Identifying Oil Exploration Leads using Integrated Remote Sensing and Seismic Data Analysis, Lake Sakakawea, Fort Berthold Indian Reservation, Williston Basin

Final Report

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Abstract

The Fort Berthold Indian Reservation, inhabited by the Arikara, Mandan and Hidatsa Tribes (now united to form the Three Affiliated Tribes) covers a total area of 1530 mi^2 (980,000 acres). The Reservation is located approximately 15 miles east of the depocenter of the Williston basin, and to the southeast of a major structural feature and petroleum producing province, the Nesson anticline. Several published studies document the widespread existence of mature source rocks, favorable reservoir/caprock combinations, and production throughout the Reservation and surrounding areas indicating high potential for undiscovered oil and gas resources. This technical assessment was performed to better define the oil exploration opportunity, and stimulate exploration and development activities for the benefit of the Tribes. The need for this assessment is underscored by the fact that, despite its considerable potential, there is currently no meaningful production on the Reservation, and only 2% of it is currently leased.

Of particular interest (and the focus of this study) is the area under the Lake Sakakawea (formed as result of the Garrison Dam). This "reservoir taking" area, which has never been drilled, encompasses an area of 150,000 acres, and represents the largest contiguous acreage block under control of the Tribes. Furthermore, these lands are Tribal (non-allotted), hence leasing requirements are relatively simple.

The opportunity for exploration success insofar as identifying potential leads under the lake is high. According to the Bureau of Land Management, there have been 591 tests for oil and gas on or immediately adjacent to the Reservation, resulting in a total of 392 producing wells and 179 plugged and abandoned wells, for a success ratio of 69%. Based on statistical probability alone, the opportunity for success is high.

Executive Summary

The overall objective of this study was to evaluate the oil exploration potential under Lake Sakakawea, using a variety of techniques, and identify possible leads. Further, pro-forma reserves and economics for those leads were developed. Based on the results from this study, the following results and conclusions have been drawn:

- Fort Berthold Indian Reservation is in favorably located within the Williston Basin, with good exploration potential. An excellent opportunity exists to capture a 150,000 acre contiguous block on the Reservation under Lake Sakakawea.
- An integrated geology, remote sensing, potential fields and seismic study provided on improved understanding of the structural setting and hydrocarbon potential under the lake. That potential has been determined to be very promising.
- Eleven specific leads have been identified based on the study. Expected recoveries range from ~300 to ~1,700 MBO each (8,900 MBO in total), with F&D costs of ~$6/bbl to ~$15/bbl.
- To further define prospects, the following technical recommendations are made:
    - Acquire and reprocess balance of seismic data available over the lake (~300 line-miles)
    - Acquire and interpret a high-resolution aeromag survey
    - Integrate those results with the existing study
    - Evaluate need for 3D seismic for further prospect definition and/or drill well

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1.0 Introduction and Background

The Fort Berthold Indian Reservation, inhabited by the Arikara, Mandan and Hidatsa Tribes (now united to form the Three Affiliated Tribes) covers a total area of 1530 mi^2 (980,000 acres). The Reservation is located approximately 15 miles east of the center of the Williston basin, and to the southeast of a major structural feature and petroleum producing province, the Nesson anticline (Figure 1). Several published studies document the widespread existence of mature source rocks, favorable reservoir/caprock combinations, and production throughout the Reservation and surrounding areas indicating high potential for undiscovered oil and gas resources.

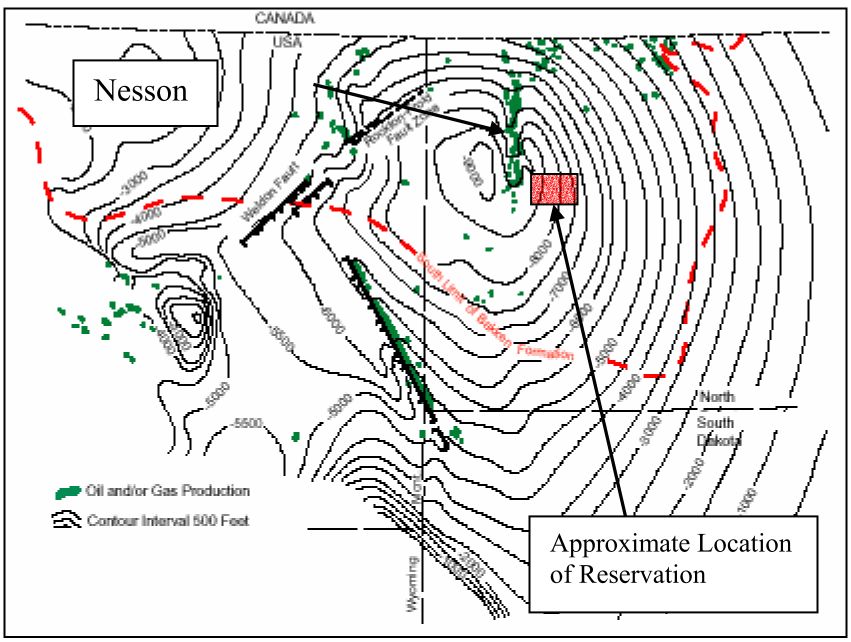


Figure 1: Location of Fort Berthold Indian Reservation, Williston Basin (modified from Ref. 55)

While there has been past interest by oil companies in exploration on the Reservation, factors such as high royalties and lease acquisition costs, inability to assemble large blocks of acreage, rights to seismic data, taxes, and a 100% signature requirement imposed by the federal statute on Trust Lands, have served as deterrents. The Tribes have achieved advancements on a number of these issues, such as a Congressional action in 1997 to waive the 100% signature requirement on allotted Lands, the passing of special tax relief provisions by the State of North Dakota, and improved royalty and lease terms. While these issues are administrative/financial in nature, the absence of a credible, detailed technical assessment of the oil exploration potential remains a deterrent for oil companies to explore on the Reservation. Such a technical assessment was therefore needed to better define the oil exploration opportunity, and hence attract oil companies to proceed with exploration and development for the benefit of the Tribes. This need is highlighted by the fact that, despite its considerable potential, there is currently no meaningful production on the Reservation, and only 2% of it is currently leased.

Of particular interest (and the focus of this study) is the area under the Lake Sakakawea (formed as result of the Garrison Dam). This "reservoir taking" area, which has never been explored, encompasses an area of 150,000 acres, and represents the largest contiguous acreage block under control of the Tribes. Furthermore, these lands are Tribal (non-allotted), hence leasing requirements are relatively simple.

While there are numerous oil and gas plays on the Reservation, most historical production has come from the Mississippian Madison carbonate structural play, and the non-conventional (continuous, naturally-fractured) Devonian Bakken/Sanish Sand play on the western side of the Reservation (Figure 2). According to the USGS, these two plays represent about 320 MMBO of undiscovered resource potential in the wider Williston basin (Table 1).

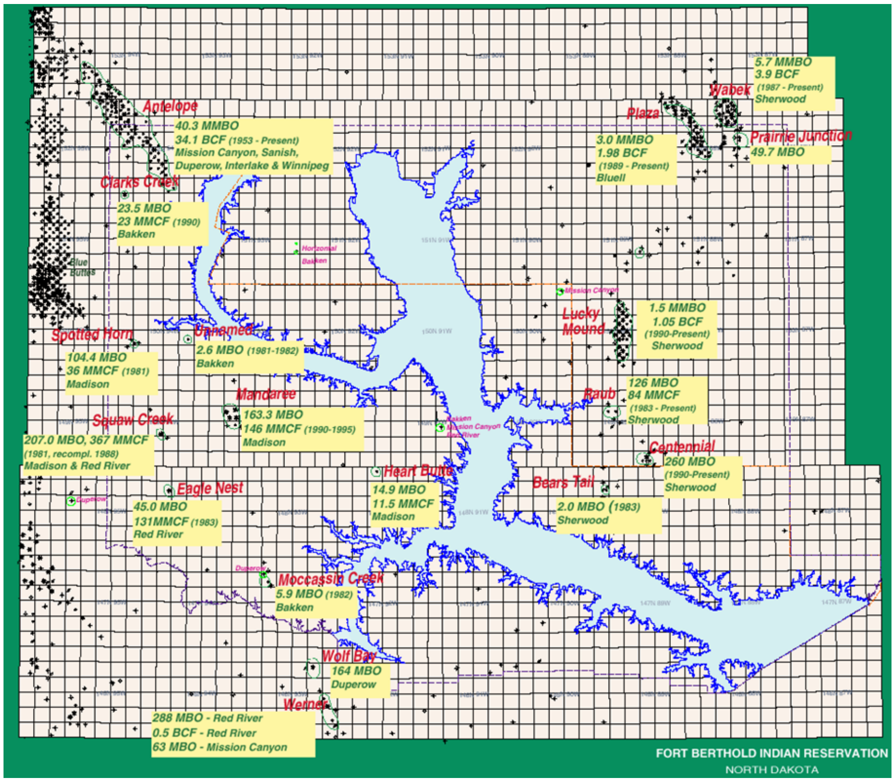


Figure 2: Producing Fields/Reservoirs on the Reservation (from Ref. 54)

Table 1: USGS Undiscovered Recoverable Resources, Madison/Bakken Plays (from Ref. 1)

Play	Code	Assigned Success Rate	Total Recoverable Resource (MMBO)
Madison Structural	3101	-----	169*
Bakken Fairway	3110	0.70	73
Bakken Intermediate	3111	0.20	70
Bakken Outlying	3112	0.10	8
TOTAL			320

* 32 undiscovered fields with an average EUR of 5.3 MMBO each

The opportunity for exploration success insofar as identifying potentially productive leads under the lake is high. According to the Bureau of Land Management, there have been 591 tests for oil and gas on or immediately adjacent to the Reservation, resulting in a total of 392 producing wells and 179 plugged and abandoned wells, for a success ratio of 69%. Based on statistical probability alone, the opportunity for success is high.

The prospectivity of the lands underlying the lake can also be compared to the nearby Antelope field, one of the Williston basins' most prolific oil fields (discovered in 1953 and with over 40 MMBO of cumulative production, mainly from the Madison and Bakken/Sanish plays). The field is a southeast plunging structural splay off the main Nesson anticline, which extends onto the Reservation on-strike with the lake's general orientation. This trend roughly parallels major regional structural elements, such as the Bismarck shear and Williston lineament, which extend onto the Reservation (Figure 3). It is hypothesized that the lake itself is suggestive of a continuation of those favorable underlying geologic features for oil accumulation and production that created the Antelope field.

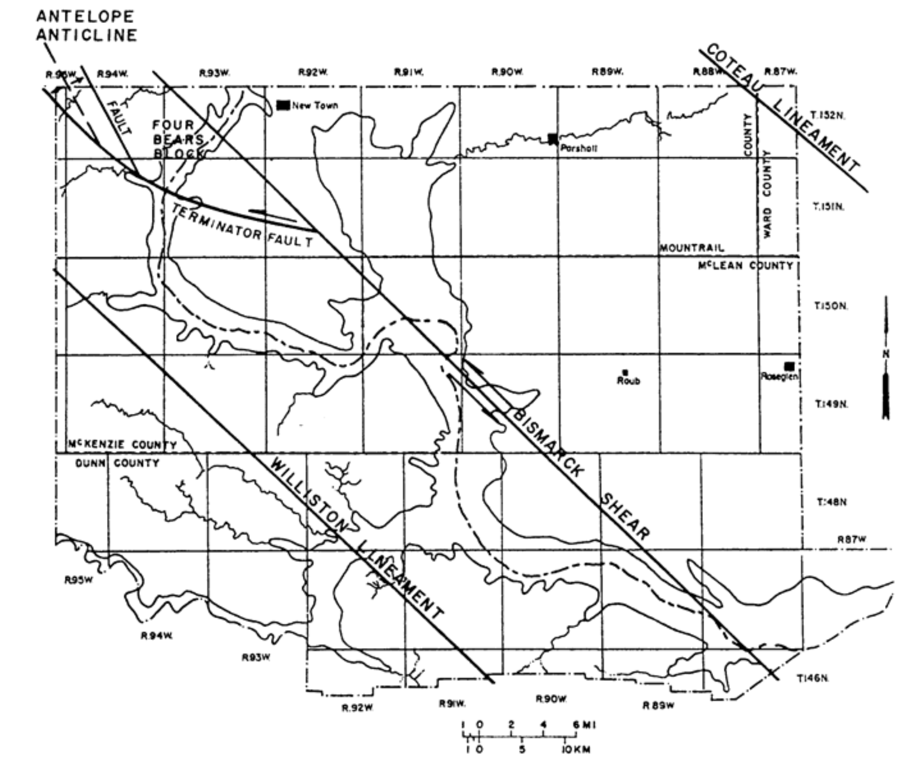


Figure 3: Main (Regional) Geologic Features on the Reservation (from Ref. 20)

Thus, the overall objective of this study was to evaluate the oil exploration potential under Lake Sakakawea, using a variety of techniques, and identify possible leads. Further, proforma reserves and economics for those leads were to be developed, and the information packaged in a manner that would allow potential development partners to evaluate the opportunity. This report describes the approach taken and results of that study.

2.0 Technical Approach

The study was performed by performing the following tasks:

2.1 Data Collection

The first project task involved collecting all the data required to perform the study. That data included:

- Satellite imagery (LandSat 7) over the entire Reservation, plus some overlap to capture portions of existing oilfields. These data were acquired commercially.
- Low-resolution, publicly-available potential fields data over the same area. These data were available from the public domain.
- High-resolution aeromagnetic survey data targeted on the lake area. These data were acquired commercially.
- Approximately 200 line-miles of early-1980's vintage 2-D seismic data over the lake. These data were acquired commercially.
- Approximately 125 line-miles of 2-D onshore seismic data, currently held by the Bureau of Indian Affairs (BIA).
- Digitized well logs from selected wells near the lake, and in the producing oilfields. These data were provided by the BIA.
- Commercially available well/production data for the existing oilfields on and near the Reservation. These data were provided by Advanced Resources International (ARI).

2.2 Geologic and Geophysical Analysis

The geologic analysis began with a lineament study of the satellite imagery data. Major linear features were identified and mapped, and then analyzed via Rose diagrams and lineament density maps. Next, the low-resolution potential field data were integrated. These data, already corrected for altitude, topography, etc., were interpreted for basement structure and faulting, and horizontal gradient maps generated. The high resolution aeromagnetic data were similarly corrected and interpreted, and the interpretations based on the two data resolutions compared.

Next the offshore seismic data was reprocessed, including interval velocity correction, restacking and time migration. Given that it was early-1980's vintage, this was expected to provide a considerable improvement in data clarity. The onshore seismic data was used to tie-in the offshore data. Structure/faulting (in the time domain) was then interpreted. Finally, the resultant seismic interpretation was integrated with the remote sensing interpretations. To supplement the analysis, an independent geologic study of the Reservation, performed by the BIA, provided an overall background and context to the study.

2.3 Lead Identification

Based on the results of the geologic/geophysical analysis, new exploration leads under Lake Sakakawea were identified. The leads, and the basis for selecting them were fully described, and the appropriate offset well or field analogs identified.

2.4 Production Data Analysis

Production data from existing Madison and Bakken wells on or near the Reservation were evaluated. Decline curve analysis was performed on each active well to obtain a well performance metric, specifically the estimated ultimate recovery (EUR). A statistical analysis of production performance was generated to provide an estimate of oil recoveries.

2.5 Pro-Forma Reserves and Economics

Once the leads were identified, reserve estimates for each were developed based on their size, as well as the appropriate well/field analogies. Exploration and development program costs were estimated, plus operating cost, and a finding and development (F & D) cost derived for each lead.

The following sections describe the results of the study.

3.0 Results and Discussion

3.1 Regional Geology

The Fort Berthold Indian Reservation is located near the center of the Williston Basin, the largest intra-cratonic basin in the United States. The basin covers the western two-thirds of North Dakota and extends into southern Canada, eastern Montana and northwestern South Dakota. The basin contains sedimentary deposits of every geologic period from Cambrian through Tertiary. It became a distinct geologic feature in mid-Ordovician time when crustal subsidence created a wide, shallow depression on the cratonic shelf. The deepest portion of the basin is in McKenzie County, North Dakota, approximately 40 miles west of the Reservation. Here, Precambrian rocks are overlain with up to 16,000 feet of predominantly Paleozoic sedimentary strata, most of which were deposited as shallow water carbonates.

Hydrocarbon production in the North Dakota portion of the basin began in 1951, with the discovery of oil from the Mississippian Madison Group on a surface mapped structure. That structure is part of the largest structural trend in North Dakota, the Nesson Anticline. This productive, multi-pay, anticlinal trend extends in a north-south direction for approximately 100 miles is located about five miles west of the Reservation. A major structural splay off this trend extends onto the Reservation and is the location for Antelope Field, the most productive field on the Reservation (Figure 4). This field has produced more than 40 million barrels of oil, primarily from four different formations.

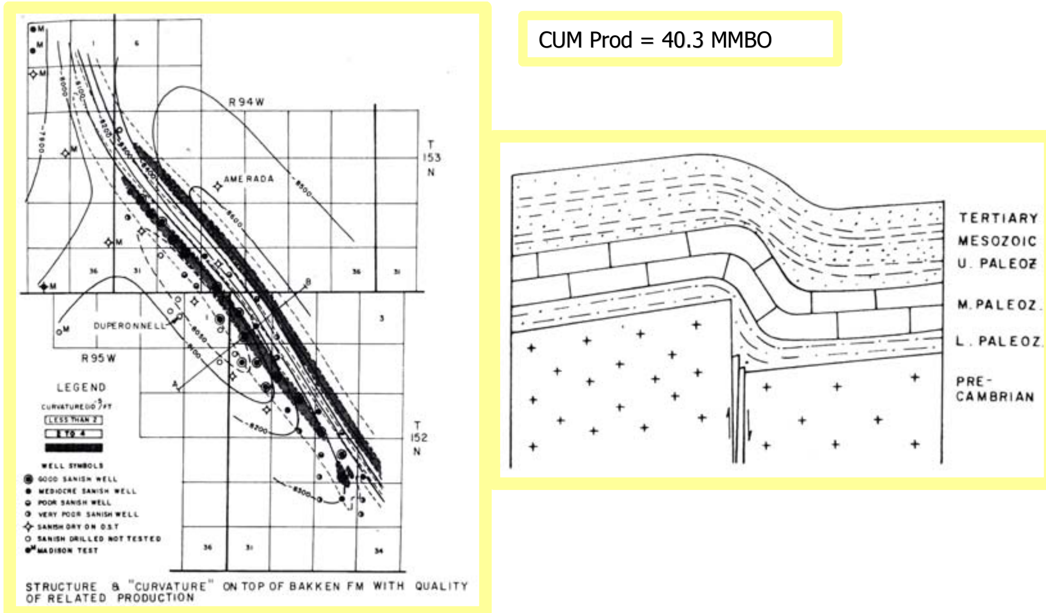


Figure 4: Structural Framework of Antelope Field
(from Ref. 40)

Additional undrilled large structures exist on the western half of the Reservation and offer an opportunity for major hydrocarbon accumulations. In the mid-1950's, a series of stratigraphically trapped Mississippian Madison fields were first discovered in Bottineau and Renville Counties (Figure 5). These fields produce from mappable trends that extend along a series of ancient shorelines for a distance of nearly 200 miles. These trends extend onto and through the Reservation and produce from six fields in the eastern part of the Reservation. These six fields are all located on non-Indian lands. The Sherwood zone of the Mississippian Mission Canyon Formation is the most prolific of these shoreline trends. It has the best per well reserves and accounts for numerous multi-well (20+) oil fields. Both the Sherwood and the Bluell shorelines extend through the eastern portion of the Reservation and produce from the aforementioned six fields on the non-allotted land portion of the Reservation. Wabek Field is the best of these six fields, having so far produced approximately six million barrels of oil and averaging about 250,000 BO/well.

As mentioned in the introduction, the non-allotted portion of the Reservation is significantly under explored and these productive shoreline trends offer an excellent exploration target. In fact, other than Antelope Field, six of the seven fields on the Reservation are one well fields and there have been only nineteen wells drilled to the Red River Formation or deeper (one well/48 sections). As mentioned previously, this is due in large part to the 100% signature requirement for allotted acreage that heretofore existed on all U.S. Indian Reservations. In 1997, the U.S. Congress passed an exception to this requirement for Fort Berthold, and only for Fort Berthold, reducing this requirement to only 51%.

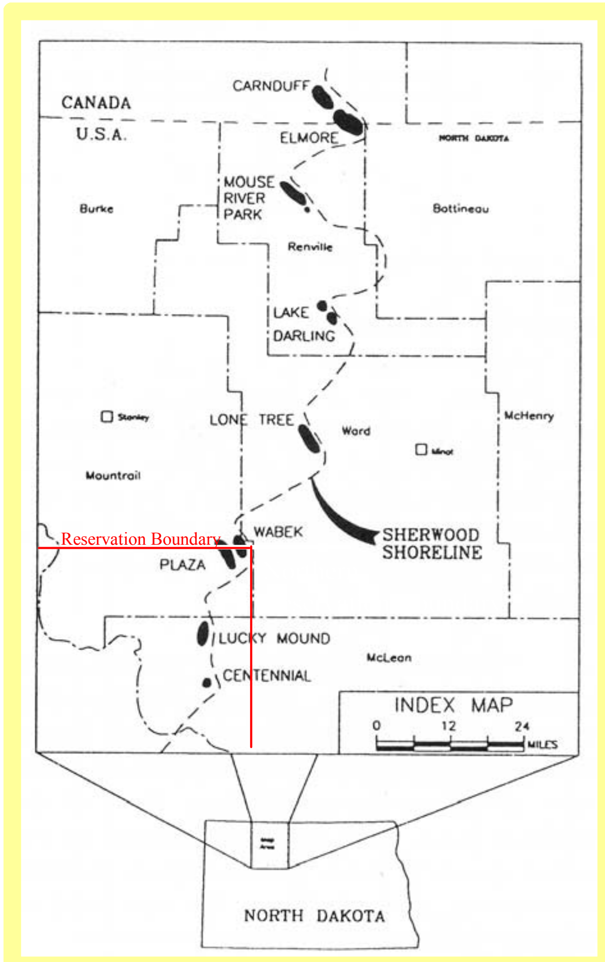
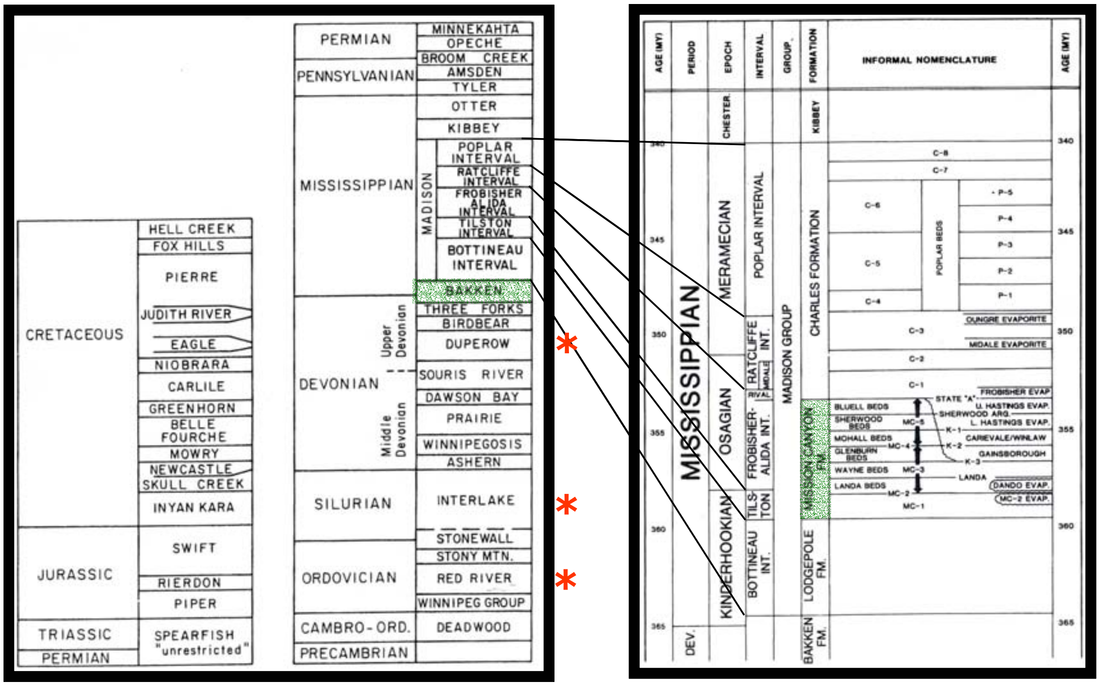


Figure 5: Extension of Sherwood Shoreline onto Reservation (from Ref. 51)

Subsequent exploration in North Dakota has found production from more than thirty formations/zones ranging in age from Pre-Cambrian to Cretaceous. One of the major benefits to exploration in the Williston Basin, and therefore Fort Berthold, is this multi-pay potential. The primary objective formations on the Reservation are the Mississippian Madison, Bakken, Sanish, Devonian Duperow, Silurian Interlake and Ordovician Red River. Secondary objectives include the Lodgepole, Nisku, Dawson Bay, Winnipegosis, Stonewall, Gunton, Winnipeg and Deadwood formations. Figure 6 provides a stratigraphic column for the area.



* "Secondary" productive intervals

Figure 6: Williston Basin Stratigraphy (from Ref. 36)

The primary source rock in the area is the Devonian Bakken shale. The shale maturity is at its maximum to the west of the Reservation, at the basin epicenter. Bakken shale resistivity is a common measure of maturity, with value greater than 167 ohm-m considered mature and oil saturated. Figure 7 is a map of the Bakken resistivity across the Reservation. Note that most of the Reservation is underlain by thermally mature Bakken.

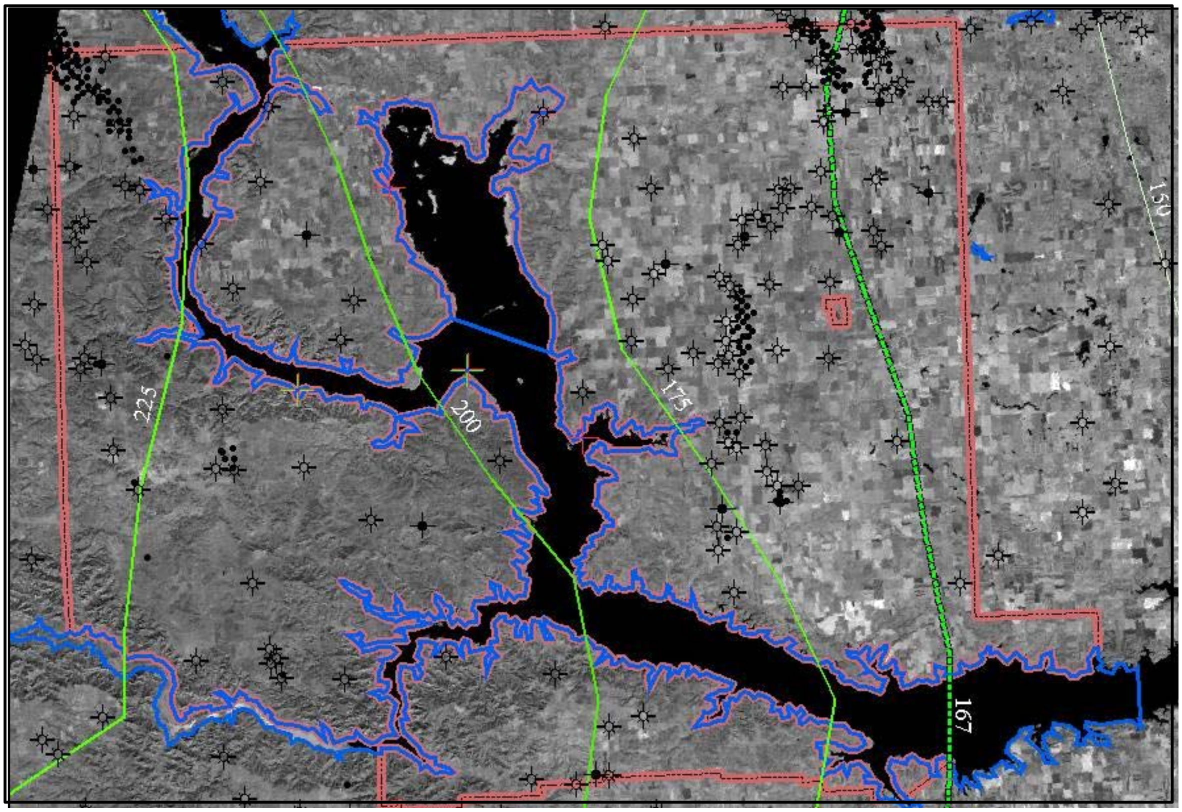


Figure 7: Bakken Maturity (resistivity, ohm-m)

Oil migration on the eastern flank of the Williston Basin was primarily eastward and northward, filling the various structural and stratigraphic traps, including the Nesson Anticline and Sherwood Shoreline trend (Figure 8). There is a strong likelihood that if closed structural/stratigraphic traps exist under Lake Sakakawea, they will contain oil.

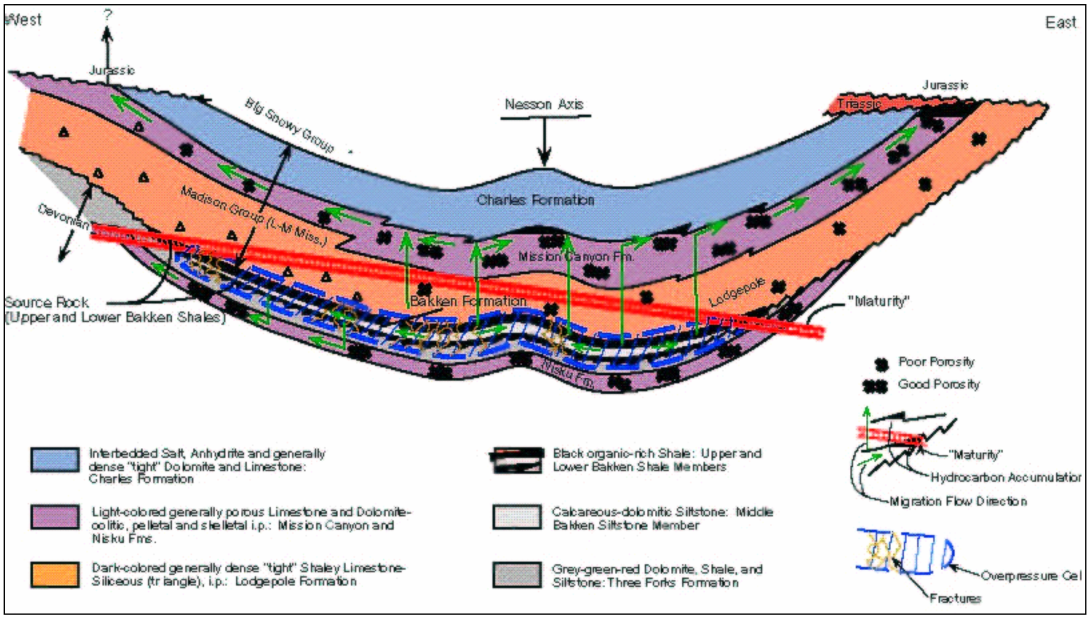


Figure 8: Oil Generation and Migration in the Williston Basin
(from Ref. 39)

3.2 Remote Sensing Evaluation

Surface remote sensing techniques were employed during the study to identify and map the surface traces of faulting across the Reservation. A surface fault map could then be integrated with maps generated from the gravity and aeromag investigations to provide an improved interpretation of the nature and type of faulting present in the subsurface and, thus, higher quality prospects. Two LandSat 7 Earth Thematic Mapper (ETM+) images were acquired and georectified using the USGS 1:100k digital line graph (DLG) maps of cultural features such as roads, dams and railroads. Digital elevation data from the National Elevation Database (NED) was also acquired to provide topographic control and enhance the surface interpretation of the imagery.

Figure 9 is a 3D perspective view of the study area physiography from the southeast. Yellowish browns are higher elevations and the blues are lower. The apparent rough texture of the southwestern area is an artifact of the diagram's severe vertical exaggeration. Lake Sakakawea (narrow aqua area, center of diagram) is formed behind dams on the Missouri River where it flows along the boundary between the Missouri Plateau (southwestern uplands) and the till covered glacial lowlands to the northeast (deeper blues). The Missouri Plateau is underlain by remnants of lower Tertiary strata dissected along lines of erosional weakness inferred to reflect faulting. Till cover increases to the northeast obscuring the subsurface fracture patterns. While some faults remain visible, the utility of surface remote sensing declines to the northeast and the increasing amounts of till and gravel deposits also complicate the seismic acquisition environment on the lake.

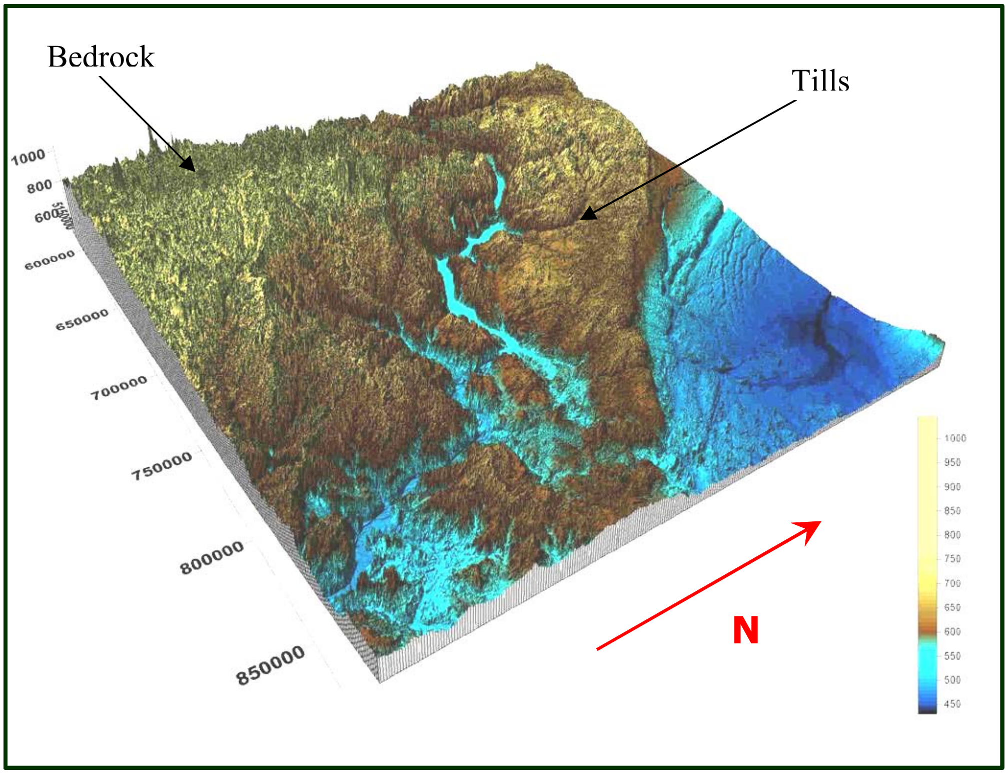


Figure 9: 3 D Perspective of Reservation

Figure 10 is a detailed image of the immediate Reservation area showing the decline in frequency of observable surface faulting due to glacial till coverage moving from southwest to northeast. Band 4 of the Landsat was superimposed on the digital elevation data to form a composite image. Black linears are interpreted to be evidence of faulting at the surface. The combination of imagery and digital elevation data allowed a significantly improved interpretation in this low relief area.

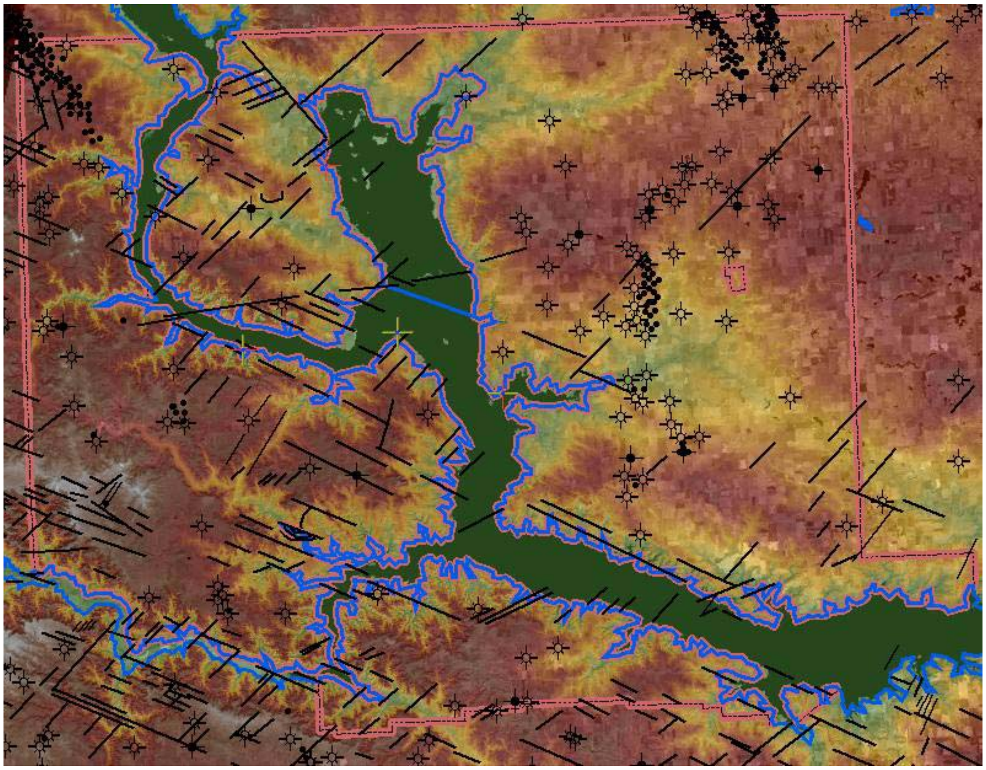


Figure 10: Detail View of Lake Sakakawea and Reservation Area

The lineament interpretation indicates a strong WNW faulting component on the Reservation that seems to control the major arms of Lake Sakakawea. A less pronounced but significant NNE lineament trend is also present. Surface lineations frequently delineate fault bounded structural blocks in cratonic basins like the Williston. Lineament intersections may also indicate areas of higher fracture frequency in the subsurface which can be prospective for naturally fractured reservoir plays. For this reason, lineament density maps are frequently made to guide exploration or high-grade acreage for further evaluation. Figure 11 is such a map. In this case, however, lineament density does a better job of identifying the till covered areas than any individual prospects. The red areas are high lineament density and the blue areas are low (till covered).

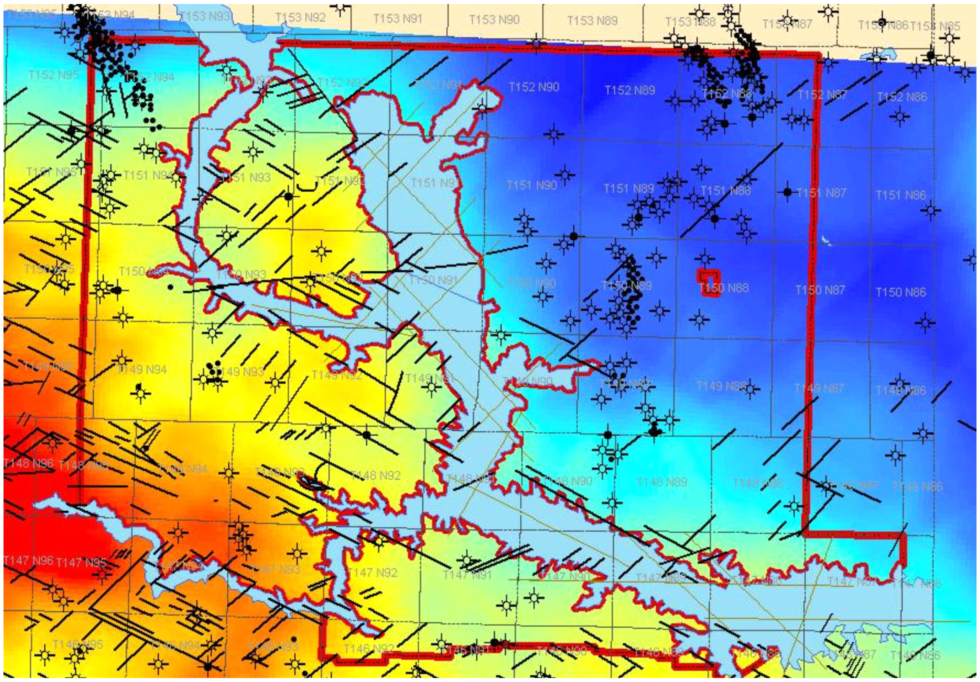


Figure 11: Lineament Density of the Reservation area

Overall, the surface remote sensing effort confirmed the presence of a strong WNW trending pattern of basement faults with a lesser developed but significant NNE subordinate trend. The interpretation was complicated by the glacial deposits across the northeastern portion of the area which covered the pre-Pleistocene bedrock surface.

3.3 Regional Potential Fields

The subsurface structure of the Reservation was initially evaluated using regional, publicly available, gravity and aeromagnetic data sets. These data were sourced from the USGS as preprocessed, gridded data sets. Details of the processing and gridding are available along with links to the data at http://crustal.usgs.gov/geophysics/ . The gravity data was originally published as part of USGS Digital Data Series 9 (DDS-9). The aeromagnetic compilation is of more recent vintage, published in 2002 as part of a broad, North American compilation sponsored by the governments of Canada, Mexico and the USA (http://crustal.usgs.gov/projects/namad/). Both data sets represent compilations of smaller surveys, merged, filtered and gridded at a 5 km spacing to remove boundary effects and achieve a smoothed grid suitable for regional (basin scale) interpretation. The quality of the data varies considerably across the country as a function of the original input surveys.

Figure 12 is a map of the regional isostatic gravity grid across the Reservation area (red outline). The colored squares are the 5 km grid values represented as individual pixels in order to depict the level of accuracy contained in the data. Gray represents the highest value and shifts through brown, red, orange, yellow, green, aqua, blue, lavender, etc to bluish red as the lowest. The remote sensing lineaments are shown in black; the lake in blue. The regional gravity indicates the area is underlain by broad gravity highs and lows with some variability in the directional trends along the transitions. Potential field interpretations are, by the nature of the tool, non-unique, because the variability in the mapped values may be the result of lateral density changes in the basement or vertical relief on a surface of uniform density. The surface lineaments, judged representative of faulting in the subsurface, generally bound the large areas of extreme highs or lows and are coincident with the areas of transition. By combining the interpretations from independent data sources, it can be inferred that basement structure in this area has two directions of faulting with sufficient vertical displacement to affect the regional isostatic gravity.

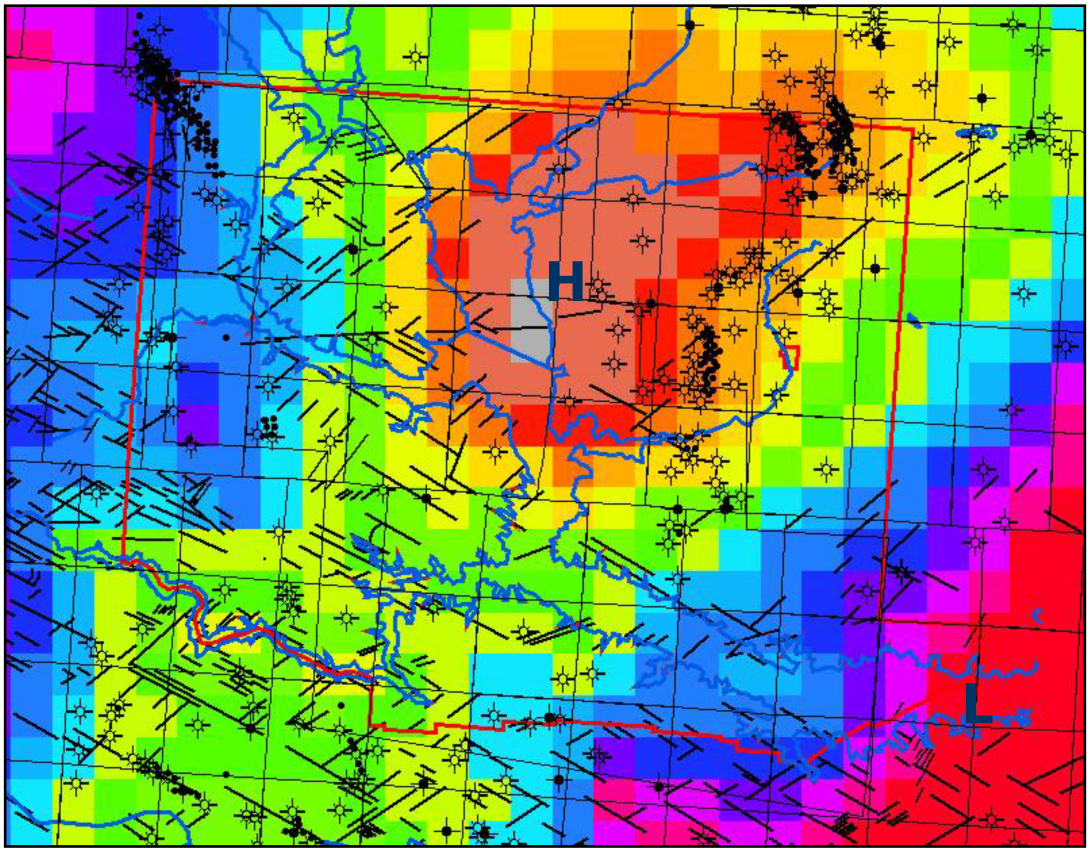


Figure 12: Map of the Regional Isostatic Gravity Across the Reservation Area

3.4 Regional Aeromagnetic Interpretation

The regional aeromagnetic grid was windowed, converted from a latitude-longitude coordinate system to North Dakota, North, State Plane, NAD 83 feet and re-gridded to a 1 km spacing (mainly for cartographic appearance). The same color scheme (used for the isostatic gravity mapping) was used for consistency. Figure 13 is a total magnetic field map from the regional aeromagnetic data. As with the gravity mapping, the remote sensing lineaments generally fall in the transition areas between the highs and lows, indicating faulting, rather than lateral changes in magnetic susceptibility, is responsible for the general map patterns. It should be noted that Wabek and the other fields of the Sherwood shoreline trend in the northeast quarter of the Reservation lie along a distinct structural trend in the basement that appears to control the transgressive surface upon which the stratigraphically trapped accumulations form. Also evident, the gravity and magnetic high areas are not coincident, indicating the presence of high density, low magnetic susceptibility materials as one of the components of basement lithology.

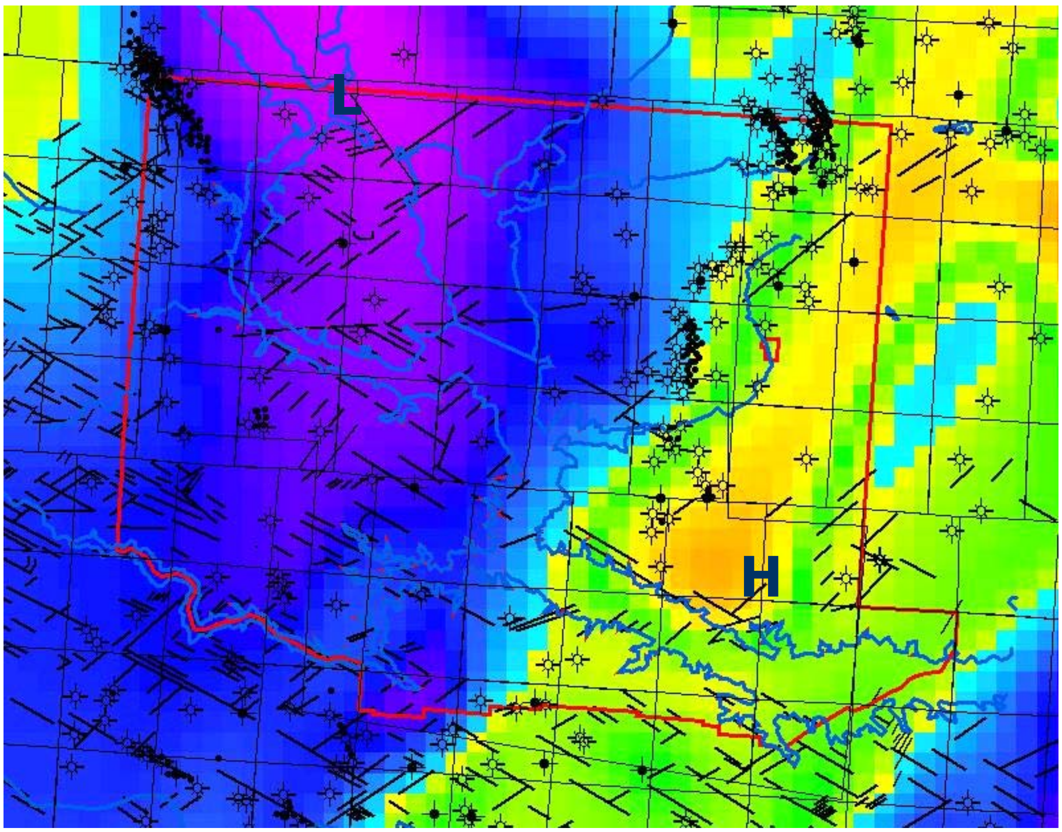


Figure 13: Total Magnetic Intensity from the Regional Aeromagnetic Compliation

Seven significant basement faults can be inferred using the WNW directionality of the remote sensing surface lineaments as the dominant faulting direction and their coincidence with the changes in trend along the high to low transition zones (Figure 14). There is less direct surface evidence in the northeastern portion of the study area but that is understandable given the pervasive glacial drift covering the area. Figure 15 is a comparison between a previous interpretation of faulting in the area based on sparse well control and the present interpretation. Significantly, there is a subtle change in trend (more westerly) and more faulting identified in this interpretation. Identification of additional fault trends crossing the Reservation improves the potential for attractive structures around and beneath the lake area.

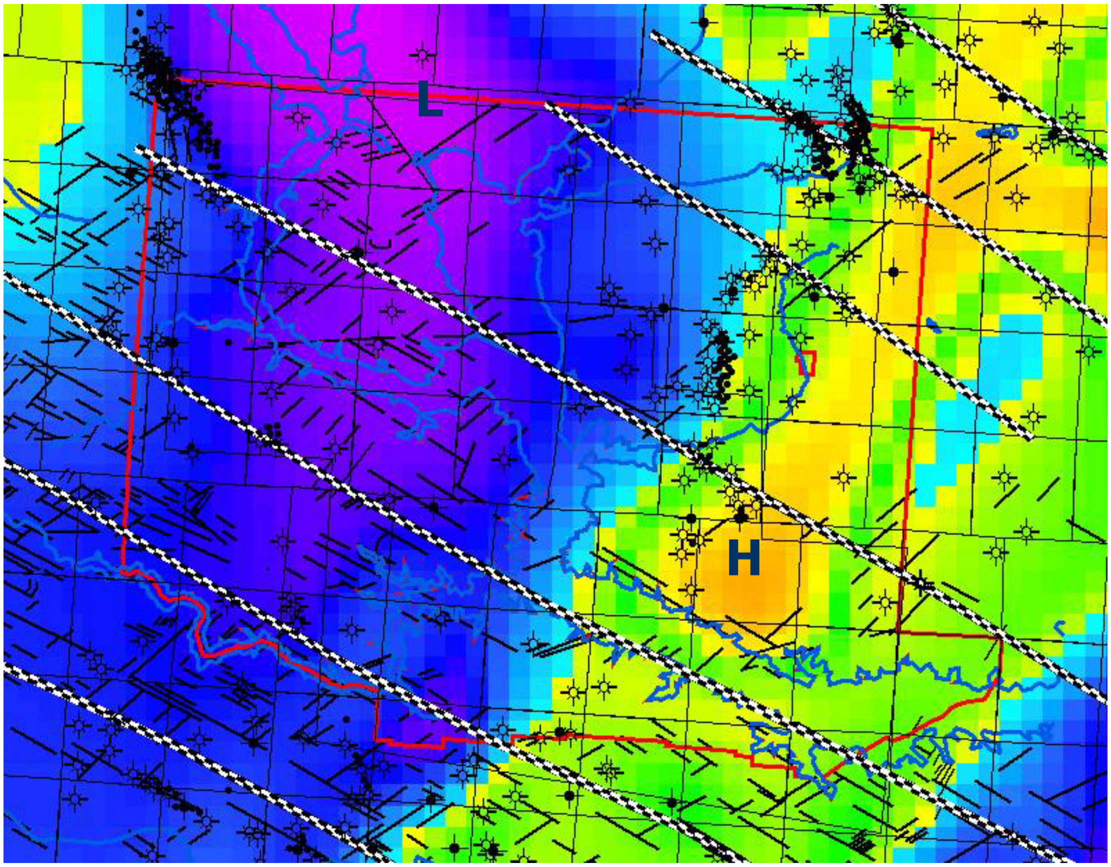


Figure 14: Total Magnetic Intensity with Interpreted Regional Basement Faults Identified from Surface Remote Sensing and Potential Fields data

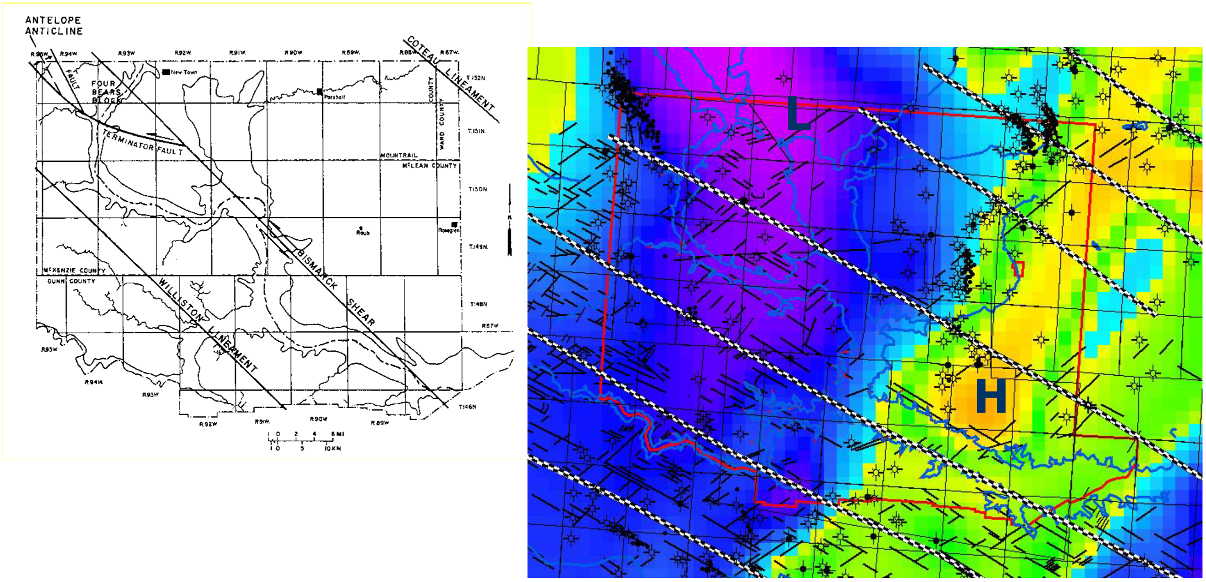


Figure 15: Comparison of Basement Faulting (3 total) Mapped in Reference 20 with Basement Faulting Identified in this Evaluation (7 total)

Results from the surface remote sensing study combined with the coarse regional potential fields grids indicates the Fort Berthold Reservation area contains more structural basement complexity than previously identified. More than twice the number of WNW basement faults cross the area in and along Lake Sakakawea offering significantly more opportunities for development of subtle basement paleohighs as potential hydrocarbon prospects. Prospect definition, however, requires additional geophysical detail over and above that provided by the imagery and regional potential field data

3.5 Detailed Aeromagnetic Survey

A moderate resolution aeromagnetic survey of sufficient extent to cover the Reservation portion of Lake Sakakawea and significant adjacent producing areas for calibration and prospect generation purposes was acquired. Figure 16 shows the outline of the survey data purchased for this evaluation. Included with the purchase of the survey was a detailed processing, interpretation and modeling study by Pearson Technologies, Inc which was incorporated into the prospect generation effort of this study. The results of the study as they pertain to prospect generation will only be summarized here. The complete report by Pearson Technologies documenting processing, modeling and interpretation is included as Appendix A to this report.

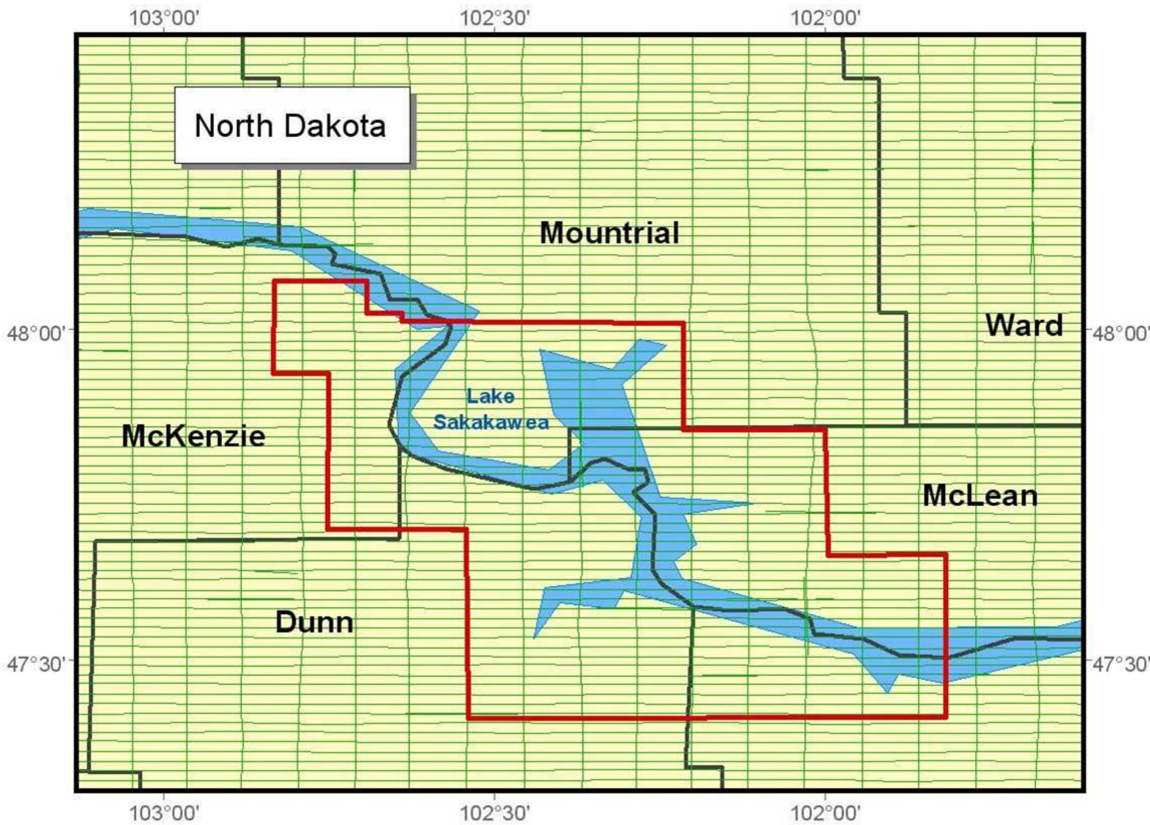


Figure 16: Outline (red) and Line Profile (green) Map for the Aeromagnetic Survey over the Lake Sakakawea Area

The primary reasons to purchase the intermediate resolution magnetic survey were to increase the spatial resolution and move the depth of investigation higher in the basin, closer to the objective horizons across the Reservation. Also, access to the profile data adds a much greater degree of flexibility and power to the processing, modeling and interpretation of the data than possible with compiled grids of uncertain quality. The improvements in resolution and interpretation will be readily apparent as the prospect generation discussion evolves.

Figure 17 is map of the Total Magnetic Intensity (TMI) across the study area (color scheme as before). An additional feature indicated on this map is the Sherwood shoreline represented by the double line of semicircles trending southwestwards from the Wabek field area. As mentioned before, this is an updip stratigraphic truncation forming along a transgressive surface of erosion. It is strongly influenced by the underlying basement structure during the transgression. As before, the remote sensing lineations tend to bound the high and lows but the magnetic anomalies are smaller and there are more of them. The extremes are located in quadrants of fault intersections as one would expect if the magnetic data were imaging tilted basement fault blocks. The areal size of the extremes ranges from approximately 18 to 50+ square miles which compares favorably to the general areal extents of the existing fields around the Reservation. The Sherwood shoreline trend was originally located by stratigraphic mapping from electric logs. There is good correspondence between the structural features mapped by imagery/potential fields and the stratigraphy interpreted from well control. On balance, the proprietary aeromag survey is imaging (at better resolution) the basic structural fabric of the lake area (as corroborated by independent lines of data) and is appropriate for prospect definition.

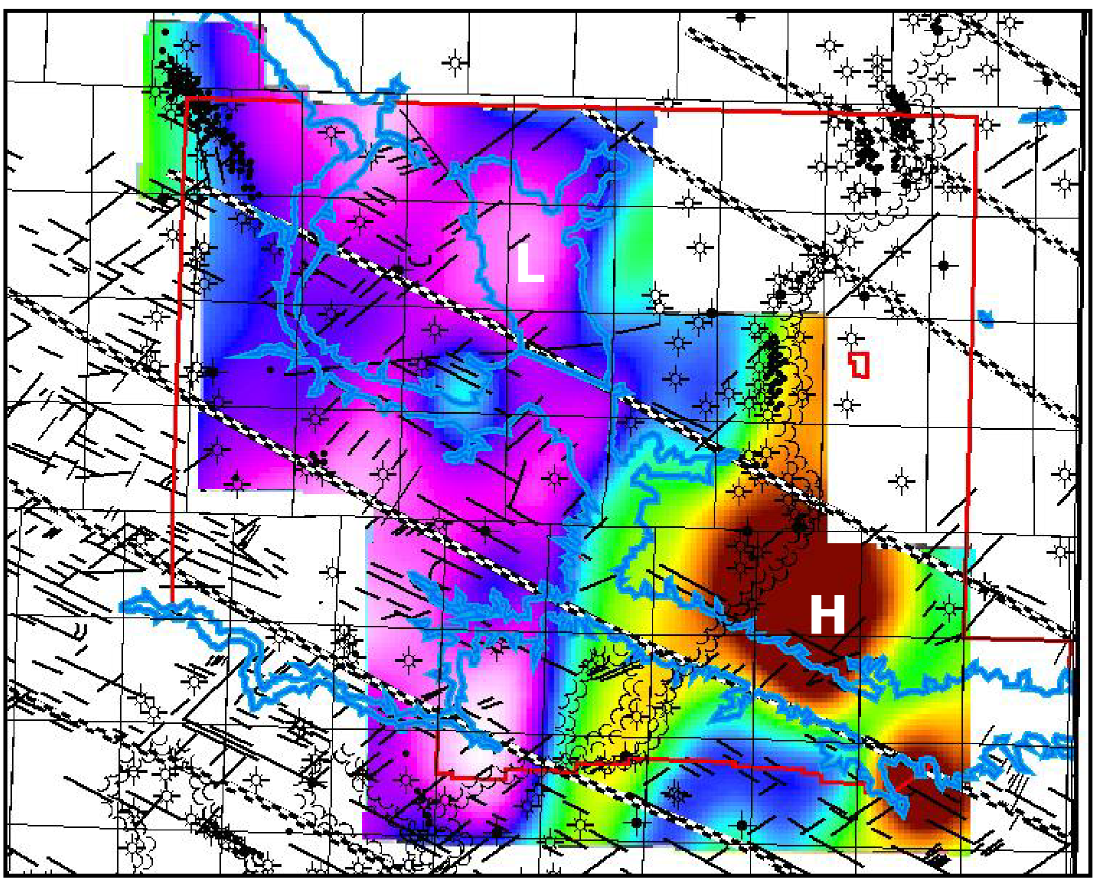


Figure 17: Total Magnetic Intensity (TMI) Map of the Lake Sakakawea Area

A detailed model study was performed on the survey to refine the structural interpretation and generate a "basement" structure map. Details of the modeling are contained in Appendix A. Magnetic basement over most of the area was interpreted to be a preCambrian mafic sheeted dike terrane of oceanic origin. This lithology has considerable lateral variation in magnetic susceptibility and appears as a pronounced set of NNE "stripes" in the data (Figure 18). The pronounced NNE striping was judged to be the result of linear lateral susceptibility changes in the preCambrian magnetic basement. The NNE trending "stripes" are disrupted by the WNW trending faults, discussed previously. One positive aspect of this situation is that cross cutting faults are readily identifiable on any of several display techniques such as an autofault display where horizontal gradient inflection points appears as dotted lines (Figure 19). On the other hand, NNE trending faults are more difficult to identify. Also, once recognized, the effects can be removed by processing.

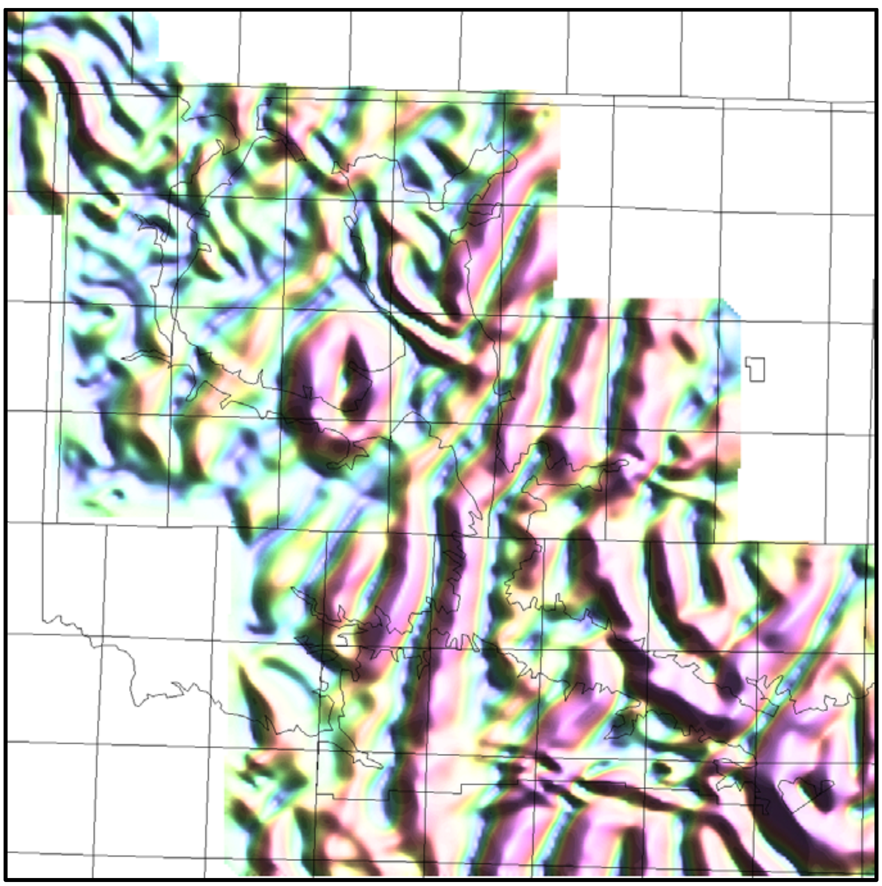


Figure 18: Shaded Relief, Horizontal Gradient Map of the Moderate Resolution Aeromag Survey

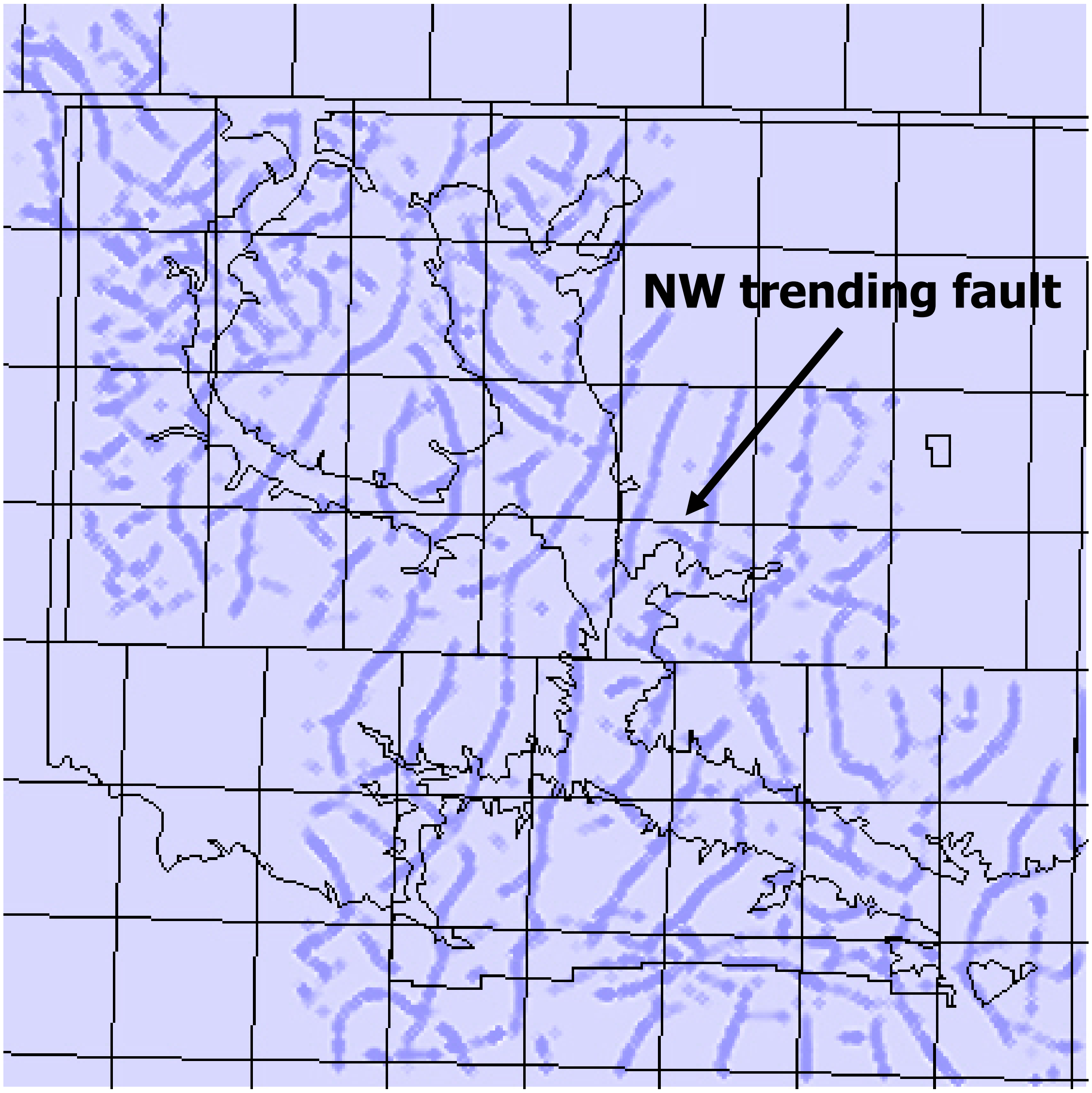


Figure 19: Autofault Display of the Moderate Resolution Aeromag Survey

The shaded relief gradient display and other images were interpreted to identify the general pattern of smaller scale faulting that would be most likely to disrupt the overlying sediments and create the potential for traps or enhance permeability from natural fractures. Figure 20 is a dip azimuth plot interpreted for smaller scale faulting. The smaller scale faults (black lines) disrupt the basement striping and appear to form along and between the major basement shears identified during the regional study. This is consistent with an upward propagating basement fault system. The intermediate resolution aeromag survey is imaging more complex features significantly higher in the section than the regional magnetic survey.

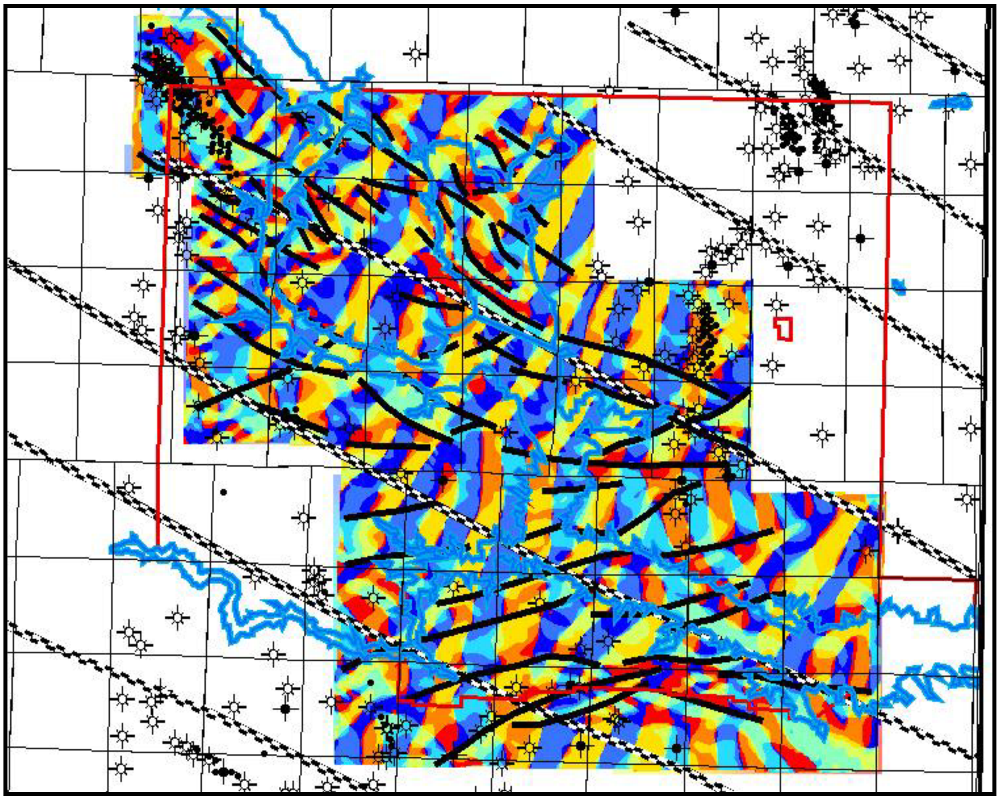


Figure 20: A Dip Azimuth Map of the Intermediate Resolution Survey

A limited number of preCambrian penetrations are present in the study area which were used to perform an inversion of the aeromagnetic survey to generate a preCambrian basement structure map, Figure 21. The inversion shows the gentle northwesterly dipping basement mapped by well control but also numerous, potentially prospective, isolated structures that could be paleohighs or pop-ups.

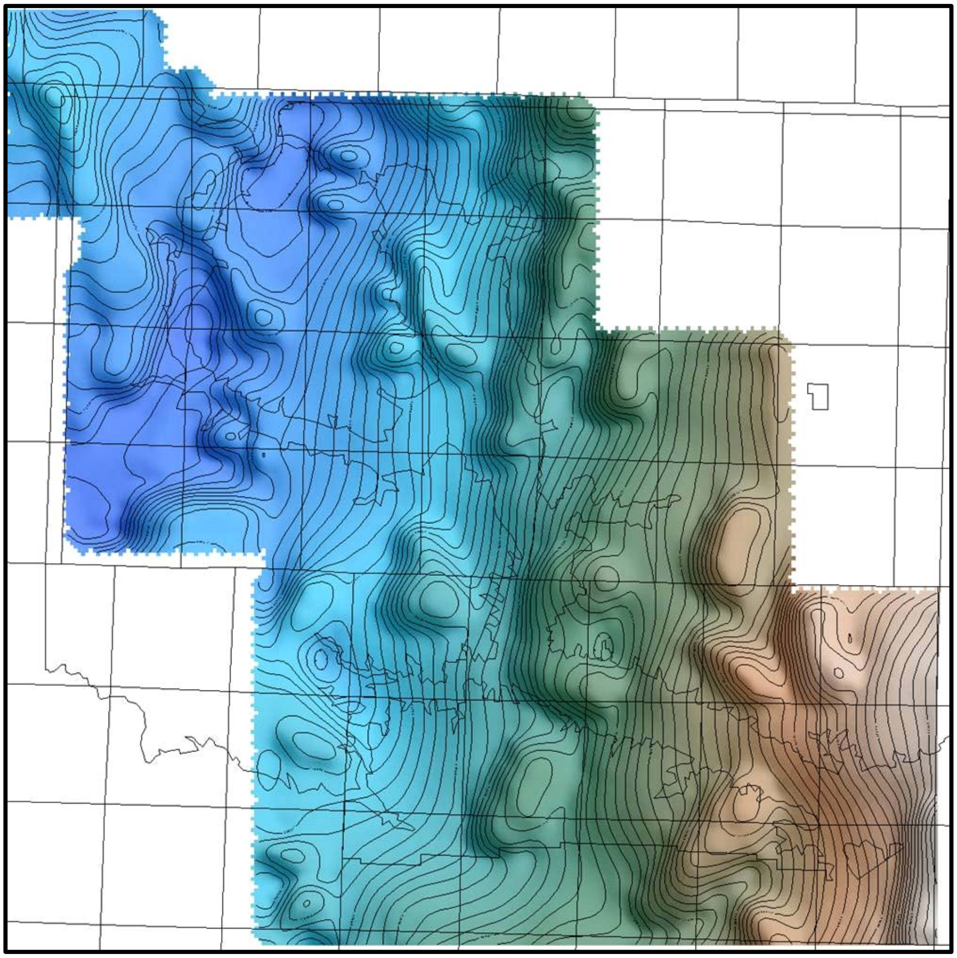


Figure 21: Shaded Relief Map of Inverted Depth to PreCambrian Structure Derived from the Intermediate Resolution Aeromagnetic Survey and Sparse Basement Penetrations

The intermediate resolution aeromagnetic survey provides important, high quality information to the overall Fort Berthold prospect generation process. The survey indicates the presence of basement structures in and around the available Lake Sakakawea acreage. It's uniform coverage and higher resolution of shallow magnetic basement is an important complement to the less widespread seismic data also purchased for the evaluation.

3.6 Seismic Evaluation

200 of 500 available miles of existing 1980's vintage 2D seismic over Lake Sakakawea were acquired for the project (on behalf of the Tribes and maintained at the BIA office, Lakewood, Colorado) to directly identify prospective structures beneath the lake. The seismic was reprocessed and interpreted as part of the prospect generation process. Significant but not insurmountable problems were encountered during the reprocessing effort by BIA, and are documented in Appendix B. The distribution of the seismic lines is shown in Figure 22. The seismic data was interpreted in time and time structure maps were constructed for the Mission Canyon, Winipeg and Greenhorn Formations. An isochron was interpreted for the Winipeg to Bakken interval, which is an important paleostructure indicator for successful Williston Basin prospects. The seismic data remains proprietary and available for review at the BIA office in Lakewood.

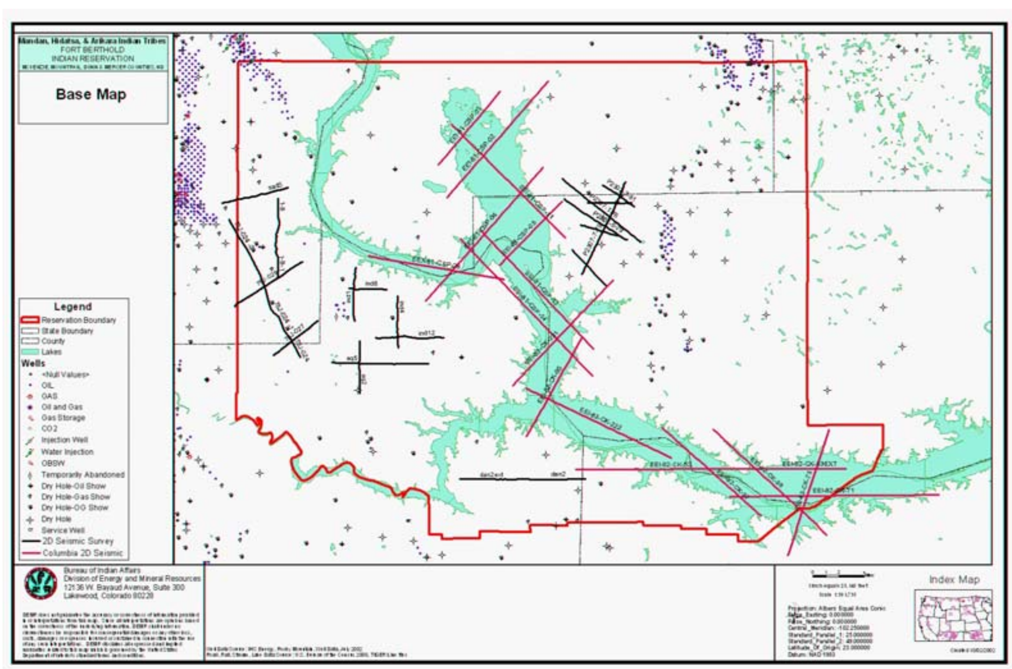


Figure 22: Distribution of 2D Seismic Used for this Evaluation

Interpretation of the seismic indicates the presence of several low relief structures beneath the waters of Lake Sakakawea. Sparse seismic coverage, however, means that most are single line anomalies. Figure 23 is a time shape map of the Ordovician Winipeg from the seismic interpretation. The majority of the low relief structures are associated with a Winipeg-Bakken thin on the isochron map.

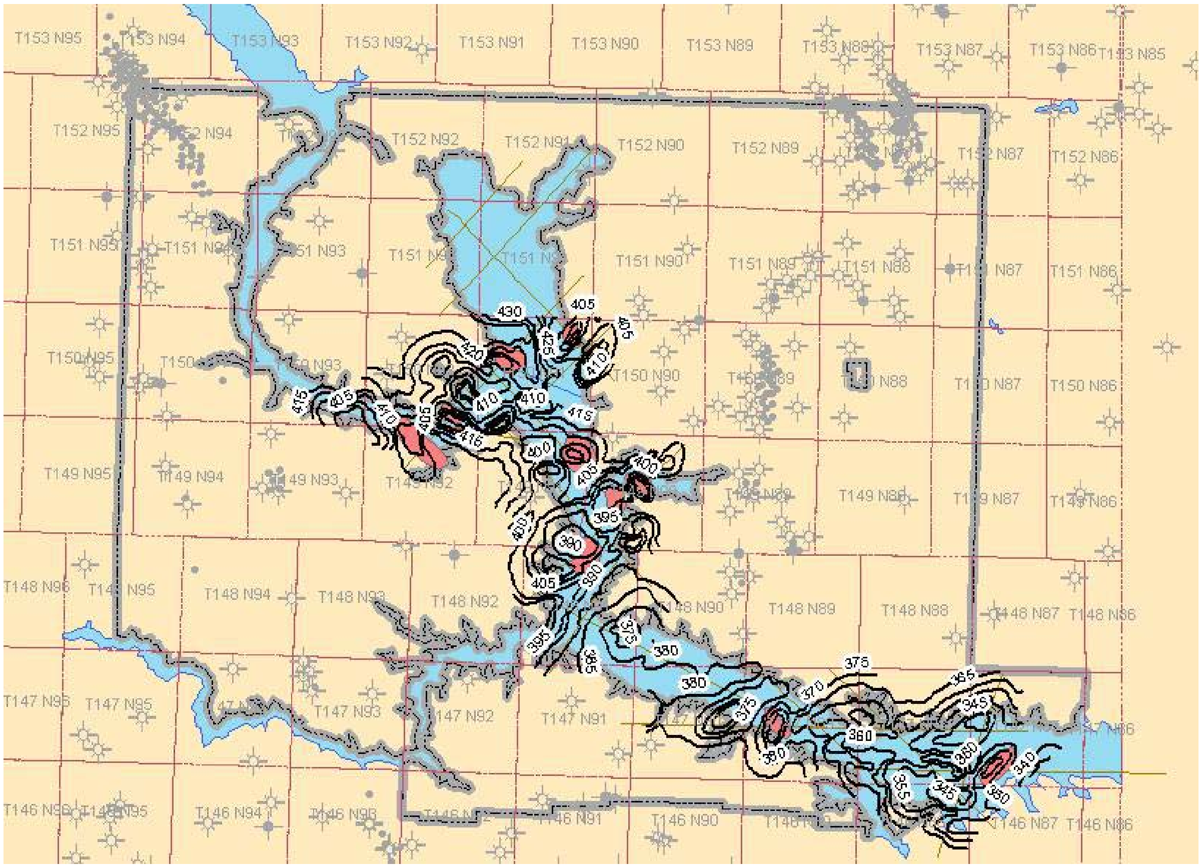


Figure 23: Ordovician Winipeg to Bakken Isochron from Seismic Interpretation

Values from the Winipeg-Bakken isochron were cross correlated with the preCambrian depth structure map to assess the validity of the isochron. Results of the curve fit (R^2= 0.91, Figure 24) indicate a strong correlation between the mapped attributes. The strong correlation is consistent geologically if the mapped basement highs are long standing paleohighs that influenced deposition of younger sediments through time. Such paleohighs are strong exploration targets for their potential to have localized diagenetic enhancement of porosity and permeability and potential long-lived trapping configuration. The isochron-magnetic inversion relationship could also be used to project the isochron values away from the actual lake area, if desired.

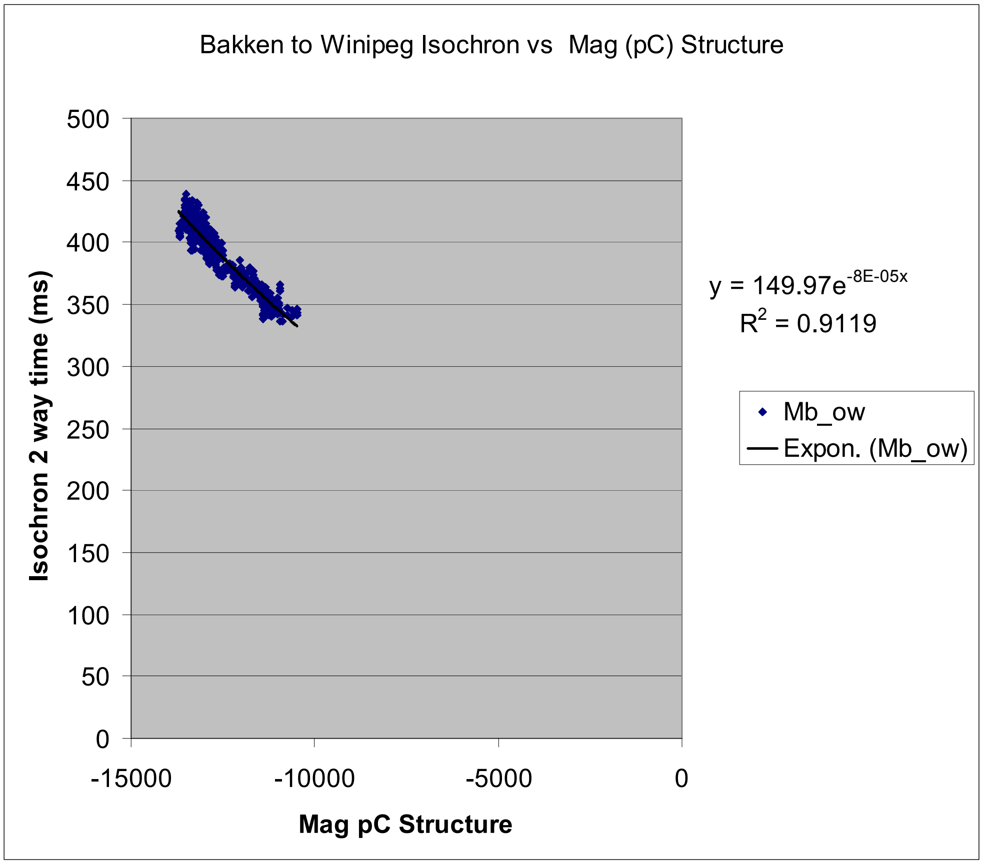


Figure 24: Correlation of Winipeg to Bakken Isochron Values with Inverted Depth to pC Map from Aeromag

The seismic data indicate the presence of several significant, low relief structures along and under Lake Sakakawea on the Fort Berthold Reservation. Isochron thins in overlying sediments can be validated using aeromag data and indicate they are likely long standing paleo-highs potentially prospective for hydrocarbons.

3.7 Lead Generation

Based on extensive experience of BIA personnel in this area, two geologic settings are most likely to yield positive results in the area east of Antelope field and southwest of Wabek, where the majority of the Lake Sakakawea acreage lies. Long lived paleohighs are attractive for their favorable charge position, diagenetic potential, fracture potential and multiple reservoir potential (Mission Canyon, Bakken, or Winnipeg). The Sherwood shoreline trend, while somewhat structurally controlled, is a true high potential but also high risk stratigraphic trap target.

Using these general criteria, eleven leads (ten structural and one stratigraphic) were identified using the maps and interpretations generated as a result of this project. Their locations are shown in Figure 25 together with the locations of existing production, the Bakken maturity map and the mapped extent of the Sherwood shoreline trend. The Bakken is considered the local oil source and its maturity is regarded as essential for effective oil charge. Bakken maturity is commonly estimated by mapping its resistivity and the green contours on Figure 25 represent mapped resistivity of the Bakken Formation across the Fort Berthold Reservation. The heaviest, green contour, labeled 167 ohm-m, is regarded as the updip limit of effective Bakken generation. The Sherwood shoreline trend is indicated in yellow and downdip of the intersection between the shoreline trend and the lake is considered a high risk Sherwood shoreline lead. The lead areas are summarized by type and size in Table 2.

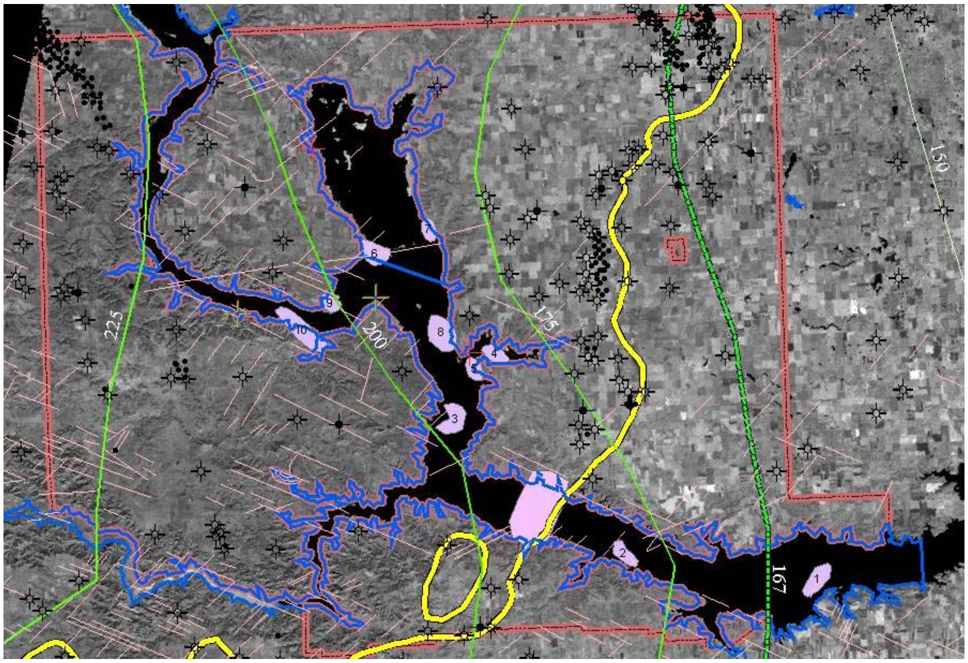


Figure 25: Generalized Lead Map

Table 2: Summary of Leads by Number, Type and Areal Extent.

Lead (from E to W)	Play Type	Size (acres)
1	structural	1,295
2	structural	842
3	structural	1,386
4	structural	823
5	structural	758
6	structural	1,202
7	structural	674
8	structural	1,941
9	structural	628
10	structural	2,308
Sherwood	stratigraphic	7,177

3.8 Pro-Forma Reserves and Economics

3.8.1 Statistical Analysis of Well Performance

The first step to assess the potential reserves and economics for each lead was to develop an understanding of how existing wells on or near the Reservation have historically performed. To do this, a statistical approach was adopted. All of the wells in the six county area surrounding the Reservation were first identified using the IHS Energy database. Then, wells completed in the primary targets – the Madison and Bakken/Sanish - were selected and, due to the large number of resulting wells, the database was further reduced based on proximity to the Reservation. Maps showing the locations of the Madison and Bakken/Sanish wells used in the statistical analysis are shown in Figures 26 and 27.

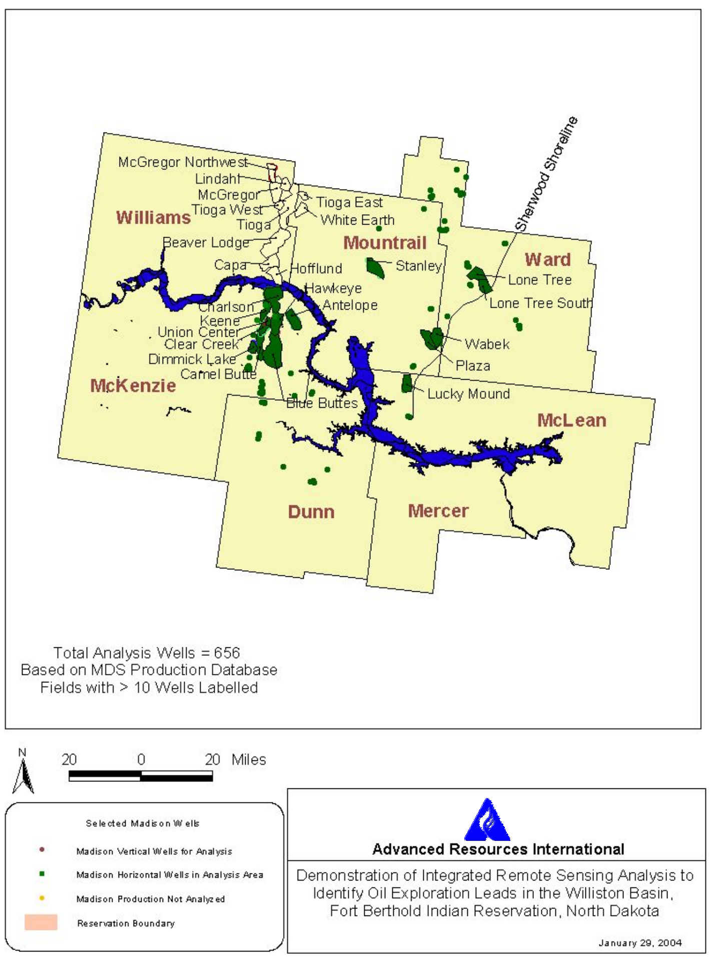


Figure 26: Location of Madison Wells

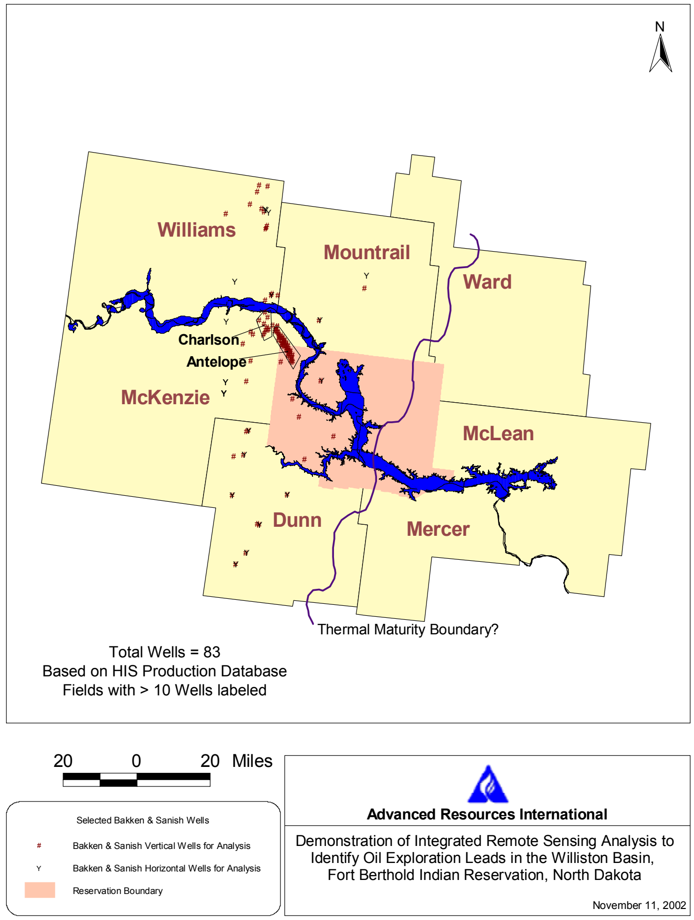


Figure 27: Location of Bakken/Sanish Wells

Note that the Madison dataset (now consisting of 655 wells) was further subdivided into wells that were along the Sherwood shoreline (stratigraphic play), and those that were further to the west (structural play). The Bakken/Sanish dataset (consisting of 81 wells) was similarly subdivided into the Antelope field Sanish, a unique geologic condition, with all other wells being Bakken producers. These subdivisions were made to better reflect the expected differences in the plays based on their distinctly different geologic characteristics.

Due the scarcity of horizontal wells, only production from vertical wells was analyzed in this study. Review of completions by time period and current well status for the Madison and Bakken/Sanish plays were examined, the results being provided in Figures 28 through 31.

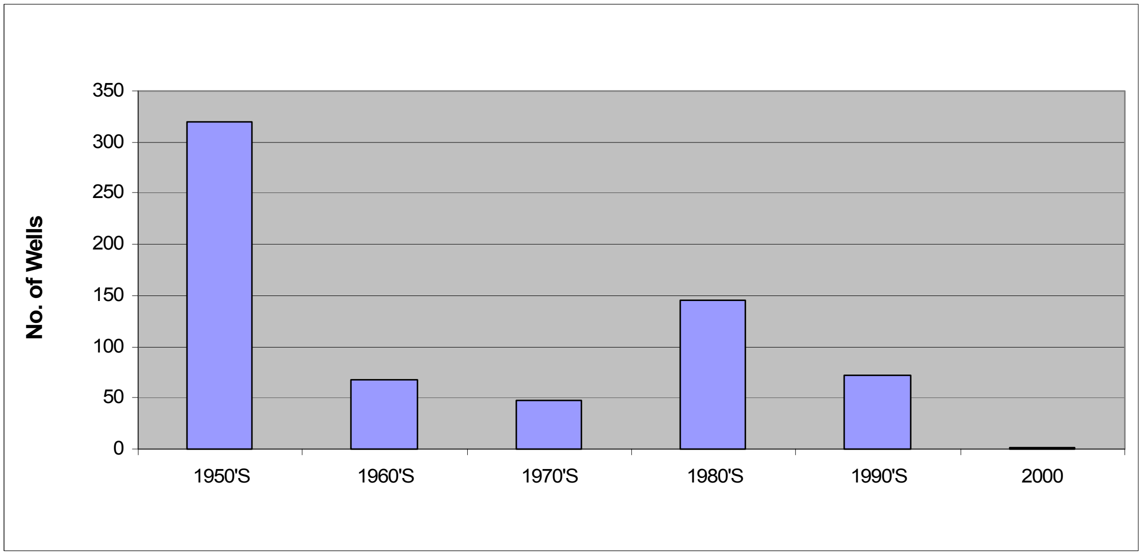


Figure 28: Madison Completions by Time Period

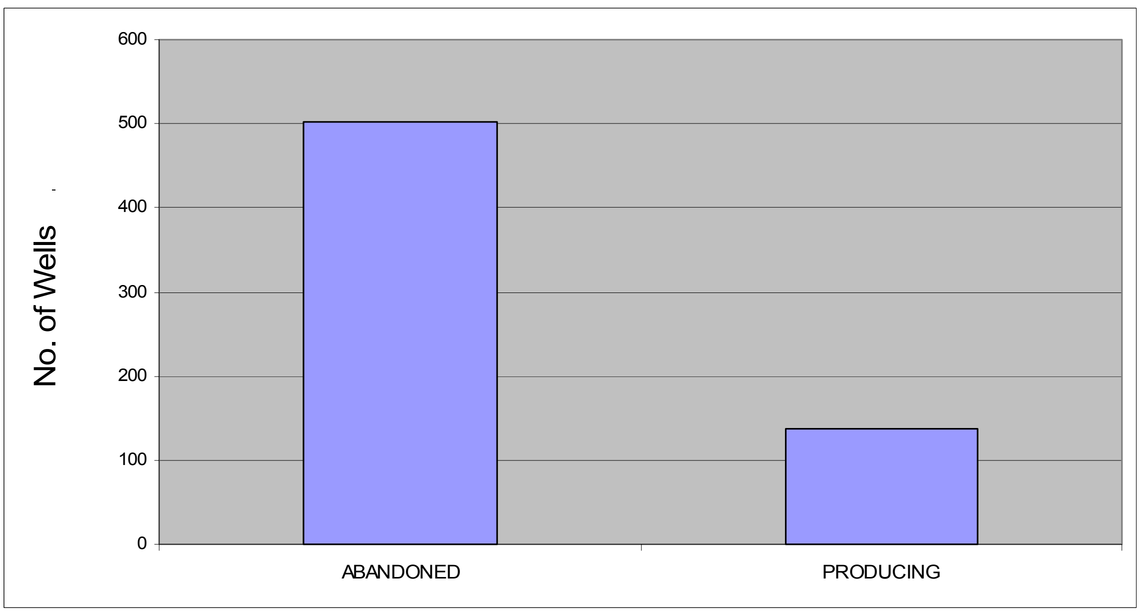


Figure 29: Current Status of Madison Completions

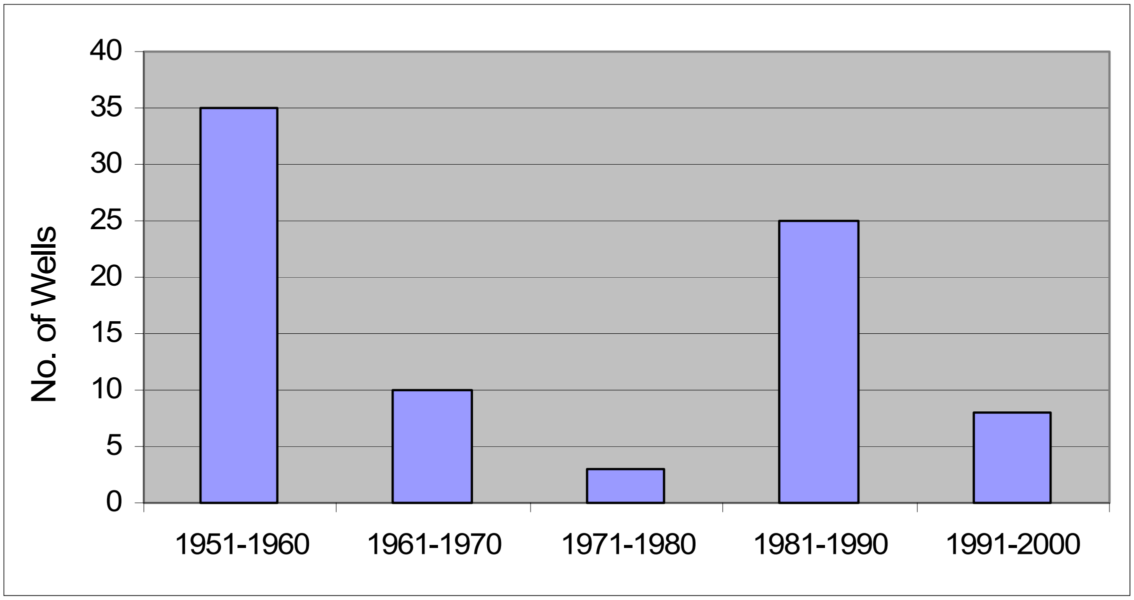


Figure 30: Bakken/Sanish Completions by Time Period

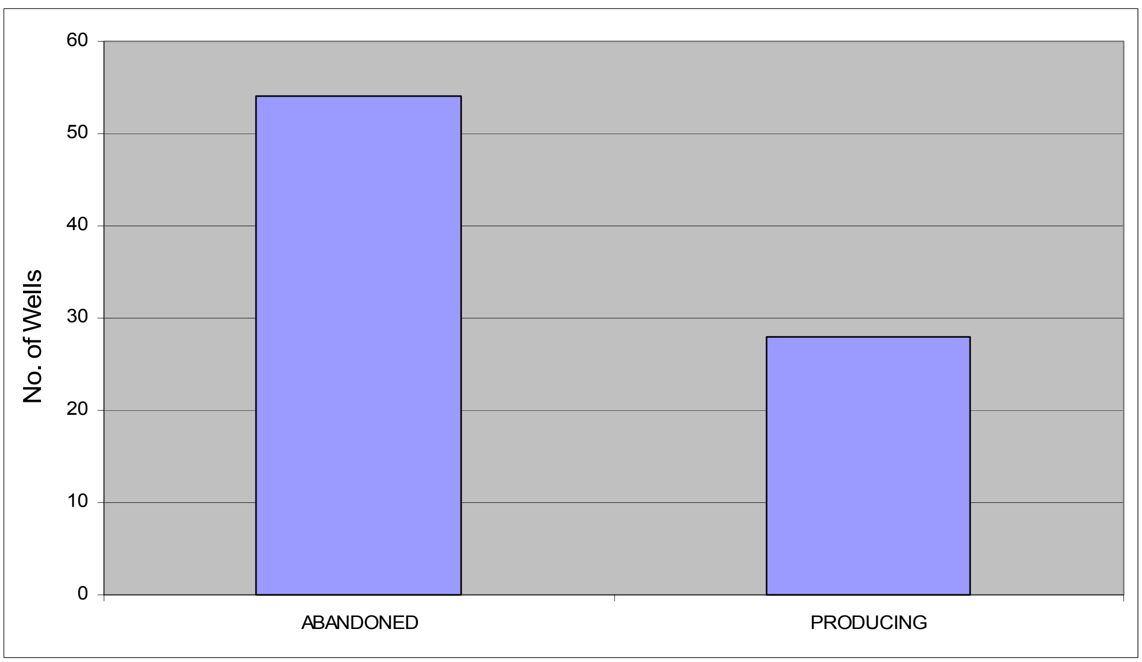


Figure 31: Current Status of Bakken/Sanish Completions

One can easily see from these figures that the most active drilling period was in the 1950's, shortly after the various fields were discovered, and a subsequent "mini-boom" in the (early) 1980's, when oil prices were high. One can also see that for both of these plays, most of the total completions are now abandoned.

To perform a statistical analysis, EUR's were required for all wells. In the cases of the abandoned wells, cumulative production represents the EUR. For all the active wells, decline-curve analysis was performed to estimate remaining recovery, and hence EUR when combined with cumulative recovery. Based on those results, oil recovery by play, field and field size were compiled, and are presented in Figures 32 through 39.

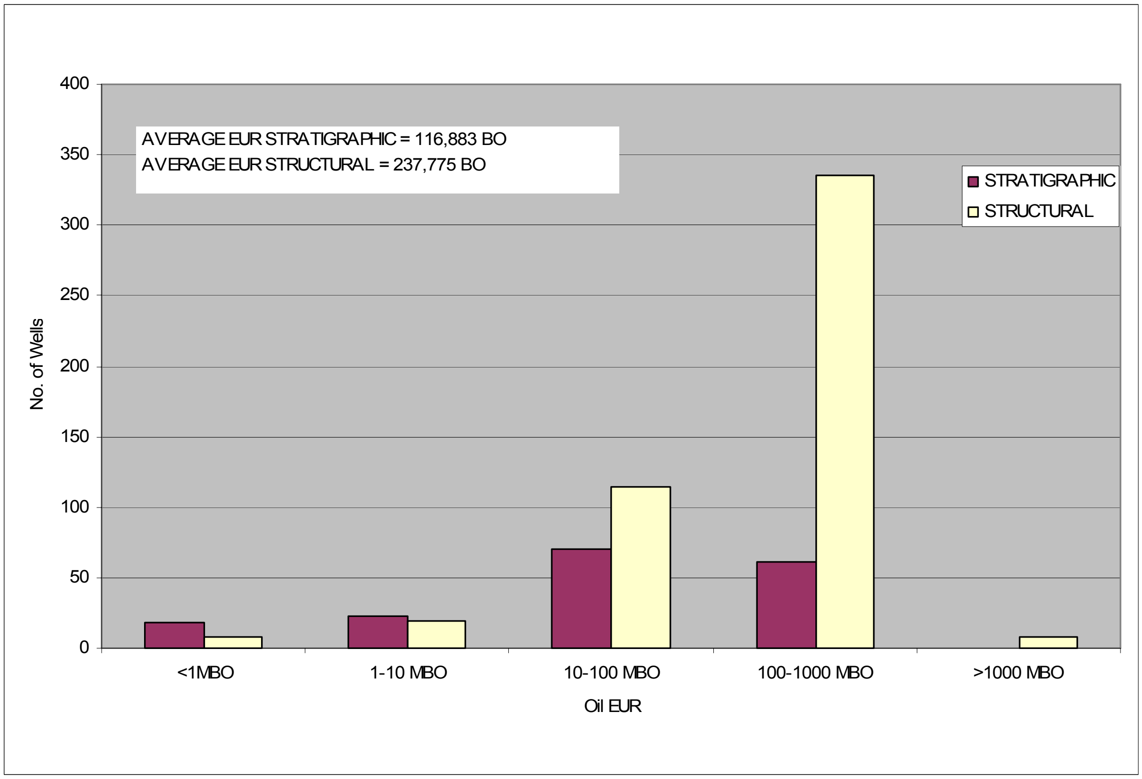


Figure 32: Average Recovery by Play, Madison

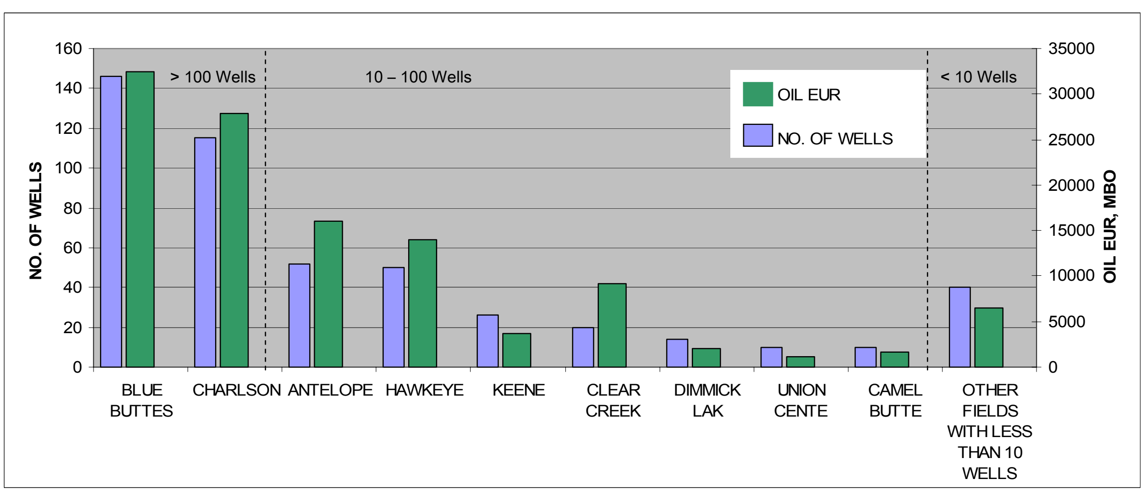


Figure 33: Field Size Distribution, Madison Structural Play

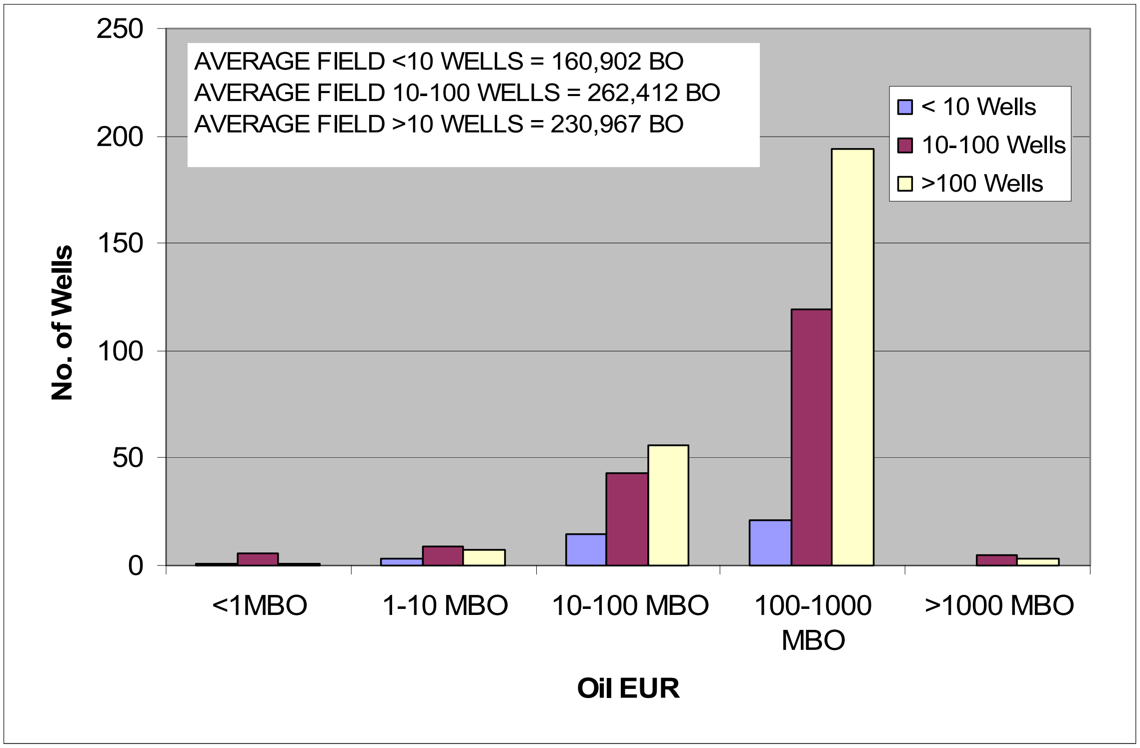


Figure 34: Recovery by Field Size, Madison Structural Play

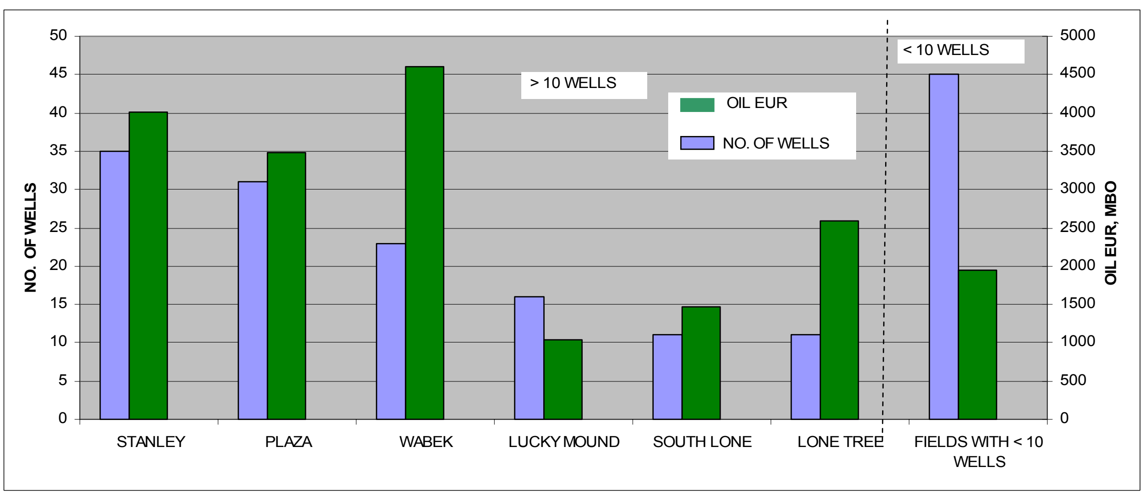


Figure 35: Field Size Distribution, Madison Stratigraphic Play

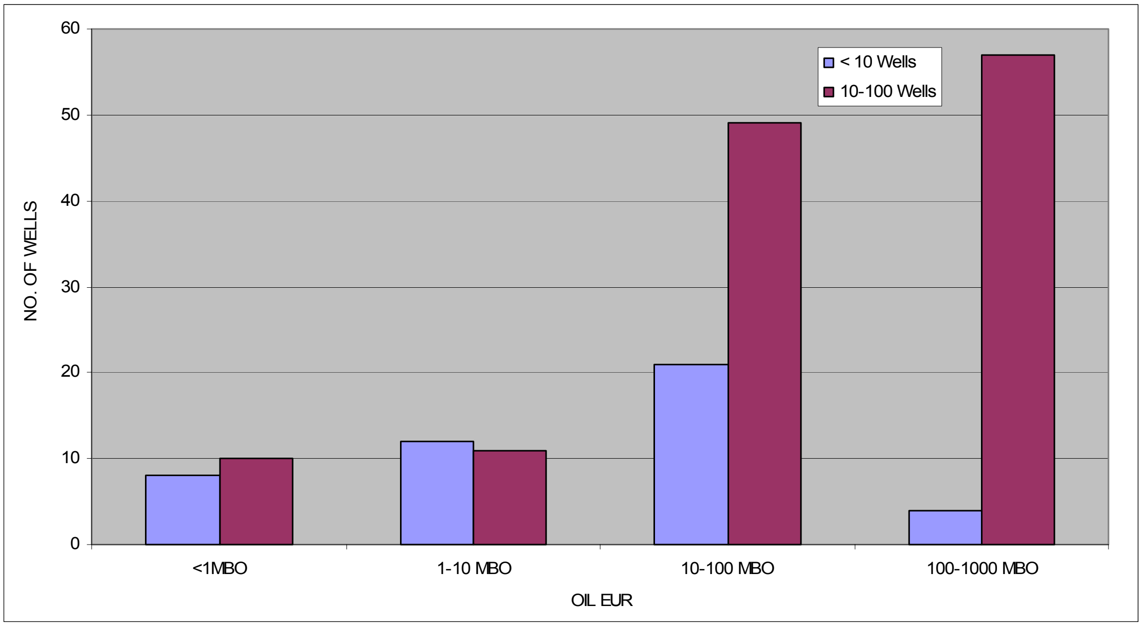


Figure 36: Recovery by Field Size, Madison Stratigraphic Play

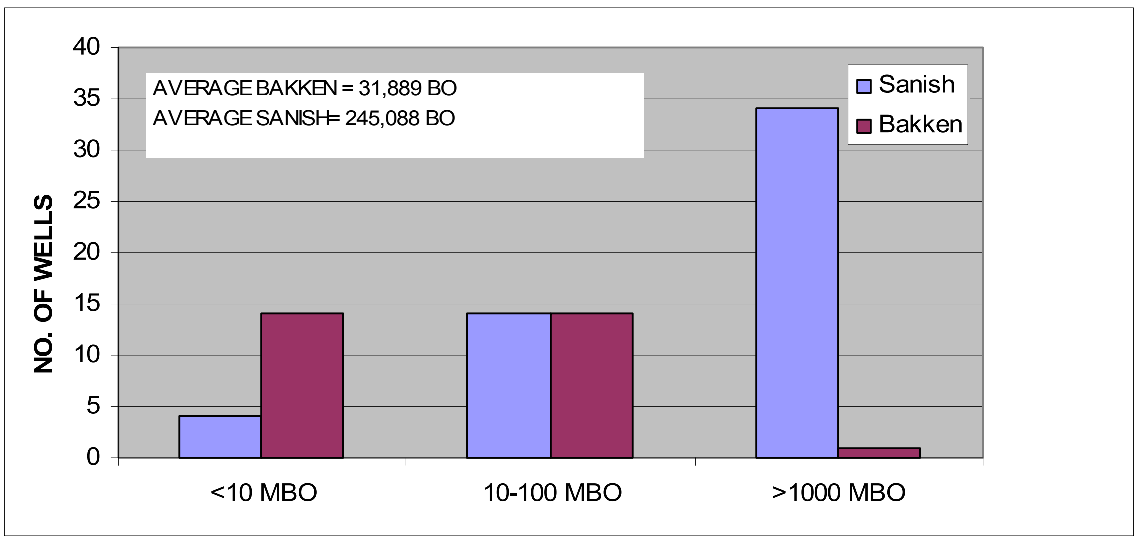


Figure 37: Average Recovery by Play, Bakken/Sanish Play

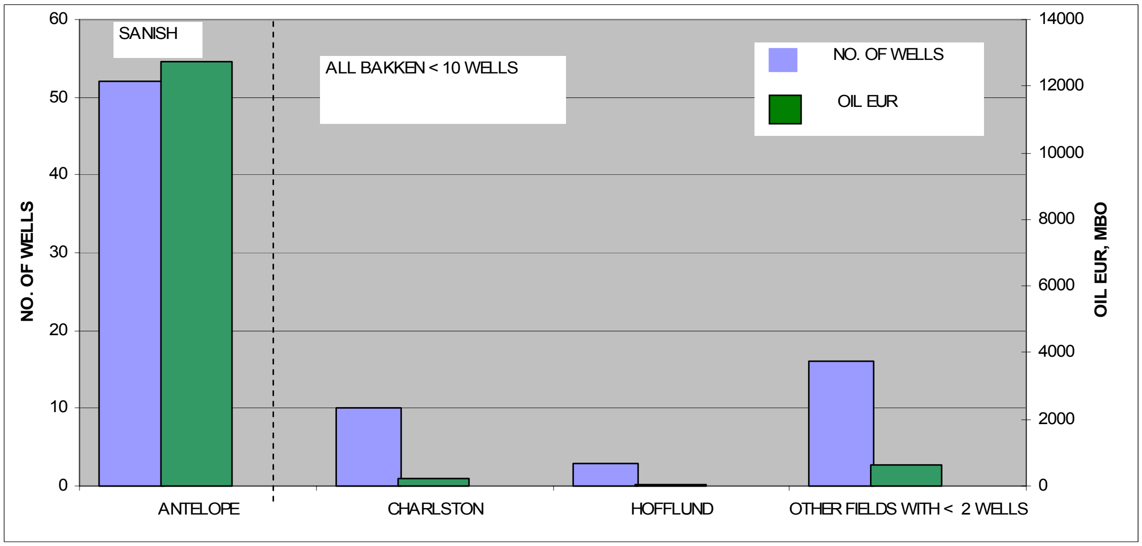


Figure 38: Field Size Distribution, Bakken/Sanish Play

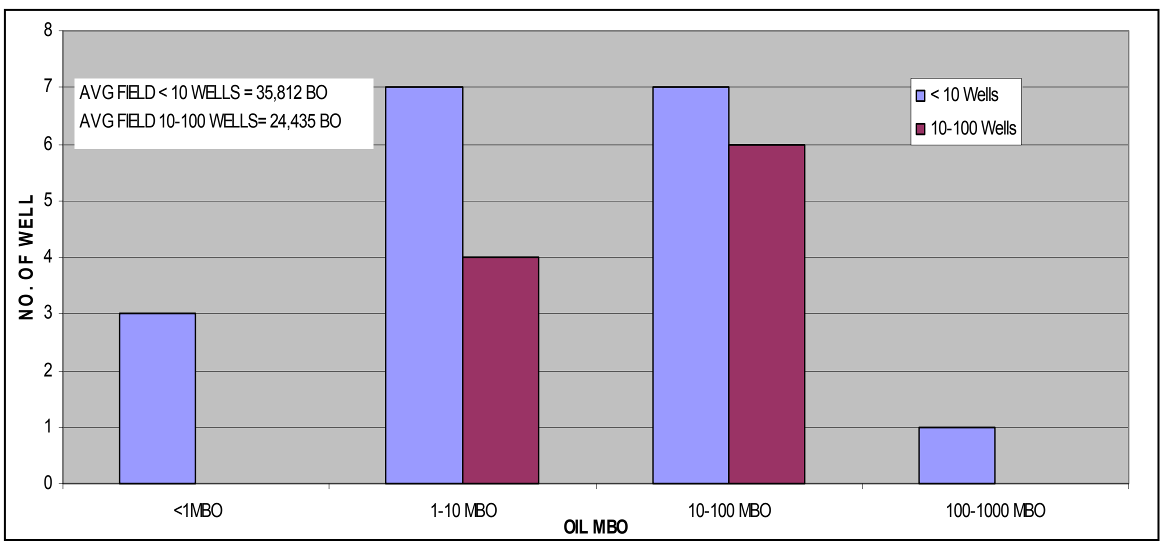


Figure 39: Recovery by Field Size, Bakken Play

A similar statistical analysis was performed for two secondary target formations on the Reservation, the Duperow with (15 active and 47 inactive wells) and Silurian/Interlake with (37 active and 99 inactive wells). Those results are provided in Figures 40 and 41.

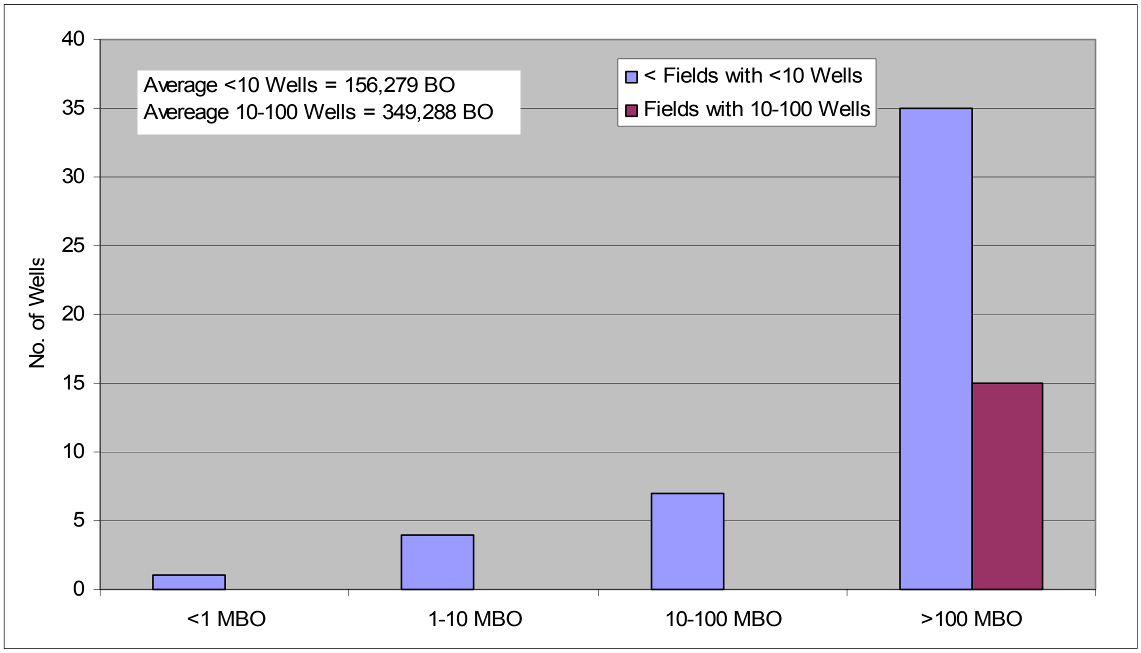


Figure 40: Recovery by Field Size, Duperow Play

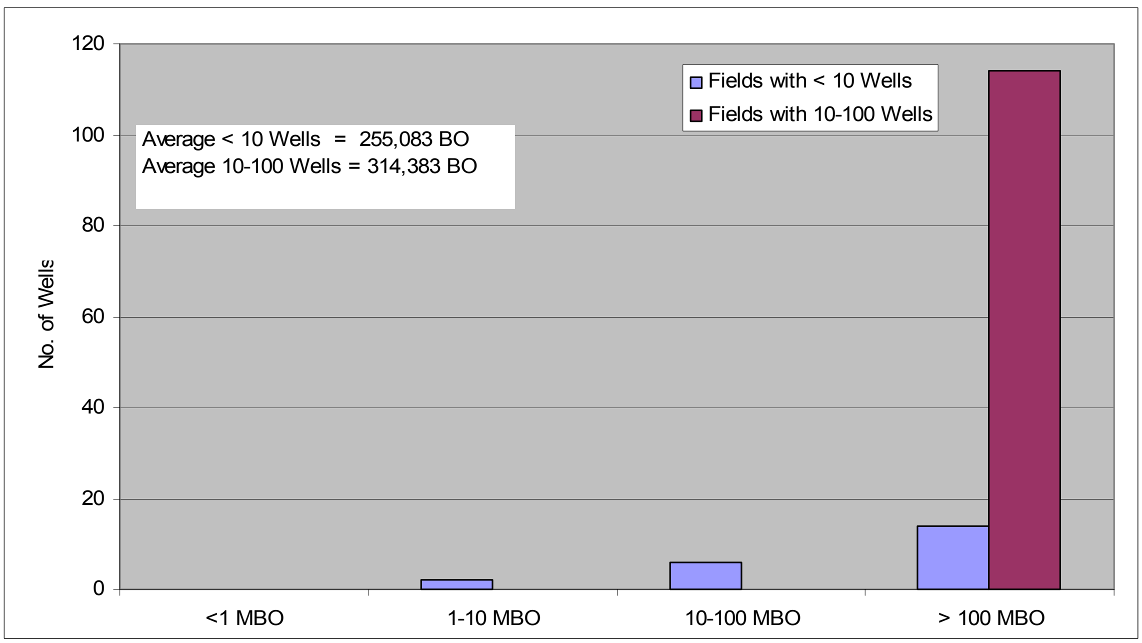


Figure 41: Recovery by Field Size, Silurian/Interlake Play

A summary of the results of the statistical analysis is presented in Table 3. It should be noted that the nominal well spacing for each of the plays evaluated was 80 acres per well.

Table 3: Summary of Well Performance Data

	Summary of Well Performance Data		
	Recovery, MBO (STB)		
	< 10 Wells	10 - 100 Wells	> 100 Wells
	Average	Average	Average
Madison Structural	161	262	231
Madison Stratigraphic	43	135	n/a
Sanish (i.e., Antelope)	n/a	245	n/a
Bakken	35	24	n/a
Duperow	156	349	n/a
Silurian/Interlake	255	314	n/a

3.8.2 Recoveries and Economics

To convert the statistical results into projected oil recoveries for the leads, several adjustments had to be made, to account for:

- Expected recovery based on which formations would likely be completed in a well
- Oil occurrence risk
- Exploration risk
- Development risk
- Spacing adjustment

The expected recovery from any particular well is the sum of the probabilities that a particular horizon is the primary producer multiplied by the average recovery for that horizon, as determined by the statistical analysis. The expected recoveries were computed by field size using the probabilities provided in Table 4. With that assumed distribution of probabilities, the expected recovery for a well in a small field (<10 wells) is 155 MBO, whereas the expected recovery for a well in a large field is 247 MBO. Note that for the Sherwood lead, the only Madison stratigraphic lead, the Madison stratigraphic recovery directly from Table 3 was used.

Also, since no leads were considered “Sanish style”, the data for that play type was not included in the expected recovery estimate.

Table 4: Expected Recovery by Field Size

		Recovery	
Horizon	**Probability of Completion**	**< 10 Wells (MBO)**	**10-100 Wells (MBO)**
Madison	55%	161	262
Bakken	15%	35	24
Duperow	15%	156	349
Silurian/Interlake	15%	255	314
Total	100%	155	247

Next, the risk that oil actually exists at a particular location was accounted for. Since we know that oil migrated through most of the area from the basin epicenter based on known production, these probabilities were fairly high. However, as one moves to the east, towards less-mature Bakken source rock, the likelihood of oil occurrence was decreased. The assumed values are shown in Table 5.

Table 5: Oil Occurrence Likelihood based on Bakken Maturity

Resistivity (ohm-m)	Probablity of Oil Occurance
200 – 225	100 %
175 – 200	90%
167 – 175	80%
< 167	70%

Based on estimates by the Tribes, exploration and development risk factors were also applied. Those values are provided in Table 6.

Table 6: Exploration and Development Risks

	Structural	Stratigraphic
Exploration	40%	25%
Development	80%	75%

Finally, since it is assumed that the leads would be drilled from onshore locations using extended reach and/or horizontal wellbores, and presumably on larger well spacing that 80 acres/well, some reduction in recovery factor should be applied. A value of 75% was chosen as a spacing adjustment.

The recoveries for each lead were then computed using the areal size of the lead to determine the number of 80-acre equivalent wells that could be drilled, using the expected recovery information, and applying the various risk factors and adjustments. Those results are provided in Table 7. The recoveries range from 283 MBO to 1.7 MMBO, and average 813 MBO. For all 11 leads, the expected recovery is 8.9 MMBO.

Table 7: Expected Total Recoveries by Lead

Lead	Type	Area (acres)	80-acre Wells	Average Recovery (MBO/well)	Unadjusted Field Recovery (MBO)	Oil Occurrence Risk	Exploration Risk	Development Risk	Spacing Adjustment	Expected Recovery (MBO)
1	structural	1,295	16	247	4,001	70%	40%	80%	75%	672
2	structural	842	11	247	2,603	90%	40%	80%	75%	562
3	structural	1,386	17	247	4,282	90%	40%	80%	75%	925
4	structural	823	10	247	2,542	90%	40%	80%	75%	549
5	structural	758	9	155	1,473	90%	40%	80%	75%	318
6	structural	1,202	15	247	3,713	90%	40%	80%	75%	802
7	structural	674	8	155	1,310	90%	40%	80%	75%	283
8	structural	1,941	24	247	5,997	90%	40%	80%	75%	1,295
9	structural	628	8	155	1,219	100%	40%	80%	75%	293
10	structural	2,308	29	247	7,131	100%	40%	80%	75%	1,711
Sherwood	stratigraphic	7,177	90	135	12,111	90%	25%	75%	75%	1,533

Then, to estimate F & D costs, costs were estimated for geophysical surveys ($25,000/mi^2) and drilling/completion using information provided by the Tribes. Those costs are presented in Table 8.

Table 8: Cost Assumptions

	Structural (12,500 ft)	Stratigraphic (8,000 ft)
Dry Hole	$ 1,000,000	$450,000
Completion	$350,000	$250,000

In addition, a cost premium of 20% per quarter mile each lead was from shore was added to account for the added costs of extended/horizontal wells. Well spacing was assumed to be on 320 acres, so fewer wells were assumed to be drilled than Table 7 indicates based on 80-acre spacing. However dry-hole costs were included. The results of the analysis are provided in Table 9.

Table 9: Summary of Finding and Development Costs for Each Lead

Lead	Geophysical Cost		Vertical Well Cost		Average Distance from Shore	Cost Premium	No. 320-acre Wells		Well Costs	Total F&D Costs	
	($/sq-mi)	($)	Dry Hole ($)	Completion ($)	(mi)	(%)	Dry	Successful	($)	($)	($/bbl)
1	$ 25,000	$ 50,588	$ 1,000,000	$ 350,000	1.1	88%	1	3	$ 9,738,761	$ 9,789,348	$ 14.56
2	$ 25,000	$ 32,908	$ 1,000,000	$ 350,000	0.1	48%	1	2	$ 4,987,202	$ 5,020,110	$ 8.93
3	$ 25,000	$ 54,136	$ 1,000,000	$ 350,000	1.4	112%	1	3	$ 11,752,321	$ 11,806,457	$ 12.77
4	$ 25,000	$ 32,136	$ 1,000,000	$ 350,000	0.1	8%	1	2	$ 3,554,000	$ 3,586,136	$ 6.53
5	$ 25,000	$ 29,621	$ 1,000,000	$ 350,000	0.1	8%	0	2	$ 3,275,891	$ 3,305,512	$ 10.39
6	$ 25,000	$ 46,947	$ 1,000,000	$ 350,000	0.8	64%	1	3	$ 7,884,065	$ 7,931,012	$ 9.89
7	$ 25,000	$ 26,335	$ 1,000,000	$ 350,000	0.1	8%	0	2	$ 2,912,472	$ 2,938,807	$ 10.39
8	$ 25,000	$ 75,828	$ 1,000,000	$ 350,000	0.6	48%	1	5	$ 11,491,842	$ 11,567,670	$ 8.93
9	$ 25,000	$ 24,515	$ 1,000,000	$ 350,000	0.6	48%	0	2	$ 3,715,267	$ 3,739,782	$ 12.78
10	$ 25,000	$ 90,160	$ 1,000,000	$ 350,000	0.1	8%	1	6	$ 9,970,992	$ 10,061,153	$ 5.88
Sherwood	$ 25,000	$ 280,351	$ 450,000	$ 250,000	0.8	64%	6	17	$ 23,448,527	$ 23,728,877	$ 15.48

The leads are ranked based on F & D costs in Table 10. The top 5 leads, shown in Figure 42, each have F & D costs of under $10/bbl.

Table 10: Ranking of Leads based on F & D Costs

Rank	Lead	Expected Recovery (MBO)	F&D Costs ($/ bbl)
1	10	1,711	$5.88
2	4	549	$6.53
3	2	562	$8.93
4	8	1,295	$8.93
5	6	802	$9.89
6	5	318	$10.39
7	7	283	$10.39
8	3	925	$12.77
9	9	293	$12.78
10	1	672	$14.56
11	Sherwood	1,533	$15.48
	Totals	8,944	$10.45

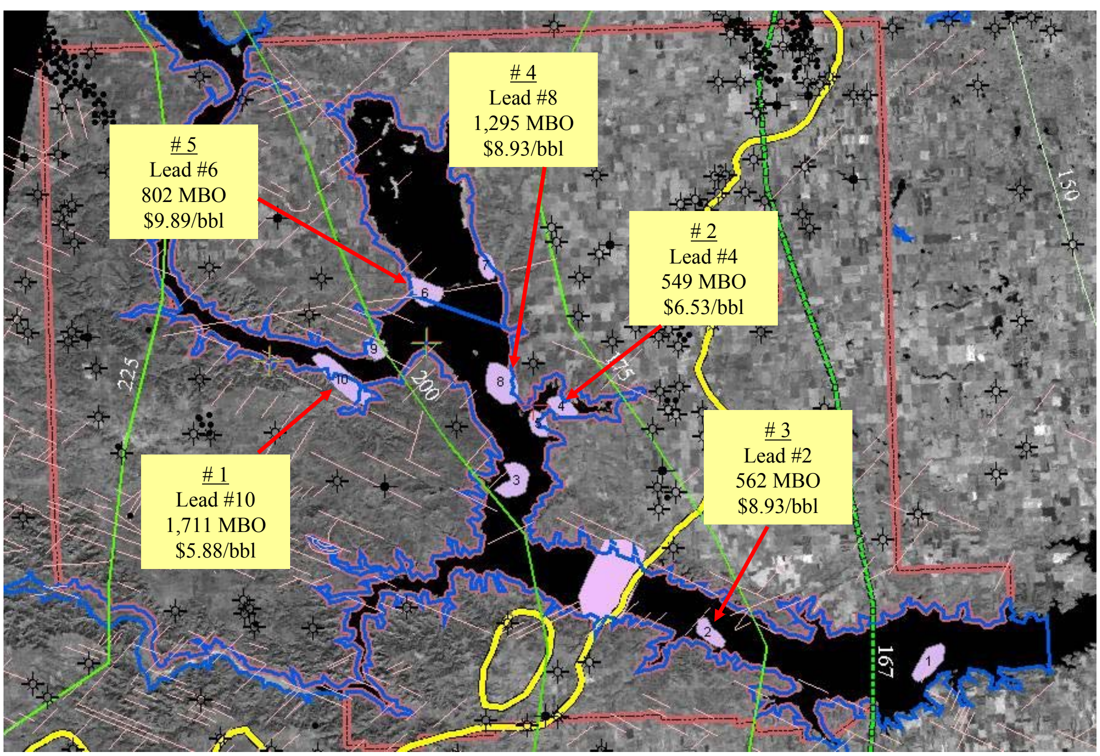


Figure 42: Location of Top Five Leads

The leads identified through this evaluation appear to offer considerable technical and economic promise as potential prospects for oil under Lake Sakakawea.

4.0 Conclusions and Recommendations

Based on the results from this study, the following results and conclusions have been drawn:

- Fort Berthold Indian Reservation is in favorably located within the Williston Basin, with good exploration success. An excellent opportunity exists to capture a 150,000 acre contiguous block on the Reservation under Lake Sakakawea.
- An integrated geology, remote sensing, potential fields and seismic study provided on improved understanding of the structural setting and hydrocarbon potential under the lake. That potential has been determined to be very promising.
- Eleven specific leads have been identified based on this study. Expected recoveries range from ~300 to ~1,700 MBO each (8,900 MBO in total), with F&D costs of ~$6/bbl to ~$15/bbl.
- To further define prospects, the following technical recommendations are made:
  - Acquire and reprocess balance of seismic data available over the lake (~300 line-miles)
  - Acquire and interpret a higher (than used in this study) resolution aeromag survey
  - Integrate those results with the existing study
  - Evaluate need for 3D seismic for further prospect definition and/or drill well

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Appendix A: High-Resolution Aeromag Study- Pearson Technologies

AN AEROMAGNETIC BASEMENT INTERPRETATION OF THE EAST CENTRAL WILLISTON BASIN NORTH DAKOTA

for

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3. EXECUTIVE SUMMARY

High sensitivity aeromagnetic surveying in the Williston Basin is very helpful in mapping faults and structures at the top of Precambrian basement. Analyses and interpretation of residual magnetic anomaly, shaded relief and **SUNMAG** images as well as the stacked profile displays define local basement faults.

The mapping which resulted from the integration of subsurface based basement structural mapping with the basement structures defined by aeromagnetic line profile analysis, and faults defined by the interpretation of the horizontal derivative of the reduced-to-pole magnetic **SUNMAG** and shadowgraph displays, resulted in the definition of 17 lead prospective areas, 8 are graded good while 7 are graded as fair. These lead areas lie on magnetically defined basement structures.

Nearby multilevel production along the Nesson Anticline to the northwest and especially the production in Antelope Oilfield in T152N, R94-95W is directly related to the location of basement structural highs and wrench faults interpreted from the magnetic displays and illustrated on the basement structure map and fault overlays delivered with this report. Essentially all fields in this portion of the Williston Basin occur on the tops or immediate flanks of mapped structures. Although production is associated with the smaller faults bounding these smaller structures, many of the larger structural and stratigraphic fields are located immediately adjacent to wrench faults. Several large structural and significant stratigraphic fields either end abruptly, or the production within them changes orientation, at their intersections with the northeast trending wrench faults. These faults appear to be of critical importance in controlling not only structural development, but also the updip productive limit in many of the fields, whether this is created by loss of structure or change in facies or facies trends.

Because most of the significant structural and stratigraphically influenced production appears to be concentrated on structures which straddle the major northwest or northeast trending wrench faults transecting the area, we recommend that similar undrilled structures and wrench fault trends be targeted in future exploration efforts. The excellent correlation between subsurface-defined local Mississippian Mission Canyon and Ordovician Red River structural highs and Precambrian structures delineated by line profile analysis indicates that many of the same areas of uplift and subsidence prevailed throughout Lower Paleozoic time. It is likely that this study can also help in mapping areas of likely paleotopographic relief that may be favorable for Waulsortian mound growth of the Dickinson Oilfield type. Therefore, acreage acquisition and 3-D seismic program planning should be focused along edges of basement structures, particularly where regional basement faults intersect. A number of these are highlighted on the basement structure map which accompanies this report, and Table I lists these prospective areas, which are based upon grade of structural anomaly and their proximity to major wrench faults and/or fault intersections.

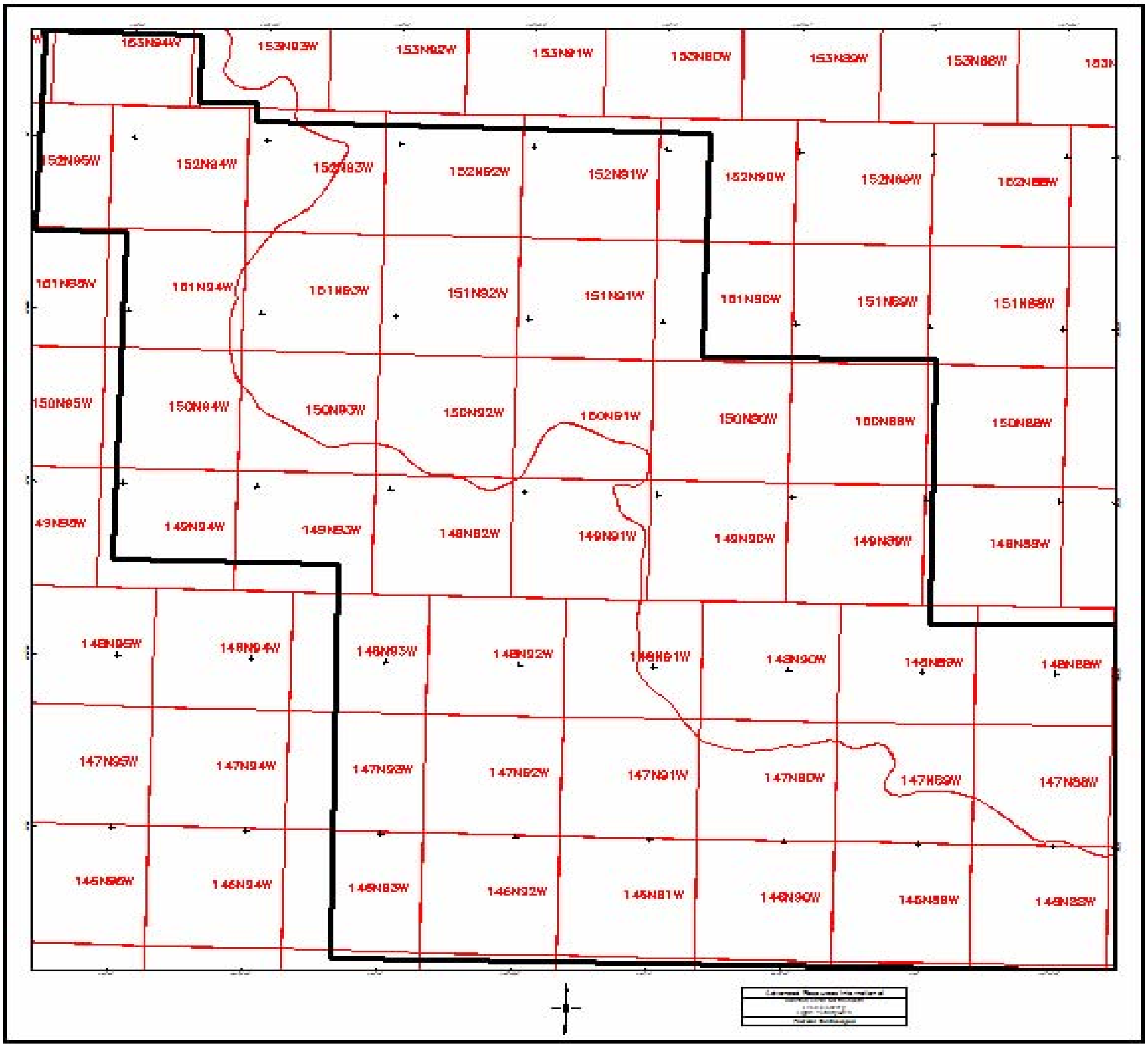
I. INTRODUCTION

In November 2002, Pearson Technologies Inc. of Lakewood, was hired by Advanced Resources International on behalf of The Three Affiliated Tribes, North Dakota to reprocess and interpret 38 townships of aeromagnetic data in the east central portion of the Williston Basin in North Dakota (Fig. 1). This area encompasses production from Mission Canyon (Miss.) carbonates, and Lower-Upper Paleozoic multipay zones in the Antelope Oilfield. The Three Affiliated Tries purchased a license to use aeromagnetic data acquired by FUGRO Airborne Surveys of Houston, Texas as the data base for this study.

The goal of the study was to determine how effectively aeromagnetic data can identify lead basement structural highs, faults, and structural trends that may be pursued in exploration for Mississippian Mission Canyon, Lower Mississippian Lodgepole Mounds, Tyler sands, the Interlake, Ordovician Red River and other potential pays. The scope of the study includes comprehensive reprocessing and integrated geological interpretation of the aeromagnetic data in both 2-D profile and 3-D map forms. In order to accomplish this, a detailed series of reprocessing steps were performed on the aeromagnetic data set, including deculturing, micro leveling, spectral whitening and grid interpolation to allow new higher dynamic range displays. Detailed analysis of the individual profiles was conducted to enhance and identify basement structures that produce subtle but identifiable anomalies and merged with basement structural interpretation derived from subsurface evaluations.

The study encompasses a high-sensitivity aeromagnetic survey, careful reprocessing and an integrated interpretation. The portion of the Geoterrex survey purchased for this study was flown on a nearly constant 3800 foot barometric elevation on a one by four mile grid of flight lines. The acquisition company used a high sensitivity Cesium Vapor magnetometer mounted in a twin engine fixed wing aircraft. Navigation was determined by strip chart camera that was compared to topographic maps, digitized and merged with the on-board digital magnetic, barometric and radar data.

Figure 1 Study Area



Pearson Technologies utilized sophisticated aeromagnetic interpretation techniques including the 2-D profile modeling and correlation with observed magnetic profiles in both individual and stacked form. This method is conducted by hand to provide for detailed integration with well control provided by the North Dakota Geological Survey and thus provides a subjective qualitative method for basement structural anomaly identification. Map interpretation tools such as reduction-to-pole filtering, second-vertical derivative filtering, shaded relief images of the horizontal derivative of the reduced-to-pole magnetic field and a new **SUNMAG** display with a continuous spectrum of color for different azimuths of magnetic anomalies were also utilized to identify basement faults and tectonic lineaments.

The excellent correlation between magnetically definable basement faults and basement structures (horsts, paleotopographic highs) with good oil production suggest that this type of integrated aeromagnetic and geologic data will be beneficial for future exploration in other portions of the Williston Basin and elsewhere. Approximately 17 under-evaluated structural prospective leads were identified, along with a set of major wrench faults which appear to control the location and limits of existing production. Final interpretation results were provided in digital form compatible with the Surfer mapping software system used by ARI.

II. AEROMAGNETIC SURVEY

A. DATA ACQUISITION

Contractor:	Geoterrex Ltd. Ottawa, Ontario
Date of Survey:	The survey was flown in 1981.
Flight Pattern:	Flight lines 5,280 feet spacing Direction--east-west Tie lines 4.0 mile spacing Direction--north-south
Flight Altitude:	3,800 feet above sea level
Airborne Magnetometer:	Varian split beam cesium magnetometer
Ground Magnetometer:	Same
Fiducials:	0.25 second readings

B. DATA COMPILATION AND REPROCESSING

Flight line recovery for the 1981 survey was performed by Geoterrex through visual correlation between photographic strip charts and the topographic maps. Once the fiducial ticks were marked on the topographic maps, the location ticks were digitized to produce a computer file of fiducial numbers, flight lines, latitudes and longitudes.

PTI viewed both the raw magnetic field trace and the original Geoterrex processed trace on a PC computer screen. Both the sensitvity and processing were good, however, short wave-length cultural or surficial geologic anomalies were being recorded with amplitudes in excess of 3 gammas. Therefore, PTI used a technique to identify and to remove cultural and surficial noise from the magnetic trace. The following interactive procedure was utilized:

(1) Identify noisy portions of the magnetic profiles by use of an anomaly detector set to the flight height of the aircraft;

(2) Turn off the samples at and in close proximity to noisy samples;

(3) Interpolate across the gaps using a gaussian interpolation and smooth the patch with a five point triangular filter;

(4) View results on screen and reiterate where necessary.

The original processing by Geoterrex was good but in preparation for the high dynamic range displays being generated for this study a detailed flight line tie line leveling procedure was applied. A second order polynomial adjustment was applied to the profiles to bring the intersection misties to within 1.5 gammas. A final round of flight line decorrugation was applied after grid interpolation to remove this last 1.5 gammas of line intersection mistie.

1. Total Magnetic Intensity Contour Map

The TMI Contour map is plotted in color to highlight areas of stronger magnetic field in warmer colors and weaker magnetic field in deep blues. The resulting total magnetic intensity values vary 100 gammas above and below zero. Areas of strong positive anomalies are areas containing locally more magnetic Precambrian rocks associated with the suturing of the Superior craton to the east to the Wyoming craton to the west .

III. INTERPRETATION OF AEROMAGNETIC DATA

A. PROFILE ANALYSIS

1. 2-D Modeling

Interactive two-dimensional magnetic modeling on a computer graphics terminal is an efficient means of defining magnetically susceptible bodies in the subsurface. These magnetic bodies best explain the observed field.

The first step in modeling is to select target structures with desired widths and vertical reliefs to adequately represent the anticipated magnetic basement anomalies. The initial geologic cross-sections were constructed with magnetic susceptibilities that are consistent with rock types found in the study area. Polygons are assigned a susceptibility and are superimposed in geologically reasonable parts of the modeled section. In this case, magnetic anomalies are fitted with polygons in crystalline Precambrian basement.

The computer calculates the magnetic signature of the geologic cross-section assuming either an infinite strike length perpendicular to the profile or a limited strike length. No change in shape along strike is accounted for except for the truncation of the geologic body (ies) at their half widths.

Based upon known and anticipated basement structural and compositional features, PTI computed a series of three theoretical cross-section 2-D models. Figure 2 is a horst block, Figure 3 is a normal fault and Figure 4 is an intrabasement block model.

Figure 2 Horst Block 2D Magnetic Model

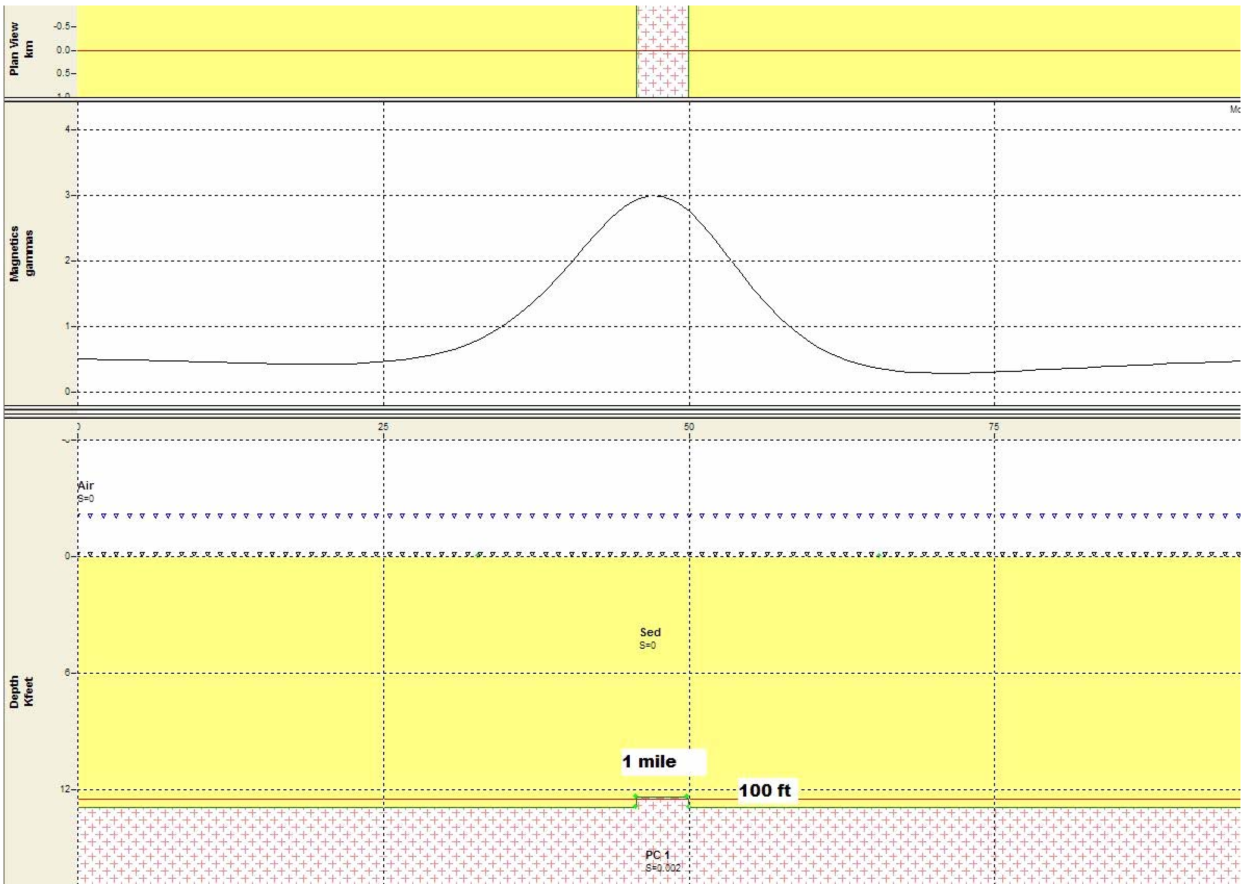


Figure 3 Normal Fault 2D Magnetic Model

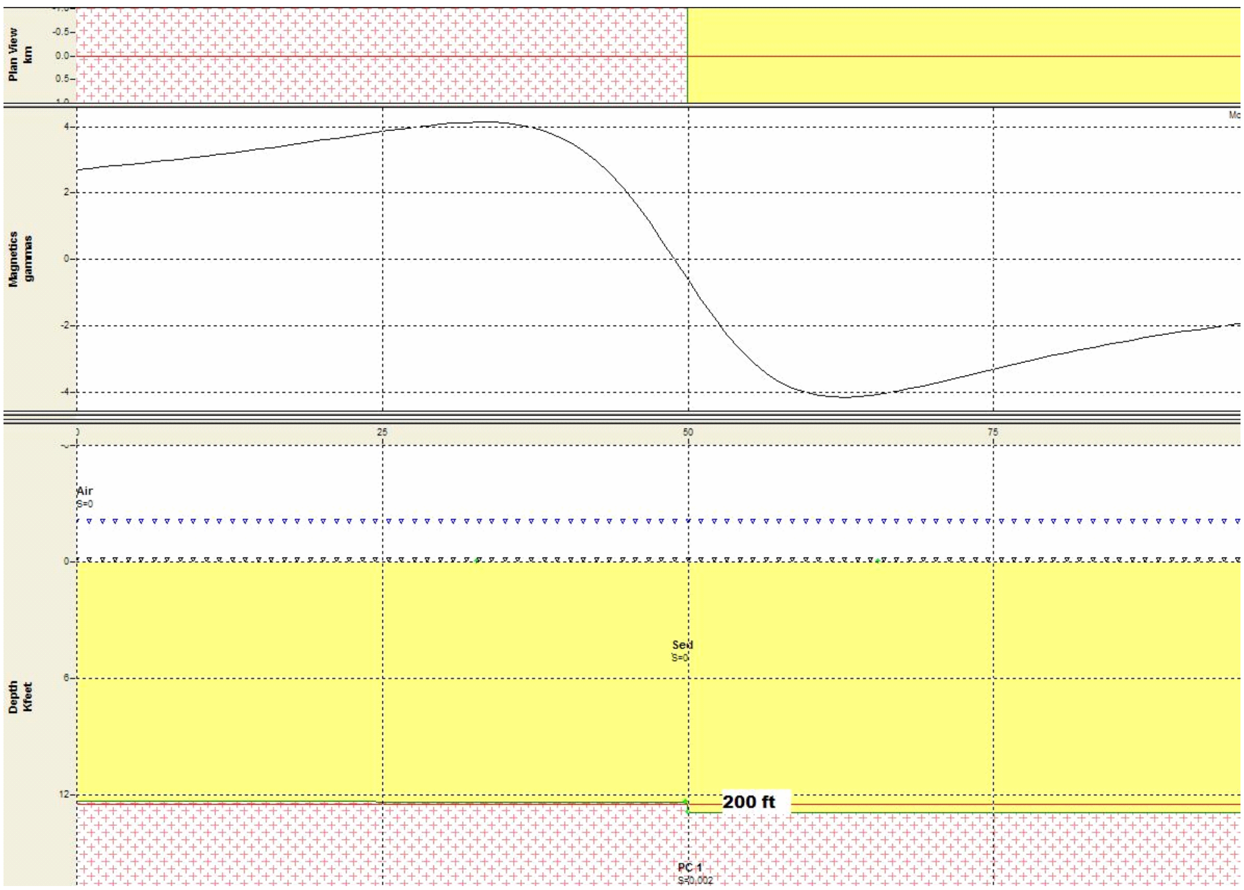
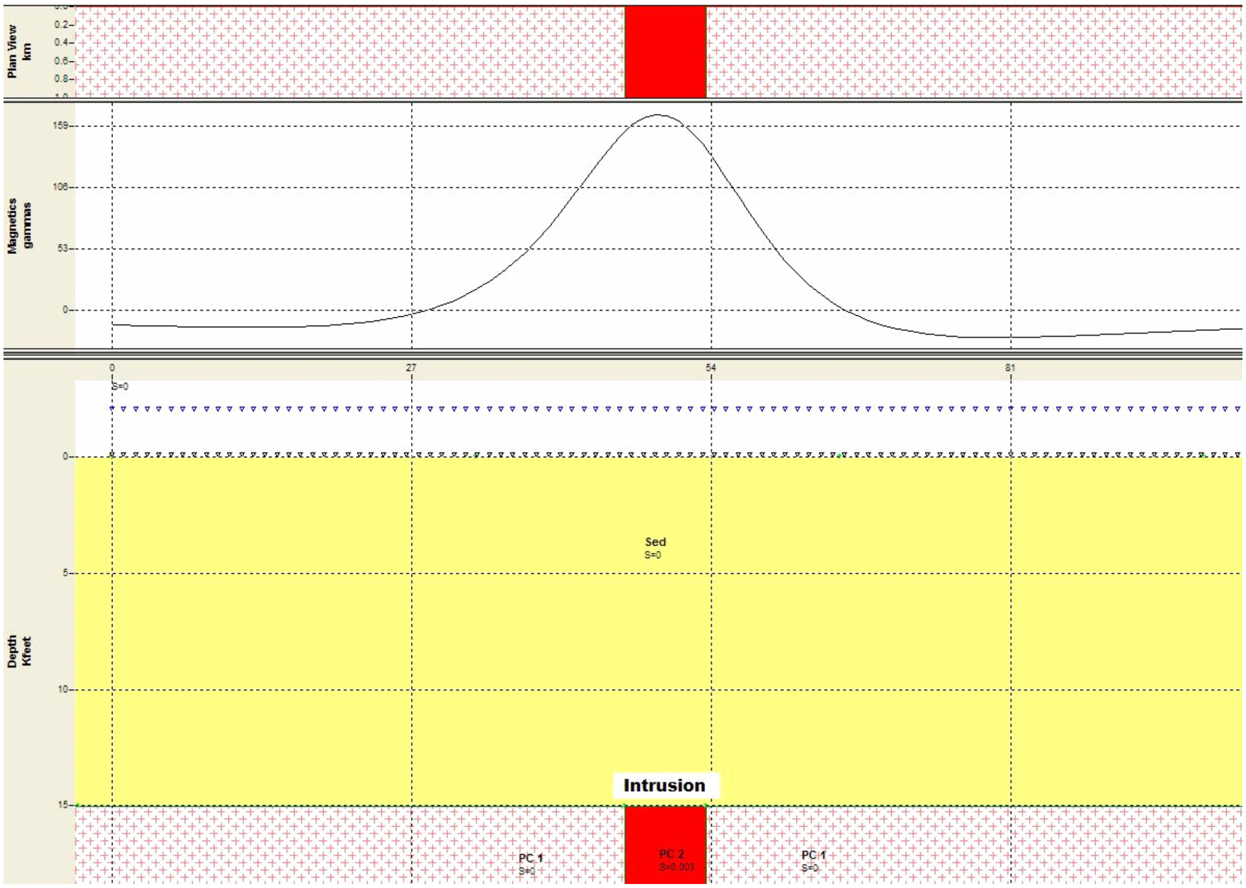


Figure 4 Intrabasement 2D Magnetic Model



B. LINE PROFILE ANALYSIS

Interpreted Local Basement Highs

Local basement structural magnetic anomalies are interpreted by a sequence of steps including:

- Construction of 2-D target magnetic models
- Line profile filtering with a high pass filter (vertical derivative of reduced-to-pole trace)

- Manual interpretation picking the anomalies on the individual profiles by matching the local 2-D target anomaly models

- Posting structural picks on a stacked profile work map and correlating from line to line

- Integrating fault picks from *SUNMAG* image

- Contouring interpreted structures by relating structural relief to residual anomaly amplitude

- Mapping

- Finally compositing the Interpreted Local Basement High grid with the regional depth to Precambrian basement grid from the subsurface tops interpretation.

This line profile interpretation approach assigns quantitative values to the structural relief even though the amplitude of local magnetic anomalies over structural high blocks is partly associated with structural relief and partly associated with magnetic susceptibility strength of the basement.

Two-dimensional modeling of profiles by Pearson Technologies confirmed that the larger mapped magnetic anomalies must be caused by very thick (several kilometers) magnetization contrasts within basement. The line profile analysis that lead to the Interpreted Local Basement High grid was a detailed attempt to extract more structural detail from the data by carefully studying local higher frequency and lower amplitude anomalies that can only be observed on the line profiles.

The final Magnetic Depth to Basement Structure map is a composite of the longer wavelength depth grid from the well control interpretation with the local highs, often bounded by interpreted faults.

Once the magnetic profiles have been interpreted and correlated between adjacent lines, each feature is assigned a structural relief contour based on the amplitude of the anomaly. The structurally-defined anomaly features are then digitized and gridded. Next, this grid is added to the smooth Precambrian grid based upon the Precambrian well tops and Red River derived smoothed structure shape (see discussion under **IV. GEOLOGIC INTEGRATION AND MAP INTERPRETATION**. The result is a Magnetic Basement Structure map (1:96,000 scale) showing localized structures on the basement surface.

C. MAP INTERPRETATION

1. Total Magnetic Intensity

The Total Magnetic Intensity map of the study area exhibits very broad smooth anomalies, plus subtle high frequency anomalies. Very little, if any, structural information can be obtained from such a display. Therefore, an anomaly-enhancement routine is utilized to bring the subtle structural anomalies into focus while diminishing the effect of large-scale, broad intrabasement magnetization contrasts. At the same time, the phase shift of anomalies due to the dipolar effect of the earth's field can be corrected.

2. Reduction-to-Pole Filtering

At high magnetic latitudes where the magnetic inclination is nearly vertical, the associated anomaly is located almost directly over the body. However, for intermediate or lower latitudes, the magnetic anomaly is shifted so as not to appear over the center of its causal body. For this area of the Williston Basin, the earth's field principal magnetic elements are:

Total Intensity = 56,500 gammas
Declination = 6E east of north
Inclination = 68.5E down to the north

The shape of a magnetic anomaly not only depends upon the shape of the perturbing body, but also upon the direction of magnetization and the direction of the regional field. Reduction-to-the-pole filtering transforms an observed anomaly into the anomaly that would be observed if the magnetization and regional field vectors were vertical as they would be for total-field measurements over a body with induced magnetization at the north magnetic pole. A symmetrical body produces a symmetrical anomaly if both of these vectors are vertical. Hence, reduction-to-the-pole is a way to remove the asymmetries caused by non-vertical magnetization or regional field and to produce a more straightforward set of anomalies to interpret. This filtering results in the observed anomalies being more nearly centered over their respective causative bodies.

Within the study area, the reduction-to-pole filter shifted high frequency anomalies by up to 2,000 feet to the north. Longer wavelength maxima were shifted a mile or more to the north. Lower frequency anomalies prior to reduction-to-the-pole have a high/low bimodal character. After filtering the anomalies are more symmetrical.

3. Horizontal Derivative Filtering

Magnetic anomaly maps, after proper reduction-to-the-pole filtering, have highs centered over magnetic bodies and lows surrounding them. The horizontal gradient, the magnitude of the field's dip, develops a high centered over faults that control the basement body edges (Pearson et al, 2001)

In map form, the absolute value of the horizontal derivative produces maximum ridges over each of the contacts between magnetic basement blocks and over faults. This grid can be contoured but the subtle contiguous faults show up better by reflection imaging.

4. Shaded Relief Displays and SUNMAG

Contour displays of the horizontal derivative are generally confusing and bland because only the largest values corresponding to the highest amplitude intrusion edges are visible on the contours. The dynamic range of the horizontal derivative map requires a better display technique for exhibiting the full dynamic range of the data. The shaded relief form of display, is therefore an important tool in enhancing both regional and local magnetic lineaments. As a review, the following list of procedures is combined to produce the dramatic horizontal derivative displays:

Interpolation of profiles onto a square grid;
Reduction-to-the-pole;
Horizontal derivative;
Absolute value;
Shaded Relief displays with various sun angles.

The shaded relief displays highlight basement fracture zones that are difficult to see on the contour displays. Although the faults are visible on the filtered magnetic profiles, it is much easier to trace the direction of fault trends (but not the direction of throw) on the shaded relief images than it is on the profiles. The following discussion may help to explain the production and use of shaded relief images.

a. **What are Shaded Relief Displays?**

Shaded relief displays of aeromagnetic data are produced by near photographic imaging of a digitally-stored grid. Synthetic shaded relief images are produced by assigning gray-scales to the reflectance as a function of the data gradient. The eye sees the actual sun's reflectance from objects in our visual world. Similarly, the computer can treat the magnetic field as a topographic surface and can compute the reflectance of a synthetic sun's illumination from that surface.

Various sun illumination angles are tested to enhance the desired anomaly trends. The result is an obliquely illuminated view of the surface, a view that enhances subtle terrain effects and facilitates magnetic basement interpretation. Slopes of the filtered magnetic field "terrain" are more brightly Illuminated and thus are whiter if they face the false sun's position. Conversely, slopes are less illuminated and thus darker if they tilt away from the sun.

b. How are Shaded Relief Displays Produced?

After processing and gridding of the aeromagnetic data were completed, the data grids were contoured and edited. The edited grids were then fed into PTI's shaded relief computer program. PTI tested sun positions of west, northwest, north, northeast, east, southeast and south. Sun elevations ranging from 30^0 to 60^0 above the horizon were also tested. A third parameter, vertical scale, is adjusted to vary the gray shade contrast to an optimum level. A larger value sharpens contrast while a smaller value enhances subtle gray shade variation to depict subtler features.

After testing and selecting sun angles on PTI's interactive graphics screen, each image was plotted with latitude and longitude tick marks for location. Detailed township grids are plotted as an overlay to the shaded relief images.

c. How are Shaded Relief Displays Used?

Shaded relief displays are particularly valuable when used in conjunction with other geophysical and geological data and displays. In this study, the results were integrated with stacked profile displays, and Red River structure contour maps from well control.

In general, the interpreter is looking for two types of features on the sun shade plots: (1) linear anomalies highlighted by a perpendicular or near-perpendicular sun position and (2) shear zones, generally in basement, which are highlighted best by a near-parallel sun angle. Interpretation begins by placing a sheet of mylar over the shaded relief display and plotting the subjective lineaments onto the overlay. We have most often found it best to use a different colored marker for each sun position angle. Also, it may help to grade lineaments as to the size and/or subjectiveness of the interpreted lineament.

As mentioned earlier, when using the shaded relief display it is easier to interpret linear anomalies trending near-perpendicular to the sun angle and shear zones trending near-parallel to the sun angle. This is because a linear anomaly will have its highest reflectance values at angles normal to the sun, and because shear zones are best recognized by terminations and offset in anomalies they intersect. Although they will not be quite as obvious, features at an oblique angle to the false sun angle can also be interpreted. A natural azimuthal bias is minimized by using two or more sun angles.

After careful tracing of linear trends onto mylar overlays, the trends are compared to lineaments or structures developed from well control. The major features interpreted on the shaded relief displays coincide with and often extend features located with other disciplines. Additionally, new linear features have been interpreted. When using shaded relief lineaments, it is important to remember the source of magnetic anomalies is generally magnetic basement.

The shaded relief display tests of aeromagnetic intensity can help locate lineaments in the study area. The shaded relief display of aeromagnetic intensity can be used to connect structures at the top of magnetic basement, shear zones in basement, and also tectonic province boundaries in basement.

An interpreter of shaded relief images needs to keep the sun's position in mind while picking linear and curvilinear trends. If the sun is in the northeast, then fault locations are picked where a lighted slope facing the northeast turns to a dark southwest slope. The theoretical line of the fault or contact is the exact ridge where the light turns to dark.

Interactive testing of sun angles for the horizontal derivative of reduced-to-pole magnetic anomaly grid settled upon the following sun directions and vertical exaggeration:

Inclination 45^0 Declination 45^0 (NE) Vert. Exag. 3,000
Inclination 45^0 Declination 135^0 (SE) Vert. Exag. 3,000

Although the original proposal included reduced scale images, displays were generated at 1:96,000 scale for detailed interpretation along with the other profile and contour map displays.

5. <u>SUNMAG Displays</u>

Since a given sun direction highlights features that strike perpendicular to it, it is important to generate enough images with varying sun angles to illuminate all azimuths of lineament/fault trends. PTI developed a multi-sun imaging format by using a succession of 24 different sun angles simultaneously each with a unique color. A color palette is selected that progresses around a color wheel so that it forms a continuous color variation that can quickly be related to strike direction.

Interpretation of the SUNMAG image is performed by first picking the linear breaks between opposing colors on the color wheel key that are appropriate for the selected strike direction. An automatic lineament picking algorithm was also applied that performs the selection of color breaks by application of a moving window operator. This AUTOFAULT interpretation is supplied on a clear film overlay with orange linear fault picks. Although these linear picks are a combination of normal faults, strike slip faults and compositional basement block boundaries, even the block boundaries will be likely zones of fault movement during episodes of tectonism. The more significant lineament/fault trends were digitized and plotted with the basement depth map.

6. Magnetic Lineaments

Production of the Magnetic Lineaments Overlay map involved an integration of the above forms of display. In the pursuit of basement fault and structural interpretation several manual and computer techniques are utilized. Magnetic lineaments were interpreted as visual linear features on the shadowgraphs and **SUNMAG** displays.

The interpreted lineament picks overlay exhibits the strongest linear magnetic anomaly trends. Two basic scales of lineaments have emerged from the study. The first is a large-scale, several-mile-long set associated with larger tectonic features such as the larger Precambrian plutons in the north, central and eastern portions of the study area. A second, more local set of lineaments, of one- to three-mile length, acts as a more local fracturing of the larger basement blocks. Further interpretation of these lineament patterns led to the definition of regional NE trending wrench faults important in the formation of structures which entrap hydrocarbons.

IV. GEOLOGIC INTEGRATION AND MAP INTERPRETATION

A. DATA

A regional database containing over 1000 wells with tops for the Red River, Winnipeg, Deadwood, and Precambrian was used as control for mapping the Red River structure and Cambrian/Ordovician isopach maps that served to generate a regional Precambrian structure map. Published data was relied on for the detailed 50 ft and 100 ft contouring around the producing fields. The map which resulted from the integration of these data with the basement structures defined by line profile analysis and faults defined by **SUNMAG** and shadowgraph analyses resulted in the definition of 17 lead prospective areas. Table I lists a number of these prospective areas based upon grade of structural anomaly, proximity to major wrench faults and/or fault intersections, and proximity to production.

B. METHODOLOGY

The regional basement structure map was constructed utilizing all available Red River, and basement penetrations in and around the study area. A preliminary Red river structure map based on approximately 20 penetrations was generated to gain a regional understanding of the orientation, vertical relief, and extent of structures assumed to be the result of drape over pre-existing basement topographic features.

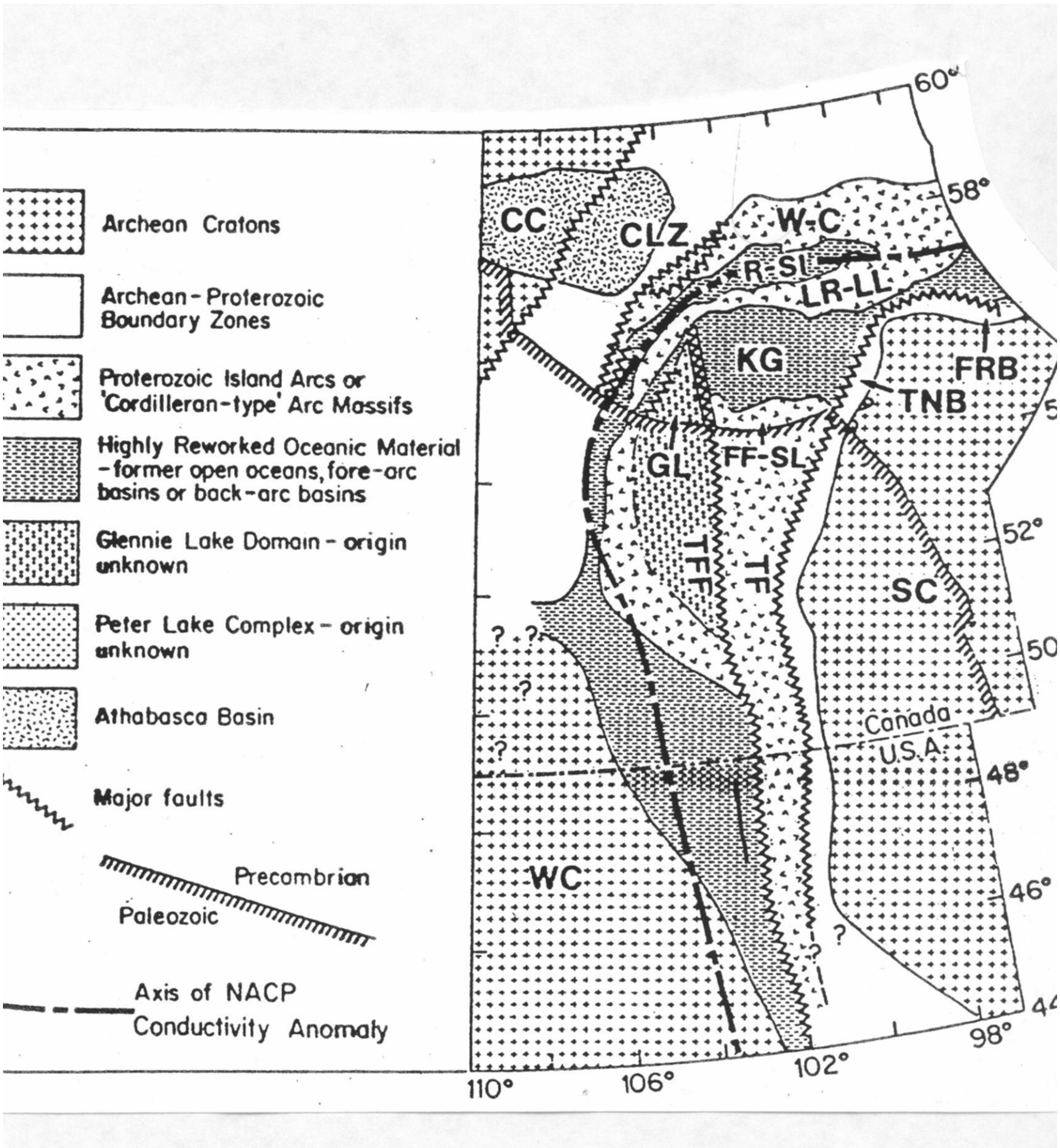
The Red River was chosen as the preliminary structural datum from which deeper structural features would be mapped because it is the closest datum to basement (1500 ft -1700 ft above basement) which has a significant number of penetrations and which does not have any salt sequences or significant unconformities in or between it and basement. A minor angular unconformity separates the Deadwood from the Winnipeg, but regionally less that 100 ft of Deadwood section has been removed (LeFever, Thompson, and Anderson, 1987).

Producing fields and lineament trends defined by **SUNMAG** and shadowgraph analyses were used to guide the contouring of the Red River and the construction of underlying isopach maps. Red River isopach maps were constructed using all available penetrations through these intervals. All maps were then digitized and the Red River isopach added to the Red River structure to generate a first pass Precambrian structure map was generated, which was also digitized. The anomalies defined from the line profile analysis were digitized and added to this Precambrian map via gridding to generate a detailed Precambrian structure map. This map was then hand contoured in order to make it as geologically correct as possible.

C. RESULTS

Cambrian through Jurassic oil and gas production in the Williston Basin lies principally along north/south, east-west, N55W and N 25E trends, each of which is well defined by shaded relief (shadowgraph) and **SUNMAG** images. These productive fairways are controlled to a large extent by intersecting fault and flexure trends in the basement. This structural pattern was imposed on the basement during the Hudsonian Orogeny (1.8 - 2 billion years old) when the Wyoming craton was fused to the Superior craton (Fig. 5). Certain of the trends, primarily the N30W trends, most likely existed in pre-existing basement blocks. However, tectonism associated with plate collision, including subduction, wrench faulting, and associated igneous activity in the forearc to backarc systems, added new trends which dominate over portions of the basin. Isopach maps published by others chronical several episodes of primarily vertical structural rejuvenation along these features from Precambrian to Recent. The variations in trends obvious on the isopach maps (not included in this report) indicated the primary stress field changed orientation through time.

Figure 5 Williston Basin Tectonics



D. Basement Structural Features

Structurally and stratigraphically entrapped hydrocarbons, as well as the trends and limits of reservoir facies, and hydrocarbon migration pathways have been delineated by analyzing the delivered aeromagnetic displays and integrating them with subsurface geological control. At least three types of basement structural features influence production:

1. Basement structural highs

2. Relatively short basement faults which mostly define the margins of basement structural highs

3. Regional cross-cutting fault systems which define and create major structural and compositional discontinuities.

These three structural feature types also give rise to three easily recognizable north/south oriented basement provinces most readily observed on the Second Vertical Derivative and **SUNMAG** displays.

Structural Highs

Local structurally highs developed on the basement surface are defined by analyzing a filtered version of the line profiles.

These large residual structural bodies manifest themselves on the tilted basement surface as somewhat smaller features. These possess relatively steep, fault bounded flanks, and relatively steep noses which extend downdip to the north, northeast, and northwest for distances of 2 - 6 miles. Maximum structural relief or any one future is upwards of 500 ft to over 6 miles, but features with structural closure are smaller and range from 1 - 10 miles (average 4-6 miles). These individual structures extend along structural noses more readily defined by the residual line profile analyses.

Basement structures are mostly oriented N/S and N45W and N30E in the study area. In the central deepest portion , however, structural trends are not as well organized; although northeast and northwest oriented elongate features are present, numerous smaller round to slightly oblate structures dominate. These Precambrian structures are presumably of fault block and erosional origin, display relief upwards of 250 feet, and are asymmetrical with steep flanks and basinward plunging noses and gentler out-of-the-basin extensions. Most are 4-6miles long. The edges of the structures, particularly where they coincide with the fault/lineament overlay, are of importance for macrofracture porosity/permeability prospects.

Basement Faults

Production, both structural and stratigraphic, is directly related to the location of right-lateral wrench faults and the northwest oriented shorter faults interpreted from **SUNMAG** and shadowgraph displays and the structural highs associated with these features.

Northwest faults are associated with and typically form the boundaries of the structural highs interpreted from the line profile analysis. Whether the northwest faults represent inherited pre-existing basement structural trends or antithetic shears, some of which may follow pre-existing trends, is not known. Numerous northwest lineaments end abruptly at wrench faults boundaries. Others display distinct offsets, especially obvious on north/south lineaments, or are curved or kinked in a way as to suggest lateral wrench faults movement.

Numerous northeast/southwest oriented right-lateral wrench faults offset older compositional basement blocks and the shorter, north and northwest oriented faults which give rise to more localized fault blocks with structural relief. These faults not only offset numerous large magnetic bodies defined on the Second Vertical Derivative color display, but also delimit or offset the north, northwest and southeast extents of numerous structural highs defined by the line profile analyses. Production commonly ends abruptly or changes trend, at wrench fault discontinuities.

The trends of these interpreted wrench faults are the best delineated by interpreting the discontinuities and offsets in north/south and northwest oriented **SUNMAG** lineaments and the packages of short, northwest/northeast lineaments in the central part of the study area. Most of these local faults are spaced at 3 - 7 mile intervals, but they become shorter, less regularly spaced, and more north - northeast oriented in the southern and eastern portions of the study area. Analyses of the **SUNMAG** and Second Vertical Derivative displays suggests that most offsets are right lateral and range upwards of 1-3 miles.

SUMMARY

V. CONCLUSIONS, LIMITATIONS AND RECOMMENDATIONS

A. CONCLUSIONS

Significance to Exploration

High sensitivity aeromagnetic surveying in the Williston Basin is very helpful in mapping faults and structures at the top of Precambrian basement. Two-D magnetic block models provide calibration signatures for separation of basement structural anomalies from compositional signatures. Shaded relief and **SUNMAG** images of the horizontal derivative of the reduced-to-pole magnetic field contour map enhance local basement faults at the expense of the broader compositional features. Stacked profile displays of the decultured and filtered magnetic profiles allow efficient recognition and multiple line correlation of basement structural anomalies.

The mapping which resulted from the integration of subsurface based basement structural mapping with the basement structures defined by line profile analysis, and faults defined by **SUNMAG** and shadowgraph analyses, resulted in the definition of 17 lead prospective areas. Table I lists a number of these prospective areas based upon grade of structural anomaly and proximity to production.

Analogous production northwest of the area is directly related to the location of basement structural highs and wrench faults interpreted from the magnetic displays and illustrated on the basement structure map and fault overlays delivered with this report. Essentially all fields occur on the tops or immediate flanks of mapped structures. Although production is associated with the smaller faults bounding these smaller structures, many of the larger structural and stratigraphic fields are located immediately adjacent to the northeast trending wrench faults. Several large structural and significant stratigraphic fields either end abruptly, or the production within them changes orientation, at their intersections with the northeast trending wrench faults. These faults appear to be of critical importance in controlling not only structural development, but also the updip productive limit in many of the fields, whether this is created by loss of structure, or change in facies or facies trends.

Because most of the significant structural and stratigraphically influenced production appears to be concentrated on structures which straddle the major northwest trending wrench faults transecting the area, we recommend that similar undrilled structures and wrench fault trends be targeted in future exploration efforts. The excellent correlation between local Mississippian structural highs and Precambrian structures delineated by this study indicates that many of the same areas of uplift and subsidence prevailed throughout Lower Paleozoic time. It is likely that this study can also help in mapping areas of likely paleotopographic relief that may be favorable for multi-level structural growth. Therefore, acreage acquisition and 3-D seismic program planning should be focused along edges of basement structures, particularly where regional basement faults intersect. A number of these are highlighted on the basement structure map which accompanies this report.

Aeromagnetic Processing

Line leveling and diurnal corrections produced the 1 mi. X 4mi. grid network with better than one gamma average mistie. The roughly 1000 foot ground clearance dampened cultural noise to the point where "deculturing" noise removal was only necessary over significant surficial geologic or town size cultural noise areas. Topographic magnetic anomalies are viewed in less than 5% of the study area. High frequency, intrasedimentary anomalies may also be present, but it is unlikely that direct detection of geochemical halos would lead directly to Mississippian or other Paleozoic discoveries at this time.

Detailed map and profile analysis are an important part of magnetic interpretation for faults and structures. A popular method of grey and color shaded relief imaging of filtered magnetic grid attributes reveals a subtle but real pattern of basement faulting that has eluded magnetic analysis until recently.

B. LIMITATIONS

Potential field interpretations such as aeromagnetic studies to explain observed anomalies caused by subsurface bodies are limited in resolution. The magnetic basement interpretation is believed to be a reasonably accurate representation of the actual subsurface geology. However, in magnetic interpretation studies, it is not 100% certain whether a given observed anomaly is produced by a basement structure or by a change in basement lithology. Large amplitude magnetic anomalies must be explained at least partly by intrabasement sources since the magnitude of **structure** needed to match the observed anomaly would be unreasonably large.

Magnetic anomalies have been interpreted and correlated along the individual flight lines to differentiate between suprabasement and intrabasement sources. For instance, suprabasement anomalies have a lower amplitude and a higher degree of curvature than the intrabasement anomalies. Unfortunately, the ability to differentiate between basement structures and very local basement lithology changes is limited. An unknown but probably small percentage of mapped basement structures will fail to shoot out on seismic profiles because localized mineralization along a fault will mimic a suprabasement structure. Such errors would be termed false positives. Fortunately, the mineralized fault may have been reactivated along strike and may be seen as structurally high near the aeromagnetic anomaly.

Precambrian basement does not have consistent susceptibility. Basement composition varies from granite to metamorphic gneisses. A basement structural high in an area of lower susceptibility basement, such as a metasediment, will not produce a measurable anomaly. It is, therefore, possible that basement faults and structures exist that are undetected by this study the lack of response would be termed a false negative.

C. RECOMMENDATIONS

Prospective lead areas indicated by the interpretation should be evaluated with reflection seismic data prior to drilling. A brief review of well control in the northwestern part of the study area provided confirmation of some magnetic structural anomalies. Seismic data integration of all geological and geophysical information sources will help to better calibrate the aeromagnetic signatures.

When possible, prospects pursued in the study area should be approached from a multiple pay approach. This study indicates that there are intersecting large scale structural features that should provide structure and fracturing. It is very likely that future drilling will be able to locate new reservoirs and hydrocarbon sources in this major regional Paleozoic basin flank.

Table 1 Lead Areas

ANOMALY LOCATION SEC/TWP/RANGE	GRADE OF LEAD	PROXIMITY TO PRODUCTION
14-T147N-R93W	G	
22-T147N-R91W	G	
2-T148N-R92W	G	
27-T149N-R89W	G	
29-T149N-R93W	G	
9-T150N-R94W	G	8
4-T150N-R91W	G	
34-T151N-R93W	G	
32-T147N-R89W	F	
28-T148N-R89W	F	
10- T136N-R93W	F	
32-T136N-R90W	F	
33-T136N-R93W	F	
2-T136N-R92W	F	
32-T137N-R93W	F	9

VI. REFERENCES

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Appendix B: Seismic Reprocessing Study – Bureau of Indian Affairs

SEISMIC DATA PROCESSING REPORT

Lake Sakakawea Seismic Project

Fort Berthold Indian Reservation
North Dakota

Summary and objectives

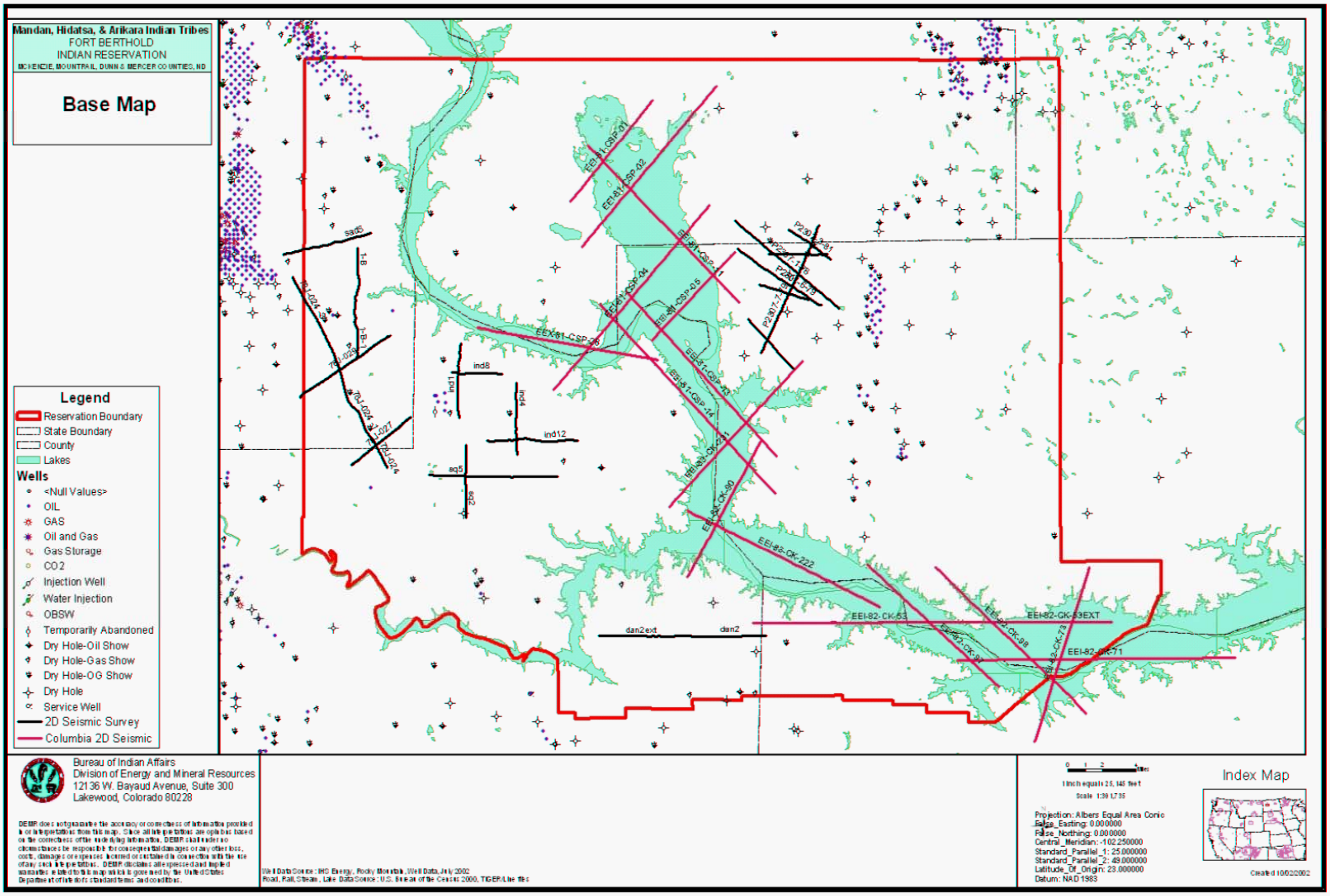
Seventeen 2D seismic lines were acquired by Advanced Resources International (ARI) from Seismic Exchange, Inc. (SEI) for display and demonstration at the North American Prospect Exposition (NAPE) to be held in Houston, Texas in January 2004. The main thrust was to attempt to improve the temporal resolution, and hence the interpretability, of all lines through more modern and robust seismic processing techniques. Further, it was hoped to improve noise attenuation and also obtain relative amplitude products to aid in estimating additional geophysical properties of the stratigraphy. Since budgetary constraints prevented the purchase of all data in the original collection effort, lines were chosen to sample the area based on a variety of factors including tie points, data quality, and proximity to previously processed lines.

Data were received beginning on March 11, 2003 and were processed by Larry Shanabrook and Shelley FitzMaurice of ACS Government Services, contractor to the Bureau of Indian Affairs (BIA) Division of Energy and Mineral Resources Management (DEMRM). Numerous difficulties with the data were encountered immediately (detailed below) and were dealt with through a collaborative effort involving several parties. Thanks are due to all those involved, including Marshall Thomsen, Dennis Bodenchuk, Rebecca Miller of Geophysical Development Corp., Kevin Wright and John McCague of Fairfield Industries, and Scott Reeve of ARI. Nevertheless, those difficulties contributed substantially to the lengthy 4 month processing time frame.

Although some problems proved to be somewhat intractable, acceptable seismic sections were produced for all lines and delivered to the BIA on July 1, 2003. Other investigation and testing, however, are still underway to refine and improve the processing results. Revised sections will be provided to Mr. Anderson as improvements become available.

Description of Seismic Data

The data included in this project consists of seventeen 2D reflection seismic lines collected during two separate phases of exploration from 1981 through 1983 over Lake Sakakawea, formerly known as Garrison Reservoir, located in the Ft. Berthold Indian Reservation in west central North Dakota (Figure MAP-1*)*.



Mandan, Hidatsa, & Arikara Indian Tribes
FORT BERTHOLD
INDIAN RESERVATION
MCKENZIE, MOUNTRAIL, DUNN & MERCER COUNTIES, ND
Base Map
Legend
Reservation Boundary
State Boundary
County
Lakes
Wells
<Null Values>
OIL
GAS
Oil and Gas
Gas Storage
CO2
Injection Well
Water Injection
OBSW
Temporarily Abandoned
Dry Hole-Oil Show
Dry Hole-Gas Show
Dry Hole-OG Show
Dry Hole
Service Well
2D Seismic Survey
Columbia 2D Seismic
Bureau of Indian Affairs
Division of Energy and Mineral Resources
12136 W. Bayaud Avenue, Suite 300
Lakewood, Colorado 80228
Index Map
Projection: Albers Equal Area Conic
False_Easting: 0.000000
False_Northing: 0.000000
Central_Meridian: -102.250000
Standard_Parallel_1: 25.000000
Standard_Parallel_2: 49.000000
Latitude_Of_Origin: 23.000000
Datum: NAD 1983
EEI-82-CK-222
EEI-82-CK-71
dan2ext
dan2
ind8
ind12
sq5

Figure MAP-1

The first effort was collected by Seis Pros Inc. during July, August, and September of 1981 for Columbia Gas, a company no longer in operation. The latter phase was collected by Kemp Geophysical Corp. from June through September of 1982 and June and July of 1983, also for Columbia Gas.

The Seis Pros lines selected for reprocessing include: CSP-81-1, CSP-81-2, CSP-81-4, CSP-81-5, CSP-81-11, CSP-81-13, CSP-81-14, and CSP-81-28, all of which are located across the northern and northwestern arms of the reservoir. The reprocessed Kemp lines include: CK-82-53, CK-82-53 ext. (an eastern extension of CK-82-53), CK-82-71, CK-82-73, CK-82-90, CK-82-97, CK-82-98, CK-83-222, and CK-83-231. All Kemp lines are located on the southeastern arm of the reservoir with the exception of lines CK-83-231 and CK-82-90 which were shot across the central part. For the purpose of brevity in this report all lines will be referred to only by the ending numerical portion of their line name. Both Kemp and Seis Pros data were recorded similarly and subsequent descriptions apply to both except where noted.

Data were recorded to a 4 second record length (except for the 1982 Kemp shooting which recorded 5 sec) at a 2 msec sample rate. Field instruments incorporated the Texas Instruments DFS-V, recorded with SEG-B format on ½ inch 9 track magnetic tapes. The analog recording filter was set to 8-128 Hz for the Seis Pros data and out-128 Hz for the Kemp data. A 60 Hz notch filter was incorporated in both cases.

Receiver group intervals were a constant 330 feet but shot intervals varied from a nominal 330 ft over water to 660 ft on land, although numerous skips of greater than 660 ft were encountered. On land, Geospace GSC-20D 10 Hz geophones were used in a 16 phone inline array of 315-360 ft. On the lake, Mark L-44 10 Hz hydrophones were used in a 6 phone inline array of 200-400 ft.

The land cable was configured in a 48 channel, symmetric split spread configuration with a 1 group gap. At land/lake transition areas the cable was often left stationary with either 48 or 60 (Seis Pros) channels and no gap and shots walked through the spread. The lake cable consisted of 30 channels with a 2 group offset (660 ft) to the near channel. Note that in most transition zone shots a mix of both geophones and hydrophones were typically recorded. The exact configuration of the lake cable is not clear from the documentation provided but was probably a drag cable towed separately from the air gun barge. It was reported by Marshall Thomsen that the crews encountered numerous underwater obstacles which snagged the cable and forced several offsets and re-shoots.

The land data source was deep-hole dynamite using primarily 25 lb charges at depths of 188-200 ft, with a few scattered smaller charges and shallower holes. Lake shooting employed air guns in arrays of 4 units shooting 4-5 pops per shot except for the 1983 Kemp shooting which used 8 pops per shot. Guns were usually towed at a depth of 20 ft except when shallow lake depth dictated otherwise. Air gun volumes were not documented and further array information was not available. Most lake data were already vertically stacked upon receipt except for lines 1 and 28 which were stacked in house.

Missing Data, Data Errors and Other Issues

At this point it is important to note a number of serious issues regarding the accuracy and completeness of some of the data supplied by SEI. These issues should be kept in mind when considering the data description above.

- Conflicts exist between the supplied hardcopy and SEG-P1 diskette versions of the coordinate data. It became apparent that the SEG-P1 versions were generated via digitization from some basemap (not supplied). A few gross digitization errors prompted the careful scrutiny of all lines with appropriate corrections applied as needed. In addition, only every 5th recording station was digitized and no elevations were included on the diskette and were, in fact, initially missing entirely for all the Seis Pros lines, although they were supplied several days later when requested.
- No information was available describing the depths of the hydrophones used for lake shooting except for verbiage on the original sections stating "Hydrophones are suspended at 35 foot depth where water depth exceeds 35 feet". It was eventually determined that the best course of action was to assume that the verbiage was correct and to infer that at lesser depths the hydrophones were lying on the lake bottom.
- Lake Bottom elevations were obtained either directly from elevations supplied or, in some cases, derived from values listed without reference which appeared to be consistent with a descending lake bottom when viewed from the shoreline. Again, documentation for this was in some cases missing. In addition, examination of the resulting elevation profiles revealed a few suspicious lake bottom anomalies which, upon further investigation, turned out to be transcription errors on the part of the original technicians. Depths could only be verified for the three lines (1, 2, and 5) for which depth soundings were later supplied by SEI. It is possible that similar errors exist for other lines.
- Mention was made on the original sections that an air gun delay correction was employed for lake shots but did not specify the amount. From examination of both the observer logs and data and auxiliary channels (where available) it appeared that the delay was probably 50 msec. This value was listed on the observer logs as an "uphole" for the airgun shots and was corroborated by the uphole auxiliary channel. This was deemed a reasonable value by other processors with marine processing experience as well; consequently, a -50 msec time correction was applied to all air gun shots. However, since no mention was made of such a delay in any support data this assumption must be considered suspect. Also, see below regarding QC check processing on line 90 by Fairfield Industries.
- Seismic data transcription and/or vertical stacking errors were found on several lines. In one case several adjacent shots were combined into one, requiring corrective separation. In others several shots were irreparably vertically stacked with incorrect channel-to-channel pairings, requiring their elimination from the dataset. A number of short records (possibly caused by demultiplex scan errors) were encountered. Shots were occasionally missed on the transcription. Line 14 was missing 40 consecutive shots from the last three original field reels, representing about three surface miles of shooting. Line 28 was missing 24 consecutive shots from two original field reels, comprising about 1.5 surface

miles.

- Only 4 lines (1, 28, 222, and 231) included any auxiliary channels which could have been used to verify uphole times and, possibly, air gun delays.
- The usual assortment of documented and apparent undocumented shooting geometry errors were found and corrected.

Parameter testing

Line 231 was chosen for testing to determine certain seismic processing parameters due to its central location and the fact that it reasonably typified the data in the prospect. The line is about 11 miles long, contains both land and lake shots and receivers, and intersects two other lines in the current prospect as well as one other line north of the lake. The final processing parameters derived from the testing may be viewed on the respective section side labels and hence will be omitted here.

The data were first reformatted into Landmark Graphics ProMAX® internal format and the shooting geometry entered into the database from the provided support data. Initial quality control steps included examination of the raw trace data to identify and remove unusably noisy traces and also to ensure consistency between the support data and the observed characteristics of the seismic records. One of the first steps in the testing sequence was to determine the approximate spectral content, amplitude decay, and noise modes present in the raw data. Since it was known that a relative amplitude product was to be produced, and due to the presence of multiple source and receiver types, greater attention was paid to this process than might ordinarily be done.

Two land shots and two lake shots were selected for testing (*figure 5)*. Files 40 and 130 are land shots and files 80 and 123 are lake shots. "True amplitude recovery" (TAR) parameters are commonly determined empirically from an examination of a suite of trial values, selecting those that seem to best temporally modulate the amplitudes. Here it was found, due to the different source and receiver coupling between land and lake shots, that different parameters for each was required to adequately balance the amplitudes (*figures 1-4)*. This test was later repeated after severe water wave noise was encountered and subsequently removed on several lines. The results remained the same and were applied universally to all lines.

Spectral analysis was performed using several analytical tools. Autocorrelations were displayed to gain an initial feel for the bandwidth and to reveal reverberation problems (*figure 6)*. As expected, the air gun records exhibited a broader central peak with more side lobe energy than the dynamite shots, indicative of narrower bandwidth and a possible reverberation problem. In addition, an initial estimate of deconvolution operator length was obtained from the energy decay pattern observed in the side lobes. Next, a spectral analysis display showing mean amplitude and phase spectra was obtained from each shot (*figures 7 through 10)*. Although not as pronounced as expected, the dynamite shots displayed an overall whiter amplitude spectrum than the air gun shots. The effect of the 60 Hz notch filter can be seen plainly on the amplitude spectra for all shots. Also, the white noise level employed in deconvolution was determined from this analysis.

Several processing steps which are normally subject to testing were established as given parameters of the processing, including surface consistent amplitude compensation and surface consistent spiking deconvolution. These were established due to the desired relative amplitude product (mentioned above), the impulsive nature of both source types, and the marked differences in source and receiver characteristics between land and lake shooting. The trace amplitudes were decomposed into common source, receiver, and offset domains with the resultant scalars similarly applied. Deconvolution operators were determined in shot, receiver, offset, and cdp domains but applied only in the surface consistent shot and receiver domains.

Experimentation with lines 231 and 222 showed that a refraction static solution was necessary to solve longer wavelength statics exhibited by both lines, especially at the land-lake boundaries. Much testing was involved in this process, including: constant and spacially varying weathering velocities; two independent algorithms, delay time (DLT) and diminishing residual matrices (DRM), from two separate vendors, Landmark Graphics (ProMAX) and Green Mountain Geophysics (GMG); one, two, and three layer refractor models; numerous data

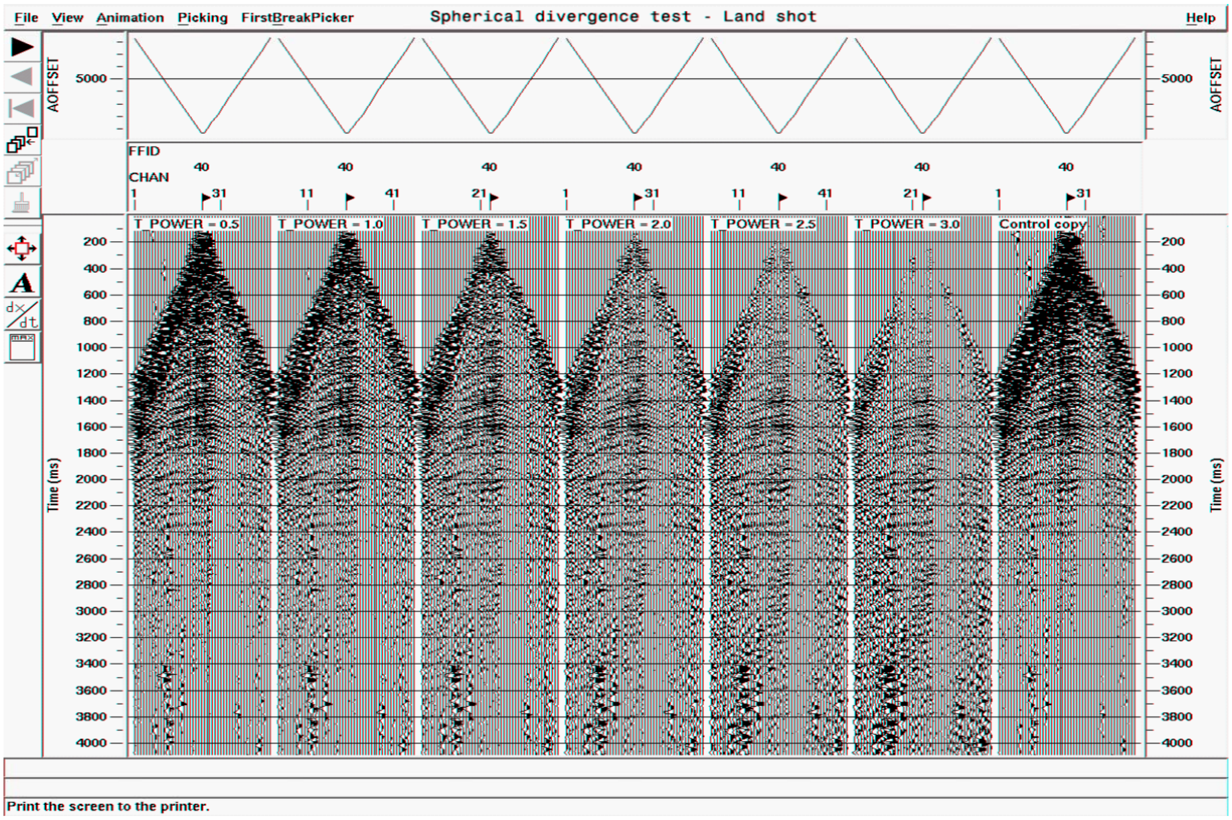


Figure 1

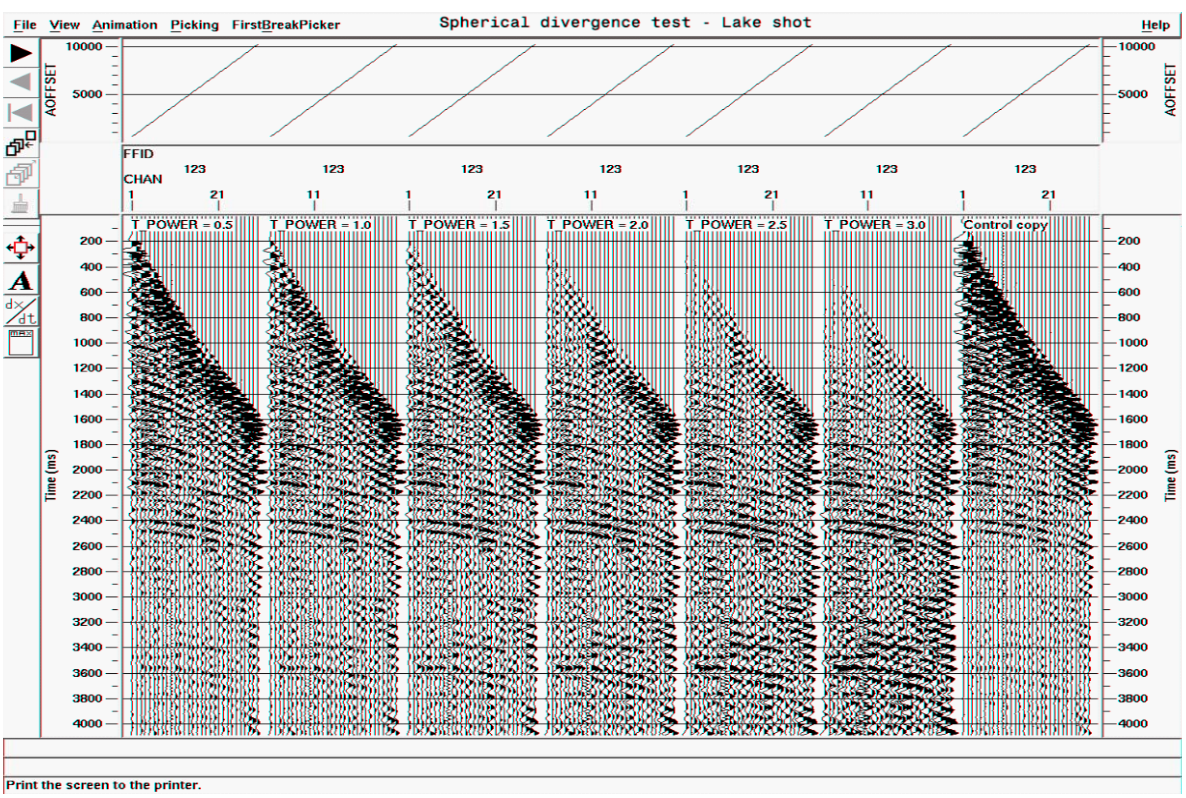


Figure 2

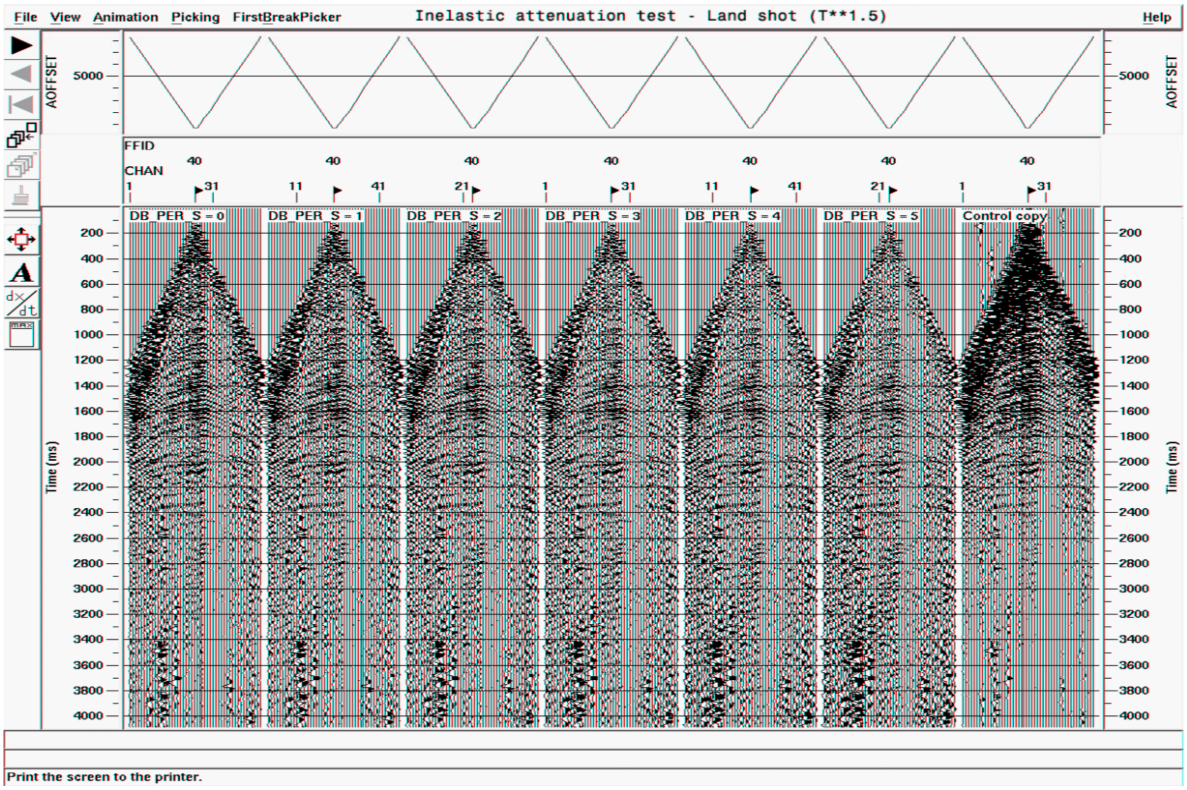
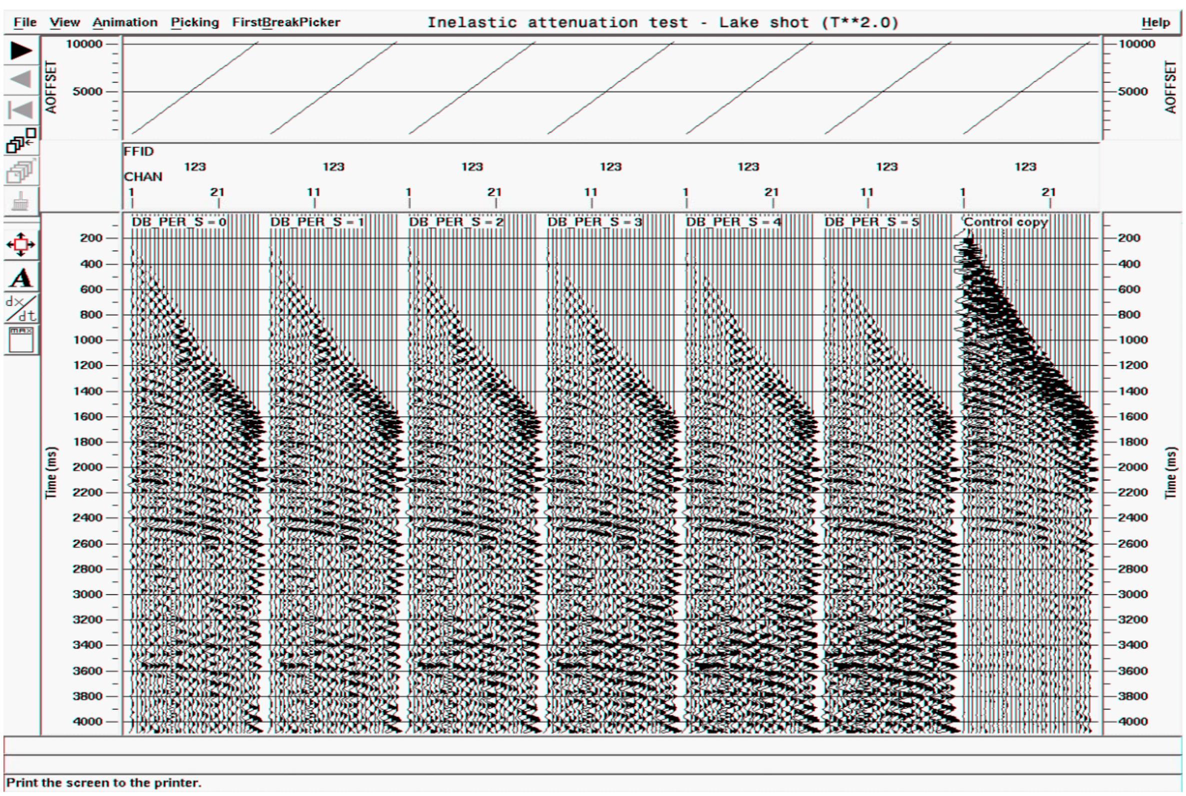


Figure 3



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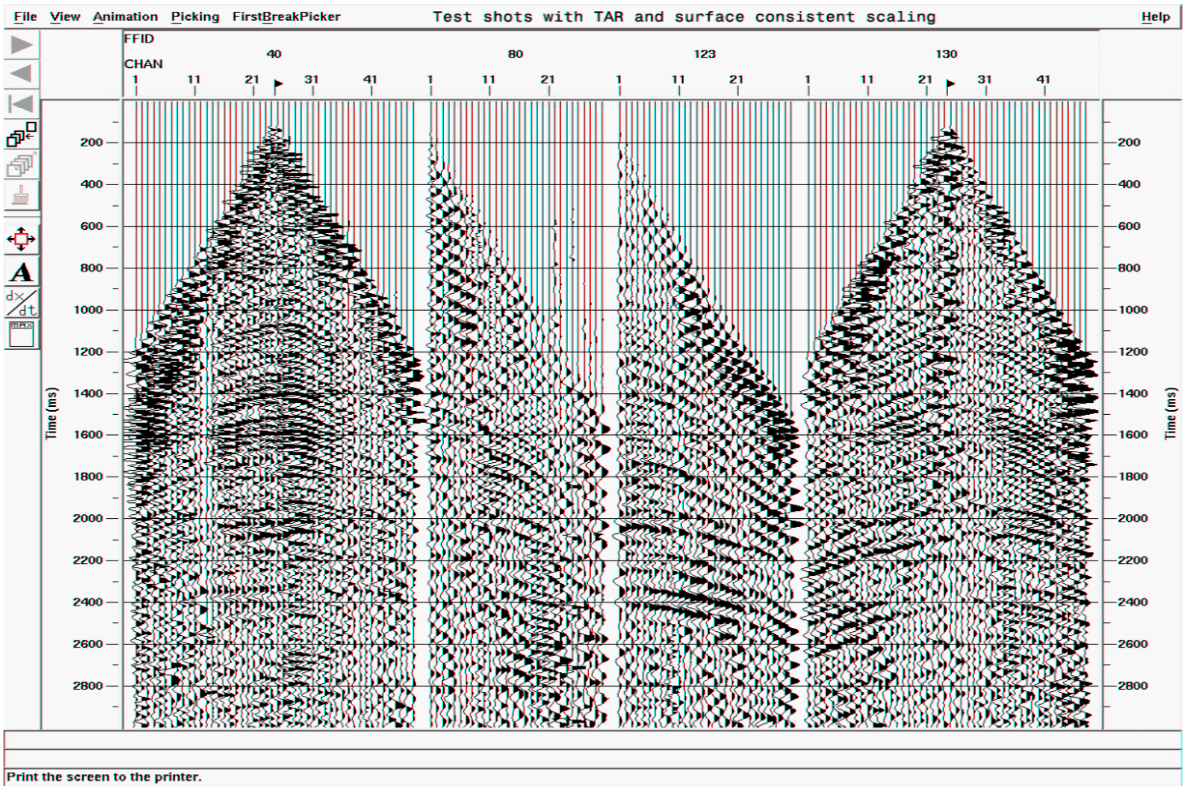

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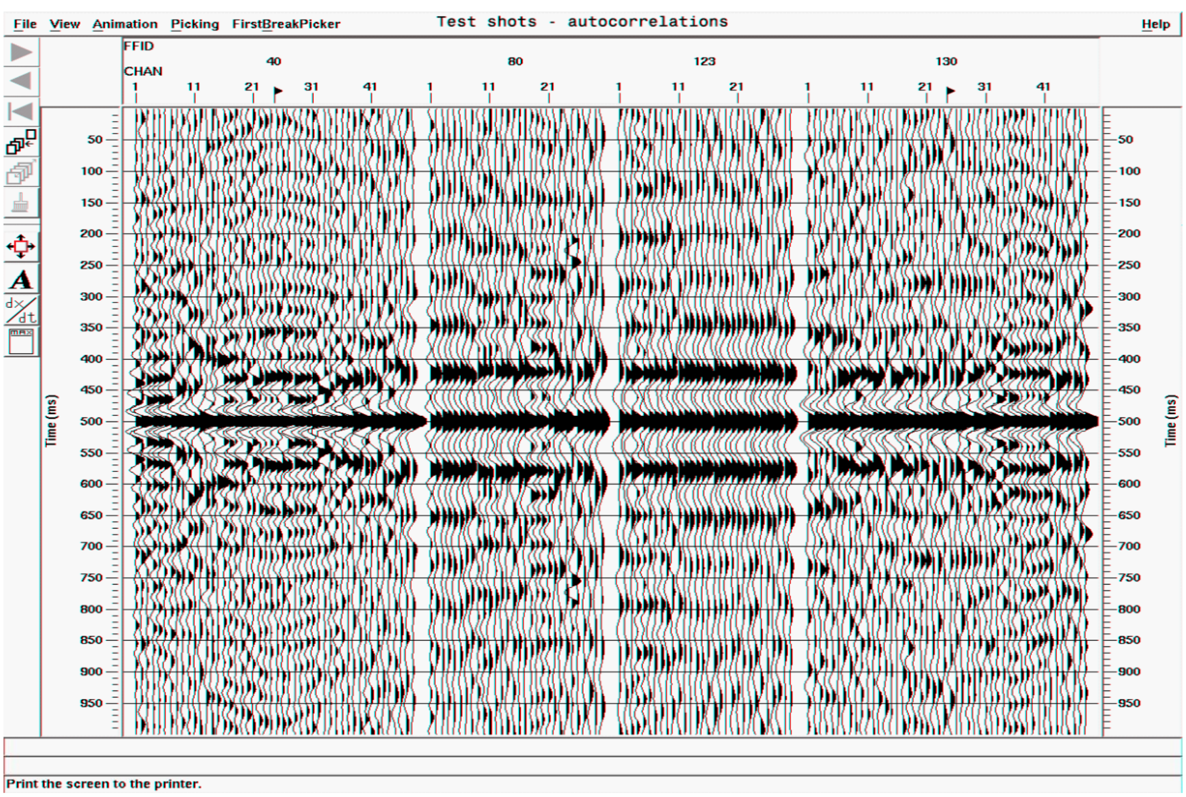

Figure 6

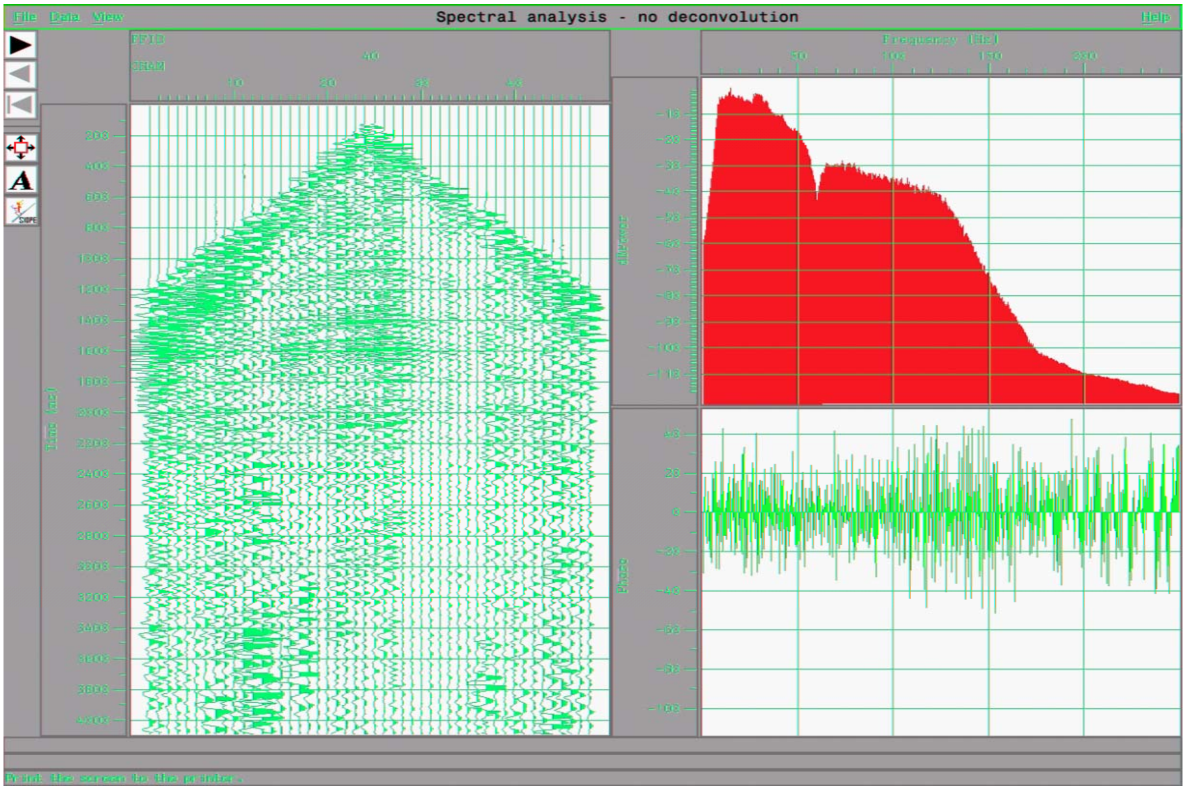

Figure 7

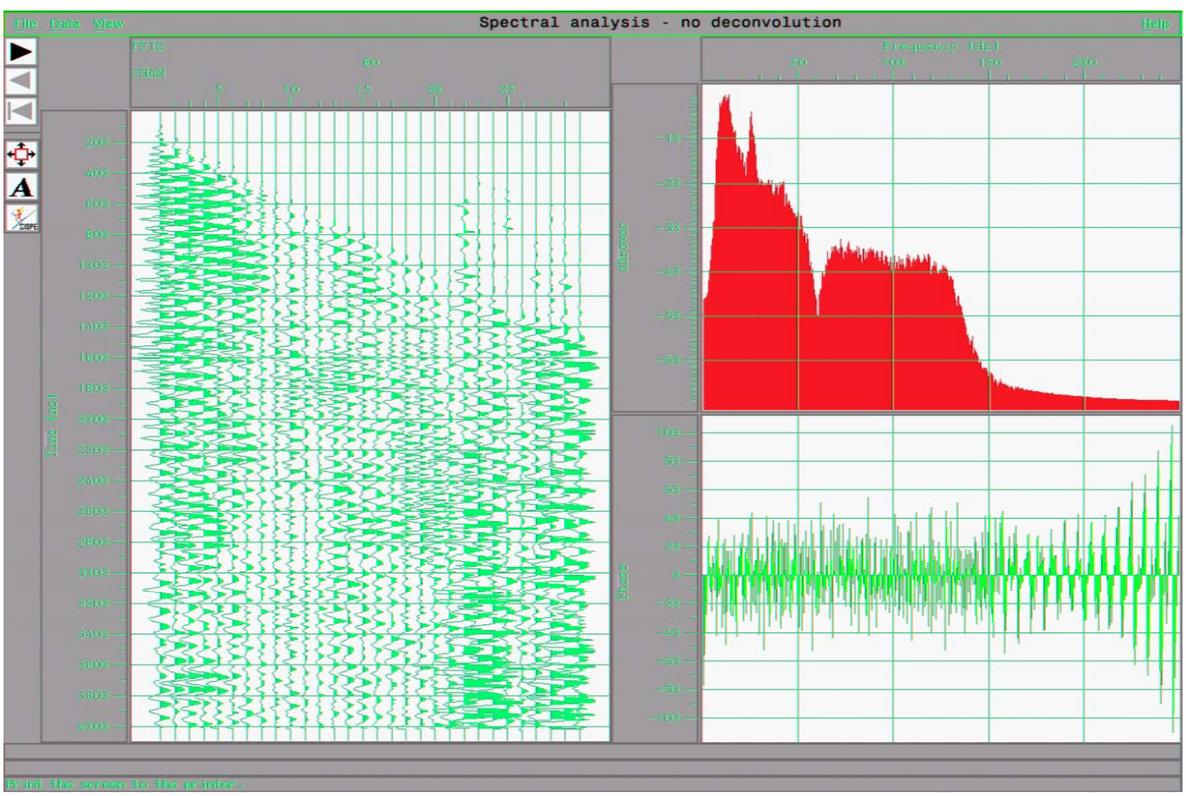

Figure 8

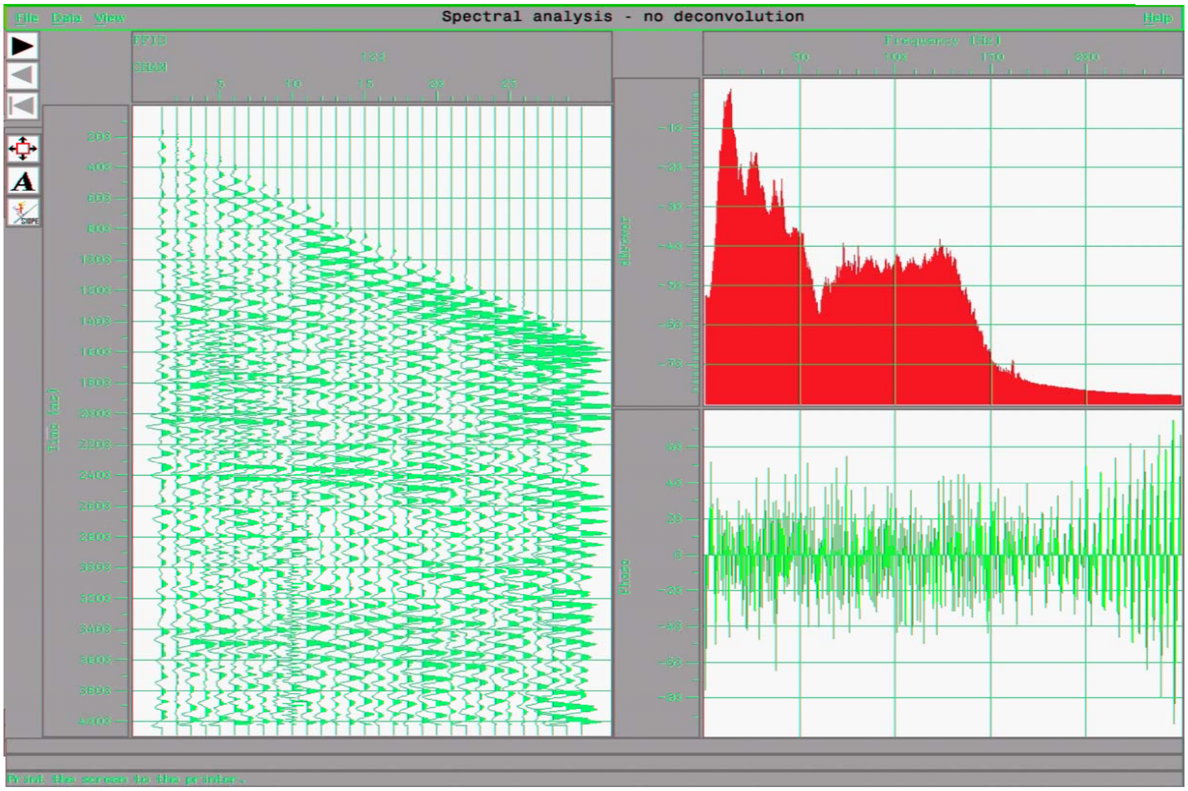

Figure 9

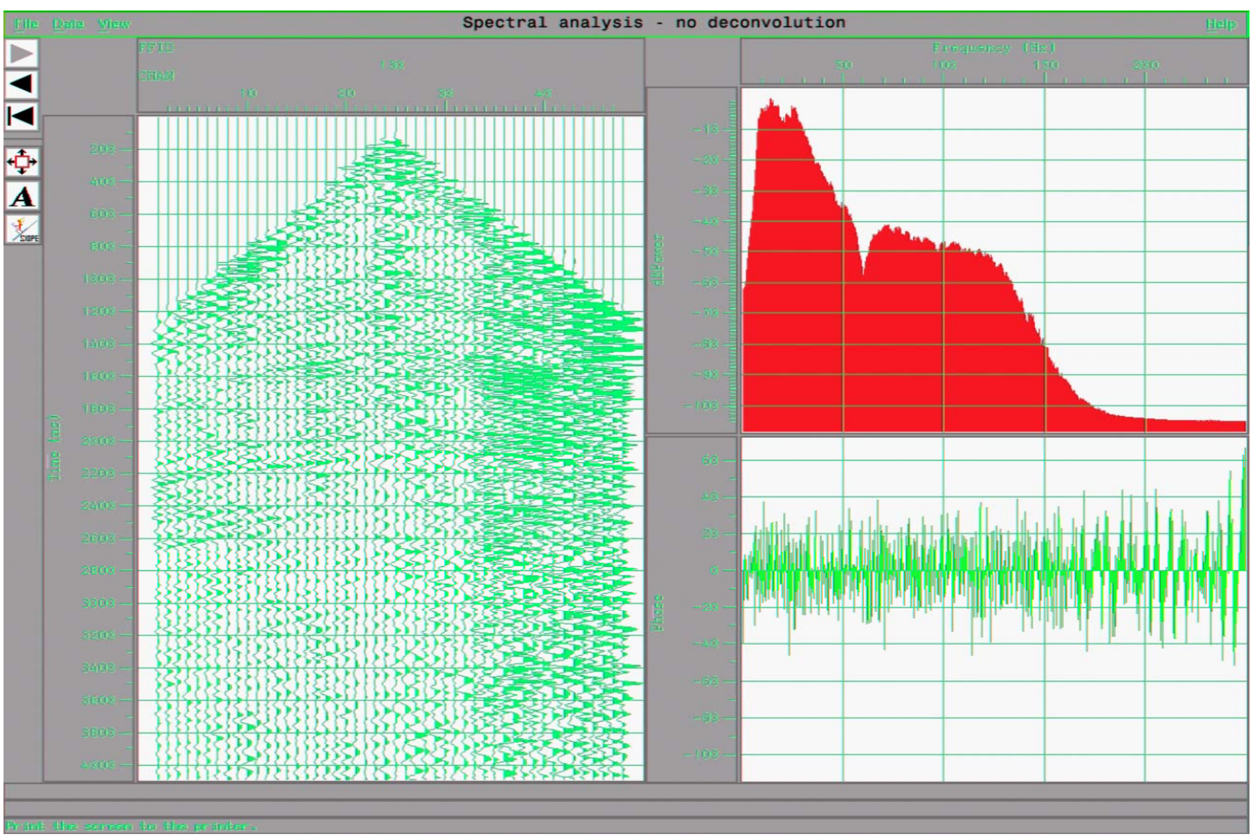

Figure 10

conditioning methods and smoothing of weathering and refractor velocities and depths; and almost countless combinations and permutations of the above. After some testing and consultation with Mr. Anderson and Mr. Wright, it was felt that correcting the data to the lake bottom elevations using fresh water sonic velocites before refraction static analysis was a geophysically defensible method to simplify the solution. The result, while marginal, was universally at least equal, and in many cases superior, to including the water layer in the refraction analysis. In the end, the method arrived at was to pick the first arrivals with the GMG package (after correcting to lake bottom), importing the picks to ProMAX, and solving the DRM solution using a constant weathering velocity with mild smoothing of the refractor velocities but no smoothing of the weathering layer.

Stacking velocities were initially measured every surface mile and applied to the data using both refraction statics and standard elevation statics to evaluate the effectiveness of the static solution. Although unable to always achieve the desired degree of static resolution, the refraction static version was always superior in the medium to long wavelength statics and often in high frequency statics as well. First arrival muting was next tested via several methods, including nmo stretch muting, variable offset stacks, and time-variant post-nmo mutes. The most consistently effective method was found to be NMO stretch muting performed in the NMO module (*figures 11 and 12*). Residual statics methods were tested and found to be largely data dependent; thus, both correlation based and maximum power based methods were tried on each line and chosen empirically from the respective stacks. The final velocity analyses were performed every 3/4 mile with benefit of the respective residual statics and somewhat higher bandpass filter.

In an attempt to retrieve the highest frequencies possible, spectral balancing was tested in several respects including gate widths, bandpass frequency slices, and scalar recovery methods. The result was to include spectral balancing in the final product using 5 equal width slices between 5 Hz and 80 Hz and log average recovery scaling. The effect on coherent high frequencies was minimal but it was seen to help stabilize the source wavelet, thus the decision to include it.

Match filtering was necessary to minimize the negative effects of differing phase, frequency, and amplitude between the two source and receiver types. Testing consisted of trials of the various types of match filter algorithms using several adjacent stacked cdps as input (*figure 13*). To avoid spatial smearing, source-receiver types were cross-correlated on a CDP by CDP basis, producing one filter per CDP. The filters were then summed and normalized resulting in one averaged filter. Algorithms included L1 and L2 norms, spectral division, simultaneous multi-channel, and phase rotation only. Inconsistent results and high frequency degradation were observed using all but the phase-only algorithm. Consequently the phase-only method was used to equalize the phase and ignore frequency and amplitude variations, especially since those attributes were addressed previously via surface consistent amplitude and deconvolution (*figure 14*).

Several post-stack signal enhancement techniques were tested to attenuate random noise and strengthen coherent reflection events. Methods included dynamic signal/noise filtering, coherency filtering, eigenfiltering, and two types of F-X deconvolution (*Figures 15-17*). The success of these techniques is largely data dependent and almost always involves a trade off between noise reduction and loss of geologic information. Input from the interpreters is critical

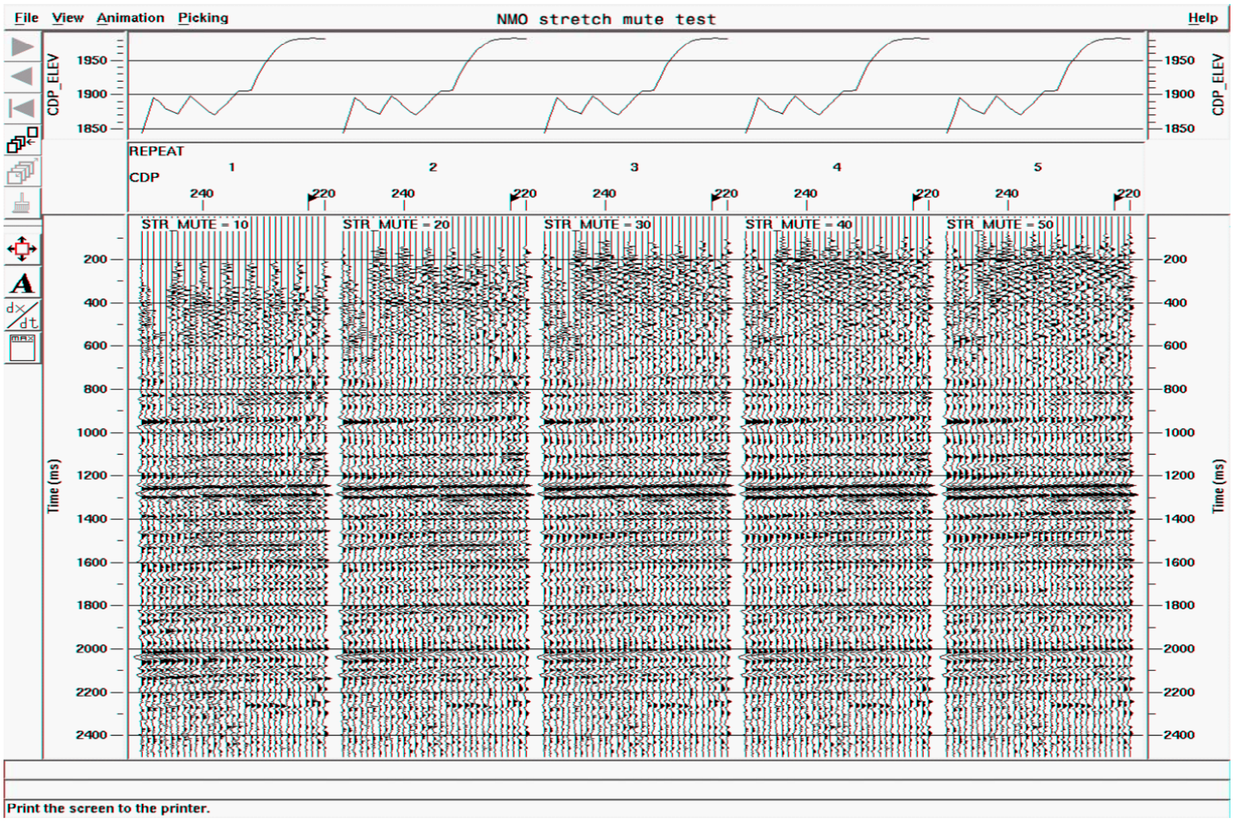

Figure 11

in selecting the method and parameters best suited for the individual situation. Although all methods

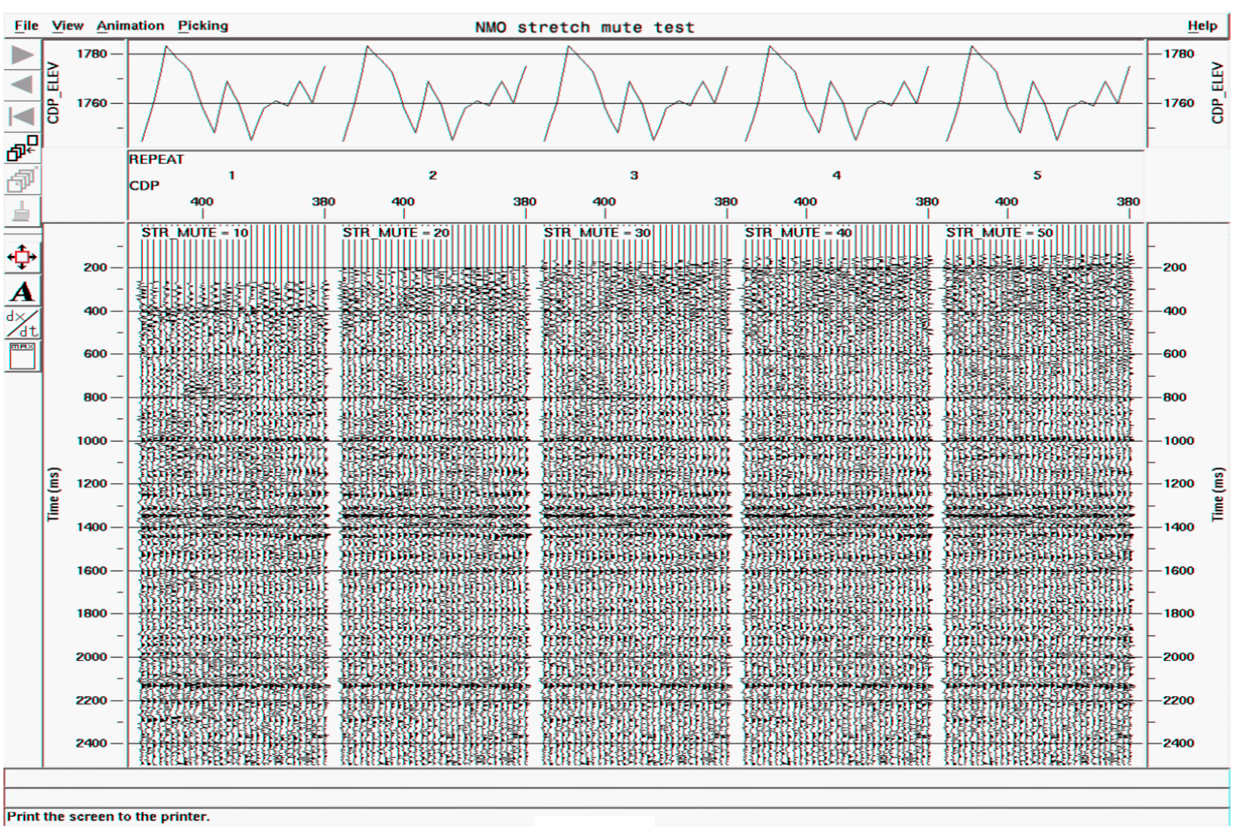

Figure 12

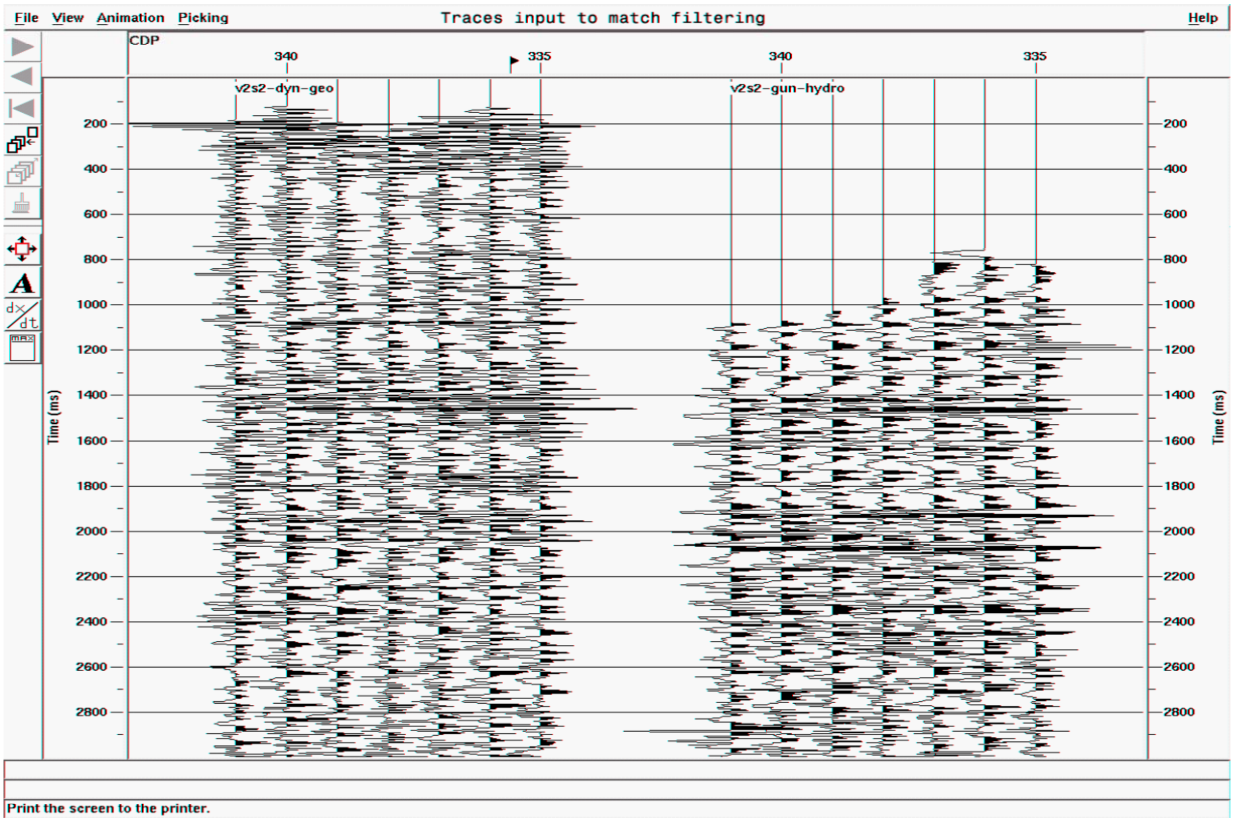

Figure 13

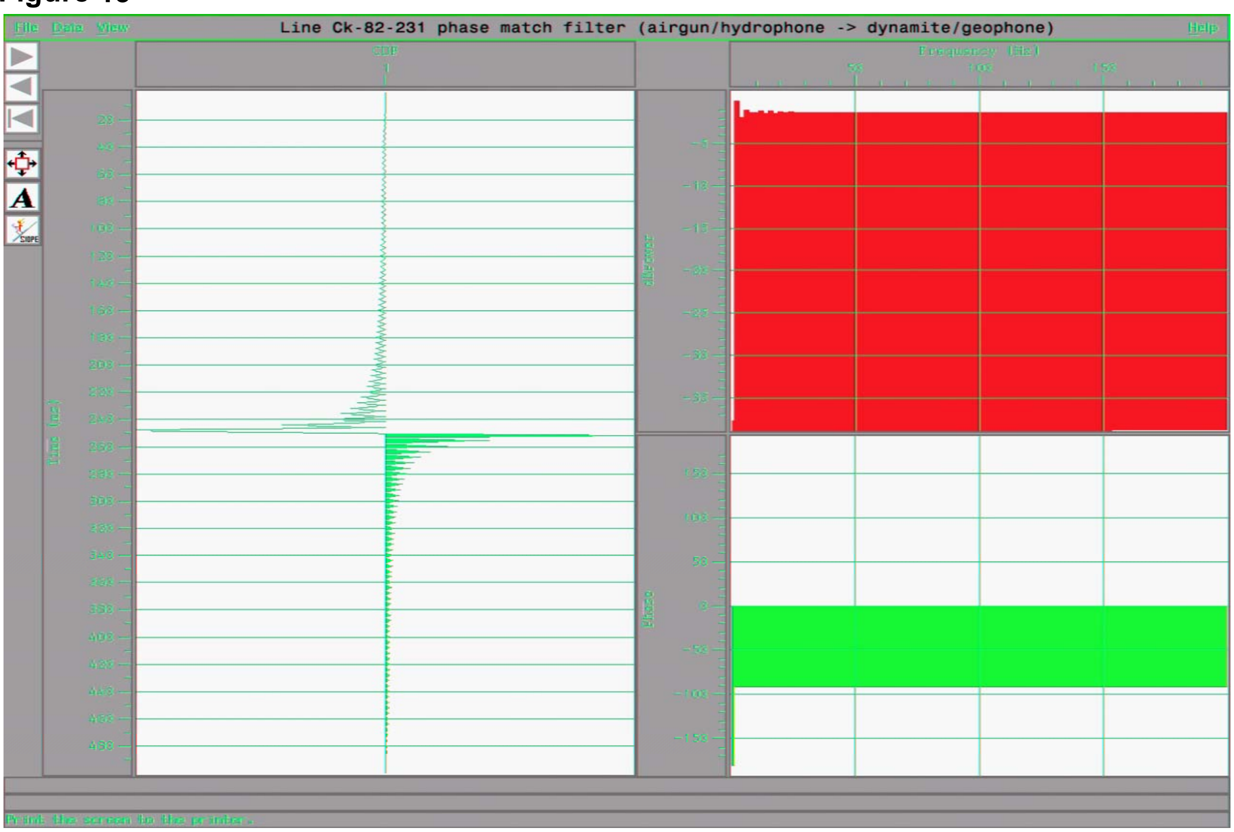

Figure 14

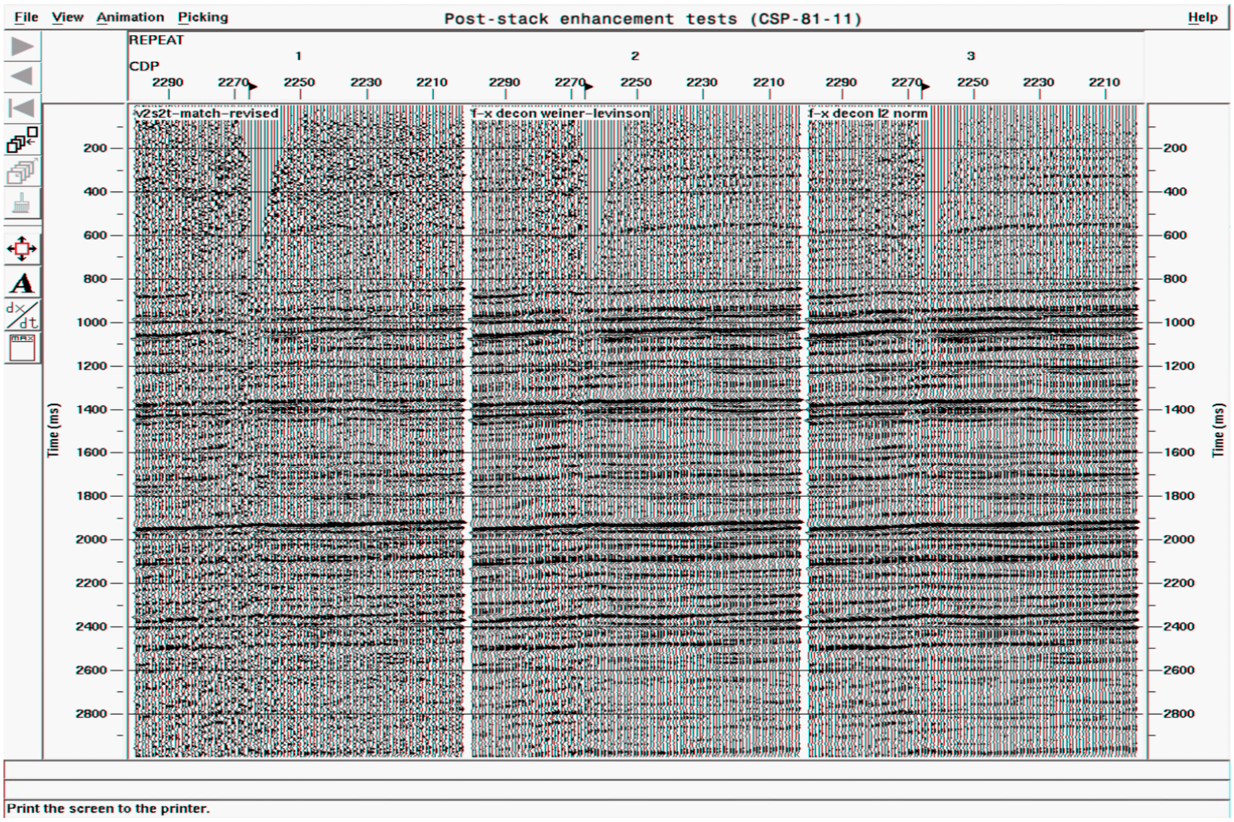
File View Animation Picking
Post-stack enhancement tests (CSP-81-11)
Help
REPEAT
CDP
1
2
3
2290 2270 2250 2230 2210
v2s2t-match-revised
f-x decon weiner-levinson
f-x decon l2 norm
Time (ms)
200 400 600 800 1000 1200 1400 1600 1800 2000 2200 2400 2600 2800
Print the screen to the printer.

Figure 15

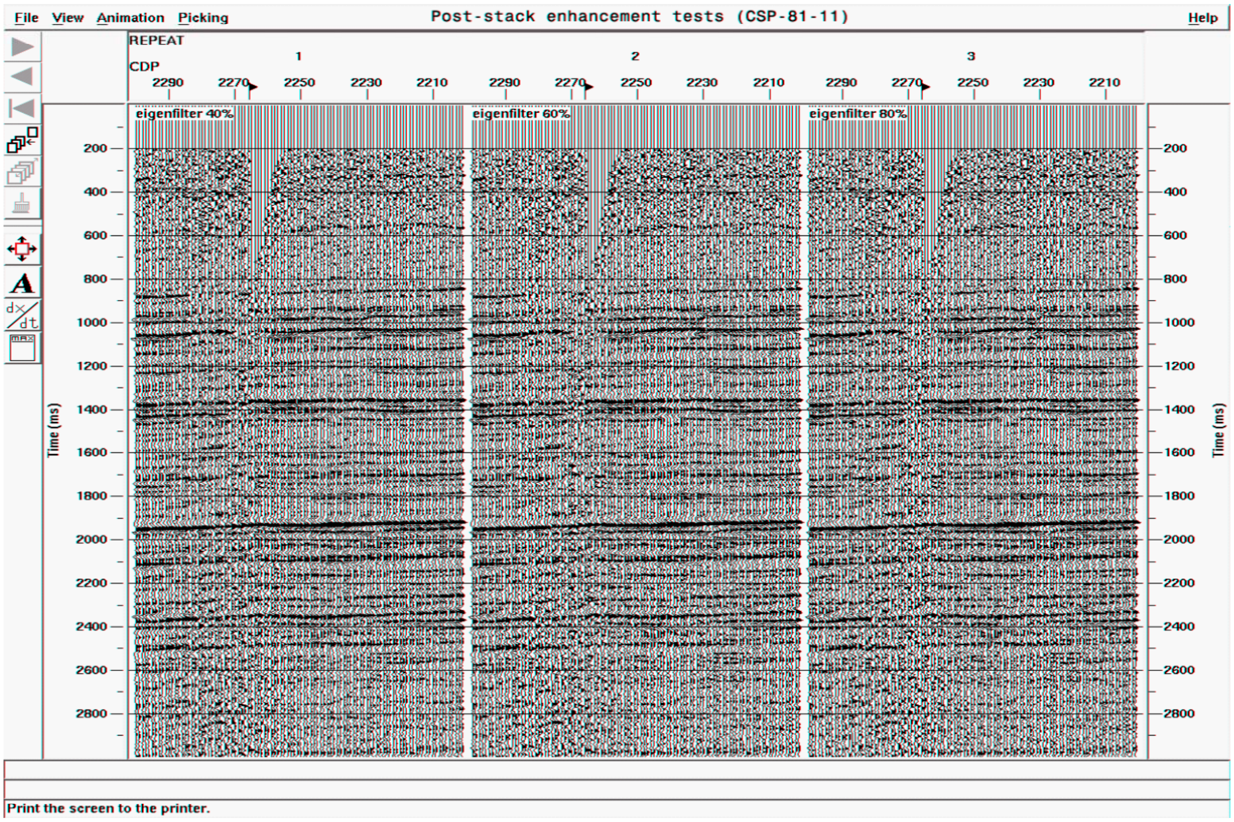

Figure 16

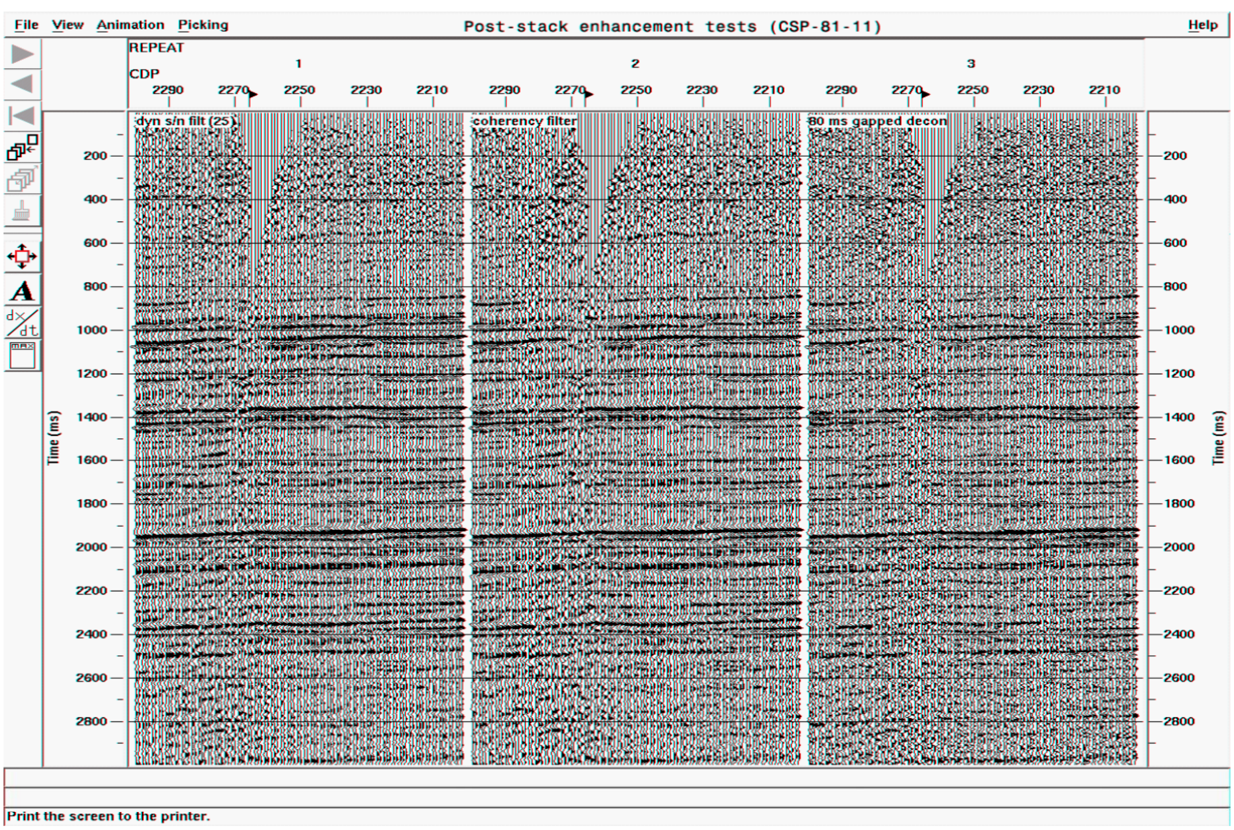

Figure 17

were successful to varying degrees, the most robust enhancement was observed with the L2 norm F-X deconvolution. Once the enhancement method was determined little further testing was required because of the lack of steep or conflicting dip.

General Processing Flow

Data processing for this type of data is more complex because of the multiple source and receiver types used in the acquisition, and because of the land and water environments. As explained above, additional issues were encountered when dealing with the problematic support data. Where necessary, these are expanded upon below. Otherwise, processing progressed more or less in a normal manner.

The first step in processing consists of transcribing the input data into ProMAX internal format and quality control checking the trace data for bad traces. Concurrently, support data is entered into the database to describe the shooting and recording geometry, i.e. coordinate and elevation data, spread geometry, uphole information, and so on. Since an examination of the trace data can often reveal errors in the annotated support data, this is done at the same time as the trace data QC step. A number of such errors were discovered in the process and corrections to the geometry database made accordingly. In a few instances the evidence for the error was not completely compelling; in those cases it was felt that it was less risky to leave the geometry as originally defined rather than guess at a possible correction. As described previously, doubt remained regarding the accuracy of both coordinate and elevation data, especially regarding the elevation of the hydrophone string in the water. Absent any clarifying documentation, assumptions were made which were deemed to be reasonable and processing continued on that basis.

Once satisfied with the quality of the trace and geometry data, the shots were copied to a PC for input to the GMG refraction statics program. Originally it was intended to derive a complete weathering model with that software, from first break picking through final statics. However, when compared with the ProMAX refraction static program, the final GMG solution was found to be consistently less capable of correcting both short and long wavelength statics. After a lengthy testing phase, it was decided to employ GMG for picking the first breaks and then copy those pick times to ProMAX for input to that program to compute the final static solution. Both DLT and DRM solutions were computed in parallel using a single refractor model and constant weathering velocity of 3500 ft/sec to minimize mistie problems. The DRM-derived statics were chosen in all cases because they exhibited more consistency between shot and receiver delay times. Brute stacks were produced using both conventional elevation statics and refraction statics. In all cases, once optimal refraction static parameters were determined, that product was superior to elevations statics.

After parameter testing was complete, the data was further processed with source-dependent TAR, surface consistent amplitude correction, surface consistent deconvolution, air gun delay corrections, and time corrected to the lake bottom where appropriate. This conditioned data was then used as input to all subsequent processing steps, the first of which was stacking velocity analysis.

The first velocity analysis was performed every mile using a suite of 40 trial velocity functions ranging from 6000 ft/sec to 18000 ft/sec with input data resampled to 4 msec, truncated to 4 sec, bandpass filtered to 8-50 Hz, and scaled via 500 msec automatic gain control (AGC). Initially, velocities were evaluated twice, once with elevation statics and once with refraction statics, in order to apply the optimal velocities to their respective stacks. This was soon abandoned when no significant difference could be detected on the velocity picks. From then on velocities were run only once using refraction statics and applied to both versions. A brute stack was produced from these velocities, again using both elevation and refraction statics and 1000 msec prestack AGC to evaluate the effectiveness of the refraction static solution. Since they more effectively removed the medium-to-long wavelength static anomalies, refraction statics was applied exclusively to the subsequent processing.

Next, a pass of both correlation and maximum power model-based, surface consistent residual statics were run using the velocities just derived. In each case the same gated model was used with 10 iterations performed on data filtered to 8-50 Hz and scaled with 500 msec AGC. A QC stack was produced for each method to evaluate the relative success of each. In most but not all cases maximum power statics were felt to be better overall, though any superiority was usually not universal. The better statics were then used for all subsequent processing.

It was at this stage that post-nmo first break muting was tested, after which a second round of velocity analyses were performed. These were run every 3/4 mile, again using 40 velocity functions, resampled to 4 msec, truncated to 4 sec, bandpass filtered to 8-60 Hz, and scaled with a 500 msec AGC. In this case, however, residual statics were applied, the revised post-nmo mute was employed, and the trial velocities were based on the stacking velocities determined from the first analysis. Again, QC stacks were produced and compared with the previous results. Velocities at most locations varied little from the first functions and thus little difference was noted, though a few locations did exhibit more substantial improvement. Of some note here is the fact that the observed velocities were fairly consistent across each line and even throughout the entire project area. This was to be expected due to the uniform and generally flat nature of the geology in the area. What significant departures did exist can probably be attributed to unresolved medium-to-long wavelength statics and/or inaccuracies in the geometry database.

A final round of residual statics was then run using the previous statics and new velocities as input. The upper limit of the bandpass filter was raised from 50 Hz to 60 Hz, and gates were picked to more closely follow the target horizons and this time only the previously used static method was run. As before QC stacks were produced and compared to the previous stack with small but positive improvements usually observed.

It was at this point in the processing that match filter derivation was performed. Theoretically this process would be performed prior to any residual static applications in order to prevent any phase differences from being erroneously detected as statics. However in this case the noise and static problems contaminated the stacked sections to the point that match filtering would have been completely unreliable without their removal. Up to four stacks were generated for each line representing each possible source-receiver combination: dynamite-geophone, dynamite-hydrophone, air-gun-geophone, and air-gun-hydrophone. The match filters were then computed based on overlapping ranges of stacked CDPs. Since it was desired to eventually tie with preexisting dynamite-geophone lines, filters were designed to correct to that combination. Finally QC stacks were generated by applying the appropriate filters pre-stack to the respective source-receiver pairs and stacking as before. Comparing the results with the previous stack was somewhat disappointing from a signal/noise improvement perspective. However since this process was considered a mandatory step, the results were used in all subsequent processes.

The next step in the processing sequence consisted of non-surface consistent trim static calculation and application. For this type of residual statics a wide, flat gate with a small smash is employed in order to avoid the possibility of introducing processing-induced artifacts. Input consisted of refraction statics, both sets of residual statics, match filters, 8-60 Hz bandpass filter, and 500 msec AGC. A maximum of 6 msec shift was allowed. The QC stacks thus produced were compared to the previous product and were found to be a slight to moderate improvement overall.

Since temporal frequency enhancement was one of the desired results of the reprocessing, prestack spectral balancing was included as part of the final product using all the previously determined statics, velocites, and filters. The resulting stack, while not overwhelming, showed occasional improvements in resolution and became the final primary delivered product, as well as the basis for the other three auxilliary products generated later:

- Post-stack F-X deconvolution was applied to the final stack to reduce random noise. The L2 norm adaptive decon option was used.
- The Greenhorn formation was the basis for horizon flattening at 1.050 sec using the F-X decon product as input.
- The non-enhanced final stack was used in the Kirchoff time migration product. Velocities were based on the re-datumed and smoothed final stacking velocities adjusted to 90% of original. The migration aperture was left wide open, frequency limited to 70 Hz, and dips limited to 45 degrees.

Summary

Considering the dated and ambiguous nature of the data, and given the desired results, it is felt that the project was at best marginally successful. Increasing the temporal resolution was an elusive goal despite considerable efforts in the data processing. Possible explanations include limitations of the source energy types and near surface absorption of high frequency energy.

Likewise, there were some disappointing results in correcting the near surface, long wavelength static problems. Possible explanations include the uncertain and problematic nature of the support data which may have led to geometry errors that manifested themselves as static problems (when in fact they were not). Another possibility was that the solution for the refraction static model was not achieved with DEMRM’s static software. However, DEMRM did test one of the lines using a reputable commercial data processing company, and they were not able to provide any better solution than DEMRM.s.

Land to lake source and receiver match filtering, initially considered critical to the final results, proved to be of mixed benefit. The poor signal to noise nature of the data made a more rigorous match filter unattainable, and a quirk in the software prevented matching anything except phase. The results with match filtering were, while different, not noticeably superior to those without. On the other hand, the above observations notwithstanding, it is felt that the general wavelet character and amplitude definition were significantly better preserved in the current processing. This is doubtless due to the surface consistent deconvolution and amplitude corrections employed as well as a less heavy handed technique in overall amplitude balancing.