

IMPROVED RECOVERY DEMONSTRATION FOR
WILLISTON BASIN CARBONATES

Final Report
1998

By
Mark Sippel

July 1998

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Luff Exploration Company
Denver, Colorado

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National Petroleum Technology Office
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FINAL REPORT

IMPROVED RECOVERY DEMONSTRATION FOR WILLISTON BASIN CARBONATES COOPERATIVE AGREEMENT DE- FC22-94BC14984

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FINAL REPORT

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Abstract

The purpose of this project was to demonstrate targeted infill and extension drilling opportunities, better determinations of oil-in-place, and methods for improved completion efficiency. The investigations and demonstrations were focussed on Red River and Ratcliffe reservoirs in the Williston Basin within portions of Montana, North Dakota and South Dakota. Both of these formations have been successfully explored with conventional 2-dimensional (2D) seismic. Improved reservoir characterization utilizing 3-dimensional (3D) seismic was investigated for identification of structural and stratigraphic reservoir compartments. These seismic characterizations were integrated with geological and engineering studies. The project tested lateral completion techniques, including high-pressure jetting lance technology and short-radius lateral drilling to enhance completion efficiency. Lateral completions should improve economics for both primary and secondary oil where low permeability is a problem and higher-density drilling of vertical infill wells is limited by drilling cost. New vertical wells were drilled to test bypassed oil in areas that were identified by 3D seismic. These new wells are expected to recover as much or greater oil than was produced by nearby old wells. The project tested water injection through vertical and horizontal wells in reservoirs where application of waterflooding has been limited. A horizontal well was drilled for testing water injection. Injection rates were tested at three times that of a vertical well. This demonstration well shows that water injection with horizontal completions can improve injection rates for economic waterflooding. This report is divided into two sections, part 1 covers the Red River and part 2 covers the Ratcliffe. Each part summarizes integrated reservoir characterizations and outlines methods for targeting by-passed oil reserves in the respective formation and locality.

FINAL REPORT
IMPROVED RECOVERY DEMONSTRATION
FOR WILLISTON BASIN CARBONATES
COOPERATIVE AGREEMENT DE- FC22-94BC14984

Executive Summary

This project applied certain characterization and completion technologies for improved production from Red River and Ratcliffe reservoirs in the Williston Basin. Reservoir characterization studies included 3D and multi-component seismic surveys. High-pressure jetting lance and short-radius lateral drilling technologies through existing wellbores were tested for improving primary recovery. New-well, medium radius horizontal drilling was tested for improving waterflooding.

Three vertical wells were drilled based on study of 3D seismic surveys in Bowman Co., North Dakota. These wells encountered by-passed oil in complex carbonate reservoirs at locations near old wells. The new wells were completed with an average initial rate of 190 bbl oil per day. Recoverable reserves from the demonstration wells are expected to equal or exceed reserves produced by the nearby old wells. Cumulative production from the old wells is 637,000 bbl oil. In addition to the reserves developed by the demonstration wells, further development potential was identified within the 3D seismic areas and will be tested in the near future.

Application of horizontal wells was tested for improved waterflooding. Thirty-day water injection tests were performed in both a vertical and a horizontal well in Harding Co., SD. A new horizontal well was drilled between two vertical wells that produce from a partially depleted Red River reservoir. Production and injection tests in this well indicate up to three times the productivity of nearby vertical wells. Data from these tests were used to predict long-term injection and oil recovery. These predictions precipitated a 12-month injection pilot using the horizontal injection well. Water injection was also tested in a vertical well in the Ratcliffe. This test indicates low potential for secondary recovery with vertical injection wells. The injection rate was less than 16 m³ water per day (100 bwpd).

Several technologies were evaluated for re-entry drilling of horizontal drain holes through casing for improving primary recovery. Tests of short and medium-reach jetting lance technologies were unsuccessful. Reservoir depths of 2590 to 2900 m (8500 to 9500 ft) are greater than appropriate for the mechanical capability of these tools. Steered, mud-motor drilling was mechanically successful. A re-entry lateral completion in the Ratcliffe was mechanically successful but did not increase production. A topical report was written that discusses these activities and their results (Carrell et al 1997).

Two 3D seismic surveys were obtained in the Red River area of Bowman Co., ND. These surveys revealed the complexity of reservoir porosity and were used to target wells for by-passed oil. A 3D seismic survey and a special shear-wave seismic survey were obtained in the Ratcliffe area of Richland Co., MT. The shear-wave survey was a failure. Fracture characterization in the Ratcliffe includes acquisition of an oriented core and a special electrical log at North Sioux Pass Field, Richland Co., MT.

Part One - Red River

Introduction

Detailed interpretations of attributes from three-dimensional (3D) seismic data can be used to successfully target development wells on flanks of small features of the Ordovician Red River. New wells, drilled at close proximity to mature wells, have encountered significant undrained and poorly drained oil reserves. The reservoir compartments, which develop on flanks of structures, can contain reserves that equal or exceed those developed by crestral wells. This case study is from an area in the southwestern Williston Basin shown in figures 1 and 2 that covers portions of Bowman Co., North Dakota and Harding Co., South Dakota.

Exploration for Red River oil reserves in the southwestern portion of the Williston Basin began in the 1940's with drilling on the Cedar Creek Anticline. This major feature of the Williston Basin was identified by surface mapping. In the early 1950's, single-point seismic data were used to extend Red River exploration along trend with the axis of the Cedar Creek Anticline into Harding county, SD. The advent of common-depth point (CDP) 2D seismic technology in the 1960's allowed delineation of small, deep structures. With this technology, operators began to develop many small structural features in the area. Exploration methods traditionally involved mapping time structure and isochrons of various horizons to identify paleo thinning and structural growth. Exploration and development strategies involved drilling one or two wells at crestral positions on small features. Well spacing has been 65 to 129 ha (160 or 320 acres) per well with producing depths from 2590 to 2900 m (8500 to 9500 ft). With the emergence of 3D seismic, it is becoming apparent that there are probably many opportunities to develop additional oil reserves in mature areas.

There are four porosity benches in the Upper Red River, labeled in descending order A, B, C and D zones. The Red River B and D zones contain the principal reservoirs in the area. Engineering studies of ultimate recovery from vertical wells in Red River reservoirs indicate that recovery ranges from 7 to 14 percent of volumetric OOIP in 129-ha (320-acre) spacing units. For comparison, maximum recovery by water-drive should be about 28 percent of OOIP. Most Red River B reservoirs produce by solution-gas and fluid-expansion drive while many Red River D zone reservoirs produce by moderate to strong water-drive. Many Red River reservoirs in the area have areal extent of less than 2.6 km² (1.0 sq. mile). Structural relief ranges from 15 to 30 m (50 to 100 ft). Primary reserves from the Red River B zone average 25,800 m³ (162,000 bbl) per well while Red River D zone completions recover an average of 59,100 m³ (372,000 bbl).

Exploitation of poorly drained reserves is possible where seismic amplitude anomalies, indicative of better porosity development, are found at sufficient structural position to be above an oil-water contact and have not been penetrated by existing wells. It is concluded that 3D seismic can provide a much-improved interpretation of structure and information about porosity development. 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. It was found that amplitude variation within the Red River interval is primarily diagnostic of porosity development in the D zone. 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 area of the amplitude anomalies ranges from 16 to 64 ha (40 to 160 acres).

Lateral completions should improve economics for both primary and secondary where low permeability is a problem and higher-density vertical wells is limited by drilling cost. Several technologies were evaluated for re-entry drilling of horizontal drain holes through casing for improving primary recovery. Tests of short and medium-reach jetting lance technologies were unsuccessful. Reservoir depths of 2590 to 2900 m (8500 to 9500 ft) are greater than appropriate for the mechanical capability of these tools. Steered, mud-motor drilling was mechanically successful. A new horizontal well was drilled between two vertical wells that produce from a partially depleted Red River reservoir.

Production and injection tests in this well indicate up to three times the productivity of nearby vertical wells.

The reader is also referred to previous topical reports (Carrel et al 1997; Sippel et al 1997) for additional discussions of Red River characterizations, field studies and demonstration activity.

Data Acquisition

Recording 3D seismic surveys and drilling of demonstration wells were performed during this cooperative project with the U.S. Department of Energy, National Petroleum Technology Office. The areas investigated cover Red River structures that have areal extent of less than 2.6 km² (1.0 sq. mile) and relief from 15 to 30 m (50 to 100 ft). The purpose of the seismic surveys was to determine if structural and porosity compartments can be observed and whether there is potential for developing additional reserves on small-bump features with previous production. Targeted drilling of three wells resulted in commercial production of poorly drained reserves at offset distances of less than 400 m (1300 ft) and down-dip from mature wells nearing depletion. The developed and probable reserve additions exceed the expected ultimate recovery of existing wells prior to acquisition of 3D seismic.

Two 3D seismic surveys were obtained in Bowman Co., ND using dynamite as source energy. Recording bin spacing was 33 m (110 ft). The surveys are separated by about 2.4 km (1.5 miles) and image the Red River in a similar setting and depth (figure 3). 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 km² (4.4 sq. 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 m³ (1,523,000 bbl) oil with an estimated ultimate recovery of 295,000 m³ (1,858,000 bbl). The Grand River School survey covered 17.1 km² (6.0 sq. miles) where there was only one well which had produced 41,700 m³ (262,000 bbl) oil.

Technologies for improving completion efficiency were also investigated. These technologies include high-pressure jetting lance and drilling of medium-radius horizontal wells. Detailed discussion of jetting-lance and drain-hole technology investigations can found in an earlier topical report (Carrell et al 1997). Lateral re-completions with high-pressure jetting lance equipment were not successful. Both 3-m and 15 m (10-ft and 50-ft) tools were tested. The 3-m (10-ft) tools did not improve productivity in tests at two wells. Working at reservoir depths of greater than 1830 m (6000 ft) is beyond the ability of the 15-m (50-ft) lance equipment. Down-hole mud-motor systems were the only successful technology for lateral completions at depths of 2590 to 2900 m (8500 to 9500 ft). A new horizontal well was drilled between two vertical wells that produce from a partially depleted Red River reservoir. Production and injection tests in this well indicate up to three times the productivity of nearby vertical wells. Data from these tests were used to predict long-term injection and oil recovery. These predictions precipitated a 12-month injection pilot using the horizontal injection well.

Reservoir Intervals

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

The base of the Red River is a gradational change from Ordovician Winnipeg Shale. The Red River is overlain by the Stony Mountain Shale (figure 4). The total Red River Formation thickness in the study area is slightly greater than 152 m (500 ft) between the Winnipeg shale and Stony Mountain shale. 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 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. 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 these 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). The primary intervals for oil production in the Bowman-Harding area are the B and D zones.

Numerical comparisons of rock properties observed in each of the porosity zones are presented in five tables at the end of this chapter. Table 1 summarizes porosity-permeability data from cores obtained in the study area. Table 2 shows the statistics of thickness and porosity from a large sampling of electrical logs. Porosity-thickness is the quantity that describes the storage capacity of an interval. Table 3 is a summary of transmissibility ($kh/\mu B$). Transmissibility is permeability-thickness divided by fluid viscosity and volume factor. This quantity describes the ability of an interval to transmit fluid. Tables 4 and 5 present typical oil reserves and drainage for a representative sampling of Red River D and B zone completions in the study area. These tables summarize what could be termed as functional characteristics of the Red River.

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 Red River D zone can develop the thickest reservoir interval and greatest permeability compared to the other Red River zones. Gross porous interval ranges in thickness from 12.1 to 25.9 m (40 ft to 85 ft). Average porosity is 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). Productive porosity has permeability, at the geometric mean, of $5.2E-3 \mu m^2$ (5.3 md). The D zone averages 77 percent of the flow capacity (kh) and 46 percent of storage ($\phi-h$) within the upper Red River.

The Red River D zone produces the most reserves per completion (comparing vertical wells). The Red River D zone was evaluated from 107 drill-stem tests and found to have a transmissibility ($kh/\mu B$) at the geometric-mean of $31.6E+6 \mu m^3 / Pa-s$ (105.1 md-ft/cp). The representative flow rate of these drill-stem tests is $38.0 m^3$ per day (239 bbl per day) at the geometric mean. A production study of 33 wells completed in the D zone is presented in table 4. It is concluded that a typical Red River D completion will recover between 20 and 25 percent of contacted OOIP where the 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).

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 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 younger intervals indicate high-relief paleo structure. Thick interval wells are found on flanks or low areas of paleo topography. This suggests that variation of thickness in the D zone is the result of 1) compensating deposition in low areas and 2) compaction with pressure dissolution resulting from uplifting shortly after deposition.

Red River C Zone

The Red River C zone is found at approximately 26 m (85 ft) from the top of the Red. Conventional permeability and porosity data from three cores of the C zone indicate an average gross porous thickness of 11.6 m (33 ft) with a geometric-mean permeability to air of $8.9\text{E-}4 \mu\text{m}^2$ (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 total potential storage. The Red River C zone exhibits a wide range of porosity development and storage capacity. From digitized electrical log data, 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). The low permeability of the C zone is caused by small pore-throat size in cryptocrystalline porosity that 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 was evaluated from 86 drill-stem tests and found to have a mean value for $kh/\mu B$ of $3.28\text{E}+6 \mu\text{m}^3/\text{Pa-s}$ (10.9 md-ft/cp). The geometric-mean flow rate from these tests was determined to be 6.0 m^3 (38 bbl) per day. The low number of tests attest to the lack of shows found in this interval. Most drill-stem test recoveries from the C zone consist of mud and water without free oil. Generally, 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. None of the non-commingled C zone completions has produced economical reserves that would pay for drilling costs.

Red River B Zone

Among the four porosity zones of the Red River, the B zone is the most widespread and consistently developed. Cores, electrical logs and drill-stem tests indicate a narrow range of porosity and permeability. The Red River B zone is found at approximately 12.2 m (40 ft) from the top of the Red River. Unlike the lower C and D zones, the B zone consists of one contiguous block of porosity. 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; Schowalter and Hess 1982). An arbitrary cross-section of the Red River A and B zones is shown in figure 7. 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 (9.4 ft). Productive porosity averages 18.4 percent with permeability of $4.2\text{E-}3 \mu\text{m}^2$ (4.3 md) at the geometric mean. The B zone typically develops 15 percent of the combined flow capacity and 16 percent of the combined potential storage. The average storage capacity (fractional thickness) is 0.57 m (1.76 ft) with a value at one standard deviation above the mean of 0.91 m (2.50 ft).

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

Production data from the Red River B zone across the Bowman-Harding area were analyzed from 35 wells, which were completed only in this zone. Table 5 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 with poor permeability, lower gravity oil and dissolved gas, have recovery factors of 6 to 10 percent of OOIP. In deeper portions of the study area where 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.

Red River A Zone

There is limited production from the Red River A zone and very few cores exist from this interval. The Red River A zone is found approximately 3 m (10 ft) from the top of the Red River 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. 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 $1.0E-3 \mu\text{m}^2$ (1.0 md).

The A zone has not been documented to have produced oil in commercial quantities by isolated drill-stem test or perforation in the Bowman-Harding area. When the A zone has been perforated, it has been produced commingled with other zones. It is generally considered a non-reservoir interval in the area. There are too few isolated cores or drill-stem 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.

Reservoir Heterogeneity and 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.

Structural Closure

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 framework (Thomas 1974; Brown and Brown 1987). Many of the small-bump features exhibit structural relief from 15 to 30 m (50 to 100 ft) from a base of 0.8 to less than 1.6 km^2 (0.5 to 1.0 square mile). A typical small-bump feature from Bowman Co., ND is shown in figure 8.

Faulting

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 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. 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 that affected late-burial diagenesis. An example of faulting at Winnipeg time is shown in figure 9, which is an example cross-section from a 2D seismic line in Harding Co., SD.

Porosity Variation

An area of the Horse Creek Field in Bowman Co., ND has been described as a stratigraphically trapped reservoir in the Red River D zone with no structural closure (Longman et al 1992). 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 stratigraphic intervals can still be correlated with down-dip wells. On several structurally closed features, there are examples of reduced porosity and thickness in the Red River B and D zones at crestal wells with flank wells having much better porosity and thickness.

Pore-throat Size

Mechanisms for stratigraphic trapping of B zone reservoirs at Buffalo Field, Harding Co., SD were discussed by Schowalter and Hess in 1982. The stratigraphic 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 were one continuous accumulation, the maximum oil column would be about 122 m (400 ft). They 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.

Targeting Reservoir Compartments

From reservoir characterization studies, it is clear that there are two types of reservoir compartments that may be targeted from 3D seismic. These are structural-fault compartments and stratigraphic-porosity compartments. As the Red River D zone exhibits the greatest porosity-thickness and variation, it is most susceptible to producing a measurable change in seismic attribute response. Many examples can be found where porosity is poorly developed on the crest of structural features. Because reservoir-quality porosity was the result of late-burial dissolution and diagenesis, the distribution of porosity blooms are not easily predicted without seismic imaging.

Seismic Modeling

An extensive modeling study was done to evaluate 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. The seismic responses of porosity zones within the Red River A, B, C, and D zones were 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 10, which demonstrates seismic response to important horizons from the Mission Canyon to Winnipeg. Average depths to the Mission Canyon and Winnipeg are 2408 m and 3078 m (7900 ft and 10,100 ft), respectively. These depths 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. These events are: 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 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 transit time and bulk density is shown in figure 11. Minimum and maximum values for porosity 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 12). In addition, an increase in B zone porosity causes a decrease in the amplitude of trough T1, which underlies 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 suggests 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 13). 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. In addition, a lower trough (T2) develops with an increase in D zone porosity that 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 14. Visual comparison of figure 14 (increasing B and D zone porosity) to figure 13 (increasing only D zone porosity) demonstrates the dominance of D zone variation.

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: 1) amplitude of trough T1 and 2) peak P2. The third map would be a combination (sum of absolute values) 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 concluded that porosity development within the D zone may be discerned and mapped with accuracy to a minimum thickness of 5 m (15 ft). 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.

Seismic Interpretation

Two 3D seismic surveys were obtained in Bowman Co., ND. The surveys are separated by about 2.4 km (1.5 miles) and image the Red River in a similar setting (figure 3). 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 km² (4.4 square miles) and three structurally isolated features. Four producing wells and four dry holes were drilled prior to the survey in 1995. These wells produced 242,000 m³ (1,523,000 bbl) oil, as of 1996, with an estimated ultimate recovery of 295,000 m³ (1,858,000 bbl).

Structural feature 1 (location shown in figure 15) has an areal extent, based on seismic time-structure and isochron maps, of 174 ha (430 acres). Critical closure of the Red River at feature 1 is estimated at about 30 m (100 ft) based on well-log and seismic data. The potential OOIP for the combined B and D zones could be 1,192,000 m³ (7,500,000 bbl). Recoverable oil at 15 percent of the potential OOIP is estimated at 179,000 m³ (1,120,000 bbl). The cumulative oil from the Faris No. 1-22, pre-existing well on feature 1, was 59,600 m³ (375,000 bbl) in 1997. The under-developed reserves, which could be contacted by additional drilling on feature 1, were estimated at 105,000 m³ (655,000 bbl), suggesting a sufficiently rich target for exploitation drilling.

A seismic-time cross-section over structural feature 1 is shown in figure 16. The cross-section demonstrates the amplitude variation of trough T1 and peak P2 previously described in the modeling section. The data show amplitude response of D zone porosity is preferentially developed on the flanks of the feature and poorly developed on the crest. The seismic response and interpretation are supported by the fact that the Faris No. 1-22 well has poor porosity development in all zones. A structural cross-section shown in figure 17 shows how porosity and thickness of each zone increases down-dip from the

crest of the feature. One of the objectives of the 3D seismic survey was to assess the distribution of porosity development on small-bump features.

A time-structure map at the Winnipeg horizon is shown in figure 18. Superimposed on the time contours is shading that represents amplitude variation of the Red River seismic event T1. Darker shading indicates stronger amplitude. Each of the three structural features exhibits a low-amplitude area at or near the crest of the Winnipeg time structure. The strongest amplitude response is indicated in low areas; however, the amplitude blooms are random and spotty. Overlaying the amplitude of Red River seismic event T1 on the isochron map of Greenhorn to Winnipeg is shown on figure 19. Similar to the Winnipeg time-structure map, the greater amplitude response is generally found on flanks and low areas but the amplitude does not indicate a consistent correlation with the isochron. In similar fashion, the amplitude of T1 is shown with isochrons of the Greenhorn to Mission Canyon and Mission Canyon to Winnipeg on figures 20 and 21, respectively. Visual inspection of these maps indicates that amplitude variation does not correspond to one isochron better than another isochron.

It is concluded that porosity development in the Red River D zone is randomly developed but less likely to be developed on the crest of paleo structure and more likely to be developed in flank and low areas. Targeting optimal locations for Red River D zone development becomes a compromise of structural position a maximum amplitude response. A map of computed Red River depth structure and T1 amplitude for structural feature 1 is shown in figure 22. This display was the basis for targeting locations to test for undeveloped reserves in the Red River on structural feature 1. The Red River depth was computed from the Greenhorn to Red River isochron which converted to thickness from a velocity field that was determined from well control. This thickness map was hung from the Greenhorn subsea structure that was based on well-log depths. The resulting structure map indicates relief of 21 m (70 ft) to spill-point. There are five porosity blooms above the spill-point depth. There were several questions which could only be answered by drilling: 1) are the porosity blooms hydraulically isolated from each other, 2) do they have a common oil-water contact or water-saturation with depth profile, and 3) do they contain sufficient reserves that are economic targets?

Targeted Drilling

The Muslow-State B-27 was drilled on feature 1 to test a seismic-amplitude anomaly in the Red River, which is down-dip from the Faris No. 1-22 well. The Faris No. 1-22 well is perforated in the Red River B, C, and D zones; however, net thickness of each zone in this 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 structural crest. The Muslow-State B-27 well is located 389 m (1275 ft) southeast from the original well. A stratigraphic cross-section is shown in figure 23 that compares the Muslow-State B-27 and Faris No. 1-22 wells.

The Muslow-State B-27 encountered oil production in the B and D zones based on drill-stem tests. The B zone DST recovered oil, drilling mud and mud filtrate. 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 new well is in pressure communication with the Faris No. 1-22. The C zone was drill-stem tested and found to have very poor permeability and near-original pressure. The D zone recovered oil and water on drill-stem test at near-original pressure. It is not known how much production at the older well has been from the D zone as all perforated intervals have been produced down-hole commingled. After perforation and acidizing the D zone the Muslow-State B-27 well was completed with a production rate of 26.4 m³ oil and 21.1 m³ water per day (166 bopd and 133 bwpd) during December 1996. Cumulative oil production through December 1997 was 7052 m³ (44,361 bbl).

Six months later, during July 1997, the Pang-Faris K-22 was drilled on structural feature 1 to test a seismic-amplitude anomaly on the opposite flank of the feature from the Muslow-State B-27 well. This well penetrated the Red River at a depth about 16 m (53 ft) below the structural crest. Drill-stem tests 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 in this interval with the Faris 1-22 and Muslow-State B-27 wells. The drill-stem test in the D zone recovered about 2190 m (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 m³ (175 bopd) per day at 690 kPa (100 psi) wellhead pressure with no water during July 1997. A stratigraphic cross-section is shown in figure 24 that compares the Pang-Faris K-22 and Faris No. 1-22 wells.

The cumulative oil produced from the two new wells on structural feature 1 was about 9860 m³ (62,000 bbl) through December 1997. Extrapolation of the oil-rate data suggests ultimate recovery from the D zone for these wells of 63,600 m³ (400,000 bbl). Each well also has behind-pipe oil reserves in the Red River B zone. The producing rate at the Faris No. 1-22 well has remained unchanged following completion of the new wells. Figures 25 and 26 depict the production history and extrapolation of old and new wells at structural feature 1, Cold Turkey Creek Field.

Drill-test and completion data from the two new wells suggest dissimilar water-saturation-with-depth profiles for the two porosity blooms. Pressure data from the drill-stem tests suggest probable hydraulic communication of the D zone; the Pang-Faris K-22 drill-stem test recorded pressure which was about 2100 kPa (300 psi) less than that measured seven months earlier at the Muslow-State well. Calculations of water saturation from electrical logs suggest similar water-saturation gradient with depth and extrapolation to a down-dip productive limit, which matches the apparent structural spill-point. At the end of 1997, both wells were producing with a similar water-cut of about 50 percent.

The Grand River School 3D seismic survey was acquired over an area that exhibits strong structural relief from the regional trend. The Hanson No. 1-6A well was drilled and completed more than 20 years ago on the crest of this feature. This well was perforated in the B, C and D zones that are thinly developed with low porosity. Cumulative oil production was 41,700 m³ (262,000 bbl) through 1997. Interpretation of certain seismic data from the Grand River School 3D survey are shown in figure 27. This figure is a map of Winnipeg time with amplitude relevant to the Red River D zone. The interpretation indicates the Red River D zone is poorly developed on the crest and better developed in random blooms on the flank. The porosity blooms appear related to a steep north-south hinge.

Following results from identification of porosity and drilling at Cold Turkey Creek Field, the Watson O-6 was drilled 0.95 km (0.59 mile) southeast from the Hanson No. 1-6 well. The well was drilled to test amplitude character of Red River events, which indicate thicker and more porous D zone development. This amplitude character is not coincident with the high point on seismic-time structure maps or thinnest point on isochron maps (figure 27). Drill-stem test of the Red River B zone indicates communication with drainage from the Hanson well as the measured reservoir pressure was 15,200 kPa (2200 psi). 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 drill-stem test with an extrapolated rate of 76.3 m³ per day (480 bopd) based on pipe recovery. Reservoir pressure was undisturbed from original at 26,900 kPa (3900 psi). Wire-line 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. A stratigraphic cross-section comparing the Watson O-6 and Hanson No. 1-6 is shown in figure 28. The Red River D zone was perforated in September 1997 and the well placed on pump with an initial rate of 35 m³ oil and 6 m³ water per day (220 bopd and 40 bwpd). Cumulative oil production through December 1997 was 3970 m³ (25,000 bbl). A graph of production history at Grand River School is shown in figure 29.

Results from the Watson O-6 are similar to those from the two new wells at 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 with seismic amplitude. Porosity in the Red River D zone is poorly developed on the seismic crest of the structure. There is an excellent match of predicted Red River D zone porosity and electrical log data.

Economics

Drilling costs to test Red River reservoirs at 2900 m (9500 ft) were approximately \$400,000 in 1997. A completed well cost approximately \$800,000. For small surveys, costs for 3D seismic acquisition with processing average \$45,000 per square mile (2.6 km²). A small survey to evaluate one or two small-bump features might require from 5.2 to 10.4 km² (2 to 4 square miles) of coverage for a cost of \$90,000 to \$180,000. It is obvious from the examples that the cost of 3D seismic is much less than the cost of a dry-hole and provides more information.

The successes from the drilling of three wells on the two 3D seismic surveys indicate that drilling for flank reserves in the Red River D zone can be economical. Both of the small-bump features have poor porosity development on the crest, which is indicated from seismic amplitude and confirmed by electrical logs. Both features have old wells, which were perforated in the D zone that was commingled with the Red River C, and B zones.

Attractive economics are indicated using ultimate recoverable reserves that are apparent from extrapolation using an harmonic decline over a 20-year life. The average ultimate recovery of the three wells is projected at 31,800 m³ (200,000 bbl) per well. The initial rate averages 30 m³ (190 bbl) oil per day. Based on an oil price of \$18.00 per bbl, future income (after drilling, operating costs, royalty and state production taxes) is calculated to be slightly more than \$1,000,000 per well. A discounted rate-of-return of about 32 percent is calculated for a completed well cost of \$800,000. At a recovery of 23,800 m³ (150,000 bbl), the rate-of-return is about 16 percent. The economics for a completed well are break-even if reserves are only 15,900 m³ (100,000 bbl).

Horizontal Wells for Improved Recovery

From results of characterization study and demonstration wells, several conclusions were reached regarding reservoir heterogeneity and compartments. The Red River D zone exhibits great variation in porosity development and can be imaged from 3D seismic. The Red River B zone is, relatively speaking, the most consistent reservoir interval with regard to thickness, porosity and permeability. The Red River B zone is too thin and lacks enough variability to be targeted from seismic. The producibility problem of the Red River B zone is primarily low permeability. Pressure data from the vertical demonstration wells, and many others, indicate that a completion in the Red River B zone will affect a large drainage area. Partial depletion of reservoir pressure has been observed at distances greater than 3 km (2 miles) from old wells. It is an ideal candidate for lateral drain-holes because the constant thickness and stratigraphic position make it an easy drilling target to follow. Pressure-transient tests, reservoir simulation and the drilling of a horizontal well were performed during the project to compare horizontal with vertical completions in the Red River B zone for improved primary and secondary recovery.

Data and Analysis from Vertical Wells

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 30. 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 m³ per day (100 bwpd) for 600 hrs and then shut-in for 120 hrs. Bottom-hole 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 m³ 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 μm² (0.6 md) and a stimulation factor (S) of -2.4. The static reservoir pressure was determined to be 10,200 kPa (1474 psi). Pressure buildup and falloff analyses indicate radial-flow characteristics. The

original drill-stem-test data of the Red River injection interval indicate permeability to the water phase of $0.64\text{E-}3 \mu\text{m}^2$ (0.65 md).

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 shown on figure 31. 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 water-cut was 49.5 percent. An absolute permeability of $2.5\text{E-}3 \mu\text{m}^2$ (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 $4.5\text{E-}4 \mu\text{m}^2$ (0.46 md) which is in good agreement with the permeability to water of $5.9\text{E-}4 \mu\text{m}^2$ (0.60 md) determined by well-test analysis and analytical simulation. 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. The resulting pseudo steady-state injection pressures with rate are shown in figure 32. 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 bottom-hole pressure of 34,500 kPa (5000 psi).

Data and Analysis from Horizontal Wells

The M-20H Stearns (Sec. 20, T.22N., R4E.) was drilled in December 1996 as a horizontal well for the purpose of evaluating oil productivity and water injectivity in a mature, partially depleted reservoir in the Red River B zone (figure 30). A drill-stem 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. Because of lost circulation and losing the bottom-hole 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.

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 that has 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 m^3 per day (550 bwpd) for the remainder of a 30-day test. The recorded pressure data are shown on figure 33. The final pressure at reservoir depth of 2670 m (8760 ft) was 27,920 kPa (4050 psi).

A single-layer, finite-difference black-oil reservoir model was constructed to history match the water injection test data from the M-20H Stearns. This computer model was successful in matching the injection-test pressure data. 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. The reservoir parameters which matched producing water-cut and pressure were permeability of $5.3\text{E-}3 \mu\text{m}^2$ (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 injection pressures shown in figure 32. 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 m³ 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 of the vertical completion at the A-19 Stearns.

At commencement of this project in 1993, there were no horizontal wells drilled in the Red River study area. In 1994, a significant horizontal drilling play began in the northwestern portion of the study area in Bowman Co., ND in townships T.131N., R.105-106W. The horizontal wells drilled in this area have laterals that average about 914 m (3000 ft) in the Red River B zone. Analysis of production data from ten wells with more than 18 months of history demonstrates that these wells have about 3.5 times the oil rate at initial semi-steady-state conditions compared to typical vertical wells completed in the Red River B zone at Buffalo Field (north area). Core and log data of the Red River B zone at Buffalo Field (north area) exhibit similar thickness, porosity and permeability to that in the horizontal-play area. After 18 months from initial completion, normalized production from the horizontal wells averages 18 m³ oil per day (113 bopd) compared to 7.3 m³ oil per day (46 bopd) at Buffalo Field. Comparison of transmissibility (kh/μB) to oil for the horizontal wells to the vertical wells indicates an improvement by a factor of 2.9 to 1.0. Ultimate reserves from the ten horizontal wells should average at least 58,800 m³ (370,000 bbl) per well. This represents improvement by a factor of 2.3 to 1.0 over the average ultimate recovery (25,800 m³ or 162,000 bbl) from vertical wells in the Red River B zone.

Conclusions

In the southwestern portion of the Williston Basin, there are four porosity zones in the upper Red River. These are, from youngest to oldest, the A, B, C and D zones. Only the Red River B and D zones are considered to have commercial oil potential. Comparisons of core, electrical log, and drill-stem test data show that the Red River D zone is the most heterogeneous of the porosity zones. It is also the richest target for drilling because of potential porosity-thickness and permeability. The Red River B zone, although variable, does not exhibit the same degree of compartmentalized behavior as the Red River D zone.

Throughout the Williston Basin, there may be significant oil reserves hidden on the flanks of previously drilled structural features and 3D seismic will play an important role in exploiting these hidden reserves. This appears especially true where recording high-frequency seismic data is possible as in the southwestern portion of the Williston Basin. Keys to successful interpretation of 3D seismic data are understanding the reservoir response from seismic modeling and proper processing.

Examples were shown where porosity development in the Red River D zone was successfully imaged with amplitude response. Porosity development in the Red River D zone is random and spotty but most likely to be found in low areas and at flank position on structural features. The typical area of porosity blooms) at two seismic surveys was found to range from 16 to 65 ha (40 to 160 acres). Porosity changes in the Red River B zone do affect seismic response in synthetic models; however, in practice the changes are too subtle to confidently target the best location for this reservoir. Net thickness of the Red River B zone is typically about 2.9 +/- 0.9 m (9 +/- 3 ft) while the Red River D zone averages 5.4 +/- 4.5 m (18 +/- 15 ft).

Three wells were drilled on two small-bump features that have relief of about 30 m (100 ft) and cover about 1.3 km² (0.5 sq. mile). Each of the features has poor porosity in the Red River D zone on the crest, which is indicated from seismic amplitude and confirmed by electrical logs. Both features had old wells that were completed more than 20 years ago and produced above-average oil reserves. Testing and completion data from the new wells provide important information regarding reservoir compartments in the upper Red River. Drill-stem tests of the Red River B zone showed that the interval was pressure depleted from the original well. Extrapolation of early production data indicate that reserves from the Red River D zone in the new wells should be equal or exceed those produced by the original crestal wells.

Recommendations

Investigations undertaken at the study area have led to several recommendations for possible further research in three areas. The first subject concerns length of effective laterals in horizontal completions. The second subject is refined prediction and correlation of thickness and porosity with seismic attributes. The third is prediction of oil-column height.

The horizontal well drilled at the Buffalo Field (north area) has a relatively short lateral because of drilling problems. Yet, the apparent completion efficiency is comparable to horizontal wells with laterals of 900 m (3000 ft) or more. It would be valuable to know if there is an optimum length that can be applied for cost-effective wells. Phrased as a question, is 90 percent of horizontal-well productivity the result of the first 150 m (500 ft) and 95 percent the result of 300 m (1000 ft)? A possible demonstration test for this question could be made by drilling a lateral to successive greater lengths with stabilized injection tests performed for each length.

Prediction of porosity and thickness, as applied in this project, relied on qualitative assessment of amplitude. There are several other seismic attributes which could be used for this purpose. It would be useful to compare various attributes from a 3D seismic survey with good electrical log data from a statistically meaningful number of wells. Also, a correlation of amplitude (or other attribute) area with reserves or drainage area would aid the economic-assessment process.

Finally, there is the question of oil-column and transition-zone height. In the setting of small structural features, it is difficult to predict the gradient of water-saturation with depth. An empirical case study supplemented with capillary-pressure and simulation study may be warranted.

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Tables

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 (h) 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 (h) - mean	0.52 ft	1.76 ft	1.88 ft	2.72 ft
(h) + 1 standard deviation	0.98 ft	2.50 ft	2.98 ft	5.51 ft
(h) maximum	1.31 ft	3.20 ft	5.80 ft	15.75 ft
Porosity () – mean	8.3%	18.4%	12.7%	14.6%
() + 1 standard deviation	10.9%	23.2%	15.7%	21.3%

Table 3: Transmissibility (kh/μB) of Red River from Drill-Stem Tests

Porosity Interval	Median	Geometric 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 4: 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 5: 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

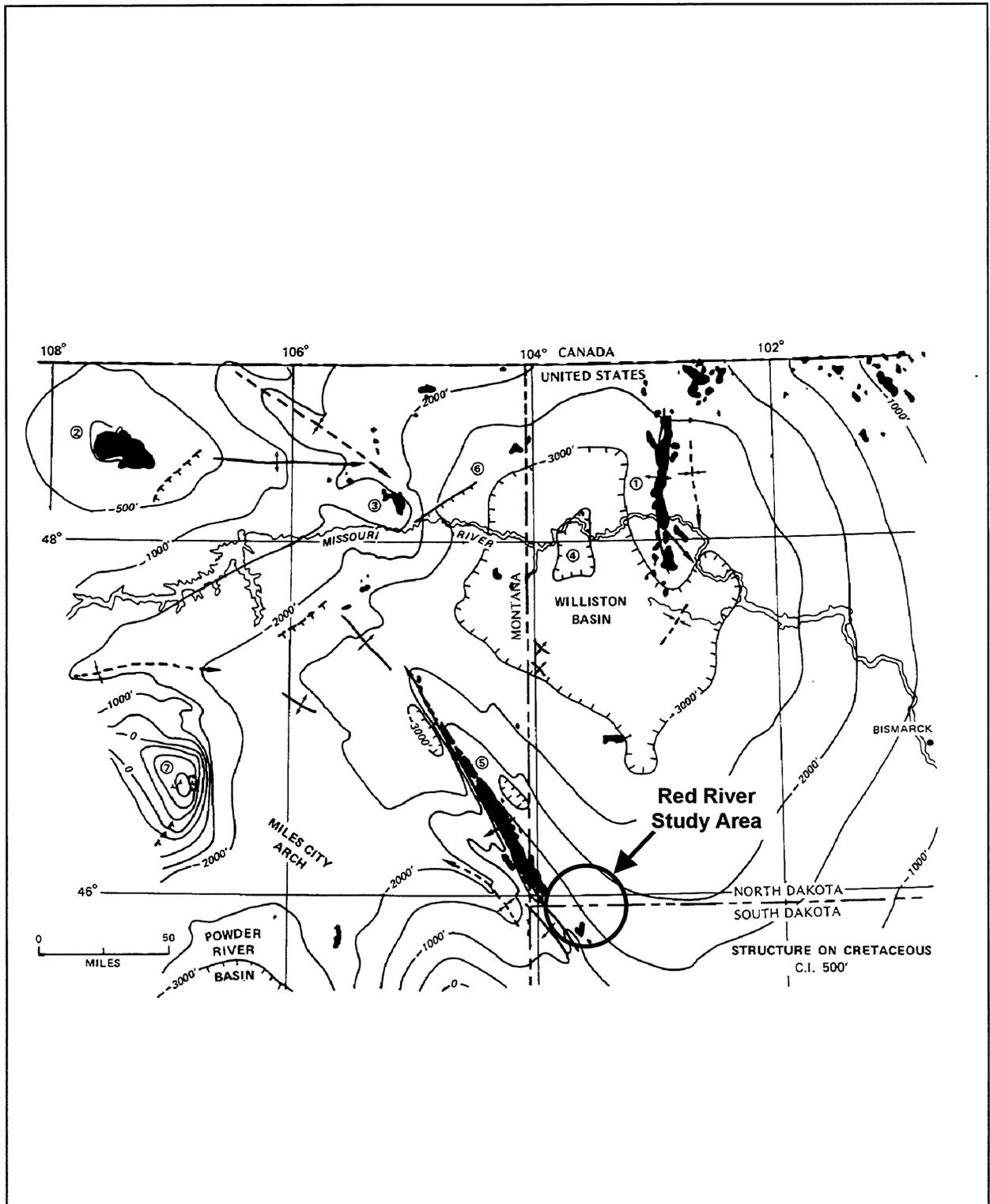


Figure 1: Map of the Williston Basin with Red River study area. The Red River study area straddles the state line between North Dakota and South Dakota in Bowman and Harding counties.

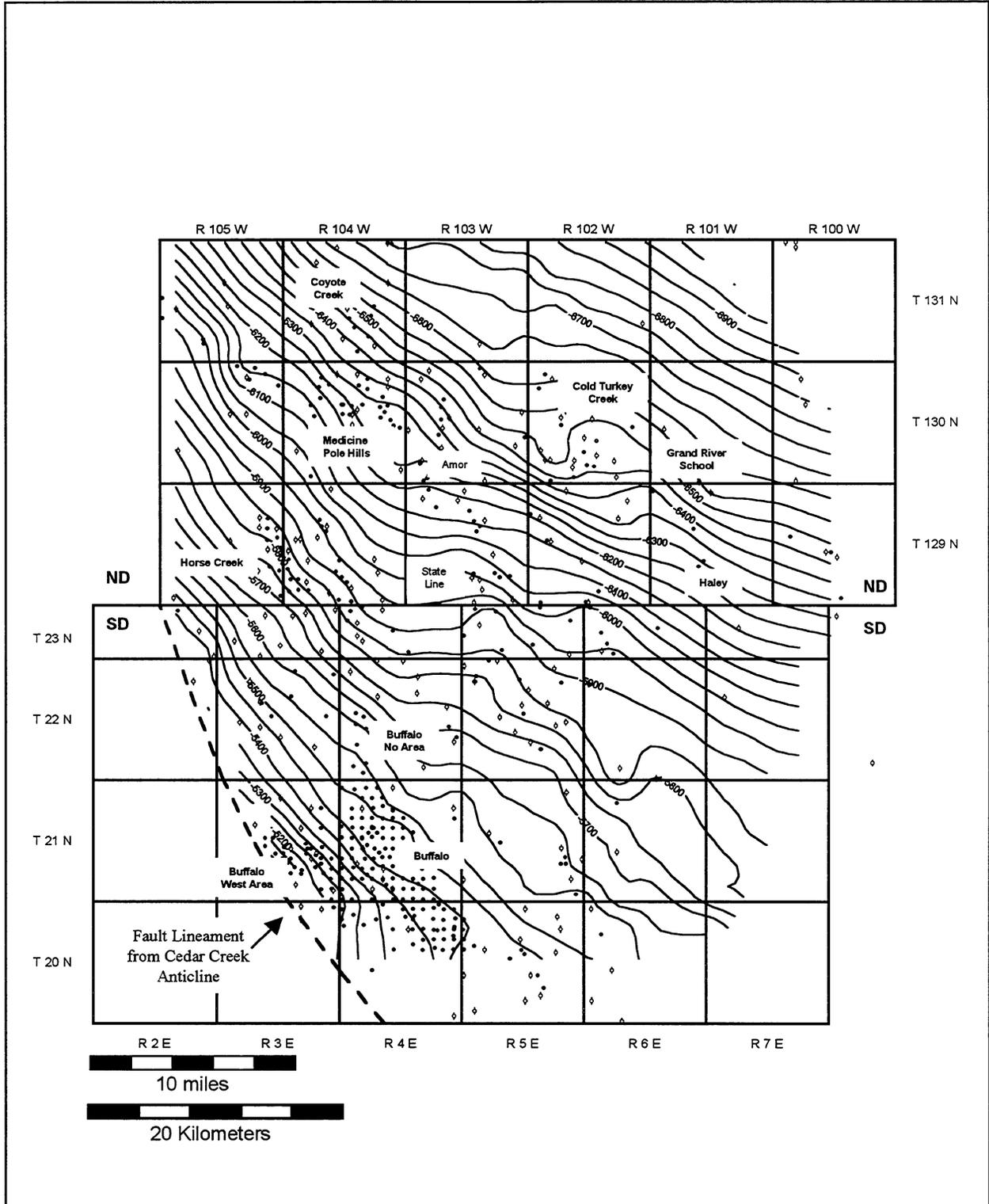


Figure 2: Map of Red River study area with fields annotated. Structure contours are on top of Red River. Contour interval is 50 ft (15 m).

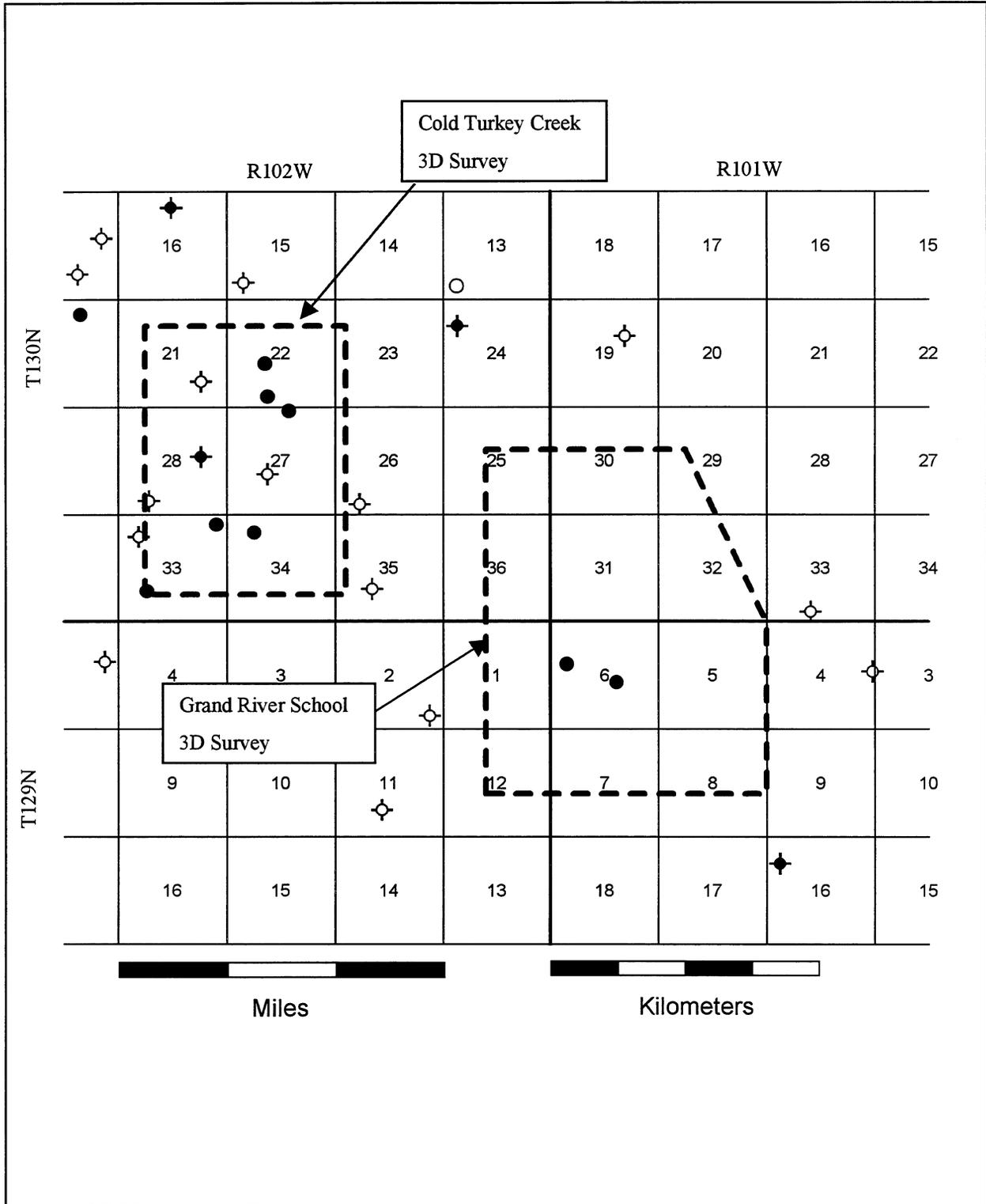


Figure 3: Map showing location of two 3D seismic surveys in Bowman Co., North Dakota.

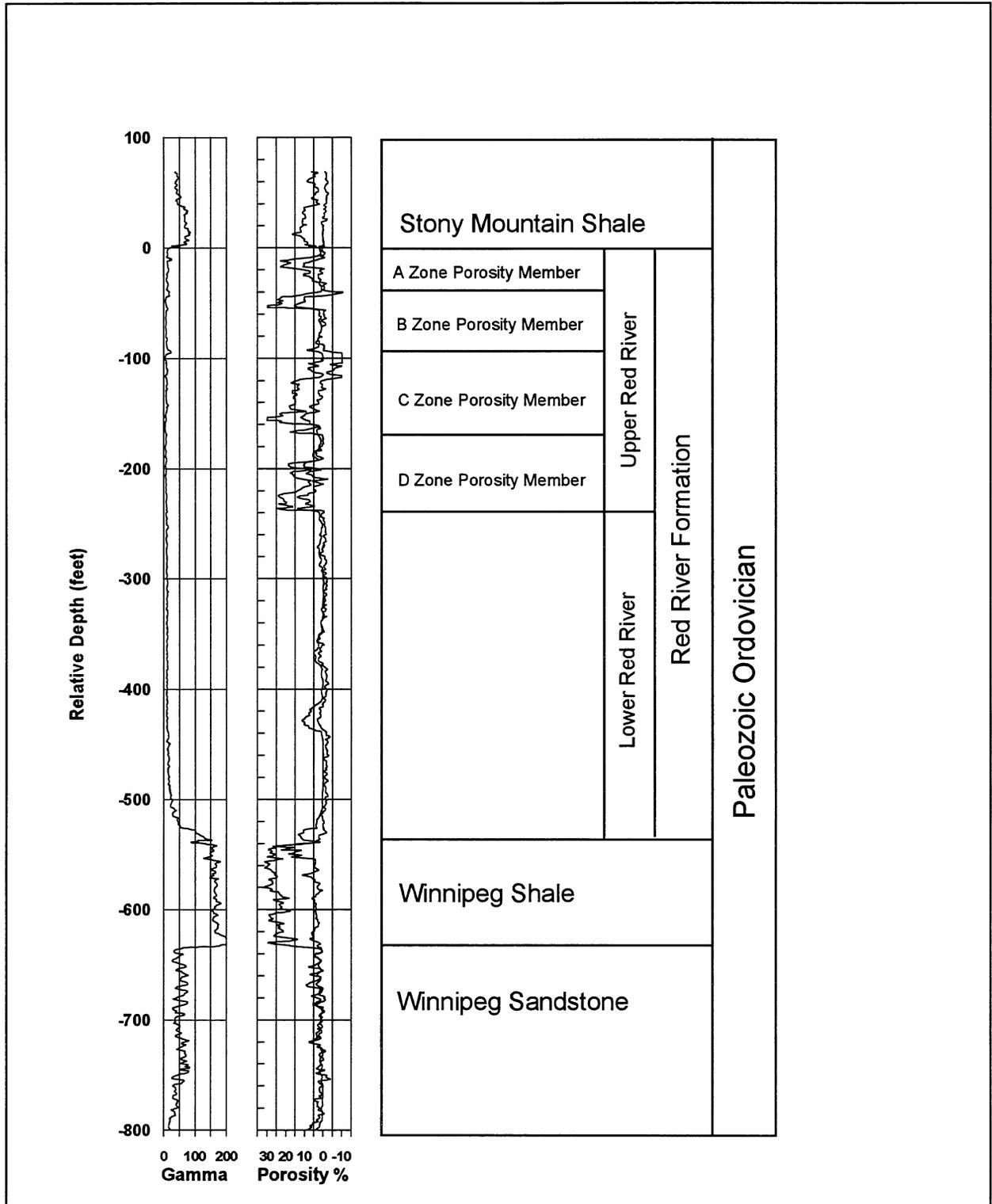


Figure 4: Type log of the Red River Formation through the Winnipeg This log is typical for the southwestern portion of the Williston Basin, Bowman Co., ND and Harding Co., SD..

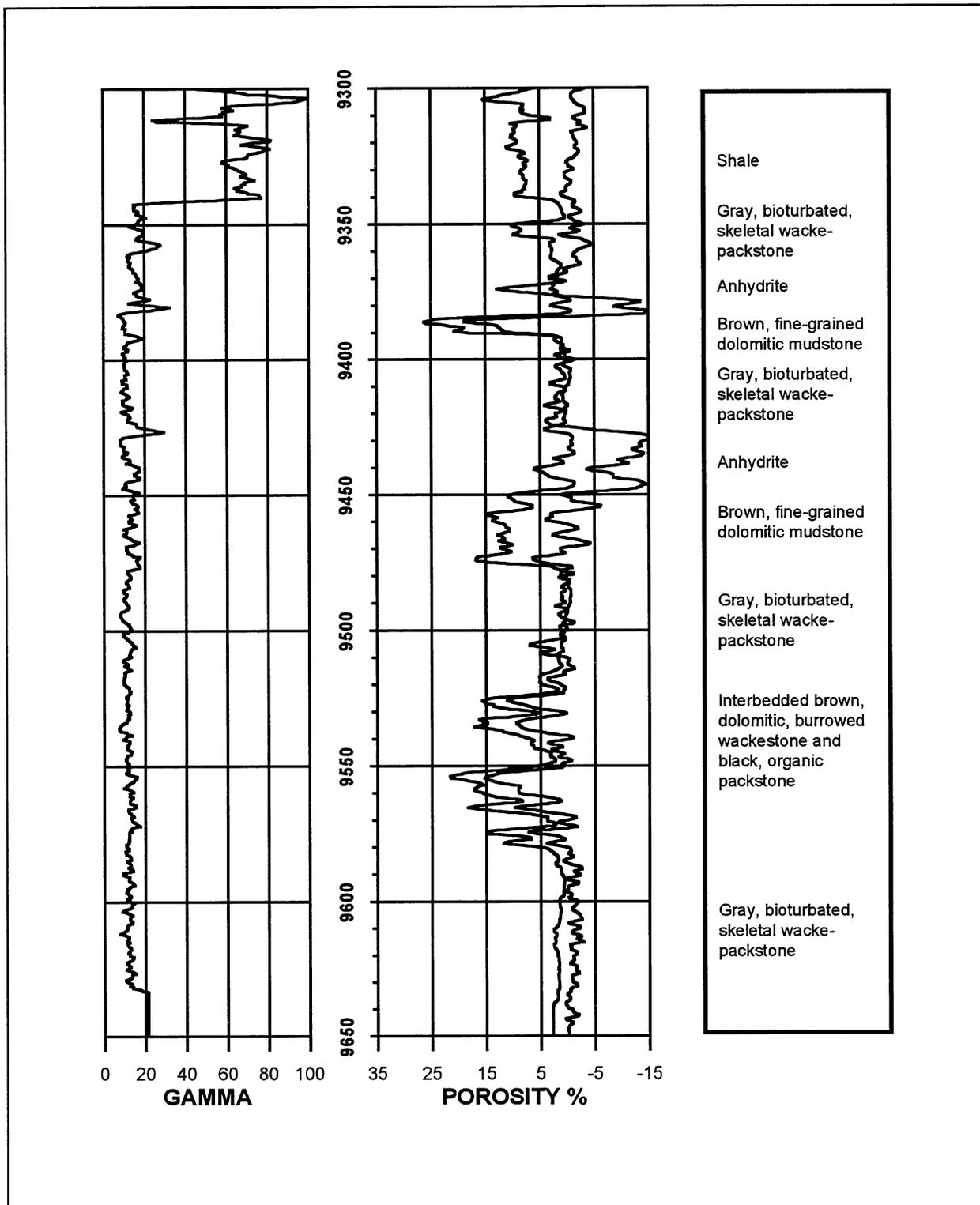


Figure 5: Type log showing stacking of lithologies in the Red River sequence. Log is from Cold Turkey Creek Field, Bowman Co., ND. Depth scale is in feet.

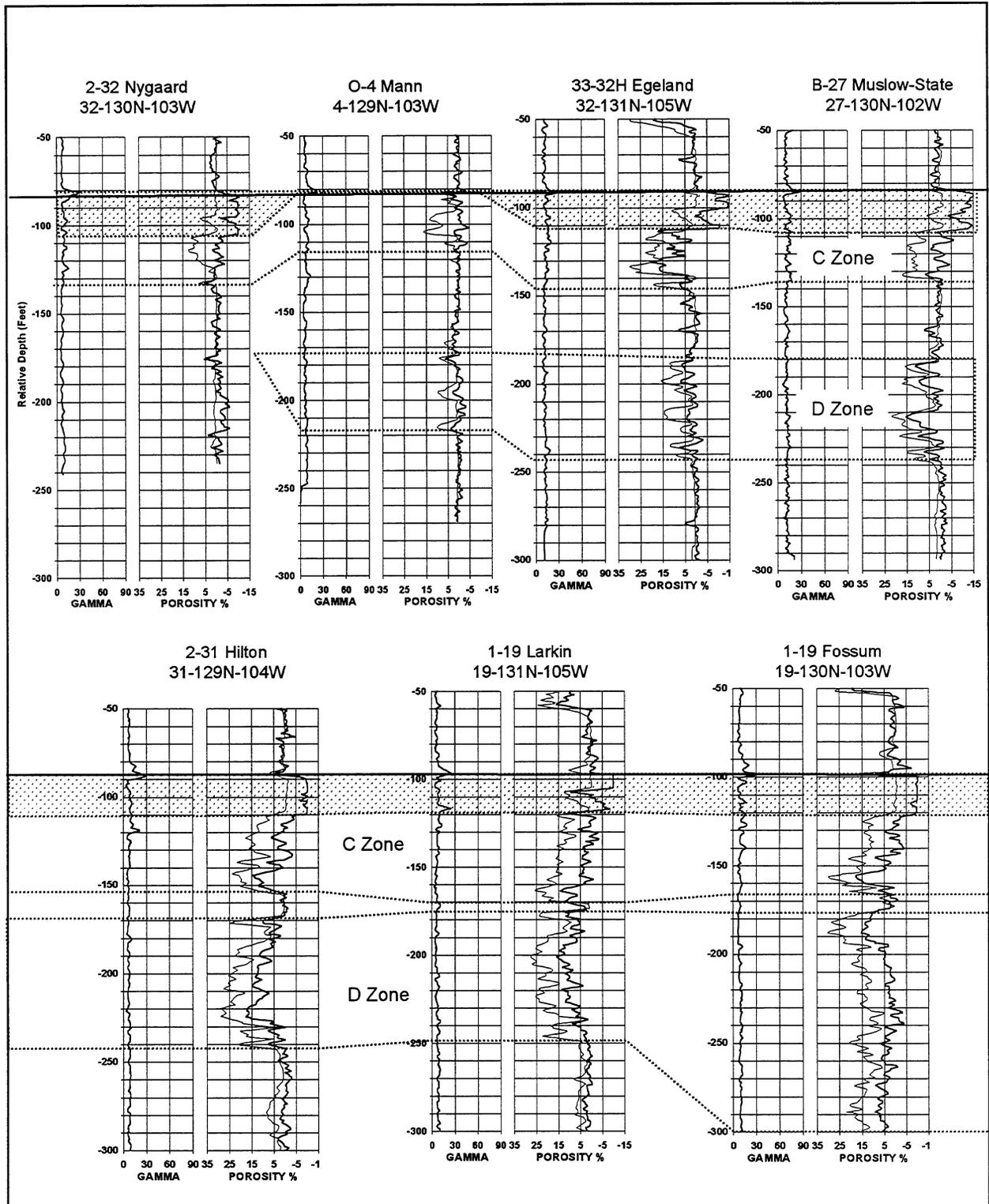


Figure 6: Cross section showing variability in Red River C and D zones.

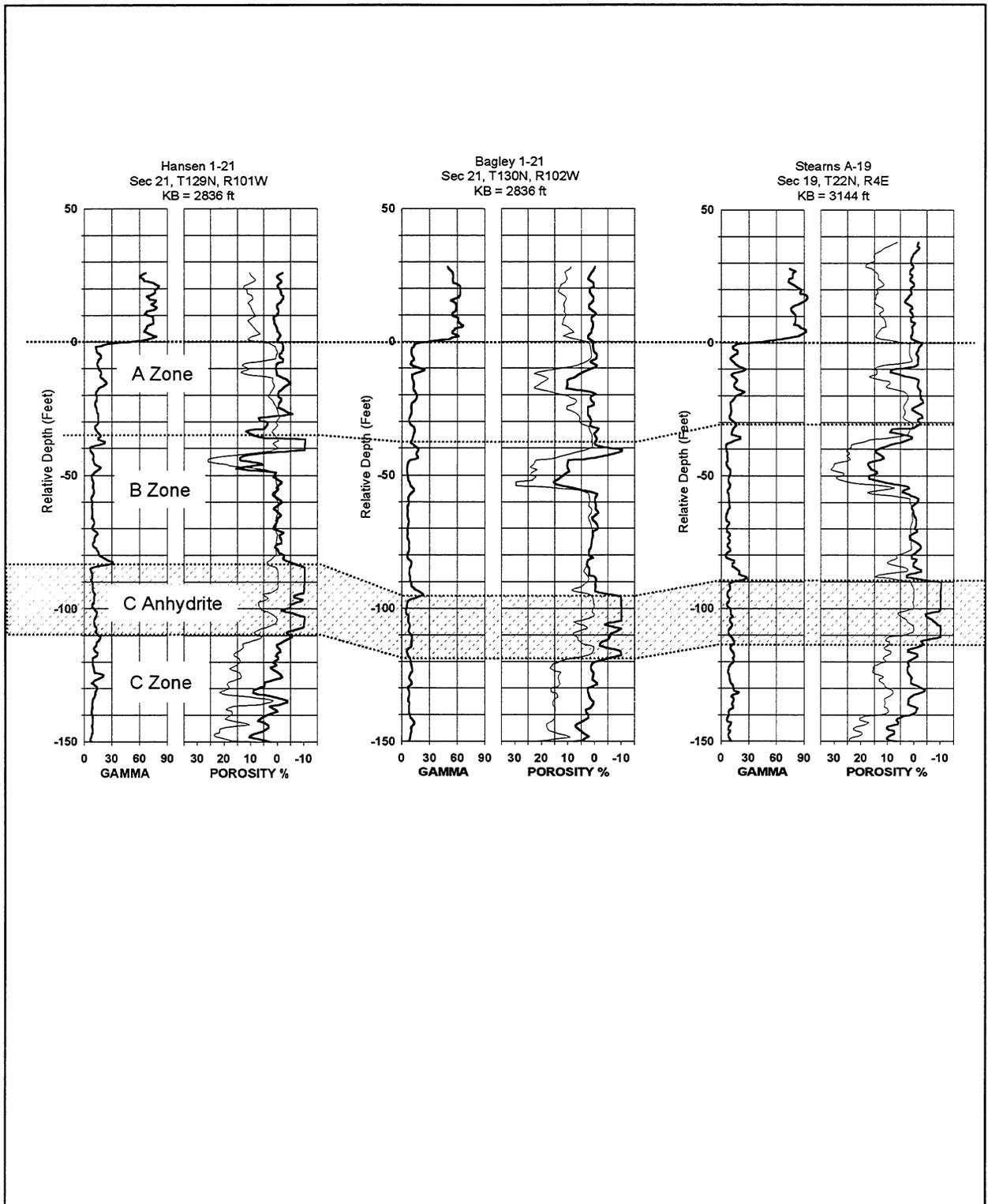


Figure 7: Cross section showing variability in Red River A and B zones.

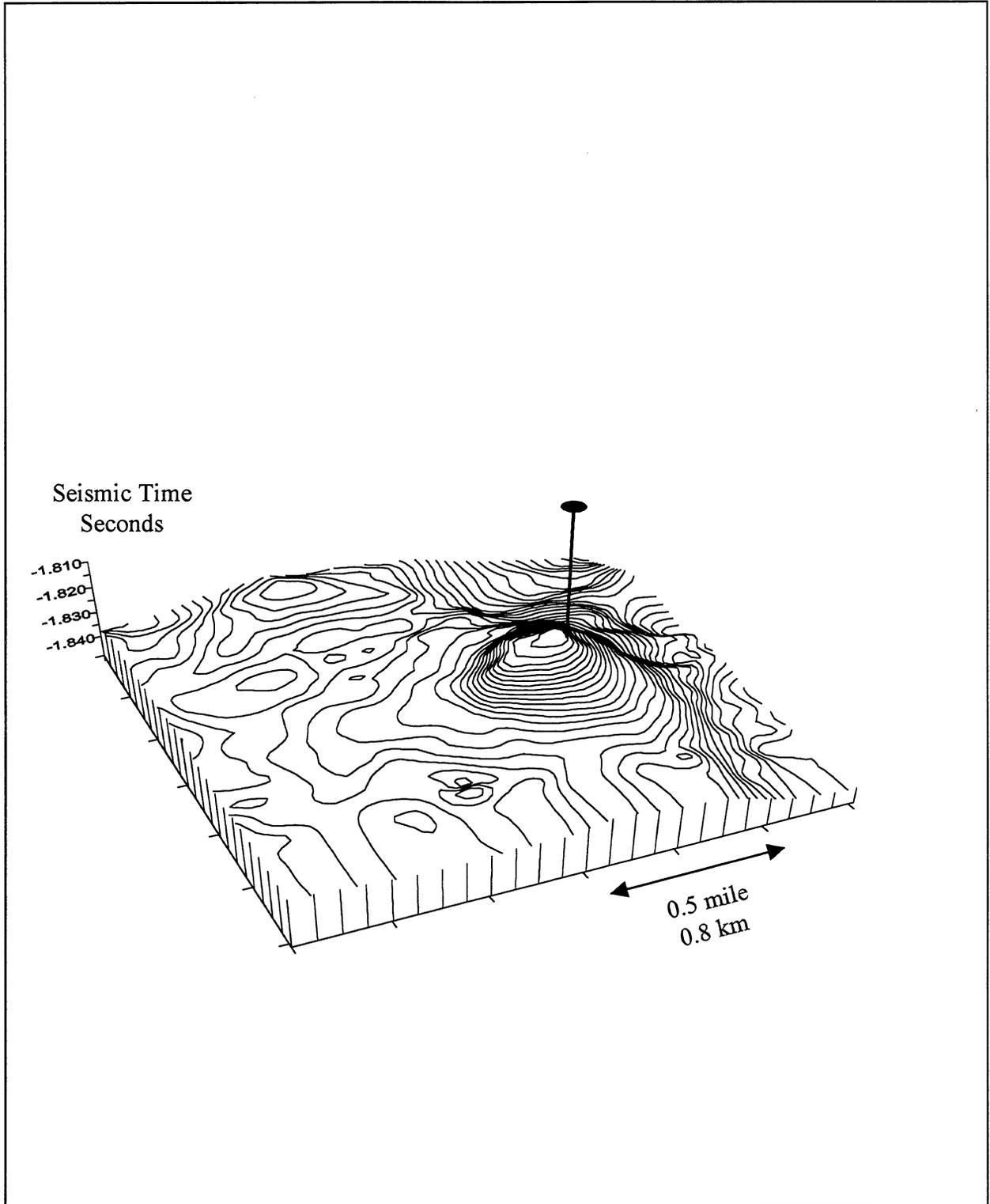


Figure 8: View of Winnipeg time contours from a typical small-bump feature in Bowman Co., North Dakota. During the 1970's, these small features were generally exploited with one well on the structural crest.

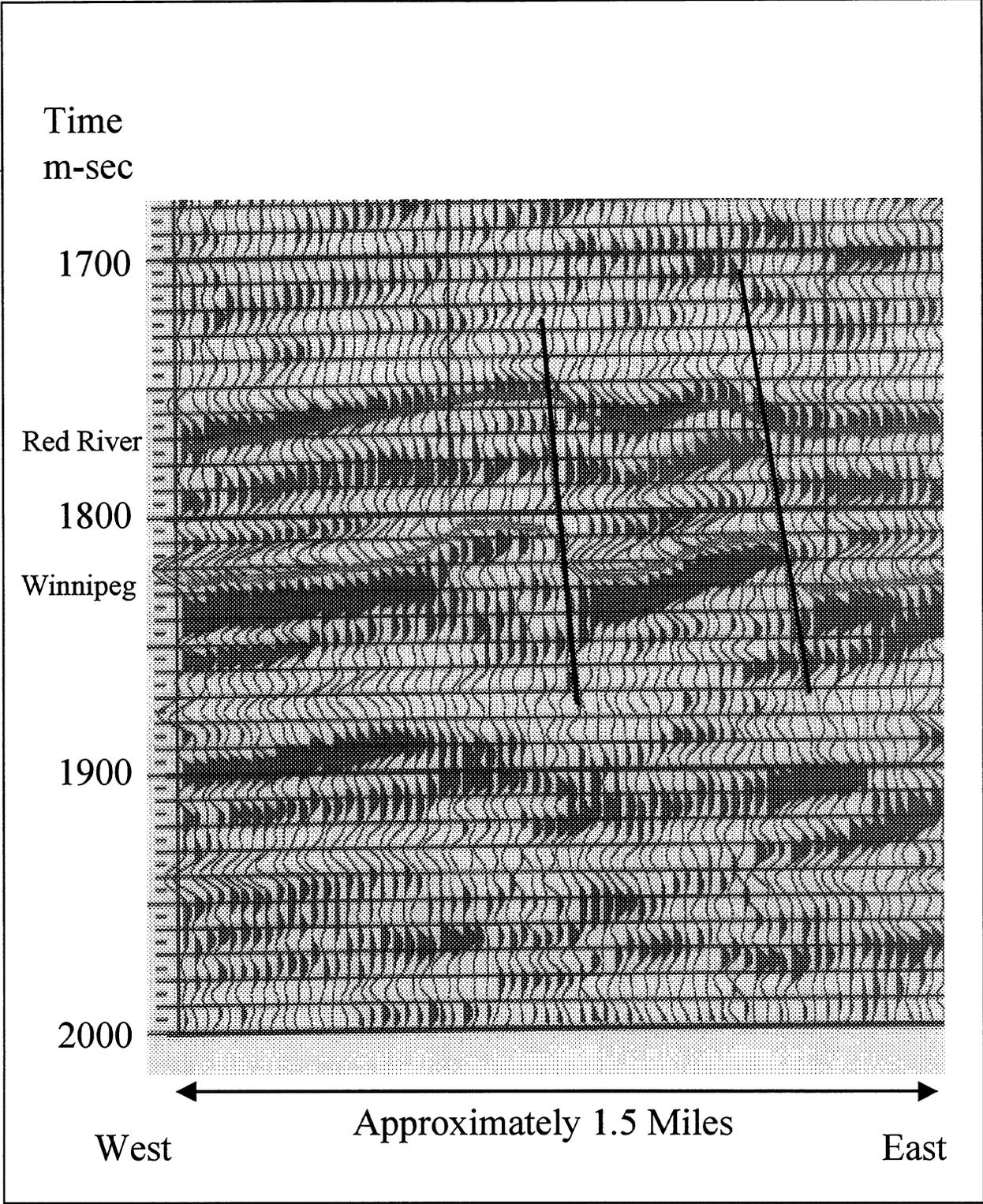


Figure 9: Example of faulting at Winnipeg time. Seismic line is from Harding Co., South Dakota.

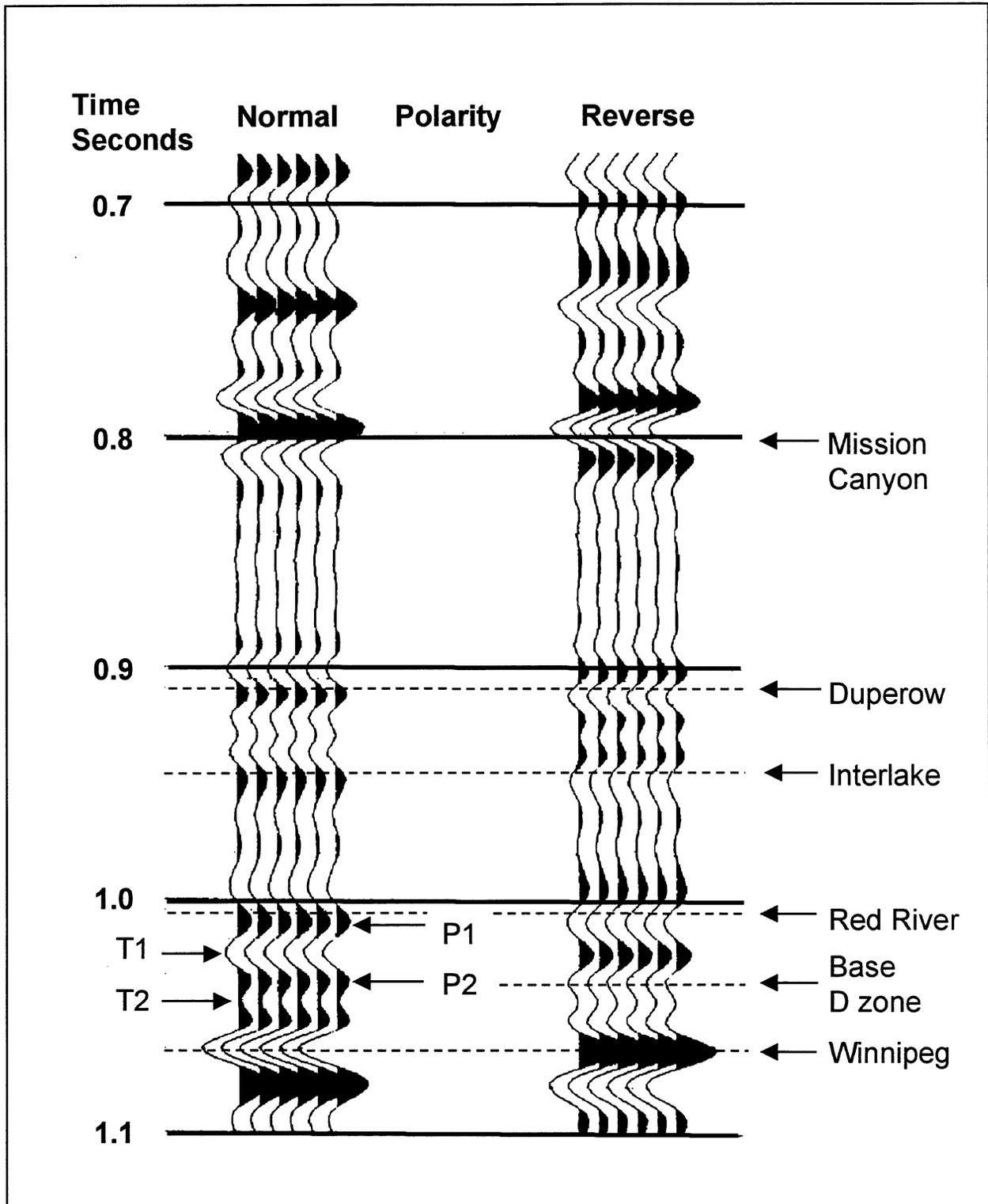


Figure 10: Synthetic seismogram showing typical events relating to the Red River.

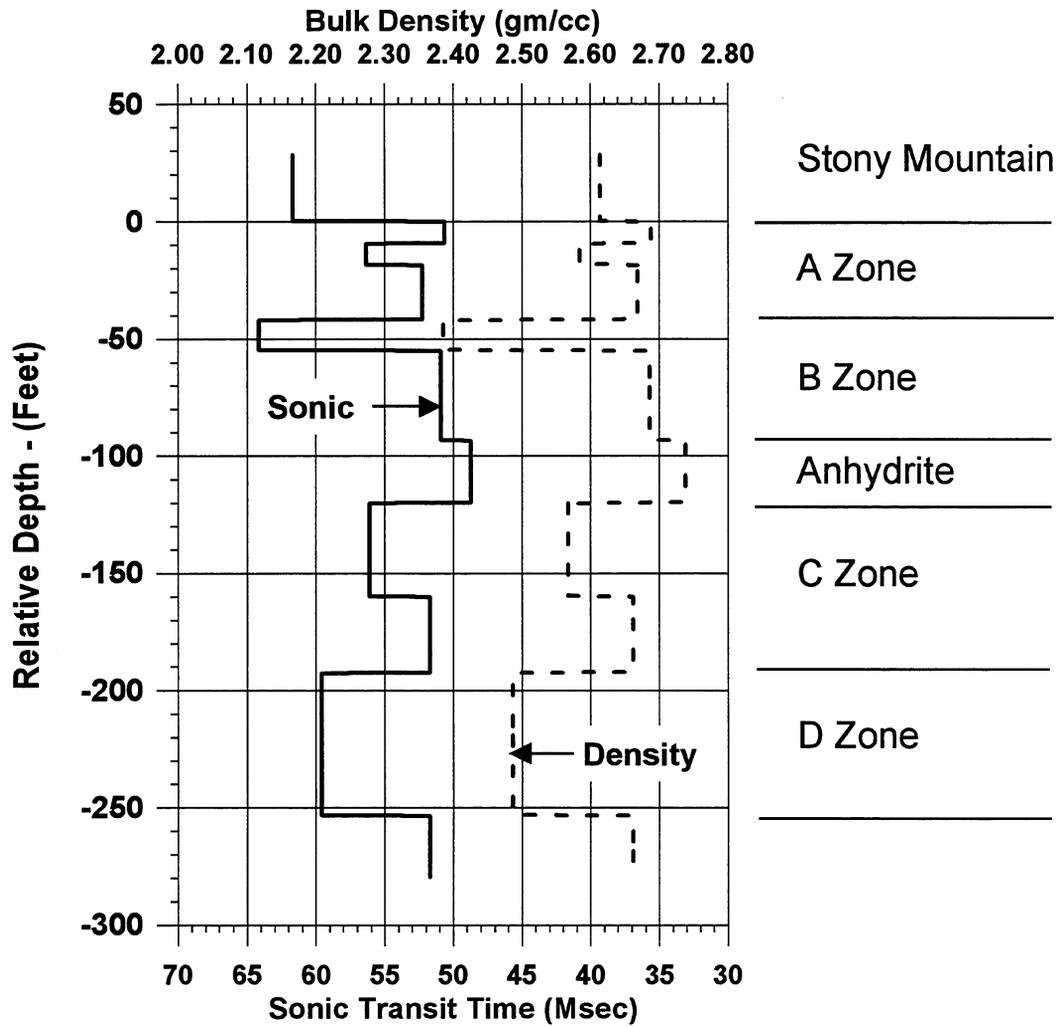


Figure 11: Example of an earth-model for generation of synthetic seismic response.

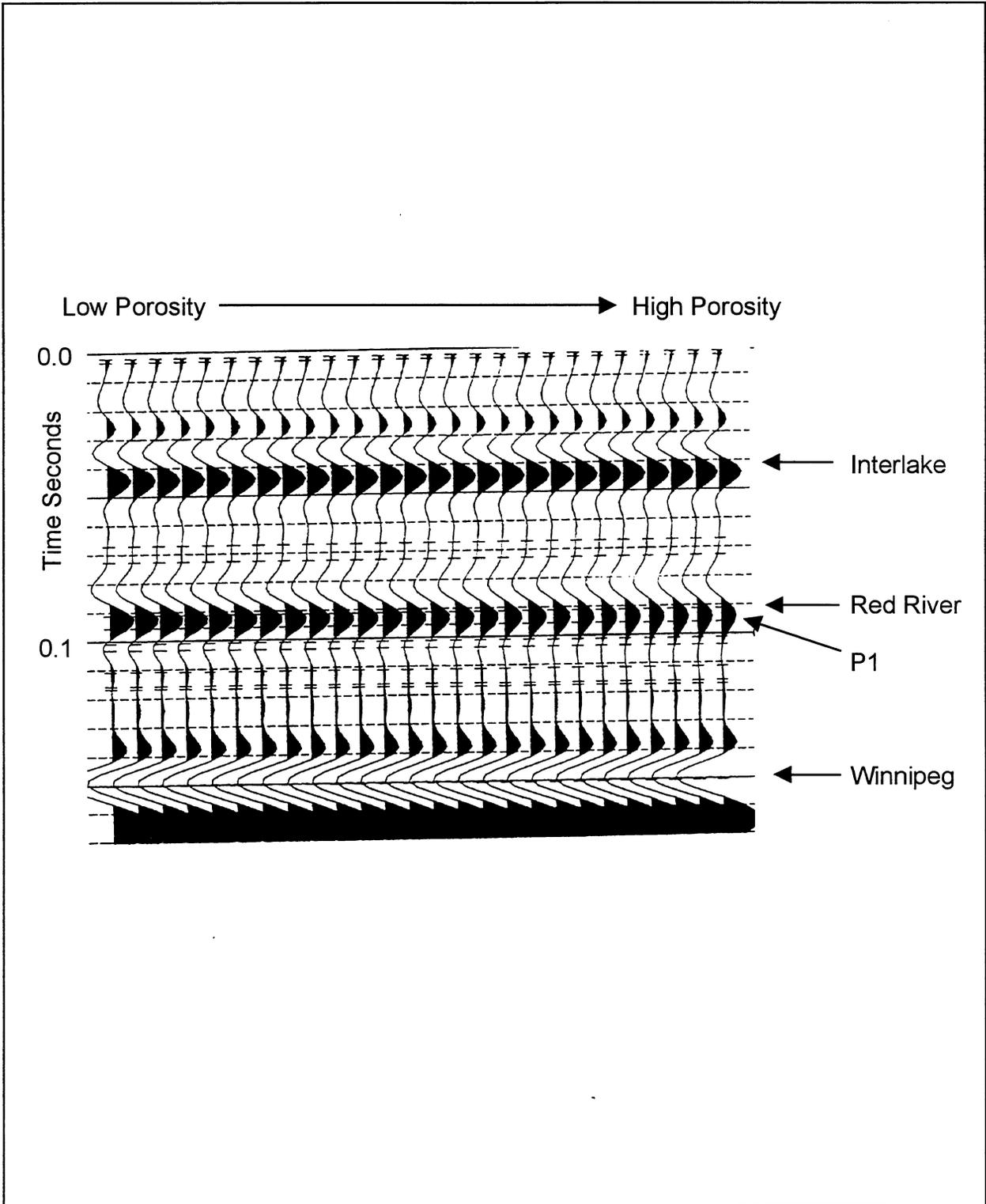


Figure 12: Synthetic seismic response with Red River B zone porosity. Other intervals at 0% limestone.

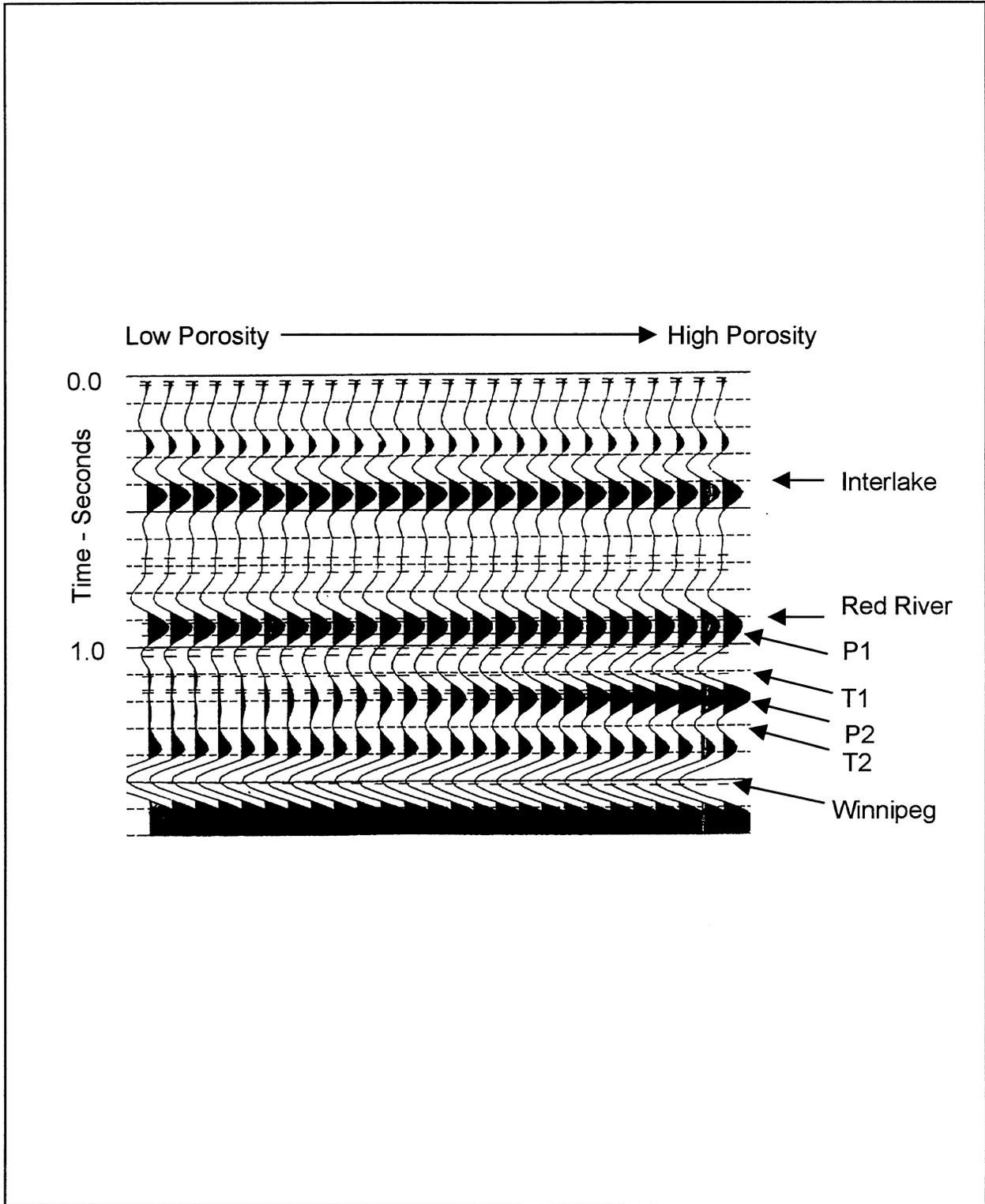


Figure 13: Synthetic seismic response with Red River D zone porosity. Other intervals at 0% limestone.

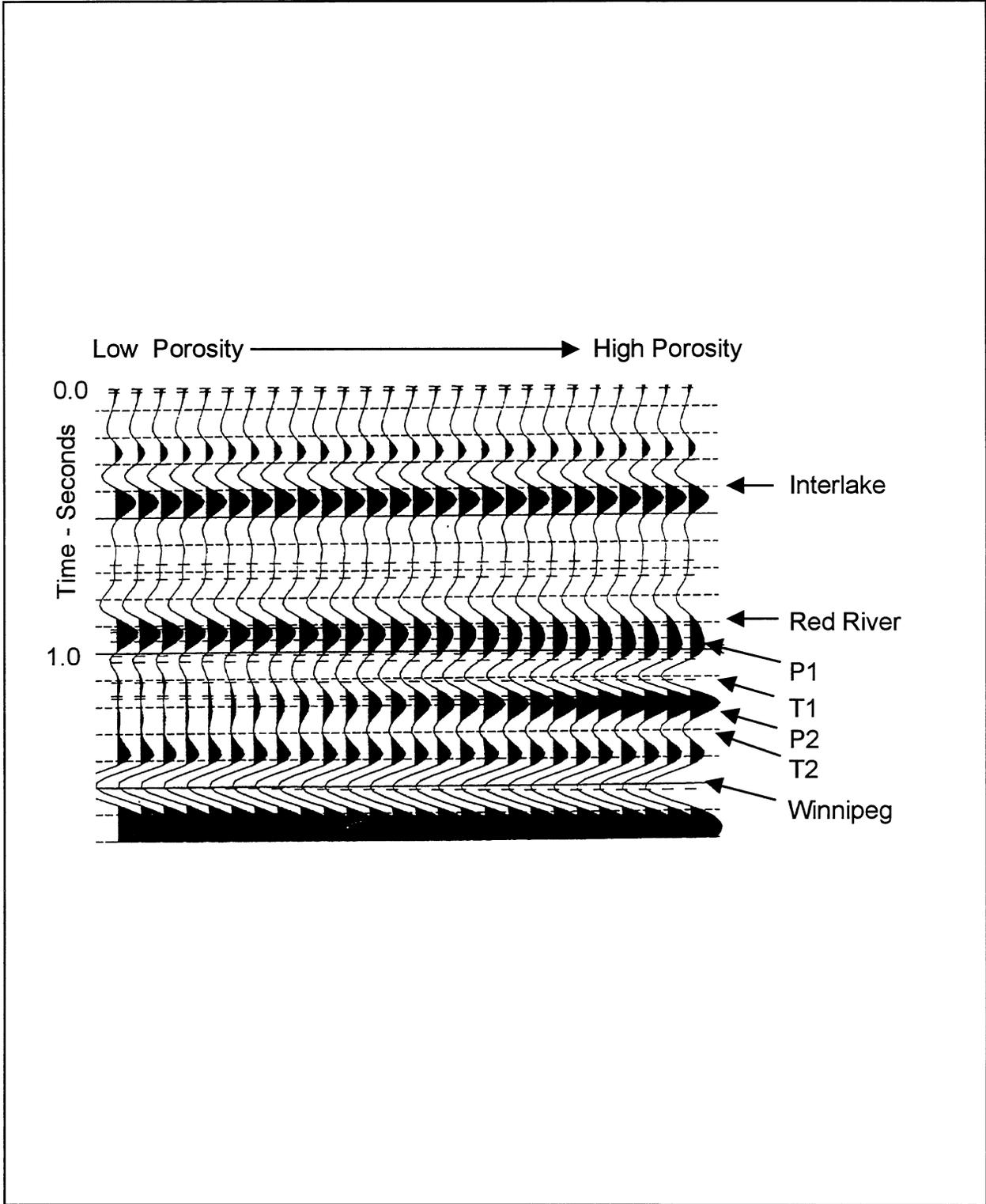


Figure 14: Synthetic seismic response with both Red River B and D zone porosity. Other intervals at 0% limestone.

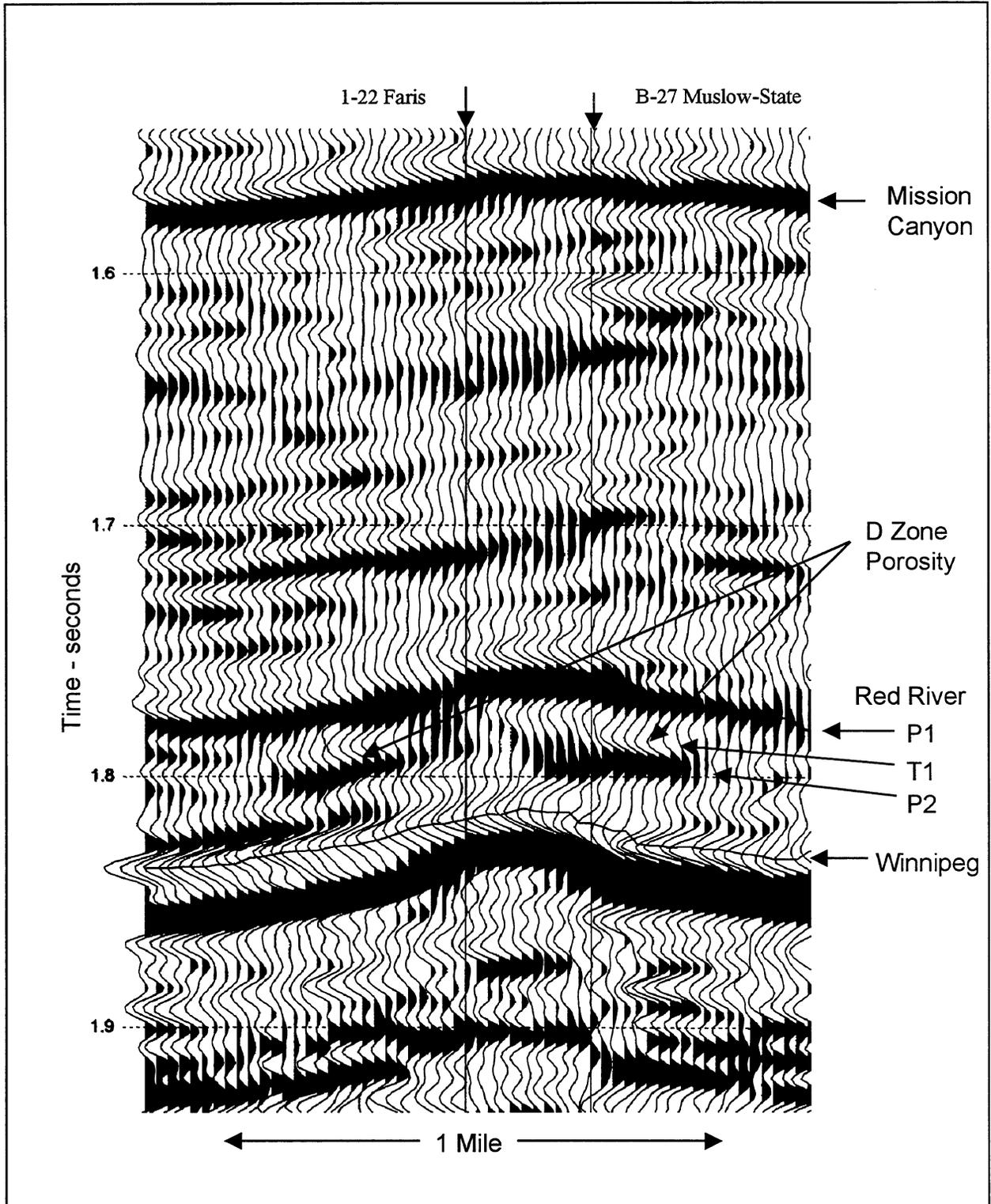


Figure 16: Structural cross-section from 3D seismic data at feature 1, Cold Turkey Creek.

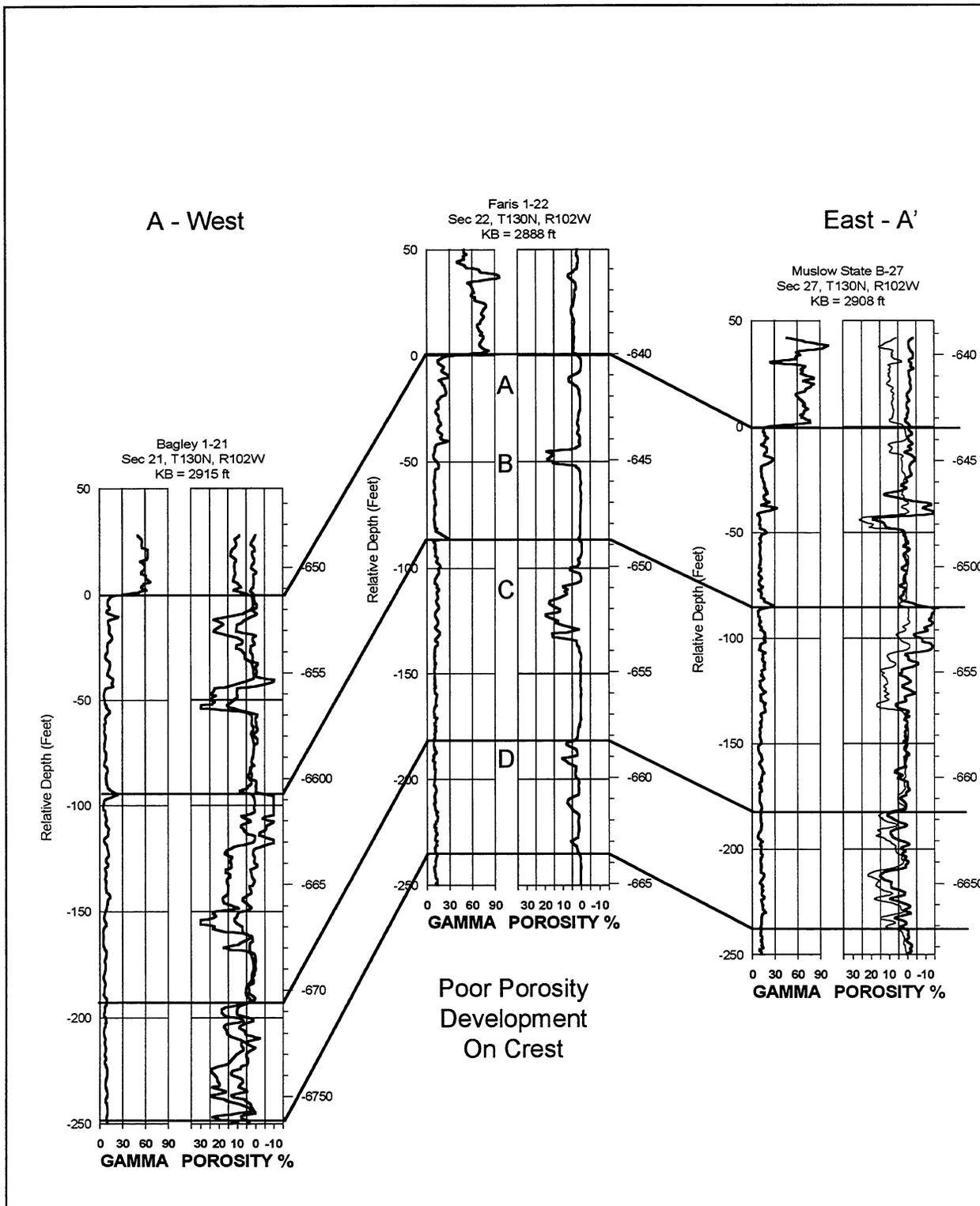


Figure 17: Structural cross-section from electrical logs at feature 1, Cold Turkey Creek.

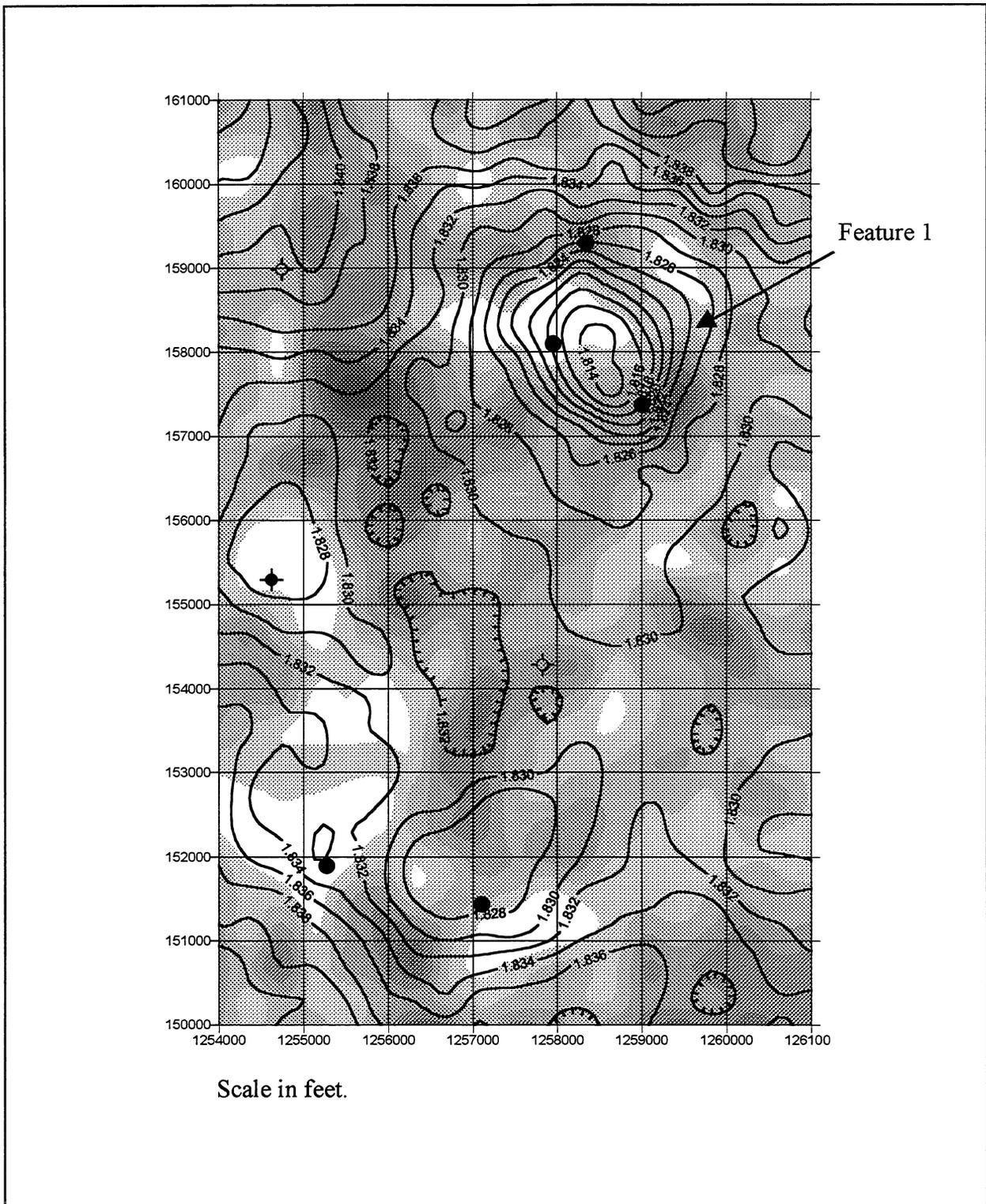


Figure 18: Winnipeg time structure with Red River D zone amplitude. Contour interval of Winnipeg time is 2 msec. Darker shading indicates increasing amplitude intensity of T1 event..

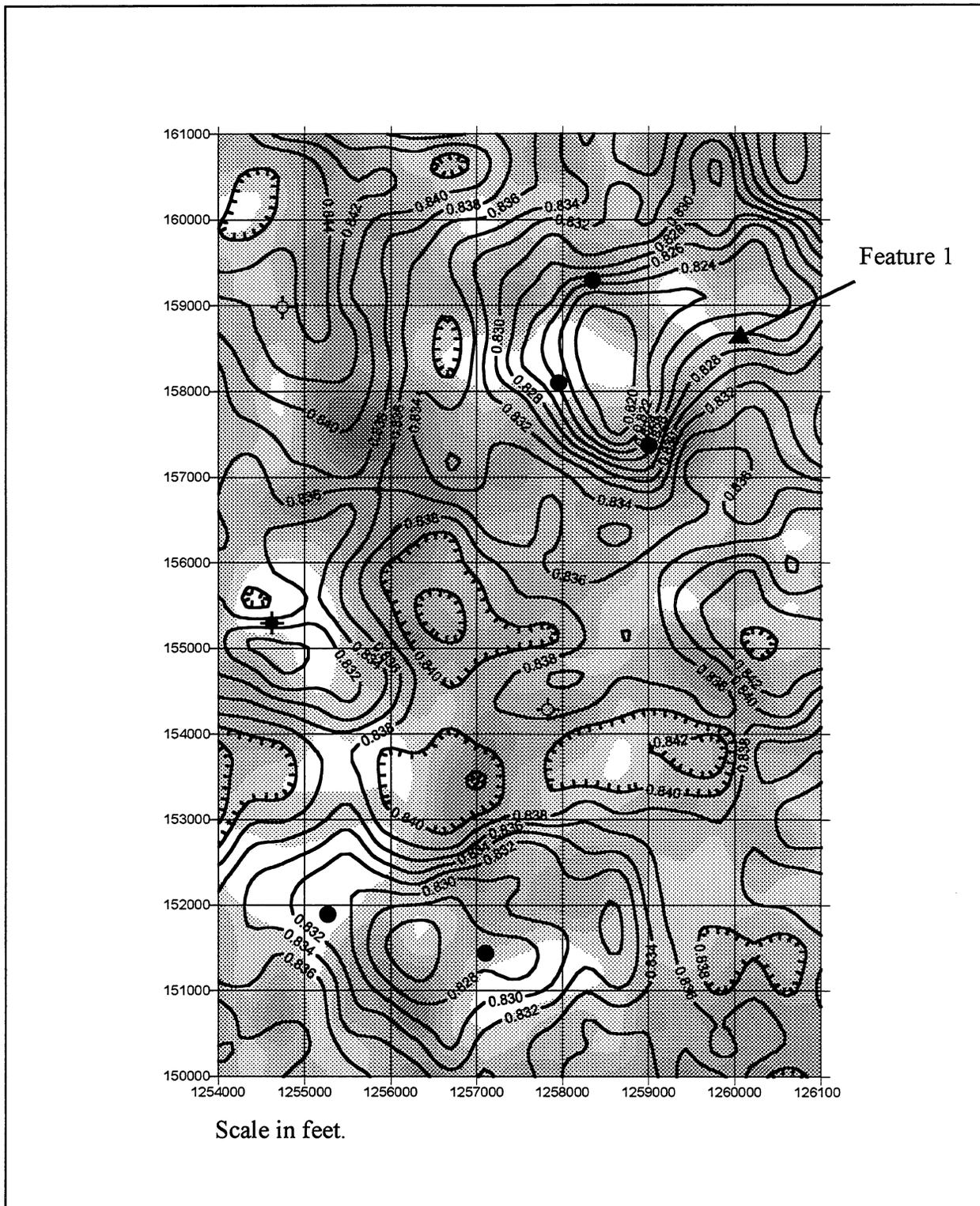


Figure 19: Greenhorn -Winnipeg isochron with Red River D zone amplitude. Isochron contour interval is 2 msec. Darker shading indicates increasing amplitude intensity of T1 event.

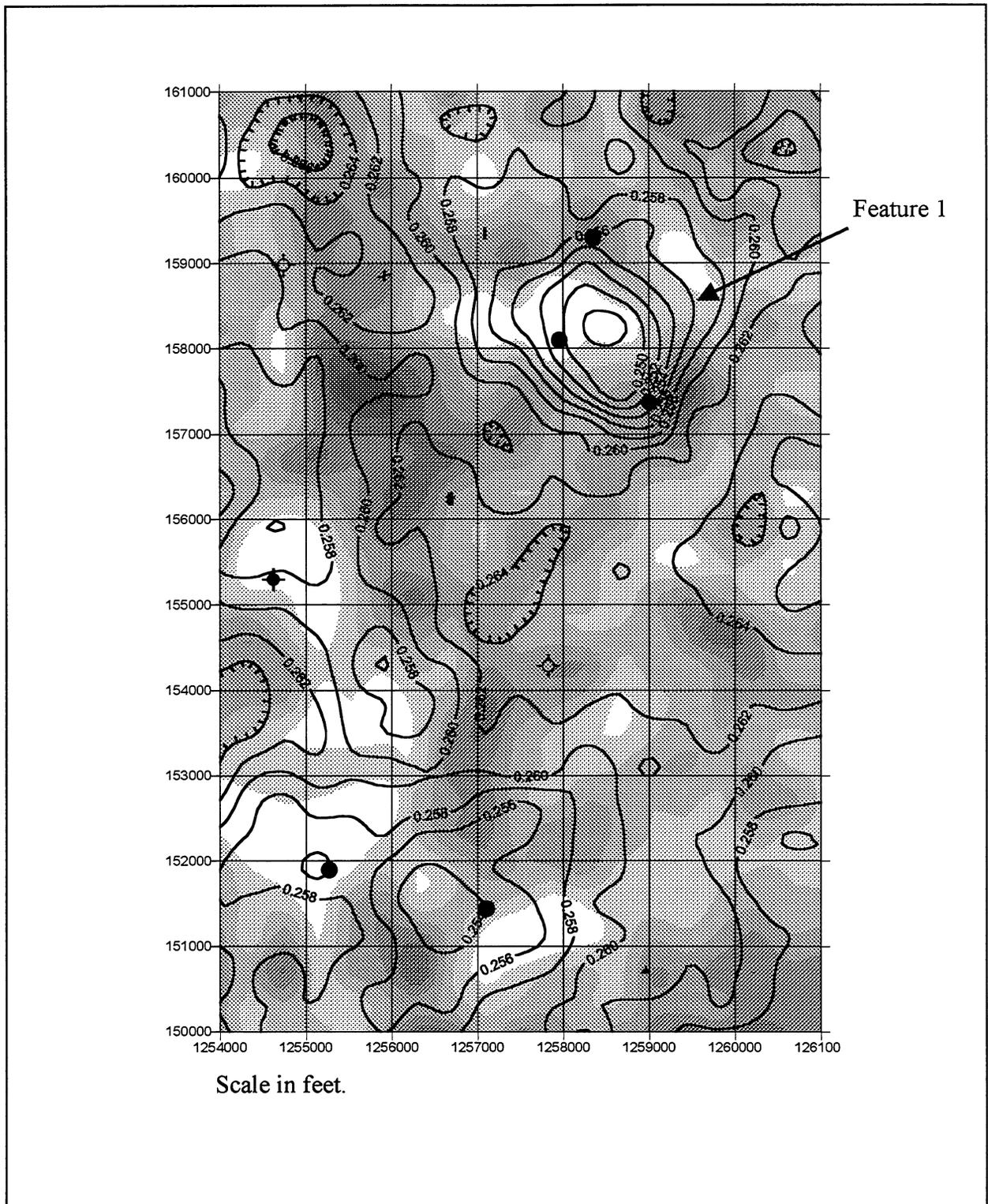


Figure 20: Mission Canyon - Winnipeg isochron with Red River D zone amplitude. Isochron contour interval is 2 msec. Darker shading indicates increasing amplitude intensity of T1 event.

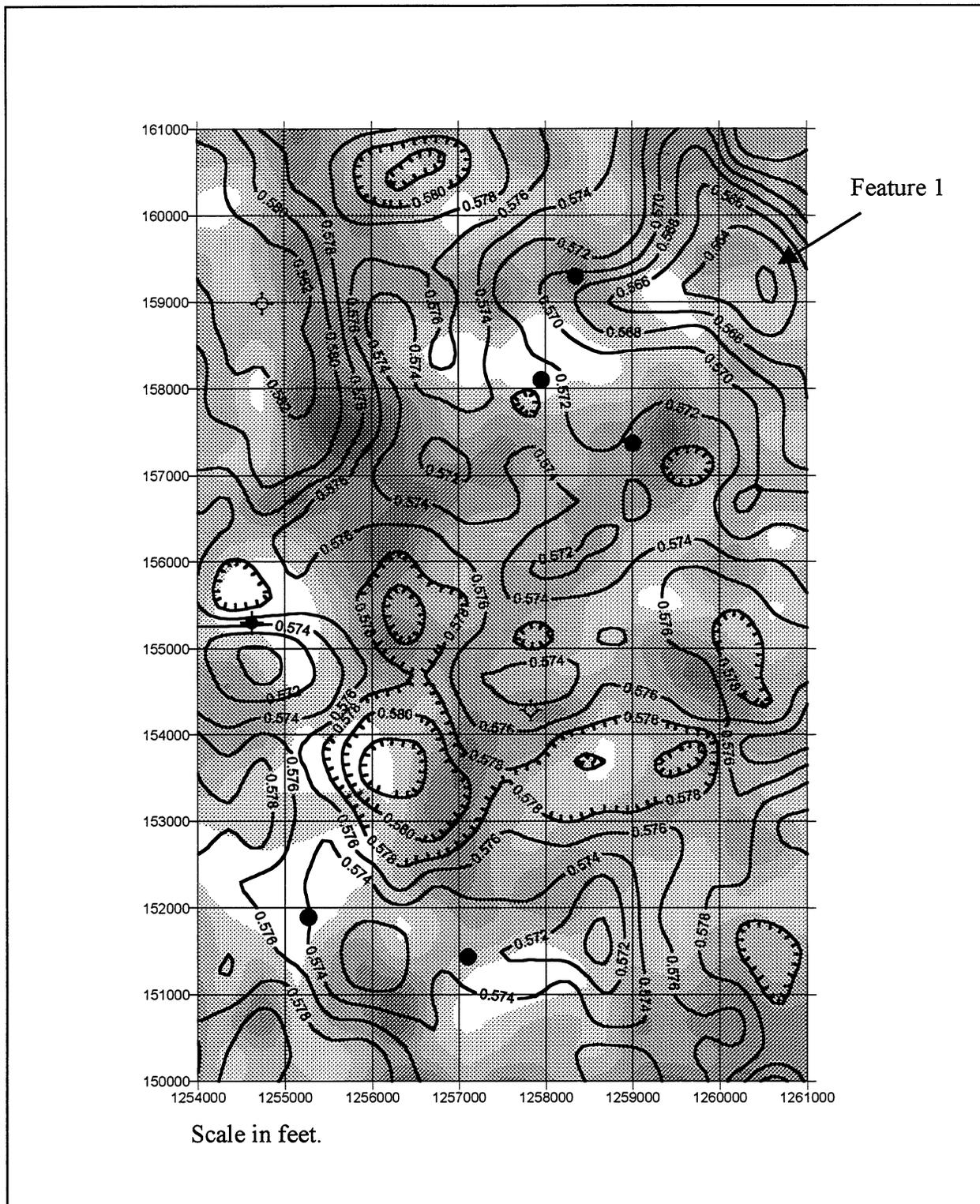


Figure 21: Greenhorn - Mission Canyon isochron with Red River D zone amplitude. Isochron contour interval is 2 msec. Darker shading indicates increasing amplitude intensity of T1 event.

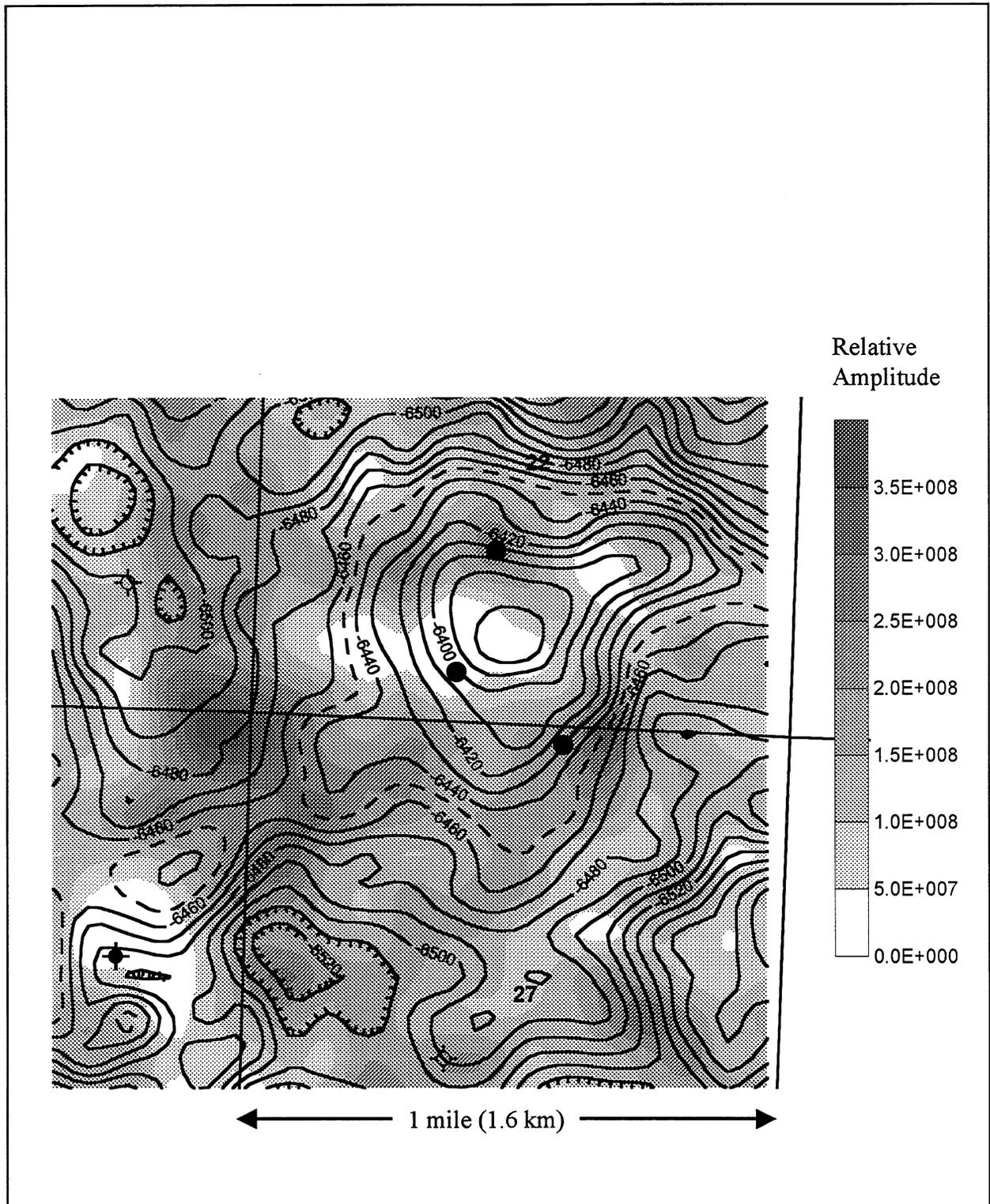


Figure 22: Red River structure with Red River D zone amplitude at feature 1, Cold Turkey Creek. Contour interval is 10 ft (3 m). Darker shading indicates increasing amplitude intensity of T1 event.

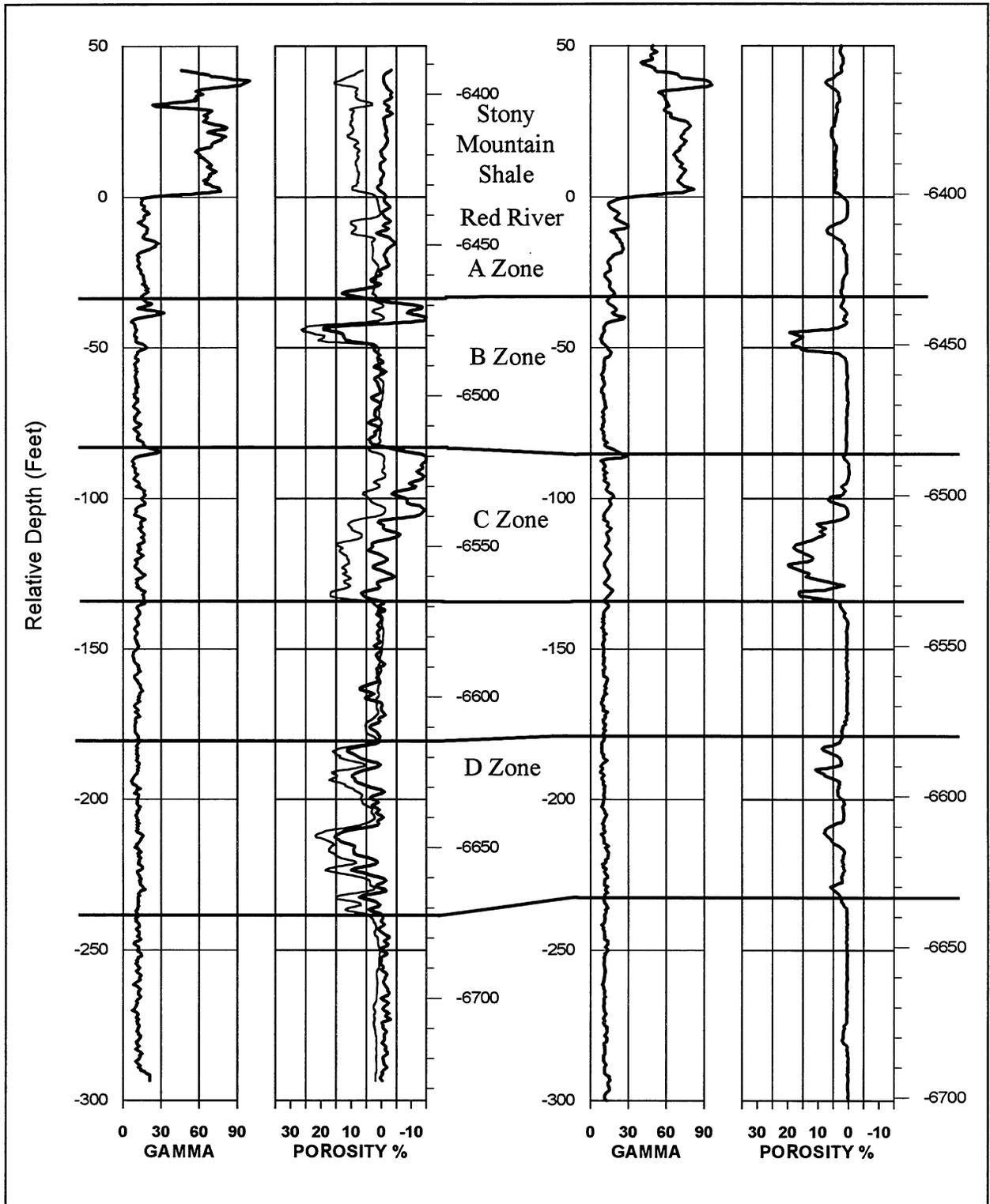


Figure 23: Stratigraphic cross-section comparing the B-27 Muslow-State (left) and Faris No. 1-22 (right), Cold Turkey Creek Field.

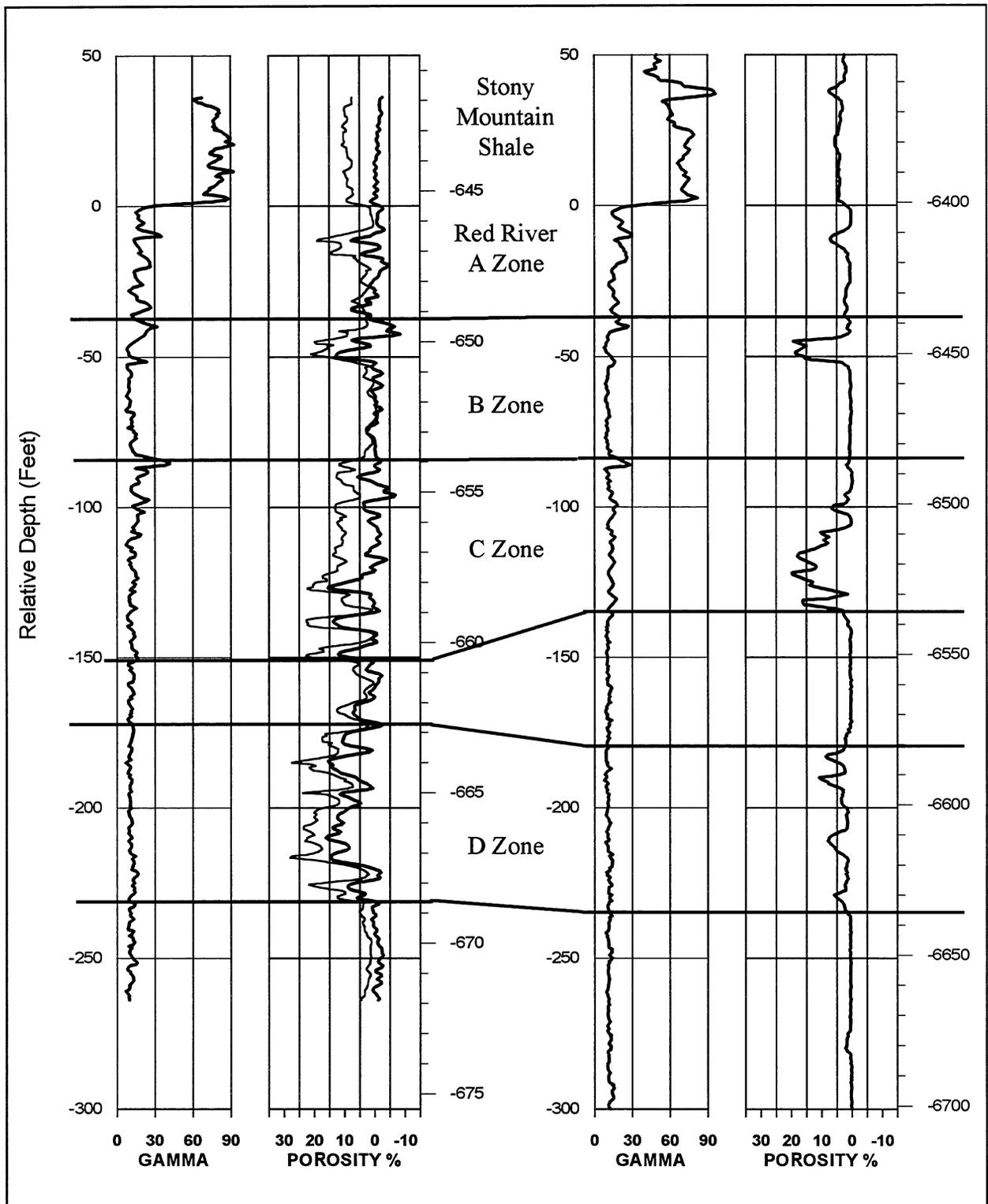


Figure 24: Stratigraphic cross-section comparing the Pang-Faris K-22 (left) and Faris No.1-22 (right), Cold Turkey Creek Field.

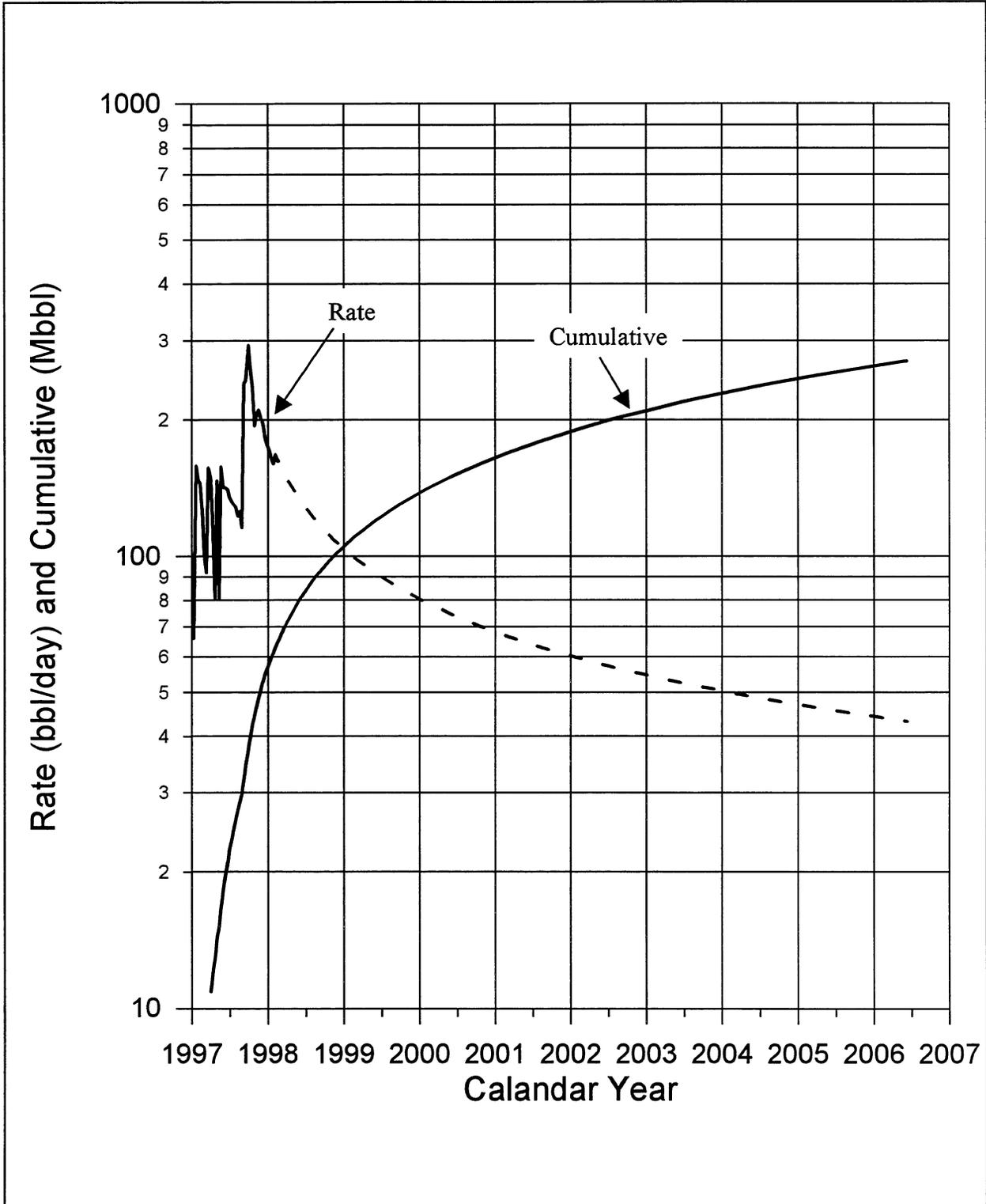


Figure 26: Production from new wells on structural feature 1, Cold Turkey Creek Field, Bowman Co., North Dakota. Extrapolations are based on six months of data and indicate a possible ultimate oil recovery of 400,000 bbl (63,600 m³).

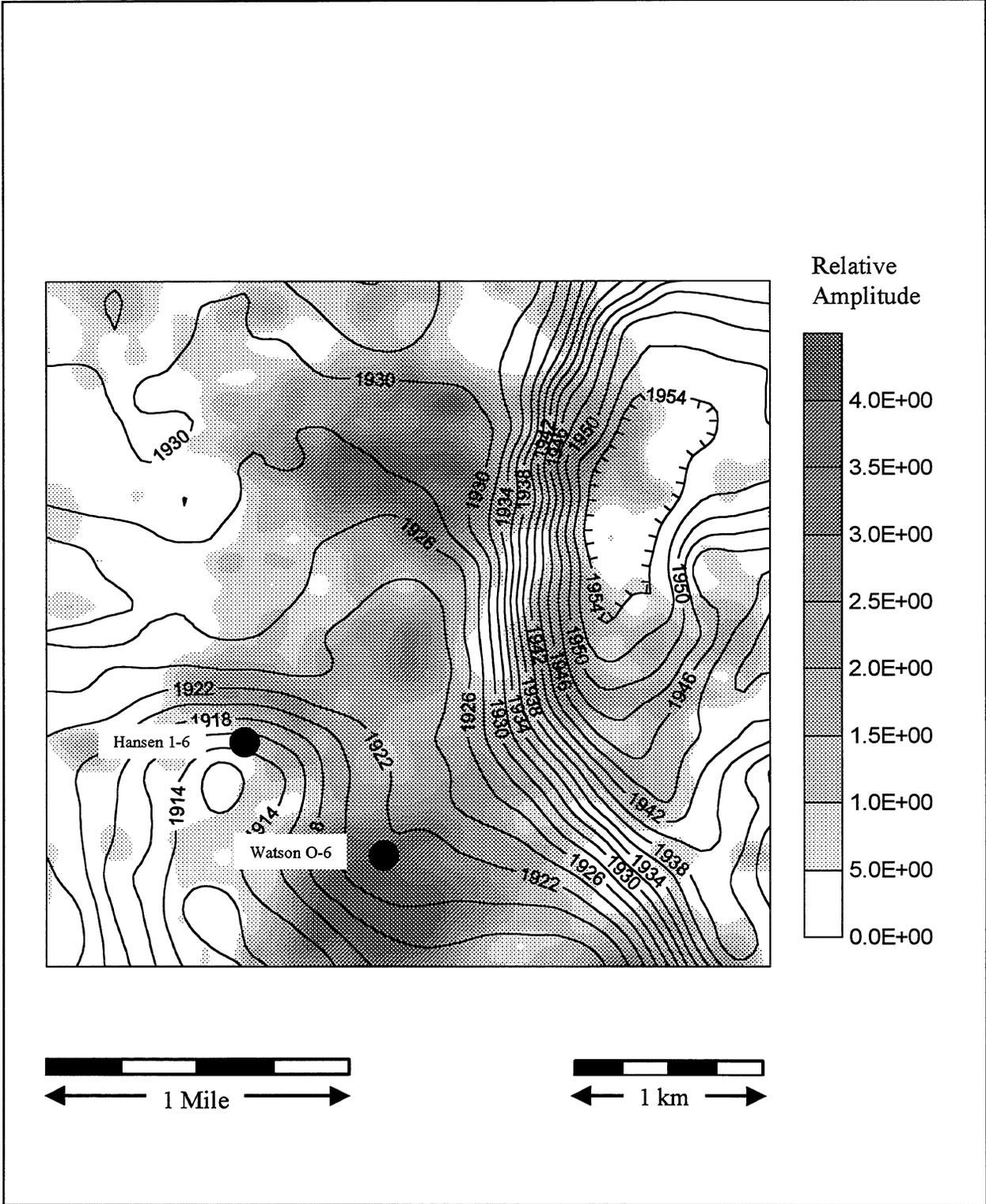


Figure 27: Winnipeg time structure with Red River amplitude, Grand River School. Contour interval is of Winnipeg time is 2 msec. Darker shading indicates increasing amplitude intensity of P2 event.

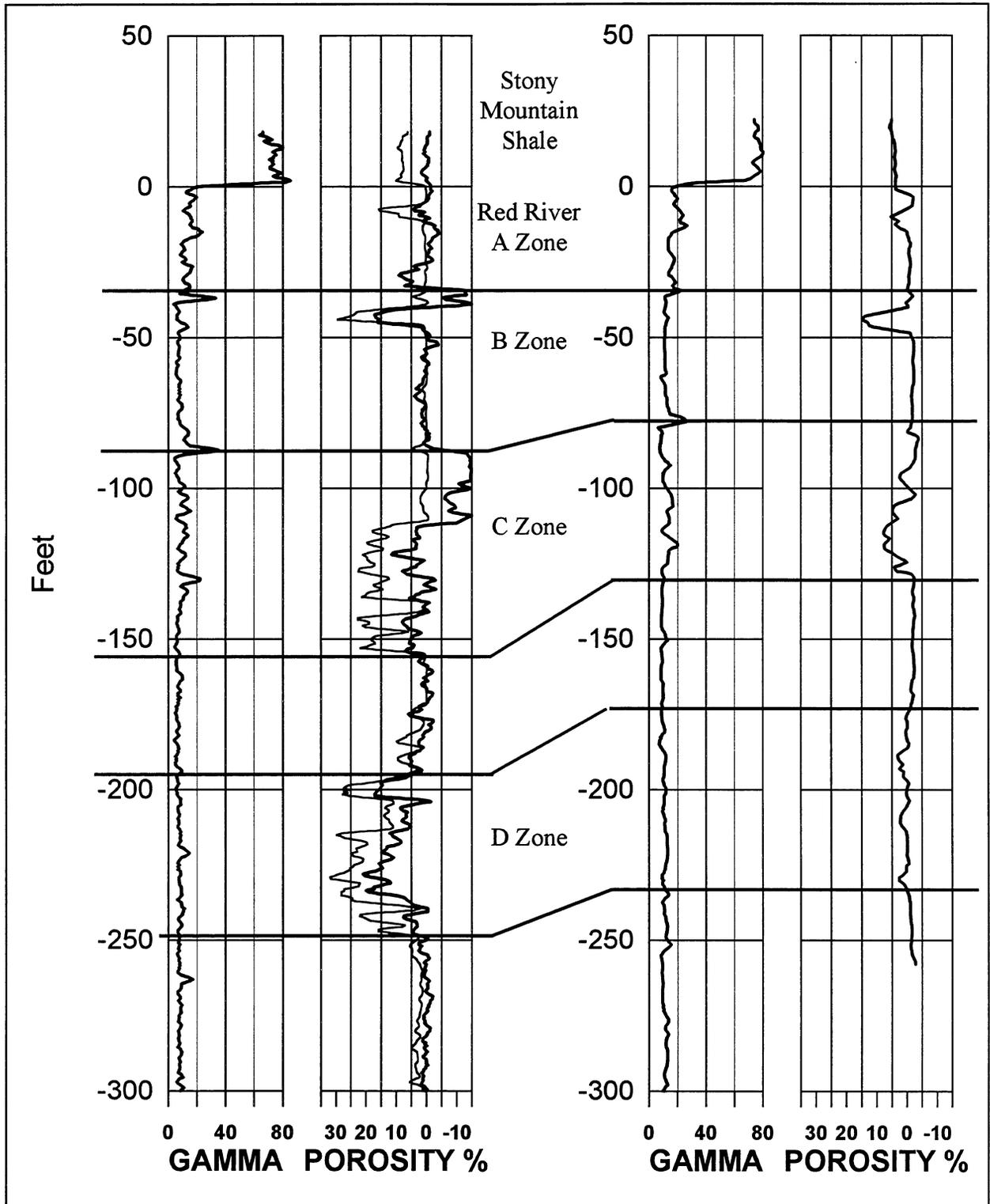


Figure 28: Stratigraphic cross-section comparing the Watson O-6 (left) and Hanson No. 1-6 (right), Grand River School Field.

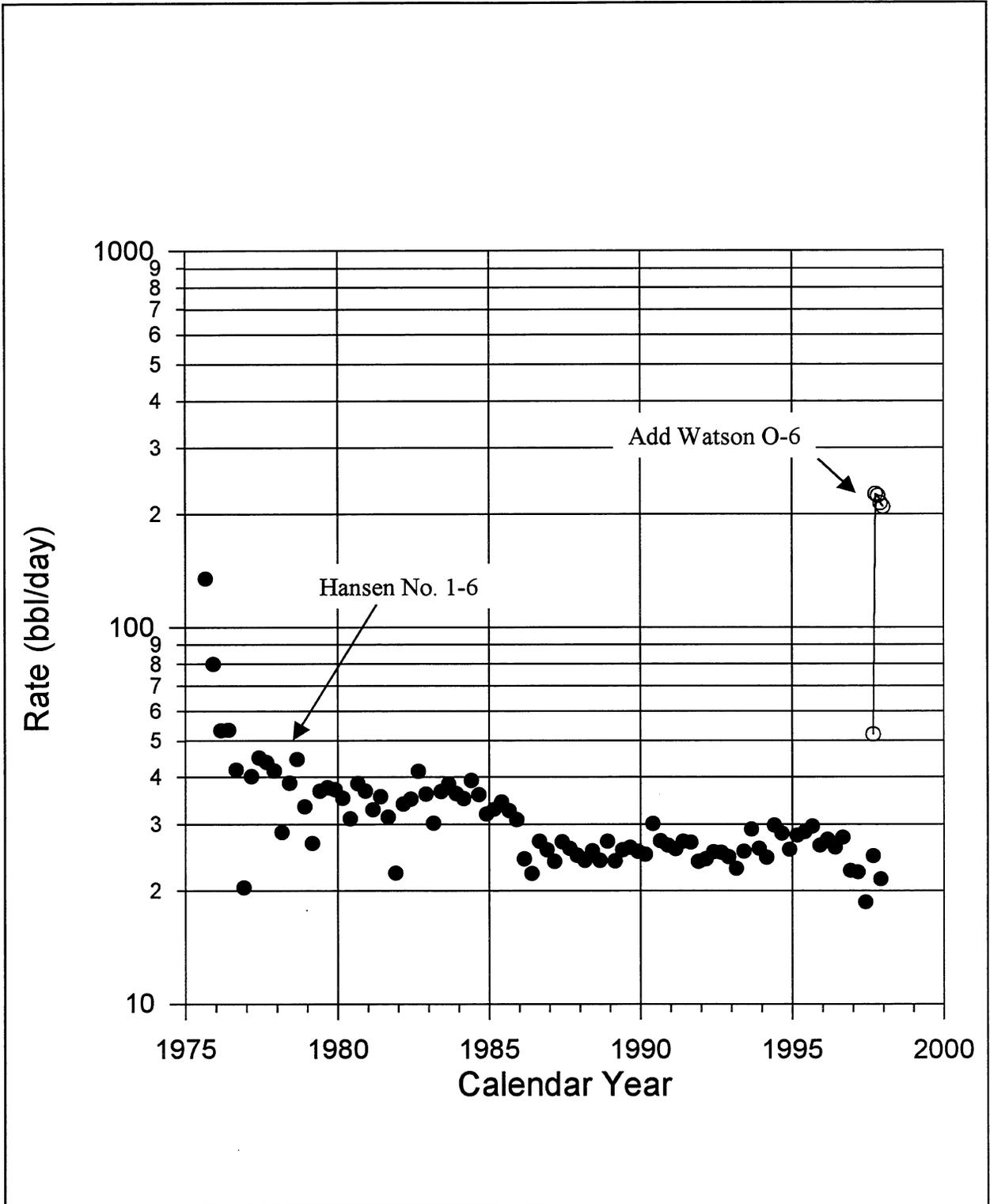


Figure 29: Production history from Grand River School Field, Bowman Co., North Dakota.

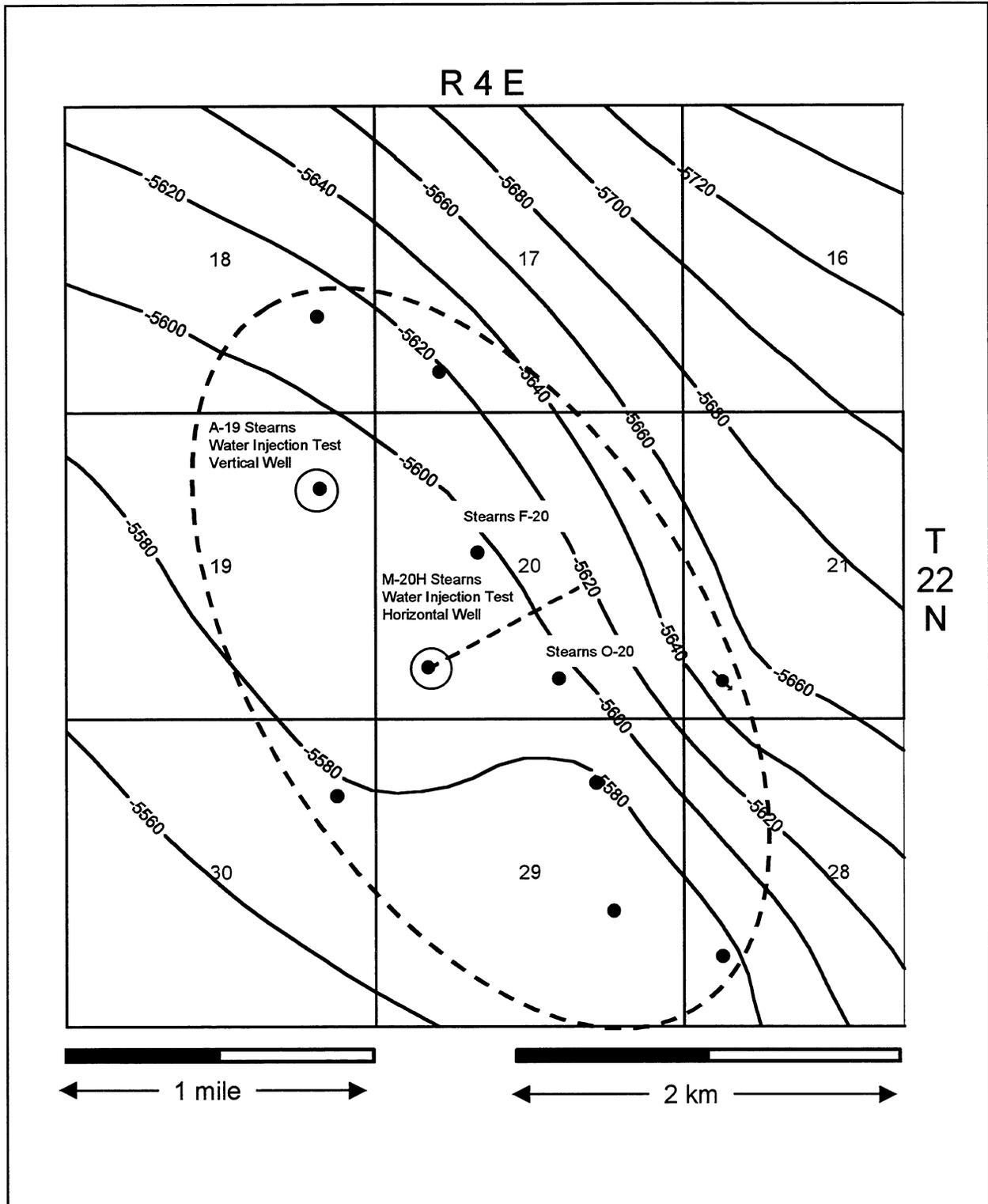


Figure 30: Map of Buffalo Field (north area), Harding Co., SD. Structure contours are on top of the Red River. CI = 20 ft (6 m).

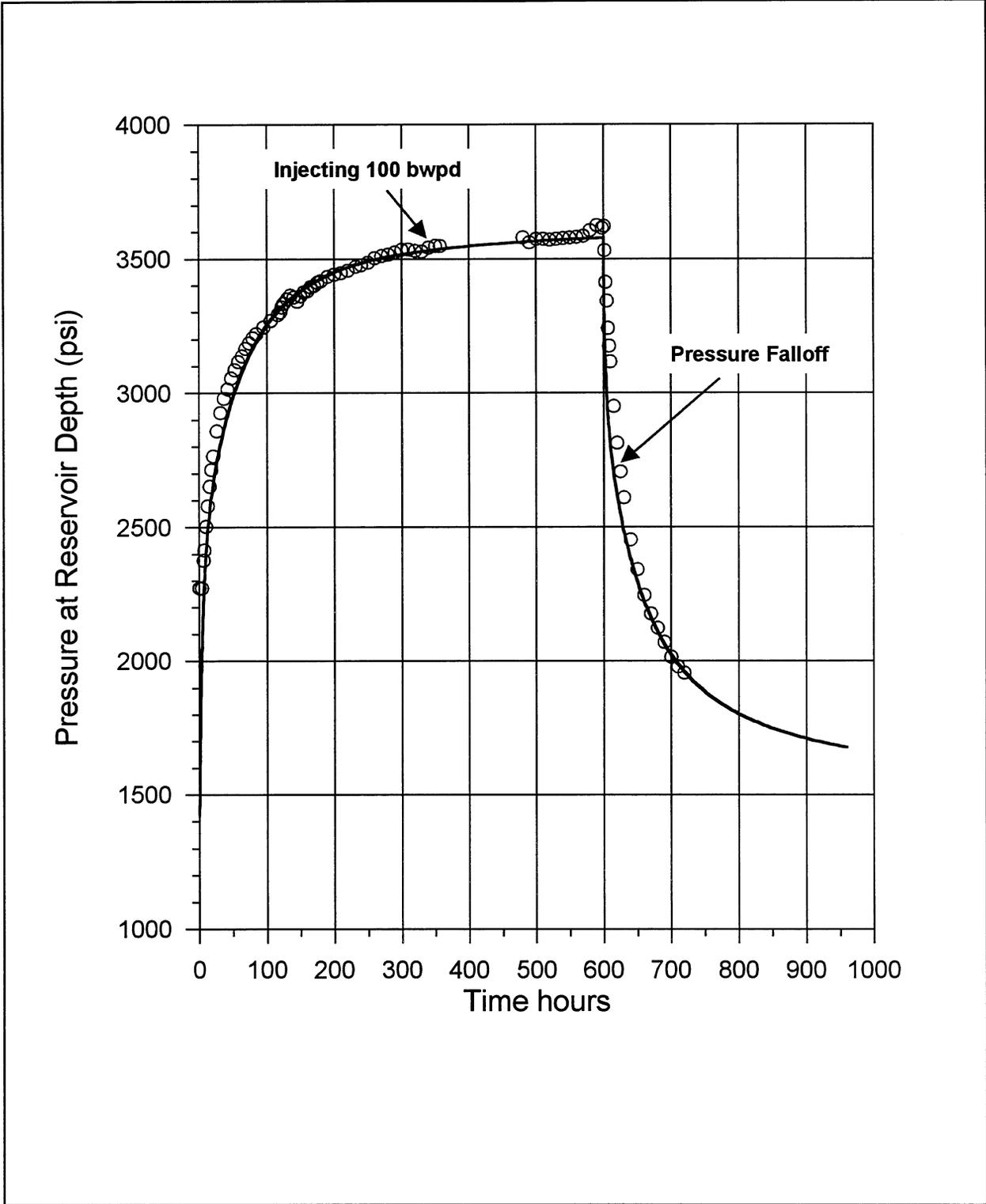


Figure 31: Water injection test in a vertical well at Buffalo Field (north area). The solid line represents prediction from computer simulation. Circles are measured data.

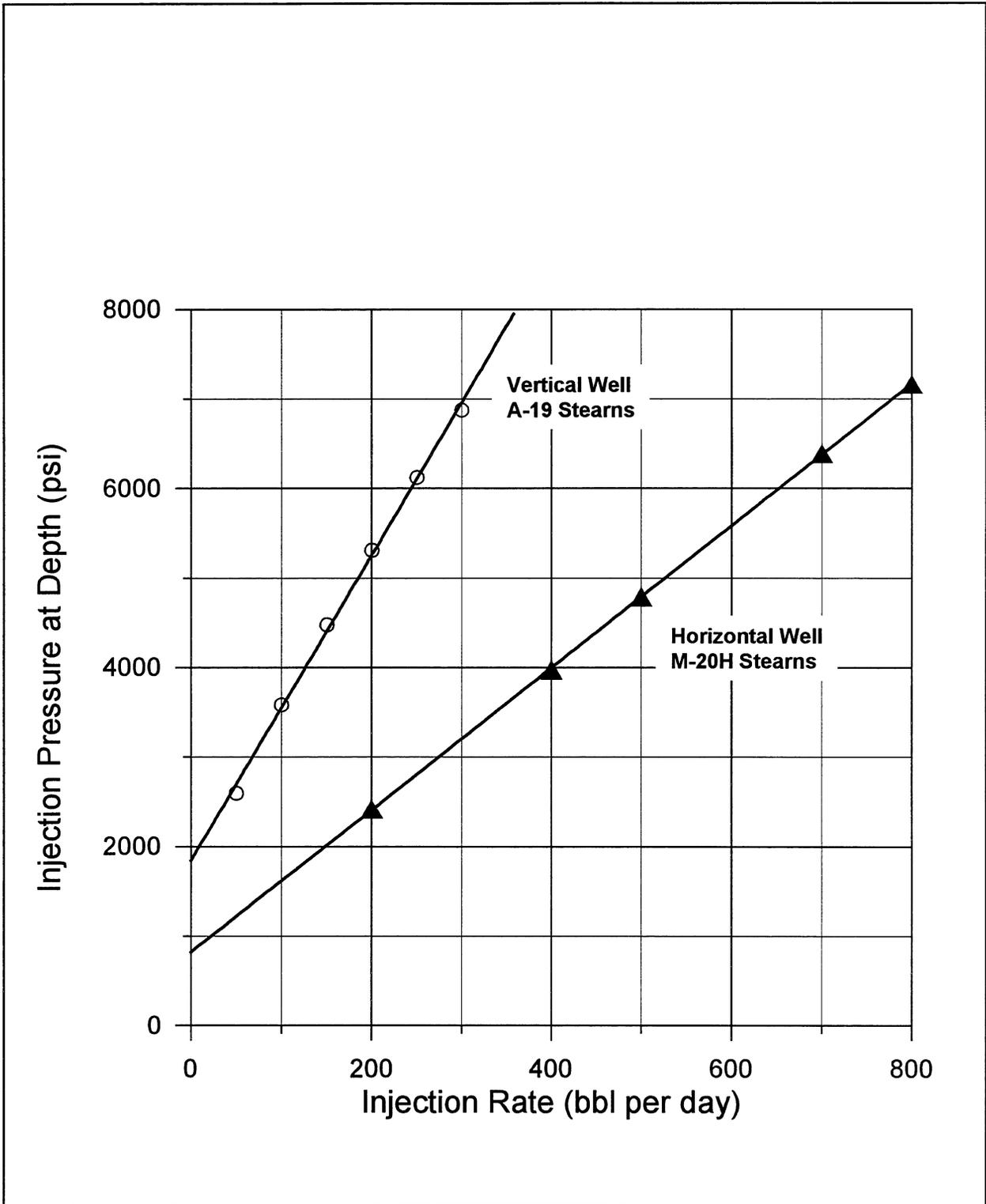


Figure 32: Stabilized water-injectivity into the Red River B zone at Buffalo Field (north area). The horizontal injection test was with a lateral of 1000 ft (300 m).

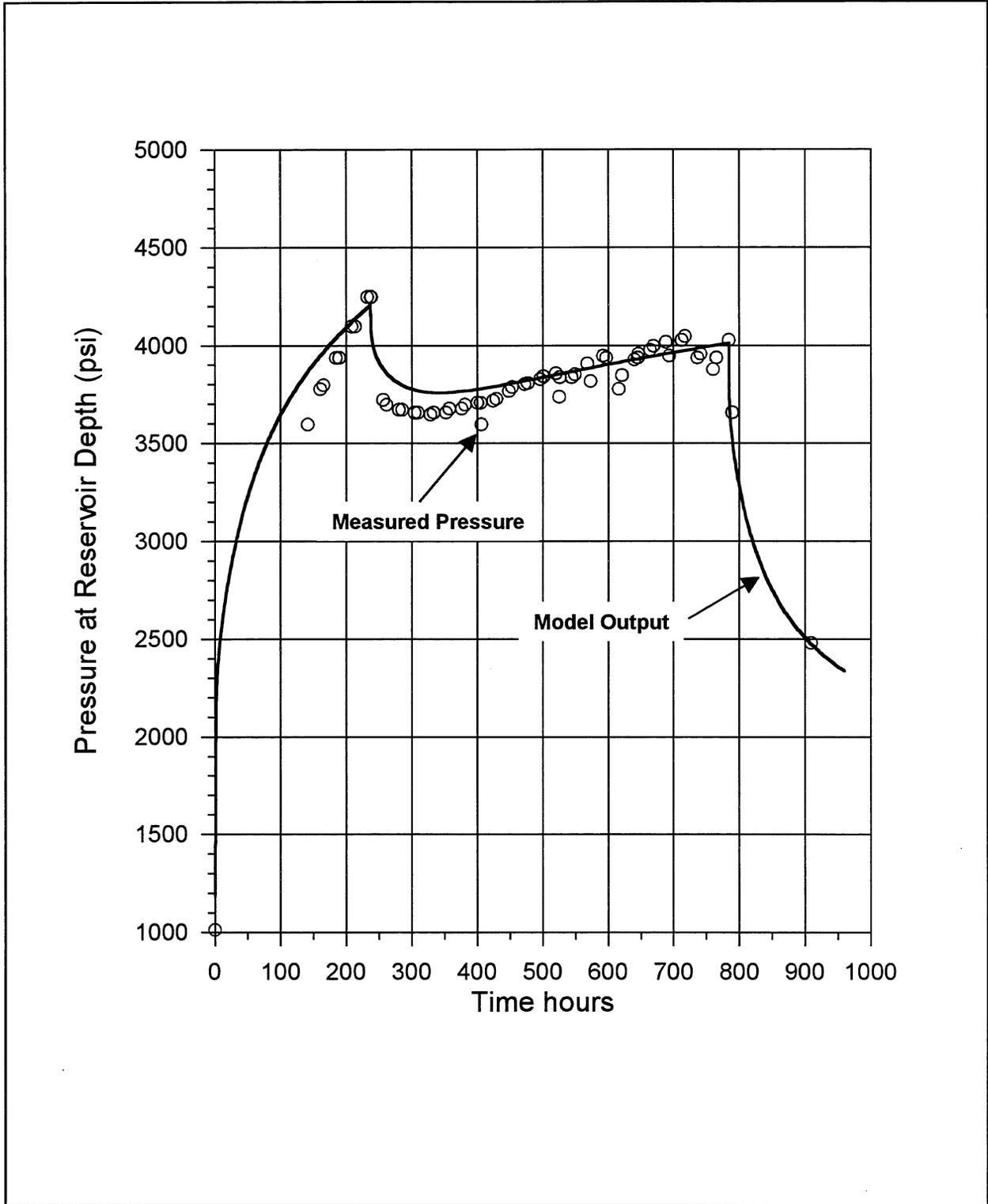


Figure 33: Water injection test in a horizontal well at Buffalo Field (north area). The solid line represents prediction from computer simulation. Circles are measured data. The lateral in the M-20H Stearns has a length of about 1000 ft (300 m).

Part Two – Ratcliffe

Introduction

The Ratcliffe study area is located in northeastern Richland Co., MT, approximately 32 km (20 miles) north of the town of Sidney, on the western shelf of the Williston Basin. The study area is approximately 80 km (50 miles) west from the basin center (figure 34). The study area covers approximately 466 km² (180 sq. miles) containing oil accumulations at several fields which produce from Ordovician through Mississippian-age reservoirs. An index map of the study area and locations of fields is shown in figure 35.

Historically, the Ratcliffe has been a secondary completion objective within the study area. The Ratcliffe is found at an average depth of 2590 m (8500 ft) and is consistently developed across large areas but typically has low permeability. Median reserves in the area have been less than 16,220 m³ (102,000 bbl) which is less than needed for an economical drilling objective. With an ultimate recovery cut-off of 25,438 m³ (160,000 bbl), less than 40 percent of the Ratcliffe producers in the area would be considered economical drilling targets. Volumetric calculations indicate sufficient oil-in-place; however, recovery is restricted by low permeability. Oil trapping does not appear to be structurally controlled and reservoir development is affected to some degree by fractures. For the Ratcliffe to be a viable drilling objective, methods need to be developed for 1) targeting better reservoir development and 2) better completions.

A 3D seismic survey and a special shear-wave seismic survey were obtained in the Ratcliffe area of Richland Co., MT. The shear-wave survey was to test the technology for fracture identification but it was a failure. Fracture characterization in the Ratcliffe includes acquisition of an oriented core and a special electrical log at North Sioux Pass Field, Richland Co., MT. A re-entry lateral completion in the Ratcliffe was mechanically successful but did not increase production. Water injection was also tested in a vertical well in the Ratcliffe. This test indicates low potential for secondary recovery with vertical injection wells. The injection rate was less than 16 m³ water per day (100 bwpd). It is concluded that the horizontal drilling attempts made during the project do not provide sufficient data to determine whether horizontal completions or lateral drain-holes can be more efficient than hydraulic fracture stimulation. However, it is concluded that completion with lateral drain holes still has potential for improving recovery. Examples are presented which describe a methodology for targeting the best Ratcliffe potential. The reader is also referred to previous topical reports (Carrell et al 1997; Sippel et al 1997) for additional discussions of Ratcliffe characterizations, field studies and demonstration activity.

Reservoir Characterizations

Geology

Common structural characteristics are found at the study area and other Ratcliffe fields of the western Williston Basin. These characteristics are strong structural nosing that trends southeast and the absence of significant closure which correlates with oil production. Ratcliffe production in the study area, and at other fields, is frequently better along the flanks of present-day structures. Larger Ratcliffe fields demonstrate reservoir development that is associated with structural relief but is not controlled by a common subsea datum. The strike across the study area is slightly west of north-south with several monoclinical terraces and localized closures reflected at the base of the Last Charles Salt and top of Ratcliffe markers. A present-day structure map on the top of the Ratcliffe is shown in figure 36. Present-day structural closure is subtle at many Ratcliffe fields. Within the study area, maps from well-log data reflect structural relief on top of Ratcliffe beds of only 3-8 m (10-25 ft) magnitude at Rip Rap Coulee, Cottonwood and Nohly fields in T.25-26N., R.59E. To the west in the North Sioux Pass Field in T.26N., R.58E., Ratcliffe structure is more pronounced. Structure in the area is frequently caused by basement tectonic activity associated with strike-slip and wrench faults (Mueller and Klipping 1978).

Reservoir Intervals

The Ratcliffe is characterized by complex inter-tonguing of basinal, shallow shelf, and peritidal carbonate and evaporite beds. The sediments were laid down in ramp/sabkha systems. In the study area, there are two productive intervals which generally are not coincident with the other. Both upper and lower Ratcliffe porosity zones (Flat Lake and Alexander intervals) appear to have been deposited areas of shallow ponds. This depositional model suggests that better reservoir rocks should be found along coastal areas and around barrier islands, inter-tidal buildups and tidal bars. Individual depositional units (facies) in the Ratcliffe can be correlated beyond productive limits and it is concluded that deposition of facies exerts only a secondary influence on production. The primary control on production is dolomitization of reservoir facies. Dolomitization of these rocks is the result of downward-migrating magnesium-rich brines. Faulting and fracturing during and after Ratcliffe deposition are mechanisms which were probably most efficient for allowing the migration of these dolomitizing brines from overlying hyper-saline ponds.

Ratcliffe porosity in the study area generally develops either in the lower or upper section (Alexander and Flat Lake intervals, respectively) but never is well developed in both. This observation leads to the conclusion that a dramatic change in shoreline direction occurred during and after Ratcliffe time. Porosity development on electrical logs is not always an indication of producibility.

Wells in Cattails, Rip Rap Coulee, Cottonwood and Nohly fields (T.26 N., R.59 E.) demonstrate development of the lower-porosity zone (eastern log shown on figure 37). This porosity zone is positioned just above the underlying Midale. It is similar in stratigraphic position as the lower-porosity bench which is labeled the Alexander interval in the Glass Bluff area of North Dakota (Hendricks 1988). Often, the lower-porosity zone exhibits a shallowing-upward profile on logs.

Upper-porosity development is demonstrated in wells at North Sioux Pass Field located in township T.26 N., R.58E. (western log shown on figure 37). The upper-porosity zone is similar in stratigraphic position as the Flat Lake interval (Hendricks 1988). In the North Sioux Pass Field, most wells that have upper-porosity development appear to be productive. Upper-zone porosity also shows a shallowing-upward profile. The cross-section in figure 37 also shows that porosity develops where the upper Ratcliffe interval is thicker.

A third type of section is demonstrated in the study area which can be productive yet has minimal porosity development. Porosity develops as thin spikes on logs and rarely exceeds 6 percent (middle log shown on figure 37). These porous spikes consist of limestone. Two wells completed in sections 22 and 27 of township T.26N., R.58E. were completed in this transitional-type section of the Ratcliffe and have averaged over 15,900 m³ (100,000 bbl) per well. These wells are an enigma and presumed to be connected to better porosity through a fracture system.

Geological mapping of various horizons indicates a correlation of better Ratcliffe development and oil producibility with thick areas of the Ratcliffe to Bakken interval. The Bakken lies at the contact between Mississippian and Devonian time. Interpretations of electrical logs from productive wells indicate tectonic activity during and after Ratcliffe time. This tectonic movement uplifted the Ratcliffe reservoirs resulting in a thinning of the interval from Cretaceous Greenhorn to Ratcliffe. Isopach maps indicate changes in regional trends from Bakken to Greenhorn time which is interpreted as a continual tectonic adjustment. Isopach maps show that thin and thick areas change through time indicating movement of horst and graben blocks. This tectonic activity probably resulted in fracturing at the joints of moving blocks.

Fracture Development

The most faulted and probably fractured areas are on the flanks of deep structures found at Ordovician Winnipeg and Red River depths. Seismic data across the study area show faults at the Red River and Winnipeg on the flanks of many of these structural features. The dominant direction of basement lineaments is northwest-southeast. After Ratcliffe time, there was significant structural growth which occurred to the northwest. This is shown by the Greenhorn to Base Last Salt isopach map. Uplifting to the northwest resulted in another set of faulting lineaments which run northeast-southwest.

The role of fractures for enhancing Ratcliffe production has been documented qualitatively in the literature (Mueller and Klipping 1978; Hendricks 1988; Longman and Schmidtman 1985). At Glass Bluff Field, McKenzie Co., ND, local fracturing is attributed with increasing permeability and reservoir performance (Hendricks 1988). Similarly, at Lustre Field, Valley Co., MT, vertical fractures are credited for enhancing production (Longman and Schmidtman 1985). Cores taken from the Ratcliffe interval in the study area also suggest that fracturing maybe responsible for better porosity development and production. Cores taken at North Sioux Pass, Cattails and Nohly fields have vertical fractures.

A 27-m (90-ft) oriented core from the Luff Federal No. 1-17R well (section 17, T.26N., R.58E.) was obtained to confirm observations concerning fracture orientation, facies distribution, and general reservoir characterization (see figure 35 for well location). A formation micro-imaging (FMI) electrical log was also obtained to image fracture orientations and porosity development. Figure 38 shows fracture orientations from observations of the Ratcliffe at the Federal 1-17R. Both the core and FMI log indicate a preferential orientation of fractures aligning northwest-southeast. The FMI indicates a primary orientation of 30° west from north. The core data indicate that fracturing has a primary orientation of 60° west from north. These fractures are nearly vertical with an average angle of 70°. The bedding dip of the Ratcliffe interval is indicated to be 30° east from north. This bedding dip is in good agreement with dip indicated from the isopach maps of Midale to Bakken and Base Last Salt to Bakken (figures 39 and 40).

It is concluded that the primary fracture orientation at the Federal No. 1-17R is parallel to the axis of the structural nose at North Sioux Pass Field (figure 36) and is between 300° and 330°. This orientation probably reflects wide-spread tectonic activity, both locally in the study area and regionally as indicated by the numerous fields that have orientations of northwest-southeast. However, it may be that the orientation indicated at the Federal No. 1-17R is only local. Detailed mapping of horizons using 3D seismic at North Sioux Pass Field indicates other lineaments exist which have orientations of northeast-southwest.

Reservoir Trapping

Reservoir trapping is primarily stratigraphic in nature and occurs locally with the presence of vertical fracturing. Fracturing is favorable for dolomitization via seepage-reflux of magnesium-rich brines. Primary controls on production are the degree of dolomitization of burrowed mudstone and wackestone facies and vertical fracturing. Individual facies from a variety of depositional environments can be correlated across the area, but depositional facies appear to exert only a secondary influence on production. At larger Ratcliffe fields, better oil production is located off structure and along flanks of paleo structures where most producing Ratcliffe wells lie in embayments and the porous intervals slightly thicken due to compensating deposition. It is observed in the study area, and elsewhere, that productive Ratcliffe is associated with subtle structure but is not controlled by a common subsea datum.

Heterogeneity

There are three types of heterogeneity observed in the Ratcliffe. Regional heterogeneity is the development of the upper and lower zones (Flat Lake and Alexander intervals). These intervals were deposited in two different cycles which were affected by a shifting regional setting. Well-developed porosity does not occur simultaneously in the Flat Lake and Alexander intervals. The second type of heterogeneity is the degree of dolomitization and porosity development through diagenesis. The third type of heterogeneity is faulting and fracturing. Fracturing appears to play a dual role in reservoir development as a factor in dolomitization and as permeable conduits for production. There is also evidence of structural compartmentalization in one Ratcliffe completion in the study area. Targeting better reservoir development involves locating areas conducive to deposition of thicker facies and subsequent fracturing by tectonic movement. The application of horizontal drilling should improve producibility from the Ratcliffe because of the low-permeability nature of the reservoir. Because better Ratcliffe production is associated with fracturing, a horizontal drain hole offers the potential for connection with more fractures and greater producibility if the fractures are not damaged by invasion during drilling.

Petrography

A core and petrographic study was undertaken to describe depositional setting and development of porosity within the Ratcliffe beds of the Charles Formation (Meramecian) found in northeast Richland County, Montana. Graphical descriptions were made from three slabbed cores and were augmented by petrographic study of thin sections.

Several cores in the area have vertical fractures. It is observed in the study area, and at other Ratcliffe producing areas, that vertical fracturing is coincident with better porosity development and productivity. It is concluded that Ratcliffe reservoirs in the study area consist of low energy sediments which have undergone varying degrees of dolomitization. Preserved primary porosity is not a major constituent of reservoir rock. Faulting and fracturing, coincident with deposition, probably provided pathways for downward movement of dolomitizing brine into lower rocks. Thus, fracturing is thought to play a dual role in reservoir development as an important factor in dolomitization and as permeable conduits for production.

Vertical Facies Successions

Ratcliffe lithofacies can be arranged in a vertical assemblage that depicts inter-tonguing of shallow-shelf, restricted subtidal, peritidal, and supratidal facies associated with forward stepping, shallowing-upward paracycles. Ratcliffe reservoir beds in the study area include the Alexander and Flat Lake sub-intervals. Reservoir facies are incompletely to completely dolomitized mudstones and wackestones that occur in the middle and upper portions of paracycles. Forward stepping and vertical stacking of lithofacies controlled sediment accumulation and lateral distribution. Progradation of the Ratcliffe system was from east to west and sediment off-lapping produced facies belts that are laterally continuous along depositional strike. This ramp style of deposition characterizes the entire Ratcliffe.

In the project area, progradational facies belts crossed paleo-anticlines. Burrowed mudstones and wackestones became sites for selective dolomitization. Magnesium-rich brines which developed in overlying sabkha environments percolated through these restricted subtidal sediments producing porous, but generally low permeable reservoirs. Local fracturing which occurred during the Laramide Orogeny (Early Paleocene) enhanced these reservoirs.

Depositional Environments

Ratcliffe core lithofacies were described from three wells in order to determine lithology, textures, skeletal and non-skeletal allochems, cements, porosity types and oil shows. Ratcliffe sediments gradually filled the Charles basin with off-lapping or progradational wedges of carbonates and evaporites. From base to top, the Ratcliffe is characterized by shallowing-upward and salinity-restricting paracycles.

Facies 1. Black to dark gray, shaley lime mudstones with sparse crinoid skeletal fragments were deposited in open marine environments during base level rise. These sediments represent the deepest Ratcliffe depositional environments in the study area. This facies commonly displays an increased gamma-ray response on electrical logs.

Facies 2. Open marine sediments are dark gray to black and contain crinoids, bryozoans, brachiopods, rugose and tabulate corals, and sparse mollusks. These lime wackestones and packstones were deposited in normal marine environments. Minor oscillations in bathymetry produced inter-tonguing of these sediments with restricted subtidal sediments.

Facies 3. Brown, burrow-mottled sediments locally contain normal marine fauna, but were probably deposited in environments that were slightly to highly stressed by elevated salinity and/or low oxygen levels. *Thalassinoides*, *Rhizocorallium*, *Chondrites*, and *Planolites* trace fossils are common, and are part of the *Cruziana* ichnofacies which has been described along shallow shelf environments (Pemberton et al 1992). Burrowed sediments are slightly to completely dolomitized. It is inferred that burrowing infauna probably increased sediment transmissibility and made these shallow subtidal sediments susceptible to seepage dolomitization from overlying gypsum (anhydrite) beds.

Facies 4. Light brown to brown, algal and skeletal lime mudstones and wackestones were deposited in protected-shelf and lower-shoal environments. These sediments are sparsely burrowed, slightly dolomitic, and generally not reservoirs. Algal fragments are broken and coated *Ortonella* fragments, and skeletal fragments are ostracods.

Facies 5. Upper shoal environments commonly cap burrowed mottled sediments. Shoal sediments are peloidal and algal mudstones to packstones. Textural variations are related to differences in depositional energy and relative bathymetry across ancient structural noses. Shoal sediments were probably deposited in very shallow sub-aqueous environments based on the presence of the Codiacean alga *Ortonella*. This alga characteristically is nodular with well-developed radiating microtubules. Peloidal grains indicate reworking of muddy substrates and algal fragments in swash zones and possibly intertidal environments. Coated grains are sparse. Original porosity within grain-rich beds is commonly occluded by calcite spar cements and secondary anhydrite. Because of early cementation and sparse dolomitization, the shoal facies in the study area is generally not a reservoir.

Although not cored in the project area, laminated beds commonly underlie and immediately overlie sabkha sediments. These intertidal beds are dolomites with millimeter-scale, flat to wavy laminations. This facies was deposited in environments where the trapping and binding activities of cyanobacteria were common. Desiccation features are sparse, and in situ fossils are missing. Anhydrite caps the shallowing-upward paracycles. The presence of anhydrite (gypsum) indicates that restriction accompanied progradation and basin filling. Displacive nodular and enterolithic anhydrites are common, and it is inferred that deposition of gypsum was in coastal sabkhas which were both intermittently wet and desiccated.

Diagenesis

In the study area, Ratcliffe oil is typically entrapped within dolomitized burrow-mottled mudstones and wackestones. Dolomites are fabric preserving and microcrystalline to cryptocrystalline. Most of the visible porosity is associated with burial diagenetic processes (moldic and vuggy pores). Intercrystalline porosity is poor to fair and associated permeability is the same.

Vuggy and channel pores commonly occur within dolomitic strata and possibly developed during burial diagenesis. Late-burial dissolution associated with chemical compaction, maturing hydrocarbons, or hydrothermal processes may be a common control in Ratcliffe reservoir development (Dravis and Muir 1993). This evaluation has shown that Ratcliffe dolomitic reservoirs were subjected to burial diagenesis which modified pre-existing reservoir conditions and both improved and reduced porosity and permeability.

Anhydrite and calcite replacements are locally present in Ratcliffe reservoirs. These occluding and diagenetic minerals decrease both porosity and permeability. Anhydrite commonly occurs as a late precipitating and occluding cement, and calcite is locally present as a pore-occluding mineral. Both minerals precipitated during mesogenesis.

Natural fractures within the Ratcliffe are developed within limestones and dolomitic beds and are observed in each core studied. These fractures are nearly vertical and have fluorescence. Many fractures within limestones were subsequently occluded by sparry calcite. Fractures in dolomites are usually 0.15 to 0.60 m (0.5 to 2.0 ft) long and occur within the burrow-mottled facies (Facies 3). Swarms or closely spaced vertical fractures are also present, but within thin beds.

Pressure-solution features, ranging from micro-stylolites to high-amplitude stylolites, wispy seams, and individual or isolated solution seams are present in Ratcliffe beds. Stylolitization is more common in non-reservoir limestones and these compaction features do not appear to adversely affect dolomitic reservoirs.

Engineering

Volumetric calculations from log and core data indicate that the Ratcliffe contains from 1701 to 2531 m³/ha (4331 to 6441 stb per acre) across the study area. Oil recovery from hydraulically fractured,

vertical wells has a median of 16,220 m³ (102,000 bbl) per well and represents about 6 percent of OOIP in a 129-ha (320-acre) spacing unit. Permeability from core and pressure-transient testing indicate the Ratcliffe has a representative permeability of 2.0E-4 μm² (0.2 md). Core data indicate that permeability is seldom greater than 9.9E-4 μm² (1.0 md). Reservoir simulations, matching producing rates and pressures, confirm that Ratcliffe wells are capable of draining less than 7 percent of OOIP because of low permeability. Water-injection testing indicates that recovery by waterflooding with vertical wells would be limited by low injection rates.

Reservoir Fluids

At formation depth and temperature in the study area, Ratcliffe reservoirs are initially under-saturated systems and exhibit black-oil characteristics. The Ratcliffe produces a paraffinic, slightly sour crude oil with a density of 0.85-0.88 gm/cc (30° to 35° API) and contains associated gas with a specific gravity of nearly 1.0. Produced gas-oil ratios in the area vary from 53 to 107 m³/m³ (300 to 600 scf/bbl). Water produced from the Ratcliffe is saturated brine with total dissolved solids in excess of 300,000 mg/l. An oil sample was obtained for PVT analysis. The recombined sample is based on a solution-gas content of 88 m³/m³ (495 scf/stb) at a reservoir temperature of 102°C (215°F) which results in a bubble-point pressure of 13,670 kPa (1983 psi). Viscosity ranges from 6.5E-4 Pa•s (0.65 cp) at bubble-point pressure to 7.9E-4 Pa•s (0.79 cp) at initial conditions. The original reservoir pressure in the area is about 28,270 kPa (4100 psi) with a maximum of 31,030 kPa (4500 psi).

Porosity and Permeability

Data from four Ratcliffe cores indicate permeability has a geometric mean of 2.2E-4 μm² (0.22 md) with a range from 5.9E-5 to 7.6E-4 μm² (0.06 to 0.77 md) at one standard deviation. Porosity ranges from 3.0 to 12.8 percent with a mean of 9.3 percent. Vertical fractures with fluorescence in pay intervals are frequently observed in cores. Density-neutron porosity logs from 22 wells were analyzed in the Ratcliffe interval. It was found that net-pay thickness from logs has a mean of 5.5 m (18 ft) with a range from 2.7 to 8.5 m (9 to 28 ft) at one standard deviation. Porosity-thickness ranged from 24 to 76 percent-m (78 to 250 percent-feet) with a mean value of 50 percent-m (164 percent-feet). Calculated water saturations are usually about 50 percent in productive intervals.

Log calculations from the upper Ratcliffe porosity (Flat Lake subinterval) at North Sioux Pass Field indicate productive thickness of 4.6 m (15 ft) with average porosity of 8.8 percent and water saturation of 45.8 percent. The apparent oil-in place is 1701 m³/ha (4330 stb per acre). Petrophysical properties of the lower Ratcliffe porosity (Alexander subinterval) at Cattails Field indicate thicker net pay of 9.1 m (30 ft) that contains 2531 m³/ha (6441 stb per acre). Petrophysical calculation of productive intervals utilized neutron-density logs for average porosity. Water resistivity of 0.011 ohm-m is based on a salinity of 325,000 mg/l TDS at 107°C (225°F). Porosity cut-off of 4 percent and water saturation cut-off of 80 percent were used to discriminate productive intervals.

Drill-stem tests in the Ratcliffe are generally run with a two or three-hour flow period and recoveries are usually less than 305 m (1000 ft) of oily mud-emulsion with some water. Storage and after-flow usually dominate the entire character of the shut-in pressure data. Original reservoir pressure ranges from 27,579 to 31,026 kPa (4000 to 4500 psi). Transmissibility (kh/μB) calculations average 9.0E+6 μm³/Pa•s (30 md-ft/cp) and range from 9.0E+5 to 1.8E+7 μm³/Pa•s (3 to 60 md-ft/cp). Transmissibility from post-completion, pressure-transient testing at North Sioux Pass Field averages about 6.0E+6 μm³/Pa•s (20 md-ft/cp). Permeability to liquid is about 3.9E-4 μm² (0.4 md) for 7.6 m (25 ft) and viscosity of 5.0 E-4 Pa•s (0.5 cp).

Production

Analyses by production type-curve analysis (Fetkovich 1980) and computer simulation were performed on 55 Ratcliffe completions to assess productivity, reserves and drainage. These completions are all in vertical wells that had been hydraulically fractured. The reservoir parameters were calibrated by

finite-difference black-oil simulation of eight Ratcliffe completions in the North Sioux Pass Field. Late-time production performance and ultimate recovery were the primary objectives of the computer simulations. The primary calibration parameter is compressibility which is used for calculation of contacted pore volume and oil-in-place. The system compressibility (C_t) which most frequently matched pore volume calculations from type-curve analysis and computer simulation was determined to be $1.67E-6$ vol/vol/kPa ($11.5E-6$ vol/vol/psi). Oil PVT data from the Iversen No. 2-2 (Sec. 2, T.25N., R.58E.), South Otis Creek Field, were used for the computer simulations and production type-curve analyses. Water saturations of about 50 percent produced results which matched reported water production. The majority of Ratcliffe completions have a water-oil ratio of nearly one over the producing life. All wells were analyzed using the same values for pore-feet, water saturation, and pressure conditions. Projected recoverable reserves were extrapolated to an economic limit of 1.3 m³ oil per day (8 bopd).

Based on these analyses, Ratcliffe reserves range from $4,610$ to $35,610$ m³ (29,000 to 224,000 bbl) per completion with an geometric mean of $16,220$ m³ (102,000 bbl). Stabilized initial production is typically less than 11.1 m³ oil per day (70 bopd) and ranges from 6.0 to 15.4 m³ oil per day (38 to 97 bopd). Apparent drainage averages 75 ha (186 acres) based on an average net pay of 5.5 m (18 ft), porosity of 9 percent and water saturation of 50 percent. The average recovery factor from contacted drainage is indicated to be 13 percent.

Reserves and Economics

Volumetric analysis indicates there is potential for sufficient oil-in-place to achieve economical drilling for the Ratcliffe in the study area. Using reservoir parameters of 5.5 m (18 ft) for average net-pay thickness, 9 percent for matrix porosity, 50 percent for water saturation and an oil volume factor (B_o) of 1.282, the average oil-in-place is calculated to be 1925 m³/ha (4900 stock-tank barrels per acre). Using a recovery factor of 13 percent, potential recoverable oil is calculated at 250 m³/ha (637 stock-tank barrels per acre). In a 129-ha (320-acre) spacing unit, the potential recoverable reserves are therefore calculated to be $32,400$ m³ (203,800 bbl). The Ratcliffe can be an economical, single-zone drilling target if the risked reserves are greater than $25,438$ m³ (160,000 bbl) and completed-well costs are less than \$900,000. This economic assessment is based on an oil price of \$18.00 per barrel. Only 40 percent of the Ratcliffe completions in the production study area have projected ultimate recoveries greater than $25,438$ m³ (160,000 bbl).

Targeting Reservoir Development

The majority of wells drilled in the study area were targeted for deeper Red River reservoirs from interpretations of 2D seismic data. The criteria for targeting the Red River are not necessarily appropriate for the Ratcliffe. It is concluded that oil accumulations in the Ratcliffe are developed as low-permeability reservoirs which do not exhibit structural closure in many examples. Primary factors controlling development of Ratcliffe reservoirs are dolomitization of certain facies and fracturing. It is concluded that thicker areas of the isopach of Ratcliffe to Bakken should correlate with areas of thicker reservoir facies in the Ratcliffe. Thin areas of the Greenhorn-Ratcliffe isopach should indicate locations of upward movement after Ratcliffe deposition. Diverging trends from these two isopachs should indicate areas most likely to have experienced tectonic stress and fracturing of Ratcliffe intervals.

Identification of fracturing using converted-wave multi-component data was attempted by acquisition of a special 2D seismic line. It was not possible to exact coherent shear-wave data from these records and further attempts to investigate identification of fracturing using shear-wave data were abandoned. Because of problems identified with a surface weathered zone and the great cost associated with recording a multi-component seismic survey, it was concluded that conventional 3D seismic would be more appropriate for project objectives and budget.

A 65 -km² (25 square-mile) 3D survey across North Sioux Pass Field was used to characterize the Ratcliffe and develop a methodology for identifying areas most prospective for Ratcliffe reservoir development. Seismic modeling indicates that increasing porosity development in the Ratcliffe is

expressed as an observable amplitude change. However, the variation of amplitude is subtle and should be used only as a guide after targeting from isopach and structure mapping.

Test for Multi-Component Seismic

A 4.8-km (3-mile), 2-dimensional 3-component (2D-3C) seismic line was recorded in May 1995, using converted, compressional waves (dynamite) over the Cattails Field in Richland Co., MT (figure 41). The quality of converted-wave data was poor. Field recordings show a significant source-generated noise train that dominates the split-spread records. Although the converted-wave data were processed by two different well-known geophysical companies, these efforts did not yield coherent shear-wave data. It is concluded that adequate data do not exist on the processed horizontal components to evaluate applicability of converted-wave methodology for fracture detection and characterization or to measure shear-wave splitting. A thick, surface-weathering zone is a major impediment for shear-wave acquisition in the study area.

The purpose of the Cattails 2D-3C acquisition was to make use of converted shear waves, recorded on the horizontal phones (inline and crossline) to locate vertical fractures in the Ratcliffe reservoir. Three-component geophones were used to record the data. There were initially four goals of the 2D-3C acquisition:

- 1) locate fractures by means of effects in the shear-wave data,
- 2) evaluate the feasibility of recording converted waves with slightly modified P-wave acquisition,
- 3) determine S-wave (converted wave) quality in the area, and
- 4) design acquisition techniques that can be used for future surveys.

It is still not known if shear-wave data can help identify fractures in the Ratcliffe study area. Recording converted waves does not appear to be feasible or practical. Several possible problems were identified with the acquisition, and recommendations were made for future multi-component recording. However, the existence of a thick, weathered layer in the area suggests that quality shear waves would be very difficult to record.

The conclusions reached after processing are that the recorded data do not contain sufficient converted shear-wave energy to be useful. All stacks produced from inline and transverse components indicated an absence of coherent events. This can be attributed to either (or both) a lack of signal energy reaching the surface geophones or severe noise generated by the shots. This does not fully answer the question whether usable converted-wave data can be acquired in the area. Some problems with the original recording are identified and several suggestions follow that should improve any efforts to conduct future multi-component seismic acquisition.

Several possible mistakes were made during the first-round of processing. The second processing followed a processing flow which has been successful on other data. The key to imaging shear waves is to resolve the statics. Shear waves are more affected by the degree of consolidation than P-waves, since their propagation depends on the rigidity of the rock matrix. They do not propagate at all in liquids and in very loose soil. Shear waves are greatly slowed in poorly consolidated (and fractured) rock. Because of this, S-wave statics can be from two to ten times as great as P-wave statics. For converted waves, processor 2 first resolves the P-wave statics, then uses the P-wave shot statics and double the P-wave receiver statics as a first pass S-wave static solution. The static program is then iterated, focusing on some coherent event, until convergence on the S-wave receiver static. In order for the automatic static routine to work, a reflector must be resolved sufficiently to allow correlation along the line. Eventually, the event must be associated with a corresponding P-wave reflection.

With the Cattails data, no reflection was sufficiently coherent on the S-wave section to correlate across the data. This was the case despite the pre-processing performed to reduce noise and improve the signal (surface-consistent de-convolution and Radon transform). Because no coherent signal could be identified, there was no basis for running the static routine. Further processing was aborted at this point.

The question remains whether the line was properly recorded, or whether the area simply does not allow recording useful shear-wave data. One indication that the area may be unsuitable for shear waves is a thick, weathered layer. Shot holes were drilled 37 m (120 ft) deep, probably because the weathering was that thick. As stated above, shear-wave statics can be much larger than P-wave statics. An unusually thick weathered layer compounds the problem of statics, and may absorb much of the shear-wave energy. There are some field techniques which may improve future data acquisition. The offsets should be longer. The Cattails acquisition used a split spread with maximum offset of 1636 m (5368 ft), except on both ends of the line where they shot through the cable and the offset increased to over 10,000 ft. (However, the fold decreased because of the taper). For the depths of the Ratcliffe zone, offsets should have been at least 2438 m (8000 ft) for optimal mode conversion.

There was a strong noise cone, generated by the shot, that obliterated the near traces and spread with depth, covering most of the traces at target depth. A smaller charge or deeper shot holes may improve this situation.

The line was shot at 12 fold and is lower than is desirable. It is recommended that 24 to 30 fold be used for future acquisitions of this type.

Ground coupling for shear-wave phones is more critical than for P-wave data. Each horizontal phone must be leveled, with more care warranted than with vertical phones. The phones are also often buried to improve coupling. It is recommended that a consultant experienced in shear-wave recording be placed on the crew to supervise planting of geophones. It is also recommended that recording be done in winter because frozen ground couples better, minimizing the static problem for shear waves.

The initial processing of the 2D-3C data may not have been ideal; however, subsequent processing by a company with successful shear-data experience also failed to image shear waves. This leads to the conclusion that further processing of data will not produce results. The existence of a thick, weathered layer in the area suggests that quality shear waves would be difficult to record.

3D Seismic Interpretation

Subsequent to the attempt to record and process shear-wave seismic data, efforts were focussed on other seismic data which may provide indirect inference for locating favorable Ratcliffe drilling locations. In previous sections of this report, there are conclusions with regard to criteria favorable for probable better Ratcliffe development. These criteria include: 1) compensating deposition in low areas results in thicker productive facies, 2) post-Ratcliffe structural movement and 3) fracturing. Most of the wells drilled in the area were targeted for deeper Red River production. Unfortunately, criteria for locating Red River wells do not appear compatible with Ratcliffe reservoir development.

A 3D-seismic survey was recorded over the North Sioux Pass Field in Richland Co., MT during December 1996. The survey covered approximately 65 km² (25 sq.-miles). The receiver and shot-line spacing was 402 m (1320 ft). The energy source was 2.3 kg (5 lb) of dynamite placed in shot holes drilled to 18 m (60 ft). The nominal fold ranges from 15 to 20. The data were recorded by Geco-Prakla using an I/O System 2 recording unit. Processing was performed by Tricon Geophysical and Western Geophysical. Recording parameters and statistics for the North Sioux Pass 3D seismic survey are summarized in table 6. An example seismic section from the 3D survey is shown in figure 42. The Ratcliffe occurs at about 1.900 seconds at the crest of the North Sioux Pass Field.

As noted above, the seismic data were processed by two different companies employing different methods and algorithms. The two processed data sets were found to be different with regard to frequency and amplitude character. The reader is advised to be aware that different geographic areas may require different processing methods to optimize seismic data. Processing methods which yield good results in one area may not work as well elsewhere.

Following the observations and conclusions made in the sections covering geological and engineering characterizations of the Ratcliffe, seismic events corresponding to the Greenhorn, Ratcliffe and Bakken were picked and mapped. Summaries of the seismically enhanced mapping of these horizons and intervals follow. The methodology described was used to target several areas most prospective for

Ratcliffe reserves and drilling new wells. However, these locations remain untested at the close of the project.

Ratcliffe to Bakken Isopach

The Ratcliffe to Bakken isopach was computed from seismic interval time and velocity trends from well-data formation tops (figure 43). This isopach map shows details which are not possible from electrical-log data alone. The map shows an amorphous collection of thick and thin areas which represent lows and highs during Mississippian deposition. The prevailing trend of these thick and thin areas is nearly northeast-southwest. The thicker areas on this map are likely to contain thicker Ratcliffe facies. This is the first map for selecting areas favorable for better Ratcliffe development.

The interval from the Ratcliffe to the Bakken can be used to identify areas which were probably low prior to and during Ratcliffe deposition. The Bakken Formation was deposited at the end of Devonian and beginning of Mississippian time. Thick areas from this isopach correlate very well with better Ratcliffe completions found at Nohly and Cattails Fields. Other investigators have made similar conclusions at other Ratcliffe fields in Montana and North Dakota (Longman and Schmidtman 1985; Hendricks 1988).

Greenhorn to Ratcliffe Isopach

The second interval map for screening of Ratcliffe potential is the Cretaceous Greenhorn to Ratcliffe isopach. The map shown in figure 44 was constructed from seismic data and well-data formation tops as discussed for the previous map. Thin areas on this map represent positive structural movement occurring after Ratcliffe deposition. It is interpreted from this map that a strong northwest-southeast trending structure developed during the period between Ratcliffe and Greenhorn deposition. This structural growth was dominated by a regional uplifting to the northwest.

Overlaying the Greenhorn-Ratcliffe and Ratcliffe-Bakken isopach maps is the next step in targeting areas which have favorable conditions for better Ratcliffe development. Divergent trends of contours are interpreted to indicate a change in location of tectonic stress. Areas of structural movement after Ratcliffe time which were low before Ratcliffe time are thought to be most likely fractured, especially those which are normal to basement lineaments trending regionally northwest-southeast.

Ratcliffe Structure

A computed Ratcliffe structure map is shown in figure 45. It was constructed from seismic time and integrated with velocity trends from well-log formation tops. The map shows a large structural platform trending northwest-southeast. Ratcliffe production on the North Sioux Pass Field has been from recompletions in wells which produced previously from the deeper Red River. These wells are shown on figure 45 which indicates their position on the northeast and southeast hinge lines of the platform. Structural nosing and areas of steep dip are thought to be prone to fracturing. The Ratcliffe structure with the Ratcliffe to Bakken isopach can be used to identify positive present-day structure with thick deposition during Ratcliffe time.

Seismic Amplitude

Synthetic seismograms were constructed from sonic and density log data with modifications to show minimum and maximum porosity development within the two Ratcliffe porosity zones (Alexander and Flat Lake sub-intervals) present in the area. Figure 46 shows type logs of Ratcliffe development in the Alexander and Flat Lake intervals. Logs from wells in the area do not indicate simultaneous development of thick porosity in the Flat Lake and Alexander intervals. Models were constructed with a zero-phase, band-pass filter using frequencies of 10/12 - 60/70 Hz. Examples of the models with normal polarity are shown in figure 47. The modeling shows that seismic response to porosity variation within the 26-m (85-ft) Ratcliffe interval produces variation in one trough and one peak event. With normal polarity, the absolute value of trough amplitude increases with increasing porosity for both the Flat Lake and

Alexander porosity benches (either individually or in combination). The underlying peak event also increases in amplitude with porosity development in the Ratcliffe. Increasing amplitude of the underlying peak is most notable when the lower-porosity zone (Alexander sub-interval) is well developed.

At North Sioux Pass Field, the Ratcliffe develops the greatest porosity in the upper or Flat Lake interval. It is concluded that amplitude of the seismic-trough event correlates with porosity development at North Sioux Pass Field. A map of relative amplitude from the Ratcliffe trough event overlain on the Ratcliffe depth structure is shown in figure 48. This attribute appears to correlate with the geologic model for favorable Ratcliffe development. Across much of the North Sioux Pass Field, the Ratcliffe trough amplitude is better developed on the northeast and southwest flanks of the platform. The coincidence of greater amplitude on the flanks of the North Sioux Pass platform is encouraging because it is consistent with observations at several larger Ratcliffe fields. At these fields, better reservoir is preferentially developed on the flanks and not on crestral areas. Amplitude variation is very subtle, however. It appears that this attribute should be used as a final indication of better reservoir development within prospect areas delineated from isopach and lineament mapping.

Targeting Drilling Locations

The first step for targeting prospective Ratcliffe locations is comparing the Ratcliffe to Bakken isopach and Ratcliffe amplitude maps. The thick areas represented on this isopach are likely to have thicker productive facies in the Ratcliffe because of compensating deposition. Geological characterizations at Cattails and Nohly fields indicate a correlation of better reserves with a thick isopach of the Ratcliffe to Bakken interval. Areas of greater Ratcliffe amplitude that are coincident with thick areas of the Ratcliffe to Bakken isopach should have greatest potential for thicker Ratcliffe with porosity.

The next step is identification of potential fault lineaments adjacent to previously identified thick areas. These lineaments can be interpreted from breaks in seismic section, steep structural contours and movement inferred from Ratcliffe to Bakken and Greenhorn to Ratcliffe isopach maps. Reversal of Ratcliffe to Bakken and Greenhorn to Ratcliffe isopach intervals is demonstrated at the Cattails and Nohly fields. It is thought that areas most likely to be fractured are adjacent to blocks with recurrent and reversal of movement.

The final step is comparison of present-day structure and the Ratcliffe trough amplitude. Favorable amplitude response located in thick areas of deposition should be associated with positive structural position.

Horizontal Wells for Improved Recovery

Two attempts were made to drill a horizontal completion from wells which were previously producing from the Ratcliffe. One well was mechanically drilled with a lateral of 604 m (1980 ft), but it did not result in commercial oil rates. Drilling of a lateral at a second well was aborted after unsuccessful attempts to achieve a drilling curve from the casing-window exit. The mechanically successful lateral may have been drilled out of zone. It is concluded that the horizontal drilling attempts made during the project do not provide sufficient data to determine whether horizontal completions can be more efficient than hydraulic fracture stimulation in a vertical well. Reservoir simulation of horizontal completions with productivity of three times that of a vertical well suggest two or three horizontal wells in a 640-acre area could recover sufficient reserves for profitable drilling.

Data and Analysis from Vertical Wells

A production study was made during this project to evaluate the long-term production response after proppant-fracturing. The study evaluated production data from 17 Ratcliffe and Ratcliffe with upper Mission Canyon completions which were completed by fracture stimulation from 1983 through 1985. The average treatment used 98,430 kg (217,000 lb) of 20/40 proppant. These wells are in fields mostly in Richland Co., MT along the Montana-North Dakota border from T.23N. to T.27N. and R.57E. to R.60E. The wells were selected based on having from 6 months to 18 months of pumping data prior to re-

stimulation with a proppant-fracture system. Production type-curve analysis after the method of Fetkovich was used to estimate stabilized production rates, reserves and productivity.

The projected ultimate reserves from these wells prior to re-stimulation are estimated at a median recovery of 11,450 m³ (72,000 bbl) per well. After re-stimulation with proppant-fracture systems, the ultimate reserves are projected at a median recovery of 27,030 m³ (170,000 bbl) per well. While production increases immediately after stimulation of up to 200 percent are observed, the increase in stabilized productivity is determined to average 66 percent over pre-fracture trends. Pre-fracture stabilized rates average 7.3 m³ oil per day (46 bopd), while post-fracture stabilized rates average 11.4 m³ oil per day (72 bopd). Of the 17 wells, three wells exhibited no improvement in stabilized long-term production trends or ultimate reserves.

Ratcliffe reserves in the project study area range from 4,610 to 35,610 m³ (29,000 to 224,000 bbl) per completion with an geometric mean of 16,220 m³ (102,000 bbl). Stabilized initial production is typically less than 11.1 m³ oil per day (70 bopd) and ranges from 6.0 to 15.4 m³ oil per day (38 to 97 bopd). Apparent drainage averages 75 ha (186 acres) based on an average net pay of 5.5 m (18 ft), porosity of 9 percent and water saturation of 50 percent. The average recovery factor from contacted drainage is indicated to be 13 percent.

Computer simulation was performed based on reservoir data obtained from wells in the study area. A single-layer, isotropic model was constructed using a thickness of 7.6 m (25 ft) with a porosity of 9 percent and water saturation of 45 percent. The net-pay thickness is based on actual values observed in wells with thicker development. Effective fluid permeabilities were adjusted to match data from core and pressure-transient testing. Recoveries from a 129-ha (320-acre) model were calculated for various development situations. This model contains an OOIP of 383,500 m³ (2,405,800 bbl) at 28,600 kPa (4150 psi).

Two wells completed in the hypothetical 129-ha (320-acre) reservoir, separated by 850 m (2800 ft), are predicted to produce 25,300 m³ (159,000 bbl) of oil after 13 years to an abandonment rate of 1.2 m³ oil per day (8 bopd) per well. This represents a recovery factor of 6.6 percent. Final reservoir pressure is computed to be about 11,000 kPa (1590 psi) from an original pressure of 28,600 kPa (4150 psi). The recovery predicted by the model is about half the reserves needed for economic justification of drilling two vertical wells.

Waterflooding the two-well reservoir was modeled with one well injecting 15.9 m³ water per day (100 bwpd). This injection rate is based on tests performed at the State No. 2-16 well, North Sioux Pass Field. A recovery of 54,200 m³ (341,000 bbl) is predicted after 27 years for a recovery factory of 14.2 percent of OOIP. Final producing rate is computed to be 3.3 m³ oil and 12.7 m³ water per day (21 bopd and 80 bwpd). Of course, this model is fully contained with no injection losses and is therefore optimistic. However, the amount of recoverable oil is almost sufficient to justify drilling.

The same 129-ha (320-acre) model was used to predict recovery using four wells, two producers and two water injectors. Injection was constrained to 15.9 m³ water per day (100 bwpd) per well. Recovery after 27 years is indicated to be 80,700 m³ (507,800 bbl) of oil at a final rate of 3.3 m³ oil and 28.6 m³ water per day (21 bopd and 180 bwpd). A recovery factor of 21.1 percent of OOIP is indicated from this hypothetical model. While the recovery factor is a substantial improvement, the average recovery per well is only 20,200 m³ (127,000 bbl) and still provides insufficient economic incentive for drilling new vertical wells.

It becomes evident from analysis of historical production data and forward modeling that conventional vertical wells are not likely to be economic. Better completions are necessary. Horizontal completions may provide sufficient productivity and drainage to overcome the low permeability found in Ratcliffe reservoirs.

Predicted Recovery with Horizontal Wells

Recovery using horizontal wells was simulated with the same 129-ha (320-acre) model as described previously. Horizontal wells were represented using a narrow grid with high permeability and a length of 790 m (2600 ft). Productivity of the horizontal wells was assumed to be three times that of the

vertical wells in previous models. A productivity factor of three is arbitrarily based on analogy with horizontal wells in thin-bed Red River reservoirs.

Depletion of the model with two horizontal wells is predicted to produce 55,500 m³ (349,000 bbl) of oil after 19 years. This represents a recovery factor of 14.5 percent of OOIP and is barely sufficient for economic justification of two new horizontal wells. The final production rate from both wells is 2.5 m³ oil and 3.5 m³ water per day (16 bopd with 22 bwpd) at an abandonment pressure of 6300 kPa (917 psi).

Injecting 47.7 m³ water per day (300 bwpd) into one horizontal well in the model results in a predicted recovery of 74,700 m³ (470,000 bbl) of oil after 27 years. The ending producing rate is 2.7 m³ oil and 45.3 m³ water per day (17 bopd and 285 bwpd) after recovery of 19.6 percent of OOIP. This recovery is sufficient for economic justification of two new horizontal wells.

Recoveries predicted by these models are idealized using reservoir pore-thickness that is found in about one-third of the Ratcliffe wells in the area. Additionally, about half of the pore-thickness in most wells is concentrated in a more permeable layer that has a thickness of about 3.0 m (10 ft). Incremental oil recovery by waterflooding would be less than predictions made by the simple models described above.

Horizontal Completion Demonstrations

Two wells were chosen for application of re-entry slim-tool mudmotor short-radius technology. These wells are the No. 2-16 State and the M-17 Trudell. The horizontal lateral on the No. 2-16 State well (sec. 16, T.26N., R.58E.) was successfully drilled with a lateral section of 812 m (2667 ft). The length of lateral in the Ratcliffe interval was 604 m (1982 ft). The M-17 Trudell horizontal attempt (sec. 17, T.26N., R.58E.) was abandoned after unsuccessful attempts to build angle for departure from the casing.

The No. 2-16 State well was originally completed in the Ratcliffe in 1982 after depletion of the deeper Red River (see figure 35). The original Ratcliffe completion was by perforation and acidizing with 38 m³ (10,000 gal). Production from the Ratcliffe completion had declined to 1.9 m³ oil and 1.6 m³ water per day (12 bopd and 10 bwpd) by 1994 and was shut-in after a cumulative of 17,200 m³ (108,193 bbl) oil. A pressure-transient test was performed by injecting water for 10 days prior to drilling the re-entry lateral to quantify bottom-hole pressure and transmissibility. The bottom-hole pressure was measured to be 21,800 kPa (3160 psi) which is 6200 kPa (900 psi) less than the original pressure. An oriented core from a well one mile west indicated natural fractures orienting northwest-southeast in the Ratcliffe. It was concluded that the presence of natural fractures and high bottom-hole pressure made the No. 2-16 State well a good candidate for a lateral drain hole.

After drilling operations were completed, the well was put on pump. The well was produced for 108 days and averaged about 0.5 m³ oil and 16.7 m³ water per day (3 bopd and 105 bwpd). Although the No. 2-16 State well was producing significantly more fluid than from the previous vertical completion, the fluid volume was not much greater than the offset State-Pass No. 16-1 well. The State-Pass No. 16-1 well is structurally lower at the Ratcliffe than the State No. 2-16 and was producing 5.6 m³ oil and 5.6 m³ water per day (35 bopd and 35 bwpd) at the time. The horizontal completion results from the State No. 2-16 are therefore perplexing and disappointing. There are several possible explanations for the results from the State No. 2-16 horizontal completion attempt: 1) a water-bearing fracture was encountered, 2) the wells are located in separate reservoirs, and 3) the lateral was drilled out of zone.

Conclusions

The project set out to better understand reservoir development, predict areas of better reservoir development and test lateral drain-hole technologies for more efficient completions. It is concluded that oil accumulations in the Ratcliffe are developed as low-permeability reservoirs which do not require structural closure. Productive Ratcliffe intervals appear developed across large areas of the study area but average reserves from hydraulically fractured vertical completions have been insufficient to justify drilling new wells. Integrated reservoir characterizations improved understanding of reservoir development. Oriented core and a special formation-micro-imaging log were obtained to help define fracturing and orientation. Seismic surveys were acquired to help identify fracturing and areas prone to

fracturing. A multi-component (converted shear-wave) seismic survey was acquired but it was not possible to resolve coherent shear-wave data. A conventional 3D seismic survey was acquired and was used to target areas which should have better reservoir development (porosity and fracturing). The reservoir model and targeted locations remain untested at the close of the project, however.

Two attempts were made to drill lateral drain-holes from existing wells with casing. One well was successfully re-entered and a lateral drain-hole drilled. Production results from the well were not encouraging, however. A second well was entered but it was not possible to achieve the curve required to drill a lateral.

Information from 3D seismic may be able to target better Ratcliffe development which would increase the probability of greater oil reserves. Primary factors controlling development of Ratcliffe reservoirs are dolomitization of certain facies and fracturing. Targeting the most prospective areas for Ratcliffe reserves involves integration of a multi-step process. This process first involves identification of areas which were most likely to have thicker Ratcliffe deposition through mapping the Ratcliffe to Bakken interval. The next step in the process is identification of areas which were uplifted after Ratcliffe time, as indicated from isopach mapping of the Greenhorn to Ratcliffe interval. Divergent trends of contours of these two maps are interpreted to indicate a change in location and direction of tectonic stress. Seismic modeling work indicates that increasing porosity development in the Ratcliffe is expressed as an observable amplitude change. However, the variation of amplitude is subtle and should be used only as a guide after targeting from isopach and structure mapping.

Recommendations

The reservoir model and targeted locations developed from this study remain untested at the close of the project. Two locations were identified that satisfy criteria for better reserve potential. These targeted locations would test a model that may have wide-spread application over much of the Williston Basin. Drilling of the locations would also confirm applicability of seismic for prediction of stratigraphic development. The acquisition of fracture imaging logs or cores would help confirm conclusions made regarding fracture development and producibility. Additionally, the fracture orientation would guide the azimuth of lateral drain-holes. Project study confirms the presence of fracturing in the Ratcliffe and measured fracture orientation at one well. Additional information regarding fracture orientation would help predict fractures in context with the local and regional structural setting.

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Tables

Table 6: Production Characteristics of Ratcliffe Completions

Field or Area	Wells	Initial Rate		Reserves		Drainage	
Cattails	13	80 bopd	12.7 m ³ /D	109,000 bbl	17,300 m ³	173 acre	70 ha
Fairview	7	38 bopd	6.0 m ³ /D	29,000 bbl	4,600 m ³	90 acre	36 ha
Nohly	9	97 bopd	15.4 m ³ /D	224,000 bbl	35,600 m ³	272 acre	110 ha
No. Sioux Pass	11	55 bopd	8.7 m ³ /D	64,000 bbl	10,200 m ³	154 acre	62 ha
RipRap Coulee	5	59 bopd	9.4 m ³ /D	217,000 bbl	34,500 m ³	326 acre	132 ha
Total Study	55	67 bopd	10.7 m ³ /D	102,000 bbl	16,200 m ³	186 acre	75 ha

Note: Characteristic values represent the expected case per completion. Apparent drainage area is based on net thickness of 5.5 m (18 ft), porosity of 9% and water saturation of 50%.

Table 7: Petrophysical Properties of Ratcliffe from Electrical Logs

Property	North Sioux Pass		Cattails Field	
Productive Thickness	15 ft	4.6 m	30 ft	9.1 m
Average Porosity	8.8 %		7.1 %	
Average Water Saturation	45.8 %		49.7 %	
Hydrocarbon Thickness	0.715 ft	0.218 m	1.071 ft	0.326 m
Oil-in-Place	4300 stb/ac	1689 m ³ /ha	6441 stb/ac	2531 m ³ /ha

Table 8: Acquisition and Recording Parameters for Cattails 2D-3C Seismic

Recording			
Instruments:	DFSV	Shot Depth:	120 feet
Sample Rate:	2.0 msec	Data Channels/ Component:	120
Record Length:	6.0 msec	Group Interval:	88 ft
Format:	SEGB	Source Interval:	440 ft
Source:	dynamite	Recording Filter:	8/18 - 128/72 db per Octave
Charge Size:	10 lb	Sub-surface Coverage:	1200%

Table 9: Acquisition and Recording Parameters for North Sioux Pass 3D Seismic

Recording		Source Line	
Instruments:	I/O System 2	Interval:	1320 feet
Sample Rate:	2.0 msec	Receiver Line Interval:	1320 feet
Record Length:	3.0 msec	Group Interval:	220 ft
Format:	SEGB	Source Interval:	220 ft
Source:	dynamite	Recording Filter:	12 - 128/72 db per Octave
Charge Size:	5 lb	Surface Area:	25 sq. miles
Shot Depth:	60-80 feet	Sub-surface Coverage:	1500-2000%

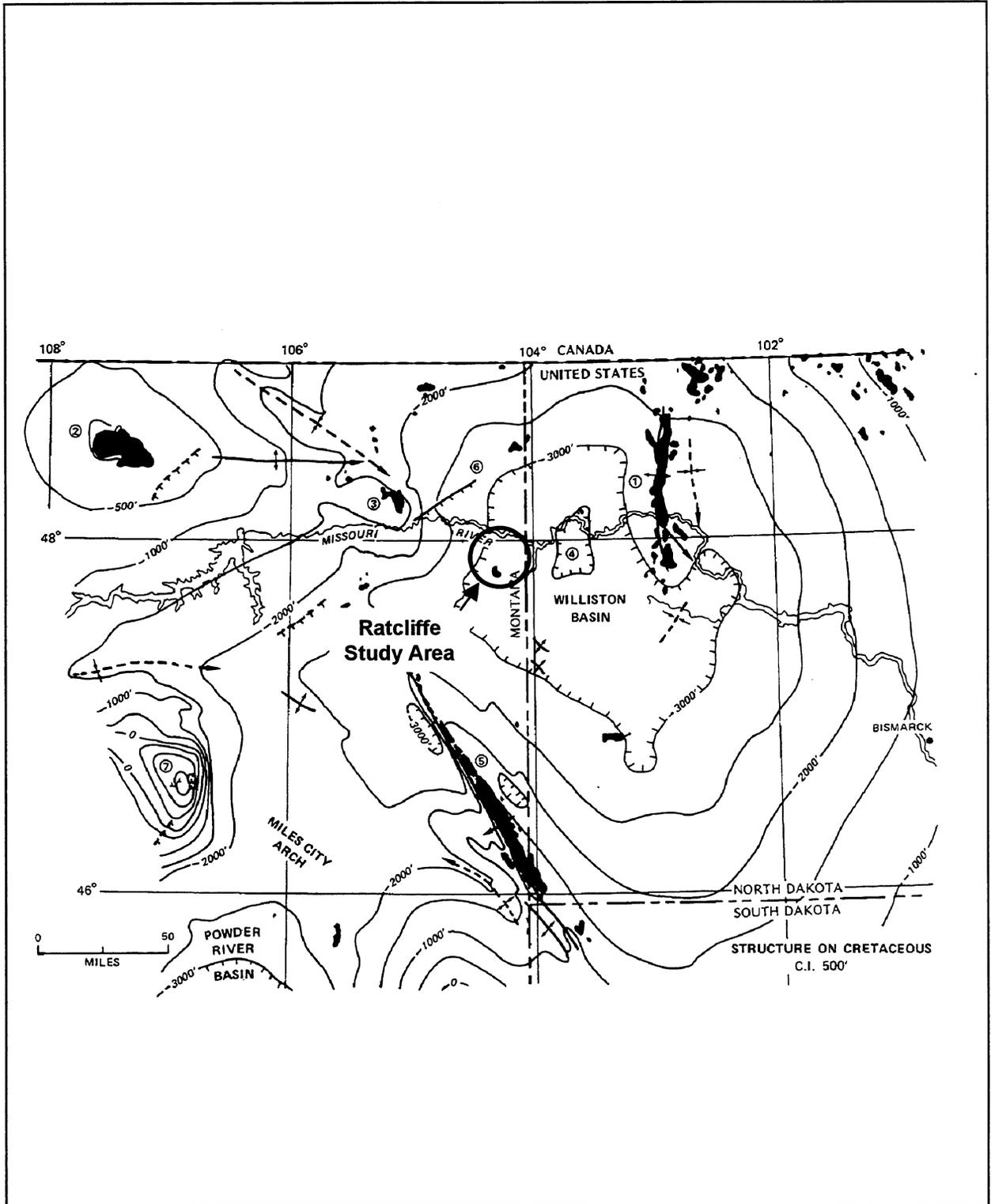


Figure 34: Map of the Williston Basin with Ratcliffe study area.

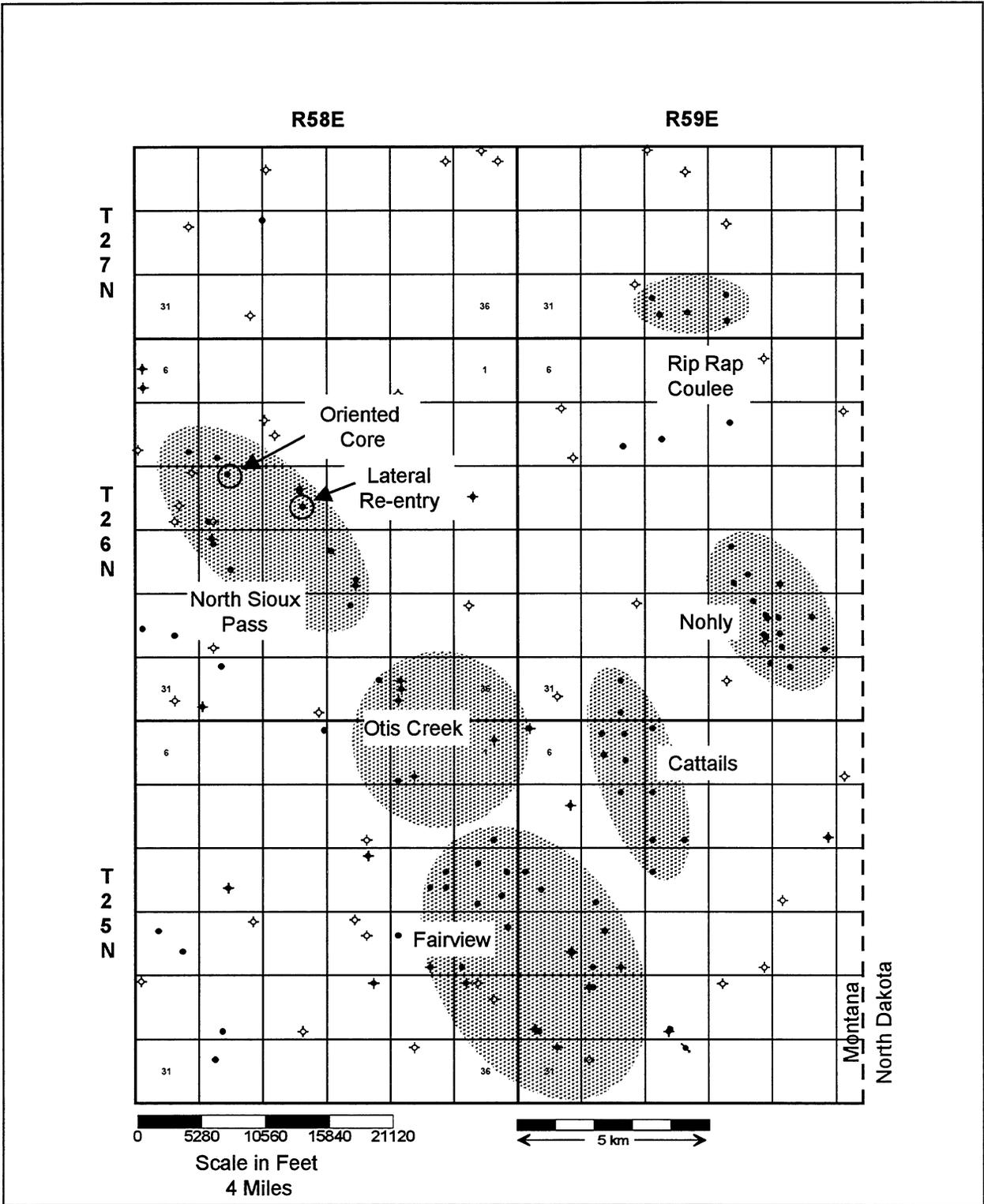


Figure 35: Map of Ratcliffe study area with fields annotated.

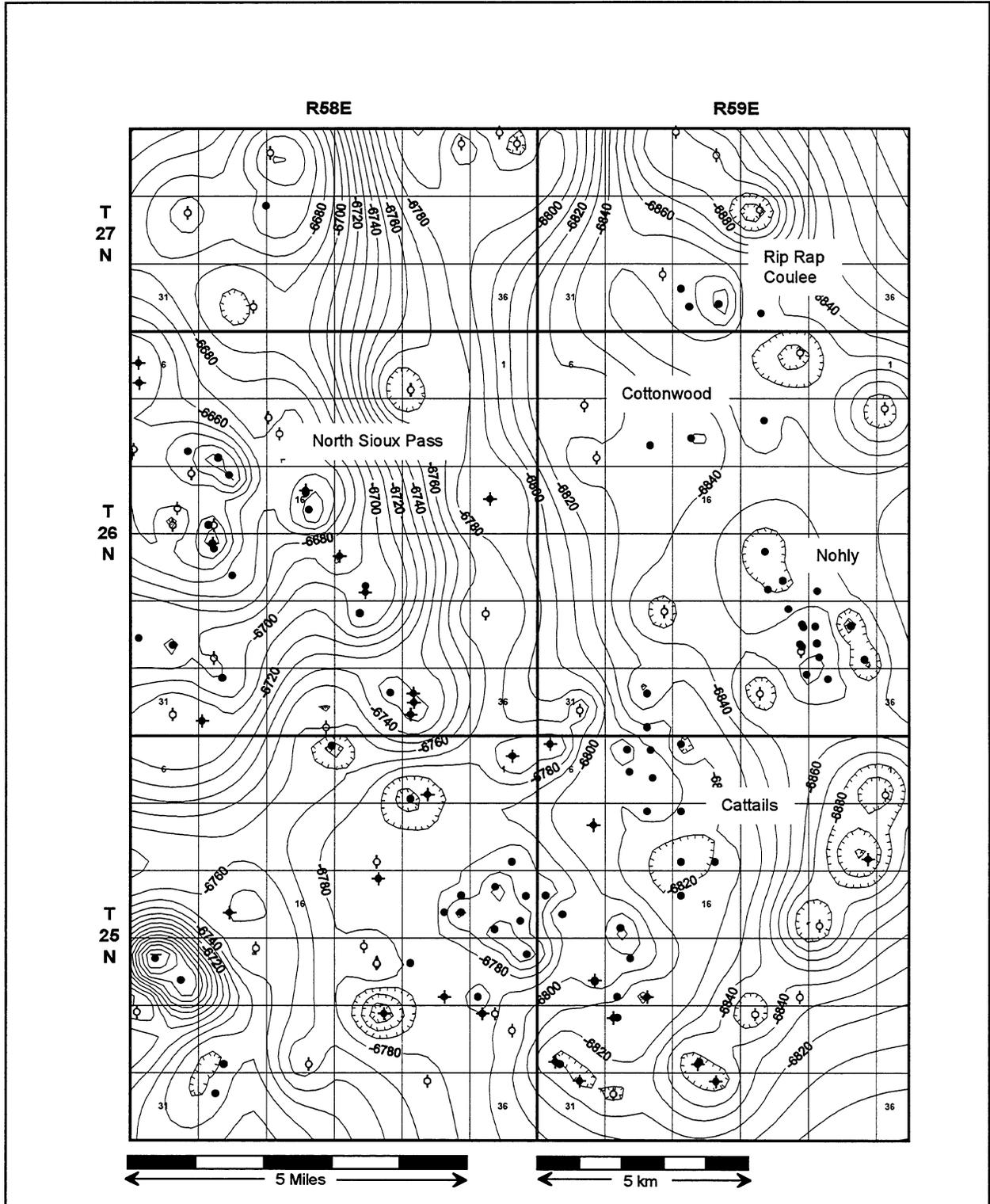


Figure 36: Map of Ratcliffe structure across study area. Present-day structural closure is subtle at several Ratcliffe fields with 3 to 6 m (10 to 20 ft) maximum and is apparently not critical to reservoir development. C.I. = 3 m (10 ft).

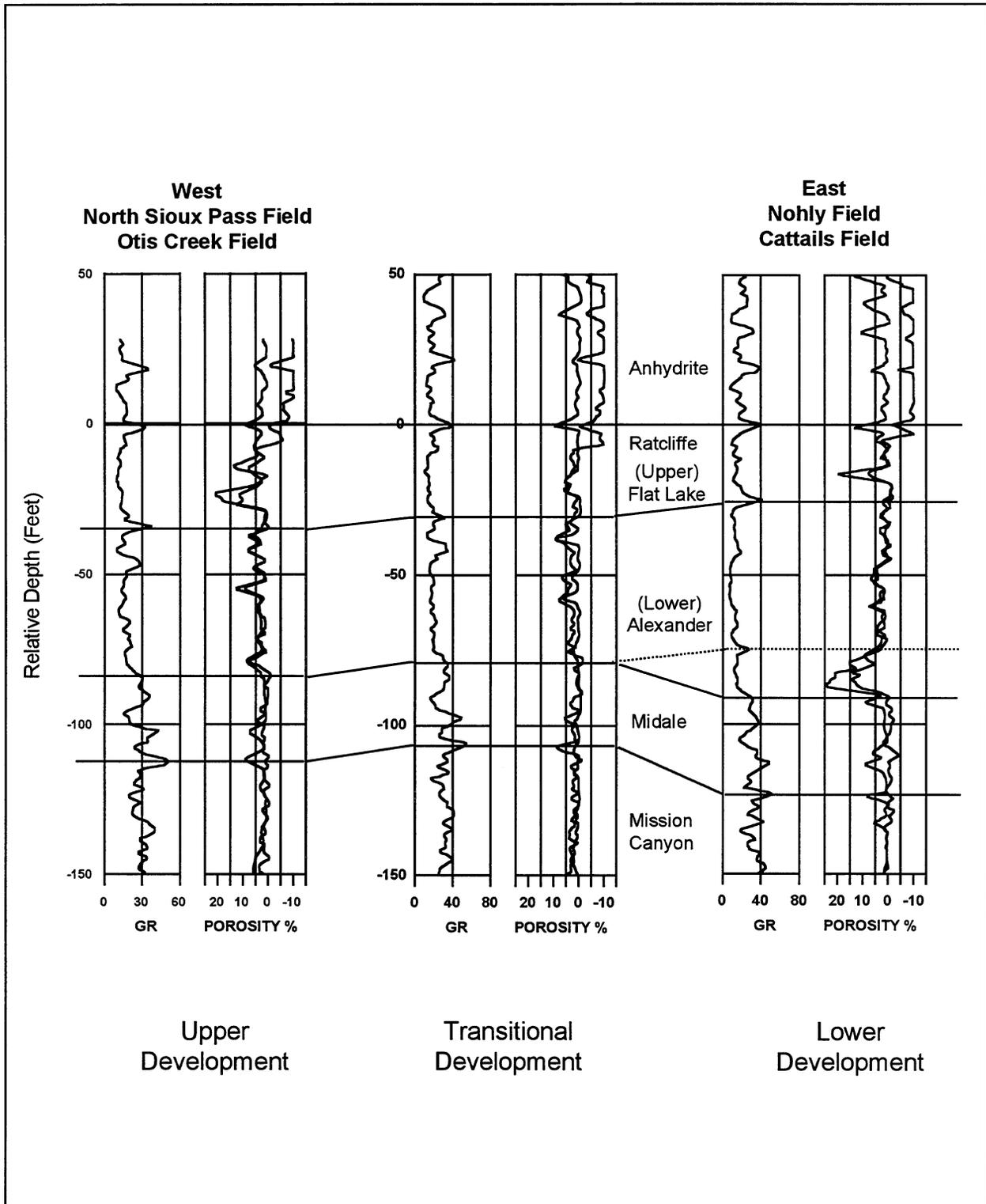


Figure 37: Cross-section of Ratcliffe type-logs showing variability of porosity development.

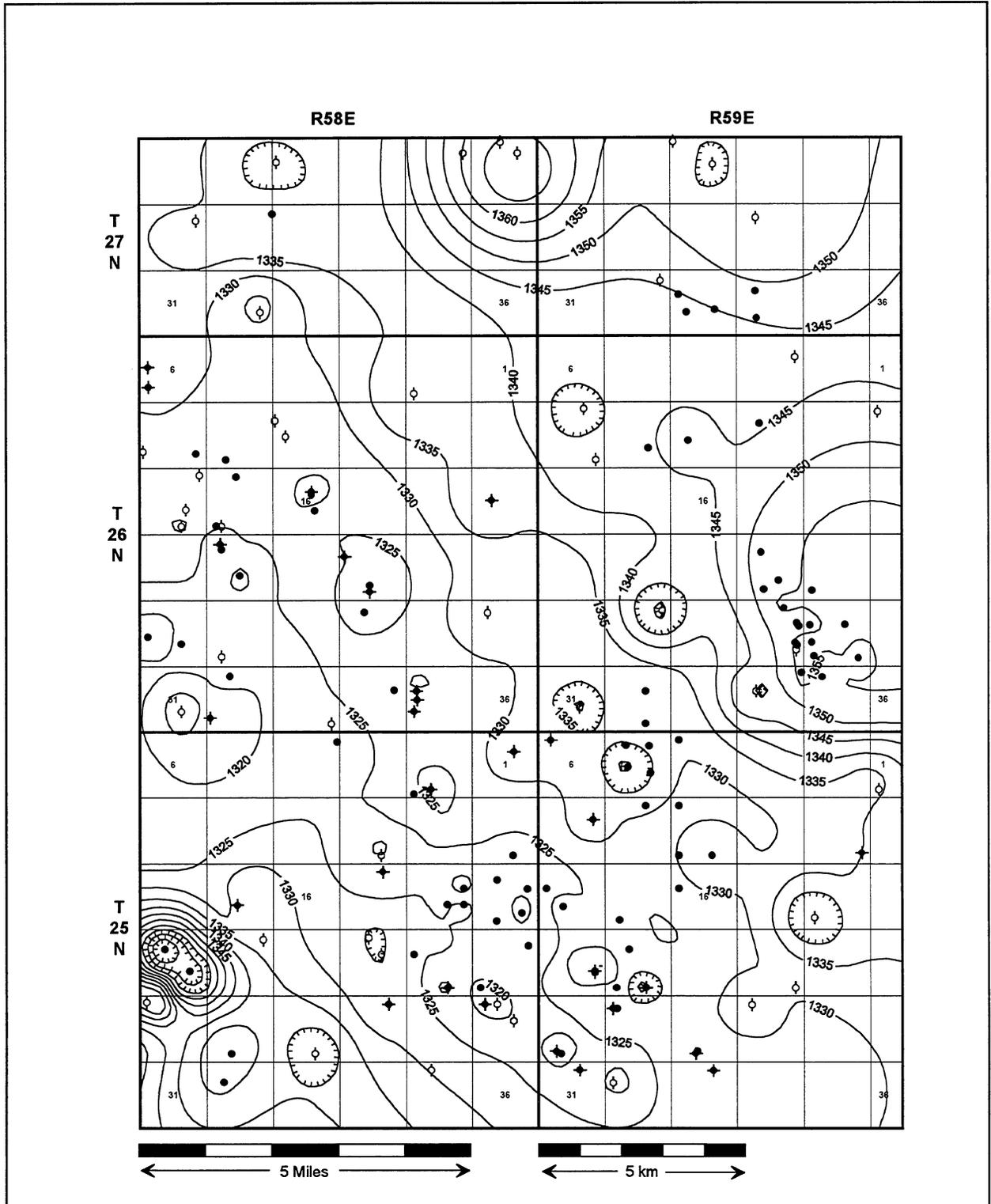


Figure 39: Map of base Ratcliffe (Midale) to Bakken isopach. Isopach thicks suggest structurally low areas before Ratcliffe deposition. C.I. = 1.5 m (5 ft).

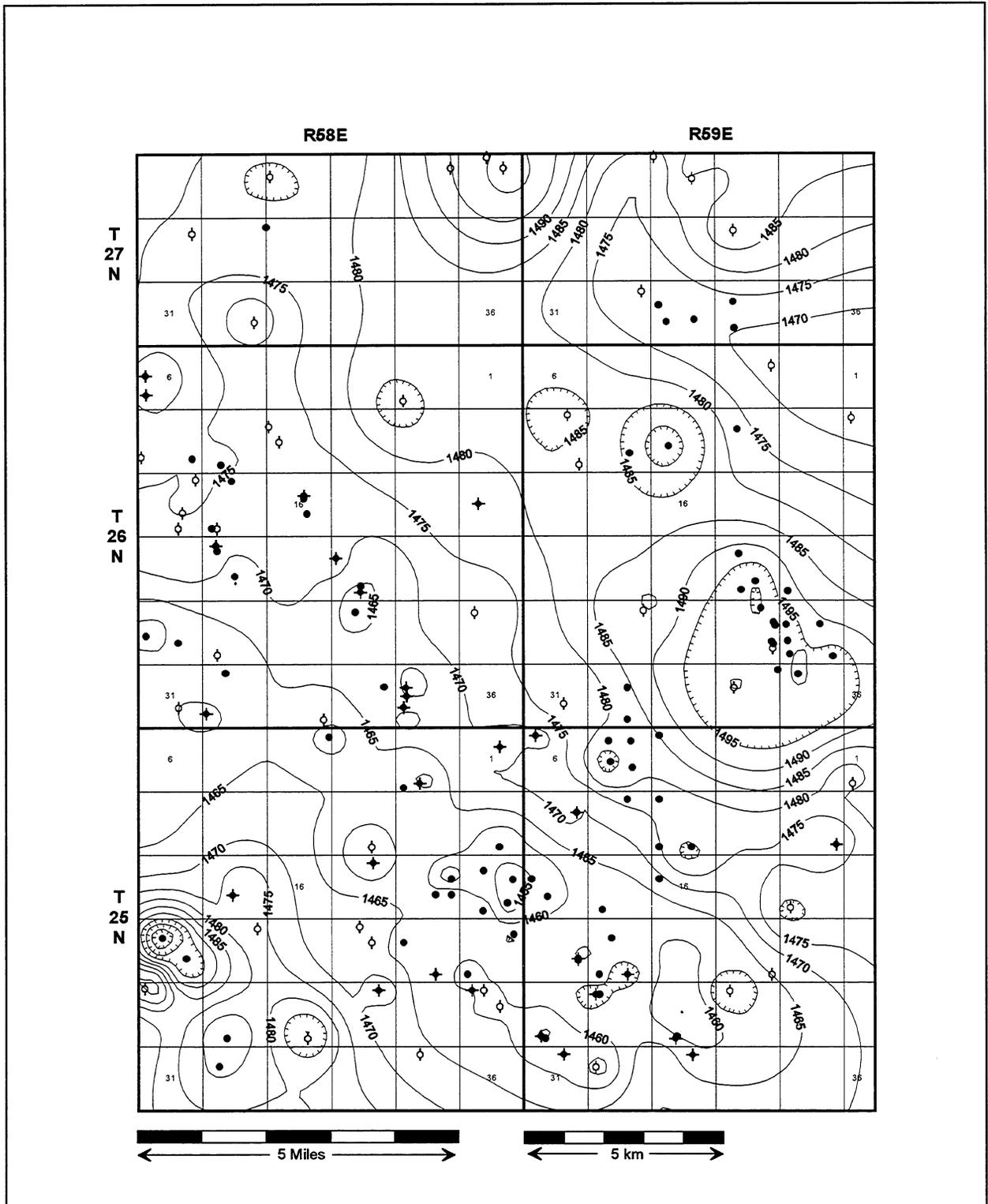


Figure 40: Map of Base of Last Charles Salt to Bakken isopach. C.I. = 1.5 m (5 ft).

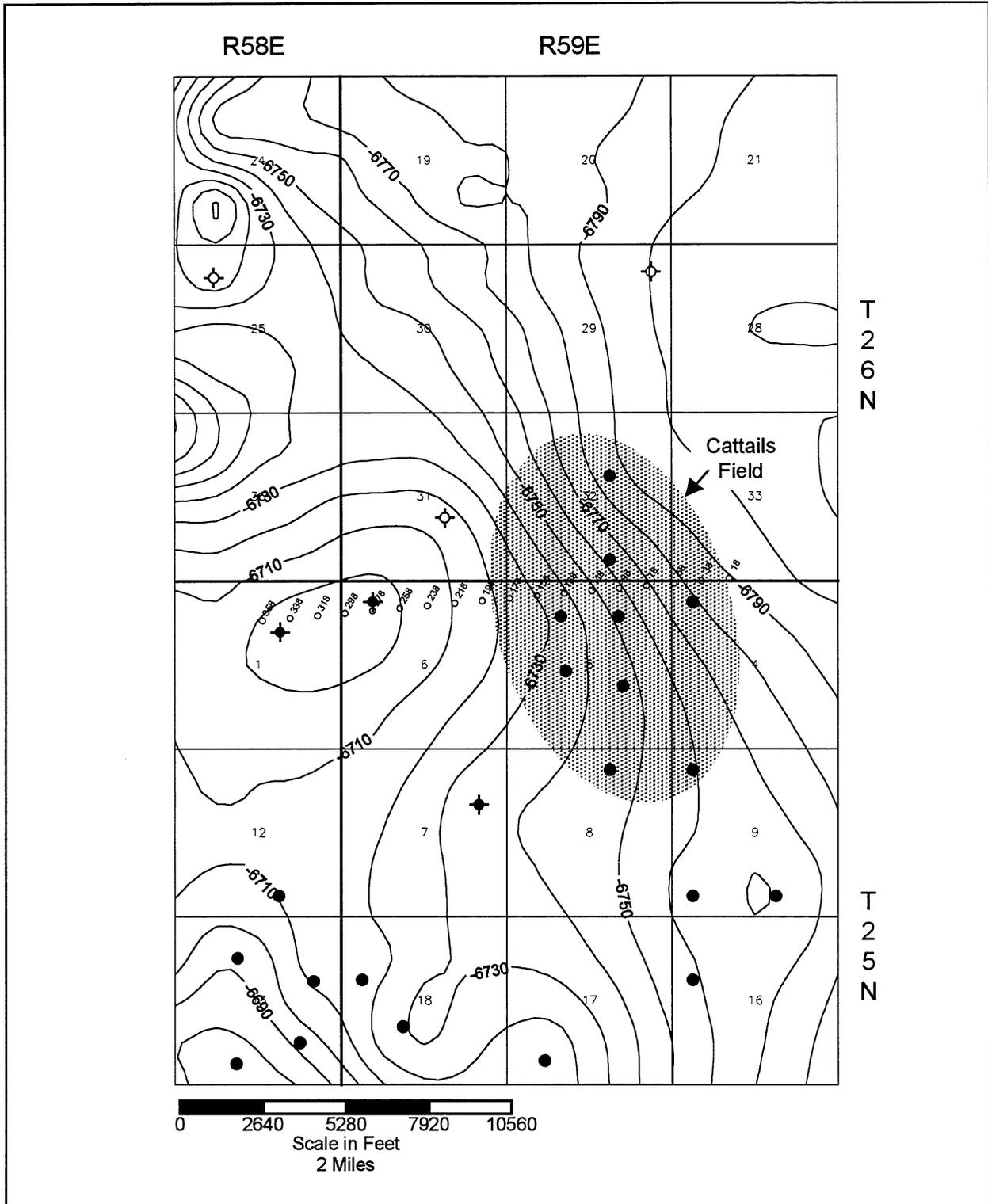


Figure 41: Location of multi-component 2D seismic line at Cattails Field. Contours are on the top of the Ratcliffe. C.I. = 3 m (10 ft).

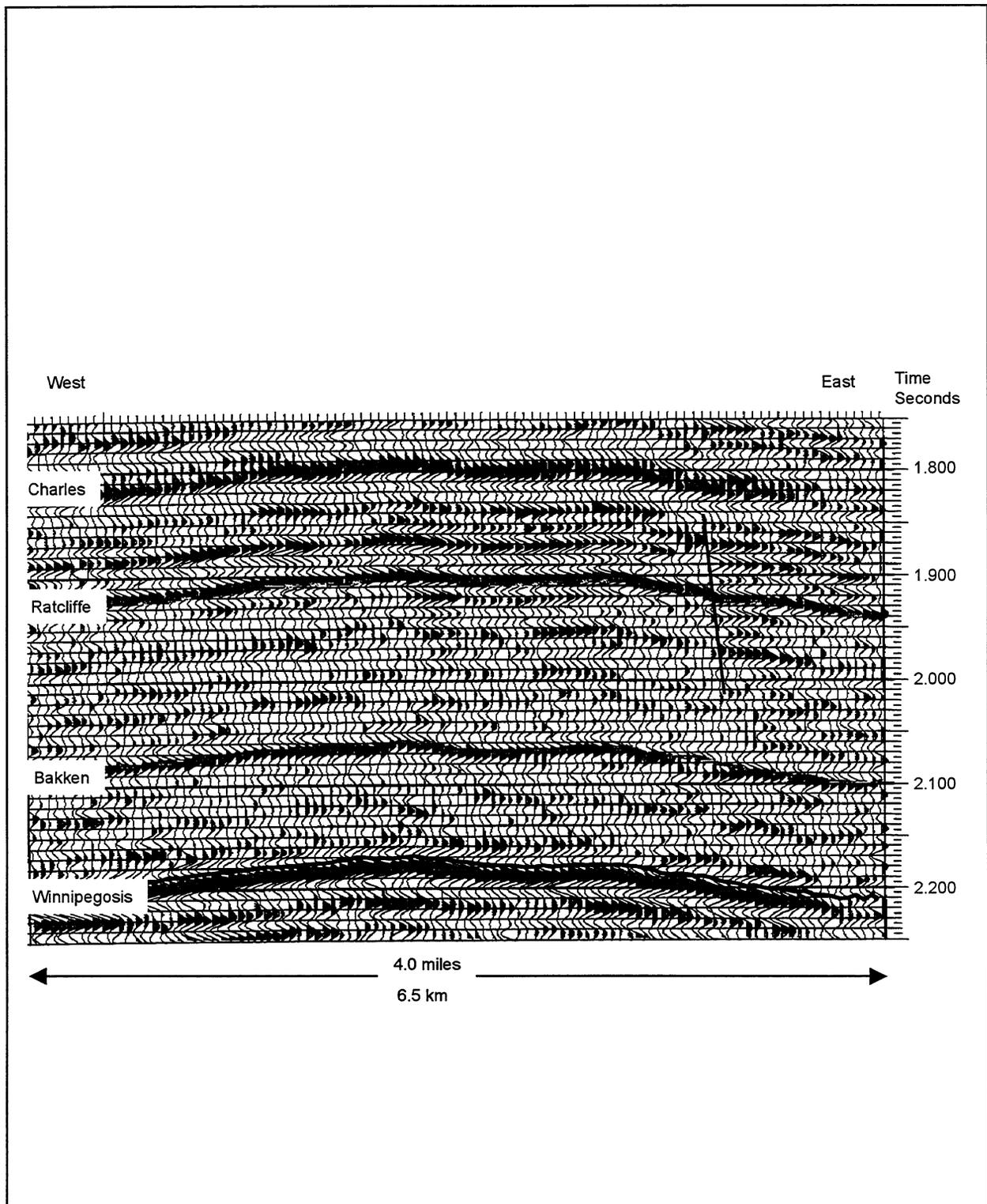


Figure 42: West-east seismic section (inline 229) across North Sioux Pass Field.

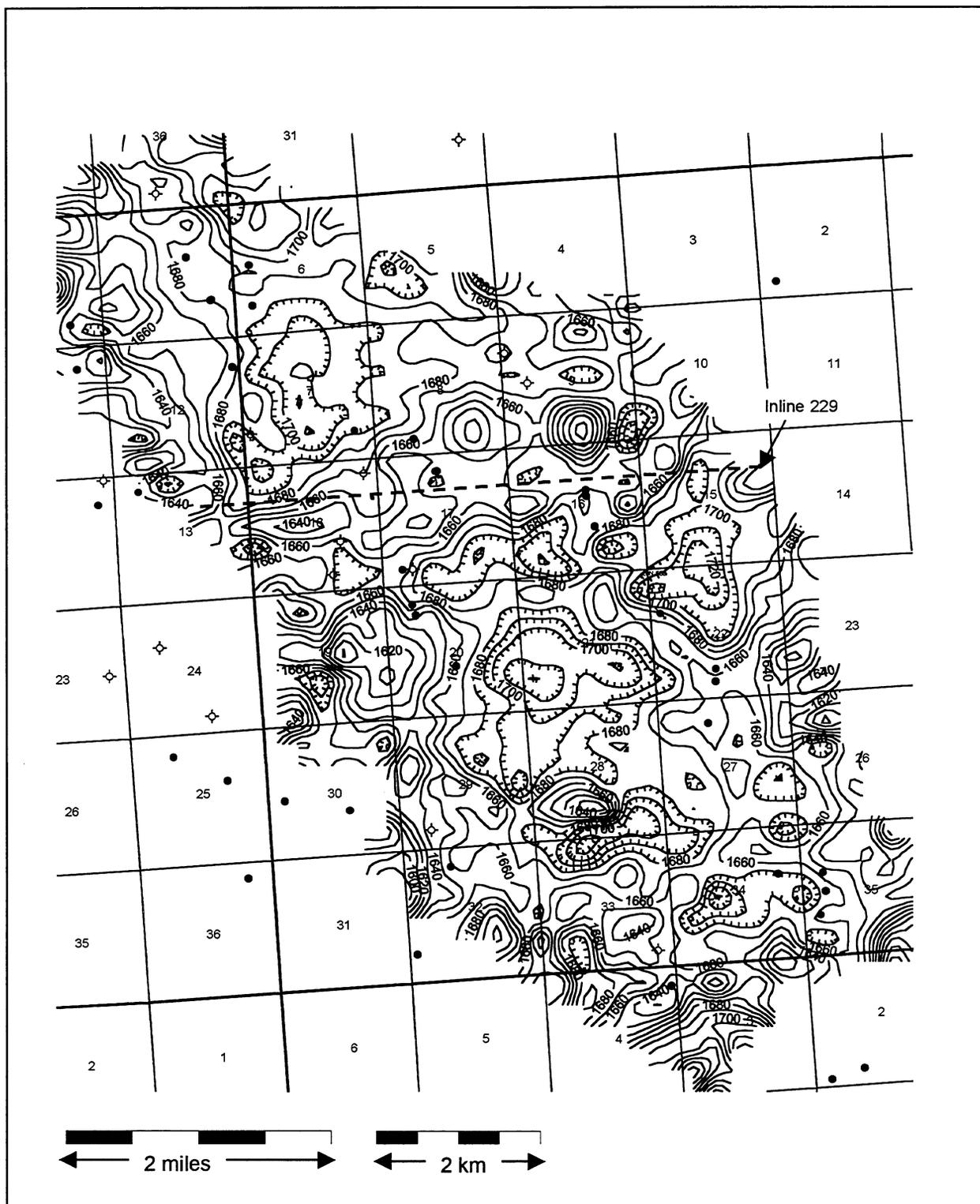


Figure 43: Map of Ratcliffe to Bakken isopach from 3D seismic at North Sioux Pass Field. Isopach values are computed from seismic interval time and velocity trends from well-log data. Hachures indicate thickening direction. C.I. = 3 m (10 ft).

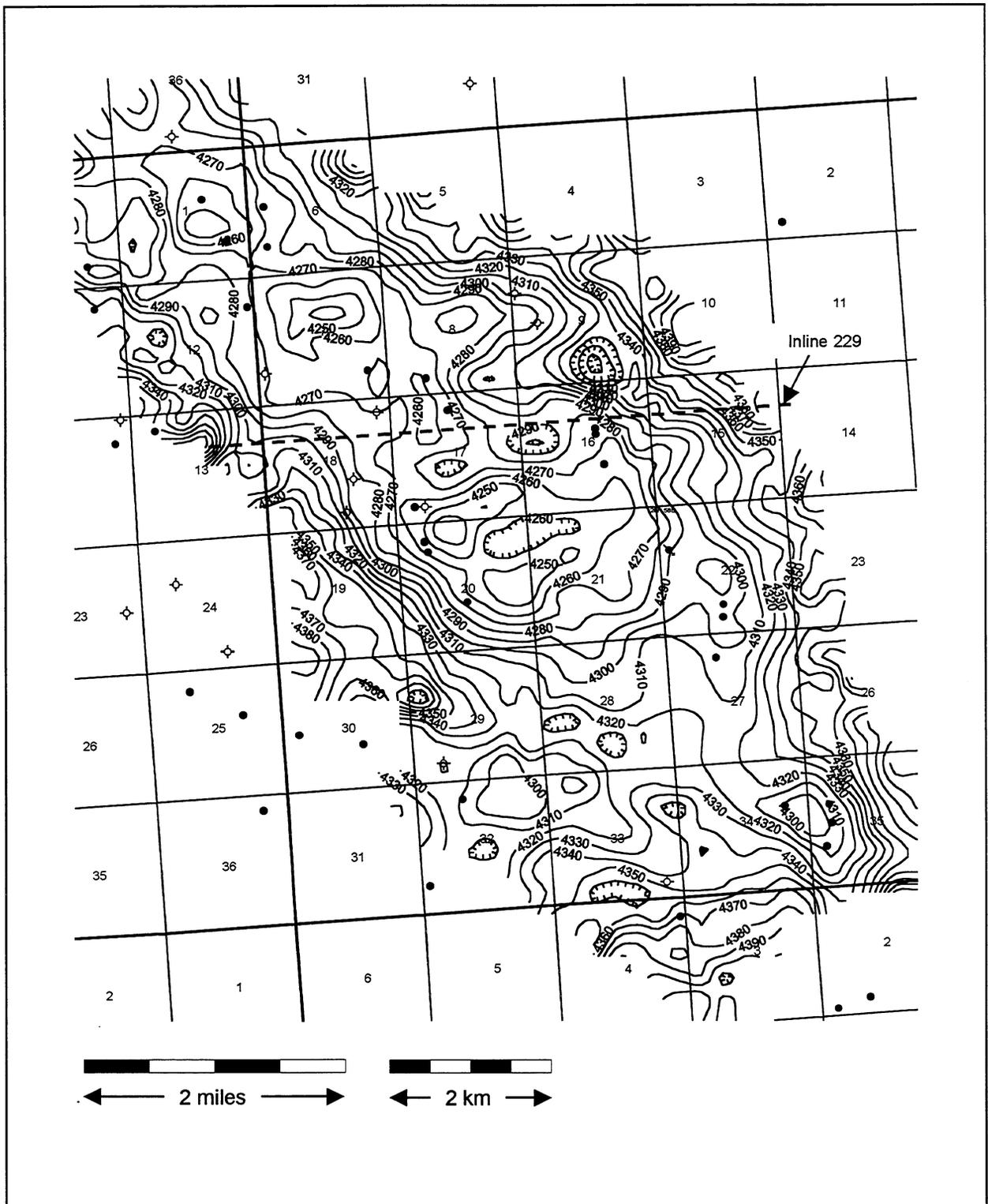


Figure 44: Map of Greenhorn to Ratcliffe isopach from 3D seismic at North Sioux Pass Field. Isopach values are computed from seismic interval time and velocity trends from well-log data. Hachures indicate thickening direction. C.I. = 10 feet.

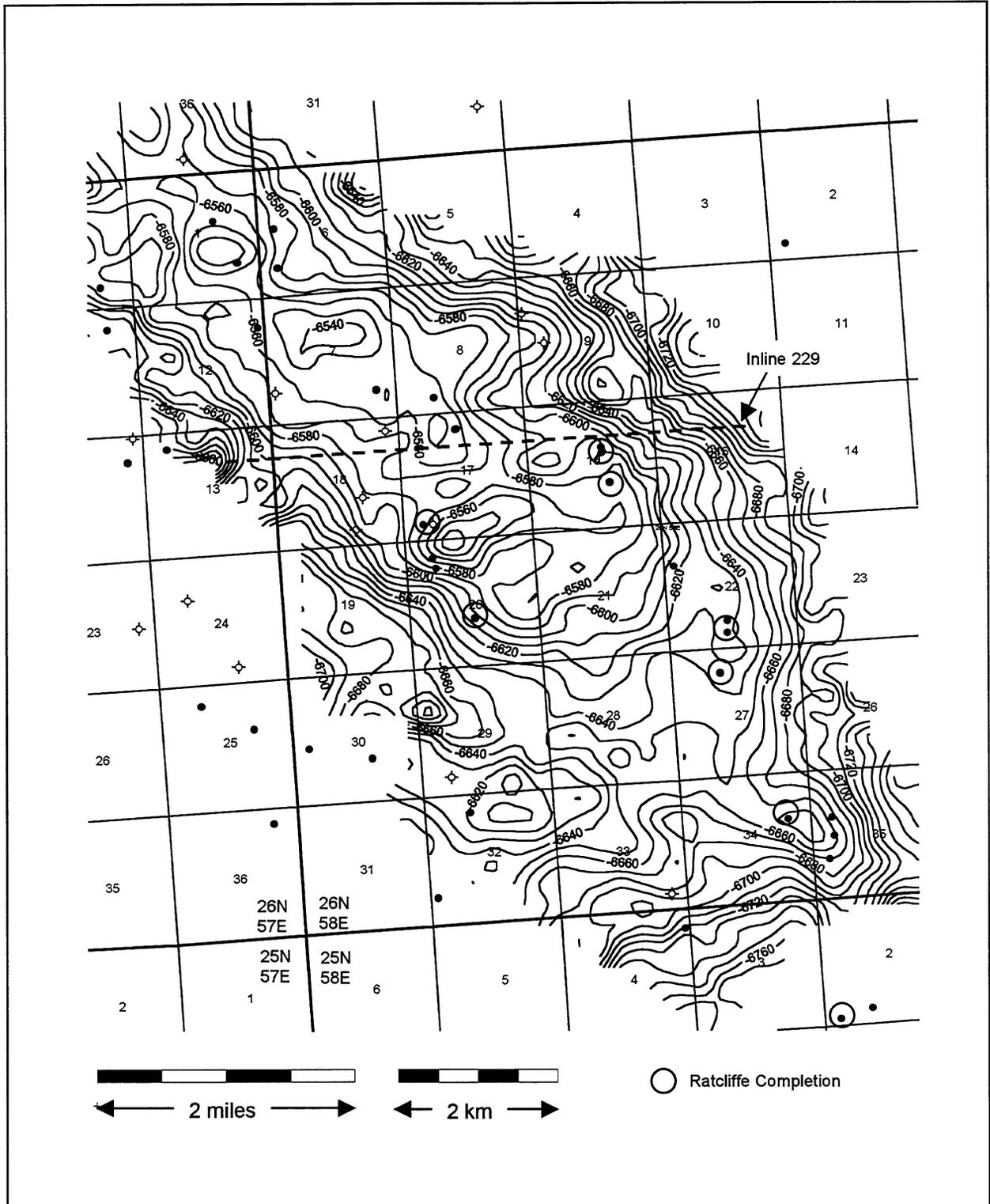


Figure 45: Map of Ratcliffe structure from 3D seismic at North Sioux Pass Field. Depth values are computed from seismic interval time and velocity trends from well-log data. C.I. = 3 m (10 ft).

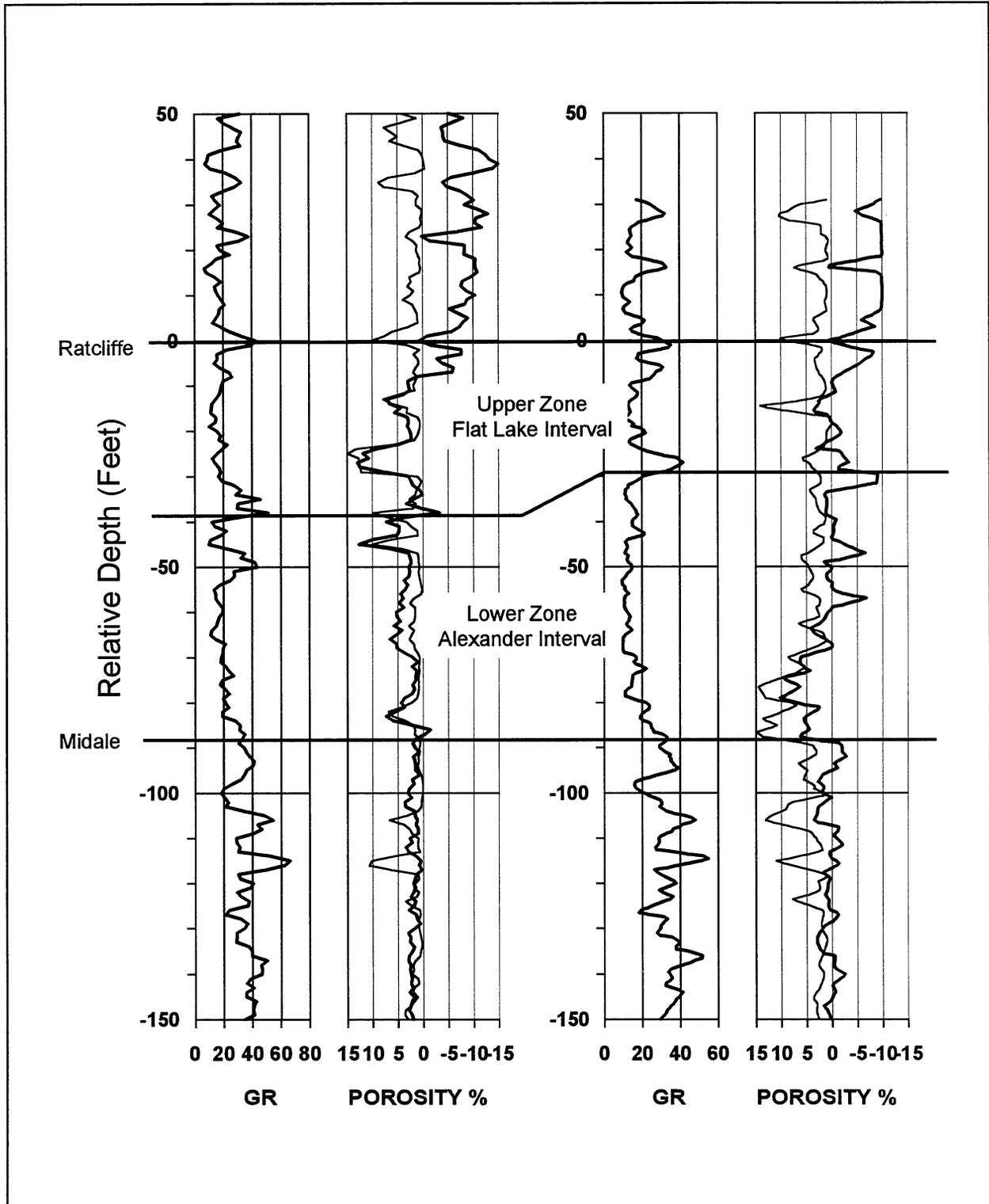


Figure 46: Ratcliffe type logs used for synthetic seismograms.

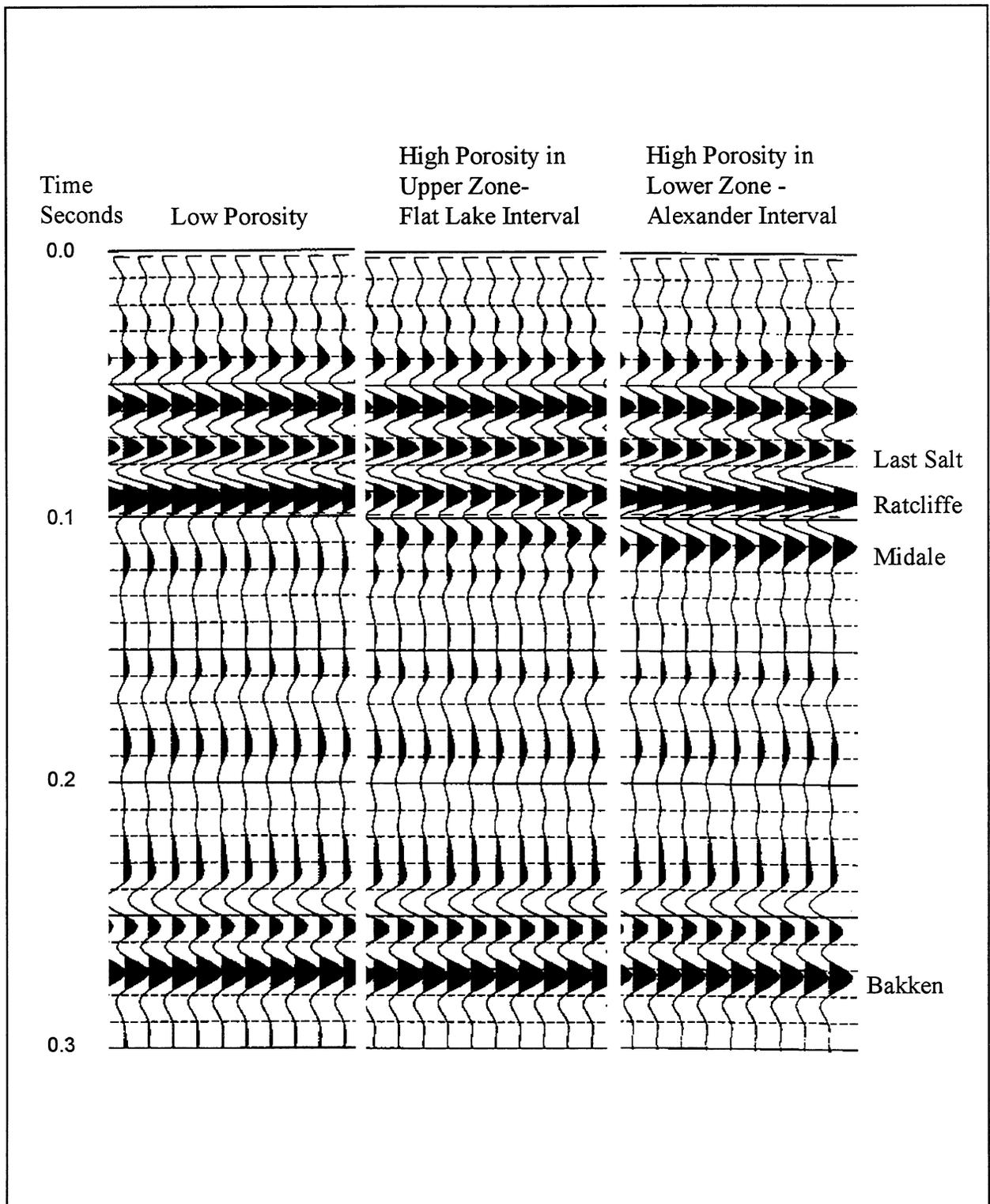


Figure 47: Synthetic seismograms of Ratcliffe variation. The top of Ratcliffe occurs approximately at 0.1 seconds. A greater negative response of the Ratcliffe trough amplitude corresponds to increasing porosity in either Flat Lake or Alexander intervals. A greater positive response of the underlying peak is associated with porosity development in the Alexander interval.

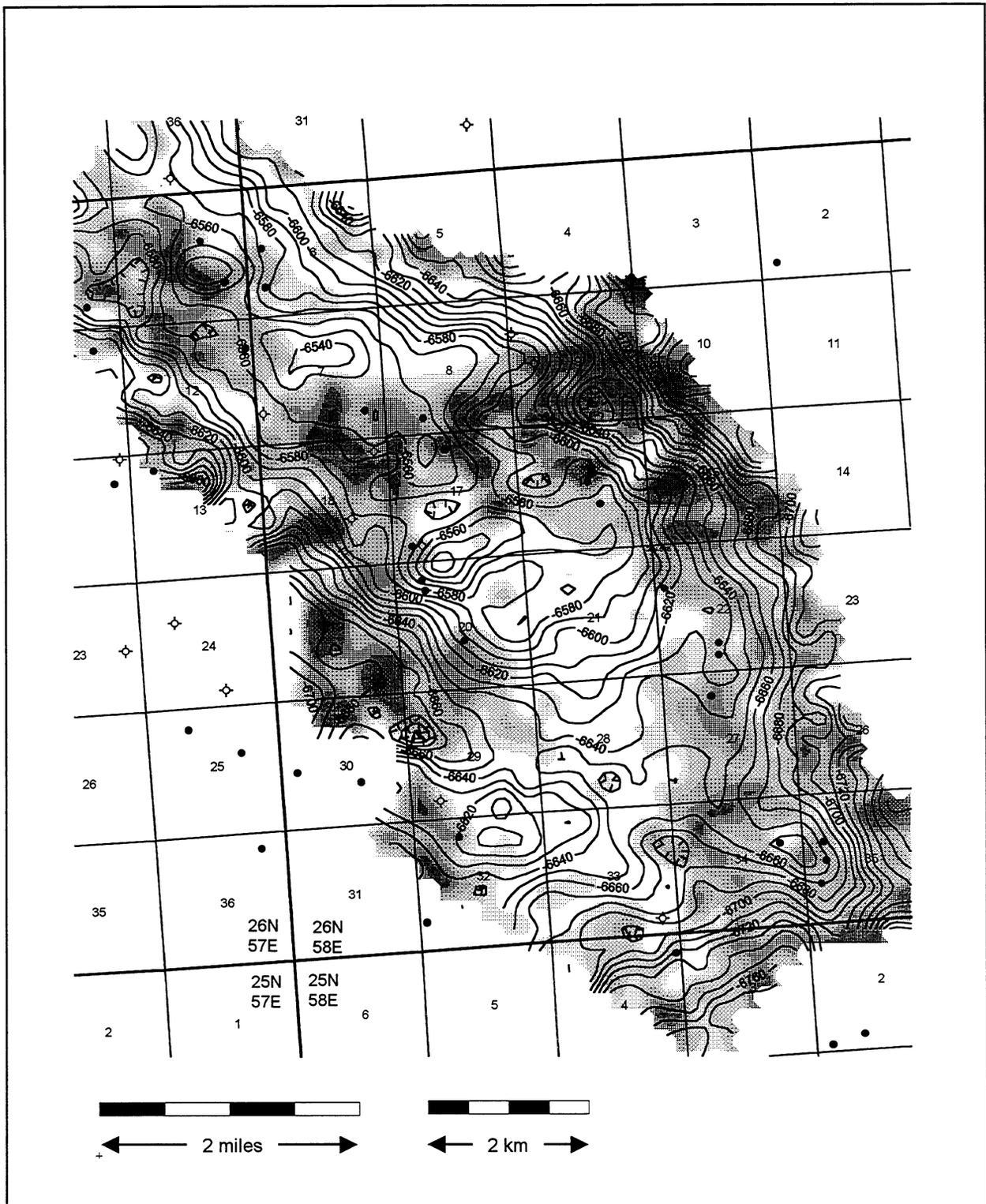


Figure 48: Map of Ratcliffe structure with seismic amplitude of Ratcliffe trough event. Darker shading indicates greater absolute amplitude response.

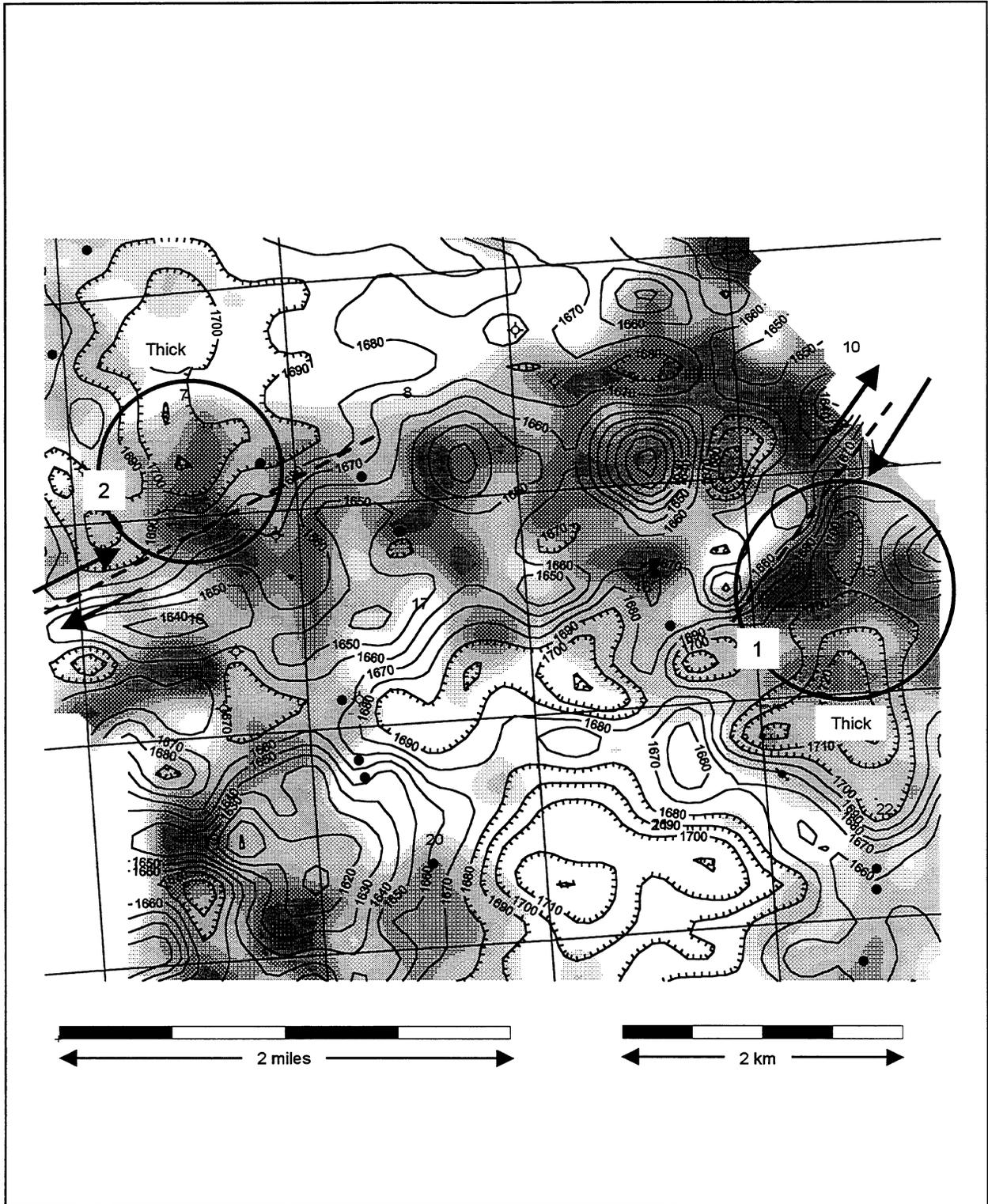


Figure 49: Map of Ratcliffe to Bakken isopach with Ratcliffe amplitude. Map shows 2 areas prospective for Ratcliffe drilling. Lineaments relating to recurrent movement are shown as dashed lines. Darker shading indicates stronger amplitude of trough event.

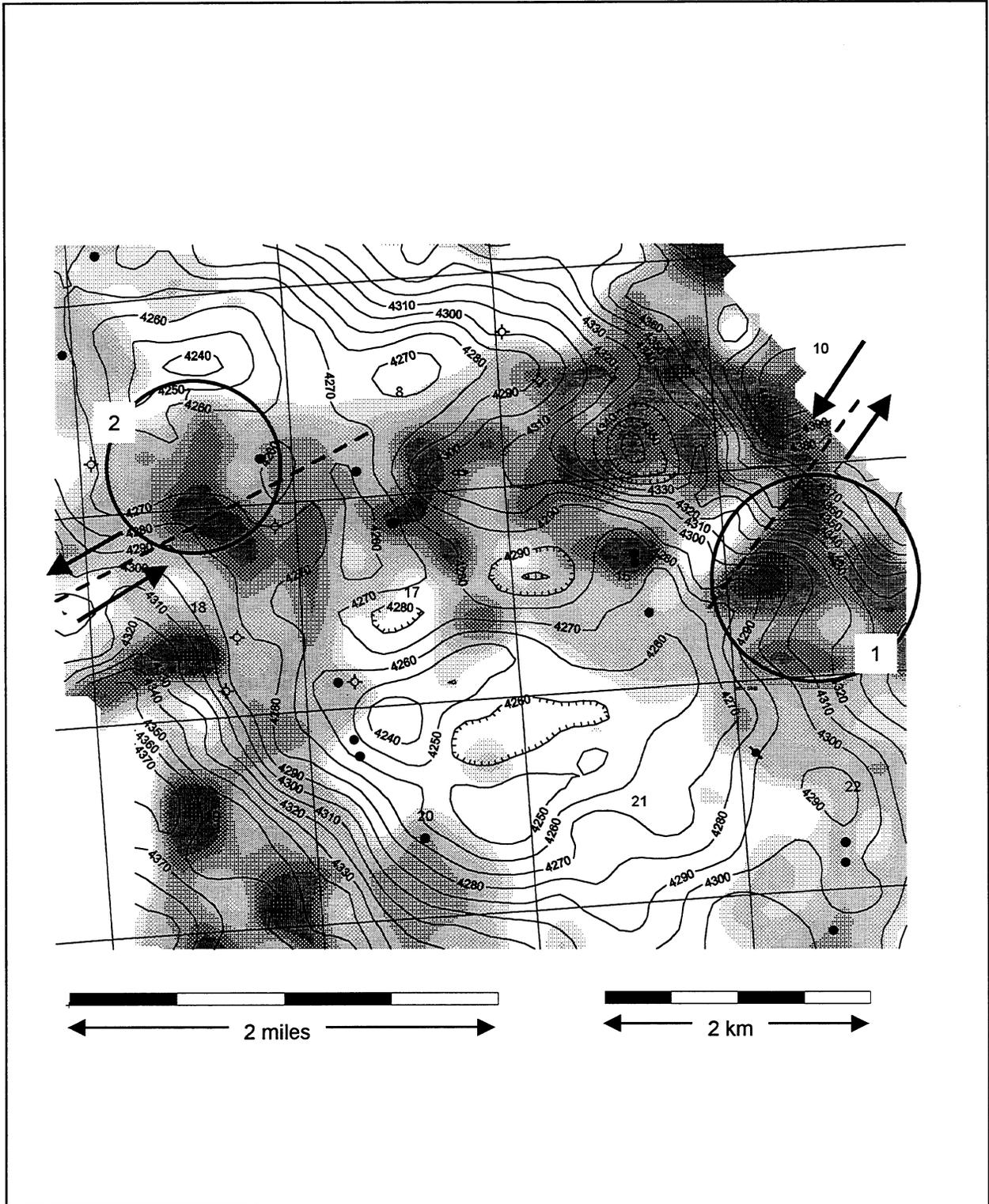


Figure 50: Map of Greenhorn to Ratcliffe isopach with Ratcliffe amplitude. Map shows areas prospective for Ratcliffe drilling. Lineaments relating to recurrent movement are shown as dashed lines. Notice reversal of movement from figure 53. Darker shading indicates stronger amplitude of trough event.

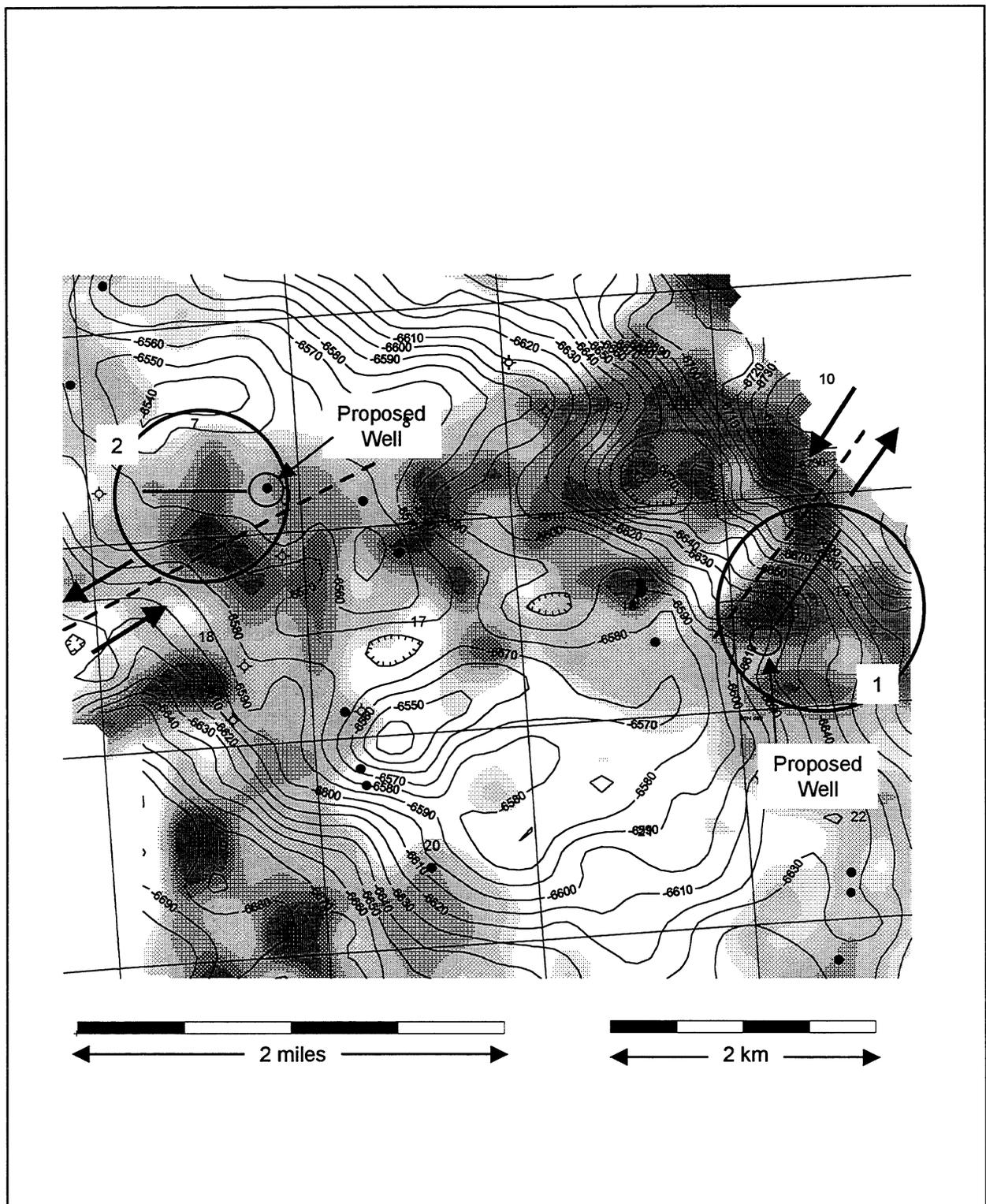


Figure 51: Map of Ratcliffe structure with Ratcliffe amplitude. Map shows areas prospective for Ratcliffe drilling. Locations of proposed horizontal wells are shown. Lineaments relating to recurrent movement are indicated as dashed lines. Darker shading indicates stronger amplitude of trough event.

