FOSSIL ENERGY

DOE/BC/14984-14
(DE98000487)

RESERVOIR CHARACTERIZATION OF THE ORDOVICIAN RED RIVER FORMATION IN SOUTHWEST WILLISTON BASIN BOWMAN CO., ND AND HARDING CO., SD

Topical Report
August 1997

By
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July 1998

Performed Under Contract No. DE-FC22-94BC14984

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U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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Improved Recovery Demonstration for Williston Basin Carbonates

Topical Report

Reservoir Characterization of the Ordovician Red River Formation in Southwest Williston Basin, Bowman Co., ND and Harding Co., SD

Abstract

This topical report is a compilation of characterizations by different disciplines of the Red River Formation in the southwest portion of the Williston Basin and the oil reservoirs which it contains in an area which straddles the state line between North Dakota and South Dakota. Goals of the report are to increase understanding of the reservoir rocks, oil-in-place, heterogeneity, and methods for improved recovery. The report is divided by discipline into five major sections: 1) geology, 2) petrography-petrophysical, 3) engineering, 4) case studies and 5) geophysical. Inter-woven in these sections are results from demonstration wells which were drilled or selected for special testing to evaluate important concepts for field development and enhanced recovery.

The Red River study area has been successfully explored with two-dimensional (2D) seismic. Improved reservoir characterization utilizing 3-dimensional (3D) and has been investigated for identification of structural and stratigraphic reservoir compartments. These seismic characterization tools are integrated with geological and engineering studies. Targeted drilling from predictions using 3D seismic for porosity development were successful in developing significant reserves at close distances to old wells. Short-lateral and horizontal drilling technologies were tested for improved completion efficiency. Lateral completions should improve economics for both primary and secondary recovery where low permeability is a problem and higher density drilling is limited by drilling cost. Low water injectivity and widely spaced wells have restricted the application of waterflooding in the past. Water injection tests were performed in both a vertical and a horizontal well. Data from these tests were used to predict long-term injection and oil recovery.

Reservoir Characterizations of the
Ordovician Red River Formation in Southwest Williston Basin
Bowman Co., ND and Harding Co., SD

Executive Summary

This topical report is a compilation of characterizations by different disciplines of the Ordovician-age Red River Formation and the oil reservoirs which it contains in an area in the southwest portion of the Williston Basin which straddles the state line between North Dakota and South Dakota. This area is off the flank from the Cedar Creek anticline, a major feature in the Williston Basin. Oil production was established in the 1950's following exploration activity on the Cedar Creek anticline. Many of the reservoirs were found by exploration aided with 2D seismic and are characterized by relatively small structures. Although there are four major porosity intervals in the Red River, only two have produced significant oil reserves.

The Red River Formation in the southwest portion of the Williston Basin has recently become an active area for drilling. Bowman County became the leading oil-producing county in the state of North Dakota because of successful completions of horizontal wells in Red River B zone reservoirs. This increase in production exemplifies the under-developed potential of the Red River in the area.

Recovery factors by primary depletion from various fields have been low with an average of 11.4 percent of original-oil-in-place (OOIP). Producing mechanisms vary by field and porosity zone from liquid expansion to water-drive from the flanks. The highest recovery factors are about 28 percent of OOIP. Low recovery at many fields is the result of widely spaced wells and low to moderate permeability. A limited number of enhanced-recovery projects in the area have experience some technical success but with questionable profitability.

The goals of this report are to increase understanding of the reservoir rocks, oil-in-place, heterogeneity, and methods for improved recovery. This report is divided by discipline into five major sections: 1) geology, 2) petrography-petrophysical, 3) engineering, 4) case studies and 5) geophysical. Inter-woven in these sections are results from demonstration wells which were drilled or selected for special testing to evaluate important concepts for field development and enhanced recovery.

The upper Red River consists of four porosity intervals which recorded wide-spread episodic events. These intervals are labeled (from youngest to oldest) A, B, C and D zones. The primary intervals for oil production are the B and D zones. The A and C zones are generally non-productive to marginal. Depositional environments were constant across most of the Williston Basin which resulted in laterally continuous units with uniform primary fabrics. While primary fabric is important to subsequent diagenetic processes, lateral changes in depositional environments cannot be used for explaining variable porosity within a given genetic unit.

Reservoir heterogeneity was evaluated by the drilling of four wells. Three of these were vertical wells which tested predictions from 3D seismic of reservoir compartments in the Red River D zone at locations which offset mature production. These three wells successfully achieved their objective in penetrating thick, porous intervals in the D zone which had not been affected by offset completions. Recoverable reserves from the D zone in the demonstration wells are estimated at from 31,800 to 47,700 m^3 (200,000 to 300,000 bbl) for each well. Results from the demonstration wells confirm great variability of the D zone. Porosity blooms in the D zone are

preferentially located on the flanks of structural features where demonstration wells were drilled. The Red River B zone was found to exhibit less variability of reservoir development compared to the D zone. Pressure data from drillstem tests taken in demonstration wells and other pressure buildup data confirm good communication with offset wells.

Modern seismic methods of processing and 3D acquisition can help improve reservoir definition leading to better recovery by primary and secondary from existing reservoirs by targeting thicker porosity development and identifying subtle basement faults or lineaments. Two 3D seismic surveys were acquired over areas with multiple structures and mature production. A highlight of the project is the development of a seismic model for predicting porosity development in the Red River D zone. Amplitude mapping of properly processed data can predict thicker and more porous intervals in the Red River D zone. Seismic amplitude indicates the distribution of porosity development in the D zone to be spotty and random, but primarily located in low areas and along flanks of structurally positive features. Modeling also suggests that thicker and more porous B zone development can be observed seismically but that the variation is subtle and ambiguous in actual recorded data.

Water injection tests were performed in both a vertical and a horizontal well in the Red River B zone in the north area of the Buffalo Field, Harding Co., SD. Data from these tests were used to predict long-term injection and oil recovery. Ultimate recovery after waterflooding with horizontal wells as injectors is predicted to be 26 percent of OOIP, an incremental recovery of 15 percent, in that particular reservoir. Both productivity and injectivity from horizontal wells are a factor of three to four compared to conventional, vertical wells in the Red River B zone. It is advantageous to drill horizontal wells in place of higher-density, vertical wells for enhanced recovery in the Red River B zone because drilling and completion costs are only about 50 percent more than conventional wells.

Based on the results of this study, significant reserve additions in the Red River D zone may yet be found along the flanks of small structures where there has already been production. The demonstration areas of this project appear to be identical (with respect to deposition, diagenisis and tectonic influence) to many other fields in the study area. The potentially under-developed structures may not be limited to just those where crestal wells exhibit poor reservoir development. These reserves will be found by application of 3D seismic and subsequently targeted wells. Other significant reserve additions will be developed from waterflooding the Red River B zone with horizontal wells. Low water injectivity and widely spaced wells have restricted the application of waterflooding in the past. As field demonstration activity of this project proceeds, the application of new horizontal wells and drainholes in existing wells will be assessed for incremental primary reserves and acceleration of secondary reserves.

GEOLOGICAL CHARACTERIZATIONS

Mark A. Sippel and Kenneth D. Luff

Introduction

This report covers basic geological characterizations of major reservoir and non-reservoir units of the upper Red River. Depositional environments in the Red River Formation were constant across the study area and much of the Williston Basin which resulted in laterally continuous units with uniform primary fabrics. Lateral changes in depositional environments cannot be used for explaining variable porosity within a given genetic unit. Subsequent diagenetic and dissolution processes and faulting are the source of most heterogeneity found in porosity units of the upper Red River. Activity for exploration and development of Red River reservoirs has undergone several cycles. Each cycle has been precipitated by emerging technologies. In the 1970's it was two-dimensional (2D) seismic. Horizontal drilling has been popular since 1994. Three-dimensional (3D) seismic has been recently applied. Each technology and development cycle present new sources of data and opportunities for advancing reservoir characterization of the Red River. This report summarizes observations and characterizations made in the past and offers additional insights resulting from recent drilling activity and study.

Setting

The Ordovician Red River fields studied for this project lie in the southern Williston Basin on the northeastern flank of the southern end of the Cedar Creek Anticline (figure 1) The study area includes portions of Bowman Co., ND and Harding Co., SD (figure 2). The area has gentle northeasterly regional dip of less than 1° at Red River depth. Oil entrapment occurs by up-dip porosity pinch-out, low-relief structural closures and low-displacement faulting. Reservoir rocks in all oil accumulations are dolomitized carbonate mudstones and wackestones which were deposited in open to restricted shelf environments.

The Ordovician Red River in the Bowman-Harding area is characterized mostly by accumulations of small areal extent at depths from 2590 to 2895 m (8500 to 9500 ft). Well spacing for initial exploration has been 129 ha (320 acre) and some areas which have been unitized for enhanced recovery are developed with 65-ha (160-acre) patterns. The primary exploration tool during initial development of the area in the 1970's and 1980's was two-dimensional (2D) seismic. The earliest wells were drilled based apparent structural closure defined by an Ordovician Winnipeg time reflector and various isochron maps for overlying horizons. Published reservoir studies indicate primary recoveries averaging 15 percent with a range of 6 to 20 percent.

Reservoir Intervals

The base of the Red River is a gradational change to Ordovician Winnipeg Shale. The Red River is overlain by the Stony Mountain Shale (figure 3). The total Red River Formation thickness in the study area is slightly greater than 152 m (500 ft) between the Winnipeg and Stony Mountain shales. Oil production occurs only in the upper 76 m (250 ft) of the Red River interval.

The Red River is informally divided here into upper and lower units based on the occurrence and absence of hydrocarbon production and follows terminology used by Carroll, 1978. This distinction is different from others (Kendall 1976) who placed the lowest (oldest) oil-productive porosity in the lower Red River unit based on petrographical observations relating to relative water depth.

The Red River Formation is an example of cyclical carbonate sedimentation. In the southern Williston Basin, the Red River Formation records periods of increasing restriction in the Middle to Late Ordovician which culminate in deposition of anhydrite. The stratigraphic terminology used in the area has undergone an evolutionary process and can present a communication problem and mis-correlation for those who have followed the oil activity in the area over the past couple decades. An attempt has been made to use stratigraphic terminology most generally employed by operators on the Bowman-Harding area. Figure 4 demonstrates the current, commonly used terminology and examples of terminology employed in the past. Four cycles (zones) in the upper Red River have been recognized in the Bowman-Harding area from youngest to oldest as A, B, C and D. The B and C zones of the Red River Formation represent more complete depositional cycles and consist of several distinct parts or sequences (figure 5). In ascending order theses are (1) impermeable, mottled, slightly dolomitic, bioturbated fossiliferous wackestone, (2) locally dominant burrowed carbonate mudstones and skeletal wackestones, (3) irregularly laminated, dolomitized carbonate mudstones, (4) beds of nodular-mosaic, nodular or enterolithic anhydrite and (5) a thin argillaceous bed that corresponds to a gamma-ray log marker (Carroll 1978 and Longman et al 1992). This depositional sequence has been described as analogous to modern subkha depositional systems found in the Persian Gulf . The primary intervals for oil production in the Bowman-Harding area are the B and D zones.

Lower Red River. The lower Red River occurs approximately 69 m (225 ft) below the top of the Red River and at the base of the D zone porosity (figure 3). There are approximately 10 wells in the study area which drilled through the lower Red River to the Winnipeg. None of these wells encountered porosity in this approximately 91-m (300-ft) interval. The lower Red River consists of deep-water, open-shelf limestone which is dark gray in color.

Red River D Zone. The Red River D zone is found at approximately 53 m (175 ft) from the top of the Red River or base of the Stony Mountain Shale (figures 3 and 6). The gross porous interval ranges in thickness from 12 to 26 m (40 ft to 85 ft), with an average net porous thickness of 10 m (32 ft). Productive porosity has an arithmetic mean of 14.6 percent with a geometric-mean permeability of 8.1E-3 μm^2 (8.2 md). The Red River D zone develops the thickest reservoir interval and greatest permeability compared to the other Red River zones.

The D zone began with deposition of lime mudstone in a relatively deep normal marine environment. As the water depth decreased, layers of lime wackestone were deposited in approximately eight layers. These layers range in thickness from 0.6 to 6 m (2 to 20 ft). Deposition of the D zone cycle ended with a transgression (deepening of water depth) that resulted in lime-mud deposition. The top of this layer roughly marks the beginning of the C zone cycle.

There exists a difference of opinion whether the oldest porosity member, here called D zone, is part of the cycle which includes the second oldest porosity zone, here called C zone. Some workers have correlated the Bowman-area porosity members described here as the C and D zones with the Laminated "C" and Burrowed "C" zones of the central Williston Basin, respectively (figure 3). The reader is advised to be aware of the conflicting terminology. The Red

River D zone does not exhibit the repeated depositional sequence of the overlying A, B and C zones which culminate in the deposition of an anhydrite cap. Most workers agree that the deposition of the D zone was in deeper water than the A, B or C zones. Whatever the label, the oldest and lowest porosity has a consistent character and is usually separated from the overlying C zone by 6 to 9 m (20 to 30 ft) of dense lime mudstone.

The D zone wackestone grains consist of broken fossil debris. Animal burrows are observed in cores from the D zone. These wackestone layers are frequently dolomitized and can be important oil reservoirs. It is noted that these layers can be identified in every well except in those few wells that are so heavily dolomitized that the original depositional fabric has been destroyed. The wackestone layers can still be observed on resistivity logs from wells with low-porosity in the D zone. Study has shown that D zone porosity development is related to local topography during Red River time.

Figure 6 is a cross section from selected wells and demonstrates the wide variation of porosity development in the D zone. Individual layers in the D zone can be correlated between most wells in the study area. The cross section shows that greater porosity is associated with a thickening of the gross D zone porous intervals. Thin-interval wells are found where isopach mapping of overlying Red River and higher intervals indicate high-relief paleo structure. Thick interval wells are found on flanks of paleo topography or in embayments. This suggests that variation of thickness in the D zone is the result of 1) more sediments being deposited in low areas and 2) uplifting, shortly after deposition, which caused compaction and pressure dissolution of D zone beds.

The D zone has been a prolific source of oil reserves in some wells. Early in the exploration history of the area, it was commonly thought that structural closure of 23 to 30 m (75 to 100 ft) was necessary for oil entrapment in the D zone. However, stratigraphically trapped and prolific D zone accumulations have been found as exploration in the area evolved. In the upper Red River, D zone completions have the greatest average oil reserves from vertical wells. Frequently, D zone completions exhibit a water-drive behavior, with a constant fluid rate and increasing water cut.

Red River C Zone. The Red River C zone is found at approximately 26 m (85 ft) from the top of the Red River or base of the Stony Mountain Shale (figures 3 and 6). The Red River C zone porosity typically exhibits a shallowing-upward sequence that culminates with a thick anhydrite. The gross porous interval ranges in thickness from 6 to 15 m (20 to 50 ft), with an average net porous thickness of 5 m (15 ft). Porosity in the C zone has an arithmetic mean of 12.7 percent with a geometric-mean permeability of 1.3E-3 μm^2 (1.3 md). The low permeability of the C zone is caused by small pore-throat size in crypto-crystalline porosity which is often plugged with anhydrite. Drill cuttings from the C zone typically consist of soft, white, chalky dolomite. Oil shows are generally weak to rare in the C zone.

The Red River C zone cycle began with deposition of lime mudstone. In some wells, a few layers of wackestone were deposited on top of the mudstone. In other wells, the equivalent strata consists of tight limestone. Several thin layers of dolomite were then deposited culminating in deposition of anhydrite. Better porosity development is usually found at the base of the C zone.

The C zone has been attributed with commercial reserves in only one field in the study area. Medicine Pole Hills Field in Bowman Co., ND produces from Red River C zone. The Red River C zone at Medicine Pole Hills Field has always been commingled with the B zone and occasionally with the D zone. Results from development drilling and testing after unitization at

Medicine Pole Hills Field indicate that the C zone was not as prolific as initially credited. Elsewhere, the C zone has been found to be non-commercial or with marginal reserves because of poor permeability despite the appearance of thick porosity on logs.

Red River C Anhydrite. The anhydrite which caps the Red River C zone is wide-spread over the Williston Basin. It is also known as the Lake Alma Anhydrite (Kendall 1976). The anhydrite above the C zone is generally consistent but is occasionally very thin or missing. The total upper Red River thickness is often anomalously thin where the anhydrite is thin or missing. However, these thin wells do not always correspond to present-day structure in the Red River. Low-porosity dolomite was deposited in place of anhydrite in most thin-anhydrite wells, but some wells appear to have experienced erosion or non-deposition during this time. There should be significance to the thickness of the anhydrite at the top of the C zone if the anhydrite were an important element in the dolomitization processes for the underlying C and D zones. However, there is not a simple relationship between presence or absence of this anhydrite and oil production. As shown by cross-section in figure 6, there can be wide variation in porosity development in the Red River C and D zones while the C anhydrite is fairly uniform. Some non-anhydrite wells have good reserves, some have poor producibility and some are dry holes.

Red River B Zone. Among the four porosity zones of the Red River, the B zone is the most widespread and consistent with respect to thickness and porosity development based on core and log data. Continuous oil columns of up to 152 m (500 ft) have been described for the Red River B zone in some areas adjacent to the crest of the southern end of the Cedar Creek Anticline (McClellan 1994; Showalter 1982). Reservoir rock in the Red River B zone is sucrosic, vuggy dolomite which consists of an agal, laminated packstone to wackestone. The upper bounding rocks are bedded anhydrite and lithographic limestone. The Red River B zone is found approximately 12 m (40 ft) from the top of the Red River or base of the Stony Mountain Shale (figures 3 and 7). The gross porous interval ranges in thickness from 1.8 to 5.5 m (6 to 18 ft), with an average net porous thickness of 2.7 m (9 ft). Productive porosity has an arithmetic mean of 18.4 percent with a geometric-mean permeability of 5.4E-3 μm^2 (5.5 md). Unlike the lower C and D zones, the B zone consists of one contiguous block of porosity. The B zone sometimes exhibits a two-layer character within the contiguous block of porosity.

The Red River B zone demonstrates the most simple and consistent character compared to the other zones in the upper Red River. Cores, electrical logs and drillstem tests indicate a narrow range of reservoir porosity and permeability. The Red River B zone is generally thickest at the Buffalo Field, near the crestal axis of southern end of the Cedar Creek Anticline, and thins toward the north and east. Where there have been several wells drilled on a local structural feature, it is observed that localized thinning of the B zone occurs over paleo high-relief topography and thickens on flanks and in low areas. Similar to observations made for the D zone, it is suggested that variation of thickness in the B zone is the result of 1) more sediments being deposited on flanks or in embayments and 2) uplifting, shortly after deposition, which caused compaction and pressure dissolution of B zone beds.

Oil reserves from the B zone occasionally exceed 79,000 m^3 (500,000 bbl) per well but generally have been much less than reserves produced from Red River D zone completions. After the advent of horizontal drilling and completions, reserves per horizontal well in the Red River B zone have been comparable reserves from vertical wells completed in the D zone. Production from vertical wells in the B zone generally exhibit depletion or solution-gas drive characteristics with decreasing total fluid and constant water cut.

Red River A Zone. There is limited production from the Red River A zone and very few cores exist from this interval. Throughout the Williston Basin, this interval has been perforated more frequently in the Bowman-Harding area than elsewhere (Kohm and Louden 1988). However, the Red River A zone is considered a non-commercial interval. The A zone has not been documented to have produced oil in commercial quantities by isolated drillstem test or perforation in the whole of the Bowman-Harding study area. When the A zone has been perforated, it has been produced commingled with other zones. It has a finely laminated, non-fossiliferous, dolomitic limestone member which is sometimes overlain by anhydrite. The Red River A zone is found approximately 3 m (10 ft) from the top of the Red River or base of the Stony Mountain Shale and it is sometimes absent by result of erosion or non-deposition (figures 3 and 7). The A zone is similar to the B zone in that porosity is found in one contiguous bench. The average porous thickness is 1.5 m (5 ft) but porosity is usually less than 10 percent. Porosity has an arithmetic mean of 6.0 percent with a geometric-mean permeability of less than 1.0E-3 μm^2 (1.0 md).

Post A Zone - Pre-Stony Mountain. Above the Red River A zone lies another bed of wacke-packstone, variably dolomitized and sometimes slightly argillaceous. It comprises the final episode of the Red River which was terminated by the influx of fine clastics of the Stony Mountain Shale. The thickness of this final interval is about 3 m (10 ft).

Depositional Model for the Upper Red River

Depositional models for the A, B and C zones have been described by some investigators as analogous to modern subkha systems found in the Persian Gulf (Carroll 1978), but this model is not widely accepted. During deposition of each of these sequences, the Williston basin was inundated with shallow, normal salinity, open-marine water. The environment primarily consisted of inter-tidal and supra-tidal flats. Precipitation of evaporite beds close the final stage of these intervals. Matching a modern depositional model for the Red River D zone has been more difficult (Carroll 1978; Kendall 1985).

Trapping

Oil entrapment in the Red River occurs by complex combinations of up-dip porosity pinch-out, reduction in pore-throat diameter, low-relief structural closures and low-displacement faulting. Examples for each trapping mechanism can be found in both D zone and B zone reservoirs across the study area. As more wells have been drilled, combinations of trapping mechanisms are more apparent.

Wells in Medicine Pole Hills Field, (T.130N., R.104W.) have been completed in each porosity bench of the Red River (figure 2). Anticlinal closure and faulting are reported to provide the principal traps for the field (Kohm and Louden 1988). The maximum structural closure for the field is 15 m (50 ft). Isopach mapping of the Silurian-Interlake to Red River indicates about 9 m (30 ft) of thinning corresponding to maximum structural positions in the field. Anticlinal closure of up to 30 m (100 ft) has been documented for D zone production at South Horse Creek, State Line, Cold Turkey Creek and other fields in Bowman Co., ND.

In addition to structurally trapped D zone reservoirs, an area of the Horse Creek Field has been described as a stratigraphically trapped reservoir. This stratigraphic trap is reported to consist of an up-dip pinch-out of porosity which runs parallel to structural strike along a hinge line of relatively steep dip. It is noted that although porosity and permeability are much reduced in up-dip wells, the rock does not degrade to impermeable and stratigraphic intervals can still be correlated to down-dip intervals. At Cold Turkey Creek Field, stratigraphically trapped D zone oil accumulations have been identified from 3D seismic and drilling of demonstration wells. Separate oil-water contacts were found in these wells on a structurally closed feature (see discussions in section covering seismic characterizations).

Reservoir trapping in the Red River B zone is both structural and stratigraphic. Mechanisms for stratigraphical trapping of B zone reservoirs at Buffalo Field (T.21N.,R.4E. on figure 2) have been discussed by Schowalter and Hess in 1982. The stratigraphical trap at Buffalo Field is located on the southern end of the Cedar Creek anticline and has a northeasterly dip of about 1°. If the field is one continuous accumulation, the maximum oil column would be about 122 m (400 ft). It has been observed that proximal wells with similar porosity from electrical logs and cores can have distinctly different producibility and oil cut at similar structural position. Special core studies of mercury injection and capillary pressure tests indicate that small pore-throat size and low permeability can provide a trapping mechanism for B zone oil accumulations even where porosity and thickness are similar. Poor producibility and low oil-cut are the result of small pore-throat size.

Structure

A basement-block wrenching framework has been hypothesized as controlling the direction and extent of structural features in the Williston Basin (Thomas 1974; Brown and Brown 1987). A wrench system is characterized by a series of geometrically arranged grabens, horsts, and half-grabens that may undergo continuous adjustment to compressional stress. Early exploration models of the Red River included deposition over buried pre-Cambrian hills or structures (Gerhard et al. 1982). More recently, basement structure and lineaments are thought to be the result of a complex wrench-fault frame work (Thomas 1974; Brown and Brown 1987). Early investigators noted that isopach mapping of the total Red River interval indicated thin areas orienting northwest-southeast at right angles to depositional strike. Furthermore, based on isopach mapping within the Red River interval, these thin areas were concluded to be related to topographical ridges and not caused by erosion. Two primary tectonic alignments are noted in Montana and North Dakota: (1) a northwest-southeast trend and (2) a northeast-southwest trend, the former being dominant. From these observations, it was hypothesized that the alignments represent fracture systems, faults, or shear zones which were established during pre-Cambrian time and were rejuvenated from time to time during later tectonic episodes.

Work performed in a photo-geomorphic mapping project by Thomas preceded a 1974 publication in which he described a series of basement-weakness zones which trend northeasterly and northwesterly in the Williston Basin (figure 8). They define a framework of possible basement blocks which probably affect localization of oil and gas by influencing the stratigraphic and structural conditions. The timing of these wrench-style deformation patterns was described by Brown in 1987. His work describes three potential stress orientations which probably influenced the structural architecture of Williston Basin. The oldest lineament orientation is northeasterly until late Devonian or early Mississippian time. In Devonian time, an abrupt and dramatic shift in orientation of the active shear zones occurred and re-oriented to the northwest. During middle

Mississippian time, the northeasterly shear orientations were re-activated. The re-alignment of regional forces would cause periodic movement of basement blocks in different directions through time. For example, a block may have been elevated in Ordovician time, depressed in Silurian time, dormant in Devonian time and elevated again in Mississippian time.

Faulting is observed on seismic data and has been reported by publication in the study area. Kohm and Louden (1988) examined the Medicine Pole Hills Field and found evidence for faulting. These faults were found to be of Silurian age with subtle to modest displacements of 3 to 6 m (10 to 20 ft). The orientation of the high-angle faults were mapped as generally southwest-northeast. The northwest portion of Bowman Co., ND, was identified by McClellan in 1994 as having potential for development through horizontal drilling in the Red River B zone. His prediction has proved to be correct and many successful horizontal wells have been drilled in this area. His work postulated that this local area was affected by tectonic activity as late as Jurassic time. He described a prominent and persistent basement lineament trending southwest-northeast which repeatedly affected depositional and tectonic history. He further stated that oil migration occurred after Jurassic Piper time and that relative structural position of the Red River at that time is important for oil accumulation.

During early exploration of the Red River in the study area, the general opinion was that structure should be well developed before the end of Silurian time. Current opinion is not so adamant about early structural position.

Structure Maps

Red River. The area has gentle, northeasterly regional dip of 9.1 m/km (48 ft/mile) at 34° from north at Red River depth (figure 9). A major fault is located in the southwest portion of the study area which is an extension from the Cedar Creek Anticline. Mapping at the scale shown in figure 9 does not indicate structural closures of 30 m (100 ft). With seismic data it is possible to identify structures with up to 30 m (100 ft) of closure at Red River depth; however, many producing wells are located where structural closure is less than 15 m (50 ft) and many are on structural noses with minimal up-dip closure.

Interlake. The Silurian Interlake is a major unconformity approximately 152 m (500 ft) shallow to the Red River. The structure map of the Interlake shows similar regional grain and dip as the red River structure map. A regional dip of 8.5 m/km (45 ft/mile) at 27° from north is indicated from figure 10. The Interlake is an important interval because empirical observations in the past were used to conclude that structural growth or thinning before Interlake time was crucial to oil accumulations in the Red River. A high-relief structure at Interlake time would be eroded, resulting in an accentuated thin over structure at Red River depth.

Mission Canyon. The Mississippian age Mission Canyon structure map on figure 11 indicates a northeasterly regional dip of 6.6 m/km (35 ft/mile) at 25° from north. The Mission Canyon is an important seismic horizon for interpretation of Red River structure by isochron mapping.

Greenhorn. The Cretaceous age Greenhorn Formation has northeasterly regional dip of 5.9 m/km (31 ft/mile) at 54° from north as interpreted from figure 12. The Greenhorn is a very good seismic reflector and is commonly used for seismic interpretation of Red River structure by isochron mapping.

Isopach Maps

Top Red River to base of D zone. Regional isopach mapping of the thickness of the upper Red River indicates a random pattern of thick and thin areas. The isopach shown in figure 13 is from the top of Red River to a consistent kerogenite bed near the base of the Red River D zone porosity interval. The variation is from 61 to 75 m (200 to 245 ft). Trend analysis of the isopach suggests a subtle dip toward the northwest of 0.1 m/km (0.5 ft/mile) at a bearing of 346°.

Interlake to Red River. The isopach map of the Interlake to the Red River is shown in figure 14. The contours suggest several lineaments with northeasterly bearings which are normal to present day strike. This orientation is consistent with regional wrench-faulting and lineament work done by Brown (1987). Trend analysis of this isopach map indicates a dip of 0.8 m/km (4 ft/mile) at a bearing of 48°.

Mission Canyon to Interlake. The isopach map of the Mission Canyon to Interlake shown in figure 15 indicates a dip of 3.3 m/km (11 ft/mile) at 41°. Many producing Red River wells are located on thin areas of this interval that appear as noses or closely spaced contours. One area of special interest is in the southwest corner of township T.130N., R.102W. in Bowman county. The isopach shows a dramatic thin which is not related to a structural high at Red River depth but is the result of a low at the top of the Mission Canyon. This anomaly was studied by Gerhard et al. (1995) and they reported that faulting produced the graben at Mission Canyon time (figure 11). These faults are described as having strike-slip components (wrench faulting) with recurrent movement and reversals. The down-thrown block in the southwest portion of this township probably compensates for the structural features at Cold Turkey Creek Field, to the east.

Greenhorn to Mission Canyon. An interesting isopach map is the Greenhorn to Mission Canyon interval which is shown in figure 16. The map shows an obvious shift of the depositional center from northeast to northwest between Mission Canyon and Greenhorn time. The isopach map indicates a dip of 3.4 m/km (18 ft/mile) at a bearing of 322°. After Greenhorn time, re-alignment occurred with dip to the northeast.

Conclusions

The upper Red River consists of four porosity intervals which recorded wide-spread episodic events. These intervals are labeled (from youngest to oldest) A, B, C and D zones. The primary intervals for oil production are the B and D zones. The A and C zones are generally non-productive to marginal. Depositional environments were constant across most of the Williston Basin which resulted in laterally continuous units with uniform primary fabrics. While primary fabric is important to subsequent diagenetic processes, lateral changes in depositional environments cannot be used for explaining variable porosity within a given genetic unit.

Both anticlinal-structure and stratigraphical trapping has been described for upper Red River reservoirs. The old model of Red River reservoirs draping over buried hills in the underlying Winnipeg does not hold much favor today. A complex system of basement wrench-fault tectonic activity has caused some (perhaps many) local areas to have had re-occurring movement during the history of the Williston Basin. Fault blocks could have moved up or down several times. Because these wrench or scissor faults are difficult to observe on 2D seismic, it is postulated that what has been credited to stratigraphical trapping may be actually caused by subtle wrench-faults.

The thinner Red River B zone should be more susceptible to this wrench-fault activity.

Depositional models for the A, B and C zones may be analogous to modern subkha systems found in the Persian Gulf, but this conclusion is not widely accepted. Matching a modern depositional example for the Red River D zone is even less certain. The individual layers (genetic units) of each of the zones in the upper Red River can be correlated across the study area. Porosity in A, B, C and D zones was caused by similar diagenesis and dolomitization. The important variability in each zone is thickness and porosity development. Empirical observations show that porosity development is related to local topography during Red River time. This suggests that variation of thickness is the result of 1) more sediments being deposited in low areas and 2) uplifting, shortly after deposition, which caused compaction and pressure dissolution of porous beds.

Porosity development in all zones should be preferentially found on the flanks of paleo structure (not necessarily current-day structure). More sediments would be deposited on flanks or in embayments. Migration pathways of magnesium-rich brines would follow subtle faulting and fracturing which preferentially occurred on flanks of high-relief features. The tops of paleo-features are the least favorable place to find porosity because compaction and pressure dissolution further reduced thinly deposited porosity-prone sediments. Ideally, the best location for Red River porosity would be locally low (an embayment) at Red River time but rising. By the end of Red River time, the local topographical relief would become positive and remain positive.

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PETROGRAPHICAL AND PETROPHYSICAL CHARACTERIZATIONS

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Introduction

A core and petrographic study was undertaken to describe development of porosity within the Upper Ordovician (Champlainian-Cincinnatian) Red River Formation within portions of Bowman Co., ND and Harding Co., SD (figure 17). This report summarizes geologic and petrographic descriptions of Red River reservoir and non-reservoir lithofacies from cored wells within the study area. Interpretations are made of depositional environments along with descriptions of diagenetic processes that have greatly altered original depositional facies. Some petrographical descriptions and conclusions presented in this report are different from those presented in previous annual reports. Descriptions and conclusions made in this report supersede those earlier reports. Color and texture are important components of core description; however, converting core images to black and white and then reproducing them frequently does the images an injustice. Core photographs in color with electrical logs and descriptions will be available on CD-ROM as a project product.

The base of the Ordovician Red River is a gradational change to Winnipeg Shale while the top is overlain by the Stony Mountain Shale (figure 3). The total Red River Formation thickness in the study area is slightly greater than 152 m (500 ft) between the Winnipeg and Stony Mountain shales but oil production occurs only in the upper 76 m (250 ft) of the Red River interval. The Red River is informally divided here into upper and lower units based on the occurrence of hydrocarbon production.

The local stratigraphic terminology used has undergone an evolutionary process and can present communication problems and mis-correlation. An attempt has been made to use common stratigraphic terminology employed by operators in the Bowman-Harding area. Four important porosity zones in the upper Red River are currently recognized in the Bowman-Harding area from youngest to oldest as A, B, C and D. The primary intervals for oil production in the Bowman-Harding area are the B and D zones.

Vertical Facies Successions

In the study area, vertical stacking of lithofacies is the principal control on sediment accumulation and lateral distribution. Progradation of depositional facies is insignificant or absent. Vertical stacking results in widespread and laterally continuous trends of lithofacies that extend over most of the Williston Basin. Therefore, restriction associated with sediment filling of the basin is an important component in lithofacies deposition and distribution.

Red River lithofacies are composite vertical assemblages which depict distinct shallowing-upward or brining-upward paracycles (Figure 3). The lower paracycle includes the Red River D and C zone intervals and culminates in capping with the C zone anhydrite. The middle paracycle includes the Red River B zone which begins with a flooding surface at the top of the C zone anhydrite and terminates at the B zone anhydrite or anhydritic limestone (the anhydrite is not ubiquitous). The upper interval, or Red River A zone, is also a shallowing-upward paracycle which is capped by a major, basin-wide flooding surface at the base of the Stony Mountain Shale.

The Red River paracycles record filling of the Williston Basin during periods of restriction. For the lower paracycle, the vertical decrease in open-marine fauna, and succeeding presence of restricted fauna (cyanobacteria) and gypsum (anhydrite) indicate gradual but nearly complete restriction. Bedded and enterolithic anhydrites are common, and it is inferred that deposition of gypsum was in shallow, subaqueous environments.

Red River Lithofacies

The Red River Formation in the study area is interbedded dolomite, limestone, and anhydrite. Oil reservoirs occur within dolomites. Tight limestone and anhydrite provide vertical permeability barriers. Variations in porosity and permeability, possibly related to paleo-structural orientation, occur along and across present day plunging anticlines. Descriptions of 10 lithofacies were made from core for lithology, textures, skeletal and non-skeletal allochems, cements and porosity types. Figure 18 shows the stratal occurrence of these facies on a wireline log.

Facies 1. Facies 1 is black, shaley limestone (figure 19). The texture is mudstone with skeletal grains of crinoids, brachiopods and cleoclpsamorpha. There is no visual porosity. Depositional environment is deep, open-shelf associated with flooding surface.

Facies 2. Facies 2 is dark gray limestone (figure 20). The texture is mudstone, wackestone and packstone with skeletal grains of crinoids, brachiopods, corals and mollusks. There is no visual porosity. Depositional environment is open-marine with normal salinity.

Facies 3. Facies 3 is dark gray limestone (figure 21). The texture is packstone, grainstone and framestone with skeletal grains of crinoids, brachiopods, corals, mollusks and stromatoporoids. There is no visual porosity. Depositional environment is patch reef or skeletal buildup on open-marine shelf.

Facies 4. Facies 4 is brown dolomite and limestone (figure 22). The texture is mudstone and wackestone with skeletal grains of crinoids and brachiopods. Visual porosity is poor to good. Depositional environment is Thalassinoides burrowed open-shelf with increased salinity or low oxygen levels.

Facies 5. Facies 5 is brown dolomite and limestone (figure 23). The texture is mudstone and wackestone with skeletal grains of crinoids and brachiopods. Visual porosity is poor to good. Depositional environment is Planolites burrowed open-shelf with increased salinity or low oxygen levels.

Facies 6. Facies 6 is gray limestone (figure 24). The texture is packstone and grainstone with skeletal grains of crinoids, brachiopods, corals and mollusks. There is no visual porosity. Depositional environment is open-marine.

Facies 7. Facies 7 is gray to brown limestone (figure 25). The texture is mudstone and wackestone with skeletal grains of mollusks and bryozoans. There is no visual porosity. Depositional environment is restricted-shelf with minor shoaling.

Facies 8. Facies 8 is gray limestone (figure 26). The texture is wackestone and packstone with skeletal grains of crinoids, brachiopods, bryozoans and corals. There is no visual porosity. Depositional environment is open to slightly restricted-shelf.

Facies 9. Facies 9 is gray to brown dolomite and limestone (figure 27). The texture is mudstone with peloidal grains of ostracods. Visual porosity is good. Depositional environment is highly restricted subtidal, intertidal and salina.

Facies 10. Facies 10 is gray anhydrite with no fossil grains (figure 28). Depositional environment is salina with areas of extensive restriction and evaporation.

Reservoir Intervals

Lower Red River. The lower Red River occurs approximately 69 m (225 ft) below the top of the Red River and at the base of the D zone porosity. There are approximately 10 wells in the Bowman-Harding area which drilled through the lower Red River to the Winnipeg. None of these wells encountered productive porosity in the approximately 91-m (300-ft) interval. The lower Red River consists of deep-water, open-shelf limestone which is dark gray in color.

Red River D Zone. The Red River D zone is found at approximately 53 m (175 ft) from the top of the Red River or base of the Stony Mountain Shale. The gross porous interval ranges in thickness from 12.1 to 25.9 m (40 ft to 85 ft). Productive porosity has a arithmetic mean of 14.6 percent from logs with a geometric-mean permeability of 5.2E-3 μm^2 (5.3 md). The Red River D zone develops the thickest reservoir interval and greatest permeability compared to the other Red River zones.

Conventional permeability and porosity data from ten cores of the D zone indicate an average gross interval of 20.7 m (68 ft). Porosity-thickness averages 1.65 m (5.41 ft) with a permeability-thickness of 6.9E+4 μm^3 (230 md-ft) at the geometric mean (table 1). Permeability to air has a value of 5.2E-2 μm^2 (5.3 md) at the geometric mean. The D zone averages 77 percent of the combined flow capacity within the upper Red River.

The Red River D zone exhibits a wide range of porosity development and storage capacity. Data from 50 digitized electrical logs were used for statistical quantification of D zone storage (table 2). The mean porosity is found to be 14.6 percent with a net thickness of 5.4 m (17.6 ft). Average storage capacity (fractional porosity-thickness) is 0.83 m (2.72 ft) with a value at one standard deviation above the mean of 1.7 m (5.51 ft). Core data from the D zone indicate an average porosity of 11.4 percent with a range at one standard deviation of 3.5 percent (table 1). Maximum porosity at the 95 percentile is 22 percent.

Rocks of this interval are burrowed dolomites and sparse to common, skeletal limestone interbeds. Thin beds of black organic-rich shales (kerogenites) are locally present and occur at the base or tops of skeletal limestones. Red River D zone sediments are skeletal limestones (figure 29) and burrowed dolomites (figure 30) which were deposited in open-marine environments. These sediments typically contain crinoids with associated bryozoans, brachiopods, mollusks, rugose and tabulate corals, ostracods, and primitive stromatoporoids. Commonly, skeletal packstones, grainstones, and sparse framestones occur at the base of paracycles and represent flooding or deepening events. Maximum flooding surfaces and interbedded deepening events are represented by shaley lime mudstones with sparse, skeletal fragments and possible cyanobacteria which are informally named kerogenites (figure 29). Open-marine sediments are interbedded with burrow-mottled sediments indicating minor oscillations in bathymetry or salinity associated with basin filling.

Burrow sediments commonly contain normal marine fauna. These sediments were deposited in environments that were slightly to highly stressed by elevated salinity or low oxygen levels. Thalassinoides and Planolites trace fossils are common (figure 31), and are part of the Cruziana ichnofacies which has been described along shallow-shelf environments (Pemberton et al. 1992). Infauna burrowing probably increased the initial transmissibility within sediments for subsequent dolomitizing fluids.

Dolomitization of burrowed sediments produced porosity in the Red River D zone. Original dolomitization probably occurred by seepage of magnesium-rich brines from the overlying Red River C anhydrite (gypsum). This early dolomitization produced cryptocrystalline dolomite (10 μ). Dolomites in the Red River D zone are characterized by sparse cryptocrystalline and abundant fabric destructive, medium-crystalline (60-200 μ), euhedral to subhedral replacement crystals. Coarser crystalline dolomites typically display sucrosic intercrystalline porosity and moderate to high permeability because of well-developed, uniform intercrystalline pore space. These dolomites produce the best conventional reservoirs within the project area and were formed by late diagenetic replacement or recrystallization of cryptocrystalline dolomites in the deep subsurface. Recrystallization probably occurred by the interaction of original dolomites with saline and dolomitic-rich hydrothermal fluids.

Pore occlusion in the D interval occurs by finely dispersed, early and late paragenetic anhydrite, sparse calcite spar, and sparse to moderate amounts of solid hydrocarbons (bitumen). Fractures are absent to sparse and appear to have little if any control on permeability and productive potential.

Red River C Zone. The Red River C zone is found at approximately 25.9 m (85 ft) from the top of the Red River or base of the Stony Mountain Shale. The Red River C zone porosity typically exhibits a shallowing-upward sequence that culminates with a thick anhydrite. The gross porous interval ranges in thickness from 6.1 to 15.2 m (20 ft to 50 ft). Porosity in the C zone from core averages 12.3 percent with a geometric-mean permeability of 8.9E-4 μm^2 (0.9 md). The low permeability of the C zone is caused by small pore-throat size in cryptocrystalline porosity which is often plugged with anhydrite.

Convention permeability and porosity data from three cores of the C zone indicate an average gross porous thickness of 11.6 m (38 ft) with a geometric-mean permeability to air of 8.9E-4 μm^2 (0.9 md). The C zone typically develops only 6 percent of the combined flow capacity in the upper Red River despite development of 34 percent of the combined total potential storage (table 1). The Red River C zone exhibits a wide range of porosity development and storage capacity. From digitized electrical log data shown in table 2, the average porosity is found to be 12.7 percent with a net thickness of 4.5 m (14.7 ft). The average storage capacity (fractional thickness) is 0.57 m (1.88 ft) with a value at one standard deviation above the mean of 0.91 m (2.98 ft). Core data from the C zone indicate a mean value for porosity of 12.3 percent and a range of 4.7 percent. The porosity-thickness from three cores has an average value of is 0.50 m (1.64 ft). The C zone develops 34 percent of the potential storage in the upper Red River, but is hindered by low permeability.

Rocks in the C zone are dolomites with millimeter-scale, flat to wavy laminations and stromatolites which are laterally linked hemispheroids and low-relief, vertically-stacked hemispheroids (figure 32). The C zone has significantly reduced permeability from the cryptocrystalline nature of the dolomite and finely dispersed anhydrite.

This facies was deposited in low energy, shallow subaqueous, and salinity-stressed environments where the trapping and binding activities of cyanobacteria were common. Desiccation features are sparse, and fossils are missing, with the exception of sparse ostracods. Thin interbeds of bioclastic and peloidal sediments are storm deposits within these restricted subaqueous settings. Single-burrow mottling by small Planolites is common, especially near the base of these laminated beds.

Dolomitization of laminated and burrowed sediments produced porosity in the C interval. Proximity to the overlying C zone anhydrite (gypsum) produced early dolomitization by seepage of magnesium-rich brines. Syndepositional precipitation of dolomite may have also occurred in this interval. These types of early or syndepositional dolomitization produced abundant cryptocrystalline dolomite (10 μ) with poor permeability.

The C zone has moderate variation in thickness, generally fair to good porosity, but poor permeability. It is inferred that early dolomitization, with its concomitant loss of permeability produced by extensive intergrowth of dolomite rhombohedrons, prohibited the C zone interval from being an effective petroleum reservoir. Because of low permeability, these dolomites appear to have been poorly affected by hydrothermal fluids and late diagenetic dolomite replacement or recrystallization like the underlying D zone.

Pore occlusion in the C zone occurs by finely dispersed, early and late paragenetic anhydrite and sparsely scattered, clear 20 to 50-μ dolomite rhombohedrons along stylolites and pressure-solution seams. Fractures are absent to sparse and appear to have no control on permeability.

Red River B Zone. The Red River B zone is found at approximately 12.2 m (40 ft) from the top of the Red River or base of the Stony Mountain Shale. The gross porous interval ranges in thickness from 1.8 to 5.5 m (6 to 18 ft), with an average net thickness of 2.7 m (9 ft). Productive porosity has an average of 18.4 percent with a geometric-mean permeability of 4.2E-3 μm^2 (4.3 md).

Conventional permeability and porosity data from seven cores of the B zone (table 1) indicate an average gross porous thickness of 4.3 m (14 ft) with geometric-mean permeability of 4.2E-3 μm^2 (4.3 md). The flow-capacity (kh) of the B zone is 1.29E+4 μm^3 (43.0 md-ft) at the geometric mean. Core data from the B zone indicate porosity has a mean value of 16.7 percent with a range of 5.2 percent. Typical porosity-thickness from these cores is 0.59 m (1.93 ft). An average porosity of 18.4 percent with an average net thickness of 2.9 m (9.4 ft) were determined for statistical quantities of B zone storage from digitized electrical logs (table 2). The average storage capacity (fractional thickness) is 0.54 m (1.76 ft) with a value of 0.76 m (2.50 ft) at one standard deviation above the mean.

The base of the Red River B zone is tight, skeletal, burrowed and nodular bedded limestone which is capped by laminated, massive and burrowed porous dolomites. The laminations are flat to wavy and are millimeter-scale. The laminations are similar to those in the C zone interval, but are thinner with locally well-developed permeability.

The base of the B zone was deposited in open-marine environments (Facies 2) that were sparsely to moderately burrowed (Facies 4). Effective porosity is absent in these beds. The overlying porous dolomites were deposited in low-energy environments where increased salinity or loss of oxygen, along with trapping and binding activities of cyanobacteria, were common (Facies 9). These laminated and locally burrowed sediments were deposited in shallow subaqueous, salinity-stressed settings.

Initial dolomitization probably occurred by seepage of magnesium-rich brines from the overlying and proximal anhydrite (gypsum). This type of dolomitization produced cryptocrystalline to fine-crystalline dolomite (10 to 20 μ) with poor to good permeability. Pore interconnection is variable resulting in very poor to fair reservoir development. Unlike the C zone interval, early dolomitization occurred across a terrain that appears to have less original vertical variation based on the thickness of the B zone. This might have reduced the effects from seepage of magnesium-rich brines thereby slowing processes of dolomitization and producing greater permeability. Also, the thickness of the B anhydrite is variable and locally absent which may have resulted in less extensive and rapid early dolomitization.

Pore occlusion in the Red River B zone occurs by finely dispersed, early and late paragenetic anhydrite. Sparse, clear 20 to 50-μ dolomite rhombohedrons along stylolites and pressure-solution seams and white to light brown, late paragenetic crystals of baroque or saddle dolomite occlude intercrystalline pores. In cores, fractures are absent to sparse and appear to have no control on permeability.

Red River A Zone. Red River A Zone. The Red River A zone is found at approximately 3.0 m (10 ft) from the top of the Red River or base of the Stony Mountain Shale and it is sometimes absent by result of erosion or non-deposition. The A zone is similar to the B zone in that porosity is found in one contiguous bench. Conventional permeability and porosity data from two cores of the A zone indicate an average gross porous thickness of 1.8 m (6 ft). Average porosity from these cores is 12.3 percent. As shown in table 1, net thickness averages 1.8 m (6 ft) with a geometric-mean permeability to air of 0.89E-4 μm^2 (0.9 md). The average porous thickness from log data is 1.5 m (5 ft) but porosity is usually less than 10 percent (table 2).

The A zone is a laminated, massive, and burrowed dolomite. The dolomites are similar to rocks in the B zone interval, but well developed permeability is absent. Below and above the A zone porosity, tight skeletal and sparsely burrowed limestones are present. The base and top of the A zone were deposited in open marine environments (Facies 2). Effective porosity is absent in these beds. Between these subtidal beds, burrowed mudstones were deposited in moderately restricted subtidal environments (Facies 4, 5 and 9). These sediments were poorly dolomitized.

Original dolomitization probably occurred by seepage of magnesium-rich brines from an overlying or proximal Red River A zone anhydrite (gypsum) which was subsequently eroded and capped by open marine sediments. This early dolomitization produced abundant cryptocrystalline dolomite (10 μ) with poor permeability. Low permeabilities reduced the effects of late diagenetic replacement or recrystallization. It is inferred that capping anhydrite in the A interval, if present, was very thin and was not an abundant source for magnesium-rich brines. Dolomitization, therefore, is discontinuous and ineffective.

Pore occlusion in the A interval occurs by finely dispersed, early and late paragenetic anhydrite and sparsely scattered, clear 20 to 50-μ dolomite rhombohedrons along stylolites and pressure-solution seams. In core, fractures are sparse to absent.

Dolomite Types

Red River oil is most typically entrapped within dolomitized burrow-mottled mudstones and wackestones, and within laminated and cryptalgal dolomites. The best matrix porosity occurs within burrow-mottled dolomites which are commonly thick and well developed within the Red River D zone.

There are four types of dolomite present within the study area, and these are, from earliest to latest in the paragenetic sequence, DOLOMITE-1 through DOLOMITE-4. DOLOMITE-1 is the most abundant (figure 33) and occurs as early diagenetic and fabric preserving, microcrystalline to cryptocrystalline (<10 μ) dolomite replacement in which most of the visible porosity is associated with depositional and early diagenetic processes (interparticle, intraparticle, and moldic pores). Porosity in this type of dolomite is commonly good, but associated permeability is generally poor. DOLOMITE-1 is abundant in the A, B, and C zone intervals. The Red River D zone interval contains sparse to common DOLOMITE-1 in low permeable strata. This dolomite probably developed by the seepage of magnesium-rich brines into muddy sediments from overlying and proximate gypsum beds.

DOLOMITE-2 is characterized by fabric destructive, medium-sized (60-200 μ), euhedral to subhedral replacement crystals. It typically displays sucrosic intercrystalline porosity and moderate to high permeability because of well-developed, uniform intercrystalline pore space (figure 34). This dolomite appears to account for the best conventional reservoirs. This type of dolomite was formed by late diagenetic replacement or recrystallization of earlier dolomites (DOLOMITE-1) by saline hydrothermal fluids. This type of late replacement is relatively sparse in the B and absent in the C zone intervals, but abundant in the D zone.

The third type of Red River dolomite is scattered clear, 20 to 50-μ dolomite rhombohedrons along stylolites and pressure-solution seams (figure 35). DOLOMITE-3 clearly formed in the subsurface during, or after, significant compaction and matrix pressure-solution, and is generally associated with loss of pre-existing matrix porosity due to its precipitation as an important reactant mineral during pressure solution (Wanless 1979). It appears to be most abundant in the Red River A, B, and C zones.

The fourth type of dolomite consists of pore-filling cements in the form of very coarse (up to 1 cm across), white to light brown crystals of dolospar and baroque or saddle dolomite (figure 36). This dolomite formed under moderate to high temperatures (>90°C). Baroque dolomite and dolospar are present in the Red River B zone where early and late pore space is plugged by this cement. DOLOMITE-4 is relatively sparse within Red River D zone beds.

Fractures

Three principal types of fracture systems are present in the Williston Basin (Fritz 1991). The first is related to regional lineaments which developed in response to regional tectonic stresses and crustal flexure during the Phanerozoic (Clark and Christensen 1992). The second developed locally along drapes over basement structures. The third is related to over pressuring.

In the study area, natural fractures found in core are not abundant, but where present, are best preserved within dolomite beds. Most fractures in limestones were healed by calcite or anhydrite cements. Fractures in dolomites are usually short-segment, tension gashes within the burrow-mottled facies. However, swarms or closely spaced vertical fractures are also present within other dolomitized facies. Most of the fractures within the Red River D zone interval contain solution enhancement.

Stylolites

Stylolites are burial diagenetic features that occur in many reservoirs, but are particularly abundant in Paleozoic dolomites and limestones (Wanless 1979). They are recognized as seams or films of insoluble residues that record removal of carbonate rock by pressure-solution processes. Stylolites can affect reservoir performance and reservoir compartmentalization by forming barriers to fluid flow (Koepnick 1984 and 1985; Dunnington 1967).

Red River dolomites and limestones within the study area display a complete range of pressure-solution features, ranging from microstylolites to high-amplitude stylolites, wispy seams, and individual or isolated solution seams. Many of these types of pressure-solution structures modified primary depositional and faunal structures (cryptalgal laminates and burrows) into stylolite-bounded fabrics which have distinctive laminated, nodular, and mottled appearances in subsurface cores. During and after oil migration into structural traps, stylolites commonly form at oil-water transition zones or in beds with high water saturations. This may account for some of the reservoir compartmentalization in Red River intervals.

Late-stage Dissolution

The development of dolomitized micro-porosity produced storage capacity. This micro-porosity is the result of extensive, burial-related, dissolution processes. These subsurface processes may be controlled by local structure as much as by stratigraphy and sedimentation. Commonly associated with micro-porosity are other features indicative of late dissolution of matrix in pre-existing Red River dolomites and dolomitic limestones. These include vuggy and channel pores which commonly occur along stylolites and micro-fractures. Halos of moldic, micro-vuggy, channelized and chalky porosity are very common around the stylolites within burrow-mottled facies. The orientation and abundance of such pore systems may affect reservoir drainage.

Pore Occlusion

Solid hydrocarbons or bitumen in variable amounts within Red River reservoirs occluded porosity and reduced permeability. Within medium, non-fabric selective sucrosic dolomites, the bitumen is probably not a problem, although it might be responsible for lower recovery factors than from non-bitumen-bearing sucrosic dolomites. Bitumen occlusion is probably a problem in fabric-selective, cryptocrystalline dolomites or micro-porous dolomites. Anhydrite, calcite, and minor chert replacement are also locally present in Red River reservoirs. These occluding and diagenetic minerals decrease both porosity and permeability.

Conclusions

This evaluation indicates that Red River dolomite reservoirs were subjected to burial digenesis which modified pre-existing reservoir conditions. Late-burial dissolution associated with chemical compaction, maturing hydrocarbons, or hydrothermal processes may be a common control in reservoir development and behavior. Late-burial diagenisis can both improve and reduce porosity and permeability. Occluding cements are dominated by baroque dolomite and anhydrite.

Early seepage dolomitization of muddy beds was locally modified by burial digenesis, especially in the D zone interval where recrystallization produced reservoirs with large pores and high permeability. It is inferred that early dolomitization, with its concomitant loss of permeability produced by extensive intergrowth of dolomite rhombohedrons, prohibited the C zone interval from being an effective petroleum reservoir. Because of low permeability, these dolomites appear to have been poorly affected by hydrothermal fluids and late diagenetic dolomite replacement or recrystallization like the underlying D zone. Based on thickness of the B zone, early dolomitization occurred across a terrain that appears to have less original vertical variation than the C or D zones. This might have reduced the effects from seepage of magnesium-rich brines thereby slowing processes of dolomitization and producing greater permeability. Also, the thickness of the B anhydrite is variable and locally absent which may have resulted in less extensive and rapid early dolomitization. Late dolomitization of the A zone appears discontinuous and ineffective.

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Table 1
Porosity and Permeability of Red River Intervals from Cores

Petrophysical Item	A Zone	B Zone	C Zone	D Zone
Number Cores	2	7	3	10
Gross Thickness	6 ft	14 ft	33 ft	68 ft
Net Thickness	3 ft	10.4 ft	10.7 ft	28.3 ft
Porosity-thickness	0.5 ft	1.93 ft	4.02 ft	5.41 ft
Porosity (mean and std dev)	12.3%	16.7 +/- 5.2%	12.3 +/- 4.7%	11.5 +/- 3.7%
Porosity (maximum 95%)	NA	24.8%	22.0%	17.9%
Permeability-thickness	<5 md-ft	43 md-ft	17 md-ft	230 md-ft
Geometric Mean Permeability (air)	0.9 md	4.3 md	0.9 md	5.3 md
Dykstra-Parsons Coef.	NA	0.52 - 0.78	0.75 - 0.83	0.60 - 0.84
Relative Storage (ϕh) Total = 1	0.04	0.16	0.34	0.46
Relative Capacity (kh) Total = 1	0.02	0.15	0.06	0.77

Table 2
Characteristics of Red River Intervals from Electrical Logs

Petrophysical Item	Red River A	Red River B	Red River C	Red River D
Mean Thickness (h)	5.6 ft	9.4 ft	14.7 ft	17.6 ft
(h) + 1 standard deviation	9.4 ft	12.4 ft	22.5 ft	32.4 ft
Porosity-thickness (ϕh) - mean	0.52 ft	1.76 ft	1.88 ft	2.72 ft
(ϕh) + 1 standard deviation	0.98 ft	2.50 ft	2.98 ft	5.51 ft
(ϕh) maximum	1.31 ft	3.20 ft	5.80 ft	15.75 ft
Porosity (ϕ) - mean	8.3%	18.4%	12.7%	14.6%
(ϕ) + 1 standard deviation	10.9%	23.2%	15.7%	21.3%

ENGINEERING CHARACTERIZATIONS

Mark A. Sippel

Introduction

Previous sections covering geological and petrographical characterizations of the Red River discuss rock fabric, deposition, diagenesis and structural elements which affect reservoir heterogeneity. Engineering characterizations of the Red River cover dynamic reservoir properties which relate to fluids, producibility, primary recovery and the potential for enhanced recovery. Cost and economics are also briefly covered. The discussion progresses through basic reservoir data by individual zone in the Red River, productivity and recovery from production data, computer-simulation predictions of recovery, and results from demonstration wells.

There are four distinct porosity intervals in the Red River found in the southwest Williston Basin study area, labeled in descending order A, B, C and D zones. The Red River B and D zones are the most important reservoirs in the area. In addition to an introduction to typical reservoir fluids found in the study area, producibility and storage data for each of the zones are presented from various sources such as electrical logs, drillstem tests, cores and production histories. Typical recoveries by zone and from certain important fields are presented which demonstrate low recovery of oil by primary methods and the opportunity for additional recovery by enhanced recovery processes, infill drilling and horizontal completions. Efficient primary recovery has been limited because of widely spaced wells, low to moderate permeability in the B zone and great heterogeneity in the D zone. There have been a few enhanced recovery projects in the area but these have demonstrated questionable profitability.

There are four key fields in which there was a focus for demonstration aspects of the project. These fields are Cold Turkey Creek, State Line and Grand River School in Bowman Co., ND and Buffalo Field (north area), in Harding Co., SD. Wells were drilled and tested in these fields to evaluate concepts for incremental recovery from higher density drilling, waterflooding and horizontal wells. Elements of these demonstrations include computer simulations of primary recovery and enhanced recovery by waterflooding with horizontal wells. The Buffalo Field (north area) was used to evaluate water injectivity with both a vertical and horizontal well in the Red River B zone. Cold Turkey Creek and Grand River School fields were used for drilling targeted, vertical wells from seismic data for the Red River D zone. Implications concerning reservoir heterogeneity and the potential for incremental reserves are presented.

Drilling and Operations

Before discussion of reservoir characterizations, a brief review of drilling and production operations will help put the reservoir discussions in an economic perspective. Wells in the area of this study are being drilled as either vertical or horizontal completions. Horizontal projects typically target the Red River B zone. Wells drilled as vertical completions usually have a 31.1-cm (12¼-in.) surface hole drilled to approximately 610 m (2000 ft). Surface casing, 8⅝-in. O.D., is run and cemented to ground surface. A 20-cm (7⅞-in.) hole is then drilled to total depth and, if justified, 14-cm (5½-in.) O.D. casing is run and cemented at total depth. Heavy casing, 14.0-cm

15.5 kg/m or 14.3-cm 17.9 kg/m (5½-in. 23 lb/ft or 5⅝-in. 26.7 lb/ft), is usually placed across salt zones to provide extra strength to avoid collapse due to dynamics of the salt zones.

Wells drilled as horizontal completions usually have a 31.1-cm or 34.3-cm (12¼-in. or 13½-in.) surface hole drilled to approximately 610 m (2000 ft). Surface casing, 24.4 (9⅝-in.) O.D., is run and cemented to ground surface. A 22.2-cm (8¾-in.) hole is then drilled to total depth. The wells are frequently drilled vertically through the Red River formation and technically evaluated prior to drilling horizontally. The hole is then plugged back to allow for deviating off of a cement plug about 152 m (500 ft.) above the Red River B zone. A medium radius curve is then drilled with a 137 to 152 m (450 to 500 ft) radius to land nearly horizontally at the top of the zone. At that point, 17.8-cm (7-in.) O.D. casing is run from surface to the end of the curved section. It is then cemented in place. The horizontal section is then drilled utilizing 15.9-cm (6¼-in.) drill bits. Thus far, most horizontal sections have been drilled using fresh water for drilling fluid. The horizontal portion of the well is normally left open with no casing.

Drilling fluids used have generally been either near-saturated to saturated salt systems or oil-based, reverse-emulsion systems. Salt systems have historically been used on most vertical wells and most horizontal wells have used oil-based fluids. The choice of mud system used in vertical wells depends upon assessment of the potential problems with salt zones. The oil based systems tend to be more predictable for drilling gauge hole through salt zones. Most horizontal wells have been drilled with oil based systems because of the better lubricating characteristics that assist with running casing through the curved section of the hole.

The only common drilling problem in the area is loss of circulation in the Mission Canyon formation. This problem can be dealt with by pre-treating the drilling fluid with lost circulation material. If precautions are not taken, the volume of drilling fluid lost can be sizable resulting in significant extra costs, particularly with an oil-based system.

Drilling a vertical well, evaluating potentially productive zones and running casing for completion should take 20 to 23 days. With recent cost increases a completed well total cost is in the $750,000 to $800,000 range (including pumping, treating and storage equipment). A horizontal well drilled and completed as discussed above will require 34 to 40 days to reach total depth and will cost $1,100,000 to $1,200,000 for a completed well.

Operating cost for wells depends much on electrical power and water disposal requirements. Red River wells are most frequently produced by beam and rod pumping. A very few wells flow on initial production, but this is short lived. Many wells are produced to individual production facilities and tankage. Generally, well operating costs range from $2500 to $4500 per month. Using an average lease operating cost of $3500 per month per well, an economic limit of about 8 bopd is computed from an oil price of $19.00 per barrel, a net revenue interest of 85 percent and 11.5 percent for state production taxes. For discussion purposes, an economic well could be described as having a profitability ratio of 2 to 1 for net income (before federal and state income taxes) and investment for completing a new well. For a hypothetical well which produces 20 years, it would require 27,200 m^3 (171,000 bbl) oil to achieve a profitability ratio of 2 to 1 for a capital investment of $800,000 and the other general assumptions described above.

Completion Efficiency

Conventional completions in Red River intervals have historically been by perforations through casing followed by treatment with hydrochloric acid. Large-volume treatments and fracture-inducing treatments often result in vertical communication between porosity zones and unwanted water production. Low to moderate permeability in the Red River B zone results in low water injection rates and has therefore been a deterrent to interest in waterflooding. A need for more efficient completions in the Red River B zone has long been recognized. In an effort to improve completion efficiency, through-casing jetting lance technologies were evaluated (a full discussion of these technologies is addressed in a separate topical report prepared by this project). Because this completion technology should be capable of significant improvement of productivity (by increasing the effective wellbore radius) in thin-bed reservoirs, re-completion work with jetting-lance technology was performed during the project on four wells in the Bowman-Harding area. Two wells were selected for evaluation of 3-m (10-ft) jetting-lance penetrations. This work was unsuccessful for improving oil production. A proto-type 15-m (50-ft) jetting-lance technology was also attempted in two other wells, but the tools were not able to function at reservoir depths of 2740 m (9000 ft) or greater. It was concluded that this technology is inappropriate for deep, carbonate reservoirs and the application of horizontal drilling was beginning to be successfully applied for the Red River in the area. It became clear that drilling a conventional-diameter, horizontal borehole with a downhole mudmotor and measurement-while-drilling technology is most practical method for improved completion efficiency in the Red River.

Reservoir Fluids

There are four distinct porosity intervals in the Red River found in the southwest Williston Basin study area. Reservoir depths range from 2500 to 3050 m (8200 to 10,000 ft) from surface. Original pressures range from 24,130 to 29,600 kPa (3500 to 4300 psi) with a subsurface gradient of 10.0 kPa/m (0.44 psi/ft). Reservoir temperatures range from 93 to 110 °C (200 to 230 °F). At formation depth and temperature in the study area, Red River reservoirs are initially under-saturated systems. Red River oil exhibits a black-oil character with densities from 0.825 to 0.887 gm/cc (28 to 40 °API) with an average oil density of 0.865 gm/cc (32 °API). The dissolved gas is rich in butane and propane resulting in a specific gravity of greater than 1.0. Initial gas-oil ratios range from less than 17.8 to 107 m^3/m^3 (100 to 600 scf per bbl). Table 3 summarizes Red River oil properties from PVT studies and field reports from the area. Figure 37 shows oil PVT characteristics for 0.830 gm/cc (39 °API) oil with a solution gas content of 102 m^3/m^3 (575 scf per bbl) where the bubble-point viscosity is 5.0E-4 Pa-s (0.50 cp) at 15,200 kPa (2200 psi). Red River reservoirs with lighter oil (0.830 gm/cc or 39 °API) have bubble-point pressures of greater than 13,800 kPa (2000 psi), while reservoirs with heavier oil (0.876 or 30 °API) have bubble-point pressures of less than 3450 kPa (500 psi). Saturated or free-gas conditions do not develop at the end of primary depletion at many Red River fields because of a low bubble-point pressure.

Red River water salinity varies greatly across the study area and sometimes vertically between zones in a well. Salinity generally increases with depth. In the Buffalo Field, salinity is about 30,000 ppm total dissolved solids (TDS). At Cold Turkey Creek Field the maximum salinity is about 150,000 ppm TDS. Water viscosity at reservoir conditions varies from 3.0E-4 to 3.5E-4 Pa-s (0.30 to 0.35 cp) for these salinities, respectively. Table 4 summarizes formation water found in the study area. Water resistivity can quickly change, both laterally and vertically, and poses a problem for water saturation calculations from electrical logs. It has been found that mixing of D zone and B zone waters can cause scale precipitation.

Pressure Transient Tests

A key characterization of any reservoir is transmissibility, the intrinsic property or ability to transmit fluid to the wellbore. Transmissibility is the product of permeability-thickness divided by fluid viscosity and volume factor (kh/μB). Drillstem tests (DST), when properly run, provide a good measure of reservoir transmissibility near the wellbore. The drillstem test provides a consistent measure of transmissibility which allows a comparison between wells and porosity benches. It has been an important tool for evaluating the economic potential of Red River intervals in the Bowman-Harding area and most of the wells drilled in the area have been drillstem tested in at least one interval. Drillstem tests from a large sampling of Red River tests in the Bowman-Harding area were analyzed for transmissibility and tabulated for statistical comparison between the main porosity intervals in the area. It is noted that transmissibility from these DST evaluations appears to be distributed in a log-normal manner. Table 5 summarizes the evaluations from drillstem tests taken in wells in the Bowman-Harding area. The B and D zone develop sufficient transmissibility to have commercial reserves. The D zone develops the greatest transmissibility because of thickness.

A Zone. The Red River A zone is seldom tested or perforated. It is considered a non-reservoir interval in the area. There are too few isolated tests of this interval to make statistical observations. A qualitative observation is that the A zone has the least transmissibility of the Red River intervals.

B Zone. The Red River B zone was evaluated from 252 tests and found to have a log-normal mean for kh/μB of 9.14E+6 μm^3/ Pa-s (30.4 md-ft/cp). The statistical distribution of kh/μB from the B zone has the lowest variance of the porosity benches. The geometric-mean flow rate from these tests is 15.6 m^3 per day (98 bbl per day).

C Zone. The Red River C zone was evaluated from 86 tests and found to have a mean value of kh/μB of 3.28E+6 μm^3/ Pa-s (10.9 md-ft/cp). The geometric-mean flow rate from these tests was determined to be 6.0 m^3 per day (38 bbl per day). The low number of tests in the middle interval attest to the lack of shows found in this interval. Most DST recoveries from this interval consist of mud and water without free oil. Only a very few wells have been completed solely in this interval and none of the C-only completions have produced economical reserves which would payout drilling costs.

D Zone. The Red River D zone was evaluated from 107 tests and found to have a transmissibility at the geometric-mean of 31.6E+6 μm^3/ Pa-s (105.1 md-ft/cp). The mean flow rate from these tests was determined to be 38.0 m^3 per day (239 bbl per day). The D porosity bench can develop the greatest thickness of the Red River benches and also shows the greatest variance in transmissibility.

Post-completion pressure transient testing requires long shut-in times to evaluate pseudo steady-state conditions. Because of low permeability and large wellbore-storage factors, the middle-time region may not finish for many weeks and conventional semi-log analysis can be misleading. For those considering a buildup test from a pumping well and looking for guidelines to run such a test, it is recommended to run the test for at least two weeks and use analysis software with analytical-simulation capabilities and type-curve matching.

Post-completion buildup tests from the Red River B zone, using pressure data computed from well soundings, were analyzed with an analytical simulator. The buildup data were from eight wells in the Buffalo Field (north area) and each well had a drillstem test (DST) for comparison. The typical shutin times of the buildup tests were from 5 to 10 days. The average fluid transmissibility from DST data is 1.41E+7 μm^3/ Pa-s (47 md-ft/cp). Conventional semi-log and type-curve analysis of the buildup data indicate insufficient shutin time for conventional, middle-time-region analysis. With the analytical simulator, the pressure transient data are found to be meaningful with an average fluid transmissibility of 1.38E+7 μm^3/ Pa-s (46 md-ft/cp). It is concluded that analysis of post-completion pressure data can compare with analysis of DST data if shutin time is sufficiently long and the analysis is aided with analytical simulation software.

Characterization from Cores

Conventional core studies were used to describe various engineering parameters of Red River reservoir intervals and are summarized in the following paragraphs and in table 1 (found in petrographical/petrophisical characterization section).

A Zone. Conventional permeability and porosity data from two cores of the A zone indicate an average gross thickness of 1.8 m (6 ft) from top to base porosity. Average porosity from these cores is 12.3 percent with a geometric-mean permeability to air of 0.9E-3 μm^2 (0.9 md). The permeability-thickness is less than 1.5E+3 μm^3 (5.0 md-ft). Pore-throat size of A zone rocks range from sub-micro to micro class. Special core analysis from mercury injection tests indicate pore-throat radii of 0.1 to 0.5 microns from a sample with permeability of 5.9E-4 μm^2 (0.6 md) and porosity of 14 percent.

B Zone. Data from seven cores of the B zone indicate an average gross thickness of 4.3 m (14 ft) with geometric-mean permeability of 4.2E-3 μm^2 (4.3 md). The flow-capacity (kh) of the B zone is 1.29E+4 μm^3 (43.0 md-ft) at the geometric mean. Pore-throat size of B zone rocks with better permeability range from meso to macro class. Special core analysis from mercury injection tests indicate pore-throat radii of 1.0 to 5.0 microns from a sample with permeability of 62E-3 μm^2 (63 md) and porosity of 22 percent. Core data from the B zone indicate porosity has a mean value of 16.7 percent with a range of 5.2 percent. The typical porosity-thickness from cores is 0.588 m (1.93 ft).

C Zone. Convention permeability and porosity data from three cores of the C zone indicate an average gross thickness of 10.0 m (33 ft) from top to base porosity with a geometric-mean permeability to air of 0.9E-3 μm^2 (0.9 md). The C zone typically develops only 6 percent of the combined flow capacity in the upper Red River. Pore-throat size of C zone rocks with better permeability range from micro to meso class. Special core analysis from mercury- injection tests indicate pore-throat radii of 0.25 to 0.75 microns from a sample with permeability of 1.0E-3 μm^2 (1.0 md) and porosity of 17 percent. The Red River C zone exhibits a wide range of porosity development and storage capacity. Core data from the C zone indicate a mean value for porosity of 12.3 percent and a range of 4.7 percent at one standard deviation. The porosity-thickness from three cores has an average value of is 1.23 m (4.02 ft). The C zone develops 34 percent of the potential storage in the upper Red River, but is hindered by low permeability.

D Zone. Large pores and greatest permeability can be developed in the D zone which produces 77 percent of the combined flow capacity and 46 percent of the storage within the upper Red River. Conventional permeability and porosity data from ten cores of the D zone indicate an average gross interval of 20.7 m (68 ft) with an average porosity-thickness of 1.65 m (5.41 ft) and flow capacity of 69E+3 μm^3 (230 md-ft) at the geometric mean. Permeability to air has a value of 5.2E-3 μm^2 (5.3 md) at the geometric mean. Pore-throat size of D zone rocks with larger, vugular pores range from macro to super-macro class. Special core analysis from mercury injection tests indicate pore-throat radii of 1.0 to 5.0 microns from a sample with permeability of 1.9E-3 μm^2 (1.9 md) and porosity of 15 percent. Core data from the D zone indicate a average porosity of 11.5 percent with a range at one standard deviation of 3.7 percent.

Characterization from Electrical Logs

Electrical log data from Red River intervals were digitized from selected wells across the study area. A summary of log-derived porosity by zone are shown in table 2 (found in petrographical/petrophisical characterization section).

A Zone. The A zone is thin with an average thickness of 1.71 m (5.6 ft) and typical porosity of 8.3 percent. The average storage capacity from logs is 0.16 m (0.52 ft) with a value of 0.30 m (0.98 ft) at one standard deviation above the mean.

B Zone. The best porosity is developed in the B zone and net pay thickness in the B zone is fairly consistent throughout the area. An average value of 18.4 percent with an average net thickness of 2.87 m (9.4 ft) were determined for statistical quantities of B zone storage from digitized electrical logs. The average storage capacity is 0.54 m (1.76 ft) with a value of 0.76 m (2.50 ft) at one standard deviation above the mean.

C Zone. The C zone has the lowest average porosity but indicates substantial values for total pore volume. However, the pore volume in the C zone has poor producibility because of low permeability and small pore-throat size. From digitized electrical logs, the average porosity is found to be 12.7 percent with a net thickness of 4.48 m (14.7 ft). The average storage capacity is 0.57 m (1.88 ft) with a value at one standard deviation above the mean of 0.91 m (2.98 ft).

D Zone. The D zone has the greatest average porosity-thickness and produces the greatest reserves per completion. The Red River D zone exhibits a wide range of porosity development and storage capacity. Data from 50 digitized electrical logs were used for statistical quantification of D zone storage from which the mean porosity is found to be 14.6 percent with a net thickness of 5.36 m (17.6 ft). Average storage capacity is 0.83 m (2.72 ft) with a value at one standard deviation above the mean of 1.68 m (5.51 ft).

Characterization from Production Data

With 129-ha (320-acre) spacing and limited number of wells completed in each reservoir, it is problematic to accurately determine original-oil-in-place (OOIP), drainage area and recovery efficiency. A consistent approach to evaluation of these reservoir characteristics is analysis of production data using type-curves (Fetkovich 1984). The most important reservoir parameter for estimation of OOIP using type-curve analysis is total compressibility (C_t). A value for total compressibility of 1.60E-6 vol/vol/kPa (11.0E-6 vol/vol/psi) was used in type-curve calculations. This value for compressibility was tested with finite-difference, black-oil reservoir simulations and was also found to reasonably match OOIP values by volumetric methods reported in various Red River unitization studies. Table 6 summarizes recoveries for eight significant fields or areas in the Bowman-Harding area. The extrapolated ultimate recovery (EUR) is based on an economic limit of 1.2 m^3 per day (8 bopd) per well.

Analysis of OOIP by type-curves results in a computation for contacted or effective OOIP which is influencing production at the well. It is independent of volumetric calculations based on mapping or spacing. The projected ultimate recoveries from the eight fields indicate an average recovery factor of contacted or effective OOIP of 11.4 percent with a range from 8.7 tp 13.5 percent.

Recovery and OOIP by type-curve analysis reasonably match estimations from other sources. Feasibility studies for unitization of three Red River reservoirs indicate that primary recovery of OOIP, determined by reservoir mapping and volumetric calculation, ranges from 6 to 15 percent. The West Buffalo 'B' Red River Unit (WBBRRU), shown in figure 38, has a reported volumetric OOIP of 3,298,000 m^3 (20,750,000 bbl) according to the unit feasibility study. The projected primary for the WBBRRU was placed at 199,300 m^3 (1,254,000 bbl) or 6 percent of OOIP (Harper Oil 1985). The Buffalo Red River Unit (figure 38) has a reported primary recovery factor of 6 percent of OOIP with a recovery of 349,000 m^3 (2,200,000 bbl). The Medicine Pole Hills Unit (MPHU), shown in figure 39, has a volumetric OOIP of 6,375,000 m^3 (40,100,000 bbl) which is reported in the unitization study and several published articles. According to these sources, the projected primary for the MPHU was placed at 954,000 m^3 (6,000,000 bbl) or 15 percent of OOIP (Kumar et al. 1995; Koch Exploration 1985). The Horse Creek Unit (figure 39) unitization study reported a volumetric OOIP of 7,272,000 m^3 (45,740,000 bbl). The projected primary for the Horse Creek Unit was placed at 721,000 m^3 (4,536,000 bbl) or 10 percent of OOIP (Total Minatome 1995).

In addition to recovery performance reported in unitization studies and previously published articles, production data from the Red River B zone were analyzed from 35 wells across the Bowman-Harding area which were completed only in this zone. Table 7 summarizes production characteristics from the B zone as determined from this study. The table shows that a typical vertical completion in the B zone will efficiently contact and drain 42 ha (105 acres). The more prolific B completions are assumed to be in rock with greater pore thickness and can efficiently drain 71 ha (175 acres). Red River B completions in lower permeability rock in the Buffalo area, with lower gravity oil and dissolved gas, have recovery factors of 6 to 10 percent of OOIP. In deeper portions of the study area where the oil gravity and solution gas content is higher, the average Red River B completion has a recovery factor of greater than 15 percent of contacted OOIP.

The Red River D zone produces the most reserves per completion. A production study of 33 D zone wells, which includes a mix of both stratigraphic and structural reservoir types, is presented in table 8. It is concluded that a typical Red River D completion will recover between 20 and 25 percent of contacted OOIP and the typical contacted drainage area is between 67 to 99 ha (165 to 244 acres) per well. Ultimate primary recoveries from these 33 D zone completions, representative of stratigraphic and structural reservoir types, have a geometric mean of 59,100 m^3 (372,000 bbl).

Where water-drive is the producing mechanism with water encroachment from the flanks, small structural features with 30 m (100 ft) of relief have a mean ultimate recovery of 98,300 m^3 (618,000 bbl) per completion. Total fluid rates remain constant and water-cuts steadily increase over the life of completion in this type reservoir. Stratigraphically trapped D zone oil has been recognized at Horse Creek and Horse Creek South fields in Bowman Co., ND (Longman et al. 1992). Fluid rates and reservoir pressure decreased with time from this reservoir while water-cuts remained nearly constant. The geometric-mean recovery from stratigraphically trapped D zone reservoirs is 32,400 m^3 (204,000 bbl) per well.

An estimate of recovery and drainage from structural water-drive D zone reservoirs was also made by Longman et al in 1992. Two structural reservoirs with a total of five producing wells were studied. This study reported that wells in these structurally trapped reservoirs drained an average of 91 ha (225 acres) per well with a recovery factor of 19.9 percent of OOIP. The computations performed by the Longman study are consistent with the results from the type-curve production analysis of the D zone shown in table 8 for expected reserves at one standard deviation above the geometric mean.

Recovery from the Horse Creek area should also allow a reasonable estimate of volumetric OOIP as the reservoir has 15 producers and several dry-holes at the perimeter. However, two groups (using essentially the same data) determined significantly different values for OOIP and recovery. The OOIP at Horse Creek Unit was estimated to be 26,500,000 bbl by Longman et al in 1992. The Longman study predicted an ultimate recovery of 565,200 m^3 (3,555,000 bbl) or 13.3 percent of OOIP. The unitization and feasibility study for the Horse Creek Unit estimated 7,272,000 m^3 (45,740,260 bbl) for OOIP in 1995 with a projected recovery of 721,200 m^3 (4,536,502 bbl) or 9.9 percent of OOIP (Total Minatome 1995). The results from these two studies demonstrate the potential inconsistency of volumetric calculations from planimetered areas using structural and dryhole control. The type-curve method of production analysis for estimating contacted OOIP (and other reservoir parameters) is more consistent. Analysis of the 15 wells at Horse Creek is summarized on table 6 which shows a calculated OOIP of 7,385,000 m^3 (46,451,000 bbl) and a more optimistic primary recovery of 816,400 m^3 (5,135,000 bbl) for a recovery factor of 11.1 percent.

In summary, primary production from Red River fields ranges from 8.7 to 13.5 percent of contacted OOIP based on type-curve analysis of production data. Primary recoveries from three fields, based on published results of conventional volumetric calculation and production extrapolation, demonstrate a range from 6 to 15 percent. By porosity interval, the Red River B zone demonstrates the ability to produce 13.4 percent of OOIP from an average 65-ha (160-acre) drainage while the D zone produces more efficiently at 20.3 percent of an average 65-ha (160-acre) drainage.

Enhanced Recovery Projects

There are three air-injection (insitu-combustion) projects and one waterflood project in the study area (figures 38 and 39). All projects are primarily in the Red River B zone except for the newly formed Horse Creek Unit which produces from the D zone. A water-injectivity test of the Red River B was performed by Shell in the early development stages of the Buffalo field and concluded that waterflooding was not feasible due to poor water injectivity. Partially for this reason, Koch Exploration formed the Buffalo Red River Unit (BRRU), Harding Co., SD in 1978 as an air-injection project in the Red River B zone. This project was subsequently expanded to adjacent units. Koch Exploration also formed the Medicine Pole Hills Unit (MPHU), Bowman Co., ND as an air-injection project in 1985 for the B and C zones of the Red River. Total Minatome formed the Horse Creek Unit (HCU), Bowman Co., ND in 1995 for air injection in the Red River D zone. Harper Oil Company formed the West Buffalo 'B' Red River Unit (WBBRRU) in 1986 as a secondary project in the Red River B zone using water injection.

Projected ultimate recovery for the air-injection project at MPHU is reported in the literature to be 25.9 percent of OOIP (Kumar et al. 1995). However, extrapolation of more current production trends through April 1997 by this project indicate an ultimate (primary and secondary) recovery of 22 percent. Ultimate recovery at BRRU is reported to be 21.6 percent of OOIP (Kumar et al. 1995). Published predictions by the operator at the HCU indicate an ultimate recovery after air-injection of about 26 percent of OOIP (Watts et al. 1997). It is concluded here from detailed review of data from the HCU that a significant number of additional wells will be required for the operator to achieve this ultimate recovery. A detailed review of the MPHU and HCU is presented in later sections which present Red River field case studies.

From the original feasibility study, the projected ultimate recovery after waterflood from the WBBRRU project was predicted to be 15.1 percent of OOIP (Harper Oil 1985). Water injectivity at the WBBRRU has been poor, but this reservoir has the lowest transmissibility ($kh/\mu B$) of all the Red River B zone fields studied. In an effort to improve project performance, two horizontal wells were drilled in the WBBRRU during 1995 and 1996, one for injection and one for production. Additional vertical wells have been also drilled. The current operator has made predictions of ultimate recovery with the current number of wells of 12.7 percent of OOIP and that with additional wells the recovery should be 14.4 percent of OOIP (Citation Oil and Gas 1996). Cumulative production from the reservoir, as of April 1997, is 178,900 m^3 (1,125,000 bbl) or 5.4 percent of OOIP. Extrapolation of current production trends for this project indicate an ultimate recovery of 259,100 m^3 (1,630,000 bbl) or 7.9 percent of reported OOIP. Much of the low-recovery problem at WBBRRU is severe heterogeneity and compartmentalization as demonstrated by the low OOIP from type-curve production analysis of 2,080,000 m^3 (13,083,000 bbl) compared to the volumetric calculation of 3,299,000 m^3 (20,750,000 bbl) from the unit feasibility report. Comparison of these two disparate numbers indicate a possibility that the initial wells were contacting only two-thirds of the reservoir.

The feasibility studies for these enhanced recovery projects all made initial predictions of incremental recovery of about 10 percent of OOIP. Some of these projections were based on analogy and others were based on simulation studies. The older projects (both air and water) were clearly not achieving the initially predicted production increases and subsequently had new wells drilled and large stimulation treatments performed on many older wells (Kumar et al. 1995; Citation Oil and Gas 1996). Consequently, it is difficult to separate true incremental secondary oil from additional primary oil. Both types of secondary methods have demonstrated technical success. Although there has been technical success from these projects, their profitability is debatable.

It is concluded that although air-injection, insitu-combustion does produce incremental oil, the initial capital investment and subsequent operating costs are very high and would not be profitable for small reservoirs with only a few wells. Waterflooding has also demonstrated incremental oil and costs are much less for both initial investment and operations. Water injection rates with vertical wells are low but horizontal completions offer promise for sufficient injectivity to allow waterflooding to be profitable. Demonstration activities by this project for suitability of waterflooding the Red River B zone have been focussed in the Buffalo Field (north area).

The north area of the Buffalo Field, shown in figure 38, includes seven wells completed in the Red River B zone and operated by Luff Exploration Company. This area became a field-demonstration site for reservoir testing and application of technologies for improving oil recovery by waterflooding. The sequence of demonstration activities include the following:

1) Water injection test in a vertical well,
2) Production and water injection test in a horizontal well,

3) Extended water injection test for one year,
4) Evaluate horizontal drainholes for producing wells, and
4) Expand waterflood to cover the entire reservoir.

At the time of this report, the water injection tests at a vertical and horizontal well have been completed. A request for hearing has been made to the South Dakota Department of Environment and Natural Resources for the granting of a one-year pilot injection test with a horizontal well in the core area of the reservoir. Approval is expected in the fourth quarter of 1997. After successful results from the pilot, the reservoir will be unitized and a full waterflood implemented.

Computer Simulation of Primary Recovery

Key demonstration activities for this project involve the Red River B zone at Buffalo Field (north area). This area of the Buffalo Field has a relatively thick B zone and average permeability. A single-layer, finite-difference black-oil reservoir model was constructed to history match production from two Red River B zone producers in the center of the Buffalo Field (north area). The two wells represented in the model are spaced 129-ha (320-acre) per well for an allocated area of 258 ha (640 acres). These two wells, Stearns F-20 and Stearns O-20, are located in section 20, T.22N., R.4E. (figure 40) and are representative of average production from the B zone reservoir. These wells also had data from several pressure buildup tests to aid the history-matching process. This computer model was successful in matching the production and reservoir pressure data from the wells without water influx. The model consisted of a reservoir grid which was 13 by 13 which was adjusted in size during the history-match process with a final area of 233 ha (575 acres). Reservoir thickness and porosity were obtained from electrical log data for a net thickness of 3 m (10 ft) and porosity of 20 percent. Water saturation and permeability were varied to match rate data, watercut and pressure data from the wells. The water saturation which matched the prior producing watercut was 38 percent. An absolute permeability of 7.9E-3 μm^2 (8.0 md) resulted in a good match of the simulation results with production-rate data. Initialization pressure was 21,700 kPa (3150 psi) and the bubble-point pressure was 9700 kPa (1400 psi). Oil produced from the reservoir has a density of 0.865 gm/cc (32° API).

The original-oil-in-place computed by the model was 755,200 m^3 (4,750,000 bbl). After matching the 12-year production history, the model was allowed to continue production at constant flowing conditions to an economic limit of 1.3 m^3 per day (8 bopd) per well. The cumulative, historical production from the two wells is 48,205 m^3 oil and 43,886 m^3 water (303,202 bbl oil and 276,035 bbl water) as of March 1997. The model indicates a ultimate primary recovery of 11 percent of OOIP but only after an unacceptably long life. The reservoir model produced 81,720 m^3 (514,000 bbl) oil before the combined economic limit or 2.5 m^3 oil per day (16 bopd) and after a life of 40 years. Current cumulative recovery of OOIP is indicated to be only 6.4 percent at a pressure of 7580 kPa (1100 psi) determined by pressure buildup tests. Final reservoir pressure, predicted by the model, at abandonment conditions is 6000 kPa (870 psi).

Oil-Water Relative Permeability

Oil-water relative permeability studies from B zone cores suggest the B zone should respond favorably to waterflooding. A study of 9 samples of the B zone from various wells in

Bowman and Harding counties indicate moveable oil of about 57.1 percent of pore volume (table 9). The relative permeability to oil at irreducible water saturations averages 56 percent of absolute permeability to air. End-point permeability to water at 100 percent watercut averages 19.2 percent of absolute permeability.

A construction of average oil-water relative permeability curves is shown in figure 41. These relative permeability curves were used in fractional-flow studies with a reservoir simulator using typical oil and water PVT data from the area. Base-line irreducible water saturation was adjusted to match empirical observations of water saturations from electrical log data and actual well production. Oil-productive intervals with 30 percent water saturations generally produce less than 5 percent water. Water-cuts of 95 percent are tested from intervals with 65 percent or greater water saturations. The fractional flow curves shown on figure 41 are for two oil systems which represent the range of typical Red River oil in the area. Oil-system 1 is for 0.865-gm/cc (32° API) oil with a bubble point viscosity of 0.8E-4 Pa•s (0.80 cp) and formation volume factor of 1.19 rb/stb. Oil-system 2 is for 0.830-gm/cc (39° API) oil with a bubble-point viscosity of 0.48E-4 Pa•s (0.48 cp) and volume factor of 1.40 rb/stb. As can be seen in figure 41, computer-simulation predictions of watercut at surface conditions match empirical observations of log-calculated water saturation and producing watercut when the average oil-water relative permeability curves are used.

Oil-water relative permeability relationships provide a baseline for potential recovery by water-displacement processes, either waterflooding or natural encroachment. The fractional-flow curves generated by this simulation study indicate recovery by water displacement of about 45 percent of OOIP in swept or encroached reservoir rock from producing watercuts increasing from 10 to 95 percent and corresponding water saturation increasing from 34 to 63 percent. Similarly, a recovery of 29 percent of OOIP is indicated where reservoir conditions result in producing watercuts starting at 50 percent and ending at 95 percent with corresponding water saturation increasing from 48 to 63 percent. These recovery calculations assume perfect sweep conformance and neglect capillary forces.

In summary, analysis of production and recovery by field and zone indicate primary recovery factors which range from 6 to 15 percent. Water displacement of oil from relative permeability studies indicates recoveries from 29 to 45 percent which correspond to 50 percent and 10 percent initial watercuts, respectively. With a sweep efficiency of only 50 percent, waterflooding should double recovery from the Red River B zone.

Water Injectivity of the Red River B Zone

A water-injectivity test was performed in 1995 at the A-19 Stearns (nene Sec. 19, T.22N., R.4E.), a vertical well completed in the Red River B zone at Buffalo Field (north area). A map of the area is shown on figure 40. The purpose of the test was to quantify permeability-thickness (kh) to water, determine reservoir pressure and identify any non-radial flow characteristics. Red River produced water was injected into the oil-completion perforations with a positive displacement pump at a rate of 15.9 m^3 per day (100 bwpd) for 600 hrs and then shut-in for 120 hrs. Bottomhole gauges recorded the injection buildup and falloff pressure data. The final injection pressure after 25 days at reservoir depth was 24,970 kPa (3622 psi). It was determined that the 4.6-m (16-ft) reservoir interval will sustain an injection rate of 28.6 m^3 per day (180 bwpd) and remain below 34,500 kPa (5000 psi). Analysis of the test data by conventional and analytical methods indicate the B zone interval has an average permeability to water of 0.59E-3 μm^2 (0.6 md) and a stimulation factor (S) of -2.4 assuming a wellbore radius of 10 cm (4 in). The static reservoir pressure was determined to be 10,200 kPa (1474 psi). Pressure buildup and falloff analyses indicate radial-flow characteristics. The original drillstem-test data of the Red River injection interval indicate a permeability to the water phase of 0.64E-3 μm^2 (0.65 md).

Computer Simulation of Water Injectivity

A single-layer, finite-difference black-oil reservoir model was constructed to history match the water injection test data from the A-19 Stearns, Buffalo Field (Red River B zone). This computer model was successful in matching the injection-test pressure data (figure 42). The model consisted of a reservoir grid which was 13 by 13 and represented an area of 65 ha (160 acres). The center 5 by 5 grids were 15 m by 15 m (50 ft by 50 ft). The remaining grids were 91 m by 91 m (300 ft by 300 ft). Reservoir thickness and porosity were obtained from electrical log data for a net thickness of 4.9 m (16 ft) and porosity of 16 percent. Water saturation and permeability were varied to match producing water-cut and the pressure data from the injection test. The water saturation which matched the prior producing watercut was 49.5 percent. An absolute permeability of 2.5E-3 μm^2 (2.5 md) resulted in a good match of the simulation results with the injection test data. Initialization pressure was 9900 kPa (1435 psi). The relative-permeability ratio of water to absolute used in the reservoir model at 49.5 percent water saturation was 0.183. The resulting effective permeability to water is 4.5E-4 μm^2 (0.46 md) which is in fair agreement with the permeability to water of 5.9E-4 μm^2 (0.60 md) determined by well-test analysis and analytical simulation. The reservoir model appears to be a valid representation of the Red River B zone at the A-19 Stearns because the permeability which resulted in matching the test data is consistent with core and pressure-transient analysis. The reservoir model was used to calculate extended-time injectivity in the 65-ha (160-acre) reservoir with a hypothetical producing well. Simulated injection was performed a various rates to pseudo steady-state conditions. The resulting pseudo steady-state injection pressures with rate are shown in figure 43. From this graph, it is concluded that the A-19 Stearns would be capable of a sustained injection rate of about 28.6 m^3 per day (180 bwpd) at a bottomhole pressure of 34,500 kPa (5000 psi).

Water Injectivity with Horizontal Wells

The M-20H Stearns was drilled in December 1996 as a horizontal well in section 20, T.22N., R4E. for the purpose of evaluating oil productivity and water injectivity in a mature, partially depleted reservoir in the Red River B zone (figure 40). Because of lost circulation and losing the bottomhole assembly (BHA) with drilling collars in the horizontal section, the lateral hole was only 305 m (1000 ft). Efforts to retrieve the BHA and drilling collars were unsuccessful. A drillstem test of the Red River B zone interval measured 7580 kPa (1100 psi) as the static reservoir pressure which was the same found by pressure buildup test at the closest offset well.

The well was produced by pump for 45 days with an average rate of 11.1 m^3 oil and 11.3 m^3 water per day (70 bopd and 71 bwpd) during the last 10 days. The average production from the two offset wells was 3.0 m^3 oil and 4.0 m^3 water per day (19 bopd and 25 bwpd) per well during that time. This indicates an improvement of productivity by a factor of 3.1 with a relatively short lateral with junk in the hole.

Immediately after the short production test, a water injection test was performed. Water was injected at 800 bwpd for 9 days then reduced to 550 bwpd for the remainder of a 30-day test. The recorded pressure data are shown on figure 44. The final pressure at reservoir depth of 2670 m (8760 ft) was 27,920 kPa (4050 psi).

Simulation of Water Injection with Horizontal Wells

A single-layer, finite-difference black-oil reservoir model was constructed to history match the water injection test data from the M-20H Stearns, Buffalo Field (Red River B zone). This computer model was successful in matching the injection-test pressure data (figure 44). The model consisted of a reservoir grid which was 13 by 13 and represented an area of 65 ha (160 acres). The lateral section was modeled using narrow grids which were 6-m (20-ft) wide with an arbitrary permeability of 1000 md in the center grids which represent the lateral hole. Reservoir thickness and porosity were obtained from electrical log data for a net thickness of 4.9 m (16 ft) and porosity of 16 percent. Water saturation and permeability were varied to match producing watercut and pressure data from the injection test. The reservoir parameters which matched producing watercut and pressure were permeability of 5.3E-3 μm^2 (5.4 md) and water saturation of 38 percent. These reservoir parameters are consistent with core and log data in the area.

The reservoir model appears to be a valid representation of the Red River B zone at the M-20H Stearns because the permeability which resulted from matching the test data is consistent with core and pressure-transient analysis. The reservoir model was used to calculate extended-time injectivity in the 65-ha (160-acre) reservoir with a hypothetical producing well. Simulated injection was performed at various rates to pseudo steady-state conditions with the resulting pseudo steady-state injection pressures shown in figure 43. From this graph, it is concluded that the 305-m (1000-ft) lateral in the M-20H Stearns would be capable of a sustained injection rate of about 82.7 m^3 per day (520 bwpd) at a pressure of 34,500 kPa (5000 psi) at reservoir depth. This is nearly a three-fold increase over the results from injection testing at the A-19 Stearns, a vertical well.

As confirmation of simulated water injectivity in the Red River B zone with horizontal wells, injection history from a horizontal well in the West Buffalo 'B' Red River Unit was researched from public data on file with the South Dakota Oil and Gas Board. In 1994, Apache Corp. completed the No. 2-26H WBBRRU well (Sec. 26, T.21N., R3E., Harding Co., SD) with a horizontal lateral length of 732 m (2400 ft). Injection began in February 1995 and was averaging 76.3 m^3 per day (480 bwpd) at 6900 kPa (1000 psi) wellhead pressure during the first half of 1996. The computed injecting pressure at reservoir depth of 2550 m (8350 ft) is about 32,100 kPa (4650 psi). During the second half of 1996, the operator obtained regulatory approval for increased injection rates and pressure at the No. 2-26H well. Injection was increased to over 143 m^3 per day (900 bwpd) at a wellhead pressure of slightly less than 9650 kPa (1400 psi) or about 35,160 kPa (5100 psi) at reservoir depth.

Simulation of Waterflood Recovery with Horizontal Injection

The reservoir model used to match injection data at the M-20H Stearns well was expanded to cover a 129-ha (640-acre) reservoir in the Red River B zone with two vertical producers in opposite corners of the square grid. A horizontal injector was centered between the producing wells with lateral of 1219 m (4000 ft). Representation of the lateral was the same as the previously described history match for the M-20H Stearns injection test. The reservoir was flat and isotropic with an initial pressure of 7600 kPa (1100 psi), which is the current average reservoir pressure. The OOIP, at original pressure of 21,700 kPa (3150 psi), calculated by the model is 1,120,000 m^3 (7,043,000 bbl) and recovery to the initiation of water injection is 4.1 percent of OOIP. Simulation of primary production to abandonment conditions of 2.5 m^3 oil per day (16 bopd) is 88,800 m^3 (558,500 bbl) or 7.9 percent of OOIP. Water injection was maintained at 127 m^3 water per day (800 bwpd) and the producing wells constrained to a flowing bottomhole pressure of 700 kPa (100 psi). Production results from the simulation area are shown in figure 45. The time to peak oil production is about three years after commencement of injection. The peak oil rate from both wells is about 39.7^3 oil per day (250 bopd) which is consistent with the average peak oil rate during primary. The computed recovery after 20 years of injection is about 159,000 m^3 (1,000,000 bbl). Extrapolation of the oil production trend with a constant percentage decline indicates a recovery of about 222,600 m^3 (1,400,000 bbl) at 2.5 m^3 oil per day (16 bopd). Incremental secondary oil is computed from the simulations to be 180,100 m^3 (1,132,800 bbl) or 16 percent of OOIP. Total recovery of primary and secondary is computed to be 268,900 m^3 (1,691,300 bbl) or 24 percent of OOIP.

The reservoir simulations of water injection and corresponding oil recovery for the Red River B zone at Buffalo Field (north area) confirm the technical feasibility of waterflooding as an effective, improved recovery technology. The models were constructed using available data from conventional core studies, special core studies for oil-water relative permeability and electrical logs and then calibrated to pressure-transient tests and production histories. The primary recovery by pressure depletion of a 32° API black-oil system with a bubble-point pressure of 9650 kPa (1400 psi) is indicated to be 11 percent of OOIP without water encroachment. This recovery is predicted after over 40 years from wells on 129-ha (320-acre) spacing which is probably longer than the expected mechanical life of a wellbore. Injection of water through a horizontal well with a 1220-m (4000-ft) lateral is expected to be at rates of 800 bwpd or more. The model was calibrated to a water saturation which produced 50 percent watercut, average from wells in the reservoir, at the start of water injection. Computed oil production after injection is nearly 159,000 m^3 (1,000,000 bbl) after 20 years with a peak response time of three years. The ultimate recovery is projected to be 24 percent of OOIP which is consistent with the upper limit of 29 percent recovery discussed previously under the section covering oil-water relative permeability. Predictions of incremental oil from the simulations indicate that 16 percent of OOIP should be feasible from Red River B zone reservoirs which are producing at 50 percent watercut.

Horizontal Wells for Production

Two horizontal wells in the study area were included in this project, the M-20H Stearns well drilled by Luff Exploration Company (swsw Sec. 20, T.22N., R.4E., Harding Co., SD, shown in figure 40) and the No. 1-26H Greni (w/2 Sec. 26, T.129N., R.103W., Bowman Co., ND, shown in figure 46) drilled by UMC as operator with Luff Exploration Company as a joint interest owner. Detailed drilling descriptions are to be found in a separate topical report.

M-20H Stearns, Buffalo Field. The M-20H Stearns was drilled between two existing Red River B zone completions to evaluate both oil productivity and water injectivity with the aim of using the technology for waterflooding the partially depleted field. The Red River B and D zones were both drillstem tested prior to drilling to total vertical depth in the M-20H Stearns well. After drilling the vertical hole, open-hole logs were then run to aid with evaluation of both intervals.

Downhole motors using mud-pulse MWD systems were used to drill the curve portion of the hole. The curve section was drilled with a radius of approximately 128 m (420 ft) to a total drilled depth of 3066 m (10,059 ft) and true vertical depth of 2664 m (8743 ft). The end of the curve section was immediately on top of the Red River B zone at an angle of 89° from vertical.

After drilling the curve section was completed, casing was run and cemented in place from surface to the end of the curve section. The horizontal section was then drilled with down-hole motors and MWD equipment. Unfortunately, circulation was lost after drilling horizontally 314 m (1029 ft) into the Red River B zone and as a result, the directional drilling tools and some of the drillstring became stuck in the hole. The main cause of loss of circulation was low bottomhole pressure of 7600 kPa (1100 psi) in the partially depleted Red River B zone.

Although the horizontal section of the wellbore was concluded at a shorter distance than planned, the well was pump tested as a producing oil well for 42 days followed by a 30-day water-injectivity test. The well produced at an average rate of 11.1 m^3 oil and 11.3 m^3 water per day (70 bopd and 71 bwpd) during the last 10 days. The average production from the two offset wells was 3.0 m^3 oil and 4.0 m^3 water per day (19 bopd and 25 bwpd) per well during that time. This indicates an improvement of productivity by a factor of 3.1 with a relatively short lateral with junk in the hole. Immediately after the short production test, a water injection test was performed. Water was injected at 127 m^3 per day (800 bwpd) for 9 days then reduced to 87.4 m^3 per day (550 bwpd) for the remainder of a 30-day test. The final pressure at reservoir depth of 2670 m (8760 ft) was 27,920 kPa (4050 psi). Results from the injection test indicate water injectivity of about three times that for a vertical well in the Red River B zone.

No. 1-26H Greni, State Line Field. The No. 1-26H Greni was drilled as an offset to existing production in the Red River B zone in State Line Field, Bowman Co., ND. The No. 1-26H Greni well is the fourth well on a Red River feature that has produced over 143,090 m^3 (900,000 bbl) of oil from B and D zones of the Red River since 1973. The No. 1-26H Greni is located on the west flank of a relatively large Red River structure in the west-half of Sec. 26, T.129N., R.103W. The structural feature was being produced by one remaining well at rate of 14.3 m^3 per day (90 bopd) without water and with indications of a large reservoir which could not be efficiently drained by that vertical well.

The 1-26H Greni well was drilled to a vertical depth of 2594 m (8510 ft) at which point the curve section was initiated. A medium-radius curve section with a 150-m (493-ft) radius was drilled. Total length of the lateral drilled from the vertical wellbore was 1129 m (3705 ft) and the total drilled depth was 3723 m (12,215 ft). The well encountered the Red River B at a subsea datum which was 20 m (67 ft) low to the existing producing well. The No. 1-26 H Greni was produced from the open-hole lateral section in the Red River B zone from October 1996 through April 1997. Production from the well was about 1.6 m^3 oil and 54.2 m^3 water per day (10 bopd and 341 bwpd) after 60 days. At that point it was decided to produce from the far portion of the lateral by isolating the near portion with inflatable packers and tubing. Production after placement of the isolation equipment was 0.6 m^3 oil and 24.2 m^3 water per day (4 bopd and 152 bwpd). The drilling of the No. 1-26H Greni appears to have resulted in a mechanical success but a failure with regard to reservoir development. The low structural position relative to offset production and poor oilcut indicate completion of the lateral below an oil-water contact. Production at the offset vertical well appears to have been impacted by the withdrawals from the horizontal well. Plans are to evaluate the horizontal well for use as a water injection well to improve production at the updip well.

In summary, horizontal wells in the Red River B zone have the potential for a three to four-fold increase of productivity over vertical wells. Experience from the wells cited above indicate several important points for drilling and reservoir characterization. The lost circulation which resulted in a stuck drilling assembly at the M-20H Stearns indicates that drilling into a partially depleted reservoir might best be accomplished with an under-balanced system. The lesson learned from the No. 1-26H Greni is that a vertical test should be drilled and evaluated by logs and DST before drilling a horizontal well along the flank of a structural feature where the reservoir may have an oil-water contact. Reservoir heterogeneity in the Red River B zone at Buffalo Field (north area) appears to be minimal at a scale of 2.6 km^2 (one square mile) from the reservoir data obtained from logs and DST at the M-20H Stearns vertical hole. Compared to the offset wells in section 20, reservoir properties of thickness, porosity, reservoir pressure and producing watercuts were found to be very similar.

Demonstration Wells and Reservoir Heterogeneity

Reservoir characterization studies and demonstration wells indicate that the Red River D zone is the most heterogeneous and may have significant under-developed reserves across the study area. The D zone is also detectable from amplitude interpretation of 3D seismic data. Two 3D seismic surveys were obtained in Bowman Co., ND, one at Cold Turkey Creek Field and a second at Grand River School Field (figure 47). These two surveys are separated by only two miles. A full discussion of seismic interpretation can be found in later sections which cover seismic characterizations of the Red River.

Cold Turkey Creek Field is a regulatory spaced area which actually covers 10 separate structures. The 3D seismic survey covered three of these accumulations. After interpretation of the seismic data, two wells were drilled on one structure to test all zones in the Red River but primarily the Red River D zone (figure 48). The structure had been produced for over 20 years by one well on the crest of the structure and had been perforated in the B, C and D zones. Based on logs and drillstem test, porosity-permeability development is poor and the intervals are thin at the old crestal well.

The structure has an areal extent, based on seismic time-structure and isochron maps to spill-point, of approximately 162 ha (400 acres). The potential OOIP for the combined B and D zones were calculated at about 1,107,000 m^3 (6,960,000 bbl). Recoverable oil at 15 percent of this OOIP is estimated at 166,000 m^3 (1,044,000 bbl). The cumulative oil from the existing well is 59,600 m^3 (375,000 bbl) with an EUR of 74,000 m^3 (465,000 bbl). The under-developed reserves which could be contacted by additional drilling were therefore estimated at 90,500 m^3 (569,000 bbl). These postulated reserves were used to justify additional wells on the structure.

Muslow-State B-27, Cold Turkey Creek Field. The Muslow-State B-27 (nwne Sec. 27, T.130N., R102W.) was drilled on the south flank of the structure to test a seismic-amplitude anomaly in the Red River. The existing well on the feature is the Faris 1-22 which has a cumulative production of 375,000 bbl oil and 119,000 bbl water and has been perforated in the Red River B, C, and D zones. The critical closure of the Red River is estimated at about 30 m (100 ft) based on well control and seismic data. The net thickness of each zone at the No. 1-22

Faris, the original well, is thinner than average and porosity development is poor. Based on seismic interpretation, the Muslow-State B-27 well was to encounter a thicker and more porous section in the D zone with a loss of structure of about 9 m (30 ft) from the existing well on the structural crest. The test well was located about 389 m (1275 ft) from the original well.

Special efforts were made to collect a full suite of reservoir charactyerization data at the Muslow-State B-27 well. The entire upper Red River section was cored and drillstem tests were run in the B, C and D zones. Wireline logs included high-resolution porosity and resistivity logs. A sonic log was also obtained. The Muslow-State B-27 well penetrated the Red River at a depth 10 m (32 ft) low to the No. 1-22 Faris and encountered oil production in the B and D zones based on drillstem tests. The B zone DST recovered oil and drilling filtrate. The reservoir pressure was 12,800 kPa (1850 psi), down 13,800 kPa (2000 psi) from original pressure. This indicates that the B zone at the Muslow-State B-27 is in pressure communication with the No. 1-22 Faris well. The C zone was drillstem tested and found very poor permeability and near-original pressure. The D zone produced oil and water on drillstem test at original pressure. It is not known how much production from the No. 1-22 Faris has been from the D zone. It is possible that the D zone between the two wells is isolated by faulting or stratigraphic change. It is also possible that the older well has produced very little from the D zone. The Muslow-State B-27 well was perforated and acidized in the D zone. The initial production rate was 26.4 m^3 oil and 21.1 m^3 water per day (166 bopd and 133 bwpd). Oil density is 0.865 gm/cc (32° API). The estimated ultimate reserves from the D zone after six months of history are about 35,800 m^3 (225,000 bbl) oil. There has been no change in production at the Faris No. 1-22.

In the D zone, calculations from electrical logs indicate a productive interval thickness of 25 ft at an average water saturation of 47 percent and average porosity of 11.4 percent. Maximum porosity in the D zone is 20 percent. Apparent oil-in-place is about 3536 m^3 per ha (9000 bbl per acre). Calculations of the B zone interval indicate a productive thickness of 2.1 m (7 ft) with porosity of 16.3 percent and water saturation of 21 percent. Apparent oil-in-place for the B zone is about 2110 m^3 per ha (5380 bbl per acre). Based on core and log data from the well, the Red River A and C zones are non-productive.

Pang-Faris K-22, Cold Turkey Creek Field. The Pang-Faris K-22 (nesw Sec. 22, T.130N., R102W.) was also drilled on the feature to test another, and apparently separate, seismic-amplitude anomaly. This well is on the north flank of the feature and penetrated the Red River at a depth about 16 m (53 ft) below the structural crest. Drillstem tests were run across the Red River B and D zones. The Red River B zone recovered mostly drilling mud (formation damage?) and recorded a shut-in pressure of 13,700 kPa (1980 psi). The B zone test indicates pressure communication with the Faris No. 1-22 and Muslow-State B-27 wells in this interval. The drillstem test in the D zone recovered about 7200 ft of mostly oil with a shut-in pressure of 24,100 kPa (3500 psi) which indicates slight pressure depletion. The Red River D zone was perforated and flowed 27.8 m^3 per day (175 bopd) at 690 kPa (100 psi) wellhead pressure with no water. Oil density is 0.865 gm/cc (32° API). Few Red River wells in the area flow on initial completion.

Calculations from logs of the D zone interval indicate a productive thickness of 5.5 m (18 ft) with porosity of 15 percent and water saturation of 30 percent. Apparent oil-in-place for the D zone is about 4430 m^3 per ha (11,280 bbl per acre). There is insufficient production history at this time to project recovery but potential recoverable reserves from the D zone are estimated at 57,200 m^3 (360,000 bbl) for 65-ha (160-acre) drainage and a recovery factor of 20 percent.

Electrical logs across the Red River B zone indicate 2.1 m (7 ft) at 15 percent porosity with 30 percent water saturation. Apparent oil-in-place for the B zone is about 1720 m^3 per ha (4390 bbl per acre). Based on log data from the well, the Red River A and C zones are non-productive.

Data from the new wells are interpreted to show that the No. 1-22 Faris has produced mostly from the Red River B zone although it was perforated in the B, C and D zones. The B zone pressure is drawndown in the new wells while the D zone is not. The oil produced at the No. 1-22 Faris has a density of 0.838 gm/cc (37.3° API) while the D zone completions in the new wells produce oil with a density of 0.861 gm/cc (32.8° API). A review of the production data from the No. 1-22 Faris (shown on figure 49) suggests that evaluation of producing wells for characteristics which might indicate potential for extension drilling should be approached in an open-minded manner.

Production data from the No. 1-22 Faris have exhibited a nearly harmonic decline throughout most of the producing life. The curves are smooth which indicate the absence of mechanical or formation-damage problems. The water-oil ratio has been on a steadily increasing trend to a value of about 1.0 at present. This could be interpreted as water encroachment; however, the new downdip wells indicate low water saturations in the Red River B zone from log calculations which should produce oil without water.

Analysis of production data from the Faris No. 1-22 using the type-curve method and a black-oil simulator for material balance indicate an OOIP for the B zone to be greater than 795,000 m^3 (5,000,000 bbl). This analysis assumes no water encroachment and that most of the water produced by the No. 1-22 Faris is from the C and D zones. Assuming an average OOIP value of 1920 m^3 per ha (4890 bbl per acre), a potential reservoir area of over 405 ha (1000 acres) is calculated. This area is greater than the size of the feature indicated from structure and mapping of seismic data. Returning to the production curves from the No. 1-22 Faris, it would be difficult to support additional drilling near this well based on these data alone. The well is producing less than 20 bopd with extrapolated reserves of about 90,000 bbl. Although the time required to achieve these reserves is about 25 years, drilling another well based on acceleration of recovery cannot be justified. However, simplistic volumetric estimates of potential OOIP in the combined Red River B and D zones for the structural feature are 1,107,000 m^3 (6,960,000 bbl). With such substantial under-exploited resources, obvious questions arise as to how can they targeted and what is the best strategy for economic development.

The reservoir data from the Red River B zone does not indicate compartmentalization between the three wells which are separated by approximately 0.40 km (0.25 mile). Drillstem test pressure data show 1850 and 1980 psi at the new wells. If the OOIP of the B zone reservoir was 795,000 m^3 (5,000,000 bbl), as type-curve production analysis and material-balance computations suggest, the recovery factor from the No. 1-22 Faris represents only 9.3 percent of OOIP. Because of the drawn-down pressure, productivity of new vertical wells completed in the B zone would probably be less than 50 bopd and would not be economical. Another option for development of the B zone reserves would be to wait for depletion of the D zone and then re-complete in the B zone. Because the depletion of D zone reserves may require 25 years, this option causes the value of the B zone to be negligible from a time-value perspective. A third approach might be to produce the B and D zones downhole commingled.

If the B zone reservoir were waterflooded, an ultimate recovery of 30 percent or greater may be possible, assuming the water saturation in the reservoir is in the range of 25 to 30 percent as computed from log data. The incremental oil would be nearly 159,000 m^3 (1,000,000 bbl). As discussed previously for the Buffalo Field (north area) Red River B zone reservoir, new horizontal wells would be required for water injection and also recommended for production. Three horizontal wells could be justified based on the previously stated reserves. The drilling of these wells for the B zone could be coordinated with further testing of other seismic anomalies in the Red River D zone. These wells would be drilled with a large diameter hole to allow plugback and drilling horizontally after logging and testing the B and D zones.

At the Cold Turkey Creek test site, the D zone was targeted from seismic amplitude character which correspond to increased thickness and porosity. Selecting the drilling locations is a compromise between structural position and amplitude development. The amplitude blooms are spotty and appear to be 16 ha (40 acres) or less in areal extent at Cold Turkey Creek. The structure has a regional relief of about 30 m (100 ft) based on seismic data and well control. Because the Pang-Faris K-22 well is 16 m (53 ft) from the crest of the structure and is producing water-free oil, it is not known at this time where the structural limit is for commercial production. There are still some undrilled amplitude anomalies which are above the structural spill-point. These will be evaluated after more confidence is gained for the ultimate reserves and profitability of the wells drilled at this time. It may be found that the structural spill-point is not the only or major controlling parameter for D zone reservoir limits. The three wells drilled a this time on the 162-ha (400- acre) structure at Cold Turkey Creek demonstrate three reservoir compartments in the Red River D zone. The original well is located in a non-productive, or at least very poor productivity, reservoir compartment on the crest of the structure (interpretation of data from new wells indicate it is producing mostly from the Red River B zone). The other two new wells are classified as separate, although some hydraulic connection may exist, because the lowest well is producing water-free oil and the other well is producing with a watercut of 45 percent. The combined incremental reserves developed in the Red River D zone by the completion of the new wells is probably near 79,500 m^3 (500,000 bbl).

In summary, at Cold Turkey Creek Field, one structural feature was tested for heterogeneity as suggested from 3D seismic and low recovery of reserves estimated from simple volumetric calculations. The potential under-developed recoverable reserves were estimated at 90,500 m^3 (569,000 bbl) before drilling additional wells. Two wells encountered production in the Red River D zone in what appear to be poorly connected, if not separate, reservoir compartments. The recoverable reserves from these wells are estimated at nearly 79,500 m^3 (500,000 bbl). Interpretation of the 3D seismic data suggest additional reserves in the D zone may be possible from a third new well which should approach 31,800 m^3 (200,000 bbl). An additional 159,000 m^3 (1,000,000 bbl) is predicted as probable reserves if the Red River B zone were fully developed and waterflooded. Total new reserves are placed at 270,300 m^3 (1,700,000 bbl).

Watson O-6, Grand River School Field. The Watson O-6 well (swse Sec. 6, T129N., R.101W.) was a targeted vertical well in the Grand River School Field (figure 47). The location of the well was selected from interpretation of seismic amplitude which was successful for predicting D zone porosity development at the Cold Turkey Creek Field. The Watson O-6 well is the second well on a large structural feature at a distance of 0.95 km (0.59 mile) from the No. 1-6 Hanson well which has been producing for over 20 years. The No. 1-6 Hanson has similar poor porosity and thin intervals as discussed previously for the No. 1-22 Faris at Cold Turkey Creek. The Watson O-6 well penetrated the Red River at a structural datum which is flat to the No. 1-6 Hanson and was drillstem tested in the B and D zones before electrical logs were run. Pressure measurements of the Red River B zone were 17,200 kPa (2500 psi), which is drawn down about 10,300 kPa (1500 psi) from the original pressure. Calculations from electrical logs indicate 1.8 m (6 ft) of productive interval with excellent porosity and low water saturation. The Red River D zone was found to be thickly developed with 10 m (30 ft) of productive interval with average porosity of 15 percent. The drillstem test recovered 6.4 m^3 (40 bbl) of oil without water for a calculated flow rate of 76 m^3 per day (480 bopd). Reservoir pressure was undisturbed from original at 26,900 kPa (3900 psi).

The results from the Watson O-6 are very similar to those found at the adjacent Cold Turkey Creek Field. The Red River B zone demonstrates pressure communication between wells separated by a distance of 0.95 km (0.59 mile). The Red River D zone is greatly variable and better development can be identified by seismic amplitude.

Conclusions

Reservoir characteristics of the upper Red River porosity zones have been described in an engineering context of storage, transmissibility, drive mechanism and reserves. Theoretical recovery from Red River reservoirs should approach 45 percent of OOIP by an ideal water-oil displacement process from reservoirs which are near irreducible water saturation. Average recoveries from historical production data are 13.4 percent for the B zone and 20.3 percent for the D zone based on a drainage area of 65 ha (160 acres).

The Red River A zone is infrequently tested and perforated. It is generally considered a non-commercial interval. Net thickness is usually less than 0.9 m (5 ft) with porosity less than 10 percent and permeability of less than 1.0E-3 μm^2 (1 md).

The Red River B has a typical liquid transmissibility of 9.14E+6 μm^3/ Pa-s (30.4 md-ft/cp). The net thickness of the B zone is fairly constant over a large area with an average of 2.9 m (9.4 ft). The average porosity is greatest in this interval at 18.4 percent with permeability of 4.2E-3 μm^2 (4.3 md). Producing mechanisms for the B zone range from liquid and rock expansion to efficient solution-gas drive. The geometric-mean recovery is 25,800 m^3 (162,000 bbl) per well with a recovery efficiency of 13.4 percent for a typical 65-ha (160-acre) drainage area. The Red River B zone offers the most potential for secondary recovery in the area and is a target of horizontal drilling.

The Red River C zone can develop considerable thickness and porosity but has poor producibility with a typical liquid transmissibility of 3.3E+6 μm^3/ Pa-s (10.9 md-ft/cp). The net thickness of the C zone is quite variable and averages 4.7 m (15 ft) with average porosity of 12.7 percent and permeability of 0.9E-3 μm^2 (0.9 md) There is an insufficient number of C zone completions to characterize expected recovery.

The Red River D zone is the most prolific reservoir interval with a geometric-mean liquid transmissibility of 31.6E+6 μm^3/ Pa-s (105.1 md-ft/cp). The D zone can develop a wide variation in thickness and porosity. The average net thickness is 18 ft with average porosity of 14.6 percent and permeability of 5.2E-3 μm^2 (5.3 md). There are both stratigraphically and structurally trapped reservoirs in the Red River D. The stratigraphically trapped reservoirs have liquid-expansion and solution-gas drive mechanisms with recoveries from 10 to 15 percent of OOIP. There are many structurally trapped D zone reservoirs with a water-drive producing mechanism and water encroachment from the flanks. Wells completed in strong water-drive D zone reservoirs can recover nearly 159,000 m^3 (1,000,000 bbl) or 28.2 percent of OOIP in a typical 65-ha (160-acre) drainage area.

Oil-water relative permeability studies of B zone core indicate efficient recovery of oil can occur by water displacement. However, injectivity tests in a vertical well with typical porosity an permeability for the B zone indicate that only modest injection rates can be achieved when limited by reservoir fracture pressure.

Methods to improve recovery from the Red River in the study area by enhanced recovery processes have included one waterflood project and three air-injection projects. These have demonstrated some technical success but poor economic success. Waterflooding is concluded to offer the most economical method for improved recovery in the Red River B zone; however, waterflooding with conventional, vertical wells is limited by low injectivity. Horizontal wells offer the means to achieve sufficient water injection rates for quick fillup and good reservoir sweep. The project evaluated water injection in both vertical and horizontal wells by field tests and reservoir simulation.

Reservoir heterogeneity was evaluated by the drilling of four wells. Three of these were vertical wells which tested predictions from 3D seismic of poorly drained or untapped reservoir compartments in the Red River D zone at locations which offset mature production. These three wells successfully achieved their objective in penetrating thick, porous intervals in the D zone which had not been affected by offset completions. Recoverable reserves from the D zone in the demonstration wells are estimated at from 31,800 to 47,700 m^3 (200,000 to 300,000 bbl) for each well. Results from the demonstration wells confirm the great variability of the D zone. Porosity blooms in the D zone are small in areal extent and are preferentially located on the flanks of structural features where demonstration wells were drilled. Development in the Red River D zone exhibits great variation at distances of only 0.40 km (0.25 mile)

The Red River B zone was found to exhibit less variability of reservoir development compared to the D zone. Pressure data from drillstem tests taken in demonstration wells and other pressure buildup data confirm good communication with offset wells at distances from 0.40 to 1.6 km (0.25 to 1.0 mile). Important factors which most effect recovery from the Red River B zone are moderately low permeability and small pore-throat diameter. Higher density drilling for Red River B zone reserves under primary depletion would result in marginal economics in most cases. Efficient exploitation of oil reserves in the Red River B zone will require coordinated drilling and waterflooding.

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Table 3
Characteristics of Red River Oil

Oil Property	Horse Creek Field	Medicine Pole Hills Field	Buffalo Field
Zone	Red River D	Red River B	Red River B
Average Depth	9000 ft	9300 ft	8700 ft
Oil Gravity	30 °API	38 °API	30 °API
Temperature	220 °F	230 °F	215 °F
Initial Pressure	3800 psi	4120 psi	3600 psi
Initial Viscosity	1.80 cp	0.57 cp	2.62 cp
Initial Volume Factor	1.15	1.37	1.12
Bubble Point Pressure	625 psi	1950 psi	300 psi
Bubble Point Viscosity	1.01 cp	0.50 cp	2.06 cp
Bubble Point Volume Factor	1.17	1.40	1.15
Solution Gas	205 scf/bbl	526 scf/bbl	173 scf/bbl

Table 4
Characteristics of Red River Water

Water Property	Horse Creek Field	Medicine Pole Hills Field	Cold Turkey Creek Field	North Buffalo Field
Zone	Red River D	Red River B	Red River D	Red River B
Temperature	220 °F	230 °F	230 °F	210 °F
Salinity TDS	68,000 ppm	56,000 ppm	132,000 ppm	22,000 ppm
Resistivity R_w	0.040 ohm-m	0.047 ohm-m	0.022 ohm-m	0.107 ohm-m

Table 5
Transmissibility (kh/μB)of Red River from Drill-Stem Tests

Porosity Interval	Median	Geometeric Mean	Mean Plus 1 Std Dev
Red River A	Insufficient Data		
Red River B	33.7 md-ft/cp	30.4 md-ft/cp	91.4 md-ft/cp
Red River C	11.3 md-ft/cp	10.9 md-ft/cp	43.9 md-ft/cp
Red River D	149.5 md-ft/cp	105.1 md-ft/cp	625.2 md-ft/cp

Table 6
Primary Recovery of Red River from Production Analysis

Field, Unit or Area	Zone	Prod Wells	EUR	OOIP (type-curve)	Primary Recovery Factor
Medicine Pole Hills Unit	B,C,D	15	6,815 mbbl	51,779 mbbl	13.2%
Horse Creek Unit	D	15	5,135 mbbl	46,451 mbbl	11.1%
Cold Turkey Creek	B,D	7	2,325 mbbl	17,187 mbbl	13.5%
Amor	B,D	9	3,469 mbbl	29,663 mbbl	11.7%
Coyote Creek	B,D	8	3,900 mbbl	32,195 mbbl	12.1%
North Buffalo	B	20	3,745 mbbl	43,053 mbbl	8.7%
West Buffalo B Unit	B	13	1,360 mbbl	13,083 mbbl	10.4%
Buffalo Red River Unit	B	24	2,728 mbbl	25,142 mbbl	10.9%
Total		111	29,477 mbbl	258,553 mbbl	11.4%

Table 7
Red River B Production Characteristics (Vertical Wells)

Production Characteristic	Geometric Mean	Mean Plus 1 std deviation
Oil Transmissibility (kh/μB)	14.0 md-ft/cp	31.2 md-ft/cp
Ultimate Recovery (primary)	162,000 bbl	476,000 bbl
Initial Oil Rate (stabilized)	64 bopd	143 bopd
Apparent OOIP (type-curve)	778,000 bbl	1,848,000 bbl
Hydrocarbon Pore Thickness	1.14 ft	1.63 ft
160-acre OOIP (volumetric)	1,178,200 bbl	2,017,000 bbl
Recovery Factor of 160-acre OOIP	13.4%	23.6%
Recovery Factor of 320 -acre OOIP	6.7%	11.8%
Apparent Drainage Area (type-curve)	105 acre	175 acre

Table 8
Red River D Production Characteristics (Vertical Wells)

Production Characteristic	Geometric Mean	Mean Plus 1 std deviation
Oil Transmissibility (kh/μB)	45.5 md-ft/cp	103.6 md-ft/cp
Ultimate Recovery (primary)	372,000 bbl	1,043,000 bbl
Initial Oil Rate (stabilized)	207 bopd	471 bopd
Apparent OOIP (type-curve)	1,757,000 bbl	5,204,000 bbl
Hydrocarbon Pore Thickness	1.77 ft	3.58 ft
160-acre OOIP (volumetric)	1,829,400 bbl	3,700,100 bbl
Recovery Factor of 160-acre OOIP	20.3%	28.2%
Recovery factor of 320-acre OOIP	10.2%	14.2%
Apparent Drainage Area (type-curve)	151 acre	225 acre

Table 9
Red River B Zone Oil-Water Relative Permeability (Various Cores)

Sample	K air md	Porosity %	Swi %	Sor %	Soi-Sor %	Koi/ Kair	Kwe/ Kair	Kwe/ Koi
1	17.0	26.5	24.1	28.9	47.0	0.388	0.204	0.524
2	18.0	21.1	10.4	41.6	48.0	0.511	0.194	0.380
3	71.0	19.2	35.5	6.8	57.7	0.648	0.394	0.609
4	5.2	22.5	17.4	28.0	54.6	0.462	0.090	0.196
5	43.3	23.9	4.9	32.1	63.0	0.441	0.109	0.246
6	26.6	27.6	5.8	31.9	62.3	0.329	0.105	0.317
7	52.5	26.5	4.7	24.9	70.4	0.886	0.194	0.219
8	53.2	21.2	8.6	30.9	60.5	0.900	0.352	0.391
9	1.5	17.8	27.4	22.5	50.1	0.467	0.085	0.182
Average	20.1	22.9	15.4	27.5	57.1	0.559	0.192	0.340

Nomenclature

K air Permeability of sample to air
K oi Permeability to oil at initial conditions
K we Permeability to water at end-point of 100% watercut
S or Residual oil saturation at 100% watercut
S wi Initial water saturation

CASE STUDIES OF RED RIVER FIELDS

Mark A. Sippel

Introduction

A total of six Red River fields are discussed for general reservoir properties, recovery and economics. These fields typify primary and secondary production from the Red River Formation in the Bowman Co., ND and Harding Co., SD area. Presentations are made for three enhanced-recovery units and three fields which have been produced only by primary.

Medicine Pole Hills Unit, Bowman Co., ND

Background. The Medicine Pole Hills Unit (MPHU) is located in southwestern Bowman Co., ND and encompasses a unitized area of 3885 ha (9600 acres) which is located in township T.130N., R.104W. (figure 50). The field was discovered in 1967 and the majority of the oil is produced from the Red River B and C zones. The Red River A and D zones were also perforated in some wells but were deemed as contributing minimal amounts to overall field production. The average depth to the Red River producing horizon is about 2900 m (9500 ft). The MPHU was unitized in 1985 as an air injection, in-situ combustion project. Results and data from the MPHU have been published in several articles and is a good analog for the recovery process in the Red River.

The air-injection, in-situ combustion project at MPHU is a technical success in recovering incremental oil over primary operations. Oil production rates more than doubled over rates prior to initiation of the project and reached levels similar to peak production under primary. The projected incremental oil recovery has been placed at 699,500 m^3 (4,400,000 bbl) or 11.0 percent of OOIP by others in references which are cited here. This report has used additional production data and tried to establish an economic basis for projecting ultimate recovery. The projected future performance using these current data and economic constraints places the incremental recovery at 405,900 m^3 (2,553,000 bbl) or 6.4 percent of OOIP. The economic viability of air-injection, in-situ combustion for the Red River is debatable, however. Economic data and calculations have been presented which show that this air injection project can produce revenues which exceed investment and expenses only if compressed air costs are less than \$0.019 per m^3 (\$0.55 per mcf).

Original-Oil-In-Place. The original-oil-in-place for the MPHU has been reported to be nearly 6,375,000 m^3 (40,100,000 bbl) in the unitization-feasibility study and other publications (Koch Exploration Company 1985; Kumar et al. 1995). The Red River B zone was attributed with 3,211,000 m^3 (20,200,000 bbl) from an average net thickness of 1.8 m (6.0 ft) and productive area of 1974 ha (4877 acres). The Red River C zone was attributed with 3,164,000 m^3 (19,900,000 bbl) from an average net thickness of 3.8 m (12.4 ft) and productive area of 1358 ha (3538 acres). The reservoir limits were interpreted by structural and net-pay mapping as being divided into three major reservoir compartments (Kumar et al 1995). No effort has been made by this project to revise the OOIP reported by the unit feasibility study.

Reservoir Trapping. According to the unitization-feasibility study, the Red River reservoirs at MPHU were determined to be primarily trapped by structural closure with some stratigraphic trapping. Maximum structural relief is about 18 m (60 ft) at the top of the Red River.

Some investigators interpreted some lateral segregation of reservoirs by high-angle faults of Silurian age (Kohm and Louden 1985).

Reservoir Properties. Samples of separator gas and oil were used to determine fluid properties and phase behavior. The stock-tank oil has density of 0.83 gm/cc (39° API). The saturation pressure of the recombined oil and gas are reported as 15,380 kPa at 110° C (2231 psi at 230° F) with a solution gas-oil-ratio (GOR) of 93 m^3/m^3 (525 scf/stb). The viscosity of bubble-point oil at reservoir temperature is 4.8E-4 Pa•s (0.48 cp). Formation volume factor of bubble-point oil is 1.40 rb/stb. The better developed wells have 3.7 m (12 ft) of pay with 18 percent porosity and 38 percent water saturation in the Red River B zone. The better-developed Red River C zone shows 9.1 m (30 ft) of pay with 17 percent porosity and 44 percent water saturation. These values are based on log calculations using a water resistivity of 0.028 ohm-m at reservoir temperature. A core from the Ernest Fossum No. 1-24 well has measured permeabilities at the geometric mean for the B and C zones of 8.9E-3 and 1.2E-3 μm^2 (9.0 and 1.2 md), respectively. The original reservoir pressure was 28,400 kPa (4120 psi). A pressure measurement in a well drilled after unitization recorded a pressure in the Red River B zone of 13,570 kPa (1968 psi) in October 1985. No similar pressure data from the C zone were available prior to air injection operations.

Primary Production. Field development on 129-ha (320-acre) spacing was completed in 1978 with 18 producing wells and 9 dry holes. Peak oil production under primary was 5470 m^3 per month (34,400 bbl per month) in May 1976 and cumulative oil produced prior to unitization in July 1985 was 648,200 m^3 (4,077,000 bbl). The extrapolated ultimate primary recovery from existing wells prior to unitization was placed at 954,700 m^3 (6,005,000 bbl) using an oil price of nearly $28.00 per barrel. This represents a primary recovery factor of 15.0 percent of OOIP. Extrapolation of remaining primary using $18.00 per barrel results in an ultimate recovery of 891,000 m^3 (5,610,000 bbl) or 14.0 percent of OOIP.

EOR Development. Enhanced oil recovery by waterflooding was considered for MPHU but was determined to be not viable because of anticipated, limited water injectivity. The estimated time for reservoir fill-up was in excess of 10 years with eight wells injecting an average of 48 m^3 per day (300 bwpd) per well and reservoir voidage of 1,192,000 m^3 (7,500,000 bbl). Air injection, in-situ combustion was selected as a recovery technology because of performance from the air injection project at the Buffalo Red River Unit in Harding Co., SD and economic benefits afforded to lower-tier oil properties under the Windfall Profits Tax (Koch Exploration Company 1985). Laboratory studies to help evaluate technical feasibility of air-injection, in-situ combustion included combustion tube, packed-column displacement and accelerating-rate calorimeter tests. The results of these tests confirm vigorous combustion at reservoir conditions and have been reported in the literature (Fassihi et al. 1994; Kumar et al. 1995).

The MPHU was unitized in July 1985 with 13 producing wells. After unitization, eight additional wells were drilled with five wells completed as producers and three wells completed for air injection service. Four existing producing wells were also converted to air-injection service.

Air injection began in March 1986 but was suspended after only five weeks because of the decline in oil price. Air injection was resumed in October 1987 and has continued to the present. Air was injected in to seven wells at a rate of 254,000 m^3 per day (9000 mcfd) at a wellhead pressure of 30,300 kPa (4400 psi) during 1994. The injection rates at most wells remained fairly constant or increased slightly over time. The maximum air injection rate has been about 339,800 m^3 per day (12,000 mcfd).

Project Facilities. High-pressure compressed air for the project is supplied by two seven-stage compressors which are each driven by 1980-kW (2650-hp) engines. The compressor plant has a maximum injection capacity of 283,000 m^3 per day (10,000 mcfd) with a pressure of 32,400 kPa (4700 psi) at the injection manifold. The compressed air is transported to the injection wells through high-pressure welded steel flowlines buried 2.4 m (8 ft) below ground level. Air goes through a vertical scrubber and filter at the injection wellhead. Typical injection wells have 14-cm (5½-in.) K-55 and N-80 grade casing and 7.3-cm (2⅞-in.) J-55 grade tubing. The annulus is isolated with a permanent-type packer and is filled with corrosion inhibitors. New injectors drilled after 1992 utilize continuous coiled tubing in place of threaded pipe. Production-well operation and produced-fluid treating are very similar to conventional oil-production operations (Kumar et al. 1995).

Capital Investment and Operating Cost. The capital investment for the MPHU through 1992 has been reported to be $14,000,000 for new wells, injection-well conversions, compressor facility and air distribution system (Kumar et al. 1995). Cost for compression and injection were initially estimated at about $0.025 per m^3 ($0.70 per mcf) of compressed air volume based on history at the Buffalo Red River Unit air-injection project in South Dakota (Koch Exploration Company 1985). Technical papers describing the performance of air injection at MPHU are silent regarding cost for air compression, distribution and injection. Fuel consumption for each 1980-kW (2650-hp) engine which drive the seven-stage compressors has been estimated (Watts et al. 1997) at 18,400 m^3 per day (650 mcfd) in a similar air-injection project. Using a fuel cost of $0.088 per m^3 and 36,800 m^3 per day ($2.50 per mcf and 1300 mcfd), the fuel cost alone for the two engines would be about $3250 per day or $0.011 per m^3 ($0.32 per mcf) of compressed air. Average monthly operating cost for producing wells is estimated at about $4000 per well. This operating cost should cover all pumping, treating, maintenance and water disposal expenses.

Project Performance and Results. Peak oil production was 182 m^3 per day (1146 bopd) in December 1991 followed by an average of 152 m^3 per day (954 bopd) during 1992. Production during 1986, prior to air injection, was about 79 m^3 per day (500 bopd). Cumulative oil produced by primary and EOR from the unitized area was 1,128,000 m^3 (7,092,000 bbl) as of December 1996 or 17.7 percent of OOIP. The extrapolated incremental oil production from MPHU after air injection has been reported by others (Fassihi et al. 1994) at 699,500 m^3 (4,400,000 bbl) for a total EUR of 1,653,000 m^3 (10,400,000 bbl) or 25.9 percent of OOIP. This projection of EUR was made using data through mid-year 1994. The primary method of extrapolation was a semi-log plot of produced gas-oil ratio (GOR) with cumulative oil production. The limiting GOR used for the extrapolation was 7124 m^3/m^3 (40 mcf per bbl) but there was no mention made of oil rate which corresponds to this GOR. The recovery of 1,653,000 m^3 (10,400,000 bbl) represents a recovery factor of 25.9 percent of OOIP or an incremental recovery of 10.9 percent over primary operations. An additional 159,000 m^3 (1,000,000 bbl) of natural gas liquids (NGL) is also projected (Fassihi et al. 1994) to be recovered and oil to be recovered during blowdown has been placed at 47,700 m^3 (300,000 bbl). The production response at MPHU demonstrates technical success of air-injection, in-situ combustion process in Red River reservoirs.

Since the projection of ultimate recovery by Fassihi et al in 1994, the oil production rate has established a stable decline rate at about 11 percent per year and the gas-oil ratio has also continued to increase. Plots of oil rate and GOR with time and cumulative oil production as of April 1997 are shown in figure 51. A semi-log fit through the GOR history with cumulative oil (using the method described by Fassihi et al. 1994) indicates an ultimate recovery of about 8,800,000 bbl at an ending GOR of 7124 m^3/m^3 (40 mcf/bbl) or 21.9 percent of OOIP. The oil-rate data shown on figure 51 have been fitted with a constant-percentage decline and indicate a rate of 1431 m^3 per month (9000 bbl per month or 300 bopd) at a GOR limit of 7124 m^3/m^3 (40 mcf per bbl).

Project Economics. The total revenue, operating costs and capital expenditures for MPHU have not been publicly reported but there is sufficient information to make an estimate of project profitability. An estimate of MPHU project economics using a current oil price of about $18.00 per barrel is summarized in table 10. Estimates of hypothetical project economics are based on several published sources and operating experience in the area. Producing wells typically experience about $3000 to $4000 per month for lease operating costs. The primary-case economics for the unit feasibility report used $3000 per month per well and 13 wells. A lease operating expense of $4000 per month was used for project economics in the unit feasibility report. There were 15 active producing wells in the MPHU during 1994.

An oil price of $18.00 per barrel was used to estimate revenues with a net-revenue interest of 85 percent and 11.5 percent for state production taxes. The economic limit for primary production is estimated at 15.9 m^3 per day (100 bopd) for 13 wells. Using a constant-percentage decline of 8.7 percent per year, remaining primary reserves of 202,900 m^3 (1,276,000 bbl) are calculated from a rate of 66.5 m^3 (418 bopd) in January 1986 to an economic limit of 15.9 m^3 per day (100 bopd) after 15 years. This projection indicates an ultimate recovery of 891,900 m^3 (5,610,000 bbl) which is slightly less than the ultimate recovery of 954,600 m^3 (6,004,000 bbl) cited in the literature and unitization report which used $27.84 per bbl. The projected value of remaining primary oil to working interest owners is computed to have been $10,258,000 using $18.00 per bbl.

The most expensive cost for air injection is related to compression. The compression facility at MPHU is designed for about 283,200 m^3 per day (10,000 mcfd) and has been running at nearly this volume. Fuel cost alone is estimated to be than $0.011 per m^3 ($0.32 per mcf) of compressed air. Monthly air-injection cost at this conservative rate is estimated at $96,000. Total cost for maintenance of compressors, distribution lines and injection wells may be twice this amount. It is projected in table 1 that the life of air injection will be 15 years for a total cost of $17,280,000. The monthly lease operating cost for 15 wells is estimated at $60,000 from which a total cost is computed of $11,520,000 over 16 years. The economic limit for air injection is therefore computed to be about 60.4 m^3 per day (380 bopd) for MPHU. Using a constant-percentage decline of 11.4 percent per year, this limit is projected to be reached after an ultimate recovery of 1,298,000 m^3 (8,163,000 bbl) or 20.4 percent of OOIP. Remaining oil to be produced with continued air injection is 170,100 m^3 (1,070,000 bbl) after January 1997. Incremental oil recovery is computed to be 405,900 m^3 (2,553,000 bbl) or 6.4 percent of OOIP.

Capital expenditures for the MPHU have been published to be $14,000,000 (Kumar et al. 1995). These cost include the compressor and distribution system, new wells, battery consolidation, and well conversions. The summary of air injection economics shown in table 10 indicates profitable air injection operations when the remaining primary reserves are ignored. The table does not include revenues from NGL production which was about 18 percent of oil production in 1993 (Kumar et al. 1995). Although NGL production may be profitable, the economics of NGL production should be also compared against a primary-production case. For this reason and a lack of operating cost data with an unknown net sales value to working interests, NGL is excluded from table 10. If the cost for air compression is really $0.019 per m^3 ($0.55 per mcf) of compressed air, the profitability of MPHU air injection project would be negligible.

Horse Creek Unit, Bowman Co., ND

Background. The Horse Creek Unit in Bowman Co., ND (figure 52) produces from a stratigraphically trapped accumulation in the Red River D zone and employs high-pressure air injection for an EOR process. The unit area covers 2590 ha (6400 acres) of which 1548 ha (3824 acres) are deemed productive by reservoir mapping. The first well was completed in 1972 and primary development of the unit area was with 15 productive wells and 6 dryholes on 129-ha (320-acre) spacing. Average depth to the producing horizon is 2793 m (9165 ft). The enhanced recovery unit for air-injection, insitu-combustion in the Red River D zone was formed in November 1995 and air injection began in May 1996.

According to the unit feasibility study, the OOIP was 7,272,000 m^3 (45,740,260 bbl) and ultimate primary recovery was projected to be about 10 percent of OOIP. The air injection has resulted in a production response in 1997 but it is too early to make projections of EOR recovery based on forecasts of production data. The operator has made a prediction of incremental recovery by computer simulation and analogy which is over 1,907,800 m^3 (12,000,000 bbl) or 16.6 percent of OOIP. The predicted time to achieve peak rate of 238 m^3 per day (1500 bopd) is 2.5 years. Assuming a sustained rate of 238 m^3 per day (1500 bopd), it would take nearly 22 years to achieve the projected incremental recovery. This calculation indicates that a significant number of additional wells will be required to achieve the projected recovery in reasonable time.

Original-Oil-In-Place. The original-oil-in-place for the Horse Creek Unit has been reported to be nearly 7,272,000 m^3 (45,740,260 bbl) in the unitization-feasibility study and other publications (Total Minitome 1995; Watts et al. 1997). The Red River D zone was attributed with an average net thickness of 6.1 m (20.0 ft) and productive area of 1548 ha (3824 acres). According to the unit feasibility study, the average porosity is 16 percent with an average water saturation of 35 percent. Another estimate of OOIP was reported by Longman et al. in 1992 using data from the same 15 productive wells. Their published description of the field places an estimate of OOIP at 4,213,200 m^3 (26,500,000 bbl) using an average thickness of 15.1 ft with porosity of 17.8 percent and water saturation of 39.4 percent.

Reservoir Trapping. The Horse Creek Unit is a startigraphic accumulation in the Ordovician Red River D zone. The reservoir is located on a monoclinal dip of 19 m/km (100 ft per mile). The stratigraphic trap is caused by a reduction in pore throat size resulting from a facies change of dolomite to limestone (Longman et al. 1992; Watts et al. 1997). The resulting trap developed an oil column with a maximum height of 46 m (150 ft). Reservoir mapping of porosity-thickness suggests the reservoir area is composed of two lobes.

Reservoir Properties. Produced oil from the unit wells has an average density of 0.865 gm/cc (32° API gravity) with a solution gas-oil-ratio (GOR) of 36.5 m^3/m^3 (205 scf/bbl). The producing mechanism is described as a depletion drive with no significant increase in water-oil ratio. A characteristic of production is a constant water cut of approximately 60 percent since first production in the field. The estimated bubble-point pressure from correlations is 4309 kPa (625 psi). Bubble-point oil has a viscosity of 1.4E-3 Pa•s (1.4 cp) and a formation volume factor of 1.21 rb/stb at reservoir temperature of 104° C (220° F). The original reservoir pressure was 26,300 kPa (3815 psi). Water resistivity is 0.03 ohm-m at reservoir temperature and resulting calculation of water saturations in producing wells ranges from 32 to 66 percent. Permeability of the D zone was measured in two cores and found to be 5.3E-3 and 1.1E-2 μm^2 (5.4 and 11.3 md) at the geometric mean. Average core porosities are 9.4 and 14.4 percent.

Primary Production. Field development was completed in 1984 with 15 producing wells. Cumulative production to May 1996 was 523,200 m^3 (3,291,000 bbl) with an extrapolated ultimate primary of 721,300 m^3 (4,536,500 bbl) for an average recovery per well of 48,000 m^3 (302,000 bbl). This extrapolation of recovery represents a recovery factor of 10.0 percent of OOIP reported in the unitization-feasibility study (Total Minitome 1995; Watts et al. 1997). Peak production from the field occurred in 1984 with an average daily rate of 242 m^3 per day (1520 bopd). Reservoir pressures were measured in July 1984 (North Dakota Industrial Commission 1985) in a field-wide survey. The average pressure from seven wells was 12,900 kPa (1870 psi).

EOR Development. The EOR process selected at Horse Creek Unit was high-pressure air injection for insitu-combustion. Waterflooding was considered but concluded to have poor applicability because of unfavorable oil-water relative permeabilities and the existing water saturation in the reservoir. The interpretation of these data led to the conclusion that an oil bank would not form (Total Minitome 1995). Nitrogen and carbon dioxide flooding were eliminated as EOR processes because of great cost (Watts et al. 1997). The decision to employ high-pressure air injection was influenced by favorable comparison of reservoir and fluid parameters with air injection projects at Medicine Pole Hills Unit, Bowman Co., ND and Buffalo Red River Unit, Harding Co., SD. The evaluation process included a series of reservoir simulations and laboratory studies (Watts et al. 1997).

Project Facilities. High-pressure compressed air for the project is supplied by two seven-stage compressors which are each driven by 1980-kW (2650-hp) engines using natural gas for fuel. Fuel gas is supplied through a 21-km (13-mile) pipeline. Nominal project design is 283,200 m^3 (10,000 mcfd) of air at 34,500 kPa (5000 psi) surface pressure. Initial development included three air-injection wells. Two of these wells were conversions and the third was a new well. During the first nine months of injection, air was injected into the reservoir at an average rate of 240,700 m^3 (8,500 mcfd) through the three injection wells.

Capital Investment and Operating Cost. The initial capital investment for the Horse Creek Unit was estimated to be $2,635,200 for drilling and completion of air-injection wells, fuel pipeline and air-distribution. Compression and injection costs were estimated at $0.021 per m^3 ($0.60 per mcf) of air. Lease operating for producing wells was estimated at $4300 per well per month (Total Minitome 1995). At 240,700 m^3 (8,500 mcfd), the daily cost for air is $5100. Average daily lease operating cost for 15 production wells is $2150. Total operating cost therefore estimated at $7250 per day. An economic limit of 88 m^3 per day (555 bopd) is computed using $18.00 per barrel, net revenue interest of 82 percent and state taxes of 11.5 percent.

Project Performance and Results. After one year of air injection, there were indications of pressurization and combustion in the Red River D reservoir. The average daily production rate increased from 46.6 to 79.4 m^3 per day (293 to over 500 bopd) and reservoir pressure increased by approximately 6895 kPa to 13,790 kPa (1000 psi to 2000 psi). The time to peak rate of 238 m^3 per day (1500 bopd), predicted by simulation studies, is 2.5 years after commencement of air injection (Watts et al. 1997).

Amor Field (Southwest Area), Bowman Co., ND

Background. The southwest Amor area is located in southwestern Bowman Co., ND and primarily produces from the Red River B zone (figure 51). The reservoir was discovered in 1978 and subsequently developed on 129-ha (320-acre) spacing with five producing wells and three dryholes. The reservoir was identified with 2D seismic using Winnipeg time structure and isochron mapping to locate wells on apparent paleo structural high areas. The spaced area for the five productive wells is 1600 acres while the productive limits of the reservoir are probably slightly less. Average depth to the producing horizon is 2850 m (9350 ft).

From production data and drillstem tests, the reservoir at southwest Amor is an example of above average development in the Red River B zone. Cumulative oil production from the reservoir represents about 11 percent of estimated OOIP. Projection of the current, shallow decline indicates a potential ultimate recovery of 19 percent of OOIP from volumetric calculations. However, the existing wellbores may not be serviceable for the indicated remaining life. At the current production rate of 19.9 m^3 per day (125 bopd), it would require nearly 19 years to recover the projected reserves of 137,900 m^3 (867,400 bbl). This reservoir should be a good candidate for higher density drilling of vertical or horizontal wells.

Original-Oil-In-Place. The original-oil-in-place of the Red River B zone at the southwest Amor is estimated at 1,748,900 m^3 (11,000,000 bbl) by volumetric calculation using a reservoir area derived from several seismic isochron maps and petrophysical data from electrical logs. This calculation may be low because type-curve analysis of production data suggest a much larger OOIP of 2,544,000 m^3 (16,000,000 bbl).

Reservoir Trapping. The reservoir appears to be trapped both stratigraphically and structurally. The productive wells lie on a gentle, structural nose at Red River depth but there is only weak evidence of closure to the west and south. Structural relief from the regional trend is less than 6.0 m (20 ft).

Reservoir Properties. Produced oil has an average density of 0.850 gm/cc (35° API gravity) with a solution gas-oil-ratio (GOR) of 89.1 m^3/m^3 (500 scf/bbl). The producing mechanism is solution-gas drive. The estimated bubble-point pressure from correlations is 13,100 kPa (1900 psi). Bubble-point oil has a viscosity of 4.7E-4 Pa•s (0.47 cp) and a formation volume factor of 1.29 rb/stb at reservoir temperature of 114° C (238° F). The original reservoir pressure was 28,900 kPa (4200 psi). Water resistivity is 0.03 ohm-m at reservoir temperature and resulting calculation of water saturations in producing wells ranges from 20 to 30 percent. The average thickness of the B zone interval is 2.7 +/- 0.6 m (9 ft +/- 2 ft). Porosity average 22 percent with a maximum of 26 percent.

Primary Production. Field development was completed in 1981 with 5 producing wells. Cumulative production through April 1997 was about 11 percent of volumetric OOIP or 197,200 m^3 (1,240,570 bbl) with an average producing rate per well of 4.0 m^3 per day (25 bopd). The wells are experiencing a very slight decline of about 4 percent per year which indicates an extrapolated ultimate primary of 335,100 m^3 (2,108,000 bbl); however, the recovery of these reserves will be limited by the mechanical life of the wells. Figure 54 shows the production history since discovery for the Amor Field (southwest area). The average projected recovery per well is 67,000 m^3 (421,000 bbl). This extrapolation represents a recovery factor of 19 percent of OOIP determined from volumetric calculation. A recovery factor of 13 percent is calculated from an OOIP of 2,544,000 m^3 (16,000,000 bbl) which is determined from type-curve analysis.

Future Development. The shallow production decline and long remaining life of the Red River B zone reservoir indicates potential for additional development and waterflooding with horizontal wells deserves consideration for exploitation of remaining reserves. A significant portion of the indicated remaining primary reserves may not be recoverable with existing wells because of limited wellbore life and the reserves have diminished value when present value is considered. At a recovery of 25 percent of the maximum indicated OOIP of 2,544,000 m^3

(16,000,000 bbl), the reservoir may be capable of producing 438,800 m^3 (2,760,000 bbl) more than the current cumulative. These reserves are categorized as possible but warrant further investigation. Further drilling is the only way to assess the certainty of the possible reserves but they could be sufficient to economically drill multiple horizontal wells and construct water supply facilities.

Cold Turkey Creek Field, Bowman Co., ND

Background. The Cold Turkey Creek Field is a located in Bowman Co., ND and covers most of township T.130N., R102W (figure 55). Cold Turkey Creek Field is a collection of 10 separate accumulations in the Red River which were found by 2D seismic and drilled in the late 1970's and early 1980's. The field area was established for wells to be drilled on 129-ha (320-acre) spacing. Generally, one well was drilled on each small, structural feature. Average depth to the Red River in the area is 2895 m (9500 ft). The Cold Turkey Creek Field is a good example of Red River production from small, structural features in the southwestern portion of the Williston Basin.

Ultimate recovery from the 11 older wells at Cold Turkey Creek has an average of 35,600 m^3 (224,000 bbl) per well. Until recently, it was concluded that this recovery was reasonable in relation to the apparent reservoir area from structural interpretation of seismic data. Recent drilling activity has demonstrated that significant untapped reserves may remain on these small features. New wells drilled at locations less than 0.4 km (0.25 mile) from mature or abandoned producers have successfully found untapped or poorly drained reserves in zones which were previously produced or tested at the old offsetting well. Expected reserves from these wells are estimated to equal or exceed the average in the township area.

Original-Oil-In-Place. Wells in the Cold Turkey Creek Field have been completed in the Red River B, C and D zones; however, most of the production has been from the B and D zones. It is not possible to estimate OOIP from maps and volumetric calculations because of the limited well control as there is usually only one or two wells per structure. Seismic time and isochron maps indicate the structures are less than 259 ha (640 acres) in areal extent and typically cover 65 to 129 ha (160 to 320 acres). In addition to the difficulty in determining a reservoir area, there is the additional problem in some cases of assessing contribution from the separate porosity benches. Assessing OOIP from production-type curves indicates the average contacted OOIP per well is about 397,500 m^3 (2,500,000 bbl).

Reservoir Trapping. Initial exploration efforts in the field assumed the Red River reservoirs were purely structural traps. As more wells have been drilled in the field, stratigraphic trapping also appears to exert significant control on reservoir accumulations.

Reservoir Properties. Produced oil density varies from 0.865 to 0.830 gm/cc (32° to 39° API gravity) with solution gas-oil-ratios (GOR) of 53 to 89 m^3/m^3 (300 to 500 scf/bbl). Producing mechanisms range from solution-gas expansion to water drive. Solution-gas expansion is more common in the B zone while water-drive is typical of the D zone. The estimated bubble-point pressure from correlations is 13,100 kPa (1900 psi). Bubble-point oil at 39° API has a viscosity of 4.7E-4 Pa•s (0.47 cp) and a formation volume factor of 1.29 rb/stb at reservoir temperature of 114° C (238° F). The original reservoir pressure was 28,900 kPa (4200 psi). Water salinity is about 115,000 ppm NaCl which has a resistivity of 0.02 ohm-m at reservoir temperature. Although there are limited core data to characterize average permeability, it is concluded from drillstem test and production data that average B and D zone permeability is about 4.9E-3 μm^2 (5 md). Data from electrical logs indicate that the average B zone has 2.1 m (7 ft) with 20 percent porosity, the C zone develops 4.9 m (16 ft) with 15 percent porosity and the D zone porosity is typically 15 percent with an average thickness of 5.2 m (17 ft).

Primary Production. The first well in Cold Turkey Creek Field was completed in 1975 and drilling continues at this time. As of 1993, there were 11 Red River completions in the township which resulted from initial exploration activities using 2D seismic. Cumulative production from these 11 wells was 337,700 m^3 (2,214,000 bbl) through the end of 1996. Ultimate primary recovery from these wells is projected at 392,100 m^3 (2,466,000 bbl) which is an average of 35,600 m^3 (224,200 bbl) per well. Production analysis using type-curves suggests an average recovery factor of 12 percent of oil contacted by the existing wells. An example of production curves from the Red River at Cold Turkey Creek is shown in figure 49. Production data typically exhibit a hyperbolic decline with some wells experiencing an increasing water-oil ratio with depletion.

Future Development. Recent application of 3D seismic in the field has resulted in the identification of drilling locations which are near offsets to older wells that are depleted or nearly depleted. Two successful wells were drilled in 1996 and 1997 which developed significant reserves in the Red River D zone at Cold Turkey Creek Field. The recoverable reserves from these wells are estimated at nearly 79,500 m^3 (500,000 bbl). Interpretation of the 3D seismic data suggest additional reserves in the D zone may be possible from a third location, identified from an apparently disconnected amplitude bloom also on the flank of the structure, which could approach 31,800 m^3 (200,000 bbl) if reservoir development is similar to the previous two wells. Measurements by drillstem tests from the new wells in the Red River B zone were about 50 percent of original reservoir pressure. An additional 159,000 m^3 (1,000,000 bbl) is predicted as probable reserves if the Red River B zone were fully developed and waterflooded. New horizontal wells would be required for water injection and also recommended for production. Three horizontal wells could be justified based on the previously stated reserves. The drilling of these wells for the Red River B zone could be coordinated with further testing of other seismic anomalies in the Red River D zone. These wells would be drilled with a large diameter hole to allow plugback and drilling horizontally after logging and testing the B and D zones. Total developed and probable new reserves are placed at 270,300 m^3 (1,700,000 bbl).

From the results of these wells, it is clear that a single well on small structures in the Red River may not be capable of contacting and producing all the reserves. Old spacing rules for one well on 129-ha (320-acre) spacing have been demonstrated to be inappropriate. More flexible and innovative spacing rules are required.

Buffalo Field (North Area), Harding Co., SD

Background. The north Buffalo area is an extension of the greater Buffalo Field in Harding Co., SD. The reservoir is located in the southwest corner of T.22N., R.4E. and covers approximately 809 ha (2000 acres) which are developed by 10 wells (figure 56). Average depth to the Red River B zone is 2670 m (8750 ft). The extension area was discovered in 1982 by 2D seismic using Winnipeg time-structure and isochron mapping to locate wells. Primary development of the area was finished in 1984 with wells spaced using 129-ha (320-acre) regulatory units.

Original-Oil-In-Place. The original-oil-in-place at the Buffalo Field (north area) is difficult to estimate for there are few dryholes on the perimeter and there is an absence of critical closure at Red River depth. The average OOIP for the Red River B zone is 3636 m^3 per ha (9230 bbl per acre), based on local log data. Assuming an accumulation of 809 ha (2000 acre) in extent, OOIP would be 2,934,000 m^3 (18,454,000 bbl).

Reservoir Trapping. The reservoir appears to be trapped both structurally and stratigraphically. The productive wells lie on a gentle, structural nose at Red River depth but there is only weak evidence of closure to the west and south. Structural relief from the regional trend is less than 6 m (20 ft). Water-cut from the producing wells does not correlate very well with structural position.

Reservoir Properties. Produced oil has an average density of 0.865 gm/cc (32° API gravity) with a solution gas-oil-ratio (GOR) of less than 35.6 m^3/m^3 (200 scf/bbl). The producing mechanism is fluid expansion and solution-gas drive. The bubble-point pressure is determined to be 8270 kPa (1200 psi) from many pressure surveys and history matching by computer simulation. Bubble-point oil has a viscosity of 8.9E-4 Pa•s (0.89 cp) and a formation volume factor of 1.17 rb/stb at reservoir temperature of 104° C (220° F). The highest pressure in the reservoir was 23,800 kPa (3450 psi). Produced water has a salinity of 22,000 ppm NaCl which has a resistivity of 0.10 ohm-m at reservoir temperature. Calculation of water saturations in producing wells ranges from 34 to 67 percent with an average of 52 percent. The average thickness of the B zone interval is 4.3 +/- 1.2 m (14 ft +/- 4 ft). Porosity averages 20 percent with a maximum of 23 percent. Cores from two wells indicate permeability of 4.4E-3 μm^2 (4.5 md) and porosity of 19 percent with a net thickness of 4.3 m (14 ft).

Primary Production. Field development was completed in 1984 with 10 wells completed as producers. Two of these completions were non-commercial and one was marginal. As of 1996 there were seven active wells. Peak production occurred in 1984 (figure 57) at about 62 m^3 per day (390 bopd). Cumulative production through September 1996 was 157,100 m^3 (988,200 bbl). Extrapolation of the field production curve to an economic limit of 238 m^3 (1500 bbl) per month using a constant-percentage decline results in an ultimate recovery of about 238,500 m^3 (1,500,000 bbl). This represents a recovery factor 8.0 percent of OOIP. Prediction of recovery by computer simulation, based on a history match of two centrally located wells, indicates primary recovery of 11.0 percent of OOIP. This is in good agreement with the volumetric estimate.

Future Development. Water injection tests were performed in both a vertical and a horizontal well and future plans call for a pilot waterflood using a horizontal injection well in the Red River B zone for a period of one year. Water injectivity in the vertical well is about 28.6 m^3 per day (180 bwpd) at a pressure of 34,500 kPa (5000 psi) at reservoir depth while the horizontal well is capable of injecting about 82.7 m^3 per day (520 bwpd) at a similar pressure. A 259-ha (640-acre) area will be pooled for the pilot test. The pilot area will have the horizontal well as the injector between two vertical producers. Computer simulations have predicted a recovery of 26 percent of OOIP. If response to water injection is as favorable as the predictions by simulation, expansion of the water injection and additional drilling will be proposed. A significant component of the pilot evaluation will be to assess whether lateral drainholes should be drilled at the existing producing wells.

West Buffalo "B" Red River Unit, Harding Co., SD

Background. The West Buffalo "B" Red River Unit (WBBRRU) produces from the Red River B zone and is located in Harding Co., SD along the southern end of the Cedar Creek anticline (figure 58). The unit area covers 1360 ha (3360 acres). The reservoir was discovered in

1980 and subsequently developed with nine producers and four dryholes on 129-ha (320-acre) spacing by 1986. Average depth to the producing horizon is 2545 m (8350 ft). The WBBRRU was formed in 1986 to increase recovery from the Red River B zone by waterflooding. Water injection began in November 1987.

The response to waterflooding has been slow because of low water injectivity in vertical wells. A typical vertical-well injector in this reservoir is 10.8 m^3 per day (68 bwpd) at wellhead pressures of 10,700 kPa (1550 psi). Water production at most producers has also remained low. The poor response to waterflooding at WBBRRU is concluded to be a rock permeability problem not adverse relative permeability of oil and water. Permeability measurements from core and calculation from drillstem tests indicate that the Red River B zone at WBBRRU is low compared to the average of the Bowman and Harding county area. Water injection with a horizontal well resulted in a rate of over 143 m^3 per day (900 bwpd) and is clearly an encouraging method for effective enhanced recovery from reservoirs such as this. The initial waterflood development plan of using peripheral injection around the downdip edge of the reservoir also appears to be inappropriate.

Original-Oil-In-Place. The original-oil-in-place for the Horse Creek Unit has been reported to be nearly 3,299,000 m^3 (20,750,000 bbl) in the unitization-feasibility study (Harper Oil 1986). The Red River B zone was attributed with an average net thickness of 14.8 m (14.8 ft) and productive area of 1153 ha (2850 acres). According to the unit feasibility study, the average porosity is 18 percent with an average water saturation of 40 percent.

Reservoir Trapping. The trapping mechanism appears to be predominately stratigraphic with porous dolomite encased in limestone and anhydrite although the reservoir is situated on a structural closure bounded on the west side by a major fault lineament of the Cedar Creek anticline. The top of the structure at Red River depth is 37 m (120 ft) above the lowest producer in the unit.

Reservoir Properties. Produced oil from the unit wells has an average density of 0.865 gm/cc (32° API gravity) with a solution gas-oil-ratio (GOR) of 30.8 m^3/m^3 (173 scf/bbl). The producing mechanism is described as rock and fluid expansion (depletion drive) with no significant increase in gas-oil or water-oil ratio. The estimated bubble-point pressure from correlations is 2070 kPa (300 psi). Bubble-point oil has a viscosity of 2.4E-3 Pa•s (2.4 cp) and a formation volume factor of 1.17 rb/stb at reservoir temperature of 99° C (210° F). The original reservoir pressure was 24,700 kPa (3579 psi). Calculation of water saturations in producing wells ranges from 30 to 50 percent with an average of 40 percent. Permeability of the B zone was measured in one core and found to be 1.5E-3 μm^2 (1.5 md) at the geometric mean. Average core porosity is 14.9 percent.

Primary Production. Primary field development was completed in 1985 with 9 producing wells on 129-ha (320-acre) spacing. Cumulative production to December 1985 was 46,300 m^3 (291,000 bbl) with an extrapolated ultimate primary of 283,200 m^3 (1,254,200 bbl). Plots of production since discovery are shown in figure 59. The average recovery per well is indicated to be 22,200 m^3 (139,400 bbl) at an economic limit of 0.8 m^3 per day (5 bopd). This extrapolation of recovery represents a recovery factor of 6.0 percent of OOIP as reported in the unitization-feasibility study (Harper Oil 1986). Peak production from the field occurred in 1985 with an average daily rate of 45.2 m^3 (284 bopd). Reservoir pressures measured by drillstem tests in new wells drilled in 1985 indicated negligible depletion had yet occurred as pressures were found to be from 22,900 to 24,900 kPa (3328 to 3611 psi).

Primary production was evaluated for this project by type-curve analysis which found that the OOIP contacted by the wells appears to be significant less than calculated and stated in the unit feasibility report. Type-curve analysis indicates contacted OOIP, before waterflood, to be 2,195,000 m^3 (13,803,000 bbl) and a primary recovery prediction of 216,200 m^3 (1,360,000 bbl) which results in a recovery factor of 10.4 percent of OOIP. This calculation suggests that the existing wells were contacting about two-thirds of the volumetric OOIP or that the volumetric OOIP used for unitization was over-estimated.

EOR Development. The EOR process selected at WBBRRU was waterflooding using a peripheral injection pattern with five injection wells. Well spacing was to be approximately 65 ha (160 acres) per well after additional drilling. The incremental secondary reserves for WBBRRU were estimated by analogy with two other Red River waterflood projects in Montana. The initial estimate of incremental secondary reserves were 300,500 m^3 (1,890,000 bbl) or 11 percent of OOIP.

Capital Investment and Operating Cost. Predicted capital investment of $2,300,000 was reported in the unit feasibility study and proposal. Initial development plans included five injectors and seven producers in the Red River B zone. A water-supply well was drilled to the Dakota sandstone at a depth of 1335 m (4380 ft). Operating cost for producing wells was projected at $3500 per month per well. Water plant and injection costs were further estimated at $14,700 per month (Harper Oil 1986). Total operating cost is therefore estimated at $39,200 per month for seven producing wells. An economic limit of 15 m^3 per day (95 bopd) is computed using $18.00 per barrel, net revenue interest of 80 percent and state taxes of 4.6 percent. At the end of 1996, there were seven active water-injection wells and seven active producing wells. Two horizontal wells were drilled in 1996, one for injection and one for production, at an estimated cost of about $1,100,000 each.

Project Performance and Results. The water injection project at WBBRRU was plagued by low water injectivity. Water injection began in 1986. By the end of 1996, a total of only 1,536,977 bbl of water had been injected. During 1996, six vertical injection wells had average injection rates of only 10.8 m^3 per day (68 bwpd) per well at wellhead pressures of about 10,700 kPa (1550 psi). A horizontal injection well was placed in service in February 1995. The average injection into this well has been over 143 m^3 per day (900 bwpd) with a wellhead pressure of about 9700 kPa (1400 psi). As of December 1996, the unit was producing an average of 274 bopd and 109 bwpd. Total cumulative oil production (primary and secondary) was 173,500 m^3 (1,091,211 bbl). Projection of declining oil rate during 1995 and 1996 to an ending rate of 15.9 m^3 (100 bopd) indicates an ultimate recovery of 1,630,000 bbl or only 7.9 percent of OOIP. According to data from public hearing before the South Dakota Oil and Gas Board, the operator (Citation Oil and Gas 1996) placed the ultimate recoverable reserves (without additional drilling) as of August 1996 at 417,200 m^3 (2,624,000 bbl) or 12.6 percent of OOIP. Plots of oil production with time and cumulative oil produced are shown on figure 59. By 1992 and after five years of injection, the unit oil production rate was still less than levels before initiation of water injection. Production increases which occurred after 1993 are the result of stimulation treatments and drilling (one vertical producer, one horizontal producer and one horizontal injector). The operator had plans for three additional horizontal completions in 1996 (Citation Oil and Gas 1996).

The recovery from WBBRRU has not yet reached the original predictions for primary after more than 10 years of water injection. Production has been slowly responding to water injection and producing wells do not exhibit quick water breakthrough which would indicate adverse oil-water mobility. The problem at WBBRRU is concluded to be low permeability and perhaps structural compartmentalization caused by proximity to a major fault lineament of the Cedar Creek anticline. The WBBRRU project demonstrates a technical success but an economic failure at this time. Improved recovery may be achieved with horizontal wells.

Conclusions

Case studies have been presented for Red River fields in the Bowman-Harding area. Primary recovery varies by field or project but is consistently 15 percent or less of OOIP. Enhanced recovery projects have been implemented in the area with initial expectations of more than doubling ultimate recovery. As the histories of these EOR units show, each of the projects was under-developed at the onset of either air or water injection. Considerable effort and expense has been applied toward infill drilling and re-stimulation of wells. From projections made for this study, it is concluded that initial expectations of ultimate recovery from the EOR projects will not be achieved with the current number of wells. Results from the EOR projects demonstrate technical success of the processes but with questionable profitability.

Results from targeted drilling from seismic at Cold Turkey Creek Field demonstrate the compartmentalization and under-developed potential of the Red River D zone. Data from these wells also show that vertical wells are not capable of efficiently depleting the Red River B zone at well spacings of greater than 65 ha (160 acres) although the profitability of wells completed in the B zone at 65 ha (160 acres) would generally be marginal based solely on primary recovery.

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Table 10
Medicine Pole Hills Unit, Estimated Air-Injection Economics

	Primary Case	**Air Injection Case**	**Incremental**
Ultimate Oil	5,610,000 bbl	8,163,000 bbl	2,553,000 bbl
Cumulative Oil 1986	4,334,000 bbl	4,334,000 bbl	
Oil Produced 1987-96		2,759,000 bbl	
Extrapolated Oil	1,276,000 bbl	1,070,000 bbl	
Total Oil Post 1986	1,276,000 bbl	3,829,000 bbl	2,553,000 bbl
Time Post 1986	15 years	16 years	
Economic Limit	100 bopd	380 bopd	280 bopd
Oil Revenue WI%	$19,523,000	$58,584,000	$39,061,000
State Prod Taxes	$2,245,000	$6,737,000	$4,492,000
Well Operating Cost	$7,020,000	$11,520,000	$4,500,000
Air Compression Cost		$17,280,000	$17,280,000
Capital Invest. Cost		$14,000,000	$14,000,000
Net Income	$10,258,000	$9,047,000	($1,211,000)

SEISMIC CHARACTERIZATIONS

Mark A. Sippel

Introduction

This report discusses characterizations of the Red River using modern, conventional seismic techniques and covers structural and porosity heterogeneity observed from synthetic modeling and field acquisition. It also addresses the application of modern 3D seismic for improving oil recovery from Ordovician Red River reservoirs in the southwest Williston Basin.

Seismic activities culminated with the drilling of wells on small structural features of approximately 1.3 km^2 (0.5 square miles) in areal extent and relief of less than 30 m (100 ft) where there had been prior production from the Red River at depths of approximately 2895 m (9500 ft). The test wells evaluated the utility of 3D seismic to accurately predict structure and porosity development and whether the drilling of additional wells is economically viable on these small features. The test wells proved the utility of 3D seismic to predict porosity development in the Red River D zone and structural position by penetration into poorly drained and untapped reserves at close distance to mature and nearly depleted wells. Incremental oil reserves of over 32,000 m^3 (200,000 bbl) were found by each of the test wells.

It is concluded that 3D seismic can provide a much improved interpretation of structure and information about porosity development. Even after processing older 2D seismic with modern methods and the use of correlation utilities available with modern seismic-interpretation software, the structural and amplitude interpretation of dense 2D seismic data is still inferior to the results obtained from 3D seismic. Older 2D seismic data which have been processed by modern methods can be useful, however, for delineation and guidance for design and layout of 3D surveys.

Background

The area of Bowman Co., ND and Harding Co., SD has been actively explored with seismic methods since the 1950's (figure 2). Exploration using 2D seismic peaked in the early 1980's. Exploration methods traditionally involved structural mapping of the Ordovician Winnipeg for identification of crestal highs on basement features. Isochron thins, identified from mapping the Cretaceous Greenhorn to Ordovician Winnipeg and the Mississippian Mission Canyon to Ordovician Winnipeg intervals, have been used historically as key maps for Red River exploration. Older 2D data was typically 6 fold with group intervals ranging from 67 m to 134 m (220 ft to 440 ft) and did not provide sufficient seismic resolution or attribute information to map Red River porosity signatures or faulting with confidence.

There are four porosity benches in the Upper Red River, labeled in descending order A, B, C and D zones (figure 3). The Red River B and D zones are the primary reservoir intervals in the area. Engineering studies of ultimate recovery from the Red River B zone indicate range from 6.7 to 11.8 percent of OOIP for vertical wells in 130-ha (320-acre) spacing units. Similarly, typical recovery from the D zone is placed at 10.2 to 14.2 percent of OOIP in 130-ha (320-acre) spacing units. For comparison, maximum recovery by water-drive should be about 28 percent of OOIP.

Many Red River reservoirs in the area have small areal extent of less than one square mile with structural relief of 15 to 30 m (50 to 100 ft). Two 3D seismic surveys were obtained in Bowman Co., ND over Red River reservoirs which are typical of this setting. The purpose of the surveys were to determine if structural and porosity compartments can be observed and whether there is potential for under-developed reserves on these features where wells have been producing for over twenty years and are near depletion.

Results

Exploitation of under-developed or uncontacted reserves is possible where amplitude anomalies are found at sufficient structural position to be above an oil-water contact and have not been penetrated by existing wells and where breaks or faults in the underlying Winnipeg suggest structural compartmentalization between wells or porosity development. Demonstration wells were drilled to evaluate the interpretations from 3D seismic and resulted in contacting previously untapped and poorly drained reserves in the Red River B and D zones. Incremental oil reserves of over 32,000 m^3 (200,000 bbl) were found by each of the test wells. Demonstration wells were less than one-quarter mile from existing and mature production.

It is concluded that 3D seismic can provide a much improved interpretation of structure and information about porosity development. Even after re-processing older 2D seismic with modern methods and the use of modern algorithms with state-of-the-art seismic-interpretation software, the structural and amplitude interpretation of dense 2D seismic data is inferior to the results obtained from 3D seismic. It was found that amplitude variation within the Red River interval are primarily diagnostic of D zone porosity development. The processing flow is important and should be carefully performed to provide a close match with zero-phase synthetic seismograms. A strong F-X filter is detrimental to interpretation of amplitude. It is advantageous to produce two processed versions, one for structural and isochron mapping and one for amplitude variation.

Amplitude variation and development relating to the Red River D zone porosity is found to be spotty and tends to be located in structurally low areas and along flanks of positive features. The areal extent of the amplitude anomalies are about 16 to 32 ha (40 to 80 acres). The random distribution and small size of these anomalies make it difficult for interpretation with 2D seismic, even with a dense grid of 0.8 km (0.5 mile) spacing.

Faulting can be observed on modern-processed 2D seismic lines at Winnipeg time. These faults generally disappear at Red River time and generally do not correlate from one 2D seismic line to another. The data obtained from the 3D seismic surveys at Cold Turkey Creek and Grand River School provide an interesting visualization of these faults. Many breaks observed from the 3D seismic do not indicate normal, down-to-the-basin faulting. The breaks are generally short with small displacement and are found primarily on flanks of positive features. They have the appearance of zipper-like tears and are probably the result of continual adjustment through geologic time. These small breaks or faults appear to segregate each of the positive features in the 3D seismic surveys. There appears to be a correlation between faulting at Winnipeg time and porosity development in the overlying Red River D zone. These faults may have been conduits for migrating waters which affected late-burial diagenesis.

Seismic Modeling

An extensive modeling study was done to evaluate the potential and limits of deriving stratigraphic information from the seismic data. This was accomplished by utilizing the available sonic log control in the area and constructing seismic models for every type of possible combination of porosity development within the Red River section. The seismic response of porosity zones within the Red River A, B, C, and D zones was modeled and conclusions were drawn relative to the ability to extract stratigraphic information on these zones from the survey.

A portion of a synthetic seismogram for the Red River study area is shown in figure 60 which demonstrates seismic response to important horizons from the Mission Canyon to Winnipeg. Average depths to the Mission Canyon and Winnipeg are 2408 to 3078 m (7900 ft and 10,100 ft), respectively. These depth correspond to approximately 1.650 and 1.900 seconds on field acquisitions with a datum of 914 m (3000 ft). The seismogram shows that lithological information from the upper 76 m (250 ft) of the Red River formation is generally contained in up to four events when normal-polarity data are displayed; an upper peak (P1) which is used to map the top of the Red River, a trough (T1), a second lower peak (P2) and a lower trough (T2).

Modeling was performed over a range of various frequencies. Obviously, the seismic response of the A, B, C and D zones are highly frequency dependent. The following discussion utilizes frequencies up to 65 hertz as those are the highest practical frequencies at the Red River horizon in recorded data. Evaluations of variation in each porosity zone in the upper Red River were made. A base-case earth model for sonic tranisit time and bulk density is shown in figure 61. Minimum and maximum porosities were varied for each zone separately and in combinations to observe the seismic character resulting from these changes. It is concluded that significant variation can be observed from changes in the D zone and lesser variation can be observed from changes in the B zone.

Variations in the A zone are below seismic resolution and do not contribute or detract from an interpretation of the B, C or D zones. Since the A zone is not of commercial importance, the inability to observe any variation resulting from development of this interval is not a concern.

Increasing porosity in the B zone causes a decrease in amplitude of the first Red River peak (P1) and a slight decrease in the frequency of peak P1 (figure 62). Also, an increase in B zone porosity causes a decrease in the amplitude of trough T1, which follows peak P1. Therefore, it is possible that increasing the B zone porosity could suppress amplitude response from the D zone.

An increase of C zone porosity causes an increase in the Red River trough T1, but is less than that resulting from D zone porosity. A review of logs across the study area suggest that C and D zone simultaneously develop or lose porosity. Therefore, an increase in deflection of trough T1 suggests an increase in both C and D zone porosity.

An increase in porosity in the D zone causes a marked increase of negative amplitude in Red River trough T1 and also positive amplitude in the underlying peak P2 (figure 63). In the ideal case, the maximum negative deflection of trough T1 is pushed lower in the section compared to results from an increase in C zone porosity alone. Also, a lower trough (T2) develops with an increase in D zone porosity which does not occur from any other porosity increase.

The ideal reservoir development in the Red River is an increase in porosity in both the B and D zones. A synthetic seismogram of increasing porosity in these zones while holding the other zones constant is shown in figure 64. Visual comparison of figure 64 (increasing B and D zone porosity) to figure 63 (increasing only D zone porosity) demonstrates the dominance of D zone variation.

Interpretation Based on Modeling

Amplitude variation of trough T1 and Peak P2 are most likely to predict porosity-thickness of the D zone. There are three potential maps of these attributes. The first two maps are the amplitude of trough T1 alone and Peak P2 alone. The third map would be the combination or sum of the absolute value of T1 and P2. Areas of high amplitude should correlate to high porosity-thickness in the C and D zones. The development of amplitude in peak P2 is concluded to relate to D zone porosity alone. It is interpreted that porosity development within the D zone may be discerned and mapped with accuracy down to 5 m (15 ft) of porosity. Below that limit, none of the zones within the Red River may be observed with any degree of confidence. The B zone porosity-thickness may be interpreted from the variation in amplitude and frequency of peak P1. Greater porosity thickness should result in a decrease in amplitude and frequency of P1. This variation is subtle and can only be used to upgrade drilling locations which have been chosen based upon the more definitive amplitude data from T1 and P2, which relate primarily to D zone porosity. It is concluded that the A zone porosity development is too thin to be observed seismically and does not affect the interpretation of zones below it.

Modern Processing Applied to Older 2D Seismic

It has been found that modern processing techniques can extract significantly greater information than was possible when much of the 2D seismic data were recorded over the area. New processing techniques which can be successfully applied to older vintage 2D seismic data in the area are application of refraction statics and radon stack. Resulting seismic sections provide good event resolution, higher frequency and allow for identification and interpretation of subtle faulting. The improved quality resulting from modern processing allows picking of additional horizons which were difficult to interpret from original processed sections. The mapping of additional horizons facilitates identification of closer geological time subdivision. A better understanding and measurement of tectonic history may permit better prediction of high-quality reservoir areas and trapping.

A comparison of results between original (1972) and modern processing is shown on figures 65 and 66. This example is from the east-west seismic line CA9-4 which crosses the center of the Southwest Amor, Bowman Co., ND (figure 67). Figure 65 shows the data as processed in 1972. These six-fold data were acquired with dynamite sources and a 134-m (440-ft) group interval. Original processing was performed on 4 msec re-sampled data and was state-of-the-art at that time. Acquisition and processing parameters for line CA9-4 are given in table 11 and table 12, respectively. The new processed version is shown in figure 66 and exhibits frequencies up to 65 hz at Red River time in comparison to approximately 40 hz from original processing. The new processing parameters are shown in table 13. The time shift exhibited between the original and modern-processed version of CA9-4 is the result of a 33 msec difference in datum correction and an additional 30 msec introduced by the refraction statics solution. As a result of new processing, additional events can be picked at the Red River, Stonewall and Interlake horizons.

Faulting is evident on a number of modern-processed 2D seismic lines. The fault trends extend from northwest to southeast in echelon patterns across the study area. An example of faulting patterns or lineaments is shown on figure 67 at Amor Field, Bowman Co., ND. The amount of throw is variable with larger faults exhibiting 15 m (50 ft) of throw at the Ordovician Winnipeg. Throw displacement decreases upward and is generally not detectable by Upper Devonian (Duperow) time. Because the Red River producing zones can be as thin as 3 m (10 ft), faulting can play a significant role in field development and enhanced-recovery design. Faulting pre-dates the Devonian-Silurian unconformity and appears to support a wrench-fault model with left-lateral motion. The productive trends found in the Red River are defined by early-stage wrench motion trends and faulting complicates production.

3D Seismic

Two 3D seismic surveys were obtained in Bowman Co., ND. The surveys cover 11.4 and 17.1 km^2 (4.4 and 6.0 square miles), respectively. The surveys are separated by about 2.4 km (1.5 miles) and image the Red River in a similar setting and depth (figure 68). These areas were selected because they are typical of the high-relief, small-structure setting and have mature wells with good to above-average production.

The Cold Turkey Creek 3D seismic area encompasses approximately 11.4 km^2 (4.4 square miles) and three structurally isolated features. There were four producing wells and four dry holes which were drilled prior to the survey in 1995. These wells have produced a total of 242,000 m^3 (1,523,000 bbl) oil with an estimated ultimate recovery of 295,000 m^3 (1,858,000 bbl).

Feature 1 (shown in figure 69) has an areal extent, based on seismic time-structure and isochron maps, from 129 to 219 ha (320 to 540 acre). The potential OOIP for the combined B and D zones could be from 890,000 to 1,494,000 m^3 (5,600,000 to 9,400,000 bbl). Recoverable oil at 15 percent of OOIP is estimated at 134,000 to 223,000 m^3 (840,000 to 1,400,000 bbl). The cumulative oil from the existing well on feature 1 is 59,600 m^3 (375,000 bbl) with an EUR of 74,000 m^3 (465,000 bbl). The under-developed reserves which could be contacted by additional drilling are therefore estimated to range from 60,000 to 149,000 m^3 (375,000 to 935,000 bbl).

The Muslow-State B-27 was drilled on the northern structural feature (feature 1) to test a downdip, seismic-amplitude anomaly in the Red River. The existing well on feature 1 is the Faris 1-22 which has a cumulative production of 59,600 m^3 (375,000 bbl) oil and 18,900 m^3 (119,000 bbl) water and has been perforated in the Red River B, C, and D zones. The critical closure of the Red River at feature 1 is estimated at about 30 m (100 ft) based on well and seismic data. The net thickness of each zone in the original well is thinner than average and porosity development is poor (a structural cross-section over feature 1 is shown using porosity logs in figure 70. Based on seismic interpretation, the Muslow-State B-27 well was to encounter a thicker and more porous section in the D zone with a loss of structure of about 9 m (30 ft) from the existing well on the structural crest. The test well was located about 389 m (1275 ft) from the original well.

A seismic-time structural cross-section across feature 1 is shown in figure 71. The cross-section demonstrates the amplitude variation of trough T1 and peak P2 described previously in the modeling section. The seismic data clearly show that D zone porosity is preferentially developed on the flanks and poorly developed on the crest. Targeting wells in these porosity blooms becomes a compromise of structural position and amplitude development.

The Muslow-State B-27 well encountered oil production in the B and D zones based on drillstem tests. The B zone DST recovered oil and drilling filtrate. The reservoir pressure was 12,800 kPa (1850 psi), down 13,800 kPa (2000 psi) from original pressure. This indicates conclusively that the B zone at the new well is in pressure communication with the No. 1-22 Faris well. The C zone was drillstem tested and found very poor permeability and near-original pressure. The D zone recovered oil and water on drillstem test at original pressure. It is not known how much production at the older well has been from the D zone. It is possible that the D zone between the two wells is isolated by faulting or stratigraphic change. It is also possible that the older well has produced very little from the D zone. The Muslow-State B-27 well was perforated and acidized in the D zone. The initial production rate was 26.4 m^3 oil and 21.1 m^3

water per day (166 bopd and 133 bwpd). The estimated ultimate reserves from the D zone after six months of history are about 35,800 m^3 (225,000 bbl) oil. There has been no change in production at the original well.

The Pang-Faris K-22 was also drilled on feature 1 to test another seismic-amplitude anomaly. This well is on the north side of the feature and penetrated the Red River at a depth about 16 m (53 ft) below the structural crest. Drillstem test were run across the Red River B and D zones. The Red River B zone recovered mostly drilling mud and recorded a shut-in pressure of 13,700 kPa (1980 psi). The B zone test indicates pressure communication with the Faris 1-22 and Muslow-State B-27 wells in this interval. The drillstem test in the D zone recovered about 7200 ft of mostly oil with a shut-in pressure of 24,100 kPa (3500 psi) which indicates slight pressure depletion. The Red River D zone was perforated and flowed 27.8 m^3 per day (175 bopd) at 690 kPa (100 psi) wellhead pressure with no water. A stabilized production rate had not been yet established at the time of this report.

The Grand River School 3D seismic survey (figure 68) was acquired over an area which exhibits strong structural relief from the regional trend. A single well was drilled and completed more than 20 years ago on the crest of this feature. The No. 1-6 Hanson well (swnw Sec. 6, T.129N., R.101W.) was perforated in the B, C and D zones which are thinly developed with low porosity. Following results from identification of porosity from seismic amplitude and drilling at Cold Turkey Creek Field, the Watson O-6 was drilled 0.95 km (0.59 mile) southeast from the No. 1-6 Hanson well. The well was drilled to test amplitude character of Red River events which indicate thicker and more porous D zone development. This character is not coincident with the high point on seismic-time structure maps or thinnest point on isochron maps. The Watson O-6 well encountered the top of the Red River at a structural datum which is flat to the No. 1-6 Hanson well. Drillstem test of the Red River B zone indicates communication with the Hanson well. Net thickness of the B zone is about 1.8 m (6 ft) with excellent porosity and low water saturation. The Red River D zone produced oil on drillstem test with an extrapolated rate of 76.3 m^3 per day (480 bopd) based on pipe recovery. Reservoir pressure was undisturbed from original at 26,900 kPa (3900 psi). Wireline logs show the Red River D zone to be thickly developed with 8.2 m (27 ft) of productive interval with average porosity of 18 percent. Completion operations were in progress at the time of this report.

Results from the Watson O-6 are very similar to those found at the adjacent Cold Turkey Creek Field. The Red River B zone demonstrates pressure communication between wells separated by a distance of 0.95 km (0.59 mile). The Red River D zone is greatly variable and better development can be identified by seismic amplitude.

Acquisition Parameters

The 11.4-km^2 (4.4 square-mile) area over a portion of Cold Turkey Creek Field was imaged in 1995 using a staggered-brick acquisition design included 378 4.5 kg (10-lb) dynamite charges buried at 18 m (60 ft) in a 536-m (1760-ft) source pattern perpendicular to receiver-line spacing. A total of 720 receivers were deployed in 8 parallel lines with 60 channels each and 268-m (880-ft) spacing. The shooting patch included 480 live-geophone groups. The data volume is approximately 20 fold with bin spacing of 33.5 x 33.5 m (110 ft x 110 ft). The 17.1-km^2 (6.0 square-mile) area at Grand River School was surveyed in 1996 using dynamite as the energy source. The surface configuration was also a staggered-brick design with group and source intervals of 67 m (220 ft). There were 96 source points and receiver groups per 259 ha (square mile). The data volume is approximately 20 fold with bin spacing of 33.5 x 33.5 m (110 ft x 110 ft).

Processing

The survey data at Cold Turkey Creek were processed by two processors. Interpretation groups found it necessary to rotate version 1 by -90° to -120° to achieve a normal polarity, zero-phase data volume. The second processing version had better phase resolution (closer to zero degrees as determined by zero-phase synthetics) and fewer migration effects around the edge of the data set (a summary of processing steps is shown in table 14). The Grand River School 3D data were processed using the same parameters as the second version from Cold Turkey Creek. It was found that processing flow is important and should be carefully performed to provide a close match with zero-phase synthetic seismograms. A strong F-X filter is detrimental to interpretation of amplitude. It is concluded that it is advantageous to produce two processed versions, one for structural and isochron mapping and one for interpretation of amplitude variation.

Interpretation

A series of horizons were picked for creation of time structure and isochron maps. These horizons include the following:

1) Greenhorn
2) Mission Canyon
3) Duperow
4) Top Red River
5) Base Red River Porosity
6) Winnipeg

In general, the isochron maps show thinning over structurally high areas. It is observed that interval thinning on present-day structurally high areas occurred from pre-Red River until after Cretaceous Greenhorn time.

A number of seismic attributes were extracted in and near the Red River seismic interval and evaluated as potential indicators of Red River porosity distribution. The isochron intervals were also evaluated. Seismic attributes and isochron intervals at wells were correlated with porosity-thickness determined from log analysis. Conclusions regarding stratigraphical correlations of Red River development were mixed and inconclusive using the version-1 processing. An interesting correlation was the isochron interval from Mission Canyon to Duperow. Increasing interval time between these horizons correlates with increasing porosity-thickness in the Red River. Reasons for this correlation are not clear, but may relate to timing of late-burial diagenesis.

The conclusions reached from interpretations using version-1 processing are that closure on present-day structure is critical for commercial reserves in this area. Interpretations using the classic isochron intervals of Greenhorn to Winnipeg and Mission Canyon to Winnipeg produce the best results. Faults are interpreted to have small displacements and limited extent. Most disappear before the end of Red River time and are found on the perimeter of present-day structural high areas.

Interpretation results after using the version-2 processing were more satisfactory. Extensive synthetic-seismic modeling was performed using well log data. It was concluded that the first trough (T1) below the first Red River event should have a high correlation with D zone porosity. Version-2 processing produced a Red River character which allowed mapping the T1 event with confidence. A map of the Red River trough T1 overlain on Red River structure shows high amplitude areas are preferentially found on perimeter areas of structural highs and in lows. The areal extent of high-amplitude anomalies is small and somewhat random.

It was concluded that structural position, faulting and porosity blooms would be the objective for identification of drilling locations. A Red River structure map was constructed from the Greenhorn to Red River isochron and interval velocity data from well control. The first step in constructing this map is to produce a Greenhorn to Red River interval-velocity map using the well control within the 3D survey. The interval velocity map (feet per second) and isochron map (seconds) are then mathematically combined by multiplication of gridded data to produce a Greenhorn to Red River isopach map (feet). A Greenhorn structure map was constructed from well control. The Red River structure map is made by adding the computed Greenhorn to Red River isopach thickness to the Greenhorn subsea structure. This method works reasonably well because the interval velocities from the Greenhorn to Red River do not vary greatly, the Greenhorn is easily identified on logs, and the Greenhorn structure is gentle and regional.

Faulting

Faulting can be observed on modern-processed 2D seismic lines at Winnipeg time which generally dies out by Red River time and infrequently observed after Devonian time (figure 67). These faults generally do not correlate from one 2D seismic line to another. The data obtained from the 3D seismic surveys at Cold Turkey Creek and Grand River School provide an interesting visualization of these faults. At Cold Turkey Creek, two interpretations were made by different geophysical consultants for faulting or breaks at the base of the Red River D zone. One of these interpretations shows a complex pattern of breaks while the other is more simple (figures 72 and 73). Close inspection of the two interpretations, however, shows a similarity of location and orientation. The primary orientation is north by northwest at 315°. Similar patterns and orientation are noted from the interpretation of 2D seismic at Amor Field shown in figure 67. Many breaks observed from the 3D seismic do not indicate normal, down-to-the-basin faulting. Faults are low relief and are generally 0.4 to 0.8 km (0.25 to 0.50 mile) in length. They have the appearance of zipper-like tears and are probably the result of continual adjustment through geologic time and most of the faults are on the flanks of positive features. Several faults are also identified which may compartmentalize each of the structural features. There appears to be some correlation between faulting at Winnipeg time and porosity development in the overlying Red River D zone. These faults may have been conduits for migrating waters which affected late-burial diagenesis. Because the Red River producing zones can be as thin as 3 m (10 ft), faulting may play a significant role in efficient field development and enhanced-recovery design.

Porosity Development

As discussed in the modeling section, the Red River trough T1 and peak P2 appear to be valid indicators of porosity development in the Red River D zone. A comparison of two interpretations of amplitude are shown from Cold Turkey Creek using the same processing version but by two different geophysical consultants (figures 74 and 75). The interpretations are not identical but do coincide at many locations. A similar pattern of T1 amplitude development is shown at Grand River School by maps displayed on figure 76. This figure shows the T1 amplitude overlain on the Winnipeg time structure and Greenhorn-Winnipeg isochron. Another visualization of amplitude and porosity development is shown in 3D perspective on figure 77. Figures 76 and 77 show that amplitude anomalies follow the up-thrown hinge of a major fault on the east side of the survey. Amplitude (porosity) appears to flow from the fault and suggests the possibility that thicker, more porous Red River D zone development was caused by late-burial diagenisis from the upward flow of deeper water. It is concluded from the two surveys that Red River D zone porosity development is spotty and random in trend and orientation. However, the occurrence of increased gain in T1 amplitude is most frequently related to structurally low areas and along flanks of positive features. The areal extent of these porosity blooms is between 16 to 32 ha (40 and 80 acres). At both Cold Turkey Creek and at Grand River School fields, wells drilled at crestal positions are thinner with lower porosity in each of the zones. While the porosity blooms have small areal extent, they may not represent limited or isolated drainage areas. Rather, they are probably areas with greater porosity thickness and allow more efficient withdrawal points for reservoir drainage and higher recovery.

Conclusions

Seismic data have made important contributions to successful exploration of the Red River in southwest Williston Basin. Modern seismic methods of processing and 3D acquisition can help improve recovery from existing reservoirs by targeting thicker porosity development and identifying subtle basement faults or lineaments. The acquisition of 3D seismic and drilling of test wells have demonstrated that reservoir heterogeneity can be observed with seismic data and used to target poorly drained and untapped reservoir compartments at close distances to existing, mature wells.

Amplitude mapping of properly processed data can predict thicker and more porous intervals in the Red River D zone. Modeling also suggests that thicker and more porous B zone development can be observed seismically but that the variation is subtle and ambiguous in actual recorded data. Seismic amplitude indicates the distribution of porosity development in the D zone to be spotty and random, but primarily located in low areas and along flanks of structurally positive features. Amplitude anomalies relating to the D zone porosity are from 16 to 32 ha (40 to 80 acres) in areal extent.

Small displacement zipper-like faults (breaks) occur frequently around perimeters of structurally positive features at Winnipeg depth. Many disappear before the top of the Red River and nearly all disappear before the end of Devonian time. Because the Red River producing zones can be as thin as 3 m (10 ft), faulting may affect reservoir entrapment should be considered in field development and enhanced-recovery plans.

Engineering studies of ultimate recovery from the Red River B zone indicate range from 6.7 to 11.8 percent of OOIP for vertical wells in 129-ha (320-acre) spacing units. Similarly, typical recovery from the D zone is placed at 10.2 to 14.2 percent of OOIP in 129-ha (320-acre) spacing units. For comparison, maximum recovery by water-drive should be about 28 percent of OOIP. It is concluded that low recovery is due in part to reservoir heterogeneity. Seismic studies of 2D and 3D data indicate that this heterogeneity is probably more localized to structural features than being affected by regional trends.

Table 11
Recording Parameters for Seismic Line CA9-4

Field Geometry		Recording Instruments	
Shot By	Newton Exploration Co	Recording System	DFS 1590
Date	June 1972	Format	SEGA
Data Channels	24	Record Length	3 sec
SP Interval	880 ft	Sample Rate	2 msec
Group Interval	440 ft	Field Filters	9-93 Hz
Coverage	6 fold		
Source		Receivers	
Type	Dynamite	Geophones per Group	12
Charge Size	25 lb	Geophone Pattern	180 ft
Hole Depth	115 ft	Geophone Frequency	20 Hz
Array	Single Hole	Spread	5060-220 x 220-5060

Table 12
Original Processing Parameters (1972) for Seismic Line CA9-4

Processing Sequence

1. Translation
2. Re-sample from 2 msec to 4 msec
3. Normal Move-out
4. Time Variant Scaling
5. Time Variant Deconvolution
   - 700-2300 msec auto-correlation gate
   - 3 Decon filters per trace
   - 800 msec gate and 60 msec filter
6. Time Variant Filter
   - 232 msec length
7. Statics - Flattened at 1100 msec
8. Re-sample from 4 msec to 2 msec
9. First-break Suppression
10. Stack
11. Time Variant Scaling
12. Structural Statics
    - 2900 ft Datum
    - 6000 ft/sec Replacement Velocity

Table 13
Modern Processing Parameters (1994) for Seismic Line CA9-4

Processing Sequence

1. Demultiplex
2. Record and Trace Edit
3. Geometry Application
4. Refraction Statics
   - Green Mountain Method
   - 3000 ft datum
   - 6000 ft/sec Correction Velocity
5. Exponential Gain Recovery
6. Pre-Decon Mute
7. Surface Consistent Spiking Deconvolution
   - 160 msec Operator 0.01 percent WNL
8. Spectral Whitening
   - 5/10-80/85 Hz
9. CDP Sort
10. Preliminary Velocity Analysis
11. Surface Consistent Residual Statics
12. Interactive Velocity Analysis
13. Surface Consistent Residual Statics
14. Normal Move-out Correction
15. Flat Datum Statics Corrections
16. CDP trim Statics
17. Noise Reduction - Radon transform
18. First Break Mute
19. Trace Equalization Scaling
20. Stack
21. Spectral Whitening
    - 5/10-80/85 Hz
22. F-X Deconvolution
23. Filter
    - 8/14-70/85 Hz
24. Trace Equalization

Table 14
Processing Flow for Cold Turkey Creek and Grand River School 3D Surveys, Bowman Co., ND.

1. Data reformatting, minimum phase correlation
2. Geometry definition and survey quality control, loading of all XY and survey, and inline information
3. Trace edit, partial or total elimination of dead or noisy traces and polarity check
4. Gain recovery/spherical divergence, gain restoration to a specified function to compensate for geometrical spreading and attenuation loss, surface consistent relative amplitude trace balancing
5. Surface consistent deconvolution, a unique operator assigned to each shot and receiver to remove source signatures, instrument and geophone responses and output the data to zero phase
6. Pre-stack signal-noise enhancement, X-T domain random noise attenuation
7. Refraction static corrections, refraction static correction applied to provide a uniform datum and correctional velocity to the grid, based on first-arrival based 3D tomographic modeling, first arrivals picked using latest in neural network algorithms
8. 3D 110 x 110 ft gathered bin, identification shot ordered trace header data into individual gathers representing one common bin
9. Interactive first velocity analysis, time-velocity displays of data to interpret velocity field for NMO correction on a 2750-ft grid
10. 3D normal move out (NMO) corrections, dynamic corrections using velocities, modified for local dip filed and applied to all data to bring each trace to zero-offset distance
11. Mute, zeroing of first arrivals to eliminate direct or refracted guide waves and noisy or very low frequency far-range traces
12. Brute stack, summation of NMO corrected CMP gathers with datum elevation static and apply a first-picked velocity function
13. 3D surface-consistent residual static, automatic correction of small, random errors in static alignment of traces within CMP on a surface consistent (shot/receiver) basis
14. Pre-stack spectral whitening and balance, frequency enhancement and balance of signal based on power-spectrum testing
15. Intermediate stack, summation of NMO corrected CMP gathers by application of one pass of velocities and a pass of residual statics
16. Final time-velocity pairs generated and picked for consistent velocity trends, minimum 2750-ft grid control points
17. 3D surface consistent residual static, second pass of automatic statics, statics eliminated from gathers refined with second set of velocity functions
18. Final filter and gain modification, final band-pass filter applied based on filter-scan test, time variant trace equalization to adjust RMS levels to polarity
19. Final stack tape, tape of stacked data for workstation loading
20. Post-stack signal noise enhancement, 3D FXY noise-reduction filter applied after stack, signal enhancements used to reduce random and linear noise
21. 3D finite difference migration, post-stack migration to image CMP in proper source to receiver plane

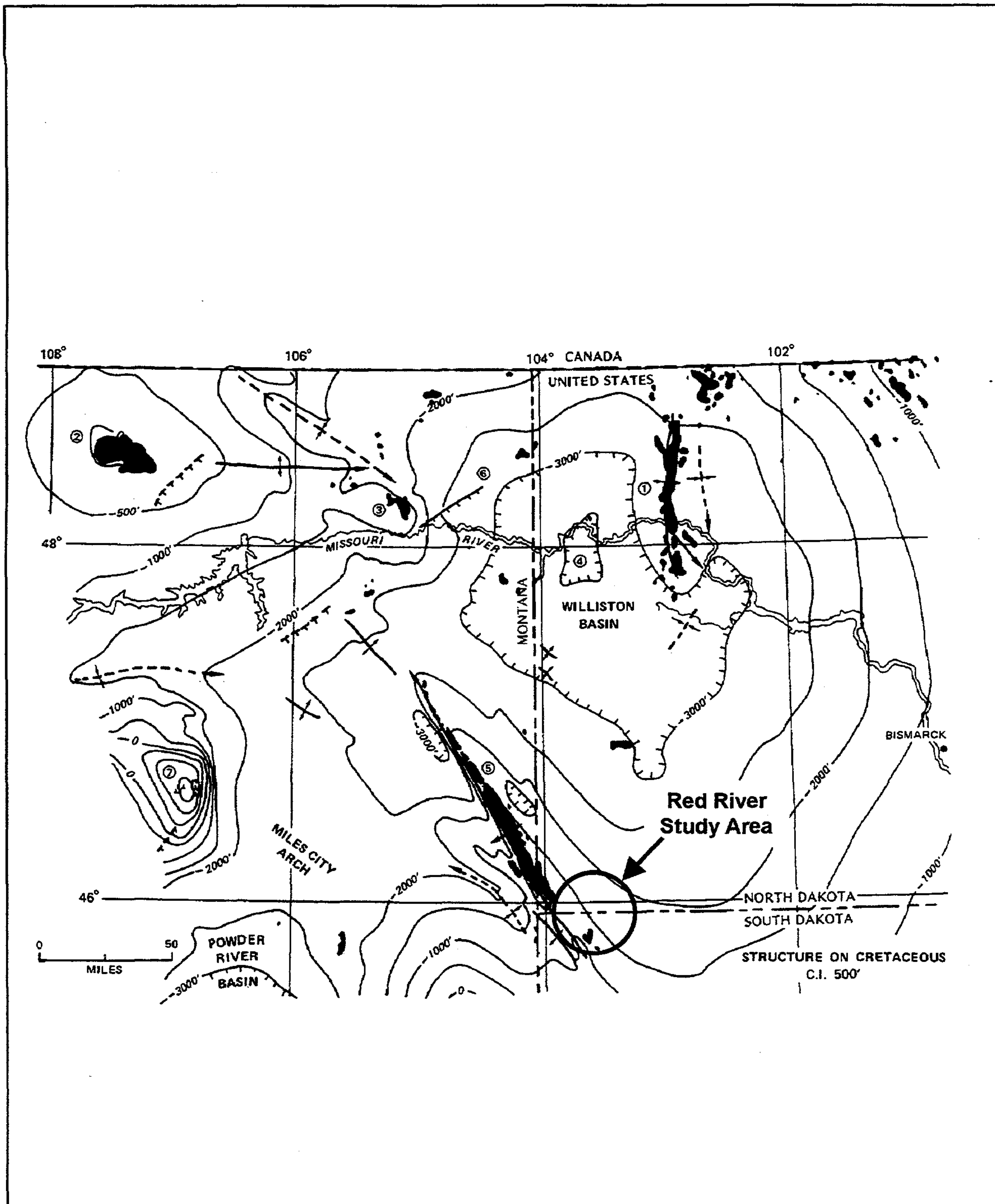


Figure 1: Map of the Williston Basin with Red River study area. The Red River study area straddles the state line between North Dakota and South Dakota in Bowman and Harding counties.

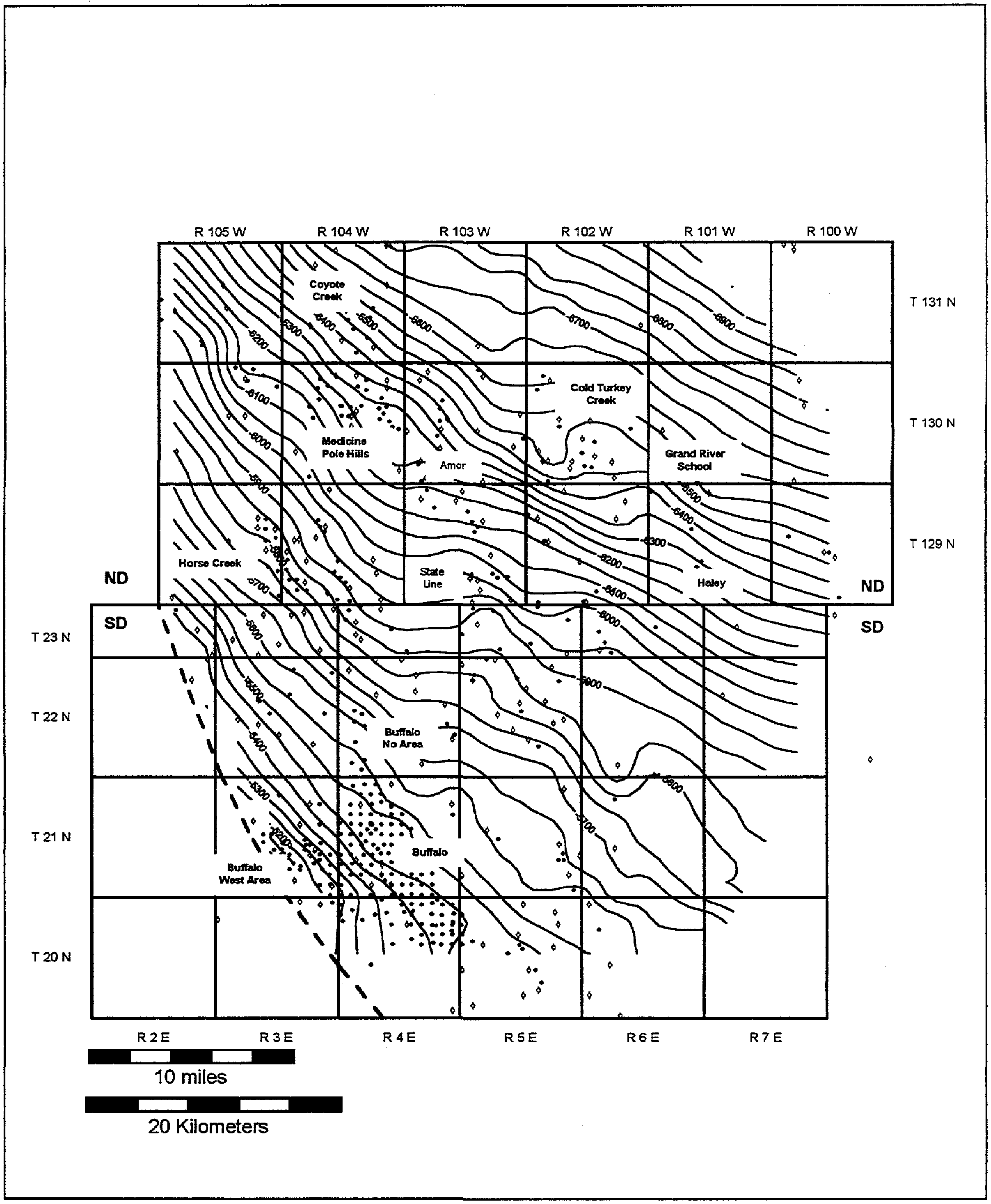


Figure 2: Map of Red River study area with fields annotated. Structure contours are on top of Red River.

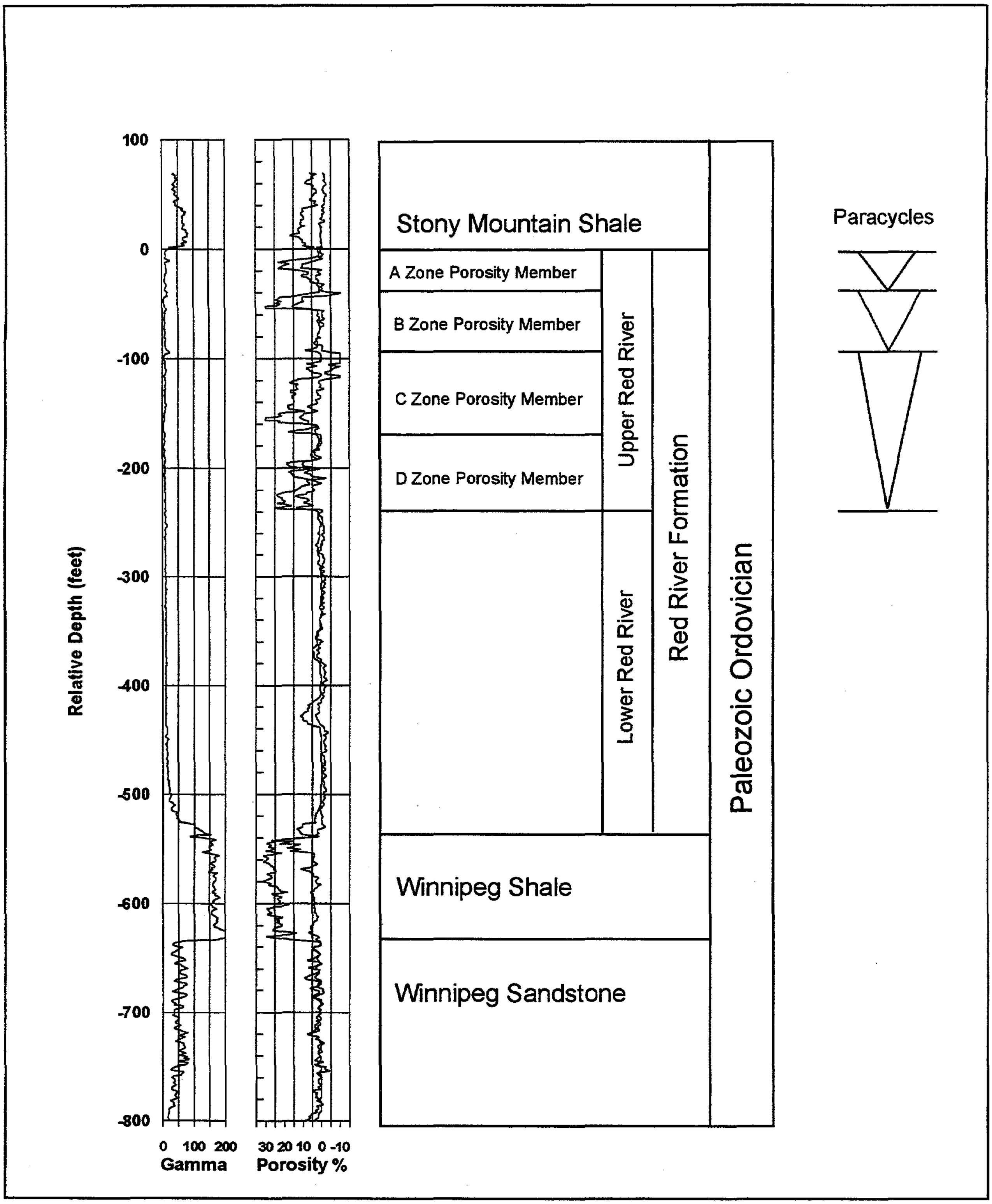


Figure 3: Type Log of Red River Formation through the Winnipeg.

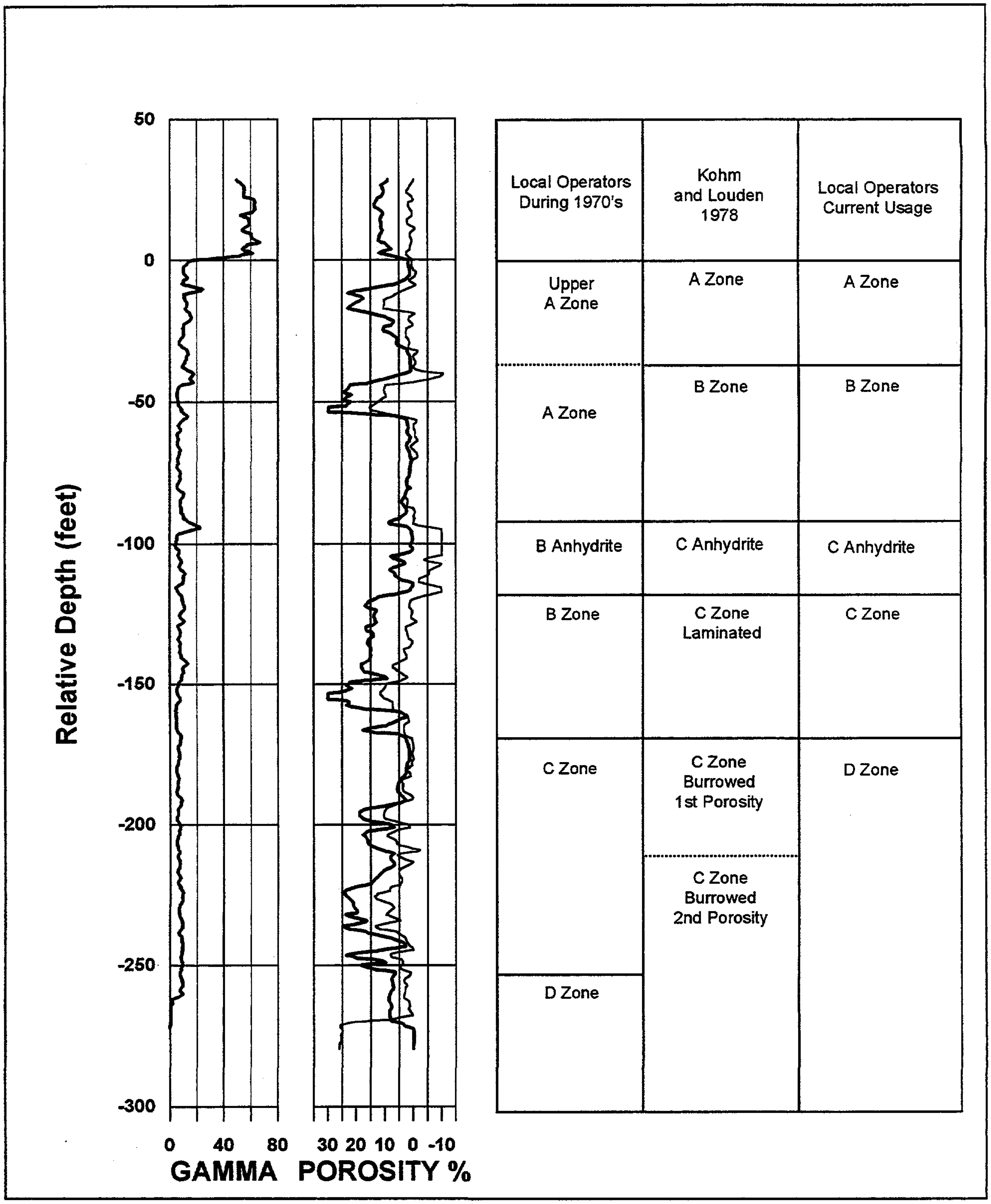


Figure 4: Type log of Upper Red River with stratigraphic nomenclature. Popular nomenclature for beds in the upper Red River have evolved with time and usage by different local operators.

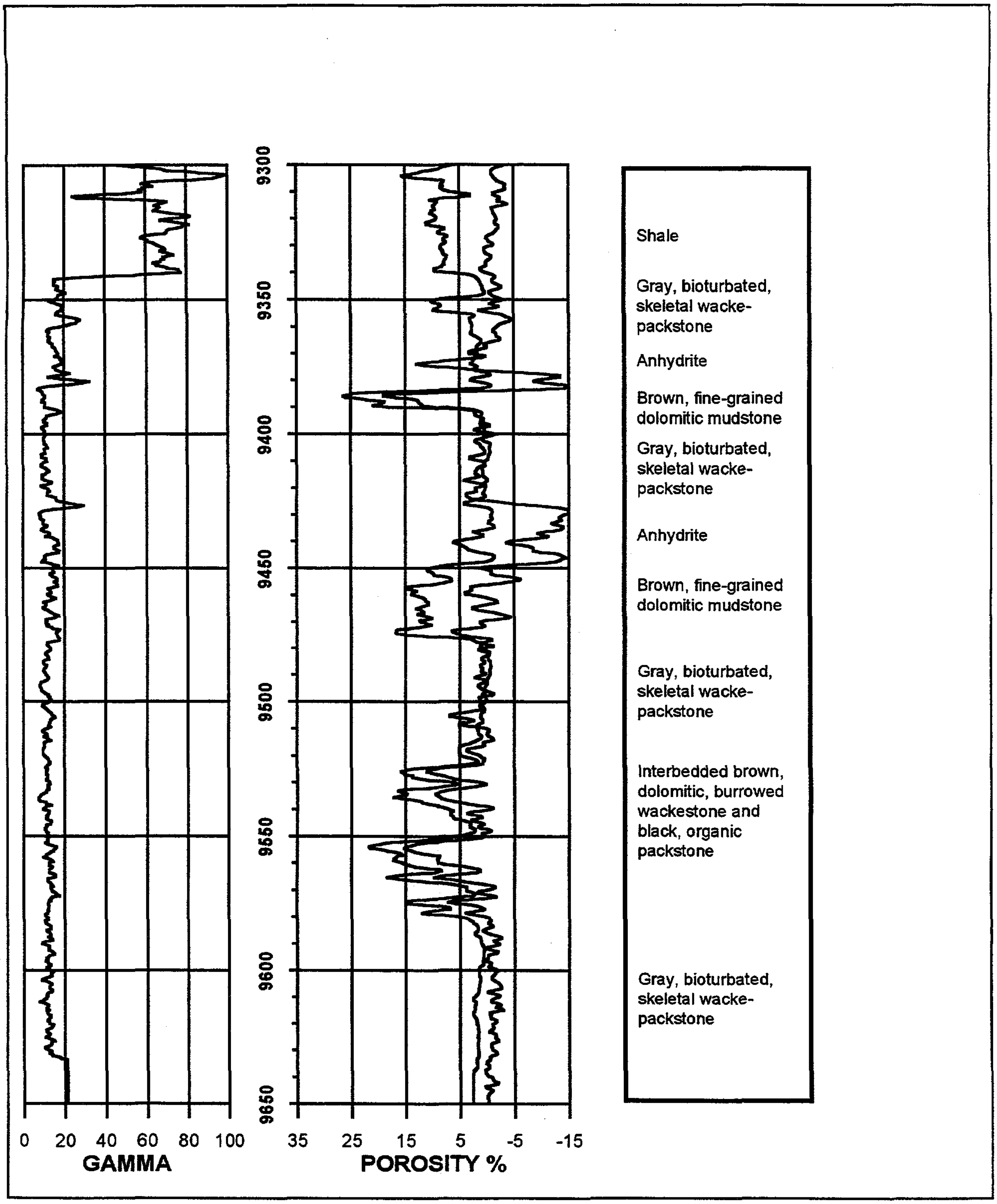


Figure 5: Stacking of lithologies in the Red River sequence.

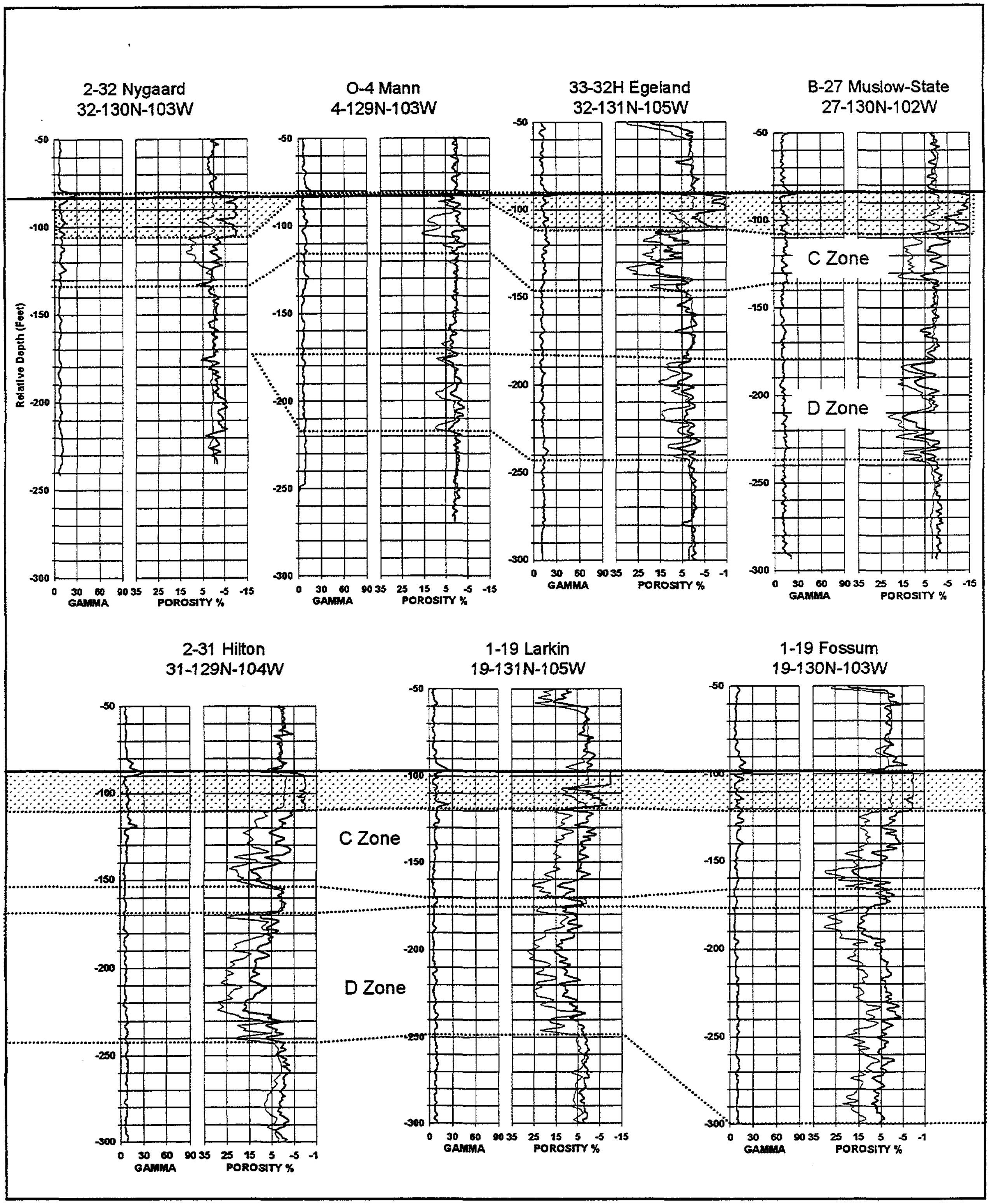


Figure 6: Cross section showing variability in Red River C and D Zones.

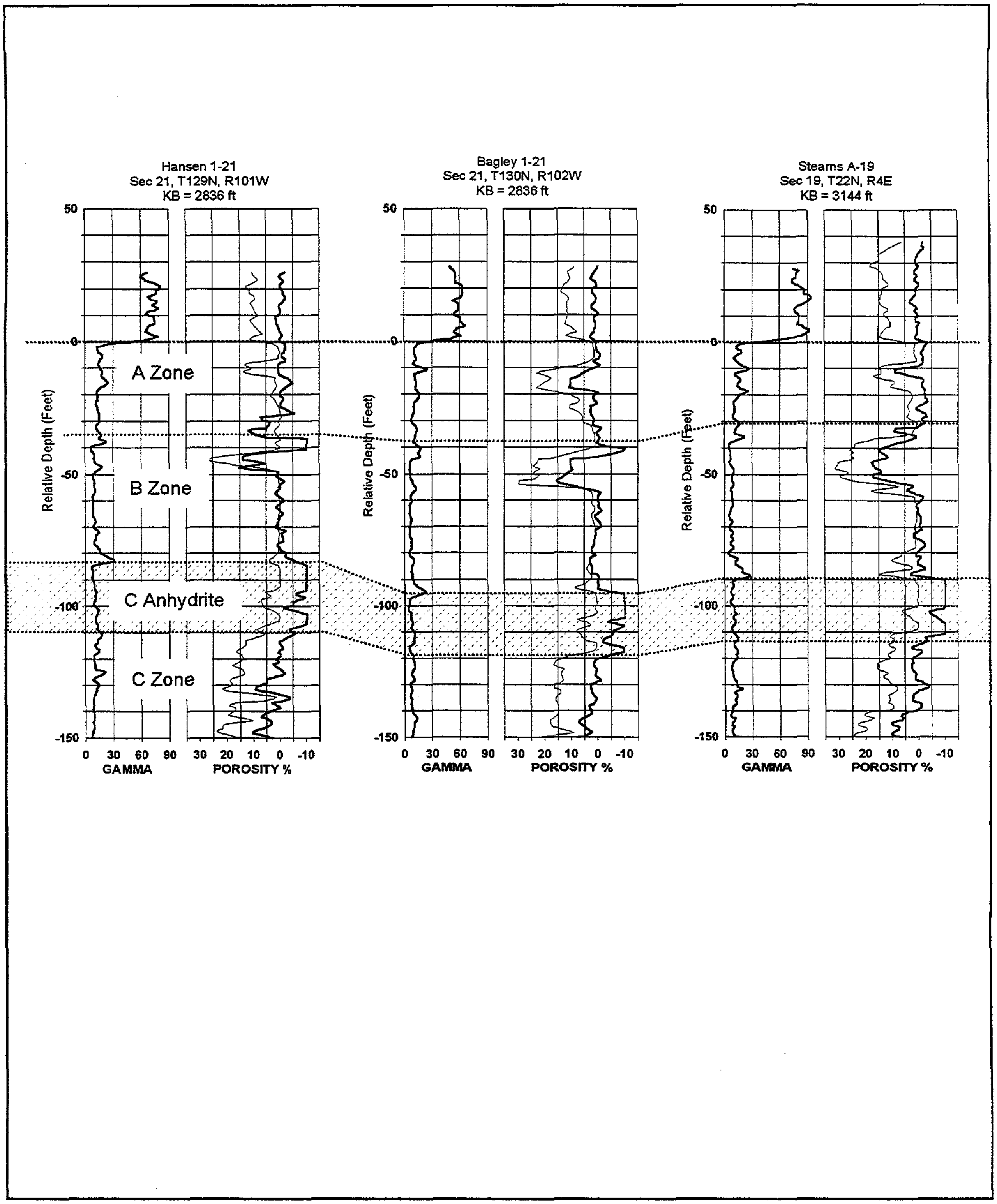


Figure 7: Cross section showing variability in Red River A and B zones.

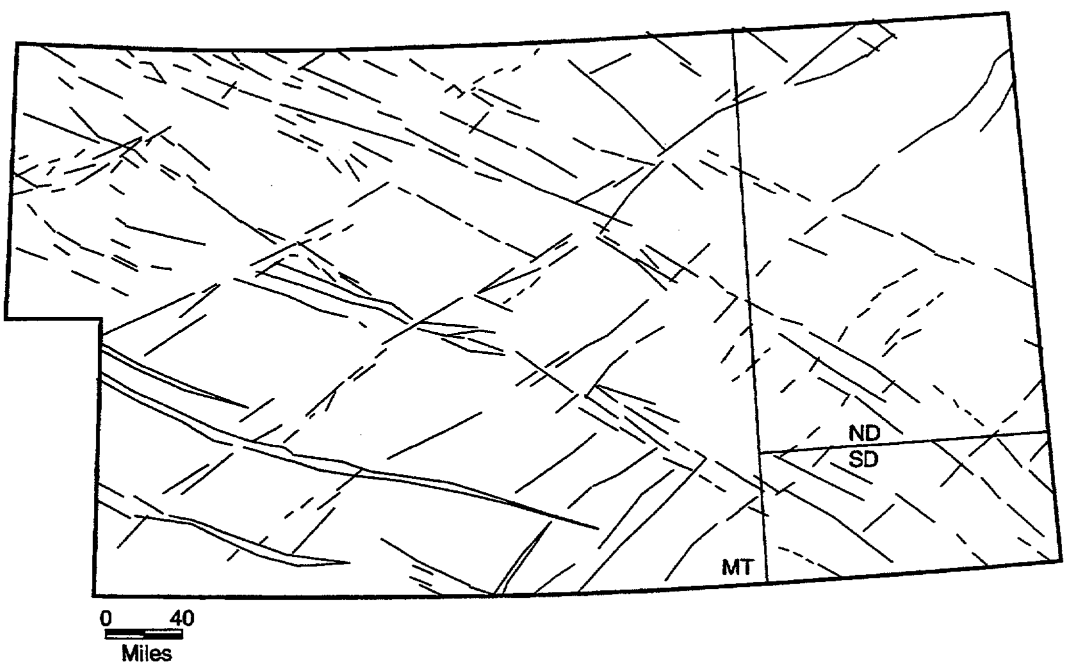


Figure 8: Regional fault and lineament patterns in the Williston Basin after Thomas, 1974. Photo-geomorphic mapping of surface lineaments defines a block pattern presumably within basement rocks.

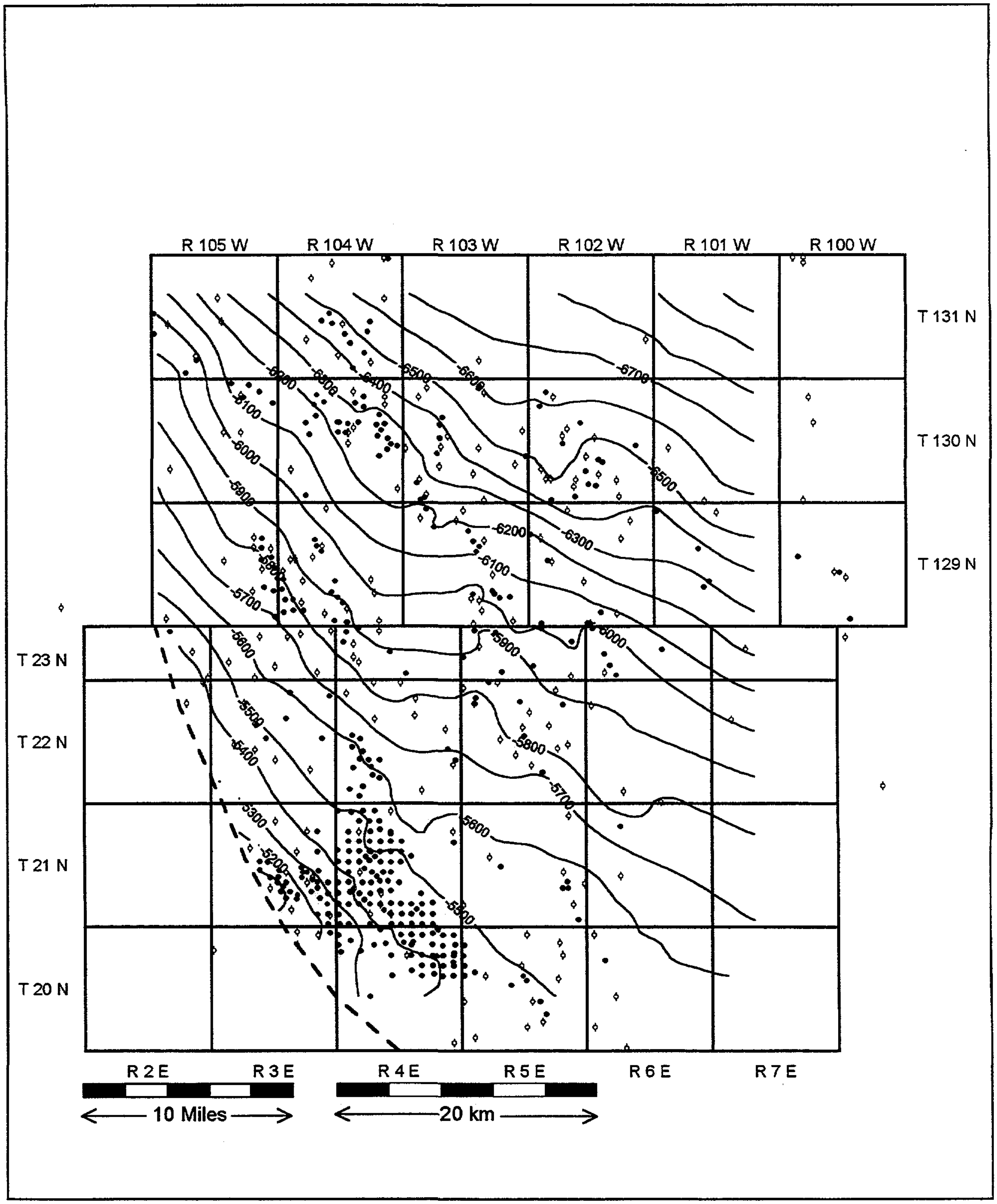


Figure 9: Map of Red River structure. Contour interval is 100 ft.

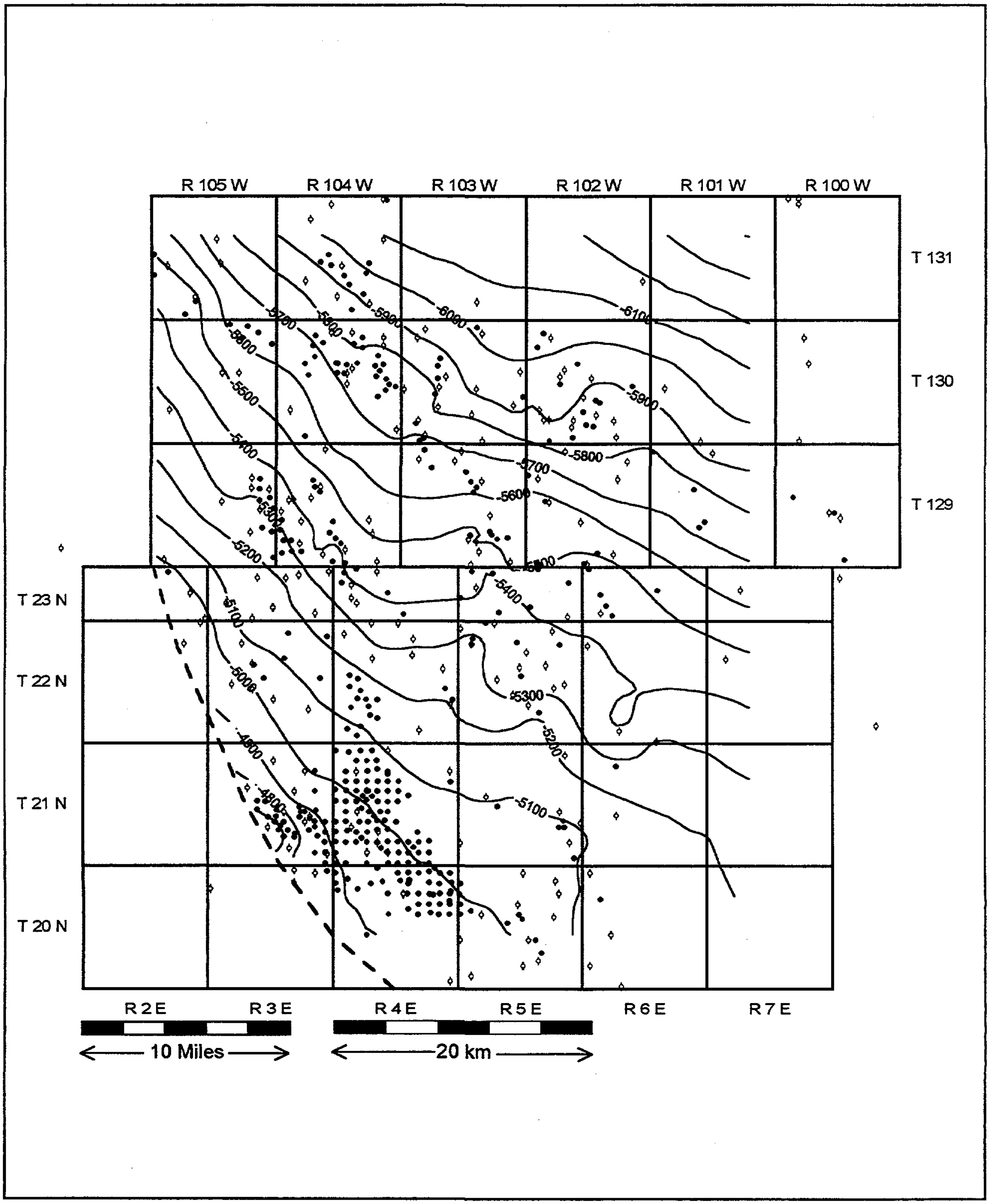


Figure 10: Map of Interlake structure. Contour interval is 100 ft.

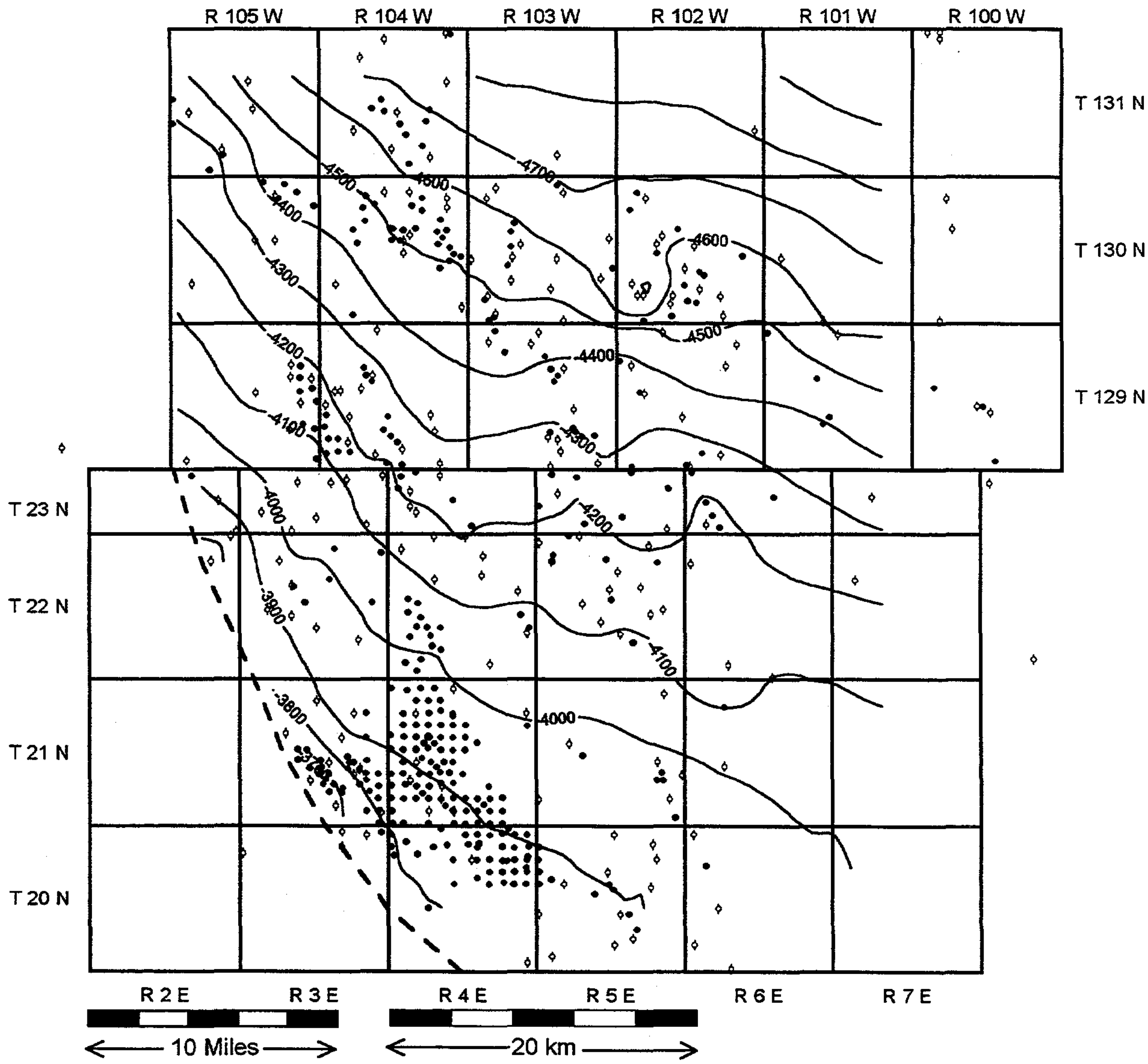


Figure 11: Map of Mission Canyon structure. Contour interval is 100 ft.

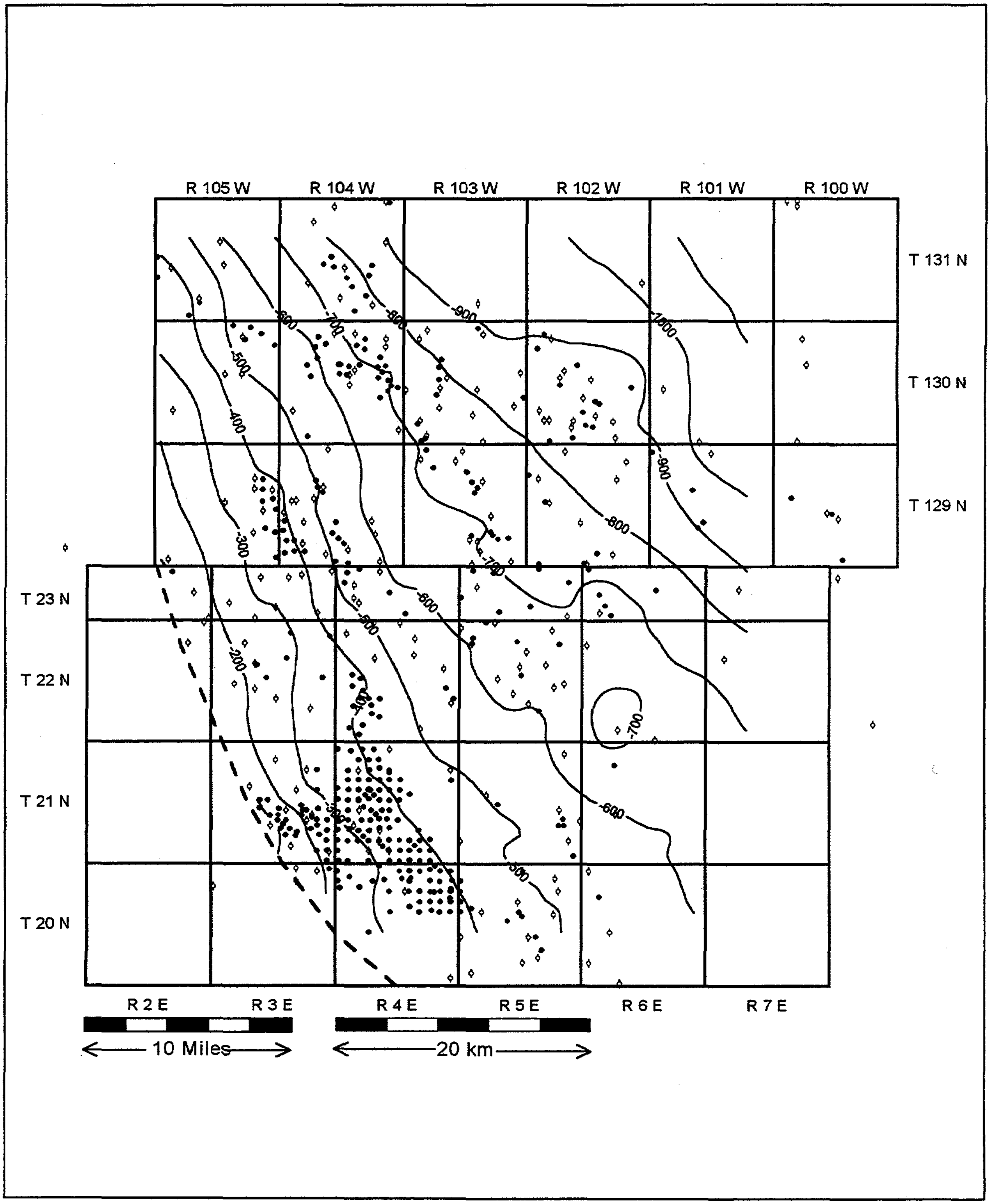


Figure 12: Map of Greenhorn structure. Contour interval is 100 ft.

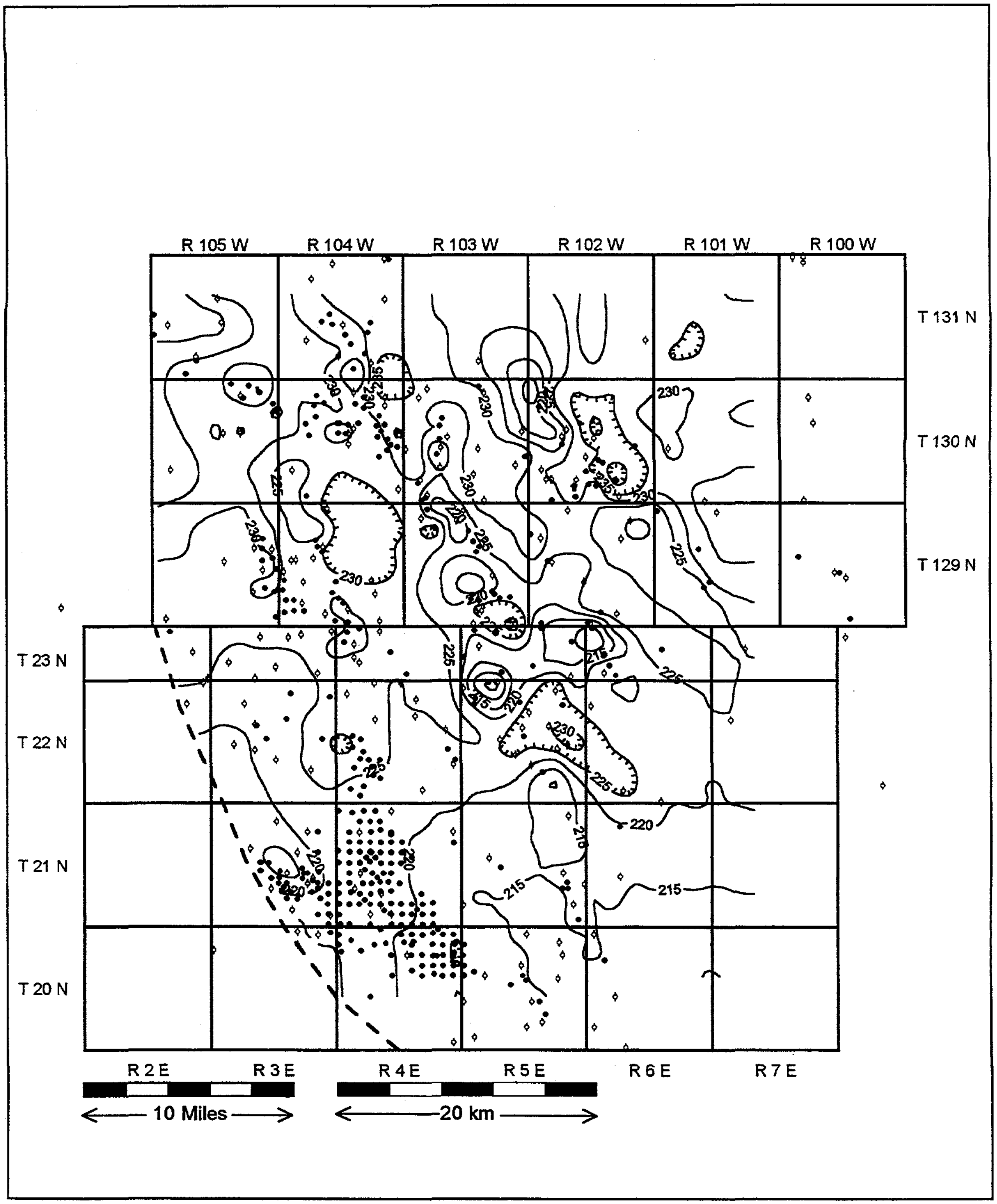


Figure 13: Map of Red River (top Red River to base of D zone) isopach. Contour interval is 5 ft.

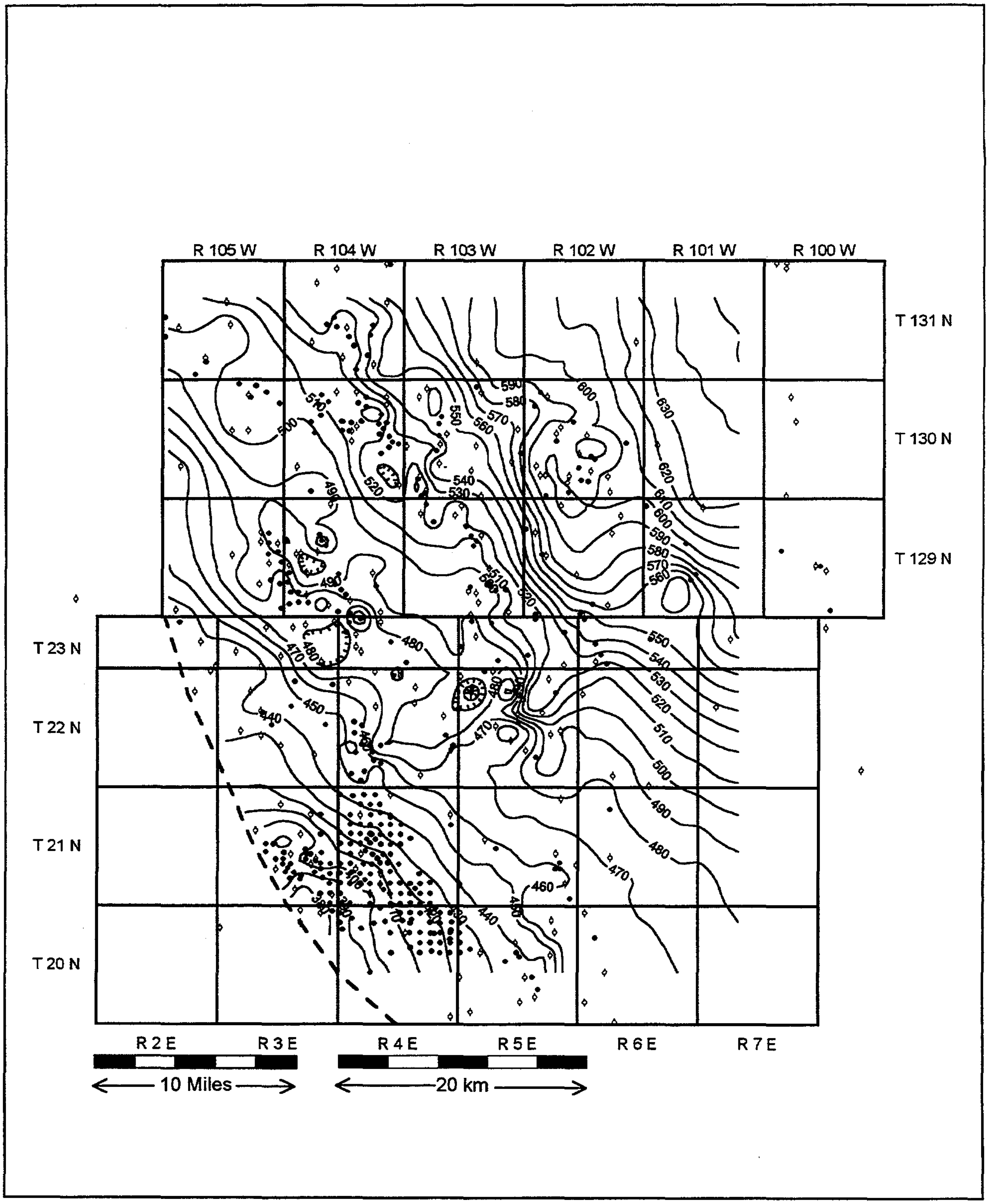


Figure 14: Map of Interlake to Red River isopach. Contour interval is 10 ft.

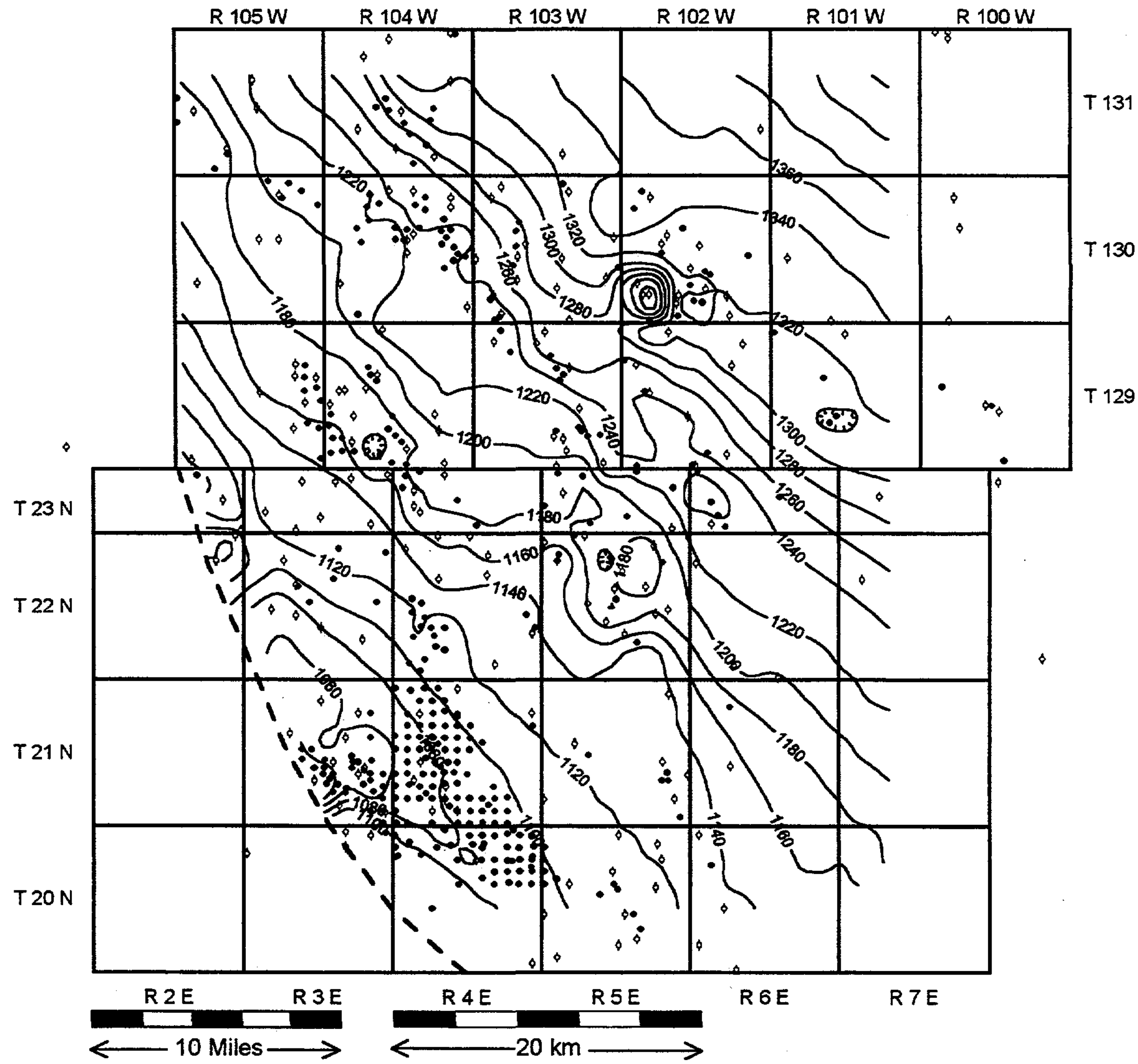


Figure 15: Map of Mission Canyon to Interlake isopach. Contour interval is 20 ft.

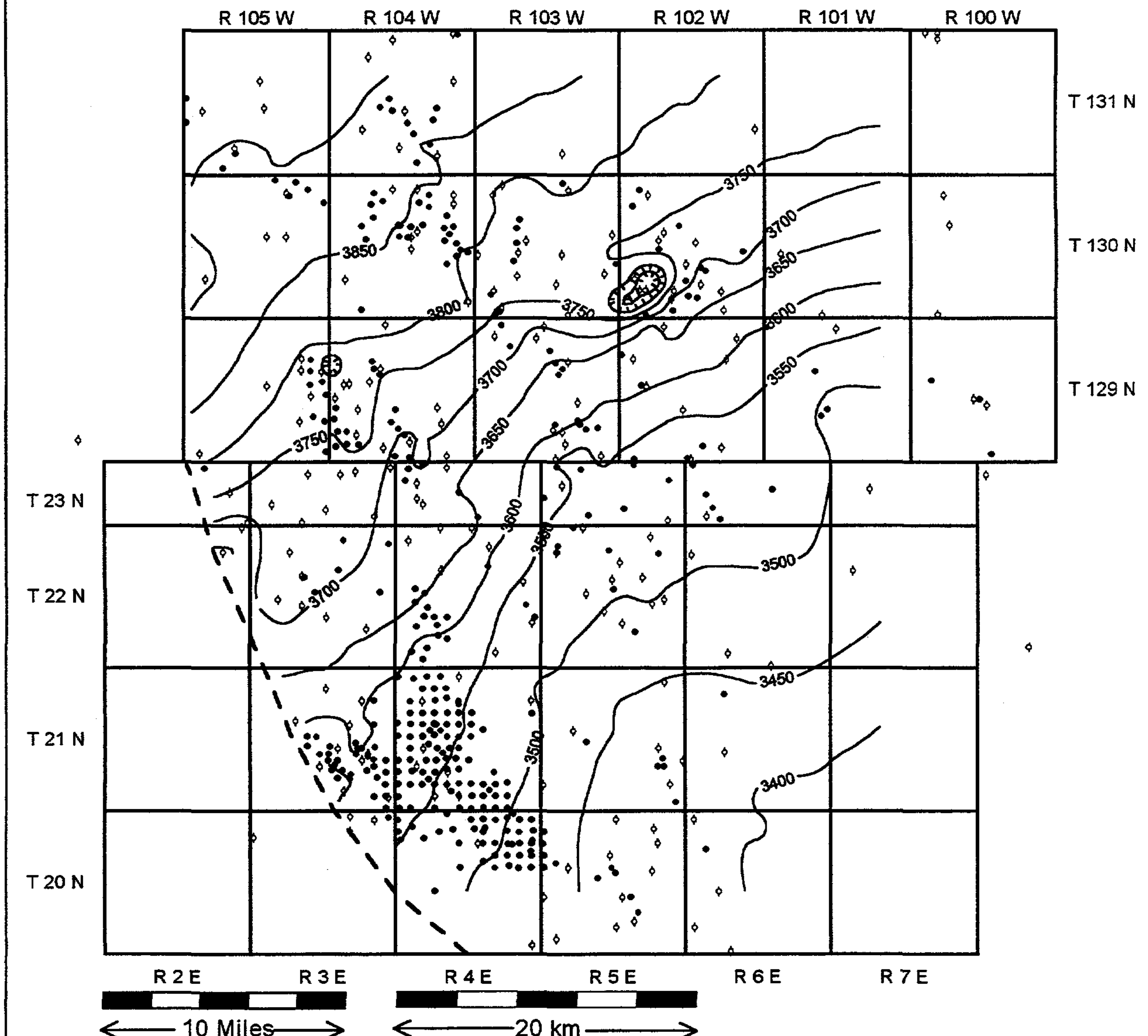
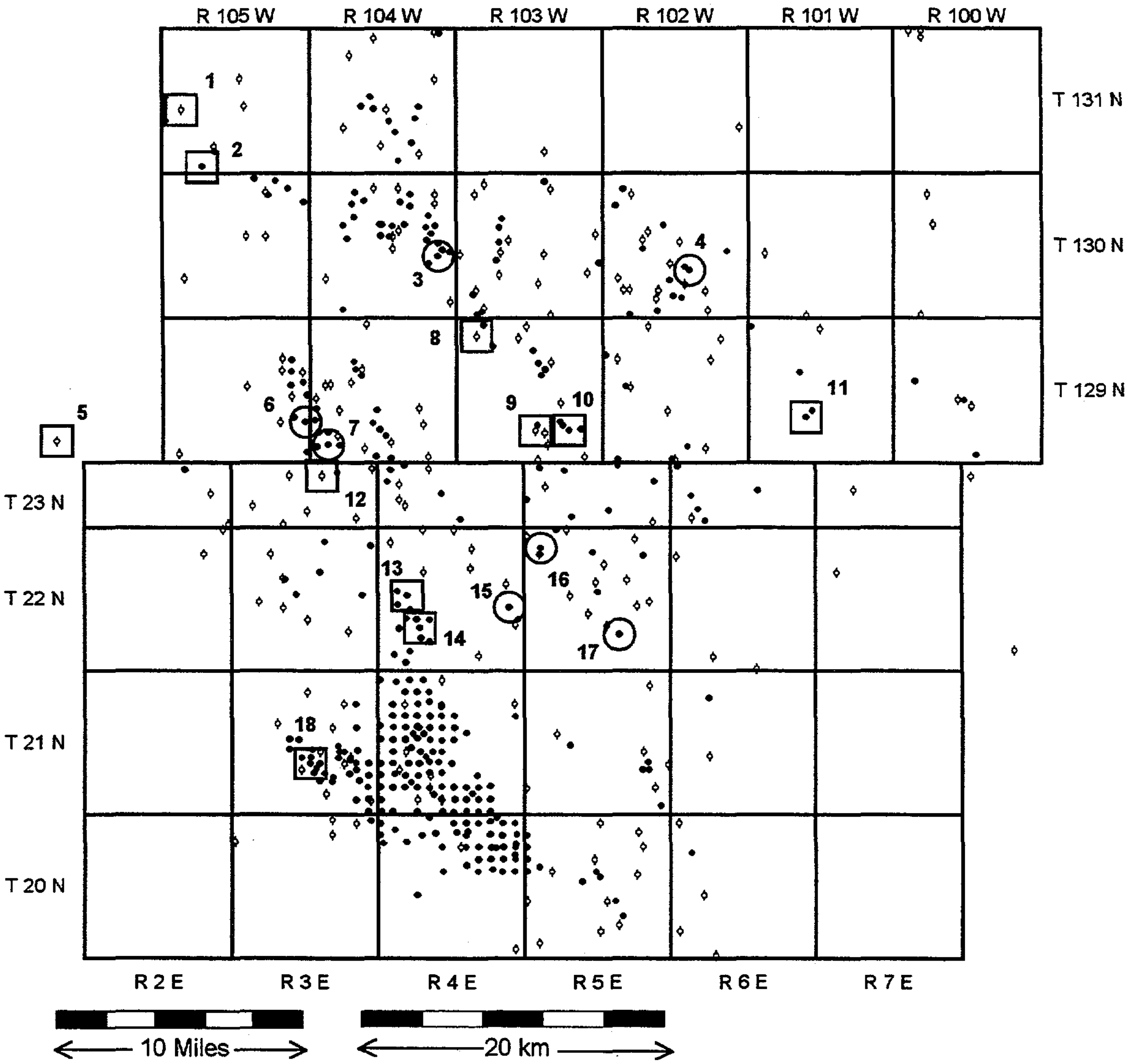
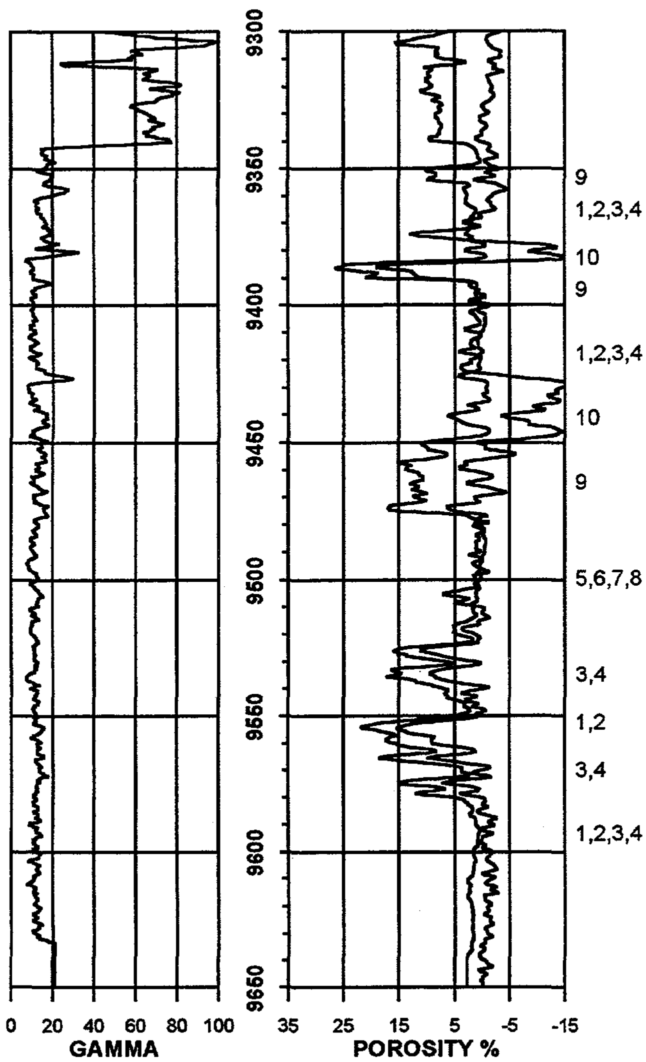


Figure 16: Map of Greenhorn to Mission Canyon isopach. Contour interval is 50 ft.



1) 1-19 Larkin,	19, 131N, 105W	10) 33-26 Greni,	26, 129N, 103W
2) 33-32H Egeland,	32, 130N, 104W	11) 1-28 Jett,	28, 129N, 101W
3) 1-24 E. Fossum,	24, 130N, 104W	12) 15-22 Stearns,	22, 23N, 3E
4) B-27 Muslow-State,	27, 130N, 102W	13) M-17 Stearns,	17, 22N, 4E
5) 31-23 Lowe,	23, 129N, 106W	14) B-29 Sohio-State	29, 22N, 4E
6) 1-25 Alexander,	25, 129N, 105W	15) 22-24 Travers	24, 22N, 4E
7) 2-31 Hilton,	31, 129N, 104W	16) 1-6 Travers	6, 22N, 5E
8) 1-6 Schaaf,	6, 129N, 103W	17) 42-27 Federal	27, 22N, 5E
9) 13-27 Hughes,	27, 129N, 103W	18) 13-22 Clarkson	22, 21N, 3E

Figure 17: Map of Red River study area with location of cores used for petrographical and petrophysical study. Squares identify porosity-permeability data only. Circles identify visual petrographical evaluations.



Facies 1. Black, shaley limestone. The texture is mudstone with skeletal grains of crinoids, brachiopods and cleoclpsamorpha. There is no visual porosity. Depositional environment is deep, open-shelf associated with flooding surface.

Facies 2.Dark gray limestone. The texture is mudstone, wackestone and packstone with skeletal grains of crinoids, brachiopods, corals and mollusks. There is no visual porosity. Depositional environment is open-marine with normal salinity.

Facies 3. Dark gray limestone. The texture is packstone, grainstone and framestone with skeletal grains of crinoids, brachiopods, corals, mollusks and stromatoporoids. There is no visual porosity. Depositional environment is patch reef or skeletal buildup on open-marine shelf.

Facies 4. Brown dolomite and limestone. The texture is mudstone and wackestone with skeletal grains of crinoids and brachiopods. Visual porosity is poor to good. Depositional environment is Thalassinoides burrowed open-shelf with increased salinity or low oxygen levels.

Facies 5. Brown dolomite and limestone. The texture is mudstone and wackestone with skeletal grains of crinoids and brachiopods. Visual porosity is poor to good. Depositional environment is Planolites burrowed open-shelf with increased salinity or low oxygen levels.

Facies 6. Gray limestone. The texture is packstone and grainstone with skeletal grains of crinoids, brachiopods, corals and mollusks. There is no visual porosity. Depositional environment is open-marine.

Facies 7. Gray to brown limestone. The texture is mudstone and wackestone with skeletal grains of mollusks and bryozoans. There is no visual porosity. Depositional environment is restricted-shelf with minor shoaling.

Facies 8. Gray limestone. The texture is wackestone and packstone with skeletal grains of crinoids, brachiopods, bryozoans and corals. There is no visual porosity. Depositional environment is open to slightly restricted-shelf.

Facies 9. Gray to brown dolomite and limestone. The texture is mudstone with peloidal grains of ostracods. Visual porosity is good. Depositional environment is highly restricted subtidal, intertidal and salina.

Facies 10. Gray anhydrite with no fossil grains. Depositional environment is salina with areas of extensive restriction and evaporation.

Figure 18: Stratal Occurrence of Red River facies with electrical log. Facies correlated to B-27 Muslow-State well from Cold Turkey Creek Field, Bowman County, ND.

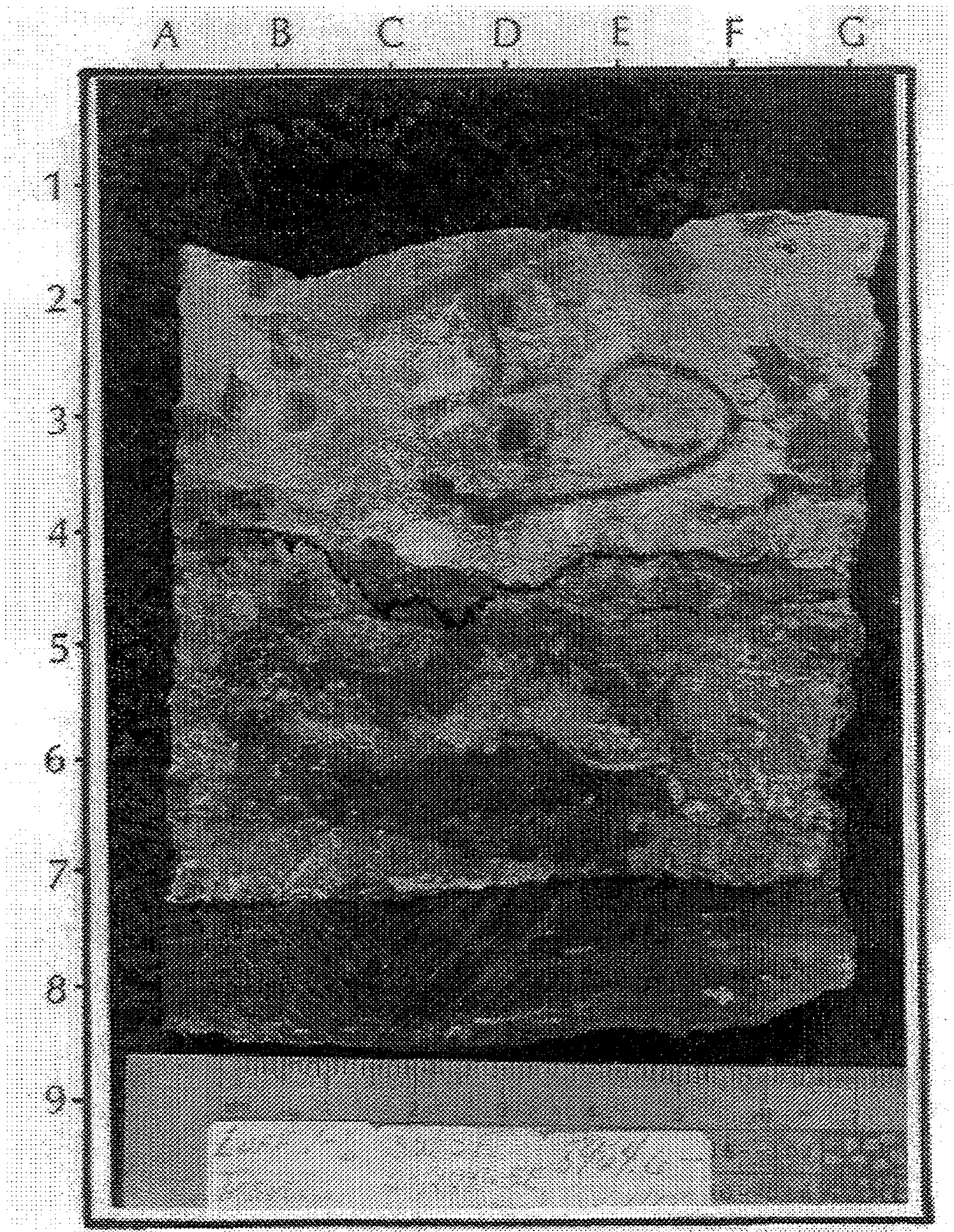


Figure 19: Core photo of Red River facies no. 1. Shaley beds at the base of this sample are typical kerogenite beds in the Red River D porosity interval. The overlying, skeletal lime wackestone bed is Facies 2. Luff No. 1-6 Travers, 8964.6 ft.

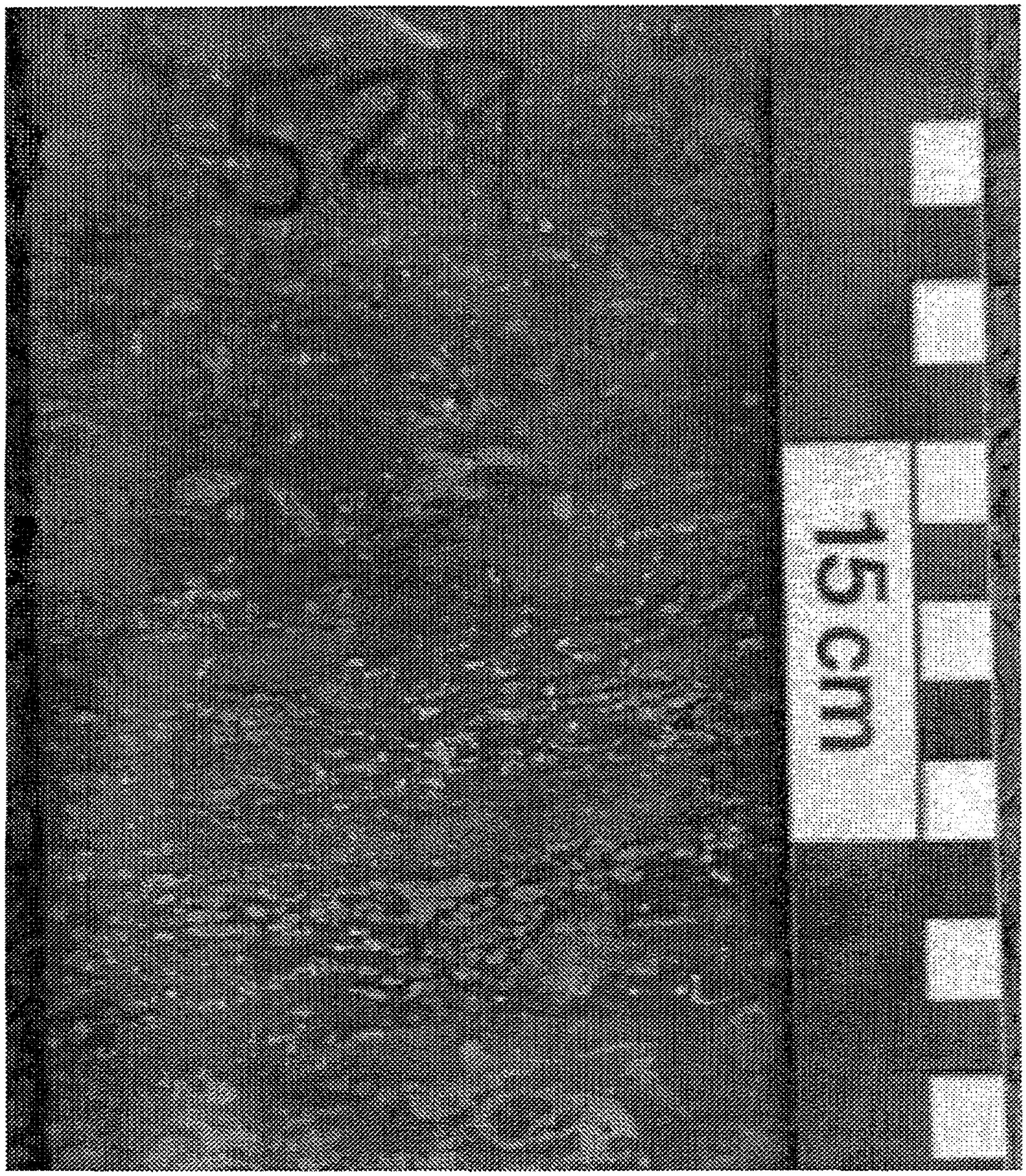


Figure 20: Core photo of Red River facies no. 2. A skeletal lime wackestone bed with white crinoid fragments is common in Red River D porosity intervals. These beds were deposited in open marine environments. Luff No. B-27 State Muslow, 9529 ft.

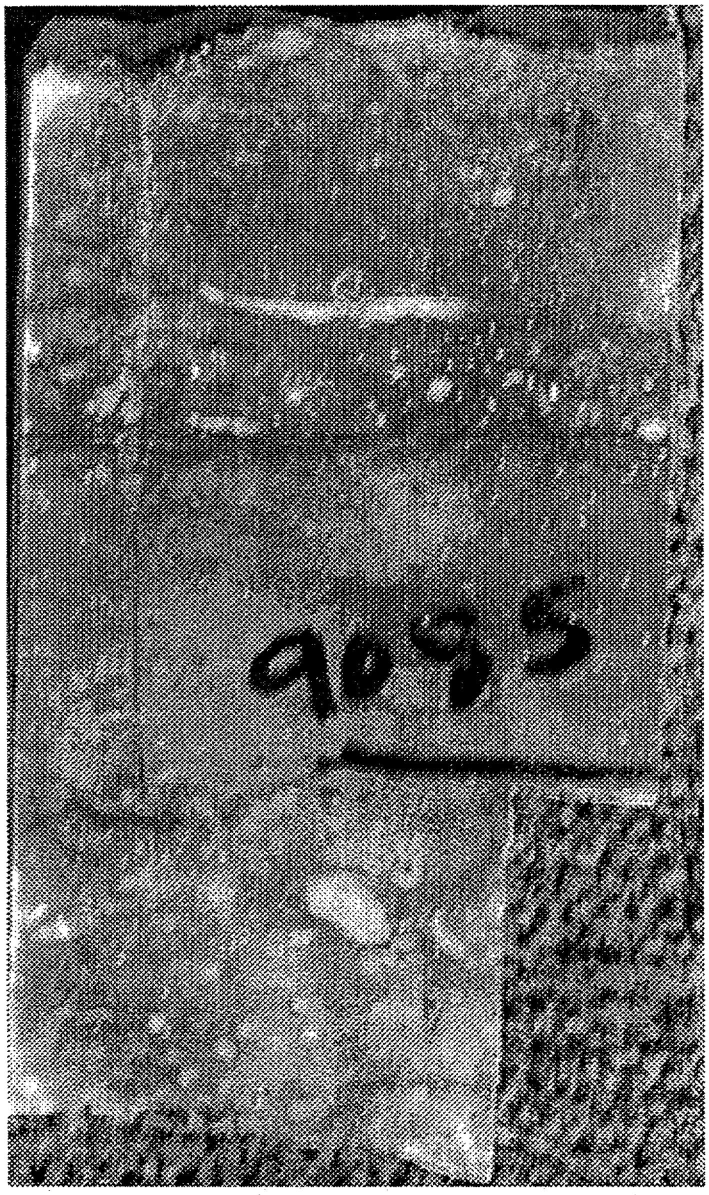


Figure 21: Core photo of Red River facies no. 3. Skeletal packstone beds associated with storm deposition are present in the Red River D interval. Total No. 1-25 Alexander, 9085ft.

Figure 22: Core photo of Red River facies no. 4. Burrow structures in this dolomite resemble Thalassinoides burrows, common along slightly restricted shelf environments. Luff No. B-27 State Muslow, 9517 ft.

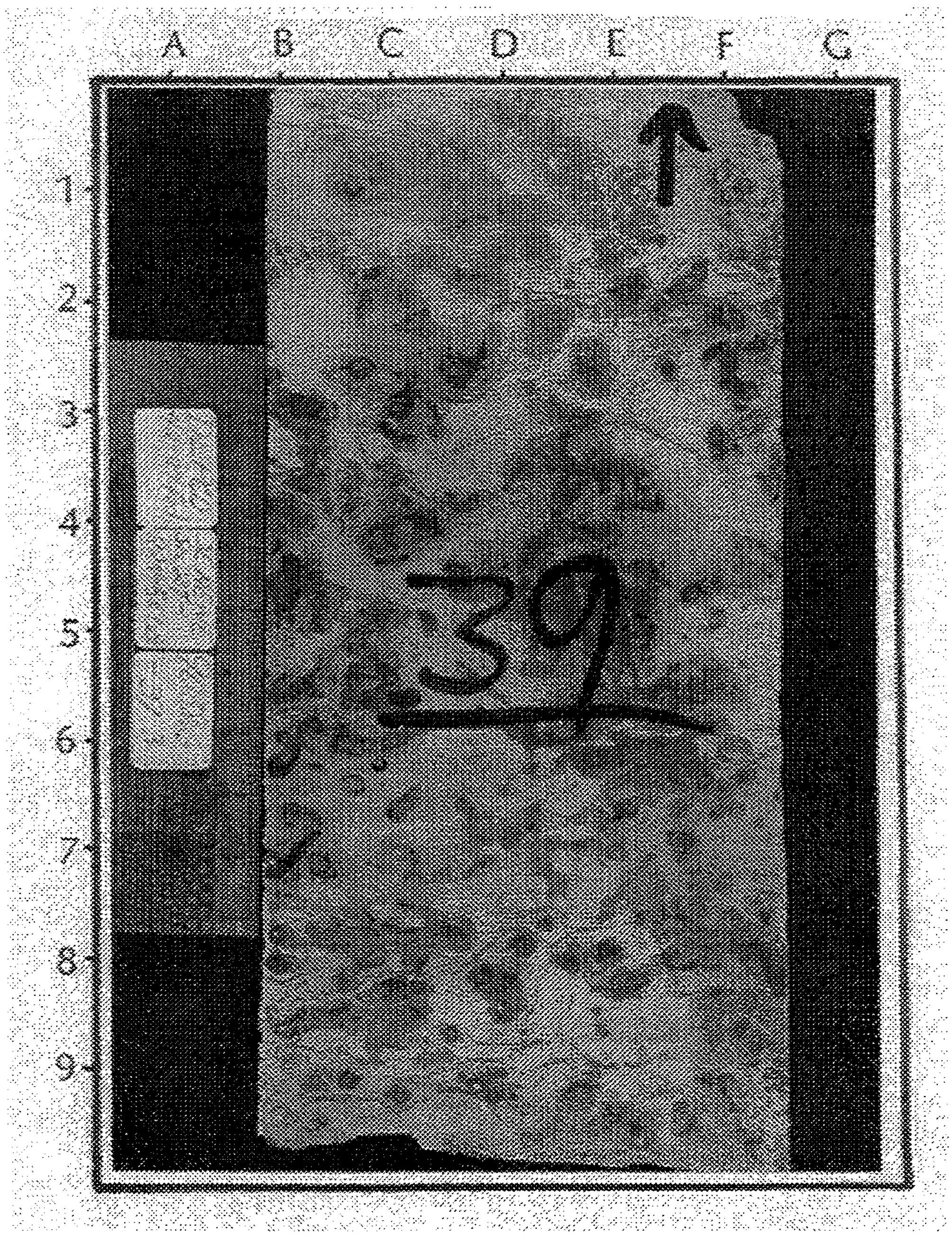


Figure 23: Core photo of Red River facies no. 5. Small circular and subhorizontal burrows are Planolites structures which are common in Red River D sediments. Depco No. 42-27 Federal, 9039 ft.

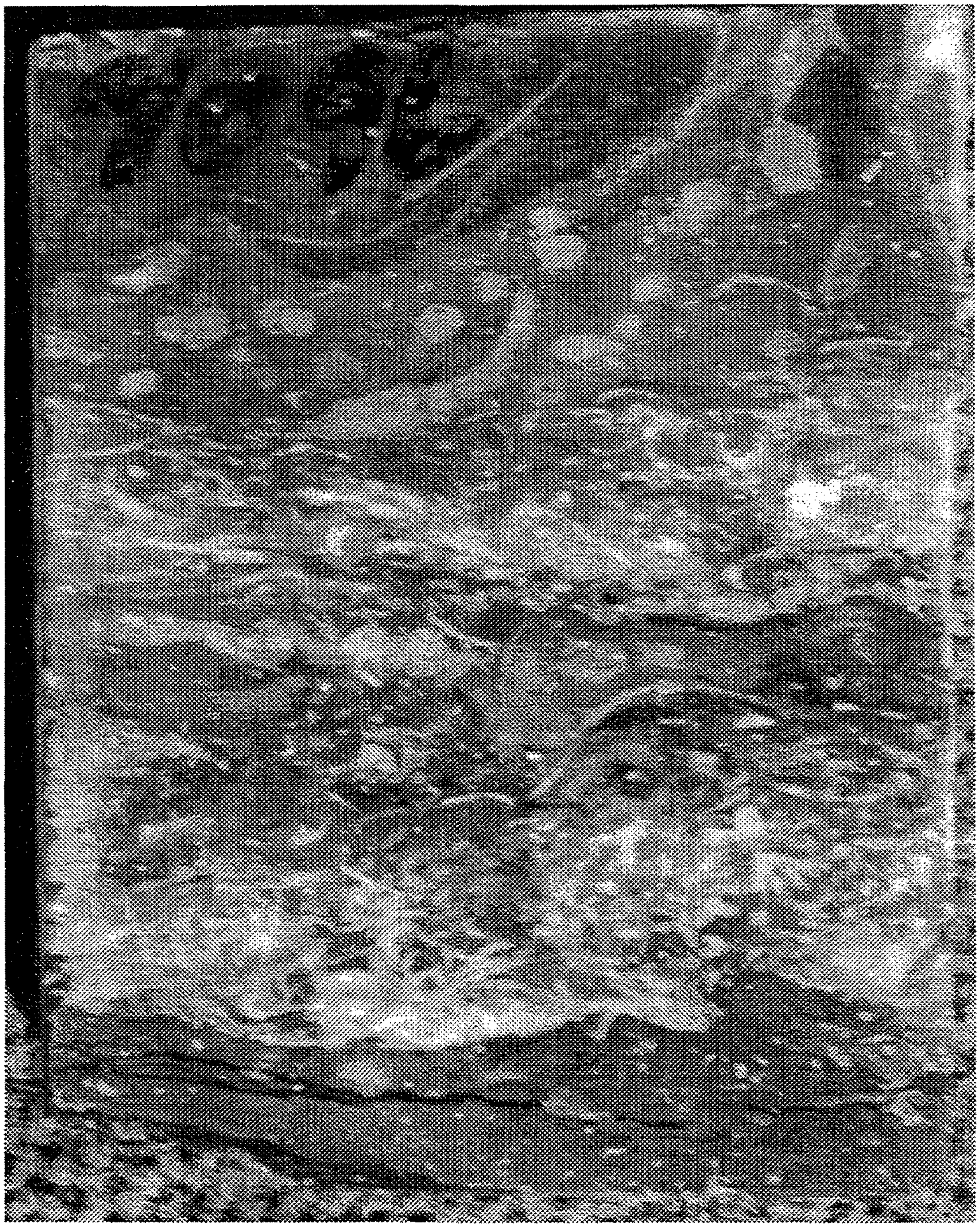


Figure 24: Core photo of Red River facies no. 6. Skeletal packstones and grainstones are common near the top of the D porosity interval and are associated with shallow shelf environments. Total No. 1-25 Alexander, 9096 ft.

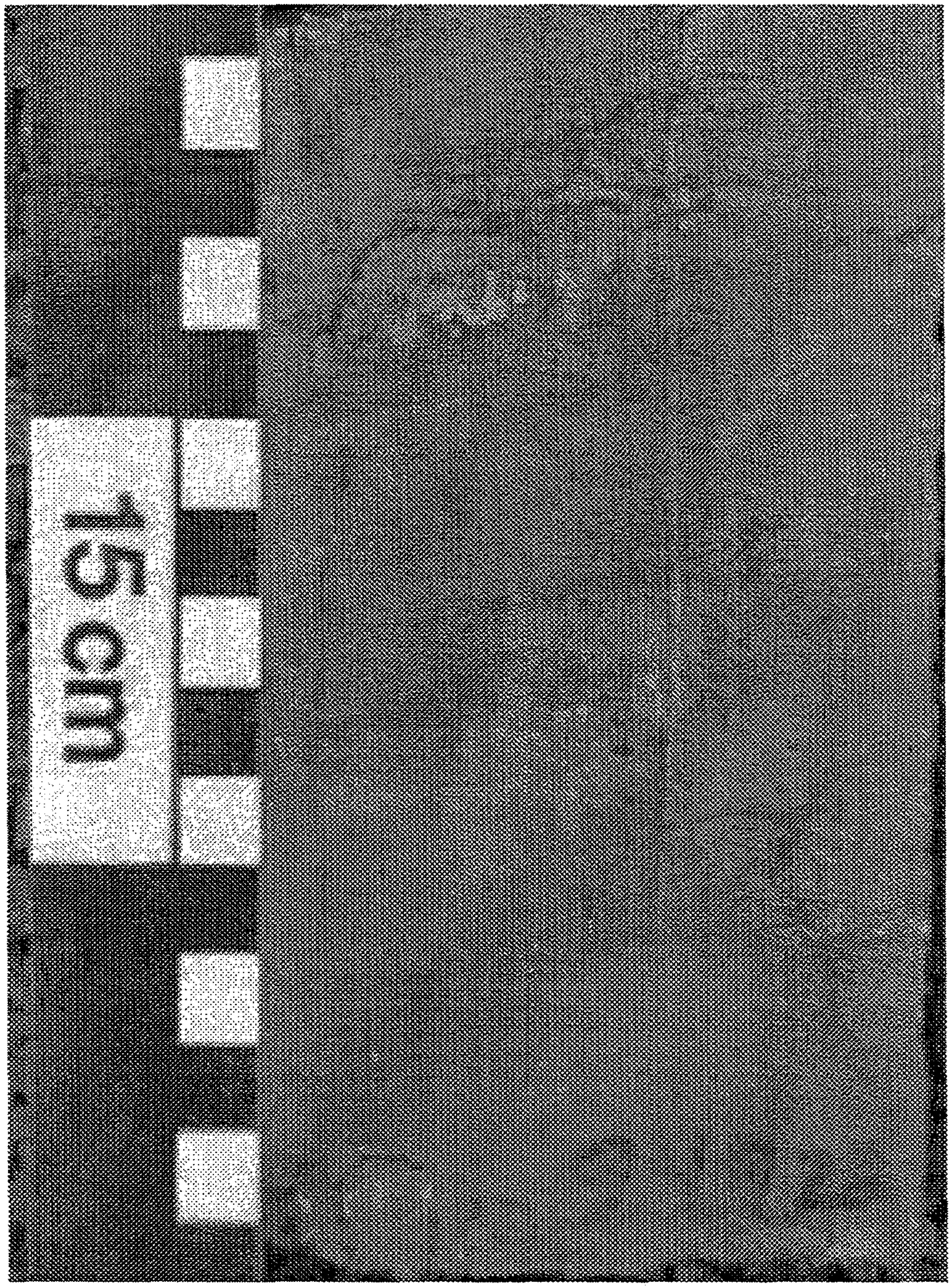


Figure 25: Core photo of Red River facies no. 7. Massive appearing, skeletal lime mudstones and wackestones are part of slightly restricted shallow shelf environments in the lower part of the Red River C interval. Note the stylolite that transects the upper portion of the core. Luff No. B-27 State Muslow, 9492 ft.

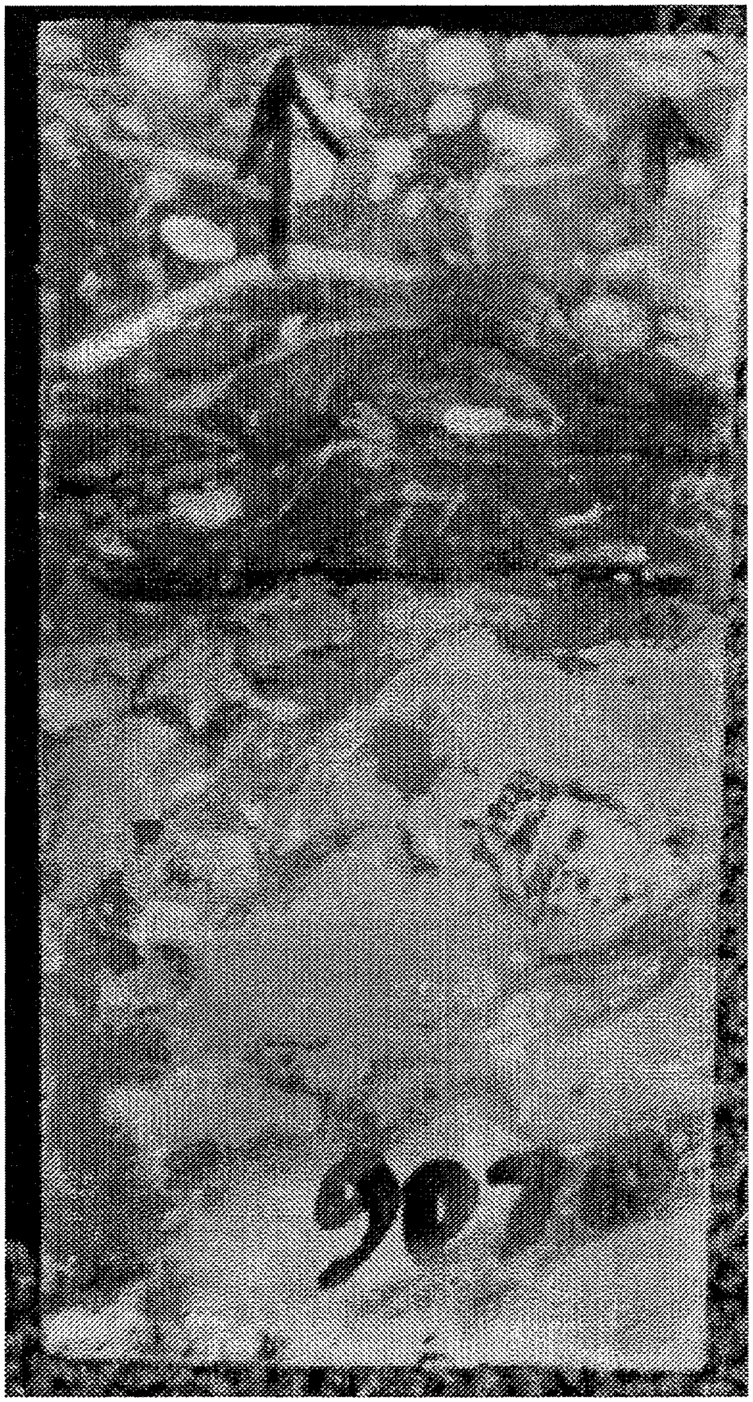


Figure 26: Core photo of Red River facies no. 8. Open marine skeletal fragments are common near the base of the C porosity interval. These skeletal fragments were deposited in patch reef or bank environments. Total No. 1-25 Alexander, 9070 ft.

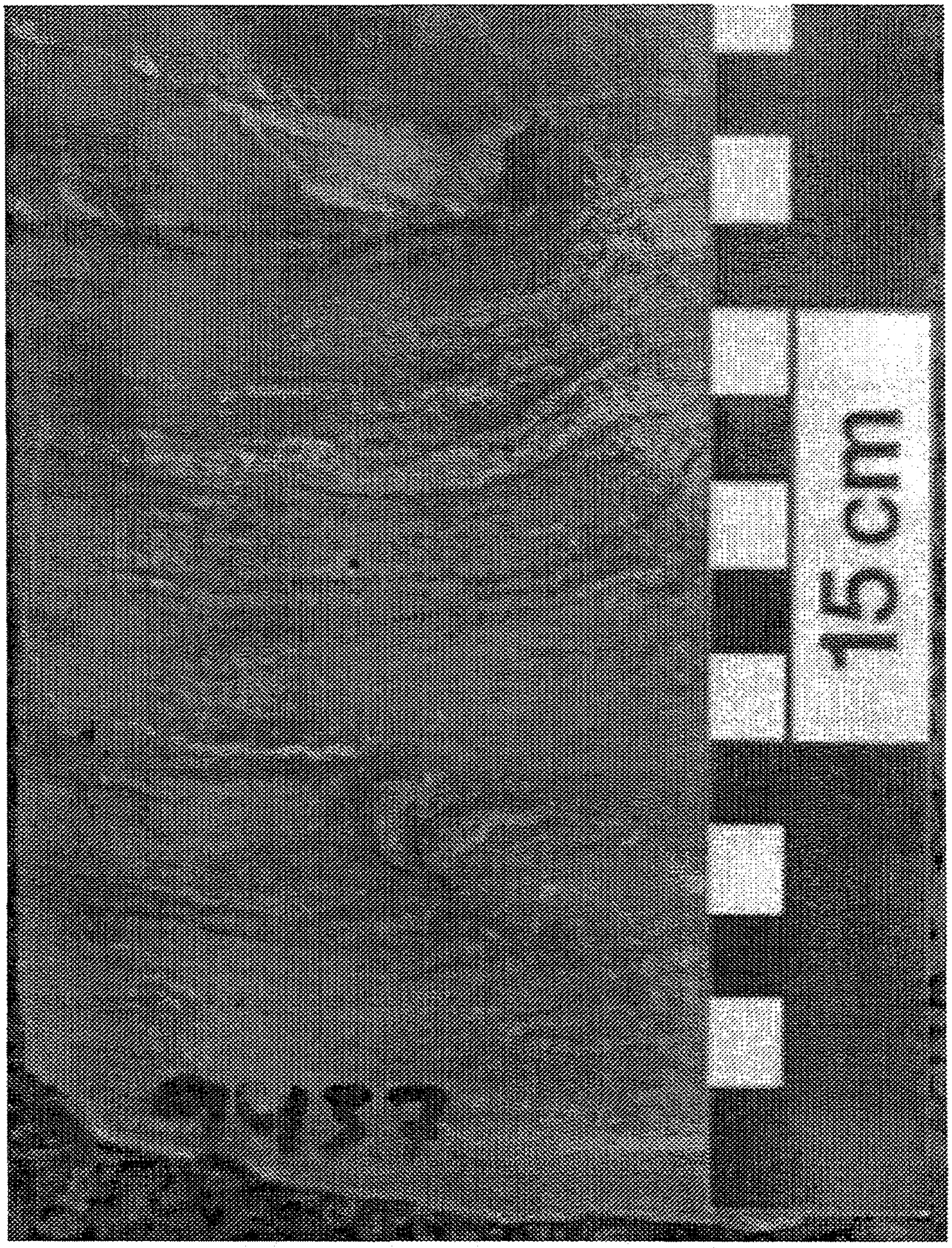


Figure 27: Core photo of Red River facies no. 9. Algal laminated beds, common in C laminated and B laminated intervals, contain fair to good porosity, but reduced permeability. This sample is capped by C anhydrite. Luff No. B-27 State Muslow, 9437 ft.

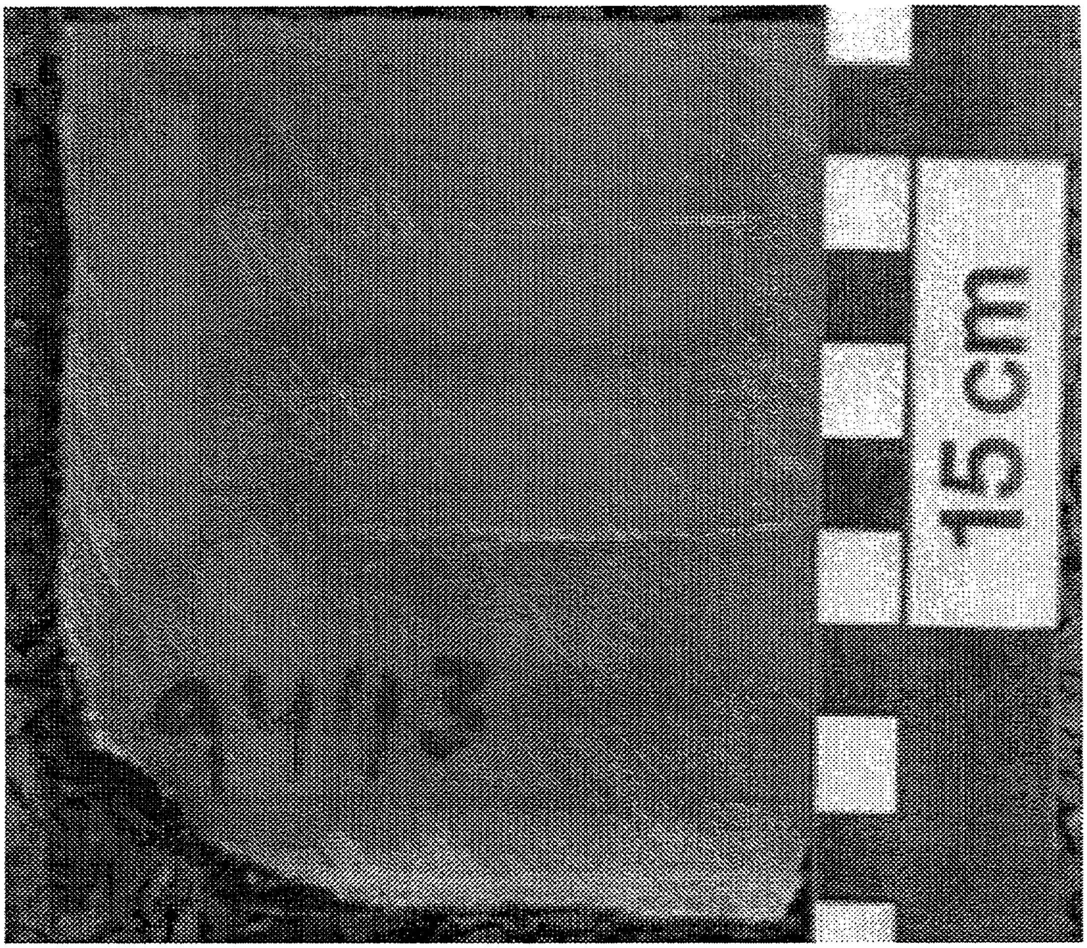


Figure 28: Core photo of Red River facies no. 10. Massive appearing bedded anhydrite common in both the C and B anhydrite beds was deposited in subaqueous and highly restricted environments. These beds were source for dolomitizing brines that produced initial porosity in the B, C, and D porosity intervals. Luff No. B-27 State Muslow, 9443 ft.

Figure 29: Core photo of D zone kerogenite beds and skeletal limestones. Shaley beds (Facies 1) are common in the Red River D porosity interval and are organic rich "kerogenites" (middle and base of sample). These sediments accumulated during sea level high stand or deepening events. Interbedded with these shales are skeletal lime mudstones and wackestone which were deposited in normal marine environments (Facies 2).

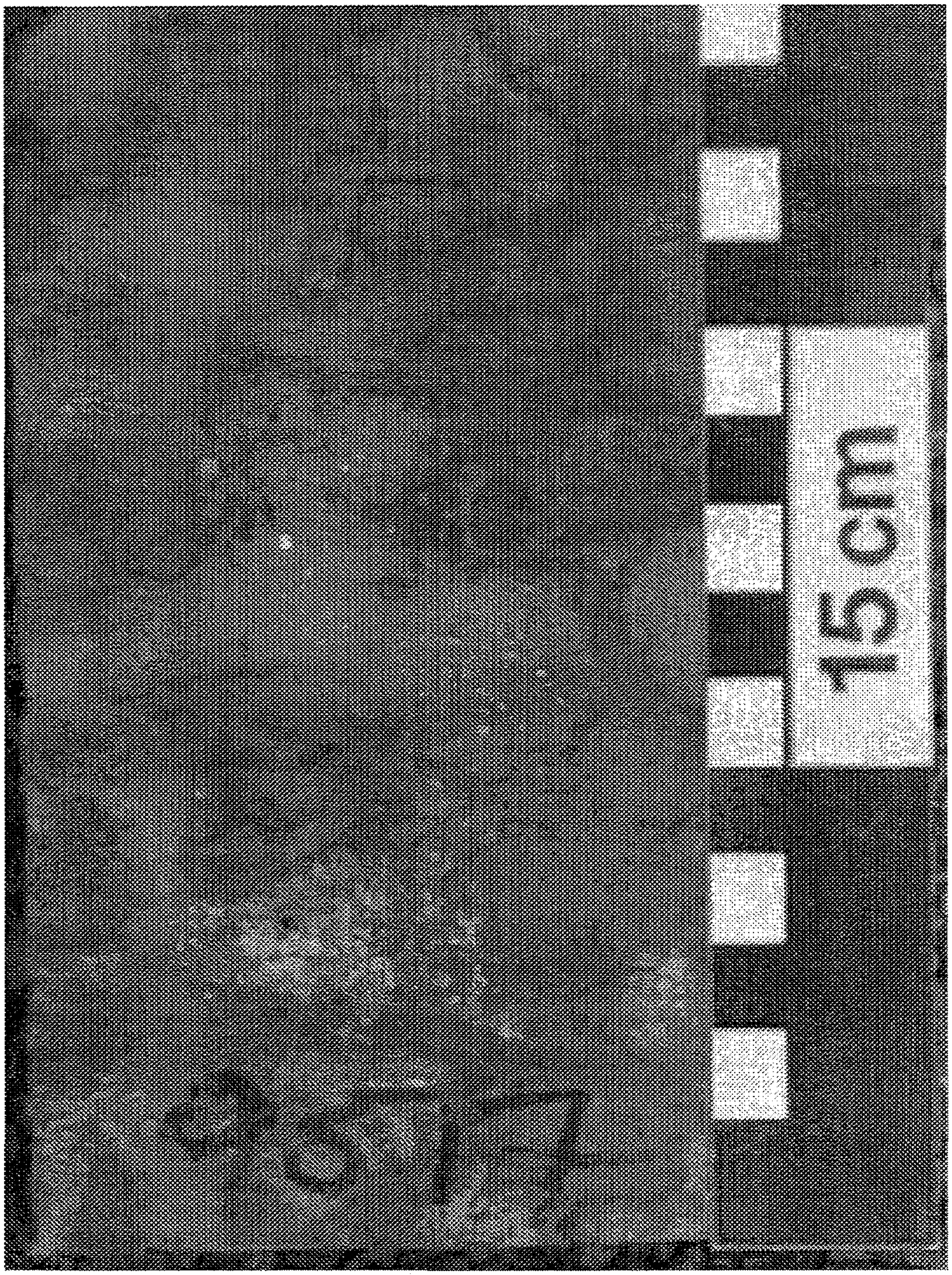


Figure 30: Core photo of D zone with Thalassinoides burrow structures. Burrowed dolomites are commonly reservoirs in the Red River D interval. These *Thalassinoides* burrow structures were conduits for early and late dolomitization.

Figure 31: Core photo of D zone with Thalassinoides and Planolites burrow structures. Burrowed dolomites are the principal reservoirs in the Red River D interval. This figure shows both large *Thalassinoides* structures and small circular *Planolites* structures.

Figure 32: Core photo of contact between the C dolomite and overlying C anhydrite. The algal laminated dolomite has fair to good porosity but poor permeability.

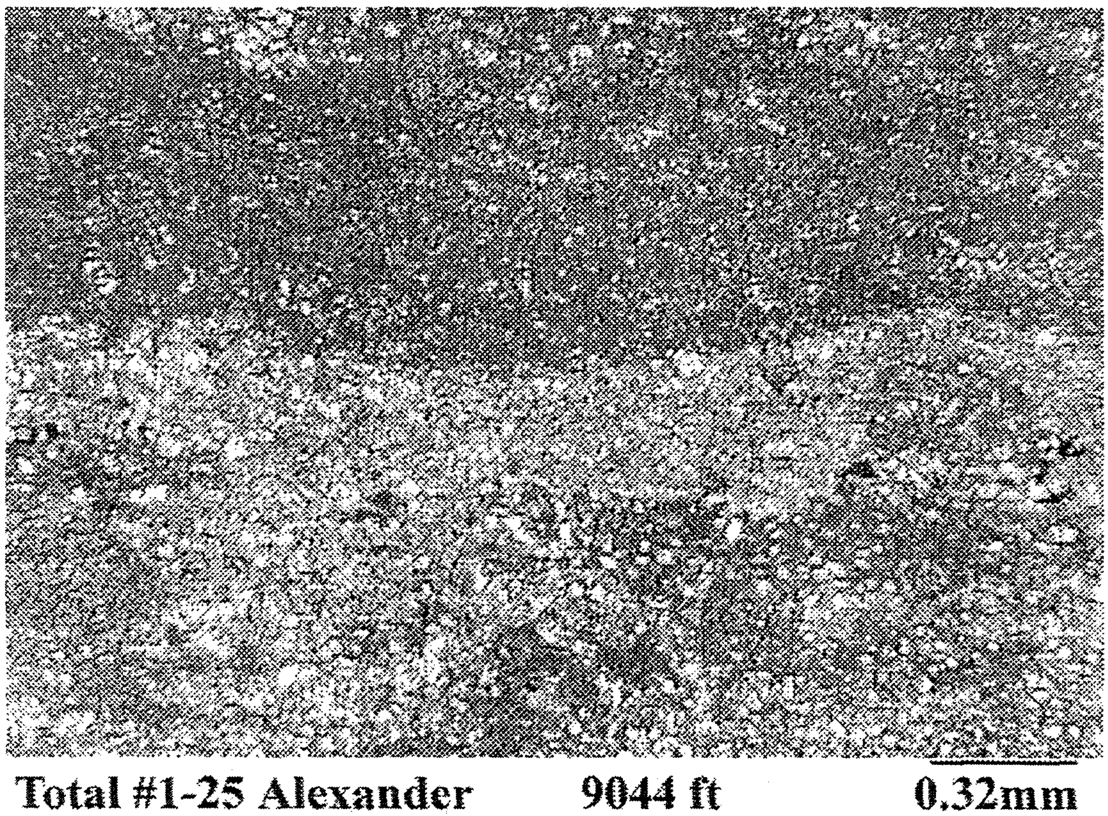


Figure 33: Photo micrograph of fine-crystalline dolomite. Microcrystalline dolomite surrounds a burrow structure with fine-crystalline dolomite. Overall porosity is fair to good, but permeability is poor.

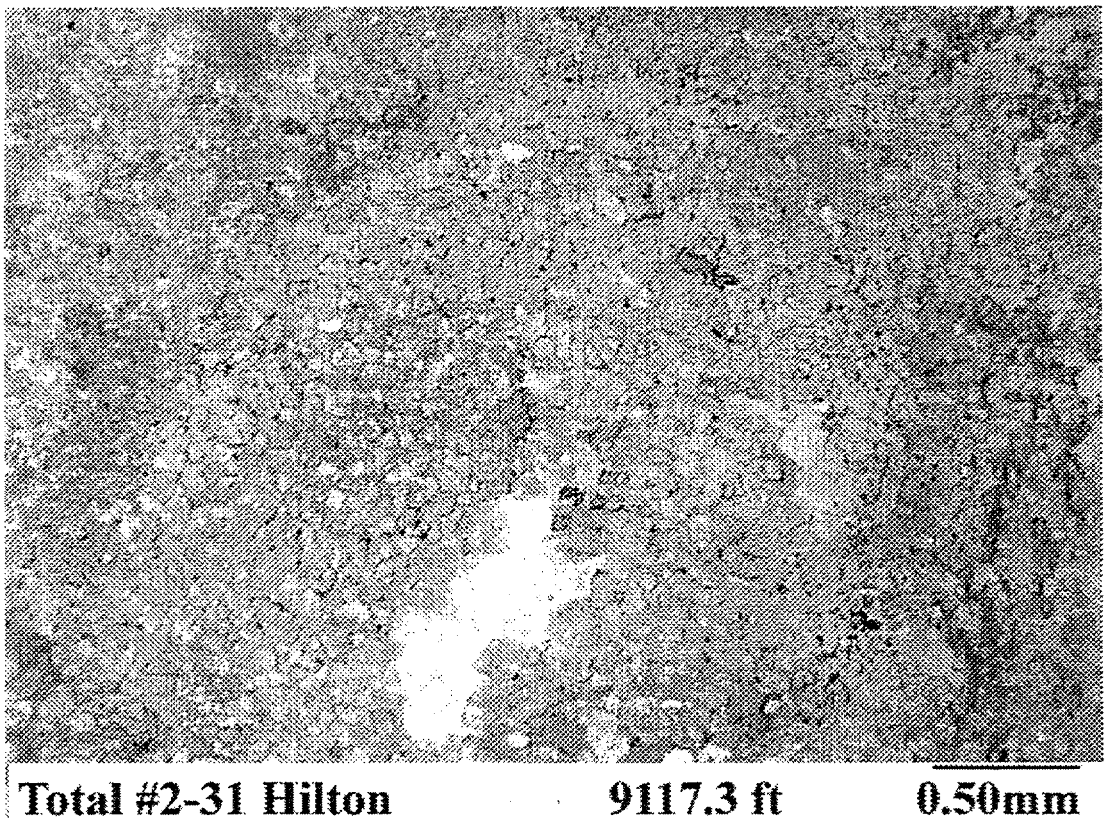


Figure 34: Photo micrograph of medium to coarse-crystalline dolomite. Medium to coarse-crystalline dolomite is common within D porosity intervals. The uniform size of dolomite rhombohedrons produced good porosity and permeability. Note the larger dolospar crystals partly occluding vuggy porosity.

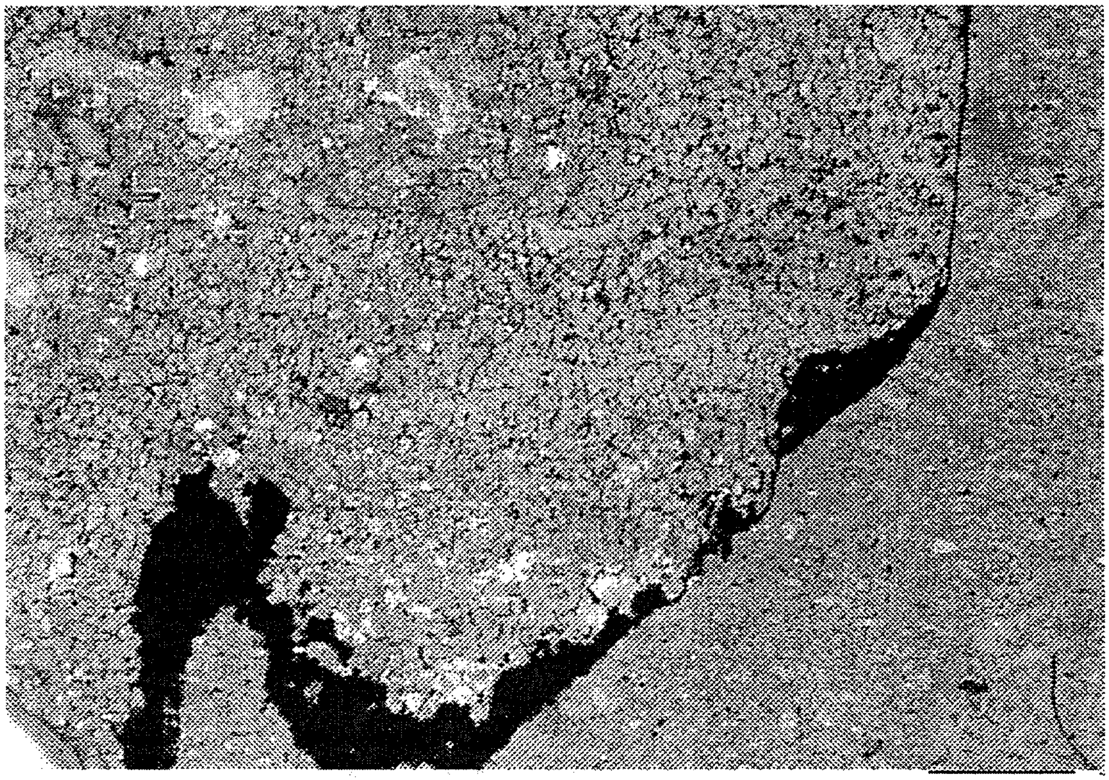
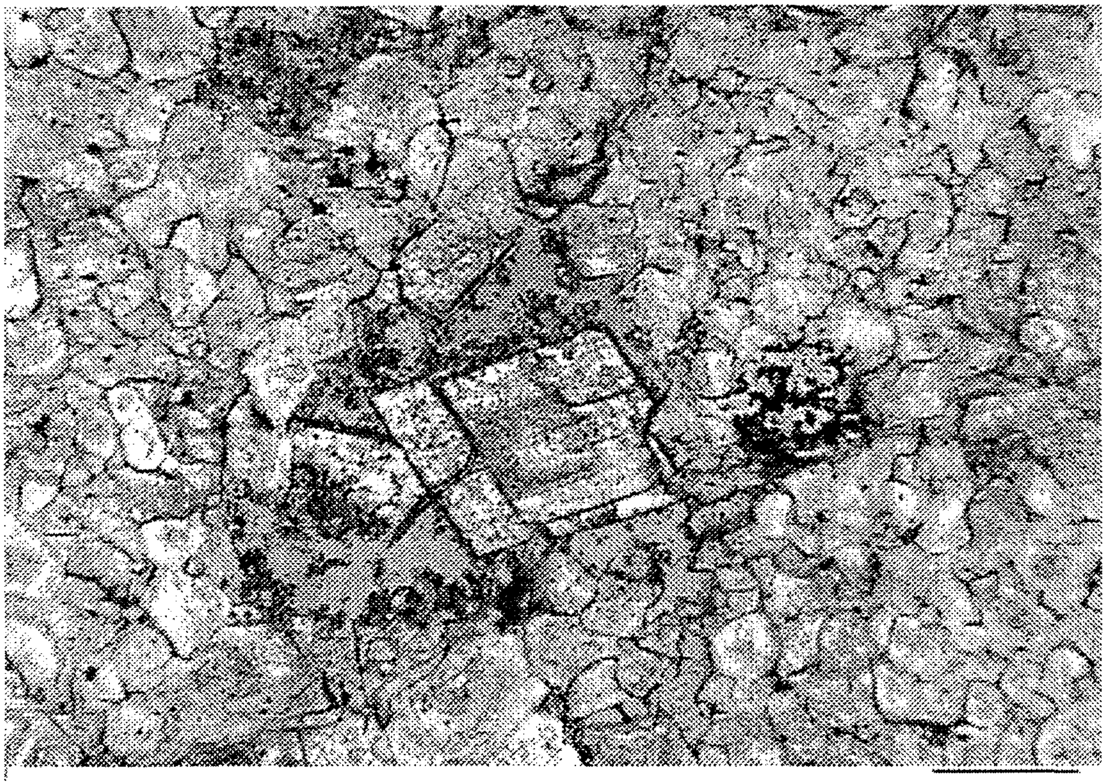


Figure 35: Photo micrograph of coarser-crystalline dolomite. Coarser-crystalline dolomite occurs along the trace of a stylolite in this Red River sample.



Total #1-25 Alexander 9129 ft 0.13mm

Figure 36: Photo micrograph of very coarse-crystalline dolomite. Very coarse-crystalline dolomite (dolospar) occluded the center of this vuggy pore. This dolomite, along with baroque dolomite, precipitated late in the paragenetic sequence.

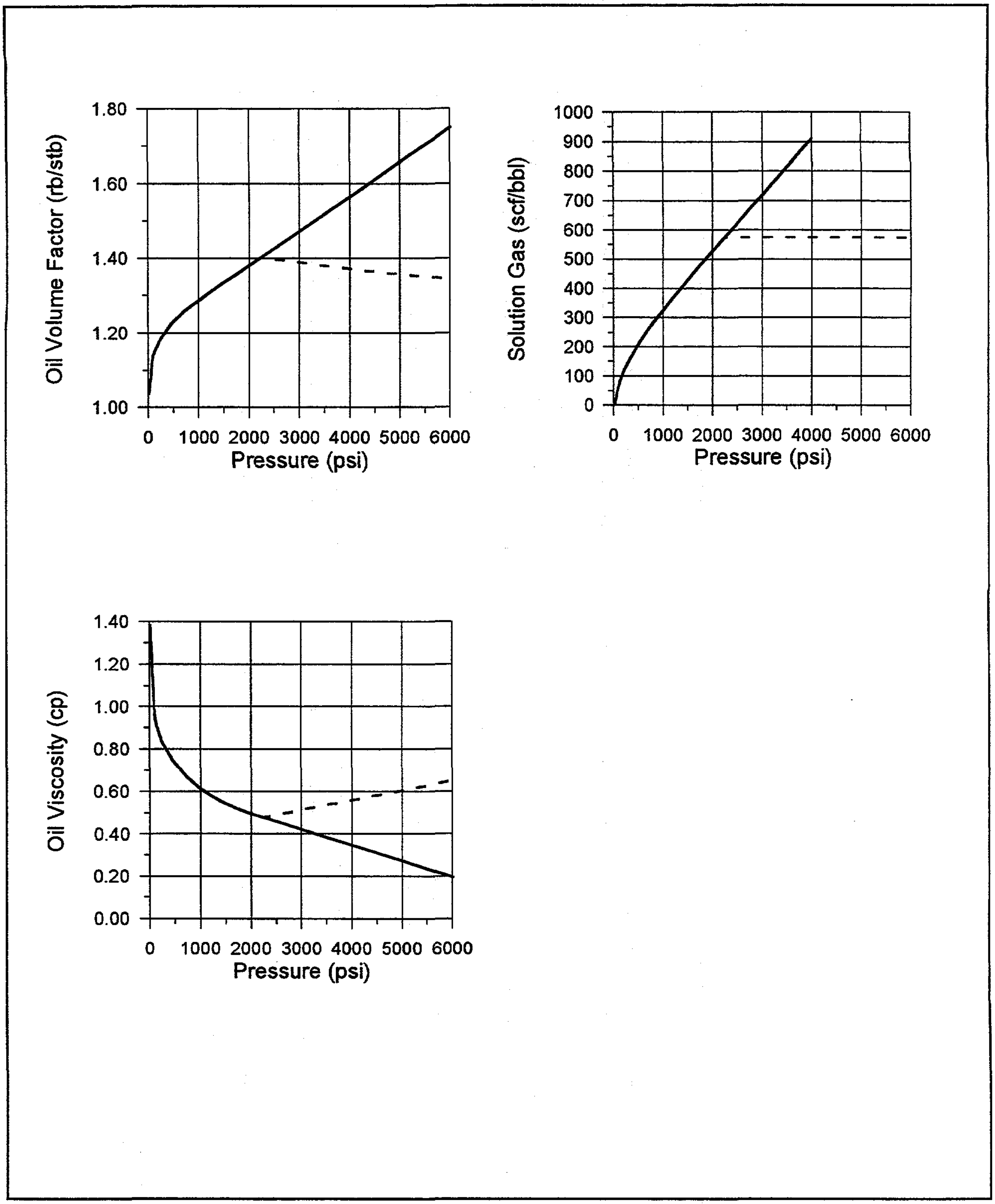


Figure 37: Properties of Red River oil. These PVT graphs are from oil of 39 deg API with solution gas of 575 scf/bbl at 220 deg F.

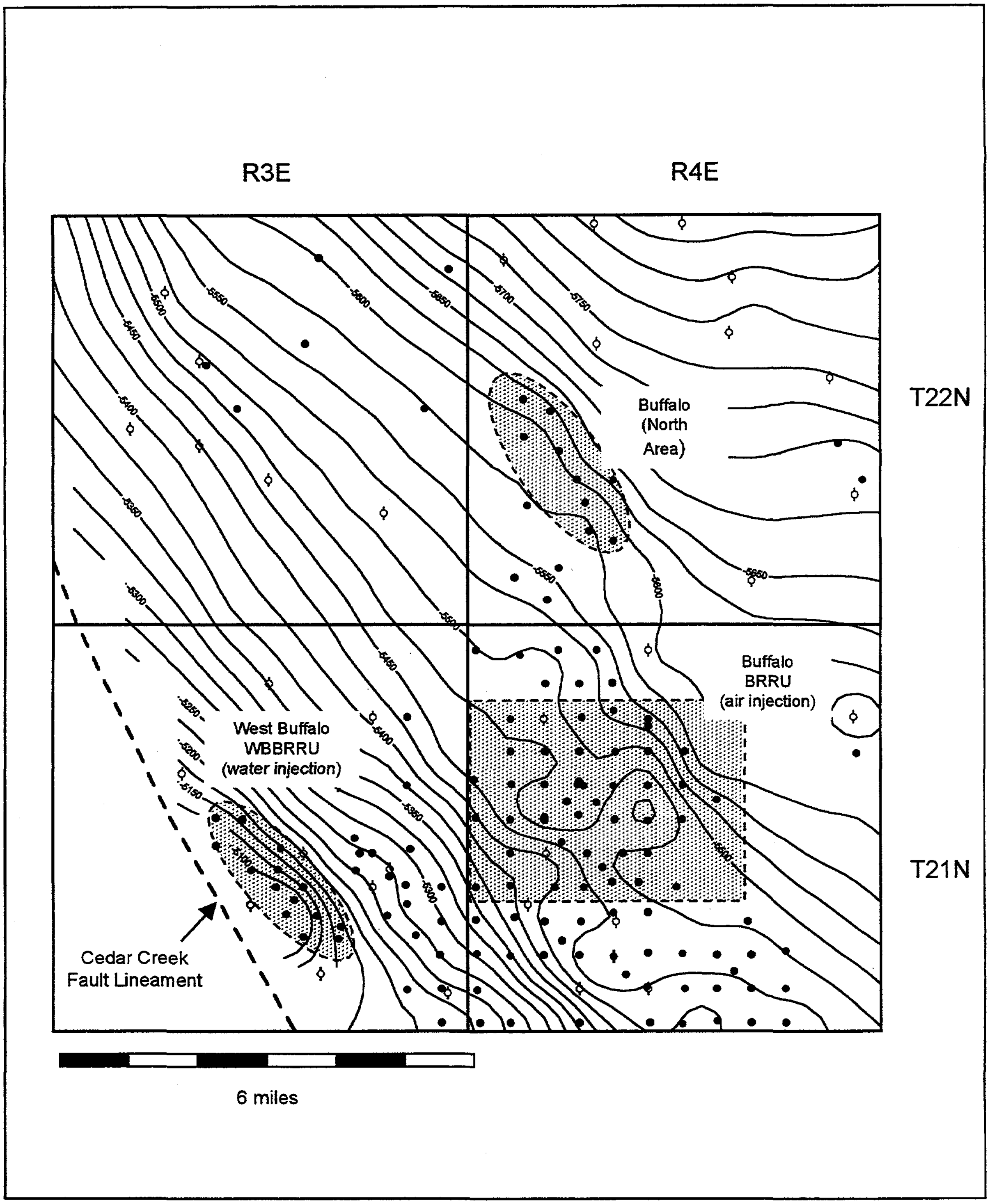


Figure 38: Index map of Red River fields in Harding Co., South Dakota.

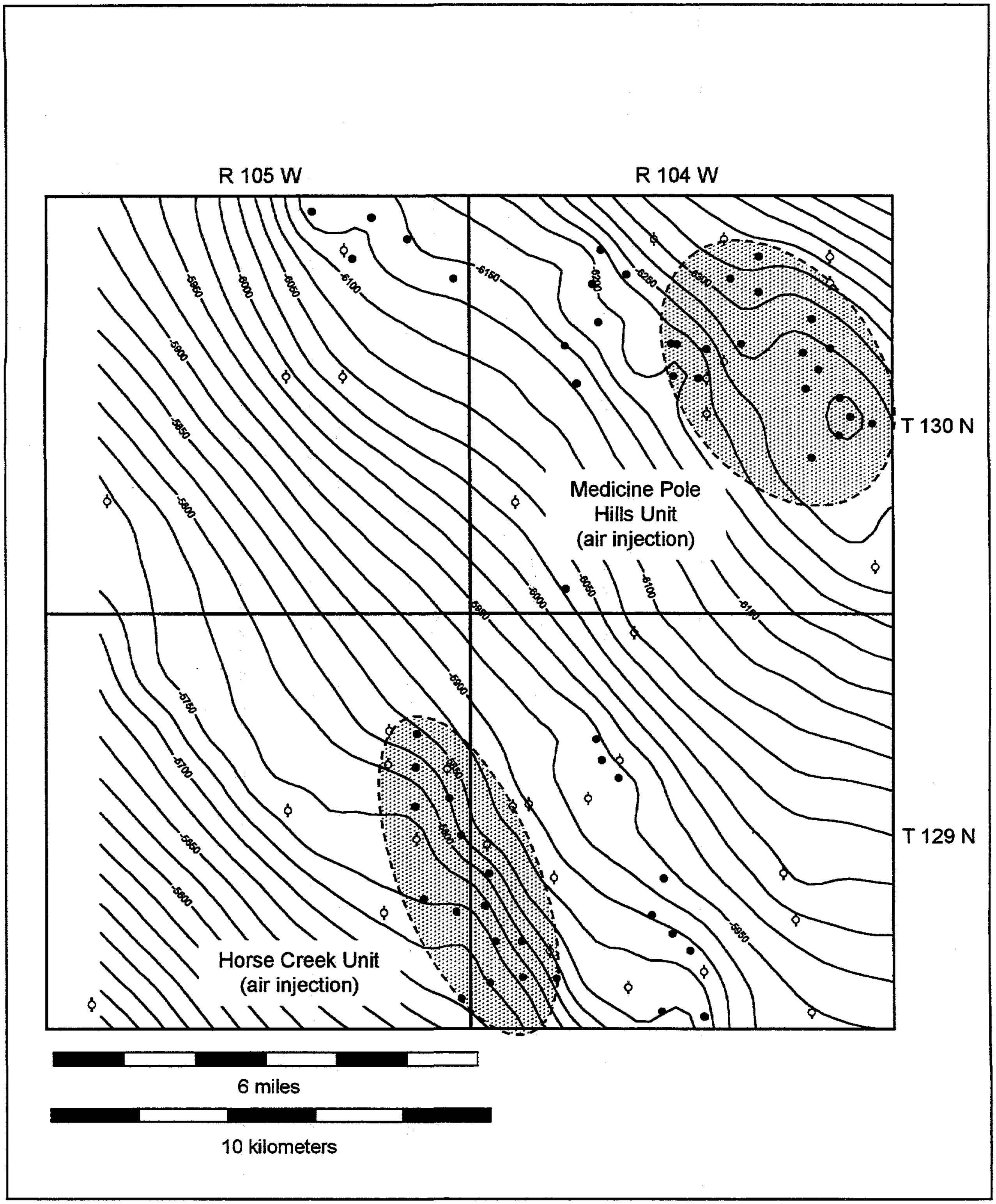


Figure 39: Index map of Red River fields in Bowman Co., North Dakota.

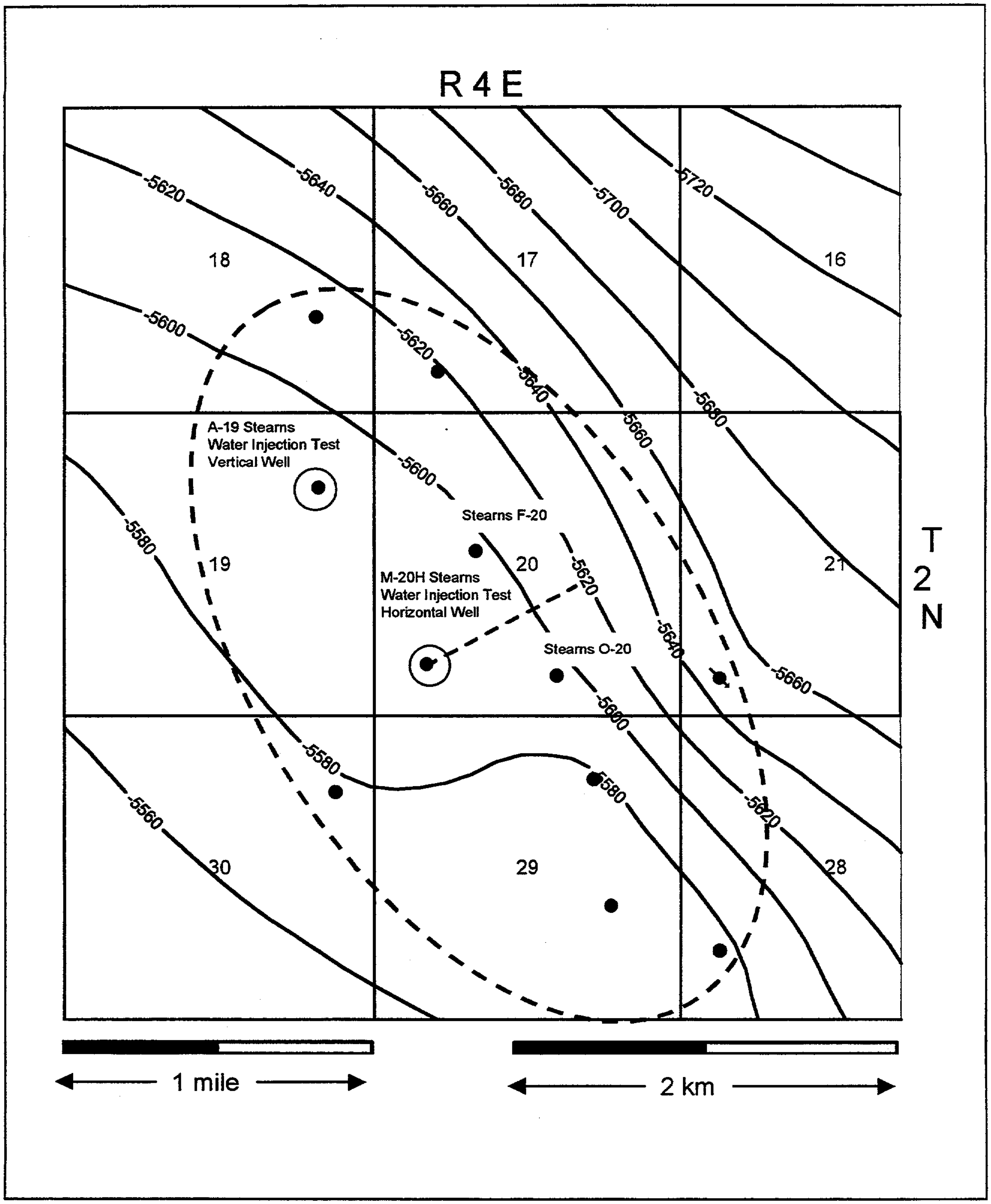


Figure 40: Map of Buffalo Field (north area), Harding Co., SD. Structure contours are on top of the Red River. CI = 20 ft.

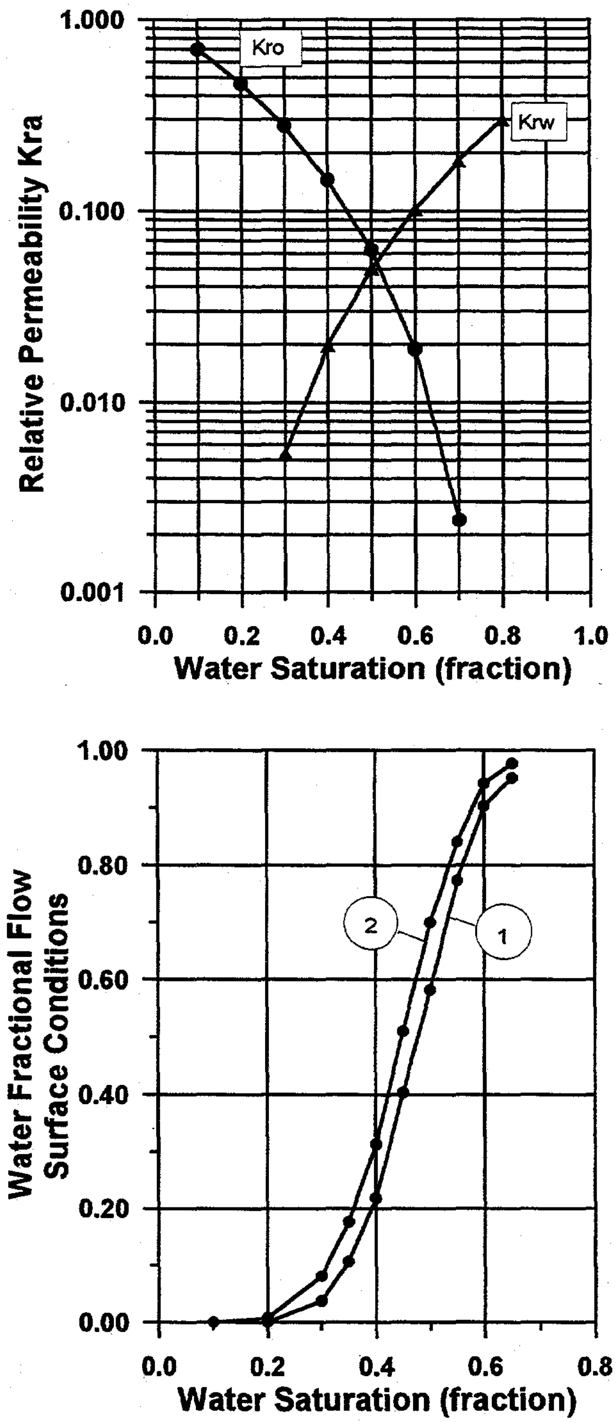


Figure 41: Oil-water relative permeability and fractional flow curves for typical Red River B zone rocks. Fractional flow curve 1 is for 39 deg API oil systems and curve 2 is for 32 deg API oil systems.

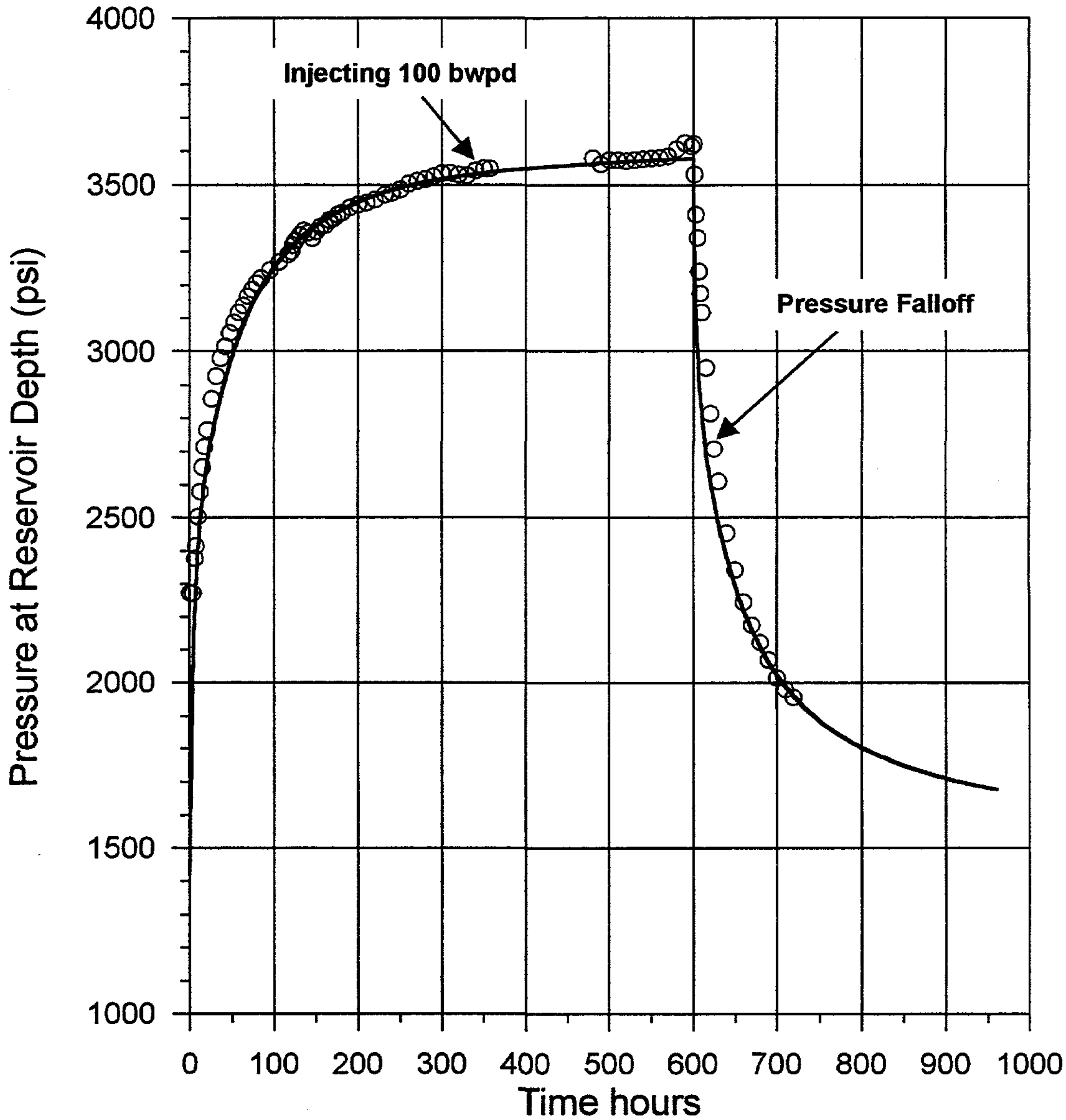


Figure 42: Water injection test into a vertical well at Buffalo Field (north area) with match by computer simulation. The solid line represents the simulation results. Circles are measured data.

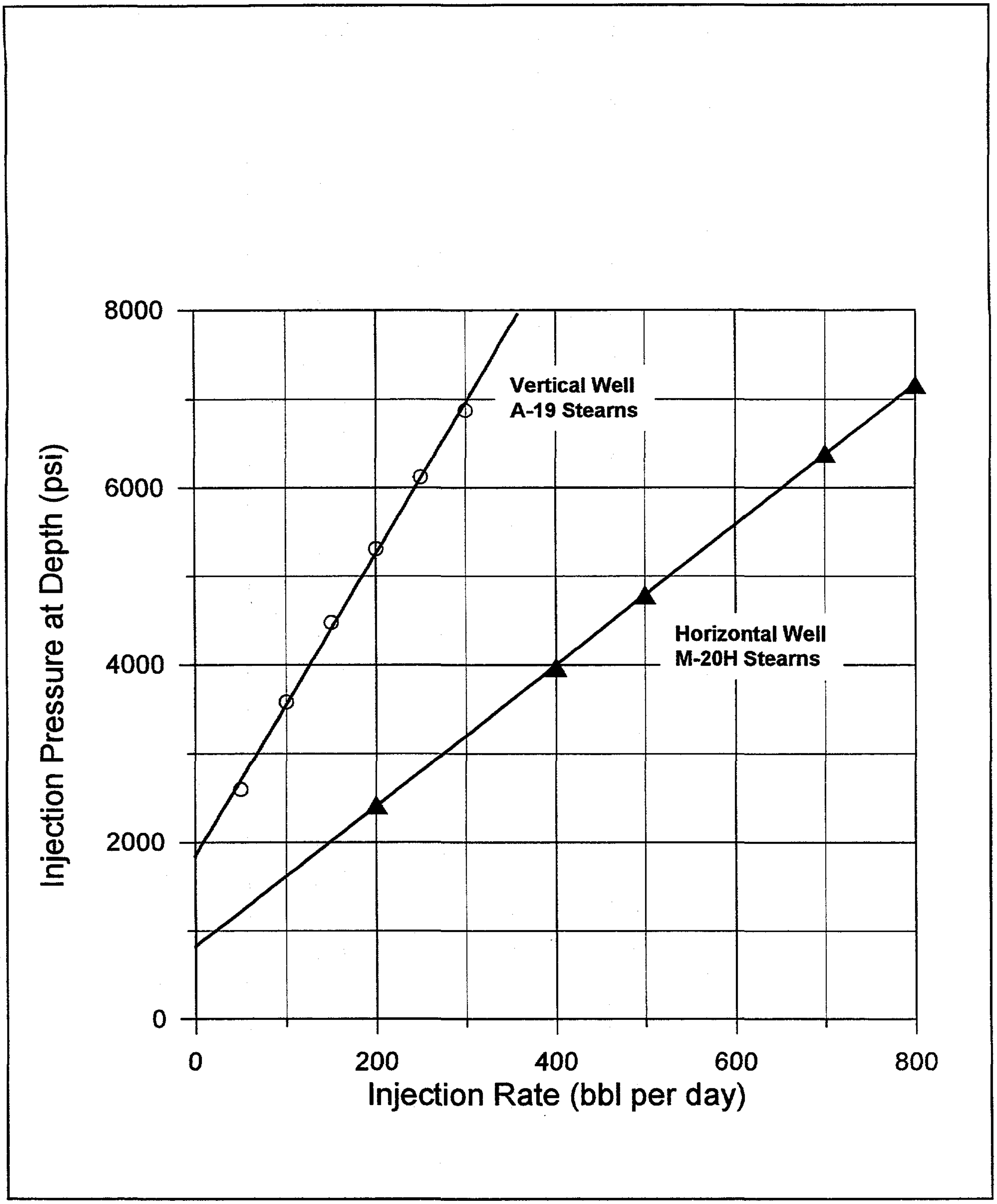


Figure 43: Stabilized water-injectivity into the Red River B zone at Buffalo Field (north area). The horizontal injection test was with a lateral of 1000 ft.

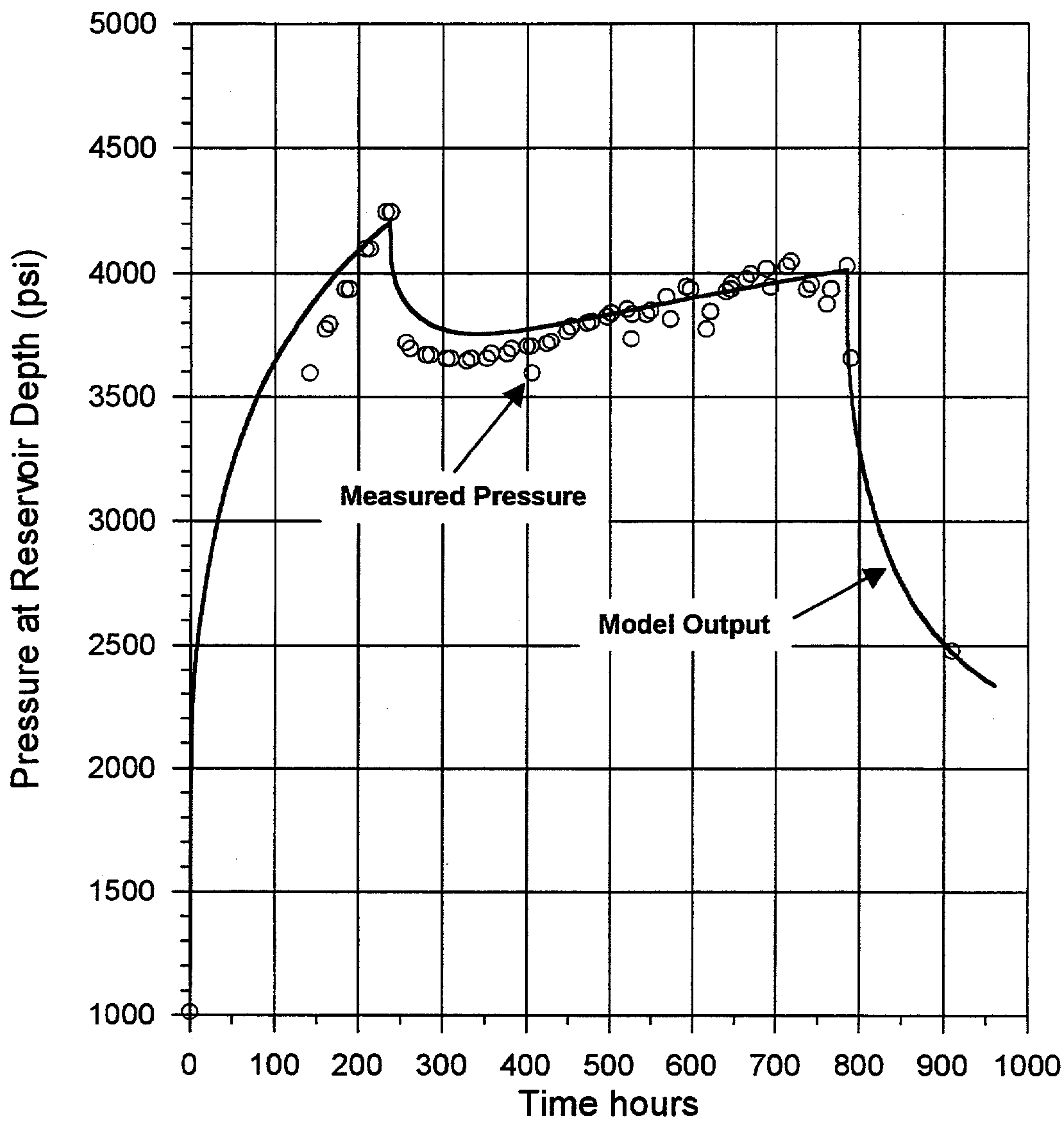


Figure 44: Water injection test in horizontal well with simulation match at Buffalo Field (north area). The lateral in the M-20H Stearns is about 1000 ft.

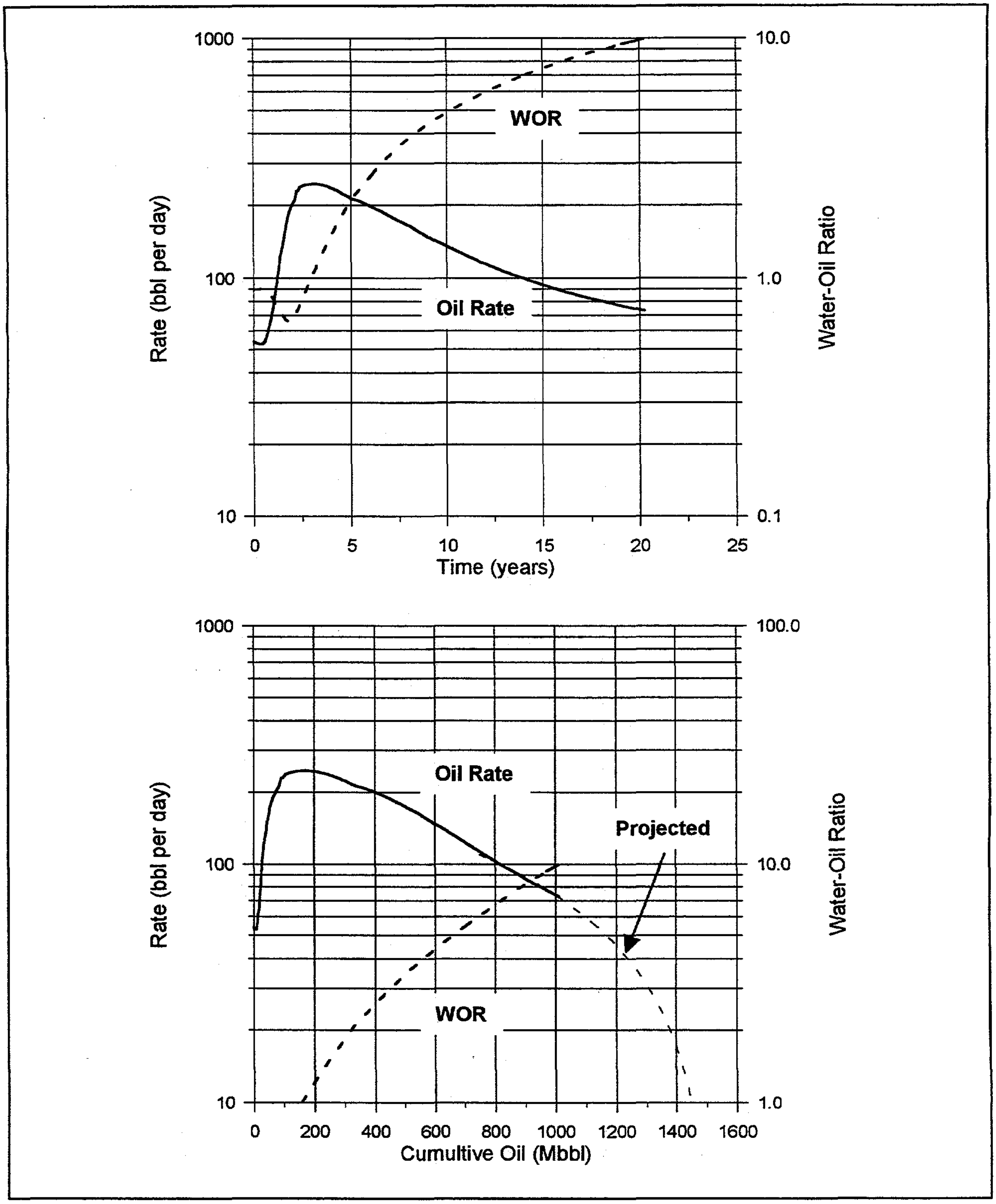


Figure 45: Prediction of recovery with a horizontal water-injection well and two vertical producers in a 640-acre reservoir in the Red River B zone at Buffalo Field (north area).

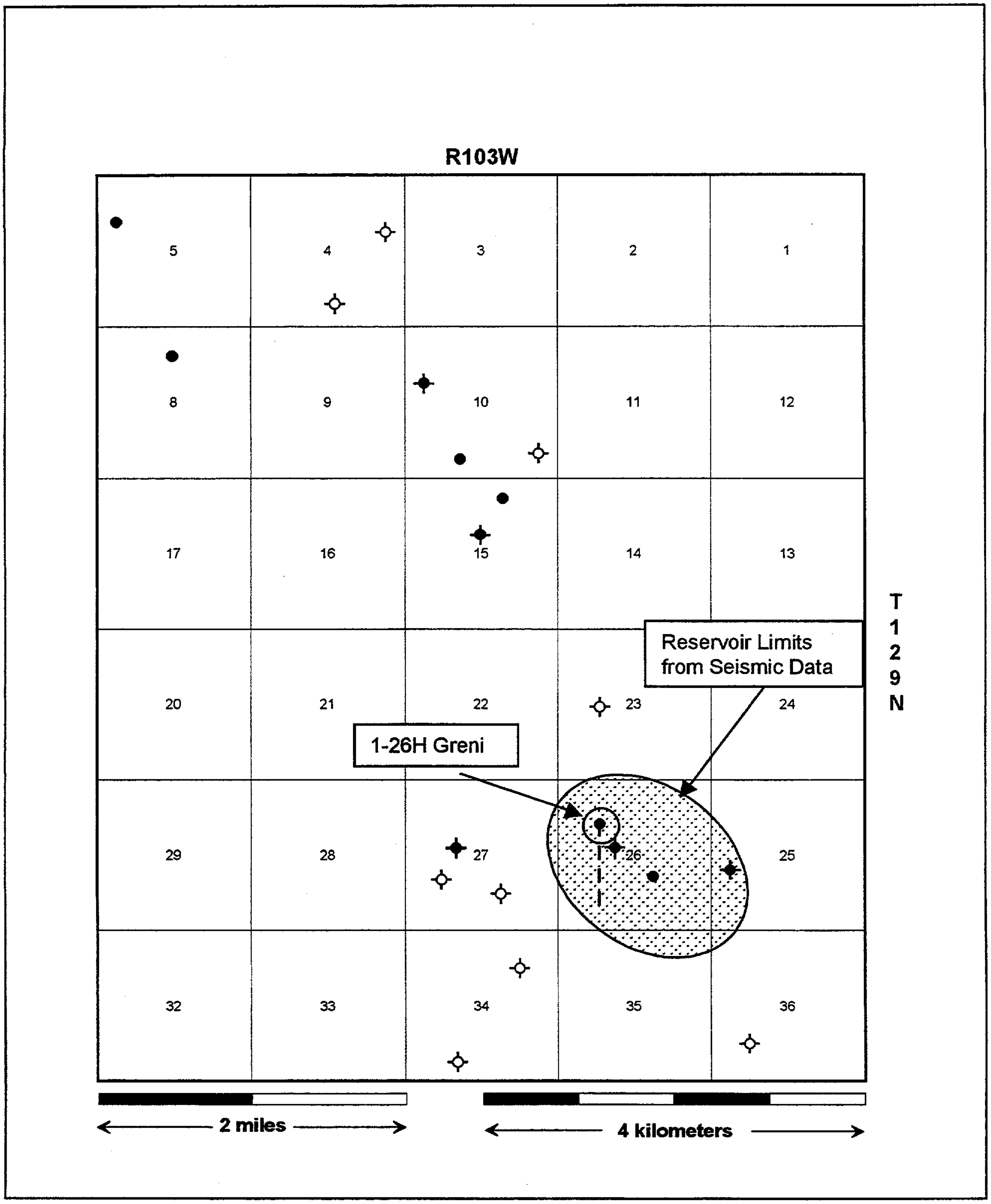


Figure 46: Map of State Line Field, Bowman Co., ND with location of No. 1-26H Greni well.

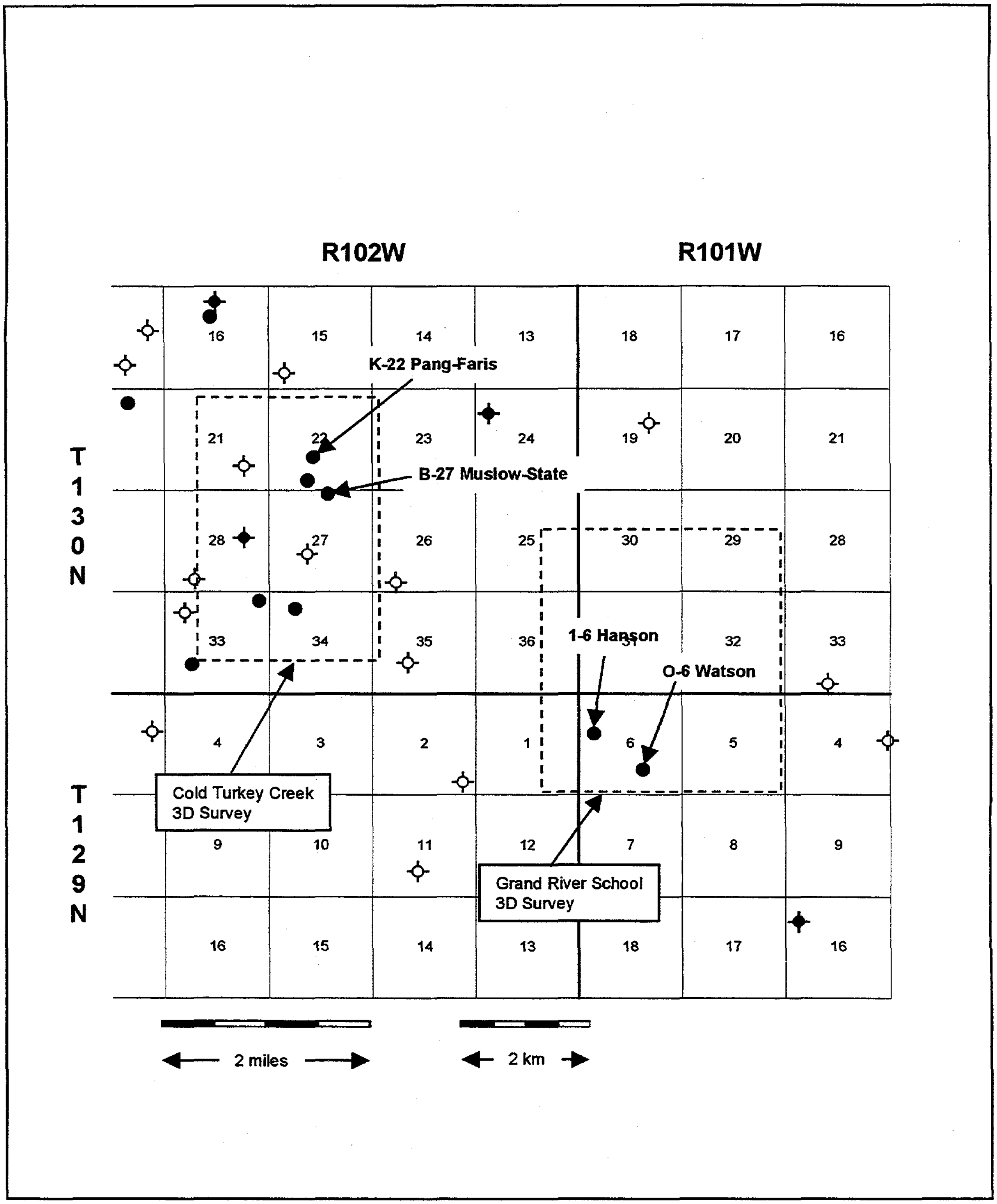


Figure 47: Map of Cold Turkey Creek and Grand River School 3D seismic areas with demonstration wells.

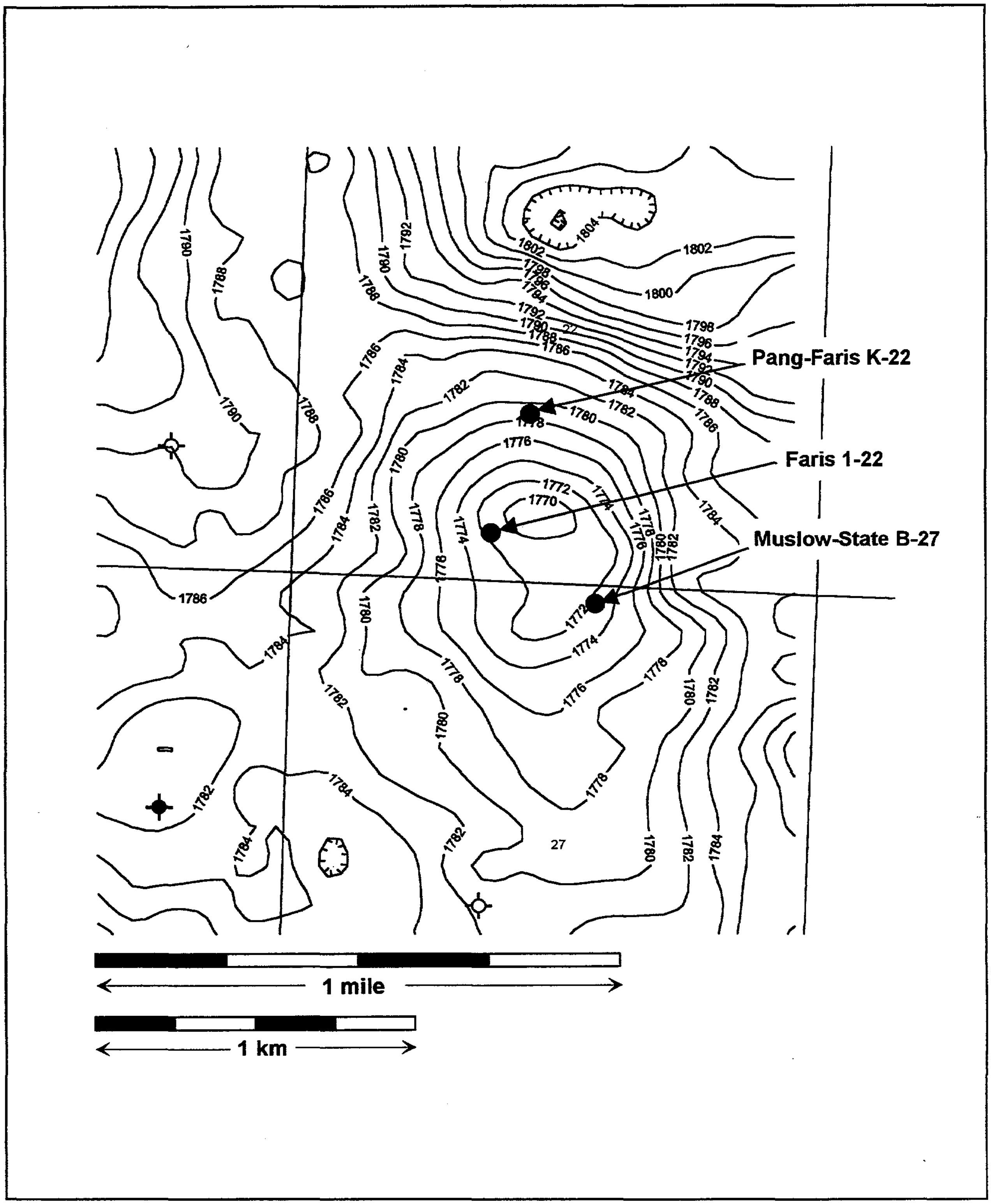


Figure 48: Map of Cold Turkey Creek Field demonstration area. Two wells were drilled to test seismic interpretation of Red River D zone development. Contours are seismic time of the Red River. CI = 2 msec.

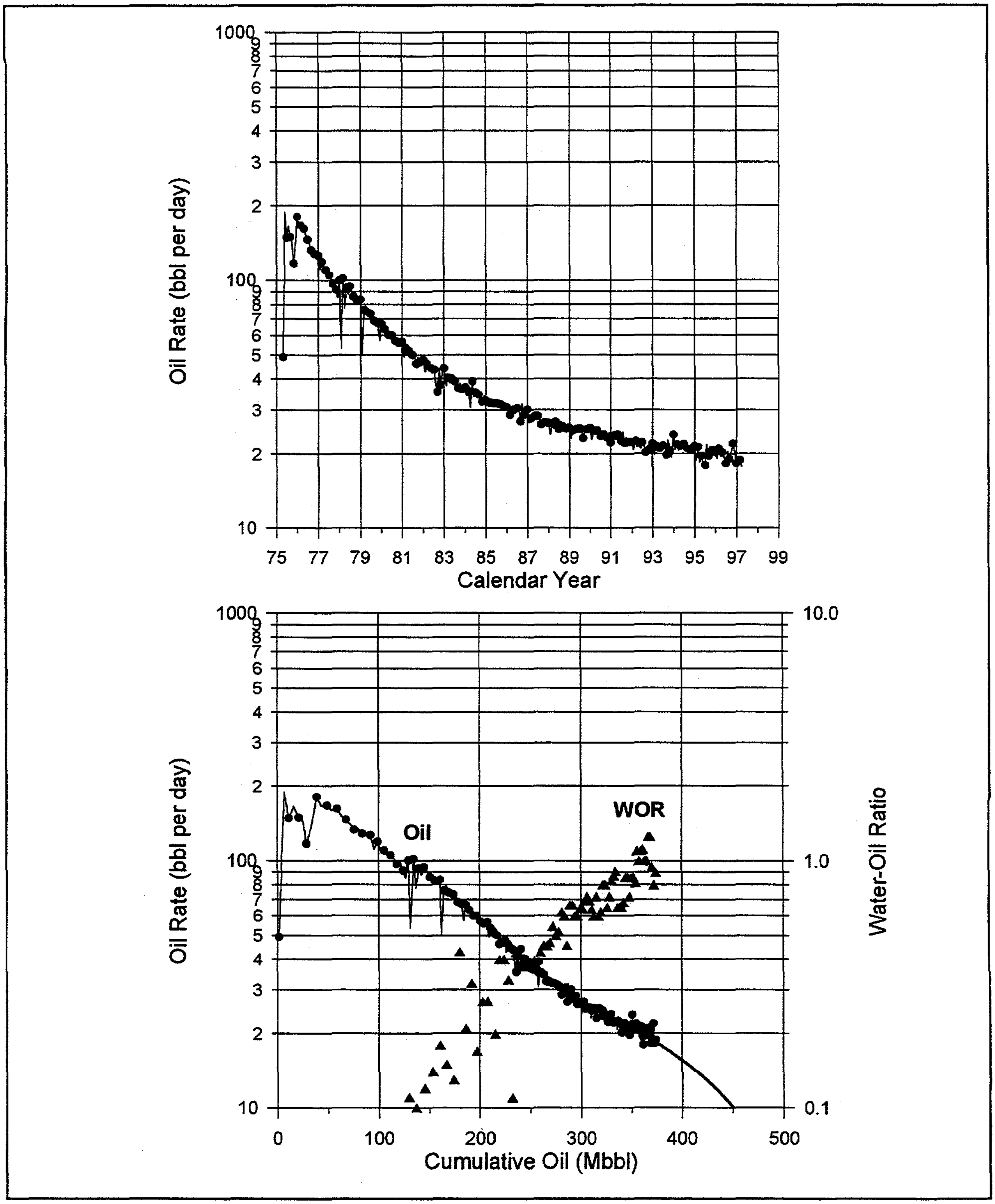


Figure 49: Production history from the No. 1-22 Faris, Cold Turkey Creek Field, Bowman Co., ND. The well is perforated in the Red River B, C and D zones.

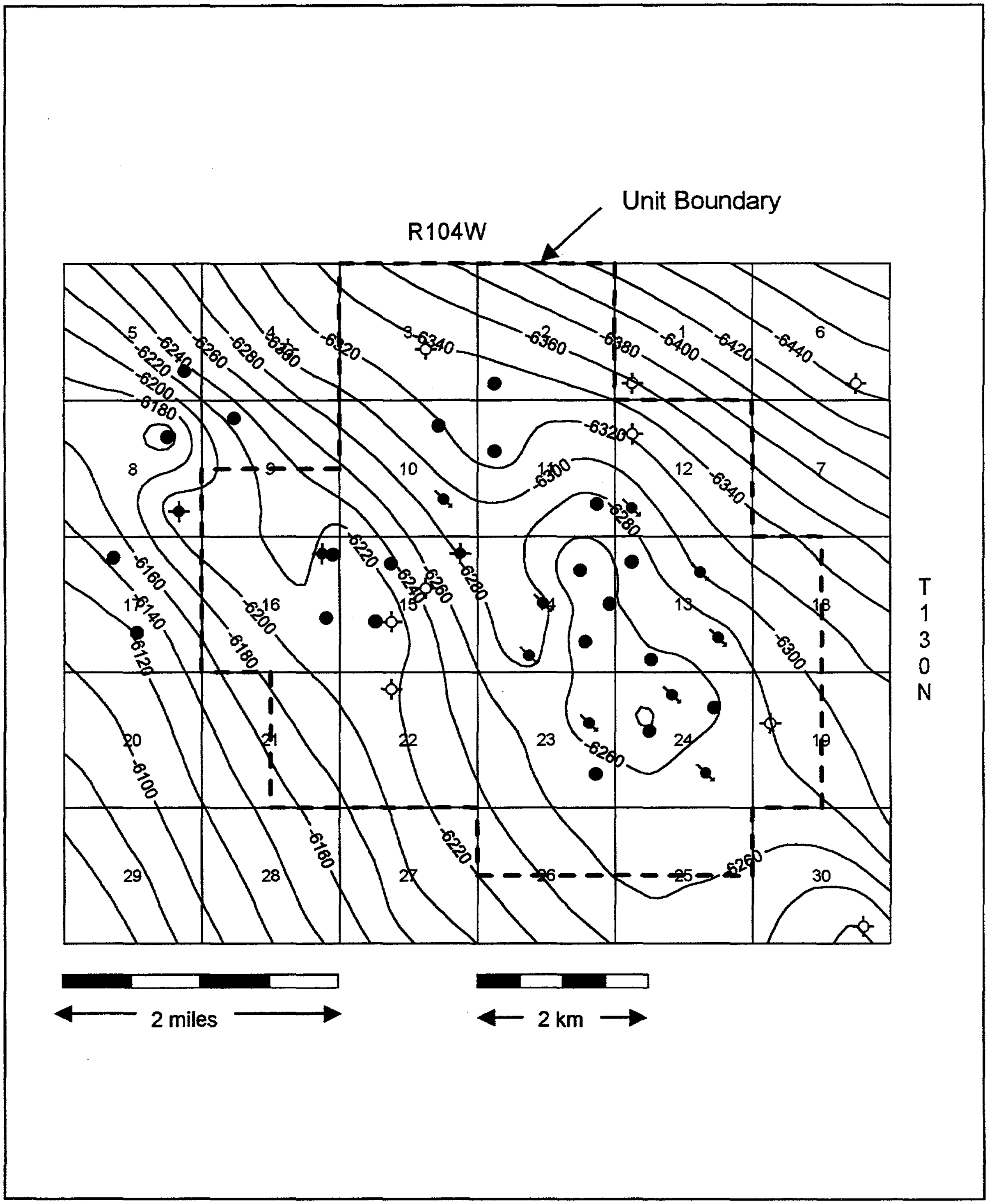


Figure 50: Map of Medicine Pole Hills Unit, Bowman Co., ND. Structure contours are on top of the Red River. CI = 20 ft.

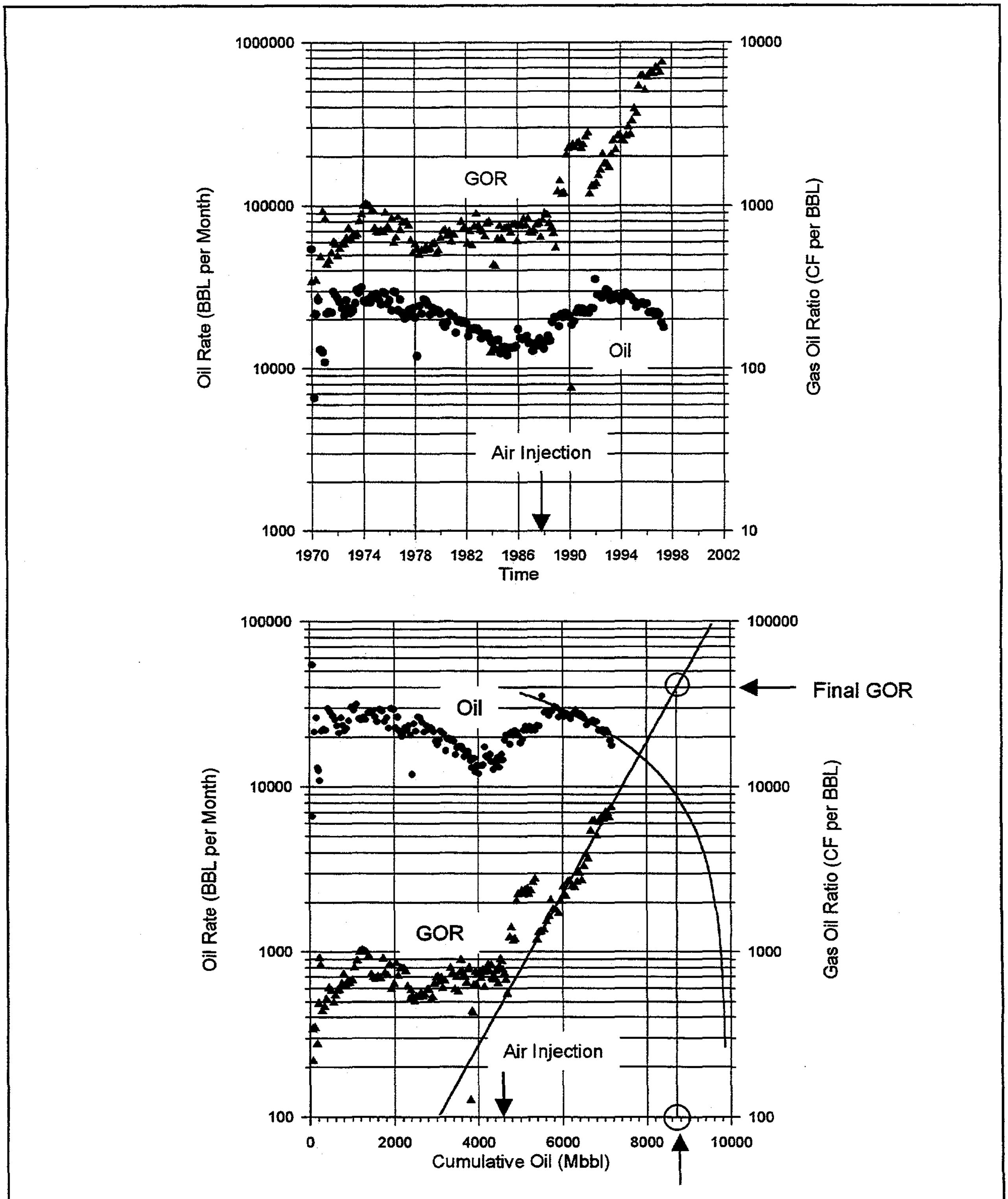


Figure 51: Oil production history from Medicine Pole Hills Unit since discovery and extrapolation. Extrapolation of GOR indicates an ultimate recovery of 8,800,000 bbl.

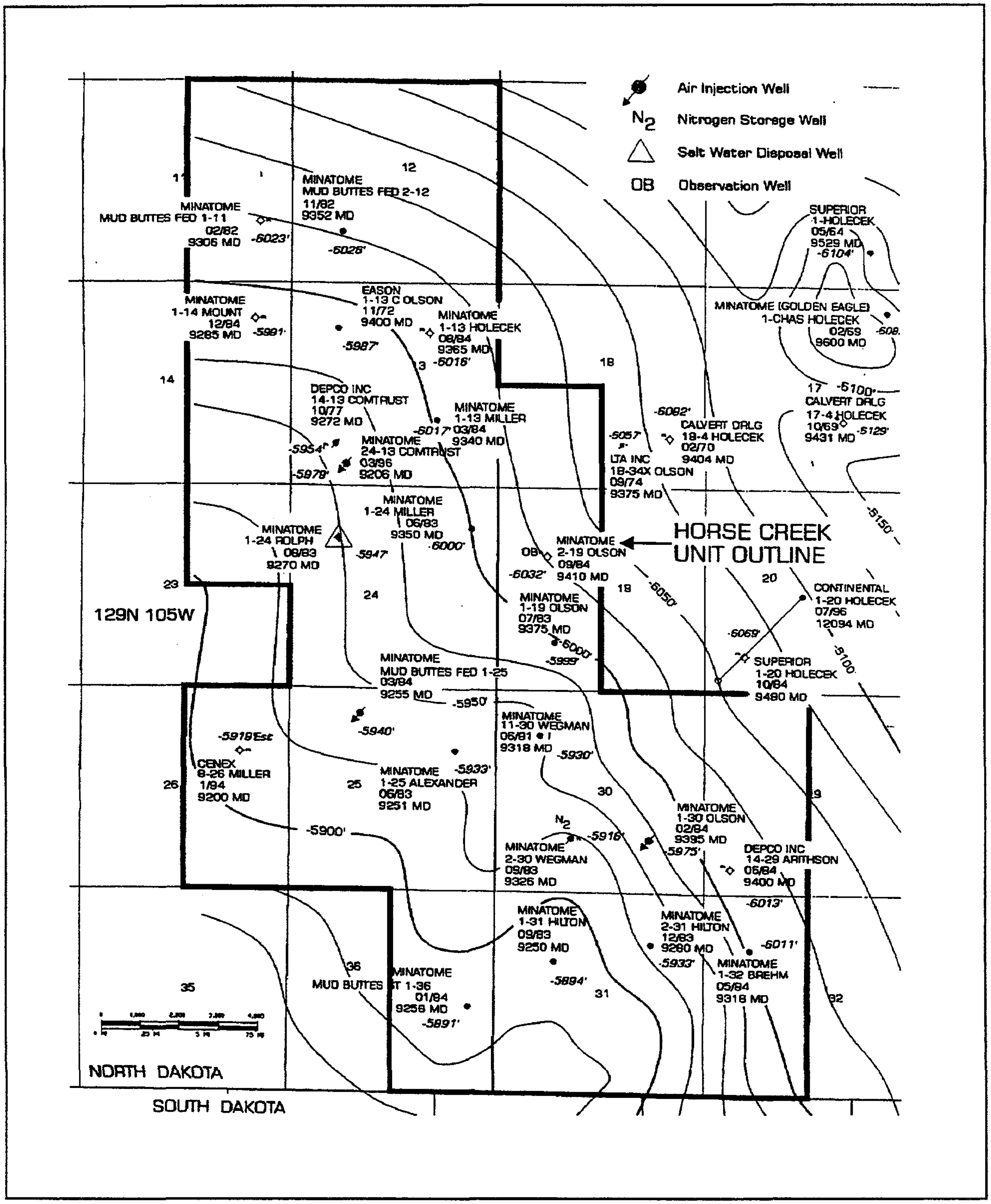


Figure 52: Map of the Horse Creek Unit, Bowman Co., ND with structure contours on top of the Red River "D" zone. CI = 25 ft.. Grid is regular governmental sections of one square mile.

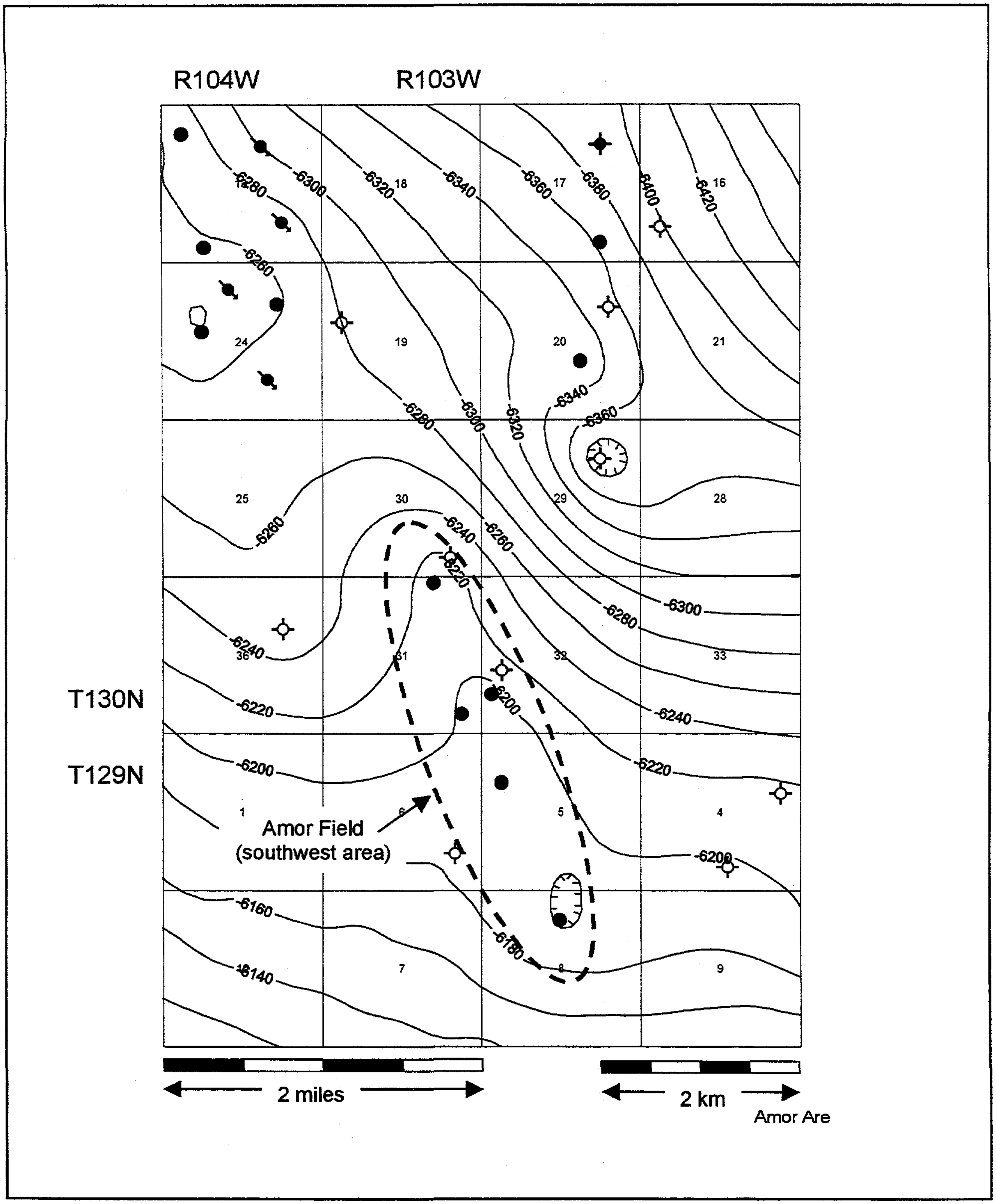


Figure 53: Map of Amor Field (southwest area) Bowman Co., ND with structure contours on top of the Red River. CI = 20 ft..

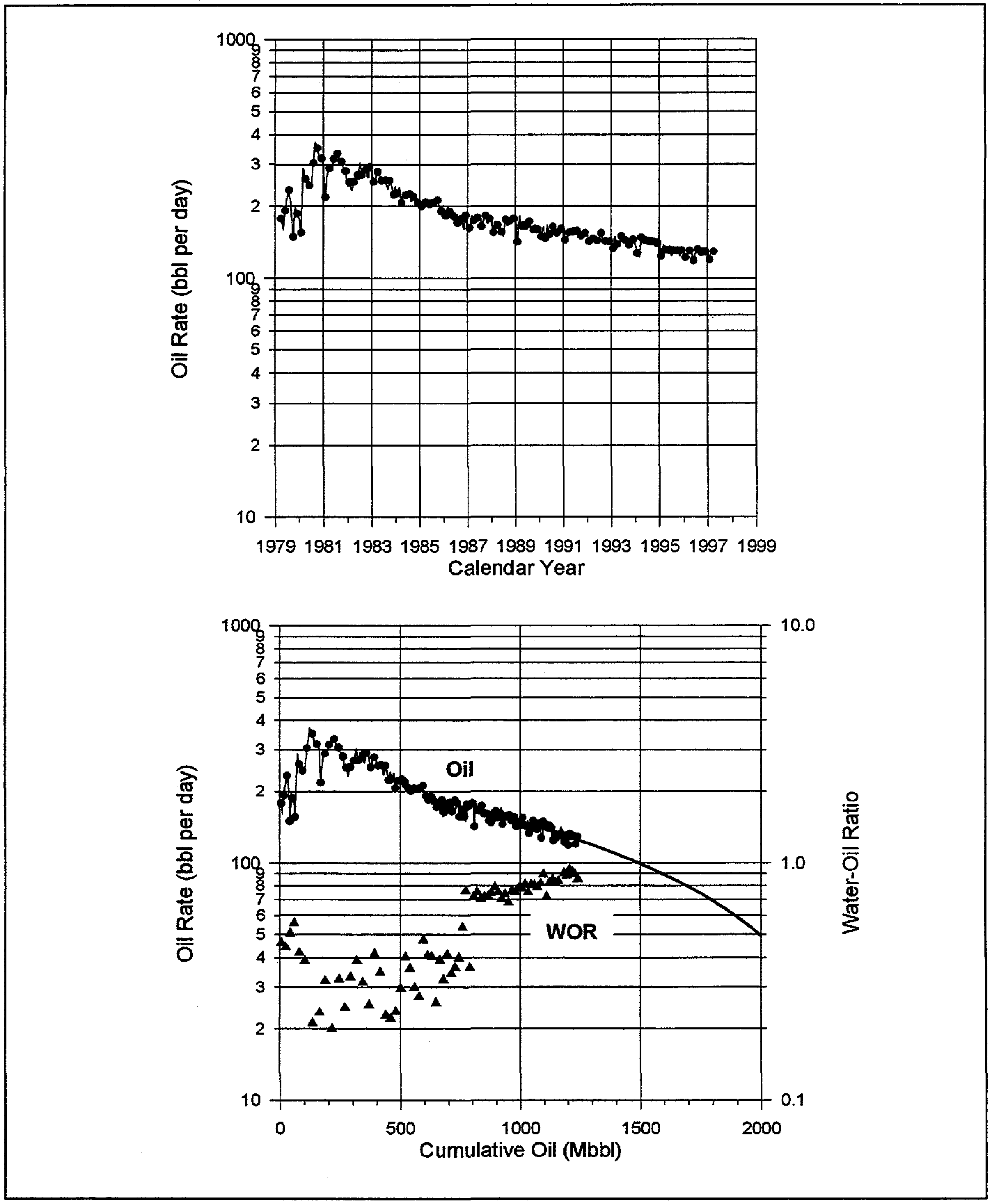


Figure 54: Production history from Amor Field (southwest area) since discovery .

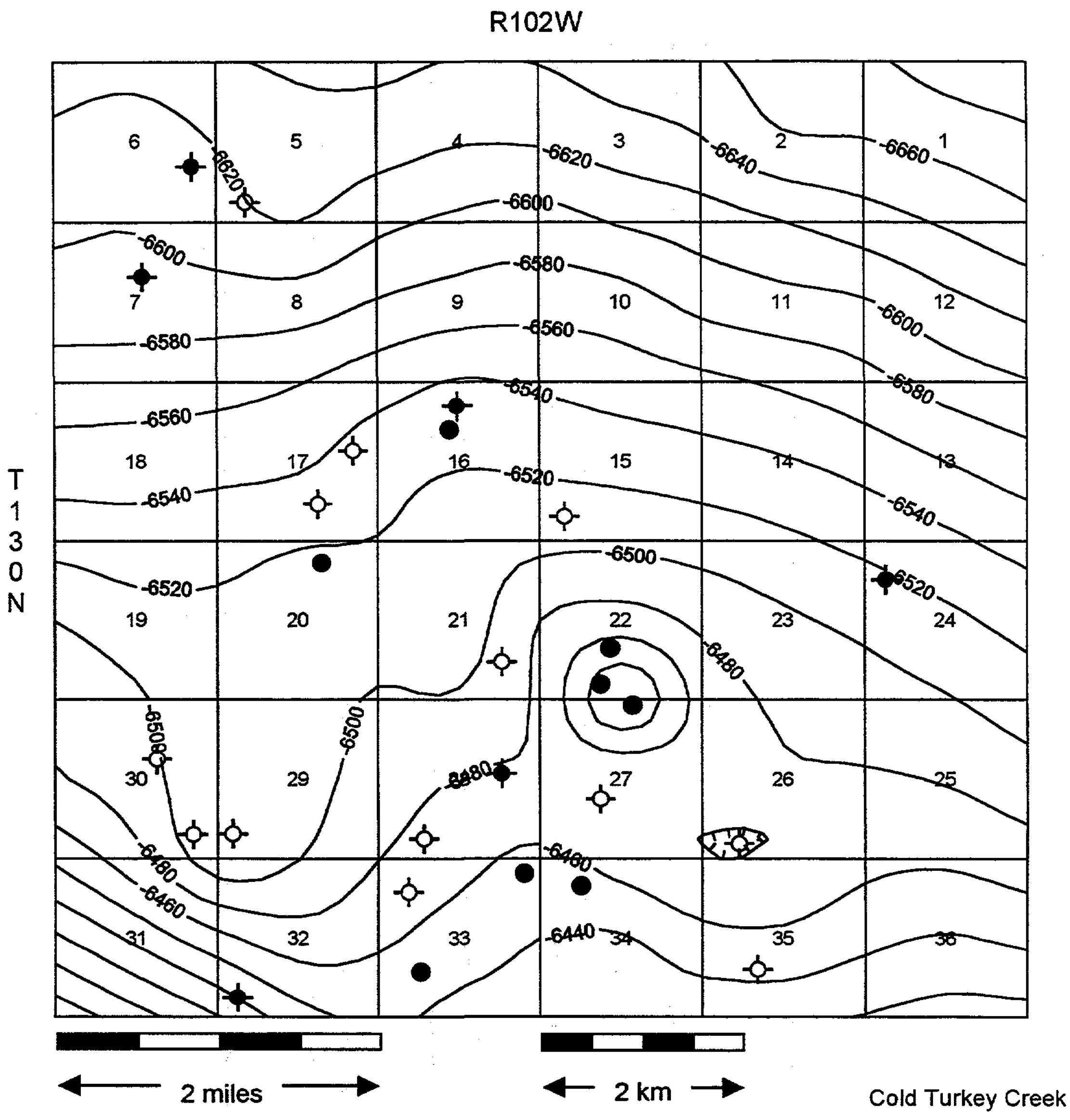


Figure 55: Map of Cold Turkey Creek Field, Bowman Co., ND with structure contours on top of the Red River. CI = 20 ft..

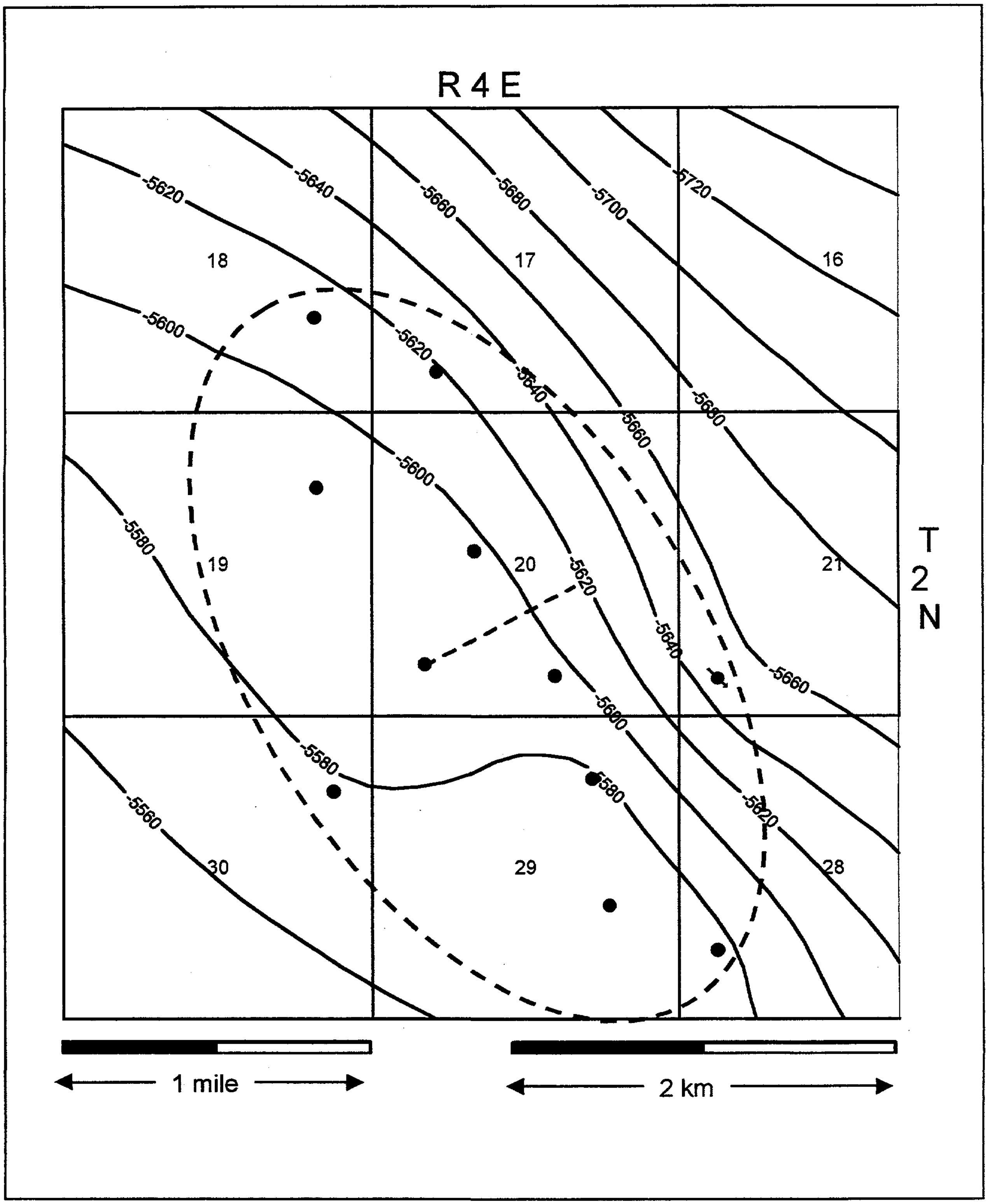


Figure 56: Map of Buffalo Field (north area), Harding Co., SD with structure contours on top of the Red River. CI = 20 ft.

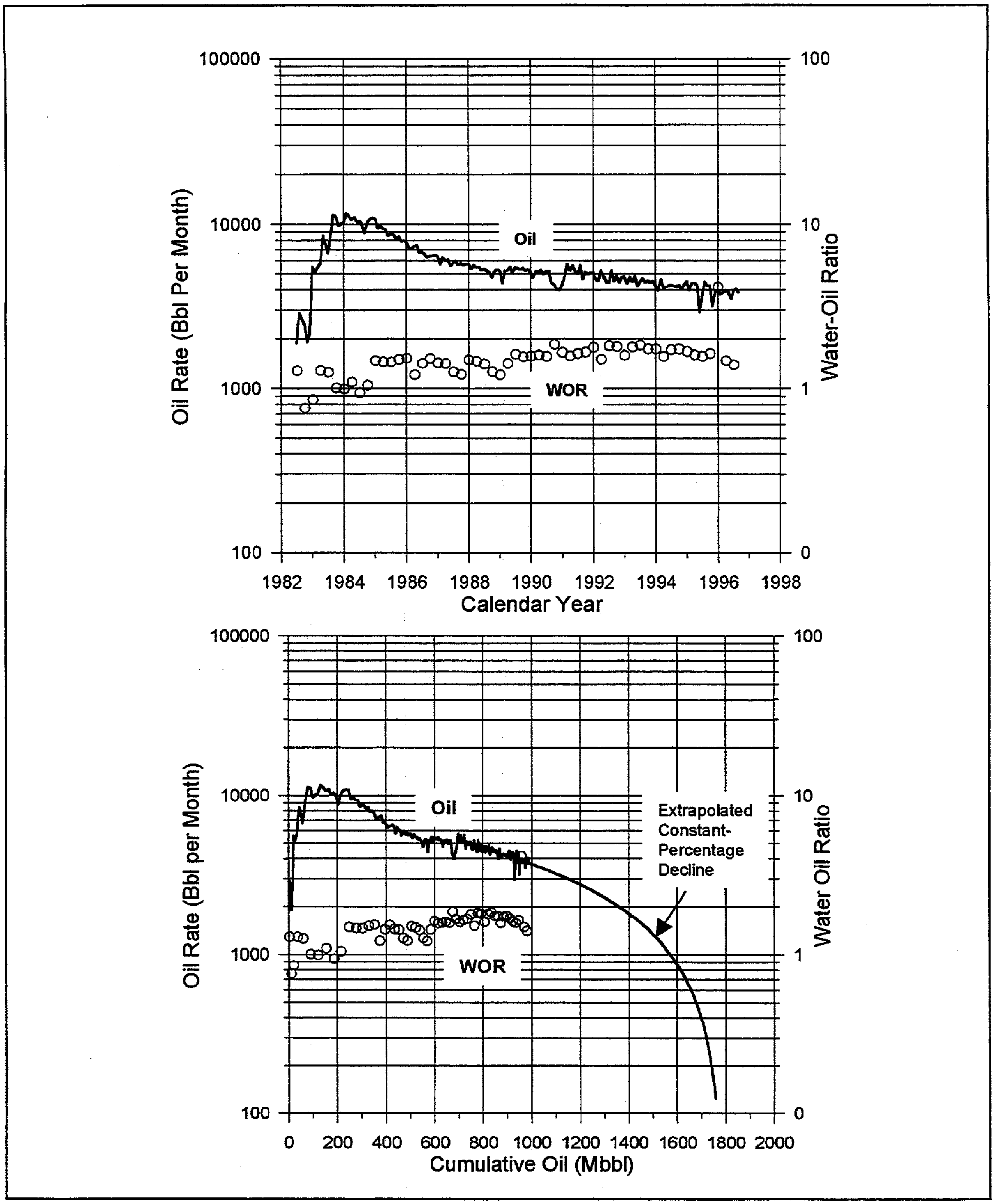


Figure 57: Production history from the Buffalo Field (north area) since discovery.

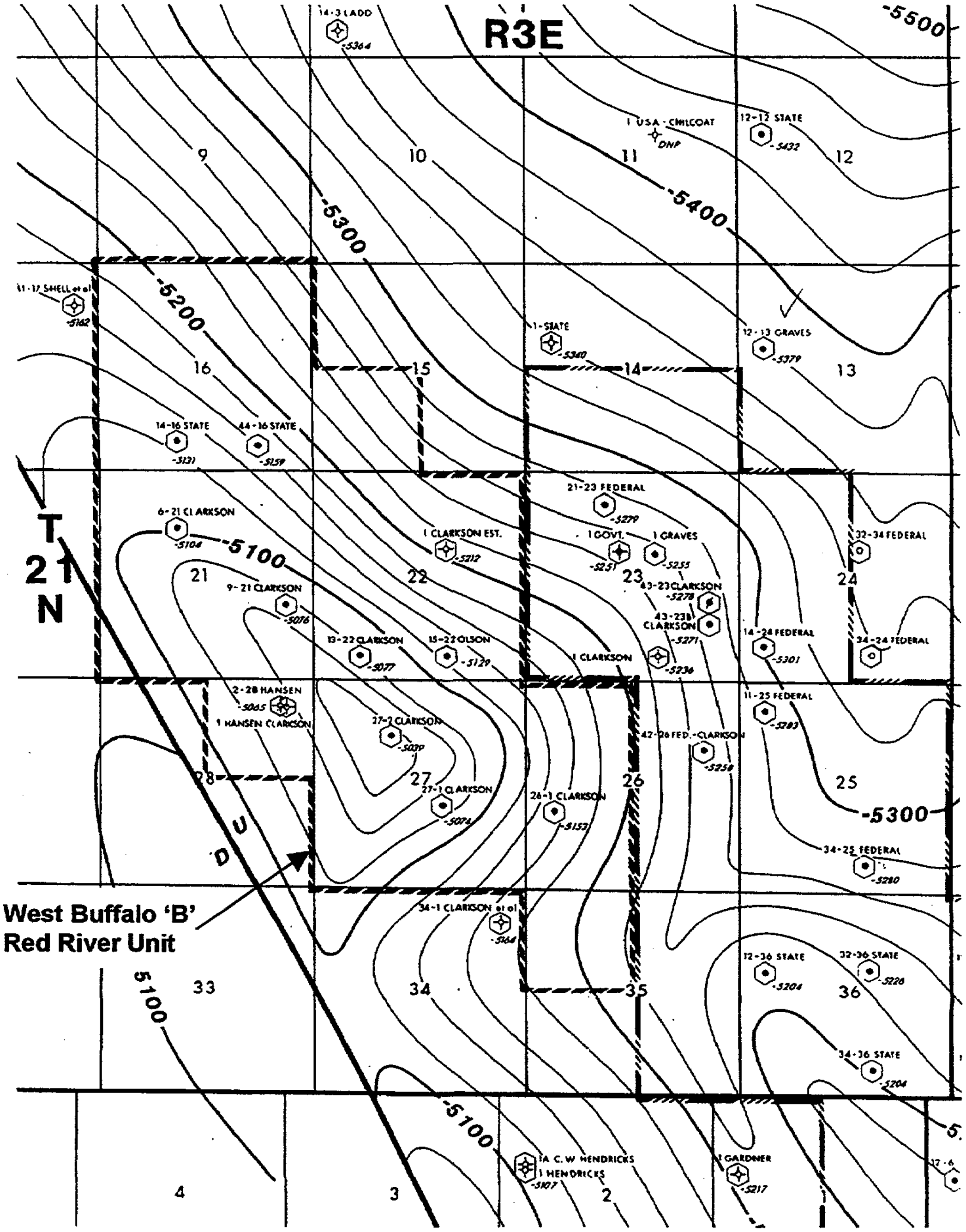


Figure 58: Map of West Buffalo 'B' Red River Unit, Harding Co., SD with structure contours on top of the Red River. CI = 20 ft..

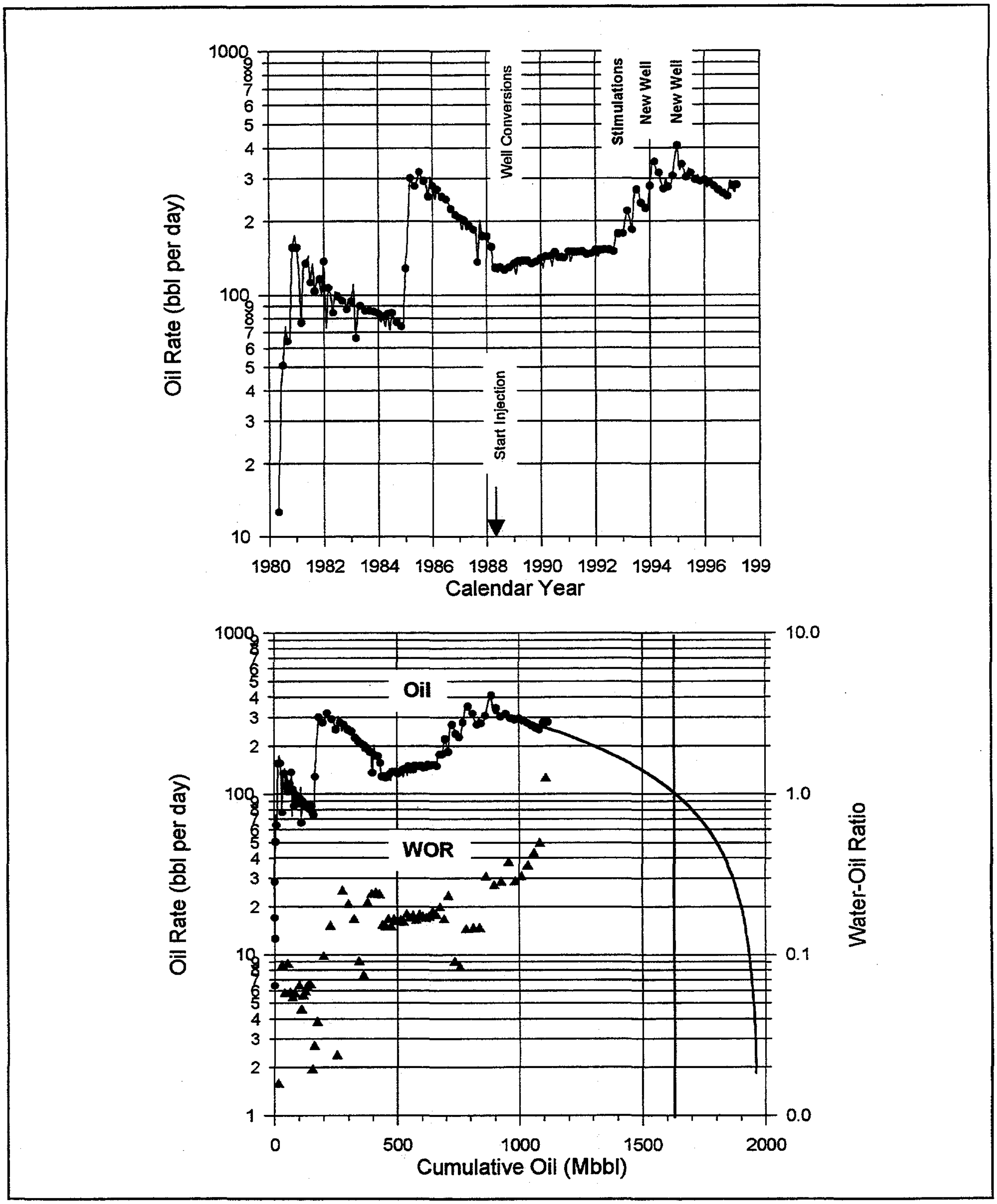


Figure 59: Production history from West Buffalo ‘B’ Red River Unit since discovery.

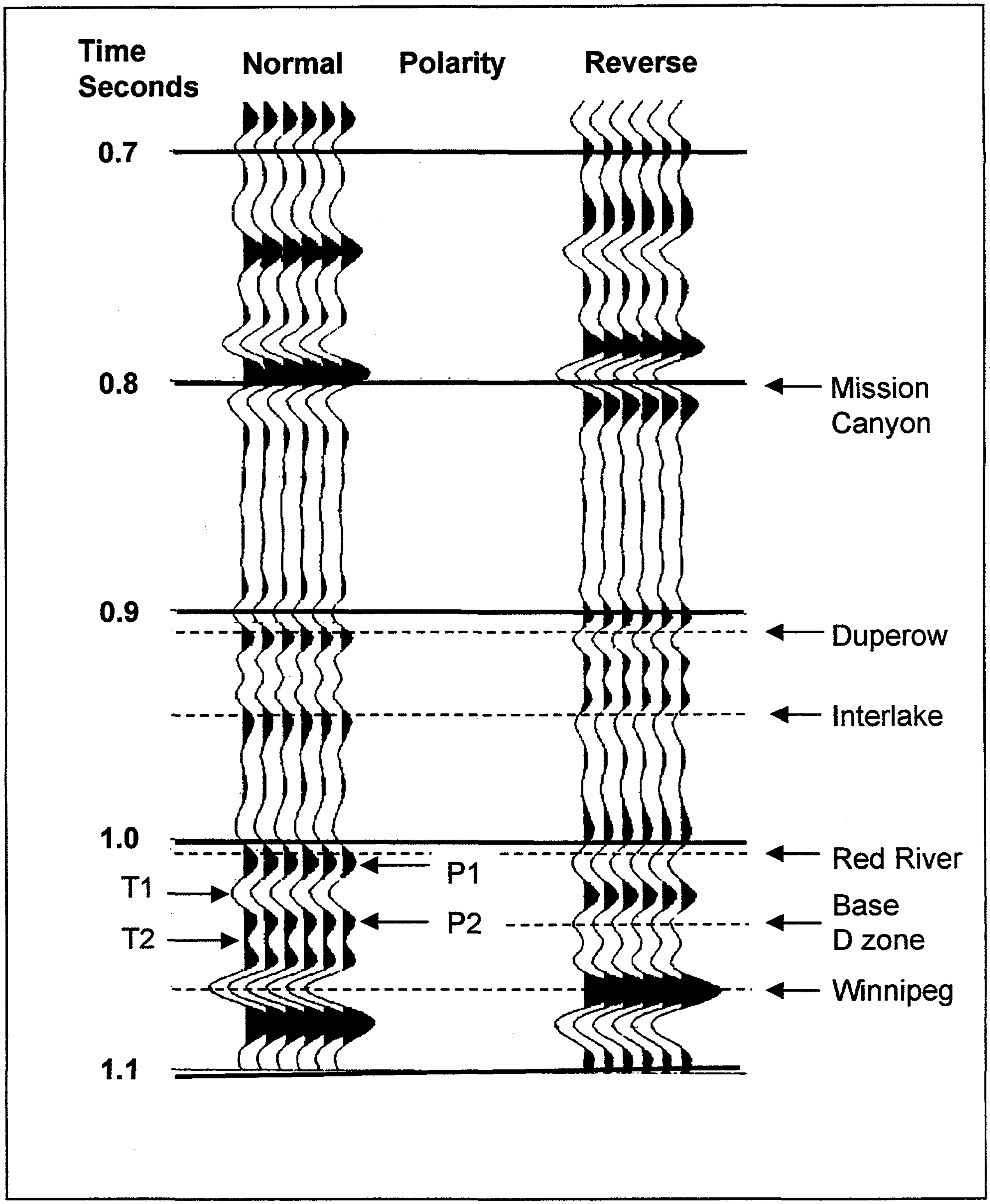


Figure 60: Ideal synthetic seismogram for the Bowman-Harding Red River area.

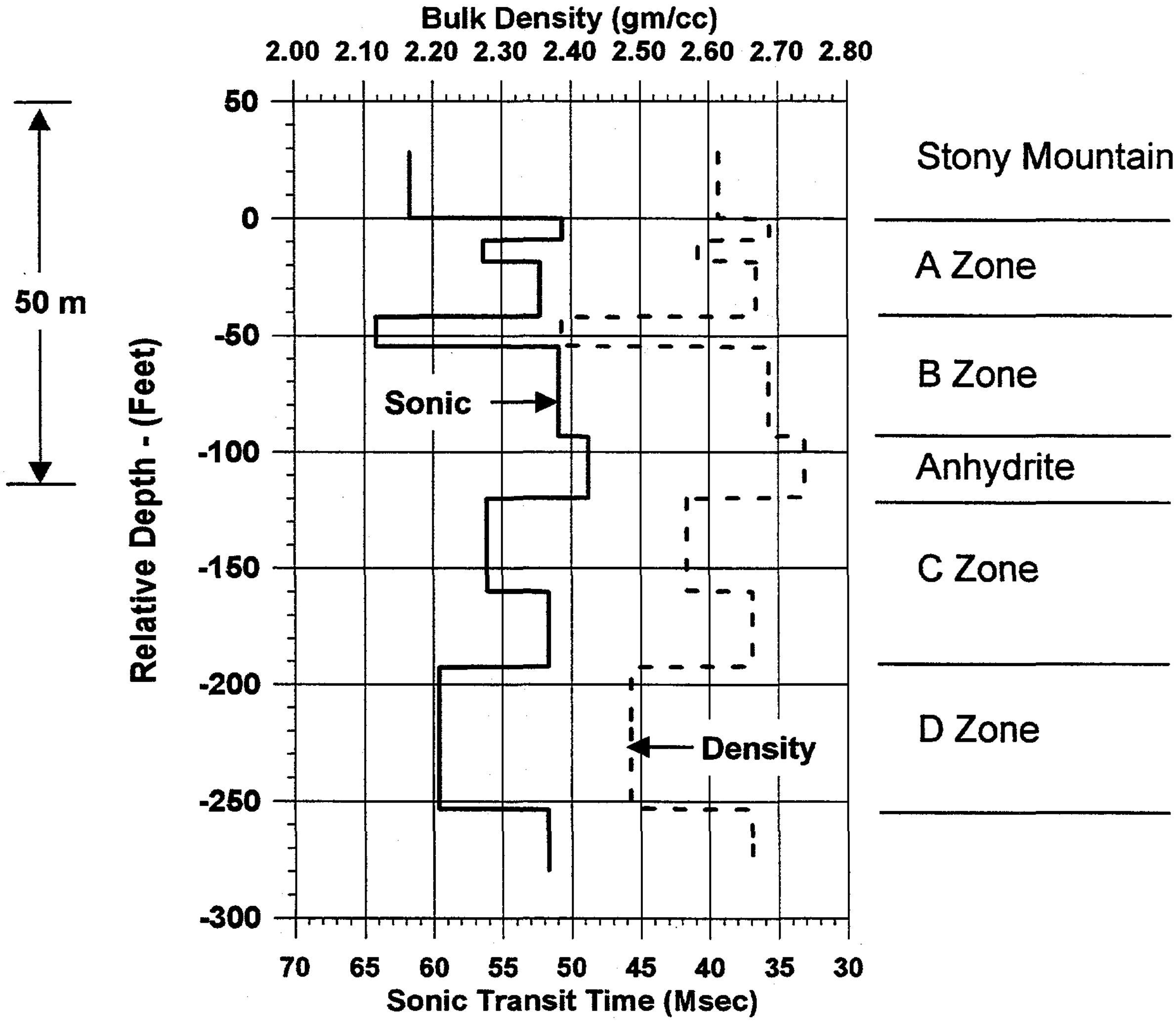


Figure 61: Earth model for Red River seismic.

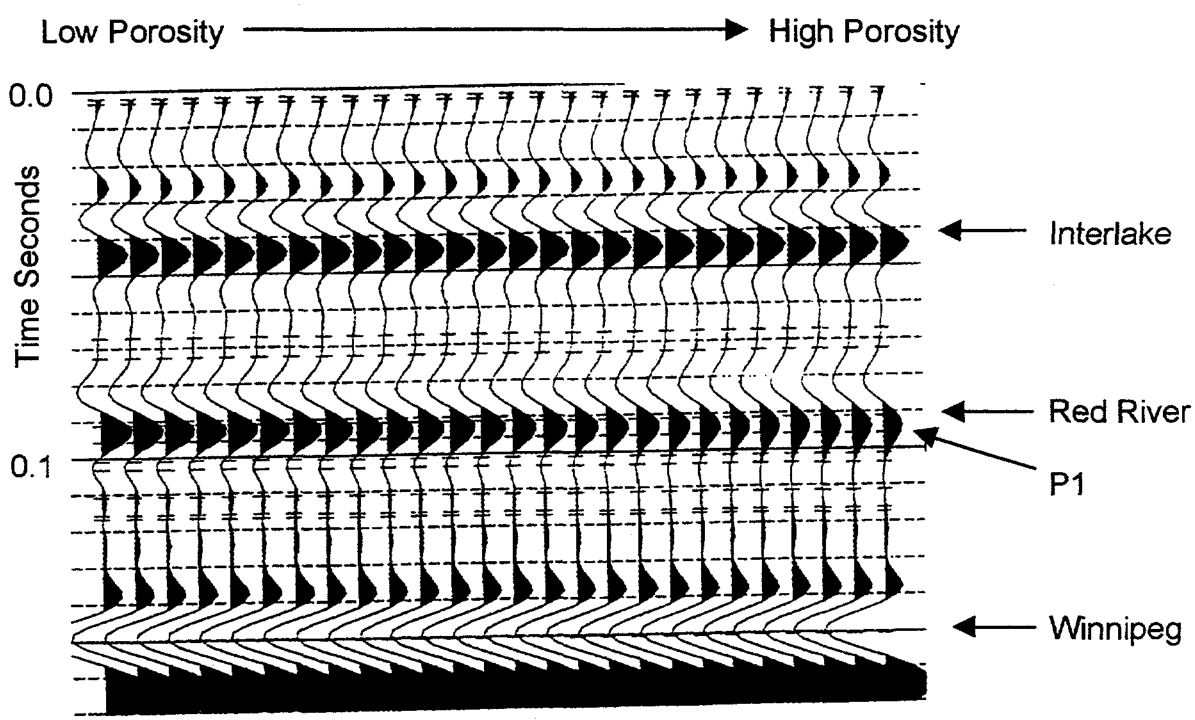


Figure 62: Seismic synthetic for Red River B zone variation. Porosity from the A, C and D zones are stripped away in this model.

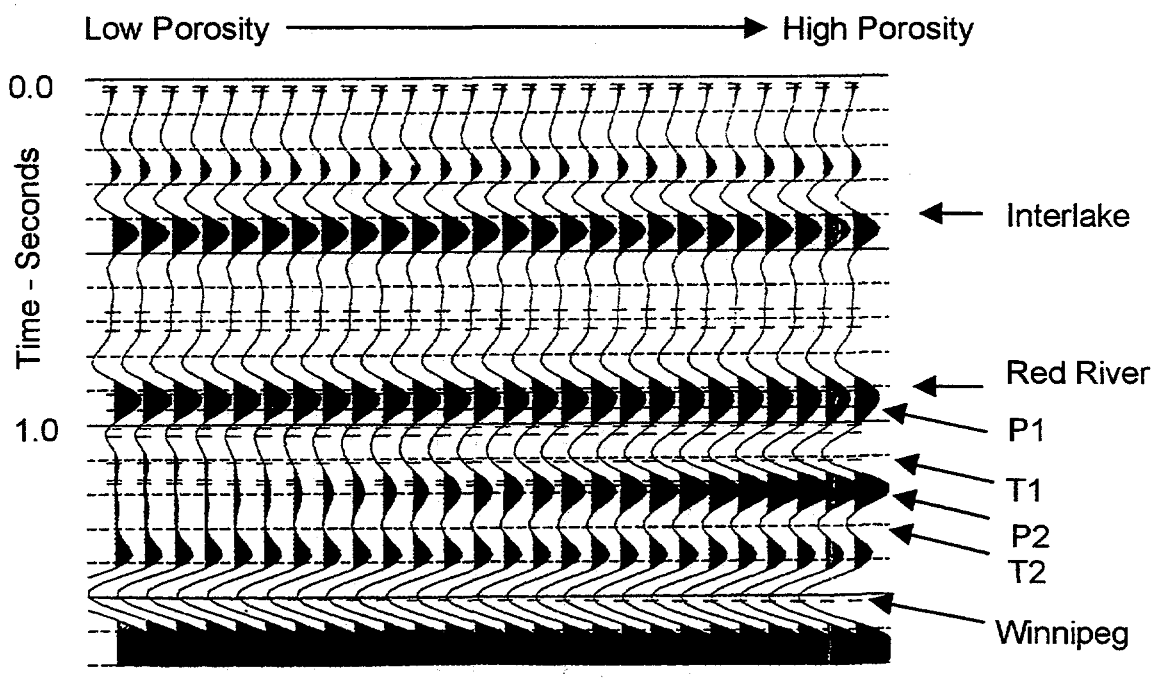


Figure 63: Seismic synthetic for Red River D zone variation.

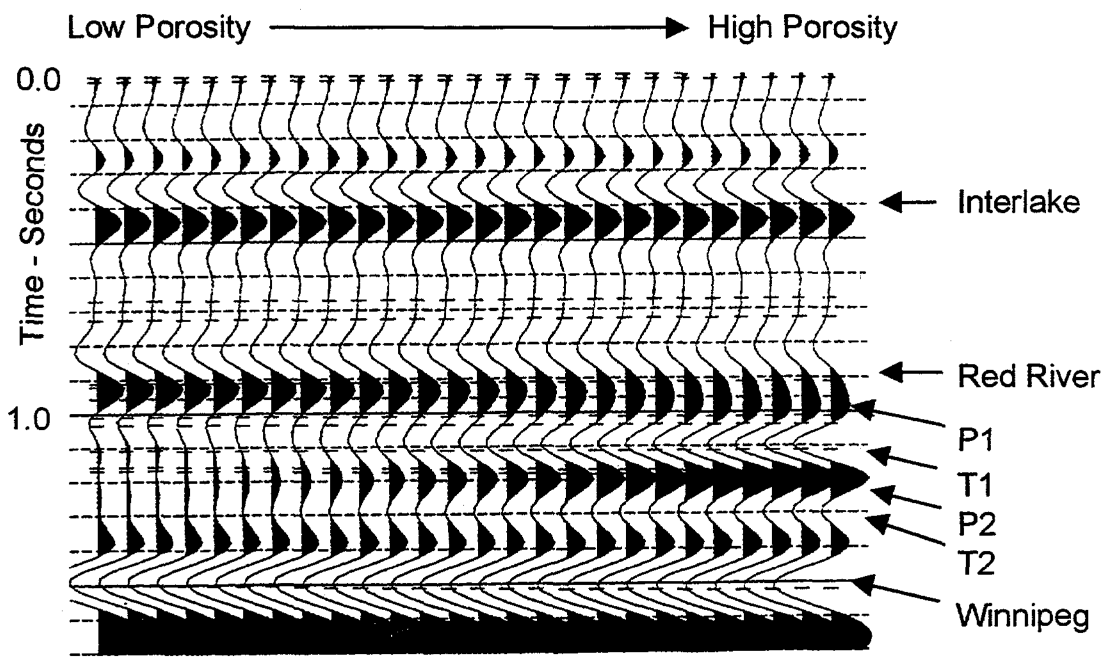


Figure 64: Seismic synthetic showing Red River B and D zone variation.

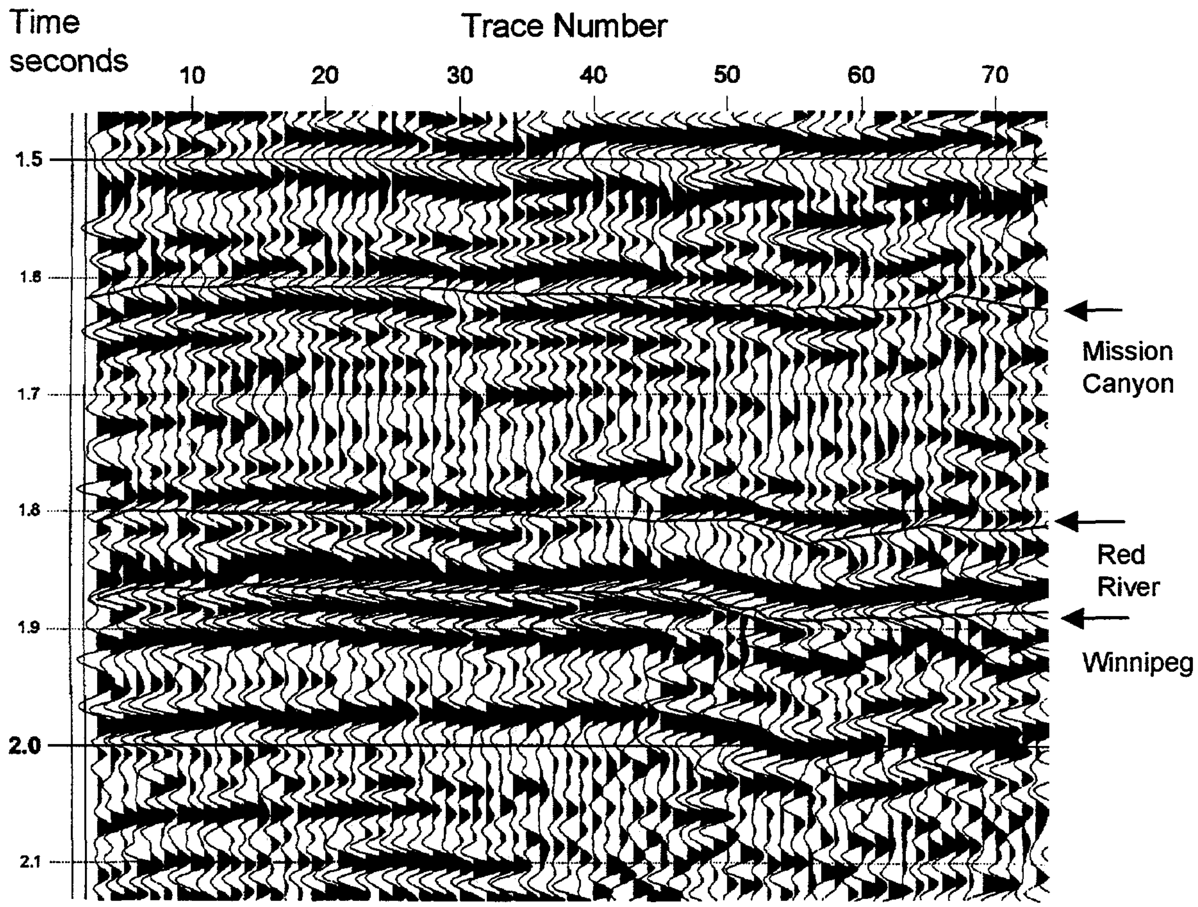


Figure 65: Seismic section from original processing of 2D seismic line CA9-4 at Amor Field. Line is oriented west-east.

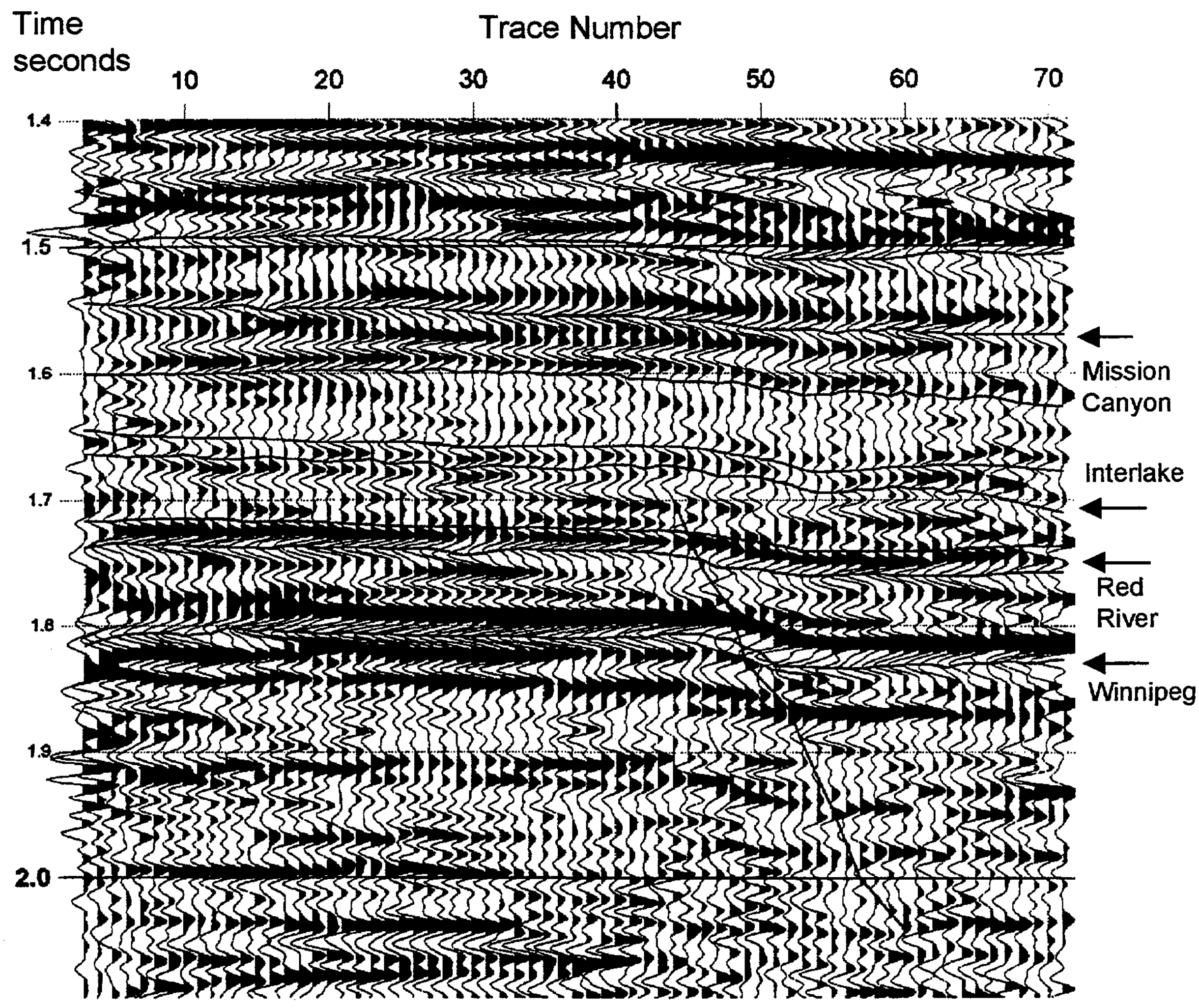


Figure 66: Seismic section from modern processing of 2D seismic line CA9-4 at Amor Field.

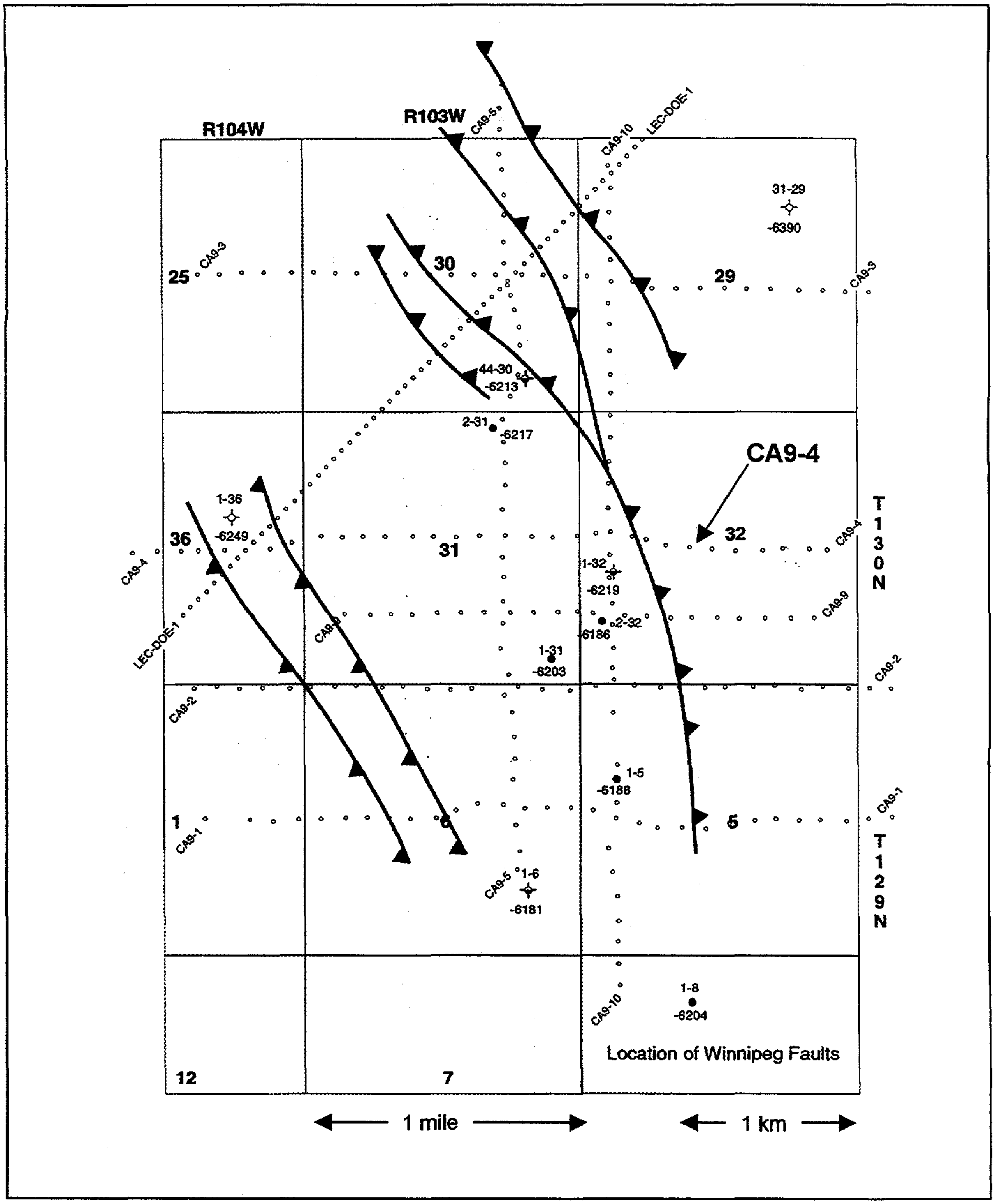


Figure 67: Map of Amor Field showing faults at Winnipeg time from 2D seismic data. Well datums are at top of the Red River.

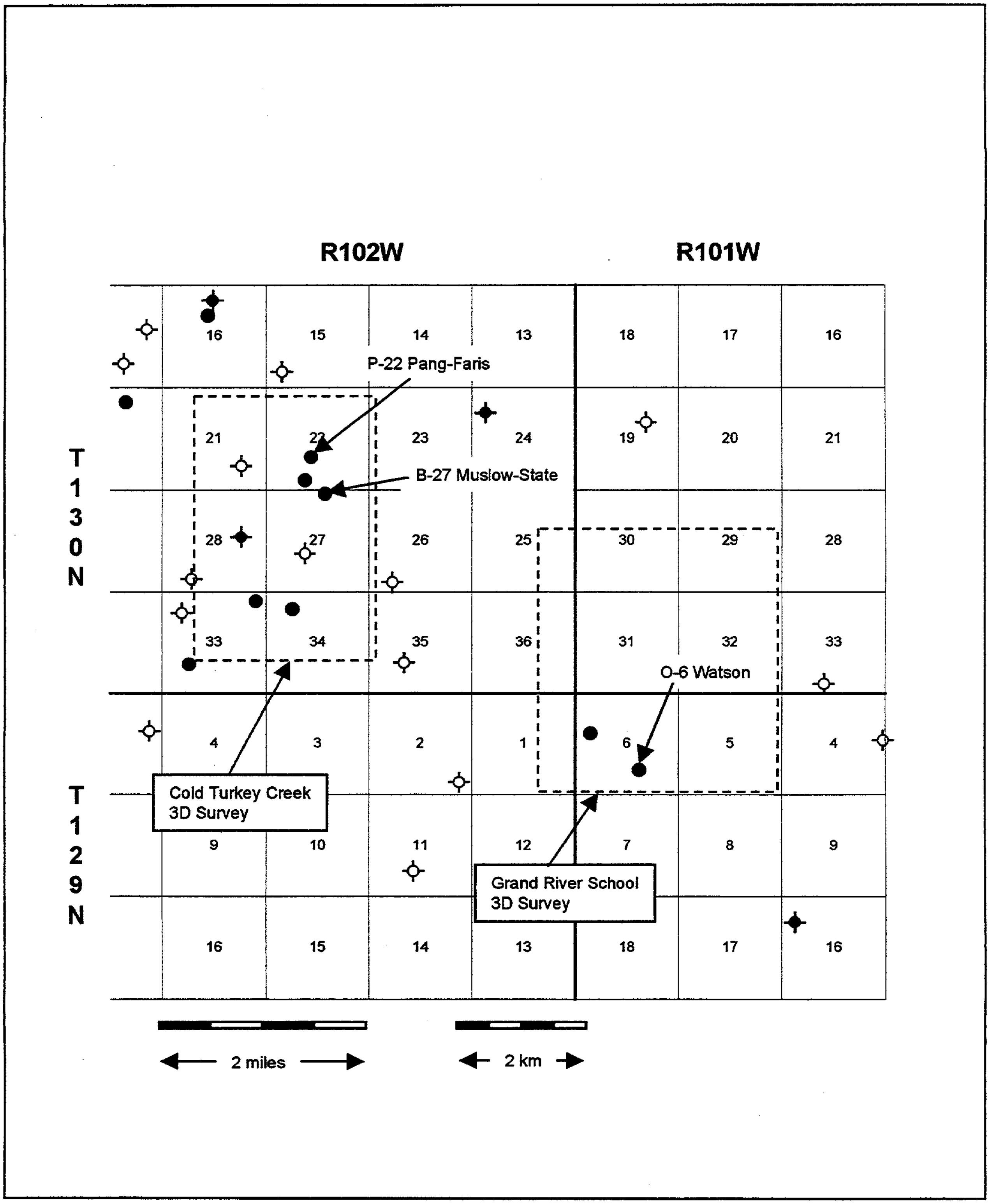


Figure 68: Map showing the location of 3D seismic surveys in Bowman Co., ND.

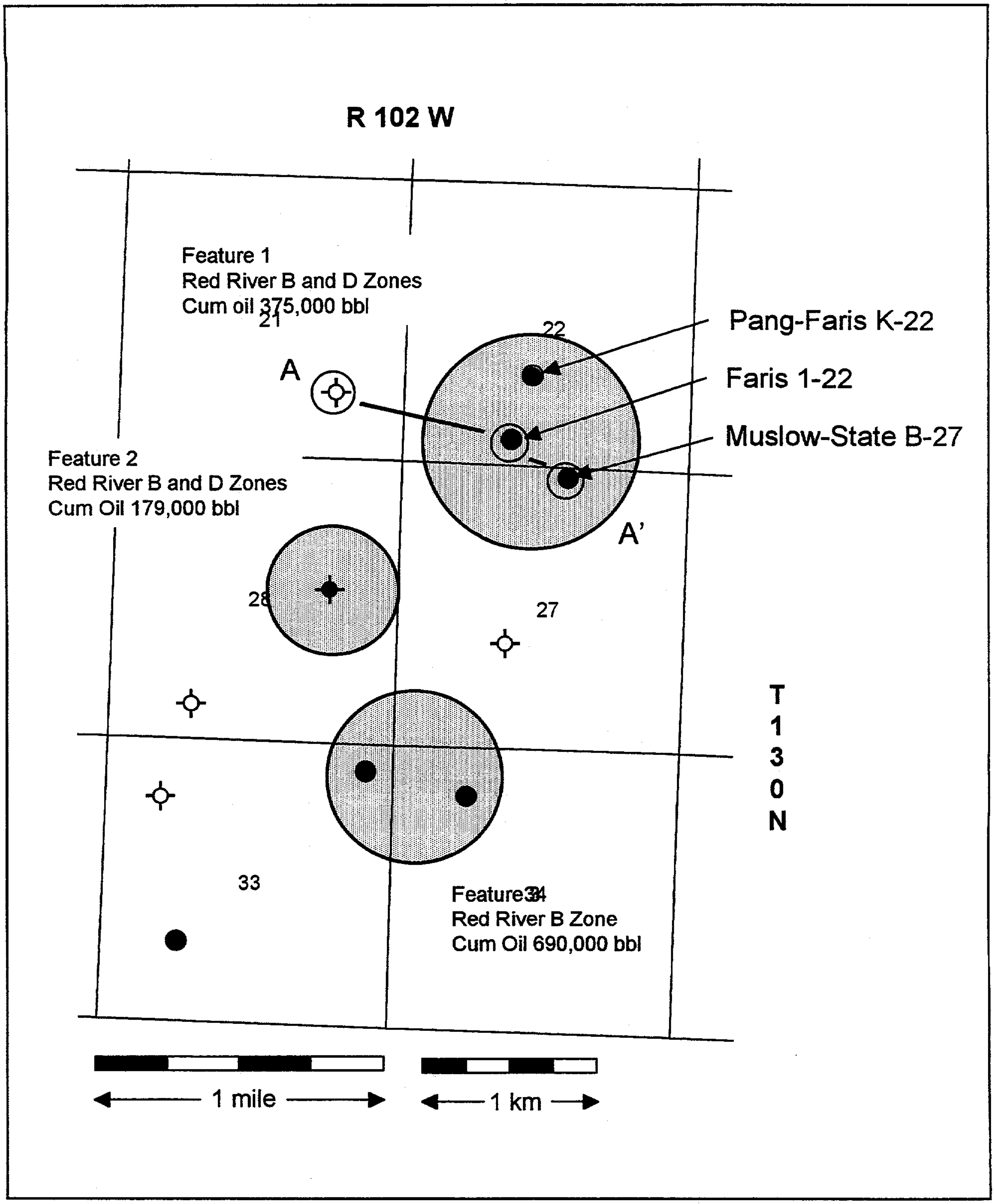


Figure 69: Map of reservoir areas at Cold Turkey Creek Field based on approximate Greenhorn-Winnipeg isochron closure.

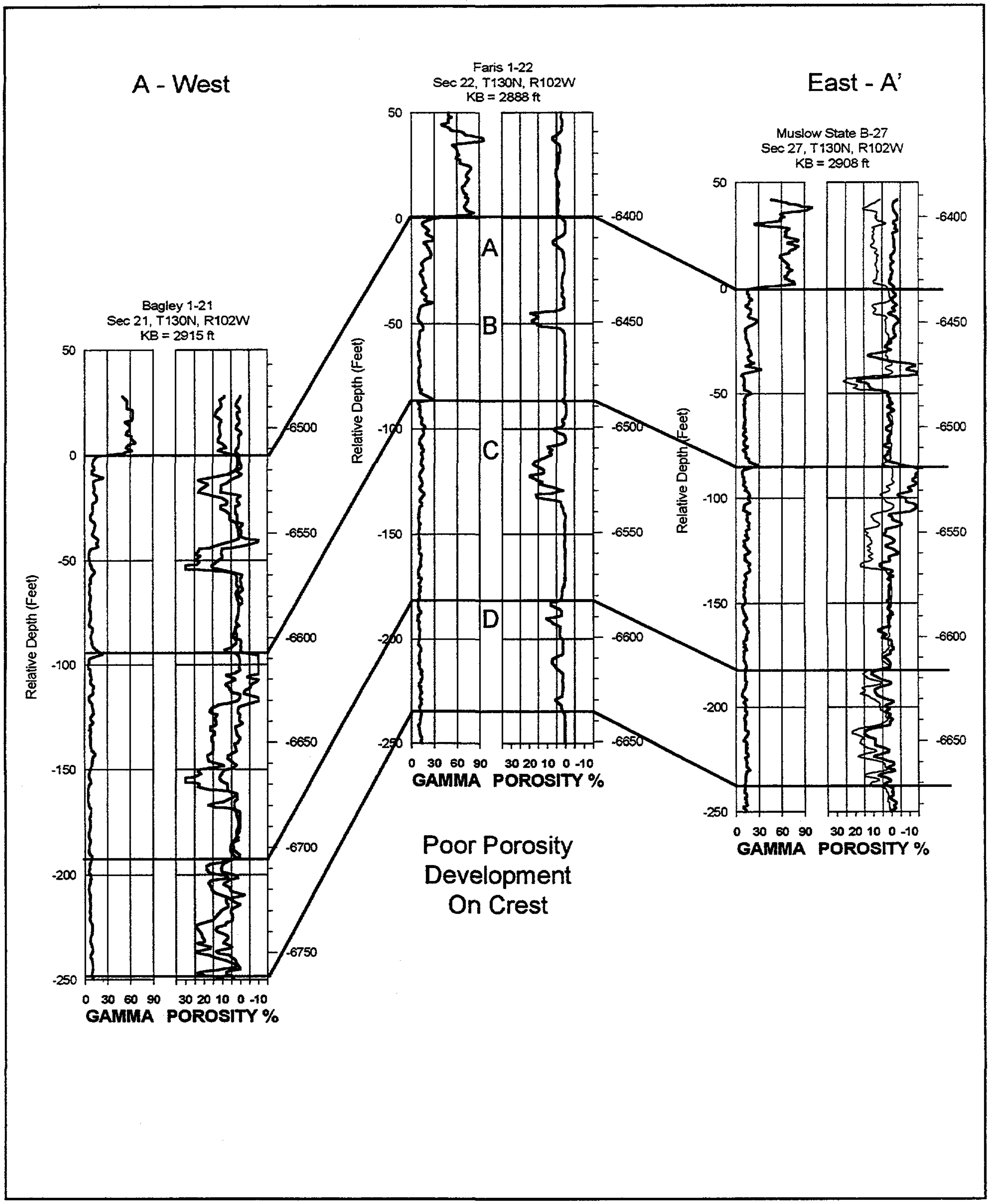


Figure 70: Structural cross-section of Red River at Cold Turkey Creek Field (feature 1). The crestal well has thin intervals and poor porosity. Flank wells have thicker intervals and better porosity.

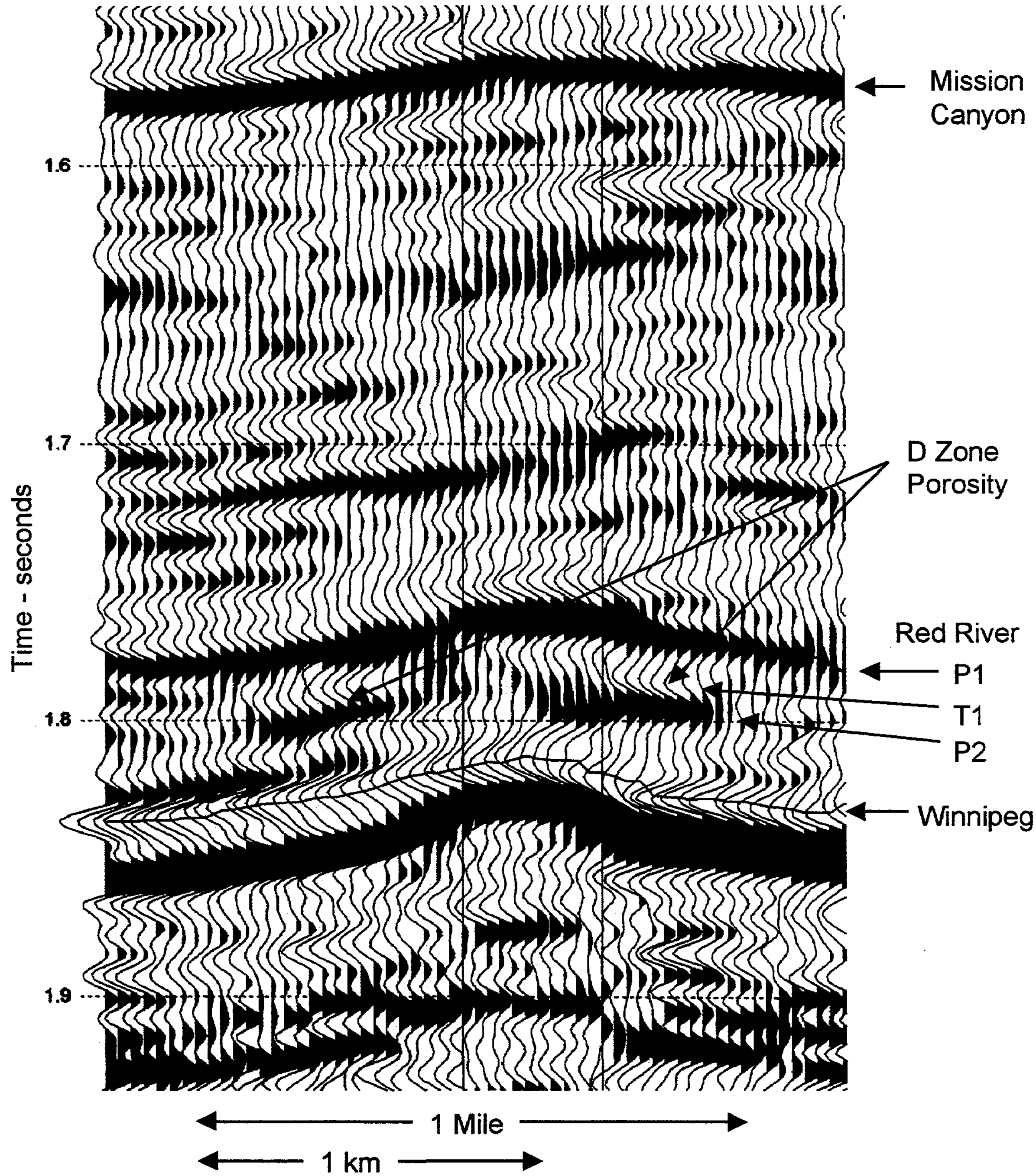


Figure 71: Seismic section from 3D survey at Cold Turkey Creek over feature 1.

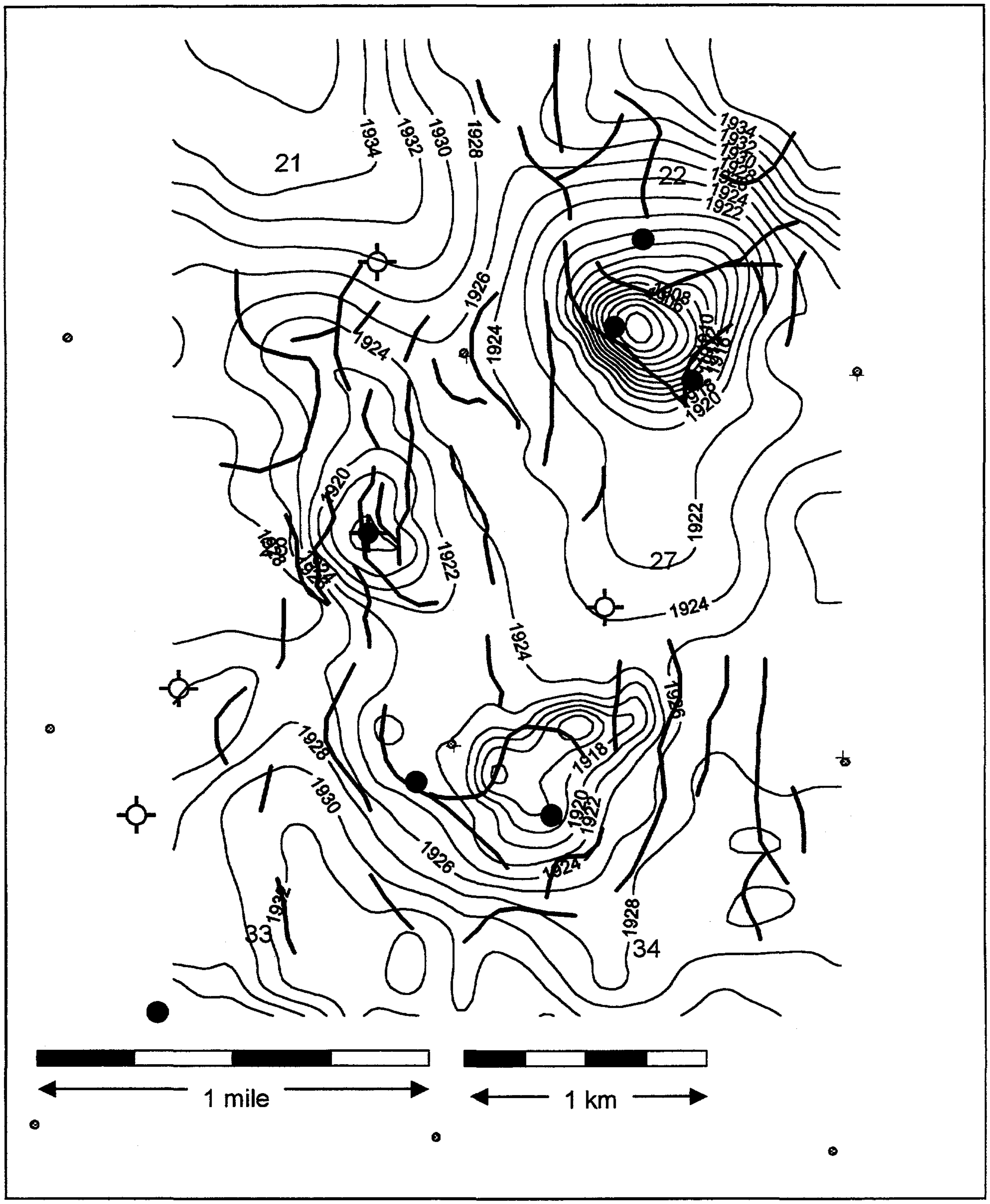


Figure 72: Interpretation 1 of faulting at base of the Red River D zone is shown with Winnipeg time structure. Contour interval is 2 msec.

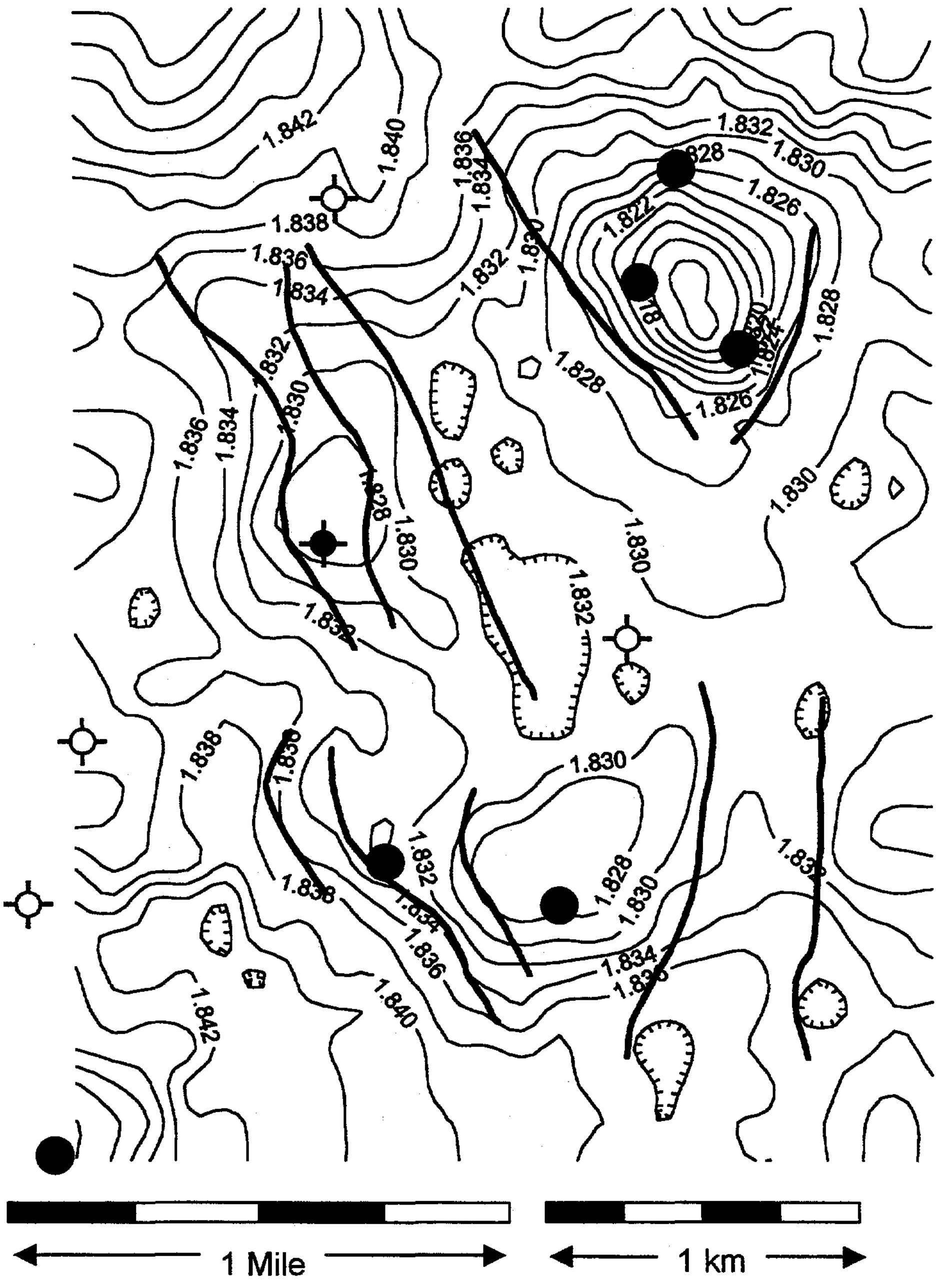


Figure 73: Interpretation 2 of faulting at base of the Red River D zone is shown with Winnipeg time structure. Contour interval is 2 msec.

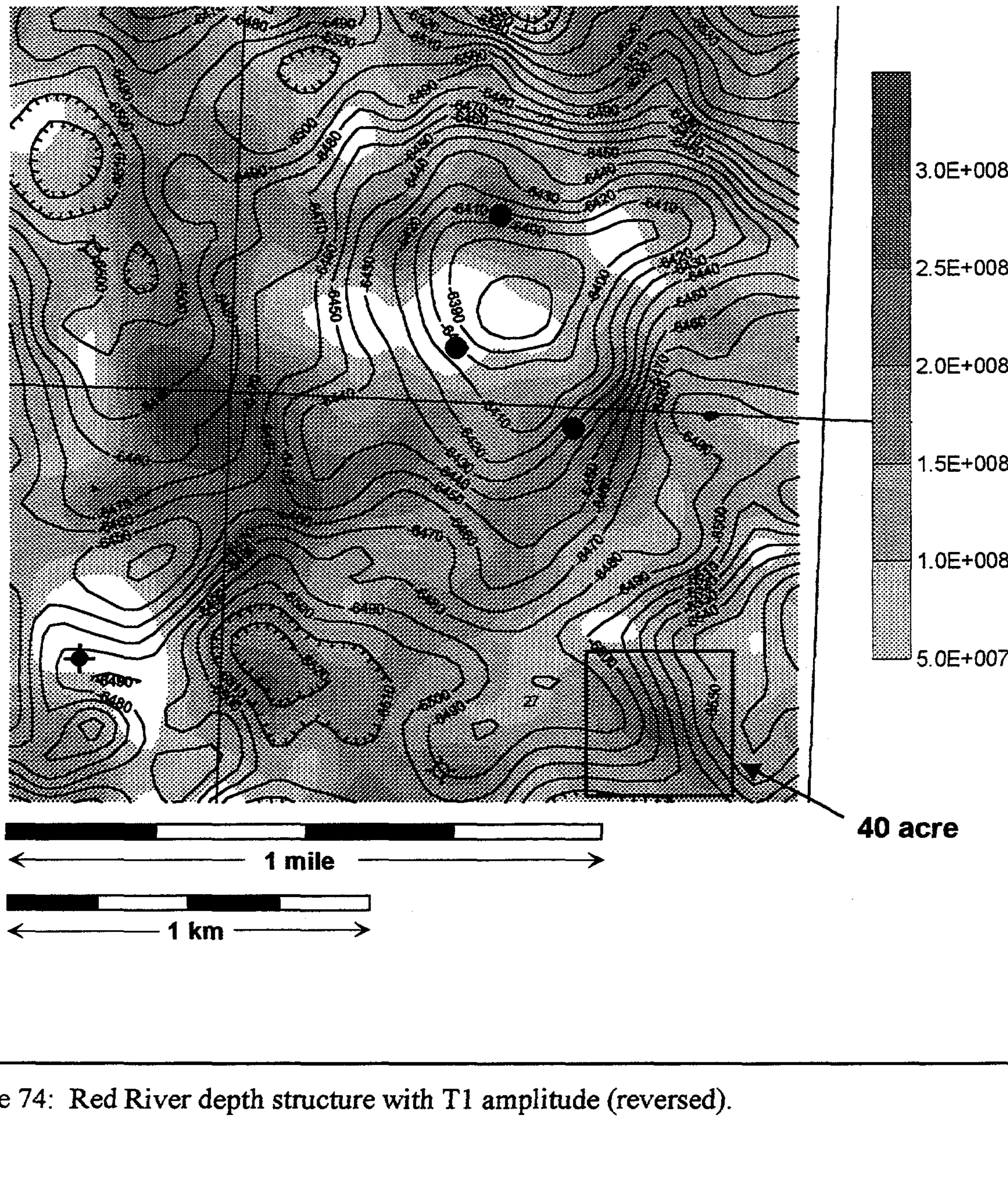


Figure 74: Red River depth structure with T1 amplitude (reversed).

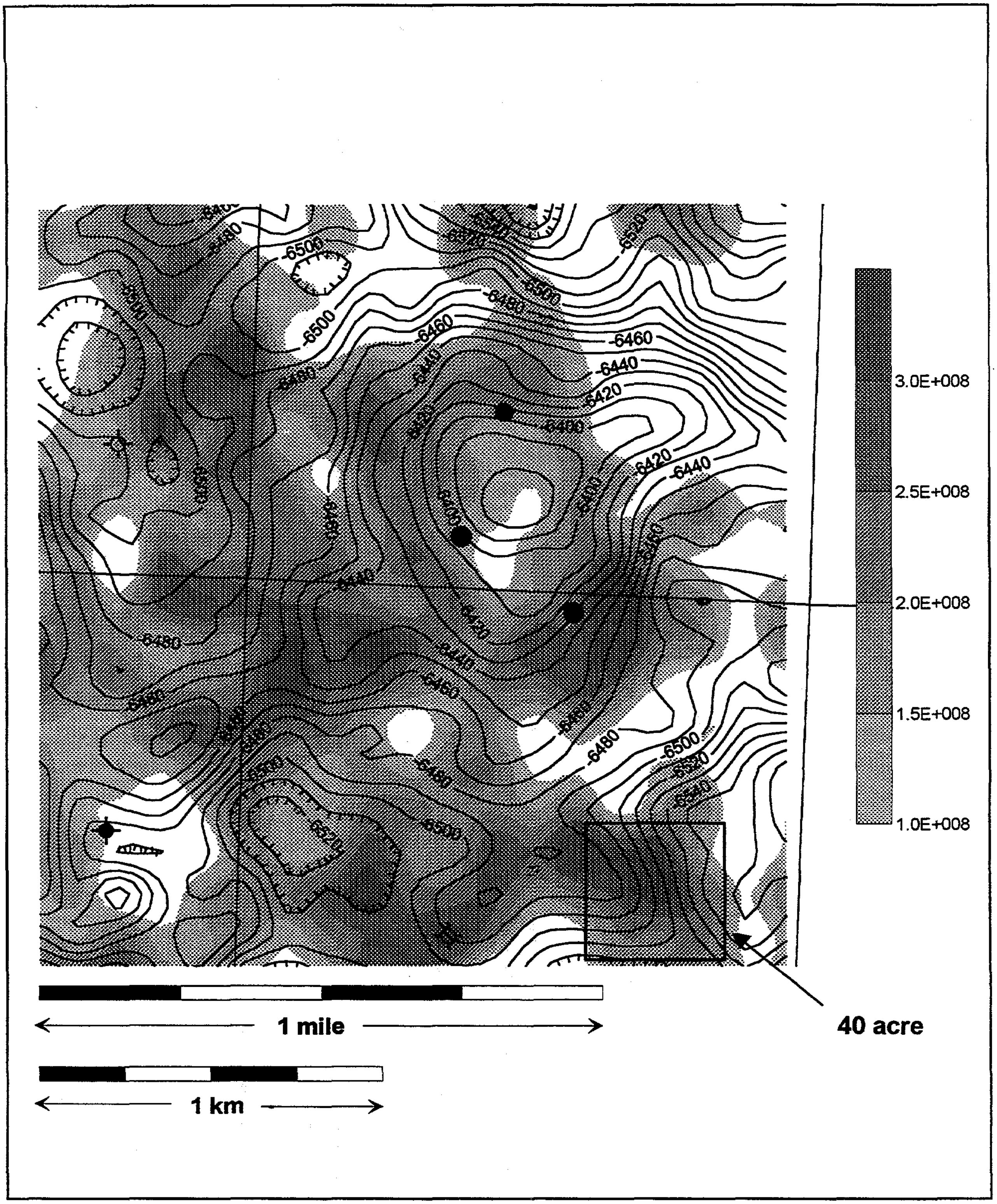


Figure 75: Red River depth structure with P2 amplitude.

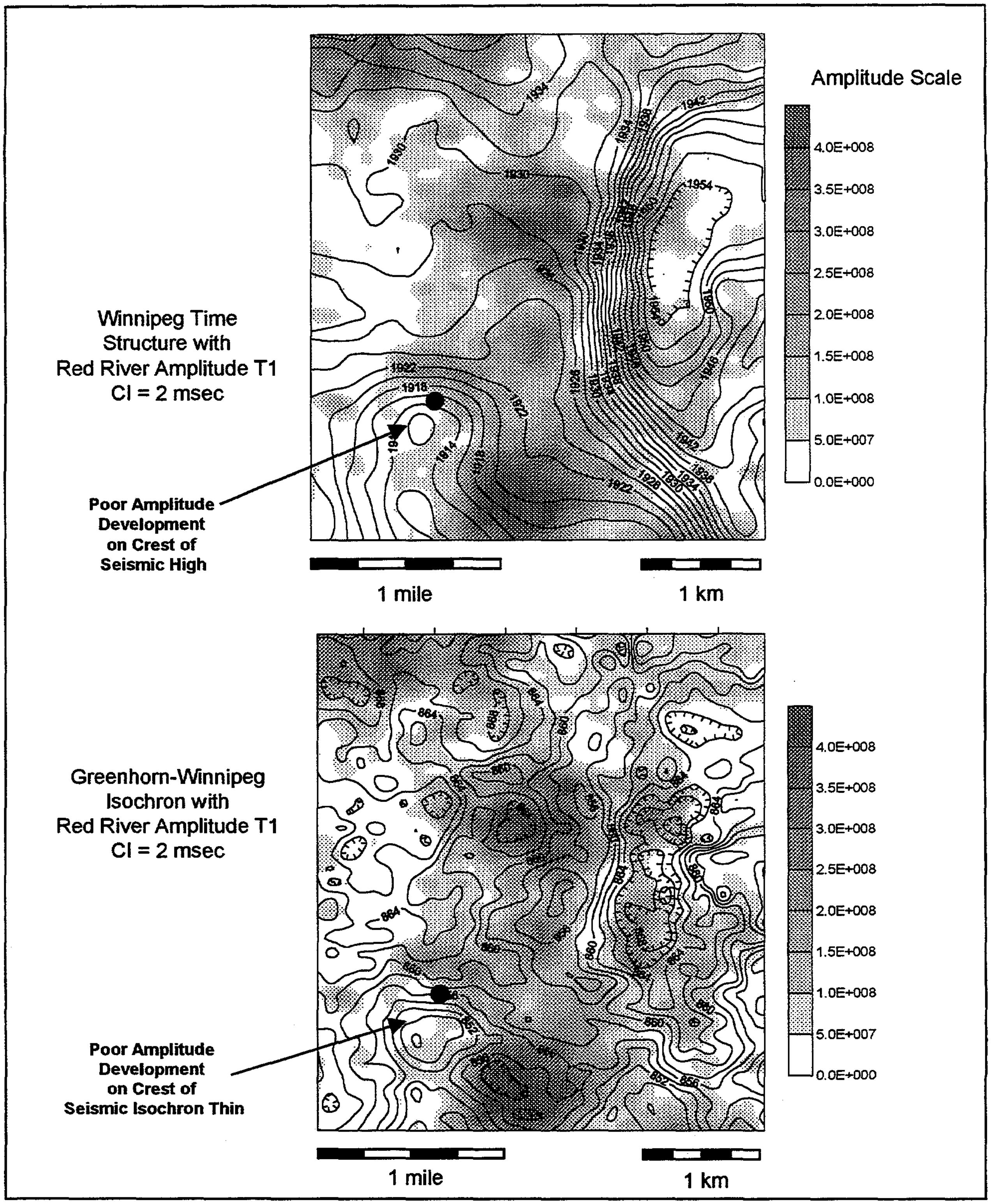


Figure 76: Interpretation from 3D seismic at Grand River School Field. Red River T1 amplitude (shaded) is shown with Winnipeg-time and Greenhorn-Winnipeg isochron contours. Amplitude indicates probable Red River D zone porosity development. Darker shading indicates better porosity development.

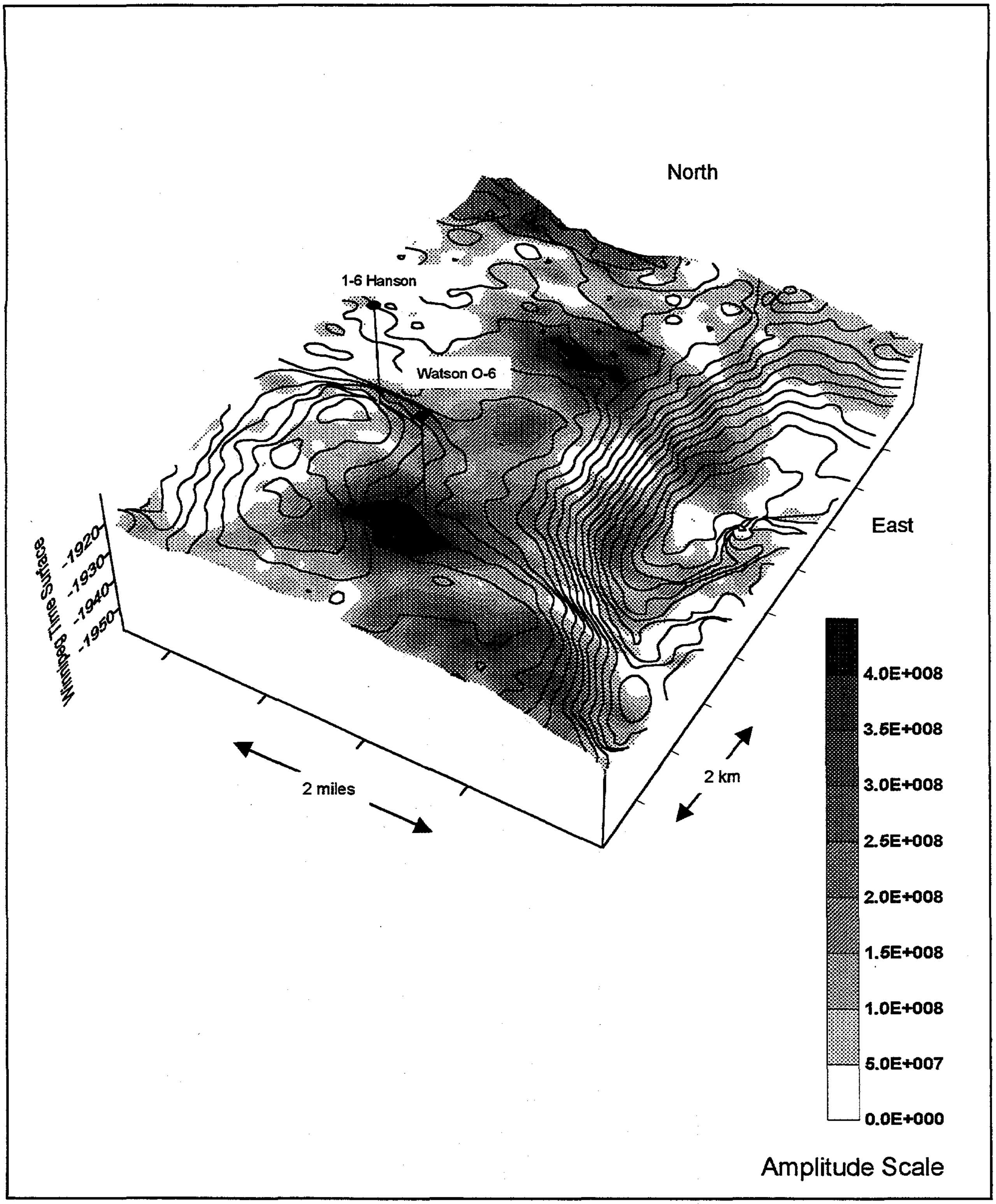


Figure 77: Perspective view of Red River T1 amplitude (shaded) on Winnipeg time contours at Grand River School Field. Darker shading indicates greater amplitude and porosity. The porosity follows the hinge line and appears to be associated with the fault on the east side.