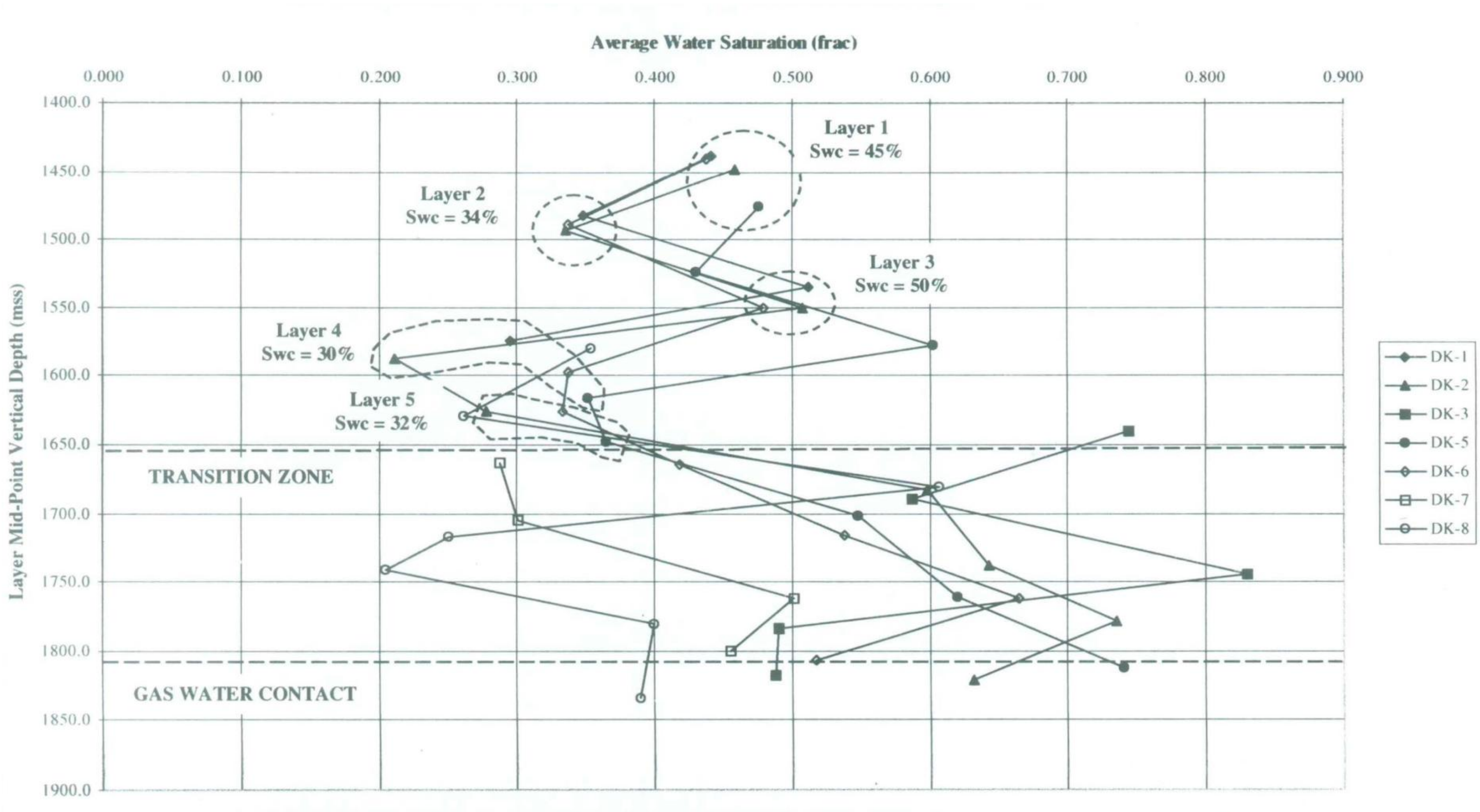

Figure 18. Water Saturation versus Depth Profiles of Dhodak Wells.

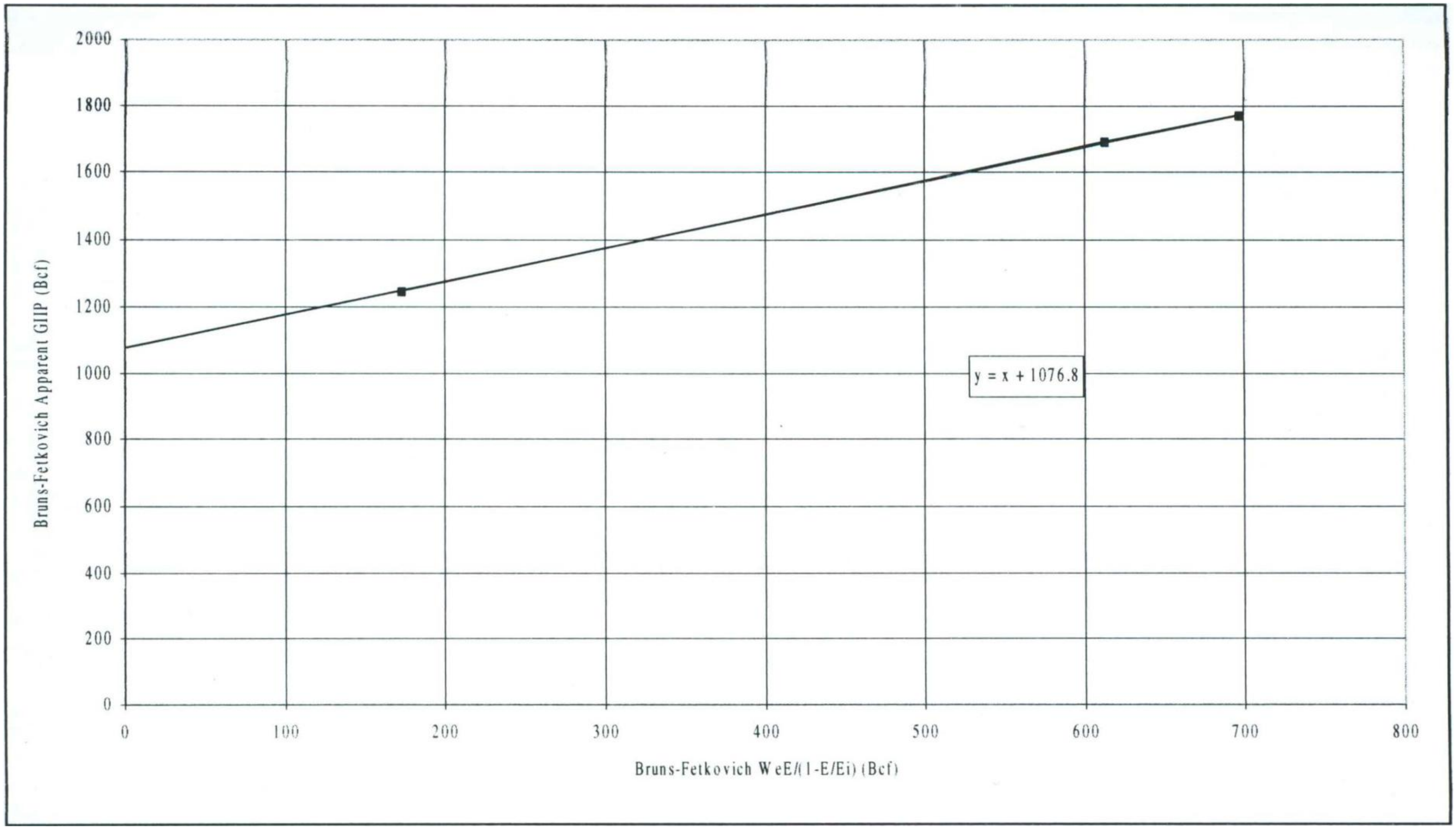

Figure 19. Bruns-Fetkovitch Material Balance for Dhodak Reservoirs.

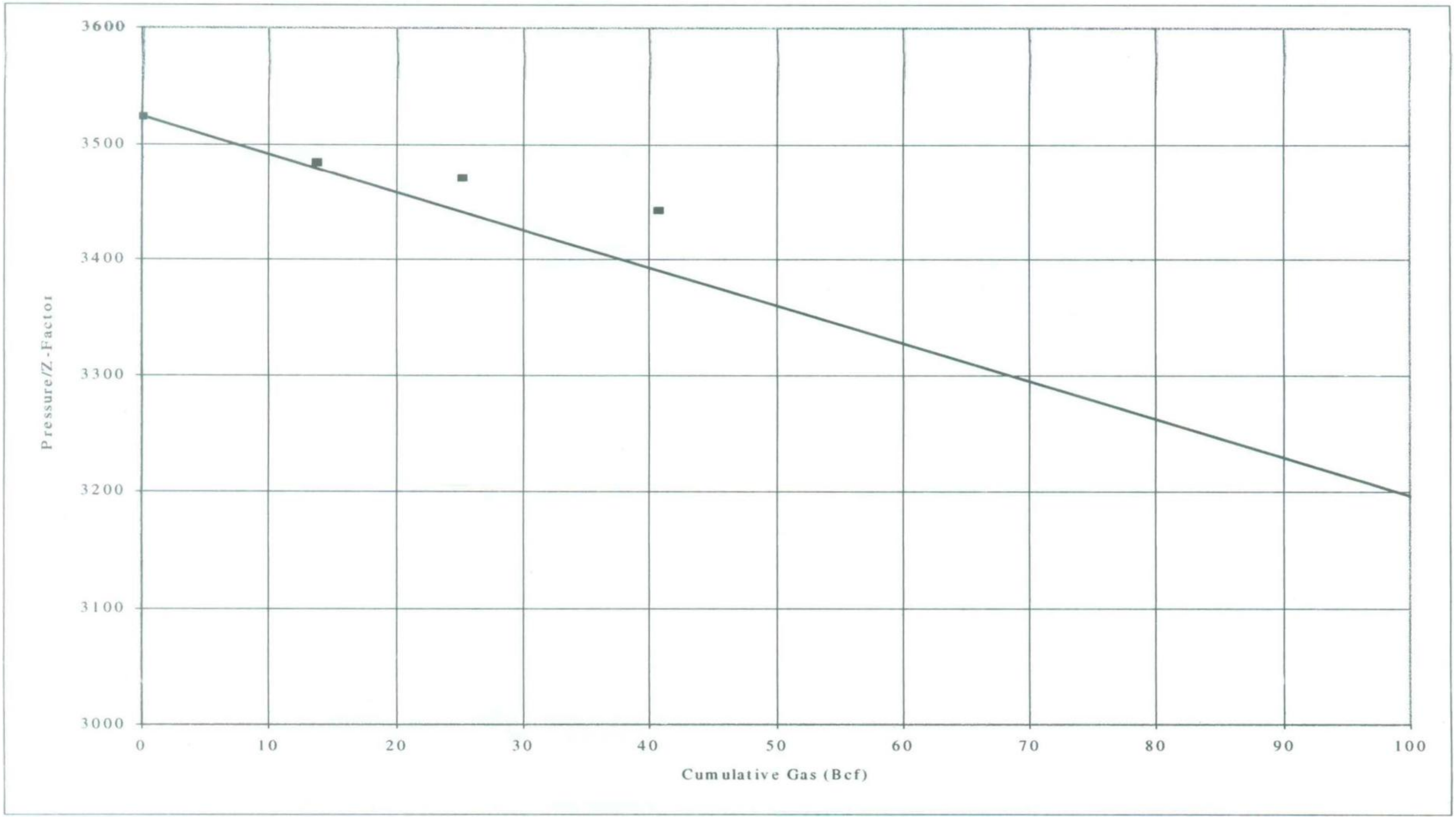

Figure 20. Material Balance (P/Z) for Dhodak Reservoirs (Enlarged).

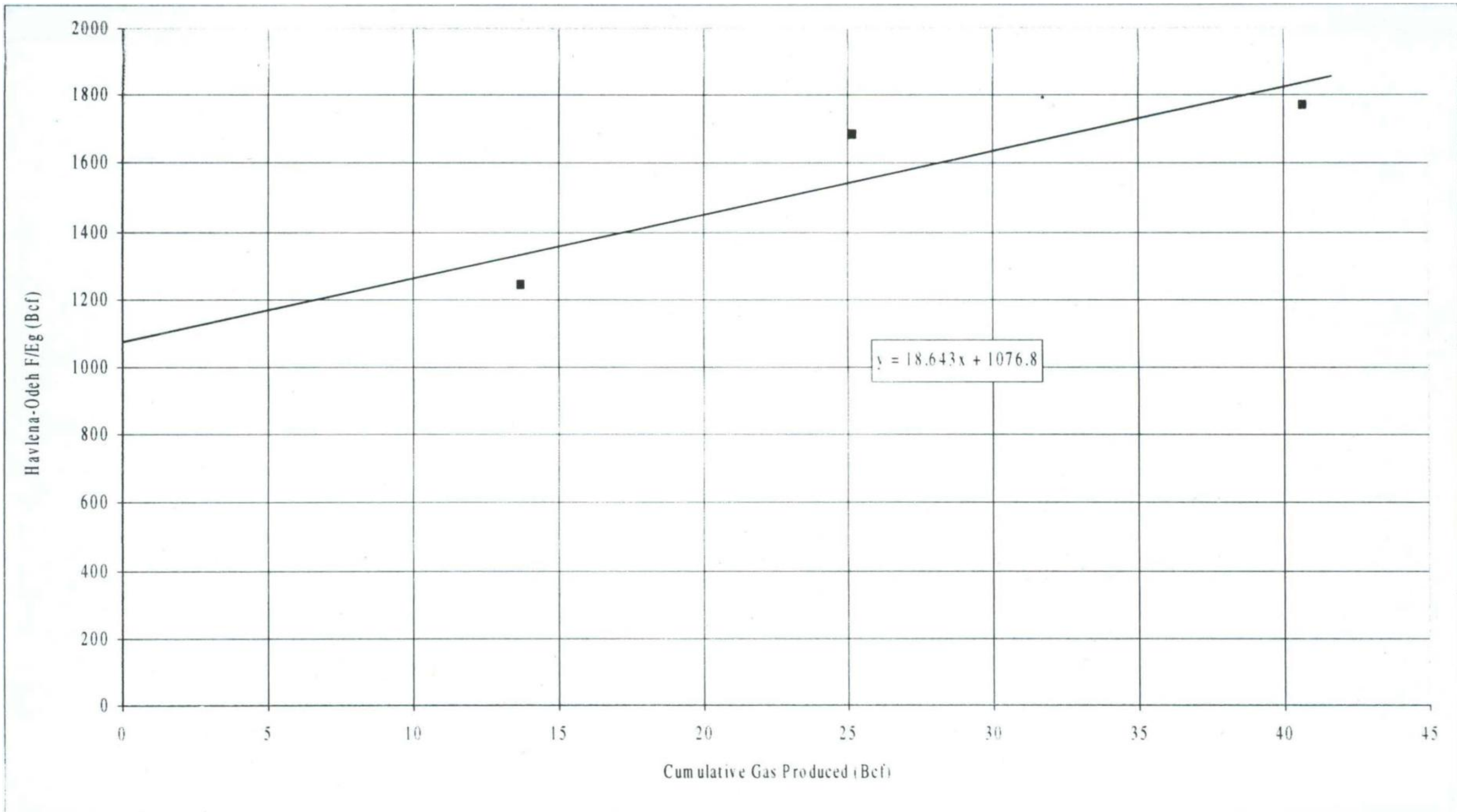

Figure 21. Havlena-Odeh Material Balance for Dhodak Reservoirs.

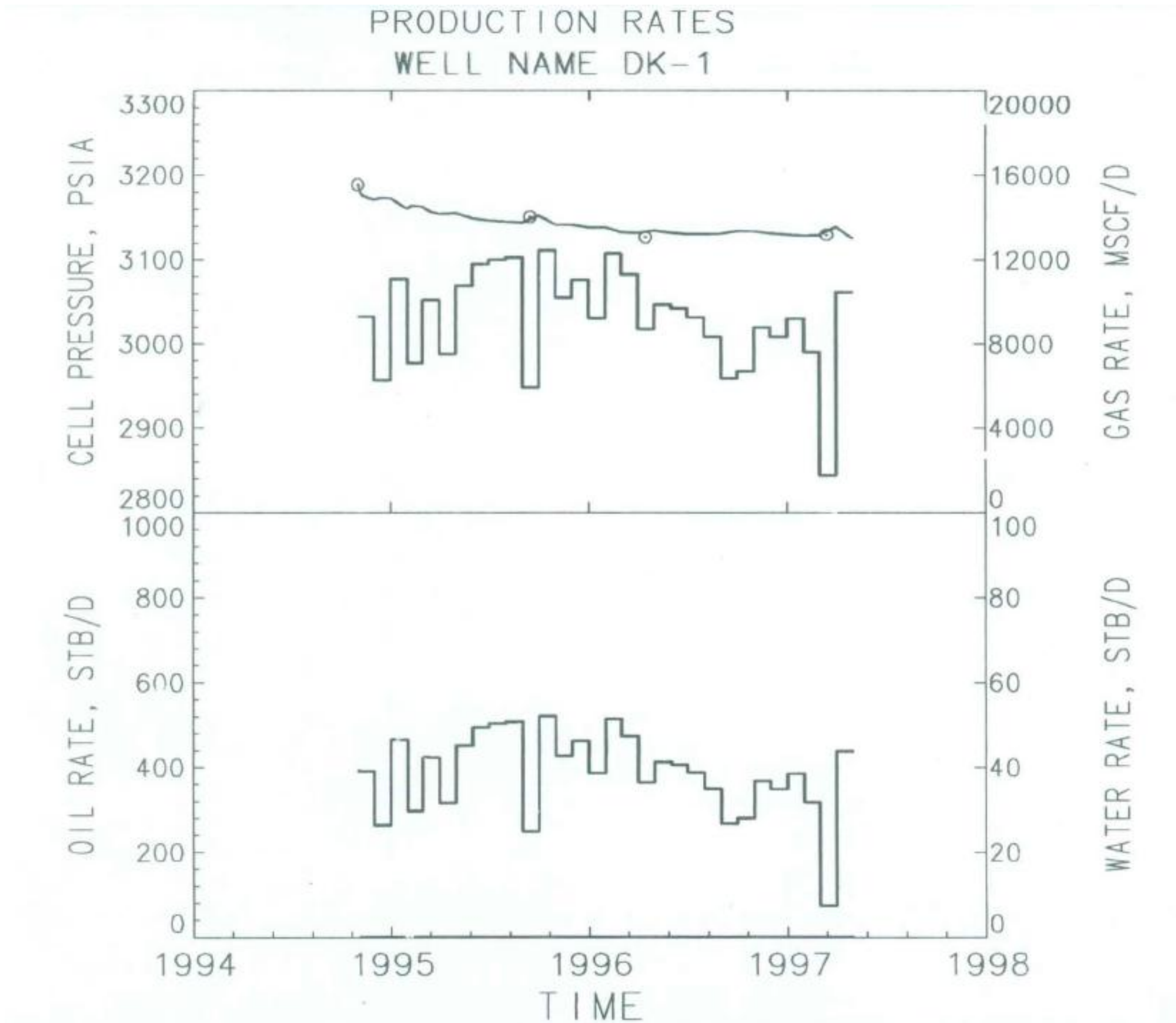

Figure 22. Full Field History Match Run for Dhodak Well DK-1.

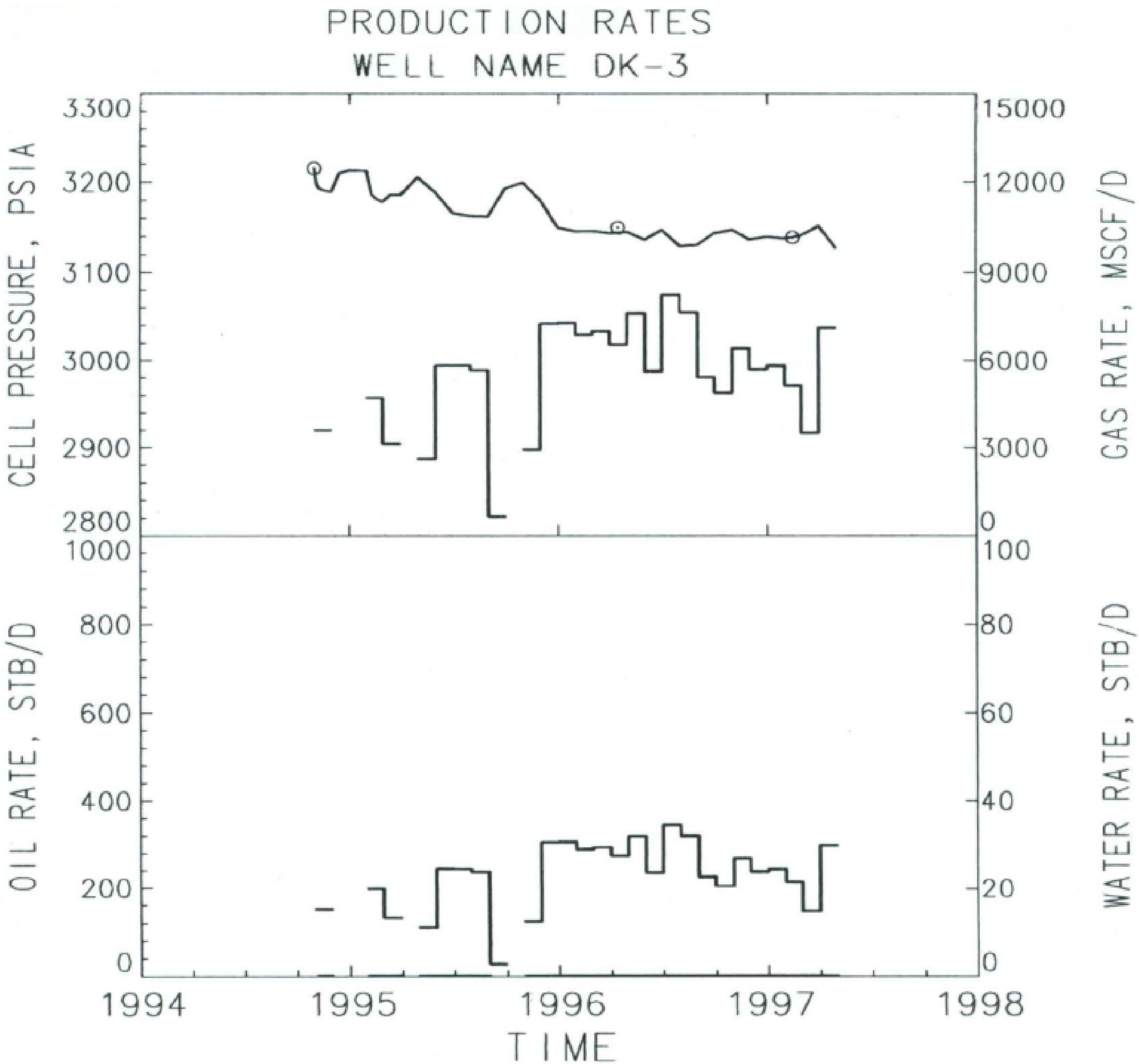

Figure 23. Full Field History Match Run for Dhodak Well DK-3.

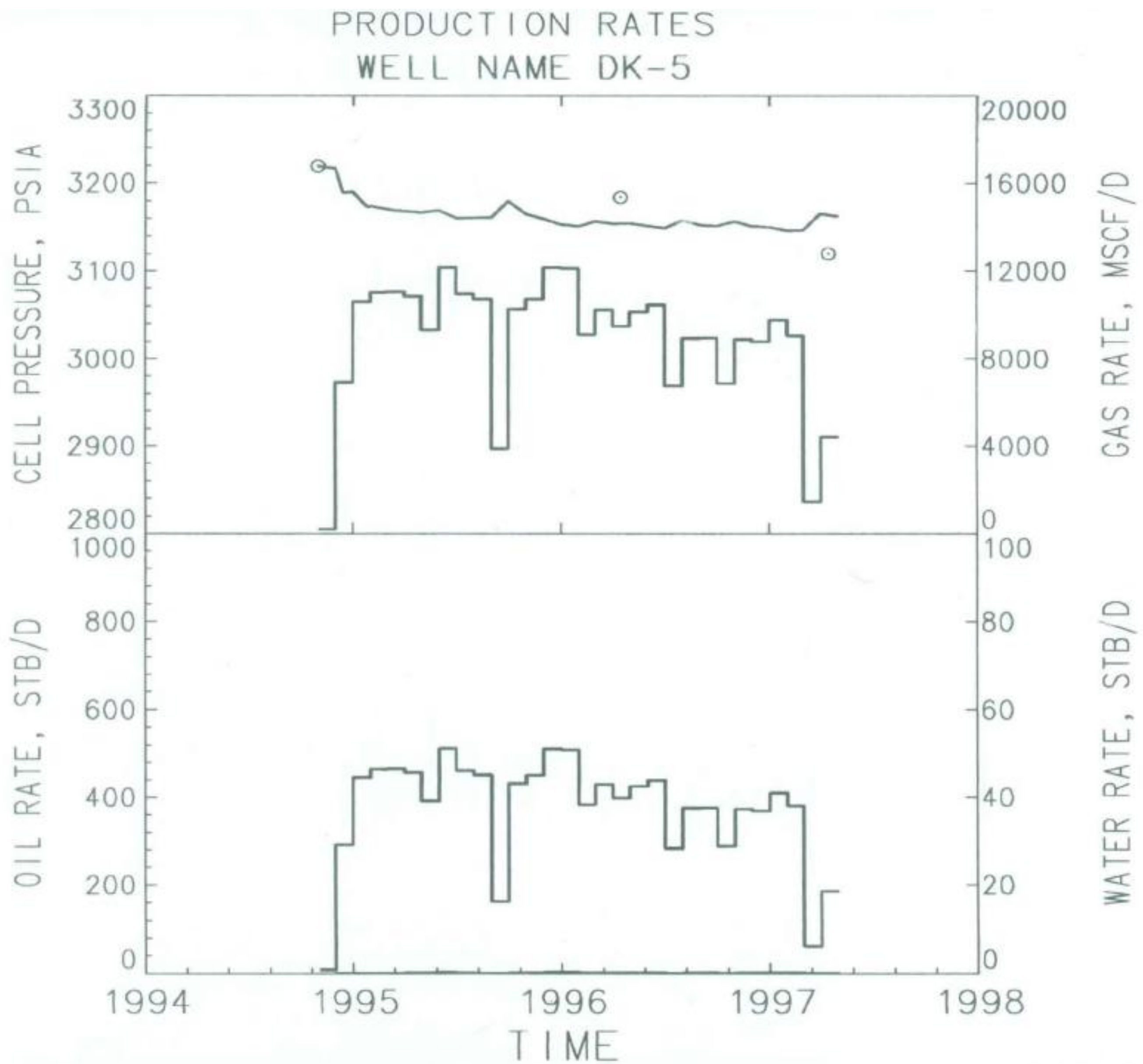

Figure 24. Full Field History Match Run for Dhodak Well DK-5.

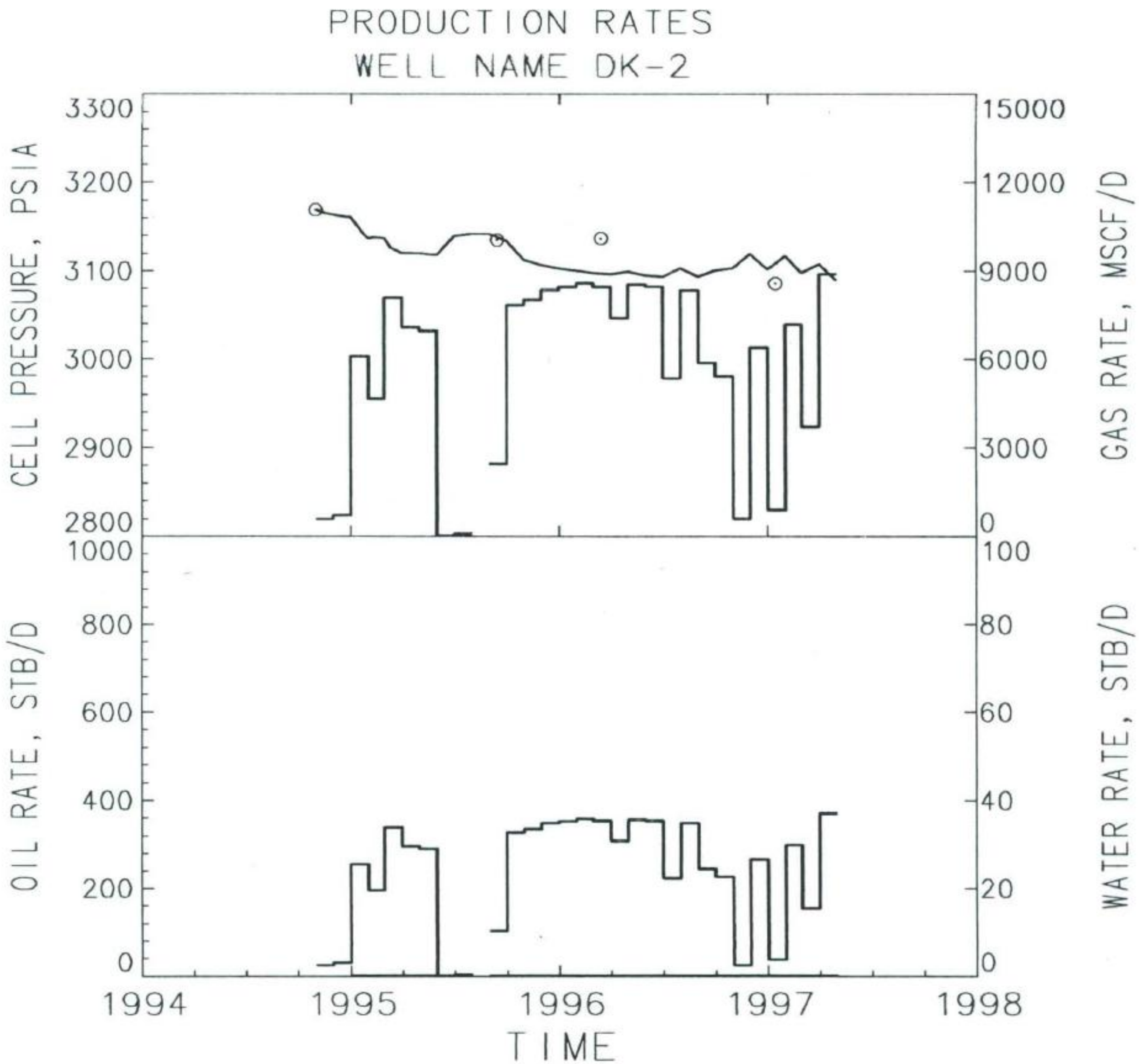

Figure 25. Full Field History Match Run for Dhodak Well DK-2.

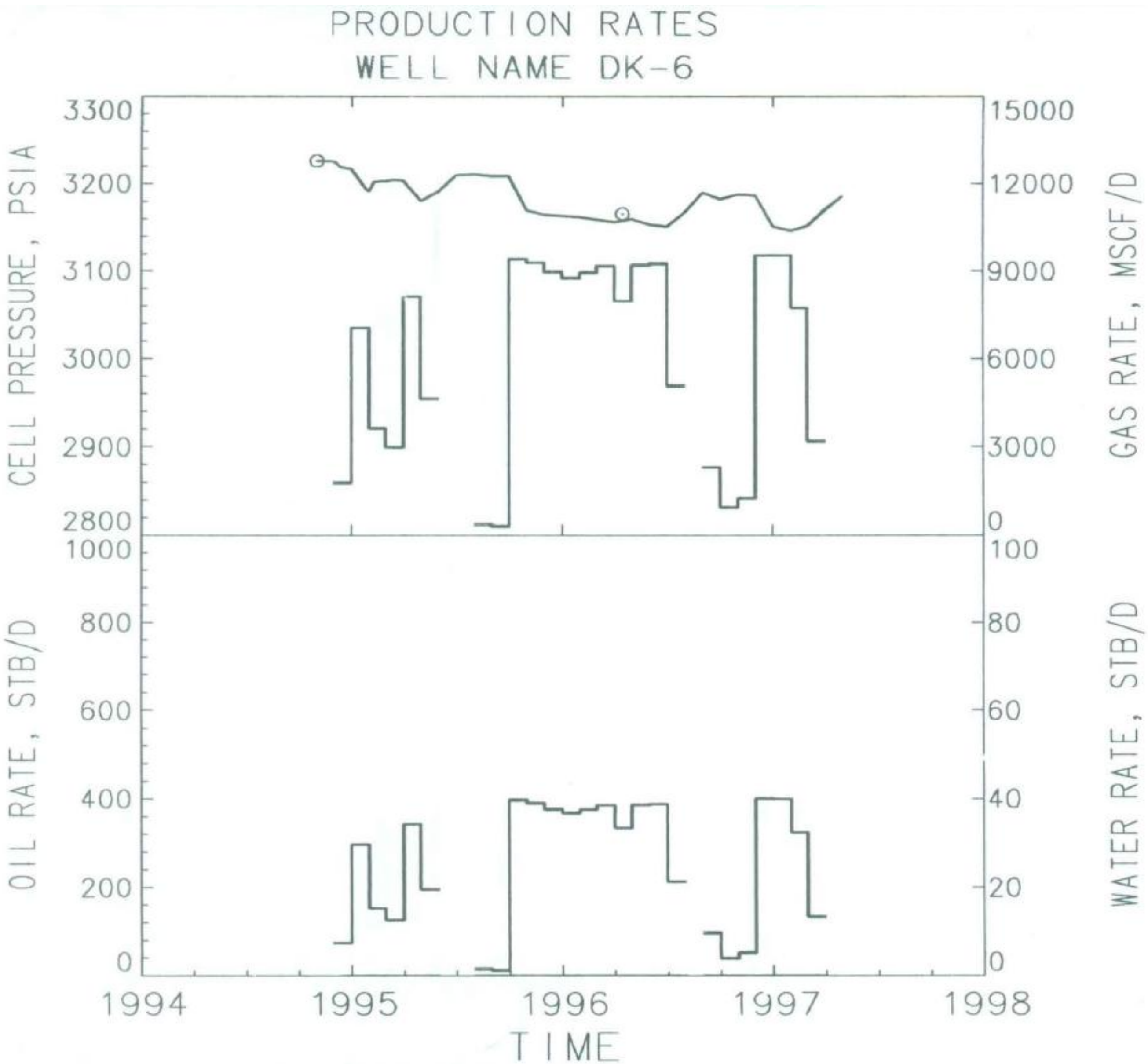

Figure 26. Full Field History Match Run for Dhodak Well DK-6.

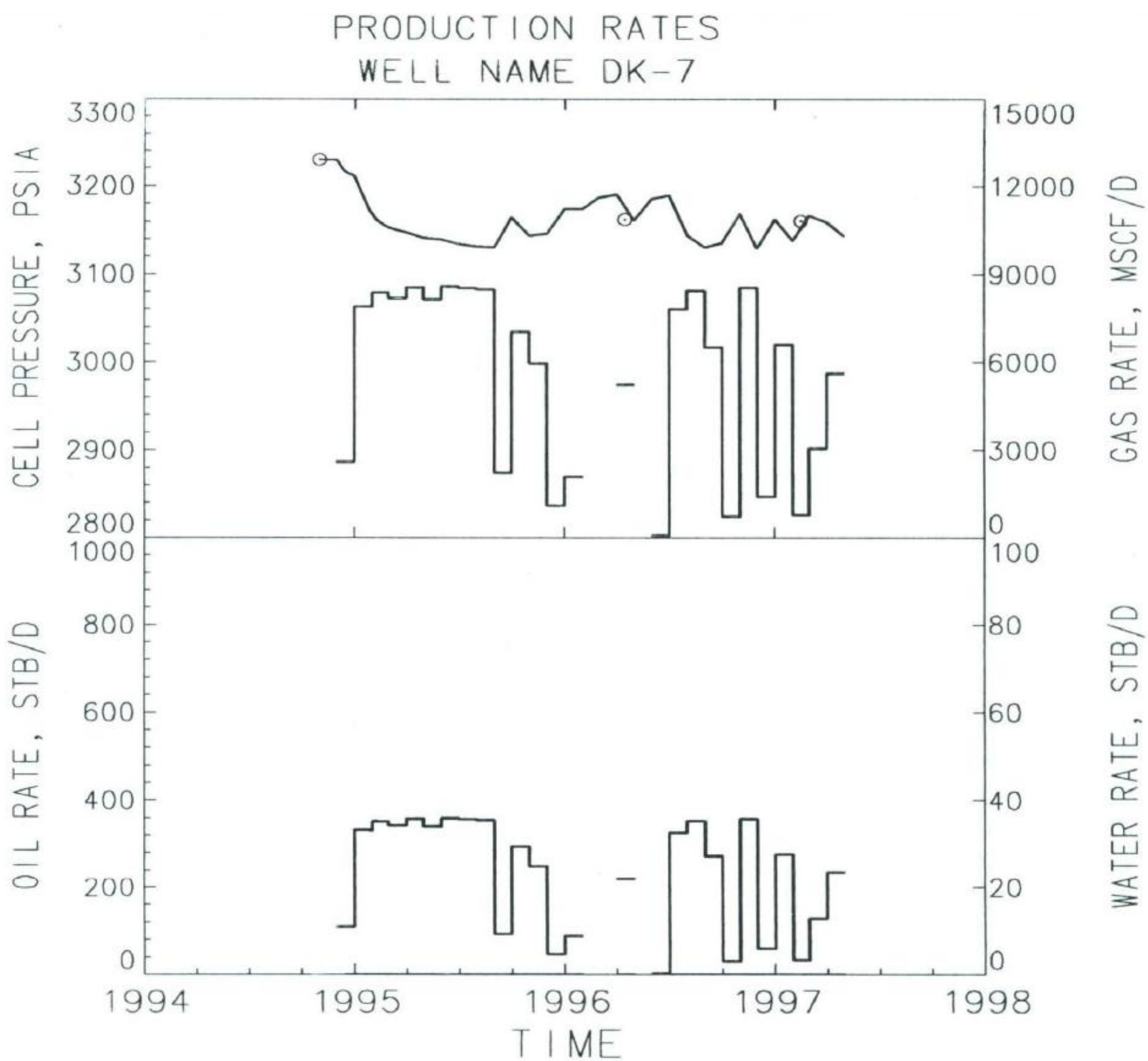

Figure 27. Full Field History Match Run for Dhodak Well DK-7.

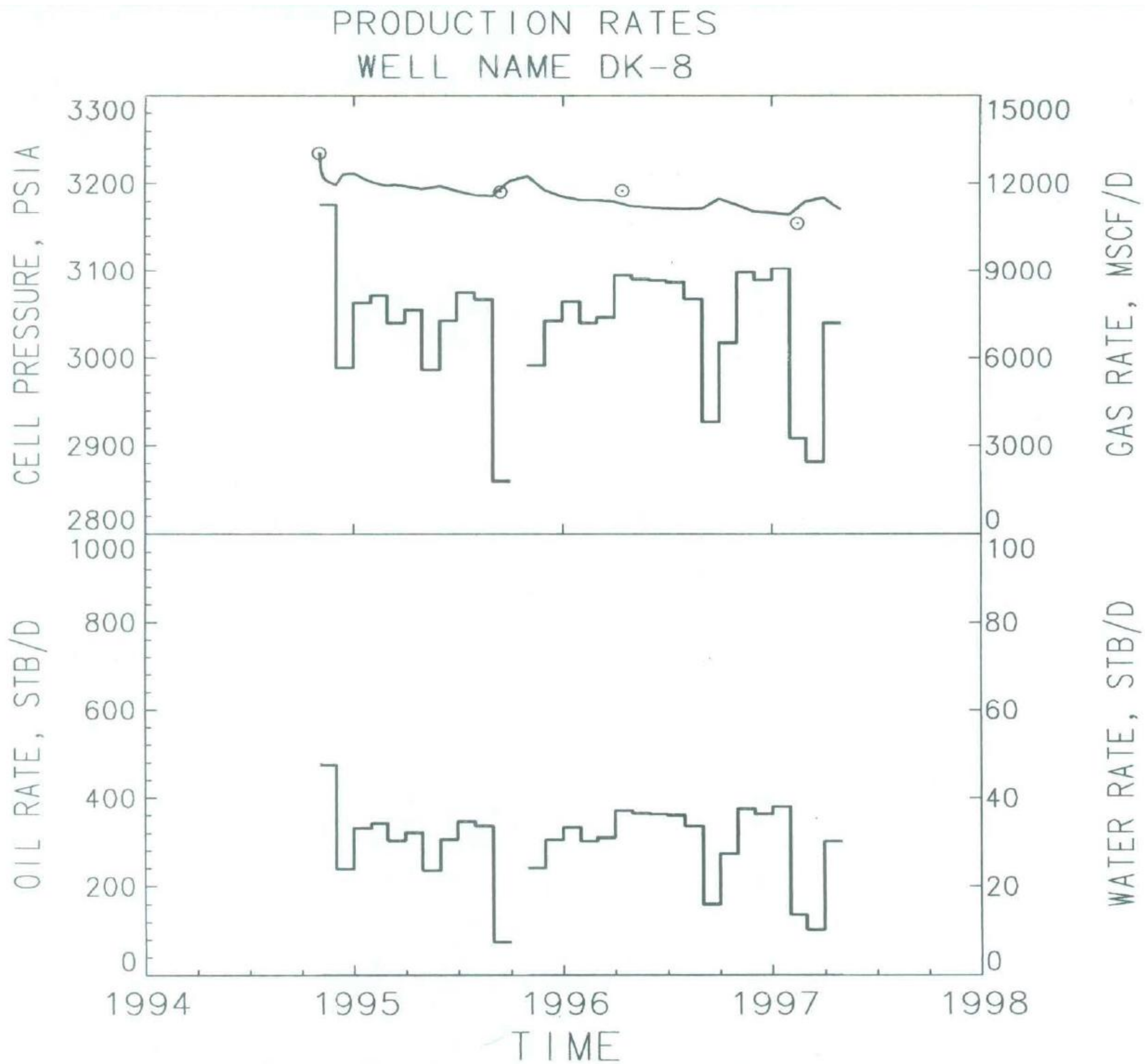

Figure 28. Full Field History Match Run for Dhodak Well DK-8.

Month	Gas (MMscft)	Condensate (bbls)	LPG (MM.Tons)	Avg. Reservoir Pressure at Datum (-1618 mss) (psia)
December-94	231.07	78759.45	2239.17	
January-95	1106.65	117296.94	3845.99	3210.0
February-95	1037.40	98115.99	4472.26	
April-95	1268.00	83494.42	4993.92	
May-95	1250.23	74549.18	5202.72	
June-95	1110.62	74263.99	4631.50	
July-95	1128.72	18407.05	4677.60	
August-95	1144.09	77744.86	5186.00	
September-95	352.70	31180.72	1424.00	3171.50
October-95	1209.66	84775.78	5472.00	
November-95	1334.76	88203.70	5856.00	
December-95	1463.16	96743.71	5978.00	
January-96	1334.16	94011.70	5025.00	
February-96	1267.33	86343.00	5787.00	
March-96	1354.65	91853.00	6029.00	3157.80
April-96	1313.39	89736.00	5816.00	
June-96	1289.27	87882.00	5687.22	
July-96	1319.39	875955.00	5931.00	
August-96	1151.55	86475.00	5816.00	
September-96	1017.47	68371.00	4547.00	
October-96	869.55	58764.00	3799.00	
November-96	1064.21	70249.00	4765.00	
December-96	1242.57	84050.00	5852.00	
January-97	1262.00	84620.00	5911.00	
February-97	1082.16	72122.00	4762.00	
March-97	527.84	33638.00	2346.00	
April-97	1134.28	75786.00	5257.00	3129.60
May-97	1335.78	87474.00	6216.00	
June-97	1313.34	86492.00	5928.00	
July-97	1076.15	71063.00	4703.00	
August-97	1091.41	72390.00	4796.00	
September-97	1050.65	68892.00	4618.00	
October-97	1105.0	73401.00	4862.00	
November-97	1091.16	72991.00	4891.00	
December-97	1293.84	88501.90	6024.00	
January-98	1285.11	87722.00	6009.00	3076.70
February-98	1161.35	78856.00	5414.00	
March-98	1249.77	83153.00	5814.00	
April-98	870.86	57397.00	3883.00	
May-98	1176.31	77804.00	5442.00	

Table 1. Production and Reservoir Pressures.

Formation	GIIP (Proven) (Bscf)	GIIP (Probable) (Bscf)	Proven + Probable (Bscf)
Lower Ranikot-1	188.00	19.07	207.07
Lower Ranikot-2	250.40	14.72	265.12
Lower Ranikot-3	-	23.14	23.14
Pab Total	274.60	11.85	286.45
Total	713.00	68.78	781.78

Table 2. GIIP Estimates by OGDC in 1994.

Company	No. of Wells	Method	GIIP (Bscf)	Recoverable (Bscf)
Fountainhead USA, 1990	5	Reservoir Simulation Model initialization	1321	938
OGDC , 1994	8	Volumetric	782	428
Ryder Scott USA, 1995	8	Volumetric	851	425
SSI - UK,1996	8	Volumetric	625	390

Table 3. Comparison of GIIP.

Rock Type	Original Connate Sw (%)	Revised Connate Sw (%)
Lower Ranikot (Layer - 1)	45	41
Lower Ranikot (Layer - 2)	34	32
Pab (Layers-1 & 2)	31	30

Table 4. Comparison of Water Saturation.

Well	n	C Mscf/d/psia^{2n}	AOF MMscf/d
DK-1	0.663	3.14	137.6*
DK-2	0.555	32.4	246.0*
DK-3	0.814	0.225	117.8*
DK-5	0.604	15.1	260.7**
DK-6	0.808	0.16	74.7
DK-7	0.623	0.78	18.0

Table 5. Deliverability Analysis of Dhodak Wells.

Zone	Initial	Revised after history match
R1	156.76	274.40
R2	203.80	372.40
R3	39.57	68.40
Total Ranikot	**400.13**	**715.20**
P1	30.17	53.90
P2	74.96	124.70
P3	61.68	85.60
P4	44.91	69.40
P5	12.11	25.00
P6	1.92	2.50
P7		0.40
Total Pab	**225.75**	**361.50**
Total Field	**625.88**	**1076.70**

Table 6. Comparison of Volumetric Estimates Wet Gas In Place.

Case	Plateau Gas Sale Rate	Cumulative Recovery in 25 Years			Plateau Period
		Gas (Bscf)	Condensate (MMbbls)	LPG (M.M. Tons)	
Base Case	47	427.6	18.1	7.6	25
Base Case with gas recycling	47	428.3	17.7	7.5	17
Increased rate by using field deliverability	90	611.1	29.8	10.8	17
Increased rate by well optimisation	90	580.5	23.3	10.4	17
Increased rate with compression	90	620.3	29.6	11.0	17
Increased rate with water shut-off	90	538.2	22.0	9.6	17

Table 7. Summary of Production Optimisation Results.