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IMPROVED RECOVERY DEMONSTRATION FOR WILLISTON BASIN CARBONATES

Annual Report for the Period
June 10, 1994 to June 9, 1995

By
M. Sippel
S. Zinke
G. Magruder
D. Eby

September 1995

Performed Under Contract No. DE-FC22-94BC14984

Luff Exploration Company
Denver, Colorado

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

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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

Reservoir Characterization and Analysis

All field data acquisitions of seismic data have been completed but lack final interpretation. The integrated seismic interpretations will be included in Budget Period 1 topical reports.

Reprocessing and re-interpretation of approximately 50 mi of two-dimensional (2-D) seismic recorded during the 1970's has been completed. These reprocessed data have allowed a better identification of faulting and picking of additional time horizons in the Bowman Co., ND, and Harding Co., SD, Ordovician Red River producing area. The identification of subtle faulting supports a wrench-fault model while the additional horizon picks allow a more detailed analysis of tectonic-growth history. An area for a three-dimensional (3-D) survey was identified at Cold Turkey Creek field (T.130 N., R. 102 W., Bowman Co., ND) which would allow integration of maximum wells and existing 2-D seismic data over an area with a relatively complex structural and stratigraphic setting. This 3-D survey has been recorded and is currently in processing. Processing and interpretation are expected to be completed in six weeks and will be included in Budget Period 1 topical reports.

A 3-mi, 2-D, multi-component seismic line has been recorded over the Cattails (Ratcliffe) field in Richland Co., MT. The data have been processed and are currently being interpreted and integrated with well data.

Core and cuttings petrophysical study and analysis of the Red River and Ratcliffe areas are completed. A total of seven cores are included in the Red River study and are supplemented by cuttings from two wells. A total of two cores are included in the Ratcliffe study and are supplemented with cuttings from four wells.

The Ordovician Red River study area has been mapped with four isopachs of intervals from the Cretaceous Greenhorn through the Red River across the study area in Bowman Co., ND, and Harding Co., SD. The sub-sea datum of the Red River is also mapped.

The Mississippian Ratcliffe study area in Richland Co., MT, has been mapped with four isopachs from the Mississippian Last Charles Salt to the Devonian Bakken. The sub-sea datum of the Ratcliffe is also mapped across the study area. Geological data are also compiled digitally in spreadsheet format.

Oil pressure-volume-temperature (PVT) analysis has been acquired for Red River and Ratcliffe oils. Drillstem test data and analysis of Red River and Ratcliffe areas are completed. Integrated studies of nine Red River and three Ratcliffe fields include drillstem test and production analysis by type-curve matching. Economics analysis (at current conditions) of these fields (primary development and secondary projects) will be included in the Topical Reports. Engineering data are also compiled digitally in spreadsheet format and tabulated for the TORIS database.

Producibility Problem Characterization

Pressure transient tests and analyses were performed on three wells: two Red River completions and one Ratcliffe completion. Reservoir barriers, such as faults, have been identified on two of these tests. Subtle faulting may be a significant factor controlling producibility in some wells in the study areas.

Recovery Technology Evaluations

Jetting-lance penetrations with a commercially available, 10-ft tool were unsuccessfully performed on two wells. These 10-ft penetrations did not result in improved productivity and there are doubts whether the tool actually penetrated the full 10 ft into the formation. Application of the longer 50-foot lance technology at reservoir depths of 9500 ft has been impeded by mechanical problems. Various components of the 50-ft tool have required redesign. The tool design has been functioning successfully at depths of less than 6000 ft; however, project wells are at 9500 ft which results in higher operating temperatures and pressures. Well-work and completion attempts with the 50-ft tools are still in progress, but there is concern that this jetting-lance design will not be capable of successfully functioning as originally envisioned. Expenses for completion attempts with the 50-ft jetting-lance tool in the project area have not been billed to the project. Luff Exploration Company and project team will assess whether additional work will be attempted with jetting-lance technology or use of other ultra-short-radius methods of lateral completions.

A baseline water injectivity test was completed in the Red River. The four-week test was monitored with bottom-hole pressure gauges. This test was performed to collect baseline data before an injectivity test which would be done after application of extended-reach jetting lance or ultra-short-radius lateral technology. Maximum injectivity to water was determined to be 150 bwpd in a 15-ft interval at 5500 psi. Pressure build-up tests were performed on two producing wells to provide baseline data before jetting-lance or ultra-short-radius completions.

Associated Technology Transfer Activities

Project-related field data for both Red River and Ratcliffe reservoir areas have been compiled and will be delivered at the end of Budget Period 1.

One oral presentation was made on July 24, 1995, at the Williston Basin Symposium in Billings, MT, which covered engineering reservoir characterizations of the Red River in Bowman and Harding counties.

Three topical reports will be delivered at the end of Budget Period 1 which will cover 1) Bowman-Harding Red River fields, 2) Richland Ratcliffe fields and 3) the extended-reach jetting lance tool as a stimulation technique.

Activities Required for Project Continuation

Meetings were held with working-interest partners in the Southwest Amor field (T. 130 N., R. 103 W., Bowman Co., ND) to discuss geological and engineering interpretations of the reservoir and interest in secondary recovery by waterflooding. The working-interest partners concluded that future meetings would be contingent on the success of 3-D seismic at Cold Turkey Creek and jetting-lance or ultra-short-radius completions which demonstrate favorable injectivity of water into the Red River.

Field Demonstrations

Additional 3-D seismic acquisition, targeted wells from 3-D seismic, jetting-lance or ultra-short-radius lateral completions and a water-injection pilot are planned for Budget Period 2. The number and location of targeted wells has not been determined and is contingent on the 3-D survey which is in data processing.

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

INTRODUCTION

This project is investigating the Ordovician Red River and the Mississippian Ratcliffe in the Williston Basin in two separate localities. The Red River area is in the southwest portion of the Williston Basin off-structure from the Cedar Creek anticline along the border between North Dakota and South Dakota. The Ratcliffe area is in the west central portion of the Williston Basin mostly in Richland Co., MT. **Figure 1** identifies the general location of the project study areas in the Williston Basin. The project consists of field demonstrations and technology transfer of under-utilized technologies for improved reservoir characterization using 3-D 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 been technically successful but marginal to uneconomical.

Data collection and reservoir characterization activities comprise most of the work accomplished during the first year of the project. Organizing and interpreting the data into comprehensive local reservoir models for each of the study areas are tasks which remain to be done during the end of the first budget period and early part of the second budget period.

Field demonstration wells and completions for the second budget period have not been specifically targeted at this time because interpretations of 3-D and multi-component seismic have not yet occurred. The final interpretations and demonstration plans are expected to be finished during the first quarter 1996.

BACKGROUND

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 ac; however, some areas which have been unitized for enhanced recovery are developed with 160-ac patterns. The primary exploration tool has been 2-dimensional 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 seismic offers 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. Jetting-lance and ultra-short-radius completions may be an effective means of 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 ac 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 do the reservoirs 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 and large-volume hydraulic stimulation is used for nearly all completions. Median 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 in 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 3-D and shear components offer the tools to better target wells. Ultra-short-radius or jetting lance completions are expected to improve productivity and the associated economics of producing the remaining reserves.

Reservoir Characterization and Analysis
Geophysical Evaluations

Multi-Component Seismic Test - Ratcliffe Area

Producibility of the Mississippian Ratcliffe in the Richland County, MT, study area (see **Fig. 2**) is frequently difficult to identify from well logs or structural mapping and it is postulated that fracture development may play a role in producibility. Mapping the orientation and distribution of high-intensity fractures could impact reservoir development in the area, especially for location of lateral drilling. Multi-component seismic surveys can be utilized to define fracture trends and other reservoir heterogeneity as well as provide conventional structural and stratigraphic interpretations.

Original plans in the North Sioux Pass (Ratcliffe) study area (see **Fig. 3**) Richland Co., MT, included possible acquisition of a dipole sonic log or multi-offset Vertical Seismic Profile (VSP) survey to test viability and parameter design for shear-wave data acquisition. Cost proposals from Schlumberger and Halliburton for a VSP ranged from $95,000 to $110,000. These costs did not include the electric wire-line truck and well preparation. Cost for a dipole log run was estimated at $28,200 by Halliburton. These costs do not include the well preparation for pulling and re-running tubing and rods. While a VSP and dipole sonic log would provide valuable data for design of a 3-component program, the costs are prohibitively high and availability of suitable well bores is problematic. The decision was made to proceed with a field test 2-dimensional 3-component (2-D, 3-C) seismic line over a Ratcliffe field with postulated fracturing. It was estimated that a test line could be acquired and processed in the Cattails field for approximately $40,000. This cost is approximately equal to a dipole sonic log and roughly one-third the cost of a VSP survey. A 2-D, 3-C line would provide a test of surface-to-surface 3-component data over a larger area across a Ratcliffe field.

A multi-component test line could provide a field analog for structural and stratigraphic relationships to Ratcliffe production. The line placement was selected so that a comparison could be made between the productive Ratcliffe area across Cattails field and an area of poor porosity immediately west and up-dip from Cattails (see **Fig. 4**). The east-west Ratcliffe cross-section in **Fig. 5** shows the porosity and productive development at Cattails. The cross-section runs parallel and proximal to the Cattails 2-D, 3-C line.

A 3 mi, 2-D, 3-C seismic line was shot and recorded in June 1995 across Cattails (Ratcliffe) field. The seismic data are in final processing at the time of this report. Converted-shear data are observed on field records of the in-line horizontal components. The preliminary processed data indicate significant attenuation of the shear waves and evaluation for fracture detection may not be achievable or practical. Preliminary vertical-component interpretation indicates excellent correlation of P-wave data to synthetic seismograms. The conclusions to date are as follows:

(1) Low signal-to-noise of compressional-to-converted-vertical-shear (P-SV) data are

the result of attenuation in the rocks from 1.0 to 1.7 seconds.

(2) A shear-source acquisition program would have provided less data.

(3) The dynamite-source acquisition and recording parameters provided the best information possible.

(4) A change of line orientation would not have improved the data record.

A buried explosive source P-S converted data was selected as the best option for the Cattails data acquisition because;

(1) Surface-source models exhibit a high level of source-generated noise.
(2) Shear-wave sources are expensive and have limited availability.
(3) Compressional sources cause less environmental damage.
(4) Compressional sources are less expensive with fewer acquisition difficulties.
(5) It was concluded that the information provided from P-SV data should be the same as that derived from shear-source data.

A recommendation for acquisition parameters for a 2-D 3-C line was requested from Western Geophysical. Western used in-house proprietary modeling software to (1) determine viability of utilizing a shear source, (2) evaluate recording of converted-waves which would be generated from a compressional (P-wave) source, and (3) develop acquisition parameters.

Parameters for the test line include: (1) 10-lb dynamite sources buried at 115 ft, 2) a 440-ft shot interval, and (3) strings of 10-hz 3-component geophones. The geophones were clustered in-line at the flag for 180 receiver locations spaced on group intervals of 88 ft. Geophone implants were leveled and checked for in-line/cross-line orientations. There were three geophones per string and a total of 36 shots were used. Three DFS-V recorders were used, one for each receiver component. Low-cut recording filters were left out on the horizontal recordings and an 8-hz low-cut filter was utilized on vertical-component recording. Near offsets were 88 ft and far offsets were 10,560 ft. Notch filters were not used. A total of 360 traces were recorded for each component using a 2 msec sample interval. Line orientation was modified to 10 degrees south of west to accommodate producing wells and other cultural problems.

The vertical component data were processed using a conventional processing sequence including pre-stack whitening, refraction statics, migration and post-stack whitening. The first basic processing step for the horizontal component data was reversal of polarity on the records from trailing receivers (negative offsets). Converted-wave data (horizontal components) then underwent standard geometry, field statics utilizing P-wave source refraction, and trace editing processes. P-wave source surface-consistent deconvolution solution was used for the converted data. Common-conversion-point (CCP) binning was performed based on Vp/Vs RMS velocity. The data processing then followed with a statics velocity and NMO corrections sequence before they were stacked. The first attempt produced poorly stacked data. Following a re-assessment of the field records and determination that the long offsets had slightly higher signal content, constant velocity stacks were used to provide better velocity input. The processes of CCP binning, velocity analysis, NMO correction and reflection statics were iterated twice to produce final stacked sections for the in-line and cross-line data.

The vertical component exhibits excellent correlation of the P-wave data to conventional synthetics generated for the Superior Oil No. 2A Vanderhoof well (sec. 13, T. 25 N., R. 58 E.) and the Slawson No. 1-5 Lund well (sec. 5, T. 25 N., R. 59 E.) in Richland Co., MT. The P-wave quality is excellent when compared to other 2-D lines obtained in the area.

The P-SV data signal-to-noise is low for the Cattails seismic data. It is concluded at this time that the low signal-to-noise is the result of S-wave attenuation above the Ratcliffe converted-wave-time from 1.0 to 1.7 seconds. The in-line P-SV section exhibits quality data above 1.0 sec but there is a significant drop in quality between those events and 1.7 sec. This interval corresponds with the Cretaceous Greenhorn to the Pennsylvanian Minnelusa from 2500 to 7300 ft below surface. The data quality does not permit identification of an exact attenuation zone but it appears to be near the Lower to Upper Cretaceous boundary. The cross-line horizontal section has poorly stacked data and rotation of the data set was not performed. Assuming that incident P-waves are 5-60 hz based on the vertical data, converted S-wave data in that zone should be in the range of 5-30 hz. Instead, the S-wave data recorded at the surface for those travel times are only 5-10 hz. This indicates high attenuation of S-waves through that portion of the section. A shear-source data set would have experienced even greater attenuation, having traveled through that section twice.

There is adequate signal on the horizontal data sets to evaluate or measure shear-wave splitting, but the P-SV data have less vertical resolution than the P-wave data. At the Ratcliffe interval, the converted data exhibit a high-frequency content of 20 hz while the P-wave data at the same interval (1.9 to 2.0 sec on the P-wave section) contain 40-60 hz. One explanation for the poor quality data is that the horizontal components may be aligned close to the two principal axes of symmetry. If the in-line direction were perpendicular to the fracture trend, then (1) all the energy should be recorded on that component, (2) there should be no S-wave splitting, and (3) the data would be the poorest quality expected for the area. If the in-line direction were parallel to the fracturing, then the data would be the best quality expected in the area and there would be no apparent shear-wave splitting. If both in-line and cross-line components show reflections and there is shear-wave splitting, the data set is at an acute angle to the fracture trend. In the last case, an absence of S-wave splitting would indicate the absence of anisotropy. The low signal-to-noise levels in the Cattails data suggests that if the in-line data were perpendicular to the fracture system and there were significant fracturing in the area, shear-wave data from a different line orientation would not be significantly better.

<u>Seismic Activities - Red River Area</u>

Seismic interpretations utilizing 2-D seismic data for exploration in the Ordovician Red River formation in Bowman Co., ND, and Harding Co., SD, (see **Fig. 6**) have traditionally involved structural mapping of the Ordovician Winnipeg for identification of crestal highs on basement features. Isochron thins, identified from mapping the Cretaceous Greenhorn to Ordovician Winnipeg and the Mississippian Mission Canyon to Ordovician Winnipeg intervals, have been used historically as key maps for Red River exploration. Older data with less than 12 fold, group intervals greater than 110 ft and without refraction statics do not provide sufficient seismic resolution or attribute information to map Red River porosity signatures with confidence.

Interpretation of 1970's vintage seismic data has been enhanced by reprocessing of approximately 50 mi of data across study areas at Southwest Amor, State Line, Cold Turkey Creek, Haley, Mrnak and Grand River School fields (see **Fig. 7**). Reprocessing has included the application of refraction statics and radon stack which produced significant noise reduction. Resulting seismic sections provide good event resolution, higher frequency and allow for identification and interpretation of subtle faulting. The improved quality of the reprocessed data allows picking of additional horizons which were difficult to interpret from the original processed sections. The mapping of additional horizons facilitates identification of closer geological time subdivision. A better understanding and measurement of tectonic history may permit better prediction of high-quality reservoir areas and trapping.

The reprocessed 2-D seismic data cover portions of six townships (216 sq mi) in Bowman Co., ND. These data are mapped and integrated with older vintage-processing seismic and well-log data. The maps are made for these intervals and horizon events:

(1) Cretaceous Greenhorn - Mississippian Mission Canyon
(2) Mississippian Mission Canyon - Silurian Interlake
(3) Silurian Interlake - Ordovician Red River
(4) Cretaceous Greenhorn - Ordovician Winnipeg
(5) Silurian Interlake
(6) Ordovician Red River
(7) Ordovician Winnipeg

Figures 8 and 9 depict the east-west seismic line CA9-4 which crosses the center of the SW Amor field, T. 129-130 N., R. 103 W., Bowman Co., ND. **Figure 8** shows the data as processed in 1972. These six-fold data were acquired with dynamite sources and a 440-ft group interval. Original processing was performed on 4 milli-second (msec) re-sampled data and was state-of-the-art at that time. Acquisition and processing parameters for line CA9-4 are given in **Table 1 and Table 2,** respectively. The re-processed version is shown in **Figure 9** and exhibits frequencies up to 65 hz at Red River time in comparison to approximately 40 hz from original processing. Processing parameters are shown in **Table 3.** Sections are displayed with the same scale for direct comparison. The time shift exhibited between the original and reprocessed version of CA9-4 is the result of a 33 msec difference in datum correction and an additional 30 msec introduced by the refraction statics solution. As a result of reprocessing, additional events can be picked at the Red River, Stonewall and Interlake horizons as depicted on **Fig. 9**.

Faulting is evident on a number of the reprocessed 2-D seismic lines. The fault trends extend from northwest to southeast in an en-echelon pattern across the study area. The amount of throw is variable with larger faults exhibiting 45 to 50 ft of throw at the Ordovician Winnipeg. Throw displacement decreases upward and is generally not detectable by Upper Devonian (Duperow) time. Because the Red River producing zones can be as thin as 10 ft, faulting can play a significant role in field development and enhanced-recovery design. Faulting pre-dates the Devonian-Silurian unconformity and appears to support a wrench-fault model with left-lateral motion. The productive trends found in the Red River are defined by early-stage wrench motion trends (see **Fig. 10**) and faulting complicates production. Regional lineament patterns have be documented in the literature (Thomas, 1974) and are shown in **Fig. 11**.

A 2-mi 2-D seismic line was acquired by the project at the Southwest Amor field (see **Fig. 12**) extending southwest to northeast across a major fault. The line was designed to

(1) evaluate a potential extension of the field area,
(2) provide better understanding of faulting,
(3) evaluate whether higher resolution data could aid in reservoir definition (i.e., porosity, thickness, continuity), and
(4) aid in selection of parameters for 3-D seismic acquisition.

The northeastern portion of line 94-LEC-DOE-1 covering approximately 1.6 mi is shown in **Fig. 13**. Acquisition and processing parameters are shown in **Table 4 and 5**, respectively. A comparison of the line 94-LEC-DOE-1 (see **Fig. 13**) with line CA9-4 shown in **Fig. 8 and Fig. 9** shows the improvement in data resolution. Line 94-LEC-DOE-1 was acquired with a higher fold (20 fold vs. 6 fold), a smaller group interval (110 ft vs. 440 ft), a smaller/shallower charge (10 lb at 60 ft vs. 25 pounds at 115 ft) and a longer far-offset (6600 ft vs. 5060 ft). The resulting data have closer sub-surface sampling and a more consistent offset-mix than line CA9-4. The signal-to-noise ratio is improved by the additional fold and events on line 94-LEC-DOE-1 exhibit better continuity. The finer horizontal sampling results from the smaller group interval and provides better definition of horizontal structural and amplitude variations.

The acquisition of line 94-LEC-DOE-1 provided a clearer picture of faults and fault density at Southwest Amor. Reprocessing of older data allowed resolution of a major fault (45 ft throw) on the east side of the field and suggested other subtle faulting. Major faulting bounds the Southwest Amor field on the northeastern flank. This fault is down-to-the-northeast and trends north-northwest to south-southeast. Maximum throw at the Winnipeg is from 45 to 50 ft with a dip of approximately 45 degrees. Several smaller faults cross the field approximately parallel the main fault. The resolution of faulting from line 94-LEC-DOE-1 allows correlation to weakly resolved events on the older 2-D data. **Figure 14** depicts the new interpretation of probable segmentation of the Red River caused by faulting. This faulting may be typical in other fields in the area. The ability to identify subtle faulting in thin zones should lead to better placement of wells and design of enhanced recovery projects. The frequency content and event resolution of line 94-LEC-DOE-1 led to confidence in design parameters for 3-D seismic surveys.

The complexity of growth history, faulting and stratigraphic variations identified from re-processed and new 2-D seismic data in the Bowman Co. study area reinforced the premise that a 3-dimensional seismic survey could provide valuable insight into reservoir development and better definition of reservoir limits. A portion of Cold Turkey Creek (Red River) field (T. 130 N., R. 102 W., Bowman Co., ND) was selected as the best candidate and an area of 4.35 sq mi was determined to optimize project objectives at minimal cost (see **Fig. 15**). Based on 2-D seismic mapping, the Cold Turkey Creek field has differing growth histories between productive areas in Sections 22, 28, 33 and 34. The well control and apparent reservoir/structural complexities in this small area are expected to provide an opportunity to demonstrate the utility of 3-D surveys.

A staggered-brick acquisition design (see **Fig. 16**) included 378 10-lb dynamite charges buried at 60 ft in a 1760-ft source pattern perpendicular to receiver-line spacing. A total of 720 receivers were deployed in 8 parallel lines with 60 channels each and 880-ft spacing. The shooting patch included 480 live-geophone groups. Subsurface bin size is 110 ft x 110 ft. Data are currently in processing at Western Geophysical.

Synthetic seismic models of the Red River interval wave-form demonstrate that there are several peak-trough events which develop in a section with good porosity in all three benches of the Red River. **Figure 17** shows the synthetic trough-peak-trough (reverse polarity) and peak-trough-peak (normal polarity) signature from a well in the Cold Turkey Creek field. The synthetic seismogram was constructed with Ormsby 10-20-70-96 hz normal and reverse polarity filters. Variations of porosity-thickness in the lower member of the Red River produce visually detectable time and amplitude variations on seismic models within the frequency ranges typically recorded in the area. Amplitude and other attributes within the Ordovician Red River from seismic data may provide a direct correlation for prediction of reservoir porosity in the Red River lower member; however, previous mapping of seismic attribute has been restricted to qualitative visual indications of amplitude. This is attributed to low fold and frequency on 2-D seismic lines acquired at different dates and with different recording parameters and field conditions. Validation of modeling is anticipated from the Cold Turkey Creek area 3-D seismic data. Pseudo-sonic synthetics will be generated from electrical logs of the nine wells within the 3-D area and inserted into the 3-D data volume for this analysis.

Table 1. Recording parameters for line CA9-4

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

Table 2. Original processing parameters (1972) for line CA9-4

Processing Sequence

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

Table 3. Reprocessing parameters (1994) for line CA9-4

Processing Sequence

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

Table 4. Recording parameters for line 94-LEC-DOE-1

Field Geometry		Recording Instruments	
Shot By	Reliable Exploration Co	Recording System	DFS V
Date	August 1994	Format	SEGB
Data Channels	120	Record Length	3 sec
SP Interval	330 ft	Sample Rate	2 msec
Group Interval	110 ft	Field Filters	8-128 Hz
Coverage	20 fold		
Source		Receivers	
Type	Dynamite	Geophones per Group	12
Charge Size	10 lb	Geophone Pattern	110 ft
Hole Depth	60 ft	Geophone Frequency	14 Hz
Array	Single Hole	Spread	6600-220 x 220-6600

Table 5. Processing parameters for line 94-LEC-DOE-1

1. Demultiplex and Gain Recovery
2. Record and Trace Edit
3. Geometry Application
4. Surface Consistent Spiking Deconvolution
   220 msec Operator
5. Trace Equalization Scaling
6. Refraction Statics
   3000 ft datum
   6000 ft/sec Replacement Velocity
7. CDP Sort
8. Preliminary Velocity Analysis
9. Residual Statics
   Automatic Surface Consistent
10. Time Domain Spectral Whitening
    5/10-80/85 Hz
11. Trace Equalization Scaling
12. Final Velocity Analysis
13. Residual Statics
    Automatic Surface Consistent
14. CDP Statics
15. Noise Reduction - Radon Transform
16. Stack
17. Spectral Whitening
    5/10-80/85 Hz
18. F-X Deconvolution
19. Filter
    8/14-70/85 Hz
20. Trace Equalization
21. Bulk Shift minus 75 msec

Reservoir Characterization and Analysis
Petrographical Evaluations

Ordovician Red River

A depositional and early diagenetic model has been developed for the lower porosity member of the Red River formation (see **Fig. 18**) because it is the best represented within the core work to date. Many of the burrow-mottled rocks of the lower member are believed to be the result of storm-wave pumping on a storm-dominated shelf of shallow to moderate water depth. The modified tempestites that result in the best quality dolomite reservoirs were originally carbonate sands (grainstones and packstones) that were introduced into open burrow systems within shelf muds during major storm events. Dolomitization, differential compaction and stylolite formation were largely controlled by the distribution of probable linear bands of tempestite burrow fills. Subsequent fracturing with solution-enlargement develop orientations largely controlled by stylolite formation. This new integrated depositional and diagenetic model for the lower Red River member for the project area should assist in determining the best reservoir development strategies.

Oil reservoirs in the Red River can be within dolomitized (1) mottled tempestites (i.e. metazoan burrows filled with sediments coarser than their surrounding matrix by storm pumping processes (see Wanless et al., 1988); (2) burrow-mottled mudstones; and (3) millimeter-scale laminates (0rgano-sedimentary laminae formed by microbial or cryptalgal mats). These depositional-controlled reservoir types can occur within any of the Red River porosity members. In general, matrix reservoir quality is best within the mottled tempestites. This type is generally much thicker and better developed within the lower porosity member. The middle porosity member frequently contains a combination of burrow-mottled mudstones and microbial laminites, which the upper member (youngest) reservoir is most typically a thin, microbial-laminate interval.

The common denominator for Red River reservoirs in the project area, regardless of the depositional fabric, is the development of dolomitic micro-porosity. In nearly all the Red River reservoir dolomites examined in this area, chalky micro-porosity, along with remnant-fine, inter-crystalline pores provide the principal storage for oil. The petrography done to date shows this micro-porosity to be the result of extensive burial-related dissolution processes. The sub-surface processes may be controlled by structure as much or more than by stratigraphy and sedimentology.

Commonly associated with the chalky micro-porosity are other significant features indicative of late dissolution in pre-existing Red River dolomites. These include vuggy and channel pores along stylolites and micro-fractures. The stylolites are generally low-amplitude to wispy-seam or horsetail types that are most frequently developed around the tempestite burrow mottles and along the microbial laminae that define two of the three common Red River reservoir facies. Dissolution along stylolites as the result of chemical compaction, and possibly some hydro-thermal overprints, have caused removal of carbonate matrix such that pseudo-breccias surrounded by vugs and micro-pores are common within good reservoirs. The late, often crossing-cutting mega-pores are probably important in controlling the drainage efficiency and direction for many Red River micro-porous dolomite intervals.

Five slabbed cores from the Ordovician Red River formation in Bowman Co., ND, and Harding Co., SD, have been examined and described in detail. Documentation of all important rock facies, sedimentary structures and diagenetic fabrics has been completed via numerous close-up photos and 35 mm slides. The core work to date consists of approximately 380 ft of slabs that provide excellent coverage of the lower porosity member of the Red River in the study area. Thirty-seven standard thin sections from four wells in the area were borrowed from the United States Geological Survey (USGS) for petrographic description under polarized and blue-light epi-fluorescence techniques as well as photo-documentation. Thin sections have been imaged and photo-documented under plane and cross-polarized lighting using a research-grade Jena microscope. Epi-fluorescence and white-card diffused lighting techniques have been used to clarify early vs. burial diagenesis developed within different reservoir styles in the project area. A catalog and display are being developed that show all of the porosity types present in Bowman-Harding Red River reservoirs and demonstrate the significant development of dolomitic micro-porosity.

Mississippian Ratcliffe

Two cores from the Mississippian Ratcliffe member of the Charles formation in Richland Co., MT, have been described and sampled. These excellent cores are from Nohly and Fairview fields (see **Fig. 3**) and are representative of the cyclic Ratcliffe oil reservoirs within the project area (see **Fig. 19** for type-log of Ratcliffe member). In addition, cuttings from four additional wells in the area are being examined. These reservoirs are developed principally in slightly dolomitic limestones, unlike some of the large Ratcliffe fields in the Williston Basin which are much more dolomitic. The reservoirs appear to be developed in peloid and bio-clastic grainstones (calcarenites) which are associated with stabilized grain flats and small islands. The fields within the main project area are seaward of offshore from the Ratcliffe shoreline-barrier-island and sabkha-salina facies documented for other Ratcliffe fields (Longman and Schmidtman, 1985 and Hendricks, 1988). These seaward accumulations built up as shoals and islands, surrounded by sub-tidal marine sediments. These reservoirs appear to be offshore from the maximum extent of shoreline progradation for any of the Ratcliffe depositional cycles.

Thin sections are being prepared to understand the diagenesis and reservoir quality of the cyclic Ratcliffe facies at Nohly and Fairview fields. This petrographic work should help clarify the relative importance of early meteoric versus marine diagenesis on reservoir quality. In addition, prediction of the amount of dolomitization and its effect on the reservoirs should be facilitated by developing a comprehensive diagenetic model. The effects of burial diagenesis other than fracture development is not thought to be important in these reservoirs.

Reservoir Characterization and Analysis
Geological Evaluations

Ordovician Red River

A wrench-style growth and structural model is being developed at a field and inter-well scale for the Bowman-Harding Red River study area. A basement block framework is hypothesized as controlling the direction and extent of structural features in the Williston Basin. A wrench system is characterized by a series of geometrically arranged grabens, horsts, and half-grabens that may undergo continuous adjustment to compressional stress. Horizontal movement is generally the greatest direction of displacement. One distinguishing feature of wrench faults is that they often take the form of scissor-type faults. In the Bowman-Harding area, the State Line field (T. 129 N., R. 103 W.) and Cold Turkey Creek field (T. 130 N., T. 102 W.) are good examples of the most structurally disturbed areas (see **Fig. 6 and 7** for location of field areas).

Work performed in a photo-geomorphic mapping project from 1964 to 1970 by Gilbert Thomas preceded a 1974 publication in which he describes a series of basement-weakness zones which trend northeasterly and northwesterly in the Williston Basin (see **Fig. 11**). They define a framework of possible basement blocks which probably strongly affect localization of oil and gas by influencing the stratigraphic and structural conditions. Differential simple shear on opposite boundaries of a block produced coupling across a block which produced drag-fold uplifts, and down-wards, faulting, and fracturing.

In 1987, Donald Brown described the timing of these wrench-style deformation patterns. His work describes three potential stress orientations which probably influenced the structural architecture of Williston Basin. The oldest lineament orientation is northeasterly until late Devonian or early Mississippian time. In Devonian time, an abrupt and dramatic shift in orientation of the active shear zones occurred and re-oriented to the northwest. During middle Mississippian time, the northeasterly shear orientations were re-activated. The re-alignment of regional forces would cause periodic movement of basement blocks in different directions through time. A block may have been elevated in Ordovician time, depressed in Silurian time, dormant in Devonian time and elevated again in Mississippian time.

Most productive areas exhibit early structural influences on sedimentation. Early growth often associated with linear trends implies existence of directional stress. Subsequent movement or growth segmented the trends into blocks that are drilled based on seismic identification. Present-day structures may be more the result of subsidence of surrounding blocks than uplift of productive blocks. It is estimated that more than half of structural compensation ended by Silurian time. Red River thickness maps represent the earliest evidence of paleo-structure. A focus on the interval below the Silurian Interlake best reveals the key paleo-growth in the Bowman-Harding area.

Structure has played a role in Red River upper and middle porosity member sedimentation and dolomitization. The affect of structure on upper member development is subtle and not readily apparent. Further exploitation of upper member reservoirs requires development of a depositional model that ties reservoir development to present-day structure, paleo structure and tectonic history. Work is being done to understand the timing, origin and distribution of these important burial pore systems which have not been well-documented in previous Red River publications. Construction of burial history curves may be one tool for clarifying some of the ambiguous relationships between burial diagenesis and structural history in each Red River field.

The Red River formation is an example of cyclic carbonate sedimentation. Four cycles have been recognized in the Bowman-Harding area. The primary intervals for oil production are the older three cycles designated the lower, middle, and upper member (see **Fig. 18**). The youngest and fourth cycle has not been documented to have produced oil in commercial quantities by isolated drillstem test or perforation and is sometimes absent. The lower member began with deposition of lime mudstone in a relatively deep normal marine environment. As the water depth decreased, layers of lime wackestone were deposited in approximately eight layers. They range in thickness from 2 to 20 ft. Deposition of the lower cycle ended with a transgression that resulted in lime-mud deposition. The base of this layer roughly marks the beginning of the middle cycle. Some geologists correlate the Bowman-area lower porosity member and middle porosity member with the Burrowed "C" zone and Laminated "C" zone of the central Williston Basin, respectively. If this is the case, there may not have been a transgression separating the lower and middle porosity members in the Bowman-Harding area. Whatever the cause, most wells have a tight lime mudstone separating the middle member porosity from the lower member.

The lower member wackestone grains consist of broken fossil debris. Worm burrows are observed in cores of the lower member. These wackestone layers are frequently dolomitized and can be important oil reservoirs. It is noted that these layers can be identified in every well except in those few wells that are so heavily dolomitized that the original depositional fabric has been destroyed. The wackestone layers are observed on electrical logs from wells with low-porosity in the lower member. The wackestones are generally thinner in wells with low-porosity than in wells with highly dolomitized and sections. Resistivity logs are useful for correlating from well to well.

Study has shown that lower-member porosity development is in some way tied to local topography during Red River time. Good porosity development on the lower member is often found on the flanks of paleo highs. Petrographical studies from Red River cores explain thicker layers of grainy rocks found in flank position. The lower-member Red River rocks were originally limestone, not dolomite. The wackestone layers are considerably more prone to dolomitization. Also, it is likely the seafloor relief at the time of Red River deposition was low, probably on the order of tens of feet.

Dolomitization of the lower member was very widespread. Of course, some wells are more dolomitic than others. Even wells with poor porosity have some dolomite. A model of fracturing along structural flanks may explain some dolomitization in the lower member, especially for rocks in wells that were heavily altered or located along areas of steep dip. But this model does not explain the widespread nature of dolomite in the lower member of the Red River. In Harding Co., SD, the Red River lower porosity member often contains relatively fresh water. This implies that the lower member porosity is hydraulically connected over a large area. Localized centers of dolomitization associated with fractures or sharp changes in structural dip also fail to explain the presence of low-salinity waters. The tempestite layers were prone to alteration and the dolomite-forming fluids were able to migrate a great lateral distance.

The middle member porosity typically exhibits a shallowing-upward sequence that culminates in anhydrite. The Red River middle cycle began with deposition of lime mudstone. In some wells, it looks like a few layers of wackestone (tempestite-like) were deposited on top of the mudstone. In other wells, the equivalent strata consists of tight limestone. Several thin layers of dolomite were then deposited culminating in deposition of anhydrite. It is not known if this dolomite was originally deposited as dolomite or limestone altered to dolomite. The first few layers immediately below the anhydrite were probably deposited as dolomite. Best porosity development is usually found in the lowest part of thick, porous sections. Drill cuttings from the middle member typically consist of soft, white, chalky dolomite. Oil shows are rare in the middle porosity member.

The anhydrite above the middle member is very thin or missing in a few wells. The Red River interval thickness is often anomalously thin in these wells. These thin wells do not always correspond to present-day structural highs. Low-porosity dolomite was deposited in place of anhydrite in most of these wells, but a few wells appear to have experienced erosion or non-deposition during this time.

There should be significance to the thickness of the anhydrite above the middle member. One model suggests that areas of non-anhydrite deposition are random. Another model states these areas are the source of dolomitizing fluids. Another explanation is that the absence of anhydrite is the result of high topography at Red River time. However, there is not a simple relationship between presence or absence of this anhydrite and oil production. Some non-anhydrite wells have good reserves, some have poor producibility and some are dry holes. Mapping the gross and net thickness of the anhydrite interval may provide some revelations.

<u>Mississippian Ratcliffe</u>

Regionally the Study Area is located on the western shelf of the Williston Basin. The strike is slightly west of north-south with several monoclinal terraces and localized closures reflected at the base of the Last Salt and top of the Ratcliffe markers (see **Fig. 19** for type-log of Ratcliffe member).

The Ratcliffe interval is the lower member of the Charles formation. The Charles formation is part of the Madison group which is separated in ascending order into the Lodgepole, Mission Canyon and Charles formations. The entire group is of Mississippian age.

The Madison group consists of limestones, dolomites, evaporites and thin shale beds which is characterized by widespread, cyclic carbonate deposition. It is thought that sea level changes were the main cause of cyclic deposition. In the study area, the Lodgepole consists of slightly argillaceous lime-mud deposited in an open-marine sub-tidal environment. The Mission Canyon formation, in general, is a regressive shoaling-upward sequence. Several Mission Canyon cycles are present in the study area but difficult to recognize. Small-scale resistivity logs are useful for recognizing the cycles. The cyclic nature of the Mission Canyon formation is best known in North Dakota where drops in relative sea level are preserved in the rocks as shoaling-upward carbonate sequences in the near-shore (down-dip and basin-ward) sub-tidal and inter-tidal environments and bedded anhydrite in the up-dip and land-ward environment along and behind the shoreline. During Mission Canyon time, the position of the carbonate-anhydrite shoreline boundary shifted basin-ward (west). This pattern continued through Mission Canyon time into early Charles time resulting in Ratcliffe carbonate deposition in the study area. Ratcliffe anhydrites of equivalent age to the study area carbonates are present approximately 10 to 20 mi east of the study area. After the Ratcliffe, Charles deposition continued with a thick sequence of evaporites.

Within the study area those maps reflect structural closures of 10-25 ft magnitude at Rip Rap Coulee, Cottonwood and Nohly fields in the eastern portion of T. 26 N., R. 59 E., South Fairview field area of T. 25 N., R. 58 E., but of much less areal extent within the North Sioux Pass field in T. 26 N., R. 58 E. (see **Fig. 3**). The significance of structural closure with oil accumulation in the Ratcliffe is more apparent in the eastern portion of the study area than in the west where fracturing and variation in reservoir development is also a component of accumulation. A salt collapse feature is present in southern portion of the study area caused by dissolution of the underlying Prairie salt.

Efforts are underway to identify both reservoir development and fracturing within the Ratcliffe interval by the use of technologies such as 2-D 3-C seismic. If these results are positive, they could be used to identify potential reservoirs on existing structural closures, salt collapse features and on steeply dipping terraces.

There is notable difference between Ratcliffe reservoirs in the study area and Mission Canyon reservoirs located east of the Nesson anticline. The up-dip trapping facies for the shoreline-type of Mission Canyon reservoirs consists of tight dolomites and bedded anhydrites deposited on the landward side of reservoir rocks. In the study area, the up-dip trapping facies consists of impermeable limestone (mudstone) deposited in what at the time was the seaward side of reservoir rocks. Other Mission Canyon reservoirs in western North Dakota also have this geometry. This does not apply to the island-type of Mission Canyon reservoirs which are surrounded by impermeable mudstones. Ratcliffe porosity in the study area develops either in the lower part of the section or in the upper part. A few wells show development in both the lower and upper portion of the Ratcliffe interval. Wells in Cattails, Rip Rap Coulee, Cottonwood and Nohly fields (T. 26 N., R. 59 E.) demonstrate lower-porosity development. Often, the lower porosity exhibits a shallowing-upward profile on logs. In general, lower porosity consists of limestone or dolomitic lime. The best example wells of lower porosity are in the Rip Rap Field, although they do not demonstrate the shallowing-upward profile. None of the producing Ratcliffe wells in North Sioux Pass field have lower-porosity development. Structurally low, non-productive wells in T. 26 N., R. 59 E. also show lower porosity but it is generally of poorer quality than the productive wells. The lower Ratcliffe represents a separate sub-interval of cyclic sedimentation.

Upper-porosity development is best demonstrated in the No. 2-20 Salsbury and No. 2-16 State wells in T. 26 N., R. 58 E. In the North Sioux Pass field, most wells that have upper-porosity development appear to be productive. Upper porosity also shows a shallowing-upward profile. Some of the upper-porosity profiles in North Sioux Pass exhibit a superficial similarity to lower-porosity profiles in the eastern portion of the study area. This suggests upper porosity was deposited in its own sub-interval cycle that was similar to the lower cycle except deposition was not as widespread. Development of upper porosity in the Ratcliffe at North Sioux Pass tends to be more dolomitic than the lower porosity. This may be due to the island-type model or may be attributed to proximity to thick anhydrites deposited on top of the Ratcliffe.

In T. 26 N., R. 58 E., a third type of porous section is demonstrated in the No. 1-22A Salsbury and No. 1-27 Salsbury wells. Porosity is poorly developed in these wells. Porosity develops as thin spikes on logs and rarely exceeds 6%. These porous spikes consist of limestone. Similar rock sections are present in sec. 9 and 16 of T. 25 N., R. 59 E. and sec. 12 of T. 24 N., R. 59 E. Though these wells have porosity development on logs, oil production from the Ratcliffe has been substantial over a long length of time. The well in section 12 has cumulative oil production over 200,000 bbl and is still producing more than 35 bopd.

The No. 2-2 Iverson (sec. 2, T. 25 N., R. 58 E.) Ratcliffe section is unique in that it has the only electrical log in the study area that exhibits resistivity response that is typically associated with fractures. The well appears to be in an area where the underlying Prairie salt was dissolved after Madison deposition. The True Oil Co. well in sec. 4, T. 25 N., R. 58 E. may also be in this same setting.

Better Ratcliffe reservoirs are often associated with a thicker Ratcliffe section between the anhydrite cap and underlying Midale shale. Thick areas occur in North Sioux Pass and Nohly fields. In both cases, the thicker areas are roughly coincident with Ratcliffe structural highs. The Cattails field Ratcliffe section is also thick, but there is no associated structure. The Cattails thick could be associated with a structurally low area at the end of Midale deposition that acted as a micro-basin which accumulated clastic-carbonate debris that washed down from shoal areas during storms. A subtle thick is also associated with the Rip Rap Coulee field. In North Sioux Pass field, the thickest Ratcliffe interval is found in the No. P-7 USA Martin (sec. 7,T. 26 N., R. 58 E.). It is noted that good porosity development is not directly related to Ratcliffe thickness. Thick Ratcliffe intervals in North Sioux Pass and Nohly fields are probably caused by shoal-building with a larger amount of carbonate grains which were deposited in relatively shallow water. The No. 1-27 and No. 1-22A Salsbury wells (sec. 22 and 27, T. 26 N., R. 58 E.) have very thin and poorly developed Ratcliffe intervals but are still productive. This indicates that the No. 1-27 and No. 1-22A Salsbury porous sections represent a different depositional or diagenetic history from other Ratcliffe wells in the study area.

An isopach map of the combined thickness of the anhydrite (which overlies the Ratcliffe) and Last Charles Salt can be used to reconstruct the relative and probable, absolute paleo-structure of the study area at the end of Ratcliffe time. This interval typically thins over Ratcliffe thicks and larger structural features that have influenced deposition since Winnipeg time.

Reservoir Characterization and Analysis
Engineering Evaluations

<u>Ordovician Red River</u>

Engineering evaluations of Red River reservoirs in the Bowman-Harding area have addressed producibility, recovery efficiency, drive mechanisms and economics. Producibility has been assessed by drill-stem tests and post-completion build-up tests. Detailed engineering evaluations have been made for nine Red River field areas. Toris data-sheets for these Red River field areas are included in the appendix of this report. These field areas are as follows:

(1) Cold Turkey Creek
(2) Coyote Creek
(3) Medicine Pole Hills Unit
(4) North Buffalo
(5) North State Line
(6) South Horse Creek
(7) South State Line
(8) Southwest Amor
(9) West Buffalo Red River "B" Unit

Production analysis by Fetkovich type-curve method In the Bowman-Harding Red River area has been performed on wells for characterization of producibility, reserves, drainage volume and drive mechanism. These evaluations are further segregated by completion interval in separate porosity members. These results will be fully documented in the reservoir characterization topical report at the end of budget period 1.

Production analyses show that wells completed in the lower member of the Red River are most likely to have a moderate to strong water-drive component. The few wells completed only in the middle porosity member have poor producibility and very limited drainage. Wells completed in the upper member of the Red River show a weak to moderate water-drive mechanism. Calculated drainage areas for wells completed in the upper member are most likely to be less than 160 ac. This is less than the 320-ac regulatory spacing which presently governs many of the fields in the Bowman-Harding area.

There are several examples from completions in the Red River upper member where the early producibility matches calculations from drill-stem test (DST) data but the subsequent decline character indicates a long transition time to pseudo steady-state. The reservoir surrounding these wells is suspected of compartmentation which may be caused by low-relief faults segmenting the thin (5 to 15 ft) upper-porosity member.

Drill-stem tests of the Red River are generally effective in providing quality producibility and pressure data. The DST data provide a statistical distribution of fluid transmissibility for each of the Red River porosity members as they are generally tested individually. Drill-stem tests from wells have been reviewed and analyzed for transmissibility (kh/μB) and static reservoir pressure. These data have been summarized for each of the field areas studied in detail for the project. These results will be fully documented in the reservoir characterization Topical Report at the end of budget period 1.

Original-oil-in-place (OOIP) has been estimated using volumetric methods for nine Red River fields in the Bowman-Harding area. These nine fields were selected for study because of their larger areal extent, producibility characteristics or as secondary recovery examples. Productive reservoir area was estimated from seismic mapping, structural closure and other well data such as drill-stem tests. Primary recoveries were found to vary from 3 to 28% a mean of 15%

Oil from Red River reservoirs in the Bowman-Harding area range from 32 to 39° API with an average of 35° API. An oil PVT analysis from the Medicine Pole Hills field was donated to the project by the operator of the Medicine Pole Hills Unit. The oil has a gravity of 38° API with an initial solution gas-oil ratio of 575 cu ft per bbl. Oil PVT estimates from published correlation methods match the actual Red River PVT analysis with reasonable accuracy based on the oil PVT analysis from Medicine Pole Hills.

Hypothetical economic summaries have been prepared for each of the nine field areas. The current economic conditions of average oil price, drilling cost and operating expense were used to demonstrate profitability if each area were drilled today without the risk of dry holes. These economic assessments show that primary recovery is profitable. However, the secondary projects (both water and air-injection-insitu-combustion) which are active in the Bowman-Harding area would not be profitable if they were initiated in the current economic climate.

Mississippian Ratcliffe

Engineering evaluations of Ratcliffe reservoirs in the Richland County, MT, area have addressed producibility, recovery efficiency, drive mechanisms and economics. Producibility has been assessed by DST and post-completion build-up tests. Detailed engineering evaluations have been made for three Ratcliffe field areas. TORIS data-sheets for these Ratcliffe areas are included in the appendix of this report. These field areas are as follows:

(1) Cattails
(2) Nohly
(3) Rip Rap Coulee

Similar to the Red River evaluations described previously, Ratcliffe producibility, recovery efficiency and economics has been described for each of these three Ratcliffe fields. These results will be fully documented in the reservoir characterization topical report at the end of budget period 1.

Producibility Evaluations
Well Completions

Buildup Tests

Extended-time pressure buildup data were obtained from the Trudell No. M-17 (Ratcliffe) and No. Hansen 1-21 (Red River) to provide base-line data for permeability-thickness (kh) and stimulation factor (S). These base-line data are part of the reservoir-characterization attributes being collected for each reservoir study area. Both of these wells are candidates for re-completion with jetting lance or ultra-short-radius.

Trudell No. M-17 (Ratcliffe)
North Sioux Pass field, API No. 25-083-200932
Sec. 17, T. 26 N., R. 58 E., Richland Co., MT

A pressure build-up test was performed in November and December 1994 with a total shut-in time of 332 hr. The pressure build-up test was performed to evaluate matrix permeability, completion efficiency and pressure draw-down.

The Trudell No. M-17 well was completed in the Ratcliffe reservoir in March 1993 after an unsuccessful completion in the Red River. The well was perforated from 8701 to 8759 ft and fracture stimulated with 105,000 gal gel-water and 204,000 lb sand. The well had an initial rate of 77 bopd with 65 bwpd and has produced 15,430 bbl of oil as of March 31, 1995. Production history is displayed in **Fig. 20**. The rapid decline of oil rate from the well indicate a producibility problem.

The transmissibility (kh/μB) to oil is about 7 md-ft/cp and the transmissibility to total fluid (oil and water) is about 10 md-ft/cp. Permeability to oil (Kro) is calculated to be 0.5 md for a net thickness of 10 ft. At late-time on the Miller-Dyes-Hutchinson (MDH) plot, it is observed that there is an upwardly change of slope. This suggests a linear boundary such as a fault with a distance to this flow barrier at about 140 ft.

The final pressure after 332 hr was 1132 psig which is a significant draw-down from the original reservoir pressure of 3800 psig after only 15,430 bbl oil. Since there are no other Ratcliffe completions nearby which could cause pressure depletion, it is concluded that the reservoir drainage area is limited. The cause of this limited drainage may be caused primarily by faulting.

Hansen No. 1-21 (Red River) Pressure Buildup Evaluation
Haley field , API No. 33-011-31900
Sec. 21, T. 129 N., R. 101 W., Bowman Co., ND

The buildup test data from October 18 through November 1, 1994 indicate non-radial drainage for the Hansen No. 1-21 well. The final bottomhole pressure was about 1550 psig and still building after 329 hr of shut-in time. A possible cause for the non-radial flow is multiple faults.

The Hansen No. 1-21 well was drillstem tested in the Red River upper member on August 6, 1980. The test has a calculated flow rate of about 177 bopd with no water reported for the pipe or sample chamber recovery. The transmissibility (kh/μB) from the test data is calculated to be 38 md-ft/cp and is near the mean value of the many DST data from the Red River upper member in the Bowman-Harding area.

The Hansen well was perforated in the Red River upper member and stimulated with 2000 gal of 15% HCl. The peak production rate was 80 bopd with 23 bwpd. Production quickly declined to 25 bopd with 15 bwpd after two weeks. Cumulative production is only 33,961 bbl of oil as of March 1995.

The pressure data from the buildup test exhibit an upward-curving trend with the logarithm of time and do not bend-over (see **Fig. 21**). Conventional MDH semi-log analysis of the late-time trend indicates a transmissibility of 1.6 md-ft/cp and a skin of -4.3. However, a better analysis is achieved by analytical simulation methods of the well placed between two parallel faults. A good history-match of the pressure data can be achieved with this reservoir model and also using the transmissibility of 36 md-ft/cp from the DST . Using the parallel-fault reservoir model in simulation of the DST data also produces a better history-match than a radial reservoir model. Comparison of the post-completion build-up test data to the DST data leads to the conclusion that the producibility problem of the Hansen No. 1-21 well is not caused by low pressure, poor permeability near the well bore or stimulation efficiency.

Re-interpretation of 2-D seismic data in the Haley area indicates subtle faulting near the Hansen well. This fault trend runs northwest-southeast. The presence of a fault or series of parallel faults can explain the poor performance of the Hansen well when compared to the results from the DST.

Recovery Technology Evaluations
Well Stimulation

Jetting Lance Field Activities

Extended-reach horizontal jetting-lance technology is under investigation as a means of improved completion efficiency in carbonate reservoirs. Two Red River wells in the Bowman-Harding area were perforated with 10-ft jetting lance tools. Although tool-operation pressures indicated full extension at each jetting perforation, neither well has experienced increased oil or total fluid production rates.

Red River reservoir intervals are typically treated with hydrochloric acid at completion. There are several examples where large acid treatments communicate behind-pipe to other adjacent Red River porosity benches. This can result in water production from wet intervals. In the case of injection wells, injected water may be diverted away from the primary pay zone through behind-pipe communication.

Low water-injectivity has impeded the initiation of waterflood projects for the Red River in the Bowman-Harding area. The one Red River waterflood project in Harding County, SD, has average water injection rates of 50 bwpd per well. Extended-reach completions should be effective in relatively thin reservoir beds such as the upper member of the Red River which is the target reservoir for secondary recovery in the area.

Hansen No. 1-21 (Red River) Jetting Lance Stimulation
Haley Field Area, API No. 33-011-31900
SWSE Sec. 21, T.129 N, R. 101 W., Bowman Co., ND

The Hansen well was originally completed in the Red River upper member in 1981 and has a cumulative production of 35,093 bbl oil and 19,650 bbl water. Before the workover, the well was producing 5 bopd with no water. After the jetting-lance perforations, the producing rate was 6 bopd and no water.

Jetting lance penetrations of 10 ft were made into the Red River upper and middle members using a commercial service (Penetrators, Inc.) did not result in improved oil production although additional intervals were added to the original completion. Four holes were made to a penetration depth of 10 ft in the upper and middle porosity members. Surface pressure monitoring of tool operation indicated full deployment of the jetting lance at each penetration. The intervals were not acidized after jetting-lance penetrations.

Swanson No. 1-32 (Red River)
East Harding Springs Field, API No. 40-063-20145
E/2SW Sec. 32, T. 23 N., T. 6 E., Harding Co., SD

Jetting lance penetrations into each of the Red River porosity members did not result in improving oil production. The Swanson well was originally completed in the Red River in 1978 and has a cumulative production of 76,815 bbl oil and 356,211 bbl water. Last production from the well prior to the well work was 6 bopd and 20 bwpd in 1994. The well had been shut-in since that time because of sub-economic production.

Jetting lance perforations with a 10-ft tool were made into each Red River bench. A total of 11 holes were made; four in the upper member, five in the middle member and two in the lower member. Surface pressure monitoring of tool operation indicated full deployment of the jetting lance at each penetration but production rates after the workover indicated no change from pre-workover rates. Production after the workover stabilized at 5 bopd and 20 bwpd. The intervals were not acidized after jetting-lance penetrations.

The project has hoped to use a 50-ft jetting lance tool. Horizontal jetting-lance operations with this tool were unsuccessfully attempted in the Luff Travers No. 1-6 well (sec. 6, T. 22 N., R. 3 E., Harding County, SD) during December, 1994. Two attempts to drill horizontal holes were made during the period December 5 - 10 . On the last attempt, the casing was penetrated and a penetration of 2 ft was made into the formation before losing pressure through the lance. Attempts were unsuccessful to retract and release the drilling tool. From December 12 through December 20, fishing operations were conducted. The Red River upper and middle zones are still accessible in the wellbore for future attempts. There was no cost sharing burden to the DOE for this work at the Travers No. 1-6 well as the work was considered developmental.

The effort to use the 50-ft horizontal jetting-lance tool clearly evidences that the tool is in a developmental stage, not implementation as was perceived. From December 1994 through June 1995, modifications and testing of the 50-ft lance tools have been made outside of project activities. The tool has worked successfully at shallower depths where less pressure is required. The tool was brought back to the Bowman-Harding Red River area in May, but is still plagued by problems associated with multiple casing weights across salt sections and the high operational pressure requirements.

Recovery Technology Evaluations
Reservoir Analysis

Injectivity Test

Stearns No. A-19 (Red River)
North Buffalo Field Area, API No. 40-063-20368
Sec. 19, T. 22 N., R. 4 E., Harding Co., SD

A 20-day water injection test commenced on March 23, 1995, at the Stearns No. A-19 well and was performed as a base-line evaluation prior to multiple penetrations with the 50-foot jetting lance tool. Water was injected at 100 bpd into the 15-foot Red River upper member at 8,774 ft with pressure gauges on bottom for the duration of the test. The pressure data do not exhibit anomalies which suggest nearby flow barriers or transmissibility changes. The reservoir characteristics from the pressure transient analysis are as follows:

Static reservoir pressure at start	2,273	psi
Water transmissibility (kh/μB)	45.5	md-ft/cp
Water permeability (Krw)	0.88	md
Skin factor "S"	-3.2	
Final injection pressure	3,625	psi

The results from this test indicate that the maximum stabilized injection rate would be about 150 bwpd at a parting pressure of 5,500 psi. This injectivity can be equated to about 10 bwpd per foot of net pay.

After re-working the completion with the 50-foot jetting lance tool or other ultra-short-radius lateral technology, plans call for a repeat of the 20-day injectivity test procedure to quantify improvements to completion efficiency in the Red River upper member.

Waterflooding

The waterflooding history at West Buffalo Red River 'B' Unit, T. 21 N., R. 3 E., Harding County, SD, (see **Fig. 6** for field location) was evaluated by computer simulation and history matching. This unit is determined to have an original-oil-in-place (OOIP) of 20,600,000 stb under a net productive area of 2,850 ac. Recovery by primary production is predicted to be 516,000 stb or 2.5% of OOIP. The low primary recovery is attributed, in part, to a bubble-point pressure (weak drive mechanism) of less than 500 psi and reservoir heterogeneity. Reservoir heterogeneity is indicated from the pressure history of the field. The DST pressure data plotted with cumulative oil production show high pressures encountered by development wells.

At the time of the simulation study, there were 10 wells spaced on approximately 160-ac patterns with water injection through down-dip, peripheral wells. The secondary recovery by waterflooding and this well configuration is predicted to be 5,000,000 stb or

24% of OOIP; however, the time to produce this recovery would be nearly 90 years. Two horizontal wells were drilled (one producer and one injector) in the last 12 months at the West Buffalo Red River "B" Unit. The first six months of reported injection volumes indicate a daily injection rate of about 400 bwpd. This is nearly an eight-fold increase over the average injection rate of the conventional vertical wells. Production rates from the horizontal producer are at 75 bopd and 30 bwpd after six months. Injection and production data from these horizontal wells will be monitored as they become available.

Computer simulation for history-matching and prediction of remaining primary recovery at Southwest Amor (Red River), T. 130 N., R. 104 W., Bowman Co., ND, were performed (see **Fig. 12** for map of field area). The reservoir is produced by four wells spaced on approximately 160-ac locations, although the production units are 320 ac according to field rules. The Southwest Amor wells produce mostly from the Red River upper-member interval. The original-oil-in-place is determined to be 8,573,000 stock tank bbl (stb) with a predicted primary recovery of nearly 2,409,000 stb or a recovery factor of 28%. The combined drainage area of the wells is determined to be 1,176 ac and is in agreement with the reservoir limits inferred from geophysical interpretations. The higher primary recovery from SW Amor compared to the West Buffalo Red River 'B' Unit is attributed to lower oil viscosity, higher solution-gas content and under-estimation of reservoir volume because of limited well control.

The configuration of the successful history-match model was used to screen three development possibilities for the SW Amor field area, which include:

(1) four additional infill wells for acceleration of primary (8 producers),
(2) secondary recovery with existing wells (2 producers and 2 injectors), and
(3) four additional infill wells for secondary recovery with existing wells (4 producers and 4 injectors).

Secondary recovery by water injection with the existing wells was predicted to add an incremental 700,000 stb, however, investment and economic calculations indicate a decrease in present-worth from the existing primary operations. The addition of four new wells for waterflooding results in a prediction of 1,160,000 stb over the current primary operations. The present-value of recovery by this prediction is nearly double that of existing remaining primary, however, the recovery time is predicted to be in excess of 40 years. A development plan for the field should consider that the effective lives of these wells may be 25 years. The simulation studies indicate that infill drilling and enhanced completion efficiency are pre-requisites for secondary recovery by waterflooding from this typical Red River reservoir.

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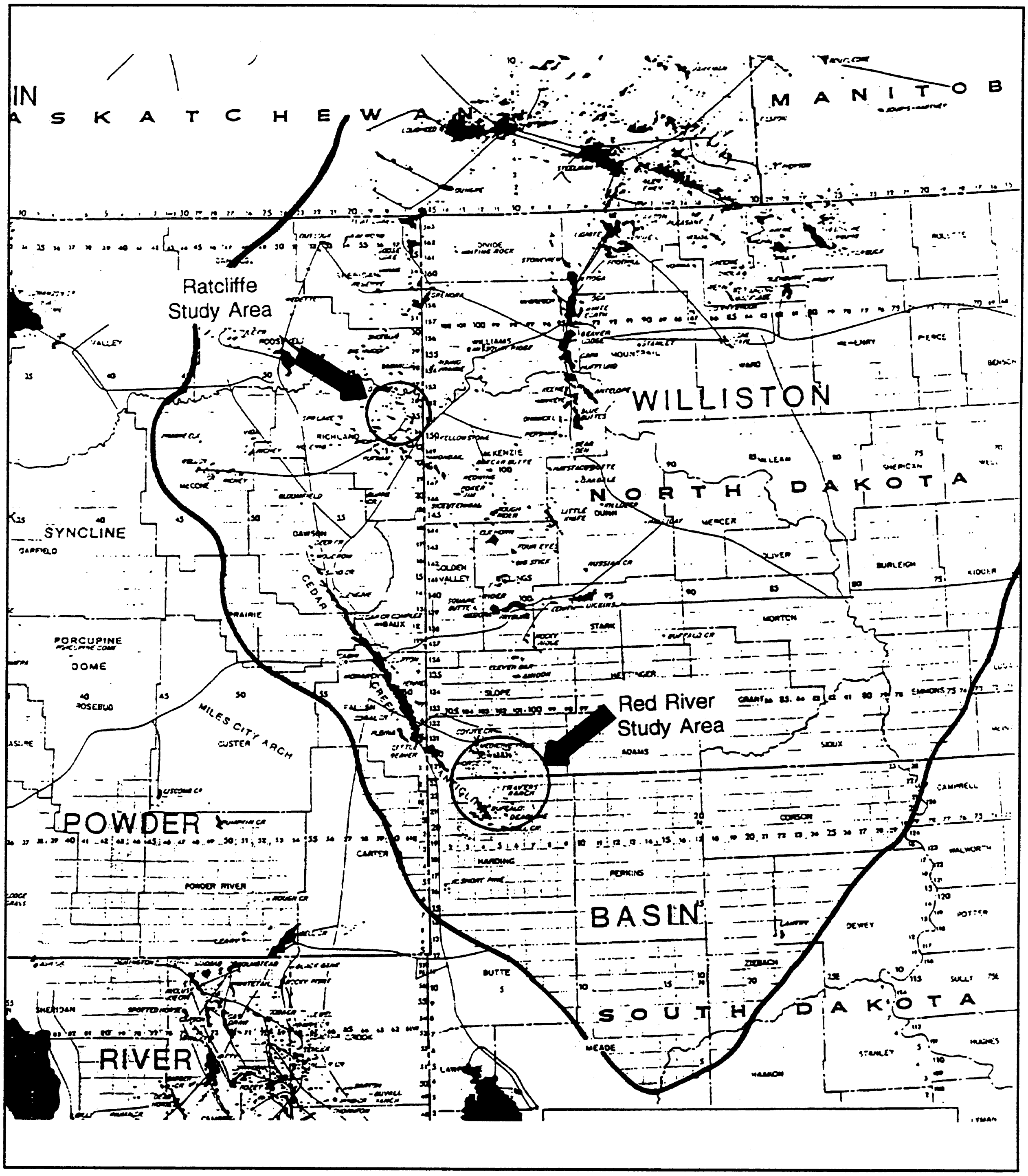

Figure 1: Map of Williston Basin showing general study areas involved in the project "Improved Recovery Demonstration for Williston Basin Carbonates". Ordovician Red River area is in Bowman County, ND and Harding County, SD. Mississippian Ratcliffe area is in Richland County, MT.

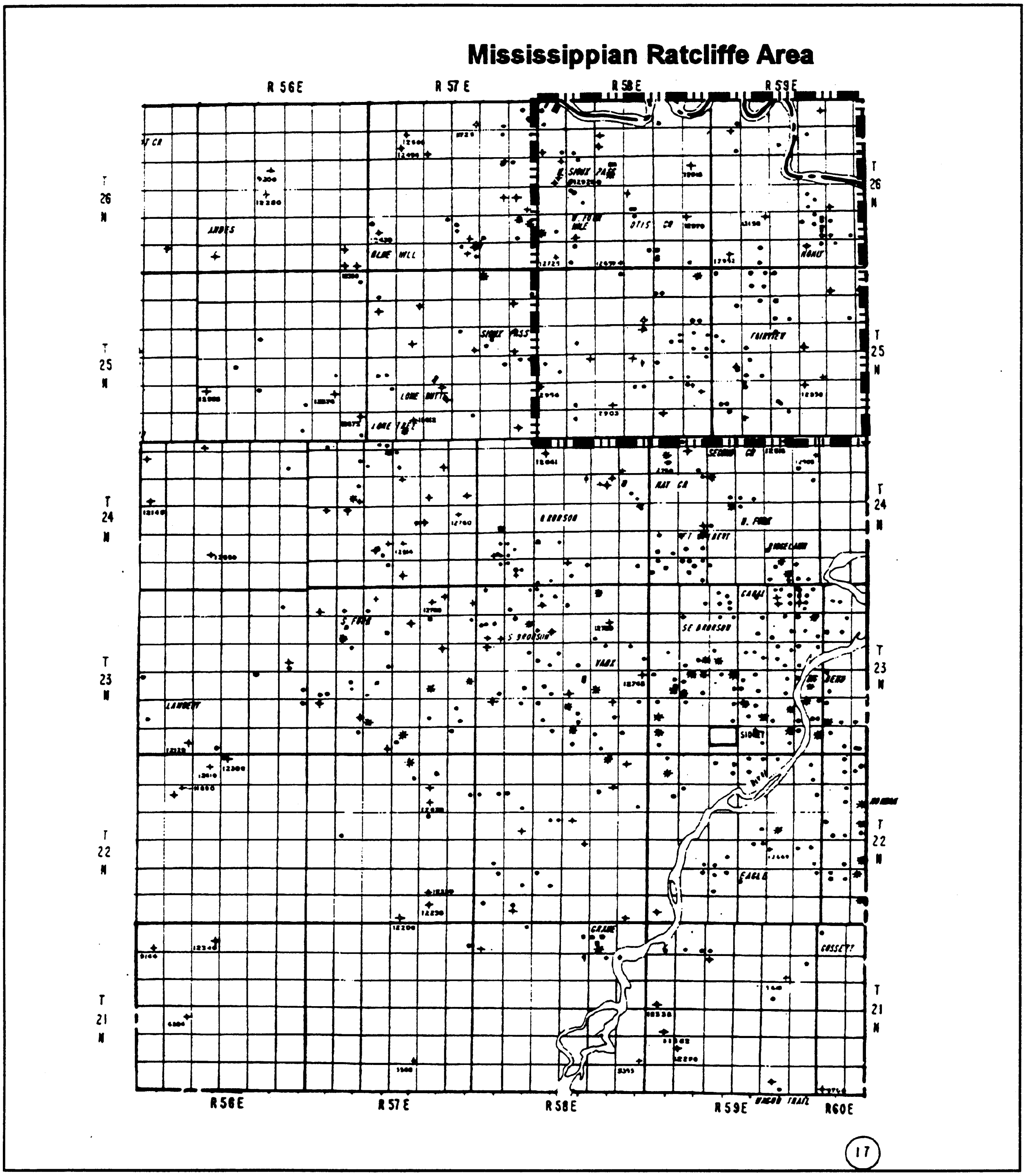

Figure 2: Map of a portion of the Williston Basin designated as the Mississippian Ratcliffe study area located in Richland County, MT.

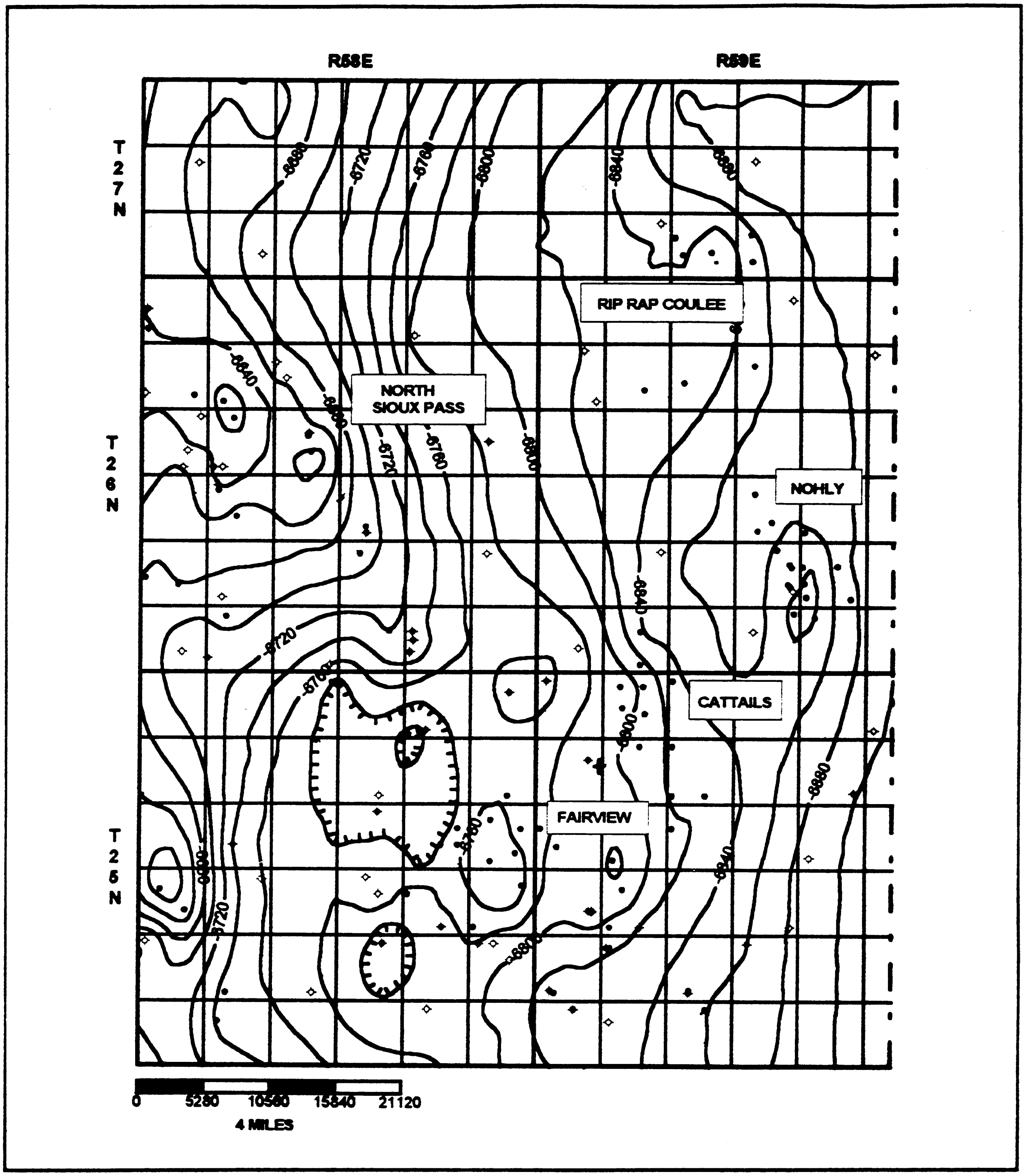

Figure 3: Detail map of Mississippian Ratcliffe study area annotated with fields of interest. Structural contours are on top of the Ratcliffe member of the Charles formation.

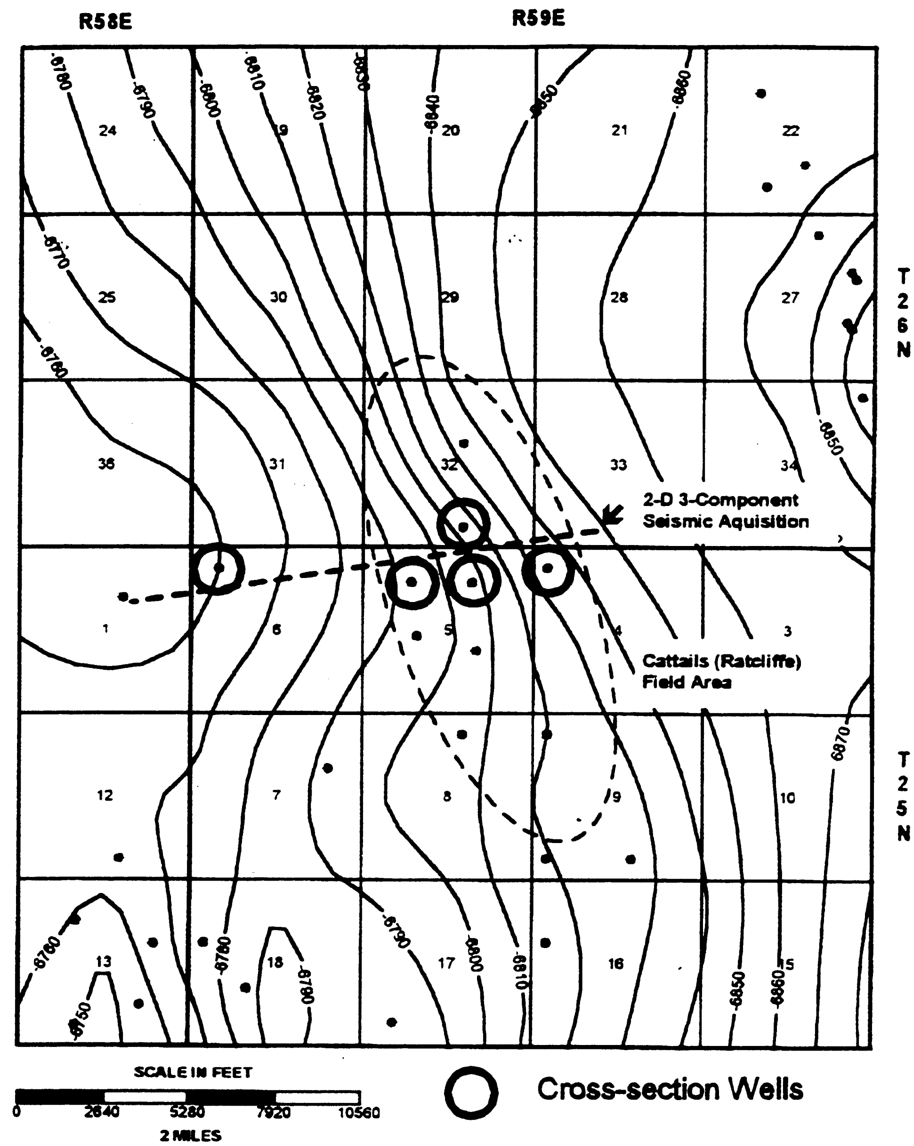

Figure 4: **Map of Cattails (Ratcliffe) field area with structure contours on top of the Ratcliffe. The 3-Component 2-D seismic line crosses the axis of the productive area. Cattails field does not demonstrate structural closure.**

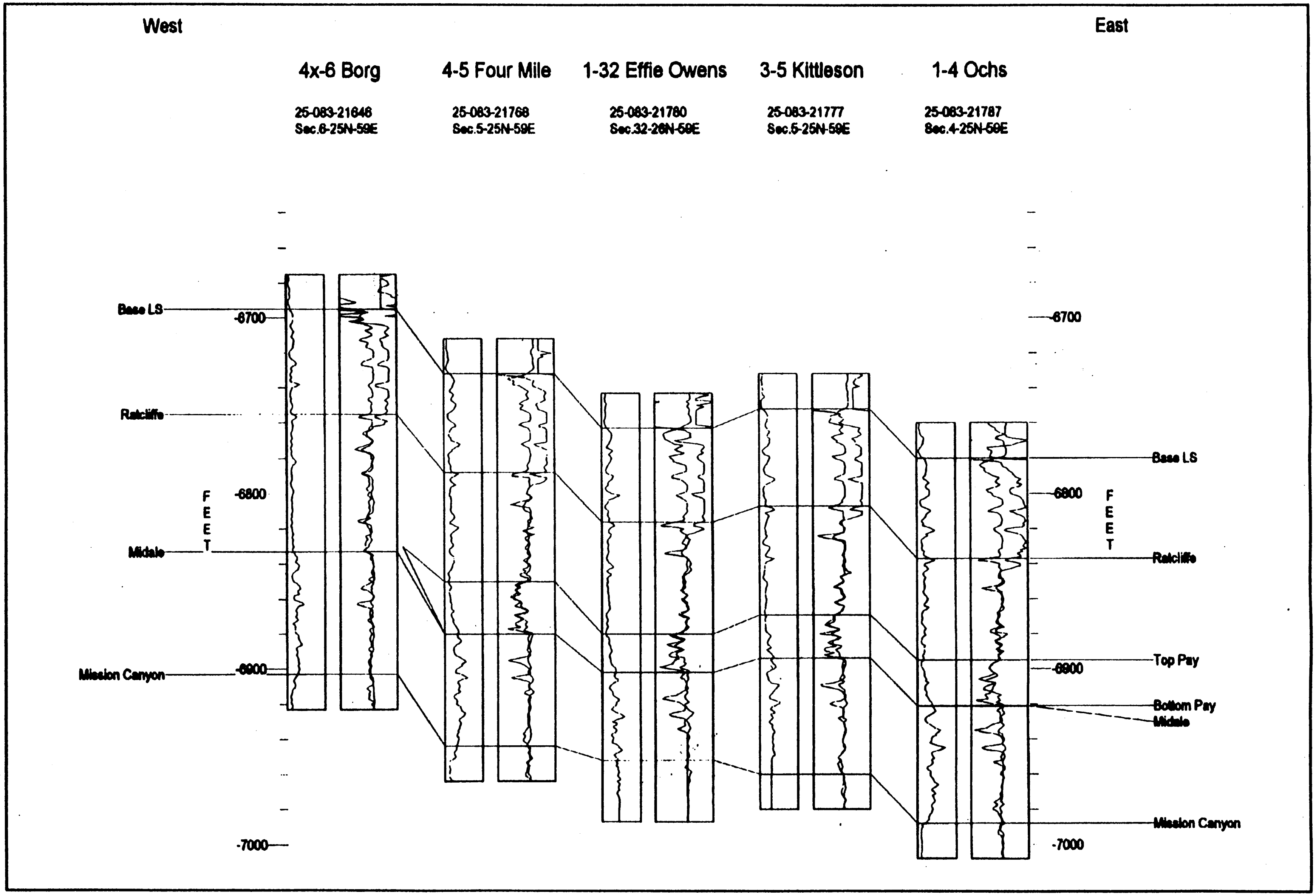

Figure 5: East-west structural cross-section of Ratcliffe interval over Cattails field in Richland Co., MT. Porosity pinches-out on the west and up-dip side, shown between the 4X-6 Borg and 4-5 Four Mile wells.

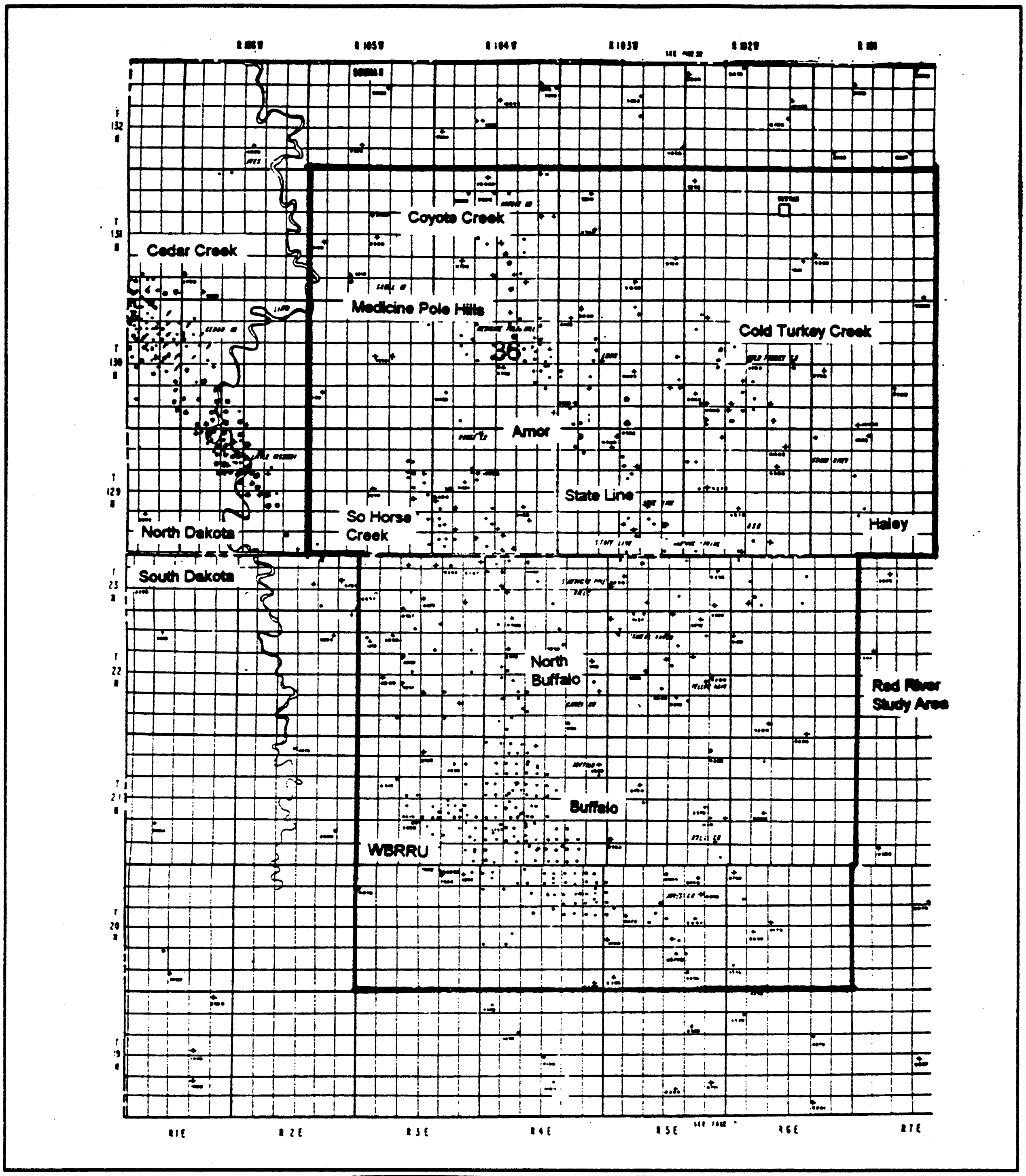

Figure 6: Regional map of southwest portion of the Williston Basin designated as the Ordovician Red River study area in portions of Bowman Co., ND and Harding Co., SD.

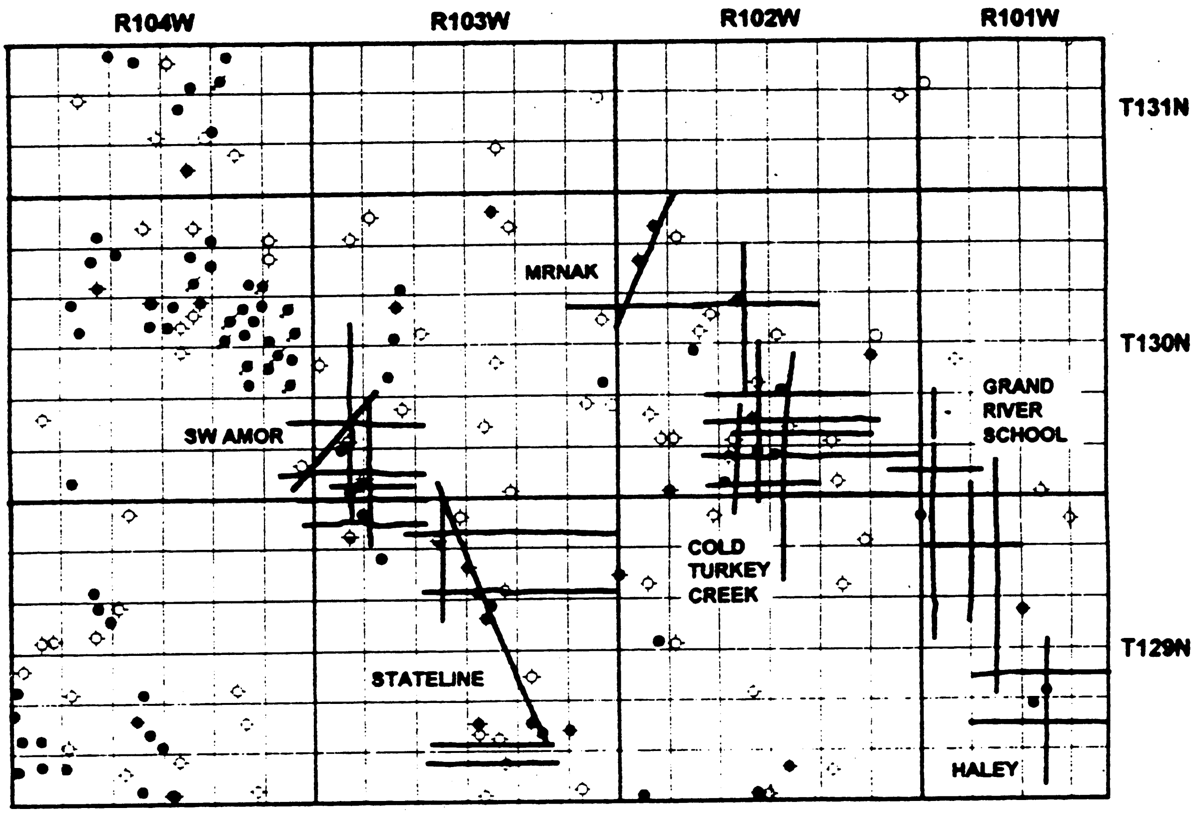

Figure 7: Map showing a portion of the Bowman-Harding Red River study area with locations of 1970's vintage 2-D seismic data which were re-processed in 1994. Fields of interest to this project are also annotated.

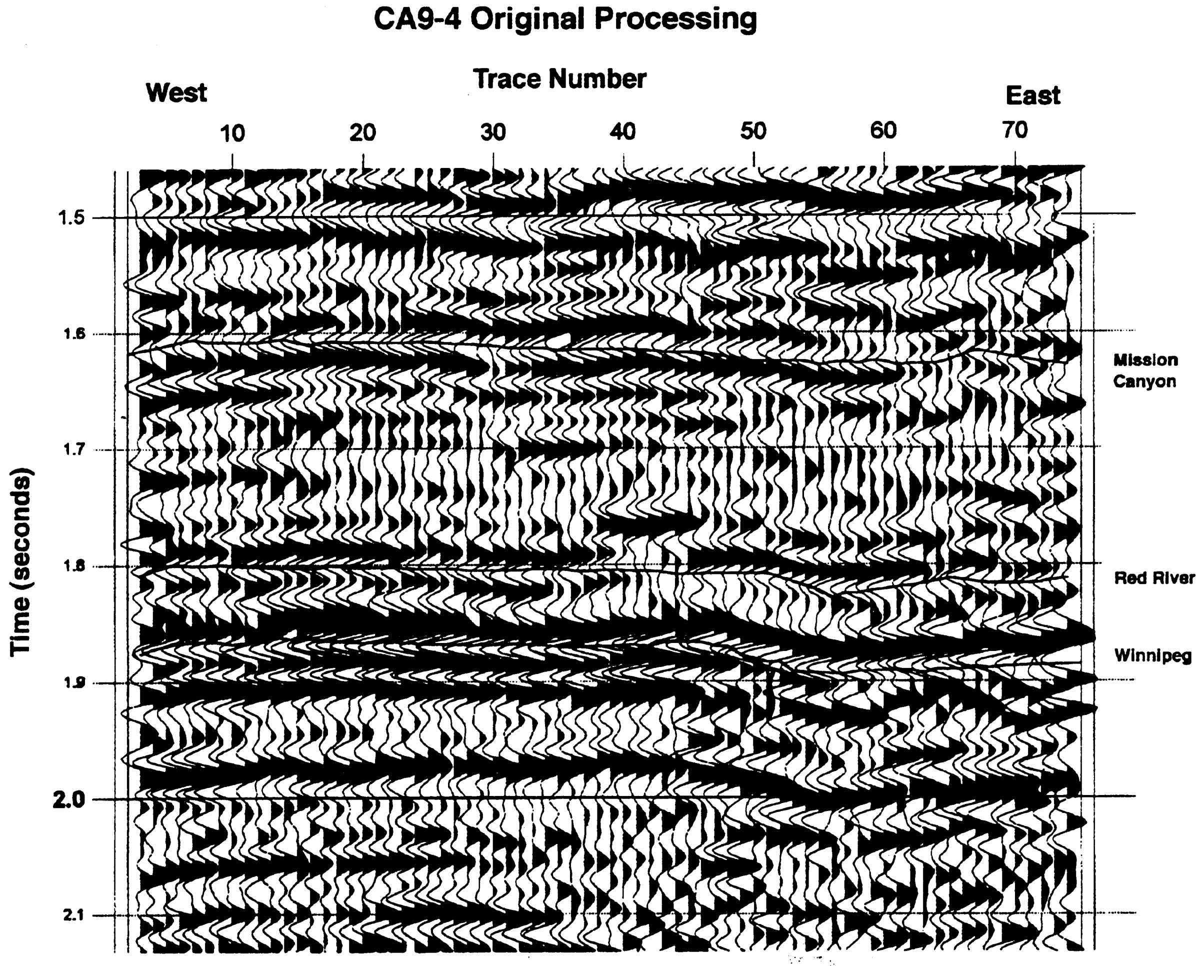

Figure 8: Example of 2-D seismic data section CA9-4 from the Southwest Amor field, Bowman Co., ND, as processed in 1972.

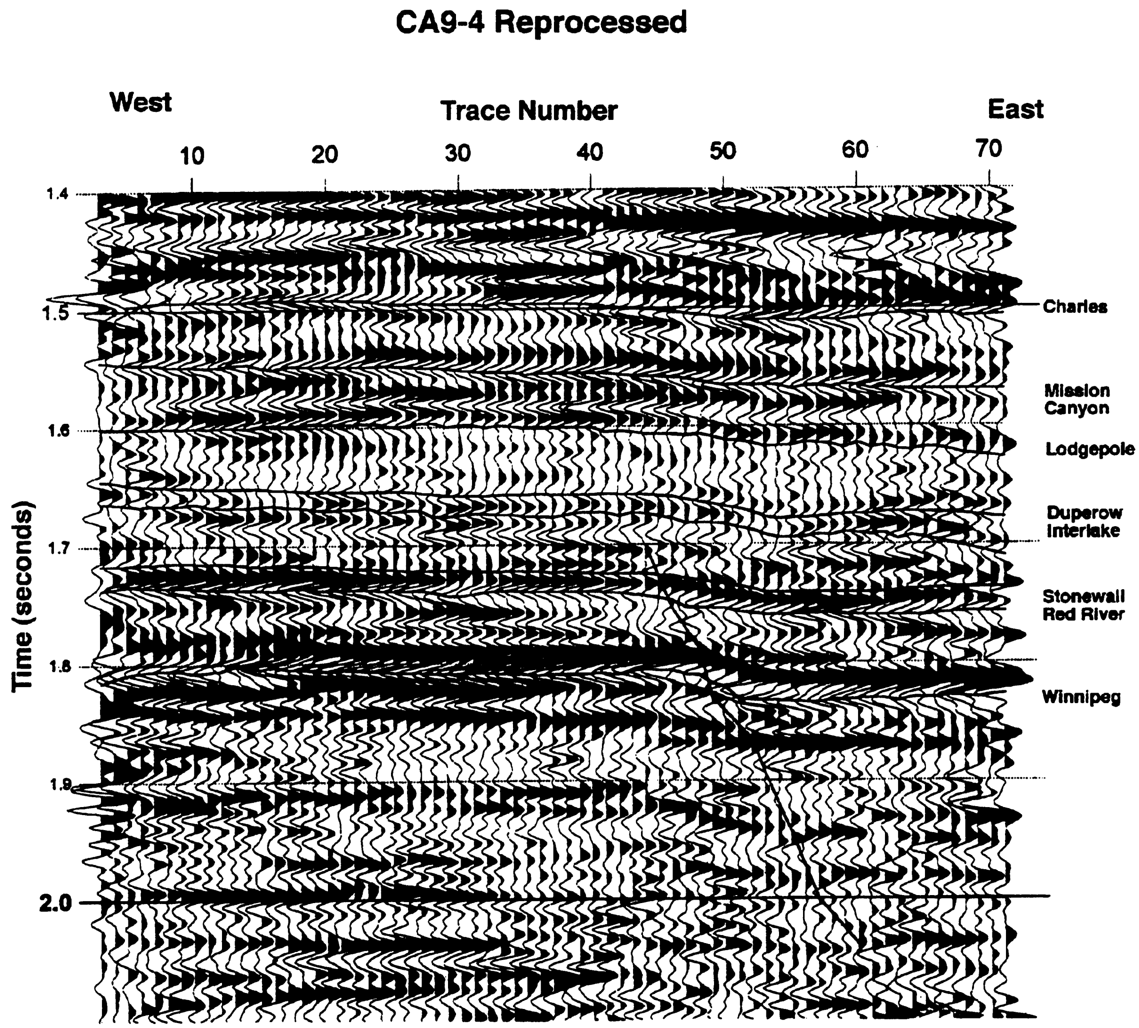

Figure 9: Example of 2-D seismic data section CA9-4 from Southwest Amor field after re-processing in 1994. The higher frequency content allows interpretation of subtle faults and mapping of additional horizons. The fault trends north-northwest and is down to the northeast. Maximum displacement is 45-50 ft at Ordovocian Winninpeg.

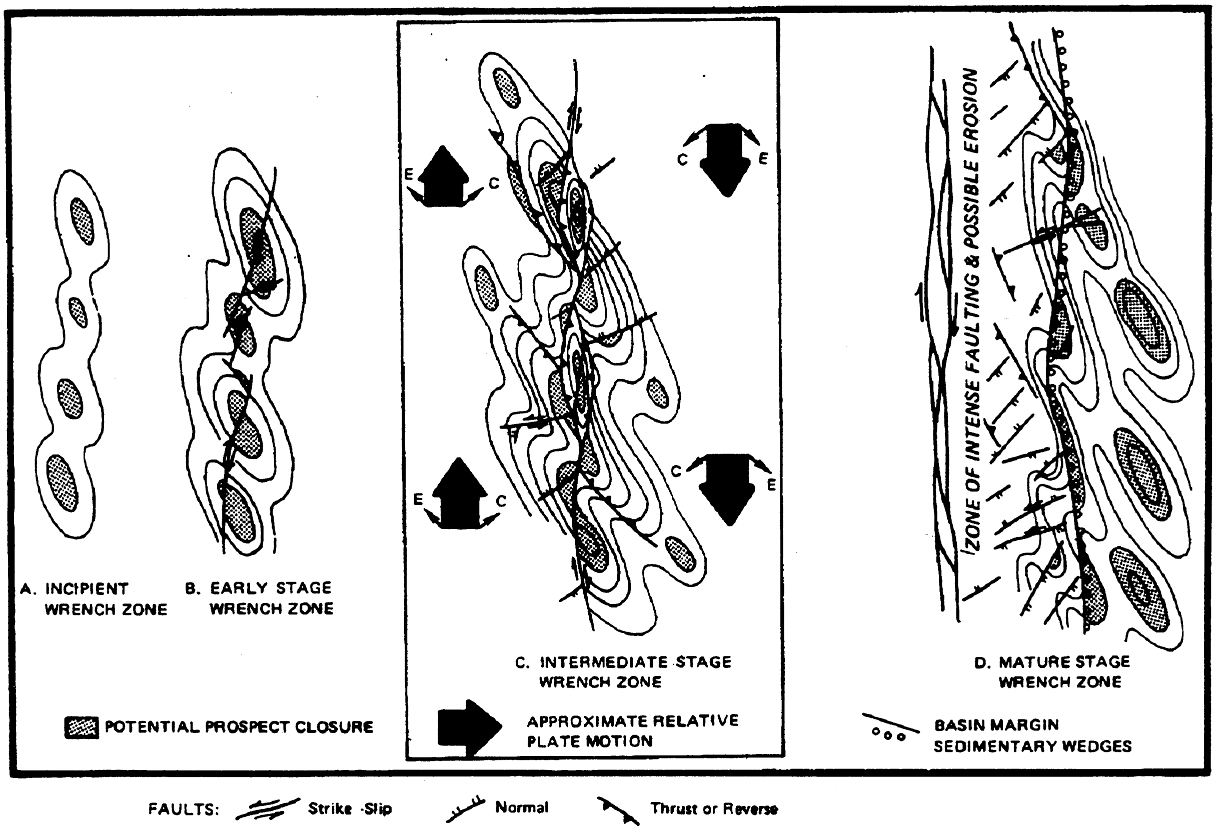

Figure 10: Schematic diagram of structural assemblages associated with wrench faulting and early stages in the evolution of hydrocarbon entrapment. Arrows depict right-lateral coupling motion. The Bowman-Harding Red River area exhibits early to intermediate-stage left-lateral wrenching. After Lowell (1985)

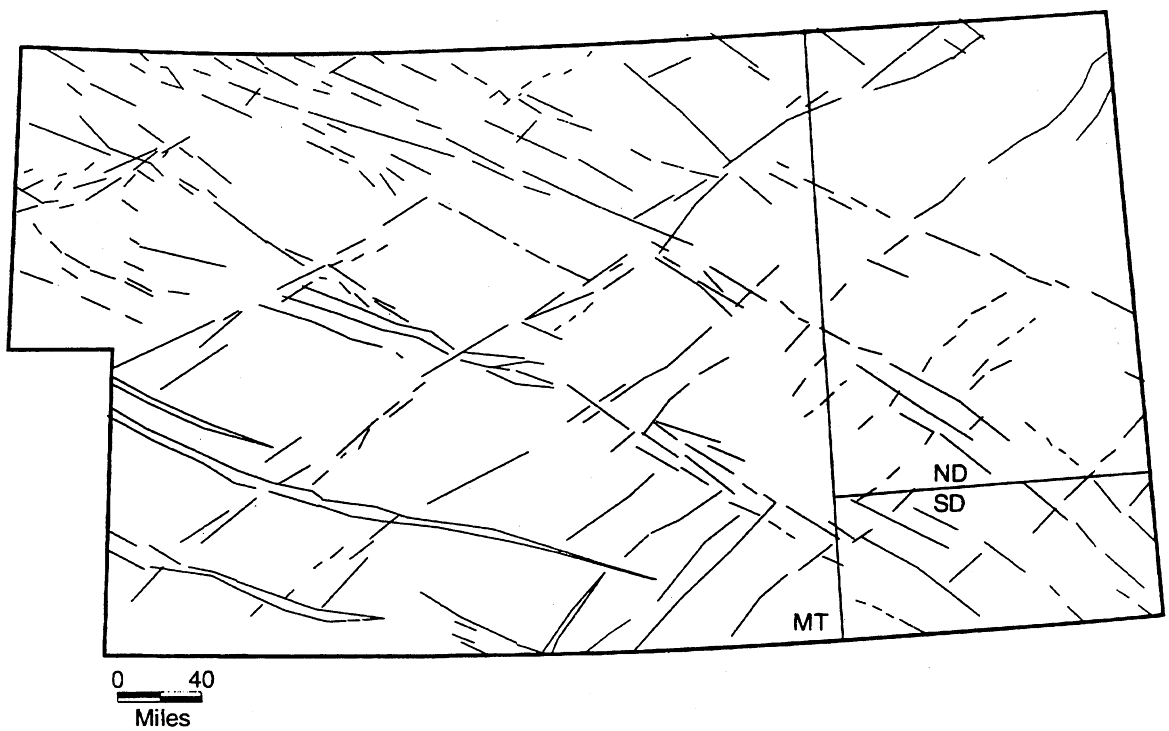

Figure 11: Regional lineament patterns in the Williston Basin after Thomas, 1974.

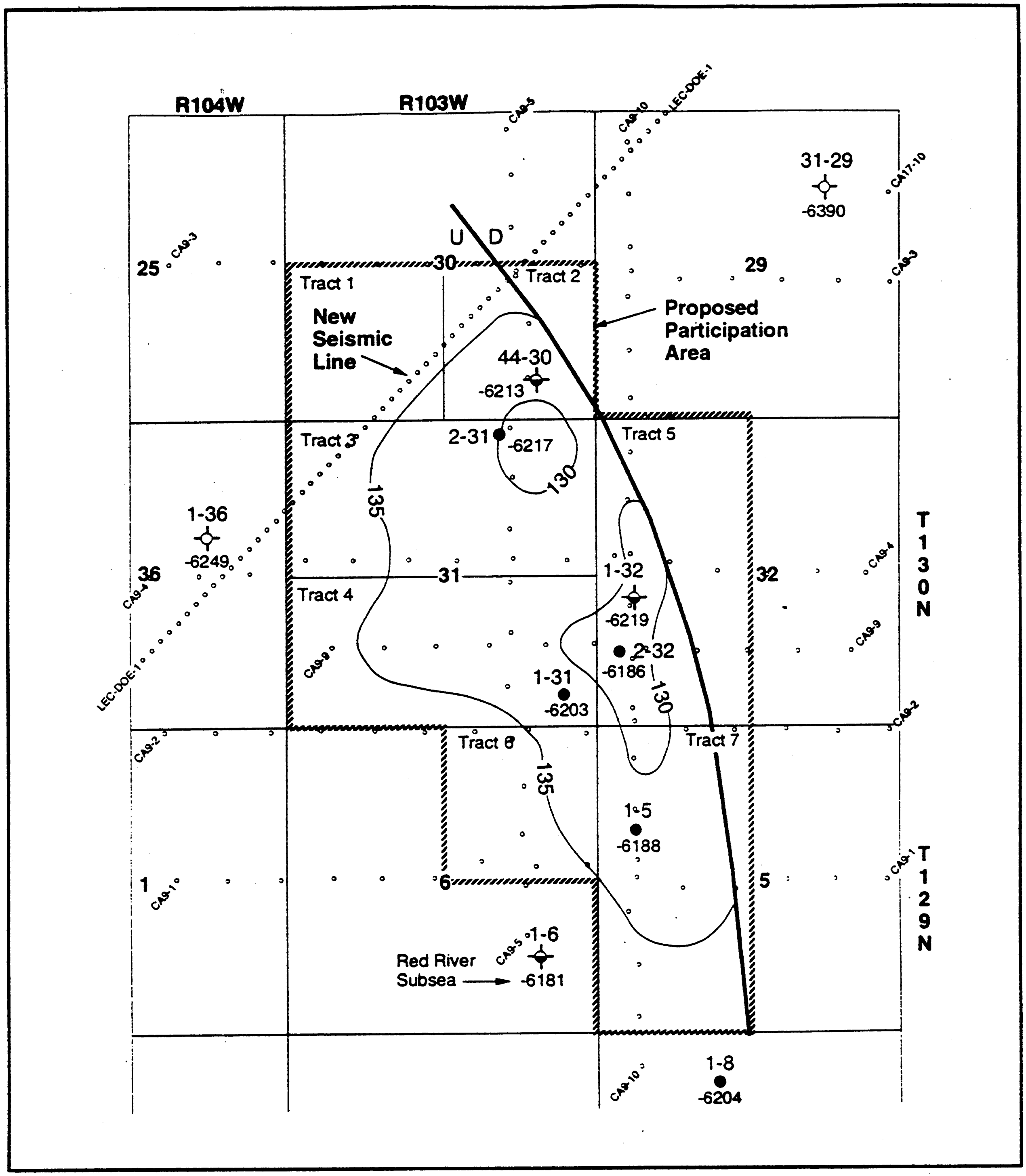

Figure 12: Isochron map of Interlake to Winnipeg horizon time over the Southwest Amor (Red River) field, Bowman Co., ND. The location of project 2-D line 94-LECDOE-1 is shown with other 2-D data coverage which were used for the interpretation.

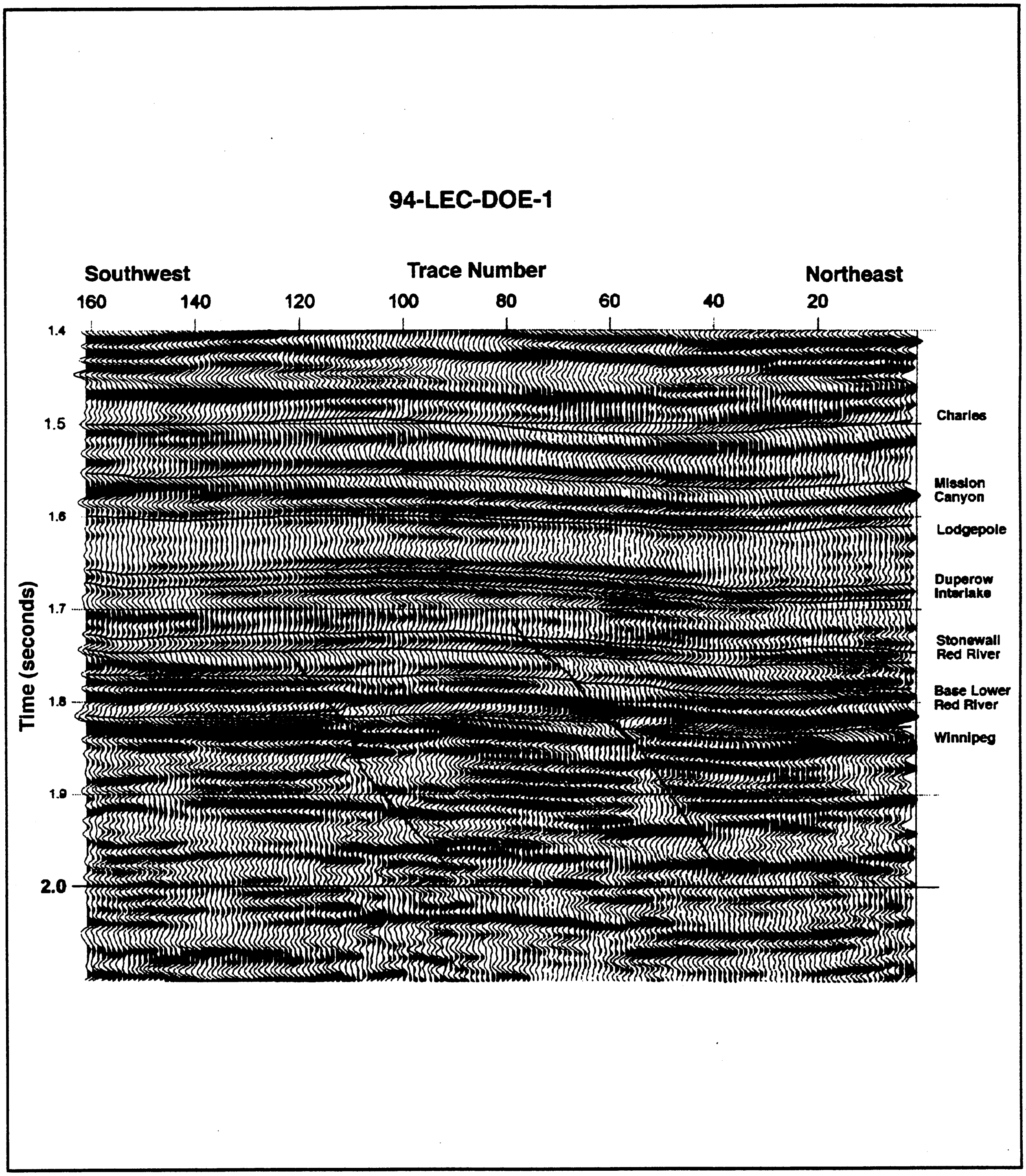

Figure 13: Portion of seismic section from 94-LECDOE-1 in Southwest Amor field, Bowman Co., ND. The line was acquired with 20-fold coverage and a 110-ft group interval. Ten-lb dynamite charges were buried at 60 ft.

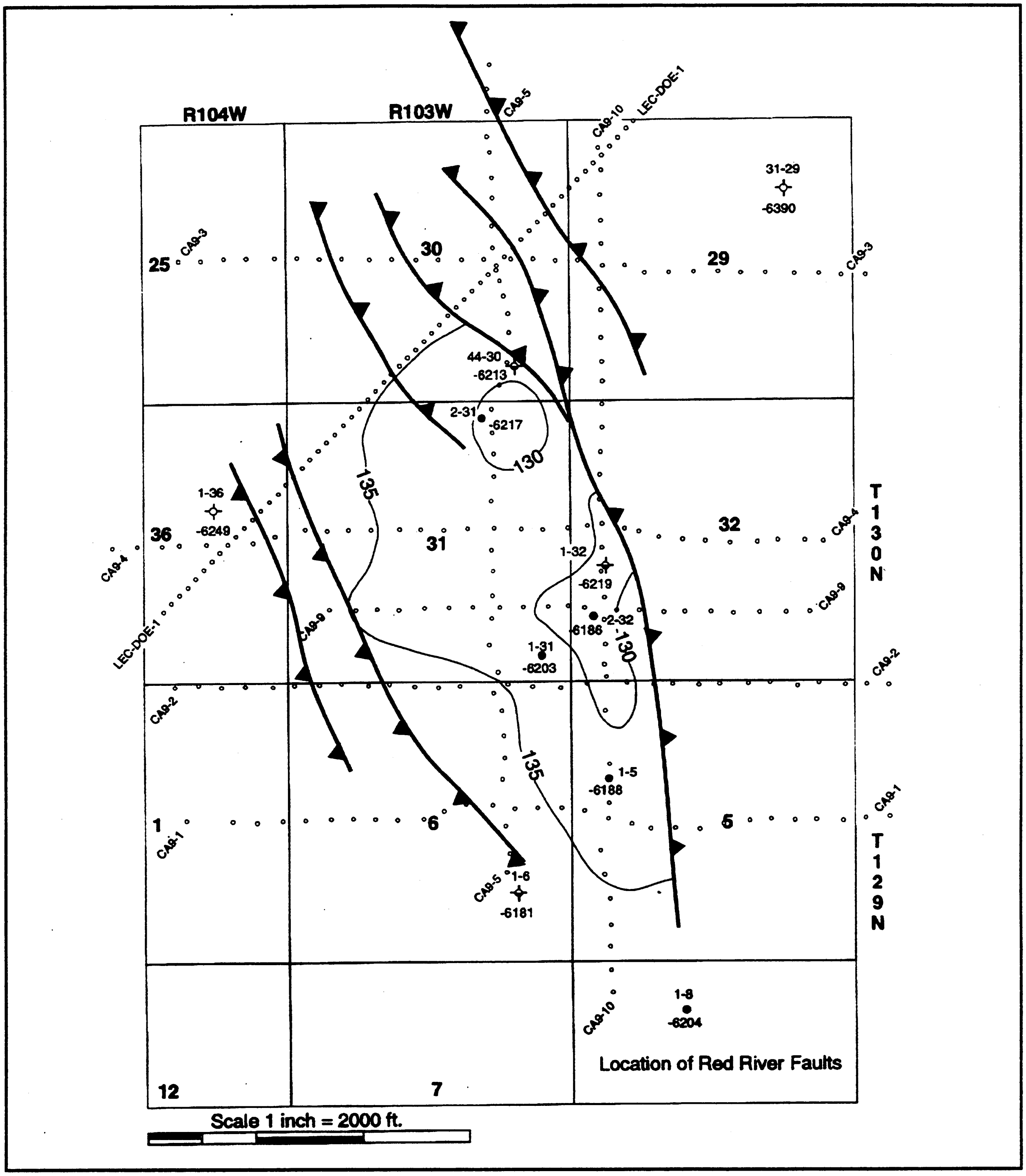

Figure 14: Map of faulting at the Red River in Southwest Amor field, Bowman Co., ND. Most of these faults could be interpreted only after acqisition of seismic line 94-LECDOE-1 and re-processing other older 2-D data.

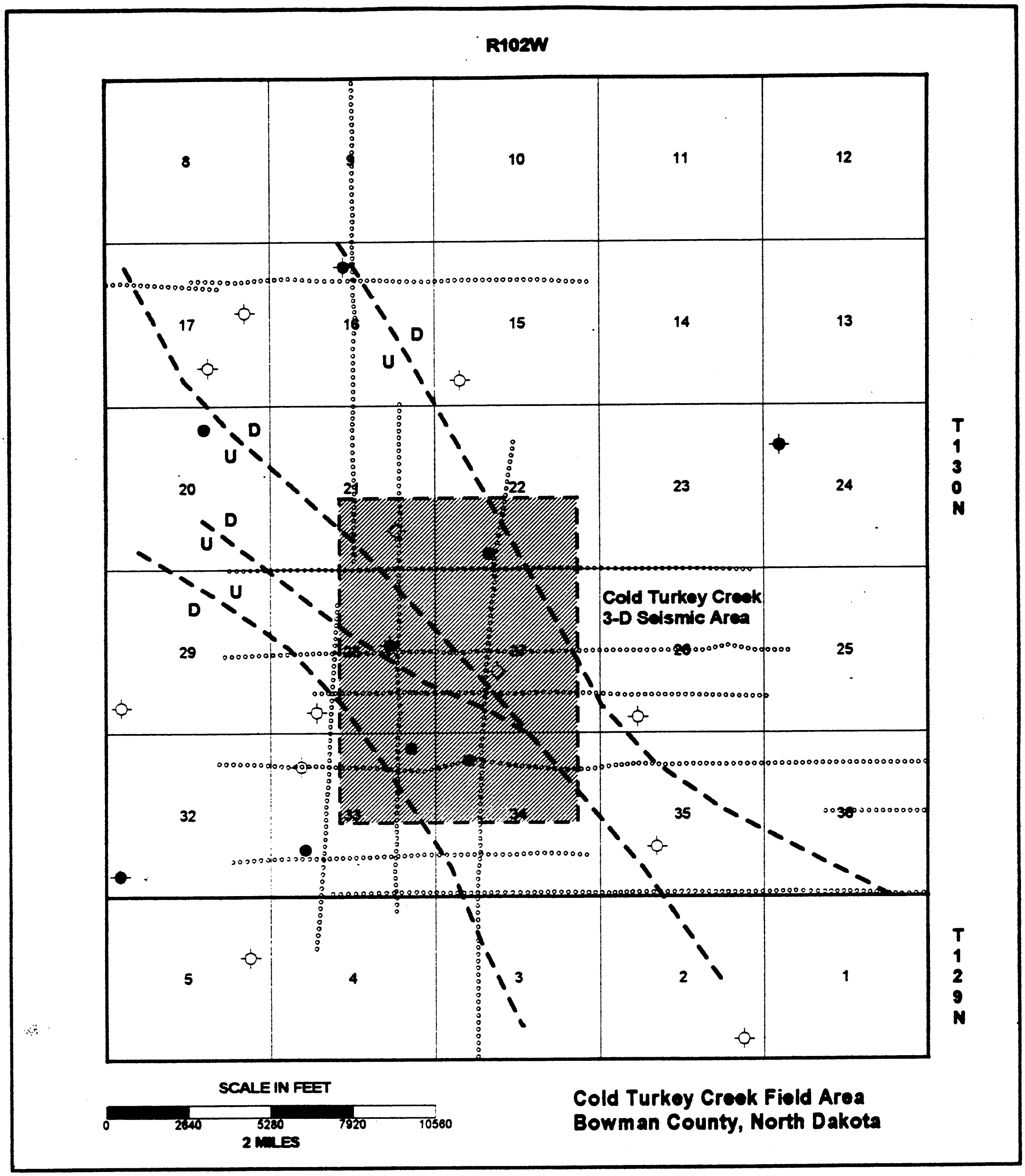

Figure 15: Map of Cold Turkey Creek field, Bowman Co., ND with locations of 3-D seismic survey and 1970's vintage 2-D seismic data. Faulting interpretation resulted from re-processed 2-D seismic data.

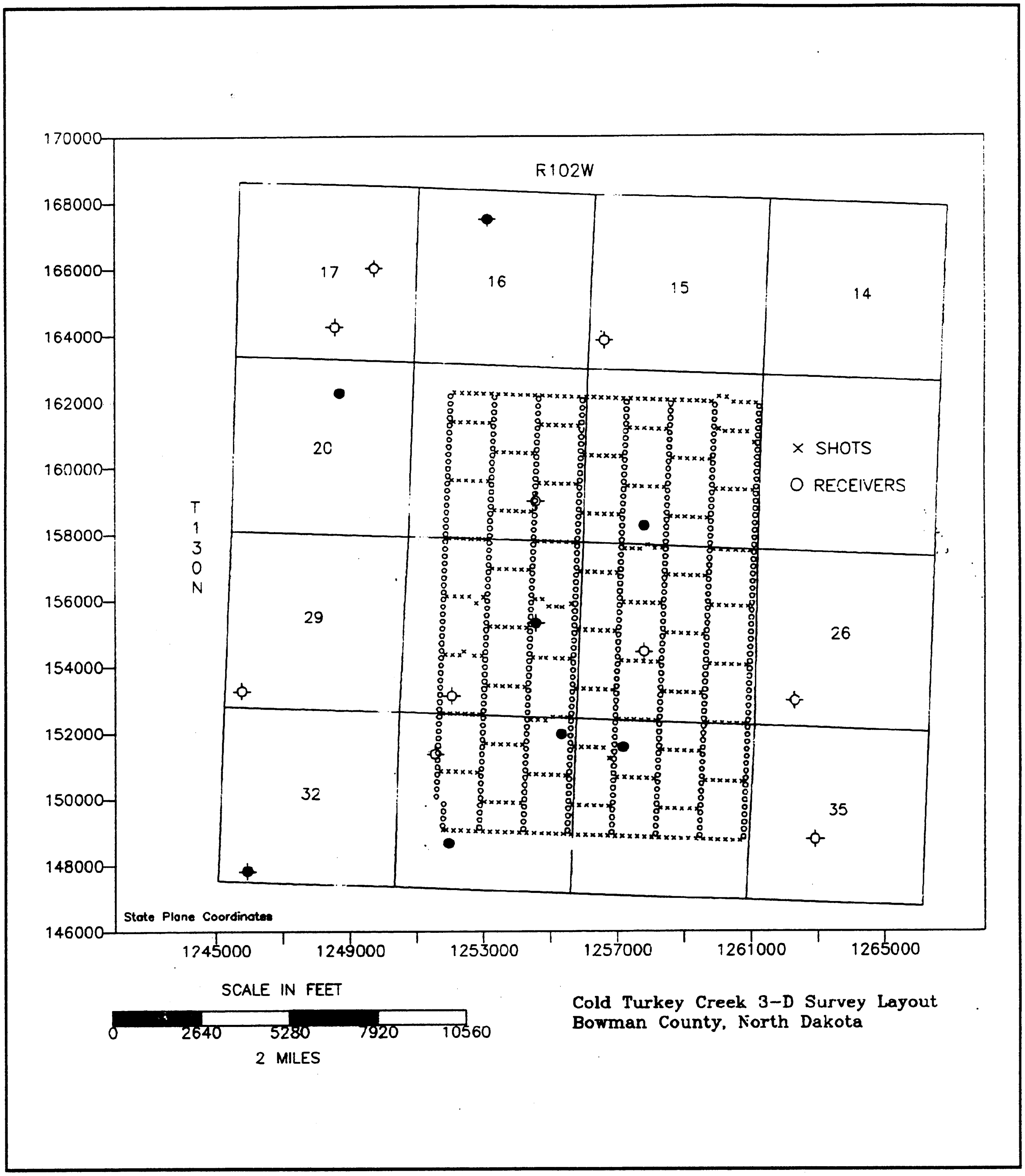

Figure 16: Acquisition design for 3-D survey at Cold Turkey Creek field, Bowman Co., ND. The staggered-brick design used 10-lb dynamite charges buried at 60 ft.

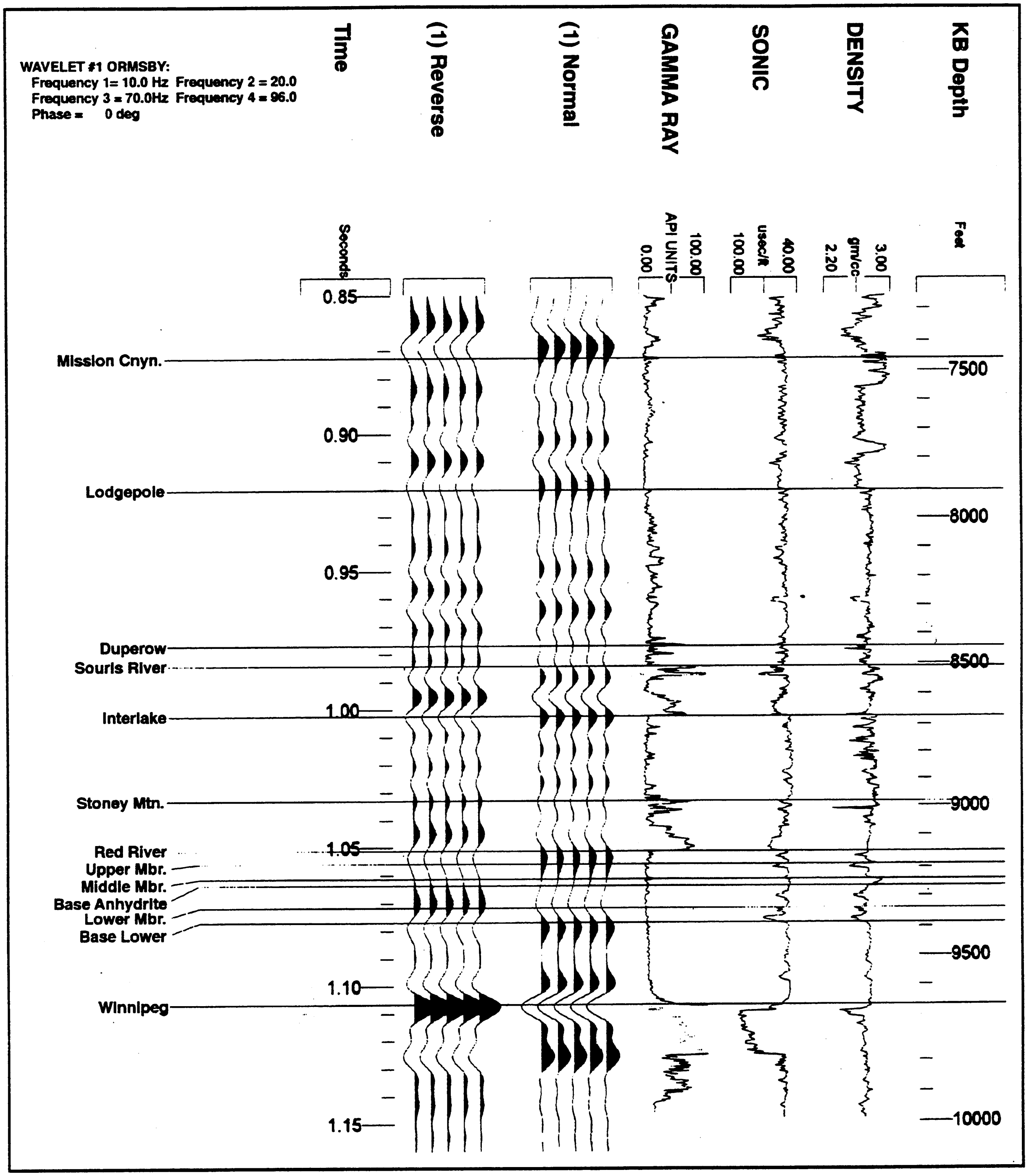

Figure 17: Typical synthetic siesmogram from the Cold Turkey Creek field, Bowman Co., ND.

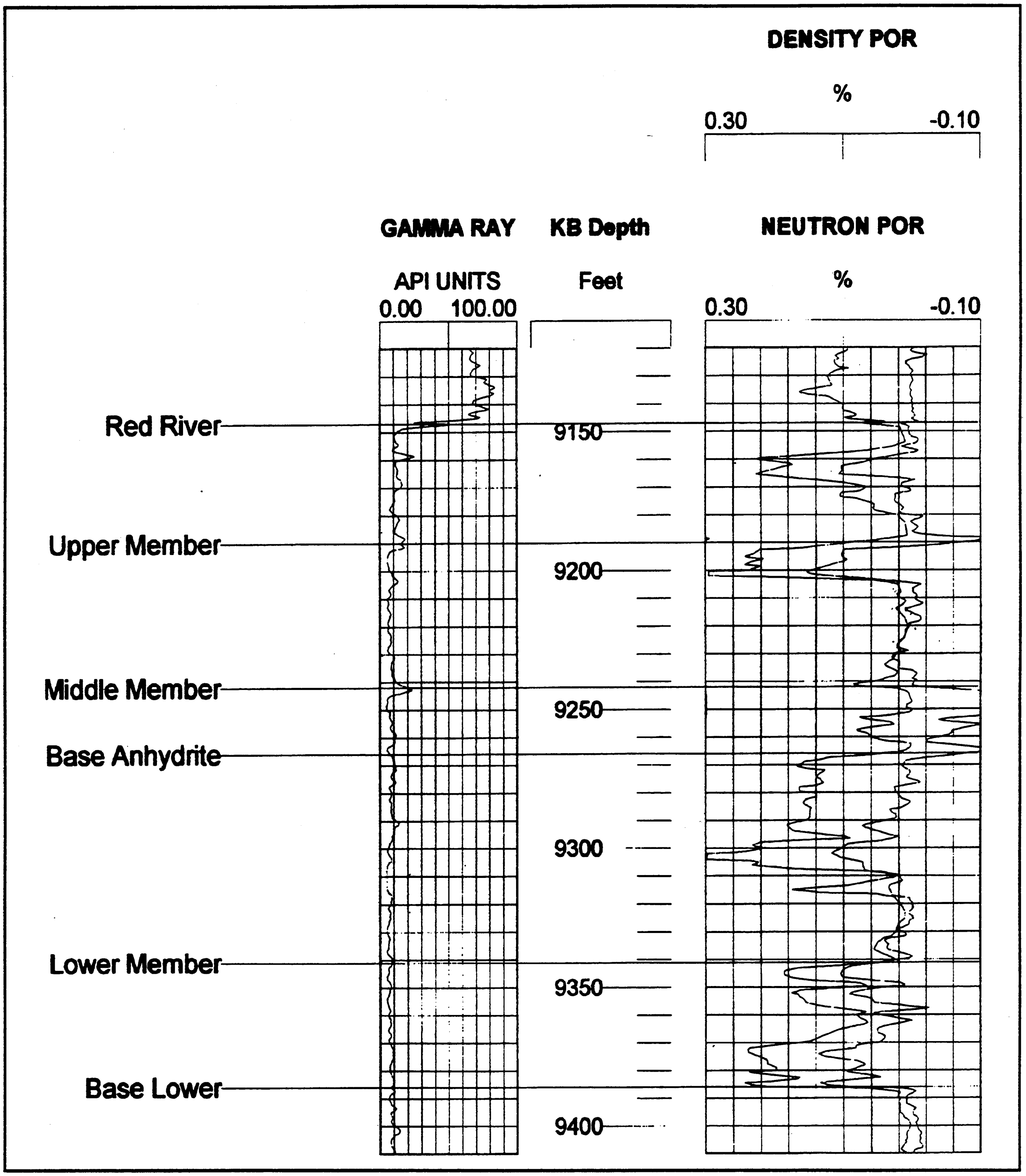

Figure 18: Type-log of Ordovician Red River in the Bowman-Harding study area. The principal oil reservoir produce from porosity benches informally designated as Upper, Middle and Lower.

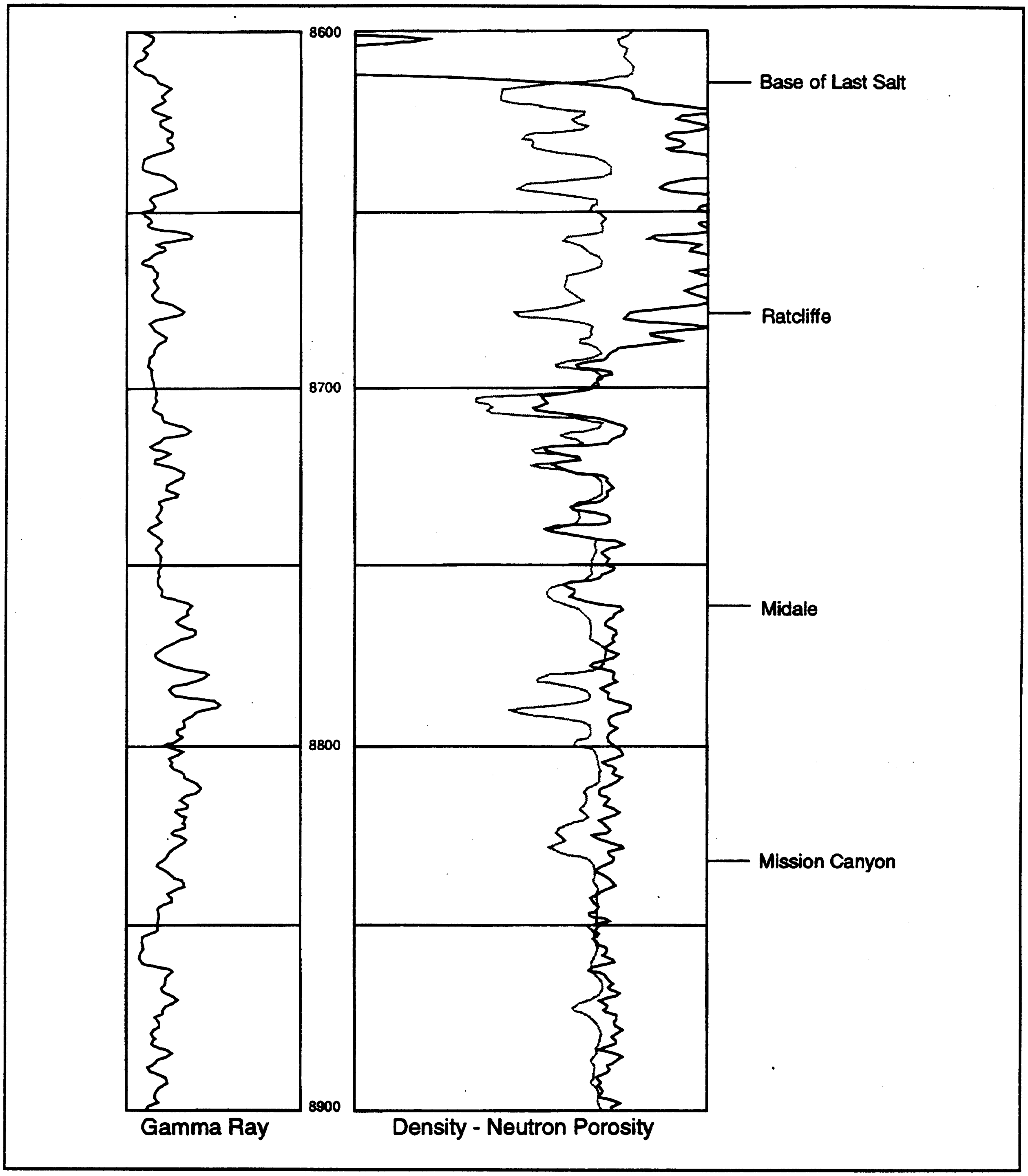

Figure 19: Type-log of Mississippian Ratcliffe in Richland Co., MT study area. Porosity develops primarily in either the upper of lower portion of the interval. A few wells develop porosity in both the upper and lower portions of the section.

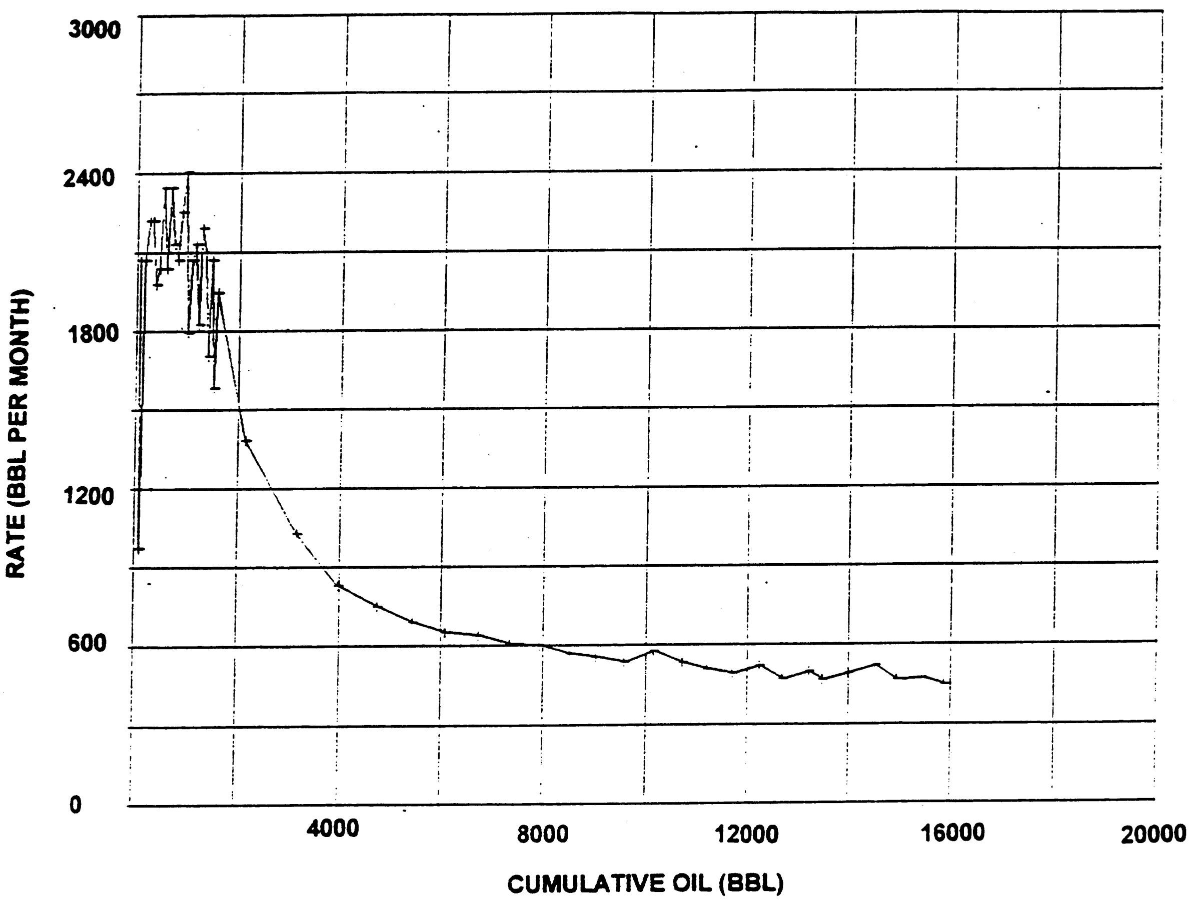

Figure 20: **Production rate plot from the Ratcliffe completion in the No. M-17 Trudell, API 25-083-200932, North Sioux Pass field, Richland Co., MT. This well was selected for a pressure build-up test to evaluate permeability, damage and reservoir pressure.**

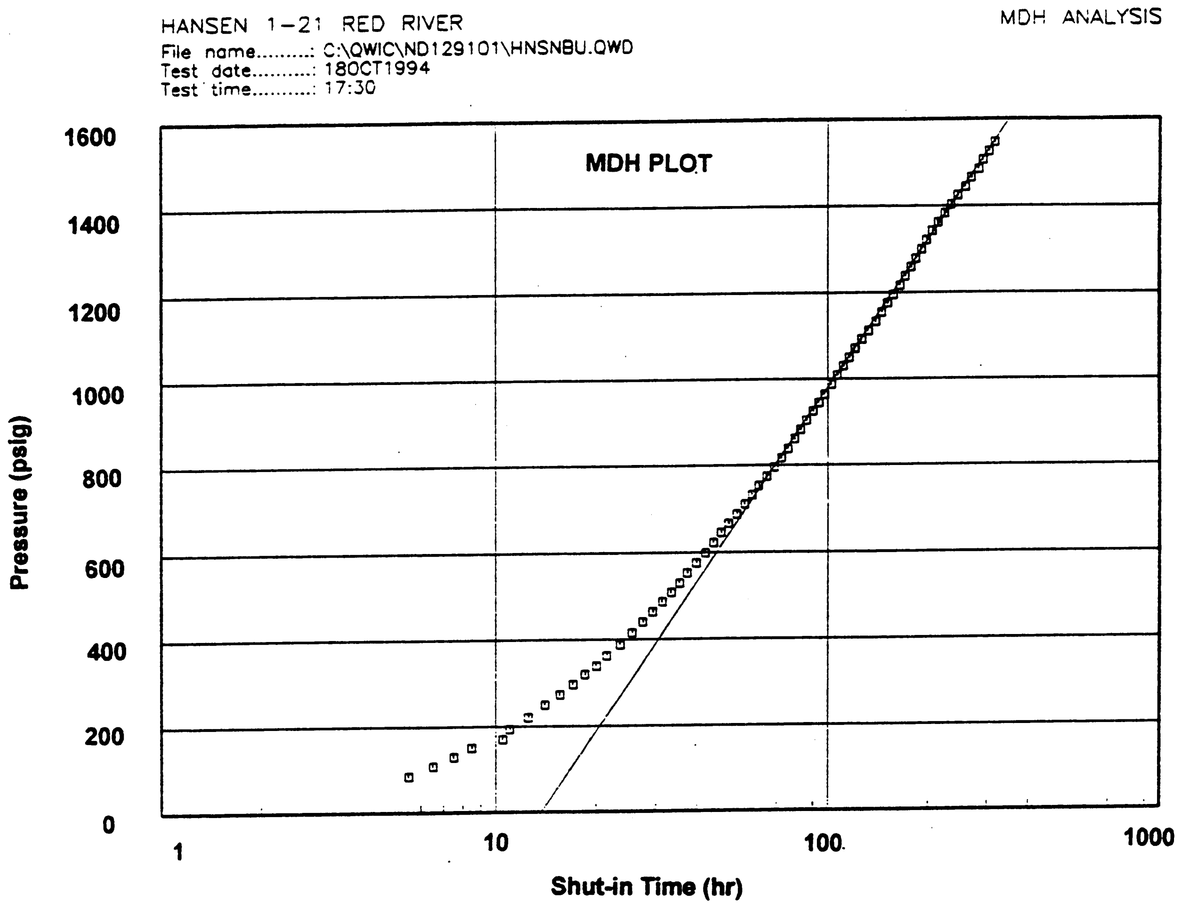

Figure 21: Semi-log plot of pressure build-up data from the No. 1-21 Hansen, API 33-011-00319, Haley (Red River) field, Bowman Co., ND. The character of the build-up data can be matched with simulation by placing the well between two faults.

TORIS RESERVOIR DATA APPENDICES

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	COLD TURKEY CREEK		
Reservoir Name	RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	4640
Proven Area		acre	2038
Well Spacing		acre	408
Total Wells		number	5
Net Pay		feet	20
Gross Pay		feet	105
Porosity		percent	20
Initial Oil Saturation		percent	52.9
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	47.1
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.268
Current Oil Volume Factor		rbbl/stb	9450
True Vertical Depth		feet	9350
Formation Temperature		deg F	220
Current Formation Pressure		psig	NA
Permeability - air		md	10
Oil Gravity		deg API	36
Oil Viscosity - reservoir cond.		cp	0.6487
Water Salinity -TDS		ppm	115000
Original-Oil-In-Place		mbbl	26382
Primary Recovery Factor		percent	6.0
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	1261
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	366
Primary Recovery		mbbl	1576
Year for Primary Recovery			1975
Current Producing GOR		scf/bbl	657
Initial Producing GOR		scf/bbl	500

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4134
Reservoir Dip		degrees	NA
Production Wells		number	5
Injection Wells		number	NA
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			O
Major Gas Cap Y/N			O
District Code TX & CA			NA
Oil Production Rate		bpd	121
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1902
Depositional System			232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	COYOTE CREEK		
Reservoir Name	RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	6080
Proven Area		acre	2461
Well Spacing		acre	308
Total Wells		number	8
Net Pay		feet	21
Gross Pay		feet	95
Porosity		percent	20
Initial Oil Saturation		percent	60
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	40
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.284
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	9800
Formation Temperature		deg F	220
Current Formation Pressure		psig	NA
Permeability - air		md	7.5
Oil Gravity		deg API	40
Oil Viscosity - reservoir cond.		cp	0.5527
Water Salinity -TDS		ppm	115000
Original-Oil-In-Place		mbbl	19625
Primary Recovery Factor		percent	20.1
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	3167
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	1212
Primary Recovery		mbbl	3935
Year for Primary Recovery			1969
Current Producing GOR		scf/bbl	885
Initial Producing GOR		scf/bbl	500

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4167
Reservoir Dip		degrees	NA
Production Wells		number	7
Injection Wells		number	1
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	163
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1902
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION		UNITS	VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	MEDICINE POLE HILLS		
Reservoir Name	RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	5440
Proven Area		acre	4877
Well Spacing		acre	195
Total Wells		number	25
Net Pay		feet	14.4
Gross Pay		feet	40
Porosity		percent	17
Initial Oil Saturation		percent	58
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	42
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.332
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	9495
Formation Temperature		deg F	225
Current Formation Pressure		psig	NA
Permeability - air		md	6.5
Oil Gravity		deg API	38
Oil Viscosity - reservoir cond.		cp	0.4902
Water Salinity -TDS		ppm	85000
Original-Oil-In-Place		mbbl	40394
Primary Recovery Factor		percent	13.3
Secondary Recovery Factor		percent	10.1
Cumulative Oil Production		mbbl	6529
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	778
Primary Recovery		mbbl	5385
Year for Primary Recovery			1967
Current Producing GOR		scf/bbl	2926
Initial Producing GOR		scf/bbl	575

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION		UNITS	VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4225
Reservoir Dip		degrees	NA
Production Wells		number	18
Injection Wells		number	7
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate	AIR	mmcfpd/well	1.11
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	922
Ultimate Recovery Factor		percent	23.4
Record 5			
Geologic Play			1902
Depositional System			232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			3
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			
State Postal Code			1
Lithology Code	SOUTH DAKOTA		SD 40
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	NORTH BUFFALO		
Reservoir Name	UPPER RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	5920
Proven Area		acre	2506
Well Spacing		acre	209
Total Wells		number	12
Net Pay		feet	13.5
Gross Pay		feet	30
Porosity		percent	16
Initial Oil Saturation		percent	62
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	38
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.107
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	8740
Formation Temperature		deg F	220
Current Formation Pressure		psig	NA
Permeability - air		md	6.5
Oil Gravity		deg API	34.5
Oil Viscosity - reservoir cond.		cp	1.9081
Water Salinity -TDS		ppm	27000
Original-Oil-In-Place		mbbl	23450
Primary Recovery Factor		percent	6.0
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	1044
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	418
Primary Recovery		mbbl	1405
Year for Primary Recovery			1982
Current Producing GOR		scf/bbl	156
Initial Producing GOR		scf/bbl	125

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	3450
Reservoir Dip		degrees	NA
Production Wells		number	15
Injection Wells		number	0
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	138
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1702
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			3
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	STATE LINE NORTH		
Reservoir Name	RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	2560
Proven Area		acre	399
Well Spacing		acre	133
Total Wells		number	3
Net Pay		feet	19
Gross Pay		feet	50
Porosity		percent	16.4
Initial Oil Saturation		percent	50
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	50
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.216
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	9150
Formation Temperature		deg F	220
Current Formation Pressure		psig	NA
Permeability - air		md	NA
Oil Gravity		deg API	36.5
Oil Viscosity - reservoir cond.		cp	0.7349
Water Salinity -TDS		ppm	93140
Original-Oil-In-Place		mbbl	3965
Primary Recovery Factor		percent	11.3
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	150
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	721
Primary Recovery		mbbl	448
Year for Primary Recovery			1975
Current Producing GOR		scf/bbl	NA
Initial Producing GOR		scf/bbl	400

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	3718
Reservoir Dip		degrees	NA
Production Wells		number	3
Injection Wells		number	0
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	133
Ultimate Recovery Factor			NA
Record 5			
Geologic Play			1902
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	SOUTH HORSE CREEK		
Reservoir Name	LOWER RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	10880
Proven Area		acre	4133
Well Spacing		acre	230
Total Wells		number	18
Net Pay		feet	17
Gross Pay		feet	70
Porosity		percent	16
Initial Oil Saturation		percent	60
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	40
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.1807
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	9170
Formation Temperature		deg F	224
Current Formation Pressure		psig	NA
Permeability - air		md	8
Oil Gravity		deg API	30.0
Oil Viscosity - reservoir cond.		cp	1.5
Water Salinity -TDS		ppm	
Original-Oil-In-Place		mbbl	44319
Primary Recovery Factor		percent	13.8
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	4130
Year for Cumulative Oil			1993
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	906
Primary Recovery		mbbl	6113
Year for Primary Recovery			1972
Current Producing GOR		scf/bbl	432
Initial Producing GOR		scf/bbl	215

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	3971
Reservoir Dip		degrees	NA
Production Wells		number	18
Injection Wells		number	NA
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	0.64
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	479
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1902
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			3
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	STATE LINE SOUTH		
Reservoir Name	RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	2560
Proven Area		acre	573
Well Spacing		acre	191
Total Wells		number	3
Net Pay		feet	12
Gross Pay		feet	40
Porosity		percent	18
Initial Oil Saturation		percent	53.6
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	46.4
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.264
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	9000
Formation Temperature		deg F	220
Current Formation Pressure		psig	NA
Permeability - air		md	
Oil Gravity		deg API	38.8
Oil Viscosity - reservoir cond.		cp	0.5832
Water Salinity -TDS		ppm	49370
Original-Oil-In-Place		mbbl	4073
Primary Recovery Factor		percent	30.9
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	926
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	1897
Primary Recovery		mbbl	1259
Year for Primary Recovery			1971
Current Producing GOR		scf/bbl	NA
Initial Producing GOR		scf/bbl	500

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	3775
Reservoir Dip		degrees	NA
Production Wells		number	3
Injection Wells		number	NA
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	105
Ultimate Recovery Factor			NA
Record 5			
Geologic Play			1902
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 1			
DOE Field Code			1
State Postal Code	NORTH DAKOTA		ND 33
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	UPPER ORDOVICIAN		361
Field Name	SOUTH WEST AMOR		
Reservoir Name	UPPER RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	2560
Proven Area		acre	935
Well Spacing		acre	234
Total Wells		number	4
Net Pay		feet	8
Gross Pay		feet	NA
Porosity		percent	25
Initial Oil Saturation		percent	74
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	26
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.236
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	9250
Formation Temperature		deg F	238
Current Formation Pressure		psig	NA
Permeability - air		md	3.5
Oil Gravity		deg API	35
Oil Viscosity - reservoir cond.		cp	0.6997
Water Salinity -TDS		ppm	65000
Original-Oil-In-Place		mbbl	8687
Primary Recovery Factor		percent	27.7
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	1038
Year for Cumulative Oil			1993
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	1978
Primary Recovery		mbbl	2409
Year for Primary Recovery			1978
Current Producing GOR		scf/bbl	429
Initial Producing GOR		scf/bbl	400

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4175
Reservoir Dip		degrees	NA
Production Wells		number	4
Injection Wells		number	0
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	135
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1902
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	SOUTH DAKOTA		SD 40
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	ORDOVICIAN		361
Field Name	WEST BUFFALO RED RIVER "B" UNIT		
Reservoir Name	UPPER RED RIVER		
DOE Reference Number			1
Formation Name	RED RIVER		
Record 2			
Field Area		acre	4480
Proven Area		acre	2850
Well Spacing		acre	204
Total Wells		number	14
Net Pay		feet	14.8
Gross Pay		feet	22
Porosity		percent	18
Initial Oil Saturation		percent	60
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	40
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.109
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	8350
Formation Temperature		deg F	210
Current Formation Pressure		psig	NA
Permeability - air		md	6.5
Oil Gravity		deg API	31.3
Oil Viscosity - reservoir cond.		cp	1.722
Water Salinity -TDS		ppm	19500
Original-Oil-In-Place		mbbl	20750
Primary Recovery Factor		percent	4.5
Secondary Recovery Factor		percent	9.2
Cumulative Oil Production		mbbl	914
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	295
Primary Recovery		mbbl	925
Year for Primary Recovery			1980
Current Producing GOR		scf/bbl	NA
Initial Producing GOR		scf/bbl	173

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	3579
Reservoir Dip		degrees	1.5
Production Wells		number	7
Injection Wells	WATER	number	7
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	48
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	368
Ultimate Recovery Factor		percent	13.7
Record 5			
Geologic Play			1702
Depositional System			231,232
Depositional System Confidence			2
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			3
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	MONTANA		MT 25
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	MISSISSIPPIAN		330
Field Name	CATTAILS		
Reservoir Name	RATCLIFFE		
DOE Reference Number			1
Formation Name	CHARLES		
Record 2			
Field Area		acre	3220
Proven Area		acre	1805
Well Spacing		acre	201
Total Wells		number	9
Net Pay		feet	16.4
Gross Pay		feet	NA
Porosity		percent	8
Initial Oil Saturation		percent	50
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	50
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	O
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.282
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	8950
Formation Temperature		deg F	220
Current Formation Pressure		psig	NA
Permeability - air		md	1
Oil Gravity		deg API	34
Oil Viscosity - reservoir cond.		cp	0.6846
Water Salinity -TDS		ppm	262924
Original-Oil-In-Place		mbbl	7165
Primary Recovery Factor		percent	18.8
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	780
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	659
Primary Recovery		mbbl	1344
Year for Primary Recovery			1987
Current Producing GOR		scf/bbl	444
Initial Producing GOR		scf/bbl	500

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4232
Reservoir Dip		degrees	NA
Production Wells		number	9
Injection Wells		number	NA
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	226
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1704
Depositional System			NA
Depositional System Confidence			NA
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	MONTANA		MT25
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	MISSISSIPPIAN		
Field Name	NOHLY		
Reservoir Name	RATCLIFFE		1
DOE Reference Number			
Formation Name	CHARLES		
Record 2			
Field Area		acre	3840
Proven Area		acre	2033
Well Spacing		acre	290
Total Wells		number	7
Net Pay		feet	13.5
Gross Pay		feet	18
Porosity		percent	15
Initial Oil Saturation		percent	50
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	50
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.201
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	8800
Formation Temperature		deg F	225
Current Formation Pressure		psig	NA
Permeability - air		md	1
Oil Gravity		deg API	31.8
Oil Viscosity - reservoir cond.		cp	0.9722
Water Salinity -TDS		ppm	262924
Original-Oil-In-Place		mbbl	13294
Primary Recovery Factor		percent	16.6
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	921
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	1070
Primary Recovery		mbbl	2203
Year for Primary Recovery			1983
Current Producing GOR		scf/bbl	497
Initial Producing GOR		scf/bbl	367

		US SYSTEM	US SYSTEM
ITEM DESCRIPTION	DESCRIPTION	UNITS	VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4372
Reservoir Dip		degrees	NA
Production Wells		number	9
Injection Wells		number	NA
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	580
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1704
Depositional System			NA
Depositional System Confidence			NA
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 1			
DOE Field Code			1
State Postal Code	MONTANA		MT 25
Lithology Code	DOLOMITE		3
Geologic Age Code, AAPG	MISSISSIPPIAN		330
Field Name	RIP RAP COULEE		
Reservoir Name	RATCLIFFE		
DOE Reference Number			1
Formation Name	CHARLES		
Record 2			
Field Area		acre	1280
Proven Area		acre	788
Well Spacing		acre	158
Total Wells		number	5
Net Pay		feet	15
Gross Pay		feet	NA
Porosity		percent	15
Initial Oil Saturation		percent	50
Current Oil Saturation		percent	NA
Initial Water Saturation		percent	50
Current Water Saturation		percent	NA
Initial Gas Saturation		percent	0
Current Gas Saturation		percent	NA
Initial Oil Volume Factor		rbbl/stb	1.283
Current Oil Volume Factor		rbbl/stb	NA
True Vertical Depth		feet	8970
Formation Temperature		deg F	218
Current Formation Pressure		psig	NA
Permeability - air		md	1
Oil Gravity		deg API	34
Oil Viscosity - reservoir cond.		cp	0.6743
Water Salinity -TDS		ppm	262924
Original-Oil-In-Place		mbbl	5284
Primary Recovery Factor		percent	17.8
Secondary Recovery Factor		percent	NA
Cumulative Oil Production		mbbl	702
Year for Cumulative Oil			1994
Technical Availability Date			1
Primary Recovery Factor		bbl/ac-ft	1074
Primary Recovery		mbbl	938
Year for Primary Recovery			1973
Current Producing GOR		scf/bbl	989
Initial Producing GOR		scf/bbl	500

ITEM DESCRIPTION	DESCRIPTION	US SYSTEM UNITS	US SYSTEM VALUE
Record 4			
Reservoir Area		acre	NA
Initial Formation Pressure		psig	4386
Reservoir Dip		degrees	NA
Production Wells		number	5
Injection Wells		number	0
Swept Zone Oil Saturation		percent	NA
Injection Water Salinity - TDS		ppm	NA
Clay Content		percent	NA
Dykstra-Parsons Coefficient		fraction	NA
Current Injection Rate		bpd/well	NA
Fractured-Fault Y/N			1
Shale Break or Laminations Y/N			0
Major Gas Cap Y/N			0
District Code TX & CA			NA
Oil Production Rate		bpd	86
Ultimate Recovery Factor		percent	NA
Record 5			
Geologic Play			1704
Depositional System			NA
Depositional System Confidence			NA
Diagenetic Overprint			3
Diagenetic Overprint Confidence			1
Structural Compartmentation			NA
Structural Compart. Confidence			NA
Predominent Heterogeneity			2
Trap Type			1
Geological Province			94

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