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Case 11526

August 16, 1999

Lori Wrotenbery, Chairman
Oil Conservation Commission
New Mexico Energy, Minerals and Natural Resources Department
Oil Conservation Division
2040 S. Pacheco St.
Santa Fe, NM 87505

Subject: Transmittal of Final Report of the Dagger Draw Complex Operators Committee

References: Division Orders R-4691-G and R-5353-L-4 dated November 14, 1996
Letter from Mr. William J. LeMay to Mr. Dave Boneau dated December 3, 1997
Letter from Mr. David F. Boneau to Ms. Lori Wrotenbery dated January 28, 1999

Dear Ms. Wrotenbery:

Pursuant to referenced Division Orders and letters, the Dagger Draw Complex Operators Committee has completed the final report required by the Oil Conservation Commission. That report is attached.

Sincerely,

Dave Boneau

David F. Boneau
Chairman, Dagger Draw Complex Operations Committee

Executive Summary

This final report was mandated by New Mexico Oil and Gas Conservation Commission Division Orders R-4691-G and R-5353-L-4 issued November 14, 1996. The report summarizes investigations by the Dagger Draw Complex Operations Committee whose formation was also mandated by the Orders. As required by the Orders, these investigations "...address OOIP, relative interference between wells, accurate porosity calculations and other measurements, critical to evaluating improved oil recovery options."

The sixteen-mile long Dagger Draw Complex is located roughly eighteen miles northwest of Carlsbad, New Mexico. The Dagger Draw Complex produces from carbonates deposited in a ramp-crest setting and are Upper Pennsylvanian in age. The Dagger Draw Complex is a vuggy reservoir adding to the difficulty of petrophysical quantification. Five facies have been identified and the vertical stacking of these facies is idealized by the stacking pattern from an algal mound complex.

Volumetrically weighted average pressure for the Canyon Reservoir corresponding to the properties operated by Yates Petroleum Corporation is 536 psi as measured in 1998 indicating an advanced state of depletion. Recent pressure measurements for properties not operated by Yates Petroleum Corporation were unavailable. The reservoir is thought to produce by depletion drive and gas cap expansion.

Using standard log analysis techniques, the OIP (oil in place at the time of logging of the majority of the wells) was calculated to be 497 MMSTB for the Canyon Reservoir. As of April 1998, nearly 12% of the this amount had been produced. OIP for only those properties operated by Yates Petroleum Corporation (YPC) was estimated as 289 MMSTB at the time of logging corresponding to an estimated recovery of 15%. The OIP compares unfavorably with an OOIP (original oil in place) of 215 MMSTB determined by material-balance methods for the YPC-operated properties. While standard log analysis techniques provide porosities that are remarkably statistically consistent with porosities obtained by whole-core analysis, the estimates of OOIP from log analysis are highly questionable owing to limitations of state-of-the-art methods of estimating saturations in vuggy carbonates and the possibility of nonrepresentative measured parameters used in the log analysis. These techniques lead to estimates of GIP of 1025 BCF for the entire Canyon reservoir and to 597 BCF for the YPC-operated properties. These are considered to be too high. A more reliable estimate of GIP for the YPC-operated properties of 291 BCF comes from extrapolation of the material-balance equations. Also, from extrapolation of the material-balance equations, it is estimated that a maximum of 13 MMSTB of oil and 57 BCF of gas remain to be recovered under primary for the YPC-operated properties. Assuming the material-balance methods to be correct, expected ultimate primary oil recovery from the YPC-operated properties will be in the neighborhood of 25% of the OOIP.

Clear cause-and-effect relationships showing interference between wells are difficult to establish, but pressure measurements on newly drilled wells suggest that the volume associated with these wells is being drained by existing wells.

Efforts to better characterize the nature of the porosity led to the general conclusion that standard porosity logs probably capture the pore volume of the majority of the vugs and represent fairly well the total porosity of the system. A spin-off of these efforts provides a potential means of quantifying vugular and nonvugular porosity. Attempts to train neural networks to predict vugular porosity did not lead to a means of quantifying it.

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Introduction and Purpose

Subsequent to a hearing held in Santa Fe, New Mexico on September 16, 1996 before the Oil and Conservation Commission (Commission), the Commission issued Division Orders R-4691-G and R-5353-L-4 on November 14, 1996. The Commission found in relevant part "....that there should be created immediately a Dagger Draw Complex Operators Committee...." hereinafter referred to as 'DDCOC' "....consisting of operator representatives who have operations in either the North Dagger Draw or South Dagger Draw -Upper Pennsylvanian Pools." The Commission ordered in relevant part that the DDCOC "...be charged with acquiring the necessary information, through testing and further reservoir analyses, to scientifically investigate recovery methods, other than primary. Said investigation shall address OOIP, relative interference between wells, accurate porosity calculations, and other measurements, critical to evaluating improved oil recovery options of these pools." As part of this charge, the DDCOC was "....to submit a final report .... to the Chairman of the Oil Conservation Commission by January, 1, 1998."

Early in 1997 the DDCOC held its first meeting. Co-Chairmen, Dave Boneau of Yates Petroleum Corporation (YPC) and Jerry Hoover of Conoco, Inc., were appointed by the Commission in February 1997. Later in 1997, when YPC acquired Conoco's interests in Dagger Draw, Mr. Boneau became the sole chairman of the DDCOC. Several meetings of the DDCOC took place in 1997 and interim reports were sent to the Commission covering the work and progress of the DDCOC. Then, however, progress of the DDCOC became impeded by two events in 1997: (1) A key representative for YPC on the DDCOC, Bob Fant, resigned from YPC, and a replacement for Mr. Fant was not found until October 1997, and (2) Work, thought at the time to be critical to the project and that was to be completed by Colorado School of Mines (CSM), became inordinately delayed. Consequently, a request was made to the Commission to delay submission of the required final report of the DDCOC until January 1999. This request was approved by the Commission by letter on December 7, 1997. YPC hired Frank Carlson in October 1997 as a reservoir engineer to fill the vacancy created by Bob Fant's resignation. YPC decided that Mr. Carlson should be assigned initially to address the reservoir engineering problems exclusively associated with Dagger Draw to include the charges of the Commission. In October 1998 the DDCOC met at Marathon Oil Company in Midland to review the work done by Mr. Carlson and to decide how best to conclude the work of the DDCOC.

The purpose of this report is to fulfill and complete the requirements of the Commission as mandated through Division Orders R-4691-G and R-5353-L-4 dated November 14, 1996. Primary contributors to this document include: Clyde Findlay II of Nearburg Producing Company (Midland, Texas), Denise Cox and John Kloosterman of Marathon Oil Company (Midland, Texas) and Tim Miller and Frank Carlson of Yates Petroleum Corporation (Artesia, New Mexico).

Geologic Setting of the Dagger Draw Complex

(Contribution by Denise Cox, Marathon Oil Company)

The sixteen mile long Dagger Draw Complex, located roughly eighteen miles northwest of Carlsbad, New Mexico is comprised of the North Dagger Draw and South Dagger Draw fields (Figure 1). These fields are northeast and down dip of the prolific Indian Basin Gas Pool (Figure 2). The Dagger Draw Complex is developed with 160-acre proration units on 40-acre well spacing in North Dagger Draw and 320-acre proration units on 40 to 80-acre spacing in South Dagger Draw. Five wells have been re-drilled with horizontal laterals in South Dagger Draw.

Trap

The trapping mechanism for the Dagger Draw Complex is both structural and stratigraphic (Speer, 1993; Reddy, 1995). The field is located over deeper-seated structural features, but structural closure alone does not account for the Dagger Draw trapping mechanism. Tight shelf limestone forms the up-dip closure on the reservoir dolomite. Authors have also noted that trapping is influenced by a west to east hydrodynamic water drive induced by the Huapache monocline (Frenzel and Sharp, 1974; Speer, 1993).

Stratigraphy

The Dagger Draw Complex produces from carbonates (limestones at the time of deposition) deposited in a shelf margin setting, more correctly referred to as a ramp-crest setting. The carbonates are Upper Pennsylvanian-aged Cisco (Virgilian) and Canyon (Missourian) formations (Cox et al., 1998). For the purposes of this report, the producing formations will be referred to as the Canyon formation. This terminology will keep consistency with the informal Canyon reservoir terminology used by the North Dagger Draw Operators.

The carbonates were not deposited as thick, continuous beds but were deposited as a series of alternating carbonates and shales in response to fluctuations in relative sea level (Figure 3). These carbonate-shale packages may compartmentalize the reservoir and have an effect on the efficiency of fluid flow.

Facies and Porosity Development

Stratigraphy compartmentalizes the Upper Penn on a gross scale. The facies, or rock type characteristic to a depositional environment, also affect porosity development and fluid flow within any given carbonate stratum. Five facies designations have been established for the Dagger Draw Complex based on the description of nine cores and their petrophysical characteristics (Cox et al, 1998) (Figure 1). Pore types are also listed for each of the facies. The Dagger Draw Complex is a vuggy reservoir so note is made of the vug distribution. An understanding of vug distribution is important because of the difficulties in petrophysical quantification of vuggy porosity (Hurley et al., 1998).

Facies 1-Algal Boundstone Facies

The algal boundstone facies consists of predominantly phylloid algal boundstone. The term boundstone is used to denote the organic buildup nature of the sediments. Phylloid algae are calcified algae that form corn flake-like grains. The algal boundstone facies is the core of the algal mound complex. The best reservoir quality in the algal mound complex is developed in mound-core algal boundstones. Vugs are the dominant pore type. They are associated with enhanced intercrystalline porosity, typically have a horizontal orientation, and vary in size from less than a cm to greater than the width of the 3 1/2 inch core.

Facies 2-Fusulinid Facies

The fusulinid facies includes wackestone (mud-dominated) to grainstone (grain-dominated) textures. Fusulinids (mm size cigar-shaped grains) along with peloids (nondescript skeletal grains) are indicative of this facies. In an algal mound complex, the fusulinid facies can represent off-mound and inter-mound deposition. Grainstone textures may represent mound caps. The fusulinid facies is characterized by interparticle and minor vuggy porosity. Vugs are generally small with patches of solution-enhanced, intercrystalline porosity that form a network of vuggy/intercrystalline porosity. The best reservoir quality in the fusulinid facies is in grain-dominated, intermound and offmound positions.

Facies 3-Crinoidal Facies

The crinoidal facies includes grainstone to wackestone textures. Crinoids (half cm sized disc-shaped grains) are typically associated with carbonate mud-dominated depositional fabrics. Stylolites or pressure-solution seams that form horizontal barriers to vertical flow are common. The crinoidal facies can represent mound substrate, intermound, and off-mound positions within an algal mound complex. Porosity is poorly developed in the crinoidal facies and varies from interparticle in grain-dominated textures to intercrystalline in mud-dominated textures. Vugs are sparsely distributed and horizontally oriented.

Facies 4-Mudstone Facies

Most of what can be confidently identified as mudstone in core is unaltered limestone with no reservoir potential. In shelfward settings, mudstone facies are interpreted as restricted-shallow water deposits. In basinward settings, mudstones represent deeper water, off-mound deposition. In the absence of fractures, mudstones may form baffles or barriers to fluid flow.

Facies 5-Siltstone and Terrigeneous Shales

Siltstones and terrigeneous shales in the Dagger Draw Complex are carbonate-rich and may not show a characteristic high gamma ray log signature. Despite their high carbonate content, the shales may behave as baffles and barriers to fluid flow. Facies 5 is typical of off-mound to basinal depositional environments.

Vertical Facies Stacking Patterns and Reservoir Development

The vertical heterogeneity of Dagger Draw Upper Penn strata is best illustrated with an idealized vertical stacking pattern or cycle from an algal mound complex (Figure 4). Terrigenous shale or mudstone marks the base of a cycle. The shale/mudstone is succeeded by crinoidal facies and fusulinid facies, and is capped by algal boundstone. This vertical facies succession is interpreted to represent a shallowing-upward trend from lower energy or deeper water deposition to high energy or relatively shallow water deposition. The shales/mudstones, interpreted as basinal deposits, were laid down during a relative sea level lowstand and early transgression of the shelf. Mud-dominated crinoid and fusulinid facies represent late transgressive deposits on the ramp. Grain-dominated crinoid and fusulinid facies represent early highstand deposits. Algal boundstones dominate the ramp crest in the late highstand . It is important to note that these Upper Penn algal mound complexes do not form a continuous or barrier reef-type geometry. Instead, the mound cores are localized and have a patchy distribution (Figure 5). Mud-dominated facies between mound cores have poorer reservoir quality and may form lateral baffles to efficient fluid flow. Low productivity intervals in wells offsetting high rate wells may be characteristic of intermound facies. The dimensions of mound/intermound facies in the Dagger Draw Complex are poorly defined at this time.

(End of Contribution by Denise Cox, Marathon Oil Company)

OOIP Investigations

Current Pressure Level

In 1998, YPC designed and implemented a pressure-testing program in order to determine the level of depletion of the Upper Pennsylvanian Canyon Reservoir in both the North and South Dagger Draw Pools. This program involved several elements:

1. Static bottom-hole pressures were measured in development wells drilled by YPC in 1998. These static pressures were measured after swabbing followed by at least a 24-hour shut-in period and were measured prior to putting the wells on production.

2. Fluid levels were determined from acoustically derived data on a number of YPC-operated wells throughout the field after a 72-hour shut-in period. To verify that these fluid levels could be converted to reasonable bottom-hole pressures, pressure buildups were also measured on three of the wells. These pressure buildups generally substantiated the validity of using fluid levels to obtain the bottom-hole pressures, especially considering their relative inexpensiveness and the order-of-magnitude level of precision needed for the studies addressed here.

3. Recently recorded bottom-hole pressure data were requested from Marathon Oil Company and Nearburg Producing Company.

Some 120 pressure measurements were taken from YPC-operated wells in the North and South Dagger Draw Pools during 1998. A contour map of these pressures is shown in Figure 6. Circles appear around those wells from which pressure measurements were taken. The datum for the pressure measurements was the seating nipple of the pump for each well. These pressures could have been converted to a datum corresponding to the midpoint of perforations which would have added a systematic 30 to 50 psi to the pressures at the seating nipple datum. This conversion was not made, however, because such accuracy was not deemed essential considering the scope of this study. Also, most of the pressure measurements were obtained from fluid-level measurements from which only approximate estimates of bottom-hole pressures can be obtained. Marathon Oil Company provided an abundance of pressure data, but only one test occurred in 1998 and the well from which the 1998 pressure was taken is located adjacent to YPC-operated wells. Therefore, this pressure was not considered to be representative of the average pressure in the Marathon-operated portion of the reservoir. Also, Nearburg Producing Company had not measured pressures recently. Therefore, for purposes of contouring the pressure data and finding a volumetrically weighted average pressure for the Canyon Reservoir, only the YPC-operated wells were considered. That volumetrically weighted average pressure is 536 psi. This average pressure is used as the current pressure level in the Canyon Reservoir in the material balance calculations discussed below.

Volumes Produced

The cumulative surface volumes of oil, gas and water produced from the Dagger Draw Field through April 1998 for the various operators are shown in Table 1. Nearly 60 MMSTB of oil and 275 BCF of gas have been produced from the field. The cumulative produced GOR is 4.75 MSCF/STB and the cumulative produced WOR is 3.96 STB/STB.

Volumetrics from Whole-Core and Log Analyses

Early after the formation of the DDCOC, the members collectively hypothesized that conventional log analyses for the Canyon Reservoir would be unreliable because of the abundance of vugular porosity present in the formation. As a result, the DDCOC decided to pursue a proposal by Dr. Neil Hurley of the Colorado School of Mines which would ultimately involve, as well, the New Mexico Petroleum Recovery Research Center in Socorro, New Mexico. The work of both groups is discussed below under the heading "Porosity Calculations". For the sake of this section of the report, however, it is sufficient to comment that the work did not result in a method that could be used reliably for quantitative analyses of the well logs. Hurley's work did inspire renewed interest in using conventional core analysis because during the course of his work, he made the observation that the neutron log porosity generally exceeded the estimate of vugular porosity in the cores derived from his measurements. This, in turn, suggested that neutron log porosity may, in general, be a good estimate of total (vugs plus matrix) porosity. Marathon personnel believe that neutron porosity is not a good estimate of total vugs in South Dagger Draw, especially where gas is present.

With the possibility that the neutron porosity could be a measure of total porosity and out of necessity to make some estimate of the volumetric quantities of oil, gas and water present in the Canyon Formation, it was decided to attempt to use conventional log analysis techniques. Also, since several of the wells had been cored, it was desirable to try to tie the log values to measurements of whole-core porosities through a correlation between whole-core porosities and log-derived porosities. Inconspicuous in this approach is the assumption that vugs larger than the scale of the whole core represent a small portion of the reservoir pore volume. Validity of this assumption is suggested by a spot-check of drilling rates through the carbonate. If vugs larger than the bit size were being encountered, spikes in the drilling rates might be expected. In the drilling rates observed, no such spikes were indicated.

The technical approach to log analysis consisted of the following steps:

1. **Plotting logarithm of permeability versus porosity for available whole-core footage**. Permeability and porosity were measured on 477 samples. A crossplot of the logarithm of permeability versus porosity for 430 of the 477 samples shows the typical poor correlation (correlation coefficient = 0.568). Nevertheless, a porosity cutoff was determined by finding the corresponding porosity where the best fit line intersected k = 1 md. The corresponding porosity was determined to be 0.032. The decision to use 1 md as a permeability cutoff was quite arbitrary and based on values used for cutoffs elsewhere. When some additional data (47 samples) were found after the log analysis had begun, it was found that the impact of the additional data would be to change the cutoff porosity from 0.032 to 0.0354. This change was not considered significant considering the poor correlation of the data. Therefore, the data was not reanalyzed using the higher porosity cutoff.

2. **Determining cementation exponent, m_{log}**. The cementation exponent, m_{log}, was determined by assuming that a=1 in Archie's equation, and averaging the experimentally determined values of m_{log}. The average value of m_{log} from 22 samples is 1.91.

3. **Determining saturation exponent, n**. The saturation exponent, n, to be used in Archie's equation was calculated by averaging the values of n obtained experimentally on four tests involving 23 measurements. That average is 2.15.

4. **Determining water resistivity, R_w**. The resistivity of the water, R_w, was determined by averaging the values obtained from an impartial selection of 10 water analyses. Corrected to reservoir temperature, the value of R_w is 0.363 ohm-m. This value compares favorably with the value used in the experimental determination of n discussed in step 3 (0.350 ohm-m). Marathon personnel report that the value for R_w in South Dagger Draw exceeds 0.75 ohm-m and suggest that there may be a gradient in R_w from South to North Dagger Draw. Such a gradient was not considered for this report.

5. **Determining gross intervals for detailed log analysis**. Digitized log data for some 180 wells were extracted from LAS files. Neutron porosity, bulk density, photoelectric effect, deep resistivity, and gamma ray data were extracted as a function of depth for each of the wells. Each of the log responses was then normalized and all normalized responses were plotted on a common graph. The gross interval was obtained by visual inspection of the common graph for all 180 wells. The gross interval generally corresponded to the data found between a few feet above the top of the Canyon Dolomite and a few feet below it.

6. **Determining porosity and phase saturations from well log analysis**. Since most wells drilled at Dagger Draw were drilled after substantial decline in pressure below the

reservoir's initial bubble point pressure, it is anticipated that a gas saturation was present when most of the wells were drilled. This presence of gas further complicates quantitative log analysis. Therefore, Visual Basic programs were developed to perform the log analyses. The first of these programs calculates the adjusted porosity at each data point such as would be obtained from manually crossplotting log-derived neutron porosity and log-derived bulk density. The purpose of this crossplot is to improve the estimate of porosity based on an assumed binary lithologic mixture of dolomite and limestone. Emerging from the crossplot are an improved estimate of porosity and also estimates of fractions of dolomite and limestone present on a volumetric basis. Marathon believes that the rock in South Dagger Draw tends to be either limestone or dolomite instead of mixtures of the two.

The second program calculates porosity and phase saturations in accordance with the procedure appearing in a Schlumberger manual (Schlumberger, 1989). In the introductory remarks to the technique, the manual suggests that the technique is for empty or gas-drilled holes. Nevertheless, others have employed similar techniques without pointing out this qualification (Bassiouni, 1994). This procedure uses as inputs the adjusted porosity from the crossplot discussed in the preceding paragraph and the bulk density response. From this program one obtains porosity and water, gas, and oil saturations.

A third program was written to calculate an adjustment to the neutron porosity to further compensate for the fact that the neutron response is reduced by the presence of gas. This adjustment, which is itself a function of porosity is called the excavation effect (Segesman and Liu, 1971 and Bassiouni, 1994). The calculated adjustment, then, is added to the value of neutron porosity. Since this adjustment changes the values obtained from the crossplot, and, in turn, changes the value of porosity, it is necessary to iterate upon the solution until convergence is obtained. Finally, a fourth program was written to perform this iterative procedure and to control the execution of the other three programs during the iterations.

7. **Attempting to tie log-derived porosities to porosities measured on whole cores**. Although this effort turned out to be an exercise in futility, considerable effort went into trying to come up with a correlation that would effectively calibrate the log-derived porosities to the porosities obtained by whole-core analysis. Even after making depth shifts in the data to improve the correlations, the best of the correlations were still very poor. In fact, the correlations were so poor that when they were applied to the log data, the variance of the predicted whole-core response from the log data was unrealistically small. Therefore, the attempt was abandoned.

Nevertheless, at the conclusion of the log analysis, summary statistics were prepared for both whole-core and log-derived porosities. Log-derived porosities from the wells and depths corresponding to the same wells and depths for whole-core analysis were extracted from the log analysis. The cutoff of 0.032 (see Step 1.) was then applied to both datasets. After applying the cutoff, 200 whole-core samples and 269 log-derived porosities remained. Remarkably, the means and standard deviations for both sets of data are very similar. For the 200 whole-core samples, the mean porosity is 0.0563 with a standard deviation of 0.022. For the 269 log-derived porosities, the mean porosity was 0.0564 with a standard deviation of 0.023. Such close proximity of the statistics of the two datasets is remarkable because no fitting parameters were applied to either set of data to force the conformance of the two datasets. It can be reasonably concluded that, on the average, the log analysis provides values of porosities representative of those found by whole-core analysis.

8. **Applying cutoffs.** After the gross interval of each well was analyzed as described in Step 6, cutoffs were applied to the resulting analysis by requiring that:

a. all saturations had to be between zero and one,

b. porosity had to be greater than 0.032 (See Step 1), and

c. gamma ray response had to be less than 75 APIU (determined empirically).

If any of these requirements were not met, that particular value was excluded from the net pay calculations. Marathon reports that the presence of Uranium is a big problem in South Dagger Draw and that its impact on the gamma ray response should be taken into consideration. For purposes of this report, the importance of Uranium was not taken into account in the assessment of the gamma ray response.

9. **Determining net pay and average saturations.** Since the log data was typically reported on one-half foot intervals, half-foot intervals passing the requirements of Step 8 were summed and the total divided by two to obtain the net pay. Of course, the sums were not divided by two for the few exceptions where the data was reported on one-foot intervals. Average saturations were obtained for the intervals passing the requirements of Step 8.

Logs from some 175 wells were analyzed using the above procedure. The distribution of those wells is displayed on the map shown in Figure 7.

The results of the log analysis were then used to calculate oil in place at the time of logging (OIP) and gas in place at time of logging (GIP). The majority of the wells were drilled after the pressure had declined from its original value (around 3000 psia) to a value of around 2000 psia. Therefore, the OIP should not be regarded as the original oil in place (OOIP) but more representatively, the OIP at the time the wells were drilled and subsequently logged. Consequently pressure-volume-temperature (PVT) data, particularly the gas in solution and formation volume factors used in estimating OIP and GIP, were chosen to correspond to the value of 2000 psia in the PVT properties shown in Table 2. OIP and GIP were calculated for each well location shown in Figure 7 using the net thickness and saturations obtained from the log analysis. Then, the results were contoured. Contour maps of net thickness, OIP and GIP are shown in Figures 8, 9 and 10 respectively.

In the captions of Figures 9 and 10 are shown the OIP and GIP obtained from integrating the surfaces using integration software available in Golden Software's Surfer. Recoveries (in per cent) through April 1998 were obtained from the production totals shown in Table 1 and the values of OIP and GIP obtained from the integration. These recoveries are also shown in the captions of Figures 9 and 10. The estimated OIP from log analysis for the Dagger Draw Canyon Formation is 497.0 MMSTB. Through April 1998, 57.8 MMSTB had been recovered amounting to 11.6 per cent. The estimated GIP from log analysis is 1025 BCF. Through April 1998, 274.8 BCF (26.8 per cent) of the gas had been recovered. When only the YPC-operated properties are considered, the OIP is 288.7 MMSTB (See Figure 11) and the GIP is 596.9 BCF (See Figure 12). These latter numbers will be used for comparison with material-balance calculations as discussed immediately below. Discussion of the reasonableness of the values obtained for OIP and GIP from log analysis will be deferred until after the results of the material-balance calculations have been presented.

Material Balance

Since there were no current estimates of reservoir pressure for offset operators and since a complete set of pressures was measured on the YPC-operated properties during

1998, only the production from the YPC-operated properties was considered in the material-balance calculations. In the material balance calculations, produced quantities of gas, oil and water are for the YPC-operated wells from Table 1. The PVT properties are from Table 2. Assuming that the initial pressure was 3015 psia and using the current estimate of reservoir pressure, 536 psia, material balance calculations were made. In making these calculations, the method of Schilthuis discussed in Craft et al, 1991, was used. These calculations require an estimate of m_{mb}, the ratio of the volume of the bulk gas zone to the volume of the bulk oil zone. Evidence exists for the presence of a gas cap. First, it can be observed that the largest amount of gas has been produced from the wells highest on the structure (See the contour map of cumulative produced gas shown in Figure 13). Secondly, the average gas saturation as calculated from log analysis increases in going from east to west, coincident with moving up structure (See Figures 2 and 14). While this evidence suggests the existence of a gas cap, it gives no hint of the value of m_{mb}.

To determine, m_{mb}, the most eastern well that has historically produced effectively only gas and water and very little oil was sought. One such well is Carl TP Com #3 located in Unit C, Section 22, Township 20S, Range 24E. As of April 1998, this well had only produced 566 STB of oil and had produced approximately 2.5 BCF of gas. By assuming that the elevation of the bottom-most perforations were coincident with the elevation of the bottom of the gas cap, the elevation of the bottom of the gas cap was calculated to be 3991 feet below sea level. Porosity-thickness products were calculated for the wells shown in Figure 7 and integrated. The total pore volume was calculated to be 12.3 billion cubic feet for the entire Dagger Draw Canyon Formation. Each of the detailed analyses for the wells shown in Figure 7 were then scanned for the amount of net footage above the estimated GOC of 3991 feet sea level. Marathon reports that the GOC in South Dagger Draw is some 100 feet below the level reported here but this observation was not taken into consideration for this report. The porosity-thickness products were determined using only the footage contained completely above the GOC. These products were then integrated. The pore volume contained within the gas zone was calculated to be 2.9 billion cubic feet. Subtracting the pore volume contained in the gas cap from the total pore volume results in 9.4 billion cubic feet being contained in the oil zone. The ratio of the pore volume of the gas zone to the pore volume of the oil zone produces an estimate of m_{mb} of 0.31. By using this value of m_{mb}, the current pressure level of 536 psia and assuming no water influx in the Schilthuis material balance equations, the resulting OOIP is 215 MMSTB for the YPC-operated properties.

Comparison of Volumetrics with Material Balance

Volumetric calculations based on log analysis of carbonates, and in particular, vuggy carbonates, remains to this day very inexact. In the log analysis used in this report, every effort was made to honor the measured data (e.g. R_w, m_{log}, etc.). Yet, there is a relatively large discrepancy between the OIP found by volumetric methods for the YPC-operated properties (288.7 MMSTB) and the OOIP found by material balance methods (215 MMSTB). Also, the amount of GIP calculated seems very high. It is hard to believe that nearly a TCF of gas was ever present in the reservoir considering the current state of depletion of the reservoir and the relatively low recovery this amount of GIP would indicate (27%). Since the porosity levels predicted from the logs are very close to those obtained from whole-core analysis, probably the pore volume is quite accurate. Most likely in error are the relative levels of fluid saturations and, in particular, the gas saturations. Such high levels of gas saturations as those calculated in this study (mean 0.46) would lead to such high mobilities of gas that essentially nothing else but gas would flow. Other methods of calculating gas saturation were tried but led to gas saturations even higher than those discussed here. As was pointed out earlier, without any real justification to do otherwise, measured values of parameters were used in this study. The accuracy of the saturations are limited by the accuracy of the parameters measured and the methods employed to calculate those saturations. The values of GIP calculated from these gas saturations is probably very unreliable.

Although the levels of gas saturation are too high in a quantitative sense, qualitative insight may be gained from contouring the calculated values of gas saturation as shown in Figure 14. Observation of this contour map shows a trend of increasing gas saturation in an updip direction. Such a trend would be consistent with the existence of a gas cap.

Having drawn into question the sufficiency of volumetric studies in vugular carbonate reservoirs, still a very positive statement can be made about the studies mentioned in the preceding paragraph. Prior to using classical log interpretation in these studies, it was the consensus that the logs could not provide a porosity, *ergo* pore volume, large enough to contain the quantities of fluids produced from the reservoir. These studies have shown that more than adequate storage capacity is predicted from these classical techniques.

Probably, the more reliable estimate of OOIP comes from the material-balance equations. While material-balance methods make many assumptions regarding homogeneity of the reservoir and the fluids contained therein, their ability to estimate OOIP become better as the reservoir becomes progressively depleted. Recall that the volumetrically weighted average pressure estimated for the Canyon Formation based on 1998 measurements is 536 psia indicating a very advanced stage of depletion in the reservoir. Therefore, the use of material balance methods should be quite reliable. If the further assumption is made that the calculated value of 215 MMSTB at 536 psia from material balance is indeed the OOIP and that the cumulative produced gas-oil ratio will not change substantially in depletion of the reservoir for the remainder of the life of the reservoir, then the Schilthuis material-balance equation can be used to estimate both the original gas in place (OGIP) and the remaining recovery of both gas and oil between current conditions of 536 psia and a given abandonment pressure.

To estimate OGIP, abandonment pressure is assumed to be 15 psia in the Schilthuis material-balance equation and the appropriate functions of pressure are changed to the values corresponding to 15 psia. Then, the amount of oil produced in the equation is varied by trial and error until the amount of OOIP is calculated to be 215 MMSTB. Using this procedure, OGIP was found to be 290 BCF for the YPC-operated properties. This is about 50% of the value found by log analysis and volumetric calculations. The value of 290 BCF should be considered the more reliable estimate because of the potential inaccuracy associated with estimating gas saturation in the log analysis as discussed above.

Similarly, it is also possible to extrapolate the Schilthuis material-balance equations and come up with values of total remaining recoverable oil and gas at a given abandonment pressure using the same procedure outlined in the preceding paragraph. For example, if a reasonable abandonment pressure is assumed to be 200 psia, then the calculated remaining recoverable oil and gas are 13 MMSTB and 57 BCF, respectively for the YPC-operated properties. It is important to note that these numbers are probably upper bounds because they do not consider economic limits and because of the probably liberal assumption that the cumulative produced gas-oil ratio will not increase in the future.

Relative Interference Between Wells

If there is a central theme of this section, it would be the difficulty in distinguishing clear cases of well interference from normal decline. Both Kloosterman and Findlay offer subjective discussion of cases which could be interference for South and North Dagger Draw respectively (see below). An attempt was made to come up with more objective techniques to assess interference. One method involved calculating a variogram of the pressures measured on YPC-operated properties in 1998. While it was possible to obtain a correlation length from the variogram, it is very likely that the calculated correlation length is exaggerated by the advanced stage of depletion. For example, if the reservoir were completely depleted, all pressures would be very nearly the same even though during the process of depletion, the pressures could have been quite different and wells might even be isolated from one another. Thus, the correlation length estimated from the variogram at the advanced stage of depletion of Dagger Draw could be quite misleading and is, therefore, not reported.

The second objective method involved attempting to find correlations between the rate history of a given well and other wells using a series of time lags to find the best correlation. While this method showed promise, it was quite cumbersome, and to the extent that it was applied, quite inconclusive.

Probably the most reliable indications of the extent of communication between wells are the pressures measured on newly drilled wells before the wells were placed on production. During 1998, YPC began obtaining static bottom-hole pressures on newly drilled wells after the well was swabbed and after a period of shut-in of at least 24 hours, but before the wells were placed in the production stream. In most cases, the static pressure recorded for these wells was highly predictable from the pressures measured in nearby wells during the 1998 pressure-measurement program. As a case in point, the static pressure recorded on a new well drilled after the pressure contour map was constructed was 770 psi. The contour map indicated that the pressure should have been 750 psi.. Such low pressure in a newly drilled well suggests that sufficient communication exists between that portion of the reservoir surrounding the newly drilled well and adjacent wells to allow drainage of that portion by adjacent wells. It is clear, then, that the newly drilled well will eventually interfere with the producers which have been draining the area prior to the drilling of the new well.

South Dagger Draw (Contribution by John Kloosterman, Marathon Oil Company)

Reviewing the wells in Dagger Draw South for possible interference effects proved to be very difficult for three main reasons. In many areas of the field new wells were coming on at a rate of one to two per month. Many of these were direct offsets, so there was no normal decline established in a well prior to an offset coming on line. Many of the wells had very high initial production rates (1500 BOPD) followed by a very steep decline, before stabilizing at a 200 to 400 BOPD rate. Another factor making analysis difficult, was the high failure rate of some of the artificial lift equipment used in area. In a few cases what might appear to be interference from a new well was actually caused by well downtime. In some areas production rates were so high it forced other wells in the proration unit to be cut back to remain under the allowable. A few examples highlighting the difficulty of identifying positive interference indications are described below.

North Indian Basin Unit (NIBU) No. 12 came on line at 500 BOPD in July 1995. The combined production from the three offsets dropped 400 BOPD during that same month but had no decline over the next ten months. It would appear that this 400 BOPD drop came from NIBU No. 20 which came on in late-May. This sharp decline could be interference from NIBU No. 12, or it could simply be flush production followed by a steep decline. NIBU No. 20 stabilized at 200 BOPD for over 18 months following the steep decline.

NIBU No. 26 came on at 1500 BOPD in February 1996. There was no obvious effect on the two offset wells. In fact, the decline rate from the two offsets flattened to zero percent for six months after NIBU No. 26 came on line.

During January and February of 1996, over 2000 BOPD was brought on line offsetting NIBU No. 23, which had an initial production of 1300 BOPD in late-August 1995. Production in NIBU No. 23 had steadily declined to 600 BOPD by December and then held relatively constant at 400 to 500 BOPD for six months after the offset production came on line. It is not clear whether the 100 BOPD decrease from December to January was due to interference or just a continuation of the established steep decline rate.

The Conoco AGK Federal No. 3 came on at 600 BOPD in May 1992. There was no noticeable change in offset production; however, offset wells were being completed during a five-month period after the Conoco AGK Federal No. 3 well came on. Both the Conoco AGK Federal No. 3 and the combined production of the eight offsets exhibited very similar decline patterns throughout the rest of the available production history. It is difficult to determine conclusive, cause-and-effect interference in this area because eight wells in this study area were completed in a ten-month period.

In the above cases the wells were on 40-acre spacing. However, over much of the study area, the wells were drilled on 80-acre spacing. In one area of the MOC Federal lease, two 40-acre infill wells were drilled with disappointing results. There is little evidence of significant interference between the 80-acre wells in Dagger Draw South. In the areas where wells were initially completed on 40-acre spacing, it is difficult to identify interference because many wells were being completed during a short period of time. In areas where 40-acre wells were drilled well after the initial 80-acre development, the infill well results were disappointing. Many more 40-acre infill wells have been drilled recently in Dagger Draw South; however, not enough data was not available for review to draw conclusions.

(End of Contribution by John Kloosterman, Marathon Oil Company)

<u>North Dagger Draw (Contribution by Clyde Findlay II, Nearburg Producing Company)</u>

Several sets of wells in the North Dagger Draw Field were examined for possible interwell interference. Production curves were plotted and examined together to assess simultaneous well behavior. Well behavior is inconclusive because some wells exhibited classic interference, some showed no interference, and one well manifested inverse interference behavior. One could infer that the reservoir is sufficiently heterogeneous to cause a wide variety of behavior as noted in Table 3.

(End of Contribution by Clyde Findlay II, Nearburg Producing Company)

Porosity Calculations

Early in the life of the DDCOC, a consensus of its members decided that imaging logs such as FMI or CIBL would more accurately represent porosity in the Canyon Formation than would conventional neutron and/or density logs. Since the imaging logs had been measured only on a small number of wells, it was desirable to find some way that the imaging logs could be approximated from other more conventional logs. In response, New Mexico Petroleum Recovery Research Center (NMPRRC) successfully proposed that neural networks could be trained to predict the imaging response from inputs available from conventional logs. In order to complete the work, NMPRRC needed estimates of the spot porosities as a function of depth in order to train the neural networks. Spot porosities are defined as the ratio of the more heavily shaded vugs to the total surface area on the graphical representation of the imaging log. Coincidentally, Dr. Neil F. Hurley of the Colorado School of Mines was organizing a consortium entitled "Quantification of Vuggy Porosity in Carbonates Using Borehole Images and Core" which eventually materialized and involved several industrial participants. It was Dr. Hurley's belief that vuggy porosity can be significantly underestimated by using conventional logging tools such as density, neutron, and sonic devices. Ultimately, YPC joined the consortium for a one-year period with the understanding that Dr. Hurley would provide the spot porosities needed by NMPRRC as a by-product of the research to be performed for the consortium.. Although delayed for several months, the spot porosities were eventually provided to NMPRRC for the purpose of training the neural networks.

One of the surprises, to Dr. Hurley, of the research done for the consortium was that the conventional neutron log porosity generally exceeded the spot porosity when the spot porosity data was averaged over a comparable interval to what the conventional neutron density tool would measure. This suggested to Dr. Hurley that the conventional tool was capable of capturing the vugular porosity as part of the total porosity and that, as a first approximation, the difference between the neutron porosity and the averaged spot porosity could be a good indication of the nonvugular, matrix porosity. This latter observation may turn out to be the most applicable part of the research. Ultimately, when and if extensive reservoir simulation is done on the Canyon Reservoir, a dual-porosity, dual-permeability model may be the most appropriate model to use where one system represents the interconnected vugular system, and the other the interconnected, nonvugular matrix system. In this type of model, the porosity assigned to each system is usually a highly uncertain assumption. The work done by Dr. Hurley could be quite useful in coming up with the relative proportions of vugular and nonvugular porosity for such models.

Unfortunately, the results of the work done by NMPRRC (see Appendix A) was largely qualitative in the fact that the trained neural networks predicted broad ranges of porosities, some of which were 2 to 3 times higher than the expected value (See Table 2, Page A9). Also, note in this same table, that this particular training of the neural network produces results that are generally biased toward the high side. Originally, it was intended to use the factors obtained from training the neural network and the architecture of the neural network to calculate the spot porosities from standard log inputs. To have done so, however, would have generally overestimated the spot porosity because of the biased results of the output of the "trained" neural network. Therefore, it was decided to abandon any attempt to use the neural network results in any quantitative sense.

Finally, it would seem that the logic behind using poorly resolved quantities from standard logs as inputs to train a neural network to predict spot porosities derived from supposedly highly resolved measurements of spot porosities is not beyond challenge. For example, suppose that an FMI log which has a resolution of inches indicates a spike in porosity at a given depth. It would seem unrealistic to expect that a neural network could accurately predict the magnitude and appropriate depth of the spike from inputs of standard logs where the resolution is in terms of feet instead of inches. Therefore, the use of neural networks to accurately predict spot porosities, even in a qualitative sense, may be limited. Nevertheless, such an attempt shows the extent to which the DDCOC was willing to try to come up with accurate estimates of spot porosities. As pointed out above, standard log analysis techniques appeared to produce reasonable estimates of porosity so the outcome of the long shot (as it was regarded by several DDCOC members) of the success of neural networks became much less important.

Other Considerations

As can be deduced from this report, the period of primary production from the Canyon Formation at Dagger Draw is rapidly coming to a close. While the data gathered and the studies reported above will be critical to any evaluation of the potential for improved oil recovery (IOR), the future of such IOR is nebulous. What potential exists for some form of IOR will be investigated in the future by the various operators independently, if at all. The results of the Sawbuck waterflood pilot conducted by YPC in South Dagger Draw doesn't inspire waterflooding as a mode of IOR, at least in the area of the pilot. There may be other areas of the field, however, where waterflooding may have more potential. Regardless, YPC will be undertaking a thorough, diagnostic study of the Sawbuck pilot in 1999 and looking at the potential for waterflooding elsewhere in the field. If waterflooding does not appear to be feasible anywhere, then other methods of IOR will be investigated. Under price conditions existing at the time of this report, it is doubtful that any IOR process would be economical. Regardless, whether such IOR methods will be implemented will depend upon their economic feasibility at any future time they may be considered.

Conclusions

1. The Dagger Draw Complex produces from carbonates deposited in a ramp-crest setting as a series of alternating carbonates and shales in response to fluctuations in relative sea level. The Dagger Draw Complex is a vuggy reservoir.

2. Five facies designations have been established for the Dagger Draw Complex: algal boundstone, fusulinid, crinoidal, mudstone, and siltstone and terrigeneous shales. The vertical stacking of these facies are idealized by the stacking pattern from an algal mound complex.

3. The current volumetrically weighted average pressure in the Canyon Formation is approximately 536 psi as determined from measurements made on YPC-operated wells only. This pressure level indicates an advanced state of depletion.

4. Nearly 60 MMSTB of oil and 275 BCF of gas have been produced from the field.

5. The mean porosity and standard deviation of the data predicted from log analysis matches very closely the mean porosity and standard deviation of the data obtained from whole-core analysis.

6. Based on log analyses, the oil in place at the time of logging (OIP) is estimated to be 497.0 MMSTB and the estimated gas in place at time of logging (GIP) is 1025 BCF. The GIP based on log analysis is probably unrealistically high and its accuracy is limited by possible inaccurate measurements of input parameters and the state of the art in calculating saturations in vuggy carbonates. For the portion of the field operated by YPC, the volumetrically determined OIP is 288.7 MMSTB and the GIP is 596.9 BCF. Again, the value of GIP is considered to be too high. Oil recoveries for the total field and the YPC-operated properties amount to 11.6 % and 15.2% respectively as of April 1998.

7. Original oil in place (OOIP), as determined from material balance in the YPC-operated portion of the field, is 215 MMSTB. This estimate of OOIP was obtained by calculating a value of 0.31 for m_{mb}, the ratio of the volume of the bulk gas zone to the volume of the bulk oil zone. The primary recovery mechanism appears to be depletion drive and gas-cap expansion.

8. Because of the inherent problems associated with log analysis of vugular carbonates, the most reliable estimates of OOIP and original gas in place (OGIP) are considered to be those resulting from material-balance calculations. Extrapolation of the material-balance equation to an abandonment pressure of 200 psia, suggests that the remaining recoverable oil and gas reserves by primary will not exceed 13 MMSTB and 57 BCF, respectively for the YPC-operated properties . By extrapolating the material-balance equation to an abandonment pressure of 15 psia, an estimate of OGIP of 291 BCF is obtained for the YPC-operated properties. This value is approximately 50% of the amount of the gas in place at the time of logging determined by log analysis and volumetrics. Assuming the material balance methods to be the more accurate method, ultimate recovery of oil will be in the neighborhood of 25% of OOIP for the YPC-operated properties.

9. Clear cause-and-effect relationships showing interference between wells are hard to establish. Nevertheless, pressure measurements in newly drilled wells indicate pressure levels close to the pressure levels measured in adjacent, existing producers. Therefore, existing producers are probably draining the volume of reservoir adjacent to the newly drilled wells which implies that interference between the newly drilled well and existing producers will eventually be assured.

10. Work performed by Dr. Neil Hurley of the Colorado School of Mines indicates, in general, that the porosity obtained from conventional logging tools will exceed the

average of the spot porosities when the averaging interval approximates the same resolution as the conventional tool.

11. Neural networks, as trained by NMPRRC, were not quantitatively useful in predicting spot porosity from inputs of conventional log responses.

12. While several operators will be considering improved oil recovery for Dagger Draw, the future of waterflooding for the field is uncertain based on the apparent results of the Sawbuck waterflood pilot.

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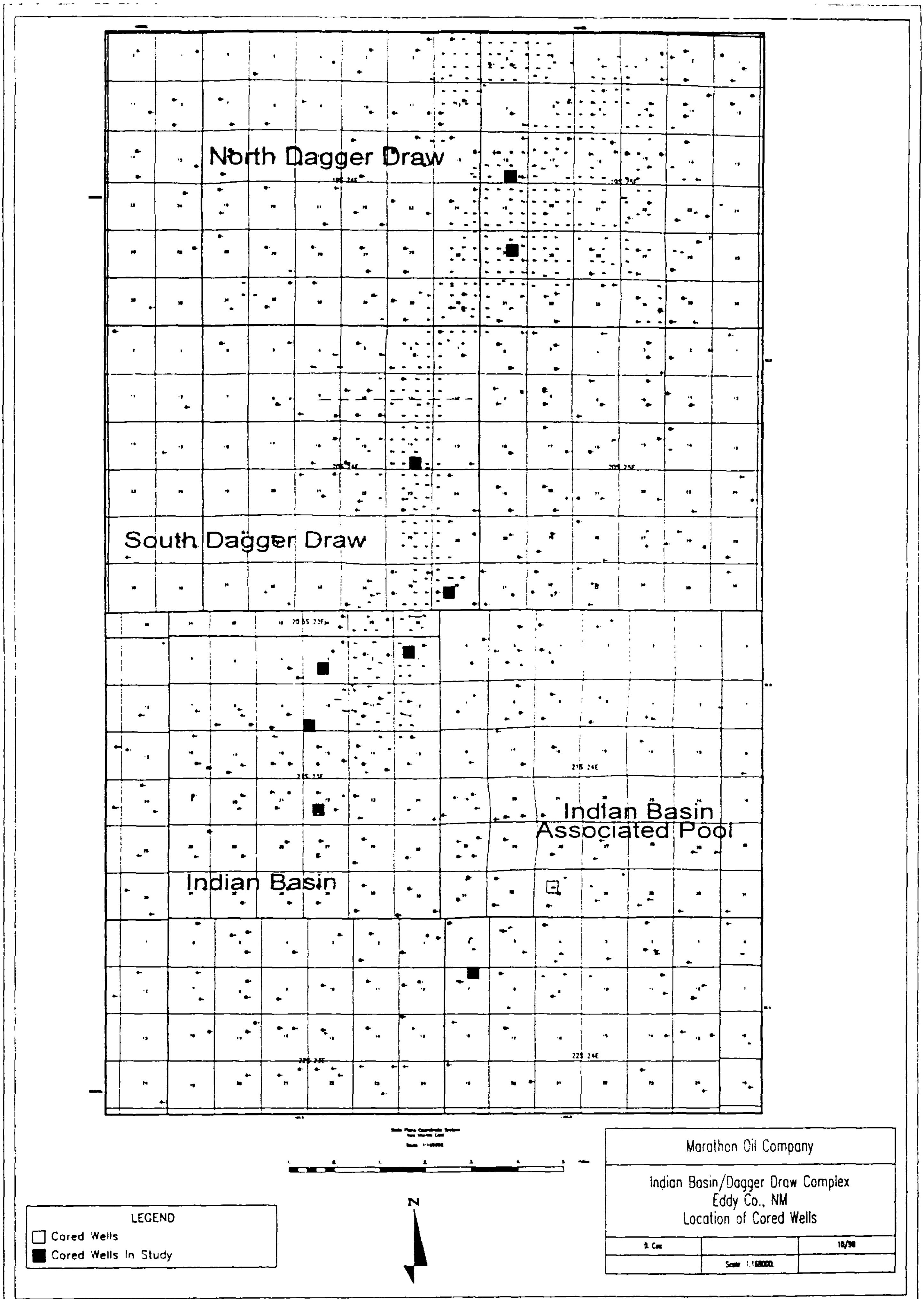

Figure 1. Location map of Dagger Draw Complex, Eddy Co., NM. Squares indicate cored wells.

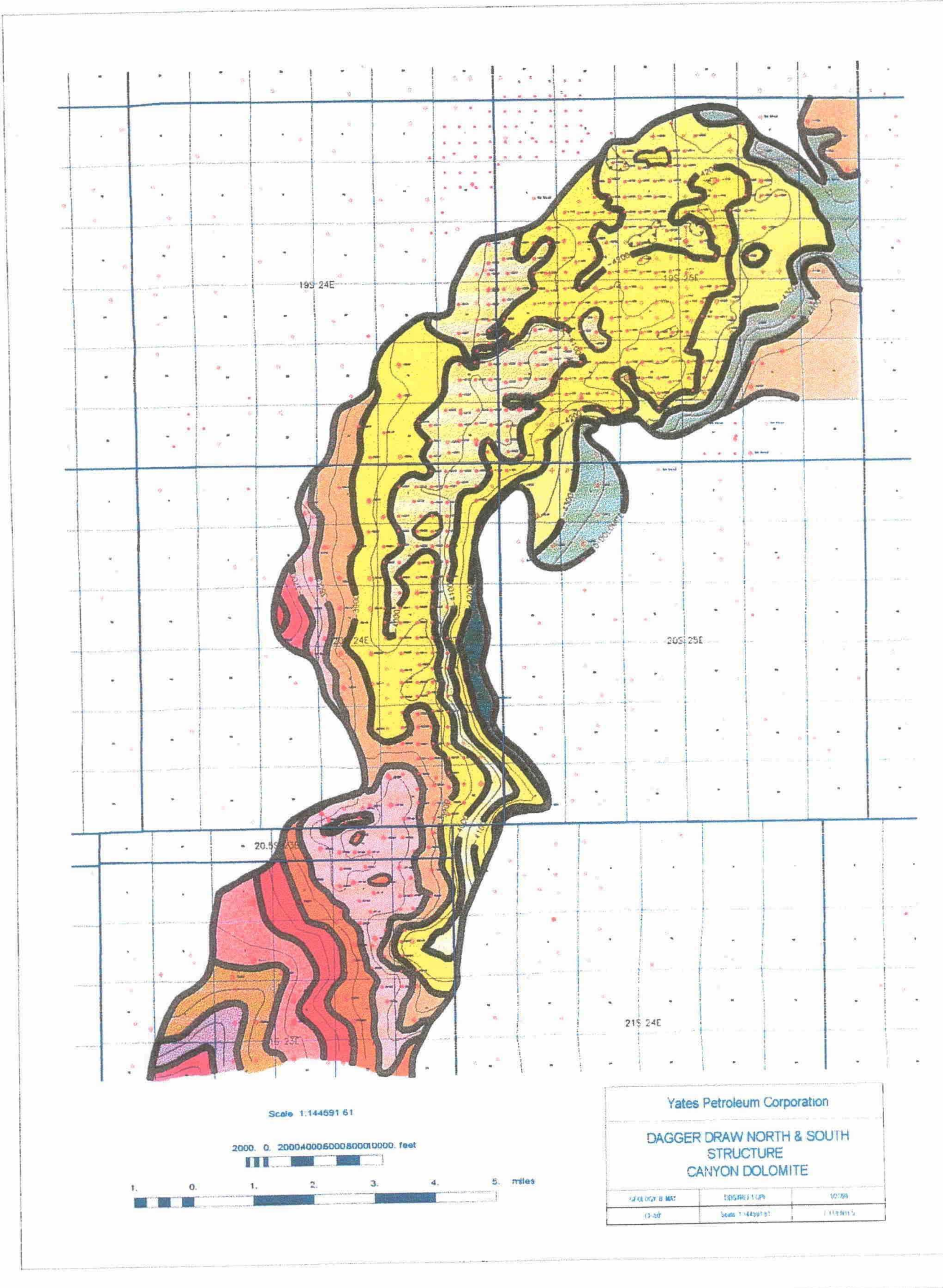

Figure 2. Structure Top of Upper Pennsylvanian Dolomite

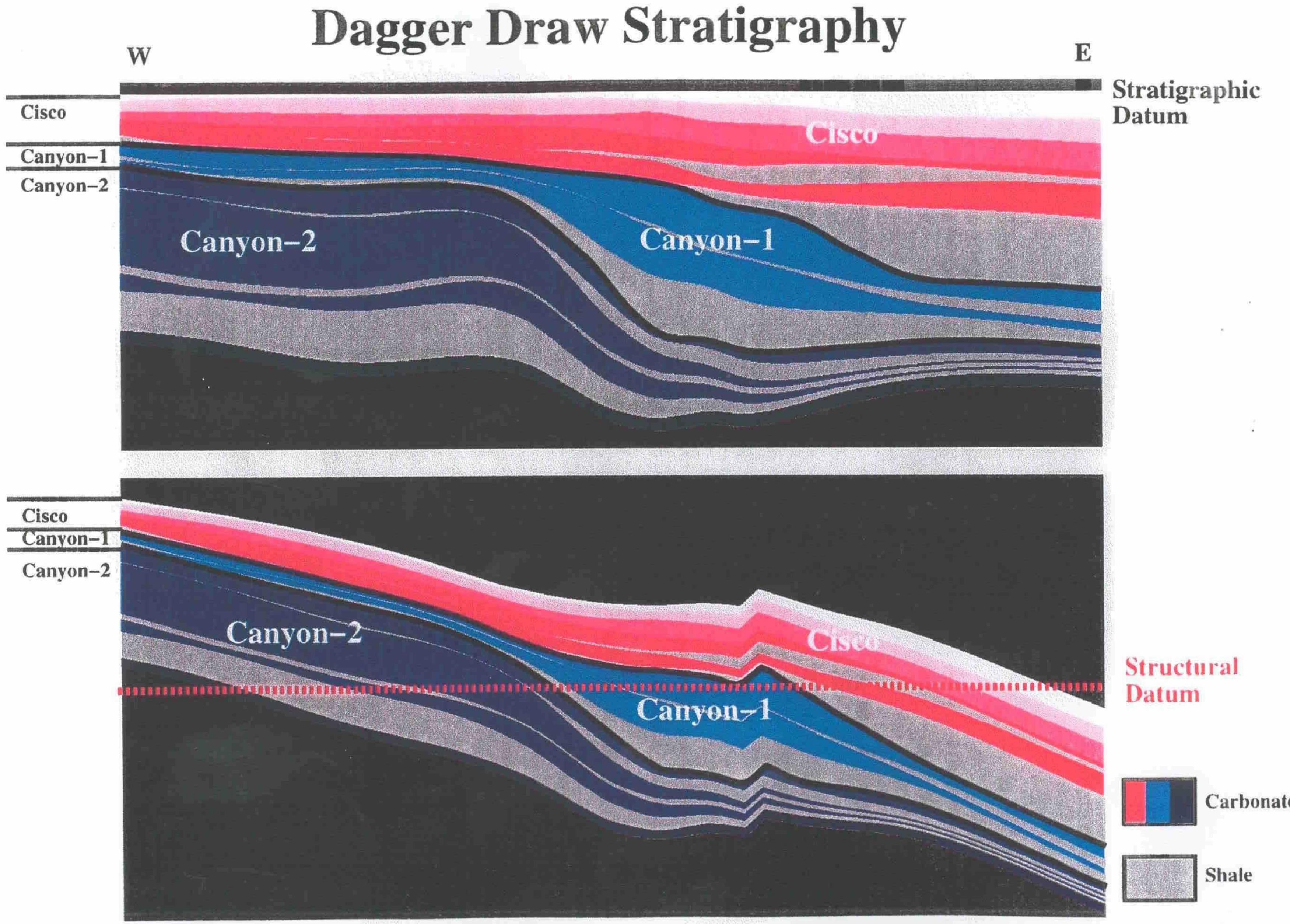

Figure 3. Upper Pennsylvanian stratigraphy for the Dagger Draw Complex.

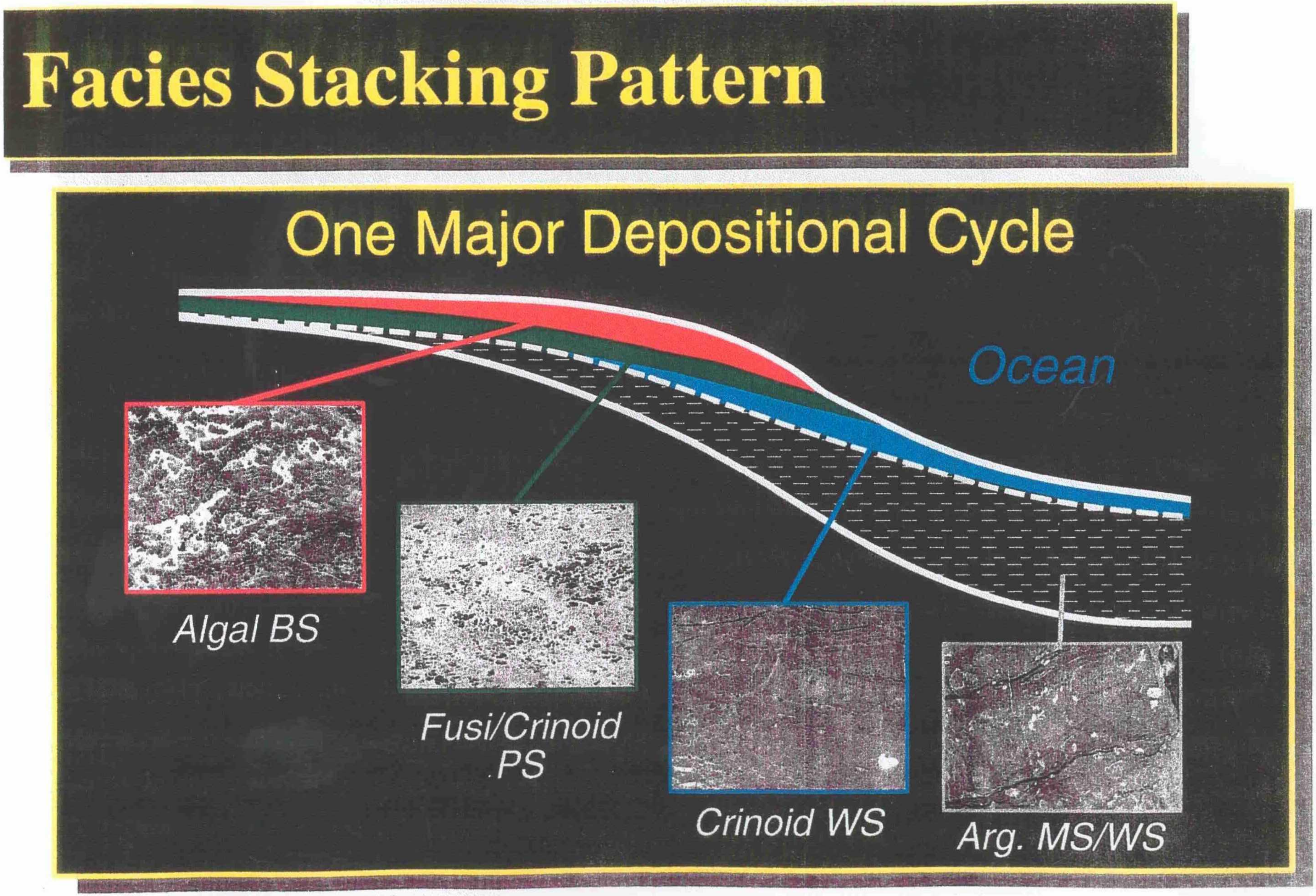

Figure 4. Idealized facies stacking pattern.

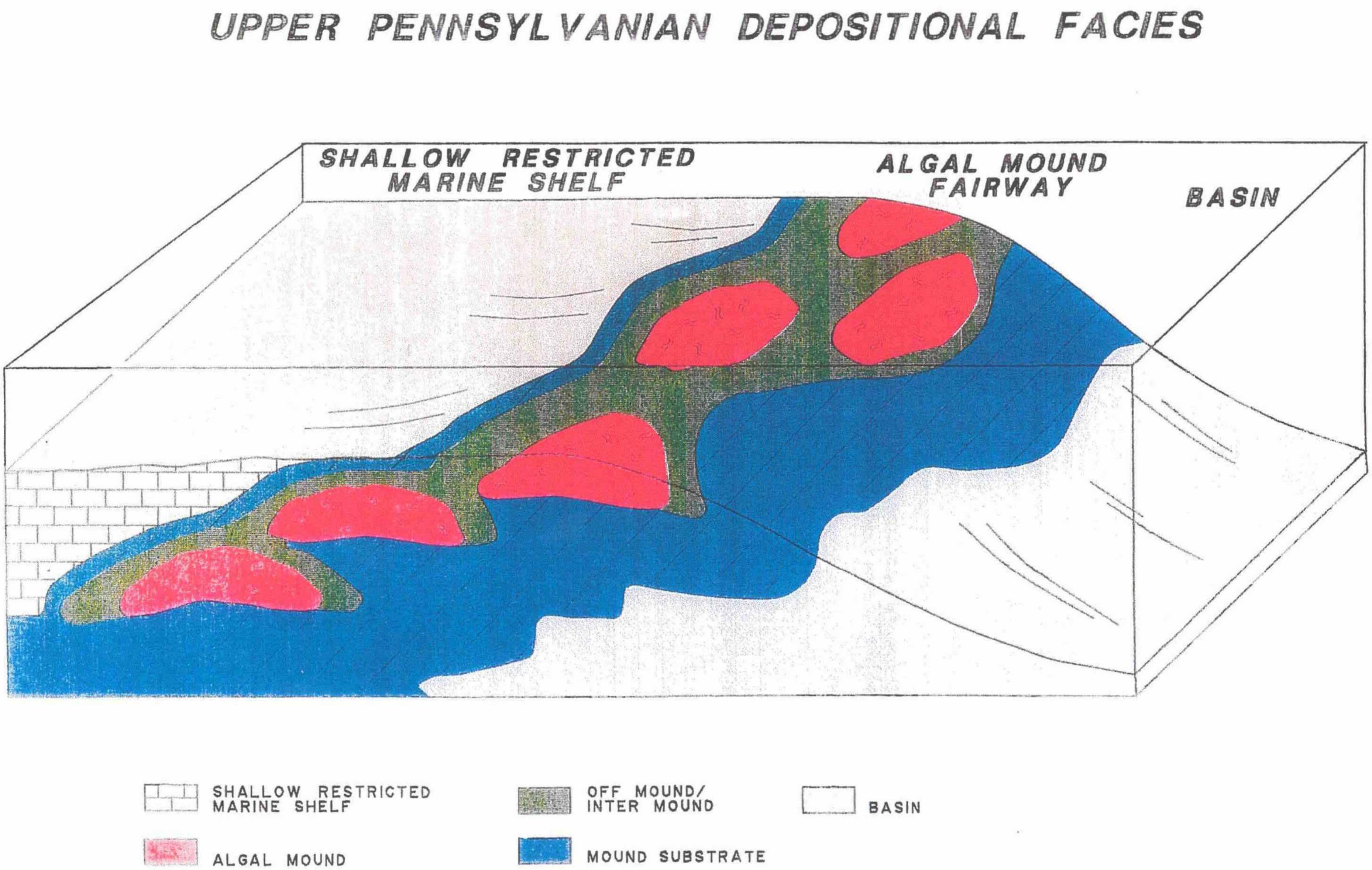

Figure 5. Depositional model for Dagger Draw Upper Penn algal mound complex. Note both the vertical and lateral facies heterogeneity.

Dagger Draw Canyon Formation
Contour Interval = 200 psi
File: DDPR98C.SRF

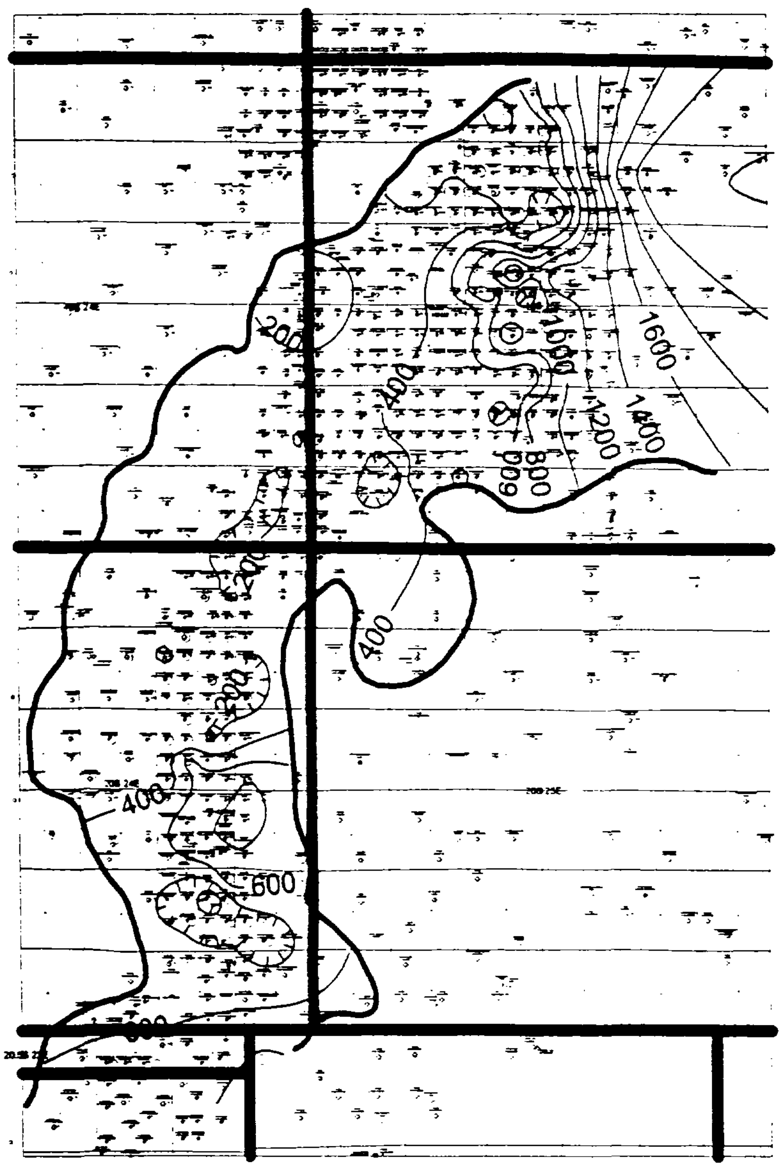

Figure 6. Pressure map (1998 pressures).

Dagger Draw Canyon Formation
File: DDLOGSCH.SRF

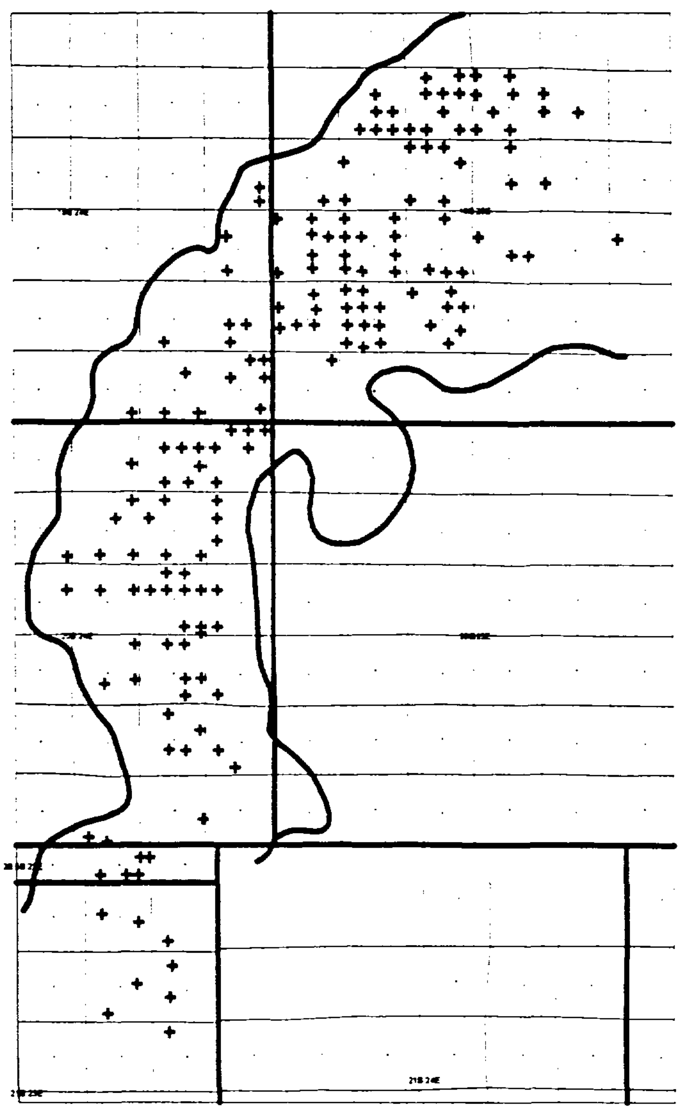

Figure 7. Distribution of wells where logs were analyzed.

Dagger Draw Canyon Formation
Scale Units Are Feet
Files: DDTHITOS.SRF, DDTHITOT.GRD,0DOLNEW.BLN

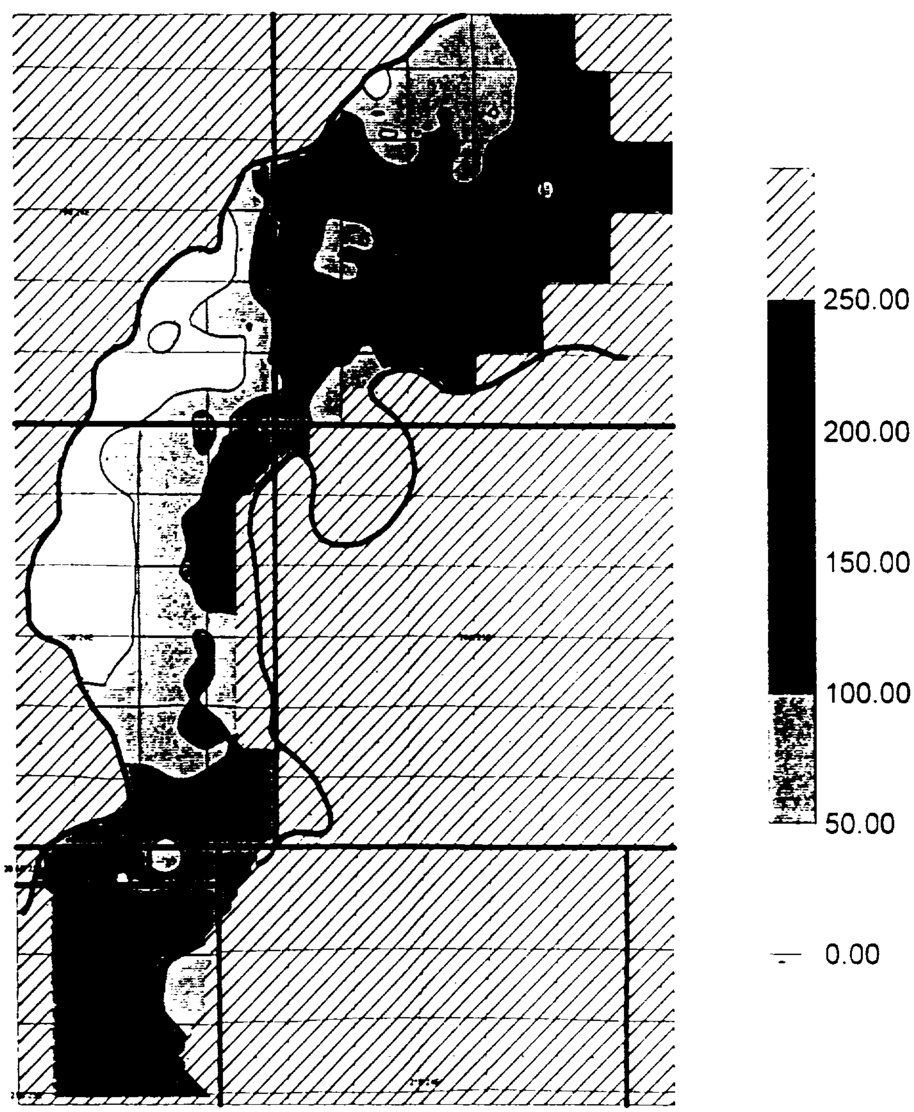

Figure 8. Net thickness from log analysis.

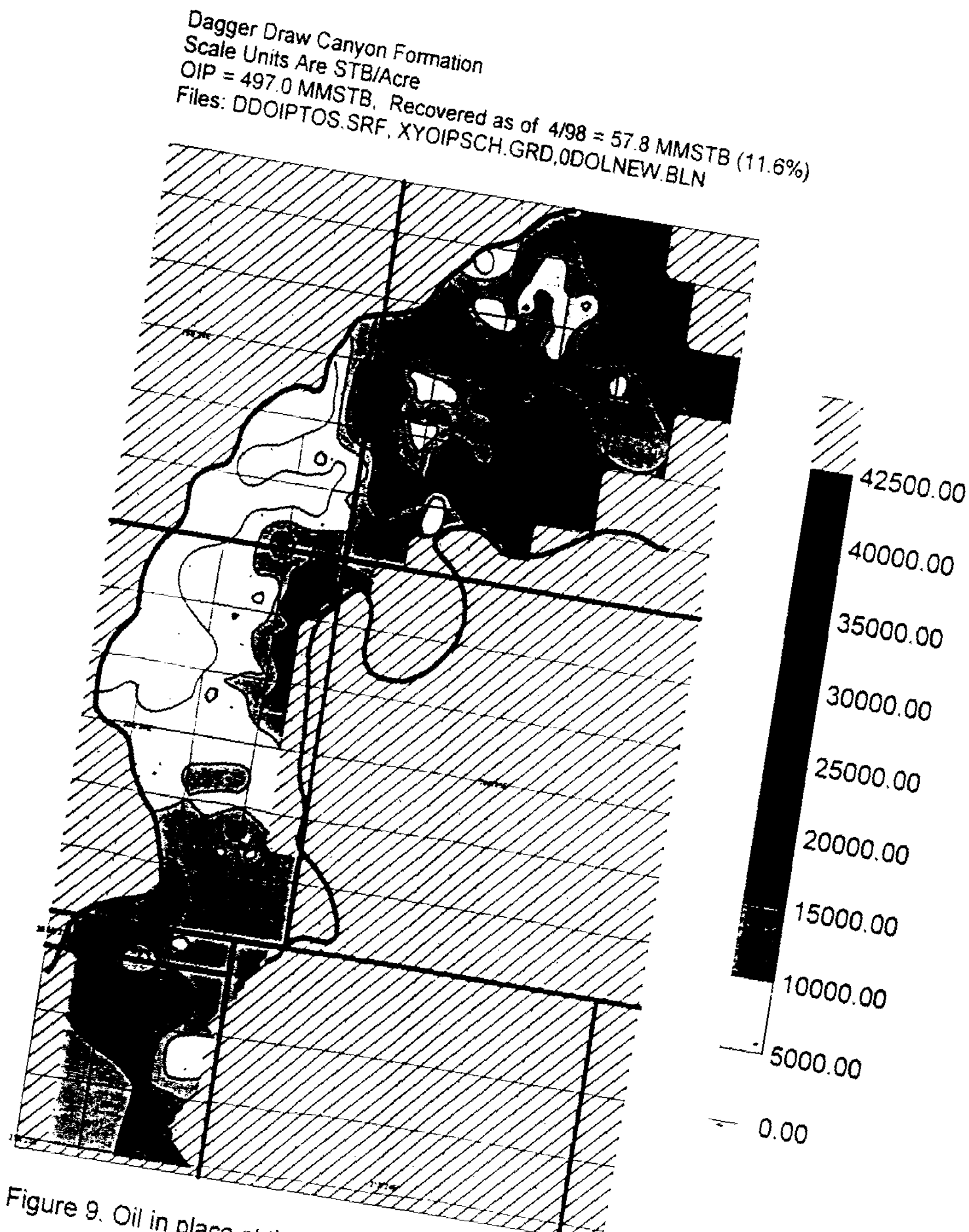

Figure 9. Oil in place at time of logging from log analysis.

Dagger Draw Canyon Formation
Scale Units Are MMSCF/Acre
GIP = 1025 BCF, Recovered as of 4/98 = 274.8 (26.8%)
Files: DDGIPTOS.SRF, XYGIPSCH.GRD, 0DOLNEW.BLN

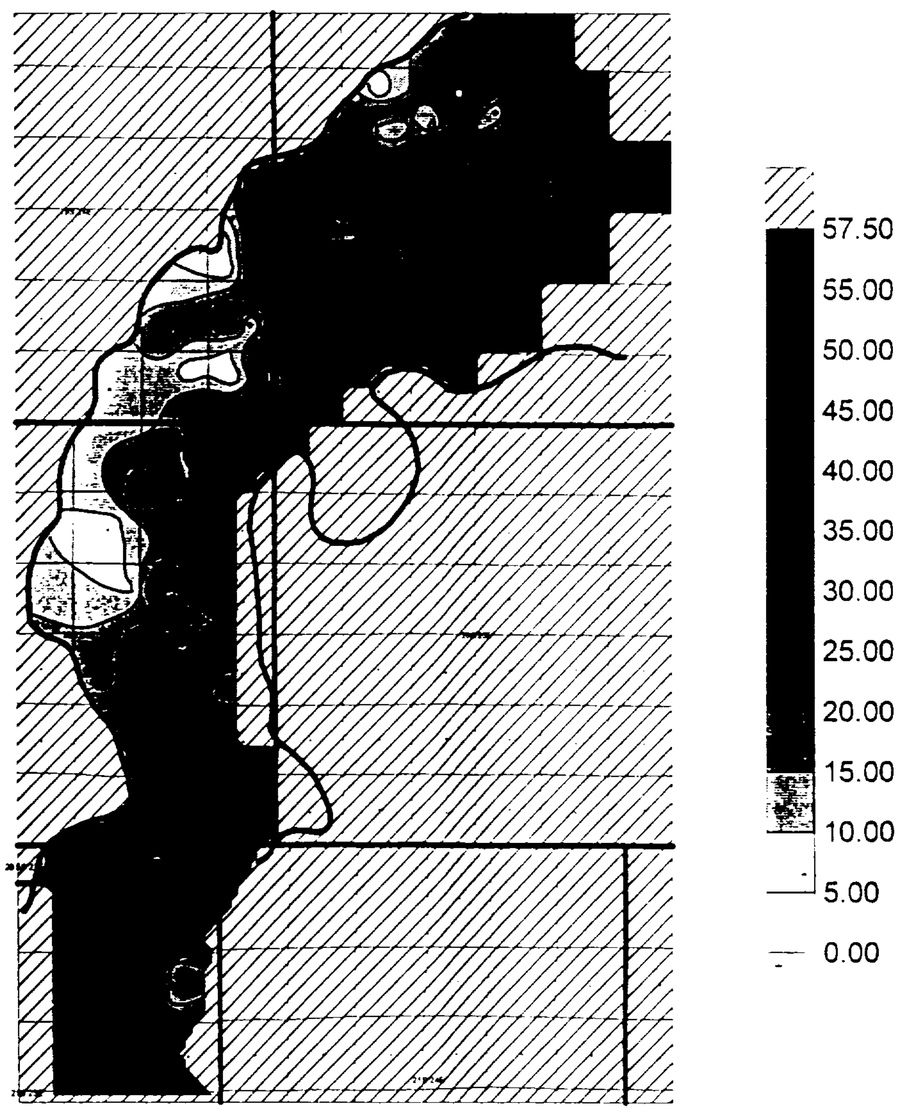

Figure 10. Gas in place at time of logging from log analysis.

Dagger Draw Canyon Formation
Scale Units Are STB/Acre
OIP = 288.7 MMSTB, Recovered as of 4/98 = 44 MMSTB (15.2%)
Files: DDOIPYPS.SRF, DDOIPSCH.GRD, YATESSCH.BLN

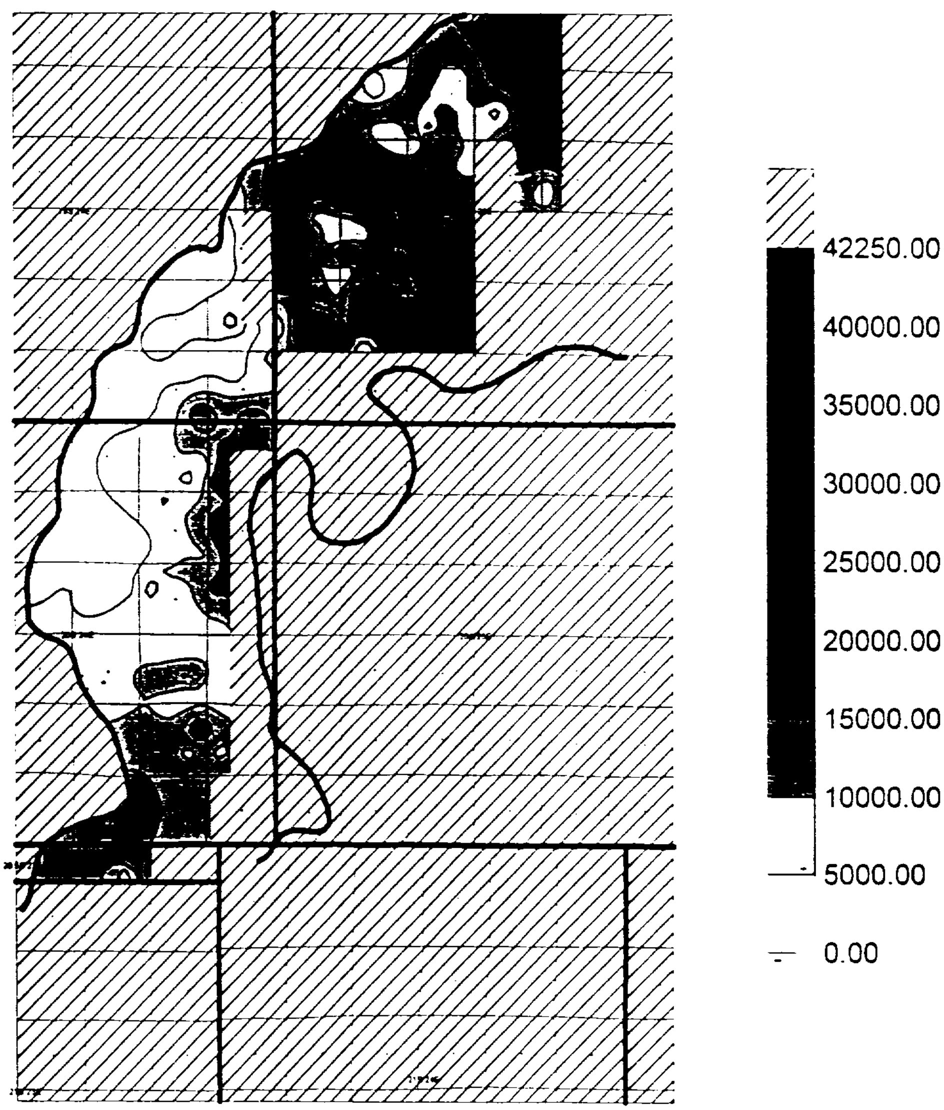

Figure 11. Oil in place at time of logging from log analysis for YPC-operated properties.

Dagger Draw Canyon Formation
Scale Units Are MMSCF/Acre
GIP = 596.9 BCF, Recovered as of 4/98 = 194.2 (32.5%)
Files: DDGIPTOS.SRF, XYGIPSCH.GRD, YATESSCH.BLN

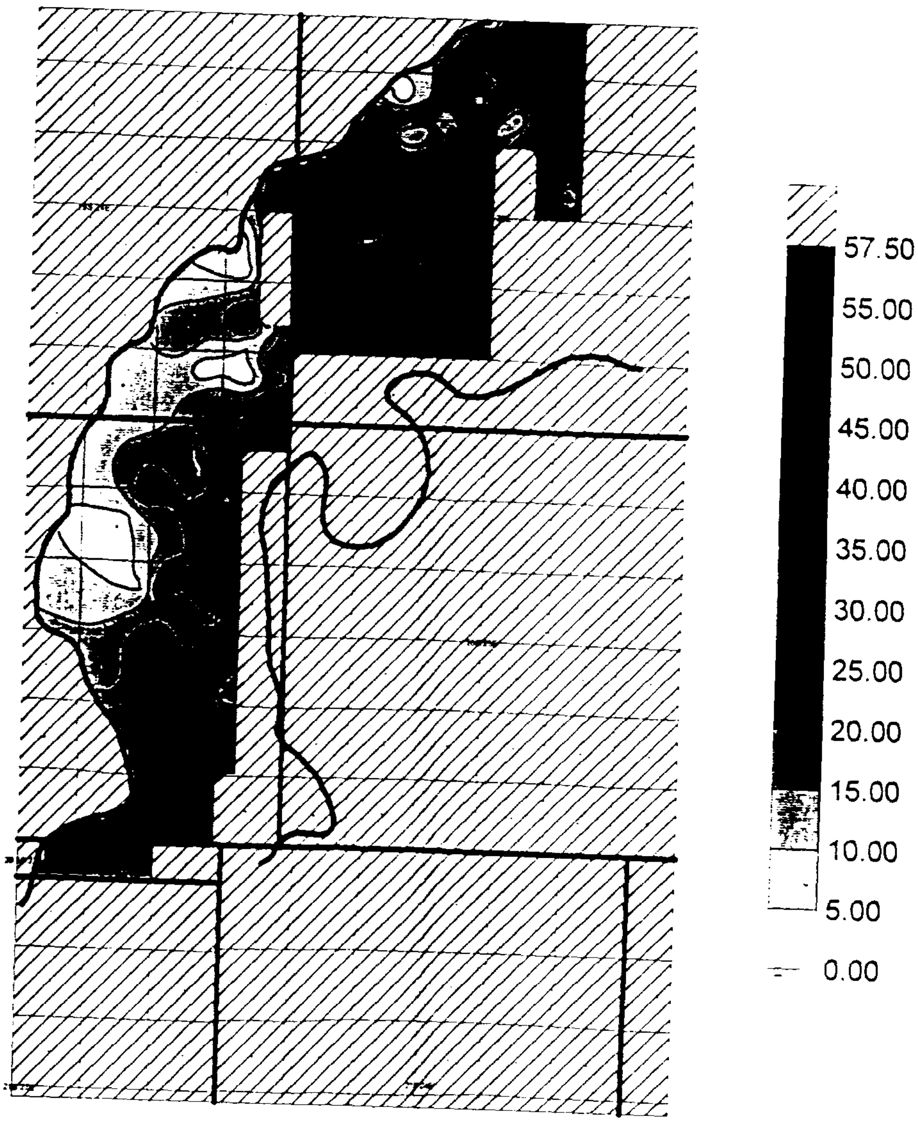

Figure 12. Gas in place at time of logging from log analysis for YPC-operated properties.

Dagger Draw Canyon Formation
Size of Bubble is Linearly Proportional to Amount of Production from Well
Scale: Diameter = 0.0 in. (0 BCF), Diameter = 0.25 in. (6.67 BCF)
Files: SCHLUM:DDCUMG.SRF, XYCUPRO1.XLS, 0DOLNEW.BLN

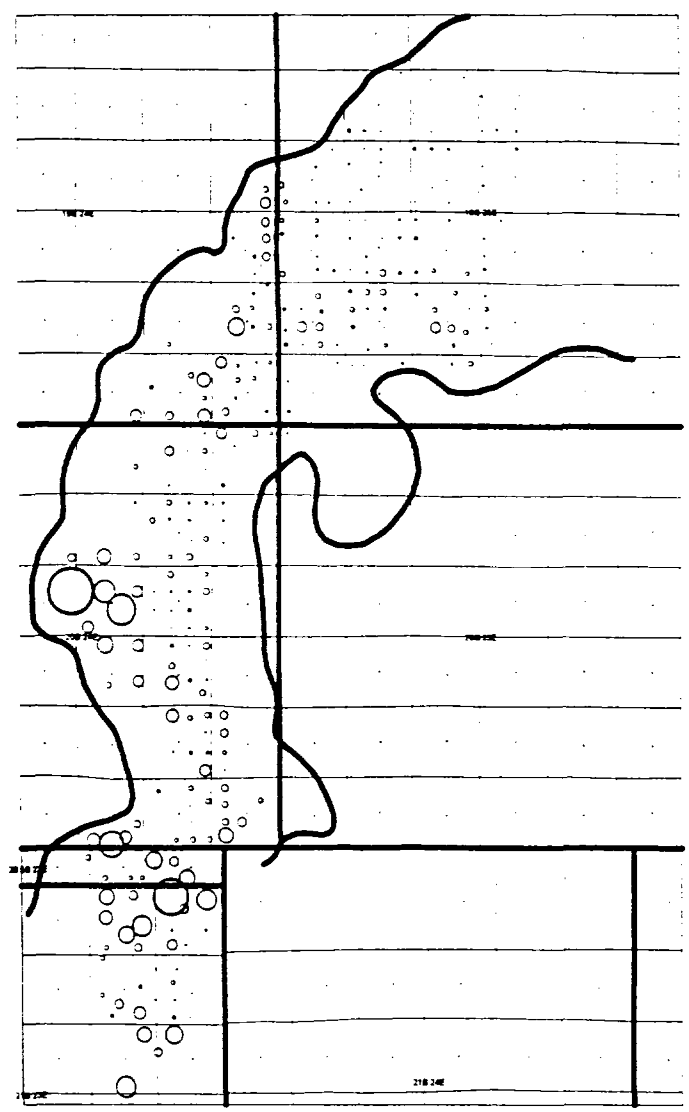

Figure 13. Cumulative gas production through April 1998.

Dagger Draw Canyon Formation
Scale Units Are Fractions
File: DDSGNF.SRF

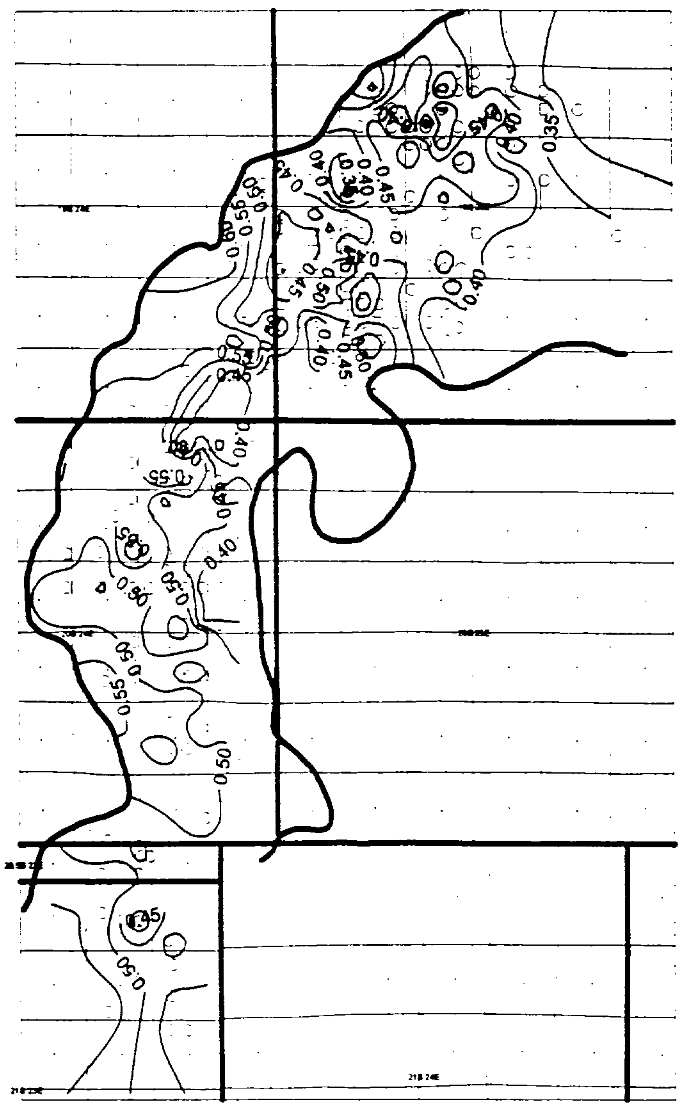

Figure 14. Gas Saturation from Log Analysis.

TABLE 1

Cumulative Production at Dagger draw Through April 1998

OPERATOR	CUMULATIVE OIL STB	CUMULATIVE GAS MSCF	CUMULATIVE WATER STB
Yates Petroleum	33,696,965	150,466,985	127,811,179
Conoco Inc, before 5/1/97	9,767,308	36,455,807	38,762,499
Conoco Wells Since 5/1/97	450,682	5,194,571	2,836,656
Nearburg Producing Co	5,559,526	10,360,924	32,080,940
Marathon Oil Co	4,991,948	51,401,292	19,381,657
Texaco Expl & Prod Inc	1,443,320	8,503,437	3,193,499
Mewbourne Oil Co	925,026	1,239,672	1,142,120
Santa Fe Energy Res Inc	822,838	10,969,651	3,514,422
Southwest Royalties Inc.	160,620	242,312	257,564
TOTAL	**57,818,233**	**274,834,651**	**228,980,536**

TABLE1.XLS
C:\Eng\Mykol\FrankC

TABLE 2
PVT Properties Used in Material-Balance Studies

PRESSURE (psia)	FORMATION VOLUME FACTOR (Bo)	GAS VOLUME FACTOR (bbl/mscf)	GAS DEVIATION FACTOR Z = (PV/NRT)	SOLUTION GAS-OIL RATIO (scf/stb)
5000	1.412			
4000	1.431			
3500	1.440			
+ 3015	1.449			846
2500	1.377	1.010	0.828	686
2000	1.324	1.283	0.841	553
1500	1.273	1.753	0.862	426
1000	1.224	2.719	0.892	304
500	1.174	5.718	0.938	185
200	1.140	14.703	0.977	108
50	1.115	60.703	0.995	55
15	1.065	203.292	1.000	0

+ Reservoir Pressure and Bubble Point Pressure

TABLE2.XLS
Eng\Mykol\FrankC

Table 3.
Discussion of Specific Cases of Interference for North Dagger Draw Field
(Source: Clyde Findlay II, Nearburg Producing Company)

Well	Comments
Patriot AIZ Com #4	Interference observed in mid-1995 when five offset wells shut-in.
Patriot AIZ Com #1	Interference observed - decline rate increased due to offset drilling.
Ross EG Fed Com #8	No interference observed.
Ross EG Com #1	Interference observed - decline rate increased when last offset well was drilled.
Ross EG Fed Com #13	No interference observed.
Hooper AMP Com #3	Interference noted - the #3 caused increased decline in offset wells.
Ross EG Fed #10	Possible interference - Ross #10 total fluid dropped when offset wells drilled.
Ross EG Fed #7	No interference observed.
Ross EG Fed #4	Possible interference - Ross #4 increased oil and gas decline rates late in life when offset locations drilled.
Ross EG Fed #3	Inverse behavior observed - when offset well increased in decline, the Ross #3 flattened. When the offset well flattened, the Ross #3 increased in decline.
Hooper AMP #4	No interference observed.
Patriot AIZ #2	No decline established prior to offsets put on production. No obvious interference.
Patriot AIZ #3	Gas rate dropped in 9-10/94; coincides with Lorene ANN #1 being put on production. Hooper #1 gas rate dropped also.
Ross EG #14	No obvious interference; oil rate drop slightly precedes offset Amole #3 being put on production.
Vann APD #1	Hooper #2 gas, oil and water decline rates increased when Vann put on production.

Table 3.

Discussion of Specific Cases of Interference for North Dagger Draw Field (Source: Clyde Findlay II, Nearburg Producing Company)

Well	Comments
Hooper AMP #1	Decline rate increased when Lorene ANN #1 was put on production. Patriot #3 gas rate dropped at the same time (9-10/95).
Patriot AIZ #10	None obvious; oil and gas rates dropped 3/96.
Patriot AIZ #5	Three offsets were put on production in the 2nd quarter of 1995; the production rates fell but recovered in the 4th quarter.
Cutter APC #1	Patriot #5 responded as described above.
Hinkle ALD #2	Hinkle #1 water rate declined at a greater rate when the #2 was put on production. The Patriot #5 responded as previously described. The Ross IZ #1's oil and gas rates dropped for two months and then recovered.
Ross IZ Com #1	The oil and gas rates dropped for two months as described above.

Dagger Draw Unit
Correlation of Traditional Wire-line logs
to Vuggy Porosity from Tuned-to-Core
Formation Micro Imager logs

Prepared for:
Yates Petroleum Corporation
Artesia, New Mexico

Study done by:
Robert S. Balch, W. W. Weiss, and Shaochang Wo
REACT Group, Petroleum Recovery Research Center
New Mexico Institute of Mining and Technology
Socorro, NM

April 6, 1998

Sketch

Project Results:

1. Well logs and Well-bore images have been collected and processed for the 15 study wells. Nine of which were from the Formation Micro Imager tool (FMI) and were selected for further analysis.
2. Artificial intelligence tools were used to correlate traditional wire-line logs (DRHO, LLD, LLS, NPHI, PEF, RHOB, and GR) to pixel-count (secondary) porosity estimated from tuned-to-core FMI logs.
3. The computed Neural Network architecture and associated weights may be used to estimate secondary (vuggy) porosity in wells containing only traditional wire-line logs.

Correlation of Traditional Wire-Line Logs to FMI Estimated Secondary Porosity

Summary

A nine well data set consisting of traditional logs, and tuned-to-core estimates of secondary porosity from FMI images was used to train an artificial neural system to predict the secondary porosity in wells in the Dagger Draw field, SE New Mexico.

Background

Initial discussions regarding the potential of using traditional wire-line logs to predict FMI secondary porosity responses were conducted during the early part of 1997. The REACT Group using 4 wells from the Dagger Draw Field had previously conducted a pilot project to match traditional logs to total porosity from Schlumberger processed FMI logs [*Chawaithe et al.*, 1997]. The pilot study was successful, and it was determined that a more ambitious study involving correlation of traditional wire-line logs to secondary (vuggy) porosity was feasible. Though the project was initially scheduled to take place between April and August 1997 (4.5 months), delays in receiving tuned-to-core FMI porosity data resulted in the completion of the work during a January through March of 1998 timeframe (3 months).

Objective

The objective of this project is to provide a tool for predicting secondary (vuggy) porosity in the carbonate reservoir of the Dagger Draw Field, SE New Mexico, from traditional wire-line logs. FMI tools are relatively expensive to run, and not yet viable after wells are cased. Using tuned-to-core FMI spot porosity logs and traditional logs, there was a need to produce an artificial intelligence tool capable of predicting spot porosity (pseudo FMI logs) using only traditional logs as input. The tool would provide an inexpensive means for evaluating vuggy porosity in the 300+ other cased wells in the field, and could aid in better understanding total porosity for OOIP and mass balance calculations.

Data Pre-Processing

<u>FMI Spot Porosity</u>

Neil Hurley analyzed image logs for 15 wells [**Table 1**], and cores for 4 of those wells at the Colorado School of mines [*Hurley*, 1997]. Hurley made spot (secondary) porosity estimates for the dolomitic sections from the image logs using thresholds determined from statistical analysis of vugs on core photographs. Hurley reported details of his work directly to Yates Petroleum. The tuned-to-core secondary porosity logs obtained from Hurley represent the secondary porosity used to train our Neural Network.

<u>Raw Data format</u>

The FMI tool is capable of much higher resolution than standard wire-line tools. The data we received from the Colorado School of Mines consisted of spot porosity at 120 samples per foot, and wire-line data interpolated from the original 2 samples per foot to 120 samples per foot. Log data was present for the dolomitic section, overlying and interspersed with limestone, and shale intervals. Spot porosity was not estimated for the shale sections.

TABLE 1	IMAGE	CORE	USED	COMMENTS	NET-DOL.
Barbara Fed. 12	PHI-CBIL	Yes	No	No FMI	Not used
Bone Flats 12-3	PHI-FMI	No	Yes	Only 8ft Dol.	Not used
Binger Aku 1	**PHI-FMI**	**No**	**Yes**		**325**
Boyd 27-5	PHI-FMI	No	No	Too few logs	Not used
Boyd x State 5	**PHI-FMI**	**No**	**Yes**	**Training Well**	**208**
Dagger Draw 12	PHI-CBIL	Yes	No	No FMI	Not used
Dagger Draw 31-1	PHI-FMS	No	No	No FMI	Not used
MOC Federal 5	**PHI-FMI**	**Yes**	**Yes**		**290**
N Indian Basin 22	**PHI-FMI**	**No**	**Yes**		**262**
N Indian Basin 23	**PHI-FMI**	**No**	**Yes**	**Training Well**	**190**
Ross Ranch 22-8	PHI-FMI	No	No	Too few logs	Not used
Ross E6 no 14	**PHI-FMI**	**No**	**Yes**	**Training Well**	**290**
Saguaro Fed com 8	**PHI-FMI**	**Yes**	**Yes**		**204**
Stinking Draw 3	**PHI-FMI**	**No**	**Yes**		**256**
Warren ANW 3	**PHI-FMI**	**No**	**Yes**		**166**

Table 1. Data obtained for the project. We selected only wells with PHI-FMI and seven common well logs - DRHO, LLD, LLS, PEF, NPHI, RHOB, and GR. The Net-Dol. Column reflects feet of dolomite in each well selected for final analysis. Wells used in this study are in bold.

Data Processing

In order to develop the most general analytical tool possible, we decided to resample the wire-line and FMI data to 2 samples per foot. The interpolated traditional log data was simply decimated from 120 to 2 samples per foot, essentially restoring it to its original form. The FMI spot porosity log, however, lost average porosity value when simply decimated. In order to retain full information we averaged the spot porosity data in 60 sample bins. A beneficial side effect of this simple "filter" [**Figure 1,** before and after] was the removal of extreme values (statistical anomalies) from the data set.

We also removed depth intervals corresponding to limestone and shale layers. Limestone does not contain vuggy porosity, but may contain fractures and/or styolite's which can be detected by the FMI tool and may cause spurious correlations between the traditional wire-line data and the spot (vuggy) porosity from the FMI analysis. Spot porosity was not evaluated for shaly intervals (we were given null values), so shale intervals were also removed from the data set. The Photoelectric log was used to remove limestone, by eliminating intervals with PEF response corresponding to Limestone ($\geq$5.08). Hurley used the Gamma Ray log to identify shaly intervals, and we simply removed intervals with null values of spot porosity from the data set.

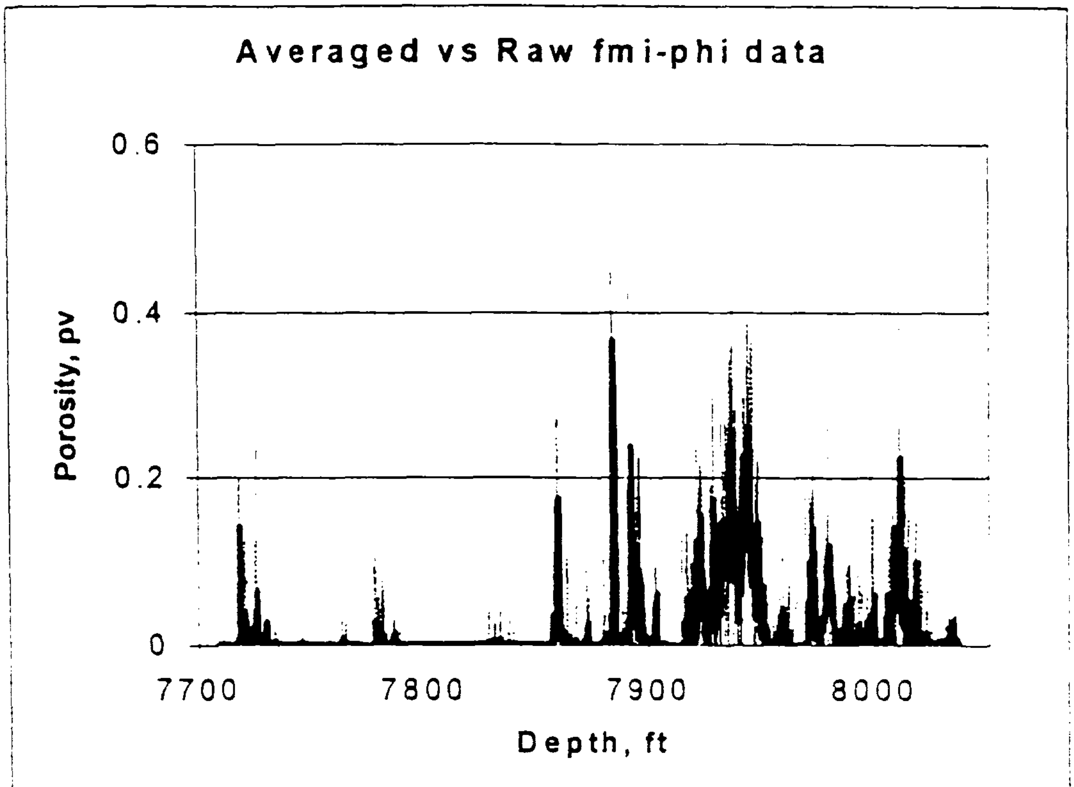

Figure 1. Reduction of Phi-FMI data from 120 samples/foot to 2 samples/foot. Heavy line is data reduced by averaging.

Neural Network Analysis

Neural Networks (NN) or Artificial Neural Systems are computer programs designed to process data by pattern recognition, much like the human brain. Pattern recognition is inherent in log analysis, as such, NN are a useful tool for working with log data. A properly trained NN can be used to predict or forecast complex situations for which linear relationships may not exist. For this study, traditional logs (DRHO, LLD, LLS, PEF, NPHI, RHOB, and GR) are used as inputs that train a NN to predict FMI derived spot porosity.

The human brain consists of billions of interconnected processing elements called neurons. While learning, the human brain adjusts pathways between neurons in response to stimuli, thus generating pattern recognition (memory). Artificial Neural systems work in a similar way, when using supervised training, and can be trained to quickly and efficiently recognize non-linear relationships. Physically, the neural network consists of layers of interconnected neurons [**Figure 2**] the interactions between connected neurons are governed by connections of variable strength known as weights. In the case of supervised learning, the network is repeatedly presented with pairs of input values (logs in this case) and output values (for this study FMI spot porosity). The weights are initially randomly assigned, and are adjusted by the learning algorithm on each successive iteration. When the difference between the predicted values and actual values is small enough, the network is "trained", and may be used to predict, without prior knowledge, the desired response in other wells.

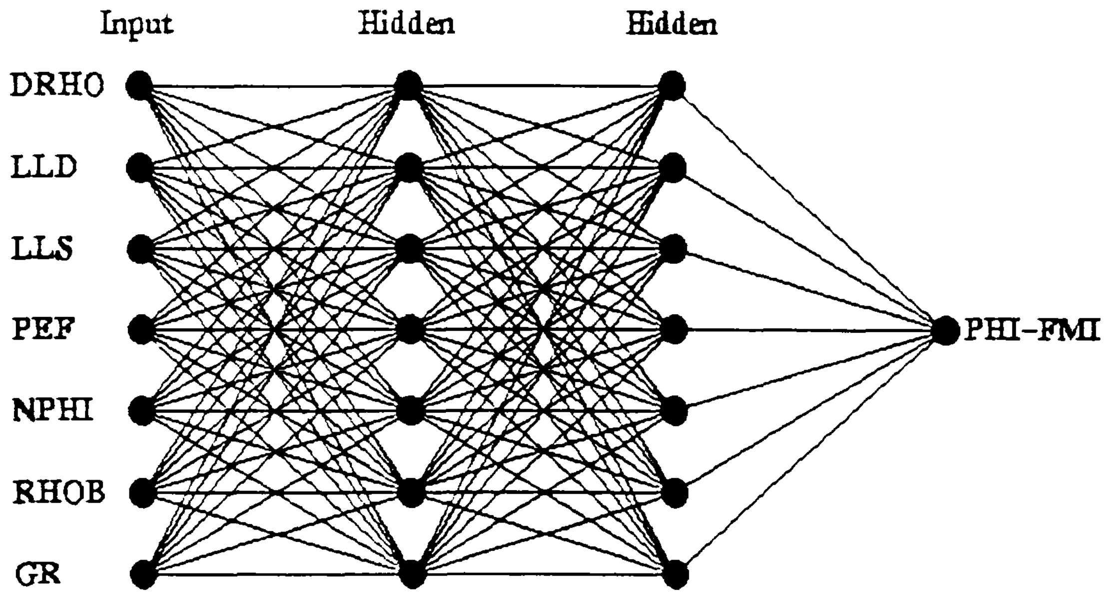

Figure 2. Fully connected 4-layer Neural Network architecture used in this study. The input layer is comprised of the seven selected traditional wireline logs. Each neuron is linked to each neuron in the next layer making this a fully connected network. Each connection generates one weight, for a total of 105 weights using this architecture.

Results

Training the Neural Network

A nine well subset was selected (see **Table 1**) for which each of the seven traditional logs were available, and FMI based spot porosity estimates had been made at the Colorado School of Mines. When training a neural network, it is best to use a portion of the data for actual training, leaving the remainder for testing the predictive ability of the Neural Net. Training data needs to be representative of the range of input and output values, and each input and output stream needs to be normalized to match the range of possible values in the study area.

The method used to select training data involved the use of fuzzy curves. Essentially, fuzzy curves "grade" the input data with respect to its ability to predict the output data. We evaluated a performance index for each input curve (traditional log) using the fuzzy algorithm of *Lin and Cunningham* [1994] for each of the nine sets of wire-line curves corresponding to the nine wells in the data set. Initial attempts to train the NN utilized wells that had high performance indexes. We found that the networks would train to a very high correlation coefficient (E.G. 0.94) but weren't general enough to predict accurate responses in the other wells. We observed that the range of performance indexes is roughly distributed as a bell curve, and the best training data should thus come from wells representing the middle of the range of performance. We trained with the three wells that had median performance indexes to a correlation coefficient of 0.8 [**Figures 3 and 4**], and yielded a generalized set of weights. More importantly, the NN predicted FMI spot porosity in the test data quite well with respect to location and magnitude of vuggy porosity. Crossplots of predicted vs. expected values are commonly used to evaluate how well a NN has trained and predicted data in testing. Crossplots do not work well as a diagnostic tool when confronted with very complex problems, or problems where each predicted point is systematically shifted, either in depth or magnitude, with respect to expected values. In the absence of well-behaved crossplots, examination by eye, of how well the predicted curve matches the trends in the expected data may be used to evaluate the success of the NN.

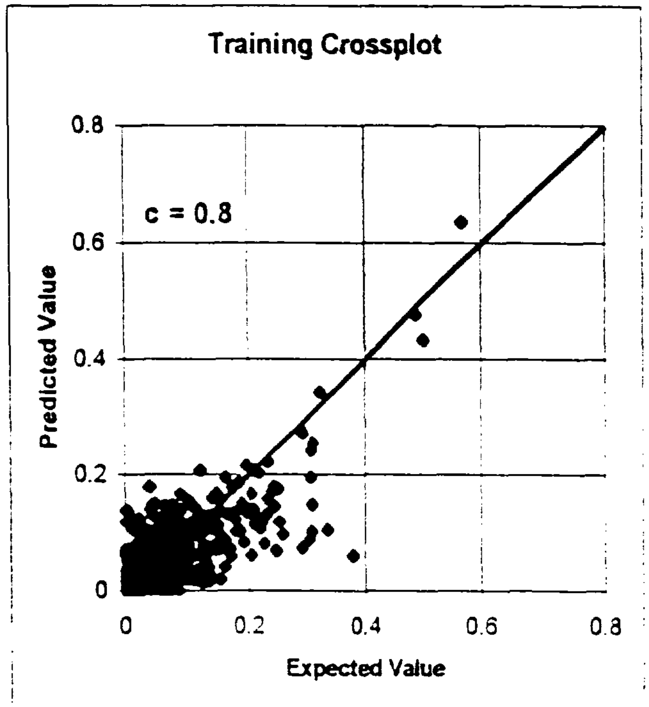

Figure 3. Crossplot of training data (1375 points). The Neural Network has done a good job of matching predicted to expected values.

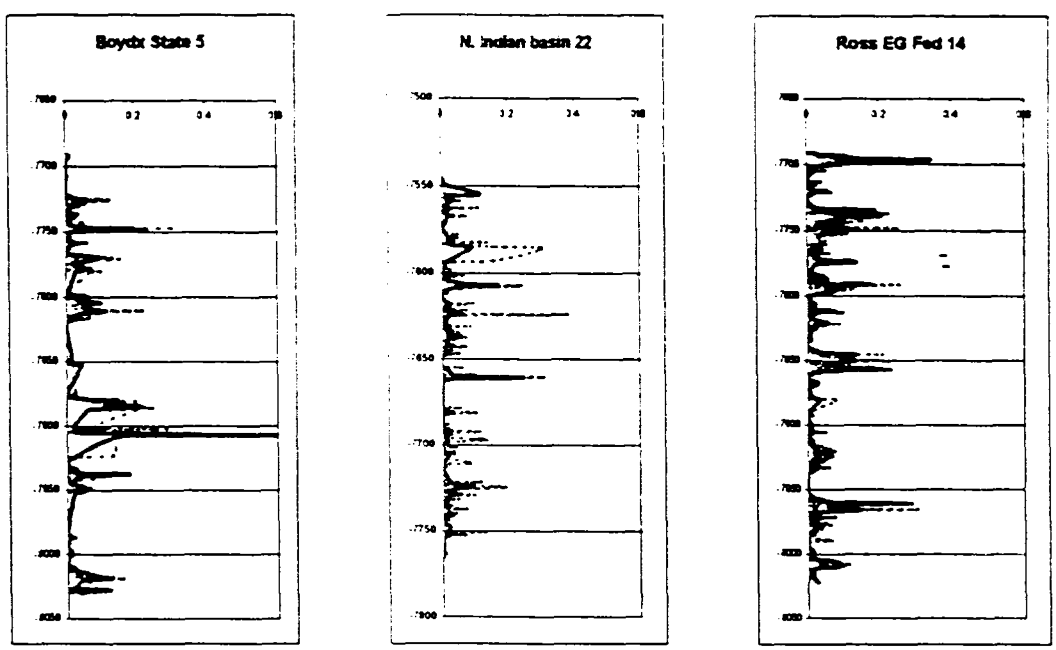

Figure 4. Predicted (thick lines) vs. Expected values for the training data set (1375 points total).

Testing the Spot Porosity Prediction Tool

While training with one-third of the wells, the remaining six wells were set aside for testing the predictive tool, and were never used during the training. For the most part the tool predicts zones and trends in the vuggy porosity from the tuned-to-core FMI log. Because it was made sufficiently general, the tool can be used for identifying vuggy zones from traditional wire-line logs across the entire field, and with good reliability (c = 0.8) can predict the magnitude of the porosity associated with those zones. **Figures 5 and 6** show the results of the prediction testing for the six wells that were not used in training the NN.

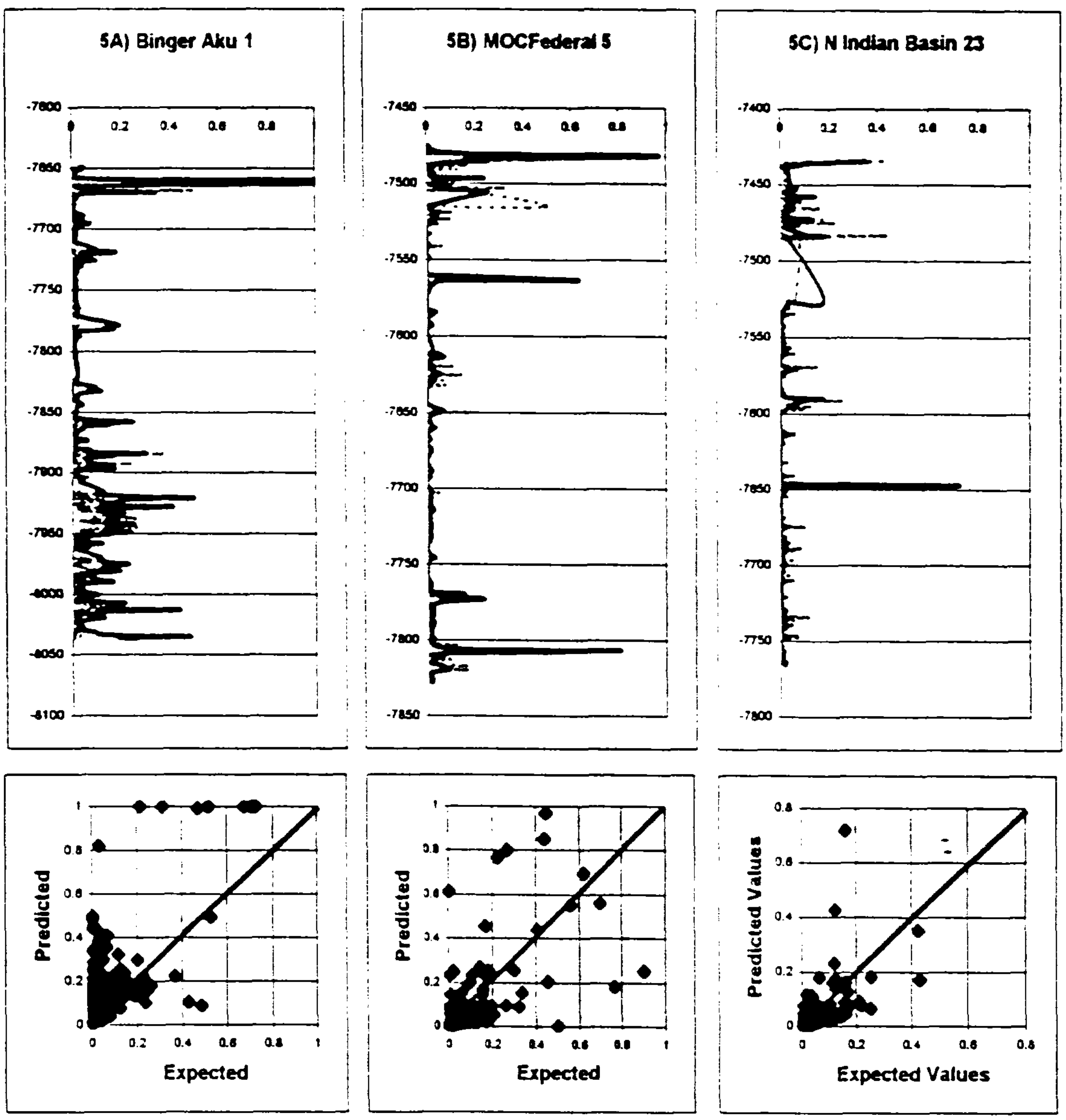

Figure 5. Testing wells, matched PHI-FMI curves and crossplots. Heavy lines are predicted values. **5A) Binger Aku 1** is somewhat over-predicted, however, only 1.2% of values poorly fitted. **5B) MOC Federal 5** has a generally good match between predicted and expected values, with only 1.3% of values poorly fitted. **5C) N Indian Basin 23** matches expected and predicted responses very well.

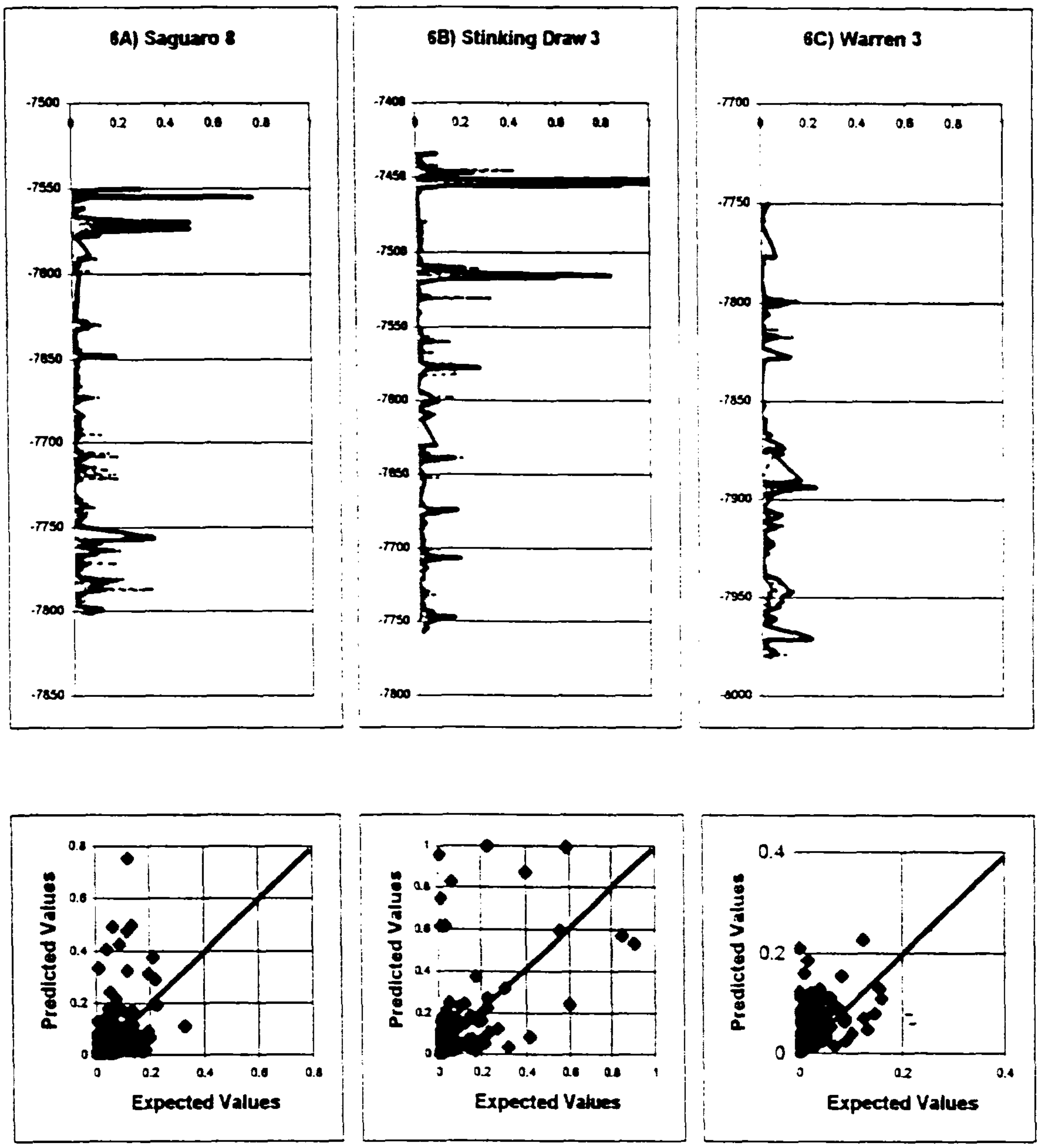

Figure 6. Testing wells, matched PHI-FMI curves, and crossplots. Heavy lines are predicted values. **6A) Saguaro 8** is well predicted, with only 1.4% of values poorly fitted. **6B) Stinking Draw 3** has a generally good match between predicted and expected values, with only 1.1% of values poorly fitted. 5C) Warren 3 matches expected and predicted responses very well, except for a general over-prediction of porosity.

How well does the predicted normalized porosity match the expected values? **Table 2** contains data on the average values for expected and predicted porosity. Unfortunately, the Binger Aku 1 well seriously overestimates porosity. The Binger well had the highest performance rating of all of the wells, followed by the Stinking Draw well, which was also slightly over-predicted. Differences in well lithology may be responsible for the over-predictions. As is shown on table 2, the predictions do match the expected values reasonably in the other wells, and on average.

Table 2	**Ave expected Φ**	**Ave predicted Φ**	**% of expected**
Boyd x State 5	3.31	3.55	107%
N Indian Basin 23	2.44	1.44	59%
Ross EG 14	3.03	3.49	115%
Binger Aku 1	**2.96**	**8.36**	**282%**
MOC Federal 5	**2.99**	**3.33**	**111%**
N Indian Basin 22	**2.22**	**1.83**	**82%**
Saguaro 8	**3.04**	**4.33**	**142%**
Stinking Draw 3	**2.93**	**4.96**	**169%**
Warren 3	**1.32**	**3.31**	**250%**
Total	*24.24*	*34.60*	*142%*

Table 2. Average normalized porosity for predicted and expected data. Testing wells are in bold.

Using the Spot porosity Prediction Tool

As illustrated with the six wells in **Figures 5 and 6**, wells with the traditional logs, DRHO, LLD, LLS, PEF, NPHI, RHOB, and GR can be evaluated for distribution and magnitude of secondary porosity, using the tool. The input data must have limestone and shales sequences removed, preferably using the PEF and GR curves as has been done with data used to train and test the NN. Input wire-line data also needs to be normalized within the same ranges used for the training and testing data.

Potential Future Studies

Field-Wide Predictions of Vuggy Porosity (All Wells)

The most logical extension of this study is prediction of vuggy intervals in other wells in the field. Potential may exist for economic recompletion of bypassed porosity.

Field-Wide Evaluation of Primary, Secondary, and Total Porosity

An interesting implication of this work is the potential to get a firm grasp of total porosity for vuggy carbonate reservoirs, an area for which there is little agreement. Neutron porosity logs are thought to underestimate overall porosity in vuggy carbonates, and as such may give inaccurate estimates for OOIP, and mass balance calculations. Knowledge of secondary porosity from predicted FMI responses, when coupled with total porosity from core data could yield a more accurate estimate of primary porosity. A NN architecture could be developed to predict core-porosity (total porosity) using the same input wire-line logs, and core-analyses from the field. Four wells from this data set have core, and primary, secondary, and total porosity could be calibrated to the FMI secondary porosity estimates, and/or neutron logs. Better estimates of FMI secondary porosity for wells may be obtained by subdividing the field into geologic units for a set of less general predictive tools.

Geostatistical Interpolation of Primary, Secondary, and Total Porosity Between Wells

Vertical and horizontal infilling of secondary and primary porosity could be accomplished using the above mentioned results, and a geostatistical mapping package such as GVIZ. Infill drilling efforts could be maximized, and risks reduced with geostatistical maps, of zones of additional porosity were created.

Recently, the *REACT* Group has gained experience in applying Neural Network technology to estimate water saturation from old logs. This technology might enhance the Sw estimates at dagger draw, and could be incorporated into future studies.

References

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