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IMPROVED RECOVERY DEMONSTRATION FOR WILLISTON BASIN CARBONATES

Annual Report for the Period
June 10, 1995 through June 9, 1996

By
Larry A. Carrell and
Mark A. Sippel

September 1996

Performed Under Contract No. DE-FC22-94BC14984

Luff Exploration Company
Denver, CO 80203

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
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Prepared for
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IMPROVED RECOVERY DEMONSTRATION FOR
WILLISTON BASIN CARBONATES
COOPERATIVE AGREEMENT DE- FC22-94BC14984

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Abstract

The purpose of this project is to demonstrate targeted infill and extension drilling opportunities, better determinations of oil-in-place, methods for improved completion efficiency and the suitability of waterflooding in Red River and Ratcliffe shallow-shelf carbonate reservoirs in the Williston Basin, Montana, North Dakota and South Dakota.

Improved reservoir characterization utilizing three-dimensional and multi-component seismic are being investigated for identification of structural and stratigraphic reservoir compartments. These seismic characterization tools are integrated with geological and engineering studies. Improved completion efficiency is being tested with extended-reach jetting lance and other ultra-short-radius lateral technologies. Improved completion efficiency, additional wells at closer spacing and better estimates of oil in place will result in additional oil recovery by primary and enhanced recovery processes.

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

Executive Summary

The purpose of this project is to demonstrate targeted infill and extension drilling opportunities, better determinations of oil-in-place, methods for improved completion efficiency and the suitability of waterflooding in Red River and Ratcliffe shallow-shelf carbonate reservoirs in the Williston Basin, Montana, North Dakota and South Dakota. The project study is divided into two areas and reservoirs. The first reservoir and area is the Ordovician Red River in the southwest portion of the Williston Basin in Bowman County, ND and Harding County, SD. The second area and reservoir is the Mississippian Ratcliffe in northeastern Richland County, MT.

In the Red River study area, 3D seismic and re-processed 2D seismic have been used to enhance reservoir interpretation through understanding of subtle faulting and variation in timing of structural growth. Efforts have been made to correlate seismic attributes, such as amplitude, with porosity development. A location for a vertical well has been selected to test the 3D seismic interpretation of potential reservoir compartments from porosity variation and faulting.

In the Ratcliffe study area, a 2D seismic line was acquired to investigate converted-wave shear data for identification of fractures. The converted-wave data were processed twice by different companies and did not yield coherent shear-wave data in either effort. A thick, surface weathering zone is a major impediment for shear-wave acquisition in the study area. Further seismic investigations of the Ratcliffe will be focussed on compressional-wave 3D data.

Improved completion technology is being investigated with lateral drainhole from existing cased wells. Two ultra-short-radius technologies were unsuccessfully tested. Jetting lance technology with penetrations of 10 ft in two Red River wells produced no change in production performance. Jetting lance tools intended to reach 50 ft, have not overcome mechanical-design problems and will not be tested further. Ultra-short-radius lateral-completion technology was also unsuccessfully tested. These lateral completion technologies will not be attempted further as they are not mechanically suitable for depths of 8800 to 9800 ft at this time. Steered, downhole mud-motors will be used for future lateral completions and re-completions in the Ratcliffe and Red River.

Water injectivity tests in vertical wells were performed in both Red River 'B' and Ratcliffe reservoirs. These tests confirmed previous experience of low injectivity and are to be used as baseline data for injection with lateral completions. Small, pilot areas for lateral-completion technology and water injection have been identified for the Red River and Ratcliffe based on engineering characterizations.

Additional 3D seismic will be acquired for Red River characterizations in Bowman County, ND.

Depositional models for the Ratcliffe and Red River have been developed from petrographical studies.

Technology transfer activity during July 1995, included an oral presentation at the 7th Annual Williston Basin Symposium in Billings, MT.

Introduction and Background

This project consists of field demonstrations and technology transfer of under-utilized technologies for improved reservoir characterization using 3D and multi-component seismic, improved completion efficiency and targeted infill drilling. Incremental primary reserves from improved completion efficiency and infill drilling will be demonstrated. The successful demonstration of better completion efficiency and economic infill wells will progress to the evaluation of water injection in an area where waterflooding has not been economically successful. There are two field study areas, located in the Williston Basin, which are utilized for demonstrations in this project (Fig. I-1). One area produces from the Ordovician Red River and one produces from the Mississippian Ratcliffe.

The Ordovician Red River area is characterized mostly by accumulations of small areal extent at depths from 8500 to 9500 ft which are produced with a single to a few wells. Well spacing for initial exploration has been 320 acre; however, some areas which have been unitized for enhanced recovery are developed with 160-acre patterns. The primary exploration tool has been two-dimensional (2D) seismic. Published reservoir studies indicate primary recoveries averaging 15% with a range of 6 to 20%. There have been only a limited number of enhanced recovery projects (two air-injection-insitu-combustion and one waterflood) in the area because of the low number of wells in each accumulation and wide spacing of wells. Additional oil recovery from this area could be achieved by drilling more wells and initiating more enhanced recovery projects. In order for this to occur, appropriate tools are needed for effective and economic placement of wells in small reservoir targets. Three-dimensional (3D) seismic may offer the potential for effective reservoir visualization which is necessary for cost-effective targeting of wells. More efficient completion methods are also required for better injectivity in waterflooding or enhanced recovery projects. Ultra-short-radius lateral completions from cased holes and new-well horizontal drilling may be effective means for improving injectivity and productivity.

The Mississippian Ratcliffe in Richland Co., MT, has been historically a secondary completion target at 8500 ft after depletion of the deeper Red River at 13,000 ft. The well spacing has been either 320 or 160 acre per well. Productive Ratcliffe intervals are often difficult to identify from drill-stem tests or electrical logs. Structural closure is not necessary for commercial accumulations nor does reservoir development always occur on top of the deeper Red River structures. Fracturing may provide permeability and storage in commercial wells which exhibit limited porosity development on logs. Recovery efficiency from the Ratcliffe is low because of poor permeability; large-volume hydraulic stimulation is used for nearly all completions. Median oil reserves of approximately 100,000 bbl per well and expensive completion cost inhibit drilling for the Ratcliffe without deeper reservoir targets. More efficient completions and additional wells placed at optimal locations are necessary for further development of the Ratcliffe in this area.

While the Red River and Ratcliffe have dissimilar reservoir characteristics, both can be better exploited by targeting additional wells on closer spacing and both require efficient, cost-effective stimulation. Seismic visualization of reservoir development with 3D and shear components offer the tools to better target wells. Lateral completions are expected to improve productivity and the associated economics of producing the remaining reserves. Economical secondary recovery by waterflooding in either the Red River or Ratcliffe will require improved completion efficiency. New drilling of horizontal wells or horizontal re-entry drilling are the most prospective technologies to improve water injectivity in these reservoirs.

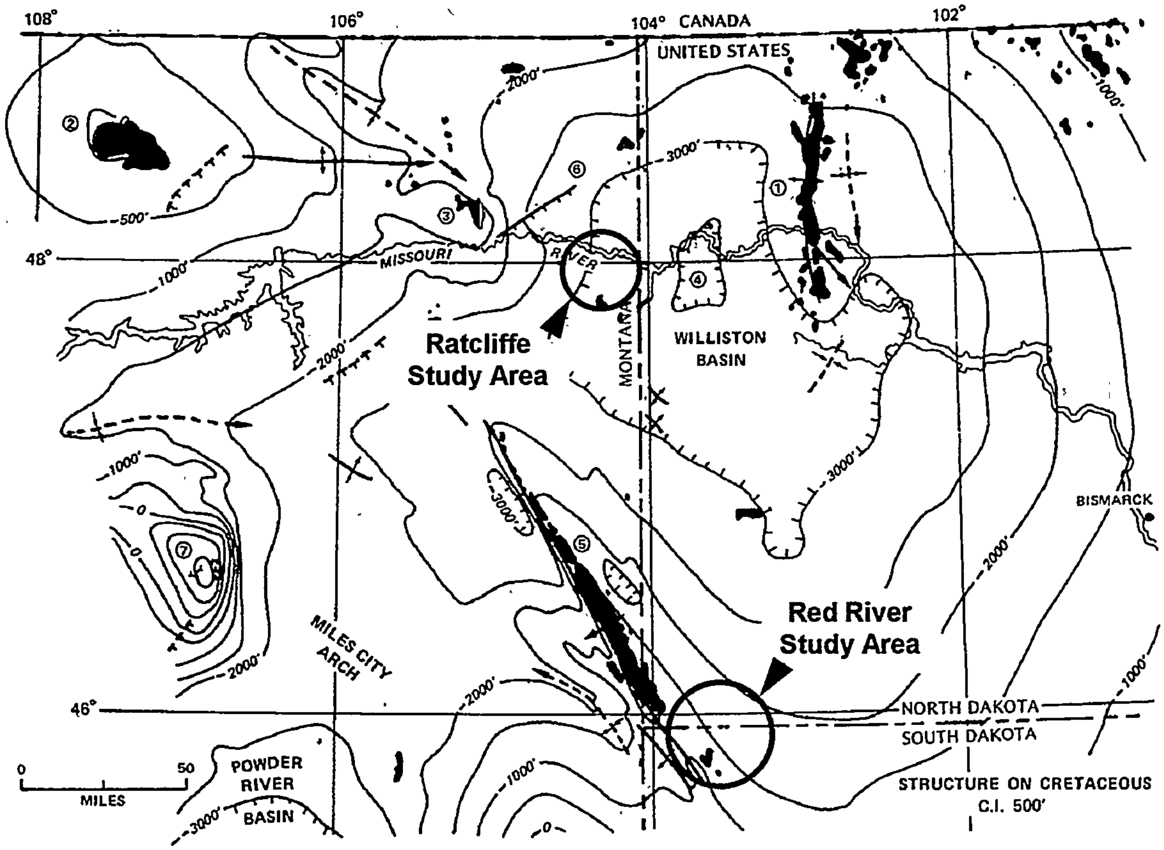

Figure I-1: Map of Williston Basin showing study areas.

Geological Evaluations - Red River

Introduction

A detailed core and petrographic study was undertaken in order to understand the development of porosity within the Upper Ordovician (Champlainian-Cincinnatian) Red River Formation (Fig. II-1) within portions of Bowman Co., ND and Harding Co., SD (Fig. II-2). The upper Red River in this portion of the Williston basin has been divided into four distinct porosity zones. The most common designation, from youngest to oldest, among industry today is 'A', 'B', 'C' and 'D'. Other designations have been used by industry workers and in previous project reports the designation of upper, middle and lower are equivalent to 'B', 'C', and 'D'. The Red River 'A' zone is considered a non-reservoir unit. Detailed graphic descriptions of slabbed cores from thirteen (13) key wells in the Bowman Co. and Harding Co. area were augmented by petrographic study of 41 thin sections from ten (10) wells. Cores, thin sections, and well cuttings examined for this study are currently available at the Core Research Center of the U. S. Geological Survey, Denver Federal Center, Lakewood, Colorado.

Sequence Stratigraphy and Vertical Facies Successions

Red River lithofacies can be arranged in composite vertical assemblages which depict two distinct shallowing-upward cycles (Fig.II-1). The lower cycle includes the 'C' and 'D' Red River porosity intervals and culminates in a capping anhydrite ('C' or Lake Alma Anhydrite). The upper cycle includes the 'A' and 'B' Red River intervals which begins with a flooding event at the top of the 'C' Anhydrite. In the project area, vertical stacking of lithofacies is the principal control on sediment accumulation and lateral distribution. Progradation of depositional facies is insignificant or absent. Vertical staking results in widespread and laterally continuous lithofacies trends that extend over most of the Williston Basin. Therefore, for both depositional cycles, restriction, associated with sediment filling of the basin, is an important component in lithofacies deposition and distribution.

Red River Depositional Environments

The two Red River cycles described above record filling of the Williston Basin during periods of restriction. For each cycle, the vertical decrease in open marine fauna, and succeeding presence of restricted fauna, cyanobacteria, and gypsum (anhydrite) indicate gradual but nearly complete restriction.

Open marine sediments typically contain crinoids with associated bryozoans, brachiopods, rugose and tabulate corals, ostracods, and primitive stromatoporoids. Commonly, skeletal packstones and grainstones occur at the base of paracycles and represent flooding or deepening events. Open marine sediments are interbedded with burrow-mottled sediments indicating minor oscillations in bathymetry and/or salinity changes associated with basin filling. These limestone beds are non-reservoir rocks.

Burrow sediments commonly contain both normal marine fauna and shallow-shelf ichnofauna. These sediments were deposited in environments that were slightly to highly stressed by elevated salinity and/or low oxygen levels. With dolomitization, burrowed sediments are commonly oil reservoirs. Burrowed strata were interpreted in previous reports to be tempestites, or storm-filled burrows. With further study and more data, this interpretation was changed.

Calcareous mudstones, peloidal and skeletal lime wackestones and packstones, and burrowed lime mudstones occur as shoaling beds associated with shallowing upward paracycles. These beds are sparsely dolomitized and are not reservoirs.

Laminated sediments are millimeter-scale dolomites with flat to wavy laminations, as well as laterally linked hemispheroids and low-relief vertically stacked hemispheroids. This facies was deposited in environments where the trapping and binding activities of cyanobacteria were common. Dolomitization of this facies, especially in the 'B' zone, commonly produces poor to good reservoirs.

Each depositional cycle is capped by anhydrite or anhydritic limestones. The presence of anhydrite (gypsum) indicates that restriction of the basin occurred. Bedded and enterolithic anhydrites are common and nodular and displacive anhydrite nodules are sparse to absent. It is inferred that deposition of gypsum was in very shallow subaqueous environments.

Stacking Patterns and Reservoir Development

From base to top of the Red River Formation, there is a significant change in the thickness of depositional facies and corresponding reservoirs. Increased accommodation space was available during deposition of the 'C' and 'D' zones; therefore, porous benches are thicker for these two intervals than in the 'A' and 'B' intervals. Filling of the basin and loss of accommodation space resulted in thinner facies tracts and correspondingly thinner benches of porosity in the upper intervals.

Porosity in the Red River 'D' zone occurs in moderately thick interbeds of burrowed dolomites and open-marine skeletal limestones. Accommodation space was filled by successive episodes of flooding and incomplete restriction. Dolomitization of the burrowed sediments occurred by either early seepage of magnesium-rich brines from overlying gypsum beds ('C' Anhydrite) or by burial dolomitization and the movement of magnesium-enriched fluids along fractures. Diagenetic data show that there is extensive mesogenetic recrystallization of 'D' zone dolomite reservoirs. Pore networks and permeability are better developed in these sucrosic dolomites than other Red River porous intervals. 'D' zone reservoirs occur along paleo-anticlines, but linear basement trends and areas of fracturing probably controlled both early and late dolomitization and the distribution of 'D' reservoirs.

Porosity in the 'C' zone was developed by seepage of magnesium-rich brines from overlying 'C' zone anhydrites. Resulting dolomites are micro-crystalline and crypto-crystalline with good porosity but very poor permeability. Proximity to the source of magnesium promoted rapid dolomitization and small crystal size. To date, the 'C' zone is not an economical drilling objective.

The 'B' zone interval was dolomitized by a similar seepage process. 'B' zone porosity and permeability are highly variable. Variations in porosity and permeability are related to relative position of the porous interval along paleo-anticlines. Minor structural variations and basement linear trends probably influenced seepage dolomitization.

Role of Fractures and Stylolites in Porosity Modification

Natural fractures within the Red River are best developed within dolomite beds. Most fractures in limestones were healed. Fractures in dolomites are usually short-segment tension gashes within burrow-mottled rocks. However, swarms or closely spaced vertical fractures are also present within other dolomitized facies.

Red River dolomites and limestones within the project area display a complete range of pressure-solution features, ranging from micro-stylolites to high-amplitude stylolites, wispy seams and individual or isolated solution seams. Stylolites which developed before oil migration are significant barriers to fluid flow, whereas stylolites which developed and were enlarged through dissolution after hydrocarbons emplacement are not significant barriers to fluid flow.

Late-stage Dissolution and Micro-Porosity Development

The development of dolomite micro-porosity produced oil storage capacity. This microporosity is the result of extensive burial-related dissolution processes. These subsurface processes may be controlled by local structure as much as by stratigraphy and sedimentology.

Commonly associated with chalky micro-porosity are other features indicative of late dissolution of matrix in pre-existing Red River dolomites and dolomitic limestones. These include vuggy and channel pores which commonly occur along stylolites and microfractures. Halos of moldic, micro-vuggy, channelized and chalky porosity are very common around the stylolites within burrow-mottled facies. The orientation and abundance of such pore systems should be an important consideration for using drilling techniques such as horizontal boreholes.

Porosity Prediction

Empirical observations show that Red River 'D' zone production is closely tied to structural closure across anticlines. Red River 'C' production is sparse, and where present, is also aligned along the crests of anticlines. Red River 'B' porosity, however, is more complex in its distribution. Production from 'B' reservoirs occurs along the crests of structures, but is better developed along structural flanks.

Pore Occlusion

Solid hydrocarbons or bitumen in variable amounts within Red River reservoirs occlude porosity and reduce permeability. Anhydrite, calcite, and minor chert replacement are also locally present in Red River reservoirs. These occluding and diagenetic minerals decrease both porosity and permeability.

Summary and Conclusions

Red River production in the project area occurs from three porosity intervals that are associated with two separate shallowing upward cycles. Early-seepage dolomitization was locally modified by burial diagenesis; especially in the 'D' zone, where recrystallization produced reservoirs with high porosity and increased permeability. Occluding cements are dominated by baroque dolomite.

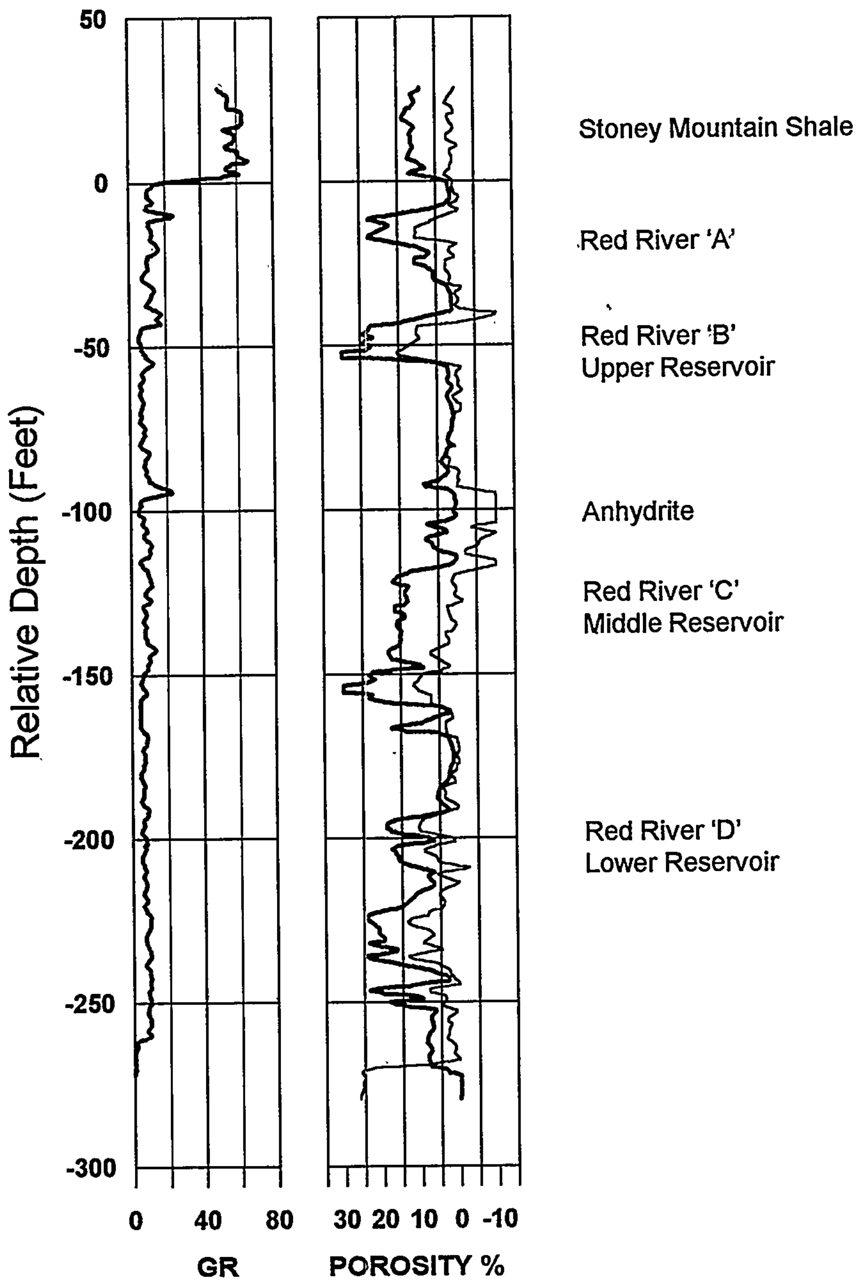

Figure II-1: Red River type log with annotated porosity benches.

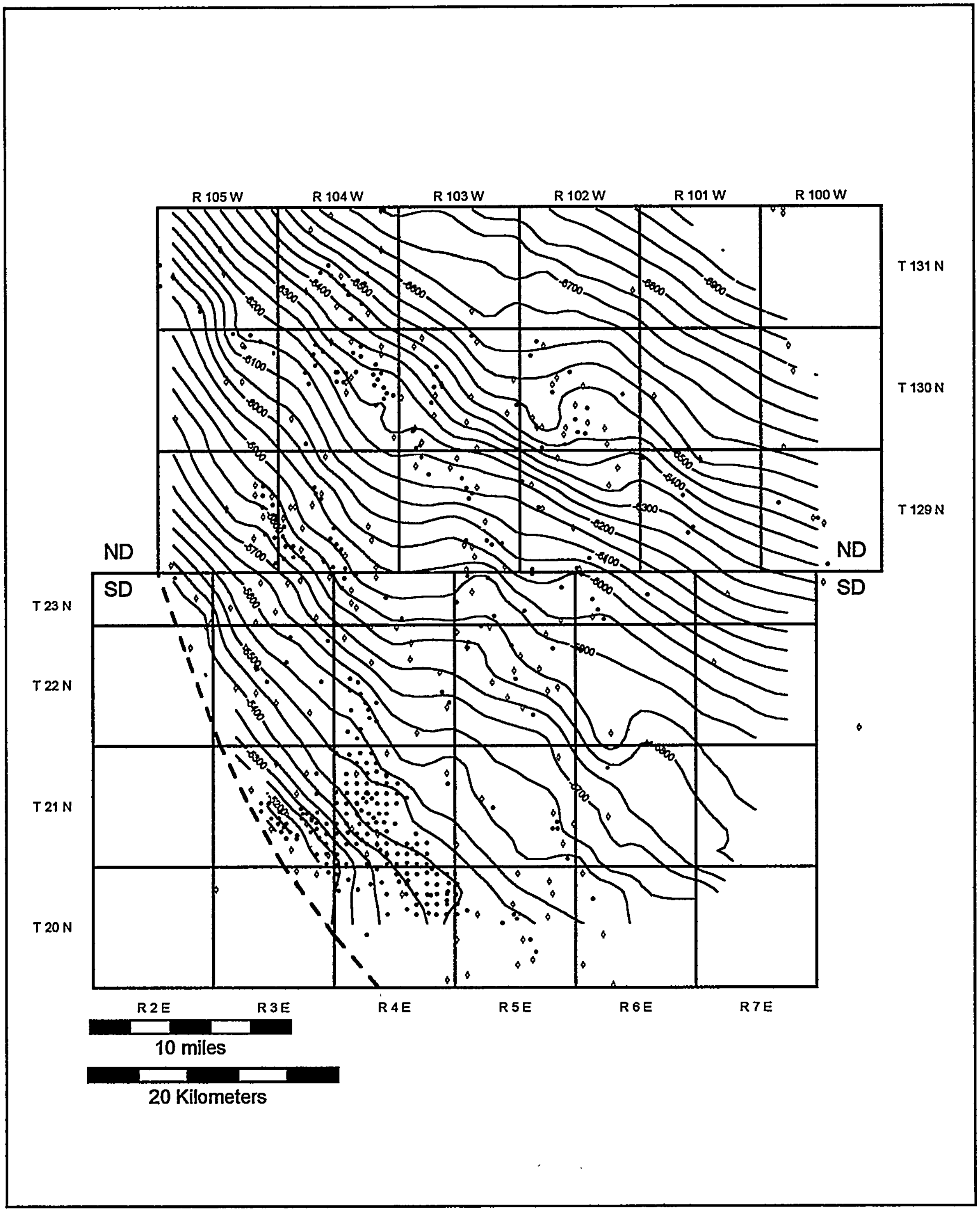

Figure II-2: Red River study area in Bowman Co., ND and Harding Co., SD. Contours are on top of the Red River. Contour interval is 50 ft.

Geological Evaluations - Ratcliffe

Introduction

A detailed core and petrographic study was undertaken in order to understand the development of porosity within the Ratcliffe beds (Fig. III-1) of the Charles Formation (Meramecian) within portions of Richland County, Montana (Fig. III-2). The Madison Group includes the Lodgepole, Mission Canyon, and Charles formations. Mission Canyon and Charles deposition is characterized by complex inter-tonguing of basinal, shallow shelf, and peritidal carbonate and evaporite beds. The Ratcliffe interval of the Charles Formation is a carbonate to evaporite, shallowing upward, regressive sequence. Locally, dolomitic mudstones and wackestones are oil reservoirs. Detailed graphic descriptions of slabbed cores from two key wells in Richland County, Montana were augmented by petrographic study of thin sections. Cores, thin sections, and well cuttings examined for this study are currently available at the Core Research Center of the U. S. Geological Survey, Denver Federal Center, Lakewood, Colorado. A new 90-ft core of the entire Ratcliffe section has been obtained from section 17, T. 26 N., R. 58 E., which is in the middle of the study area. This core has not yet been studied but should supply important additional data for understanding depositional and fracture components of the Ratcliffe.

Sequence Stratigraphy and 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 shallowing-upward cycles. Reservoir facies are incompletely dolomitized mudstones and wackestones that occur in the lower portions of para-cycles. In the project area, forward stepping and vertical stacking of lithofacies controlled sediment accumulation and lateral distribution. Progradation of the Ratcliffe system was from east to west and this off lapping produced facies belts that are laterally continuous along depositional strike. This ramp style of deposition characterizes the entire Ratcliffe.

Figure III-1 details this progradational geometry in a wireline log cross section that includes porosity development in the lower Ratcliffe (eastern log from Cattails Field) that is missing by facies change to tight open marine sediments in wells to the west. Likewise, the well to the west (North Sioux Pass Field) has restricted subtidal porosity developed in the upper Ratcliffe that is tight intertidal and supratidal sediments to the east.

In the project area, progradational facies belts crossed paleo-anticlines. Burrowed mudstones and wackestones, associated with slightly shallower bathymetry, became sites for selective dolomitization. Subtidal burrowed facies are commonly thicker along the flanks of paleo-anticlines. Work by Hendricks (1988) shows thicker development of Ratcliffe burrowed facies (and corresponding porosity development) along the northeastern edges of anticlines in Glass Bluff Field, MacKenzie Co., ND.

Magnesium-rich brines which developed in overlying sabkha facies percolated through these restricted subtidal sediments producing porous but low permeable reservoirs. Local fracturing which occurred during the Laramide Orogeny (Paleocene) interconnected these reservoirs.

Ratcliffe Depositional Environments

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 para-cycles.

Open marine sediments are dark gray to black and contain crinoids, bryozoans, brachiopods, rugose and tabulate corals, and sparse ostracods. These beds are wackestones and packstones which were deposited in normal marine environments. Minor oscillations in bathymetry produced inter-tonguing of these sediments with restricted subtidal sediments. Open marine sediments are not reservoirs.

Light brown, burrow-mottled sediments commonly contain both normal marine fauna and restricted fauna. These sediments were probably deposited in environments that were slightly to highly stressed by elevated salinity and/or low oxygen levels.

Burrowed sediments are partly to completely dolomitized. It is inferred that burrowing infauna probably increased sediment transmissibility and made these shallow subtidal sediments susceptible to seepage dolomitization. Relative position of this facies across structural nosing increases the chances for both effective dolomitization and fracturing. This is the main producing facies.

Shoaling environments commonly cap burrow-mottled sediments. Shoal sediments are peloidal and algal mudstones to grainstones. Textural variations are related to differences in depositional energy and relative position across structural noses. Shoal sediments were probably deposited in very shallow subaqueous environments based on the presence of the Codiacean alga *Ortonella (*nodules and fragments with well developed radiating microtubules).

Peloidal grains indicate reworking of muddy substrates and algal fragments in swash zones (possibly intertidal environments). Coated grains are sparse. Porosity within grain-rich beds is commonly occluded by calcite spar cements and sparse anhydrite. Because of early cementation and sparse dolomitization, the shoal facies is generally not a reservoir.

Laminated beds are sparse and commonly underlie and immediately overlie sabkha sediments. These intertidal beds are millimeter-scale dolomites with 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. This facies is commonly not a reservoir.

In the project area, anhydrite caps shallowing upward para-cycles. 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.

Dolomitization

In the project area, Ratcliffe oil is typically entrapped within dolomitized burrow-mottled mudstones and wackestones. Dolomites are fabric preserving and micro-crystalline to crypto-crystalline (<10 μ). Most of the visible porosity is associated with diagenetic processes during burial (moldic and vuggy pores). Inter-crystalline porosity is sparse, and associated permeability is generally poor. Fracturing of this rock significantly improves permeability. Without fracturing, it appears that dolomitization alone would not create economical reservoirs in the North Sioux Pass Field.

Role of Fractures and Stylolites in Porosity Modification

Natural fractures within the Ratcliffe are best developed within dolomitic beds. Most fractures in limestones were healed by calcite. Fractures in dolomites are usually 0.5 ft to 2.0 ft long and occur within the burrow-mottled facies. Swarms or closely spaced vertical fractures are also present, but within thin beds. Fractures enhance both lateral and vertical permeability, but may have an adverse effect on production if the fractures propagate into lower, water-wet intervals (Midale and Mission Canyon 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 compactional features do not appear to adversely affect dolomitic reservoirs.

Late-stage Dissolution

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. 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.

Diagenetic Cements

Anhydrite and calcite replacement 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 meso-genesis.

Porosity Prediction

Empirical observations show that Ratcliffe production in the project area is closely tied to relative position along southeast plunging anticlines and to Red River structurally high areas. Ratcliffe production also occurs in areas without anticlinal structure at the deeper Red River, such as at Cattails Field. A key to successful exploration is locating the intersection of porous fairways and paleo-anticlines. Intersection points are areas of dolomitization and fracturing.

During Ratcliffe deposition, paleo-structures were probably shallow areas on the self which allowed preferential deposition of burrowed facies and subsequent dolomitization by gravity-induced seepage of magnesium-rich brines. Localization of porosity along these paleo-structures was later enhanced by structural deformation and associated fracturing.

A 90-ft oriented, Ratcliffe core from the Luff Federal No. 1-17R well, was taken to confirm some of the observations concerning fracture orientation, facies distribution, and reservoir characterization. An FMI wireline log was run to image fracture orientations and porosity development.

Conclusions

Ratcliffe reservoirs are fractured and burrow-mottled dolomites and calcareous dolomites. Originally, these sediments were deposited along a shallow dipping carbonate and evaporite ramp that prograded from east to west across the project area. Localization of restricted subtidal facies across paleo-structures provided early diagenetic replacement of micrite by dolomite. Porosity was later enhanced by Laramide structural deformation and associated fracturing which increased permeability.

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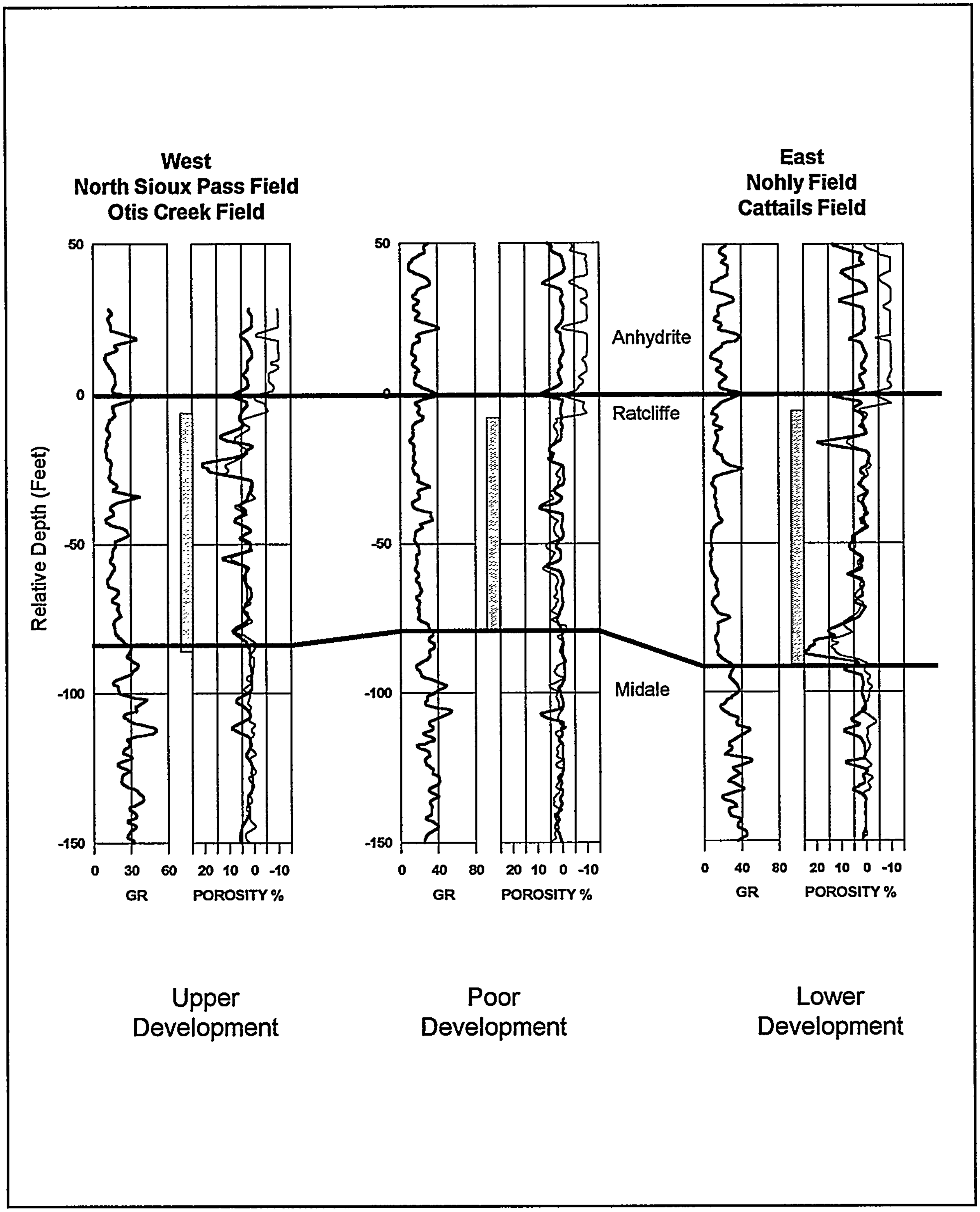

Figure III-1: Type-log cross-section of Ratcliffe in northeastern Richland Co., MT.

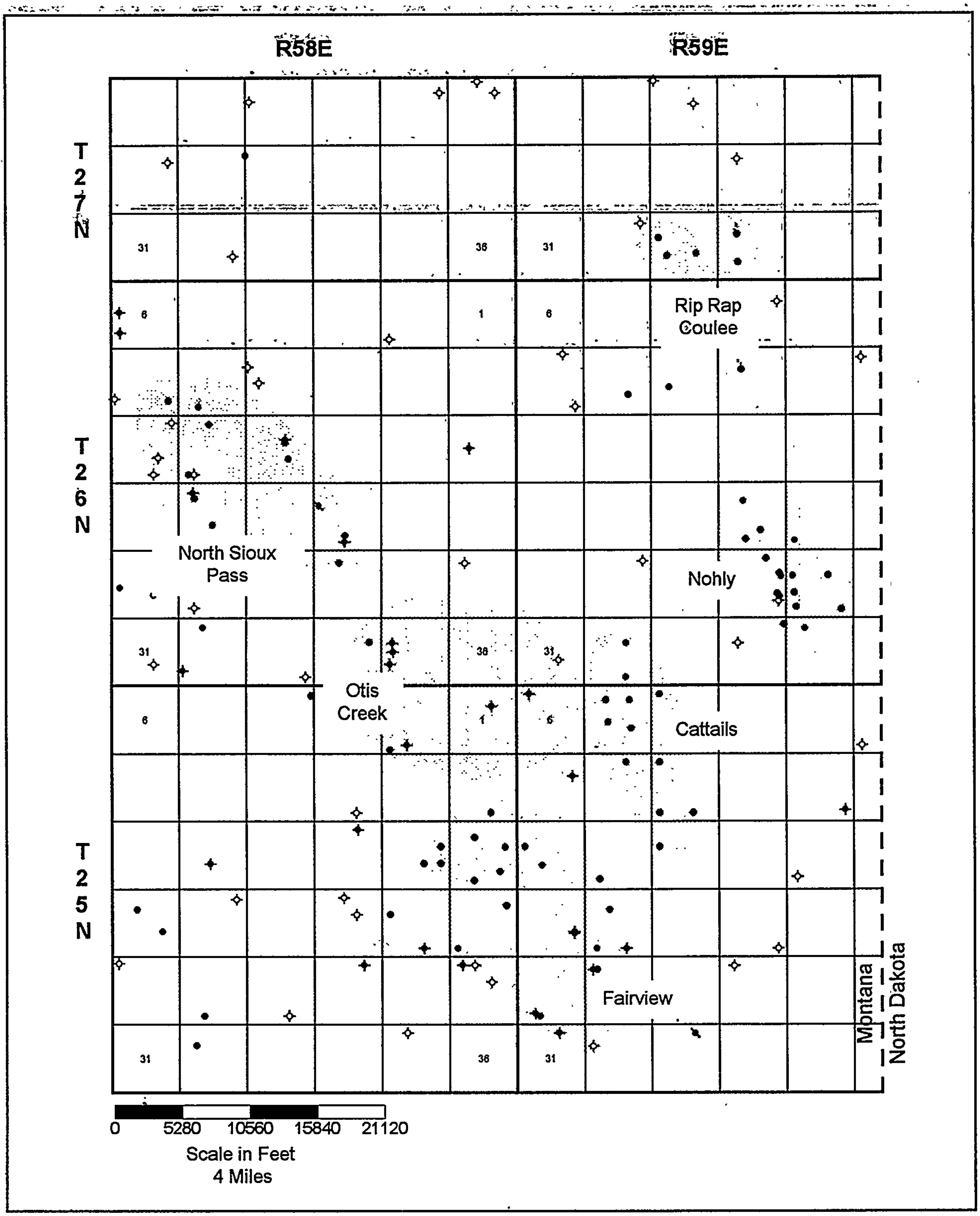

Figure III-2: Map of Ratcliffe study area, Richland Co., MT.

Geophysical Evaluations - Red River

A location for a vertical well has been selected to test potential reservoir compartments as indicated from 3D-seismic interpretations of porosity variation and faulting at Cold Turkey Creek (Red River) Field in Bowman Co., ND. The selected location does not conform to well-spacing rules and requires a hearing before the North Dakota Industrial Commission.

The 3D seismic data from Cold Turkey Creek, Bowman Co., ND, were processed twice and given to different geophysical interpretation companies for analysis. Seismic picks were made at the Greenhorn, Mission Canyon, Duperow, Interlake, Red River and Winnipeg. Time structure and isochron interpretations were made. Faulting was picked at Winnipeg and Red River events. Interpreters found that it was necessary to rotate the 3D data volume to match the synthetic seismograms. One group rotated the data -120° and the other determined that a -90° rotation provided a normal polarity, zero-phase data volume. The Cold Turkey Creek data were acquired with dynamite shots as sources. Faulting in the Cold Turkey Creek 3D area appears to be dominated by many low-relief displacements below the Red River which have limited lateral continuity. Faulting was interpreted by both groups to affect the Winnipeg to a greater degree than the Red River and most faults terminate in the Red River or slightly above the Red River. The predominant fault orientation is slightly west of north (315°). Fault breaks are primarily located on the perimeter of each structural feature (Fig. IV-1). Faults are low relief and are generally one-quarter to one-half mile in length (0.4 to 0.8 km). Several faults are also identified which may compartmentalize each of the structural features. Horizontally long or large vertical-displacement faults are not observed. Compressional-wave (P-wave) attributes and isochrons were used for geostatistical correlation with thickness and porosity development in the Red River. Conclusions regarding stratigraphical correlations of Red River development with 3D seismic attributes were mixed from the different interpreters. It was concluded that the few wells in the high-fold area of the survey limits the ability to confidently produce empirical correlations of seismic attributes and electrical log data.

The 3D data from Cold Turkey Creek were also processed by Coherency Technology Corp. for incorporation with conventional faulting and stratigraphic interpretations. The coherency-cube transform is generated by analyzing localized waveforms in both the inline and crossline directions. Coherence is lower where traces are less similar. Displays of coherency values in map-view of time or horizon slices can depict stratigraphic changes or subtle faults (Bahorich and Farmer 1995; Morris 1996). However, it was determined from the different interpreters that the coherency-processed data did little to enhance the final fault interpretation or stratigraphical analysis of the Red River. This is probably the result of a too-large time window used in processing.

The Cold Turkey Creek 3D data volume was processed in a conventional manner a second time. The second processing appears to have slightly better phase resolution (closer to zero degrees as determined by zero-phase synthetics) and less migration effects at the perimeter of the data set. This processed version of the data volume appears to exhibit a stronger amplitude event which corresponds to Red River 'D' zone porosity development (Fig. IV-2). A drilling location has been selected from the amplitude interpretation. The location is projected to be 25 ft down-dip from the existing producer on the structural feature. This location will test off-structure porosity development and the prediction of porosity with the 3D seismic.

Re-processing of 2D seismic data, originally recorded during 1980-1982, is underway across portions of Buffalo Field (North Area). The purpose of the re-processing is to help delineate subtle faulting or other reservoir development trends which could impact the length and direction of a horizontal well in section 20, T. 22 N., R. 4 E. (Fig. IV-3). The use of radon stacking in the processing flow results in a significantly improved signal-to-noise ratio and allows better discrimination of subtle faulting and stratigraphic change.

A 3D seismic survey will be acquired during summer 1996, at Grand River School (Red River) Field in Bowman Co., ND (Fig. IV-4). This survey will be adjacent to the 3D survey acquired at Cold Turkey Creek Field.

Summary and Conclusions

It was found that different processing methods and interpreters result in different interpretations of subtle stratigraphic variation and faulting in the Red River. Conventional time structure and isochron interpretations were essentially the same. A test of the current interpretation at Cold Turkey Creek will occur with the drilling of a well in the NWNE of section 27, T. 130 N., R102 W. Coherency-cube seismic processing did not produce a better resolution or interpretation of reservoir or structural development. This does not condemn this processing technique for the Red River, but suggests that further work with this seismic technology would require several iterations with time windows and other processing options.

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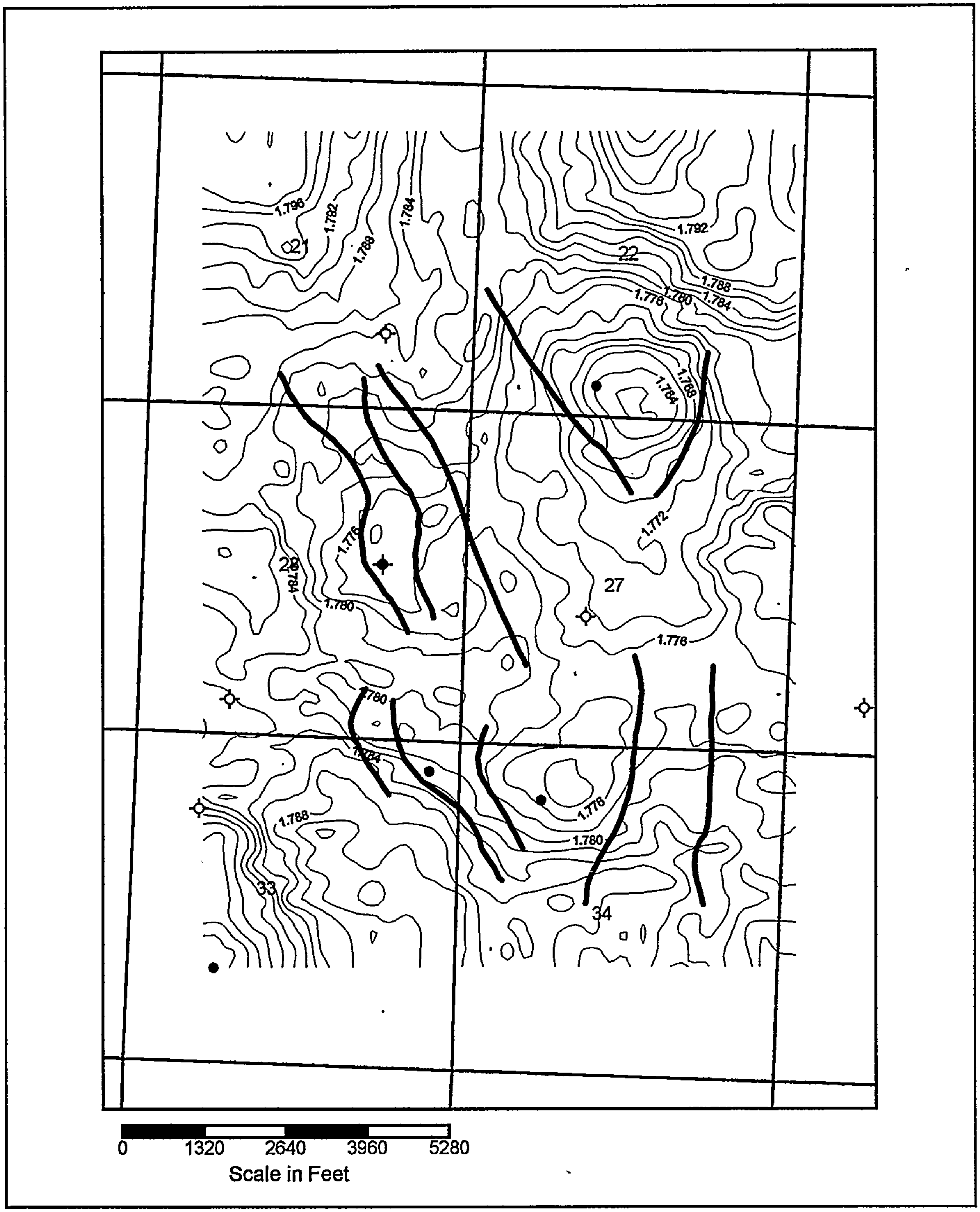

Figure IV-1: Faulting below Red River from 3D seismic interpretation at Cold Turkey Creek Field, Bowman Co., ND. Contours represent Red River time structure.

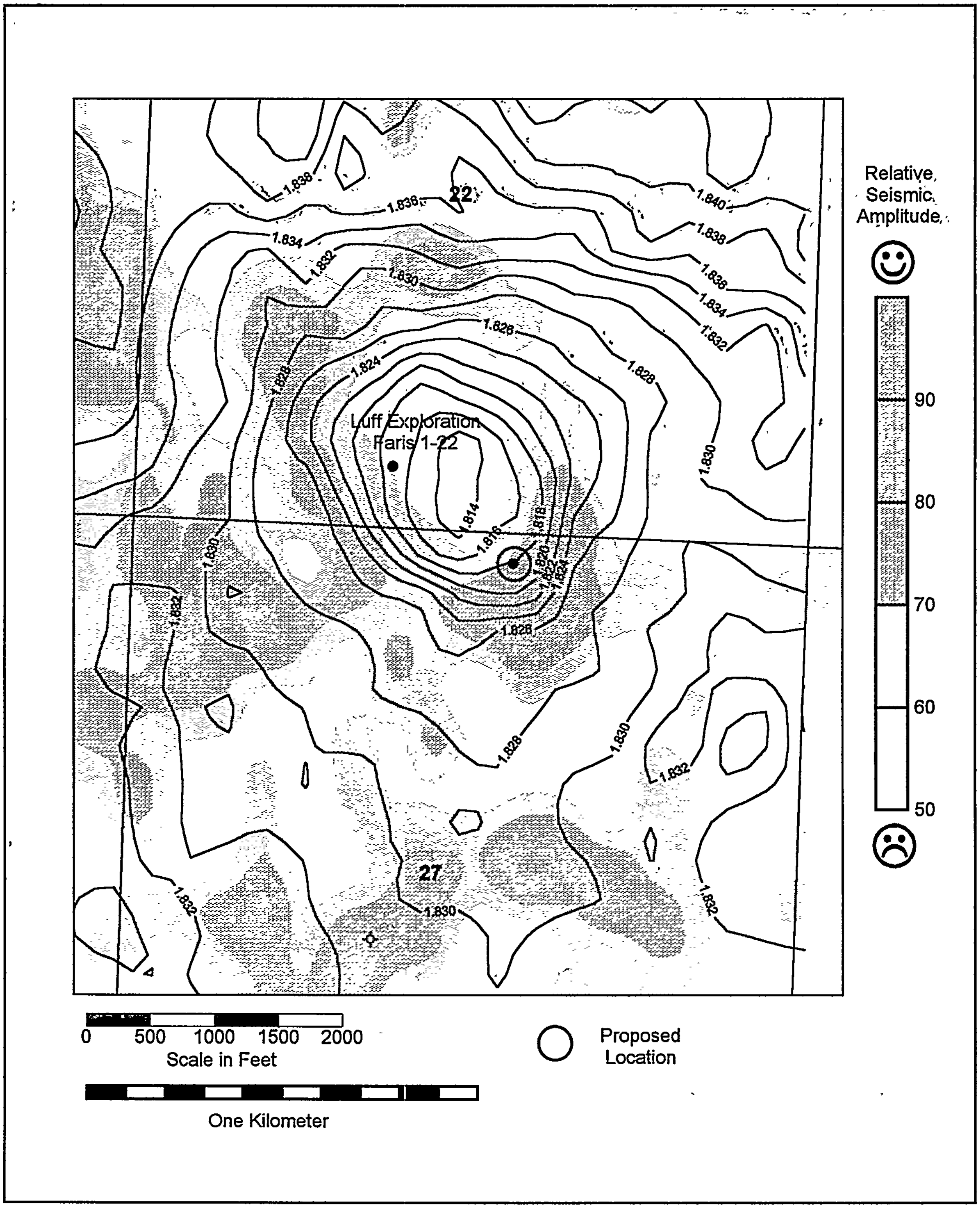

Figure IV-2: Seismic amplitude of Red River 'D' at Cold Turkey Creek. Contours are Winnipeg time structure. Amplitude suggests better porosity development on the flanks.

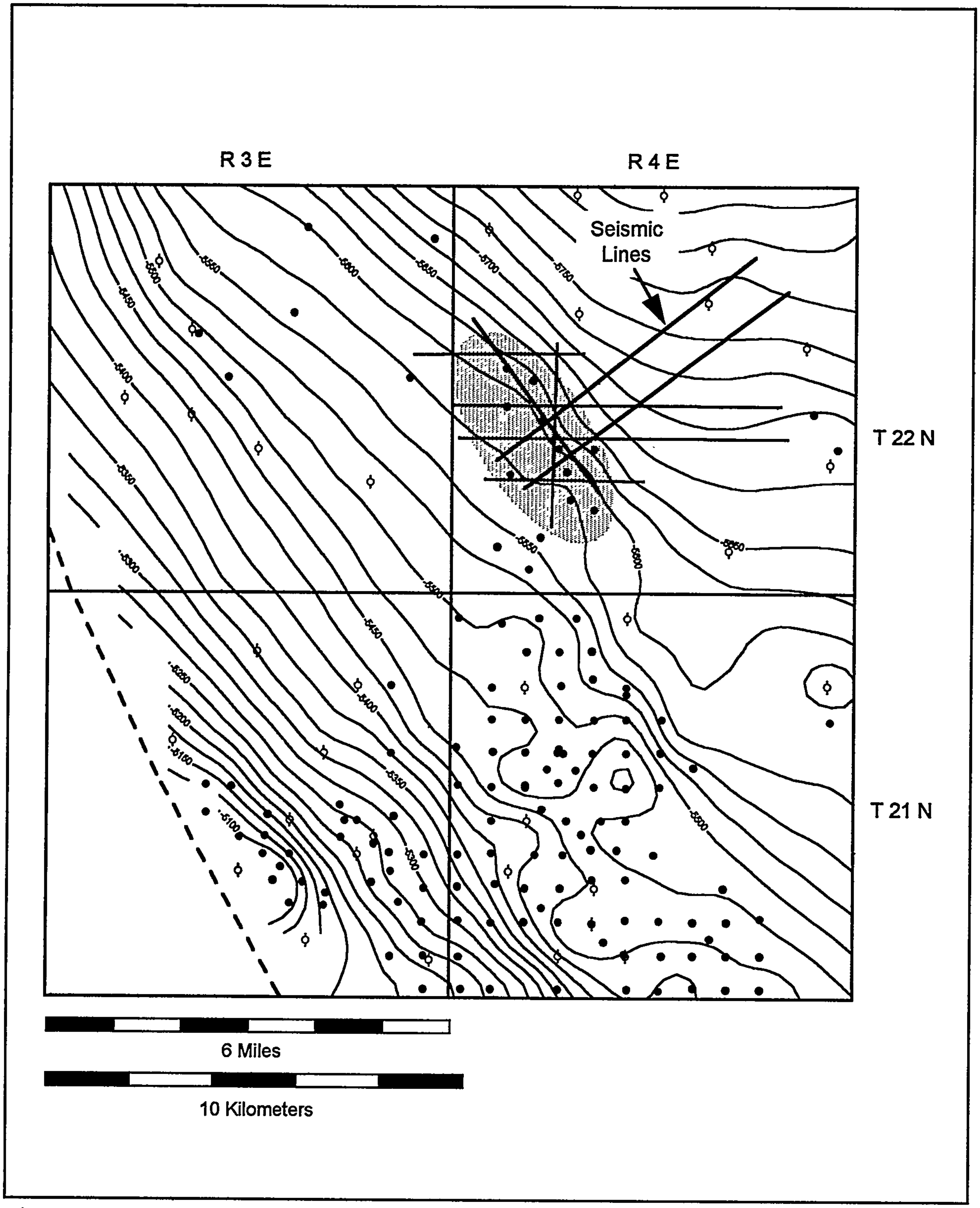

Figure IV-3: Location of 2D seismic lines at Buffalo (North Area) which were selected for re-processing. Contours are on top of the Red River. Contour interval is 25 ft.

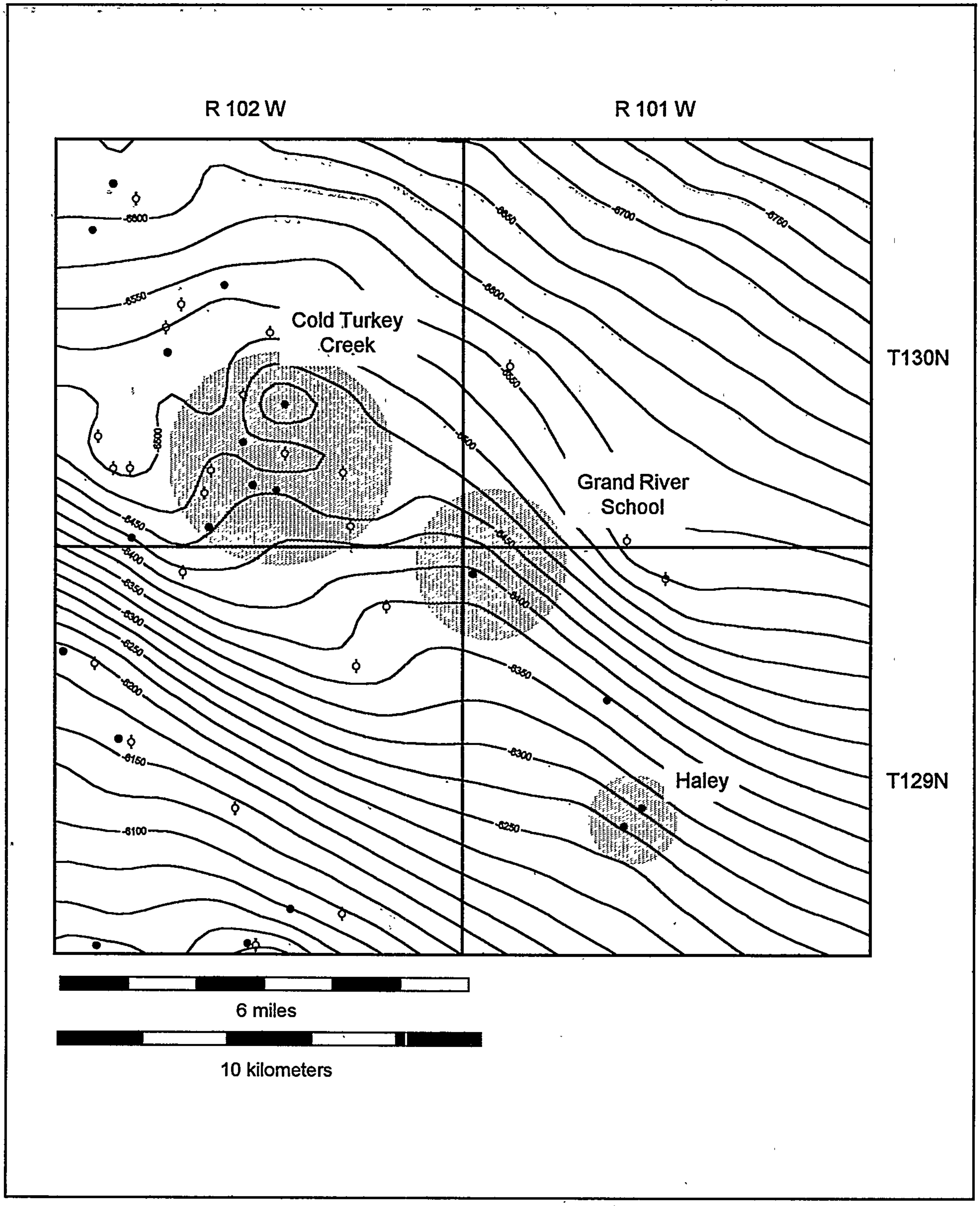

Figure IV-4: Cold Turkey Creek and Grand River School fields, Bowman Co., ND. Contours represent Red River structure based on log data. Contour interval is 25 feet.

Geophysical Evaluations - Ratcliffe

A 3 mile 2-dimensional 3-component (2D-3C) seismic line was recorded in May 1995, using converted, compressional waves (dynamite) over the Cattails (Ratcliffe) Field in Richland Co., MT (Fig. V-1). The data have been processed twice by different well-known geophysical companies. Parameters used for acquisition and recording of the Cattails were based on modeling performed by the first processor. The quality of converted-wave data was poor. Field recordings show a significant source-generated noise train that dominates the split-spread records. The converted-wave data were processed again by another processor. The second processing effort also 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. Further seismic investigations of the Ratcliffe will be focussed on 3D compressional-wave data. A display of the compressional-wave section at the Ratcliffe is shown in figure V-2. There are amplitude variations and wavelet splitting which may be related to reservoir development.

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 data were first processed in June 1995. The processing output was subsequently examined by two geophysical consultants and they recommended that the data should be re-processed by a company more experienced with mode-converted shear-wave data. The conclusions reached after re-processing are that the recorded line does 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 are presented that should improve any future multi-component seismic acquisition.

Several possible mistakes were made during the first-round of processing. The processor lacked experience with mode-converted data. At that time, the first processing company did not have specialized software for handling noise reduction and static solutions of shear-wave (S-wave) data. In displaying the data originally, they used a vertical scale factor of 2.0 rather than

1.5. This is appropriate for pure S-wave data generated by a shear-wave source, but not for mode-converted waves that only travel upward as shear, but downward as compressional waves (P-waves). This made it more difficult to compare the S-wave section to the P-wave section.

The second processor 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 (Figs. V-3 and V-4). 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. At this point, processor 2 recommended that processing be discontinued.

The first-round processing of the converted-wave data produced a section that has low-frequency periodic events across the lower portion of the section. These "events" were previously correlated to P-wave events, despite lack of significant character. It is now concluded that these events may have been artificially produced by processing procedures such as auto-statics, Miser, and subsequent dip-discrimination (F-K) filter. It is possible that the first processor overworked the data until something was imaged, where the second processor, with the benefit of their experience with converted waves, recognized that there was no meaningful shear-wave signal.

The question remains whether the line was properly recorded, or whether the area simply does not allow recording converted shear-wave data. One indication that the area may be unsuitable for shear waves is a thick, weathered layer. Shot holes were drilled 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. The recording and acquisition parameters for the Cattails 2D-3C data are summarized in Table V-1.

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 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 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. Processor 2 also recommended that recording be done in winter because frozen ground couples better and minimizes the static problem for shear waves.

The initial processing of the 2D-3C data was suspect, and 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 better processing of the existing data will not produce results. Several possible problems are identified with the acquisition and recommendations 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.

Table V-1
Acquisition and Recording Parameters for Cattails 2D-3C Sesimic

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 Hz per Octave
Charge Size:	10 lb	Sub-surface Coverage:	1200%

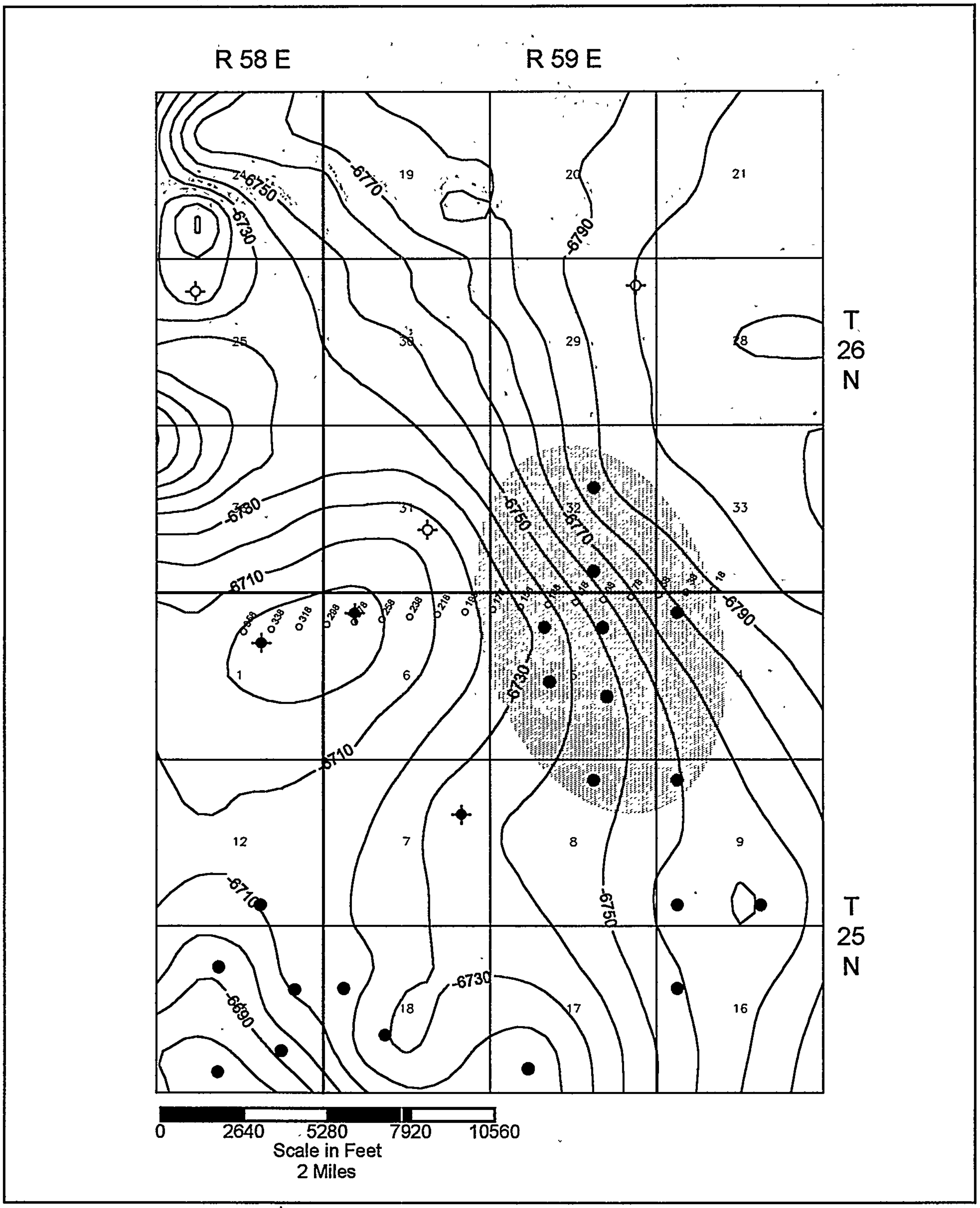

Figure V-1: Map of Cattails (Ratcliffe) Field showing location of 2D-3C seismic acquisition. Contours depict the structure of the Base of Last Charles Salt which is conformable to the Ratcliffe.

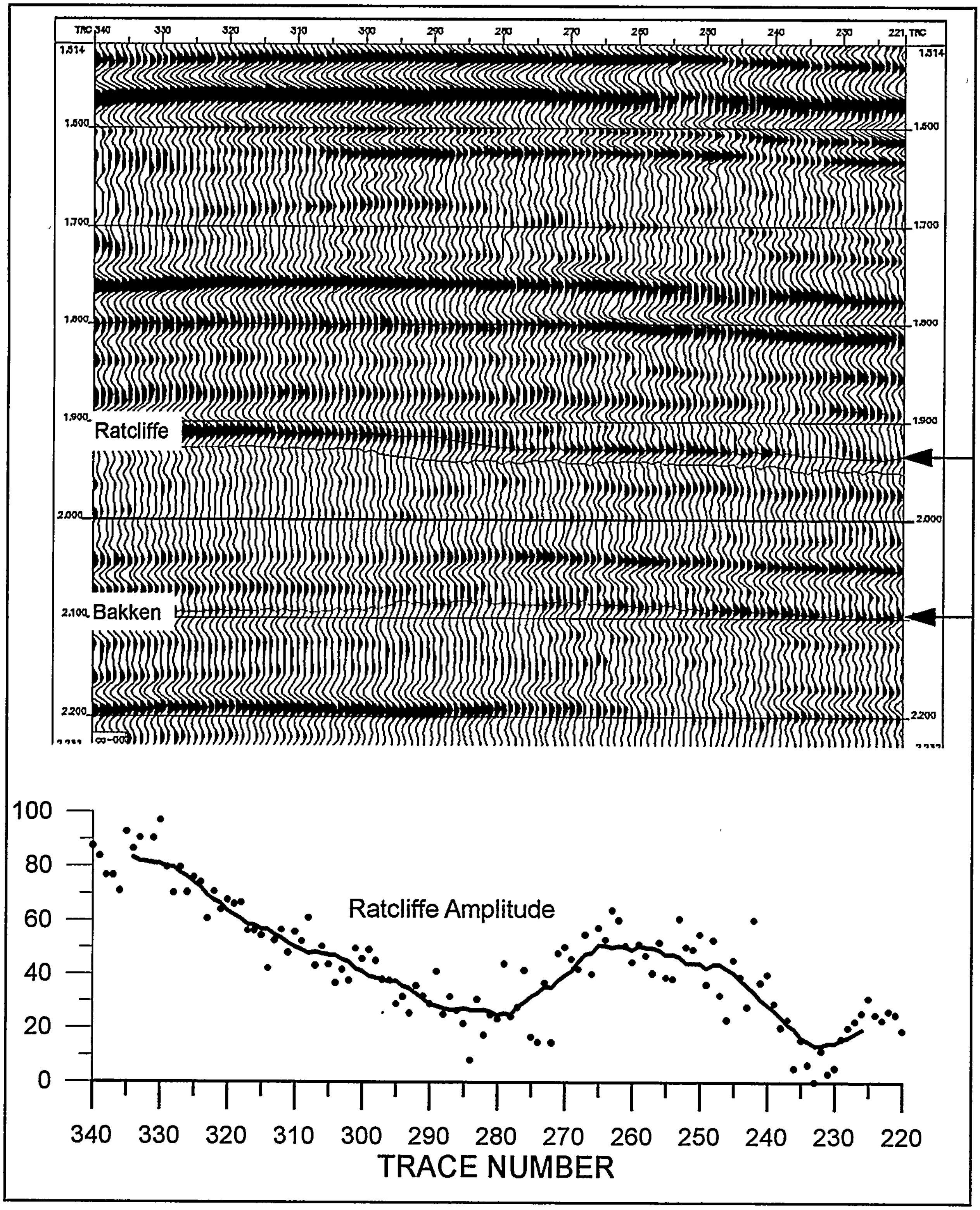

Figure V-2: Compressional-wave seismic section from Cattails 2D-3C acquisition.

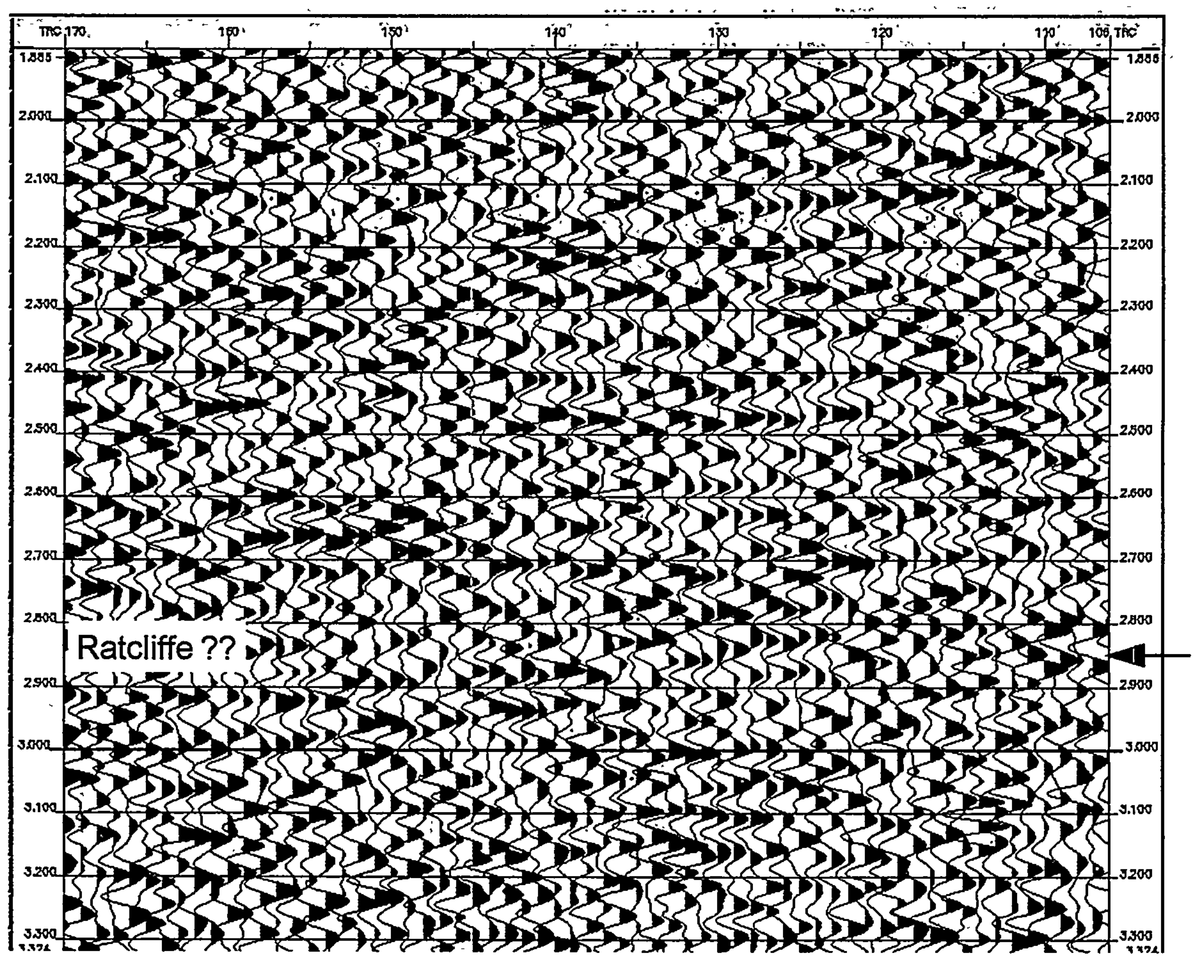

Figure V-3: Radial component of converted shear-wave seismic section from Cattails 2D-3C acquisition. Coherent events are not observed.

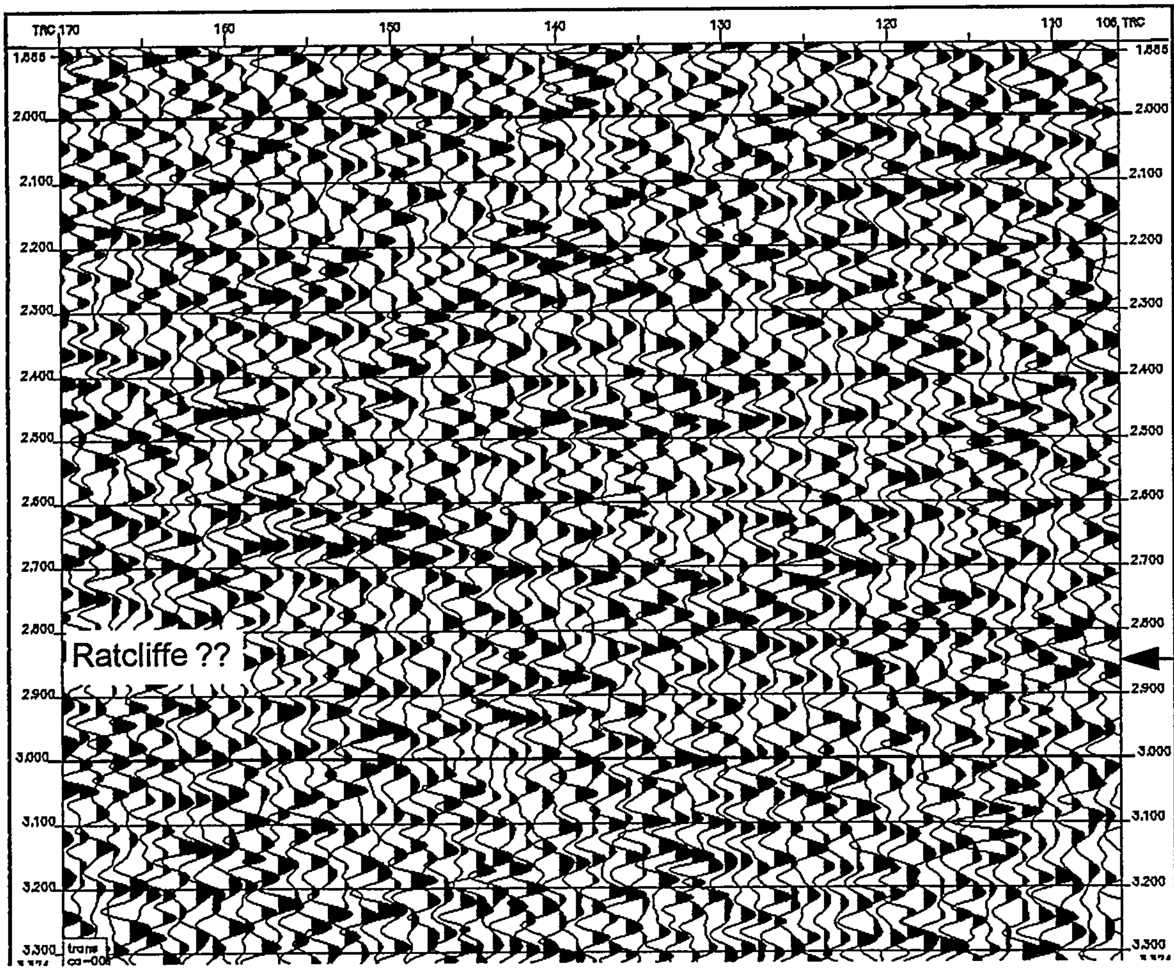

Figure V-4: Transverse component of converted shear-wave seismic section from Cattails 2D-3C acquisition. Coherent events are not observed.

Engineering Evaluations Red River - General

Introduction

There are four distinct porosity intervals in the Red River found in the southwest Williston Basin study area (Fig. VI-1). This section describes each of the reservoir units in the Red River in an engineering context of fluids, storage, transmissibility and recovery.

Reservoir Rock

The Red River Formation is composed of a series of fining-upward cyclical carbonates deposited in sub-tidal to supra-tidal environments on a restricted shelf. The upper Red River in this portion of the Williston Basin has been divided into four distinct porosity zones (Fig. VI-2). The most common designation, from youngest to oldest, among industry today is 'A', 'B', 'C' and 'D'. Other designations have been used by industry workers and in previous project reports the designation of upper, middle and lower are equivalent to 'B', 'C', and 'D'. The Red River 'A' is considered a non-reservoir unit. The Red River is composed of limestones, dolomites and anhydrites. Lithology varies from laminated mudstones to heavily bioturbated packstones and wackestones. The upper-most and youngest cycle is termed the 'A' zone and is about 10 ft from the top of the Red River. It is frequently only a few feet thick, poorly developed and is occasionally missing. The next interval is the 'B' zone and is found at about 35 ft below the top of the Red River. It is the most frequently completed oil reservoir in the area. The 'B' has a gross thickness of about 13 ft. The 'C' lies about 100 ft below the top of the Red River and has a gross thickness of about 38 ft. This interval develops porosity with low permeability and is generally non-commercial. The lowest and oldest interval is the Red River 'D' zone. It is the thickest and most permeable of the four Red River benches. Gross thickness of the 'D' zone is about 46 feet and is located at a depth of about 170 ft below the top of the Red River. When structural or stratigraphic conditions are favorable, the 'D' zone can be a prolific reservoir.

Reservoir Fluids

The gravity of Red River oils in the study area vary from 28° to 40° API. The average oil gravity is about 32°. The dissolved gas is rich in butane and propane resulting in a specific gravity of greater than 1.0 and heating value of about 1500 Mmbtu. Table VI-1 summarizes Red River oil properties from PVT studies.

Red River water salinity varies greatly across the study area and sometimes vertically between zones in a well. Salinity generally increases with depth. In the Buffalo area, salinity is about 30,000 ppm total dissolved solids (TDS). At Cold Turkey Creek, the maximum salinity is about 150,000 ppm TDS. Table VI-2 summarizes formation water found in the study area. The variation in water resistivity (R_w), both laterally and vertically, poses a problem for water saturation calculations from electrical logs. It has been found that mixing of 'D' and 'B' waters can cause scale precipitation.

Characterization from Pressure Transient Tests

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

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

The Red River 'B' zone was evaluated from 252 tests and found to have a log-normal mean for kh/uB of 30.4 md-ft/cp. The statistical distribution of kh/uB from the 'B' zone has the lowest variance of the porosity benches. The mean flow-rate from these tests was found to be 98 bbl per day. It is concluded that vertical wells with a DST transmissibility less than the mean would be considered uneconomic (would not pay for drilling and completion cost).

The Red River 'C' zone was evaluated from 86 tests and found to have a mean value of kh/uB of 10.9 md-ft/cp. The mean flow rate from these tests was determined to be 38 bbl per day. The low number of tests in the middle interval attest to the lack of shows found in this interval. Most DST recoveries from this interval are mud and water without free oil. Only a very few wells have been completed solely in this interval and none have produced economical reserves.

The Red River 'D' zone was evaluated from 107 tests and found to have a mean value of kh/uB of 105.1 md-ft/cp. The mean flow rate from these tests was determined to be 239 bbl per day. The 'D' porosity bench can develop the greatest thickness of the Red River benches and also shows the greatest variance in transmissibility.

Table VI-3 summarizes the evaluations from drillstem tests taken in wells in the Bowman-Harding area. The 'B' and 'D' zone develop sufficient transmissibility to have commercial reserves. The 'D' zone develops the greatest transmissibility because of thickness.

Characterization from Cores

Conventional core studies were used to describe various engineering parameters of the Red River reservoir intervals. The Red River 'B' is the most consistently developed and most frequently completed interval. The 'B' zone has a mean thickness of 10.4 ft with typical porosity of 18. 5 percent and permeability to air of 5.5 md. The Red River 'C' appears from core and log data to have sufficient porosity-thickness to be a major producing interval; however, the permeability of the 'C' interval is usually too low for commercial production. The 'C' zone has a mean thickness of 10.7 ft with typical porosity of 15.4 percent and permeability to air of 1.3 md. The 'D' interval has the greatest potential for oil reserves because of thickness and permeability. The Red River 'D' also demonstrates the greatest variability of development. Typical net pay in the 'D' zone is 28.3 ft with porosity of 13.9 percent and permeability to air of 8.2 md. Table VI-4 summarizes conventional permeability and porosity statistics from the major Red River reservoir intervals.

Characterization from Electrical Logs

Electrical log data from Red River intervals were digitized from selected wells across the study area. A summary of mean values and ranges of porosity by zone are shown in table VI-5. The best porosity is developed in the 'B' zone. Net pay thickness in the 'B' zone is fairly consistent throughout the area. Typical pay thickness is 9.4 ft. The 'C' zone has the lowest average porosity but indicates substantial values for total pore volume. Typical net thickness from log evaluations of the 'C' zone is 22.5 ft with porosity of 12.7 percent. However, the pore volume in the 'C' zone has poor producibility because of low permeability and small pore-throat size. The 'D' zone has the greatest average porosity-thickness and produces the greatest reserves per completion. The mean porous thickness is 17.6 ft and total porous thickness can exceed 40 ft. Typical porosity is 14.6 percent.

Stimulation Practices

Productive Red River intervals are generally perforated through casing and acidized with 100 to 200 gal/ ft with 15% hydrochloric acid. Isolation tests with packer and bridge plug have found that acidizing can occasionally communicate between porosity members. Re-acidizing after several years of production has helped some wells and restored previous production trends.

Characterization from Production Data

With wide spacing (320 and 160 acres per well) and limited number of wells completed in each reservoir, it is problematic to accurately determine original-oil-in-place (OOIP), drainage area and recovery efficiency. Production data were analyzed using type-curves after the method of Fetkovich. The most important (and uncertain) reservoir parameter for estimation of OOIP using type-curve analysis is total compressibility (C_t). A value for total compressibility of 11.0 E-6 vol/vol/psi was used in type-curve calculations. This value for compressibility was tested with finite-difference, black-oil reservoir simulations and was also found to reasonably match OOIP values by volumetric methods reported in various Red River unitization studies. Table VI-6 summarizes recoveries for various significant fields or areas in the Bowman-Harding area. The extrapolated ultimate recovery (EUR) is based on an economic limit of 8 bopd per well.

Recovery and OOIP by type-curve analysis reasonably match estimations from other sources. The West Buffalo 'B' Red River Unit (WBBRRU) has a volumetric OOIP of 20,750,000 bbl which is reported in the unitization study report (Fig. VI-3). The projected primary for the WBBRRU was placed at 1,254,000 bbl or 6 percent of OOIP (Harper Oil 1985). The Buffalo Red River Unit has a reported primary recovery factor of 6 percent of OOIP with a recovery of 2,200,000 bbl (Fig. VI-3). The Medicine Pole Hills Unit (MPHU) has a volumetric OOIP of 40,100,000 bbl which is reported in the unitization study report and several published articles (Fig. VI-4). According to these sources, the projected primary for the MPHU was placed at 6,000,000 bbl or 15 percent of OOIP (Kumar et al. 1995; Koch Exploration 1985). The Horse Creek Unit unitization study reported a volumetric OOIP of 45,740,000 bbl (Fig. VI-4). The projected primary for the Horse creek Unit was placed at 4,536,000 bbl or 10 percent of OOIP (Total Minatome 1995).

Production data from the Red River 'B' zone was analyzed from 35 wells across the Bowman-Harding area which were completed only in this zone. Table VI-7 summarizes production characteristics from the 'B' zone. The table shows that a typical 'B' zone vertical completion will efficiently drain only 105 acres. The more prolific 'B' completions are assumed to be in rock with greater pore thickness and can efficiently drain 175 acre. Red River 'B' completions in lower permeability rock in the Buffalo area, with lower gravity oil and dissolved gas, have recovery factors of 6 to 10 percent of OOIP. In deeper portions of the study area where the oil gravity and solution gas content is higher, the typical Red River 'B' completion has a recovery factor of greater than 15 percent of OOIP.

A regional study of 33 'D' zone wells, including both stratigraphic and structural reservoir types, was performed for this project. Production data from these wells were analyzed using production type-curve matching to estimate OOIP and drainage. A summary of results from this production study of the 'D' zone is presented in table VI-8.. It is concluded that a typical Red River 'D' completion will recover between 20 and 25 percent of contacted OOIP and the typical drainage area is between 165 to 244 acres per well. Ultimate primary recoveries from these 33 'D' zone completions have a geometric mean of 372,000 bbl.

The Red River 'D' zone produces the most reserves per completion. Small structural features with 100 ft of relief have a mean ultimate recovery of 618,000 bbl per completion where water-drive is the producing mechanism with water encroachment from the flanks. Total fluid rates remain constant and water cuts steadily increase over the life of completion in this type reservoir. Stratigraphically trapped 'D' zone oil has been recognized at Horse Creek and Horse Creek South fields in Bowman Co., ND (Longman et al. 1992). Fluid rates and reservoir pressure decreased with time from this reservoir. Water cuts remained nearly constant. The geometric-mean recovery from stratigraphically trapped 'D' zone reservoirs is 204,000 bbl per well.

Recovery from the Horse Creek area (Fig. VI-4) allows a reasonable estimate of volumetric OOIP as the reservoir has 15 producers and several dry-holes at the perimeter. The OOIP at Horse Creek Unit was estimated to be 26,500,000 bbl (Longman et al. 1992). This study predicted an ultimate recovery of 3,555,000 bbl or 13.3 percent of OOIP. The unitization and feasibility study for the Horse Creek Unit estimated 45,740,260 bbl for OOIP in 1993 with a projected recovery of 4,536,502 bbl or 9.9 percent of OOIP (Total Minatome 1995). These two studies demonstrate a wide variation of OOIP estimated by two groups using the same data.

An estimate of recovery and drainage from structural water-drive D zone reservoirs was also made by Longman et al. in 1992. Two structural reservoirs with five wells were studied. This study reported that average wells in these reservoirs had a recovery factor of 19.9 percent of OOIP and drained 225 acres.

Secondary Recovery

There are several air-injection (insitu-combustion) projects and one waterflood project in the study area (Figs. VI-3 and VI-4). All projects are primarily in the Red River 'B' except for the newly formed Horse Creek Unit. A water-injectivity test of the Red River 'B' was performed by Shell in the early development stages of the Buffalo field and concluded that waterflooding was not feasible due to poor water injectivity. Koch Exploration formed the Buffalo Red River Unit, Harding Co., SD in 1978 as an air-injection project. This project was subsequently expanded to adjacent units. Koch Exploration also formed the Medicine Pole Hills Unit, Bowman Co., ND as an air-injection project in 1985. Total Minatome formed the Horse Creek Unit, Bowman Co., ND in 1995 for air injection. Harper Oil Company formed the West Buffalo 'B' Red River Unit in 1986 as a secondary project using water injection. Water injectivity at the WBBRRU has been poor, but this reservoir has the lowest transmissibility (kh/uB) of all the Red River fields studied. The projected ultimate recovery for the BRRU is reported to be 21.6 percent of OOIP and 29.2 percent for the MPHU (Kumar et al. 1995). The projected ultimate recovery from the WBBRRU waterflood project is reported to be 15.1 percent of OOIP (Harper Oil 1985). All of these secondary projects have had infill drilling since unitization. Consequently, it is difficult to determine incremental secondary oil from additional primary oil. Both types of secondary methods have demonstrated technical success.

Summary and Conclusions

There are three major reservoir zones or porosity units in the Red River. The Red River 'B' has a typical liquid transmissibility of 30.4 md-ft/cp. Producing mechanisms for the 'B' zone range from liquid and rock expansion to efficient solution-gas drive. The geometric-mean recovery is 162,000 bbl per well with a recovery efficiency of 13.4 percent for a 160-acre drainage area. The Red River 'B' zone offers the most potential for secondary recovery in the area and is the primary target of horizontal drilling. The Red River 'C' zone has poor producibility with a typical liquid transmissibility of 10.9 md-ft/cp. There is an insufficient number of 'C' zone completions to characterize expected recovery. The Red River 'D' zone is the most prolific reservoir interval with a geometric-mean liquid transmissibility of 105.1 md-ft/cp. A typical 'D' zone completion is expected to recover 372,000 bbl with a recovery efficiency of 20.3 percent for a 160-acre drainage area. There are both stratigraphically and structurally trapped reservoirs in the Red River 'D'. The stratigraphically trapped reservoirs have liquid-expansion and solution-gas drive mechanisms with recoveries from 10 to 15 percent of OOIP. There are many structurally trapped 'D' zone reservoirs with a water-drive producing mechanism and water encroachment from the flanks. Wells completed in strong water-drive 'D' zone reservoirs can recover nearly 1,000,000 bbl or 28.2 percent of OOIP in a 160-acre-drainage area.

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Table VI-1
Characteristics of Red River Oils

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

Table VI-2
Characteristics of Red River Waters

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

Table VI-3
Liquid Transmissibility (kh/uB) of Red River from Drill-Stem Tests

Porosity Interval	Median	Geometeric Mean	Mean Plus 1 Std Dev
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 VI-4
Porosity and Permeability of Red River from Core

Petrophysical Item	Red River 'B'	Red River 'C'	Red River 'D'
Number Cores	7	3	9
Gross Thickness	13 ft	38 ft	46 ft
Net Thickness	10.4 ft	10.7 ft	28.3 ft
Porosity-thickness	1.93 ft	1.64 ft	3.98 ft
Porosity	18.5 +/- 6.6%	15.4 +/- 5.2%	13.9 +/- 2.7%
Permeability-thickness	93.3 md-ft	39.8 md-ft	397.7 md-ft
Geometric Mean Permeability (air)	5.5 md	1.3 md	8.2 md
Dykstra-Parsons Coef.	0.67	0.74	0.67
Relative Storage (ϕh) Total = 1	0.26	0.22	0.52
Relative Capacity (kh) Total = 1	0.18	0.08	0.74

Table VI-5
Reservoir Characteristics of Red River from Electrical Logs

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

Table VI-6
Primary Recovery of Red River from Production Characterization

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

Table VI-7
Red River 'B' Production Characteristics

Production Characteristic	Geometric Mean	Mean Plus 1 std deviation
Oil Transmissibility (kh/uB)	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%
Apparent Drainage Area (type-curve)	105 acre	175 acre

Table VI-8
Red River 'D' Production Characteristics

Production Characteristic	Geometric Mean	Mean Plus 1 std deviation
Oil Transmissibility (kh/uB)	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%
Apparent Drainage Area (type-curve)	151 acre	225 acre

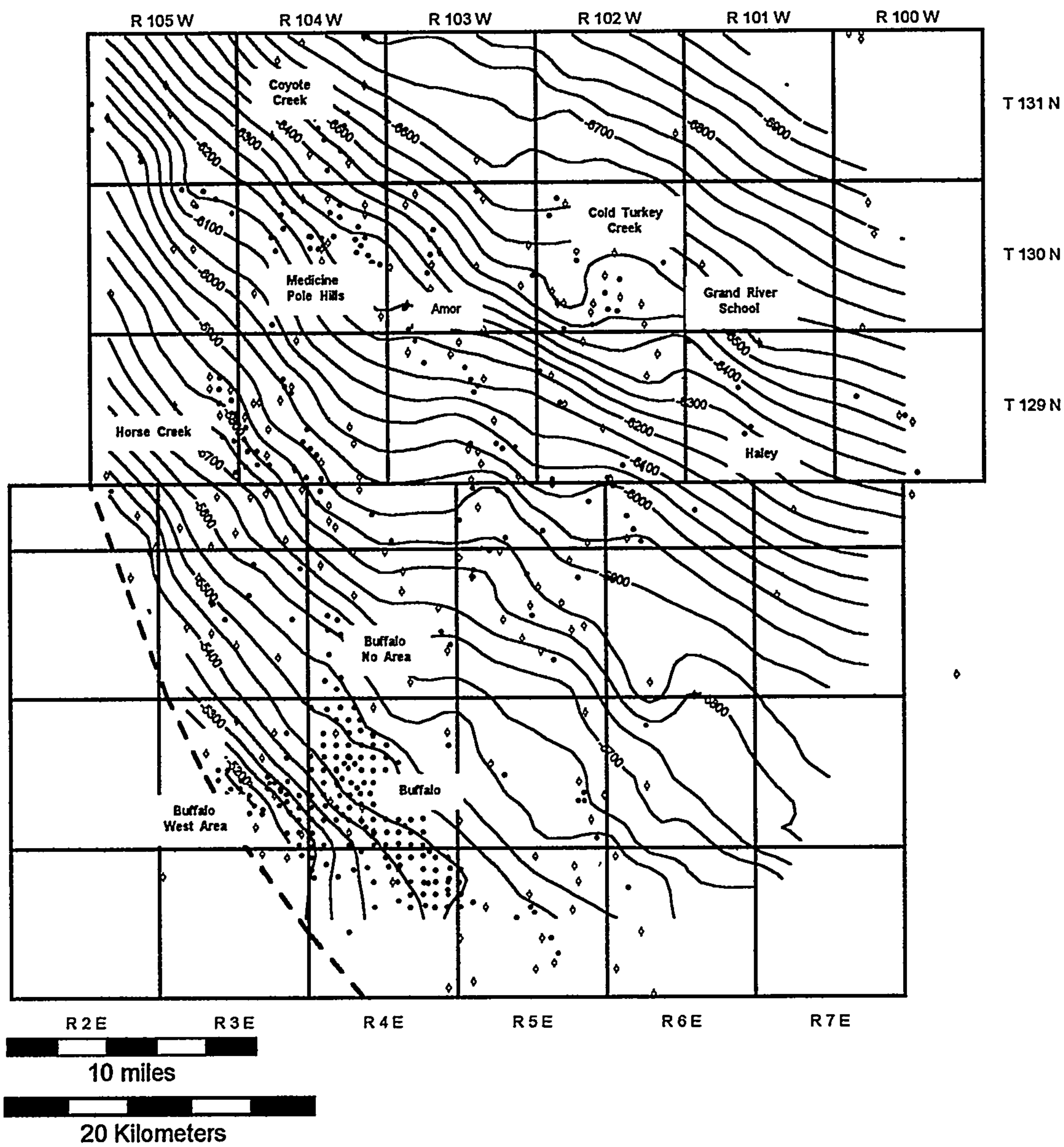

Figure VI-1: Map of Red River study area in Bowman Co., ND and Harding Co., SD. Contours are on top of the Red River. Contour interval is 50 ft.

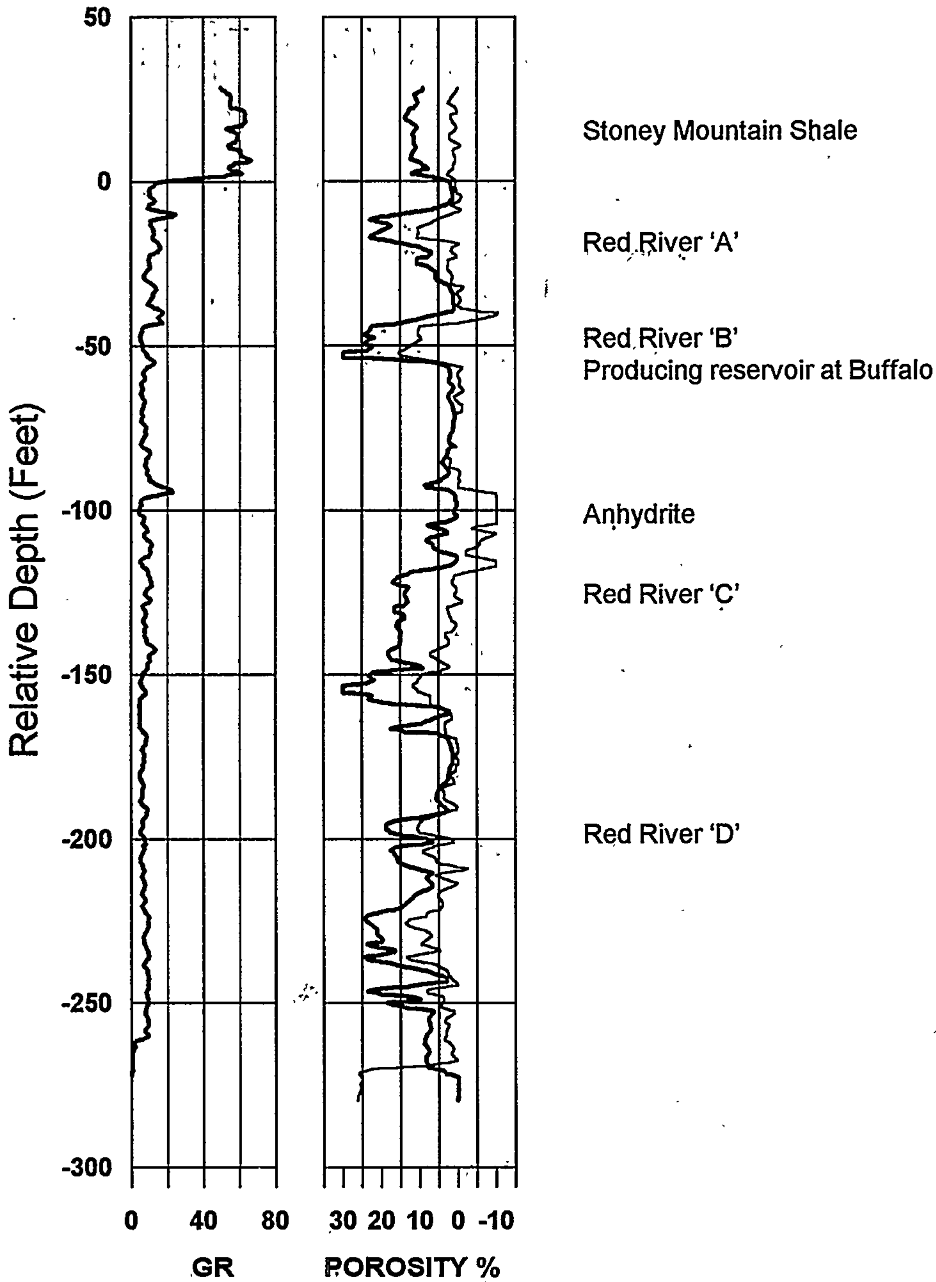

Figure VI-2: Red River type log with annotated porosity benches.

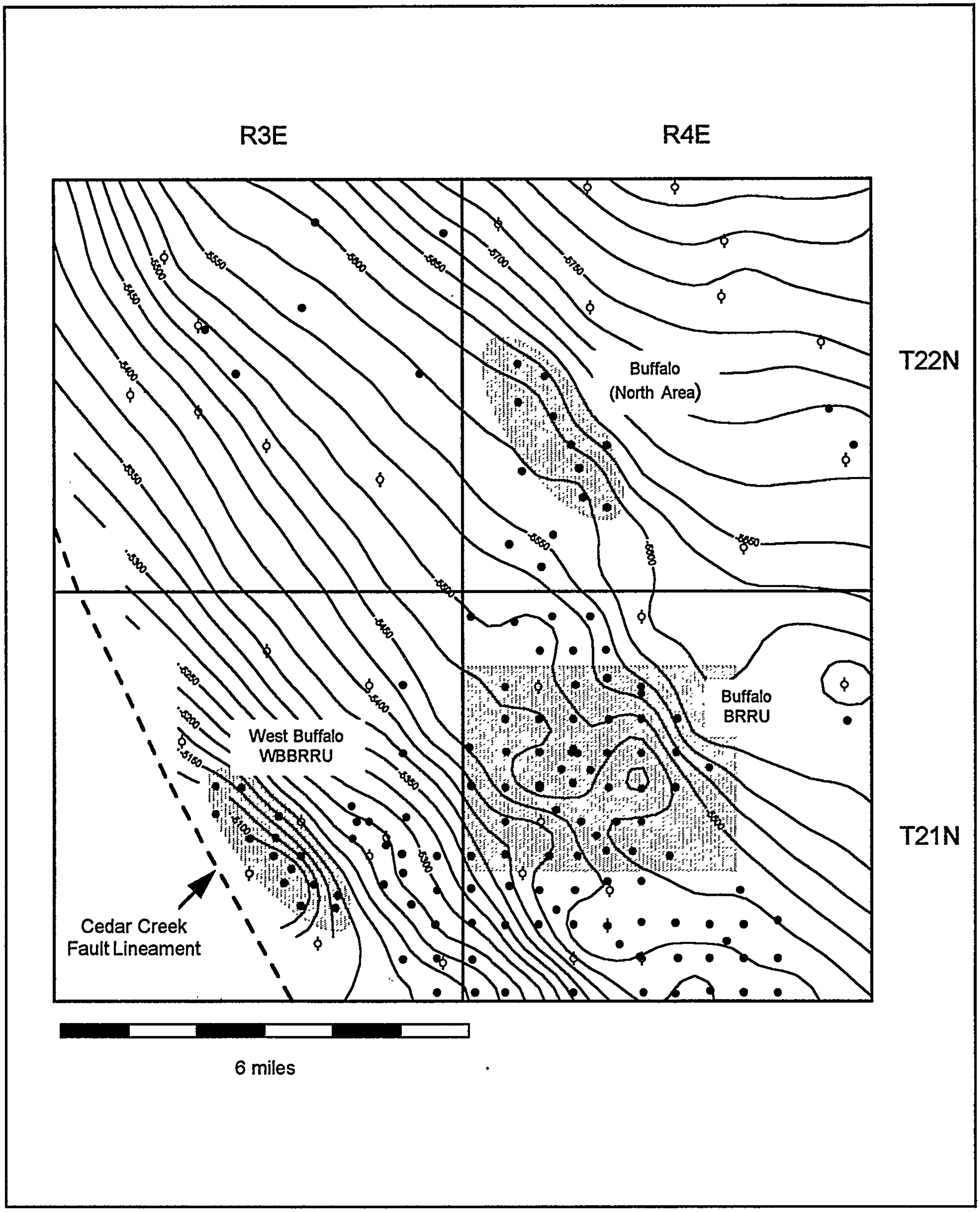

Figure VI-3: Map showing location of secondary projects in the Buffalo Field. The BRRU is an air-injection project. The WBBRRU is a water-injection project.

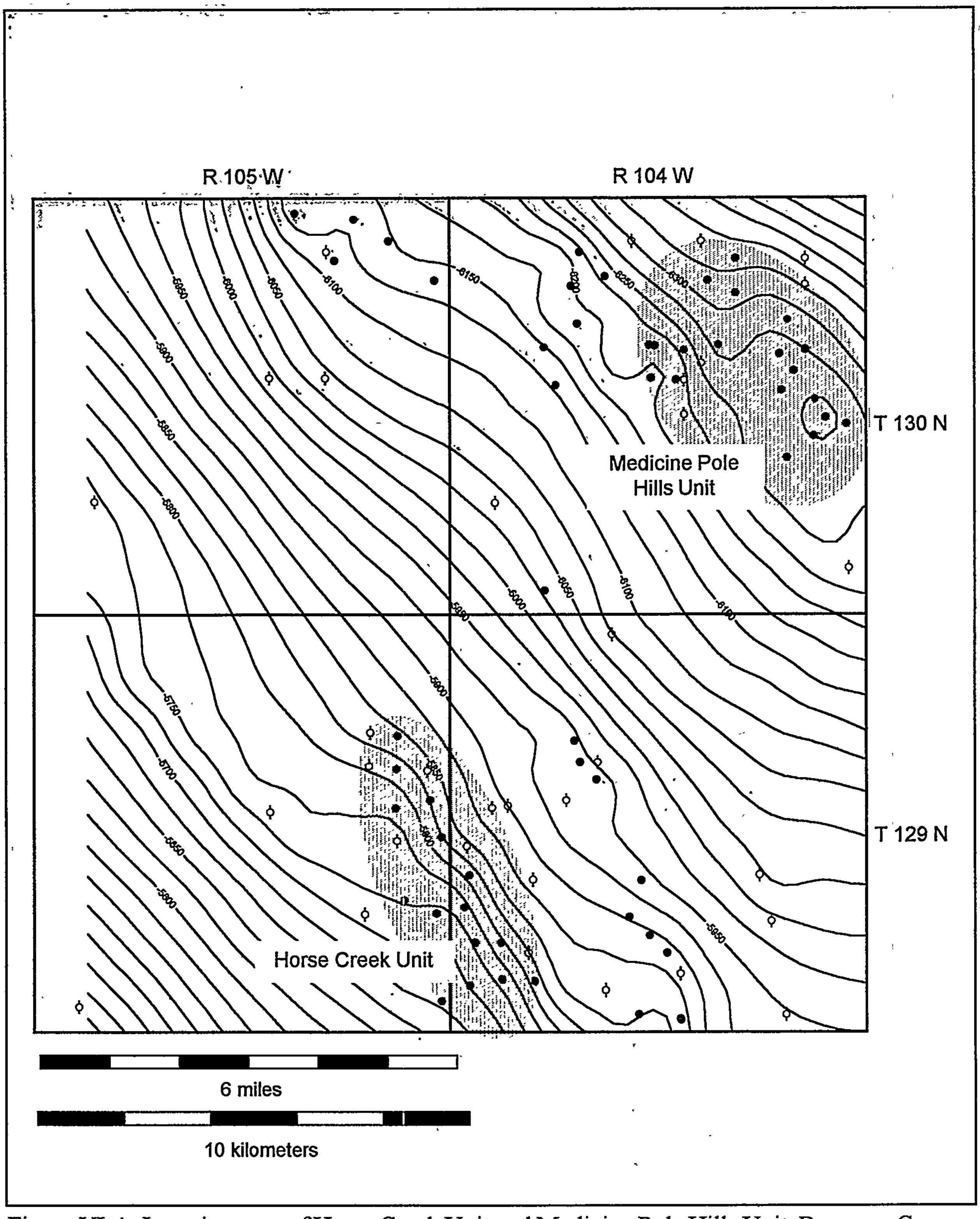

Figure VI-4: Location map of Horse Creek Unit and Medicine Pole Hills Unit, Bowman Co., ND. Structure contours are on top of Red River. Both units are air-injection projects.

Engineering Evaluations
Buffalo (Red River 'B') Field - Demonstration Area

Introduction

Engineering studies were performed for evaluation of horizontal drilling and waterflooding in the northern portion of Buffalo Field, Harding Co., SD (Fig. VII-1). Luff Exploration Company has petitioned the South Dakota Oil and Gas Conservation Board for a hearing in June 1996, to drill a horizontal well in section 20, T. 22 N., R. 4 E. Luff Exploration will commence drilling the well after the Board grants approval and arrangements can be made for necessary equipment and services. Re-processed 2D seismic data will be used to guide placement and trajectory of the lateral. The horizontal well will test water injectivity and is to be drilled mid-way between two existing wells in section 20. These wells are spaced on 320-acre production units. The horizontal injection well and two producers will comprise a pilot waterflood for the Red River 'B' reservoir.

Background

There is only one waterflood project in the Red River in Bowman Co., ND and Harding Co., SD area of the Williston Basin. This project has responded poorly to water injection and is concluded to be economically marginal to date.

Computer Simulation for Waterflooding

A computer simulation study was performed to determine the potential recovery by water injection and evaluate the effectiveness of various injection patterns in the Red River 'B reservoir in the Buffalo Field (North Area) in Harding Co., SD. The simulator BoastII was used for this study. The study indicates that a secondary to primary production ratio of greater than one is technically feasible; however, more wells and improved completion efficiency are needed to effectively and economically waterflood this reservoir. Incremental secondary oil of over 1,000,000 bbl is indicated from the acreage allocated to the six wells operated by Luff Exploration in the Buffalo Field (North Area). Seven models were evaluated for different well configurations using the same reservoir description.

1) Remaining primary with no additional development
2) Conversion of alternating existing wells to water injection
3) Infill of new wells on 160-acre patterns for water injection
4) Infill horizontal injection well
5) Infill horizontal production well
6) Two horizontal producers with three horizontal injectors
7) Three horizontal producers with two horizontal injectors

The simulation runs were limited to 15 years future production. Table VII-1 is a summary of recoveries from the simulation studies.

Simulation models were constructed and matched to historical production from the Stearns O-20 and Stearns F-20 wells located in section 20, T. 22 N., R. 4 E. This area has been selected for a pilot waterflood. The reservoir rock data used in the models are based on electrical logs, cores and drillstem tests. A porosity log of the Red River is shown in Figure VII-2. Reservoir fluid data used in the models are from correlations. Selected reservoir and fluid properties are shown in Table VII-2.

Single-layer models were constructed in a 9 by 19 rectangular grid. The distance between the Stearns O-20 and F-20 wells was fixed at 2500 ft. Key variables in the history matching process are listed below.

1) Water saturation
2) Pore volume
3) Permeability
4) Bubble-point pressure

Water saturation was adjusted to produce a match of water production. The current water-oil ratio is approximately 1.0. Pore volume was adjusted by changing the width of the model. The final model area was 4750 ft by 5283 ft (576 acres) and is shown in Figure VII-3. Thickness and porosity do not vary significantly between wells and were constrained to the average from electrical logs. Permeability and bubble-point pressure were adjusted to match the rate and decline character of the historical production data. Permeability (k) of 8 md and permeability-thickness (kh) of 80 md-ft produced a good production-match and are in close agreement with mean permeabilities from cores in the Buffalo Field. The Sohio-State B-29 core has a kh of 52 md-ft and the Stearns M-17 core has a kh of 153 md-ft. The models were structurally flat and isotropic.

An important issue regarding the waterflood potential of the Red River "B" at North Buffalo is whether reservoir water saturations and producing water-oil ratios are too high for additional oil recovery by waterflooding. Fortunately, there are water-oil relative permeability studies from several core samples in the Buffalo Field. Oil and water relative permeability curves were constructed from the average of these data and used in the models.

Another important issue is the injectivity of water through a vertical well into the Red River 'B' reservoir. At the West Buffalo 'B' Red River Unit waterflood unit, water injection has been discouragingly low with an average rate of approximately 50 bwpd per well. An injectivity test performed in April 1995, in the Buffalo Field (North Area) is more encouraging. A 25-day injectivity test was performed at the Stearns A-19 well; section 19, T. 22 N., R. 4 E. During this test, water was injected at 100 bbl per day with a pressure gauge at reservoir depth. The static reservoir pressure was approximately 1474 psi and the pressure after 25 days of injection was 3622 psi. Injection rates in the computer simulation models were constrained to a maximum of 200 bbl per day (for a vertical well) based on data from the Stearns A-19 test and a maximum injection pressure of 5500 psi.

Description of Models

Model 1 is the primary-production model and is based on the production from the Stearns O-20 and Stearns F-20 wells. Refer to Table VII-1 for a summary of recoveries from the simulation studies. The well representations in the model were produced by pressure constraint at a constant flowing pressure of 200 psi. The reservoir parameters determined from history matching in this model were used in subsequent models to predict future performance of the and additional wells. The OOIP of this model is approximately 4,750,000 stock-tank bbl. Cumulative oil production from the two wells was 282,000 bbl as of December 31, 1995. This represents only 5.9 percent recovery of OOIP contacted by these wells. The remaining primary recovery of the modeled wells is 145,440 bbl over the next 15 years. This represents an ultimate recovery of 427,440 bbl or 9.0 percent of OOIP.

Model 2 is the same as Model 1 except that one well is converted to water injection at the end of history matching. Water injection was constrained to 200 bwpd based on results from the Stearns A-19 injectivity test. The model predicts an ultimate recovery of 486,567 bbl after 15 years. This represents a recovery factor of 10.2 percent of OOIP. Response time from water injection is almost 6 years because of the distance between wells and low injection rate. This model shows that waterflooding small Red River 'B' reservoirs with only two wells is doomed to economic failure without improved completion efficiency (higher injection rates) or the drilling of additional wells.

Results from Model 2 indicate the need for significantly higher injection rates before waterflooding the Red River 'B' can be economical. Model 3 represents the drilling of two additional wells for water injection. The new wells are mid-distance between the existing wells and separated by a distance of 2348 ft. Ultimate recovery from this model is 760,561 bbl or 16.0 percent of OOIP. Incremental oil production over the primary model is 333,121 bbl. The model predicts nearly 1.5 years before there will be an increase in producing rates at the existing wells and an additional 3.5 years (5.0 years total after injection starts) before peak oil rate is achieved. This model demonstrates that significant secondary oil can be produced by waterflooding, even at reservoir conditions present at North Buffalo. The model also indicates an unacceptable payout time if total injection is limited to 400 bbl per day.

Model 4 is a representation of the reservoir with a horizontal injection well. The horizontal injection well is represented by four vertical wells with rates of 200 bbl per day each or 800 bbl per day total. The equivalent length of the horizontal section is 3522 ft. The production wells are constrained to a maximum rate of 300 bbl per day of total fluid. This constraint is based on mechanical capacity of conventional beam pumping units. A much shorter response time of less than one year is achieved as a result of the higher injection rates. The time to peak oil rate is 3.0 years after injection starts. The ultimate recovery after 15 years of injection is 870,660 bbl or 18.3 percent of OOIP. This is an incremental recovery over primary of 443,220 bbl.

Model 5 is the same as model 4 except the horizontal well is used for production only. The horizontal well has four times the productivity of a vertical well but is still constrained to a maximum fluid production rate of 300 bbl per day. Remaining primary recovery after 15 years is indicated to be 315,643 bbl with the existing two wells and the horizontal well. Ultimate recovery is 597,643 bbl or 12.6 percent of OOIP. This represents an incremental recovery of 170,203 bbl over the primary production model using only the existing two wells. Production from the horizontal well is 198,147 bbl. Production from the existing wells is 401,613 bbl or 25,827 bbl less than is predicted from Model 1.

Model 6 simulates an all-horizontal well case with three injectors and two producers. Ultimate recoveries of over 25 percent are predicted after 15 years. Incremental oil of 794,630 bbl is calculated over the two-well primary case in Model 1. Water injection was limited to 800 bbl per day per horizontal injector. Fluid production was limited to 300 bbl per day at producing wells. The production limit is based on mechanical limits of conventional rod-and-beam pumping units

Model 7 is a simulation of an all horizontal well case with two injectors and three producers. This simulation has the greatest ultimate recovery at over 26 percent of OOIP. Ultimate oil recovery is predicted to be 1,248,000 bbl. Water injection was limited to 800 bbl per day per horizontal injector. Fluid production was limited to 300 bbl per day at producing wells. The production limit is based on mechanical limits of conventional rod-and-beam pumping units.

Summary and Conclusions

Volumetric estimates of OOIP under the six wells in the Buffalo Field (North Area) are nearly 12,000,000 bbl. The projected ultimate recovery of these six wells by decline-curve analysis is 1,028,000 bbl. This represents 8.6 percent of OOIP. Computer simulation of a portion of this area indicates a reservoir-unit recovery factor of 9.0 percent. Reservoir simulation also indicates that total recovery of 25 percent OOIP is technically feasible after waterflooding. Total possible reserves for the 1920-acre area are placed at nearly 3,000,000 bbl. Incremental secondary reserves by waterflooding are placed at 1,972,000 bbl.

Computer simulation demonstrates that waterflooding the Red River 'B' reservoir with conventional, vertical wells on 320-acre spacing will recover only marginal amounts of incremental oil over primary and the incremental cash-flow is negative. For waterflooding of the Red River 'B' reservoir to be economically attractive, higher density drilling is required with vertical wells on 80-acre patterns or through the use of horizontal wells. Horizontal wells may be more attractive because of less pumping equipment and surface infrastructure.

Table VII-1
Results from Simulation of Primary and Waterflood Recovery at North Buffalo

Simulation Case	Remaining Oil Mbbl	Cumulative plus Remaining Oil Mbbl	Recovery Factor of OOIP	Incremental Oil Mbbl
Model 1	143,440	427,440	9.0%	0
Model 2	202,567	486,567	10.2%	59,127
Model 3	476,561	760,561	16.0%	333,121
Model 4	586,660	870,660	18.3%	443,220
Model 5	313,643	597,643	12.6%	170,203
Model 6	938,070	1,222,070	25.7%	794,630
Model 7	964,000	1,248,000	26.3%	820,560

Table VII-2
Reservoir and Fluid Properties from the Red River 'B' at Buffalo Field, Harding Co., SD

Reservoir Item	Value	Reservoir Item	Value
Porosity	20%	Oil API Gravity	32 °
Water Saturation	38%	Solution Gas (initial)	292 cf/bbl
Thickness	10 ft	Oil Viscosity (initial)	0.892 cp
Absolute permeability	8 md	Water Viscosity (initial)	0.320 cp
Initial Pressure	3,150 psi	Bubble Point Pressure	1,400 psi

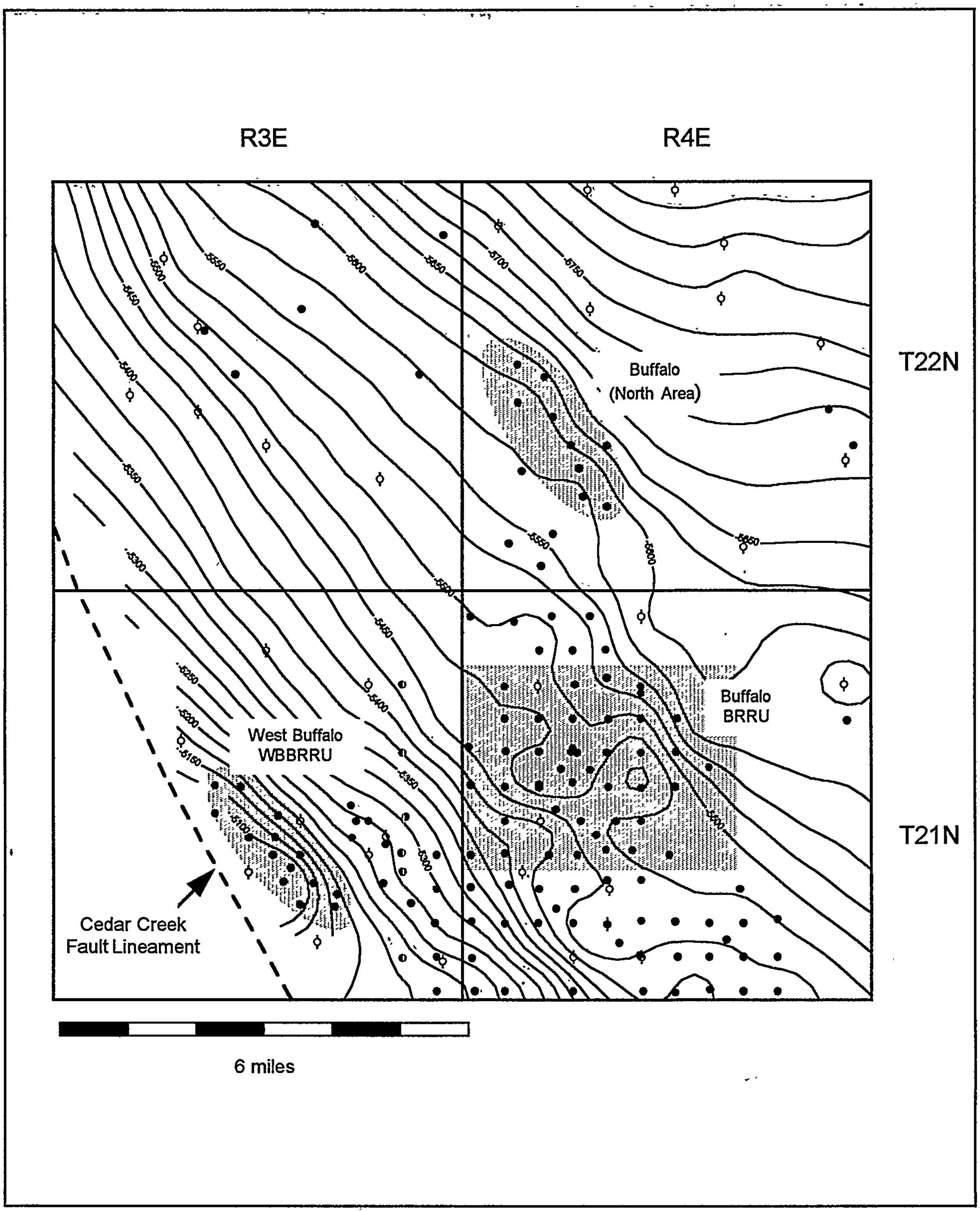

Figure VII-1: Map of the Buffalo Field, Harding Co., SD.

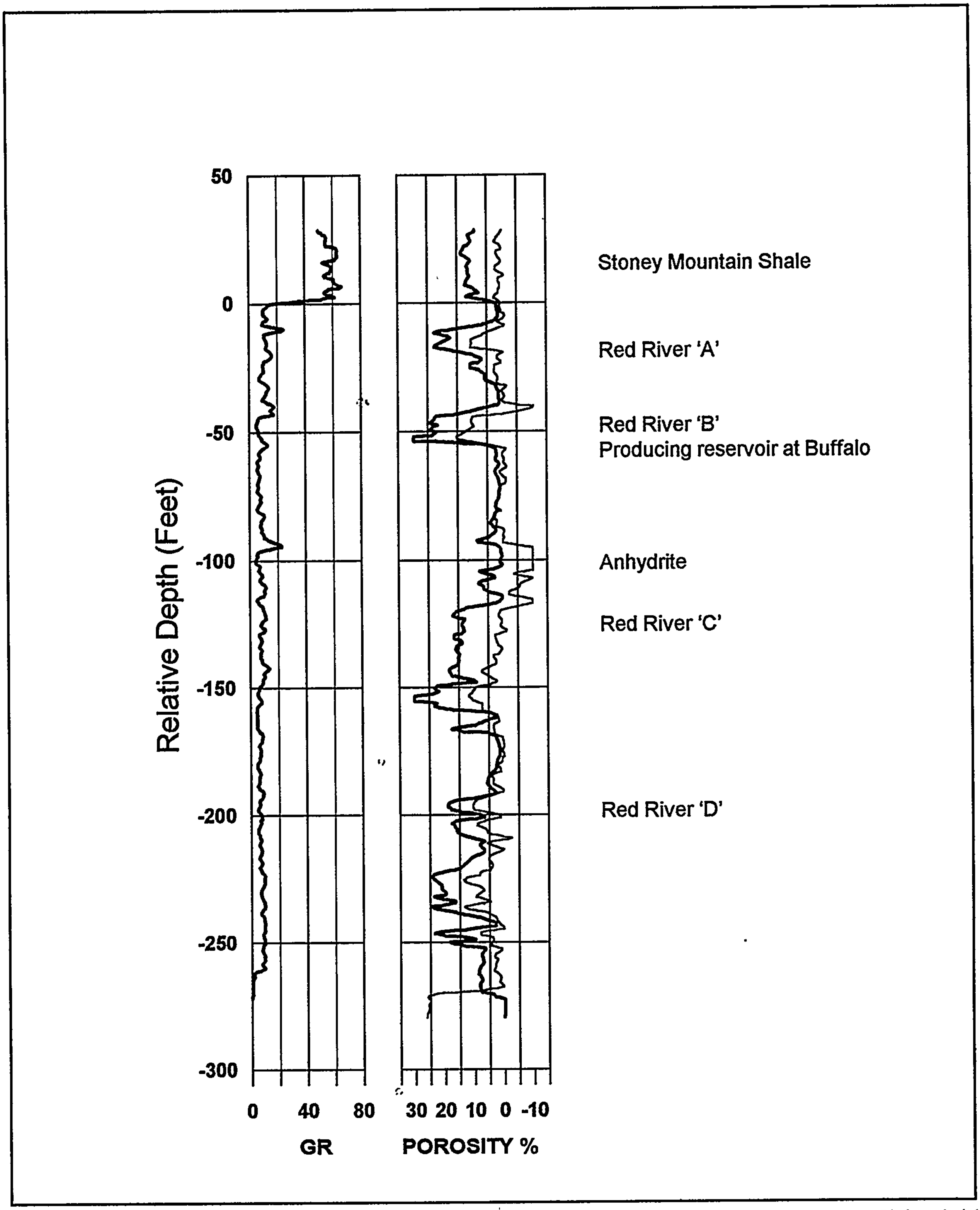

Figure VII-2: Red River type log with annotated porosity benches. All wells in the Buffalo Field produce from the Red River 'B' zone.

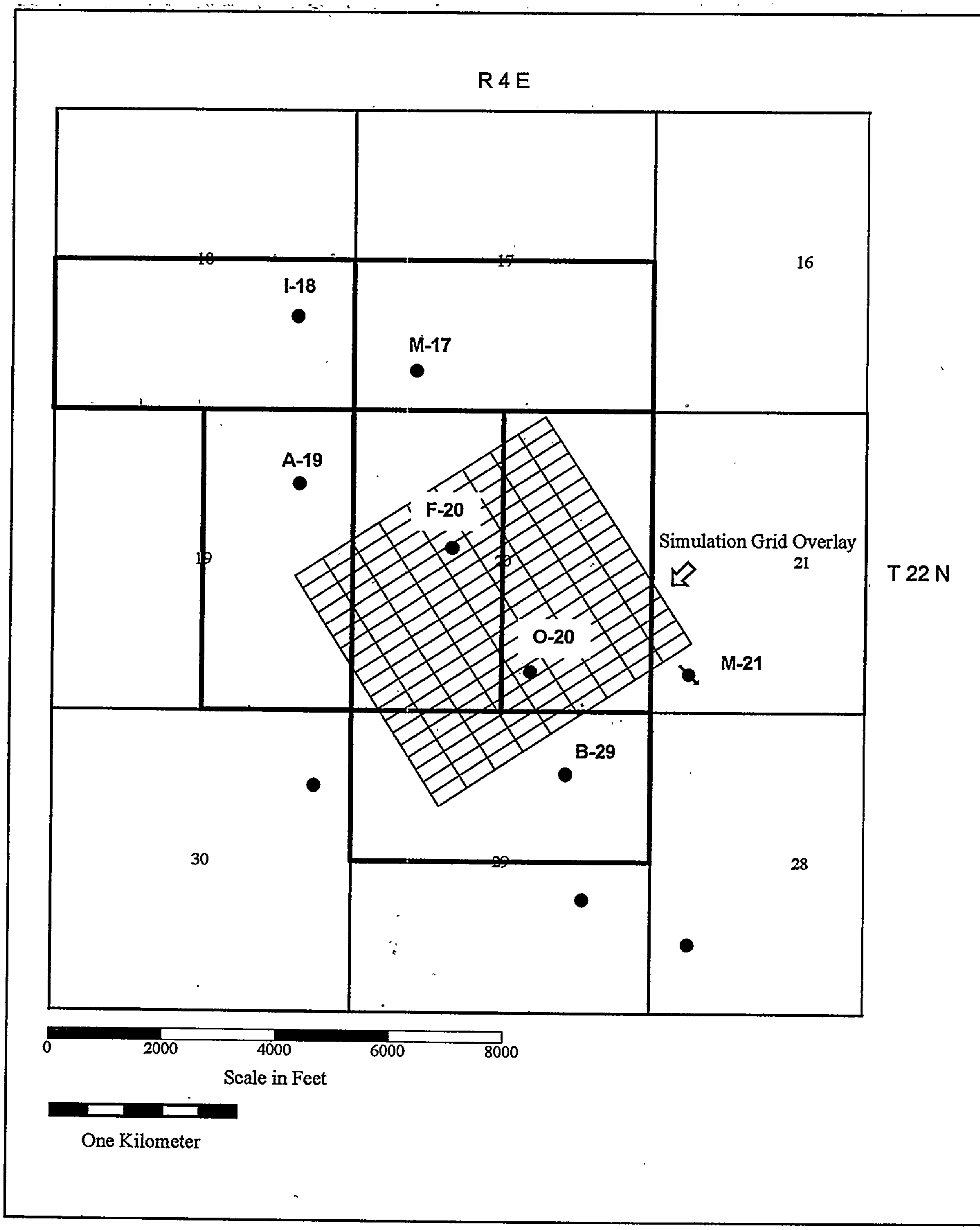

Figure VII-3: Map of Buffalo Field (north area) with simulation grid.

Engineering Evaluations Ratcliffe - General

Introduction

Engineering evaluations of the Ratcliffe show that the reservoir can develop sufficient reserves and productivity to justify drilling; however, the expected or mean Ratcliffe completion does not. This section summarizes stimulation practices, productivity and reserves for Ratcliffe completion in northeast Richland Co., MT (Fig. VIII-1).

Background

Production from the Ratcliffe Member of the Charles Formation in northeast Richland Co., MT has evolved as a consequence of deeper drilling objectives, primarily the Ordovician Red River Formation. Problems encountered in Ratcliffe completions include rapid production decline and low ultimate recovery. Salt precipitation in perforations and production equipment is a continual problem and treatments with fresh water down the tubing-casing annulus are routinely performed on most wells. While considerable improvements in producibility of the Ratcliffe have been achieved through proppant fracturing since the 1980's, the average expected ultimate recovery is perceived as less than is necessary to economically justify drilling as a single-completion reservoir target. Ratcliffe completions must have an expected ultimate recovery of greater than 160,000 bbl (after risk analysis) and stabilized initial production of greater than 100 bopd to justify drilling. Before significant additional development can occur in the Ratcliffe in northeast Richland Co., MT , more effective completion methods must be developed in conjunction with better prediction of areas with favorable reservoir development. The location of reserves is dependent on seismic interpretation methods, understanding structural influences on fracturing and depositional factors relating to porosity development. Improved completion technology includes horizontal drilling from new and existing wellbores.

The Mississippian-age Madison Group is present throughout the Williston Basin. The Madison Group is commonly divided, in ascending order, into the Lodgepole, Mission Canyon and Charles formations. The Ratcliffe interval is a lower member of the Charles and is found at an average depth of 8900 ft in the study area (-6775 ft subsea). The Ratcliffe interval consists of approximately 79 ft of limestone, dolomite and anhydrite beds (Fig. VIII-2). The top of the Ratcliffe is an anhydrite cap with an average thickness of 62 ft. The Midale interval is below the Ratcliffe and consists of 70 ft of argillaceous limestone. This zone is tight and non-productive with exception of a few feet of porosity which occasionally develops at the transition between the upper Midale and lower Ratcliffe. The upper Mission Canyon lies below the Midale interval and is also referred to as the Nesson or Rival. The upper Mission Canyon consists of low-porosity dolomitic limestone.

Most Madison Group oil reservoirs in the Williston Basin are described as being stratigraphically trapped with significant natural fracturing (Cramer 1984; Hendricks 1988). Oil reservoirs are further categorized either as hydrocarbons existing in fractured matrix porosity or hydrocarbons existing in a natural fracture system with negligible matrix porosity. Reservoir permeability and porosity are significantly related to fractures.

Oil production from Madison Group rocks in the study area has been established from both Ratcliffe and upper Mission Canyon intervals. The majority of the production, however, is attributed to the Ratcliffe interval. This conclusion is reached from drillstem test results and porosity development on electrical logs. Upper Mission Canyon completions do not appear to be commercial alone and are always commingled with the Ratcliffe. Productive limits of the Ratcliffe in the study area are not well understood but are related more to porosity and fracture development than structural position.

Reservoir Fluid Characterization

The Ratcliffe produces a paraffinic, slightly sour crude oil with a gravity from 32° to 35° API. The produced gas-oil ratios in the area vary from 300 to 600 scf/bbl. The associated gas has an average specific gravity of nearly 1.0 with heating value of about 1400 BTU/ft^3. Produced water is a saturated brine with total dissolved solids in excess of 300,000 mg/l. A summary of oil PVT from the Iversen No. 2-2 (section 2, T. 25 N., R. 58 E.) is shown in table VIII-1.

Characterization from Drillstem Test

Analysis of drill-stem tests indicate that the Ratcliffe and upper Mission Canyon are typically damaged during drilling. In the Glassbluff-Elk area, McKenzie Co., ND, (located approximately 20 miles east in T. 151-152 N. and R. 101-103 W.) it was reported that 90 percent of the drillstem tests indicated skin values from +6 to +63 (Cramer 1984). It was concluded that the formation damage was related to drilling mud deeply penetrating the fractures which resulted in permeability plugging. Calculations of formation permeability range from 0.3 to 2.0 md. Drillstem tests in the Ratcliffe are generally run with a two or three hour final-open flow period. Recoveries are usually less than 1000 ft of oily mud-emulsion with some water. In many tests, reservoir fluid does not rise above the drill collars and fluid recovery is less than 3 bbl. Storage and after-flow usually dominate the entire character of the shut-in pressure data. It is not possible to accurately calculate transmissibility and skin in most tests, but a qualitative assessment can be made of transmissibility at less than 5 md-ft/cp and skin values ranging from +10 to greater than +30. The permeability is estimated at about 0.1 md (to reservoir oil) from tests such as these. The maximum transmissibility from drillstem tests of the Ratcliffe in the Richland study area is 50 md-ft/cp, but these test results are rare. Prospective Ratcliffe intervals are judged by the presence of oil in the pipe recovery and sample chamber and also the amount of free water. High pressure gradients, calculated from shut-in pressure data, are also used to identify better completion prospects in the Ratcliffe.

Characterization from Cores

Data from three Ratcliffe cores were evaluated from Nohly and Cattails fields in the Richland County study area. Air permeability data have a geometric mean of 0.22 md with a range from 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 are reported from cores in the Cattails and Nohly fields. While this represents a small sample of Ratcliffe rock, the values of porosity and permeability are consistent with a 10-core study in the Glassbluff-Elk area of McKenzie Co., ND. The Glassbluff-Elk study reported poor correlation between permeability and porosity in Ratcliffe and upper Mission Canyon intervals. Normal porosity was described as 11 percent with permeability of less than 0.1 md.

Characterization from Electrical Logs

Density-neutron porosity logs from 22 wells in the Richland study area were analyzed in the Ratcliffe interval for net-pay thickness and porosity-feet. The mean net-pay thickness is 18 ft with a range from 9 to 28 ft at one standard deviation. Porosity-thickness ranged from 78 to 250 percent-feet with a mean value of 164 percent-feet.

In the Glassbluff-Elk area study, it was reported that full log suites can provide useful information in determining pay zones of primary and secondary porosity, but predictions of productivity and precise calculations of water saturation cannot be made because of the fractured nature of the reservoir and subsequent invasion of drilling mud.

Stimulation Practices

Stimulation is normally required to successfully complete a well in the Ratcliffe (Woo and Cramer 1984). Low efficiency slick-oil and gelled-water treatments were unsuccessfully applied to Madison reservoirs during the 1950's and 1960's. In the 1970's, acid systems using 15% and 28% hydrochloric acid were more successfully applied. The moderately high reservoir temperature of 220-245°F (104-118° C) and other factors prevent deep penetration in the formation. Since the reservoir rock is highly soluble in hydrochloric acid at these reservoir temperatures, the chemical reaction is complete in seconds and rock removal is limited to a few feet from the wellbore. A high initial production rate was followed by a rapid decline after large acidizing treatments. During the 1980's, many previously pad-acidized wells were proppant fractured with a cross-linked guar system. High fluid leak-off was determined to be an obstacle to successful treatments where the main source of fluid loss was identified as secondary fracture systems that open adjacent to the induced fracture. Significant advances were made in designing proppant-fracture systems with fluid-loss control during this decade. Fluid-loss control systems were developed using mixtures of silica flour and 100-mesh sand or oil-soluble resin and 100-mesh sand. The large majority of the proppant used was 20/40 mesh Ottawa sand in concentrations up to 6 lb per gal. Treating rates were normally 40 bbl per minute. Typical treatments consisting of 120,000 gal and 220,000 lb 20/40 sand were reported to have fracture heights from 55 to 110 ft and computer-modeled fracture lengths from 555 ft to 1297 ft (Cramer, 1984).

In the Glassbluff-Elk area study, production rates from 9 wells (with prolonged post-completion pump testing prior to fracture treatment) were evaluated in 1984 for pre-frac and post-frac performance. This study concluded that the average oil production rate increased by 330 percent after retreating with proppant-fracture systems. Of 31 wells included in the study, there were three wells (10 percent) which did not experience a positive response to proppant fracturing. The study does not make estimates of ultimate reserves before or after stimulation treatments.

Production Response to Proppant Fracturing

A production study was made for this Richland-Ratcliffe report 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. These wells are in fields mostly in Richland Co., MT along the Montana-North Dakota border from T. 23 N. to T. 27 N. and R.

57 E. to R. 60 E. These wells were identified as having from 6 months to 18 months pumping data prior to re-stimulation with a proppant-fracture system. Production type-curve analysis after the method of Fetkovich (1980) was used to estimate stabilized production rates, reserves and productivity.

Of the 17 wells, 3 wells exhibited no improvement in stabilized long-term production trends or ultimate reserves. This represents a failure rate (or risk) of 18 percent. The total projected ultimate reserves from these 17 wells prior to re-stimulation are estimated at 1,684,000 bbl with a median recovery of 72,000 bbl per well. After re-stimulation with proppant-fracture systems, the total ultimate reserves from these 17 wells are projected at 3,150,000 bbl with a median recovery of 170,000 bbl per well. While production increases immediately after stimulation of 100 to 200 percent are frequently observed, the increase in stabilized productivity is determined to average 66 percent over pre-fracture trends. Pre-fracture initial-potential rates average 43 to 48 bopd, while post-fracture initial-potential rates average 70 to 73 bopd. The mean increase in ultimate recovery is 87 percent with a median value of 71,000 bbl of incremental reserves per well. These 17 wells were completed by fracture stimulation from 1983 through 1985. The average treatment used 217,000 lb of 20/40 proppant.

Characterization from Production Data

Production history was used to characterize the Ratcliffe to establish certain baseline data for productivity, reserves and drainage area. These statistics are useful for assessing the potential for further exploitation and development of Ratcliffe oil reserves in the Richland study area.

A total of 55 completions in the Richland study area were evaluated by production type-curve analysis after the method of Fetkovich (1980) using a commercially available computer program named MIDA™. 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 11.5E-6 vol/vol/psi. Oil PVT data from the Iversen No. 2-2 well, South Otis Creek Field, section 2, T. 25 N., R. 58 E., were used for the computer simulations and MIDA™ type-curve analyses. Water saturations were also modeled to match reported water production. Water saturations of about 50 percent produced results which matched reported 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 8 bopd.

Tables VIII-2 and VIII-3 summarize production characteristics by field area. The tables show that production characteristics of Ratcliffe completions on the structural nose of the North Sioux Pass and Fairview trend are significantly poorer than those found at Cattails, Nohly and Riprap Coulee. Table VIII-2 lists mean production characteristics of Ratcliffe completions by field. The average of all Ratcliffe completions in the study area would be marginal or sub-economic as drilling targets. Table VIII-3 shows the production characteristics for each field at one standard deviation above the mean. Table VIII-3 is intended to demonstrate that the Ratcliffe can develop sufficient productivity and reserves for an economical drilling target.

Recoverable 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 18 ft for net pay thickness, 9 percent for matrix porosity, 50 percent for water saturation and an oil volume factor (Bo) of 1.282, the average oil-in-place is calculated to be 4900 stock-tank barrels per acre. The average recovery factor from contacted drainage is indicated to be 13 percent for the 55 wells in the production study. Potential recoverable oil is calculated at 637 stock-tank barrels per acre using a recovery factor of 13 percent. In a 320-acre spacing unit, the potential recoverable reserves are calculated to be 203,800 bbl. Hypothetically, the Ratcliffe can be an economical, single-zone drilling target if the risked reserves are greater than 160,000 bbl and completed-well costs are less than $700,000. This situation yields a BFIT Rate of Return (ROR) of 35% and a profit on investment (POI) ratio of 2 to 1. These economics are based on a 85% net revenue interest (NRI), monthly lease operating costs of $4000, state taxes of 13% and an oil price of $17.00 per barrel. Production parameters include a stabilized initial rate of 100 bopd, a hyperbolic exponent of 0.5 and an economic life of 13 years.

The average Ratcliffe does develop sufficient reserves in the North Sioux Pass area to satisfy the hypothetical economic situation described above. Only 40 percent of the Ratcliffe completions in the production study have projected ultimate recoveries greater than 160,000 bbl.

Summary and Conclusions

Important conclusions to be made are: 1) the Ratcliffe can develop sufficient pore-volume and oil-in-place for drilling a well in a 320-acre spacing unit and 2) productivity can be sufficient to recover those reserves economically. Problems to be addressed are locating areas where reserves are sufficient and developing completion methods which will allow efficient recovery of those reserves. The location of reserves is dependent on seismic interpretation methods, understanding structural influences on fracturing and depositional factors relating to porosity development. Completion technology includes horizontal drilling from new and existing wellbores.

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Table VIII-1
Characteristics of Ratcliffe Oil

Oil Property	Value
Oil Gravity	30° API
Temperature	215° F (102° C)
Initial Pressure	4500 psi
Initial Viscosity	0.794 cp
Initial Volume Factor	1.282 rb/stb
Bubble Point Pressure	2000 psi
Bubble Point Viscosity	0.649 cp
Bubble Point Volume Factor	1.318
Solution Gas	495 scf/stb

Table VIII-2
Ratcliffe Production Characteristics at Geometric Mean

Field or Area	Number Wells Evaluated	Initial Rate (bopd)	Permeability-Thickness kh (md-ft)	Ultimate Recoverable Reserves (Mbbl)	Contacted Drainage Area (Acre)
Cattails	13	80	12.1	109	173
Fairview	7	38	4.9	29	90
Nohly	9	97	19.3	224	272
North Sioux Pass	11	55	5.8	64	154
Riprap Coulee	5	59	7.6	217	326
Total Study	55	67	10.0	102	186

Note: Characteristic values represent the expected case per completion. Contacted area is based on net thickness of 18 feet, porosity of 9% and water saturation of 50%.

Table VIII-3
Ratcliffe Production Characteristics at One Standard Deviation Above the Mean

Field or Area	Number Wells Evaluated	Initial Rate (bopd)	Permeability-Thickness kh (md-ft)	Ultimate Recoverable Reserves (Mbbl)	Contacted Drainage Area (Acre)
Cattails	13	143	21.1	258	267
Fairview	7	67	7.0	92	190
Nohly	9	172	38.5	316	362
North Sioux Pass	11	90	10.3	211	394
Riprap Coulee	5	92	10.1	288	437
Total Study	55	129	21.3	300	339

Table VIII-4
Customary to Metric Conversion Factors

Quantity	Customary Unit	Conversion Factor	Metric Unit
Length			
	inch	2.5400	cm
	feet	0.3048	m
	mile	1.6093	km
Area			
	acre	0.4047	ha
	sq mi	2.5900	sq km
Volume			
	gal	3.7854	liter
	acre-feet	1.2335E+3	m^3
	bbl	0.15899	m^3
Pressure			
	psi	6.895	kPa
Temperature			
	°F	(°F-32)/1.8	°C
Oil Gravity			
	°API	141.5/(131.5+°API)	gm/cm^3
Permeability - k			
	md	9.8692E-4	μm^2
Viscosity - μ			
	cp	0.0010	Pa-s
Transmissibility - $kh/\mu B$			
	md-ft/cp	3.0081E+5	μm^3/Pa-s

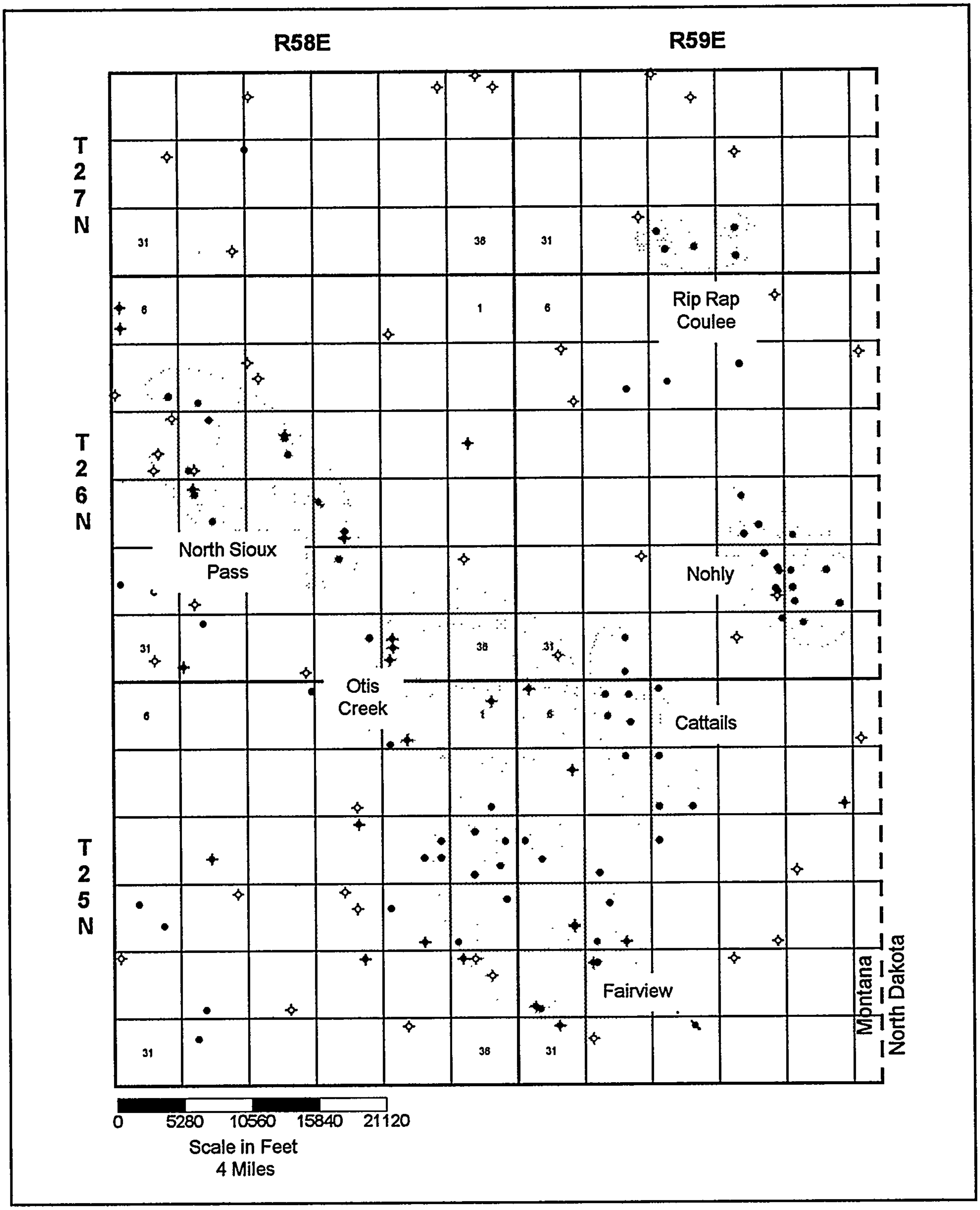

Figure VIII-1: Map of Ratcliffe study area, Richland Co., MT.

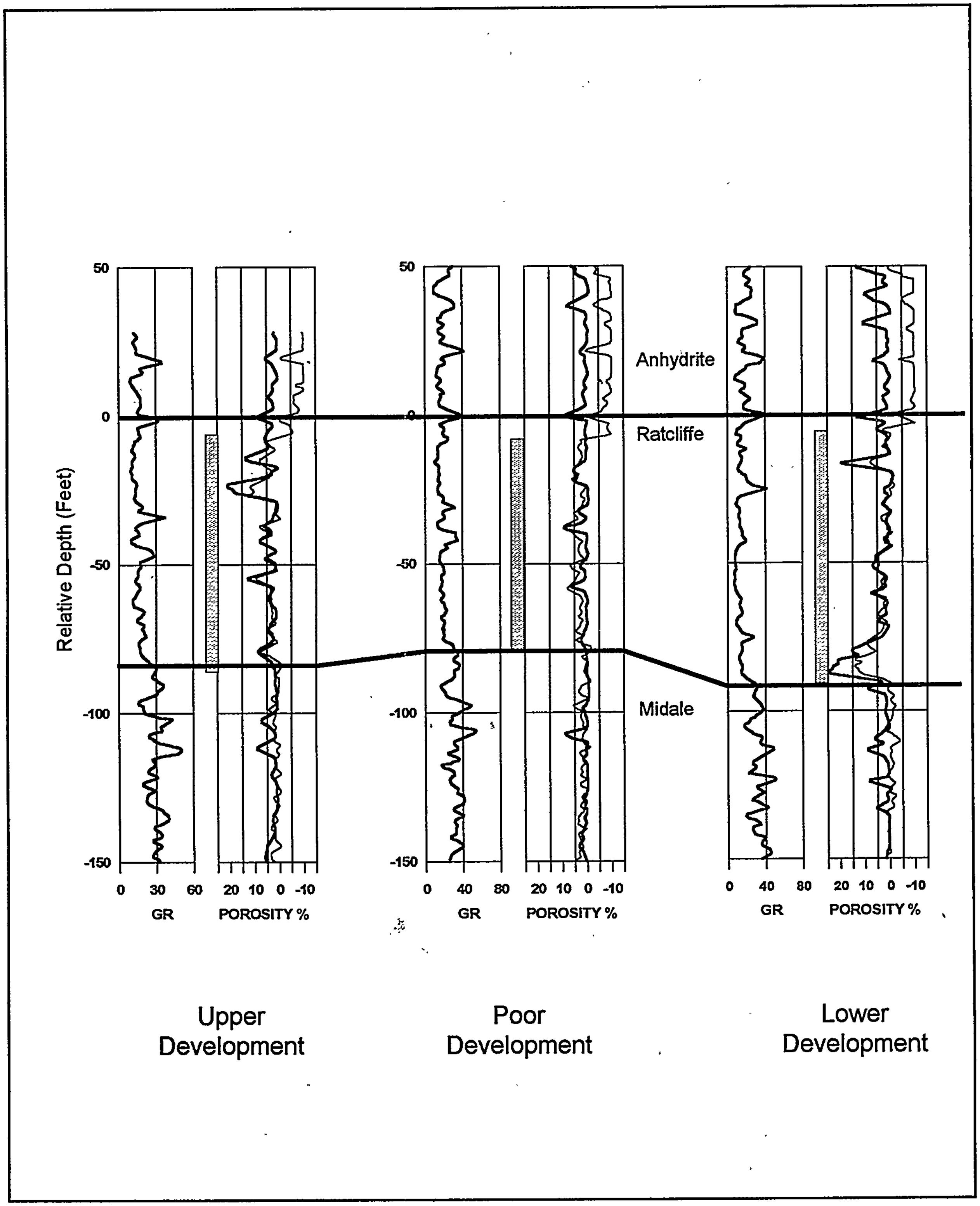

Figure VIII-2: Type-log cross-section for Ratcliffe reservoir interval.

Engineering Evaluations
North Sioux Pass (Ratcliffe) - Demonstration Areas

Introduction

After reviewing production performance and well/lease status, three areas were identified as the best prospects for testing horizontal completion technology. Additionally, a pair of wells are identified which could be used for testing water injectivity and secondary recovery if horizontal completions are successful. The potential additional reserves from each horizontal completion is placed at 100,000 bbl.

In addressing completion technology, there are three areas in the North Sioux Pass Field which offer good potential for testing horizontal completions as a method to efficiently recover Ratcliffe reserves. If horizontal completions prove to be effective and without significant mechanical risk, there is a good probability that a large area and volume of oil could be exploited in the North Sioux Pass area and elsewhere in the greater Richland study area. A map showing candidates for horizontal completion is found in figure IX-1.

Horizontal Candidate Area 1

Trudell M-17 SW/4, section 17, T. 26 N., R. 58 E., API No. 25-083-21808

The Trudell M-17 well was re-completed in the Ratcliffe from 8701 to 8759 ft in March 1993. The Ratcliffe was hydraulically fractured with 105,000 gal and 204,000 lb 20/40 sand with a maximum proppant concentration of 7 lb per gallon. The peak pumping rate after stimulation was 70 bopd and 80 bwpd; however, the production rate quickly declined. Cumulative oil production was 17,198 bbl as of July 1995, when the well was producing approximately 15 bopd and 25 bwpd. The Ratcliffe completion in the Trudell M-17 well has been a disappointment. The good porosity development on logs and modern fracture technology held promise for a much better completion in the Ratcliffe.

A 14-day pressure buildup test was performed in December 1994. The final bottomhole pressure was 1132 psi and static reservoir pressure is interpreted as 1423 psi. The Ratcliffe interval was drillstem tested in October 1992, with an extrapolated shut-in pressure of 3764 psi.

The pressure drawdown at the Trudell M-17 well is an enigma. Estimates of drainage using computer simulation and production type-curves indicate a limited drainage area of only 56 acre and recoverable reserves of 29,000 bbl. However, it can be concluded from drillstem and electrical log data from other nearby wells that the contiguous area comprised of sections 8, 16, 17 and 20 in T. 26 N., R. 58 E. may contain a continuous Ratcliffe reservoir.

The Federal No. 1-8 well (one mile north from the Trudell M-17) recorded a pressure in the Ratcliffe of 4038 psi in October 1975. The Federal D-20 well (0.25 mile south from the Trudell M-17) recorded a pressure in the Ratcliffe of 3620 psi in January 1991. The primary source of pressure depletion in the Ratcliffe is assumed to be from the Salsbury No. 2-20 well in the NWSE of section 20 (0.75 mile south from the Trudell M-17). The Salsbury No. 2-20 was completed in the Ratcliffe and upper Mission Canyon in 1978. Two other Ratcliffe completions are in Section 16, approximately 1.5 mile east.

The potential reserves to be exploited by testing a horizontal completion can be estimated from the average OOIP for a 160-acre drainage area and a recovery factor of 13 percent.

Incremental reserves are estimated at approximately 70,000 bbl after subtraction of 29,000 bbl expected to be recovered from the current completion.

Horizontal Candidate Area 2

State No. 2-16	section 16, T. 26 N., R. 58 E., API No. 25-083-21418
State Pass 16-1	section 16, T. 26 N., R. 58 E., API No. 25-083-21725

The State No. 2-16 was completed in the Ratcliffe (8924-8969 ft) in 1982 with an initial pumping rate of 70 bopd and 60 bwpd. The completion interval was treated with 20,000 gal 15% hydrochloric acid and gel pad. Cumulative oil production was 107,876 bbl as of December 1995. The well is currently shut-in.

The Ratcliffe from the State No. 2-16 produced with a shallow production decline. Analysis of the production data by computer simulation and production type-curve methods suggest a large drainage volume with original-oil-in-place which may be greater than 5,000,000 bbl.

The State No. 2-16 well is offset at a distance of approximately one-quarter mile by the State Pass No. 16-1 well which was re-completed in the Ratcliffe in August 1992. There is inference that the two wells are in pressure communication from the fact that the State No. 2-16 production dropped steeply following the completion of the State pass No. 16-1 well. Cumulative oil production from the State Pass No. 16-1 well was 40,355 bbl as of July 1995.

The State No. 2-16 well is an attractive candidate for testing a lateral completion for two reasons. The first reason is the potentially large oil-in-place that will be unrecovered with the existing condition of the well. The well has been shut-in for over a year with a pump stuck from halite deposition. The second reason is that the proximity of the two wells provides an opportunity to test secondary recovery by water injection. A waterflood pilot could be attempted if the lateral completion improved completion efficiency and further testing proved good communication between these wells.

The potential reserves in section 16 to be exploited by improved completion efficiency from lateral completions is estimated at 218,000 bbl. The potential recoverable reserves under Section 16 are estimated at 408,000 bbl using a recovery factor of 637 bbl per acre (determined from this Richland-Ratcliffe regional production study) and 640 acres. The combined cumulative recovery from the State No. 2-16 and State Pass 16-1 is approximately 148,000 bbl. Remaining reserves from the State Pass 16-1 well are estimated to be 42,000 bbl.

Horizontal Candidate Area 3

Salsbury No. 1-22A	section 22, T. 26 N., R. 58 E., API No. 25-083-21593
Salsbury No. 1-27	section 27, T. 26 N., R. 58 E., API No. 25-083-21509

The Salsbury No. 1-22A was completed in the Ratcliffe and upper Mission Canyon from 8931 to 9332 ft in October 1982. This completion has produced a cumulative of 127,266 bbl as of September 1995, and is still producing over 20 bopd. Projected ultimate recoverable reserves are placed at from 243,000 to 310,000 bbl. It is unlikely that the current completion will be able to recover all these reserves because of the limits of useable wellbore life expectancy.

The Salsbury No. 1-27 was completed in the Ratcliffe and upper Mission Canyon from

8953 to 9464 ft in September 1981. This completion has produced a cumulative of 85,290 bbl as of December 1994, when it was producing 12 bopd. Projected ultimate recoverable reserves are placed at from 116,000 to 142,000 bbl.

The combined original-oil-in-place attributed to this pair of wells is 3,400,000 bbl based on history matching by computer simulation. Cumulative recovery to-date is approximately 215,000 bbl or only 6 percent of the OOIP. Using the typical Ratcliffe recovery factor of 13 percent, there is potential for an additional recovery of 238,000 bbl. These potential reserves justify attempting to improve productivity by means of horizontal completion.

Summary and Conclusions

There are several Ratcliffe completions in the North Sioux Pass field which demonstrate a large potential resource but low productivity despite hydraulic fracture stimulation. Three areas have high potential for horizontal re-entry drilling. The potential additional reserves from each horizontal completion are placed at 100,000 bbl.

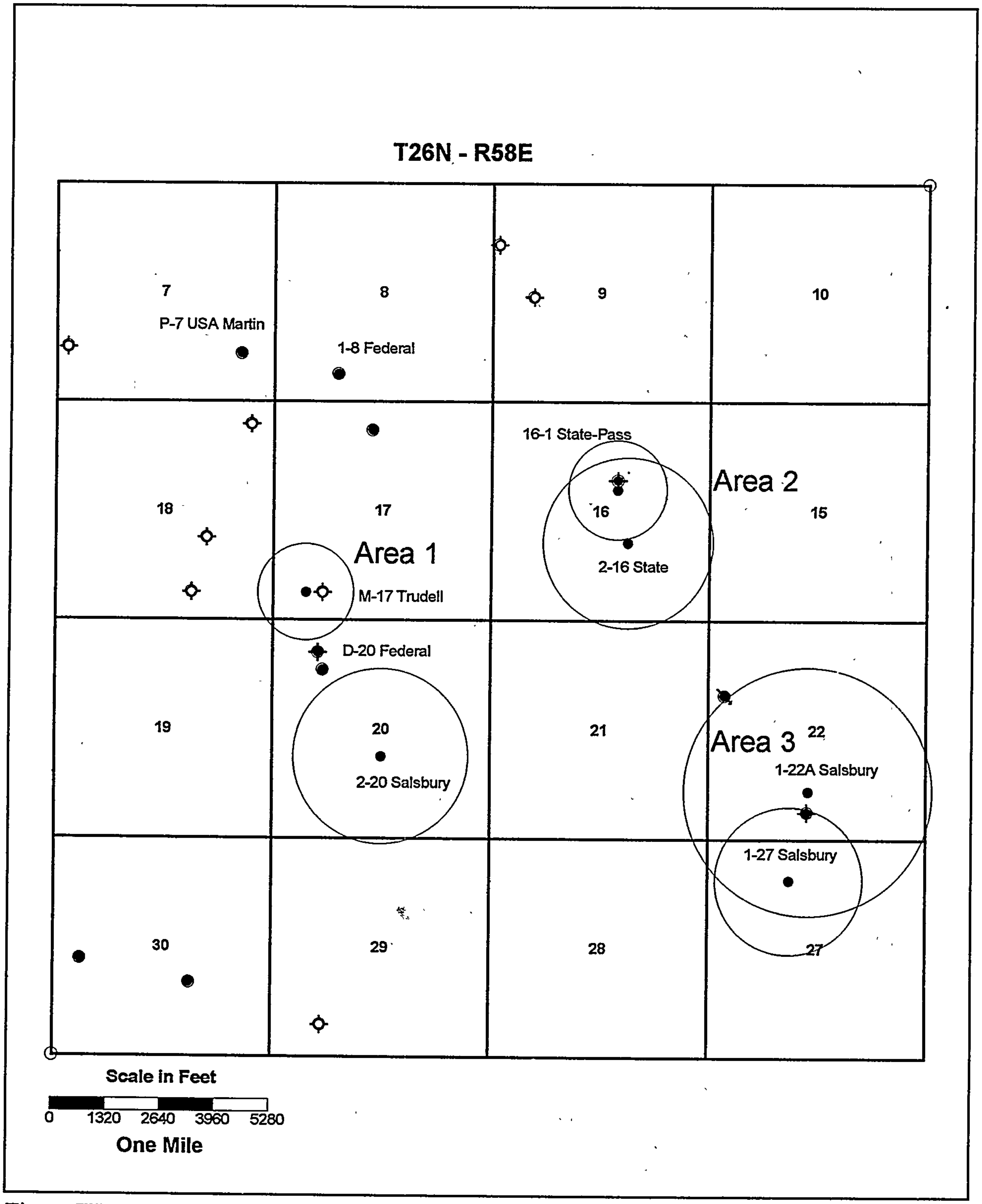

Figure IX-1: Map of candidate areas for field demonstrations in the Ratcliffe. Drainage areas of current Ratcliffe completions are shown as circles.

Recovery Technology Evaluations

Introduction

A basic premise of this project is that Ratcliffe and Red River reservoirs can produce more oil, either by primary production or application of enhanced recovery technologies. Before a significant number of new wells can be drilled for infill or enhanced recovery, better completion efficiency (productivity) needs to be demonstrated. Improved completion technolgy has focussed on lateral-drilling and jetting-lance systems. Several technologies for lateral completion from cased wells (horizontal re-entry) have been investigated. One ultra-short-radius lateral drilling system (USRLDS) is oriented, but not steered, and was described by Warren et al. (1993). The bottom-hole assembly has evolved from using articulated drill collars to the use of carbon-fiber pipe for ultra-short-radius curves of 30 to 45 ft. Instustry standard 2-7/8 inch high-grade steel pipe with Hydril PH-6 connections is used for short-radius drilling (70 to 100 ft radius). Another sytem for short-radius horizontal re-entry drilling uses down-hole steered motors with wet-connect wireline technology or MWD mud-pulse technology for steering. A third technology for short-radius re-entry drilling utilizes coiled tubing and steered downhole motors. Coiled tubing operations are prohibitively expensive in the Williston Basin unless the cost to mobilize the special equipment can be distributed over a multi-well program (10 or more wells).

The USRLDS system initially appeared attractive from a cost viewpoint. The steered motor technology is more expensive, but has several advantages. Steered-motor lateral drilling systems (SMLDS) have proved better than other horizontal re-entry technologies, particularly at depths greater than 6000 ft. SMLDS is capable of greater horizontal reach (2500 ft versus 1000 ft for the USRLDS system) and is steerable, which provides more control of trajectory and final bottom-hole location.

The project also investigated extended-reach jetting technology from cased wells as a means for improved completion efficiency. Further efforts to use extended-reach jetting technology have been abandoned because the tools have not functioned properly at depths of 9500 feet and bottom hole temperatures of 230° F (102° C).

Attention is also focussed on newly drilled wells intended for horizontal completion. There has been increased drilling activity in the northwestern portion of Bowman Co., ND and it has extended south and east into portions of the project demonstration area. Operators involved in this drilling activity have utilized medium-radius horizontal wells from surface for the Red River 'B' zone.

Short-Radius Horizontal Re-entry Wells

The drilling of a horizontal re-entry into the Ratcliffe was unsuccessfully attempted in the Trudell M-17 (Section 17, T. 26 N., R. 58 E., Richland Co., MT). The desired horizontal lateral was less than 1000 ft, and the acceptable azimuth window for the horizontal trajectory was reasonably wide. Therefore, the USRLDS system was used in an attempt to keep total cost below $150,000. High-grade 2-7/8 inch steel pipe with Hydril PH-6 connections was selected instead of carbon-fiber pipe for the curved portion of the wellbore, since the desired radius was in the range of 80 to 100 ft. The casing exit was successfully achieved by setting a retrievable whipstock and milling a window in the side of the casing and cement sheath. However, the USRLDS bottom-hole directional drilling assembly failed immediately after initiating the curved section of the planned horizontal hole. An immediate side-track attempt was contemplated, but not pursued. The wellbore is idle with the whipstock and casing window intact for possible re-entry with SMLDS technology.

After a review of the Trudell M-17 horizontal re-entry operation, it is concluded that USRLDS is a technology still in development and will likely be restricted to depths shallower than 6000 ft. The actual cost differential between the USRLDS and SMLDS (provided by several vendors) is significantly less than initially estimated. The unusually cold weather during drilling operations at the Trudell M-17 contributed to some cost over-runs, but did not contribute to the mechanical failure.

Numerous horizontal re-entries have been performed in the Red River 'B' zone west of the Red River study area with SMLDS technology. Shell Oil Company completed five short-radius horizontal re-entries in 1995, with horizontal reaches of 2000 ft to 2500 ft. Shell has completed the first re-entry of their 1996 program, with five to seven additional Red River 'B' re-entries planned. This drilling program anticipates achieving horizontal reaches of 2000 ft or more within the 10 to 15-ft Red River 'B' zone. In the horizontal portion of the hole, straight forward drilling can be achieved by rotating the drill string. Direction changes require sliding with minimal rotation and articulated-assembly mud-motor drilling.

Jetting Lance Completions

Testing of jetting-lance completion technology was performed at two wells in the Red River study area. The technology used was a commercially available 10-ft lance tool. The technology did not result in a change of production in either of the two wells. One of these wells, the Swanson No. 1-32 (East Harding Springs Field, Section 32, T. 23 N., R. 5 E., Harding Co., SD) was subsequently re-entered to evaluate whether the jetting-lance penetrations were actually open. It was determined that there were no effective penetrations after a straddle packer was used to isolate the intervals. The intervals were then re-perforated with conventional jet charges and treated with 2400 gal 15% hydrochloric acid. Previous production rates were 6 bopd and 35 bwpd. After re-perforating and acidizing, the production rate was 16 bopd and 95 bwpd. It is concluded that 10-ft jetting-lance technology is not an effective tool for improving completion efficiency or even penetrating wellbore damage at these depths or in Red River carbonate rocks.

The project had hoped to use a 50-ft jetting lance tool. Horizontal jetting lance operations with this tool at depths of 9500 ft in the Bowman-Harding Red River area demonstrated that the tool is in a developmental stage, not implementation as was initially perceived. From December 1994, through June 1995, modifications and testing of the 50-ft lance tools were made outside of project activities. The tool has worked at shallower depths where less pressure is required. The tool was brought back to the Bowman-Harding area in May 1995, but was found to be plagued by problems associated with multiple casing weights across salt sections and high-pressure requirements. Luff successfully used the jetting-lance technology to cut two 50-ft laterals at a depth of 3350 ft in a Southwestern Wyoming well during March 1996. However, success was achieved only after numerous mechanical problems.

New Medium-Radius Horizontal Wells

The Red River 'B' zone horizontal play continues to be one of the most active onshore drilling plays in the United States. Currently, there are 10 active rigs, predominantly in Bowman

Co., ND. Luff has participated in two of these wells, which had horizontal extensions of 2500 ft to 4000 ft. Activity is also occurring in Harding Co., SD and Slope Co., ND. TableX-1 presents the status for new horizontal wells as of June 1996. A smaller number of new horizontal wells have also been drilled in Fallon Co., MT, primarily in secondary-recovery units. Better production results from horizontal completions have occurred in an area northwest from the Red River study area and also within the study area in townships covering T. 130-131 N., R. 104-105 W. Tracking production performance results from new horizontal wells has been problematic since all of the wells have been treated as confidential for several months after completion. So far it has been difficult to develop rate-time production curves. However, it appears that most of the wells in northwestern Bowman Co., ND have good oil cuts, with initial oil production rates from 150 to 400 bopd.

The drilling and completion cost for new medium-radius horizontal wells is between $900,000 and $1,000,000 (a conventional, vertical well costs about $650,000 to drill and complete). The vertical-hole section is cased with 7-inch casing and medium-radius curves (400 ft to 500 ft) are then drilled using industry-standard 6-1/8 inch mud motors with MWD mud-pulse steering technology. Horizontal reaches are currently averaging over 4000 ft. Like the steered-motor re-entries, straight-forward drilling in the horizontal hole can be achieved by rotating the drill string, while direction changes require sliding with minimal rotation and bent-assembly mud motor drilling.

Summary and Conclusions

Horizontal re-entry drilling using SMLDS technology is likely the best approach for horizontal re-entries at reservoir depths within the Ratcliffe and Red River study areas. Plans have been made to employ this technology in both study areas during the next year. Electric wet-connect wireline steering technology appears to be a more reliable steering approach, although several vendors are continuing to develop small-diameter MWD mud-pulse steering for short-radius motor assemblies. As evidenced by activity near the Red River study area, drilling new medium-radius horizontal wells has become popular during the last year for developing reservoirs that are marginal or uneconomical with conventional (vertical) completions. This technology is planned in the Red River study area at Buffalo Field, Harding Co., SD for drilling and completion of a horizontal water-injection well.

References

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Table X-1
Red River 'B' Horizontal Well Status, June 1996

Well Status	North Dakota	South Dakota
Producing wells (released from confidential status)	34	2
Injection wells	0	1
Wells drilled or drilling (confidential)	43	1
Plugged or temporarily abandoned wells	1	3
Canceled drilling permits	5	1
Approved permits, not yet drilled	355	1

Field Demonstrations

Introduction

Field demonstrations for this project include 1) targeted drilling and completion using advanced seismic techniques, 2) demonstration of improved completion effectiveness with horizontal or lateral completions, and 3) pilot-waterflood injection tests. The project has identified areas and wells to perform these demonstrations. This section summarizes field demonstration activities and recommendations.

Red River Seismic

A 3D seismic survey will be acquired at Grand River School (Red River) Field in T. 129 N., R. 101 W., Bowman Co., ND during 1996. This survey will complement interpretations from the 3D survey at Cold Turkey Creek (Red River) Field in T. 130 N., R. 102 W. which was acquired in 1995.

Eight 2D-seismic lines across the North Buffalo area have been re-processed and used for locating a drilling location for a horizontal well in the Red River 'B' reservoir.

Ratcliffe Seismic

Future seismic characterizations of the Ratcliffe reservoir in Richland Co., MT will be incorporated in a 3D survey over North Sioux Pass Field in T. 26 N., R. 58 E. This survey will used dynamite for sourcing. Additional seismic efforts with multi-component (shear wave) data have been abandoned. The surface, weathered layer across the study area severely hinders the acquisition of shear-wave data. A 2D seismic line was acquired across Cattails (Ratcliffe) Field in May-June 1995. The data were processed by two companies and both were unable to recover coherent shear-wave events.

Water Injectivity Test - Red River 'B'

A water injectivitity test was performed in a vertical Red River 'B' completion in the Stearns A-19 well during May 1995. This well is located in the Buffalo Field, Harding Co., SD. Water was injected for 10 days followed by a 5-day pressure fall-off. Pressure data during the build-up and fall-off were recorded with both surface and bottom-hole gauges. The well was completed in the Red River 'B' in 1982 after stimulation by acidizing with 500 gal through perforations at 8776 to 8780 ft. The well has a cumulative production of 37,550 bbl oil and 211,678 bbl water. The data from the injectivity test indicate a transmissibility (kh/uB) to water of 28.8 md-ft/cp, a stimulation factor (S) of -2.4, and a static reservoir pressure of 1474 psi at reservoir depth. The maximum, stabilized injection rate is predicted to be 225 bbl of water per day with a bottom-hole injection pressure of 5500 psi. The original reservoir pressure in the area was about 3450 psi.

Horizontal Completion and Waterflood Pilot at North Buffalo (Red River)

Reservoir engineering studies and baseline injectivity tests have been completed in the Red

River 'B' reservoir at North Buffalo Field, Harding Co., SD. The results of this work confirm that waterflooding is technically and economically feasible but would require substantial infill drilling or the use of horizontal wells. A new horizontal well will be drilled between two vertical Red River 'B' completions in section 20, T. 22 N., R. 4 E., Harding Co., SD. This well will be completed for water injection.

Reservoir studies indicate primary recovery of only 8 to 9 percent of OOIP from the Red River 'B' at North Buffalo. A fully developed waterflood with horizontal completions is expected to recover 25 percent of OOIP. If successful, the 640-acre pilot area will be expanded to include the adjacent 1280 acres operated by Luff Exploration Company. The total OOIP immediately affected by this pilot is 12,000,000 bbl. The potential incremental recovery from a fully developed waterflood in this 1920-acre area is projected to be nearly 2,000,000 bbl.

Water Injectivity Test - Ratcliffe

A water injectivitity test was performed in a vertical Ratcliffe well in May 1996. Water was injected for 10 days followed by a 5-day pressure fall-off. Pressure data during the build-up and fall-off were recorded with both surface and bottom-hole gauges. The State No. 2-16 well was used for this test. The well was completed in the Ratcliffe in 1982 after stimulation by acid-fracturing with 20,000 gal through perforations at 8924 to 8969 ft. The well has a cumulative production of 107,876 bbl oil and 58,225 bbl water. The data from the injectivity test indicate a transmissibility (kh/uB) to water of 22.2 md-ft/cp, a stimulation factor (S) of -3.5, and a static reservoir pressure of 3160 psi at reservoir depth. The stabilized injection rate is determined to be 100 bbl of water per day with a bottom-hole injection pressure of 5500 psi. The original reservoir pressure in the area was about 3900 psi.

A water-injectivity test and possibly a longer-term pilot waterflood through a horizontal completion are planned, if a mechanically sound, horizontal completion can be made in the State No. 2-16 well. This well is one-quarter mile from another Ratcliffe completion. A waterflood pilot in this reservoir is still contingent on additional reservoir study and regulatory processes.

Horizontal Completion - Ratcliffe

A lateral re-completion in the Ratcliffe was unsuccessfully attempted in the Trudell M-17 well in North Sioux Pass Field using ultra-short-radius Amoco technology. Future lateral drilling will use steerable, down-hole mud-motors. Horizontal re-completions will be made through casing in two existing Ratcliffe wells. These wells are the Trudell M-17 and the State No. 2-16 in North Sioux Pass Field, Richland Co., MT. Reservoir studies indicate potentially large reserves in the area but poor productivity after hydraulic-fracture stimulation. Potential incremental reserves from horizontal completions in the Ratcliffe are placed at 100,000 bbl per well. An oriented core and FMI log will be obtained in July 1996, from the Ratcliffe interval in North Sioux Pass Field, T. 26 N., R. 58 E. These data will be used to evaluate fractures and their orientation. The orientation of scheduled horizontal re-entry completions will be based on these data.

Engineering reservoir characterizations of the Ratcliffe in the Richland. Co., MT study area resulted in identification of several pilot areas suitable for field demonstrations. A pair of Ratcliffe completions in section 16, T. 26 N., R. 58 E. were found to offer the greatest potential for additional recovery by improved completion efficiency and possibly water-injection. Nearly 5,000,000 bbl is estimated for original-oil-in-place (OOIP) for this pair of wells from materialbalance calculations aided by computer simulation and production type-curve analysis. Oil recovery from these wells is approximately 150,000 bbl with remaining economic reserves of only 40,000 bbl. This recovery represents only 4 percent of potential OOIP. Oil productivity and porosity development at these two wells are normal for the area. Distance between these wells is approximately one-quarter mile and may be suitable for testing water-injectivity and secondary response.

Technology Transfer

An oral presentation was made on July 24, 1995, at the 7th Annual Williston Basin Symposium in Billings, MT. The symposium is sponsored by the Montana, North Dakota and Saskatchewan Geological Societies and the Fort Peck Tribes. The abstract of the presentation is as follows:

"Assessment of Reservoir Heterogeneity Using Production Type-Curves: A Case Study of the Red River Formation in Harding Co., S.D. and Bowman Co., N.D."

This work presents results from a reservoir characterization study to identify areas near producing oil wells which could benefit from additional seismic and geological investigations for the purpose of targeting infield drilling. Statistics of drainage shape factors, effective pore volume and drive mechanisms are presented for the Red River formation in the souther portion of the Williston Basin. Screening techniques are also presented for the purpose of identifying potential reservoir heterogeneity and can be applied generally.

Wells exhibiting heterogeneous behavior can be targets for additional seismic and geological investigations with the goal of assessing potential for further primary or secondary recovery by drilling new wells. The integrated use of production type-curves supplemented with permeability data from drill-stem tests or cores can produce insights about the degree and nature of reservoir heterogeneity. However, using type-curves developed for the radial-flow case in highly irregular drainage situations can lead to erroneous estimates for kh, S (damage or stimulation) and drained pore-volume. A technique has been developed based upon production decline type-curves and presented for analysis of data from multi-well systems or non-radial drainage areas of unknown shapes. Production decline type-curves based on those previously developed by other authors are applied to solution-gas drive production data from heterogeneous reservoirs in this work. Use of this technique is demonstrated for both simulated and field data. The curves have been successfully used to estimate reservoir shape and well drainage areas and are supported by geological-geophysical interpretations of reservoir geometry which are included by example cases.