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INTEGRATED APPROACH TOWARDS THE APPLICATION  
OF HORIZONTAL WELLS TO IMPROVE WATERFLOODING  
PERFORMANCE

Annual  
January 1, 1997 - December 31, 1997

By  
Mohan Kelkar  
Dennis Kerr

May 1998

Performed Under Contract No. DE-FC22-93BC14951

University of Tulsa  
Tulsa, Oklahoma



**National Petroleum Technology Office**  
**U. S. DEPARTMENT OF ENERGY**  
**Tulsa, Oklahoma**

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## **ABSTRACT**

This annual report describes the progress during the fifth year of the project on "Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance." This project is funded under the Department of Energy's Class I program which is targeted towards improving the reservoir performance of mature oil fields located in fluvially dominated deltaic geological environments. The project involves using an integrated approach to characterize the reservoir followed by proposing an appropriate reservoir management strategy to improve the field performance. In the first stage of the project, the type of data we integrated include cross borehole seismic surveys, geological interpretation based on the logs and the cores, and the engineering information. In contrast, during the second stage of the project, we intend to use only conventional data to construct the reservoir description.

This report covers the results of the implementation from the first stage of the project. It also discusses the work accomplished so far for the second stage of the project. The production from the Self Unit (location of Stage I) has sustained an increase of 30 bbls/day over more than two years. We have collected available core, log and production data from Section 16 in the Berryhill Glenn Unit and have finished the geological description. Based on the geological description and the associated petrophysical properties, we have identified the areas for the most potential. These areas include Tracts 7 and 9. By conducting a detailed flow simulation on both these tracts, and evaluating the economic performance of various alternatives, we have made recommendations for both these tracts. At present, we are in the process of implementing the proposed reservoir management strategy in Tract 9.

## **EXECUTIVE SUMMARY**

During the last year, we have continued to monitor the reservoir management plan in the Self Unit. Over the last year, the production from the unit has remained constant up to 40 bbls/day (over 200% increase in the production). For Stage II of the project, we have evaluated two tracts within Berryhill Glenn Sand Unit. Selection of these tracts (Tracts 7 and 9) is made based on potential index mapping of the entire unit. Detailed reservoir descriptions of each of the tracts were constructed, and the performance was flow simulated. After matching part of the historical data, several scenarios for both the tracts were investigated. Based on the economic evaluation, a selective recompletion followed by drilling of a deviated well is recommended for Tract 9. For Tract 7, the best scenario is to selectively plug and recomplete the wells.

We will continue to monitor the performance. We are not satisfied with the water cut in the existing producing wells in Self Unit. We are going to conduct injection surveys in the injection wells to evaluate the location of formations where water is entering. We are also in the process of implementing the reservoir management plan in Tract 9. After monitoring the performance in Tract 9, we intend to conduct several technical workshops to transfer the technology gained from this project.

## **ACKNOWLEDGMENT**

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We would like to thank Dan Richmond from Uplands Resources, Inc. for his valuable contribution and insight to our work. Our special thanks go to Rhonda Lindsey, representative of the contracting officer of the project, for her enthusiasm and valuable suggestions.

Mohan Kelkar

January, 1998

## **1. OBJECTIVES**

The overall purpose of the proposed project is to improve secondary recovery performance of a marginal oil field through the use of an appropriate reservoir management plan. The selection of plan will be based on the detailed reservoir description using an integrated approach. We expect that 2 to 5% of the original oil in place will be recovered using this method. This should extend the life of the reservoir by at least 10 years.

The project is divided into two stages. In Stage I of the project, we selected part of the Glenn Pool Field - Self Unit. We conducted cross borehole tomography surveys and formation micro scanner logs through a newly drilled well. By combining the state-of-the-art data with conventional core and log data, we developed a detailed reservoir description based on an integrated approach. After conducting extensive reservoir simulation studies, we evaluated alternate reservoir management strategies to improve the reservoir performance including drilling of a horizontal injection well. We observed that selective completion of many wells followed by an increase in the injection rate was the most feasible option to improve the performance of the Self Unit. This management plan is currently being implemented and the performance is being monitored.

Stage II of the project involves selection of part of the same reservoir (Berryhill Unit - Tract 7), development of reservoir description using only conventional data, simulation of flow performance using developed reservoir description, selection of an appropriate reservoir management plan, and implementation of the plan followed by monitoring of reservoir performance.

By comparing the results of two budget periods, we will be able to evaluate the utility of collecting additional data using state-of-the-art technology. In addition, we will also be able to evaluate the application of optimum reservoir management plan in improving secondary recovery performance of marginal oil fields.

Successful completion of this project will provide new means of extending the life of marginal oil fields using easily available technology. It will also present a methodology to integrate various qualities and quantities of measured data to develop a detailed reservoir description.

## **2. STAGE I PROJECT MONITORING**

During the summer of 1995, we started implementing the reservoir management plan in the Self Unit. Last year, after evaluating each individual well, we decided to install electrical submersible pumps to produce three wells. The other three wells required the use of rod pumps. Production from the field improved significantly once the pumps were installed. Over the last twelve months, an average daily production has been approximately 40 bbls/day. Compared to a base line production of 13 bbls/day before the implementation, this is more than a 200% increase in production.

The water cut in producing wells is not as low as predicted. We intend to run injection surveys in injection wells to determine the location of zones where most of the water is injected.

### **3. GEOLOGICAL DESCRIPTION (By Dennis R. Kerr and Liangmiao Ye)**

#### **3.1 Refinement of Chevron Polymer Flooding Acreage**

Analysis of core data and well logs, collected from Hyperion Oil Company of Dallas, was conducted to evaluate Chevron's polymer flood in the vicinity of Tract 9. In particular, we were concerned with the oil saturation profiles before and after the initiation of the polymer flood.

Saturation profiles vs. depth for 23 cores showed a similar profile with the "upper" and "middle" Glenn having higher oil saturation compared to the "lower" Glenn. See, for example, **Figure 1**. Such a profile was also present 2 miles north of the polymer flood area (Crow 9-43 well) and was inferred from the Project's TDT logs taken in Tract 7. These results also correspond to the Project's experience in studies of the Self Unit. Thus, it appears the "middle" and "upper" Glenn still have a high potential for high oil saturation.

Permeability and porosity vs. depth indicate that the entire Glenn Sandstone is of good reservoir quality. See **Figures 2 and 3**. The "lower" Glenn (approximately DGI F and G) has porosity ranging from 15 to 20% and permeability from 10 to 100 md. The "middle" (approximately DGI D and E, but may also include C and F in some wells) and "upper" Glenn (approximately DGI A, B and C, but may also include D and E in some wells) have porosity ranging from 17-23% and permeability from 30 to 500 md. The poorer reservoir quality of the "lower" Glenn in the polymer flood area, compared to elsewhere in southern Glenn Pool field, may be the result of a higher mudstone intraclast content. The good reservoir quality of the "upper" Glenn is encouraging compared to the poor reservoir quality indicators measured in the Self No. 82 core.

#### **3.2 Tract 9 Study**

The emphasis on studying Tract 9, in this reporting year, was to construct shale maps between sandstones of each DGI, and to assist reservoir engineering efforts in estimating petrophysical properties for reservoir simulation.

Shale maps locate erosional windows between DGIs where sand-on-sand contacts are expected. The isolated areas of sand-on-sand contacts are potential vertical conduits for fluid flow. Thus, these areas need to be incorporated for or accounted for in any fluid flow simulation. **Figure 4** shows an example of such a map between DGI's B and C.

Little petrophysical property data are available from wells in Tract 9. Gamma ray intensity vs. porosity was investigated in order to estimate petrophysical properties. Although a number of factors affect gamma ray intensity,

an empirical relationship was sought in order to take advantage of the most commonly available data for Tract 9 (i.e. gamma ray logs). The Self No. 82 well data were used as this was the most complete data set available to the Project. The plot is shown in **Figure 5**. The relationship between gamma ray and core plug porosity is reasonable based on linear regression ( $R^2 = 0.66$ ); a weaker correlation is evident for low gamma ray values. The relationship between gamma ray intensity and log-based porosity was also investigated. The well log cross plot shows a weaker correlation compared to the core plug porosity correlation; the difference is readily explained by the difference in rock volume investigated by well logs compared to core plugs. See, for example, **Figure 6**. The empirical relationship between gamma ray intensity and porosity was deemed reasonable, and used to transform gamma ray logs to porosity profiles.

### **3.3 Structure Study Southeast Margin of Glenn Pool Field**

During earlier Project efforts, a well was drilled in the Self Unit, the Self No. 82. Preparation for drilling the Self 82 well included picking the expected depths to the top of the Inola limestone and Glenn Sandstone for establishing a coring point. Offset wells were about 600 ft apart from the Self 82 staked location. The coring point was picked at 1420 ft drill depth; the point was estimated independently by two geologists whose estimations were very similar. After coring and logging of the Self 82, it was realized that the estimated and actual depths were 30 ft off. This discrepancy was most puzzling given the close distance to offset wells. Consideration to the possibility of additional structural relief within the broad Glenn Pool field closure was discussed, but not given a high priority within the Project work schedule.

A study area was selected along the southeastern margin of Glenn Pool field (Sections 27, 28, 33 and 34 of T17N R12E) for the investigation of this question of localized structural relief. The working hypothesis was that such structures are large-scale slumps located along the incised valley margin. The study area is located closure to the margin than the Self Unit. Logs from 21 wells were available for this effort. Well spacing ranges from 2,600 ft to less than 300 ft apart. Structure cross sections were compiled through the well array.

The stratigraphic interval of interest spanned the Pink limestone to the Brown limestone. Top of the Pink is about 260 ft above the Glenn sandstone. Top of the Brown is about 120 ft below the top of the Glenn sandstone. The interval thickness between the top Brown and base of Glenn is highly irregular as a result of erosional relief along the base of the Glenn. Structure maps were produced for top Pink, top Inola, and top Brown.

The top Inola structure map provides evidence of localized structures similar to what would be expected for slumping. The relief within the study area measured from well log tops is 50 ft over about 1 mile. Locally, however, the relief is as high as 30 ft vertically in 400 ft laterally; relief comparable to that developed around the Self No. 82 well. From careful correlation, it is clear that stratigraphic section is faulted out of wells where the structural relief is

high. The faults appear to be listric normal in geometry, with associated antithetic faults and roll-over anticlines. The normal faults trend northeast-southwest (parallel to the local orientation of the incised valley margin) with open curvature to the northwest and down to the northwest separation. Laterally discontinuous antithetic faults mirror the normal faults. Structural separation is 30 ft across the listric faults with localized antithetic faults; is 15 ft across listric faults without antithetic faults; and is 10 ft across antithetic faults. Separation up through the Pink limestone is only locally developed.

The implication for reservoir compartments depends on the stratigraphic level within the Glenn sandstone. Faulting of the braided fluvial section probably has little effect in that fault gouge of this sand-rich interval is not likely to be a barrier to fluid flow. On the other hand, faulting of the meandering fluvial section could produce reservoir compartments in that fault gouge of this mud-rich interval will likely produce reservoir barriers/baffles. Thus, DGI A through E reservoir compartments could be developed locally in these listric faulted areas.

Future work will assess this potentially important architectural element in other areas of Glenn Pool field.

### **3.4 Well Log Characteristics**

Discussions at technology transfer workshops and at professional meetings raised the issue of objective identification or discrimination of channel-fill deposits of the braided fluvial vs. meandering fluvial systems. These sandstones volumetrically dominate the Glenn and have a first-order effect on reservoir quality. Thus, an effort is underway to attempt to discriminate these sandstones based on their well log characteristics. This has been done in a qualitative manner already, but here the emphasis is on investigating objective criteria for making such a distinction.

## **4. ENGINEERING DESCRIPTION (by Sanjay Paranjani and Mohan Kelkar)**

### **4.1 Introduction**

This section presents the work completed in the last year. In the last year's annual report<sup>1</sup> we presented a technique for grading different areas of the Berryhill Unit to discriminate between high and low potential. Using the potential index mapping technique, we decided to concentrate on two tracts of Berryhill Unit – Tract 7 and Tract 9. In addition to those two tracts, we also investigated Chevron's Berryhill Lease (Miceller –Polymer flood) which is directly north of Tract 9. The reason for investigating Chevron's lease was to evaluate the reasons for the success in increasing the oil production in the unit after the implementation of Miceller-Polymer flood.

This section is divided into three subsections. The first section discusses the evaluation of Chevron Berryhill Lease; the second section deals with Tract 9 and the third section deals with Tract 7. Based on the evaluation of these three areas, recommendations are advanced at the end of each sub-section.

## **4.2 Chevron's Berryhill Unit**

The area of analysis is the Chevron Wm. Berryhill unit which is north of Tract 9 (**Figure 7**). Chevron implemented a Micellar/Polymer flood pilot from 1979-1983, which was based on selective isolation of the upper zones. Chevron initiated field-wide implementation in 1983-1984 that resulted in a remarkable increase in oil production, which will be discussed later in more detail. The obvious success of the Chevron Micellar/Polymer flood prompted us to analyze the unit in more detail. Further, the performance and the completion strategies in this unit could be used as a focal point to compare and contrast it against Tract 9 which is a geologically similar unit with comparable oil saturation profiles.

### **4.2.1 Perforation Strategies**

Chevron used the prevalent Upper Glenn, Middle Glenn and Lower Glenn divisions of the Bartlesville sandstone to describe the reservoir. Chevron believed that the Upper and Middle Glenn layers were separated by a continuous shale barrier and implemented the pilot flood by isolating the perforations in the upper zones. This was later proved to be untrue. The strategy during the field-wide implementation was to complete the wells both in the Upper and Middle Glenn layers. **Figure 8.a** shows the contrast in completion strategies during the Pilot and Field implementation. The Lower Glenn was avoided since it is known to be water-bearing. This is in sharp contrast to the completion practices in Section 16 and Tract 9 wherein the completion density is increasing as we progress down to the lower intervals. **Figure 8.b** shows this in graphical form.

### **4.2.2 Effects Of The Micellar/Polymer Flood**

The Micellar/Polymer flood implementation resulted in 52 times increase in oil production and a WOR decrease of almost 10 times as shown in **Figure 9**. Chevron increased the number of completions dramatically in 1982-83 prior to Micellar/Polymer flood field implementation. We believe that at least part of the additional oil response could be attributed to better completion practices. Hence it was decided to conduct a flow simulation to study the effect of additional completions by waterflooding the reservoir as opposed to a Micellar/Polymer flooding effort. This enables us to quantify the additional recovery that could be expected out of a similar program in Tract 9.

### **4.2.3 Chevron Unit Flow Simulation**

The following data

- a. Core and log data
- b. Production data as a function of time
- c. Perforation/completion data

were collected for the area courtesy of Hyperion Energy Resources, the current operator for the lease. In general the porosity in the Chevron area is higher as compared to Section 16 although this is not true for permeability.

The core data at each well location was averaged for each DGI. The average values were then interpolated at interwell locations to create areal maps of porosity and permeability (**Figure 10**) for each DGI. The shale barriers between the DGI's have been assumed to be continuous since the vertical permeability is observed to be negligible as compared to the horizontal permeability.

The PVT properties input requires oil and gas properties as a function of pressure. The minimum bottom hole pressure is known to be around 20 psi and the initial pressure of the reservoir was around 900 psi. Therefore the working range of pressure is 20-900 psi. All the properties were generated using standard Black Oil model correlations for the above working range in discrete increments of pressure.

The parametrisation of the relative permeabilities was done using the power law model with reasonable end point permeabilities suggested by the Kuykendall<sup>2</sup>. The exponents of the oil and water curves were varied as a function of time.

A commercial simulator, ECLIPSE, was used for simulation purposes. The primary depletion stage simulation was carried out so as to approximate the field oil production response by standard hyperbolic decline with a reasonable guess value of initial oil production. The secondary recovery stages of the simulation were constrained to match the oil rates. The relative permeabilities were fine tuned as a function of time to get the observed water cuts. Every effort has been made to closely monitor the number of active wells and the average reservoir pressure at any time to get a reasonable forecast.

The areal expanse of the Chevron unit is 160 acres. It was decided to divide the area into 132 ftx132 ft gridblocks so that any layer is split in 400 gridblocks. The thickness of each gridblock is assigned to be the thickness of the layer itself, which is obtained by interpolating at interwell locations. The system has 11 layers, which is the sum of all DGI's B through G and the intermediate shale layers between any two DGIs.

The results are as shown in **Figure 11**. The simulated water flooding response shows a much lower kick in the field oil production (FOPR) as compared to the actual Micellar/Polymer flood response. Similarly the WOR plot shows decrease by a larger factor for the actual Micellar/Polymer flood response as compared to the simulated water flooding response. The table quantifies the responses observed.

<b>Response</b>	<b>Miceller/Polymer</b>	<b>Waterflood</b>
Field Oil Production (bls/d)	51 Times Increase	15 Times Increase
WOR (bbl/bbl)	10 Times Decrease	4 Times Decrease

#### **4.2.4 Summary of Simulation of Chevron's Unit**

Based on the simulation results from Berryhill Unit, it is clear that the favorable response observed during Miceller-Polymer flood is partly due to better completion strategies and partly due to the addition of chemicals. Conservatively, if only water flooding would have been used in the Berryhill Unit, the oil production would have increased by 15 times as compared to 51 times. The WOR would have decreased from 200 to 50 instead from 200 to 20. Although not as impressive, re-completion of upper zones would have added significant oil production. This type of completion strategy is relatively cheap as compared to injecting expensive chemicals. We will evaluate the usefulness of these strategies for Tracts 9 and 7 in the following two sub-sections.

#### **4.3 Tract 9 Evaluation**

Tract 9 is located south of the Chevron-William Berryhill unit and has an areal expanse of 160 acres (**Figure 7**). The unit is operated by Uplands Resources Incorporated and has very similar reservoir conditions to the Chevron-William Berryhill unit. The well schedule information was very difficult to reconstruct. It is known with a fair degree of certainty that number of wells that have been drilled so far from the time of discovery is close to 65. The unit currently has six active producers and ten active injectors providing pressure support. Tract 9 is one of the units that rank high with respect to the original oil in place (15 MMStb). From the report compiled by Welch<sup>3</sup> it was observed that Tract 9 had produced cumulatively 6.058 MMStb of oil through primary depletion and secondary recovery operations as shown in **Figure 12**. This amounts to a recovery of 40% of the original oil in place.

##### **4.3.1 Geostatistical Estimation of Petrophysical Properties<sup>4</sup>**

The A-G DGI model provided by the geologist was directly used as input for a thirteen layer system into the simulator with each DGI constituting one layer with shale interbedding between successive DGIs. The facies divisions used within each DGI are channel sand, splay sand and flood plain mudstone as provided by the geologist.

A well base map for each DGI is constructed with the facies code assigned at the well locations. The facies type is determined by the type of SP or Gamma ray log response observed at the well. The facies code is assigned based on the following convention

1. Channel sand
2. Splay sand
3. Flood plain mudstone, Shale

Indicator variograms are then generated for each facies, which are then input into the indicator simulation program-Sisimpdf<sup>5</sup> for constructing the areal facies map. The Sisimpdf program honors the input proportion of each facies. In this study a multi-layered model is used which compromises the variability of the petrophysical properties to a certain degree but the depositional hierarchy is strictly honored. Unlike the Chevron-William Berryhill unit study an attempt is made to simulate the shale layers between successive DGI layers to identify areas where the shale barrier is discontinuous permitting sand upon sand stacking.

The thickness of sand in each DGI at well locations is estimated from the data provided by the geologist. These estimates are then kriged at interwell locations using the ordinary kriging procedure to generate thickness maps for each DGI. It should be noted that the thickness of sand is explicitly forced to zero for interwell locations where the simulated facies is known to be shale.

The porosity at each well location was estimated based on the Gamma ray logs due to insufficient Density-Neutron or sonic logs. A gamma ray to core porosity regression relationship was established based on data from the Self 82 well located in the Self unit (**Figure 13**). This is the only physical core situated proximal to the study area. The gamma ray values were then averaged within each DGI and then kriged at interwell locations to produce gamma ray maps for all DGIs. The kriging is performed with the previously simulated facies maps as external drift.<sup>5</sup> The regression relationship is then used to translate this to a porosity map.

Gamma-ray values have a direct dependence on the shale content of the reservoir, which is inversely proportional to the porosity of section. Since gamma-ray logs show a pulsating response as opposed to the blocky response shown by SP logs, feet by feet measurements of gamma ray logs may be misleading. When they are averaged over the thickness of the DGI itself the value should be representative of the shale content and in turn porosity at a particular location.

Figure 13 shows a large scatter identified by the lines A-A and B-B around the trendline for which the equation is provided. Hence it was proposed to feed the straight-line equations of A-A and B-B and use a random number generator for determining the porosity value for a given gamma ray measurement. For example a gamma ray measurement of 30 API units could be representative of a porosity value between 15% and 26% marked on the plot as Lower and Upper bounds respectively. It should be noted that lower the gamma ray value, higher the uncertainty in the correlation.

Even though the correlations between  $\ln(k)$  and porosity are quite good it has not been used since the regression relationship may yield unreasonable values when extrapolated beyond the input porosity range used to construct the correlation. Once the porosity maps were generated for all DGIs the values in each DGI were transformed into a Standard normal Gaussian distribution. It is known that the porosity values are related to permeability without a large scatter. So the values in the Gaussian domain obtained from porosity are back transformed into permeability (real space) using the cumulative distribution function (cdf) from Chevron core data as input. This is done DGI by DGI with the input cdf for the corresponding DGI generated from the Chevron-William Berryhill unit.

**Figure 14** presents a composite diagram of the facies, thickness, porosity and permeability map. It can be observed that the thickness and the petrophysical property maps carry the geological facies imprint.

#### **4.3.2 Flow Simulation Procedure**

Tract 9 simulation study uses total liquid production as the flow constraint instead of oil production. The rationale used is that if the total liquid production were matched, discrepancies in simulated water cuts compared to the actual field values would result in unacceptable errors of simulated oil production. This should be understood in light of the fact that typical water cuts in producing wells are 99 %. If a small difference in simulated vs. observed water cut is observed, it results in significant difference in water production. It will happen if we use oil rate as a constraint. On the other hand, if we maintain total liquid rate as a constraint, small differences in water cut do not significantly influence the oil production rate, and the water rate is close to the observed value.

Another difference from conventional history matching procedure was the entire history of Tract 9 was not matched. Significant uncertainty exists as to the well locations during the early life of Tract 9. Further data on individual wells – production, completion, abandonment – are not available. Even the total production on tractwide basis is missing for many years. This makes it very difficult to simulate the historical performance. Instead of trying to match an “estimated” historical performance, it was decided to concentrate on the last five years of production history for which better quality data were available. We initialized the model in 1992, and estimated the prevalent conditions at that time using available data as described below.

The areal expanse of the Tract 9 is 160 acres. It was decided to divide the area into 66 ft. x 66 ft. gridblocks so that any DGI is divided in 1600 gridblocks. The thickness of each gridblock is assigned to be the thickness of the DGI itself, which was obtained by interpolating the values at interwell locations. The system has 13 layers, which is the sum of all DGI's A through G and the intermediate shale layers between successive DGI's.

The PVT properties input requires oil and gas properties as a function of pressure. The minimum bottom hole pressure is known to be around 20 psi and the initial pressure of the reservoir was around 900 psi. Therefore the

working range of pressure is 20-900 psi. All the properties were generated using standard Black Oil model correlations for the above working range in discrete increments of pressure.

The well test data provided an estimate of the average reservoir pressure around the well. Four well tests were conducted within Tract 9. These average pressures were gridded using the kernel smoothing technique to generate an areal base map of pressure for the year 1992. Since all the DGIs are in vertical communication with the exception of DGIs A and B vertical equilibrium was assumed to calculate the areal pressure profile for each DGI. It should be noted that the base pressure map is tied to DGI E since this layer represents a median depth in the vertical structure of Glenn sand. All other DGI pressure profiles are determined based on the hydrostatic pressure difference. **Figure 15** shows the base pressure map that is tied to DGI E. It can be seen that the southwestern corner pressures are lower as compared to other areas. It is theorized that the pressure dip around p38 is created since the pressure support from injectors K4 and J3 is mostly absorbed by producers p54, p33 and p61 which are situated closer to the injectors.

The saturation profile is derived from resistivity logs. It is then scaled using a multiplier to make it representative of the year 1992. The methodology used to determine the multiplier is as follows. The effective permeability (product of relative permeability and absolute permeability) was estimated from the model at all wells where well testing was carried out. The effective permeability, which is a function of saturation, is then compared with the observed effective permeability derived from the well test. Since the effective permeability has a direct dependence on saturation, the saturation is scaled so as to bring the model derived effective permeability closer to the well test derived effective permeability at all the wells.

#### **4.3.3 Flow Simulation Results**

The well map is presented in **Figure 16**. It shows only the active wells for clarity and does not include all the wells that have been drilled in this unit. Initially it was proposed to restrict the recompletion/redrilling program to the area marked by dotted lines in the well base map. In accordance the following scenarios were proposed.

##### **Scenario Base**

It was proposed to plug the lower DGI's (E, F, G) and then complete upper DGI's (A, B, C, D) for all existing wells within dotted area namely p33, p54, p60 and K4. Two new injectors and three new producers 70, 71 and 72 are proposed. It is intended that the injectors Z1, Z2 and K4 would form a water bank and sweep the oil east and west of the line of injectors toward the producers as shown by the green arrows in **Figure 16**.

### **Anisotropy Favorable/Unfavorable**

It was proposed to investigate the effect of anisotropy  $K_{N,S} = 3 \times K_{E,W}$  for the base case. This would be favorable for the proposed intent since the water bank formation is promoted owing to the North-South permeability being higher. It was also decided to consider the adverse case where  $K_{N,S} = (1/3) \times K_{E,W}$  to get an idea of the possible downside if the truth is an exact converse to the favorable case.

The history matching for all the cases is done from the year 1992-1997. The forecasting is done from May 1997. It should be noted that the history matching was done with total liquid production as the flow constraint. Hence the oil production curve during the history matching stage would be case dependent because of variations in the oil cuts.

### **Scenario Plug/Recomplete All Wells**

Scenario base did not yield a good response. Hence it was decided not to restrict the scope of operations to the dotted area mentioned in the base scenario. It was proposed to plug all injectors and producers in the lower DGI's (E, F, G) and complete them in the upper DGI's (A, B, C, and D) without redrilling new wells.

The proposal does not look attractive on first glance (**Figure 17**) since the incremental oil production on implementation of recompletion/redrilling program is not significantly higher as compared to the case in which existing conditions are allowed to prevail. This is indicated by the closeness of the two curves in the oil production plot. The water cut plot shows a decrease of 98.7% to 97.3% that translates to a considerable reduction in water production. Hence despite the fact that incremental oil production is not encouraging the proposal is economically viable since the water production is cut drastically resulting in a remarkable reduction in operating costs.

### **Scenario Plug/Recomplete Old Well and Drill New Vertical Wells**

This scenario is a combination of the base case and the scenario detailed in the previous section. The proposal for new wells is not changed. Hence in this scenario the new wells are p70, p71 and p72 as producers and Z1, Z2 as injectors. The intention is to capture the advantages of plugging the lower intervals in terms of reduction in water cut and still gain incremental oil production by virtue of the new wells drilled.

The incremental oil production after implementation of the proposal over the existing condition case is at best about 35 bbls/d. The water cut goes down from a value of 98.7% before implementation to a low of 97.8% which is a reduction of 0.9% as compared to a cut of 1.4% brought about by the plug/recomplete program.

### **Scenario Plug/Recomplete Old Wells and Drill New Multilaterals**

It was proposed to drill multilateral wells (**Figure 18**) with lateral sections penetrating each of the upper DGIs A, B, C, D. The well will penetrate the formation in the North-South direction. Well Z1 would be a multilateral injector and well 71 would be a multilateral producer. The intention is to gain advantage of the horizontal sections of the multilateral wells. It is hoped that multilateral injector would provide good sweep and that the multilateral producer would yield more incremental oil production as compared to vertical wells.

The incremental oil production after implementation of the proposal over the existing condition case is at best about 70 bbls/d which is considerably larger than the vertical well scenario (35 bbls/d). The maximum reduction in water cut is about 1%.

The reservoir being very shallow (1,500 feet) it is not essentially advantageous to drill a multilateral well since the cost of drilling a vertical well is much lower than the cost for a multilateral well. A multilateral well would perhaps be more appropriate for deep reservoirs in which case it is more cost effective to penetrate a layered reservoir with laterals from a single vertical section as opposed to drilling multiple vertical wells.

### **Scenario Plug/Recomplete Old Wells and Drill Deviated Wells**

Since the multilaterals proved not to be cost ineffective it was proposed to investigate a scenario wherein the multilateral wells are substituted by deviated wells. The idea is drill at an angle of 80 degrees to the vertical (almost horizontal) and penetrate all upper DGI's namely A, B, C, D with an approximate span of 80 feet in each layer. The principal direction of penetration will be North-South.

The incremental oil production after implementation of the proposal over the existing condition case is at best about 70 bbls/d, which is lower as compared to the scenario in which multilaterals were proposed. The maximum reduction in water cut is once again about 1%. Since the cost of drilling a deviated well is a cheaper proposition as compared to the cost for a multilateral well, it is economically more attractive.

### **Ancillary Scenarios**

In addition to the above scenarios, we also considered scenarios which were based on our understanding of potential index mapping of Tract 9. Based on the mapping of potential index, we had noted that all the areas of Tract 9 were not equally explored. Based on the potential maps, we investigated three additional scenarios which involved either drilling vertical producing wells, or either drilling deviated injection or production wells. These scenarios are shown in **Figure 19**.

The response from these scenarios is shown in **Figure 20**. The results are compared with the base line where existing conditions are allowed to prevail. The best response is given by drilling a deviated producing well – P76, and is second only to the scenario when all the individual scenarios are implemented simultaneously.

#### **4.3.4 Economic Evaluation**

A simple economic evaluation was conducted to identify the most favorable scenarios.<sup>4</sup> The rate of return histogram is presented which is a compilation of all scenarios (with the exception of ancillary scenarios) together arranged in ascending order. It was decided to incorporate sensitivity analysis on the oil price with variations as shown in **Figure 21**. The ROR figures do not show a large variation for any given scenario. It can be noted that the plug lower DGIs/recomplete upper DGIs flow scenario stands out among all the proposals. However, it should be noted that the production increase in plug/re-completion scenario is not significant. Most of the cost savings are achieved by reducing the water cut, and hence cost of lifting.

The ancillary scenarios are investigated separately because of the method with which locations of the wells were selected. The results of the economic analysis are presented in **Figure 22**. The deviated producer results in an impressive ROR with a positive NPV at both 15 % and 25 % interest rate. In these scenarios, we have assumed that the existing wells were selectively plugged/re-completed for three months, and the new wells were drilled following the three month observation period.

#### **4.3.5 Summary from Tract 9 simulation**

The flow simulation of Tract 9 is presented. Several scenarios have been evaluated. Economic analysis shows that plug/recomplete scenario shows high ROR. Combination of plugging/re-completion followed by drilling a deviated producing well should result in a high rate of return.

### **4.4 Tract 7 Evaluation**

Tract 7 is located north and east of Tract 9 and is also operated by Uplands Resources, Inc. The well density is higher as compared to Tract 9, and the unit has a history of good response to water flooding. The present well locations are shown in **Figure 23**. It is estimated that Tract 7 has close to 15 MMStb of Original Oil in place(OOIP). From Welch<sup>3</sup> it was noted that Tract 7 has produced about 3.9 MMStb through primary depletion and secondary recovery operations. This means that the total recovery is about 26% of the OOIP, implying there is still a lot of untapped potential in the reservoir as compared to Tract 9 which has a cumulative recovery closer to 40%. The well density being high, it is perhaps not advisable to drill new wells, but a plugging/recompletion program to exploit the upper zones may yield significant additional oil recovery.

#### 4.4.1 Data Input and Flow Simulation Technique

The facies maps for all DGIs are generated using indicator using similar methodology as discussed in the previous sub-section. Several realizations are performed, and the realization which closely matches the map generated by the geologist, is chosen for petrophysical property estimation. In this work, this selection is done by visual observation. Automation of the selection of an optimal set of realizations is a topic of ongoing research.

As discussed in the previous sub-section, we used gamma ray values to estimate the porosity data. Although gamma ray logs are common in the field, one of the major drawbacks of estimating porosity from gamma ray logs in mature fields is as follows. The engineer has to contend with the fact that calibration of the gamma ray tool is not uniform since the logs are performed by different service companies.

Open hole logs always give a higher gamma ray reading as compared to cased hole logs. Since gamma ray logs measure the natural radioactivity of the formation, cased hole logs are affected by the presence of the casing between the recording tool and the formation. Conceptually, if two different wells are logged with the same tool, a pure shale interval in the two wells would have the same reading of gamma ray API units. This is not observed in practice since the shale found at two different vertical sections may have different sand content, varying organic material content, contrasting compaction levels, all of which affect the value of the gamma ray readings.

If the raw values of gamma ray readings from different wells are translated to porosity without accounting for the facts mentioned above, it would lead to under or over estimation of porosity. It should be noted that the gamma ray to porosity regression correlation is one single relationship and the same relationship is used for all the wells uniformly. By itself, the correlation does not take into account the variations in the gamma ray readings between the wells. To overcome this problem, we used a procedure of multiwell normalization.

The objective of the procedure is to bring the shale base line for different logs in alignment so that all deviations from this base line, which are indicative of sand, are referenced from a common base datum, thus making the use of gamma ray-porosity relationship more reliable. It is observed that most of the wells in this study area are cored in the lower interval. Gamma-ray logs are transformed into porosity values for wells which are cored in the lower intervals. Then the gamma-ray derived porosity is compared with the core porosity. Only those gamma-ray logs are selected which demonstrate a good comparison. Foot by foot gamma-ray readings for such logs are pooled together to construct a probability density function (pdf) and this pdf is termed as the standard distribution. Individual well gamma-ray logs are then used to construct pdf(s) for the respective wells. The well pdf is then plotted against the standard distribution to determine the amount of linear shift in Gamma-ray absolute value required to bring the shale base lines in alignment.

**Figure 24** graphically exhibits the procedure. It can be observed that pdf curves exhibit two peaks, one for a range of gamma ray values between 15-60 units and the other centered around 90 API units. The first peak represents the range of possible gamma ray values representative of sand and splay. The range of values exhibited by the second peak is representative of shale. The underlying principle in shifting individual well pdfs is that even though the probability of occurrence of a gamma ray value representative of shale may not be the same in two different wells, the range of gamma-ray values which represent shale should be centered approximately around the same gamma ray reading. For well E-9 it was determined that a linear correction of -25 API units is appropriate. It can be seen that originally the center line of the shale peak, which was 125 API units, after adjustment is about 100 units. This is done for all the wells other than those which were used to generate the standard distribution.

Once the normalization procedure is completed the gamma ray values are averaged within each DGI at all wells. These average values are then kriged at all interwell locations DGI by DGI to produce areal maps of gamma ray readings with the simulated facies maps as external drift.

The areal gamma ray maps are transformed into porosity maps by using the gamma ray-porosity relationships with the use of a random number to aid the reproduction of the scatter seen in the gamma-ray vs. porosity plots (**Figure 25**). The correlations were generated with the use of digitized gamma ray values and density-neutron log porosity values. It can be observed that the wells show a fairly consistent relationship. In this study a cutoff is used with respect to the gamma ray values beyond which transformation of gamma ray values to porosity is meaningless. The cutoff in this case was fixed as 140 API units. Beyond this range, the porosity is fixed as 1%.

Regression relationships between  $\log(K)$  and porosity are used to generate the permeability distribution from the porosity maps.

The thickness maps for all DGIs are generated by using the ordinary kriging procedure at interwell locations. The thickness of all gridblocks for which the facies type is known as shale/flood plain mudstone is forced to zero. Since thickness is a continuous variable as opposed to facies which is a discrete variable kriging on thickness even with zero thickness points need not necessarily capture the facies boundary between sand and shale. It is therefore necessary to use explicit procedures to make the simulated facies and kriged thickness maps consistent with each other.

#### **4.4.2 Flow Simulation Process**

The conventional history matching procedure involves reconstructing the well history from inception time to present time. A deterministic initial pressure and saturation profile is mapped, and then field flow performance is matched by tuning the input parameters. In this case study the saturation and pressure profiles are derived for the year 1993 and

history matching is initiated at this time. This eliminates the need for reconstructing the well schedule history from inception time of the field. The history matching is performed for a short segment of time 1993-1997, during the course of which the input model is calibrated. It should be noted that the production and injection data were provided by the operator for this unit and is far more reliable than public sources of data.

The areal expanse of the Tract 7 is 160 acres. It was decided to divide the area into 66 ft x 66 ft gridblocks so that any DGI is split in 1600 gridblocks. The thickness of each gridblock is assigned to be the thickness of the DGI itself which was obtained by kriging at interwell locations. The system has 13 layers, which is the sum of all DGIs A through G and the intermediate shale layers between successive DGIs.

The PVT properties used for this case study are essentially the same as those used for the Chevron-William Berryhill unit study. The saturation profile derived from the resistivity logs is scaled up so as to match the water cuts. It can be recalled that the Tract 9 case study uses well test data to match the effective permeability calculated from the model with the effective permeability derived from the well test. In this simulation study, this approach could not be realized since only a single well was tested within this study area. Hence the reserves in place and the saturation multiplier used for Tract 9 were used as a guidelines for estimating the possible range of scaling coefficients of saturation.

First, a multiplier of 1.4 which was used for Tract 9 was used for this study also. The ratio of oil phase effective permeability to water phase effective permeability is similar in both the study areas justifying use of the same multiplier.

Second, a multiplier of 1.2 is chosen based on the fact that it is the lowest possible multiplier that would still yield a good history match with regard to the accuracy necessary in simulated water cuts.

It is known that reserves in place at the time when history matching is started (1993) is around 11.1 MMStb. Based on the use two multiplier coefficients 1.2 and 1.4 on the water phase saturation  $S_w$ , the reserves in place were calculated as 10.653 and 9.43 MMStb respectively. These numbers are consistent with the estimated reserves (11.1 MMStb) which were based on initial oil in place and cumulative oil production so far. The objective is to get an idea of the incremental oil production obtainable with a worst case ( $S_w \times 1.4$ ) and best case ( $S_w \times 1.2$ ) scenario.

The pressure profile is guessed for DGI E, based on which all the other DGI pressure maps are generated assuming that the pressure difference between DGIs is equal to the hydrostatic head. The guess profile is then input into the simulator and the performance of this profile is gauged by determining if it satisfies the field injection and production rates. If not, the pressure data are altered so as to be able to match the production and injection data. It should be noted that the BHP for producers (pumping wells) is about 20 psi and the BHP for the injectors is known to be 1250 psi. Hence there is only a certain range of input average reservoir pressure (year 1993) for which the production

data/injection data can be matched. This obviously assumes that there is no leverage with regard to alteration of the petrophysical property fields. If a typical fracture gradient of 0.75psi/ft is assumed, the formation fracture pressure is calculated as 1163 psi. It was found that the BHP of injectors is very close and sometimes above the fracture pressure. This is taken into account in the simulator by multiplying well transmissibility based on the instantaneous pressure difference between BHP and the calculated fracture pressure.

It should be noted that the single well test (well 7-111) that was performed in this study area demonstrated an average reservoir pressure of 1050 psi. It is also known that the row of injectors located in the southern part of the study area take in water at very high pressures only. Considering these facts there is enough reason to believe that the average reservoir pressure is high and close to about 1000 psi. Well 7-111 produces the highest volume of fluid and contributes one half of the total liquid production at any given time.

#### **4.4.3 Flow Simulation Results**

The completion density in this study area is largely skewed towards DGI G (**Figure 26**). Considering the well density in Tract 7, it was decided that a plugging/recompletion program is the most appropriate future implementation. All perforations in DGI G are plugged, and then DGIs B-F are recompleted. Recompletion of DGI A is avoided since the permeability for this layer is observed to be smaller as compared to all other DGIs. Independent simulations were conducted with two different  $S_w$  scaling factors mentioned before.

##### **Scenario $S_w*1.2$**

This is the optimistic scenario wherein it is deemed sufficient that the resistivity log derived saturation profile, when scaled up by a factor 1.2, is adequate to bring it in tune with the initial time of history matching(1993). It should be noted that the saturation profile captures the global profile of the reservoir but the relative highs and lows predicted in this profile need not necessarily be valid. Extending this logic, it could be said that when the unit is considered as one unified system, the flow simulation gives an approximate idea of how the system would behave in response to a stimulus, but there is no guarantee that wells at selected locations will honor the simulated performance in truth. The reduction in water cut for this scenario is about 2%, and the incremental production obtainable after implementation of the plug/recompletion program is about 375 bbl/d. The simulated response is shown in **Figure 27**.

##### **Scenario $S_w*1.4$**

This is the pessimistic scenario, wherein the effect of a very large multiplying coefficient for the  $S_w$  profile at 1993 is simulated, and is contrasted against the previous case. It can be observed that the incremental oil production is still quite high but the reduction in water cut is small after implementation of the plug/recompletion program. The governing factor for a proposal to be viable or not, is the possible reduction in water cut coupled with the incremental

oil production that could be obtained. In this case, oil production increases since more total fluid (oil+water) is being withdrawn. The high rates of total liquid withdrawal also result in increase of lifting or operating costs. It should be noted that, before implementation of the recompletion program, the wells were primarily producing from one DGI. But after implementation of the program fluid is withdrawn from DGIs B-F yielding more total liquid production.

It can be observed from **Figure 28** that the water cut shows a decrease of about 0.2% at best. It will be shown below in the economic analysis section that the incremental oil production does not generate enough revenue to offset the increase in lifting costs. If the saturation profile in reality is close to the saturation profile estimated in this scenario, then it can be concluded that a plug/recompletion program is not economically viable.

#### **4.4.4 Economic Analysis of Tract 7**

Only two scenarios were incorporated in the analysis of Tract 7. The forecasting was performed for observing the response of plug/recompletion program but the simulation itself was initiated with two different base maps of resistivity log derived water saturation maps. This was accomplished by using two scaling coefficients for saturation namely  $S_w \times 1.2$  and  $S_w \times 1.4$ . **Figure 29** presents the rate of return and the net present value charts for the two scenarios. The unit has 37 active wells for which the approximate plug/recompletion cost is \$500,000. It can be observed that if the water saturation profile is scaled up by a factor of 1.4, the plug/recompletion program is unfeasible as indicated by the zero rate of return and negative net present value. Conversely, if in reality the saturation profile corresponds to the resistivity log derived profile scaled up by a factor of 1.2, the implementation of the plug/recompletion program will be largely successful. These two extremes could be considered as the bounding cases for actual field implementation.

#### **Summary of Tract 7 Simulation**

Owing to the high well density and completion skewed towards the lower zones in Tract 7, the most appropriate program is plug/recompletion. Most likely, the procedure would result in successful recovery of additional oil. The bounding extremes, discussed above, have been defined by performing simulations with different saturation profiles for the time instant when history matching is started.

### **5. TECHNOLOGY TRANSFER ACTIVITIES**

The following papers were given at the professional meetings indicated:

“Reservoir Characterization and Improved Water-Flood Performance in Glenn Pool Field: DOE Class I Project,” 1997 AAPG Annual Meeting in Dallas, Texas.

“Application of Borehole Imaging for Reconstruction of Meandering Fluvial Architecture: Examples from the Bartlesville Sandstone, Oklahoma,” Fourth International Reservoir Characterization Conference in Houston, Texas; and SPWLA meeting in Tulsa, Oklahoma.

“Reservoir Management of Self Unit- Glenn Pool Field,” paper presented at Oil Recovery Conference organised by University of Kansas, Wichita, KS (March 20, 1997).

All presentations received great deal of interest from members of independent and major operators.

A technology transfer workshop was also presented in Ft Worth, Texas. The presentation was similar to those offered in 1996 except this presentation included a new set of posters outlining the geological characterization.

In August 1997, two students completed their thesis/dissertation as part of this project. Liangmiao Ye completed his doctoral dissertation titled: “Reservoir Characterization and Sequence Stratigraphy of the Pennsylvanian Bartlesville Sandstone, Oklahoma.” Sanjay Paranjani completed his masters thesis titled: “Integrated Reservoir Description and Flow Simulation Case Study: Glenn Pool Field.” These theses are available for viewing at The University of Tulsa McFarlin Library. It may also be obtained through interlibrary loan.

The following paper has been accepted for publication in the AAPG Bulletin: “Glenn Pool Field, Oklahoma: A Case of Improved Production from a Mature Reservoir.” This paper offers an overview of the progress made under Phase I.

## **6. FUTURE WORK**

The remaining future work includes implementation of the proposed reservoir management plan. Due to circumstance unrelated to the project, the implementation was delayed by several months. Currently, we are in the process of implementing the proposed plan for Tract 9. We will begin with plugging and recompletion of the existing production and injection wells. After observing the performance for three months, we will implement the drilling of deviated well if economically feasible. Based on the results of our study, we expect to present several workshops to interested operators.

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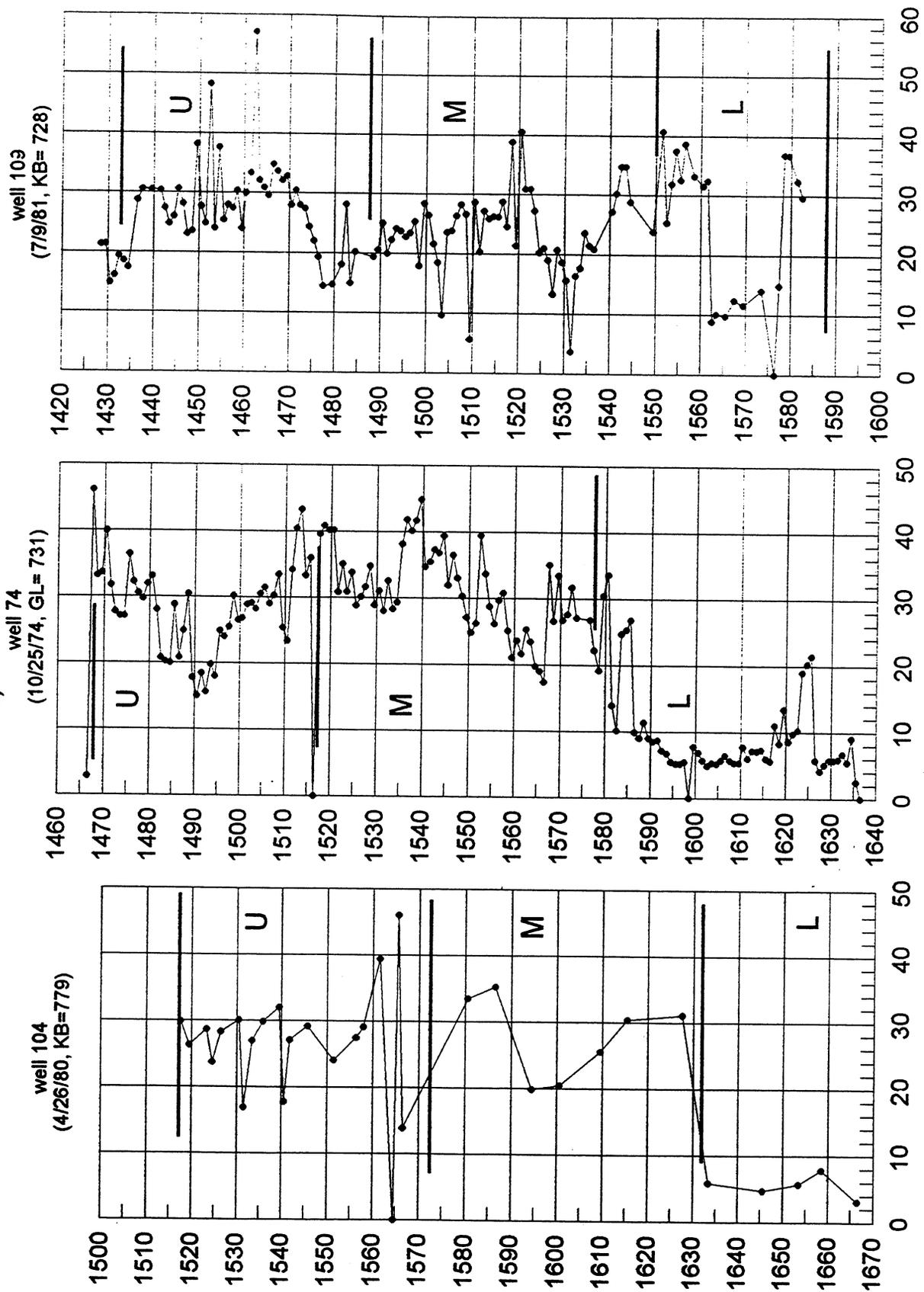


FIGURE 1: CORE OIL SATURATION (%) PROFILE (CHEVRON'S POLYMER FLOODING ACREAGE, NE/4, 17-12N-12E).

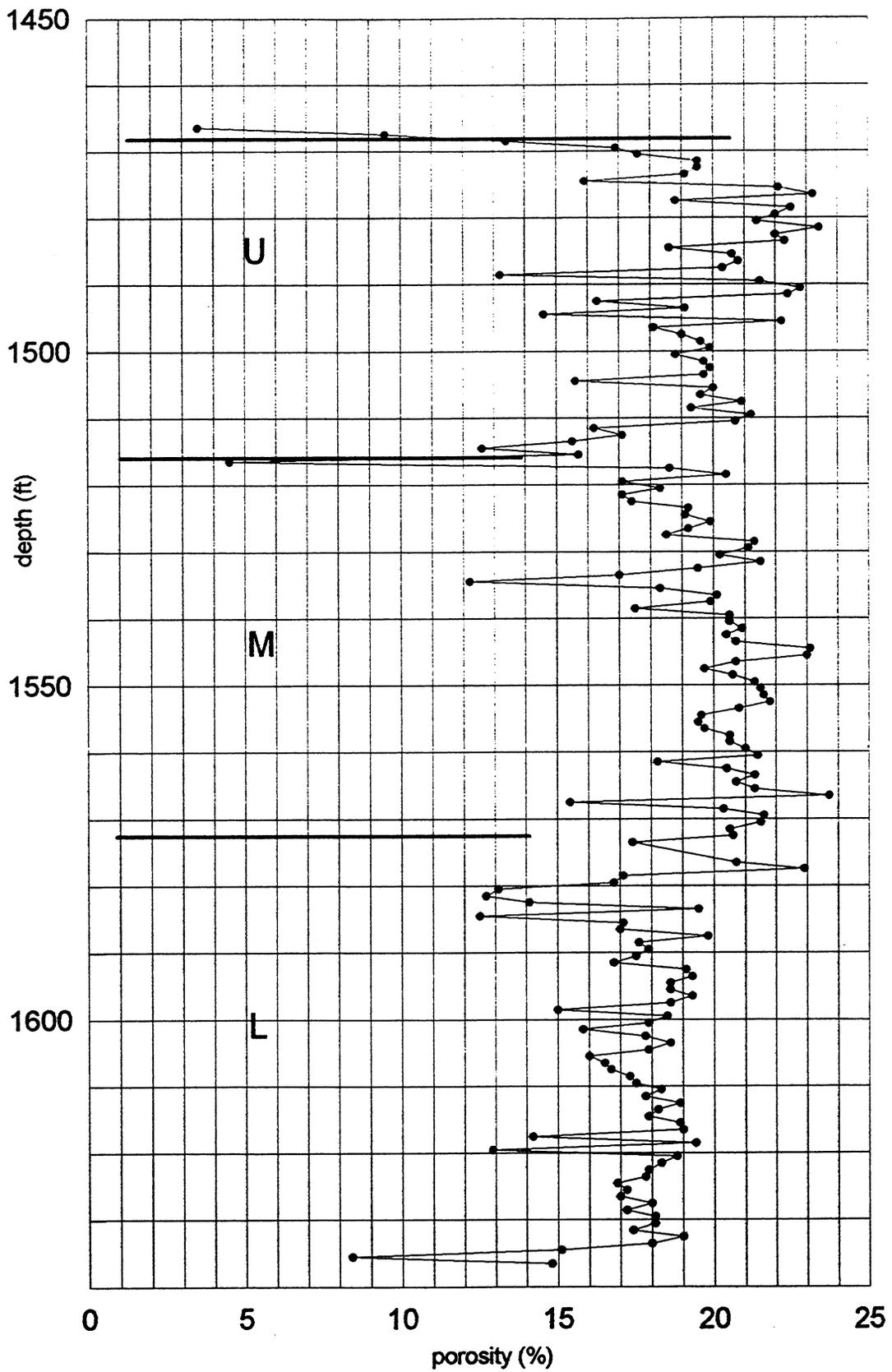


FIGURE 2: POROSITY PROFILE, WELL 74, CHEVRON POLYMER FLOODING AREA.

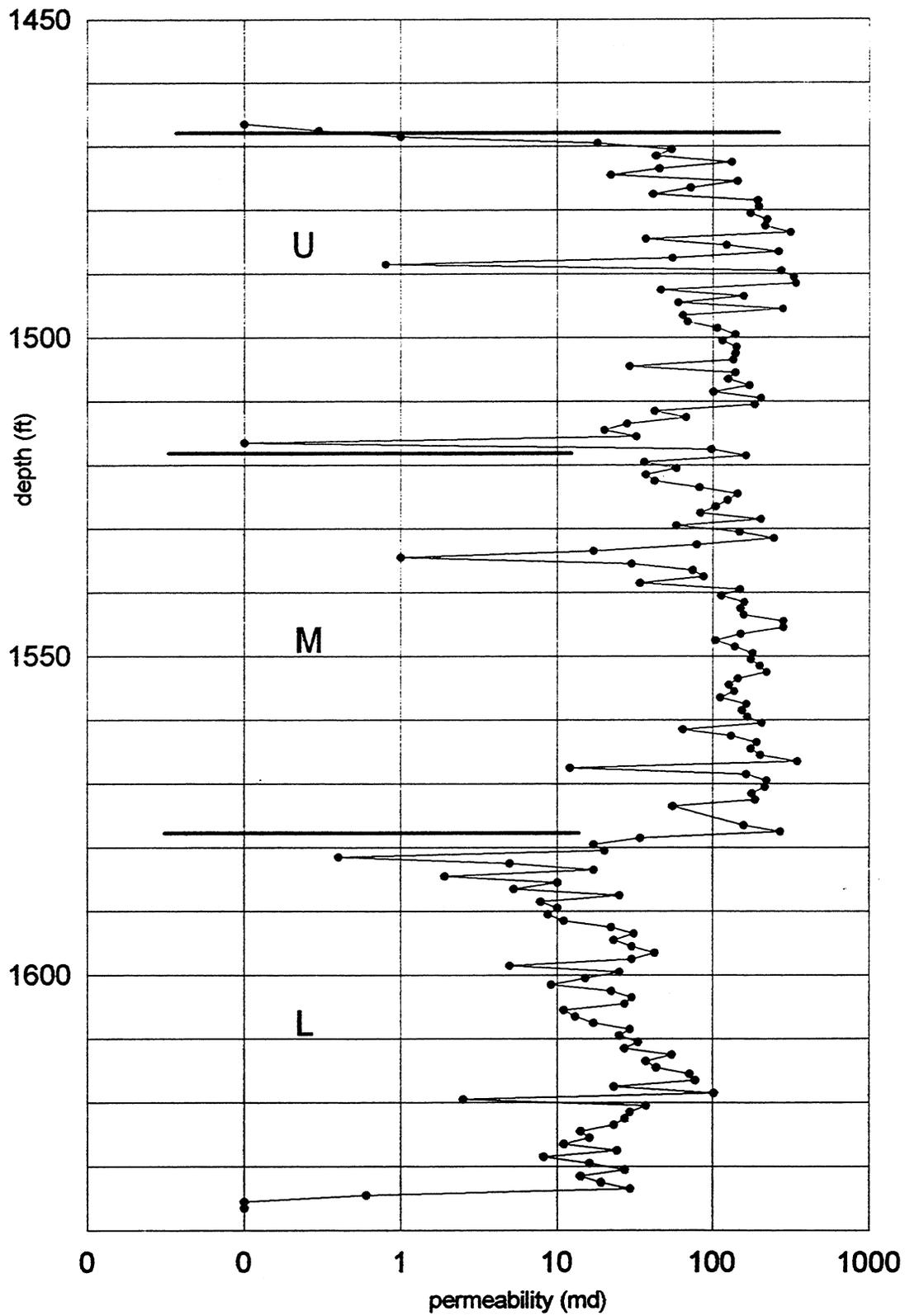


FIGURE 3: PERMEABILITY PROFILE, WELL 74, CHEVRON POLYMER FLOODING AREA.

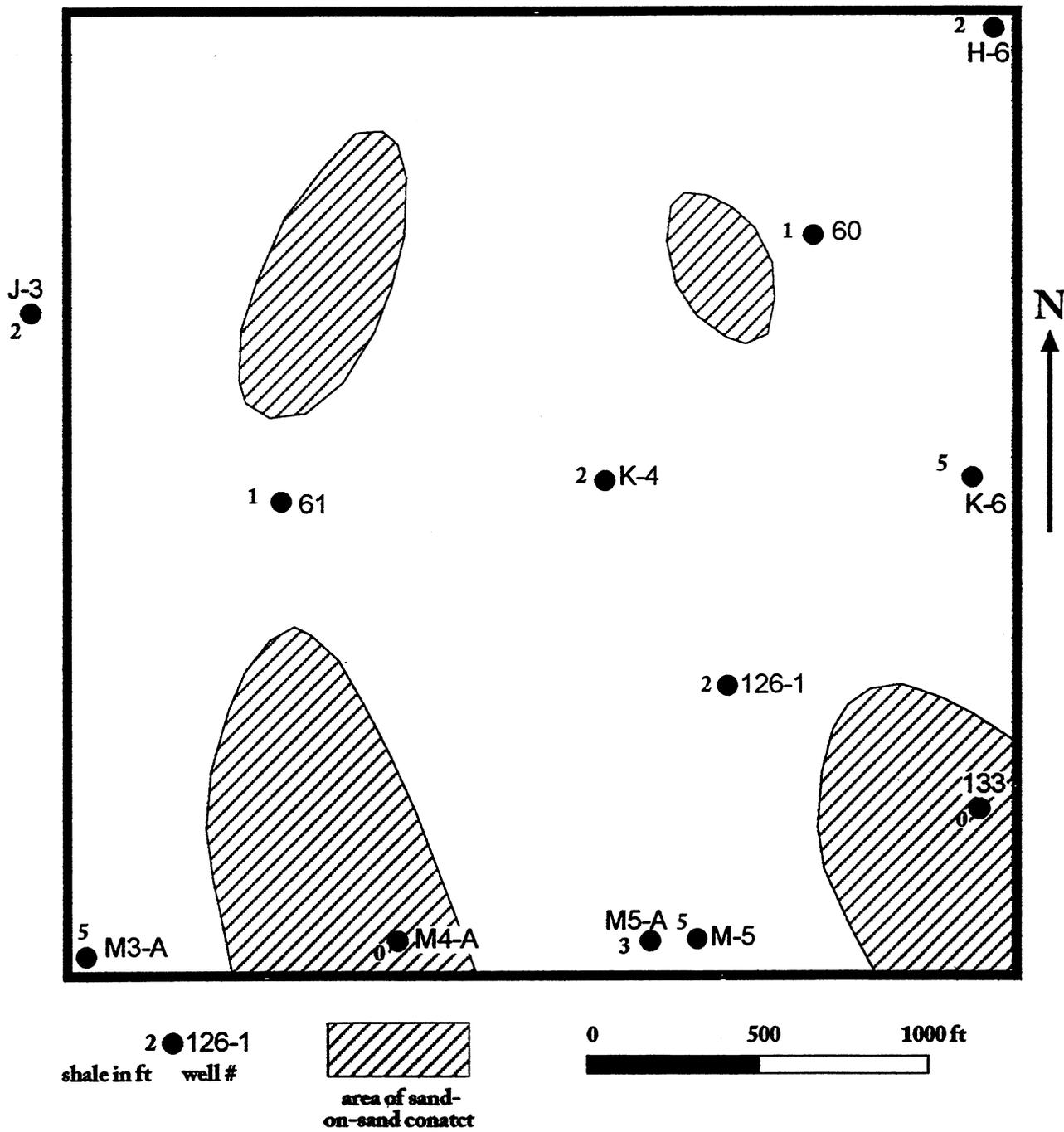


FIGURE 4: SHALE THICKNESS BETWEEN DGI B AND C SANDSTONES (TRACT 9, 17-17N-12E).

**GAMMA RAY v/s POROSITY CORRELATION CHART**  
**Well Self 82**

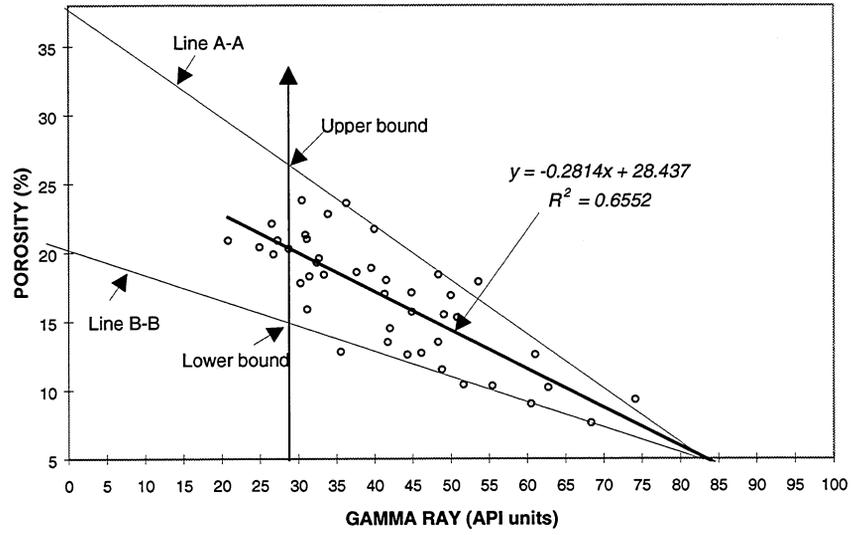
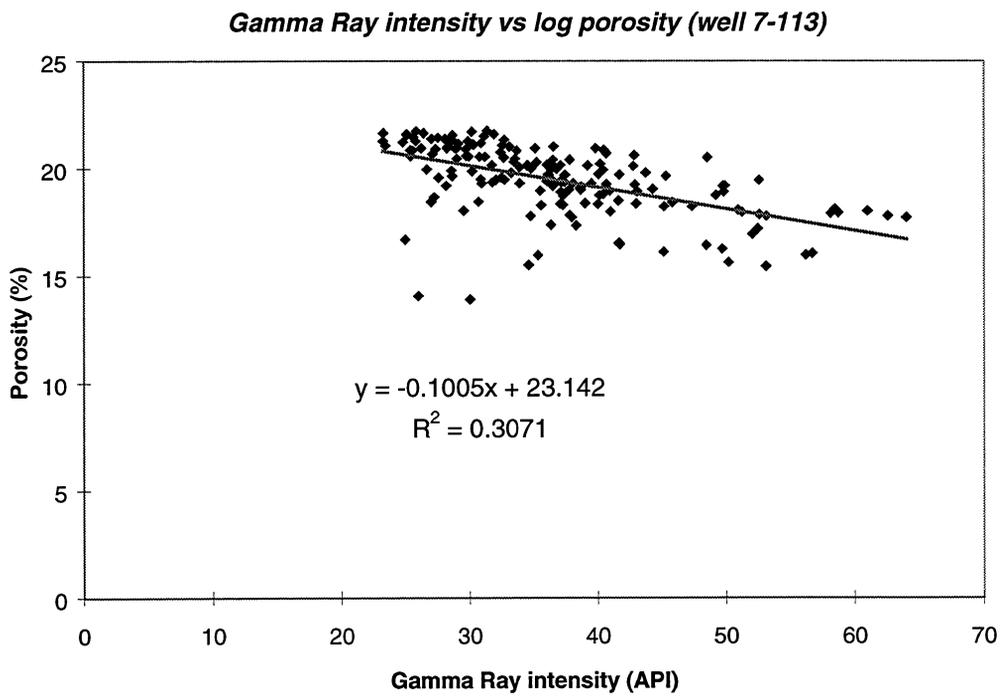


FIGURE 5: GAMMA RAY INTENSITY VERSE CORE POROSITY (WELL SELF 82).



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FIGURE 6: GAMMA RAY INTENSITY VERSE LOG POROSITY (WELL 7-113).

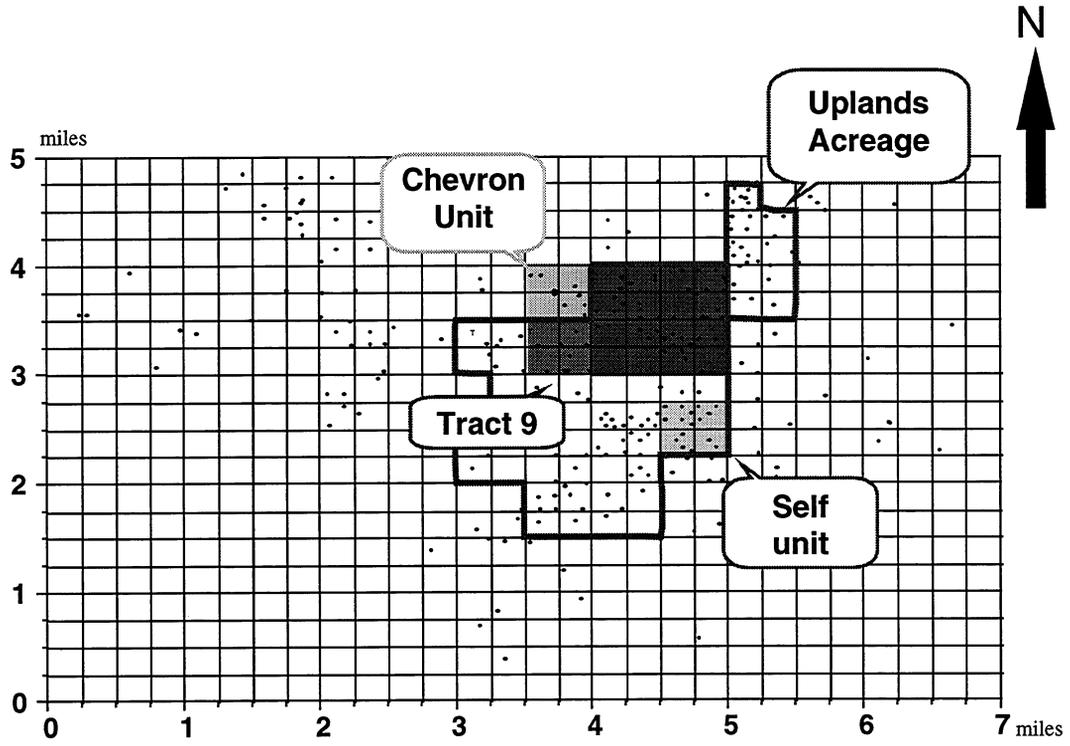


FIGURE 7: INDEX MAP SHOWING THE LOCATION OF CHEVRON UNIT.

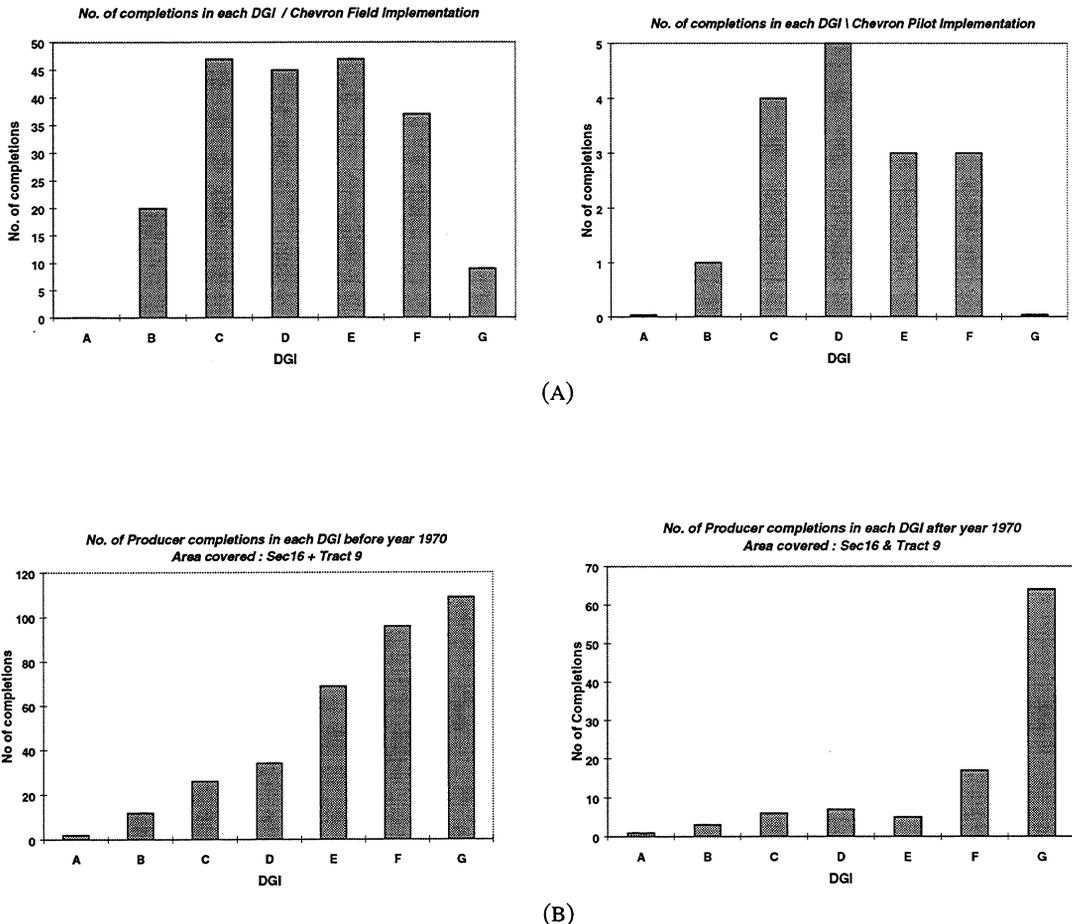


FIGURE 8: (A) COMPLETION PRACTICES IN THE CHEVRON UNIT. (B) COMPLETION PRACTICES IN SECTION 16 AND TRACT 9.

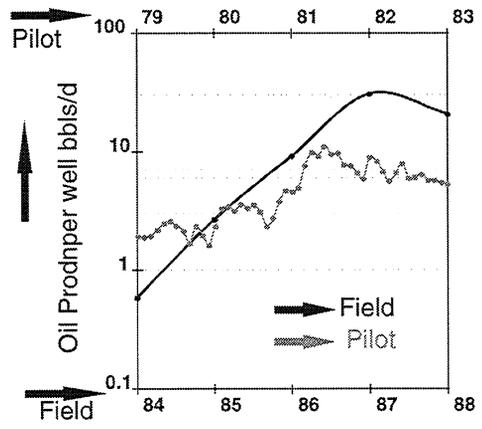
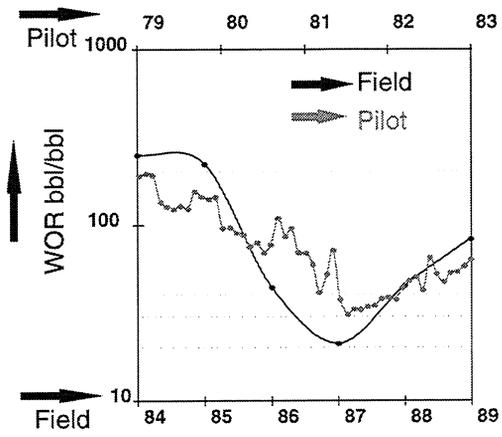
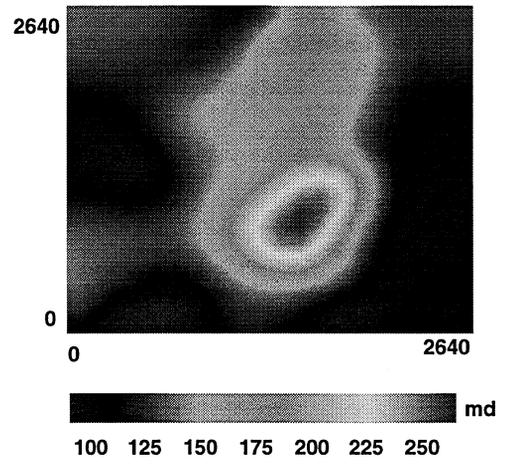
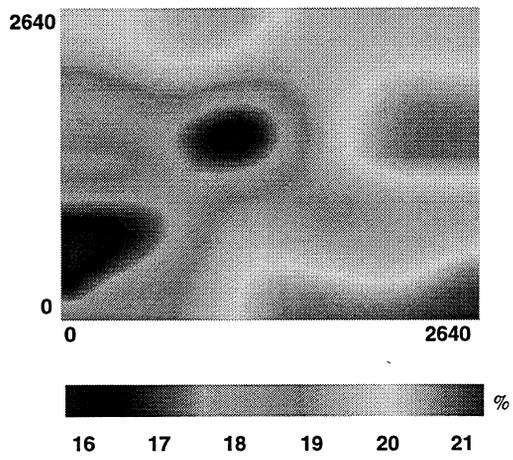


FIGURE 9: WOR AND OIL PRODUCTION RESPONSE OF THE CHEVRON UNIT.




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FIGURE 10: SAMPLE POROSITY AND PERMEABILITY AREAL PROFILES.

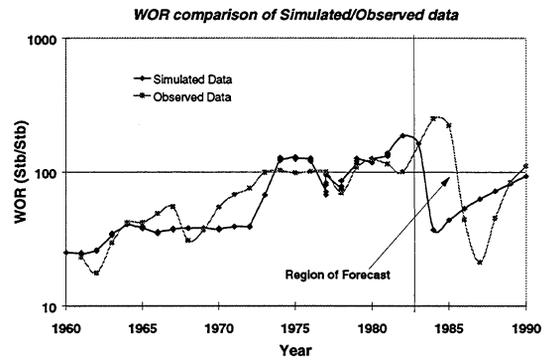
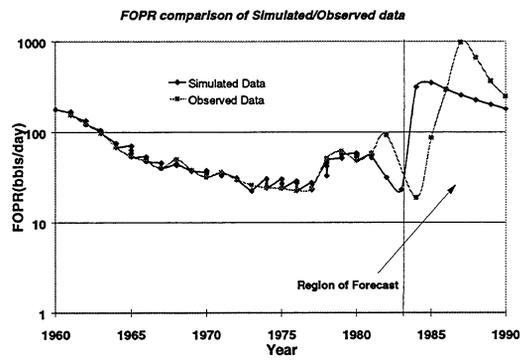


FIGURE 11: WOR AND FIELD OIL PRODUCTION CHARTS FOR THE CHEVRON UNIT.

**RAW PRODUCTION DATA OVERLAIN WITH EXTRAPOLATED DATA  
TRACT 9**

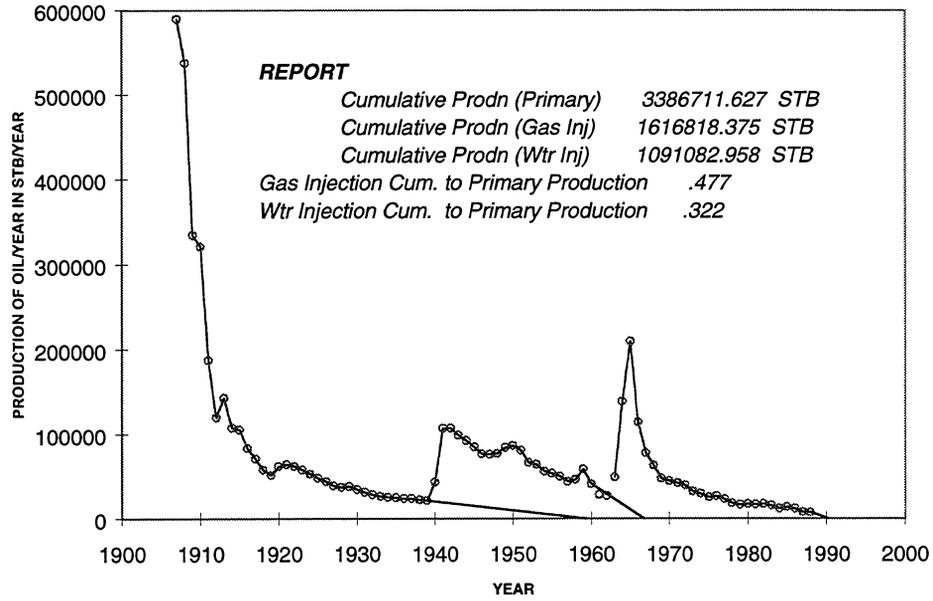


FIGURE 12: PRODUCTION ANALYSIS PLOT FOR TRACT 9 SHOWING THE PRIMARY GAS INJECTION AND WATER FLOODING STAGES OF DEPLETION.

**GAMMA RAY v/s POROSITY CORRELATION CHART**  
**Well Self 82**

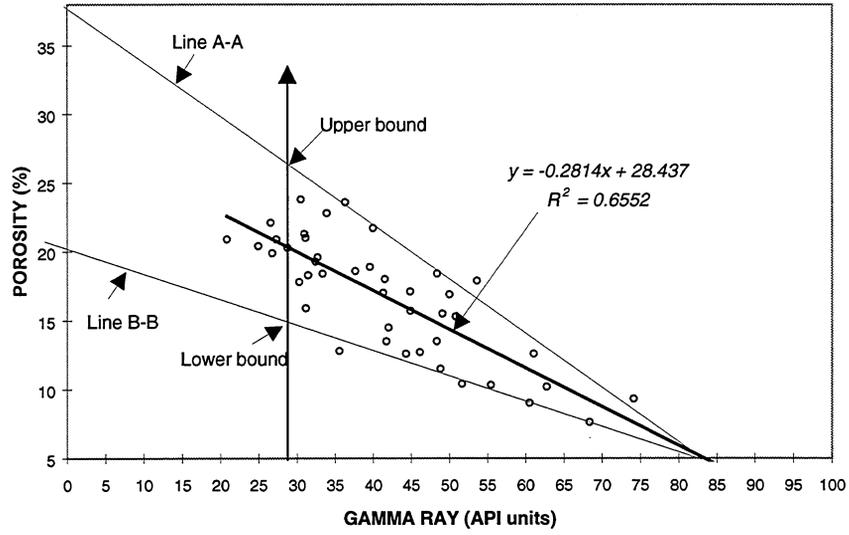


FIGURE 13: GAMMA RAY VERSE CORE POROSITY CORRELATION DEVELOPED FROM THE DATA COMPILED FROM SELF 82.

**DGI G**

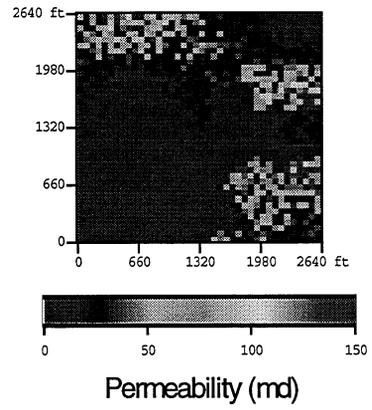
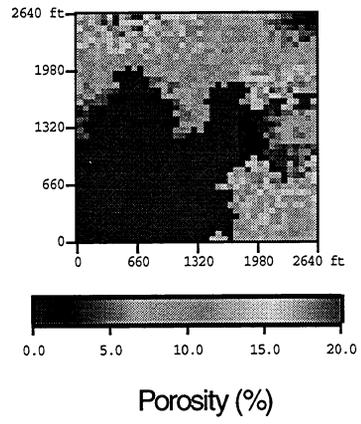
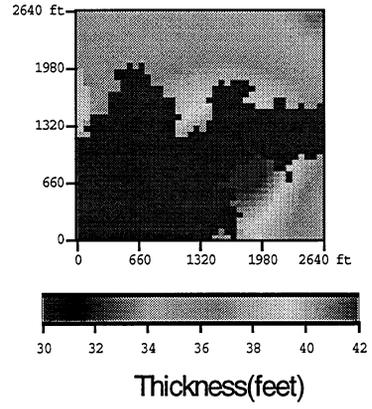
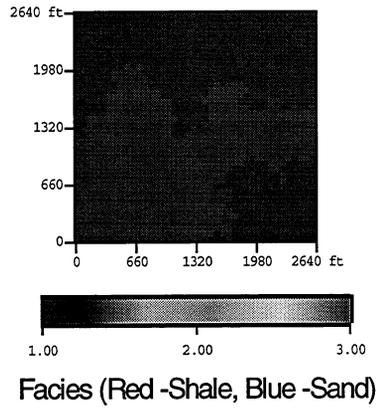
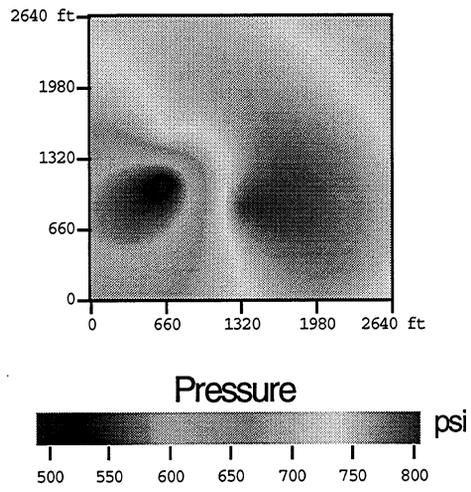


FIGURE 14: COMPOSITE DIAGRAM SHOWING AREAL MAPS OF POROSITY, PERMEABILITY AND THICKNESS HONORING THE FACIES DISTRIBUTION. ALL DIMENSIONS ARE IN FEET/TRACT 9 STUDY.

*Average reservoir pressure/Tract 9*



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FIGURE 15: AREAL RESERVOIR PRESSURE MAP THAT IS TIED TO DGI E IN PSI.

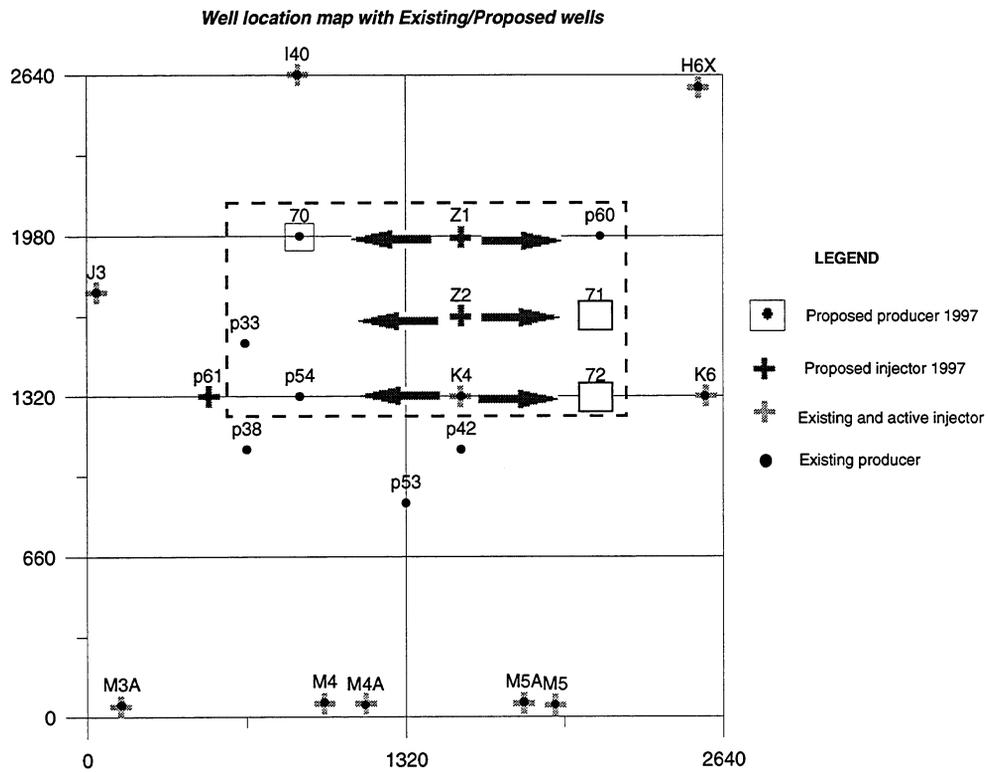
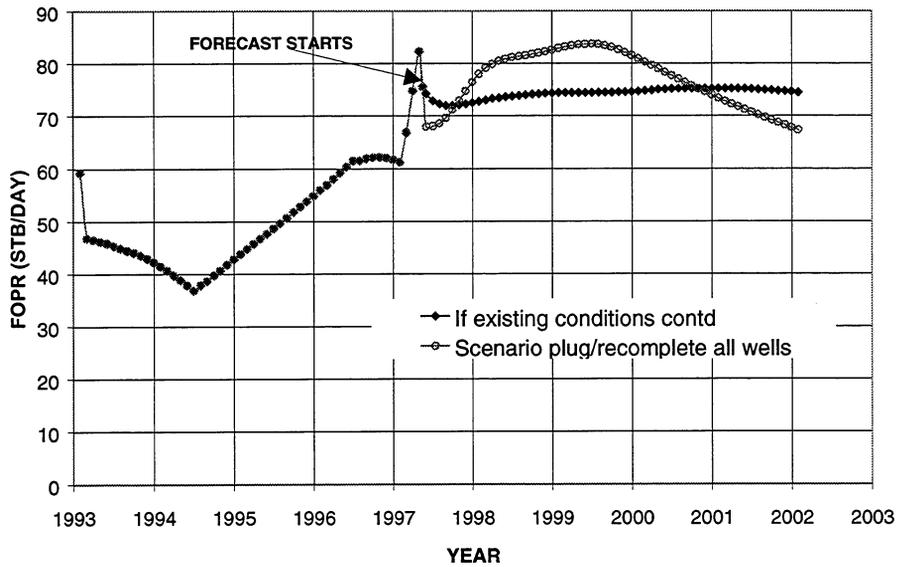


FIGURE 16: WELL BASE MAP OF EXISTING/PROPOSED WELLS FOR TRACT 9.

**FIELD OIL PRODUCTION (STB/DAY) plug/recomplete all existing wells**



**FIELD WATER CUT stb/stb plug/recomplete existing wells**

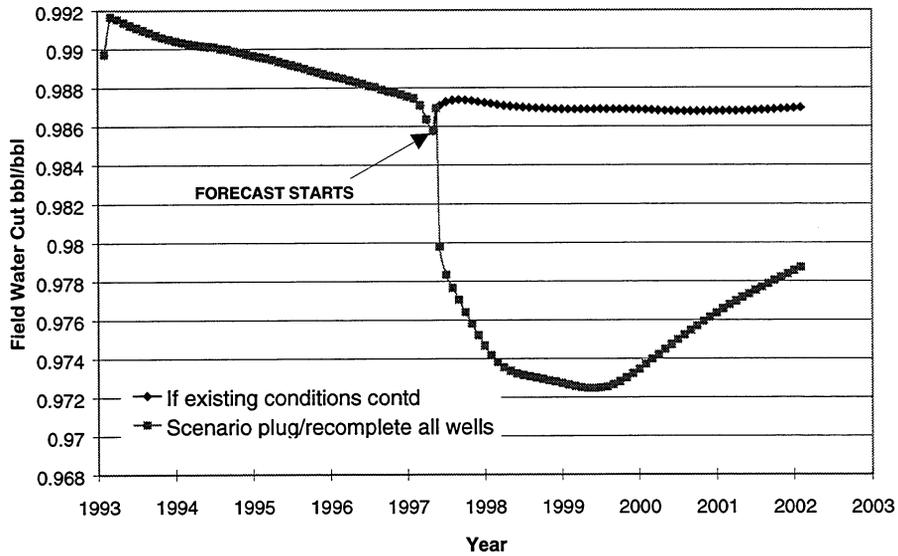


FIGURE 17: OIL PRODUCTION AND WATER CUT PLOT FOR SCENARIO PLUG/RECOMPLETE ALL WELLS

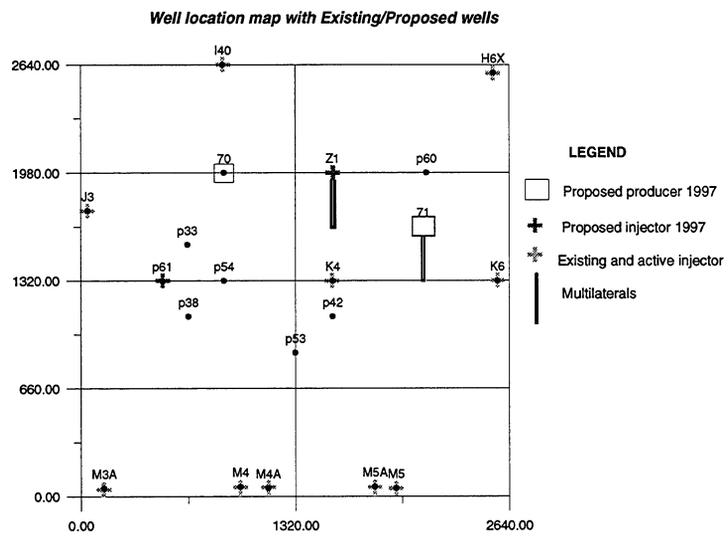


FIGURE 18: FIGURE SHOWING THE PROPOSED WELL BASE MAP WITH MULTILATERAL WELL LOCATIONS.

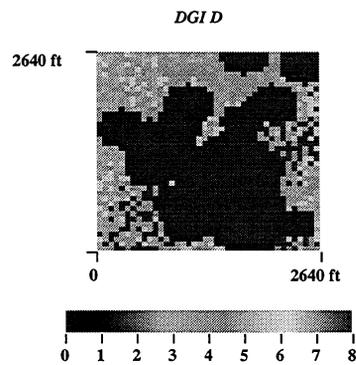
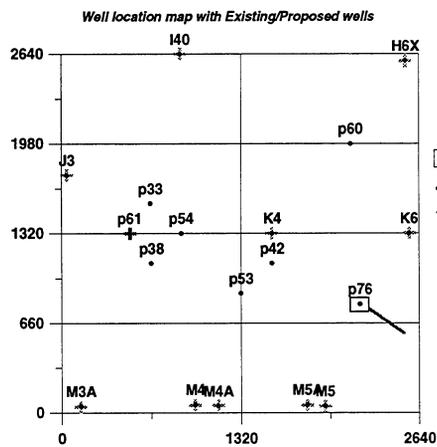
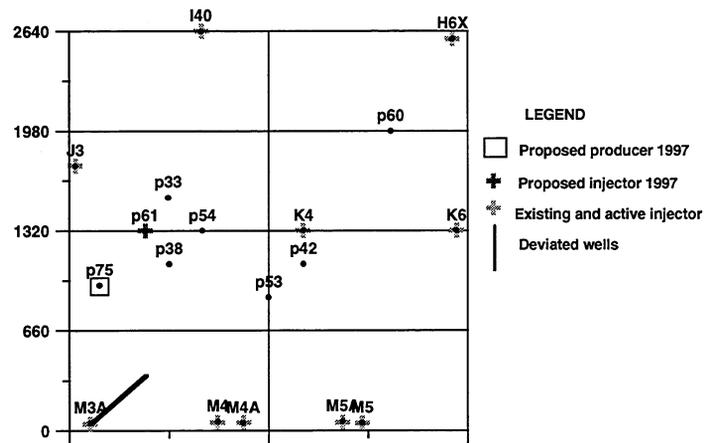
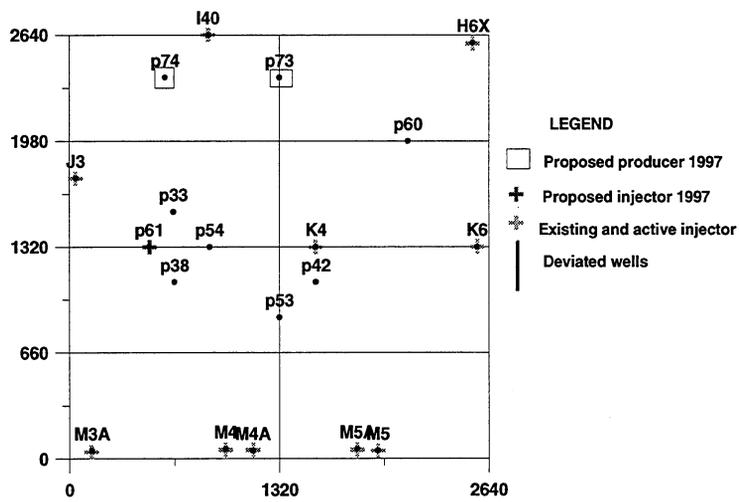
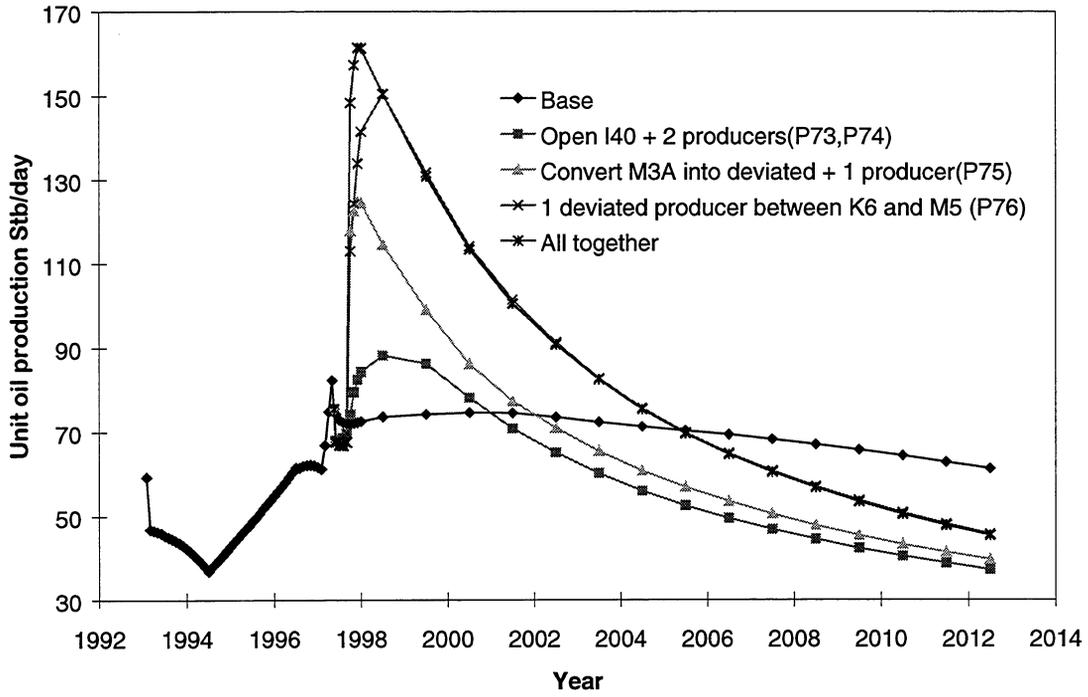


FIGURE 19: FIGURE SHOWING THE WELL LOCATIONS OF THE EXISTING/PROPOSED WELLS ALONG WITH A SAMPLE POTENTIAL INDEX MAP FOR VISUAL CLARITY. MOST OF THE PROPOSED LOCATIONS FALL RIGHT ON THE HIGH POTENTIAL INDEX REGION.

**Unit Oil production for or ancillary scanarios**



**Unit water cut for ancillary scanarios**

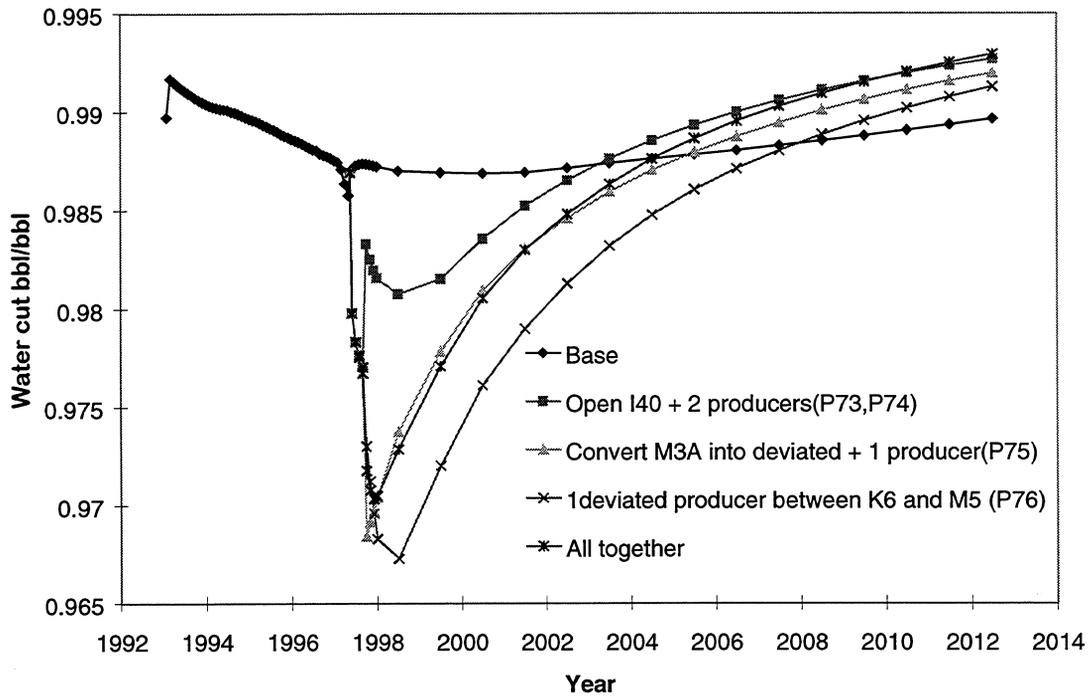


FIGURE 20: OIL PRODUCTION AND THE WATER CUT PLOT FOR ANCILLARY SCENARIOS.

**RATE OF RETURN HISTOGRAM WITH SENSITIVITY ON OIL PRICE**

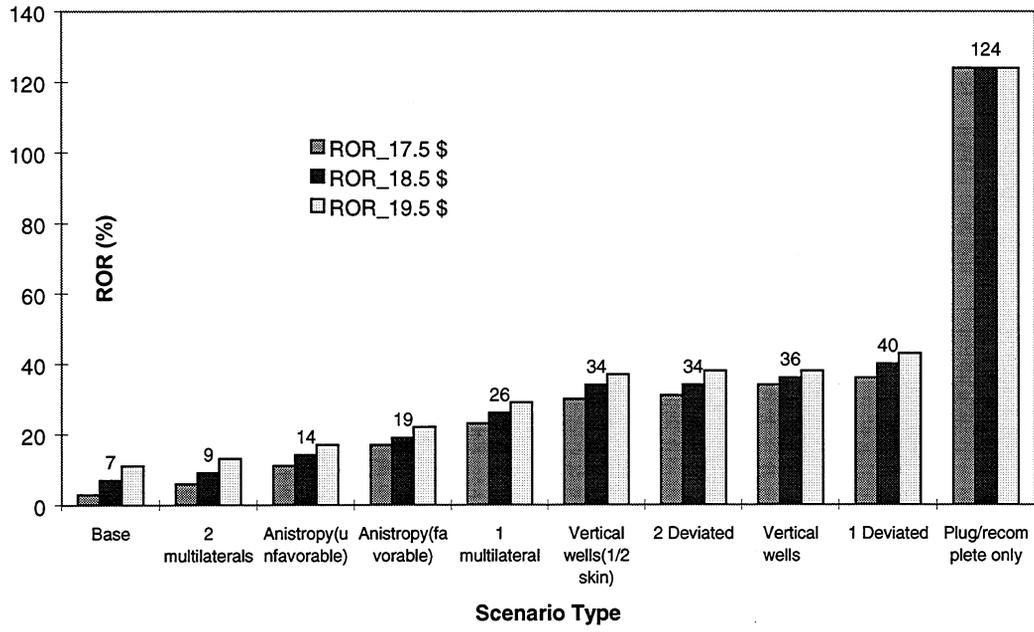
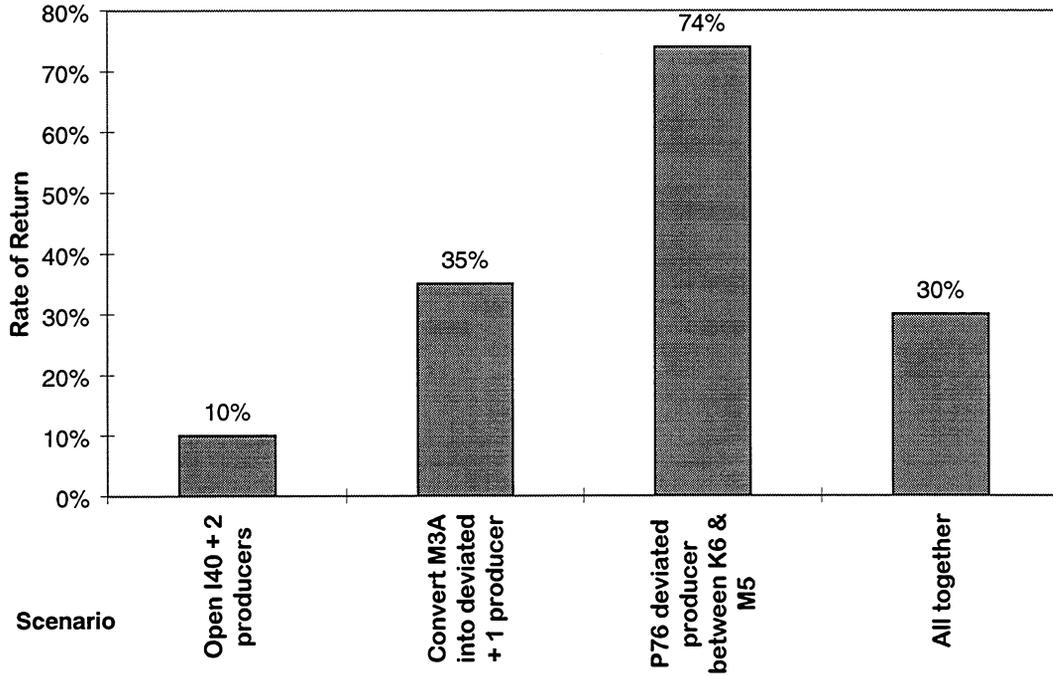


FIGURE 21: ROR HISTOGRAM WITH SENSITIVITY ON OIL PRICE.

**Rate of Return Histogram for Ancillary scenarios**



**Net present value for interest rates 15% and 25%/ Ancillary scenarios**

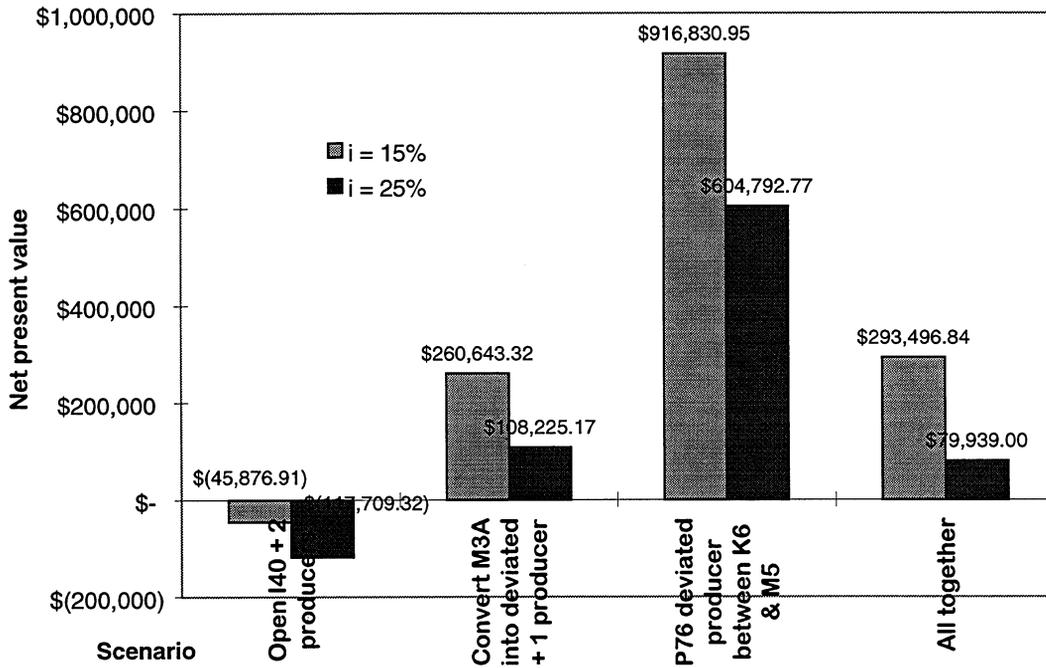


FIGURE 22: RATE OF RETURN AND NET PRESENT VALUE CHARTS FOR ANCILLARY SCENARIOS.

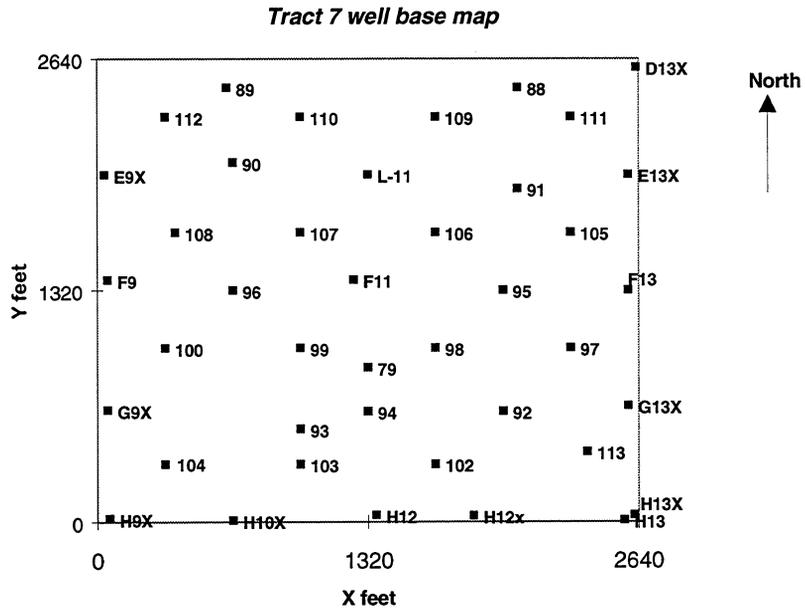


FIGURE 23: WELL BASE MAP FOR TRACT 7 WITH THE X, Y DIMENSIONS IN FEET.

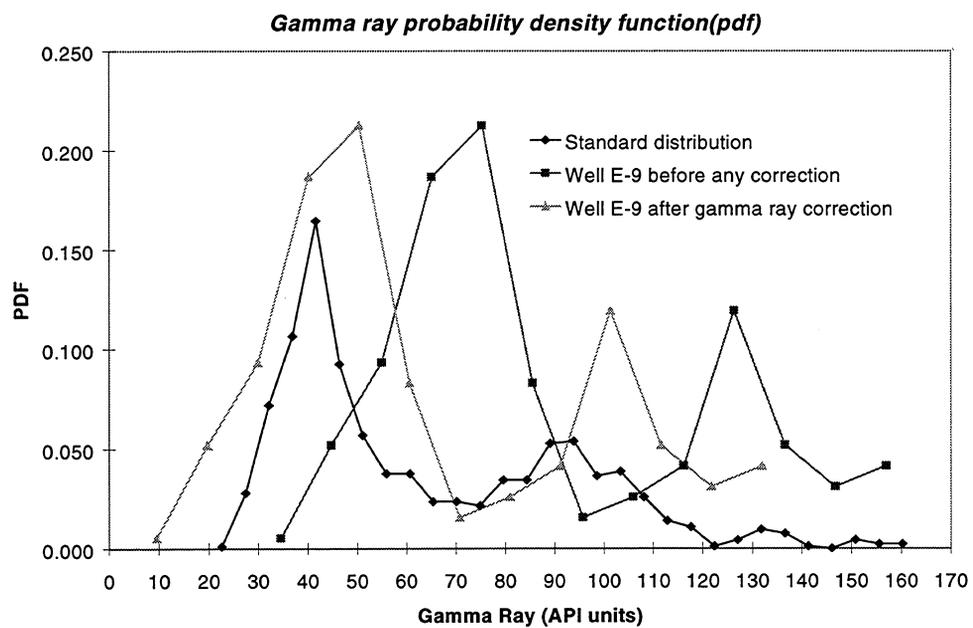


FIGURE 24: WELL E-9 PDF PLOTTED AGAINST THE STANDARD PDF. A LINEAR SHIFT OF -25 API UNITS IS NEEDED TO BRING THE WELL E-9 SHALE PEAK IN ALIGNMENT WITH THE SHALE PEAK OF THE STANDARD DISTRIBUTION.

**Gamma Ray intensity vs. log porosity (well Self 79)**

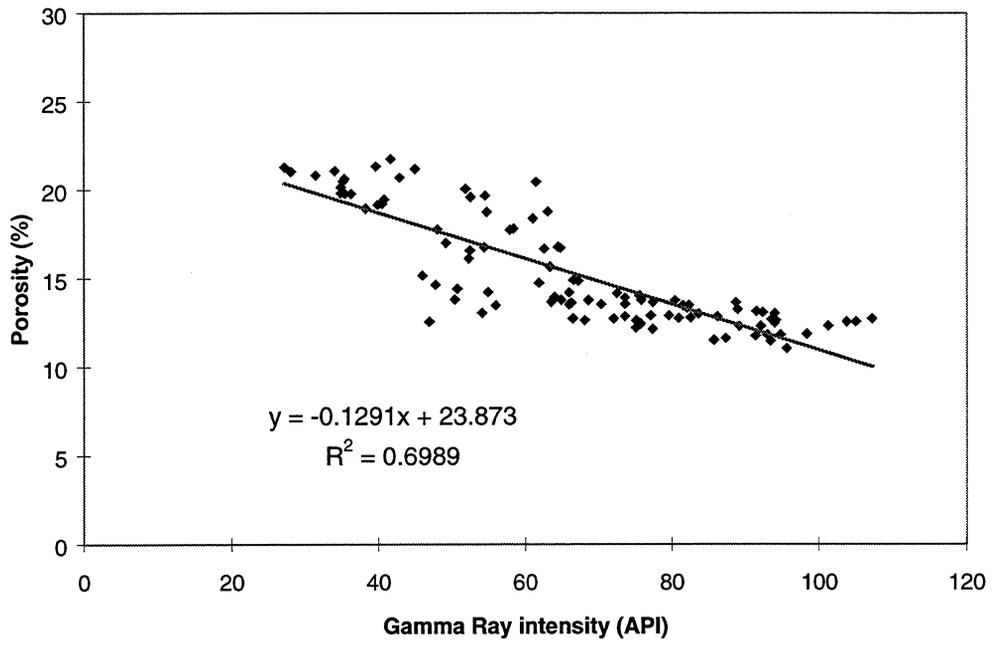


FIGURE 25: GAMMA-RAY VS. POROSITY REGRESSION RELATIONSHIPS FOR TWO WELLS LOGGED IN THE GLENN SAND RESERVOIR.

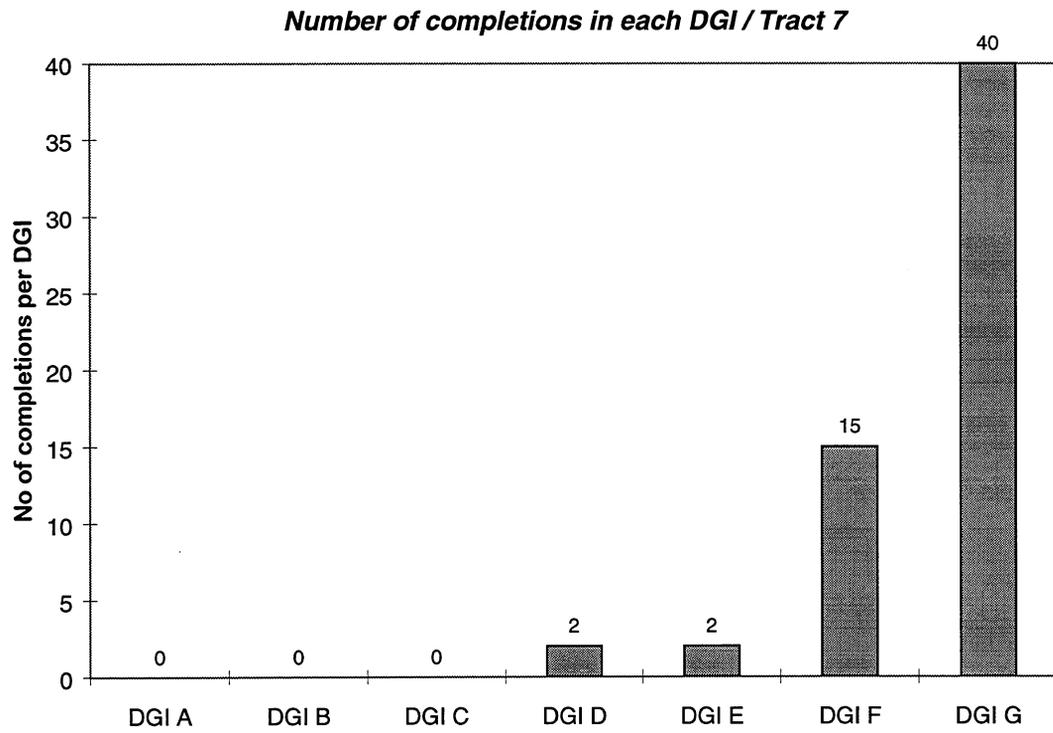
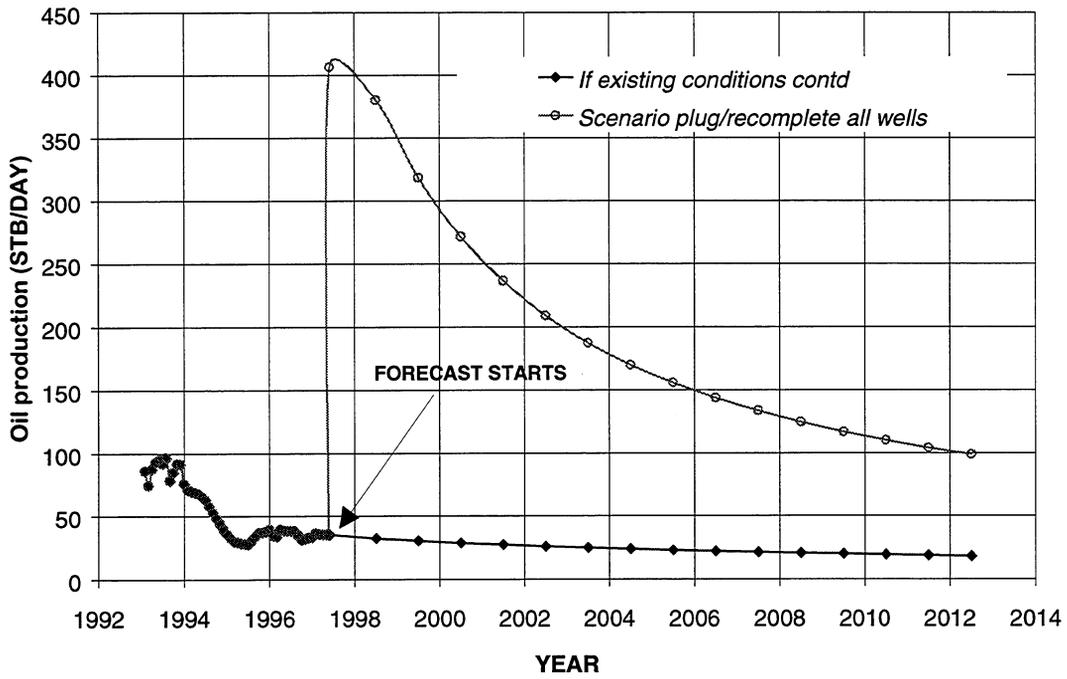


FIGURE 26: HISTOGRAM SHOWING THE CONCENTRATION OF PERFORATIONS IN DGI-G.

**UNIT OIL PRODUCTION -  $S_w \times 1.2$  / Tract 7 plug/recomplete all wells**



**UNIT WATER CUT -  $S_w \times 1.2$  / Tract 7 plug/recomplete all wells**

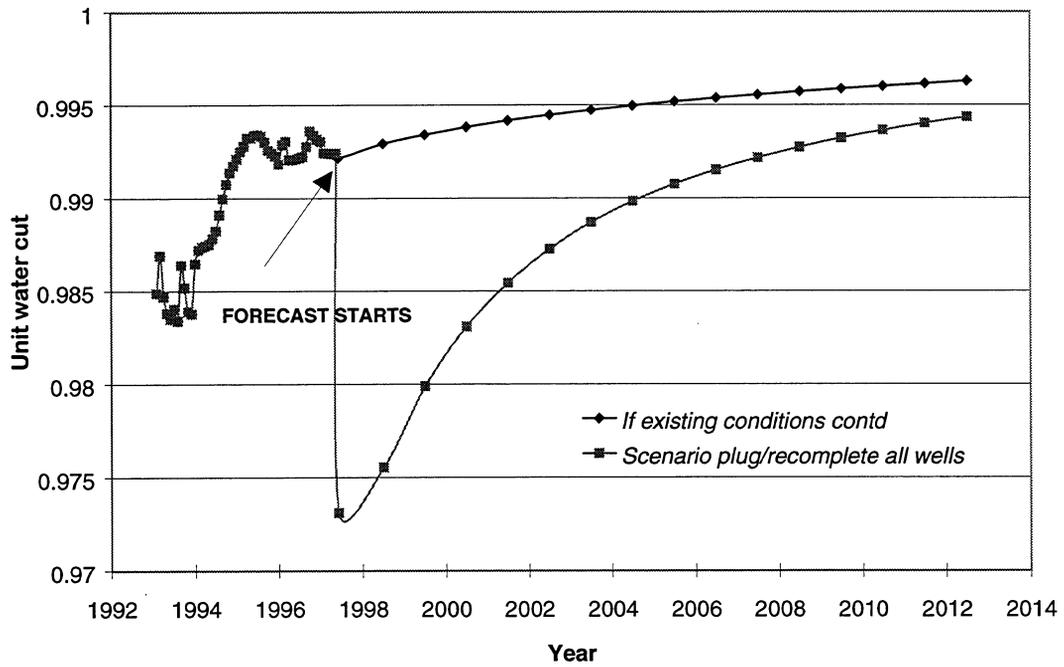
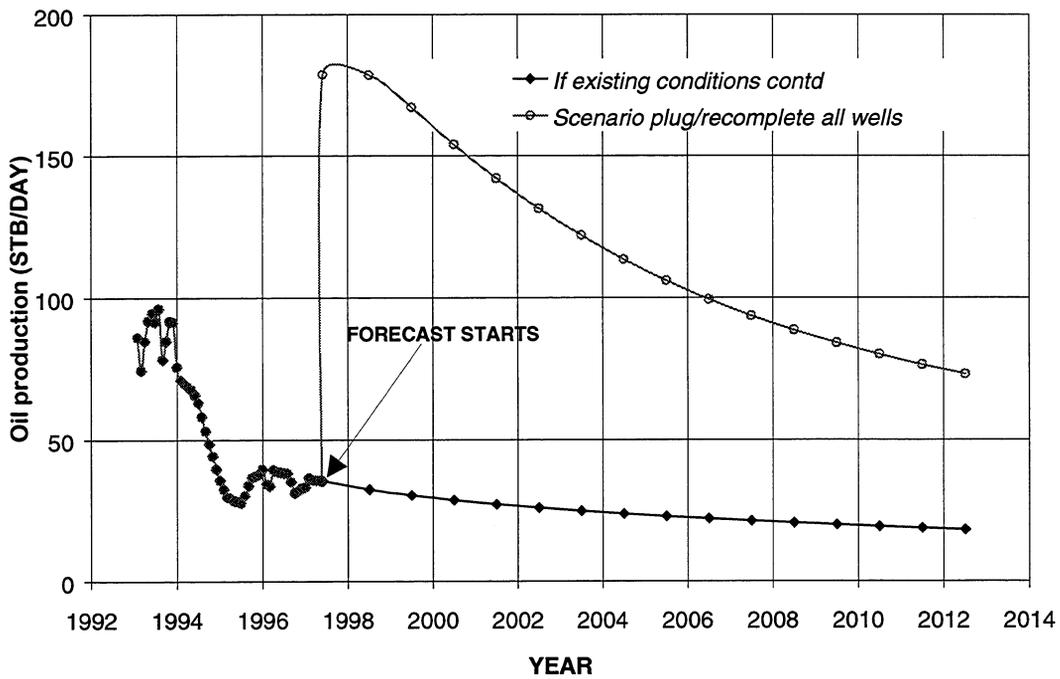


FIGURE 27: OIL PRODUCTION, WATER CUT PLOT FOR THE SCENARIO  $S_w \times 1.2$

**UNIT OIL PRODUCTION -  $S_w \times 1.4$ /Tract 7 plug/recomplete old wells**



**UNIT WATER CUT -  $S_w \times 1.4$ /Tract 7 plug/recomplete old wells**

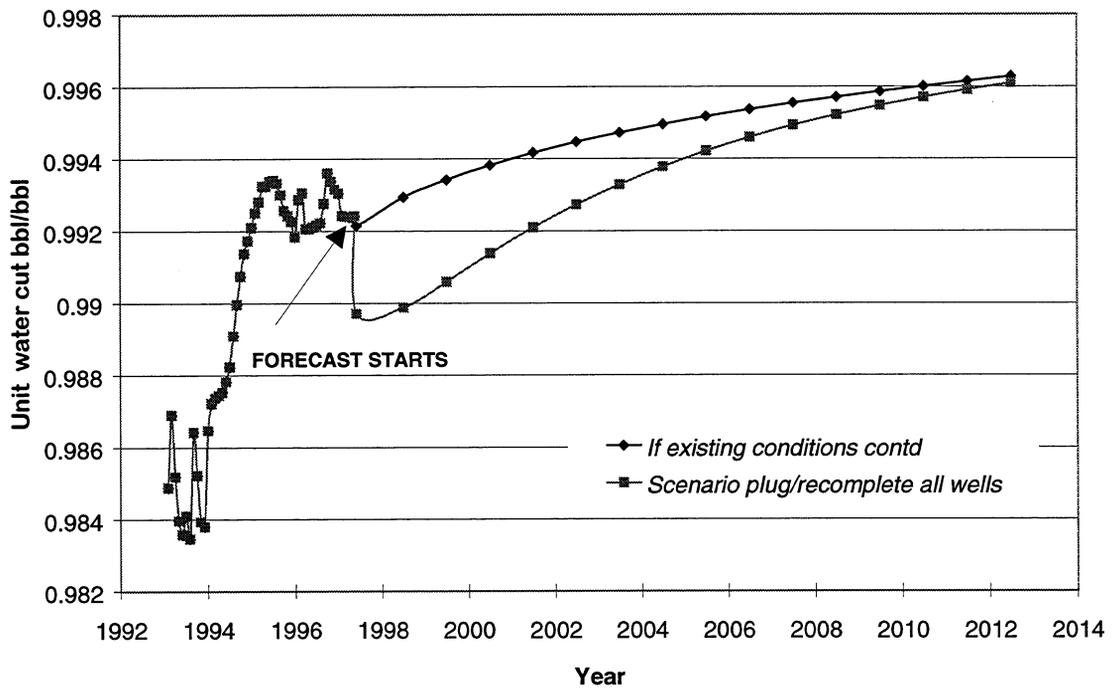
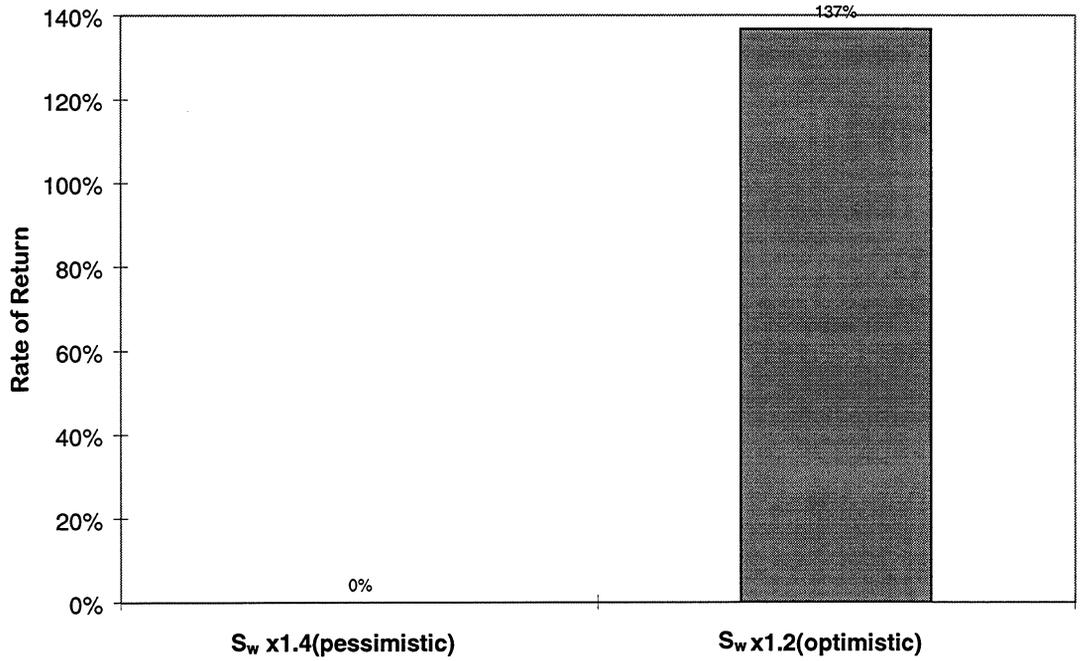


FIGURE 28: OIL PRODUCTION, WATER CUT PLOT FOR THE SCENARIO  $S_w \times 1.4$

**Rate of Return Histogram**



**Net Present Value for interest rates(i) 15% and 25 %**

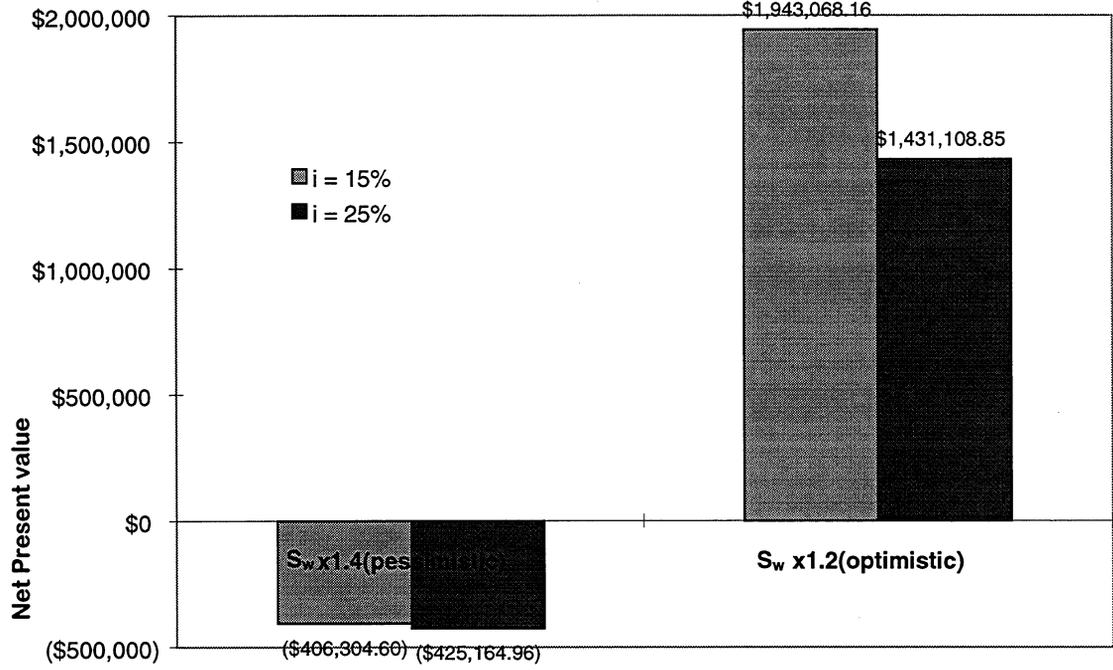


FIGURE 29: RATE OF RETURN AND NET PRESENT VALUE CHARTS FOR TRACT 7



