ADVANCING NEW 3D SEISMIC INTERPRETATION METHODS FOR EXPLORATION AND DEVELOPMENT OF FRACTURED TIGHT GAS RESERVOIRS

FINAL REPORT

Reporting Period Start Date: February 9, 2000
Reporting Period End Date: January 31, 2005

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Submitted: December 2006

U. S. Department of Energy Contract No. DE-AC26-00NT40697
Identification of Fractured Induced Anisotropy in Tight Gas Sands Using Multiple Azimuth 3-D Seismic Attributes, San Juan Basin, New Mexico
Subtask 4.2 Technology Transfer

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ABSTRACT

In a study funded by the U. S. Department of Energy and GeoSpectrum, Inc., new P-wave 3D seismic interpretation methods to characterize fractured gas reservoirs are developed. A data driven exploratory approach is used to determine empirical relationships for reservoir properties. Fractures are predicted using seismic lineament mapping through a series of horizon and time slices in the reservoir zone. A seismic lineament is a linear feature seen in a slice through the seismic volume that has negligible vertical offset. We interpret that in regions of high seismic lineament density there is a greater likelihood of fractured reservoir. Seismic AVO attributes are developed to map brittle reservoir rock (low clay) and gas content. Brittle rocks are interpreted to be more fractured when seismic lineaments are present. The most important attribute developed in this study is the gas sensitive phase gradient (a new AVO attribute), as reservoir fractures may provide a plumbing system for both water and gas. Success is obtained when economic gas and oil discoveries are found.

In a gas field previously plagued with poor drilling results, four new wells were spotted using the new methodology and recently drilled. The wells have estimated best of 12-months production indicators of 2106, 1652, 941, and 227 MCFGPD. The latter well was drilled in a region of swarming seismic lineaments but has poor gas sensitive phase gradient (AVO) and clay volume attributes. GeoSpectrum advised the unit operators that this location did not appear to have significant Lower Dakota gas before the well was drilled. The other three wells are considered good wells in this part of the basin and among the best wells in the area. These new drilling results have nearly doubled the gas production and the value of the field. The interpretation method is ready for commercialization and gas exploration and development. The new technology is adaptable to conventional lower cost 3D seismic surveys.

TABLE OF CONTENTS

DVD-ROM Table of Contents

LISTS OF GRAPHICAL MATERIALS

List of Tables

List of Figures

Figure 10. Dakota fractures seen at Dinosaur Ridge along the Eastern Front Range of the Rocky Mountains near Morrison, Colorado. North is roughly to the right. (Photo taken by John M. Ghist, 2003.)

Figure 11. Seismic lineaments are used to infer a network of northeast and northwest fracture zones in the Lower Dakota. Present day north-south tectonic stress inferred from borehole breakout (unit wells drilled pre-1999) does not preferentially close any of these fracture orientations. (However, borehole breakout data in a well to the southeast and off the map indicates a change in orientation of tectonic stress to a northeast direction.)

Figure 12. Lead areas (A through I) associated with regions of high lineament density. Notice the outstanding agreement between orientation of natural fractures measured in wells drilled pre-1999 (rose diagrams) and the seismic lineaments.

Figure 13. Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales. Borehole image data are from unit wells drilled pre-1999. The Dakota cumulative production trend is from Dakota Interval Production, San Juan Basin, New Mexico, Burlington Resources Proprietary Map, prepared by Charles F. Head, 2001.

Figure 14. Notice the strong correspondence between the multi-directional character of many of the seismic lineaments in the unit with structural troughs and noses mapped in the Lower Dakota. Structural seismic mapping is based on unit wells drilled pre-1999.

Figure 15. Correspondence between Lower Dakota Gaussian curvature (computed from the structural mapping in Figure 14) and seismic lineaments.

Figure 16. Significant wells in the unit are located to the south and west of the Lower Dakota isopach thick or "main" channel. The number above each well symbol is a modified unit well name/number, and the number below is the best of 12-months production indicator (MCFGPD).

Figure 17. Snapshot of Lower Dakota channel image ("C") from a seismic coherency horizon slice. Significant unit wells occur near the edge of the channel image.

Figure 18. Lower Dakota clay volume from wells drilled pre-1999 versus average near-trace instantaneous seismic amplitude (AVO attribute) from Lower Dakota average amplitude for a zone 3 ms thick near the MRSN horizon (Figure 7). Characteristic curve is used to compute collocated co-kriged seismic clay volume map (correlation coefficient 0.81).

Figure 19a. Collocated co-kriged Lower Dakota clay volume map using unit wells drilled pre-1999. Low clay rock types (hot colors, clay volume less than 13 percent) tend to have lower water saturations than high clay rock types (cool colors, clay volume greater than 13 percent).

Figure 19b. Collocated co-kriged Lower Dakota clay volume map using unit wells drilled pre-1999. After applying the low clay volume constraint (less than 13 percent), only three leads remain to be investigated (leads A, B and D). Notice the unique directional distribution of lineaments associated with low clay (northeast azimuths, shown in bold red) and high clay (northwest azimuths, shown in bold green).

Figure 20. Notice the agreement between the Lower Dakota acoustic impedance from the horizon slice about 10 ms above MRSN (Figure 7) and the Lower Dakota clay volume map in Figure 19b. Prospective sandstone fluvial channel pay (typically effective porosity between 8-14 percent) is defined by an acoustic impedance range of about 31,000-36,000 g/cc-ft/ms (Figure 21). Notice the unique directional distribution of lineaments associated with high impedance reservoir (northeast azimuths) and low impedance reservoir (northwest azimuths).

Figure 21. Dakota acoustic impedance vs. effective porosity.

Figure 22a. Significant gas producing Lower Dakota wells with low clay are interpreted to typically have a diagnostic AVO response compared to poor wells (Figure 22b). Note that in the stack domain the gas bearing AVO endpoint is often associated with roughly a trough near the MRSN event. (AVO modeling from Castagna, Peddy, Lausten & Mueller, 1998.)

Figure 22b. Poor producing Lower Dakota wells with high clay are interpreted to typically have a diagnostic AVO response compared to significant production (Figure 22a). Note that in the stack domain the poor producing AVO endpoint is often associated with roughly a peak near the MRSN event. (AVO modeling from Castagna, Peddy, Lausten & Mueller, 1998.)

Figure 23. Tight high impedance gas sands have a Class 2 AVO response (after Rutherford and Williams, 1989).

Figure 24. Lower Dakota gas saturation for unit wells drilled pre-1999 versus phase gradient (new AVO attribute) computed from a Lower Dakota horizon slice near the MRSN (Figure 7). Crossplot groups wells into low (less than or equal to 13 percent) and high (greater than 13 percent) clay clusters. Note the empirical red trend line through the low clay cluster (correlation coefficient 0.89). (A model switching routine using two separate trend lines could be used to describe both low and high clay rock types.)

Figure 25a. Lower Dakota seismic phase gradient map (near minus far-trace stack) showing values between –15 to –85 degrees. New well locations 52, 53, 28E, 31E, and 59 are shown. Notice this mapping constraint applied to the new AVO attribute defining gas production automatically eliminates most of the clay rich regions (compare to Figure 25b). Potentially higher gas saturated regions (dark color) shown by the attribute are regionally on the updip side of the map (Figure 14). The constrained phase gradient does not support the 55E well location that resulted in a poor producing well (Table 2).

Figure 25b. Lower Dakota seismic phase gradient map (near minus far-trace stack) showing values between -15 to -85 degrees with estimated clay volume less than about 13 percent (near-trace seismic amplitude less than 20,000, Figures 18 and 19b). New well locations 52, 53, 28E, 31E, and 59 are shown.

Figure 26. Collocated co-kriged Lower Dakota gas saturation map using unit wells drilled pre-1999. New well locations 52, 53, 28E, 31E, and 59 are shown. Wells 52 and 28E prospects have nearly the same phase gradient response / gas saturation as well 28, one of the most significant wells in the unit, indicating similar AVO attributes. The phase gradient / computed gas saturation does not support the 55E well location, a poor producing well (Table 2).

Figure 27. The nearly equivalent AVO response for sites AVO 1 and AVO 2 (near well 28E and 52 prospects, respectively) and well 28 (one of the most significant wells in the unit) indicates that sites AVO 1 and AVO 2 have low clay and are gas producing (Figure 22a). (AVO modeling from Castagna, Peddy, Lausten & Mueller, 1998.)

Figure 28. Note the similar fracture distributions indicated by the seismic lineaments (Lower Dakota, Figure 11) and interval velocity anisotropy (near Upper Dakota / Green Horn, Figure 7). The northwest striking lineaments mapped in the Lower Dakota seem to be associated with green and light pink colors in the interval velocity anisotropy map. The darker red areas in the map seem to correspond to northeast striking lineaments. The large interval/velocity anisotropy in the Upper Dakota/Green Horn at the well 52 prospect may indicate additional fracture potential of reservoir up hole. Collocated co-kriging is done using Dakota fracture counts (interpreted Lower Dakota plus interpreted Upper Dakota) from borehole image data measured in unit wells drilled pre-1999 (correlation coefficient 0.61, Figure 29).

Figure 29. A near perfect response curve is obtained by removing well 47 as an outlier and passing the curve through the origin (correlation coefficient 0.99). Total Dakota fracture counts (interpreted Lower Dakota plus interpreted Upper Dakota) are from borehole image data measured in unit wells drilled pre-1999.

Figure 30. Eleven new prospective drill locations (Sites 1-11) including the Site 4 primary location are spotted by overlaying the low clay/phase gradient attribute (Figure 25b) with the seismic lineaments (Figure 11). The new prospects are spotted where lineaments intersect.

Figure 31. Low clay and gas bearing prospective fairway with seismic lineaments. New well locations 28E (Site 1), 31E (Site 9), 52 (Site 4), and 53 and 59 (selected by unit operators) are shown (Figure 30). The best of 12-months production indicator is annotated next to each well number (Table 4).

Figure 32. Gas charged fractured reservoir prospects are indicated by the dark red areas inside the "black clouds". New well locations 52, 53, 28E, 31E, and 59 are shown.

Figure 33. Unit well production histories (updated to December 2005). Production for new wells 52, 53, 28E, 31E and 59 is shown in red. The new fractured reservoir exploration technology has nearly doubled the production and value of the unit.

INTRODUCTION

In tight gas sands reservoir quality may be highly variable. Finding the right drill site often involves identification of fracture-induced anisotropy. Multiple-azimuth 3D seismic attributes and petrophysical data help define new drill locations to find the sweet spots. This report details the justification and methodology employed to drill and complete fractured tight sand reservoir prospects. Well locations are spotted by applying modern seismic-processing techniques followed by rigorous analysis of azimuth-dependent seismic attributes and well-log data to qualify areas of high natural fracture density. Note that all well names/numbers in the report have been modified for the purpose of anonymity.

A 3 mi by 3 mi P-wave 3D seismic data set acquired with an omni-directional receiver array to provide broad-offset azimuth statistics is reprocessed. The data set has a bin size of 110 feet by 110 feet. A pre-stack time migration algorithm is used to increase spatial resolution and to dramatically increase signal to noise ratio. The processing is focused on stack analysis of anisotropy in multiple azimuths followed by pre-stack analysis of amplitude variation with offset (AVO). The processed data and subsequent statistical analysis of seismic attributes were interpreted for identification of fractures prospective for commercial gas production. Relationships between seismic attributes and measured reservoir properties, such as clay content, as well as Dakota fracture density interpreted from borehole-image logs, are investigated. A direct detection AVO attribute is used to assure that prospects are charged with gas and not water.

The gas-producing unit characterized in this study is located in the San Juan Basin, Rio Arriba County, New Mexico. Gas production in the area is mainly from the Cretaceous Dakota and Gallup Sandstones. The most significant Dakota production occurs in the Lower Dakota, mainly from the Encinal and Burro Canyon Sands. Prospective Dakota horizons include both tight (Upper Dakota) and porous/permeable (Lower Dakota) sandstones. Reservoir stratigraphy of the Dakota producing interval is complex, with production potential in five individual sandstones. Dakota Sandstone depositional environments range from near marine (fluvial-deltaic) to marine.

EXECUTIVE SUMMARY

A new P-wave 3D seismic exploration method for fractured tight gas reservoirs is developed in a study for the U. S. Department of Energy. The technique is based on a comprehensive petrophysical analysis done on the Lower Dakota Sandstone to determine critical reservoir properties and integrated to a high-resolution 3D seismic volume in a gas unit, San Juan Basin, Rio Arriba County, New Mexico.

Natural fractures are often responsible for enhancing production in oil and gas reservoirs. They play an important role for defining sweet spots especially in the Permian Basin of west Texas and New Mexico and in the Rocky Mountain region of the United States. For over 5 years, Dr. James J. Reeves and GeoSpectrum, Inc., an oil and gas exploration company in Midland, Texas, have worked with the U. S. Department of Energy to develop a new 3D seismic interpretation method for fractured tight gas reservoirs. The Department of Energy and GeoSpectrum, Inc. have spent over a million dollars in developing this program. Another million dollars was contributed by Burlington Resources through in-kind contributions of 3D seismic and well data. An additional three million dollars in drilling cost was invested by Huntington Energy to test four natural fractured Lower Dakota prospects.

A data driven exploratory approach is used to determine empirical relationships for reservoir properties. The interpretation methodology is based on four principal seismic attributes. Seismic lineament analysis is used to map lineaments through the Lower Dakota reservoir zone using horizon slices and time slices. A seismic lineament is defined as a linear feature seen in a time or horizon slice that has a negligible vertical offset. We interpret that, in a probabilistic sense, where lineaments swarm and cluster is where reservoir fractures are most likely to be found. Leads identified using lineament density are further screened using seismic rock typing to identify reservoir lithologies that are more likely to fracture. A collocated co-kriged clay volume map using near-trace instantaneous seismic amplitude (an AVO attribute) is used to identify reservoir having low clay, that is interpreted to be more brittle and more prone to fracturing. Fractured reservoir and good reservoir rock do not necessarily make a drillable prospect, as reservoir fractures may provide a plumbing system to both water and gas. For prospect development, the most important attribute, a new gas sensitive phase gradient AVO attribute is developed to further screen the leads to insure that gas is present in the reservoir. Finally, in the Upper Dakota, fractured reservoir potential up-hole is interpreted using a seismic interval velocity anisotropy attribute. Success is obtained when economic oil and gas discoveries are found.

Particular attention is given to development of seismic attributes that are insensitive to the shortcomings of the seismic data. The resulting interpretation is further validated by a unified set of seismic attributes. Clay volume is defined by near-trace seismic amplitude, acoustic impedance determined from seismic inversion, and the phase gradient, a new AVO attribute. It is further interpreted from the unique density and directional distributions of lineaments in each rock type.

Burlington Resources and Huntington Energy have drilled four wells defined by the methodology. Results indicate a success ratio of nearly 100 percent using the exploration method. The well 52 prospect drilled and completed in January 2004 had an initial potential of nearly 4000 MCFGPD and a best of 12-month production estimate of 1652 MCFGPD. The 28E well drilled and completed in May 2004 has a best of 12-month production estimate of 2106 MCFGPD and has continued to produce near this rate making it one of the best wells in the unit so far. The 31E well was drilled and completed in June 2004 and has a best of 12-month production estimate of 941 MCFGPD. The fourth well, the no. 53, was drilled and completed in April 2004 and initially produced about 2000 MCFGPD, but has a best of 12-month production estimate of only 227 MCFGPD. This prospect had favorable seismic lineament (fractured) reservoir attributes, however, it did not have good AVO (gas) or clay volume attributes. It is interpreted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir. GeoSpectrum advised the unit operators that this drill location did not appear to have significant Lower Dakota gas before the well was drilled.

The last three wells drilled earlier by Burlington Resources without applying the new exploration methodology, each had best of 12-month production indicators less than 350 MCFGPD, indicating the value of our new technology. The study has nearly doubled gas production and the value of the unit. The Lower Dakota production results of 16 wells drilled in the unit are all reasonably predicted by the methodology. The technology is ready for commercialization and industry use in exploration for tight gas reservoirs. The technique is easily adaptable to lower cost 3D seismic surveys.

EXPERIMENTAL

Tight gas fractured reservoir prospects are predicted in a 3 mi by 3 mi P-wave 3D seismic data set acquired with omni-directional receivers to provide broad azimuth-offset statistics. The data set has a bin size of 110 feet by 110 feet. Seismic processing techniques including pre-stack time migration are focused on pre-stack analysis of amplitude variation with offset (AVO) to help develop seismic attributes sensitive to gas and brittle reservoir rock likely to fracture. A data driven exploratory analysis of azimuth dependent and all azimuth seismic attributes with reservoir properties determined from an advanced petrophysical analysis of wire line well log and borehole image data is used to define areas of high natural fracture density, low clay (brittle) reservoir rock, and high gas saturation (Table 1). Four verification wells are drilled to test the new exploration method.

The data used in the study (P-wave 3D seismic data, well data, core analyses, base map data, etc.) are loaded into PC-based 3D seismic and geologic analysis systems using commercially available software for oil and gas exploration. The workflow for the project includes,

1. 3D seismic processing and interpretation,
2. Petrophysical analysis of wire line log data and borehole image data,
3. Production data analysis,
4. Exploratory data analysis of seismic attributes, and
5. Prospect development.

Seismic data are processed and interpreted in five different seismic volumes gathered in four different azimuths (North 10 degrees East, North 55 degrees East, North 100 degrees East, and North 145 degrees East, each plus or minus 22.5 degrees) and for all azimuths. These preferred azimuth directions are roughly parallel and perpendicular to the directional statistics of the seismic lineaments mapped through the Dakota seismic section. Seismic processing and analysis are done to restore the seismic response to near zero phase and true amplitude. A pre-stack time migration to increase spatial resolution is applied separately to each of the five seismic volumes. Synthetic seismograms for wells having sonic logs or pseudo sonic logs (calculated from resistivity logs) are computed and tied into the 3D seismic to map the Lower and Upper Dakota separately, in each seismic volume, using a 3D seismic computer workstation.

Reservoir properties are computed from a petrophysical analysis of wire line log data penetrating the Dakota. Borehole environmental corrections and petrophysical analyses are applied to the logs using a geologic computer workstation. A reservoir model based on core data is used to define the mineral constituents consisting mostly of clays and quartz composing the Dakota reservoir. An inversion algorithm is used to convert the log curve responses at each depth interval to a volumetric content for each mineral assemblage including fluid content (gas and water) in the reservoir model. The result is an accurate computation of gas saturation and clay volume in the Dakota section at each well from the wire line logs. Using an interactive graphical computer workstation natural reservoir fractures are interpreted and measured in the wells using borehole image logs.

Dakota production data are normalized using the average daily production from the best month out of any 12 consecutive months during the history of the well. This production parameter is insensitive to the mechanical and completion problems that often make a good well perform poorly until the problems are corrected. This is a reliable normalized production parameter used by many petroleum engineers.

The petrophysically derived reservoir properties, including the best of 12-months production indicator and Dakota fracture counts from borehole image data, are used to conduct an exploratory data analysis of seismic attributes. Seismic attributes include near-trace instantaneous seismic amplitude, phase gradient (near-trace phase minus far-trace phase), seismic lineament mapping through the reservoir section, and Dix's interval velocity anisotropy. A geostatistical computer workstation is used to crossplot reservoir properties measured at each well with the seismic attributes observed near the well. A meaningful and consistent set of relationships between seismic attributes and reservoir properties are required for a successful analysis. If strong relationships are found, reservoir properties such as clay and gas content and fracture density are then mapped between the wells and through the seismic volume using a geostatistically based collocated co-kriging technique.

In summary, prospects are developed based on three principal reservoir attributes, gas content, clay volume, and fracture density. The most important attribute is of course gas content as this is what we are trying to find. Fractures are predicted by low clay volume indicating brittle reservoir and fracture density/seismic lineament attributes.

GeoSpectrum has used a similar method to interpret fracture zones from seismic lineaments for Arco Permian in a reservoir study of the South Justis Unit, Lea County, New Mexico (Arco Permian proprietary report, GeoSpectrum, 1998 and Reeves and Smith, 1999).

RESULTS AND DISCUSSION

Summary of GeoSpectrum's Fractured Reservoir Exploration Methods

In a tight gas exploration and development study conducted for the U. S. Department of Energy a P-wave 3D seismic interpretation method for fractured sandstone reservoirs is developed. The method is based on a comprehensive reservoir characterization of the Lower Dakota Sandstone in a gas producing unit, San Juan Basin, Rio Arriba County, New Mexico. A data driven exploratory approach is used to determine empirical relationships for reservoir properties.

The following reservoir attributes from a 3 mi by 3 mi P-wave 3D seismic survey are used:

1. Fractures are predicted using seismic lineament mapping in the reservoir section. This method was developed in GeoSpectrum's study on the South Justis Unit in Lea County, New Mexico (Arco Permian proprietary report, GeoSpectrum, 1998 and Reeves and Smith, 1999). A **seismic lineament** is defined as a linear feature seen in a time slice or horizon slice through the seismic volume. Vertical offset is typically not observable across the lineament. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir.

2. The lead areas defined by regions of "swarming" or multi-directional lineaments are further screened by additional geologic attributes. These attributes may include reservoir isopach thickness, indicating thicker reservoir section, or seismic horizon slices, imaging potentially productive reservoir stratigraphy. We rely on a collocated co-kriged clay volume map (correlation coefficient 0.81) for the reservoir zone, computed from instantaneous near trace seismic amplitude (AVO), and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. This map indicates where good/clean reservoir rock is located. We interpret that clean/low clay reservoir rock is brittle and likely to be more highly fractured when seismic lineaments are present.

3. A gas sensitive AVO seismic attribute, near-trace stacked phase minus far-trace stacked phase, called the **phase gradient**, a new AVO attribute, is used to further define drill locations having high gas saturation. An exploratory data analysis of gas saturation and the phase gradient indicates a correlation coefficient of 0.89 for low clay reservoir (less than or equal to 13 percent). The importance of this attribute cannot be understated, because reservoir fractures may also penetrate water saturated zones in the Dakota and/or

Morrison and be responsible for the reservoir being water saturated and unproductive. Success is only obtained when economic gas and oil discoveries are found.

4. A seismic **interval velocity anisotropy** attribute is used to investigate fractured reservoir potential in tight gas sands up hole from the main reservoir target. We interpret that large interval velocity anisotropy is associated with fracture-related anisotropy in these sands.

Play Geology

The gas unit investigated in this report is located in Rio Arriba County, New Mexico in the central portion of the San Juan Basin (Figures 1 and 2). Gas production is mainly from the Cretaceous Dakota and Gallup Sandstones. The most significant Dakota production occurs in the Lower Dakota mainly from the Encinal and Burro Canyon Sands.

The Dakota is defined from the top of the Two Wells to the top of the Morrison Formation (Figure 3). Prospective Dakota horizons include both "conventional" tight (Upper Dakota) and permeable (Lower Dakota) sandstones. Reservoir stratigraphy of the Dakota producing interval is complex, with production potential in five individual sandstones. Dakota Sandstone depositional environments range from (near marine) fluvial-deltaic to marine. A summary of both the Upper and Lower Dakota producing zones follows (Burlington Resources, Inc., Prospect and Well Files).

Upper Dakota

The Upper Dakota is defined from the top of the Two Wells to the top of the Encinal Sandstone (Figure 3). It is comprised of both nearshore marine (Two Wells, Paguate, and Oak Canyon) and fluvial-deltaic (Cubero) members.

Two Wells and Lower Paguate. The Lower Paguate and Two Wells Sandstones are northwest trending marine shorefaces exhibiting classic coarsening upward sequences. Porosity ranges of 8-13 percent characterize both sandstones with matrix permeability between 0.05-0.20 md. These sandstones require stimulation to achieve commercial rates.

Cubero Sandstone. The upward fining fluvial-deltaic Cubero, which is oriented essentially perpendicular to these marine flow units (Lower Paguate and Two Wells), exhibits log porosity up to 10 percent and is typically a lower permeability reservoir than the marine Dakota units. It was deposited in a delta where combined fluvial and wave processes were dominant.

The Upper and Lower Cubero Sandstones have the best reservoir potential of the several Upper Dakota Sandstones that are typically completed (e.g. well 15). However, only the middle Cubero Sandstone has significant potential in well 25 (west of the study area) and in well 31 (northwest portion of the gas unit).

The deepest prospective, conventional Upper Dakota reservoir is the Lower Cubero Sandstone. The reservoir was deposited as a northeast-trending lobe of a fluvial-deltaic system and is characterized by average porosity of 9.5 percent and average matrix permeability of approximately 0.10 md. This "clean," brittle sandstone is prone to natural fracturing; however, hydraulic fracturing is required to achieve commercial production.

Lower Dakota

The Lower Dakota is defined from the top of the Encinal Sandstone to the top of the Morrison Formation (Figure 3). These reservoirs are comprised of the fluvial Burro Canyon and Encinal Canyon Sands that are typically thick and relatively permeable but lithologically and petrophysically complex.

Encinal Canyon Sandstone. The Encinal Canyon Sandstone is at the base of the Dakota Formation and was deposited by braided streams in topographic valleys. In 1993, commercial Lower Dakota gas production was established in the unit with an Encinal Canyon Sand pay-add in well 55 essentially a "new field" discovery. A three well priority program followed this initial success in 1994 to define reservoir limits and upside potential. Of those three wells, well 31 was a commercial success; well 15 was wet and unsuccessful; and well 25, a reservoir boundary (edge) well (west of the study area), was marginal.

As part of the 1994 priority program, data were collected to characterize the Encinal Canyon reservoir. Core taken from well 15 indicates that this sandstone has exceptional reservoir quality compared to "conventional" tight Upper Dakota reservoirs. Key differences include greater permeability (up to 200 md at reservoir stress), greater porosity (8-18 percent), and lower shale volumes.

In 1995, four additional wells were recommended. Wells 30 and 28 were developmental extensions, and wells 27 and 47 were exploratory extensions. In addition to the basal Dakota Encinal Canyon Sandstone, conventional tight Dakota Sandstones were secondary targets in all four proposed wells. This stacked pay zone possibility reduced the dry-hole risk and increased the upside potential gas reserves.

The four additional Lower Dakota new drills were programmed to further define the productive limits and extent of the "new field," and to test a geological valley fill reservoir model. Well 28 is one of the most significant Dakota wells drilled in the unit. Wells 47, 30, and 27 had various degrees of calculated Lower Dakota pay, but each of these wells proved to be unsuccessful.

The Encinal Canyon has exceptional reservoir qualities when compared to the overlying "conventional" tight Upper Dakota. Encinal Canyon porosity and permeability in excess of 18 percent and 200 md (in-situ), respectively, have been recorded in proximal cores. Unlike the Burro Canyon, the Encinal Canyon Sand is more typically hydrocarbon bearing.

A significant risk in Encinal completions is water invasion from sandstones either above or below the gas reservoir. Water can encroach vertically through both natural and hydraulic fractures. A highly fractured reservoir may be responsible for excellent gas production or it may be ruined by fractures providing a plumbing system to nearby Dakota and/or Morrison water reservoirs. Also, within an Encinal structural/stratigraphic trap there may be increased risk of Encinal water downdip.

Burro Canyon Formation. The Burro Canyon Sandstone is legally defined as part of the Dakota producing interval, but is stratigraphically distinct from the overlying Dakota Formation. The Cretaceous Burro Canyon Sandstone was deposited by fluvial (river) systems on top of an irregular surface formed by erosion of the Jurassic Morrison Formation. The unconformity separating these two formations represents a hiatus of approximately 23-37 million years. A thicker Burro Canyon interval was deposited in Morrison valleys and thinner Burro Canyon on higher areas. The Burro Canyon represents the base of the Cretaceous in the San Juan Basin.

Burro Canyon Sandstones were deposited in braided streams, far from marine influences; whereas Dakota Sandstone depositional environments range from (near marine) fluvial-deltaic to marine. This difference in depositional environment explains why hydrocarbon source shales (rich in organic matter) are present in the Dakota, but not in the Burro Canyon. Burro Canyon Sandstones generally have larger grain size, higher porosity, and higher matrix permeability than typical Dakota Sandstones.

The Burro Canyon Sandstone is separated from the overlying Dakota Formation by an erosional unconformity, representing 3-6 million years. Erosional down-cutting and Burro Canyon characteristic fluvial stratigraphy ultimately resulted in hydrocarbon traps, including:

1. Burro Canyon Sandstones truncated by the overlying unconformity near trends of thinning, forming hydrocarbon traps on the downdip side of the trends,
2. Irregularities in the amount of erosional down-cutting combined with the inherently irregular nature of Burro Canyon Sandstones (braided stream deposits) create hydrocarbon traps where individual sandstones are truncated updip by the unconformity, or
3. Hydrocarbon traps exist where fluvial Burro Canyon Sandstones are truncated updip by the overlying erosional unconformity.

Within the Burro Canyon Sandstone there are many individual sandstone units, each with its own reservoir boundaries. These are often too irregular to be individually mapped. They pinch out laterally, coalesce with other sandstones, and/or down-cut into underlying strata. Typically these sandstones are fine to coarse grained, upward fining deposits that are frequently characterized by wet porosity, often in excess of about 15 percent (Figure

4). Although the Burro Canyon is known as a "sandstone," interbedded shales and siltstones are common. This bewildering stratigraphic complexity has formed permeability barriers that, in conjunction with erosional truncation and structure, have trapped hydrocarbons.

Fracture Detection Methodology

Fractured Reservoir Characteristics

GeoSpectrum's reservoir analysis has resulted in the development of several potential new Lower Dakota prospect/exploratory extensions. The prospects are based on an integrated methodology using geologic as well as seismic attributes determined from advanced petrophysical and seismic data analysis (GeoSpectrum, Inc., 2003). These are a direct work product from the tasks outlined in the DOE contract's Statement of Work (GeoSpectrum and U. S. Department of Energy, 2000, Contract No. DE-AC26-00NT40697).

The primary prospect, unit well 52 (Site 4) extended the production of the unit to the northeast about ¾ mile from well 28. Figure 2 is a bubble map showing cumulative Dakota production for the unit. Notice that before drilling this prospect the field consisted of about 9 wells, 6 of which are marginal producers. Three of the wells (28, 55 and 31) each have a cumulative gas production of greater than 700 MMCFG (Table 2.) The close proximity of poor wells (55E and 27, Figure 2) to the three outstanding wells is an indication of the Dakota reservoir complexity within the boundaries of the gas unit.

In Figure 5, hydrocarbon pore volume versus porosity-thickness and the best of 12-months production for each well are shown. Note that the significant / good wells in the unit area are distinguished by a lower gas saturation cut off of about 33 percent. Also notice the apparent poor (or random) correlation between the best of 12-months production indicator (bubble size) for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality (bubble size) in the crossplot does not increase linearly with reservoir volume determined from log analysis.)

Figure 6 shows fracture counts (interpreted Lower Dakota plus interpreted Upper Dakota) from borehole image logs versus the best of 12-months production indicator. Note that the largest fracture count occurs in well 28, one of the most productive wells in the unit. This well is considered one of the most significant Dakota discoveries drilled in the area.

Figure 7 shows a seismic record section after pre-stack time migration containing wells 30, 31, 55E, and 28. The correlation of the synthetic seismograms computed at each well is excellent. The Lower Dakota seismic section analyzed in this study is between the top of the Encinal Sandstone ENSS horizon (blue) and top of the Morrison MRSN horizon (yellow). Note the varying seismic response associated with the Dakota-Morrison unconformity (yellow). All seismic attributes used in this report are computed from data within the Lower Dakota interval except for the interval velocity seismic attributes. The latter attributes were computed for an interval near the first positive reflection (Lower Cubero) above the ENSS horizon (blue) in the Upper Dakota to the first positive reflection (Green Horn) above the DKOT horizon (yellow), top of the Dakota.

Seismic Lineament Analysis

Lower Dakota lineaments are interpreted from azimuth dependent and all azimuth seismic attribute volumes. Seismic attributes include azimuth dependent and all azimuth instantaneous amplitude, frequency, phase, coherency, pre-stack time migration, and difference attributes (one azimuth attribute subtracted from another azimuth attribute separated by 90 degrees). Seismic attribute volumes were computed roughly along, and perpendicular to, the same preferred azimuths that the seismic lineaments themselves have, namely, N 10 degrees E, N 55 degrees E, N 100 degrees E, and N 145 degrees E (each azimuth +/- 22.5 degrees).

Figures 8a and b and Figures 9a and b show seismic lineaments in both horizontal (a) and vertical (b) cross section for seismic coherency and instantaneous frequency attributes. The lineaments are most easily seen in horizontal cross section.

Our interpretation is that the seismic lineaments may correspond to fracture zones in the reservoir. The highly fractured Dakota reservoir section is quite noticeable in geologic outcrop. Probably one of the most outstanding outcrops showing Dakota fractures is along the eastern Rocky Mountain Front Range near Morrison, Colorado (Ghist, 2003, Figure 10). Many of the Dakota fracture orientations in these outcrops are about in the same orientation as the seismic lineaments mapped in the San Juan Basin.

Figure 11 shows a composite map of all seismic lineaments interpreted in the Lower Dakota in the gas unit. Only seismic lineaments that were observed in two or more different seismic attribute volumes were mapped. The application of separate pre-stack time migration for each azimuth dependent seismic volume increases spatial resolution enhancing our ability to accurately map seismic lineaments. The rose diagrams in Figure 11 show borehole breakout in three wells indicating present day tectonic stress in roughly a north-south direction. This orientation of tectonic stress does not preferentially close any fractures oriented in the northeast or northwest directions. Both fracture orientations should be available for fluid or gas flow. (However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.) Note the concentrated number of lineaments found at well 28, one of the most prolific wells in the unit.

Lower Dakota lineament density (Figure 12) assuming a well drainage area or pixel size of about 900 sq ft is computed from the lineaments in Figure 11. The hotter colors indicate potentially fractured reservoir showing nine different lead areas (A through I) in the unit. Notice a number of other leads could be distinguished from a closer analysis of the seismic lineament map itself (Figure 11) from any anomalous clusters of multi-directional or intersecting lineaments. Rose diagrams in Figure 12 show Lower Dakota fracture orientations interpreted from borehole image logs. Considering the different scales of information between the well data and the seismic image, the agreement in orientation between fractures measured in wells and orientation of seismic lineaments is quite good.

Figure 13 defines fracture-related reservoir anisotropy on three different scales of information,

1. A localized scale from borehole image data,
2. A field level scale from seismic lineaments, and
3. A regional scale from Dakota production trends (after Head, 2001).

Inferred fracture orientations from all three scales of data are in excellent agreement illustrating a classic "fractal-like" dependence of the data at different scales.

Additionally, the swarming effect of many of the seismic lineaments mapped in the unit is associated with structural troughs and noses mapped in the Lower Dakota depth converted seismic structural map (Figure 14). A similar correspondence is seen in the Gaussian curvature map (Roberts, 2001, Figure 15). Lower Dakota structure appears to play a strong role in lineament orientation. More accurate results from seismic curvature attributes may be obtained from raw, un-smoothed structural maps (Blumentritt, Sullivan, and Marfurt, 2004, and Blumentritt, Sullivan, and Marfurt, in press).

Fractured Reservoir Prospecting

Upgrading Seismic Lineament Leads

Any lead areas defined by the seismic lineament mapping must be further screened using appropriate reservoir attributes. Several different reservoir attributes are considered, Lower Dakota thickness / isopach, channel imaging from Lower Dakota seismic horizon slices, and collocated co-kriged Lower Dakota clay volume. The first two are important attributes; however, clay volume has been found to be one of our main reservoir parameters for prospect development. A data driven approach is used. We try to identify leads that have similar reservoir attributes as the significant unit wells (28, 31, and 55). In summary, our analysis of primary reservoir quality attributes evaluated in the study includes reservoir thickness, channel stratigraphy, and clay volume.

Seismically corrected Lower Dakota thickness or isopach map (Figure 16). The significant unit production is located to the south and west on the edge of the thickest portions of Lower Dakota deposition, i.e., along a paleo-channel. However, notice that the thickest part of the Lower Dakota in the isopach map has not yet been tested by pre-1999 drilling.

Channel images from seismic coherency horizon slices (e.g. Figure 17). This seismic coherency horizon slice displays Encinal fluvial channel stratigraphy at about 8 ms above the MRSN (Figure 7). Note the excellent agreement of channel geometry ("C") shown in the horizon slice with Lower Dakota isopach thickness. Some of the best wells in the unit are found on the edge of this channel image (Table 2). Thinner strata associated with the channel edge may be more prone to fracturing. For the most part, the main portion of this channel has not yet been tested by pre-1999 drilling.

Collocated co-kriged Lower Dakota clay volume (Figures 18, 19a and b). This is one of our main attributes for prospect development. In Figures 19a and b, a seismic guided Lower Dakota clay volume map based on petrophysical analysis of log data from 9 wells is shown. Seismic guided mapping was done using collocated co-kriging using the average near-trace instantaneous seismic amplitude from a narrow zone 3 ms thick in the Lower Dakota (correlation coefficient 0.81, Figure 18). Similar results are seen for a zone thickness about twice as thick. Near-trace seismic offsets should include offsets of about 2000 ft to 6000 ft. The AVO horizon defining this zone is the same Lower Dakota horizon used to define the phase gradient AVO attribute described later in the paper. This horizon is near the MRSN event (Figure 7). Both the phase gradient and the near-trace instantaneous amplitude are AVO attributes.

The best gas producing wells and consequently most prospective areas are associated with wells having low clay. We interpret that reservoir rock having low clay content should be more brittle, and more likely to fracture. Furthermore, clays typically have high water content increasing the likelihood of a clay-rich reservoir being water-wet. Two distinct rock types are defined by the clay volume map, low clay (less than 13 percent) shown by hot colors and high clay (greater than 13 percent) shown by cooler colors. Figure 19b shows Lower Dakota clay volume, seismic lineaments, and lead areas (A through I, Figure 12). If we focus our attention only to low clay reservoir we eliminate all lead areas except for leads A, B, and D.

The empirical relationship of the instantaneous amplitude attribute and clay volume has not been confirmed by seismic modeling (Figure 18). Additional work should be done with full wave equation modeling to analyze the observed relationship. The crossplot in Figure 18 should only be used to divide the data into low and high clay cluster groups or rock types to define prospective trends for low clay reservoir prone to fracturing.

Notice that the directional distribution of seismic lineaments also supports the rock type definition (low clay versus high clay). Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction and high clay rocks are associated with lineaments in the northwest direction. The regions of highest lineament density are also found in low clay rocks. It is not surprising that the two rock types have differing distributions of lineaments. Fractures in these two rock masses are controlled by their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses, and how the two rock masses interact with each other during their tectonic stress history. This interpretation could be tested by modeling the state of stress underground using a finite element or finite difference method. We would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

A similar result to the clay volume map is seen in the seismic inversion. Figure 20 shows a Lower Dakota acoustic impedance horizon slice at about 10 ms above the MRSN (Figure 7) computed from a constrained seismic inversion from about 5 wells. Prospective sandstone fluvial channel pay (typically, effective porosity between 8-14 percent) is defined by an impedance range of about 31,000-36,000 g/cc-ft/ms (Figure 21), red colors. Effective porosities greater than about 15 percent (about 30,650 g/cc-ft/ms) tend to be water-wet (Figure 4). Brittle and fracture-prone lithologies are interpreted to be associated with high impedance values, hot colors.

Gas Prediction Seismic Attribute / Phase Gradient AVO Attribute

We cannot underestimate the importance of a seismic attribute to help predict gas saturation. Just as reservoir fractures can increase the drainage area of a gas productive well, they also can provide a plumbing system to aquifers for the reservoir to become water saturated. This is probably quite common for the Dakota; because of complex stratigraphy, water charged zones can be found both above and below gas bearing zones.

In Figures 22a and 22b, normal move out corrected ~ 25 fold super gathers (after pre-stack time migration) are extracted for significant gas producers, wells 55, 28, and 31 (Figure 22a) and are also extracted in regions of high clay for poor producing wells 47, 15, and 30 (Figure 22b). Note the Lower Dakota class 2 AVO anomaly near the base of pay / top of Morrison Formation (Castagna, et al., 1998). A class 2 AVO anomaly typically exhibits a low amplitude near offset response, and a phase reversal, with increased amplitude at far offsets (Figure 23). It is important to carefully process the seismic data to true amplitude and to a consistent wavelet to properly interpret the AVO response.

Figures 22a and 22b also show results from a Dakota AVO model computed using dipole sonic and density logs from well 47 (Castagna, et. al., 1998). Comparison of the modeled response of the AVO anomaly in the Lower Dakota to the AVO supergather from the field data at well 47 is excellent (Figure 22b). Lower Dakota gas saturation averages about 23 percent in this well.

We interpret that the characteristic differences between the AVO gathers at each of the endpoints, gas producing wells versus high clay/poor producing wells, are typically distinguishable and diagnostic (Figures 22a and 22b). In the stack domain the gas bearing AVO endpoint is often associated with a ~ trough whereas the poor producing AVO endpoint is often associated with a ~ peak near the MRSN event. An interpreter could easily classify most of the seismic volume for potential gas producing targets and eliminate potential clay rich poor producing regions on a gather by gather basis. In this study, we accomplish the same task through development of a new automatic computer driven routine to seek typical gas bearing class 2 AVO anomalies. We define a new AVO attribute known as the phase gradient (stacked near-trace phase minus stacked far-trace phase). Near-trace and far-trace seismic offsets should include offsets of about 2000 ft to 6000 ft and 6000 ft to 10,000 ft, respectively. The phase gradient may tend to be insensitive to seismic amplitude increasing its utility for land seismic data often difficult to correct to true amplitude.

After reviewing the supergathers at each well showing the AVO anomaly, a special AVO horizon is interpreted through the Lower Dakota to compute the AVO attribute. (This is the same Lower Dakota horizon used earlier to compute near-trace instantaneous seismic amplitude for clay mapping and is near the MRSN event, Figure 7.) The crossplot in Figure 24 shows Lower Dakota phase gradient computed for this horizon versus gas saturation. The outlying wells with gas saturations less than 24 percent have Lower Dakota clay contents greater than 13 percent. The red trend line (correlation coefficient 0.89) is based on the remaining five wells that have clay contents less than or equal to 13 percent, and gas saturations greater than 24 percent. Note that three of these five wells (28, 55 and 31) are among the most productive wells in the unit, and are associated with a phase difference range between -15 to -85 degrees. We interpret that the phase gradient is sensitive to both clay volume and gas, whereas the near-trace instantaneous amplitude, computed from a zone along the AVO horizon, is mainly sensitive to clay (Figure 18).

In Figure 25a a seismic phase difference map for values between -15 to -85 degrees is shown. Two trends shown by the prospective fairway that correspond to regional Dakota production are indicated in the northwest and northeast directions. Figure 25b shows seismic phase difference values between -15 to -85 degrees with estimated clay contents less than a cutoff of about 13 percent, near trace instantaneous seismic amplitude less than 20,000 (Figure 18). The yellow/dark regions in this map show areas of brittle fracture prone rocks having favorable AVO attributes. Also notice that more favorable AVO/gas attributes (dark color) are typically found regionally on the updip side of the map in the fairway (Figure 14). The well 55E is not in the prospective fairway which collaborates with its poor completion results (Table 3). The fractures at this well may have been responsible for providing a plumbing system for water to get into the reservoir. It is also interesting that the phase difference maps both with and without clay editing are very similar. In a spatial sense, it appears that the clay constraint is nearly automatically applied by constraining the AVO attribute to -15 to -85 degrees. Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon (Figure 17). (This is near where the gas is!) The interpretation should provide additional information as to the role of channel stratigraphy and trapping mechanism.

Figure 26 shows seismic guided Lower Dakota gas saturation computed from the new phase difference attribute with estimated clay content less than roughly 13 percent. Seismic guided mapping was done using collocated co-kriging and the empirical red trend line (phase difference vs. gas saturation, correlation coefficient 0.89) in Figure 24. Gas saturations between about 33 - 60 percent define a prospective fairway for Lower Dakota fracture controlled gas production in the unit. The lower end gas cutoff (33 percent) comes as a result of the petrophysical analysis shown in the hydrocarbon pore volume versus porosity thickness and best of 12-months of production (Figure 5). The high-end gas cutoff (60 percent) comes from the petrophysical analysis of the significant unit wells (Figure 24, well 55). Note that a model switching routine could be used to map gas saturation through the higher clay rocks by passing an empirical trend line through the high clay cluster in the crossplot (Figure 24).

The empirical relationship of the seismic phase difference attribute and gas saturation has not been confirmed by seismic modeling. Additional work should be done for full wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 26 should only be used to divide the data into gas producing and non-producing reservoir to define prospective trends for gas production.

Let us test our new computer routine to find positive gas bearing class 2 AVO attributes similar to those near well 28. The near Lead A (AVO 1) and Lead B (AVO 2) locations have phase difference attributes or a computed "gas saturation" nearly identical to those near well 28 (Figures 25b and 26), indicating similar AVO characteristics. AVO supergathers computed for well 28 and at the AVO 1 and AVO 2 locations are indeed very similar (Figure 27). It appears our computer routine has done an excellent job selecting drill locations (wells 52 and 28E). In practice, it is recommended the AVO attributes should be reviewed in the common midpoint (CMP) gathers before any prospect is drilled to further confirm the phase gradient mapping has selected a location with positive gas bearing class 2 AVO attributes.

In summary, the phase gradient attribute shows all three significant wells in the unit as gas bearing. It also explains the poor results of the nearby 55E well (Table 3). This well is not located in the gas bearing prospective fairway. It is worth mentioning that the low and high clay rock types (good versus poor reservoir quality) in the Lower Dakota are described by four different but integrated seismic attributes:

1. Near-trace instantaneous seismic amplitude (Figures 18 and 19b),
2. Acoustic impedance (Figure 20),
3. Seismic lineament density and orientation (Figures 12 and 19b), and
4. Phase gradient / AVO characteristics (sensitive to both clay and gas, Figure 24).

These seismic attributes fully collaborate to confirm and unify the rock typing in the interpretation.

Upper Dakota Fracture Density

Figure 28 shows a seismic guided Upper Dakota fracture density map modeled from Dakota fracture counts as measured from borehole image logs for 5 wells. Fracture density mapping is done using collocated co-kriging using interval velocity anisotropy. Interval velocity anisotropy is computed as Dix's interval velocity for 145 +/- 22.5 degree azimuth data minus the interval velocity for 55 +/- 22.5 degree azimuth data (Dix, 1955).

The increase in signal to noise ratio obtained by pre-stack time migration greatly improves our ability to do velocity analysis. Dix's interval velocities were computed for an interval near the first positive reflection (Lower Cubero) above the ENSS horizon (blue) in the Upper Dakota to the first positive reflection (Green Horn) above the DKOT horizon (yellow), top of the Dakota (Figure 7). This analysis is used to infer prospective Upper Dakota fractures. Figure 29 shows a crossplot of interval velocity anisotropy versus total Dakota fracture counts (interpreted Lower Dakota plus interpreted Upper Dakota, correlation coefficient .61) and was used to model Upper Dakota fracture density or counts. A better correlation coefficient of .99 is obtained if well 47 is considered an outlier and the characteristic curve is passed through the origin; however, this response was not used to generate the map.

Note the trend of high interval velocity anisotropy associated with well 28 that may be associated with fractures. Other prospective regions of possible high fracture density are also seen to the northeast of well 28 at the AVO 2 location. This anomalous interval velocity anisotropy may correspond to fractured reservoir potential up hole in the Upper Dakota.

The orientation of the Upper Dakota interval velocity anisotropy is of interest. If the anisotropy is related to natural fractures, the map indicates an abundance of northeast trending fractures (shaded in red). We conclude that northwest trending fractures (shaded in green) simply are not as common as northeast trending fractures. The distribution of fractures in the Upper Dakota in the study area is interpreted to be similar to the distribution of seismic lineaments or fractures in the Lower Dakota. The northwest striking lineaments mapped in the Lower Dakota are associated with the green and light pink colors in the interval velocity anisotropy map (Figure 28), and may correspond to an increase in Upper Dakota fractures in the northwest direction. The darker red areas in the map seem to correspond to the northeast striking lineaments.

Any differences between the Upper and Lower Dakota fracture distributions should be explained by their differing depositional environments and tectonic history. The Upper Dakota are non-marine fluvial-deltaic and marine shoreline sands whereas the Lower Dakota are non-marine fluvial-deltaic and braided channel sands. Each of these units has different rock types, geometries, and tectonic histories that will affect fracture distributions and orientation.

Validation / Blind Wells 48 and 51

During the presentation phase of GeoSpectrum's exploration methodology for fractured Dakota reservoirs, GeoSpectrum learned that Burlington had drilled two “blind wells” (no. 48 and 51) in the gas unit (Table 3). The results of these wells were not used in the exploratory data analysis in this study. Unfortunately, wells 48 and 51 are poor wells. Spotting the wells on the Lower Dakota phase gradient and gas saturation/seismic lineament maps (Figures 25a, 25b, and 26) shows that GeoSpectrum's methodology would not have recommended these locations. Both of these wells are in regions of low gas saturation (poor phase gradient AVO attributes), high clay, and low lineament density.

Prospect Development

A detailed review of seismic attributes is done by overlaying the phase gradient attribute in Figure 25b with the seismic lineaments in Figure 11. A prospective fairway is defined where Lower Dakota gas saturation is about 37 to 62 percent (phase gradient -65 to -15 degrees) and clay volume is less than about 13 percent (near trace instantaneous amplitude less than 20,000). Eleven new drill sites (1-11) situated within the prospective fairway (including the Site 4 primary drill location) are picked from the overlay (Figure 30). Four new locations were selected and drilled, well 28E (Site 1), well 31E (Site 9), well 52 (Site 4) and well 53 (selected by unit operators). Our exploration methodology is successful if economic gas and oil discoveries are found.

Selected Prospects

The three new drill locations (wells 52, 28E and 31E) are chosen to drill on swarming / intersecting lineaments in the prospective fairway (Figure 31). Well 52 tests seismic attributes near the northeast part of the fairway, well 28E tests seismic attributes near the central region of the trends, and well 31E tests seismic attributes near the southwest part of the prospective fairway. The fourth prospect, well 53 is selected to test a swarm of seismic lineaments close to the southwest / central edge of the 3D seismic coverage (Figure 31). However, well 53 does not have favorable AVO and clay volume attributes. GeoSpectrum advised the unit operators that this drill location did not appear to have significant Lower Dakota gas before the well was drilled. The four prospect locations (wells 28E, 31E, 52, and 53) are shown in the constrained phase gradient and seismic lineament map, and a composite seismic attribute map (Figures 31 and 32). All four wells are spotted on or near lineaments or intersection points of the lineaments. (Note that a number of other locations would justify drilling if we relax the reservoir constraints and pick locations based mainly on the gas sensitive phase gradient (AVO) attribute.)

Drilling Results

In 2004, Burlington Resources and Huntington Energy completed the four wells defined by GeoSpectrum's new 3D seismic interpretation method (Table 4). Results indicate a success ratio of nearly 100 percent using the exploration methodology. The well 52 prospect drilled and completed in January 2004 had an initial potential of nearly 4000 MCFGPD and a best of 12-month production estimate of 1652 MCFGPD. The 28E well drilled and completed in May 2004 has a best of 12-month production estimate of 2106 MCFGPD and continues to produce near this rate making it one of the best wells in the unit so far. The 31E well was drilled and completed in June 2004 and has a best of 12-month production estimate of 941 MCFGPD. The fourth well, the no. 53, was drilled and completed in April 2004 and initially produced about 2000 MCFGPD but has a best of 12-month production estimate of 227 MCFGPD. This prospect had favorable seismic lineament (fractured) reservoir attributes, however it did not have good AVO (gas) and clay volume attributes. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon Sandstone, located underneath the productive Encinal Sand found in Lower Dakota wells. It is interpreted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

An additional well (no. 59) was drilled and completed in January 2005. This well is located to the northeast and on trend with productive wells 31E and 52 but in an area of poor seismic (AVO) phase gradient and clay volume attributes (Figures 25a and 25b). As predicted by the new exploration methodology, this new well has a poor estimated best of 12 month production indicator of 231 MCFGPD (Table 4). The reservoir does not appear to contain significant gas.

Figure 33 shows early production histories for 16 wells completed in the unit. Production histories for the prospects (wells 28E, 31E, 52, 53 and 59) are shown in red. Note that the best well in the unit is now the new well 28E. New wells 31E and 52 are also among the better producing wells. The new fractured reservoir exploration technology has nearly doubled the production and value of the gas unit.

The GeoSpectrum Prospect Rating System assigning either a "good," "average," or "poor" grade is illustrated in Tables 3 and 4. The three rating classes are defined as follows:

1. Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
2. Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
3. Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

Table 4 shows the 2004/2005 outstanding drilling results for the four wells spotted using GeoSpectrum's exploration methods. Table 3 shows the results for the last three wells drilled earlier (1998 to 2001) in the same gas unit not using GeoSpectrum's 3D seismic interpretation methods. Note that each of these three wells have poor AVO attributes and modest gas saturation with best of 12-month production indicators less than 350 MCFGPD proving the value of our new technology. The Lower Dakota production results of 16 wells drilled in the unit are all reasonably predicted by the new methodology.

To date, a total of 12 new wells have been drilled in the unit and initiated by this study. Six of these wells were drilled within the 3D seismic survey. Production results from five of these wells (28E, 31E, 52, 53, and 59) were described earlier. The sixth well in the 3D seismic survey (no. 63) was completed in February 2006 in the northwest corner and near the boundaries of the 3D survey. This well appears to be a poor producing well. The analysis of the drilling and production results of this prospect have not been completed.

CONCLUSION

A new 3D seismic interpretation methodology for fractured reservoir exploration has been developed for conventional P-wave seismic data. An automatic picking routine using a new phase gradient AVO attribute is used to find gas bearing reservoir. Seismic rock types defined by clay content are identified to interpret brittle reservoir rock prone to fracturing. Seismic lineament mapping in the reservoir zone is used to predict fracture zones.

The three productive unit wells (28, 55 and 31) and the new prospect wells (28E, 31E, 52, and 53) completed in 2004, appear to be predicted with nearly 100 percent success using a new method to explore for Lower Dakota gas.

Prospects are developed where:

1. Lower Dakota Clay content from seismic rock typing is less than or equal to about 13 percent,
2. Lower Dakota phase gradient (AVO) attributes indicate a phase difference between -15 to -85 degrees (corresponding to gas saturation of about 37 to 62 percent),
3. Intersecting or swarming Lower Dakota seismic lineaments are present, and
4. Fractured reservoir potential in the Upper Dakota may be interpreted from Upper Dakota interval velocity anisotropy.

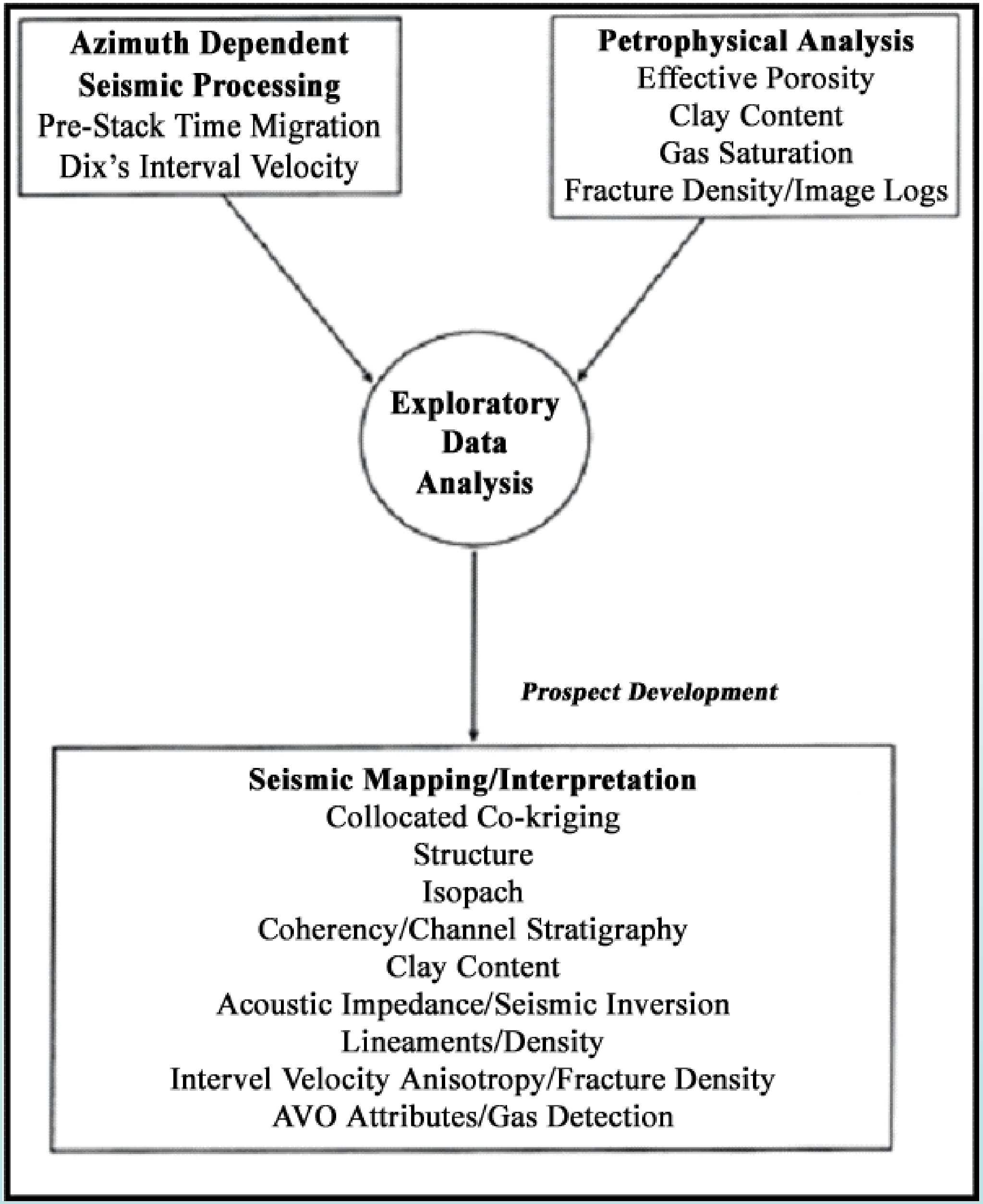
We interpret that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the four prospect wells and the economic discovery of gas in three prospects (wells 28E, 31E, and 52) and the predicted result of the poor producing prospects (wells 53 and 59) validates the results of our U. S. Department of Energy study. The results of 16 wells in the unit are reasonably explained by the interpretation methodology. These drilling results confirm the value of GeoSpectrum's applied methodology in detecting commercial and prospective targets in fractured tight gas sands.

Future work should include an automated approach to map seismic lineaments and to apply the new technology.

ACKNOWLEDGMENTS

Most of the funding for the study came from the U. S. Department of Energy, the gas unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations provided by the operators, their employees, and associates. Dakota play geology was abstracted from the Burlington Resources Prospect and Well files by Roger Smith and portions included in this report, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, and Mark Gygax prepared many of the graphics used in our publications. The Prospect Rating System was recommended by Dr. John Reeves, Jr. Dr. Emilio Mutis-Duplat and many others in the oil and gas industry have reviewed and improved the quality of this report with their questions and comments. Hoxie Smith assisted in preparation of the original project proposal, review of project reports and papers, and contract administration. Dr. James J. Reeves, the Principal Investigator, designed and managed all technical work and research resulting in the new 3D seismic interpretation methodology, prospect development, and drilling plan. Dr. Reeves is the primary author of the original technical project proposal and all technical project reports and publications. A special thanks is extended to all the technical societies and publishers, including the American Association of Petroleum Geologists, Balkan Geophysical Society, GasTIPS, Insight Information, Permian Basin Geophysical Society, Petroleum Development of Oman, Saudi Aramco, Society of Exploration Geophysicists, Society of Petroleum Engineers, Strategic Research Institute, West Texas Geological Society, World Oil, and others, who have published our technical project papers and results, some of which have been reprinted in whole or in part in this final report. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

Prospect Development Methodology



Unit Well Statistics to Develop 3D Seismic Interpretation Method for Fractured Tight Gas Reservoirs
Lower Dakota Reservoir Attributes

Modified Unit No.	Mcfpd Best-12	Cum. Mcf	Spud	LD Sg	Clay	LD Natural Fractures	Borehole Breakout	Lineament Density	Anisotropy Fractures	Impedance g/cc-ft/s	Coherency*
28	1710	2,046,590	8/95	44%	8%	10	E-W closed	9	4 to 13	34-36k	edge
55	710	865,505	12/93	60%	3%	?	?	5	-5 to 4	30-32k	edge
31	502	724,408	5/94	39%	13%	?	?	6	13 to 23	34-36k	edge
48	116	?	12/98	?	?	?	?	5	-14 to -23	34-36k	edge
27	105	81,633	9/95	41%	10%	8	?	2	4 to 13	32-26k	in
47	73	74,168	9/95	21%	18%	1	E-W closed	5	-5 to 4	28-36k	edge
30	66	19,339	8/95	10%	17%	1	No Observ.	3	-5 to 4	32-36k	out
55E	48	31,173	12/97	25%	9%	2	E-W closed	7	-5 to 4	36-38k	edge
15	45	37,212	5/94	13%	14%	?	?	4	-5 to 4	32-34k	out
41	33	44,649	6/73	3%	16%	?	?	1	-5 to 4	24-26k	out

*** Location with respect to Lower Dakota channel ~ 8 ms above MRSN**

GeoSpectrum

Table 2

Drilling Results Not Using GeoSpectrum's Recommendations
1998 to 2001

Well No.	Date Crompleted	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
55E	05/1998	Good	Low	Poor	Good	48	Poor
48	04/1999	Good	Low	Poor	Good	195	Poor
51	10/2001	Poor	Low	Poor	Excellent	346	Poor

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

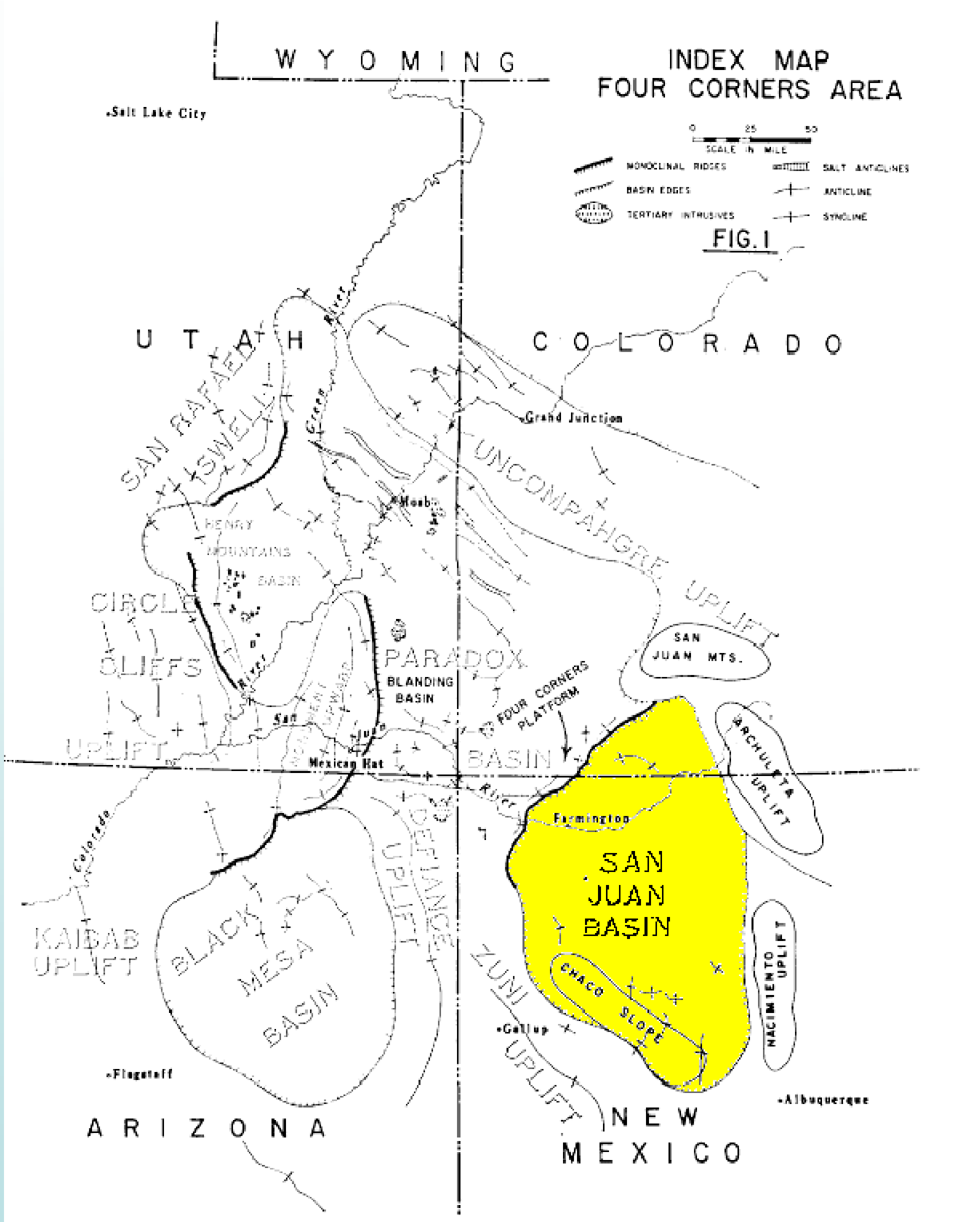
Conclusions / Prospect Drilling Results 2004/2005

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average
59	04/2005	High	Low	No AVO Attribute	Low	231 (Est.)	Poor

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

Regional Map of 4 Corners Area



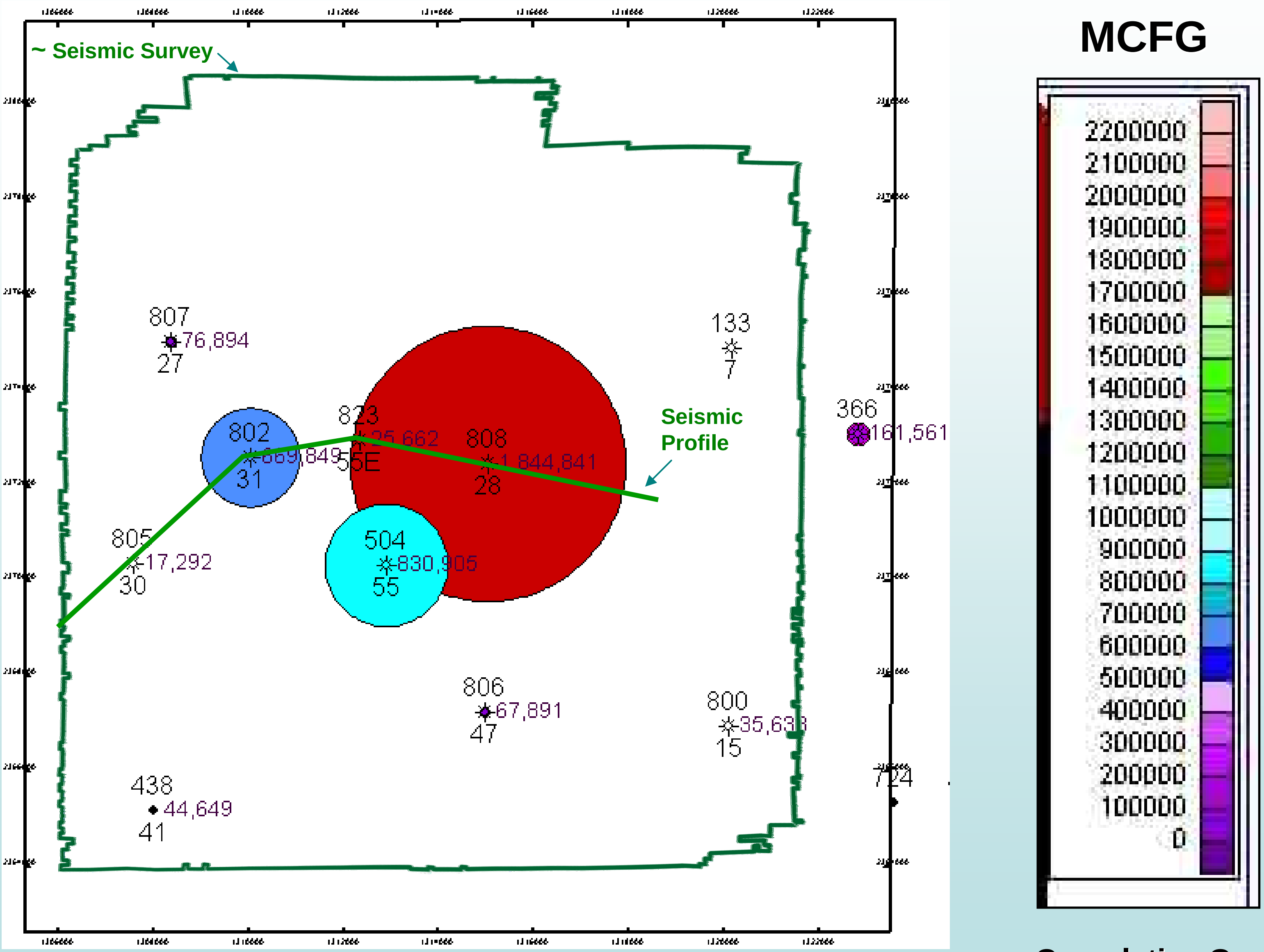
After James A. Peterson, et al (1965)

GeoSpectrum

Figure 1

Base Map / Dakota Gas Production

Outline of ~ Seismic Survey

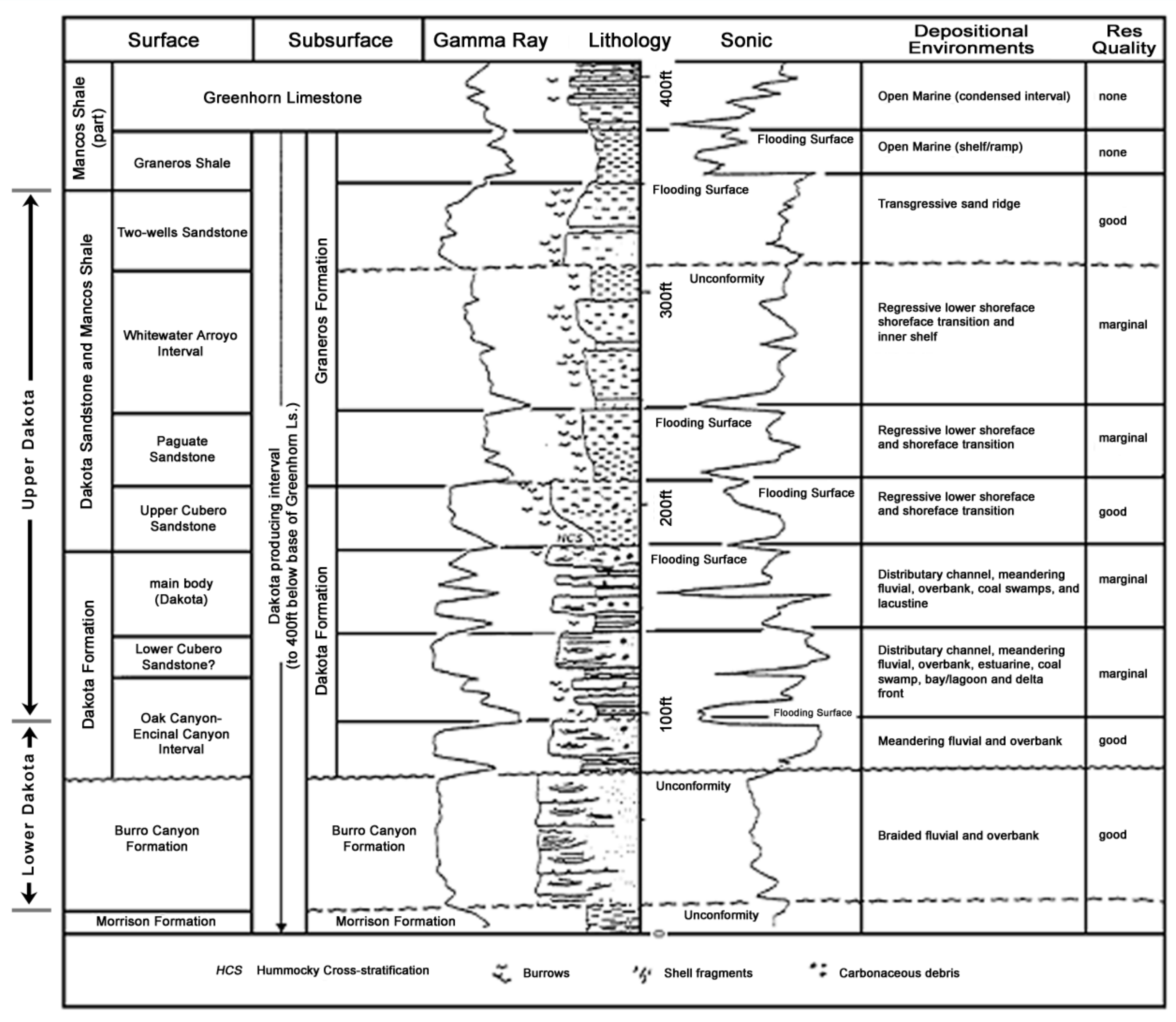


Cumulative Gas

GeoSpectrum

Figure 2

Dakota Type Log

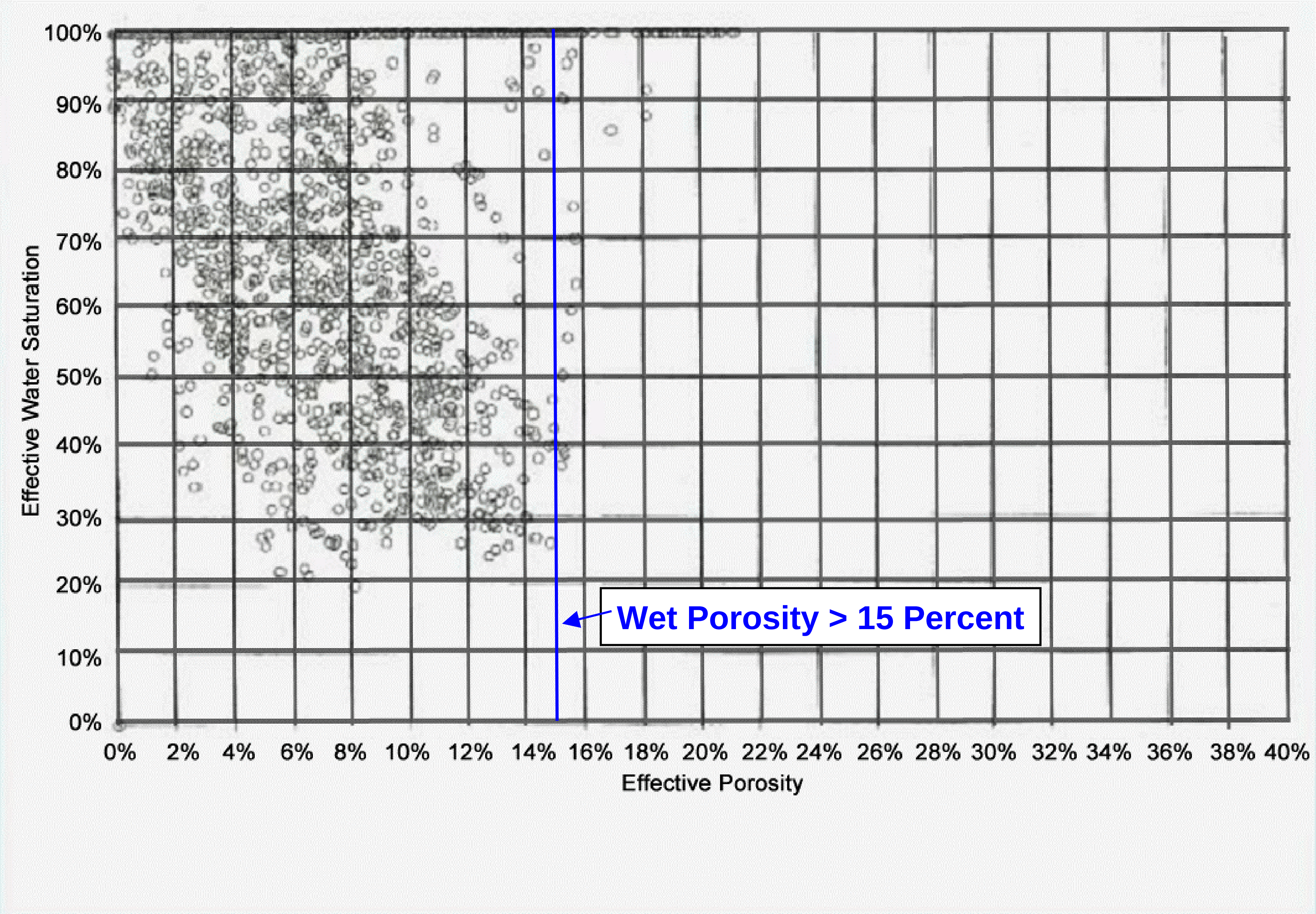


GeoSpectrum

(After Whitehead, 1993)

Figure 3

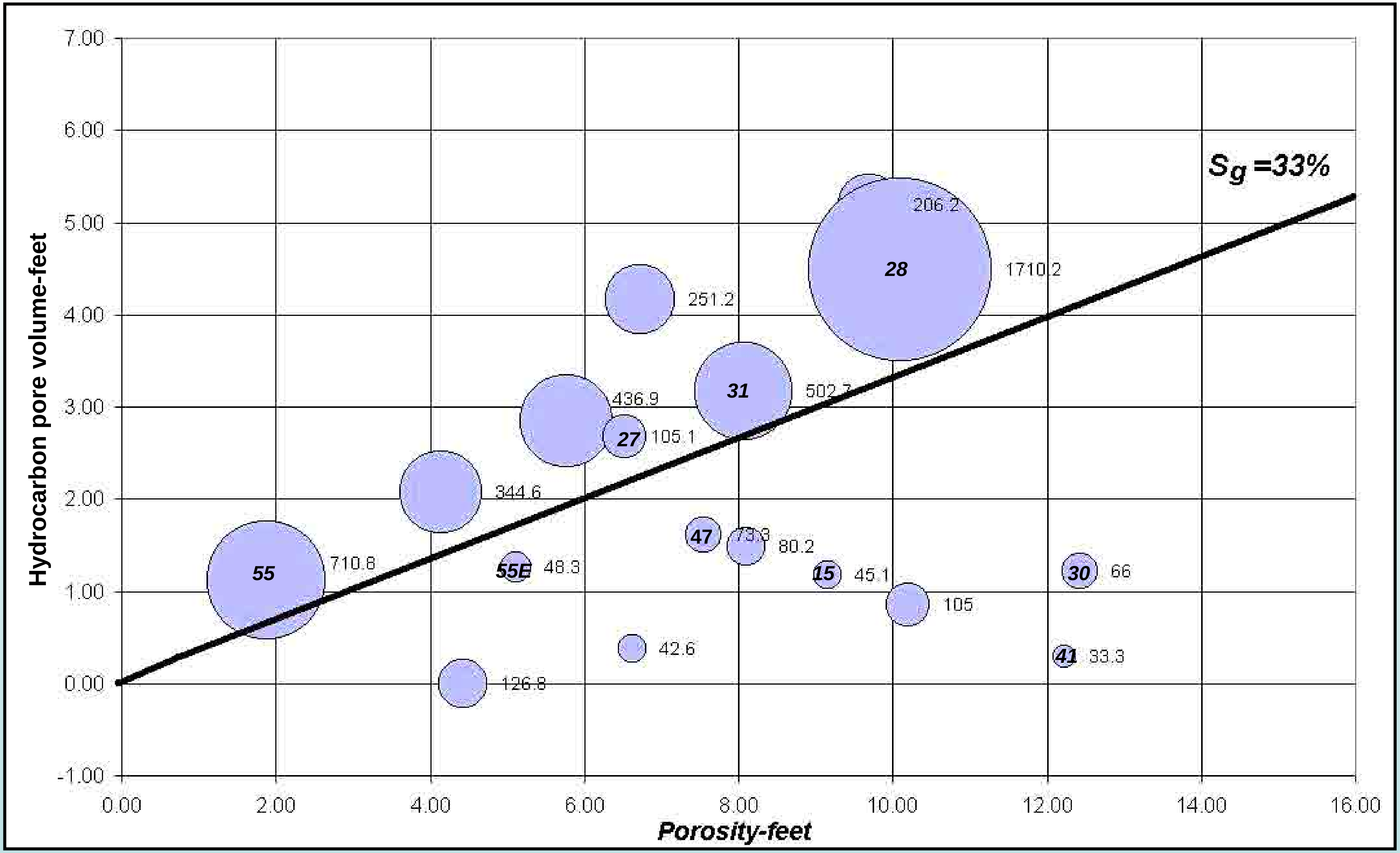
Dakota Effective Water Saturation vs. Effective Porosity



GeoSpectrum

Figure 4

Lower Dakota Hydrocarbon Pore Volume vs. Porosity-Thickness

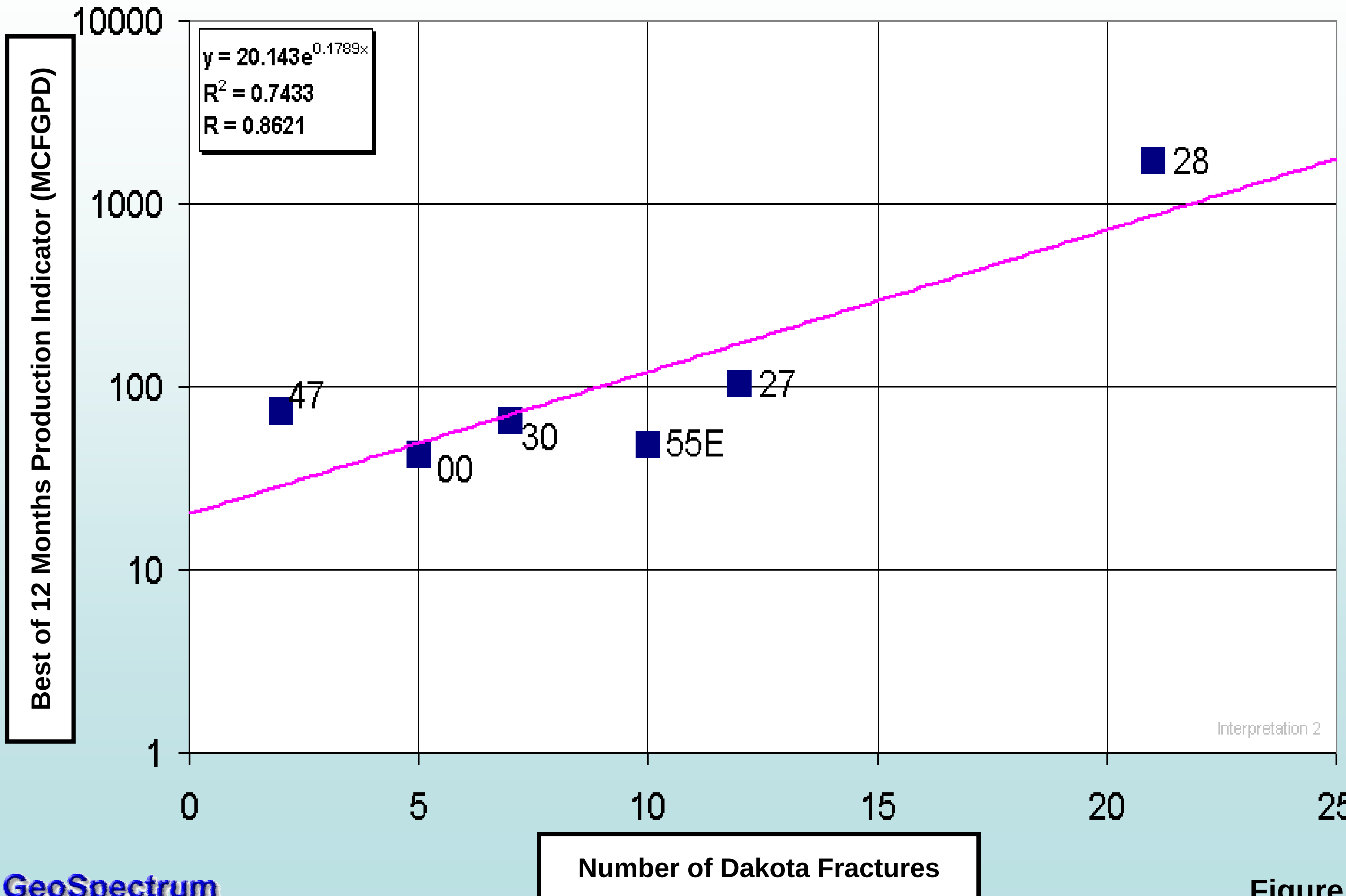


Bubble size is best of 12-months production

GeoSpectrum

Figure 5

Number of Dakota Fractures vs. Best of 12 Month Production Indicator

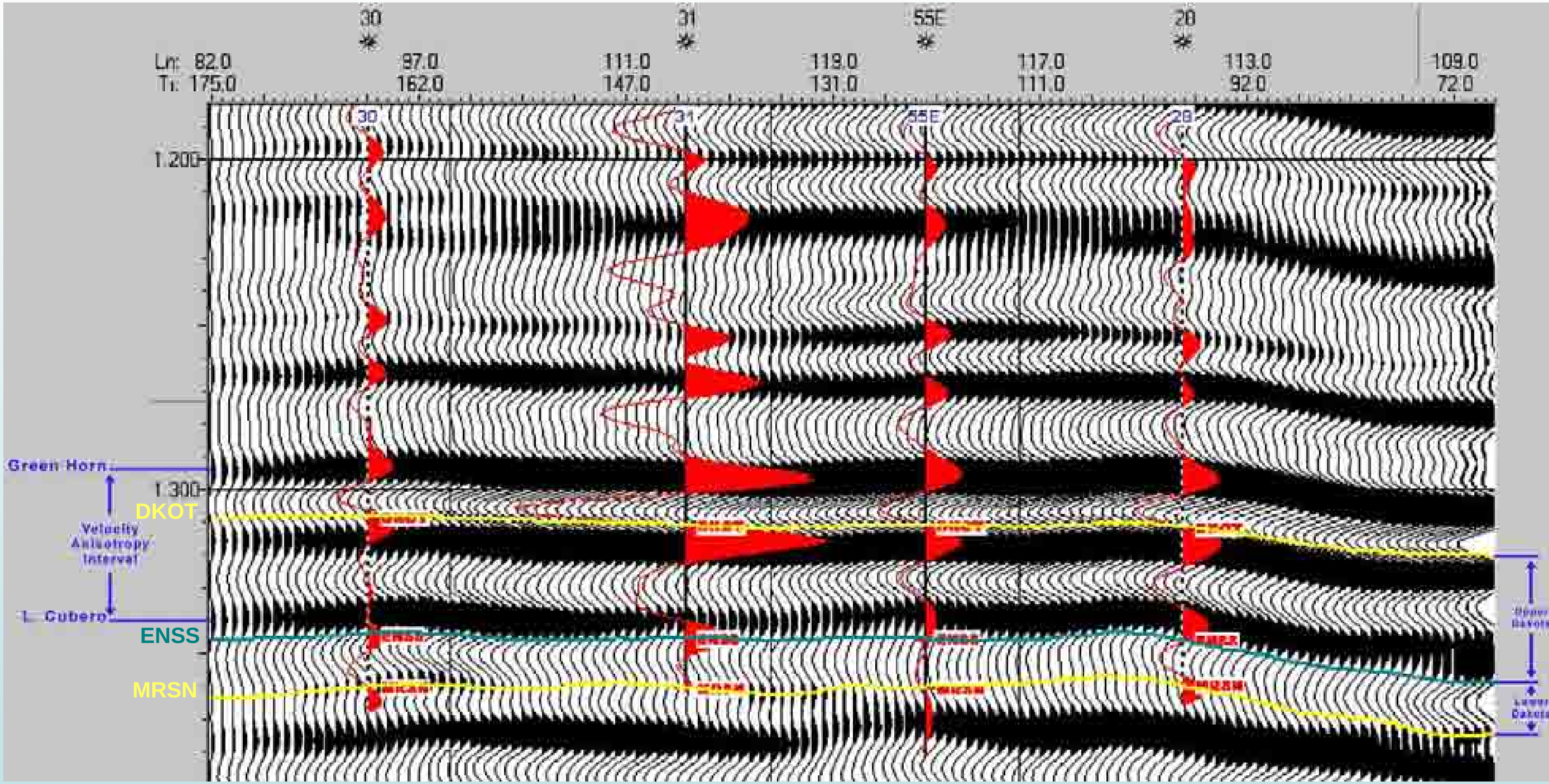


GeoSpectrum

Figure 6

Crooked Seismic Line Sample after Prestack Time Migration

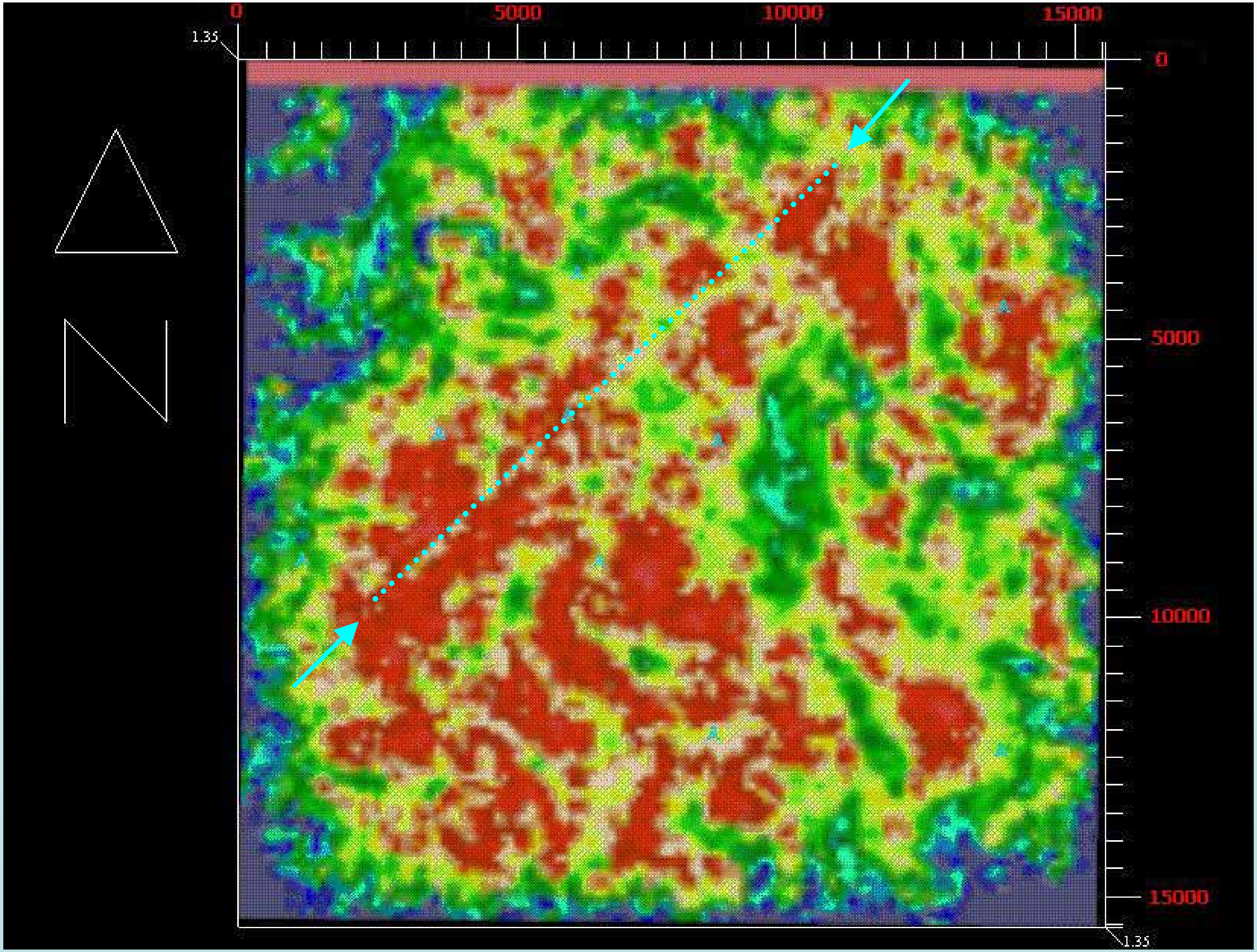
Synthetic Seismograms (Red)



GeoSpectrum

Figure 7

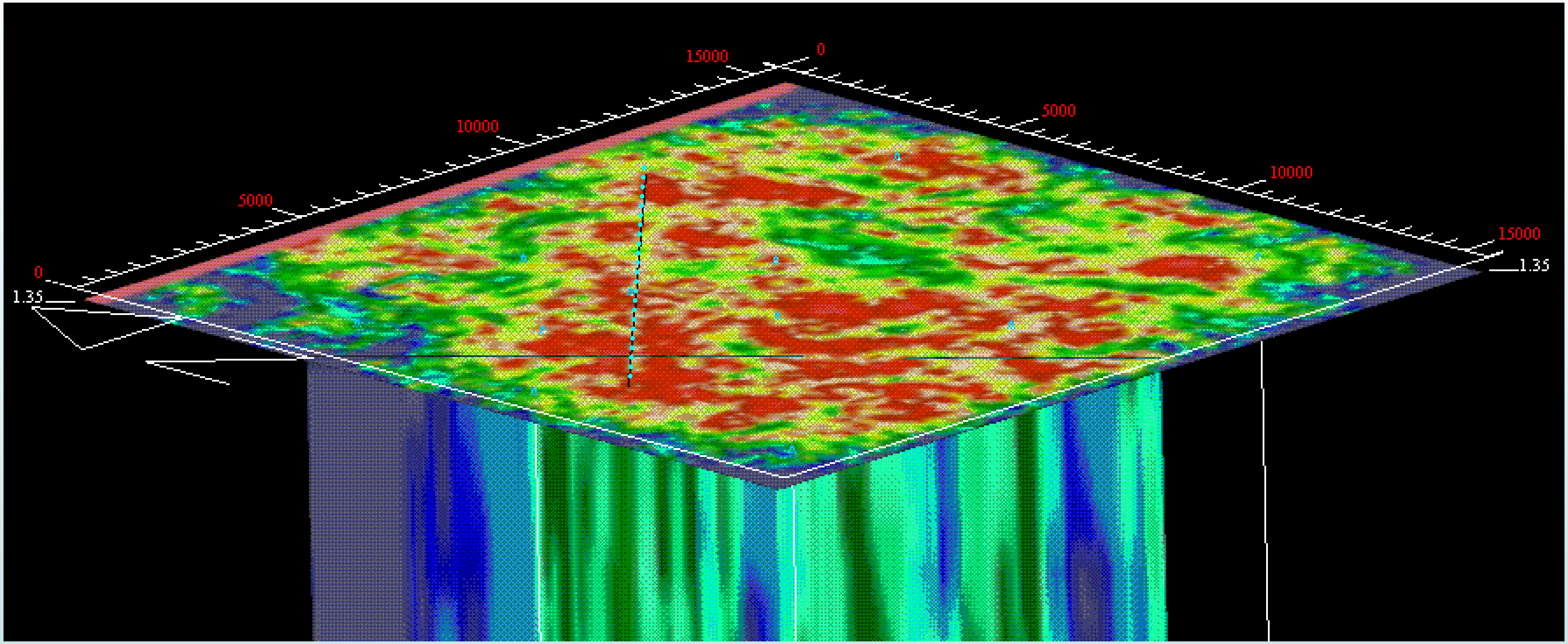
Lineaments in Seismic Section
Lower Dakota Coherency Slice at 1350 ms



GeoSpectrum

Figure 8a

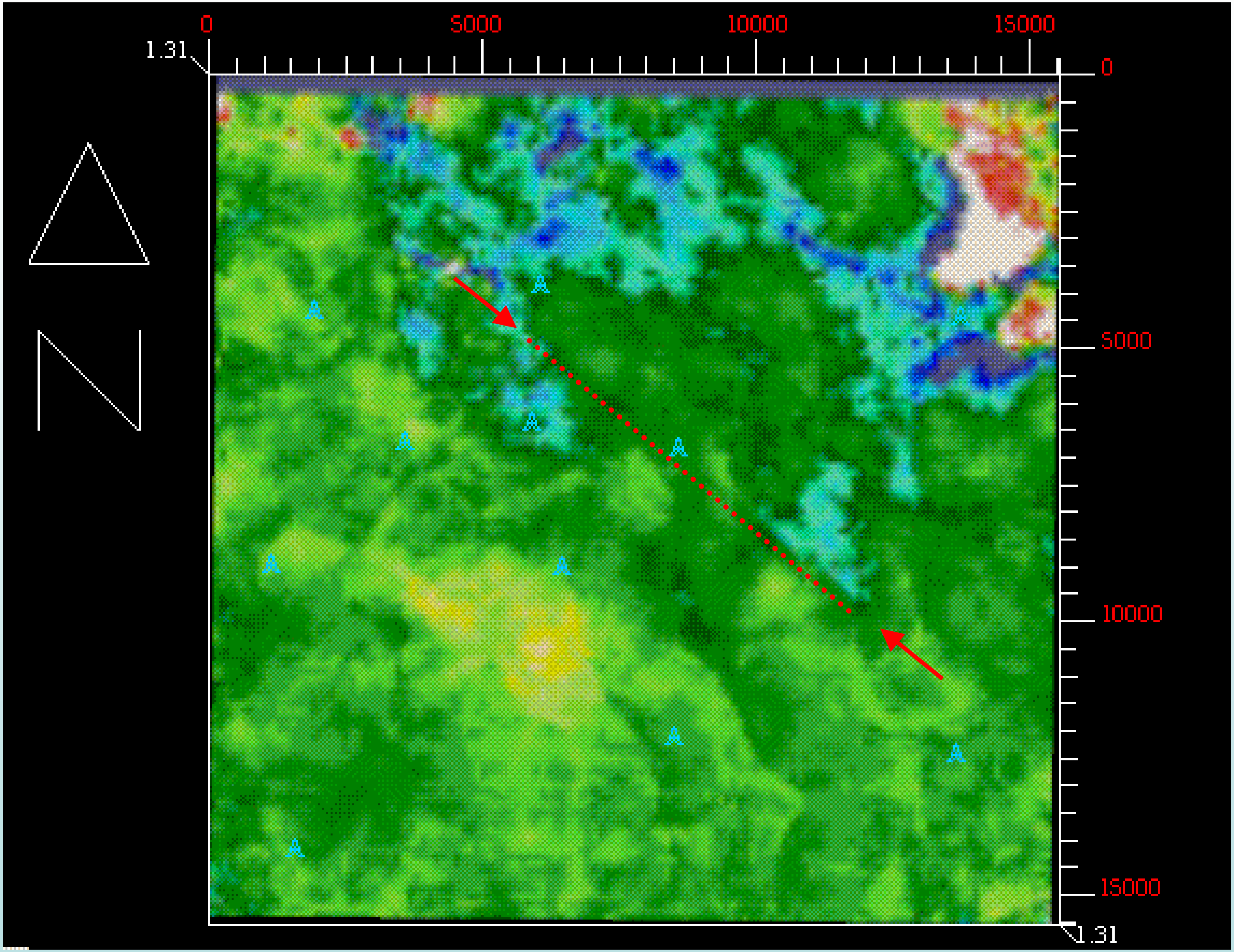
Lineaments in Seismic Section
Lower Dakota Coherency Slice at 1350 ms (3D View)



GeoSpectrum

Figure 8b

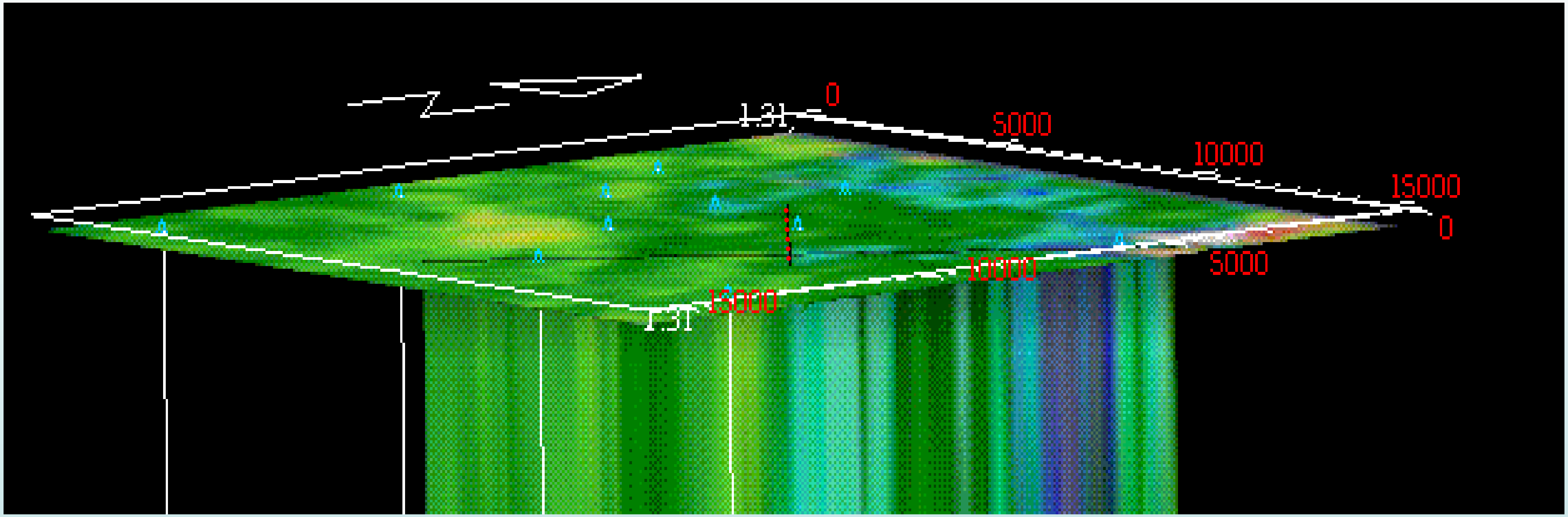
Lineaments in Seismic Section
Upper Dakota Instantaneous Frequency at Timeslice 1308 ms



GeoSpectrum

Figure 9a

Lineaments in Seismic Section
Upper Dakota Instantaneous Frequency at Timeslice 1308 ms (3D View)



GeoSpectrum

Figure 9b

Dakota Outcrop Fractures
Dinosaur Ridge Near Morrison, Colorado

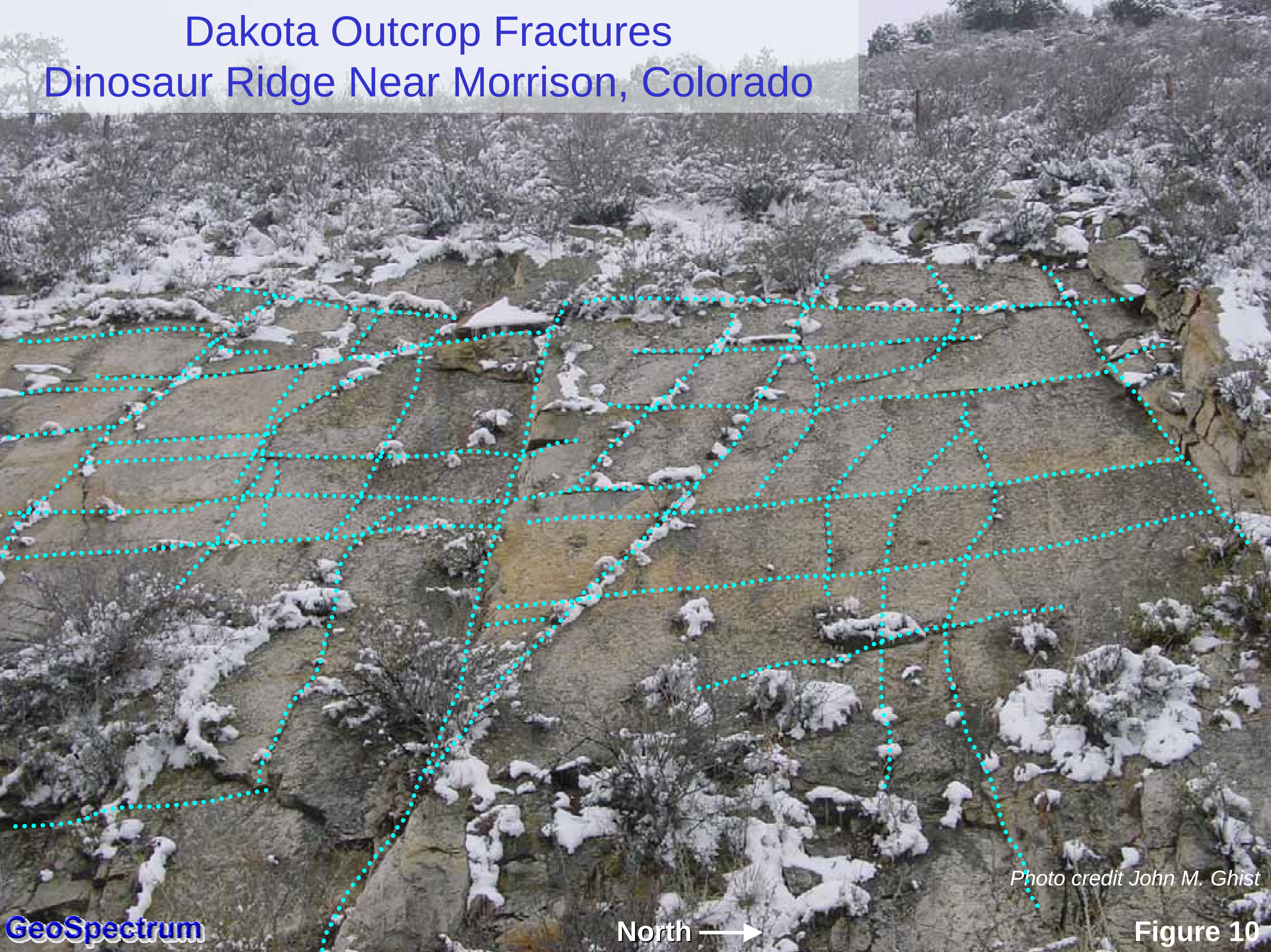
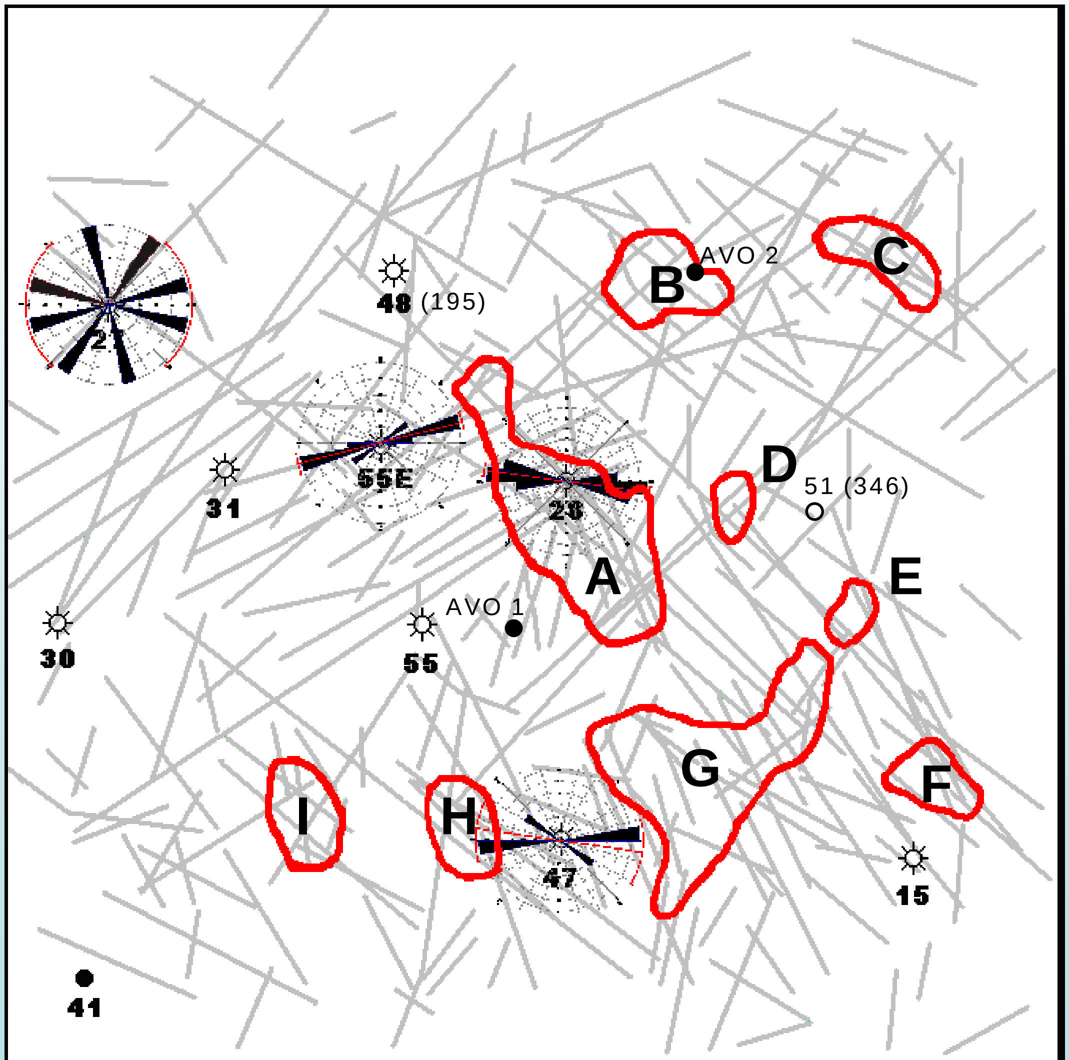


Figure 10

Lower Dakota Seismic Lineaments

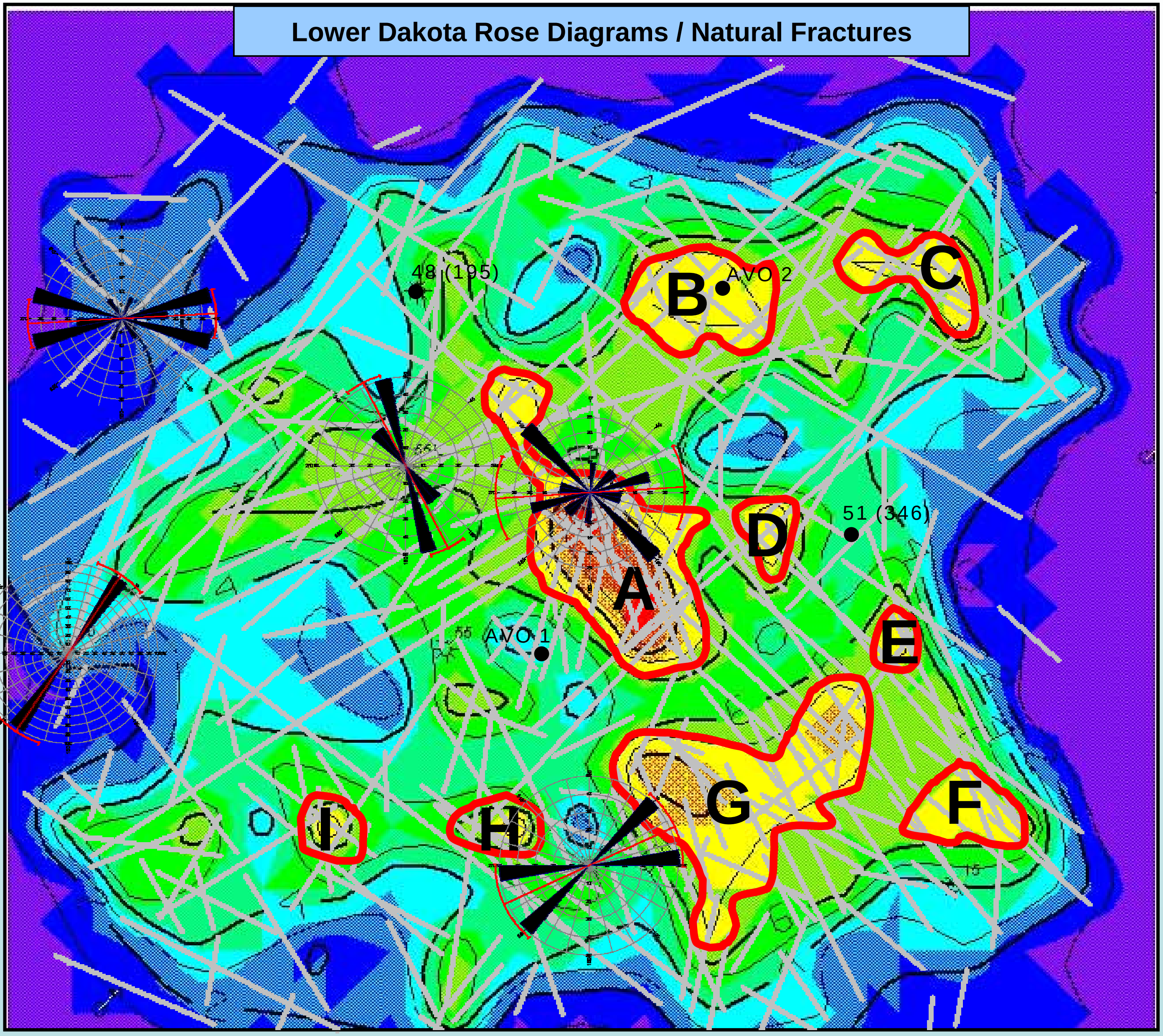
Showing Dakota Borehole Breakout Rose Diagrams

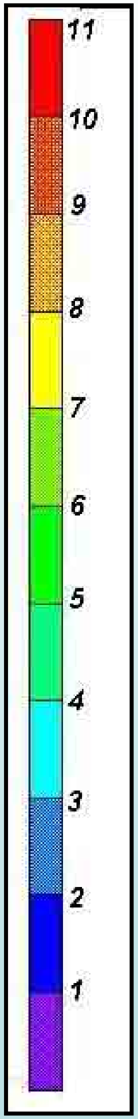


GeoSpectrum

Figure 11

Lower Dakota Seismic Lineament Density





900 x 900 ft Grid

GeoSpectrum

Figure 12

Multiple Scales of Observation

<u>Dakota Production Trend</u>

Regional Scale

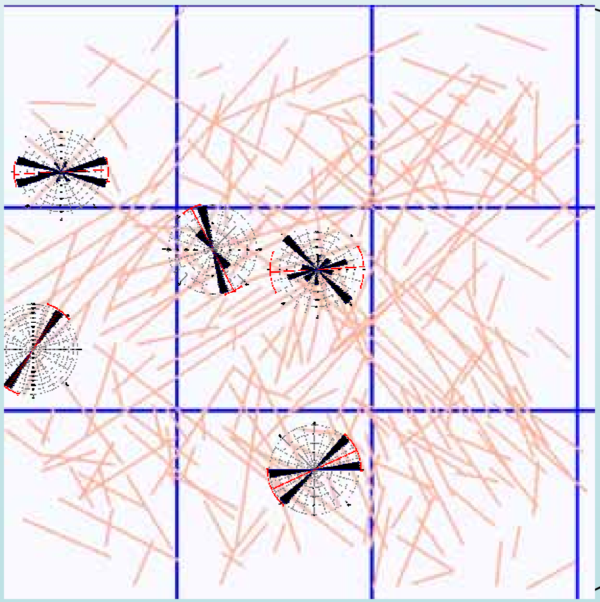
<u>Lower Dakota Seismic Lineaments</u>

Field Level Scale

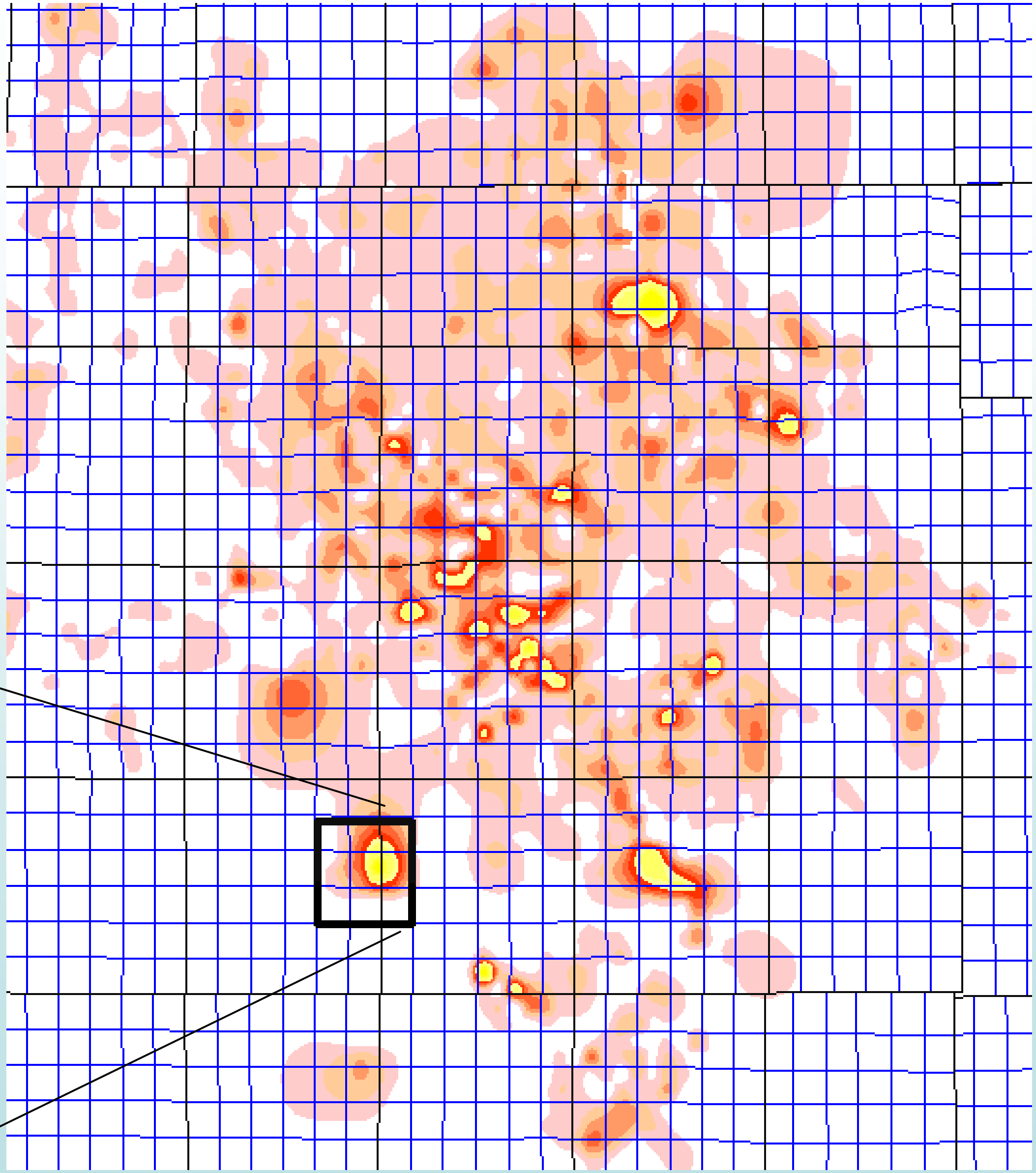
<u>Lower Dakota Borehole Image Data</u>

Rose Diagrams / Natural Fractures

Localized Scale



Lower Dakota Seismic Lineaments With Lower Dakota Rose Diagrams / Natural Fractures



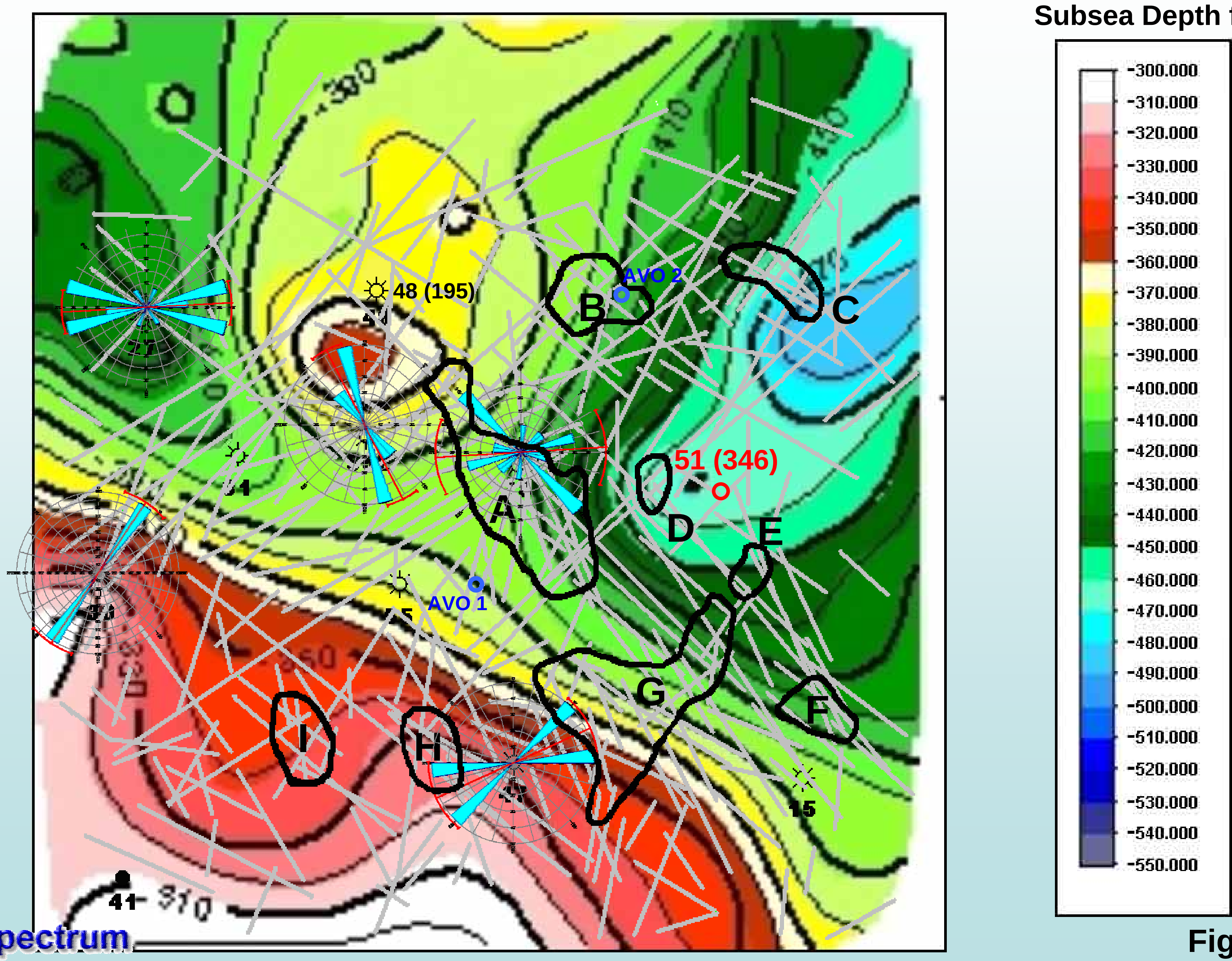
Dakota Production Mapping (*after C. F. Head, June 2001*)

GeoSpectrum

Figure 13

Lower Dakota Seismic Structure

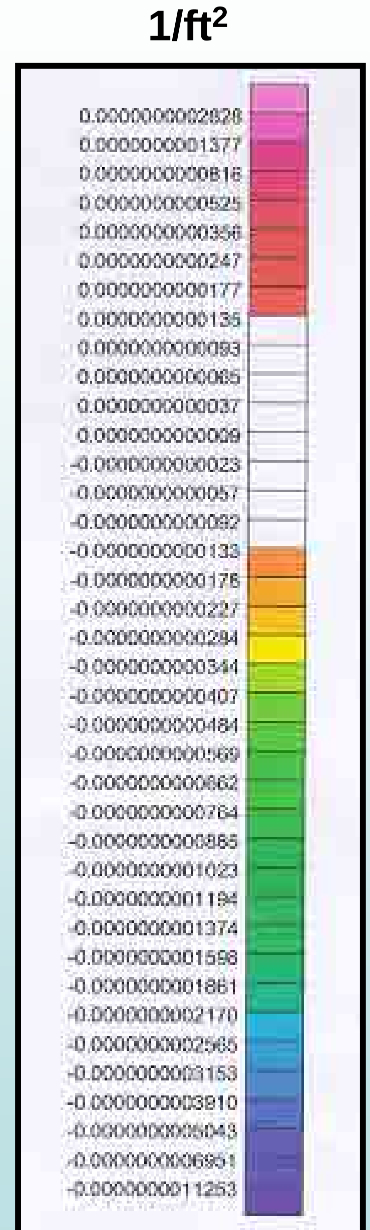
Showing Lower Dakota Rose Diagrams / Natural Fractures and Seismic Lineaments



GeoSpectrum

Figure 14

Top of Lower Dakota Gaussian Curvature

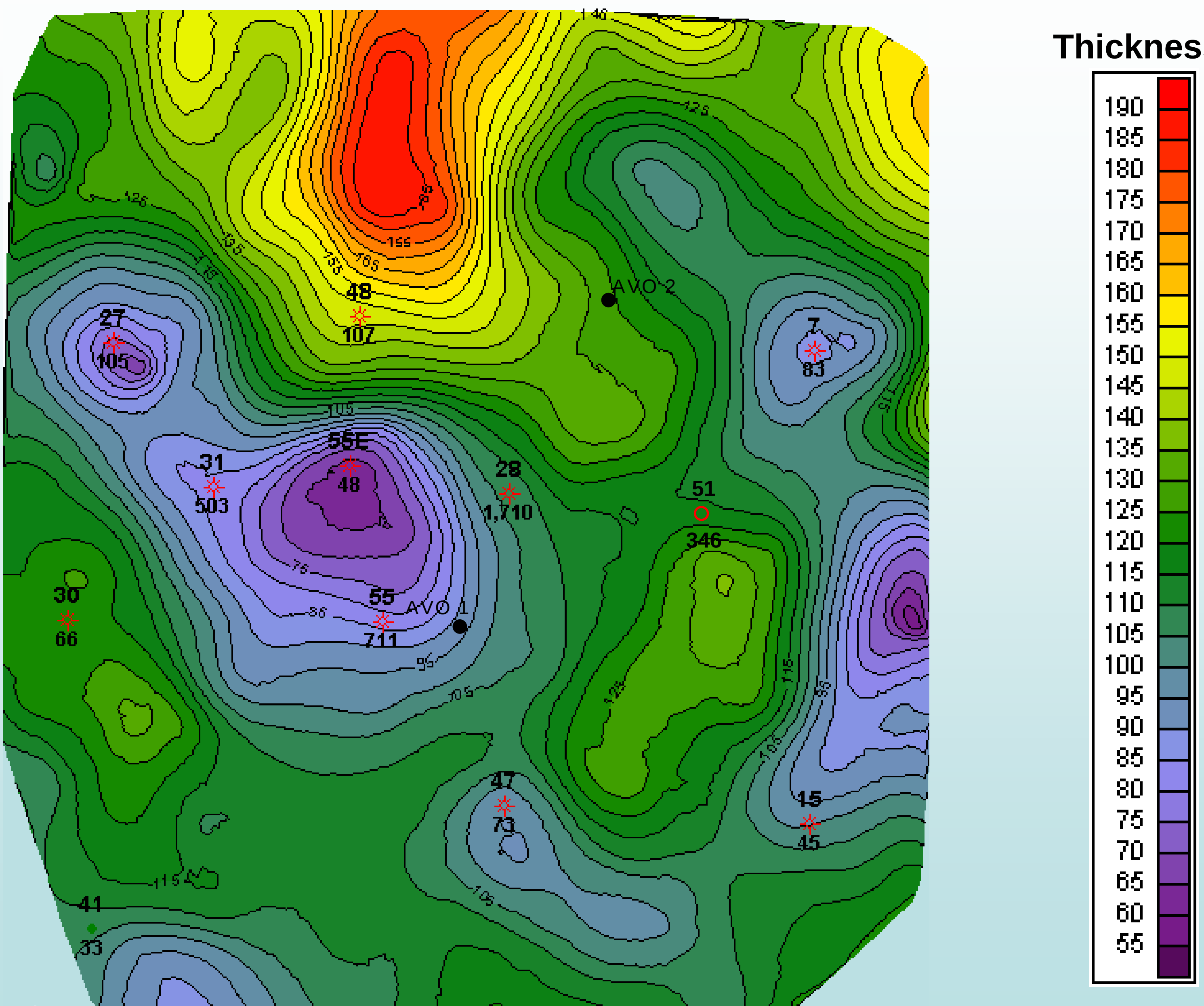


GeoSpectrum

Lower Dakota Rose Diagrams / Natural Fractures

Figure 15

Lower Dakota Seismic Isopach

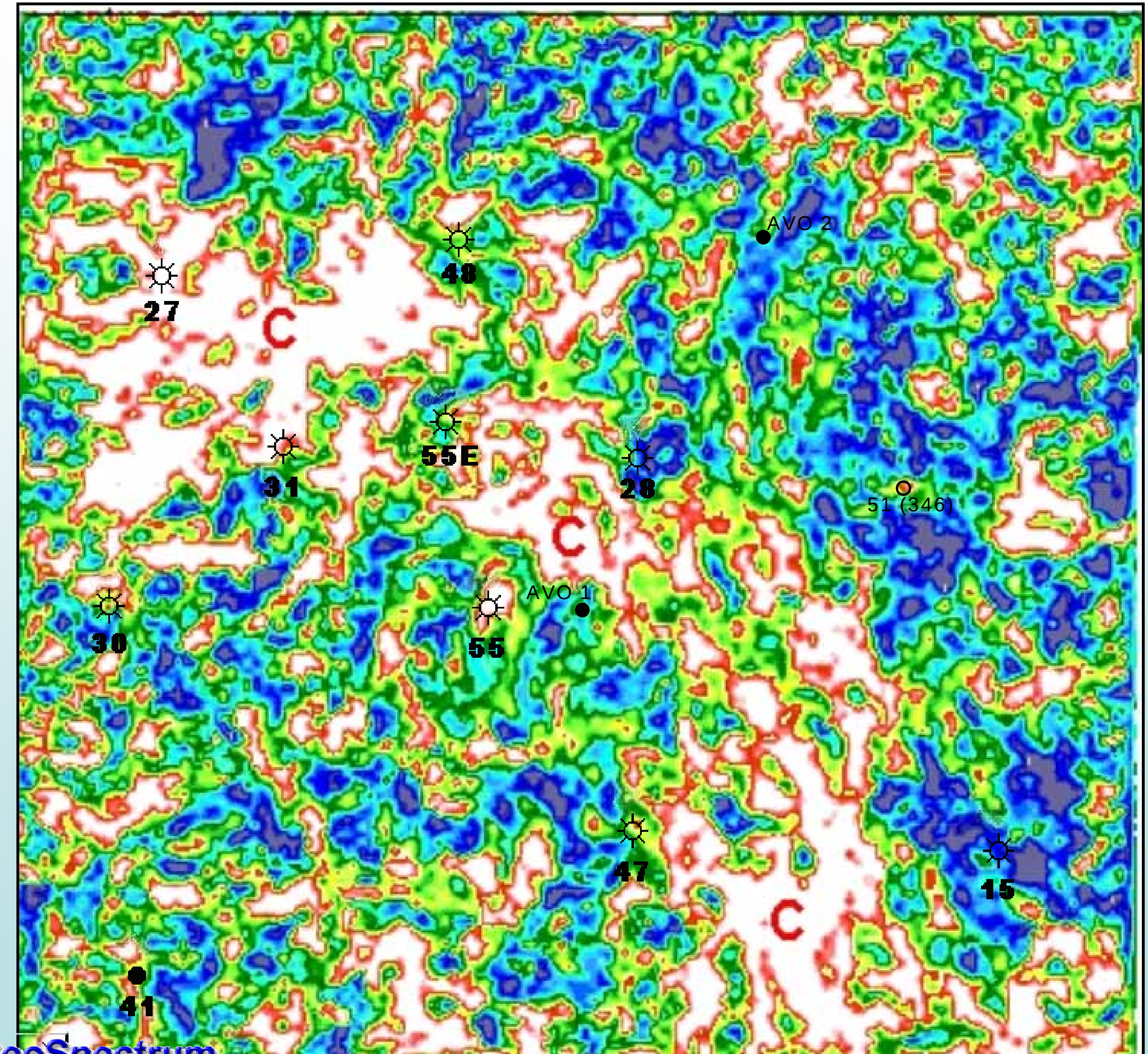


GeoSpectrum

Figure 16

Lower Dakota Seismic Coherency / Channel "C" Stratigraphy

Horizon Slice ~ 8 ms above MRSN



Coherency

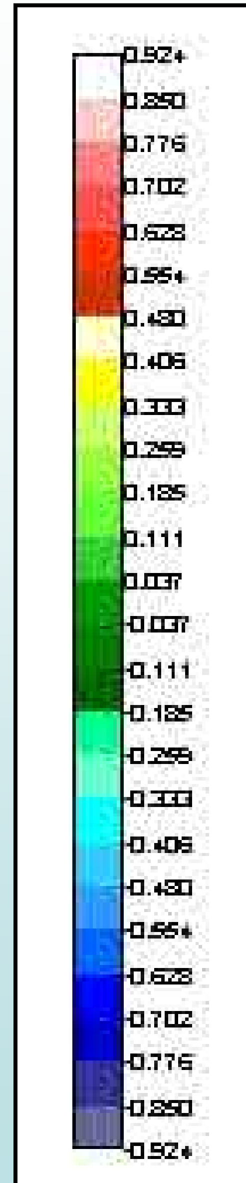
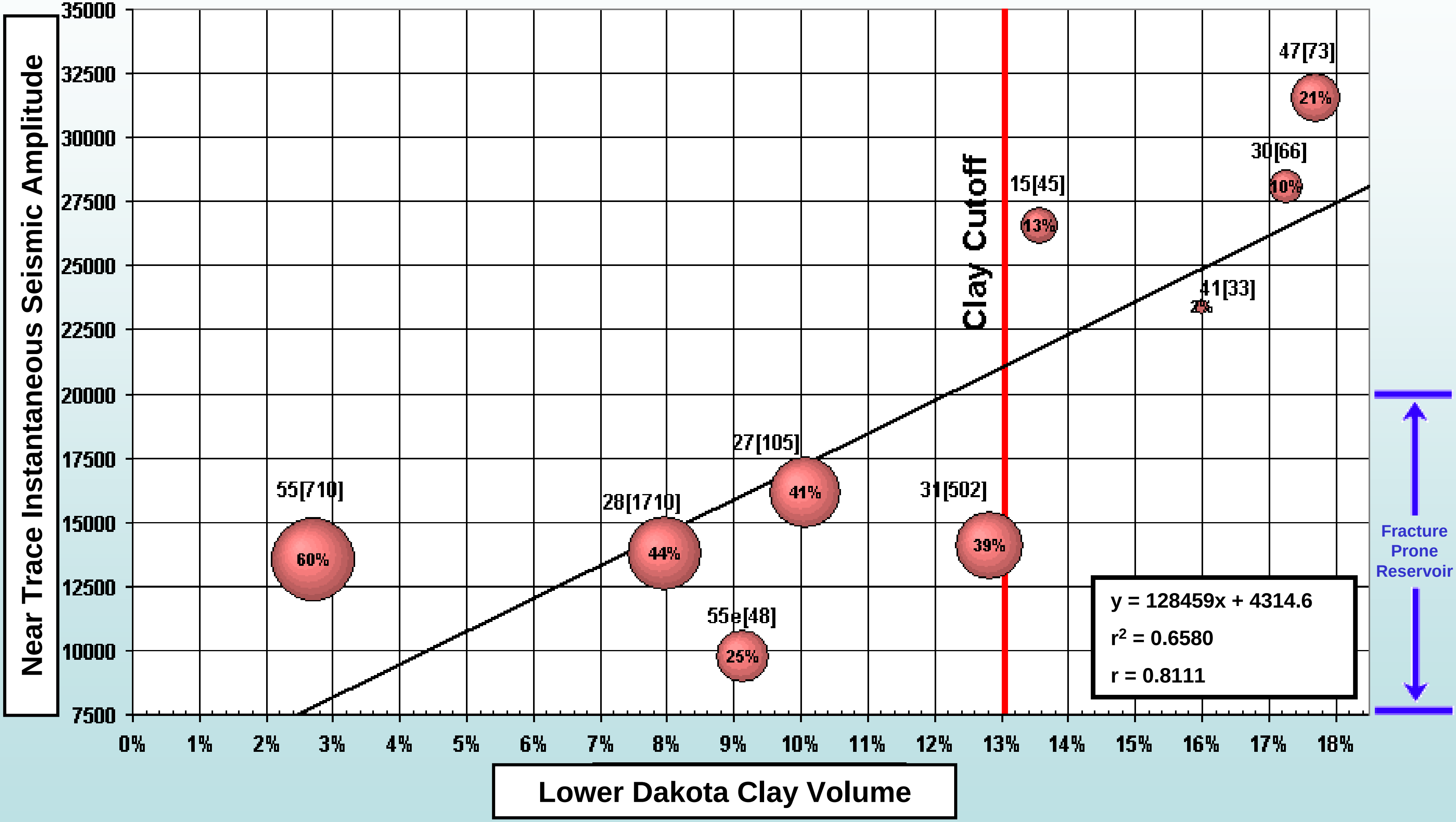


Figure 17

Lower Dakota Clay Volume vs. Average Near Trace Instantaneous Seismic Amplitude (with Sg Bubbles)

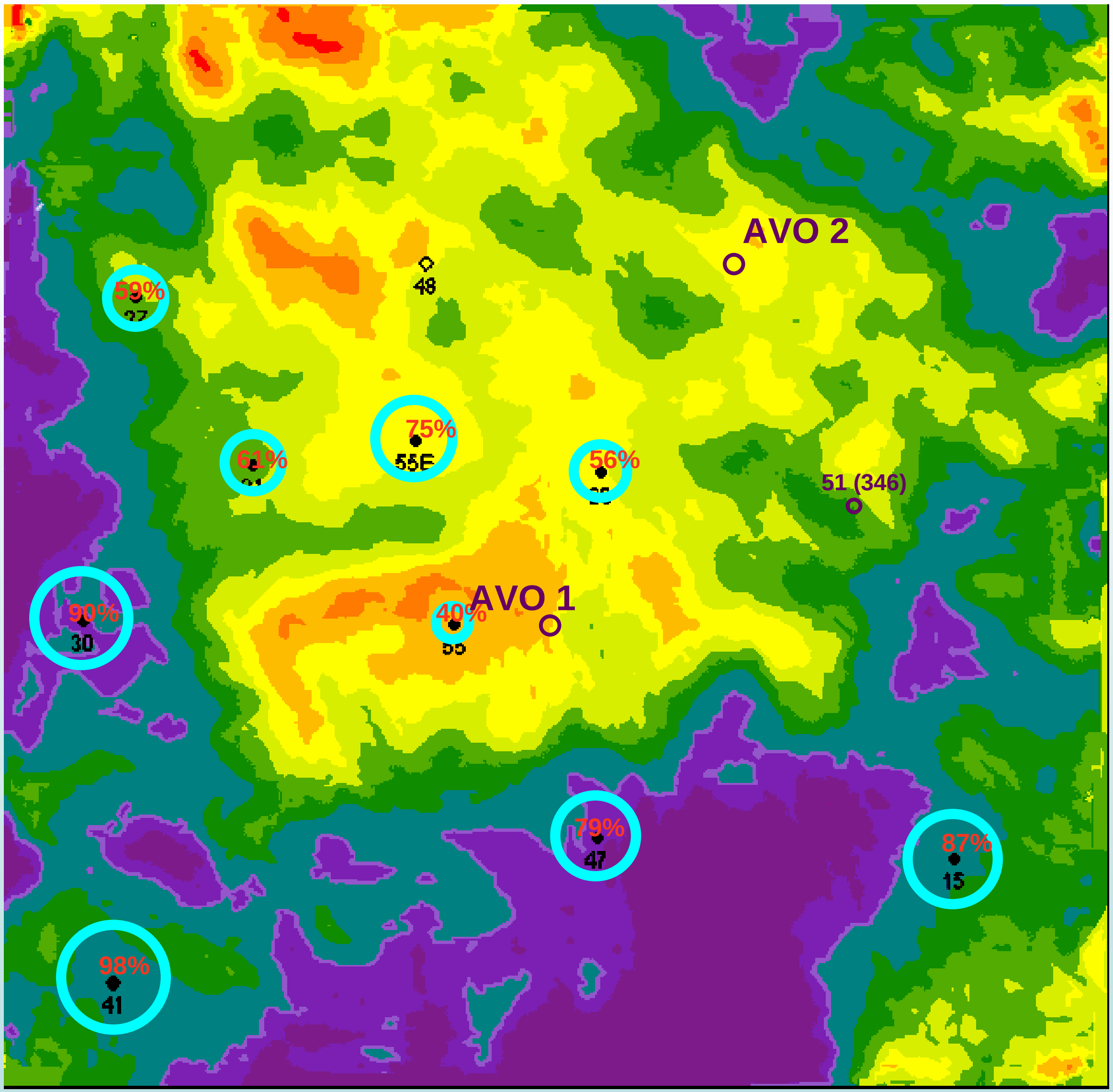
Lower Dakota Average Amplitude for a Zone 3 ms Thick Near MRSN

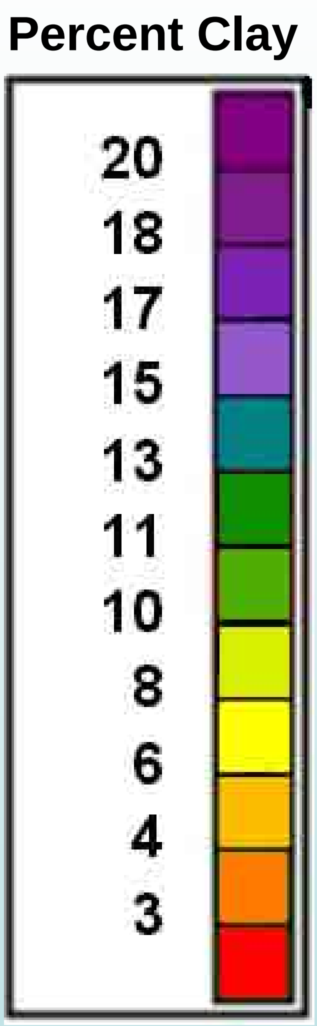


GeoSpectrum

Figure 18

Lower Dakota Co-located Co-kriged Clay Volume (with Average Sw Bubbles)





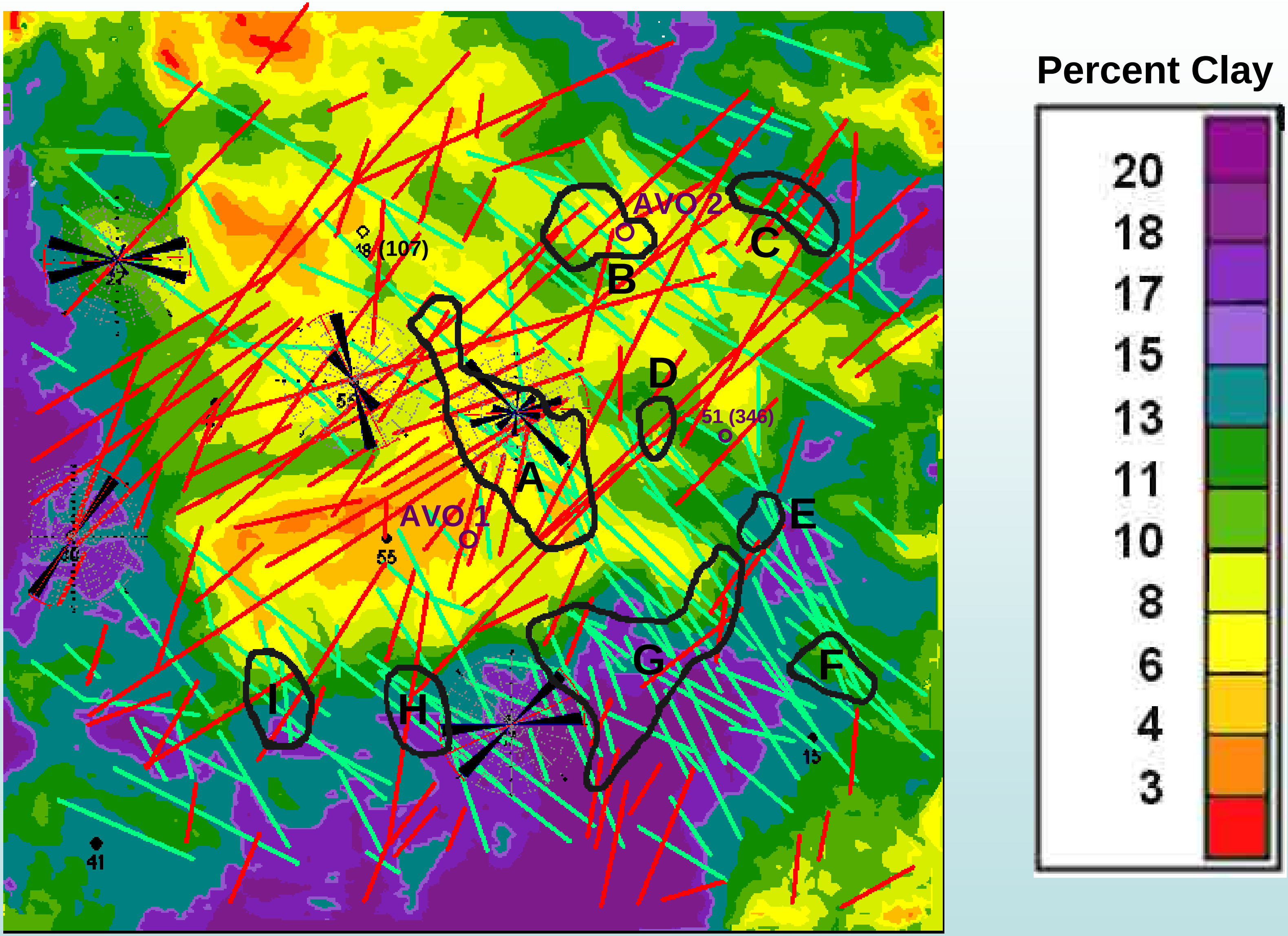
Near Trace Instantaneous Seismic Amplitude

GeoSpectrum

Figure 19a

Lower Dakota Co-located Co-kriged Clay Volume

Showing Lower Dakota Rose Diagrams / Natural Fractures and Seismic Lineaments



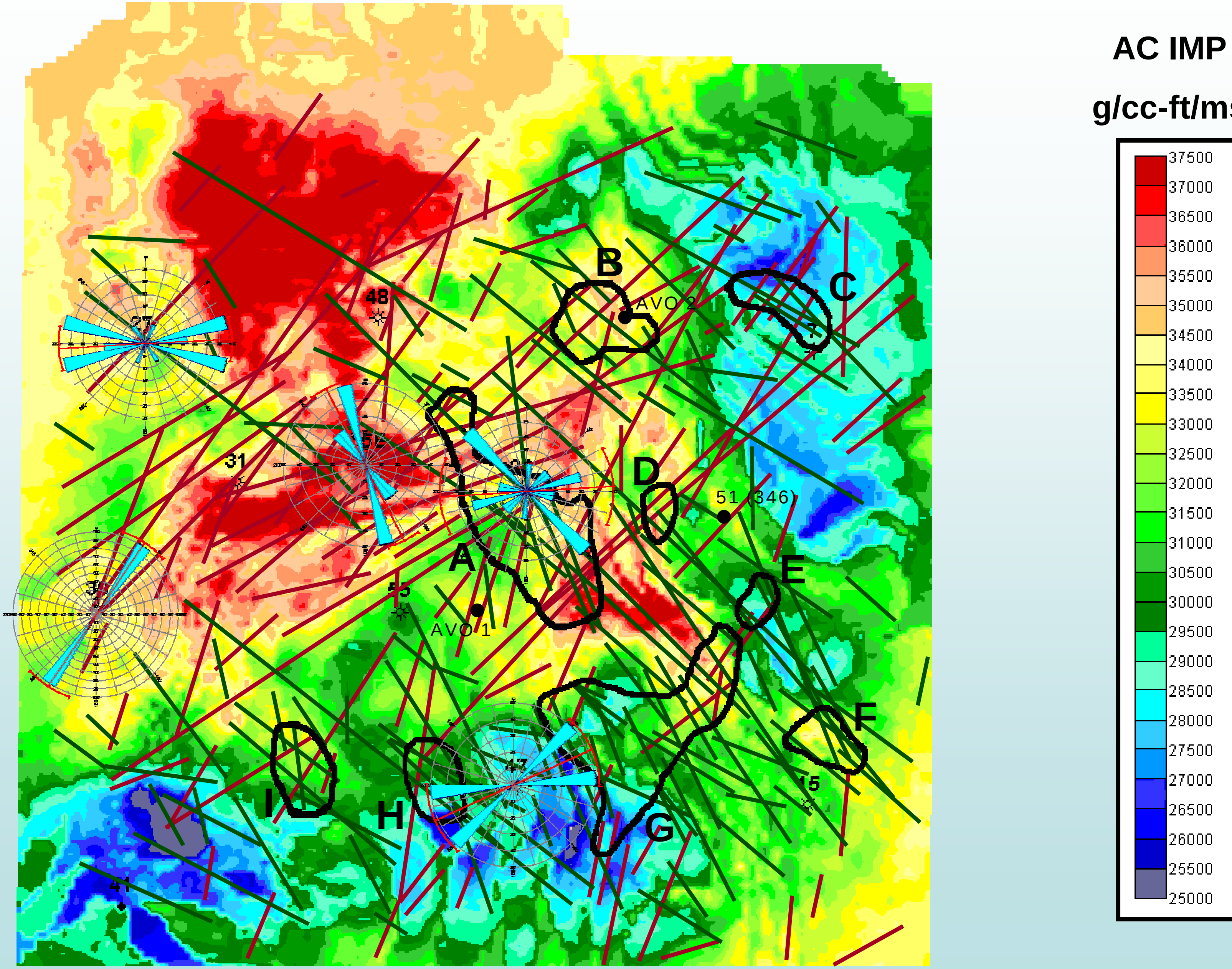
Near Trace Instantaneous Seismic Amplitude

GeoSpectrum

Figure 19b

Lower Dakota Acoustic Impedance

Horizon Slice Near 10 ms above MRSN



GeoSpectrum

Lower Dakota Rose Diagrams / Natural Fractures

Figure 20

Acoustic Impedance vs. Effective Porosity

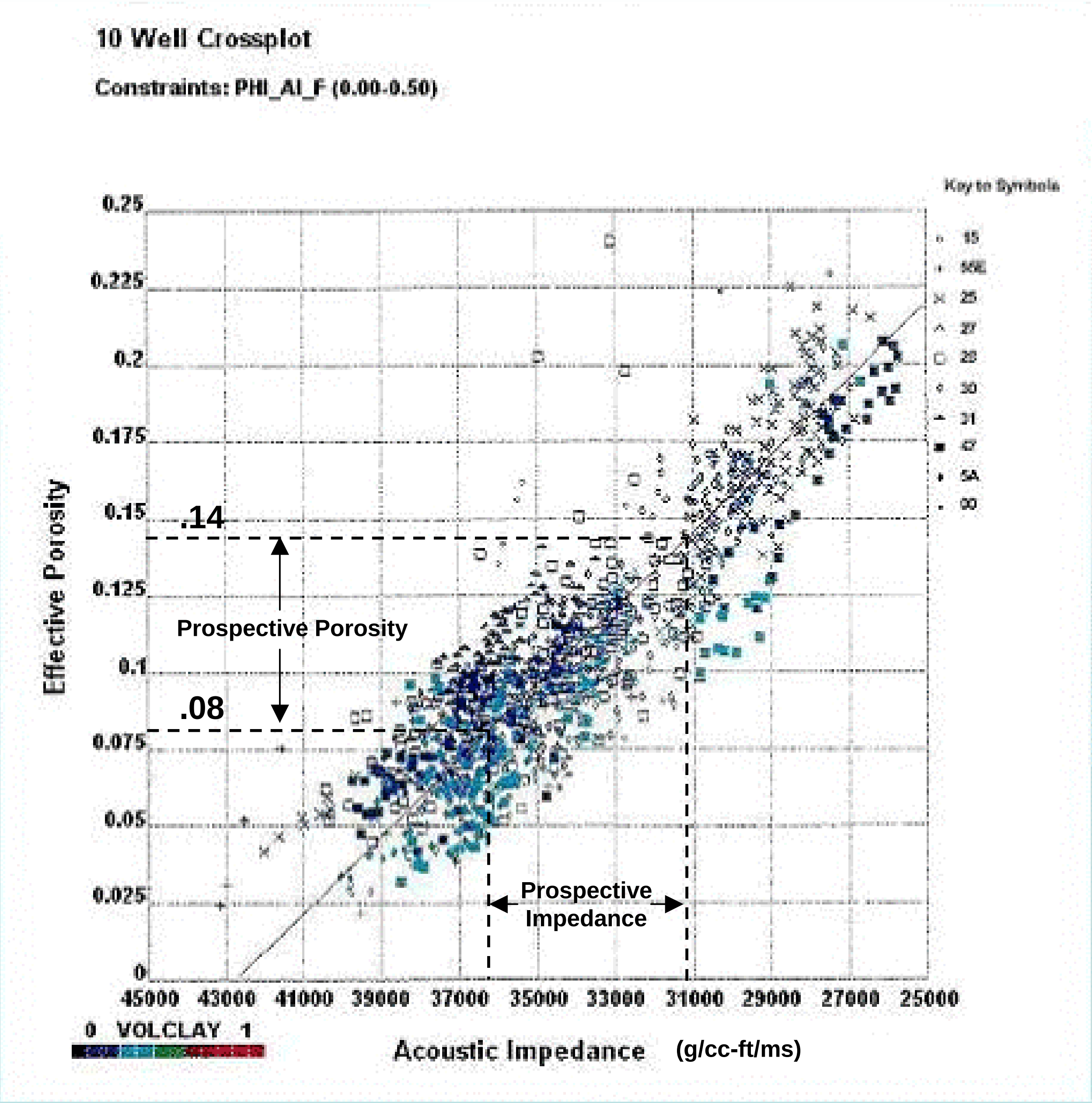
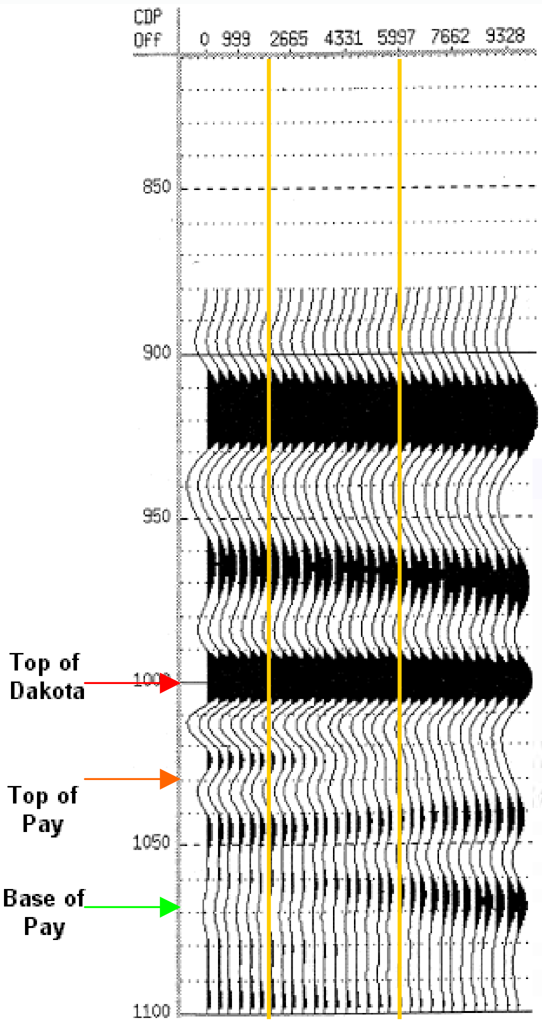


Figure 21

AVO Modeling vs. Lower Clay Volume Wells / Seismic Gathers

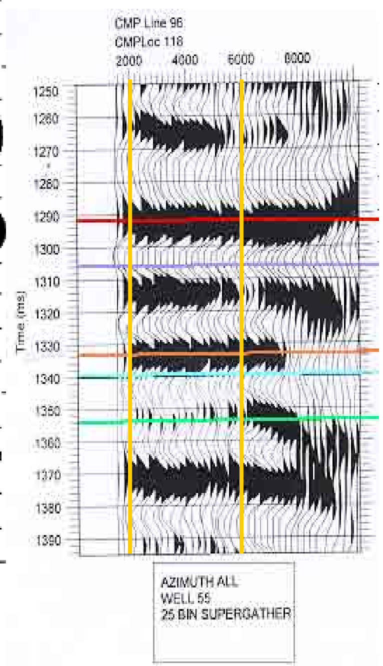
Synthetic from Well #47

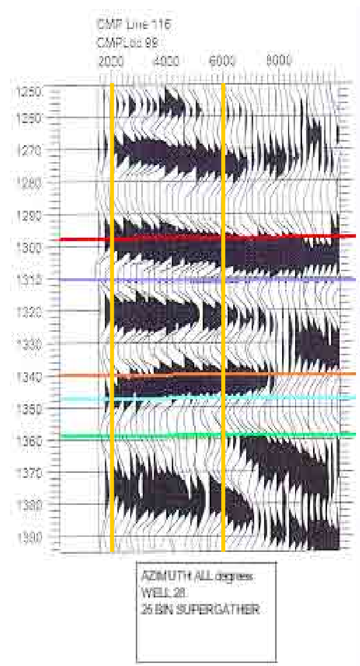
AVO Modeling from Castagna, Peddy, Lausten & Mueller (1998)

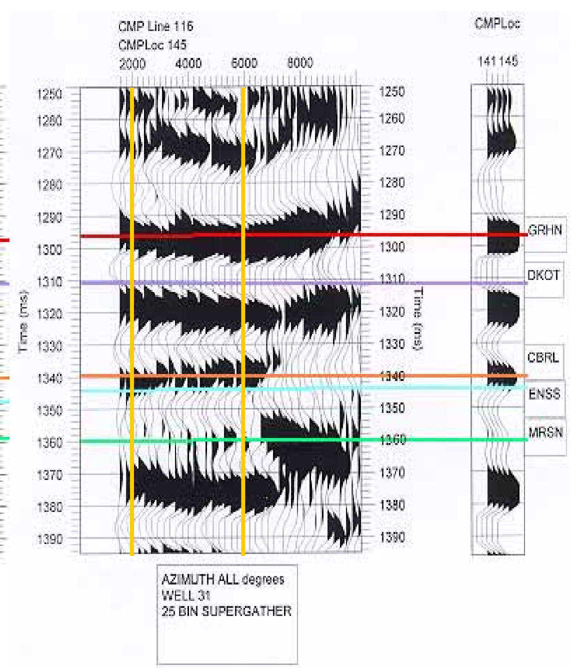


These 3 wells have some of the best production indicators in the study area.

Well #55	Well #28	Well #31
60% Sg	44% Sg	39% Sg
3% clay	8% clay	13% clay
710 MCFGPD	1710 MCFGPD	502 MCFGPD







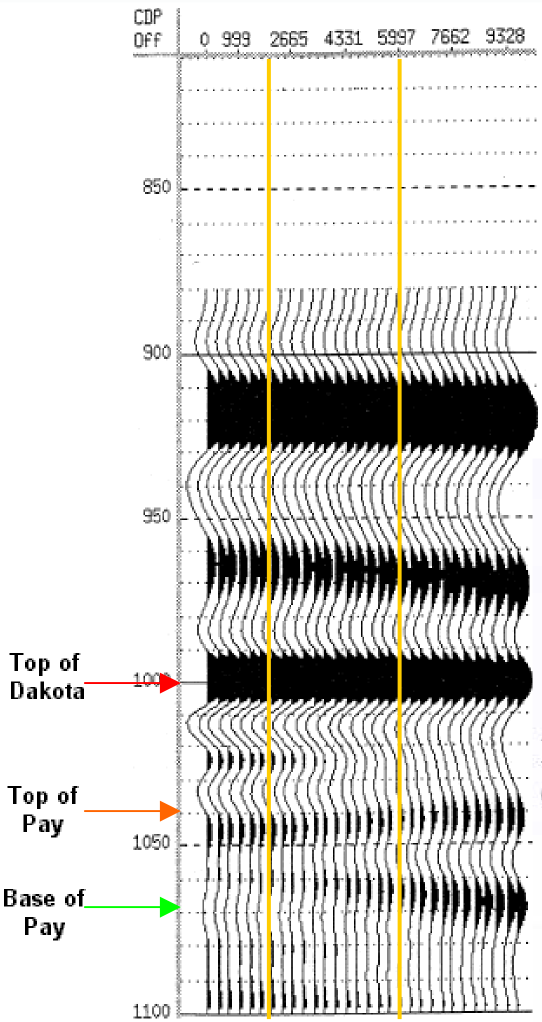
GeoSpectrum

Figure 22a

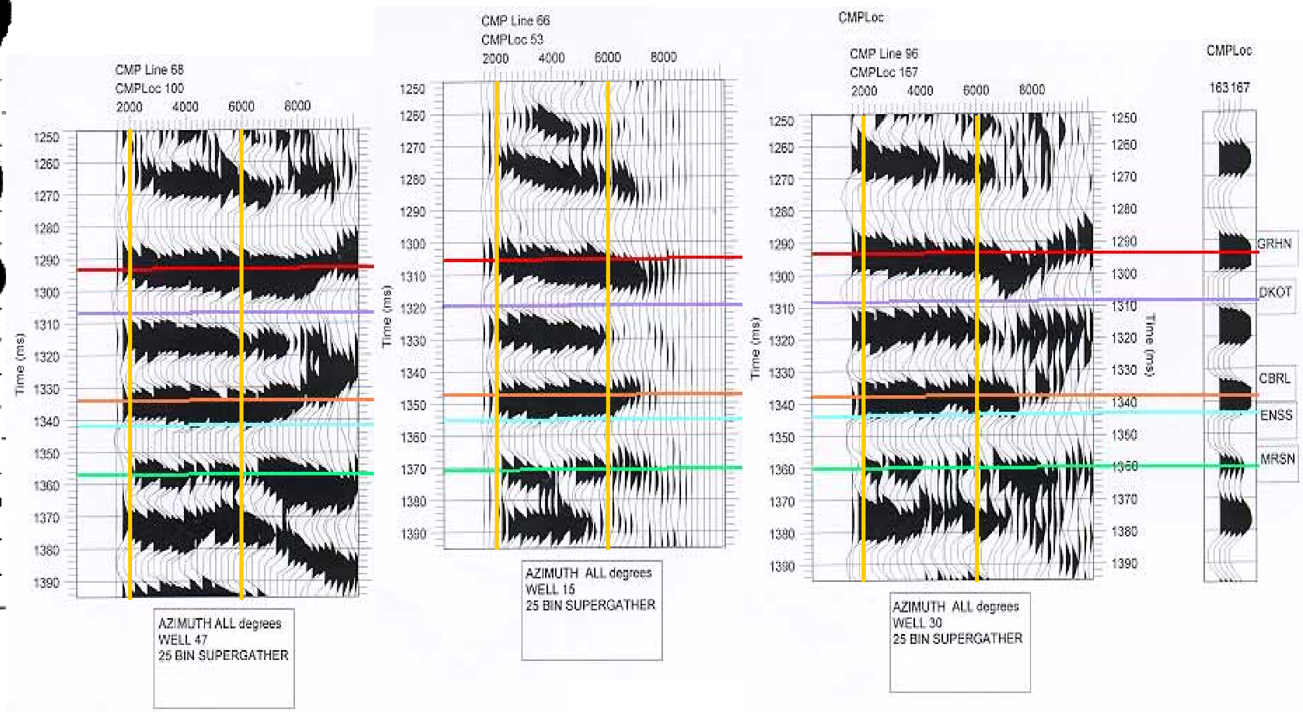
AVO Modeling vs. Higher Clay Volume Wells / Seismic Gathers

Synthetic from Well #47

AVO Modeling from Castagna, Peddy, Lausten & Mueller (1998)



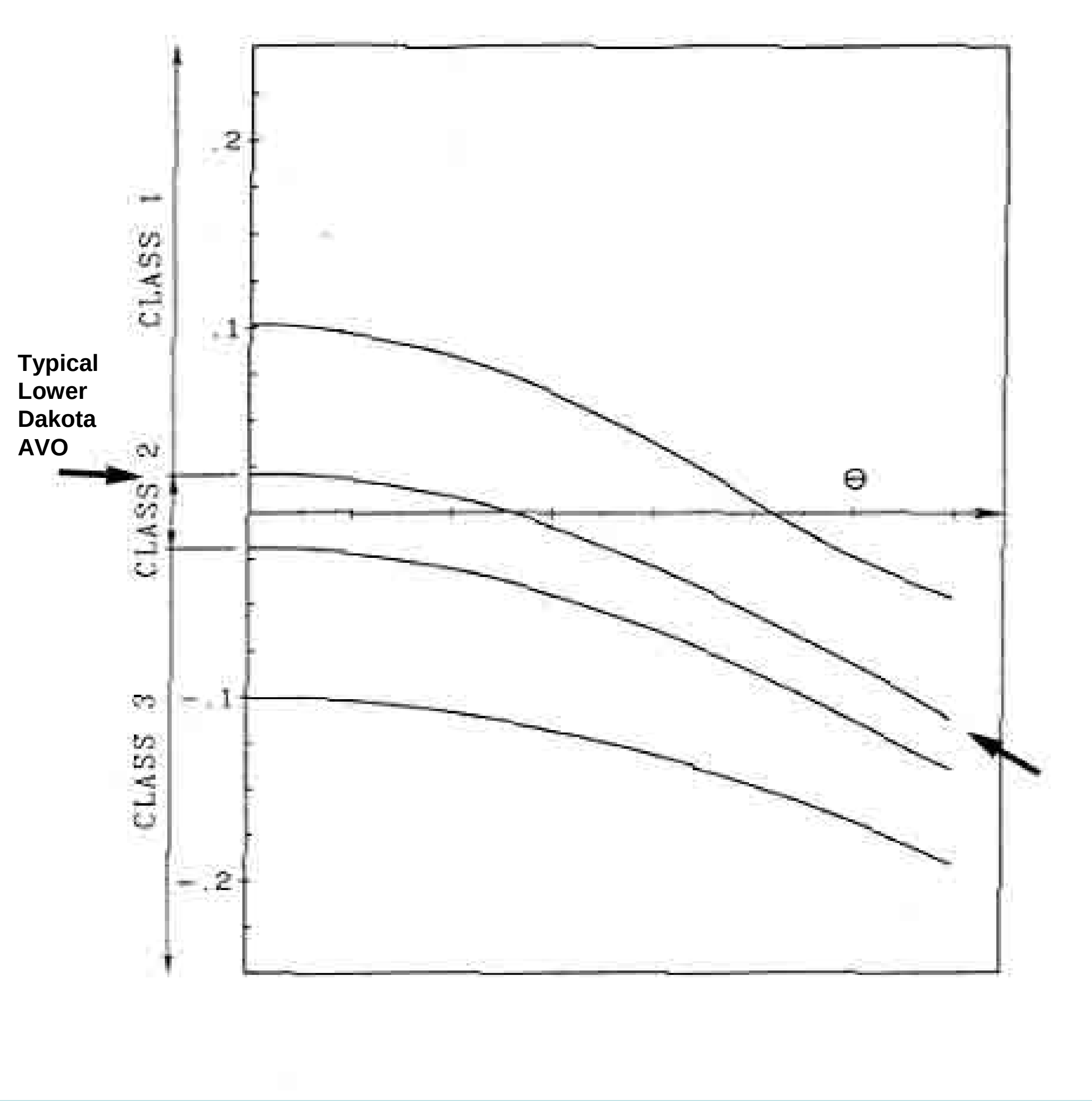
Well #47	**Well #15**	**Well #30**
21% Sg	13% Sg	10% Sg
18% clay	14% clay	17% clay
73 MCFGPD	45 MCFGPD	66 MCFGPD



GeoSpectrum

Figure 22b

Amplitude vs. Angle of Incidence



Class 1, 2, & 3 AVO anomalies

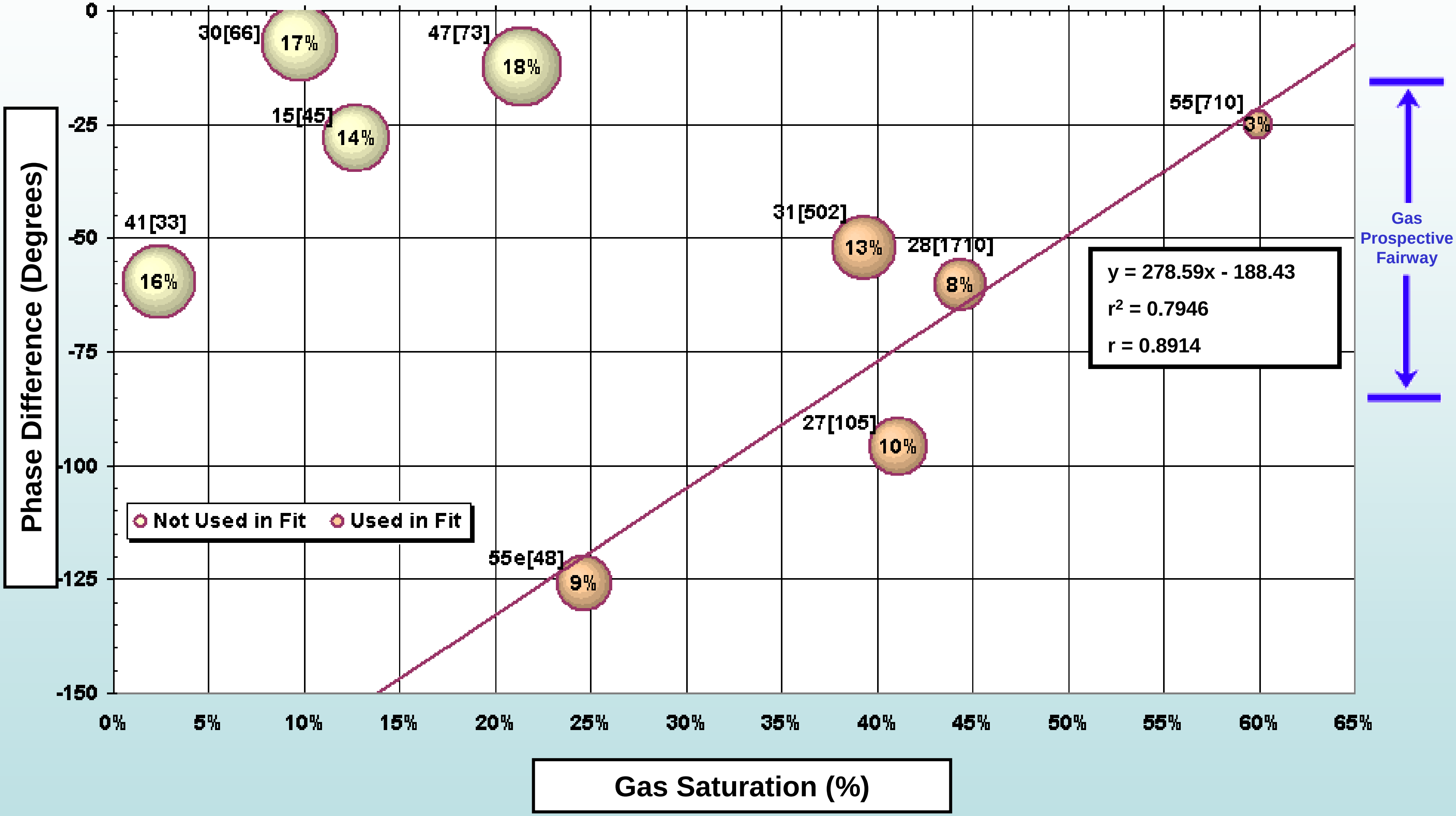
GeoSpectrum

After Rutherford and Williams (1989)

Figure 23

Lower Dakota Gas Saturation vs. Phase Difference (with Clay Volume Bubbles)

Lower Dakota Phase Difference for Horizon Slice Near MRSN



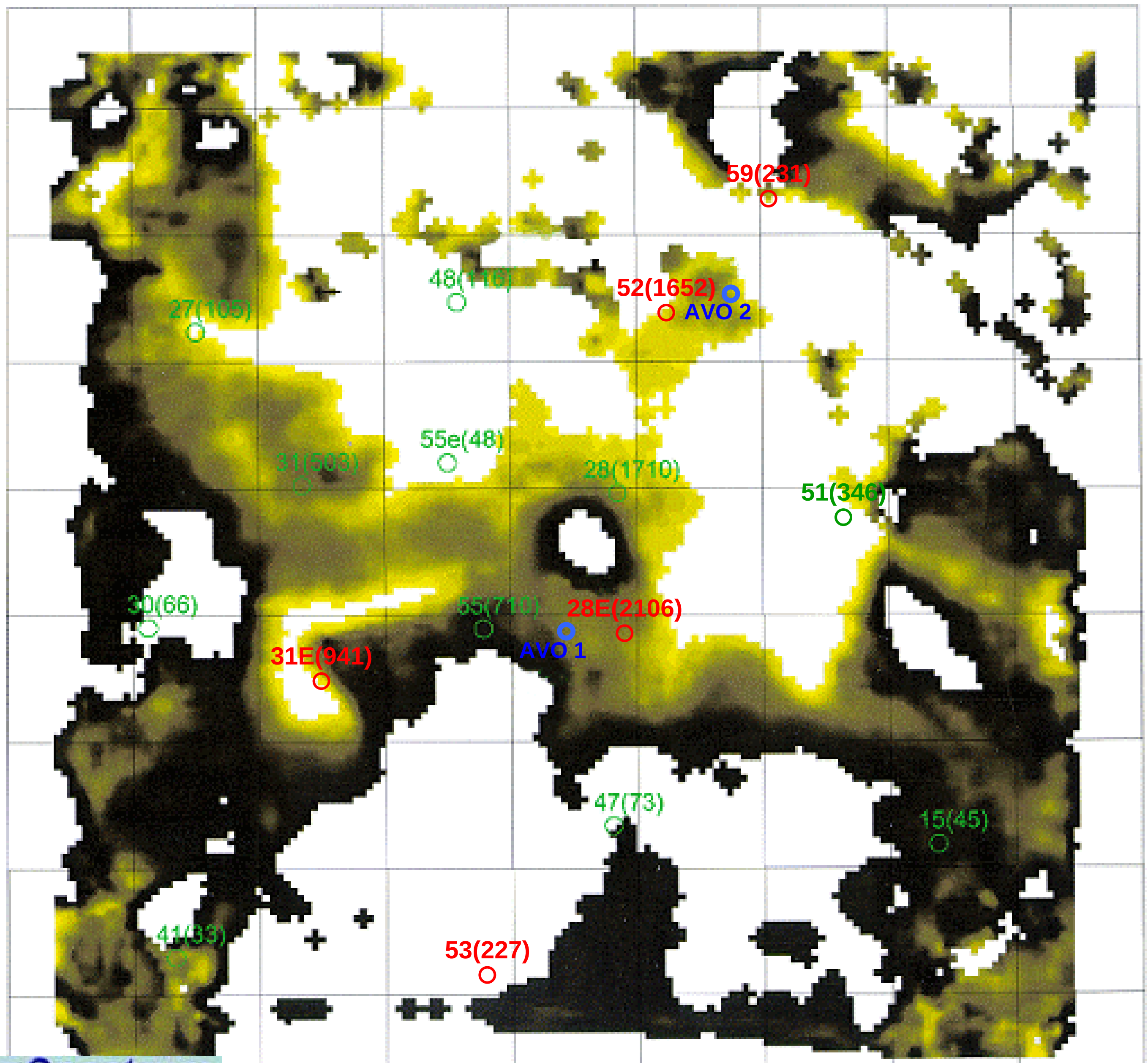
GeoSpectrum

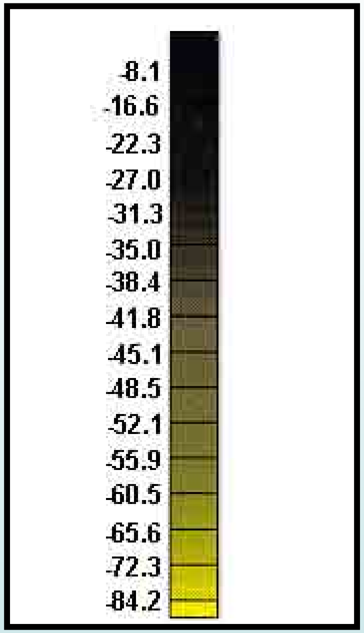
Figure 24

Lower Dakota Near-Far Phase

For Horizon Slice Near MRSN

No Clay Editing





Range:

–15 to –85 degrees

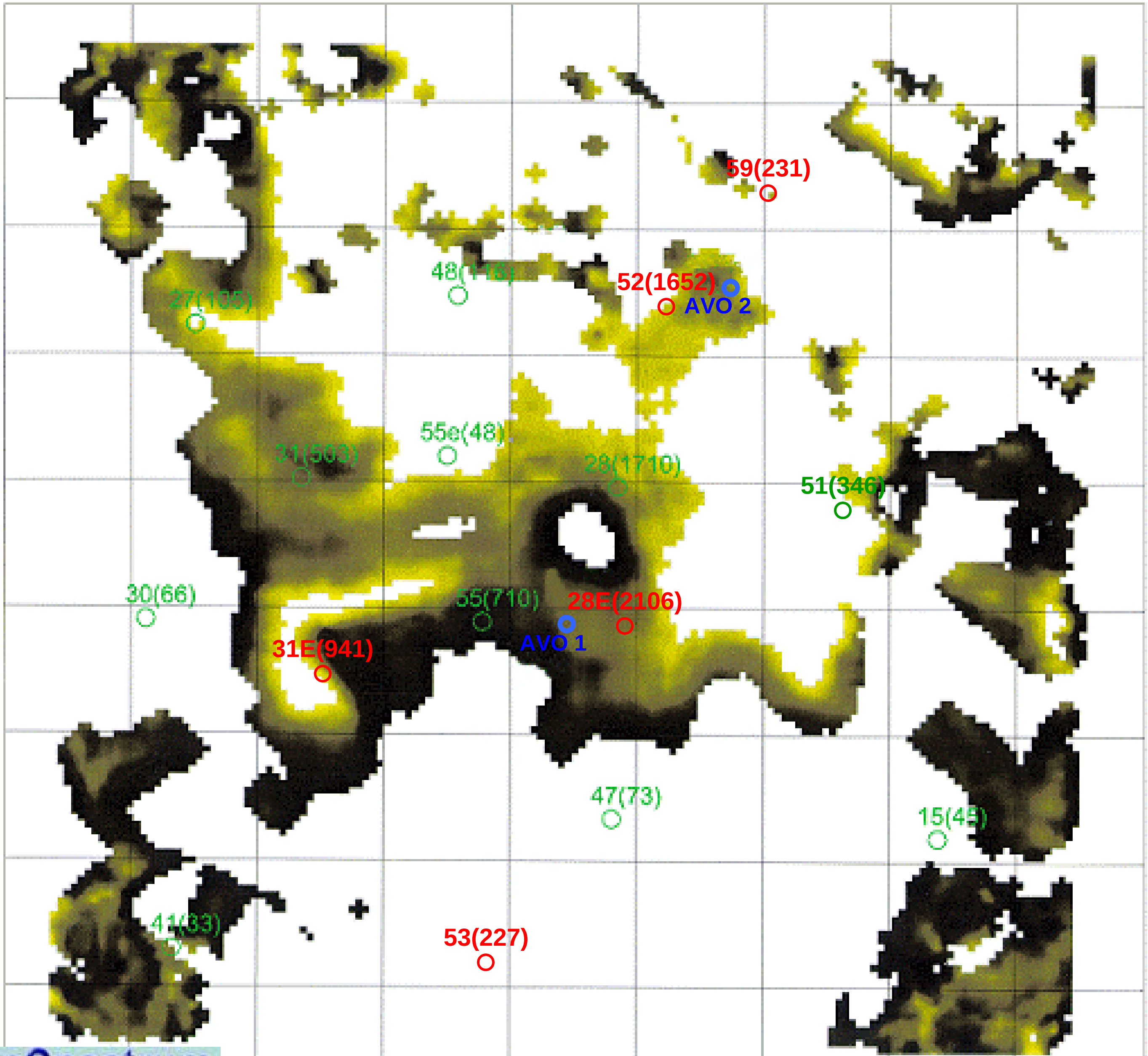
No clay editing

GeoSpectrum

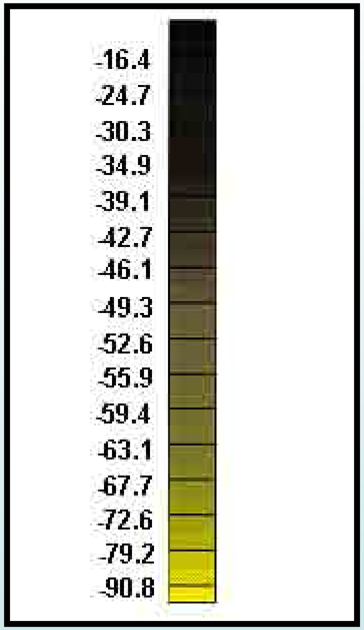
Figure 25a

Lower Dakota Near-Far Phase

For Horizon Slice Near MRSN
With Clay Editing



Near – Far Phase Difference (Degrees)



Range:

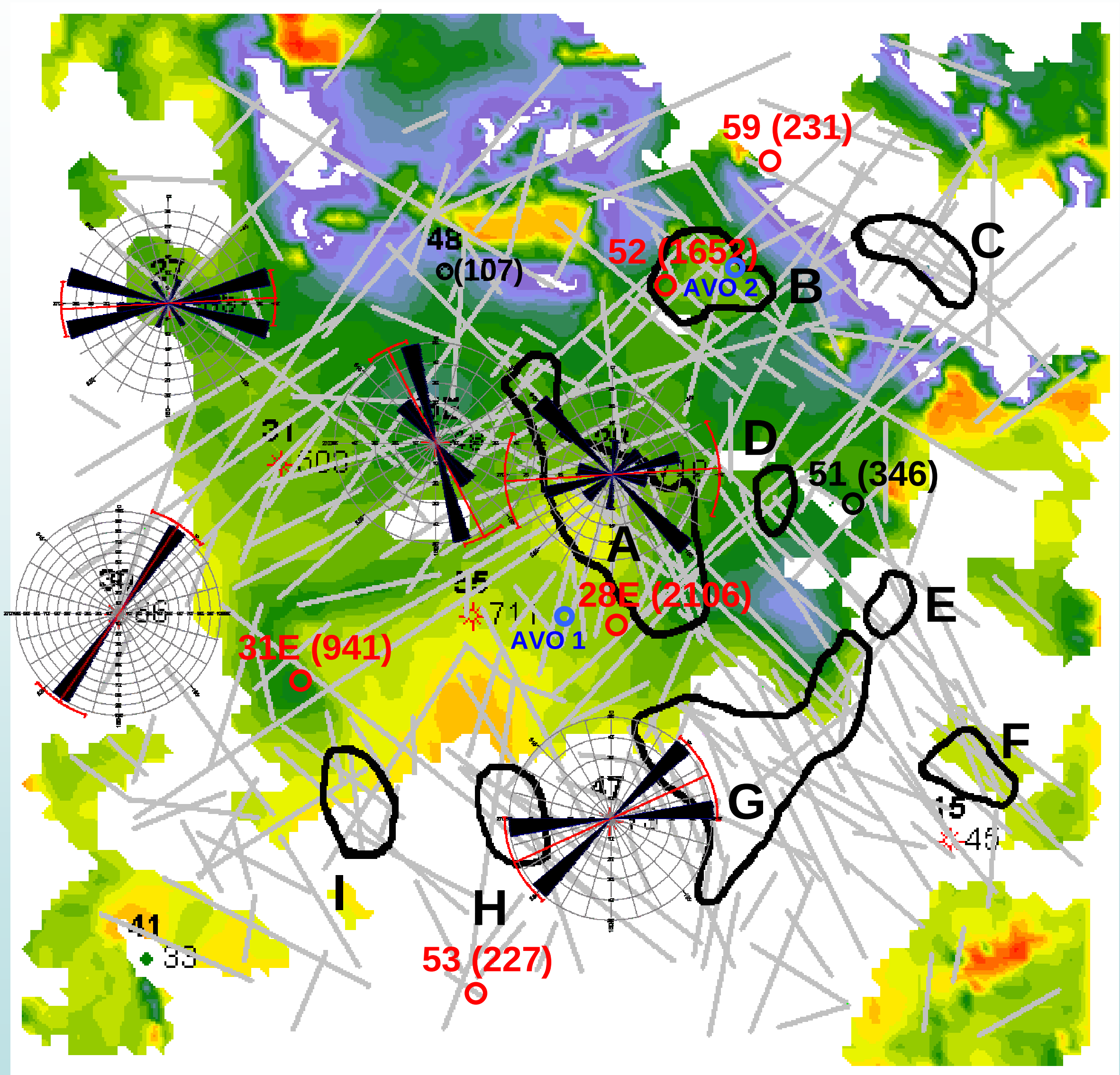
–15 to –85 degrees

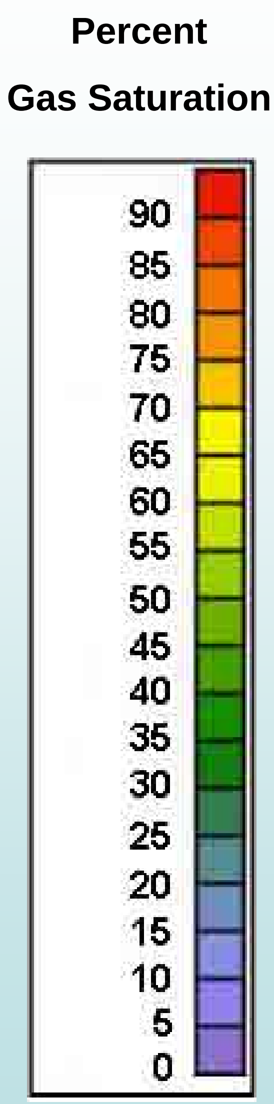
With clay editing > ~13%

GeoSpectrum

Figure 25b

Lower Dakota Co-located Co-Kriged Gas Saturation





Estimated from Lower Dakota Phase Difference

Shown with Lower Dakota Rose Diagrams / Natural Fractures

GeoSpectrum

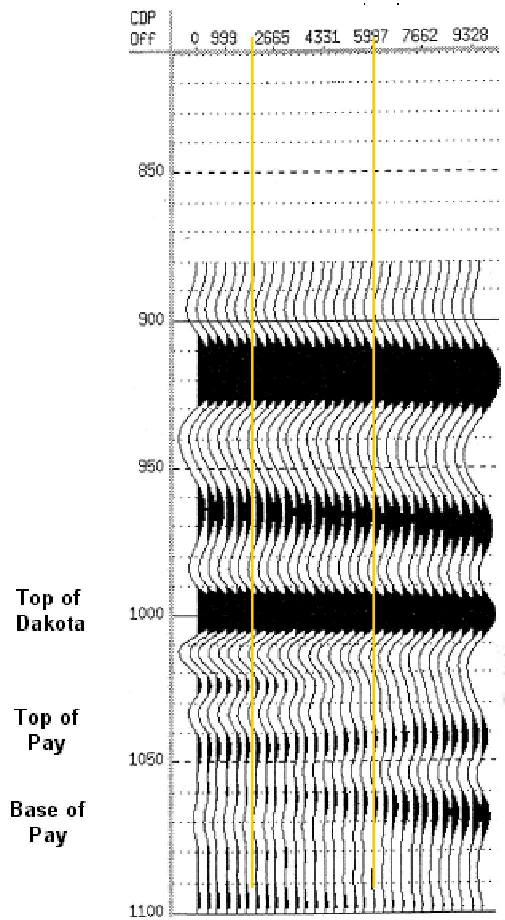
Figure 26

AVO Modeling vs. Well #28, AVO 1, and AVO 2 / Seismic Gathers

These 3 wells have some of the best production indicators in the study area.

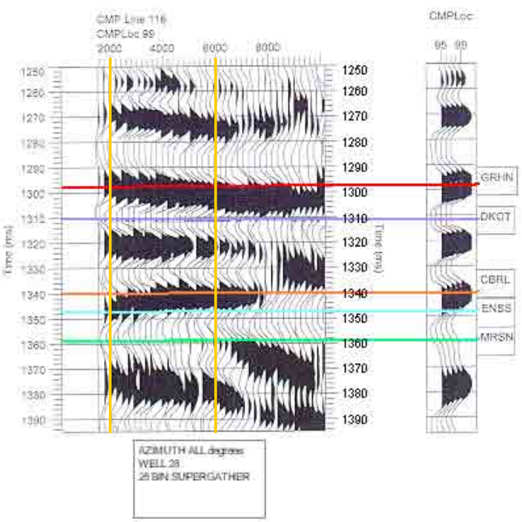
Synthetic from Well #47

AVO Modeling from Castagna, Peddy, Lausten & Mueller (1998)



Well #28

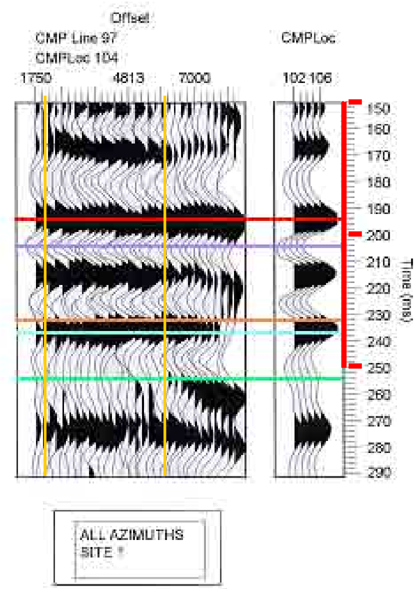
1710 MCFGPD



AVO 1

(Near Well #28E Prospect)

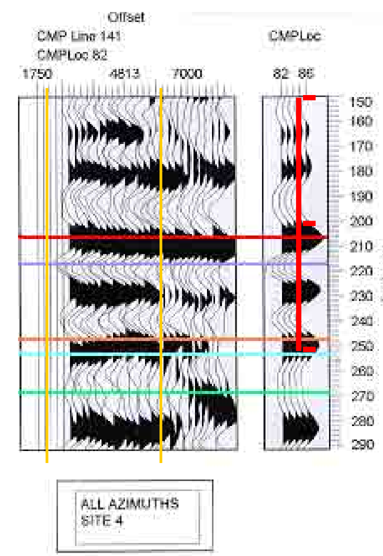
2106 MCFGPD



AVO 2

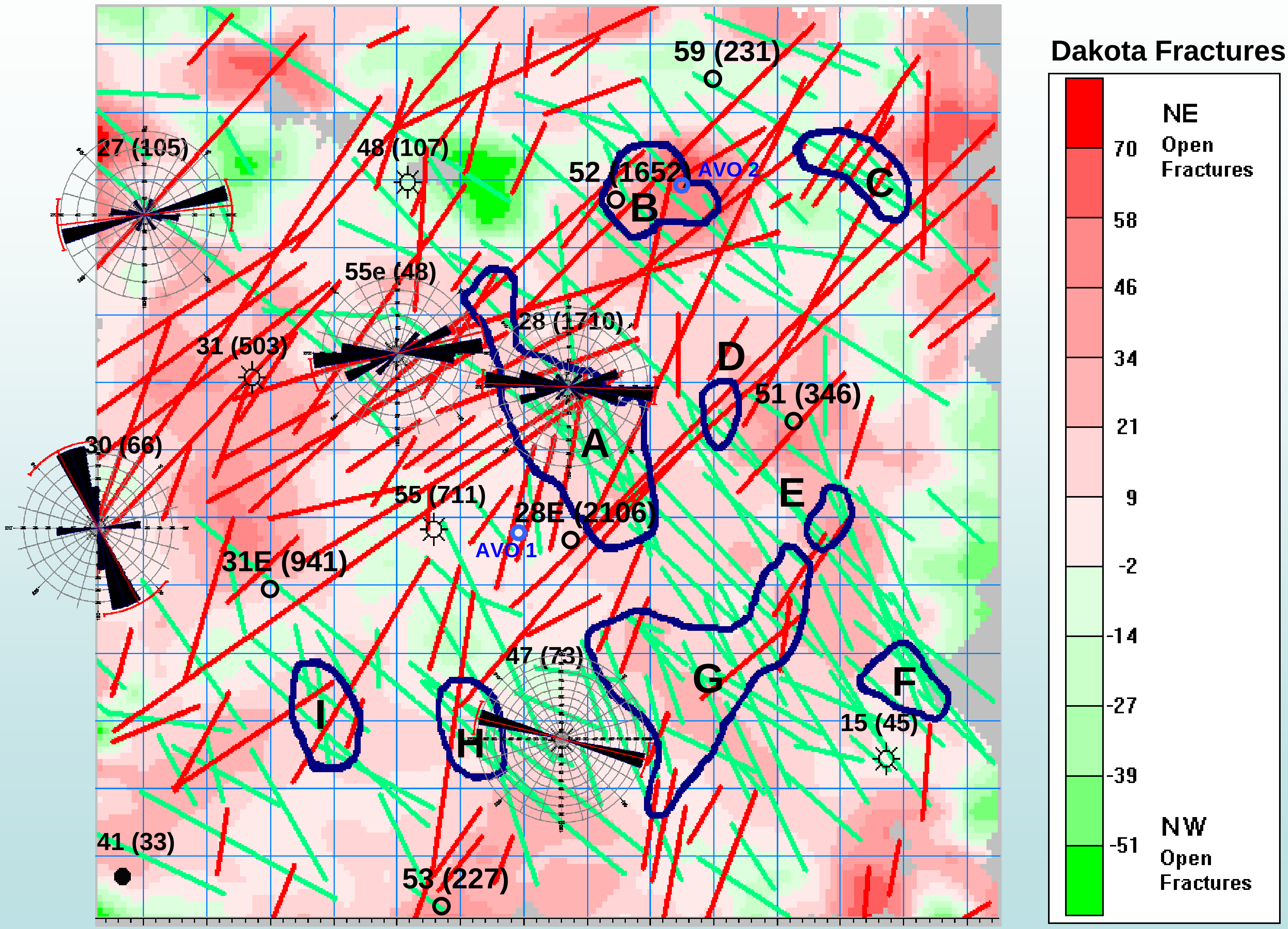
(Near Well #52 Prospect)

1652 MCFGPD



Upper Dakota Co-located Co-kriged Fractures

Showing Upper Dakota Rose Diagrams / Natural Fractures



Azimuth Dependant Dix Interval Velocity Difference
(North 145º East Minus North 55º East Azimuths)

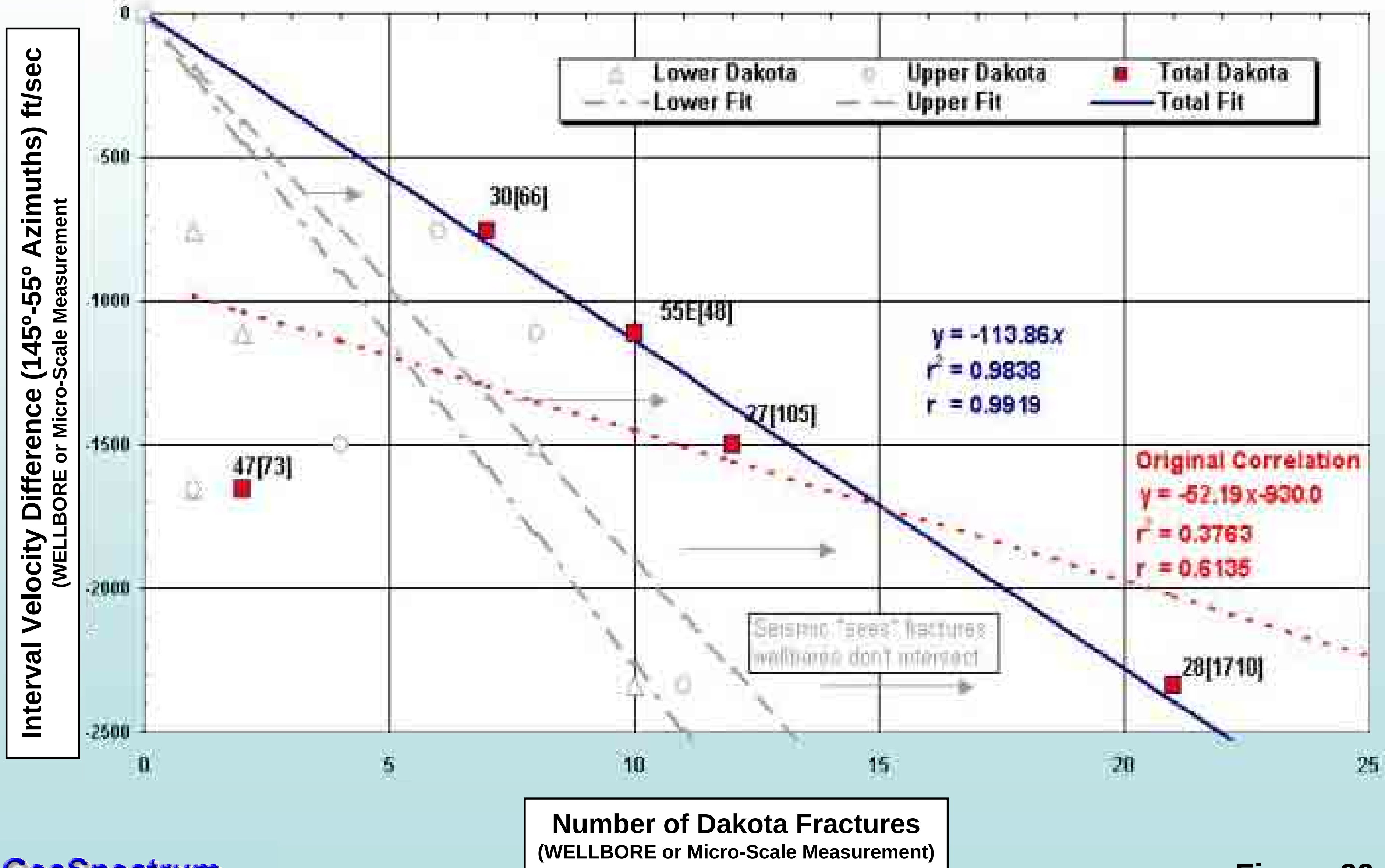
GeoSpectrum

Figure 28

Dakota Wellbore Fracture Data vs. Near Upper Dakota Velocity Anisotropy

NE Open Fractures - Negative Anisotropy / NW Open Fractures - Positive Anisotropy

(Dix's Interval Velocities Computed from Near Green Horn to Lower Cubero)

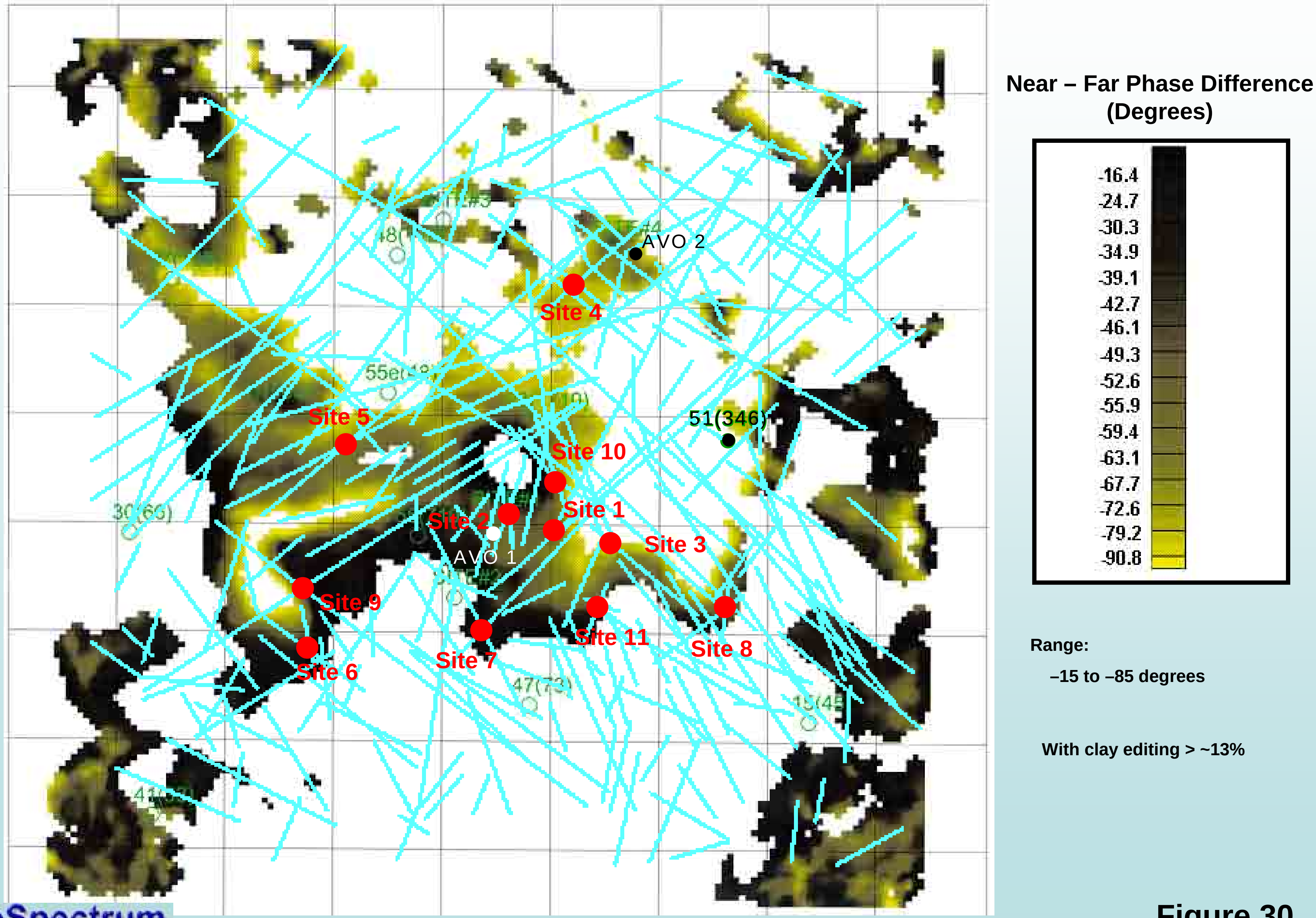


GeoSpectrum

Figure 29

Lower Dakota Prospect Development Overlay

New Prospects (Sites 1-11)



Range:

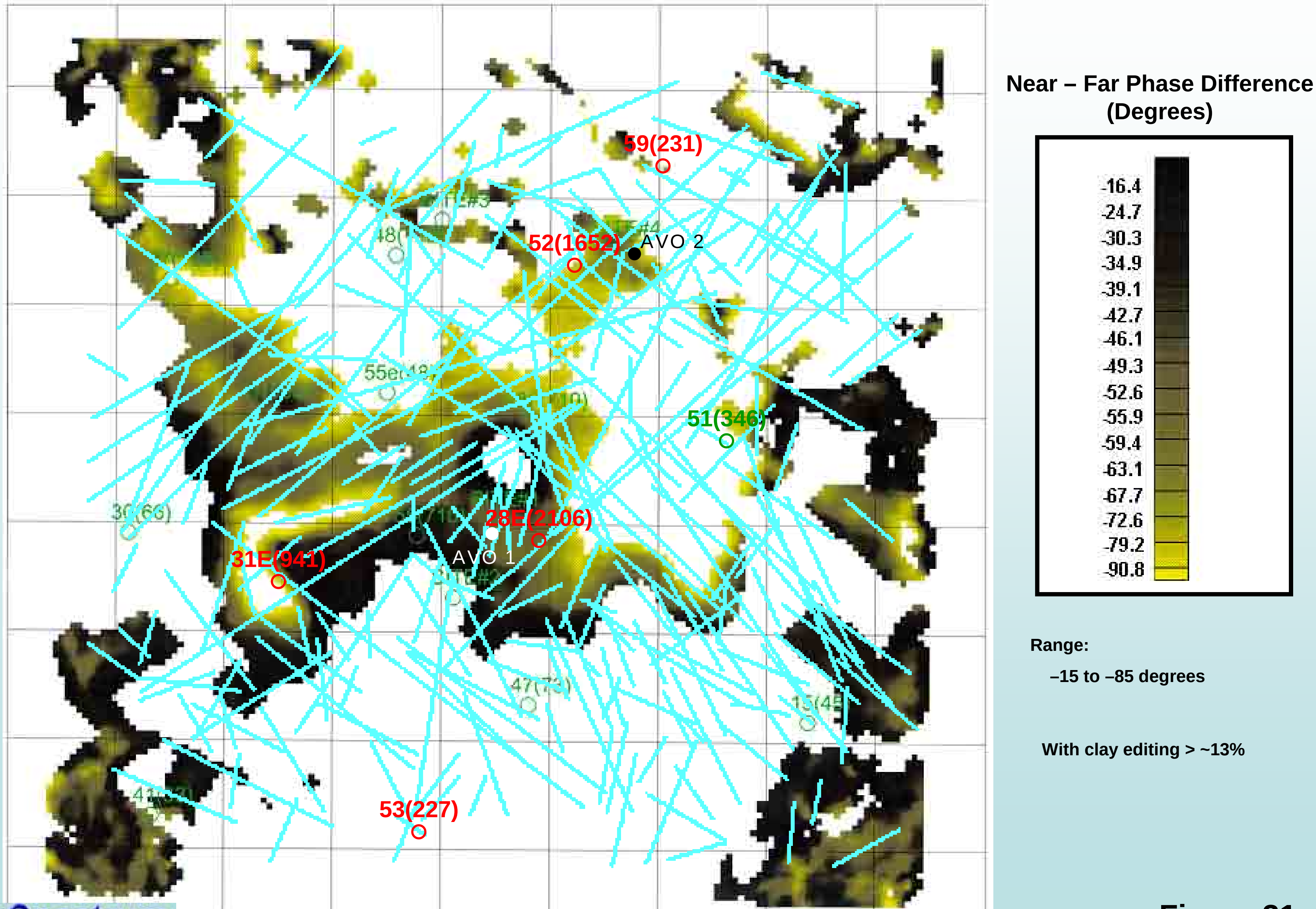
–15 to –85 degrees

With clay editing > ~13%

Figure 30

Lower Dakota Prospect Development Overlay

2004/2005 Drilling Results / Production Indicators



Range:

–15 to –85 degrees

With clay editing > ~13%

GeoSpectrum

Figure 31

Lower Dakota Reservoir Attributes

Composite Map

INTERPRETED AREAS

Gas, low clay, velocity anisotropy

Gas, low velocity anisotropy

Gas, high clay

Gas, high clay, low velocity anisotropy

No gas

No gas, low velocity anisotropy

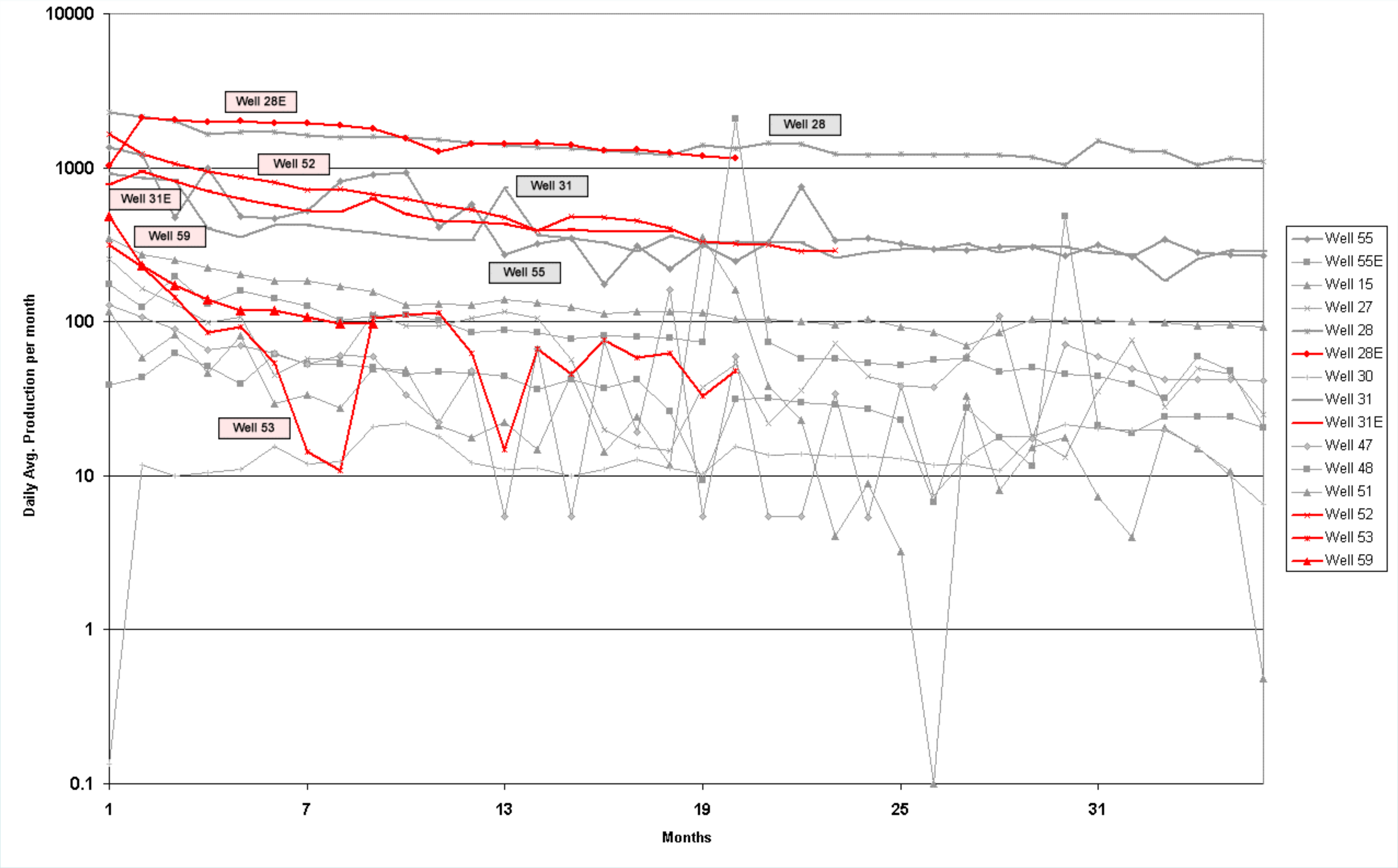
No gas, high clay

LINES

Black Lines…lineaments
Thick Black Clouds… outline of higher lineament density

4 ATTRIBUTES
Clay Content
Lineament Density
Velocity Anisotropy
Phase Difference/Gas Saturation

Unit Well Production History
2004/2005 Drilled Prospects (Red)
(Updated to December 2005)



GeoSpectrum

Figure 33

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APPENDIX 1
Picking prospects in tight gas sands using multiple azimuth attributes
("World Oil," Reeves & Smith, 2002)

In the San Juan basin, reservoir qualities are highly variable. Finding the right drill site involves identification of fracture-induced anisotropy in tight gas sands. Multiple-azimuth 3D seismic attributes and petrophysical data help find the sweet spots

Dr. James J. Reeves, Principal Investigator, and **W. Hoxie Smith,** Project Manager, GeoSpectrum, Inc.

The first phase of a U.S. Department of Energy (DOE) funded project has been successfully completed. A drill site has been recommended and both the operator and DOE agree that it should be drilled. This article details the justification and methodology employed to spot this well, an Encinal Sand fractured-reservoir prospect. It was spotted by applying modern seismic-processing techniques followed by rigorous analysis of azimuth-dependent seismic attributes, and well-log data to qualify areas of high natural-fracture density, Fig. 1.

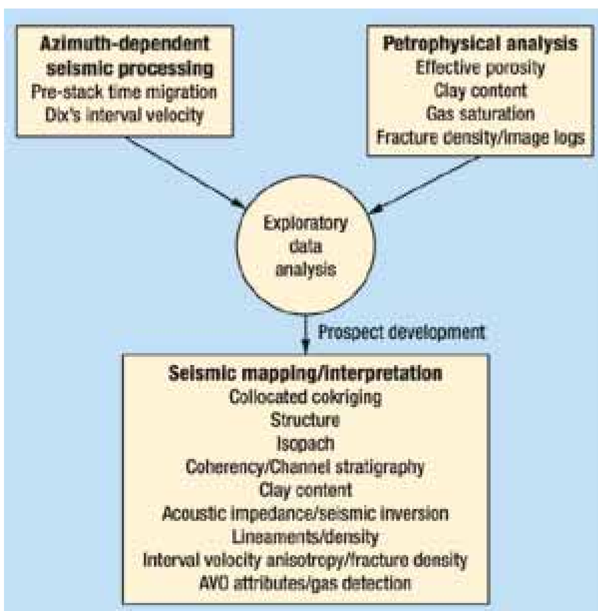

Fig. 1. *Workflow of prospect development methodology*

The contractor, GeoSpectrum, Inc., reprocessed a 9 mi^2 3D seismic data set acquired with an omni-directional receiver array to provide broad-offset azimuth statistics. The processing was focused on stack analysis of anisotropy in multiple azimuths followed by pre-stack analysis of amplitude variation with offset (AVO). The processed data and subsequent statistical analysis of seismic attributes were interpreted for identification of fractures prospective for commercial gas production. Relationships between seismic attributes and measured reservoir properties, such as clay content, as well as Dakota fracture density interpreted from borehole-image logs, were investigated.

Play Geology

The following discussion on play geology was abstracted from the operator's well files. The gas-producing unit characterized in this study is located in Rio Arriba County, New Mexico. Gas production is mainly from the Cretaceous Dakota and Gallup Sandstones. The most significant Dakota production occurs in the Lower Dakota, mainly from the Encinal and Burro Canyon Sands. Prospective Dakota horizons include both tight (conventional) and permeable (lower) sandstones. Reservoir stratigraphy of the Dakota producing interval is complex, with production potential in five individual sandstones. Dakota Sandstone depositional environments range from near marine (fluvial-deltaic) to marine. A summary of the Upper and Lower Dakota producing zones follows.

Upper Dakota. The Upper Dakota comprises both near-shore marine (e.g., Two Wells and Paguate) and fluvial-deltaic (e.g. Cubero) members.

Two Wells and Lower Paguate Sandstones are northwest-trending marine shorefaces exhibiting classic coarsening-upward sequences. Porosity of 8 - 13% characterizes both sandstones with matrix permeability between 0.2 md and 0.5 md. These sandstones require stimulation to achieve commercial rates.

Cubero Sandstone. The upward fining, fluvial-deltaic Cubero, which is oriented essentially perpendicular to the Lower Paguate and Two Wells marine sandstone members, exhibits log porosity up to 10% and is typically a lower-permeability reservoir than the marine Dakota units. It was deposited in a delta where combined fluvial and wave processes were dominant.

The Upper and Lower Cubero Sandstones have the best reservoir potential of the several Upper Dakota Sandstones that are typically completed. However, only the middle Cubero Sandstone has significant potential in the northwest portion of the unit.

The deepest prospective, conventional Upper Dakota reservoir is the Lower Cubero Sandstone. The reservoir was deposited as a northeast-trending lobe of a fluvial-deltaic system and is characterized by average porosity of 9.5% and average matrix permeability of about 0.10 md. This "clean," brittle sandstone is prone to natural fracturing; however, hydraulic fracturing is required to achieve commercial production.

Lower Dakota. These reservoirs comprise the fluvial Burro Canyon and Encinal Canyon sands that are typically thick and relatively permeable, but lithologically and petrophysically complex.

Encinal Canyon Sandstone is at the base of the Dakota and was deposited by braided streams in topographic valleys. In 1993, commercial Lower Dakota gas production was established at the unit, with an Encinal Canyon sand pay-add in Well 55, essentially a new-field discovery. A three-well priority program followed this initial success in 1994 to define reservoir limits and upside potential. Of those three wells, Well 31 was a commercial success; Well 15 was wet and unsuccessful; and Well 25, a reservoir-boundary (edge) well, was marginal.

As part of the 1994 priority program, data was collected to characterize the Encinal Canyon reservoir. Core taken from Well 15 indicates that this sandstone has exceptional reservoir quality compared to the tight Dakota reservoirs. Key differences include greater permeability (up to 200 md at reservoir stress), lower shale volumes and 8 - 18% greater porosity.

In 1995, four additional wells were recommended. Wells 30 and 28 were developmental extensions, and 27 and 47 were exploratory extensions. In addition to the basal Dakota Encinal Canyon Sandstone, tight Dakota Sandstones were secondary targets in all four proposed wells. This stacked pay-zone potential reduced the dry-hole risk and increased the economic upside.

The four additional Lower Dakota wells were drilled to further define the productive limits and extent of the new field, and to test a geological valley-fill reservoir model. The recent Well 28 was one of the most significant San Juan basin Dakota gas wells drilled in a decade, with an ultimate recovery of 9.7 Bcfg. Wells 47, 30 and 27 had various degrees of calculated Lower Dakota pay, but each of these wells proved unsuccessful.

The Encinal Canyon has exceptional reservoir qualities when compared to the overlying conventional tight Upper Dakota. Encinal Canyon porosity and permeability in excess of 18% and 200 md (in situ), respectively, have been recorded in proximal cores. Unlike the Burro Canyon, the Encinal Canyon sand is more typically hydrocarbon bearing.

A significant risk in Encinal completions is water invasion from sandstones above or below the gas reservoir. Water can encroach vertically through natural or hydraulic fractures. Also, within an Encinal structure / stratigraphic trap, there is increased risk of water down-dip.

The Burro Canyon Sandstone is legally defined as part of the Dakota producing interval, but is stratigraphically distinct from the overlying Dakota. The Cretaceous Burro Canyon was deposited by fluvial systems atop an irregular surface formed by erosion of the Jurassic Morrison Formation. The unconformity separating these two formations represents a hiatus of about 23 - 37 million years. A thicker Burro Canyon interval was deposited in Morrison valleys and thinner Burro Canyon deposited on topographic highs. The Burro Canyon represents the base of the Cretaceous in the San Juan basin.

Burro Canyon Sandstones were deposited in braided streams, far from marine influences; whereas Dakota Sandstone depositional environments range from near-marine (fluvial-deltaic) to marine. This difference in depositional environments explains why hydrocarbon source shales are present in the Dakota, but not in the Burro Canyon. Burro

Canyon Sandstones generally have larger grain size, higher porosity and higher matrix permeability than typical Dakota Sandstones.

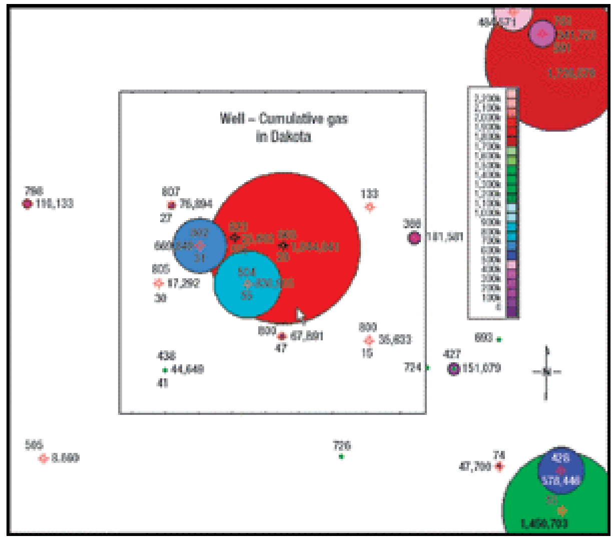

Fig. 2. *Bubble map showing cumulative Dakota production for the study area.*

Burro Canyon Sandstone is separated from the overlying Dakota by an erosional unconformity, representing 3 - 6 million years. Erosional down-cutting ultimately resulted in hydrocarbon traps, including:

- Burro Canyon Sandstones that, truncated by the overlying unconformity near trends of thinning, formed hydrocarbon traps on the down-dip side of the trends.
- Irregularities in the amount of erosional down-cutting that, combined with the inherently irregular nature of Burro Canyon Sandstones (braided stream deposits), created hydrocarbon traps where individual sandstones were truncated up-dip by the unconformity.
- Hydrocarbon traps that existed where fluvial Burro Canyon Sandstones were truncated up-dip by the overlying erosional unconformity.

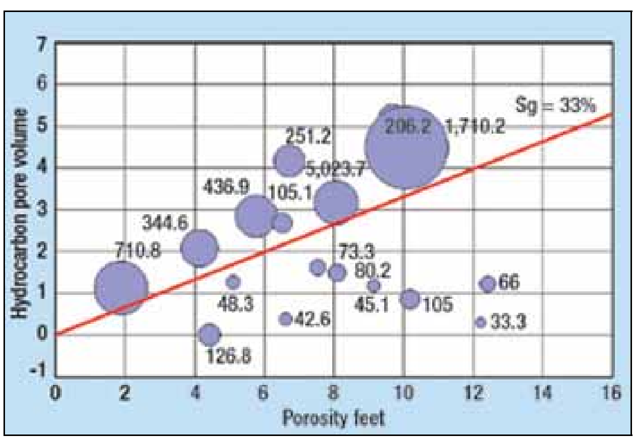

Fig. 3. *Dakota hydrocarbon pore volume vs. porosity-thickness and the average of the best 12-month production for each well.*

Burro Canyon Sandstone is a fine-to-coarse grained, upward fining deposit that is frequently characterized by wet porosity, often in excess of 15%. Within the Burro Canyon, there are many individual sandstone units, each with its own reservoir boundaries. These are too irregular to be individually mapped. They pinch out laterally, coalesce with other sandstones and/or down-cut into underlying sandstones. Although the Burro Canyon is called sandstone, interbedded shales and siltstones are common. This bewildering stratigraphic complexity has formed permeability barriers that, in conjunction with erosional truncation and structure, created reservoirs.

Prospect Development

Phase I analysis resulted in a new Lower Dakota prospect / exploratory extension in the gas unit. The prospect is based on the workflow shown in Fig. 1, and is a direct work product from the tasks outlined in the DOE contract.

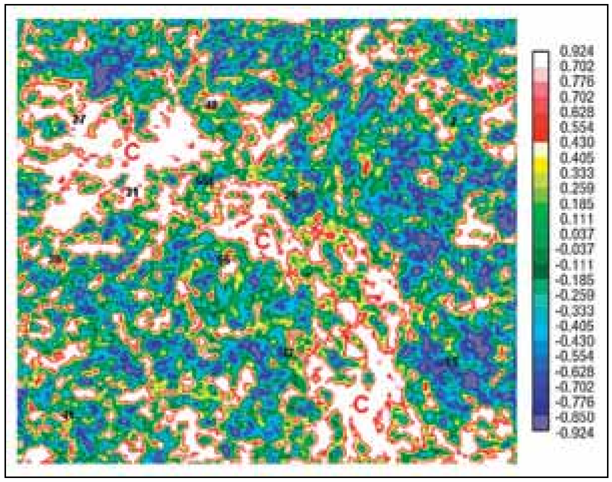

Fig. 4. *Lower Dakota seismic-coherency horizon slice.*

The prospect well should extend production of the unit to the northeast about 3/4 mi from Well 28. Fig. 2 is a bubble map showing cumulative Dakota production for the study area. Ten wells comprise the field, seven of which are marginal producers, while three have each cumulatively produced more than 700 MMCFG. The close proximity of poor producers, Wells 55E and 27, to the three outstanding wells indicates Dakota reservoir complexity within the boundaries of the unit.

In Fig. 3, Dakota hydrocarbon pore volume vs. porosity-thickness and the average of the best 12-months of production for each well are shown. Significant wells in the unit are distinguished by a gas-saturation cut off of about 33%. Notice the apparent poor correlation between the best 12-month production for the good wells and reservoir volume (porosity-feet), which suggests a fracture-controlled reservoir.

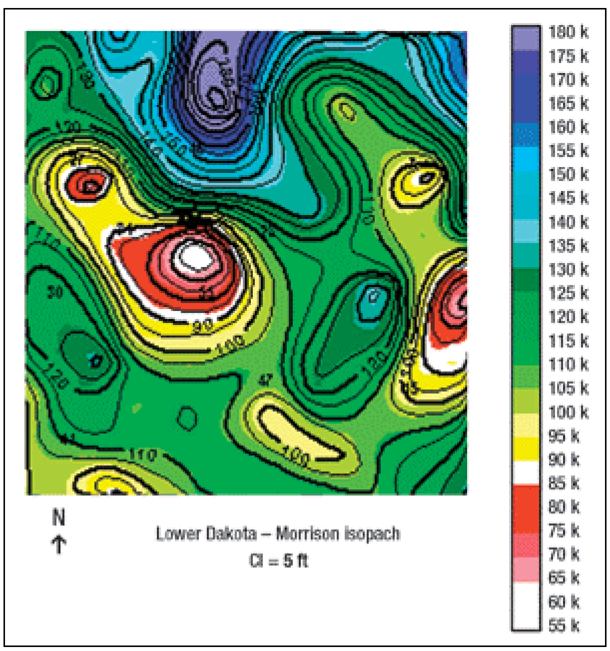

Fig. 5. *Lower Dakota seismic-isopach map.*

Dakota fracture counts interpreted from borehole image logs vs. the best 12-month production shows that most fractures occur in the best producing well at the unit, Well 28.

Fig. 4 is a seismic-coherency horizon slice displaying characteristic Encinal fluvial-channel stratigraphy. It is observed that the best wells are found on the channel edges. Fig. 5 shows a Lower Dakota seismic isopach map. Note the agreement between Lower Dakota thickness and Encinal seismic coherency defining the fluvial channel.

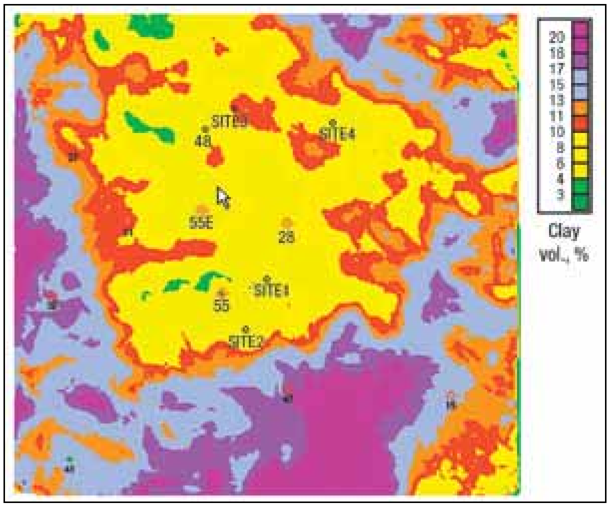

Fig. 6. *Collocated, cokriged clay volume from near-trace seismic amplitude.*

In Fig. 6, a seismic-guided Lower Dakota clay volume map is shown. It is based on petrophysical analysis of log data from nine wells.

Seismic-guided mapping was done using collocated cokriging with near-trace instantaneous seismic amplitude (measured cross correlation = 0.81). The best gas-producing wells and most prospective areas are associated with wells having the least clay. Reservoir rocks having low clay content should be more brittle and more likely to fracture. Furthermore, clays typically have high water content, increasing the likelihood of a clay-rich reservoir being water-wet.

A similar result is seen by the seismic inversion. Fig. 7 shows a Lower Dakota acoustic-impedance horizon slice computed from a constrained inversion from about five wells. Petrophysical analysis shows that prospective sandstone fluvial-channel pay (effective porosity between 8% and 14%) is defined by an impedance range of about 31,000 to 36,000 g/cc-ft/ms. A plot of water saturation vs. effective porosity reveals that sands with more than about 15% porosity tend to be water-wet. Brittle- and fracture-prone lithologies should also be associated with high-impedance values.

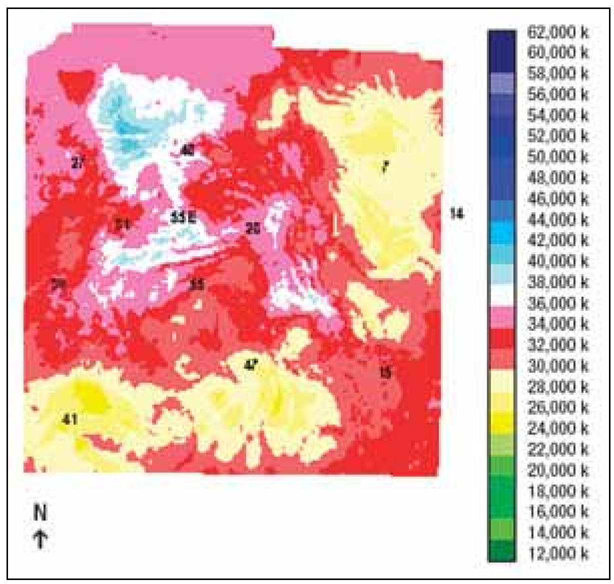

Fig. 7. *Lower Dakota acoustic-impedance slice from constrained seismic inversion.*

In Fig. 8, Lower Dakota lineaments are mapped as interpreted from azimuth-dependent / all-azimuth seismic-attribute volumes. Seismic attributes analyzed in the study include azimuth-dependent / all-azimuth Dix interval velocity, instantaneous amplitude, frequency, phase, coherency, and difference attributes. Seismic imaging was improved significantly by GeoSpectrum's reprocessing, using azimuth dependent pre-stack time migration. Migration will increase lateral spatial resolution, signal-to-noise ratio, and aid in analysis of pre-stack seismic attributes. Lineaments seen in these enhanced seismic volumes are interpreted to infer fracture zones. Note the concentrated number of lineaments found at Well 28 on the map. A similar method to interpret fracture zones using seismic lineaments was done for Arco Permian in a reservoir study of the South Justis Unit, Lea County, New Mexico. [1]

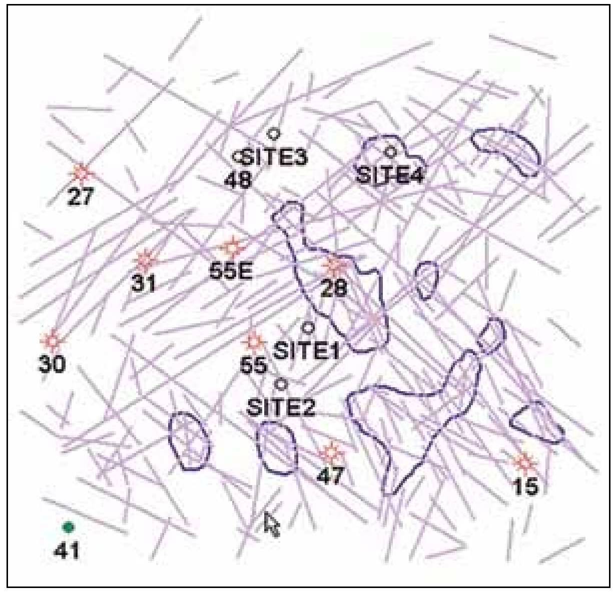

Fig. 8. *Lower Dakota seismic lineaments.*

Lower Dakota lineament density (Fig. 9) is computed from the lineaments in Fig. 8. It assumes a well-drainage area of about 900 ft x 900 ft. The hotter colors are interpreted to indicate fracture-developed reservoirs showing several prospective locations.

Fig. 10 shows a preliminary seismic-guided Dakota fracture-density map modeled from Dakota fracture counts, as interpreted from borehole image logs for five wells. Fracture-density mapping was done using collocated cokriging, with Dix's interval velocity, for an interval near the Lower Dakota, computed for 145°±22.5° azimuth data minus 55°±22.5° azimuth data (measured cross-correlation = - 0.61.) Note the trend of positive high fracture density associated with Well 28 on the map. A positive density indicates that fractures in the northeast direction will tend to be open in the interval. Other prospective regions of high positive fracture density are also seen to the northeast of Well 28 at the proposed Site 4 location.

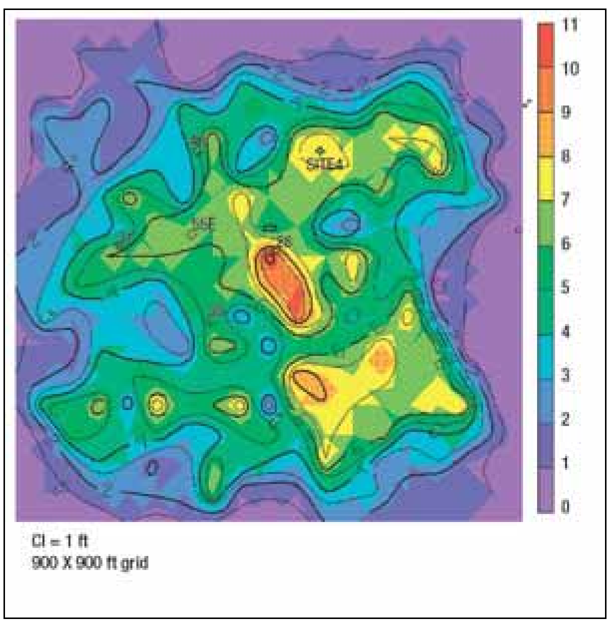

Fig. 9. *Lineament density computed from Fig. 8. Warmer colors indicate higher density.*

A Class 2 AVO anomaly typically exhibits a low-amplitude, near-offset response and a phase reversal with increased amplitude at far offsets. [2] This was confirmed in the Dakota by comparing synthetic modeling with real gathers from dipole sonic and density logs from a nearby well, where gas saturation averages about 23%. A 25-fold supergather was computed and extracted at the Well 28 location, after normal move-out and pre-stack time migration. This revealed an apparent Lower Dakota Class 2 AVO anomaly that is visible through most of the 3D seismic volume.

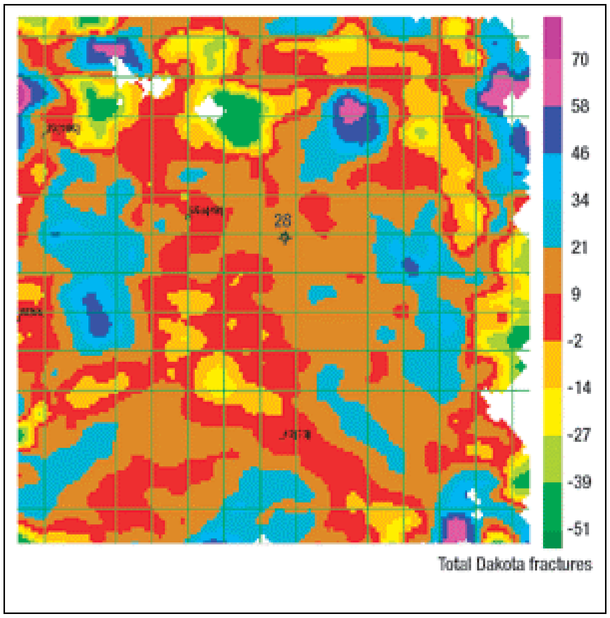

Fig. 10. Collocated, cokriged fracture density computed from Dix's interval velocity.

The cross-plot in Fig. 11 shows Lower Dakota near-trace phase minus far-trace phase vs. gas saturation. The outlying wells with gas saturations below 24% have Lower Dakota clay content greater than 13%. The red trend-line is based on the remaining five wells that have clay content less than 13% and gas saturations greater than 24%. Note that three of these five wells (28, 55 and 31) are the most productive wells in the unit, and are associated with a phase difference ranging between - 15° and - 85°. The red trend-line has a measured cross-correlation coefficient of 0.89. The analysis of a phase dependent AVO attribute decreases the concern with amplitude scaling issues in the seismic data.

Mapping seismic phase difference values between - 15° and - 85° reveals two prospective trends that correspond to regional Dakota production. If this map is further constrained by showing only areas with estimated clay less than about 12 - 13% (i.e., Fig. 6), the results show areas of brittle, fracture-prone rocks having a favorable AVO attribute. Fig. 12 shows seismic-guided Lower Dakota gas saturation modeled from the phase difference attribute with estimated clay content less than about 12 - 13%. Seismic-guided mapping was done using collocated cokriging and the empirical trend-line (phase difference vs. gas saturation) in Fig. 11. Gas saturations between about 40% and 60% define prospective trends for Lower Dakota fracture-controlled gas production at the unit. The gas saturation mapped in Fig. 12 should only be used to define prospective trends for gas production, not for actual gas saturation values.

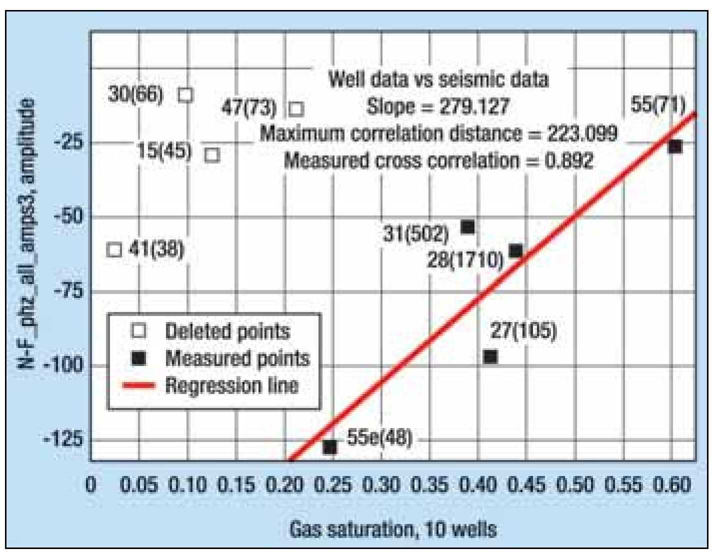

Fig. 11. Lower Dakota graph of: [near-trace minus far-trace phase] vs. gas saturation.

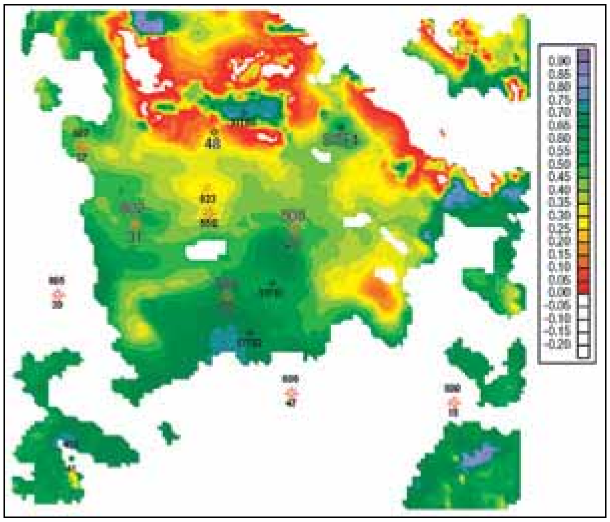

__Fig. 12.__ Seismic-guided Lower Dakota gas-saturation map (estimated clay volume <12 - 13%).

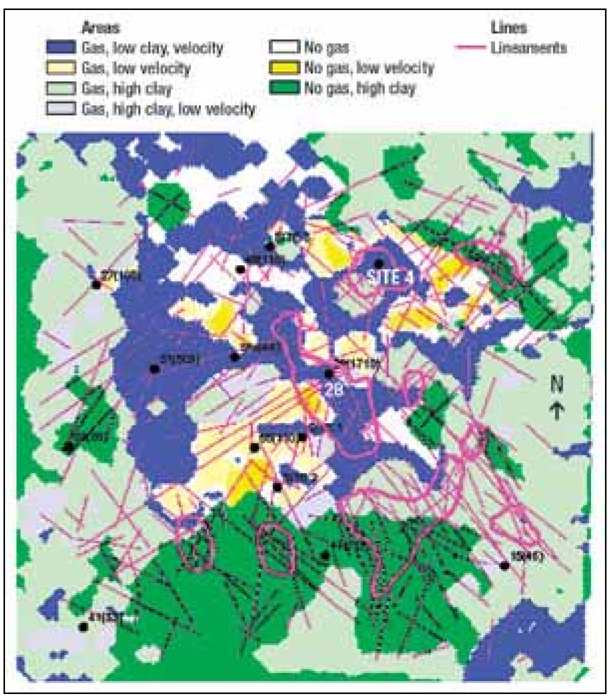

__Fig. 13.__ Composite-attribute map, showing seismic lineaments (pink lines), high lineament density (red outlines), favorable AVO attributes and low clay (blue). Well 48, a poor producer, would not have been drilled if based on current assessment methodology.

Efforts to model the phase vs. gas saturation characteristic on Fig.11 using Gassman modeling methods have been unsuccessful. The authors are hopeful to obtain additional funding from the DOE for AVO modeling.

Conclusions

In Fig. 13, a composite-attribute map comprising seismic lineaments (pink lines), high lineament density (red outlines), favorable AVO attributes and low clay (dark blue) is shown. Dark blue regions inside the red outlines therefore indicate the most prospective drill locations. The new drill location is indicated by Site 4 on the map. The three Lower Dakota productive wells (28, 55 and 31) appear to be predicted with nearly 100% success. The following methodology was used:

1. Locate well in, or on edge of Encinal channel
2. Clay content less than or equal to roughly 13%
3. AVO attribute indicating phase difference between - 15° and - 85° (gas saturation about 40 - 60%)
4. Seismic lineament density of five or greater.

Validation. The results of new Well 48 (a blind test), drilled last year about 1 mi northwest of Well 28, were held confidential from GeoSpectrum (the contractor) during the study. The results from this marginally producing well were not integrated into the work. The summary of contractor's methodology (Fig. 13) would not have supported drilling this well. The well was spotted in a region of low seismic lineament density and poor AVO attribute.

Fig. 14 shows the depth-converted Lower Dakota seismic structure map. Note that the contractor-proposed well (Site 4) is favorably located nearly on strike with the prolific Well 28. Also, the Lower Dakota seismic isopach map (Fig. 5) shows more favorable, thicker reservoir section at the proposed Site 4 location than it does for Well 28.

The contractor recommends that the proposed well (Site 4) be drilled and that the DOE contract continue on to Phase II. Drilling the new prospect is critical to further validate the results of the Phase I effort. Additionally, drilling the proposed well will determine the value of the applied methodology in detecting commercial and prospective gas targets in tight gas sands.

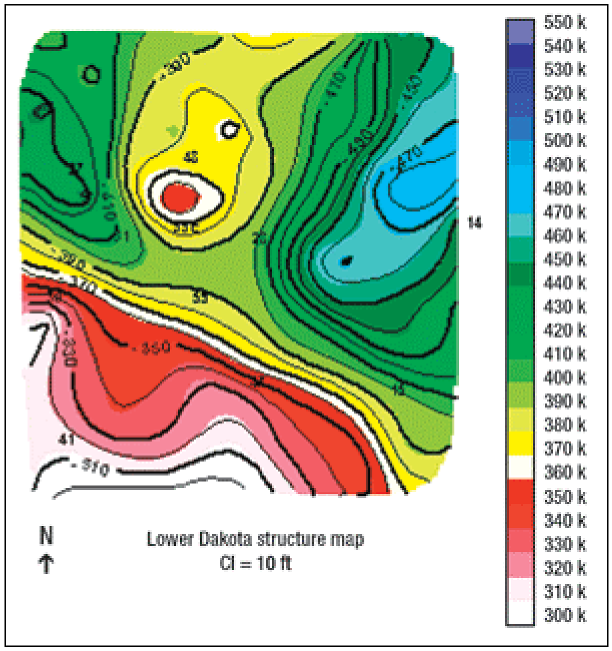

Fig. 14. *Depth-converted, Lower Dakota seismic-structure map.*

Interactive website / application services. An interactive website utilizing a generic project database is being developed to illustrate best practice methodologies applicable for fractured-reservoir exploration. The website will allow the user to interact with the latest application software and the opportunity to apply the developed technology through the contractor's Internet-based application services.

Acknowledgment

Most of the funding for the study came from the DOE and the operator. The project benefited greatly from data and interpretations provided by the operator, their employees and associates. The section on Play Geology in the paper was abstracted from the operator's well files by W. Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis / modeling, and Mark Semmelbeck did the production data analysis. The timeliness and assistance of the DOE technical contract managers is greatly appreciated.

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[2] Castagna, J. P., C. Peddy, C. D. Lausten and E. Mueller, "Evaluation of seismic amplitude versus offset techniques for the direct detection of gas reservoirs: Phase II - Increasing the use of amplitude versus offset techniques in the continental United States," Gas Research Institute Final Report, no. GRI-98/0120, 1998, p. 5 and 108 (Fig. 1 and 73, respectively).

The authors

Dr. James J. Reeves earned a BS in mineral engineering-physics (1976), MS in geophysical engineering (1979) and a PhD in geophysics (1984) from the Colorado School of Mines. He is a registered professional engineer with the State of Texas. He started his career with Gulf Oil as a seismic interpreter, exploring the Delaware and Midland basins of West Texas. After graduation, he worked for Pectin Int'l Co., coordinating seismic-data acquisition and processing in eastern Syria; as an assistant professor of geology at the University of Texas of the Permian basin; as a research associate professor for Texas Tech University's Center for Applied Petrophysical Studies; and was a co-founder and Chairman of the West Texas Earth Resources Institute (WTERI). In 1992, Dr. Reeves and his partner, W. Hoxie Smith, formed GeoSpectrum, Inc. (www.geospectrum.com) where they have been in business for the last 10 years.

W. Hoxie Smith earned a BS in geology in 1982 from Colorado State University, and a MS in geology from the University of Texas of the Permian basin in 1995. His oil and gas industry experience includes: ARCO Exploration (1983) in Colorado; ARCO Oil and Gas (1986) in Midland, Texas, and four years as a geophysicist with Dawson Geophysical. He is a principal and vice president of GeoSpectrum, Inc., where he serves as the main marketing contact and project manager for industry and government projects. Smith has presented at numerous professional society meetings, including SEG, SPE and AAPG.

APPENDIX 2
An Integrated 3-D Seismic Fracture Interpretation Methodology for Tight Gas Reservoirs
("GasTIPS," Reeves & Smith, 2004)

By James J. Reeves, Ph.D., P.G., P.E. and W. Hoxie Smith, M.S.,
GeoSpectrum, Inc.

GeoSpectrum, Inc. conducted a tight gas exploration and development study in which a 3-D seismic interpretation method for fractured sandstone reservoirs was established.

The interpretation method is based on a comprehensive reservoir characterization of the Lower Dakota sandstone in a gas-producing unit in Rio Arriba County, NM.

The following reservoir attributes are used:
- **seismic lineament mapping** predicts reservoir fractures in the reservoir section;
- seismic **interval velocity anisotropy** investigates fractured reservoir potential in tight sands up-hole from the main reservoir target;
- a **collocated cokriged clay volume map** for the Lower Dakota, along with additional geologic attributes, screen lead areas defined by regions of "swarming" multidirectional lineaments; and
- a gas-sensitive amplitude variation with offset seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient,** is used to further define drill locations having high gas saturation.

A four-well drilling program recently was completed to test the fractured gas reservoir prospects and exploration technology. The nearly 100% success ratio of the drilling program indicates the fracture detection method is ready for commercial application.

Fracture detection methodology

Lower Dakota fractures/seismic lineaments
Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the reservoir section. A seismic lineament is defined as a linear feature seen in a time or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include coherency, amplitude, frequency, phase and acoustic impedance. It has been interpreted that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir (Figure 1). For the purpose of anonymity, the names of the wells referenced in this paper have been truncated to the last two numerical digits.

The application of azimuth dependent prestack time migration to increase spatial resolution should significantly enhance the ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at well 28, one of the most prolific wells in the unit. Borehole breakout indicates present-day maximum horizontal tectonic stress in nearly a north-south direction. This orientation does not preferentially close any

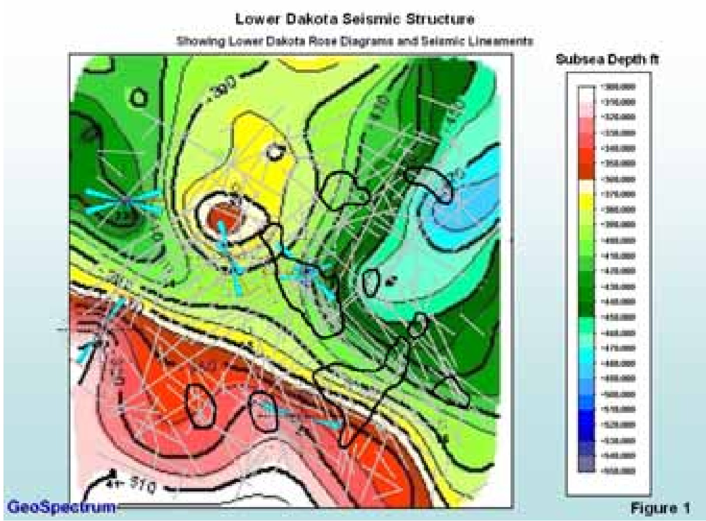

Figure 1. Seismic lineaments (silver lines) superimposed on structure contour map of the Lower Dakota (based on 3-D seismic and unit wells drilled pre-1999). Blue rose diagrams indicate fracture orientation determined from borehole image logs in the Dakota.

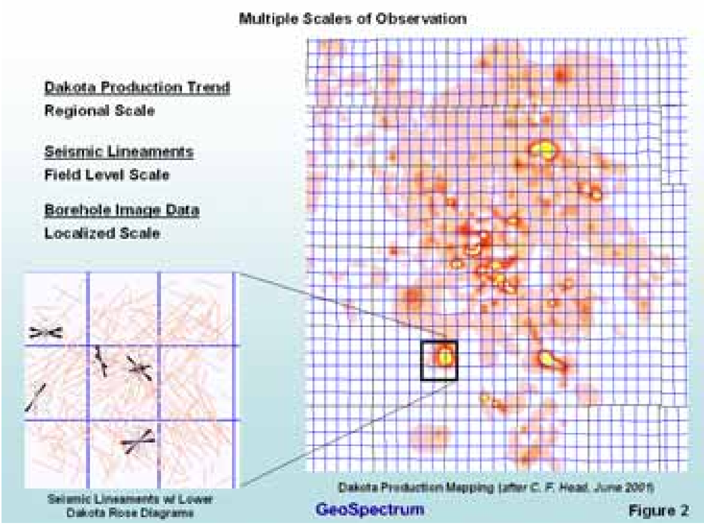

Figure 2. Dakota production map with inset detailing showing lineaments (pink lines) and rose diagrams (black symbols) indicate fracture orientation from all three scales of data are in agreement showing a classic “fractal-like” dependence of the data. (map courtesy of Charles F. Head, Burlington Resources, 2001)

fractures oriented in the northeast or northwest directions. These fracture orientations should be available for fluid or gas flow in the unit. However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.

A number of leads can be distinguished from Figure 1 from the anomalous clusters of multidirectional lineaments. Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments is associated with structural troughs and noses seen in the Lower Dakota corrected seismic structure map.

Figure 2 defines fracture-related reservoir anisotropy on three different scales of data:
• localized scale/rose diagrams show Lower Dakota fracture orientations interpreted from borehole image logs;
• a field-level scale from seismic lineaments; and
• a regional scale from Dakota cumulative production trends.

Inferred fracture orientations from all three scales of data are in agreement showing a classic “fractal-like” dependence of the data at different scales.

Upper Dakota fractures/ interval velocity anisotropy
Seismic **interval velocity anisotropy** is used to investigate reservoir potential up-hole from the main reservoir target. It is interpreted that large interval velocity anisotropy is associated with fracture related anisotropy.

Figure 3 shows a seismic-guided Upper Dakota fracture density map modeled from Dakota fracture counts measured from borehole image logs for five wells. Fracture density mapping is done with collocated cokriging using interval velocity anisotropy (correlation coefficient 0.6). Interval velocity anisotropy is computed as Dix’s interval velocity for 145 ± 22.5° azimuth data minus the interval velocity for 55 ± 22.5° azimuth data. The increase in signal:noise ratio obtained by prestack time migration has improved the ability to perform this analysis. Interval velocities were computed for a zone between two strong seismic reflectors, including most of the Upper Dakota from the top of the Lower Cubero to the top of the Green Horn immediately above the Dakota. This analysis is used to infer prospective Upper Dakota fractures.

Fractured reservoir prospects

Lower Dakota clay volume/seismic amplitude AVO attribute
Lead areas defined by regions of swarming multi-directional or intersecting lineaments should be further screened by additional geologic attributes, including reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; a **collocated cokriged clay volume map computed from near trace seismic amplitude** (an amplitude variation with offset – AVO – attribute); and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. It has been interpreted that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

In Figure 4, a seismic-guided Lower Dakota clay volume map based on petrophysical analysis of log data from nine wells drilled pre-1999 is shown. Seismic-guided mapping is done with collocated cokriging using the average near trace instantaneous seismic amplitude from a narrow zone (about 3 milliseconds) in the Lower Dakota (measured cross correlation = 0.8). Note that the horizon defining this zone is the same as that used to define the phase gradient AVO attribute described later in this article. The phase gradient and near trace amplitude are AVO attributes. Two distinct rock types are defined by the map: low clay (less than about 13%) shown by hot colors and high clay (greater than about 13%) shown by cooler colors. This article focuses on low clay reservoir and regions of swarming/intersecting lineaments.

In the figure, notice the unique directional distributions for seismic lineaments as a function of rock type, low vs. high clay. Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction, and high clay rocks are associated with lineaments in the northwest direction. It is not surprising that the two rock types have differing distributions of lineaments. Their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses and how the two interact with each other during their tectonic stress history control fractures in these two rock masses.

Modeling the state of stress underground using a finite element or finite difference method should test results. One would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

Note the orientation of fractures inferred from the Upper Dakota interval velocity anisotropy (Figure 3). Most of the values are shaded in red on the map, which may indicate an abundance of northeast trending fractures. If the anisotropy is related to fracture counts, it can be concluded that northwest trending fractures (green) are not as common as northeast trending fractures. Therefore, the distribution of fractures in the Upper Dakota over the study area appears to be more similar to the distribution of seismic lineaments or fractures in the Lower Dakota for the clean low clay rock type (Figure 4). Their differing depositional environments and tectonic history should explain the differences between the Upper and Lower Dakota fracture distributions. The Lower Dakota are non-marine fluvial channel sands, whereas the Upper Dakota are mostly marine shoreline sands. Each of these units should have differing rock types and geometries that effect fracture distributions.

Gas prediction/seismic phase gradient AVO attribute

Gas production data is analyzed using a cross plot showing hydrocarbon pore volume vs. porosity-thickness and the best of 12 months of gas production. Significant or good wells in the study area are distinguished by a gas saturation cut-off of about 33%. There appears to be a random correlation between the best of 12 months of production indicator for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality does not increase linearly with reservoir volume.)

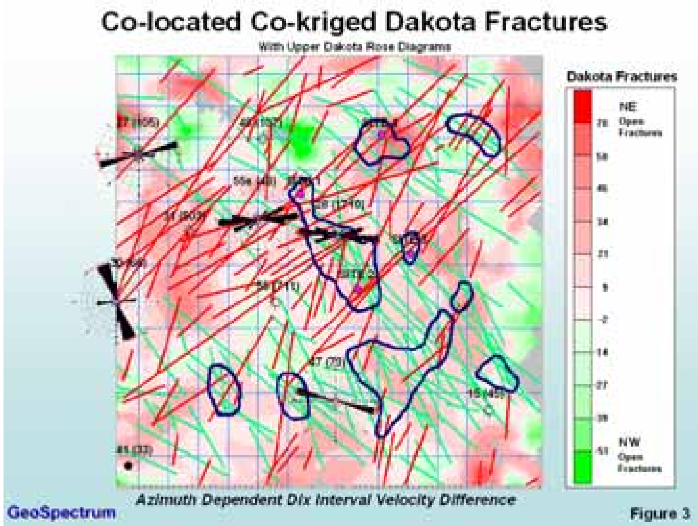

Figure 3. Collocated cokriged Dakota fractures map using seismic interval velocity anisotropy in the Upper Dakota/Green Horn fracture counts from borehole image data measured in unit wells drilled pre-1999. Black rose diagrams indicate fracture orientations determined from borehole image logs in Upper Dakota.

A gas-sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient** is used to further define drill locations having high gas saturation (correlation coefficient 0.9). The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they also may penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Figure 5 shows seismic-guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than roughly 13%. Seismic-guided mapping is done using collocated cokriging and the empirical trend line for low clay reservoir (phase difference vs. gas saturation) from unit wells drilled pre-1999. Gas saturations between about 33% to 60% (determined from petrophysical analysis) define a prospective trend for Lower Dakota fracture-controlled gas production in the unit. The lower end gas cutoff (33%) is interpreted from the cross plot of hydrocarbon pore volume vs. porosity thickness and best of 12 months of production indicator. The high-end gas cutoff (60%) comes from the hydrocarbon pore volume determined for the significant gas-producing unit wells (numbers 28, 55 and 31).

Two prospective trends that correspond to regional Dakota production are indicated in the northwest and northeast directions. Notice that more favorable gas/AVO attributes are typically found regionally on the updip side of the map. The well 52 prospect has nearly identical phase difference attributes or a computed “gas saturation” as well 28, indicating similar AVO characteristics. In practice, it is recommended the AVO attributes should be reviewed in the common midpoint offset domain before any prospect is drilled to further confirm the AVO phase gradient mapping. Well 55E, which was drilled between the productive wells 31 and 28, is not shown to be prospective, which collaborates with its poor completion results. The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir.

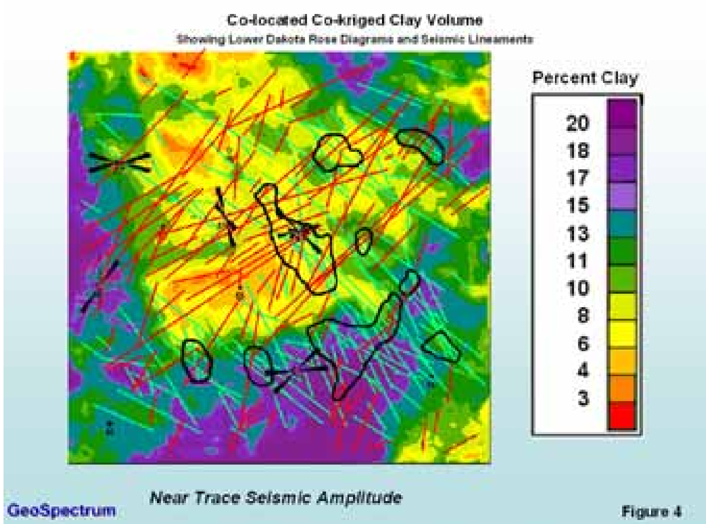

Figure 4. Collocated cokriged Lower Dakota clay volume from unit wells drilled pre-1999 indicating prospective regions defined by low clay reservoir in areas of swarming/intersecting lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths).

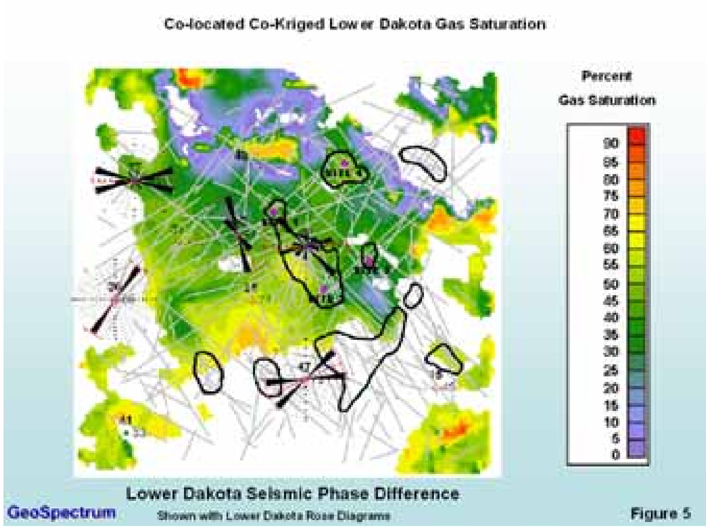

Figure 5. Collocated cokriged Lower Dakota gas saturation from unit wells drilled pre-1999 showing the well 52 prospect to have nearly the same phase gradient AVO response/gas saturation as well 28 (a significant Lower Dakota gas producer). The phase gradient/computed gas saturation also explains the poor production encountered by well 55E.

Seismic modeling has not confirmed the empirical relationship of the seismic phase difference attribute and gas saturation. Additional work could be done using full-wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 5 should only be used to define prospective trends for gas production, not for actual gas saturation values.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon, which is near the gas. The interpretation should provide important additional information as to the role of channel stratigraphy and trapping mechanism.

In summary, the phase gradient attribute shows all three pre-1999 significant unit wells (numbers 28, 31 and 55) in the Encinal Sand as gas bearing. It explains the poor results of nearby well 55E as gas not being present. Also note the low clay and high clay rock types (good vs. poor reservoir quality) in the Lower Dakota are distinguished in three different seismic attributes that confirm and unify the interpretation:

• near trace seismic amplitude (Figure 4);
• seismic lineament orientation (Figure 4); and
• phase gradient/AVO characteristics (Figure 5).

The gas-sensitive AVO attribute has defined a prospective fairway through the unit in the Lower Dakota sandstone (Figure 5) with successful recent drilling results.

Selected prospects

Overlaying the Lower Dakota phase gradient attribute with the seismic lineament map develops prospects. A prospective fairway is defined where Lower Dakota gas saturation is between 37% to 62% and clay volume is less than 13%. Three prospects (wells 52, 28E and 31E) are chosen to drill on swarming/intersecting lineaments in the fairway. Well 52 tests attributes near the northeast edge of the fairway, Well 28E tests attributes near the central region of the trend, and well 31E tests attributes near the southeast edge of the prospective fairway. The fourth prospect, well 53, is selected to test a swarm of seismic lineaments close to the southwest/ central edge of the 3-D seismic coverage. However, well 53 does not have favorable AVO attributes. The four prospect locations (wells 28E, 31E, 52 and 53) are shown in Figure 5, and are spotted on or near lineaments or intersection points of the lineaments. Note that depending on drilling results, a number of other locations would justify drilling if the reservoir constraints can be relaxed and locations picked based mainly on the phase gradient AVO attribute.

Drilling results

Burlington Resources and Huntington Energy drilled and completed the well 52 prospect in January. The well had an initial potential of nearly 4,000 Mcfg/d and is flowing about 850 Mcfg/d to 900 Mcfg/d (Table 1). The three additional prospects also have been drilled. Well 28E was drilled and completed in May and is producing greater than about 2,100 Mcfg/d, and no significant decline in production has occurred. Well 31E was drilled and completed in June and is expected to produce from roughly 850 Mcfg/d to greater than 2,000 Mcfg/d. Burlington Resources and Huntington Energy recently have laid pipe to the well to sell the gas. The fourth well, No. 53, was drilled and completed in April and initially produced about 2,000 Mcfg/d and is now only producing about 230 Mcfg/d. This well has favorable seismic lineament (fractured) reservoir attributes, however it does not have a good AVO (gas) attribute. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon sandstone, underneath the productive Encinal Sand found in the Lower Dakota wells. It has been predicted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

Conclusions

The three productive unit wells (28, 55 and 31) and the productive new prospect wells (28E, 31E, 52 and 53) completed this year, appear to be predicted with nearly 100% success (Table 1) using the following methodology to explore for Lower Dakota gas:
• locate well in or near alluvial sand channels;
• Lower Dakota clay content less than or equal to roughly 13%;
• AVO attribute indicating phase difference between -15° to -85° (gas saturation about 37% to 62%);
• spot well near intersecting or swarming seismic lineaments; and
• look for up-hole fracture potential using Upper Dakota interval velocity anisotropy.

The authors have interpreted that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the prospect wells and the economic discovery of gas in three prospects validates the results of the Phase I, U.S. Department of Energy (DOE) study. These drilling results confirm the value of the applied methodology in detecting commercial and prospective targets in fractured tight gas sands. An automated approach could be developed to apply the technology.

For more information, please contact GeoSpectrum's principal investigator, Dr. James J. Reeves, at (432) 686-8626 ext. 101 or *jreeves@geospectrum.com*, or the DOE technical contract officer, Frances C. Toro at (304) 285-4107 or *frances.toro@netl.doe.gov*.

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Initial Production (MCFGPD)
52	01/2004	Low	High	High	High	4000
53	04/2004	High	High	No AVO Attribute	High	Declined to about 230
28E	05/2004	Low	High	High	Low	2100
31E	06/2004	Low	Low	High	Low	850 – 2000 (Estimated)

Table 1. Conclusions/prospect drilling results.

APPENDIX 3
Seismic exploration for fractured Lower Dakota alluvial gas sands, San Juan Basin, New Mexico

(American Association of Petroleum Geologists Rocky Mountain Section Meeting, Denver, Colorado, Reeves & Smith, 2004)

James J. Reeves and W. Hoxie Smith
GeoSpectrum, Inc., Midland, Texas

Introduction

The first phase of a U.S. Department of Energy (DOE) – funded project has been successfully completed (GeoSpectrum, Inc. 2003). Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the Lower Dakota reservoir section. A seismic lineament is defined as a linear feature seen in a time slice or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir.

Lead areas defined by regions of "swarming" multi-directional lineaments are further screened by additional geologic attributes. These attributes include reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; and a collocated cokriged clay volume map for the reservoir zone computed from near trace seismic amplitude (an AVO attribute) and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. This map indicates where good/clean reservoir rock is located. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, (phase gradient), is used to further define drill locations having high gas saturation. The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water saturated zones in the Dakota and/or Morrison intervals and be responsible for the reservoir being water saturated and ruined.

Seismic interval velocity anisotropy is used to investigate reservoir potential in tight sands of the Upper Dakota up hole from the main reservoir target. We interpret that large interval velocity anisotropy is associated with fracture related anisotropy in these tight sands.

A four well drilling program is planned to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The first well, the Canyon Largo Unit No. 452 (Site 4) was drilled and completed last January 14th and had an initial production of 4 MMCFGPD from the Lower Dakota Encinal Formation. The well continues to produce at about 1.4 MMCFGPD at 175 PSI and is one of the better wells in the field, and a very good well in this area of the basin. Information on the well can be found in the Petroleum Technology Transfer Council (PTTC, 2004) Network News, 1st Quarter, 2004. If drilling results continue to be successful, GeoSpectrum's fracture detection methodology is ready to be applied on a commercial basis.

Discussion

In the San Juan basin, reservoir qualities are highly variable. Finding the right drill site may involve identification of fracture-induced anisotropy in tight gas sands. Multiple-azimuth 3D seismic attributes and petrophysical data help find the sweet spots. This paper details the justification and methodology employed to drill and complete an Encinal sand fractured-reservoir prospect. The well was spotted by applying modern seismic-processing techniques followed by rigorous analysis of azimuth-dependent seismic attributes, and well-log data to qualify areas of high natural-fracture density. (Portions of this paper are taken in whole or in part from Reeves and Smith, "World Oil," September 2002.)

GeoSpectrum, Inc., reprocessed a 9 mi 2 3D seismic data set acquired with an omni-directional receiver array to provide broad-offset azimuth statistics. The processing was focused on stack analysis of anisotropy in multiple azimuths followed by pre-stack analysis of amplitude variation with offset (AVO). The processed data and subsequent statistical analysis of seismic attributes were interpreted for identification of fractures prospective for commercial gas production. Relationships between seismic attributes and measured reservoir properties, such as clay content, as well as Dakota fracture density interpreted from borehole-image logs, were investigated.

The gas-producing unit characterized in this study is located in Rio Arriba County, New Mexico. Gas production is mainly from the Cretaceous Dakota and Gallup sandstones. The most significant Dakota production occurs in the Lower Dakota, mainly from the Encinal and Burro Canyon sands. Prospective Dakota horizons include both conventional tight (upper) and permeable (lower) sandstones. Reservoir stratigraphy of the Dakota producing interval is complex, with production potential in five individual sandstones. Dakota sandstone depositional environments range from near marine (fluvial-deltaic) to marine. (Note: The well names in the Figures have been changed for the purpose of anonymity.)

Seismic Lineament Mapping

In Figure 1, Lower Dakota lineaments are mapped as interpreted from azimuth-dependent and/or all-azimuth seismic-attribute volumes. Seismic attributes analyzed in the study include azimuth-dependent and/or all-azimuth Dix interval velocity, instantaneous amplitude, frequency, phase, coherency, and difference attributes. Seismic imaging was improved significantly by GeoSpectrum's reprocessing, using azimuth dependent pre-stack time migration. Migration will increase lateral spatial resolution, signal-to-noise ratio, and aid in analysis of pre-stack seismic attributes. Lineaments seen in these enhanced seismic volumes are interpreted to infer fracture zones. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Note the concentrated number of lineaments found at Well 28 on the map. Lower Dakota lineament density is computed from the lineaments assuming a well-drainage area or grid size of about 900 ft x 900 ft. Regions of high lineament density (about 7 or more lineaments per grid) are outlined in Figure 1, showing prospective locations (Site 4). A similar method to interpret fracture zones using seismic lineaments was done for ARCO Permian in a reservoir study of the South Justis Unit, Lea County, New Mexico (Reeves and Smith, 1999).

Lower Dakota lineament density (Fig. 2) is computed from the lineaments in Figure 1. It assumes a well-drainage area of about 900 ft x 900 ft. The hotter colors are interpreted to indicate fracture-developed reservoirs showing several prospective locations.

Collocated Cokriged Clay Volume Map

In Figure 3, a seismic-guided Lower Dakota clay volume map is shown. It is based on petrophysical analysis of log data from nine wells. Seismic-guided mapping was done using collocated cokriging with near-trace instantaneous seismic amplitude (measured cross correlation = 0.81). The best gas-producing wells and most prospective areas are associated with wells having the least clay. We interpret that reservoir rocks having low clay content should be more brittle and more likely to be fractured in areas of swarming seismic lineaments. Furthermore, clays typically have high water content, increasing the likelihood of a clay-rich reservoir being water-wet.

Phase Gradient AVO Attribute

The importance of a gas sensitive AVO attribute is illustrated by the petrophysical analysis in Figure 4, where Lower Dakota hydrocarbon pore volume vs. porosity-thickness and the average of the best of 12 months of production for each well are shown. Note that significant wells in the unit are distinguished by a gas-saturation cut off of about 33%. Also, notice the apparent poor correlation between the best of 12 months of production for the good wells and reservoir volume (porosity-feet), which suggests a fracture-controlled reservoir. Dakota fracture counts interpreted from borehole image logs vs. the best of 12 months of production shows that most fractures occur in the best producing well in the unit, Well 28.

A gas sensitive Class 2 AVO anomaly typically exhibits a low-amplitude, near-offset seismic response and a phase reversal with increased amplitude at far offsets. This was confirmed in the Dakota by comparing synthetic modeling with real gathers from dipole sonic and density logs from a nearby well, where gas saturation averages about 23% (Castagna, et al., 1998). A 25-fold super-gather was computed and extracted at the Well 28 location, after normal move-out and pre-stack time migration. This revealed an apparent Lower Dakota Class 2 AVO anomaly that is visible through much of the 3D seismic volume.

The crossplot in Figure 5 shows Lower Dakota phase gradient: [near-trace phase minus far-trace phase] vs. gas saturation computed from the petrophysical analysis. The outlying wells with gas saturations below 24% have Lower Dakota clay content greater than 13%. The trend-line is based on the remaining five wells that have clay content less than 13% and gas saturations greater than 24%. Note that three of these five wells (28, 55 and 31) are the most productive wells in the unit, and are associated with a phase gradient ranging between -15° and -85°. The trend-line has a measured cross-correlation coefficient of 0.89. The analysis of a phase dependent AVO attribute decreases the concern with amplitude scaling issues in the seismic data.

Mapping seismic phase difference values between -15° and -85° reveals two prospective trends that correspond to regional Dakota production. If this map is further constrained by showing only areas with estimated clay less than about 12 - 13% (i.e., Fig. 3), the results show areas of brittle, fracture-prone rocks having a favorable AVO attribute. Figure 6 shows seismic-guided Lower Dakota gas saturation modeled from the phase gradient attribute with estimated clay content less than about 12 - 13%. Seismic-guided mapping was done using collocated cokriging and the empirical trend-line (phase gradient vs. gas saturation) in Figure 5. Gas saturations between about 40% and 60% define prospective trends for Lower Dakota fracture-controlled gas production in the unit. The gas saturation mapped in Figure 6 should be used to define prospective trends for gas production, not for actual gas saturation values. The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water saturated zones in the Dakota and/or Morrison intervals and be responsible for the reservoir being water saturated and ruined. Efforts to model the phase gradient vs. gas saturation characteristic in Figure 5 using Gassman modeling methods have been unsuccessful. The authors are hopeful to obtain additional funding from the DOE for AVO modeling using a full wave equation solution.

Interval Velocity Anisotropy

Figure 7 shows a preliminary seismic-guided Upper Dakota fracture-density map modeled from Dakota fracture counts, as interpreted from borehole image logs for five wells. Fracture-density mapping was done using collocated cokriging with Dix's interval velocity anisotropy, for a thin interval including most of the Upper Dakota and some additional strata above the Dakota, computed for 145° ±22.5° azimuth seismic data minus 55° ±22.5° azimuth seismic data (measured cross-correlation = -0.61). Note the trend of positive high fracture density associated with Well 28 on the map. A positive density may indicate that fractures in the northeast direction tend to be open in the interval. Other prospective regions of high positive fracture density are also seen to the northeast of Well 28 at the proposed Site 4 location indicating possible reservoir potential up-hole from the Lower Dakota.

Conclusions

In Figure 8, a composite-attribute map comprising seismic lineaments (thin black lines), high lineament density (thick black outlines), favorable AVO gas attributes and low clay (bright red) is shown. Bright red regions inside the thick black outlines indicate the most prospective drill locations. The recently drilled prospect (CLU 452) is indicated by Site 4 on the map. The four Lower Dakota productive Wells (CLU 452, 28, 55, and 31) are predicted with about 100% success.

The following 3D seismic fracture interpretation methodology is tested for exploration of fractured developed gas sands in the Lower Dakota:

1. Clay content should be less than or equal to roughly 13%;
2. The AVO attribute phase gradient should be between -15° to -85° (gas saturation about 40%-60%);
3. Significant fractures are indicated by a seismic lineament density of at least five lineaments per 900 ft x 900 ft grid.

Well 48 Blind Test

The results of Well 48, drilled about 1 mi northwest of Well 28, were held confidential from GeoSpectrum during the study. The results from this marginally producing well were not integrated into the work. GeoSpectrum's methodology would not have supported drilling this well. The well was spotted in a region of lower seismic lineament density (Fig. 1) and poor phase gradient AVO attributes (Fig. 6).

Site 4 prospect: Canyon Largo Unit 452 – A four well drilling program is planned to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The first well, the Canyon Largo Unit No. 452 (Site 4) was drilled and completed last January 14th and had an initial production of 4 MMCFGPD from the Lower Dakota Encinal Formation. The well continues to produce at about 1.4 MMCFGPD at 175 PSI and is one of the better wells in the field, and a very good well for this area of the basin. Information on the well can be found in the Petroleum Technology Transfer Council (PTTC, 2004) Network News, 1st Quarter, 2004. If drilling results continue to be successful, GeoSpectrum's fracture detection methodology is ready to be applied on a commercial basis.

References Cited

Castagna, J. P., Peddy, C., Lausten, C. D., and Mueller, E., 1998, Evaluation of seismic amplitude versus offset techniques for the direct detection of gas reservoirs: Phase II - Increasing the use of amplitude versus offset techniques in the continental United States: Gas Research Institute Final Report, no. GRI-98/0120, pages 5 and 108 (Figures 1 and 73, respectively).

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Reeves, J. J. and Smith, W. H., 2002, Picking prospects in tight gas sands using multiple azimuth attributes: World Oil, 223, No. 9, 45-52.

Figures

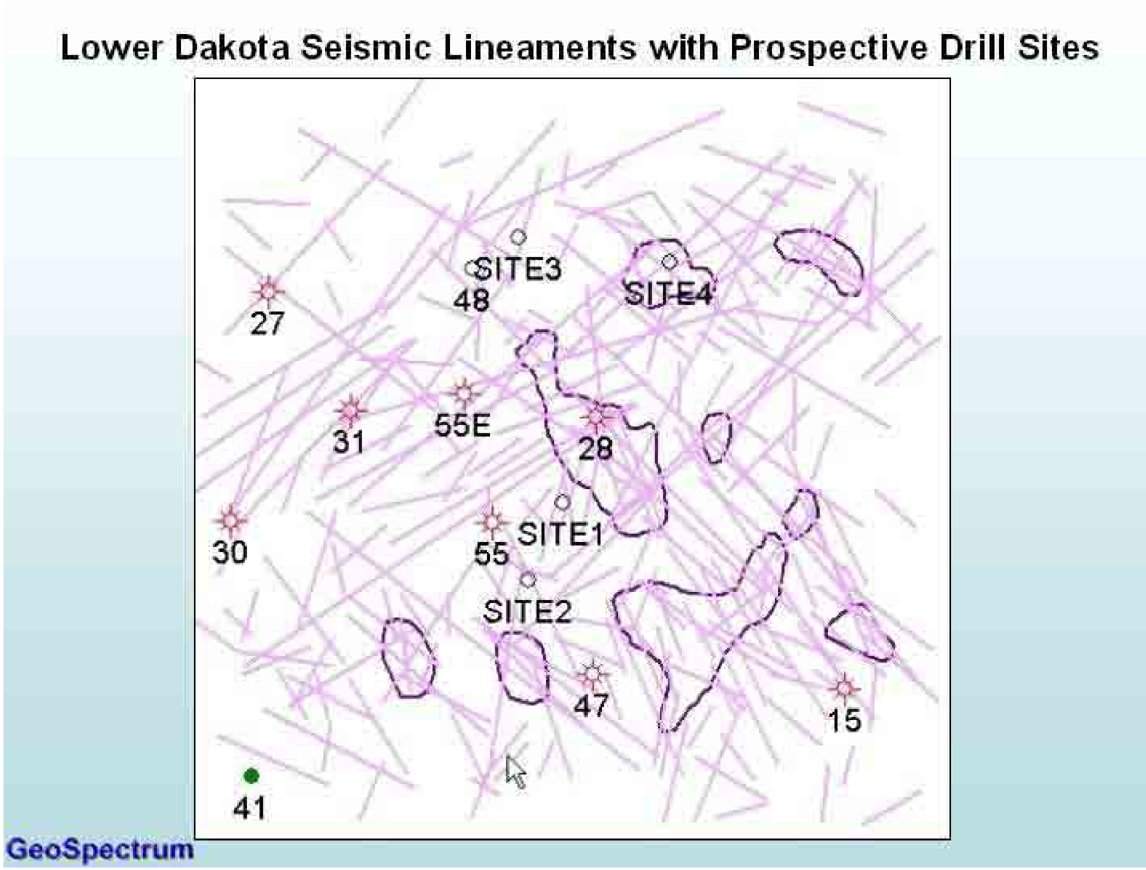

Figure 1. Lower Dakota seismic lineaments.

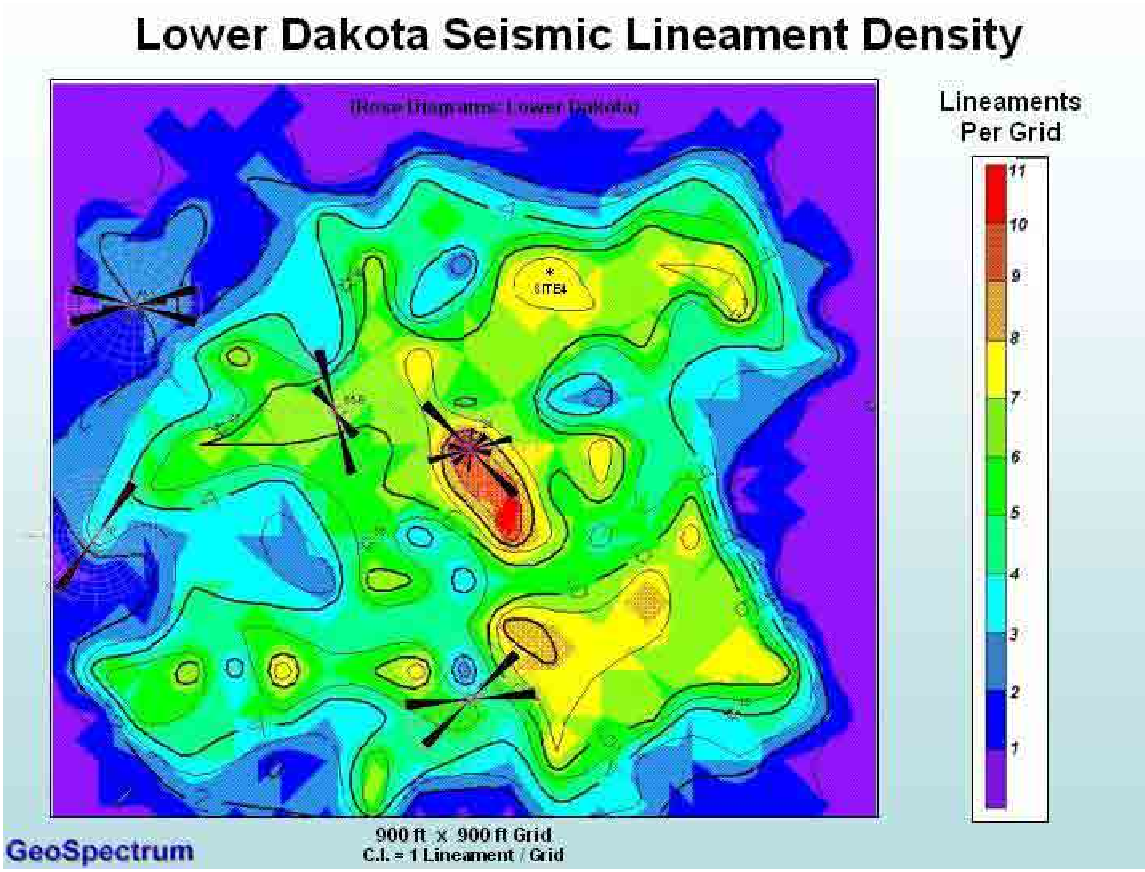

Figure 2. Lineament density computed from Figure 1. Warmer colors indicate higher density.

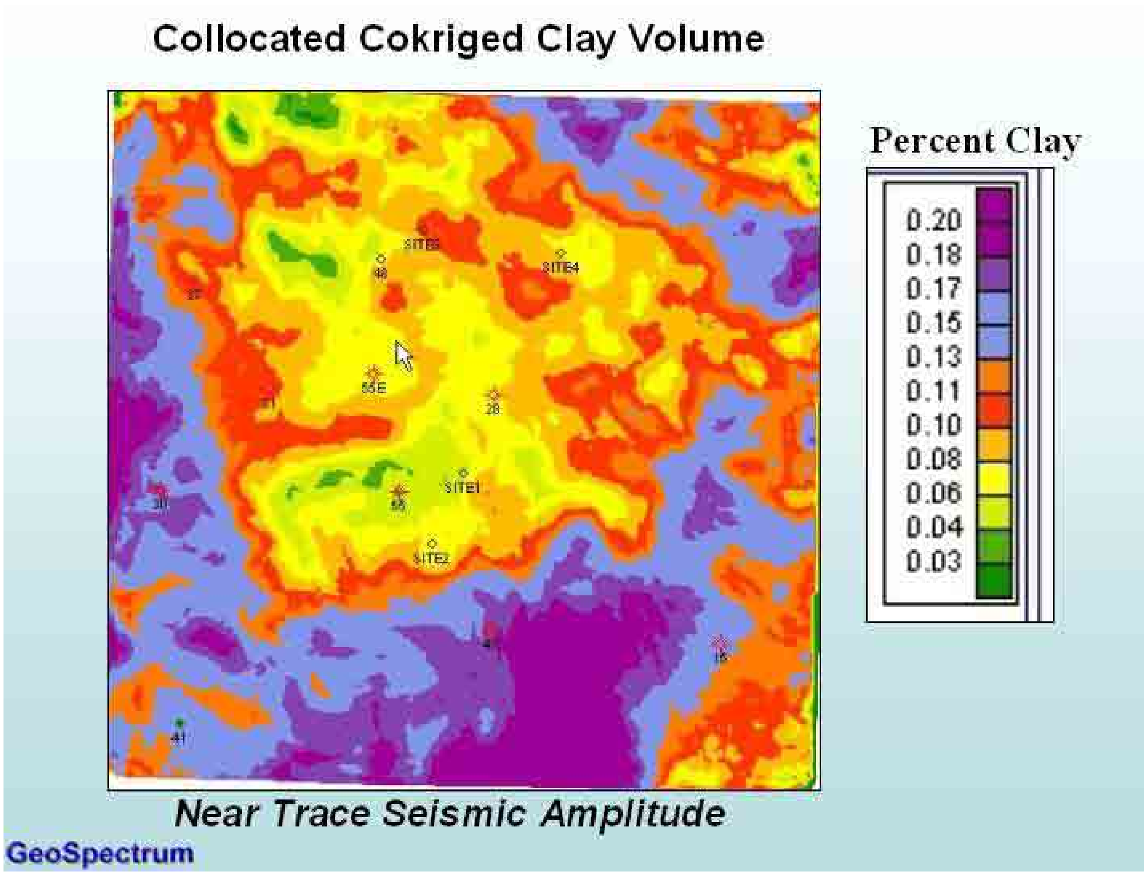

Figure 3. Collocated cokriged clay volume from near-trace seismic amplitude.

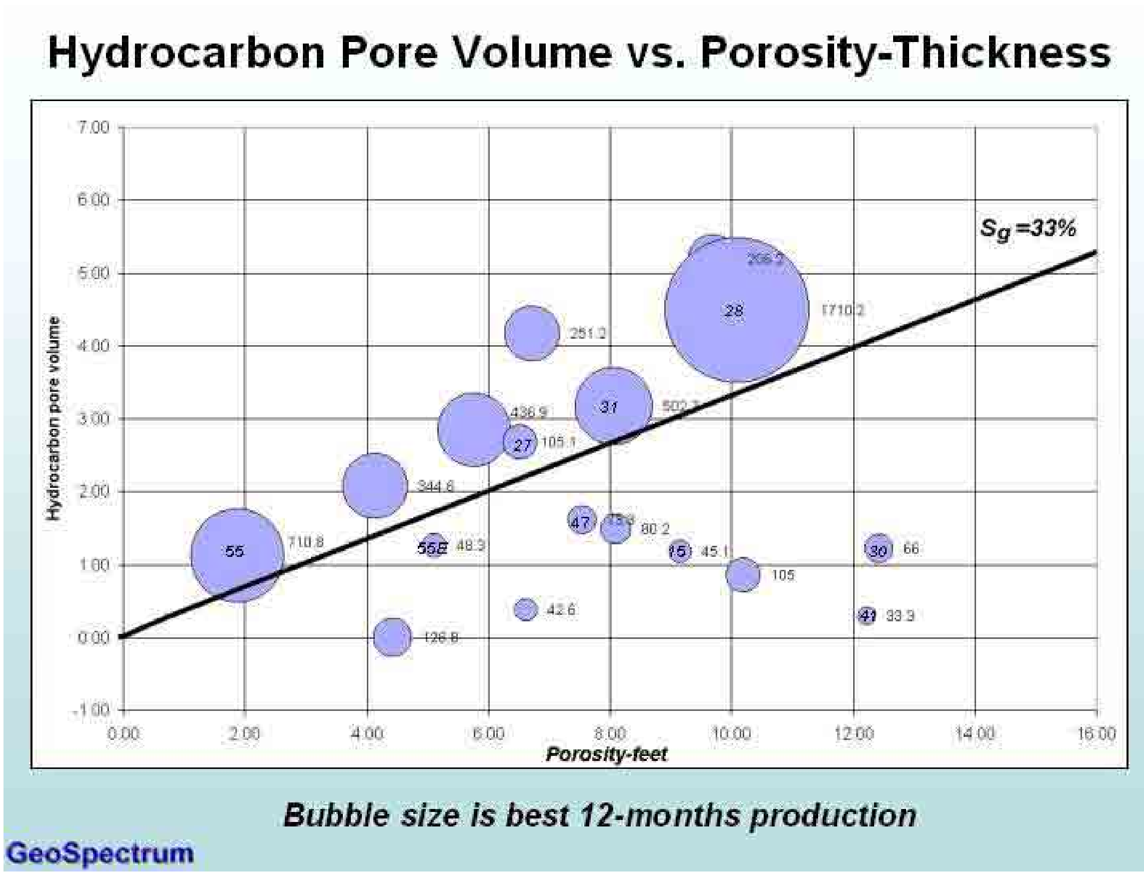

Figure 4. Lower Dakota hydrocarbon pore volume vs. porosity-thickness and the average of the best of 12 months of production for each well.

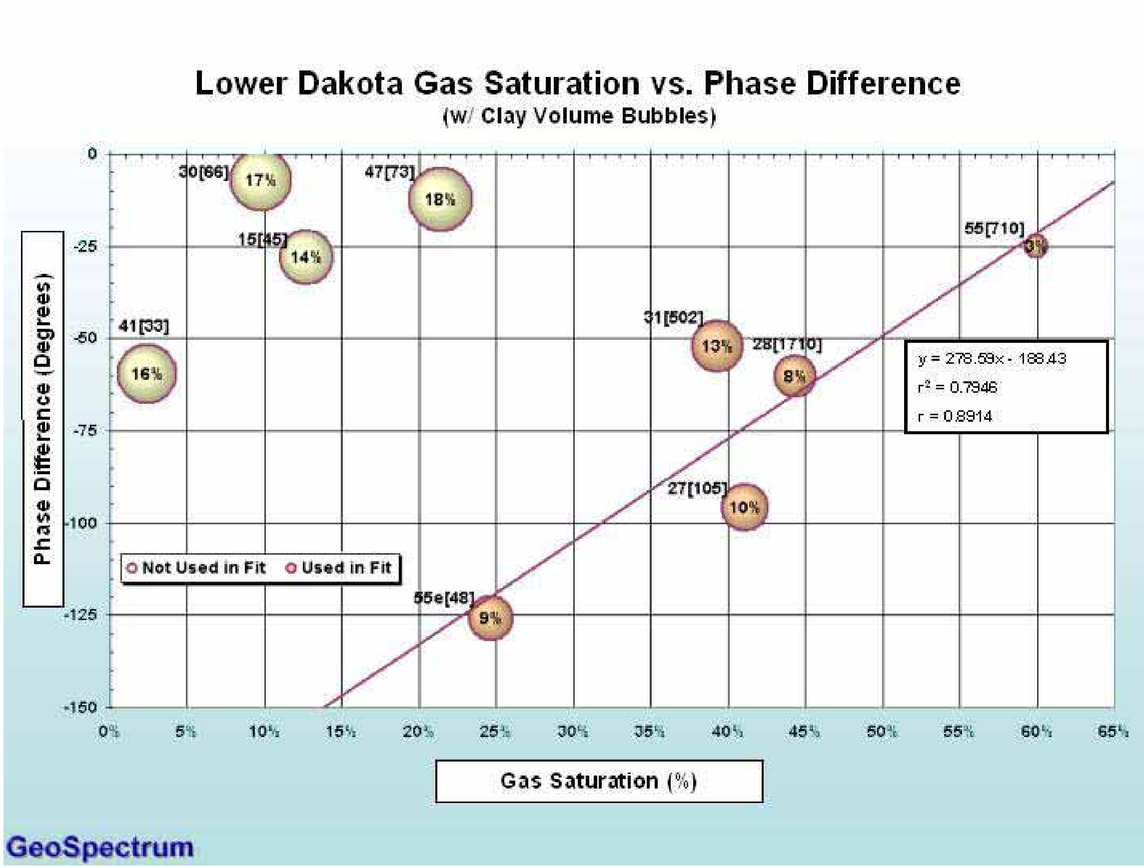

Figure 5. Lower Dakota graph of phase gradient: (near-traces minus far-traces) vs. gas saturation.

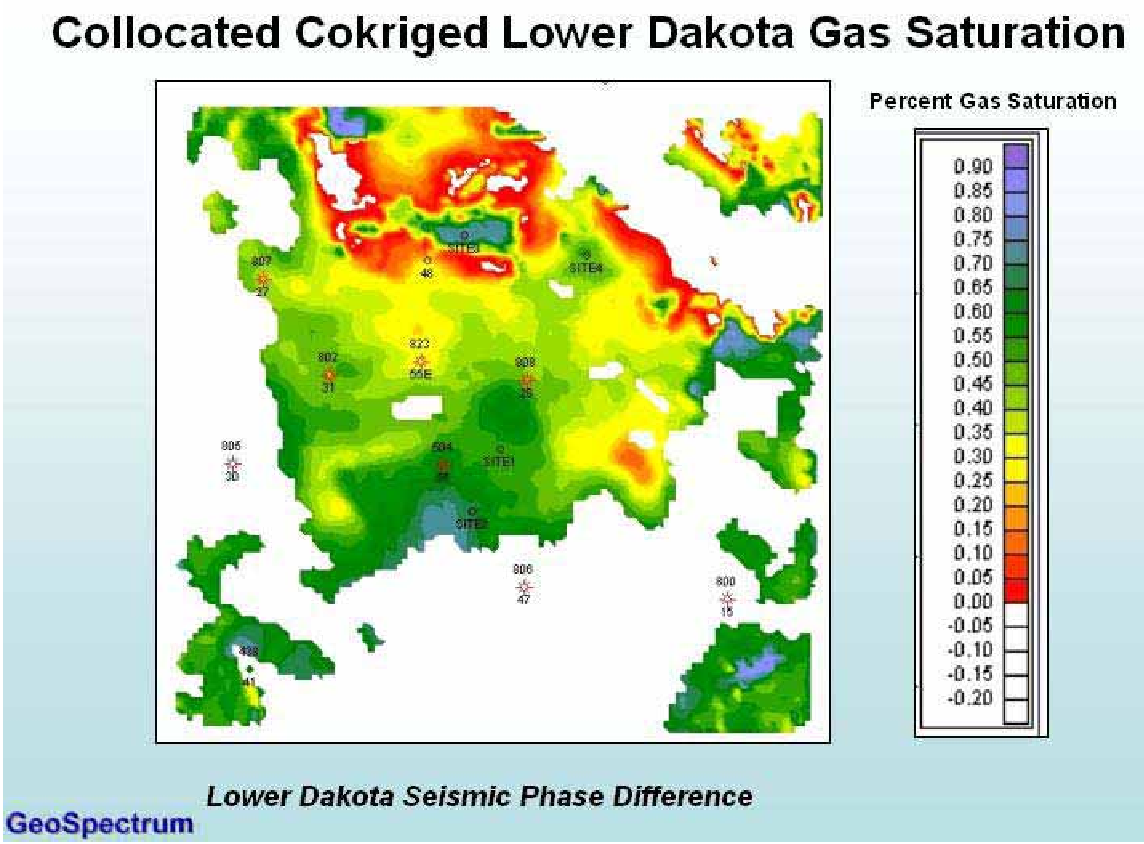

Figure 6. Seismic-guided Lower Dakota gas-saturation map (estimated clay volume <12% - 13%).

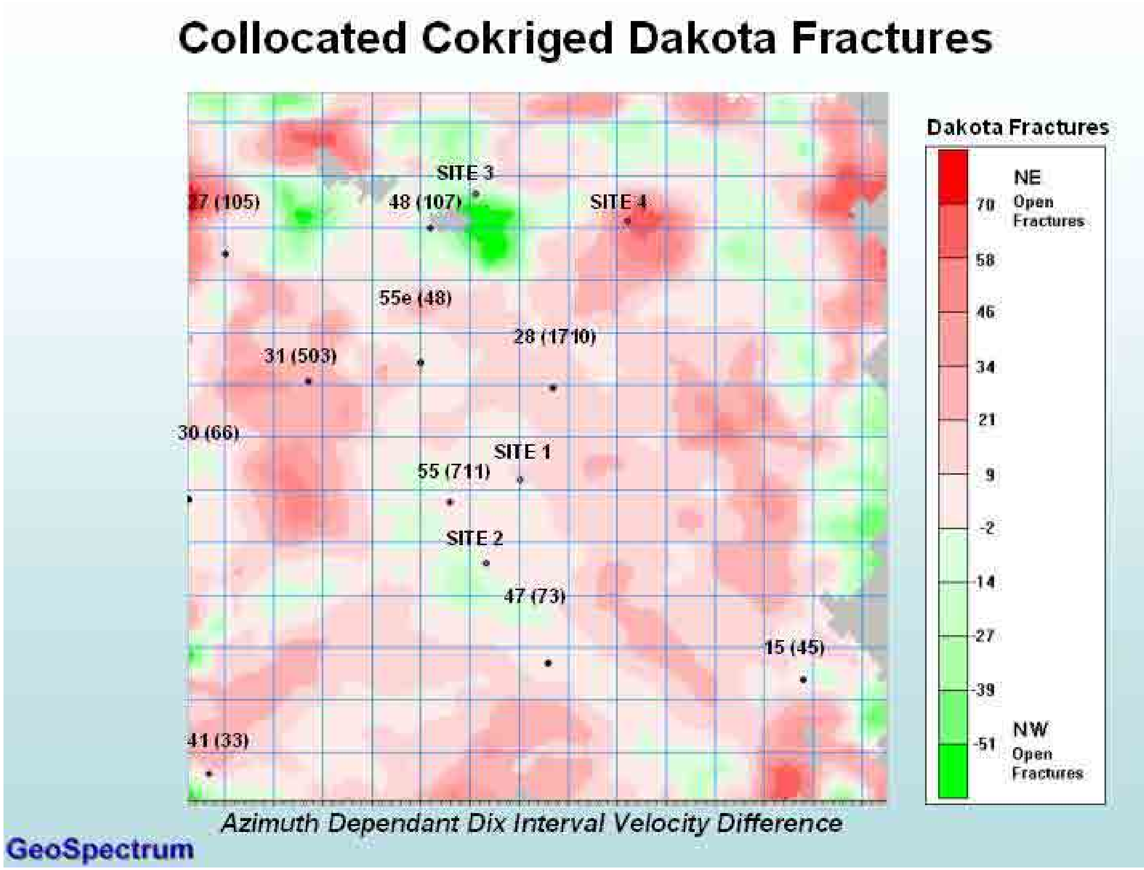

Figure 7. Collocated cokriged fracture density computed from Dix's interval velocity.

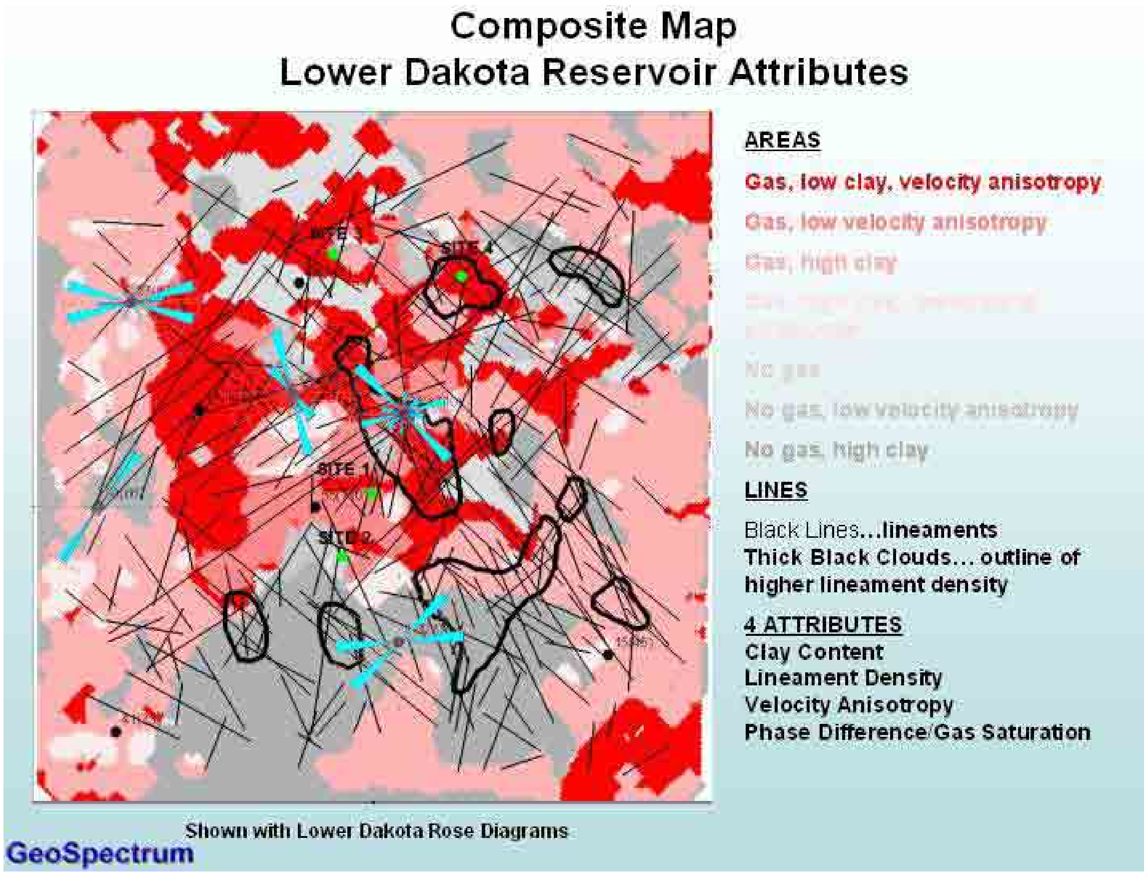

Figure 8. Composite-attribute map, showing seismic lineaments (thin black lines), high lineament density (thick black outlines), favorable AVO attributes and low clay (bright red). Well 48, a poor producer, should not have been drilled based on its poor phase gradient AVO and lineament density attributes. Clay-rich Lower Dakota reservoir is interpreted to have poor gas saturation/production.

APPENDIX 4

A 3D seismic fracture interpretation method for exploration of Lower Dakota alluvial gas sands, San Juan Basin, New Mexico

(Society of Exploration Geophysicists 74th Annual Meeting, Denver, Colorado, Reeves & Smith, 2004)

James J. Reeves, Ph.D., P.G., P.E. and W. Hoxie Smith, M.S., GeoSpectrum, Inc.*

Summary

The first phase of a U.S. Department of Energy (DOE) – funded project has been successfully completed (GeoSpectrum, Inc. 2003). Reservoir fractures are predicted using multiple azimuth **seismic lineament mapping** in the Lower Dakota reservoir section. A seismic lineament is defined as a linear feature seen in a time slice or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir.

Lead areas defined by regions of “swarming” multi-directional lineaments are further screened by additional geologic attributes. These attributes include reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; and a **collocated cokriged clay volume map** for the reservoir zone computed from near trace seismic amplitude (an AVO attribute) and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. This map indicates where good/clean reservoir rock is located. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient**, is used to further define drill locations having high gas saturation. The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water saturated zones in the Dakota and/or Morrison intervals and be responsible for the reservoir being water saturated and ruined.

Seismic **interval velocity anisotropy** is used to investigate reservoir potential in tight sands of the Upper Dakota up hole from the main reservoir target. We interpret that large interval velocity anisotropy is associated with fracture related anisotropy in these tight sands.

A four well drilling program is planned to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The first well, the Canyon Largo Unit No. 452 (Site 4) was drilled and completed last January 14th and had an initial production of 4

MMCFGPD from the Lower Dakota Encinal Formation. The well continues to produce at about 1.4 MMCFGPD at 175 PSI and is one of the better wells in the field, and a very good well in this area of the basin. Information on the well can be found in the Petroleum Technology Transfer Council (PTTC) Network News, 1st Quarter, 2004. If drilling results continue to be successful, GeoSpectrum's fracture detection methodology is ready to be applied on a commercial basis.

Introduction

In the San Juan basin, reservoir qualities are highly variable. Finding the right drill site may involve identification of fracture-induced anisotropy in tight gas sands. Multiple-azimuth 3D seismic attributes and petrophysical data help find the sweet spots. This paper details the justification and methodology employed to drill and complete an Encinal sand fractured-reservoir prospect. The well was spotted by applying modern seismic-processing techniques followed by rigorous analysis of azimuth-dependent seismic attributes, and well-log data to qualify areas of high natural-fracture density.

GeoSpectrum, Inc. reprocessed a 9 mi 2 3D seismic data set acquired with an omni-directional receiver array to provide broad-offset azimuth statistics. The processing was focused on stack analysis of anisotropy in multiple azimuths followed by pre-stack analysis of amplitude variation with offset (AVO). The processed data and subsequent statistical analysis of seismic attributes were interpreted for identification of fractures prospective for commercial gas production. Relationships between seismic attributes and measured reservoir properties, such as clay content, as well as Dakota fracture density interpreted from borehole-image logs, were investigated.

The gas-producing unit characterized in this study is located in Rio Arriba County, New Mexico. Gas production is mainly from the Cretaceous Dakota and Gallup sandstones. The most significant Dakota production occurs in the Lower Dakota, mainly from the Encinal and Burro Canyon sands. Prospective Dakota horizons include both conventional tight (upper) and permeable (lower) sandstones. Reservoir stratigraphy of the Dakota producing interval is complex, with production potential in five individual sandstones. Dakota sandstone depositional environments range from near marine (fluvial-deltaic) to marine. (Note: The well names in the Figures have been changed for the purpose of anonymity.)

Theory and/or Method

Seismic lineament mapping – In Figure 1, Lower Dakota lineaments are mapped as interpreted from azimuth-dependent / all-azimuth seismic-attribute volumes. Seismic attributes analyzed in the study include azimuth-dependent / all-azimuth Dix interval velocity, instantaneous amplitude, frequency, phase, coherency, and difference attributes. Seismic imaging was improved significantly by GeoSpectrum's reprocessing, using azimuth dependent pre-stack time migration. Migration will increase lateral spatial resolution, signal-to-noise ratio, and aid in analysis of pre-stack seismic attributes. Lineaments seen in these enhanced seismic volumes are interpreted to infer fracture zones. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Note the concentrated number of lineaments found at Well 28 on the map. Lower Dakota lineament density is computed from the lineaments assuming a well-drainage area or grid size of about 900 ft x 900 ft. Regions of high lineament density (about 7 lineaments per grid) are outlined in Figure 1, showing prospective locations (Site 4). A similar method to interpret fracture zones using seismic lineaments was done for ARCO Permian in a reservoir study of the South Justis Unit, Lea County, New Mexico (Reeves, J. J., and Smith, W. H., 1999).

Collocated cokriged clay volume map – In Figure 2 a seismic-guided Lower Dakota clay volume map is shown. It is based on petrophysical analysis of log data from nine wells. Seismic-guided mapping was done using collocated cokriging with near-trace instantaneous seismic amplitude (measured cross correlation = 0.81). The best gas-producing wells and most prospective areas are associated with wells having the least clay. We interpret that reservoir rocks having low clay content should be more brittle and more likely to be fractured in areas of swarming seismic lineaments. Furthermore, clays typically have high water content, increasing the likelihood of a clay-rich reservoir being water-wet.

Phase gradient AVO attribute – The importance of a gas sensitive AVO attribute is illustrated by the petrophysical analysis in Figure 3, where Lower Dakota hydrocarbon pore volume vs. porosity-thickness and the average of the best of 12 months of production for each well are shown. Note that significant wells in the unit are distinguished by a gas-saturation cut off of about 33%. Also, notice the apparent poor correlation between the best of 12 months of production for the good wells and reservoir volume (porosity-feet), which suggests a fracture-controlled reservoir. Dakota fracture counts interpreted from borehole image logs vs. the best of 12 months of production shows that most fractures occur in the best producing well in the unit, Well 28.

A gas sensitive Class 2 AVO anomaly typically exhibits a low-amplitude, near-offset seismic response and a phase reversal with increased amplitude at far offsets. This was confirmed in the Dakota by comparing synthetic modeling with real gathers from dipole sonic and density logs from a nearby well, where gas saturation averages about 23% (Castagna, J. P., Peddy, C., Lausten, C. D., and Mueller, E., 1998). A 25-fold supergather was computed and extracted at the Well 28 location, after normal move-out and pre-stack time migration. This revealed an apparent Lower Dakota Class 2 AVO anomaly that is visible through much of the 3D seismic volume.

The cross-plot in Figure 4 shows Lower Dakota phase gradient: [near-trace phase minus far-trace phase] vs. gas saturation computed from the petrophysical analysis. The outlying wells with gas saturations below 24% have Lower Dakota clay content greater than 13%. The trend-line is based on the remaining five wells that have clay content less than 13% and gas saturations greater than 24%. Note that three of these five wells (28, 55 and 31) are the most productive wells in the unit, and are associated with a phase gradient ranging between -15° and -85°. The trend-line has a measured cross-correlation coefficient of 0.89. The analysis of a phase dependent AVO attribute decreases the concern with amplitude scaling issues in the seismic data.

Mapping seismic phase difference values between -15° and -85° reveals two prospective trends that correspond to regional Dakota production. If this map is further constrained by showing only areas with estimated clay less than about 12 – 13% (i.e., Figure 2), the results show areas of brittle, fracture-prone rocks having a favorable AVO attribute. Figure 5 shows seismic-guided Lower Dakota gas saturation modeled from the phase gradient attribute with estimated clay content less than about 12 – 13%. Seismic-guided mapping was done using collocated cokriging and the empirical trend-line (phase gradient vs. gas saturation) in Figure 4. Gas saturations between about 40% and 60% define prospective trends for Lower Dakota fracture-controlled gas production in the unit. The gas saturation mapped in Figure 5 should be used to define prospective trends for gas production, not for actual gas saturation values. The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water saturated zones in the Dakota and/or Morrison intervals and be responsible for the reservoir being water saturated and ruined. Efforts to model the phase gradient vs. gas saturation characteristic in Figure 4 using Gassman modeling methods have been unsuccessful. The authors are hopeful to obtain additional funding from the DOE for AVO modeling using a full wave equation solution.

Interval velocity anisotropy – Figure 6 shows a preliminary seismic-guided Upper Dakota fracture-density map modeled from Dakota fracture counts, as interpreted from borehole image logs for five wells. Fracture-density mapping was done using collocated cokriging with Dix's interval velocity anisotropy, for a thin interval including the Upper Dakota and some additional strata above the Dakota, computed for 145° ±22.5° azimuth seismic data minus 55° ±22.5° azimuth seismic data (measured cross-correlation = -0.61). Note the trend of positive high fracture density associated with Well 28 on the map. A positive density may indicate that fractures in the northeast direction will tend to be open in the interval. Other prospective regions of high positive fracture density are also seen to the northeast of Well 28 at the proposed Site 4 location indicating possible reservoir potential up-hole from the Lower Dakota.

Conclusions

The following 3D seismic fracture interpretation methodology is tested for exploration of fractured developed gas sands in the Lower Dakota: (1) clay content should be less than or equal to roughly 13%, (2) the AVO attribute phase gradient should be between -15° to -85° (gas saturation about 40% – 60%), and (3) significant fractures are indicated by a seismic lineament density of at least five lineaments per 900 ft grid.

Well 48 blind test – The results of new Well 48, drilled last year about 1 mi northwest of Well 28, were held confidential from GeoSpectrum during the study. The results from this marginally producing well were not integrated into the work. GeoSpectrum’s methodology would not have supported drilling this well. The well was spotted in a region of lower seismic lineament density (Figure 1) and poor AVO attribute (Figure 5).

Site 4 prospect: Canyon Largo Unit 452 – A four well drilling program is planned to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The first well, the Canyon Largo Unit No. 452 (Site 4) was drilled and completed last January 14th and had an initial production of 4 MMCFGPD from the Lower Dakota Encinal Formation. The well continues to produce at about 1.4 MMCFGPD at 175 PSI and is one of the better wells in the field, and a very good well for this area of the basin. Information on the well can be found in the Petroleum Technology Transfer Council (PTTC) Network News, 1st Quarter, 2004. If drilling results continue to be successful, GeoSpectrum's fracture detection methodology is ready to be applied on a commercial basis.

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Petroleum Technology Transfer Council, 2004, Targeting ‘sweet spots’ in fractured reservoirs: PTTC Network News, 10, No. 1, 1st quarter 2004, p.10.

Acknowledgments

Portions of this paper are taken in whole or in part from Reeves and Smith, “World Oil”, September 2002. Most of the funding for the study came from the DOE and the operator. The project benefited greatly from data and interpretations provided by the operator, their employees and associates. The Dakota play geology was abstracted from the operator's well files by W. Roger Smith, Don Zimbeck did the seismic data processing, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for the exploratory data analysis and the AVO analysis/modeling, and Mark Semmelbeck did the production data analysis. The timeliness and assistance of the DOE technical contract managers Frances Toro and Jim Ammer is greatly appreciated.

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School: PhD Geophysics 1984, MS Geophysical Engineering 1979, BS Mineral Engineering-Physics 1976 Colorado School of Mines; Honorable discharge 1973, US Air Force Academy.

Honors: 2003 Professional Geoscientist, State of Texas; 1995 Professional Engineer, State of Texas; 1995 Professional Geologist, Commonwealth of Pennsylvania; 1994 AAPG Cox Award for best poster; 1979 Sigma Xi, Scientific Research Society; 1976 Tau Beta Pi, Engineering Honor Society.

Membership: SEG; West Texas Geological Soc.; Permian Basin Geophysical Soc.; Permian Basin Section SEPM.

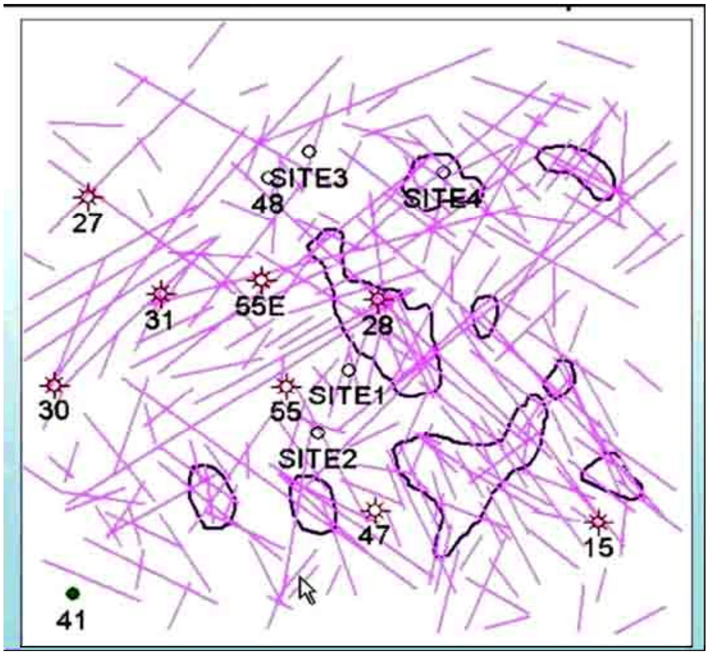

Fig. 1. Lower Dakota seismic lineaments.

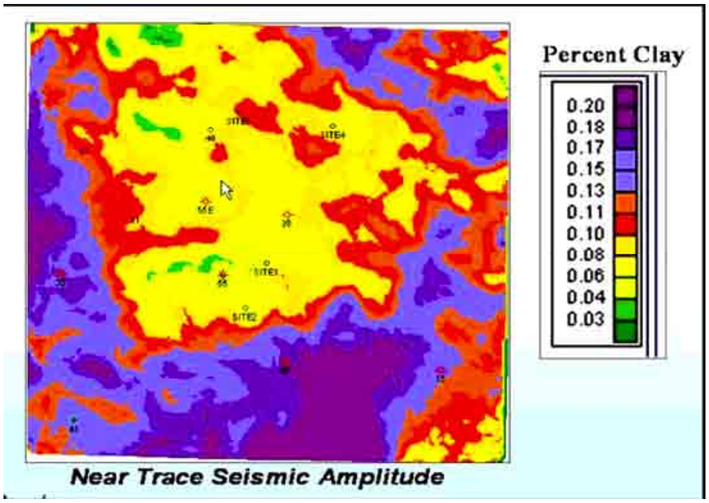

Fig. 2. Collocated cokriged clay volume from near-trace seismic amplitude.

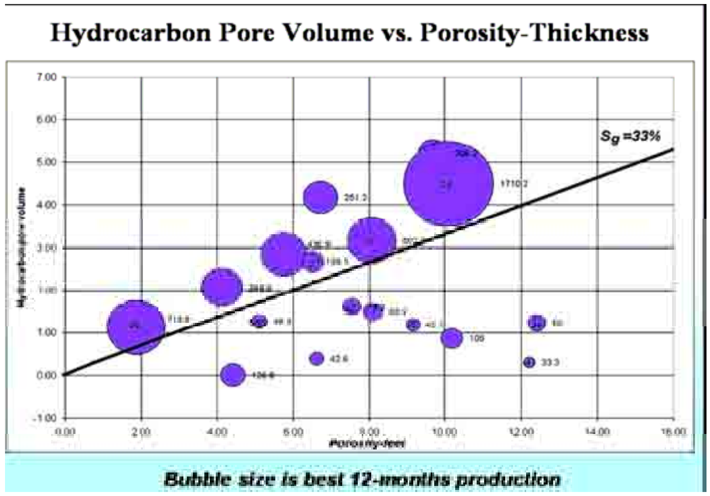

Fig. 3. Lower Dakota hydrocarbon pore volume vs. porosity-thickness and the average of the best of 12 months of production for each well.

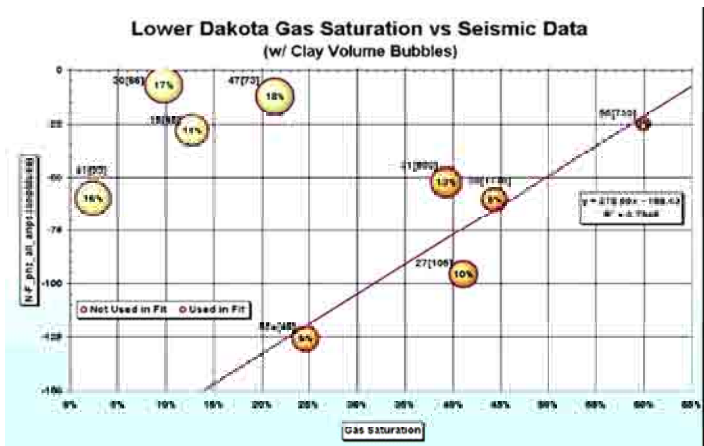

Fig. 4. Lower Dakota graph of phase gradient: [near-traces minus far-traces] vs. gas saturation.

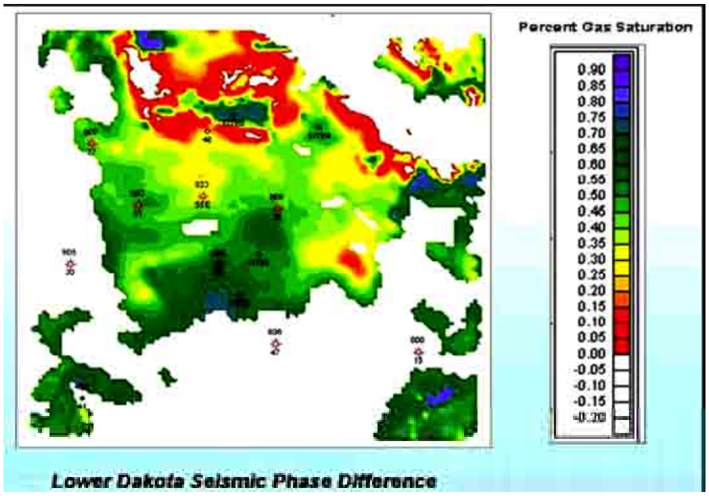

Fig. 5. Seismic-guided Lower Dakota gas-saturation map (estimated clay volume < 12% – 13%).

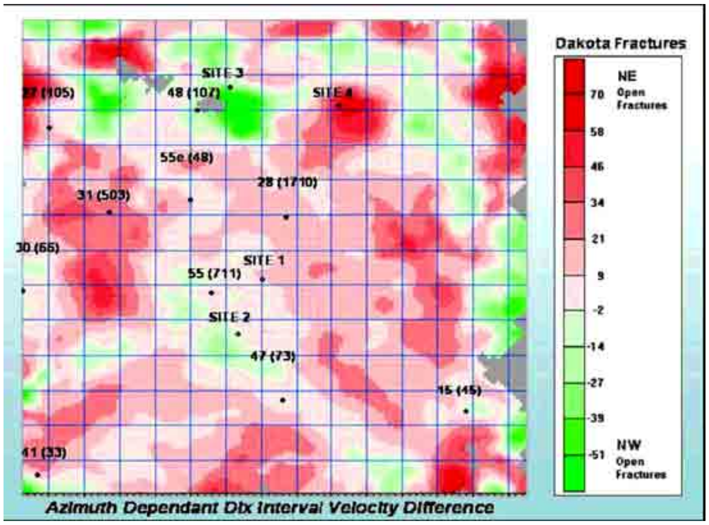

Fig. 6. Collocated cokriged fracture density computed from Dix's interval velocity.

APPENDIX 5
A 3D Seismic Exploration Method For Fractured Gas Reservoirs
(West Texas Geological Society 2004 Fall Symposium, Midland, Texas, Reeves & Smith, 2004)

By James J. Reeves, Ph.D., P.G., P.E., and W. Hoxie Smith, M.S., GeoSpectrum, Inc.

ABSTRACT

A 3D seismic exploration method for fractured gas reservoirs is developed in a study conducted for the U. S. Department of Energy. A comprehensive petrophysical analysis was done on the Lower Dakota sandstone and integrated to a high resolution 3D seismic volume in a gas Unit in Rio Arriba County, New Mexico.

The interpretation methodology is based on four principal seismic attributes. **Seismic lineament analysis** is used to map lineaments through the Lower Dakota zone using horizon slices and time slices. We interpret that in a probabilistic sense where lineaments swarm and cluster together is where reservoir fractures are most likely to be found. Leads identified using lineament density are further screened using rock typing to identify reservoir that is more likely to fracture. A **collocated cokriged clay volume map** using near trace seismic amplitude (an AVO attribute) is used to identify reservoir having low clay that is interpreted to be more brittle and more prone to fracturing. Fractured reservoir and good reservoir rock do not necessarily make a drillable prospect, as reservoir fractures may provide a plumbing system to both water and gas. For prospect development a gas sensitive **phase gradient AVO attribute** is used to further screen the leads to insure that gas is present in the reservoir. Finally, in the Upper Dakota, fractured reservoir potential up hole is interpreted using a **seismic interval velocity anisotropy attribute**.

The resulting interpretation is further validated by the unified set of seismic attributes. For example, rock typing is supported both by the unique directional distributions of lineaments in each rock type and clay volume. Clay volume is supported both by near trace seismic amplitude and phase gradient AVO seismic attributes.

The first well was drilled and completed using the interpretation methodology in January 2004 and produced 4000 MCFGPD out of the Lower Dakota, a very good well in this region of the San Juan Basin. Two other good wells have also been recently drilled. Results indicate a success ratio of nearly 100 percent using the exploration method. The technology is ready for commercialization and industry use in exploration for tight gas fractured reservoirs.

INTRODUCTION

In a tight gas exploration and development study conducted for the U. S. Department of Energy by GeoSpectrum, Inc., a 3D seismic interpretation method for fractured sandstone reservoirs is developed. The method is based on a comprehensive reservoir characterization of the Lower Dakota sandstone in a gas producing Unit, Rio Arriba, County, New Mexico.

The following reservoir attributes are used:

1. Reservoir fractures are predicted using **seismic lineament mapping** in the reservoir section.
2. A seismic **interval velocity anisotropy** attribute is used to investigate fractured reservoir potential in tight sands up hole from the main reservoir target.
3. Lead areas defined by regions of "swarming" multi-directional lineaments are further screened by additional geologic attributes including a **collocated cokriged clay volume map** for the Lower Dakota.
4. A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient**, is used to further define drill locations having high gas saturation.

A four well drilling program was recently completed to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The nearly 100 percent success ratio of the drilling program indicates GeoSpectrum's fracture detection method is ready to be applied on a commercial basis.

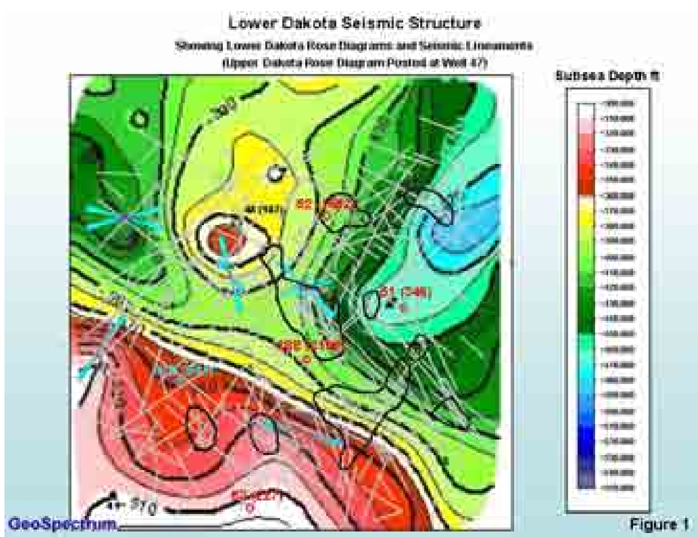

Figure 1. Seismic lineaments are used to infer a network of northeast and northwest fracture zones in the Lower Dakota. Notice the strong correspondence between the multi-directional character of many of the seismic lineaments in the Unit with structural troughs and noses mapped in the Lower Dakota. Structural mapping is based on 3D seismic and Unit Wells drilled pre 1999.

FRACTURE DETECTION METHODOLOGY

Lower Dakota Fractures / Seismic Lineaments

Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the reservoir section. A seismic lineament is defined as a linear feature seen in a time slice or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir (Figure 1). For the purpose of anonymity, the names of the wells referred to in this paper have been truncated to the last two numerical digits.

The application of azimuth dependent prestack time migration to increase spatial resolution should significantly enhanced our ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at Well 28, one of the most prolific wells in the Unit. Borehole breakout indicates present day maximum horizontal tectonic stress in nearly a north-south direction. This orientation of tectonic stress does not preferentially close any fractures oriented in the northeast or northwest directions. Both of these fracture orientations should be available for fluid or gas flow in the Unit. (However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.)

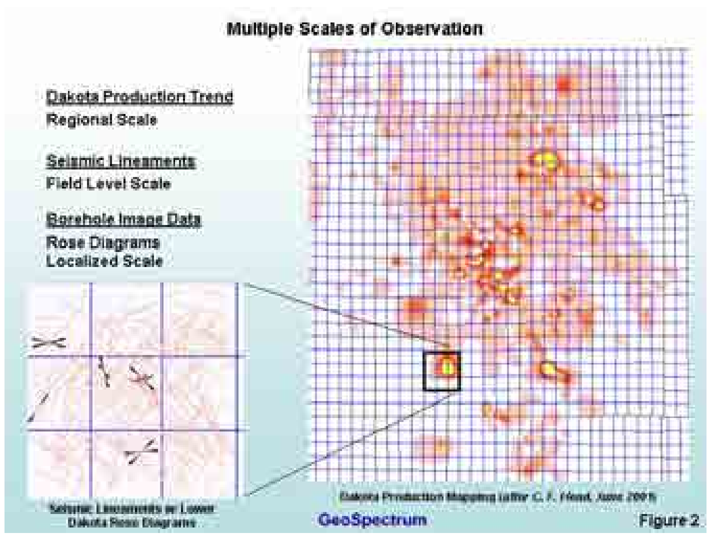

Figure 2. Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales. Borehole image data was obtained from Unit Wells drilled pre 1999.

A number of leads can be distinguished from the seismic lineament map (Figure 1) from the anomalous clusters of multi-directional lineaments. Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments are associated with structural troughs and noses seen in the Lower Dakota corrected seismic structure map.

Figure 2 defines fracture related reservoir anisotropy on three different scales of data, 1.) A localized scale / rose diagrams show Lower Dakota fracture orientations interpreted from borehole image logs, 2.) A field level scale from seismic lineaments, and 3.) A regional scale from Dakota cumulative production trends (Dakota Interval Production, San Juan Basin, New Mexico, Burlington Resources Proprietary Map, prepared by Charles F. Head, 2001). Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales.

Upper Dakota Fractures / Interval Velocity Anisotropy

Seismic **interval velocity anisotropy** is used to investigate reservoir potential up hole from the main reservoir target. We interpret that large interval velocity anisotropy is associated with fracture related anisotropy.

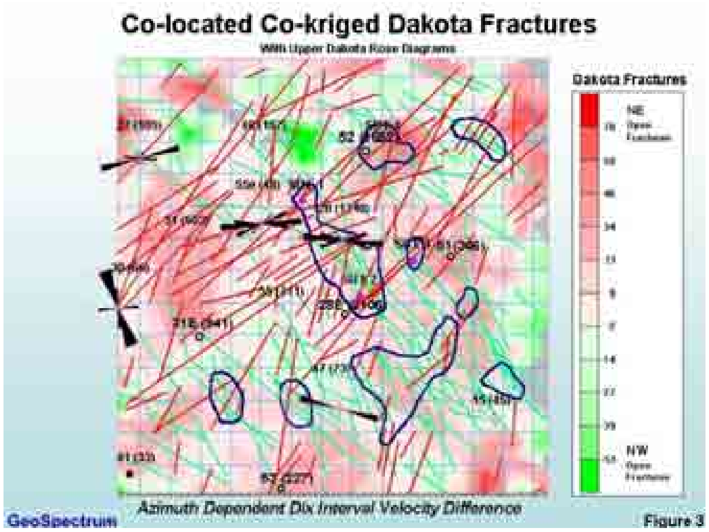

Figure 3. The large interval velocity anisotropy in the Upper Dakota / Green Horn at the Well 52 prospect may indicate additional fracture potential of reservoir up hole. Note the differing fracture distributions indicated by the seismic lineaments in the Lower Dakota (Figure 2) and by interval velocity anisotropy in the near Upper Dakota / Green Horn. Collocated cokriging is done using Dakota fracture counts from borehole image data measured in Unit Wells drilled pre 1999.

Figure 3 shows a seismic guided Upper Dakota fracture density map modeled from Dakota fracture counts measured from borehole image logs for 5 wells. Fracture density mapping is done using collocated cokriging using interval velocity anisotropy (correlation coefficient 0.6). Interval velocity anisotropy is computed as Dix's interval velocity for 145 ± 22.5 degree azimuth data minus the interval velocity for 55 ± 22.5 degree azimuth data. The increase in signal to noise ratio obtained by prestack time migration has greatly improved our ability to do this analysis. Interval velocities were computed for a zone between two strong seismic reflectors including most of the Upper Dakota from the top of the Lower Cubero to the top of the Green Horn, located immediately above the Dakota. This analysis is used to infer prospective Upper Dakota fractures.

FRACTURED RESERVOIR PROSPECTS

Lower Dakota Clay Volume / Seismic Amplitude AVO Attribute

Lead areas defined by regions of "swarming" multi-directional or intersecting lineaments should be further screened by additional geologic attributes. These attributes include reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; and a **collocated cokriged clay volume map** computed from near trace seismic amplitude (an AVO attribute) and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

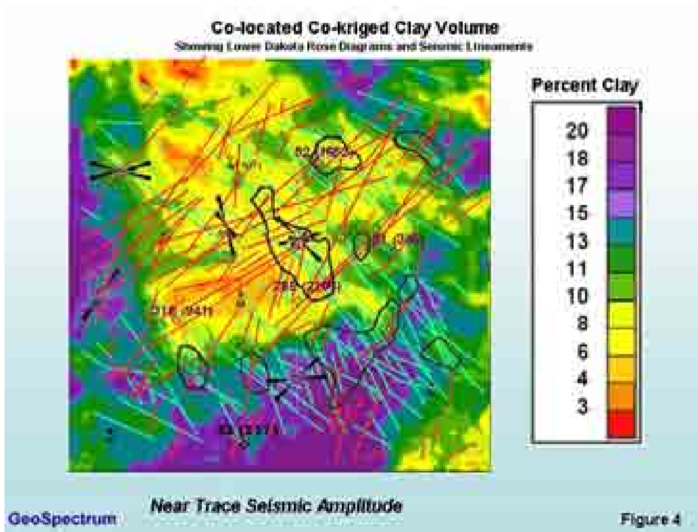

Figure 4. Collocated cokriged Lower Dakota clay volume map from Unit Wells drilled pre 1999. Prospective regions are defined by low clay reservoir in areas of swarming / intersecting lineaments. Also note the unique directional distribution of seismic lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths).

In Figure 4, a seismic guided Lower Dakota clay volume map based on petrophysical analysis of log data from 9 wells drilled pre 1999 is shown. Seismic guided mapping is done with collocated cokriging using the average near trace instantaneous seismic amplitude from a narrow zone (~ 3 ms thick) in the Lower Dakota (measured cross correlation = 0.8). Note: The horizon defining this zone is the same horizon used to define the phase gradient AVO attribute described later in the paper. Both the phase gradient and the near trace amplitude are AVO attributes. Two distinct rock types are defined by the map: low clay (less than about 13 percent) shown by hot colors, and high clay (greater than about 13 percent) shown by cooler colors. We focus our attention to low clay reservoir and regions of swarming / intersecting lineaments.

Notice the unique directional distributions for seismic lineaments as a function of rock type, low versus high clay (Figure 4). Lineaments in the northeast direction are shown in red, and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction, and high clay rocks are associated with lineaments in the northwest direction. It is not surprising that the two rock types have differing distributions of lineaments. Fractures in these two rock masses are controlled by their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses, and how the two interact with each other during their tectonic stress history.

Results should be tested by modeling the state of stress underground using a finite element or finite difference method. We would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

Note the orientation of fractures inferred from the Upper Dakota interval velocity anisotropy (Figure 3). Most of the anisotropy values are shaded in red on the map that may indicate an abundance of northeast trending fractures. If the anisotropy is related to fracture counts, we conclude that northwest trending fractures (shaded in green) simply are not as common as northeast trending fractures. If so, the distribution of fractures in the Upper Dakota over the study area appears to be more similar to the distribution of seismic lineaments or fractures in the Lower Dakota for the clean low clay rock type (Figure 4). The differences between the Upper and Lower Dakota fracture distributions should be explained by their differing depositional environments and tectonic history. The Lower Dakota are non-marine fluvial channel sands, whereas the Upper Dakota are mostly marine shoreline sands. Each of these units should have differing rock types and geometries that effect fracture distributions.

Gas Prediction / Seismic Phase Gradient AVO Attribute

Gas production data is analyzed using a cross plot showing hydrocarbon pore volume versus porosity-thickness and the best of 12-months of gas production (Figure 5). Significant / good wells in the study area are distinguished by a gas saturation cut-off of about 33 percent. There appears to be a random correlation between the best of 12-months production indicator for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality does not increase linearly with reservoir volume.)

A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient**, is used to further define drill locations having high gas saturation (correlation coefficient 0.9). The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Figure 6 shows seismic guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than roughly 13 percent. Seismic guided mapping is done using collocated co-kriging and the empirical trend line for low clay reservoir (phase difference vs. gas saturation) from Unit Wells drilled pre 1999. Gas saturations between about 33 - 60 percent (determined from petrophysical analysis) define a prospective trend for Lower Dakota fracture controlled gas production in the Unit. The lower end gas cutoff (33 percent) is interpreted from the

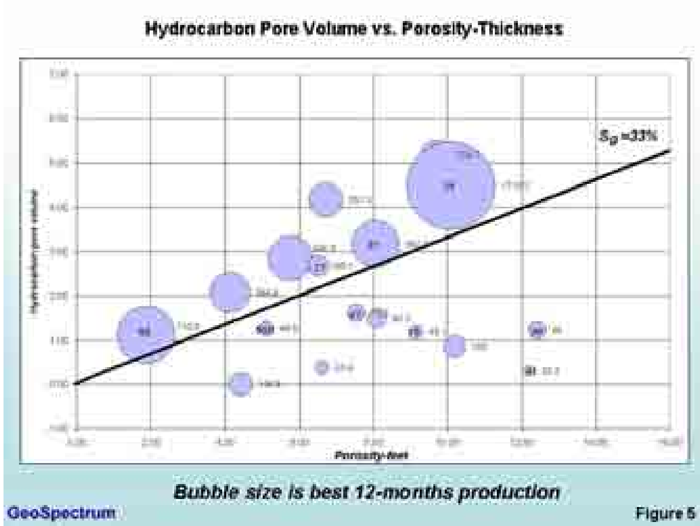

Figure 5. Advanced petrophysical analysis of Lower Dakota well log data from Unit Wells drilled pre 1999. Notice that all significant wells have a gas saturation greater than 33 percent. The random distribution of production quality (bubble size) above the gas cutoff line is indicative of fractured Lower Dakota reservoir.

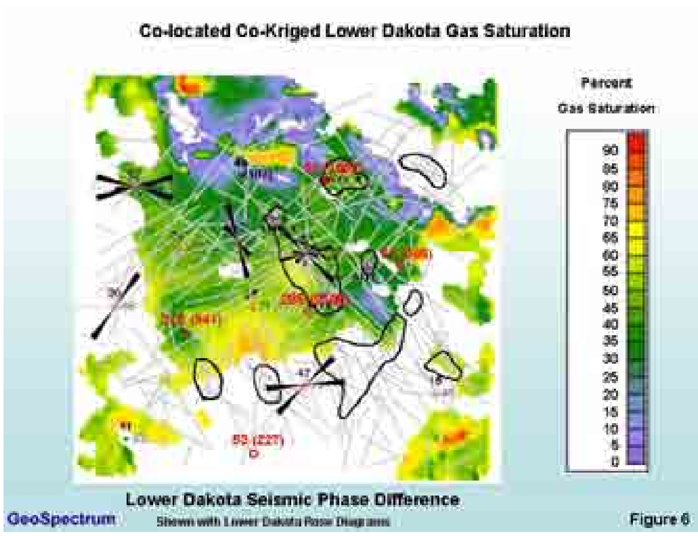

Figure 6. Collocated cokriged Lower Dakota gas saturation map from Unit Wells drilled pre 1999. The Well 52 prospect nearly has the same phase gradient response / gas saturation as Well 28, a significant gas producer, indicating similar AVO attributes. The phase gradient / computed gas saturation explains the poor production encountered by the 55E well.

cross plot of hydrocarbon pore volume versus porosity thickness and best of 12-months production indicator (Figure 5). The high-end gas cutoff (60 percent) comes from the hydrocarbon pore volume determined for the significant gas producing Unit Wells (No. 28, 55, and 31).

Two prospective trends that correspond to regional Dakota production are indicated in the northwest and northeast directions. Notice that more favorable gas / AVO attributes are typically found regionally on the updip side of the map. The Well 52 prospect has nearly identical phase difference attributes or a computed "gas saturation" as the Well 28 indicating similar AVO characteristics. In practice, it is recommended the AVO attributes should be reviewed in the common midpoint (CMP) offset domain before any prospect is drilled to further confirm the AVO phase gradient mapping. Well 55E, which was drilled between the productive 31 and 28 Wells, is not shown to be prospective which collaborates with its poor completion results. The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir.

The empirical relationship of the seismic phase difference attribute and gas saturation has not been confirmed by seismic modeling. Additional work could be done using full wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 6 should only be used to define prospective trends for gas production, not for actual gas saturation values.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon. (This is near where the gas is.) The interpretation should provide important additional information as to the role of channel stratigraphy and trapping mechanism.

In summary, the phase gradient attribute shows all three pre 1999 significant Unit Wells (28, 31, and 55) in the Encinal Sand as gas bearing. It explains the poor results of the nearby 55E well as gas not being present. Also note that the low clay and high clay rock types (good versus poor reservoir quality) in the Lower Dakota are distinguished in three different seismic attributes that confirm and unify our interpretation:

1. Near trace seismic amplitude (Figure 4)
2. Seismic lineament orientation (Figure 4)
3. Phase gradient / AVO characteristics (Figure 6)

The gas sensitive AVO attribute has defined a prospective fairway through the Unit in the Lower Dakota sandstone (Figure 5). Recent drilling results have been very successful.

SELECTED PROSPECTS

Prospects are developed by overlaying the Lower Dakota phase gradient attribute with the seismic lineament map. A prospective fairway is defined where Lower Dakota gas saturation is between 37 to 62 percent and clay volume is less than 13 percent (Figure 6). Three prospects (Wells 52, 28E and 31E) are chosen to drill on swarming / intersecting lineaments in the fairway. Well 52 tests attributes near the northeast edge of the fairway, Well 28E tests attributes near the central region of the trend, and the Well 31E tests attributes near the southeast edge of the prospective fairway. The fourth prospect, Well 53 is selected to test a swarm of seismic lineaments close to the southwest / central edge of the 3D seismic coverage. However, Well 53 does not have favorable AVO attributes. The four prospect locations (Wells 28E, 31E, 52, and 53) are shown in the gas saturation and seismic lineament map (Figure 6). All four wells are spotted on or near lineaments or intersection points of the lineaments. (Note that depending on drilling results, a number of other locations would justify drilling if we can relax the reservoir constraints and pick locations based mainly on the phase gradient AVO attribute.)

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 1

Table 1. Conclusions / Prospect drilling results.

DRILLING RESULTS

The Well 52 prospect was drilled and completed early this year (January 2004) by Burlington Resources and Huntington Energy. The well had an IP of 4000 MCFGPD and is now currently flowing about 850 to 900 MCFGPD (Table 1). The three additional prospects have also been drilled. The Well 28E drilled and completed in May 2004 is producing greater than about 2000 MCFGPD, and no significant decline in production has occurred for the well. The Well 31E recently drilled and completed in June 2004 is expected to produce from roughly 850 MCFGPD to greater than 2000 MCFGPD (similar to the Wells 52 and 28E). Burlington Resources and Huntington Energy have just recently laid pipe to the well to sell the gas. The fourth well, No. 53, drilled and completed in April 2004 initially produced about 2000 MCFGPD and is now only producing about 250 MCFGPD. This well has favorable seismic lineament (fractured) reservoir attributes, however it does not have a good AVO (gas) attribute. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon sandstone, located underneath the productive Encinal sand found in the Lower Dakota wells. We interpret that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

CONCLUSIONS

The three productive Unit Wells (28, 55 and 31) and the productive new prospect Wells (28E, 31E, 52, and 53) completed recently in 2004, appear to be predicted with nearly 100 percent success using the following methodology to explore for Lower Dakota gas:

1. Locate well in or near alluvial sand channels,
2. Lower Dakota Clay content less than or equal to roughly 13 percent,
3. AVO attribute indicating phase difference between -15 to -85 degrees (gas saturation about 37 to 62 percent),
4. Spot well near intersecting or swarming seismic lineaments, and
5. Look for up hole fracture potential using Upper Dakota interval velocity anisotropy.

We interpret that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the prospect wells and the economic discovery of gas in three prospects validates the results of our Phase I, U. S. Department of Energy study. These outstanding drilling results confirm the value of GeoSpectrum's applied methodology in detecting commercial and prospective targets in fractured tight gas sands. An automated approach could be developed to apply the technology.

For more information contact GeoSpectrum's Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

ACKNOWLEDGMENTS

Most of the funding for this study came from the U.S. Department of Energy and the operator. The project also benefited greatly from data and interpretations provided by the operator, their employees and associates. The Dakota play geology was abstracted from the operator's well files by W. Roger Smith, Don Zimbeck did the seismic data processing, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for the exploratory data analysis and the AVO analysis/modeling, and Mark Semmelbeck did the production data analysis. The timeliness and assistance of the DOE technical contract managers Frances Toro and Jim Ammer is greatly appreciated.

APPENDIX 6
A New 3D Seismic Characterization Method for Fractured Tight Gas Reservoirs

(Saudi Aramco and Petroleum Development of Oman Geophysical Reservoir Monitoring Forum, Manama, Bahrain, Reeves, 2005)

James J. Reeves, Ph.D., P.G., P.E., GeoSpectrum, Inc.

Introduction

In a tight gas exploration and development study conducted for the U. S. Department of Energy by GeoSpectrum, Inc., a 3D seismic interpretation method for fractured sandstone reservoirs is developed. The method is based on a comprehensive reservoir characterization of the Lower Dakota sandstone in a gas producing Unit, Rio Arriba County, New Mexico.

The following reservoir attributes are used:
1. Reservoir fractures are predicted using seismic lineament mapping in the reservoir section.
2. A seismic interval velocity anisotropy attribute is used to investigate fractured reservoir potential in tight sands up hole from the main reservoir target.
3. Lead areas defined by regions of "swarming" multi-directional lineaments are further screened by additional geologic attributes including a collocated cokriged clay volume map for the Lower Dakota.
4. A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, phase gradient, is used to further define drill locations having high gas saturation.

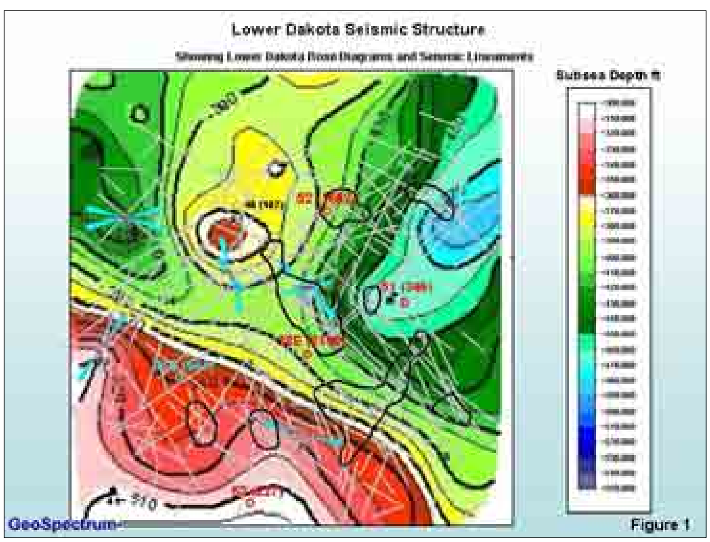

Figure 1. Seismic lineaments are used to infer a network of northeast and northwest fracture zones in the Lower Dakota. Notice the strong correspondence between the multi-directional character of many of the seismic lineaments in the Unit with structural troughs and noses mapped in the Lower Dakota. Structural mapping is based on 3D seismic and Unit Wells drilled pre 1999.

A four well drilling program was recently completed to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The nearly 100 percent success ratio of the drilling program indicates GeoSpectrum's fracture detection method is ready to be applied on a commercial basis.

Fracture Detection Methodology

Lower Dakota Fractures / Seismic Lineaments

Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the reservoir section. A seismic lineament is defined as a linear feature seen in a time slice or horizon slice through the seismic volume that has negligible vertical offset. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir (Figure 1). For the purpose of anonymity, the names of the wells referred to in this paper have been truncated to the last two numerical digits.

The application of azimuth dependent prestack time migration is used to increase spatial resolution to enhance our ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at Well 28, one of the most prolific wells in the Unit. Borehole breakout indicates present day maximum horizontal tectonic stress in nearly a north-south direction. This orientation of tectonic stress does not preferentially close any fractures oriented in the northeast or northwest directions. Both of these fracture orientations should be available for fluid or gas flow in the Unit. (However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.)

A number of leads can be distinguished from the seismic lineament map (Figure 1) from the anomalous clusters of multi-directional lineaments. Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments are associated with structural troughs and noses seen in the Lower Dakota corrected seismic structure map.

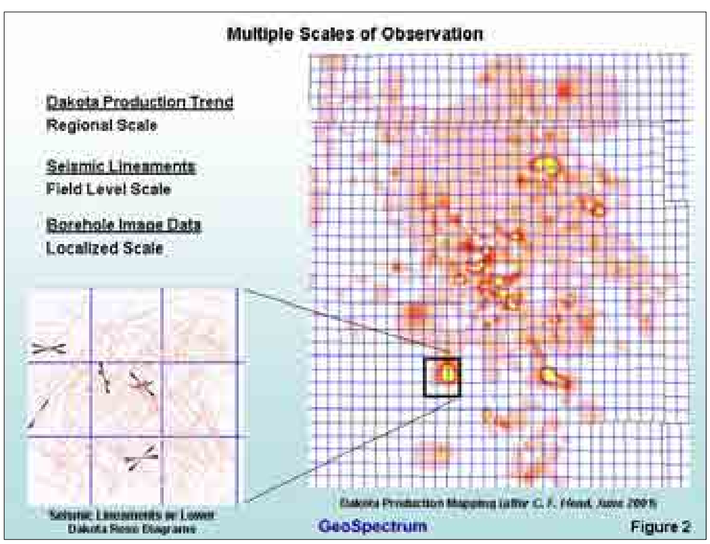

Figure 2. Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales. Borehole image data was obtained from Unit Wells drilled pre 1999. Dakota cumulative production trends from Dakota Interval Production, San Juan Basin, New Mexico, Burlington Resources Proprietary Map, prepared by Charles F. Head, 2001.

Figure 2 defines fracture related reservoir anisotropy on three different scales of data, 1.) A localized scale / rose diagrams show Lower Dakota fracture orientations interpreted from borehole image logs, 2.) A field level scale from seismic lineaments, and 3.) A regional scale from Dakota cumulative production trends (from Dakota Interval Production, San Juan Basin, New Mexico, Burlington Resources Proprietary Map, prepared by Charles F. Head, 2001). Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales.

Upper Dakota Fractures / Interval Velocity Anisotropy

Seismic interval velocity anisotropy is used to investigate reservoir potential up hole from the main Lower Dakota reservoir target. We interpret that large interval velocity anisotropy is associated with fracture related anisotropy.

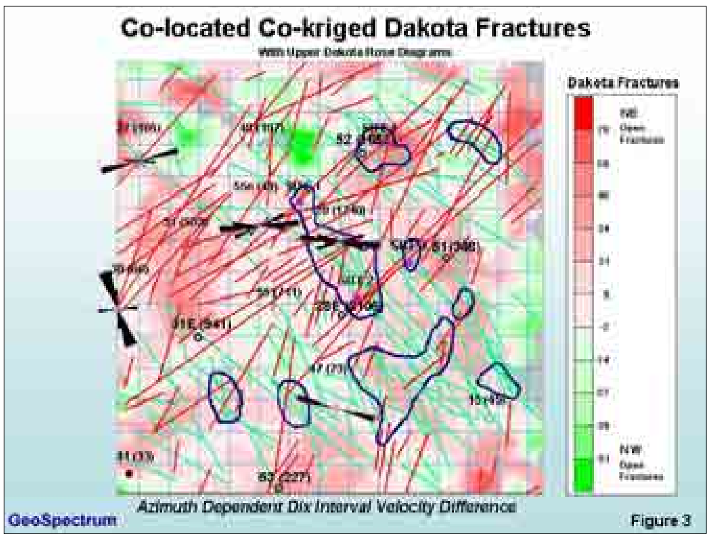

Figure 3. The large interval velocity anisotropy in the Upper Dakota / Green Horn at the Well 52 prospect may indicate additional fracture potential of reservoir up hole. Note the differing fracture distributions indicated by the seismic lineaments in the Lower Dakota (Figure 2) and by interval velocity anisotropy in the near Upper Dakota / Green Horn. Collocated cokriging is done using Dakota fracture counts from borehole image data measured in Unit Wells drilled pre 1999 (Figure 4).

Figure 3 shows a seismic guided Upper Dakota fracture density map modeled from Dakota fracture counts measured from borehole image logs for 5 wells. Fracture density mapping is done using collocated cokriging using interval velocity anisotropy (correlation coefficient 0.6, Figure 4). Interval velocity anisotropy is computed as Dix's interval velocity for 145 ± 22.5 degree azimuth data minus the interval velocity for 55 ± 22.5 degree azimuth data. The increase in signal to noise ratio obtained by prestack time migration greatly improved our ability to do this analysis. Interval velocities were computed for a zone between two strong seismic reflectors including most of the Upper Dakota from the top of the near Lower Cubero to the top of the near Green Horn, located immediately above the Dakota. This analysis is used to infer prospective Upper Dakota fractures.

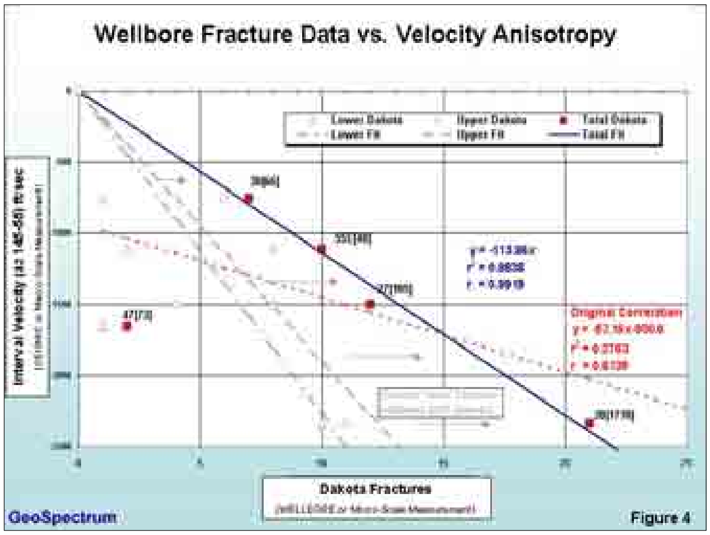

Figure 4. A near perfect response curve is obtained by removing Well 47 as an outlier and passing the curve through the origin (correlation coefficient 0.99). Dakota fracture counts are from borehole image data measured in Unit Wells drilled pre 1999.

Fractured Reservoir Prospects

Lower Dakota Clay Volume / Seismic Amplitude AVO Attribute

Lower Dakota lead areas defined by regions of "swarming" multi-directional or intersecting lineaments should be further screened by additional geologic attributes. These attributes include reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; and a collocated cokriged clay volume map computed from near trace seismic amplitude (an AVO attribute) and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

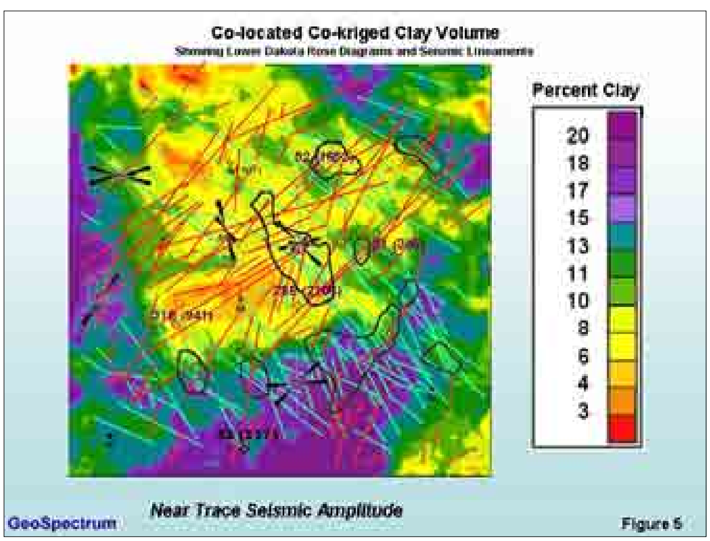

Figure 5. Collocated cokriged Lower Dakota clay volume map from Unit Wells drilled pre 1999. Prospective regions are defined by low clay reservoir in areas of swarming / intersecting lineaments. Also note the unique directional distribution of seismic lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths).

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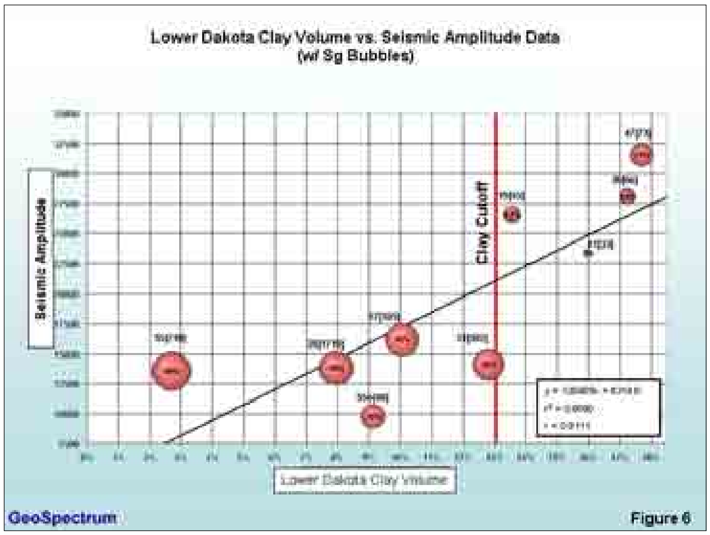

Figure 6. Clay volume versus near trace amplitude (AVO attribute) for Unit Wells drilled pre 1999. Characteristic curve to compute collocated cokriged seismic clay volume map.

Notice the unique directional distributions for seismic lineaments as a function of rock type, low versus high clay (Figure 5). Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction and high clay rocks are associated with lineaments in the northwest direction. It is not surprising that the two rock types have differing distributions of lineaments. Fractures in these two rock masses are controlled by their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses, and how the two interact with each other during their tectonic stress history.

These results should be tested by modeling the state of stress underground using a finite element or finite difference method. We would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

Note the orientation of fractures inferred from the Upper Dakota interval velocity anisotropy, Figure 3. Most of the anisotropy values are shaded in red on the map that may indicate an abundance of northeast trending fractures. If the anisotropy is related to fracture counts, we conclude that northwest trending fractures (shaded in green) simply are not as common as northeast trending fractures. If so, the distribution of fractures in the Upper Dakota over the study area appears to be more similar to the distribution of seismic lineaments or fractures in the Lower Dakota for the clean low clay rock type, Figure 5. The differences between the Upper and Lower Dakota fracture distributions should be explained by their differing depositional environments and tectonic history. The Lower Dakota are non-marine fluvial channel sands whereas the Upper Dakota are mostly marine shoreline sands. Each of these units should have differing rock types and geometries that effect fracture distributions.

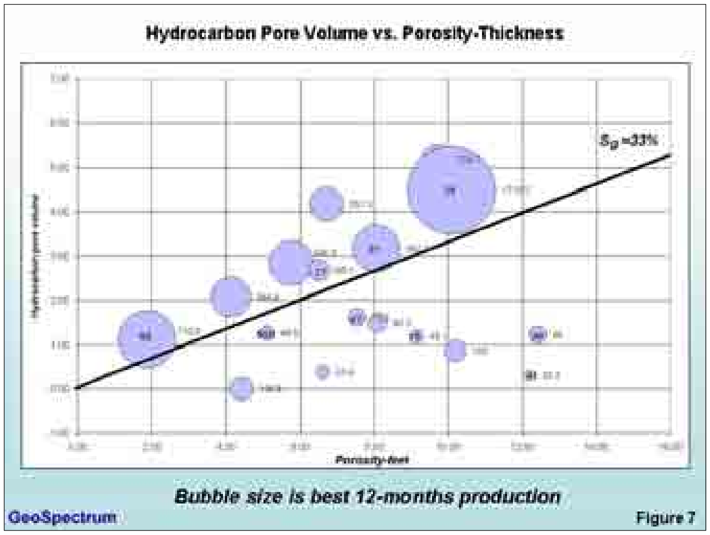

Figure 7. Advanced petro-physical analysis of Lower Dakota well log data from Unit Wells drilled pre 1999 and other surrounding wells. Notice that all significant wells have a gas saturation greater than 33 percent. The random distribution of production quality (bubble size) above the gas cutoff line is indicative of fractured Lower Dakota reservoir.

Gas Prediction / Seismic Phase Gradient AVO Attribute

Gas production data is analyzed using a cross plot showing hydrocarbon pore volume versus porosity-thickness and the best of 12-months of gas production (Figure 7). Significant / good wells in the study area are distinguished by a gas saturation cut-off of about 33 percent. There appears to be a random correlation between the best of 12-months production indicator for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality does not increase linearly with reservoir volume.)

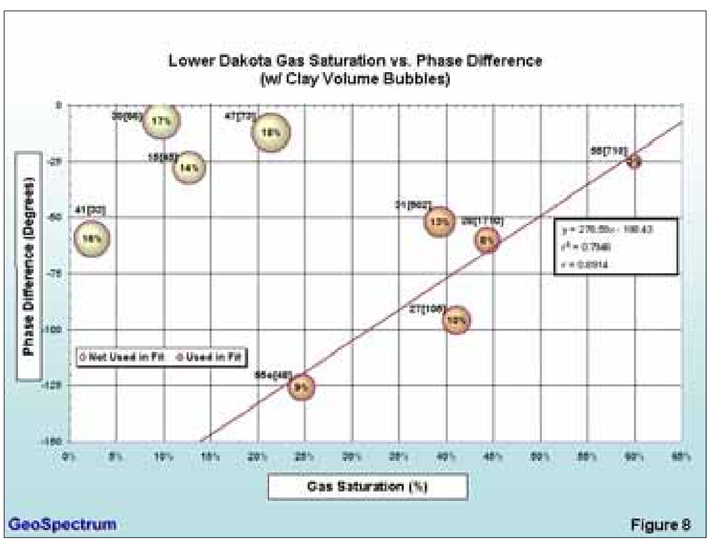

Figure 8. Gas saturation versus phase gradient (AVO attribute) for Unit Wells drilled pre 1999. Cross plot groups wells into low (less than 13 percent) and high (greater than 13 percent) clay clusters. Note the empirical red trend line through the low clay cluster (correlation coefficient 0.89).

A Lower Dakota gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, phase gradient, is used to further define drill locations having low clay and high gas saturation (correlation coefficient 0.9, Figure 8). The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Figure 9 shows seismic guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than roughly 13 percent. Seismic guided mapping is done using collocated cokriging and the empirical trend line for low clay reservoir (phase difference vs. gas saturation) from Unit Wells drilled pre 1999. Gas saturations between about 33 - 60 percent define a prospective trend for Lower Dakota fracture controlled gas production in the Unit. The lower end gas cutoff (33 percent) is interpreted from the cross plot of hydrocarbon pore volume versus porosity thickness and best of 12-months production indicator (Figure 7). The high-end gas cutoff (60 percent) comes from the hydrocarbon pore volume determined for the significant gas producing Unit Wells (No. 28, 55, and 31).

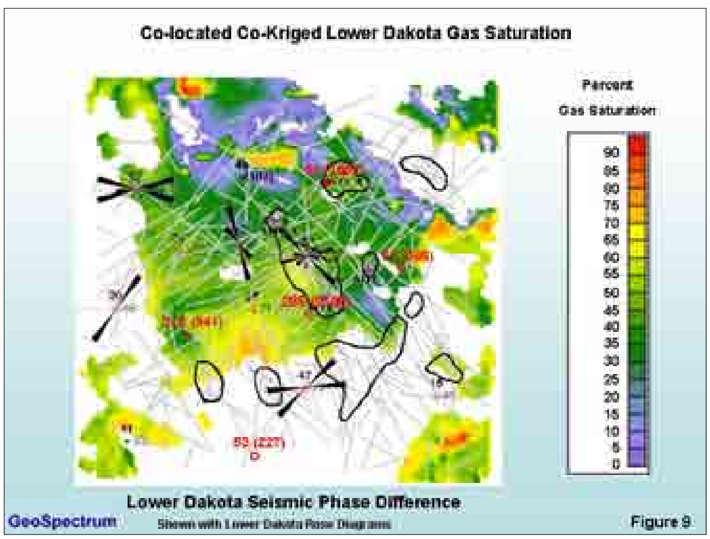

Figure 9. Collocated cokriged Lower Dakota gas saturation map from Unit Wells drilled pre 1999. The Well 52 prospect nearly has the same phase gradient response / gas saturation as Well 28, a significant gas producer, indicating similar AVO attributes. The phase gradient / computed gas saturation explains the poor production encountered by the 55E well (Table 1).

Two prospective trends that correspond to regional Dakota production are indicated in the northwest and northeast directions. Notice that more favorable gas / AVO attributes are typically found regionally on the updip side of the map. The Well 52 prospect has nearly identical phase difference attributes or a computed "gas saturation" as the Well 28 indicating similar AVO characteristics. In practice, it is recommended the AVO attributes should be reviewed in the common midpoint (CMP) gathers before any prospect is drilled to further confirm the phase gradient mapping has selected a location with gas bearing AVO attributes. Well 55E, which was drilled between the productive 31 and 28 Wells, is not shown to be prospective which collaborates with its poor completion results (Table 1). The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir.

The empirical relationship of the seismic phase difference attribute and gas saturation has not been confirmed by seismic modeling. Additional work could be done using full wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 9 should only be used to define prospective trends for gas production, not for actual gas saturation values.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon. (This is near where the gas is!) The interpretation should provide important additional information as to the role of channel stratigraphy and trapping mechanism.

Recent Drilling Results
Not Using GeoSpectrum's Recommendations
1998 to 2001

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)
55E	05/1998	Good	Low	Poor	Good	48
48	04/1999	Good	Low	Poor	Good	195
51	10/2001	Poor	Low	Poor	Excellent	346

GeoSpectrum Table 1

Table 1. Recent drilling results not using GeoSpectrum's recommendations, 1998 to 2001.

In summary, the phase gradient attribute shows all three pre 1999 significant Unit Wells (28, 31, and 55) in the Encinal Sand as gas bearing. It explains the poor results of the nearby 55E well as gas not being present. Also note that the low clay and high clay rock types (good versus poor reservoir quality) in the Lower Dakota are distinguished in three different seismic attributes that confirm and unify our interpretation:

1. Near trace seismic amplitude (Figure 6)
2. Seismic lineament orientation (Figure 5)
3. Phase gradient / AVO characteristics (Figure 8)

The gas sensitive AVO attribute has defined a prospective fairway through the Unit in the Lower Dakota sandstone (Figure 9). Recent drilling results have been very successful.

Validation / Blind Wells 48 and 51

After presenting GeoSpectrum's methodology for fractured Dakota reservoir exploration to Burlington Resources, GeoSpectrum learned that Burlington had drilled two "blind Wells" (No. 48 and 51) in the gas Unit (Table 1). The results of these wells were not used in this study. Unfortunately, Wells 48 and 51 are poor wells. Spotting the wells on the Lower Dakota gas saturation and seismic lineament map (Figure 9) shows that

GeoSpectrum's methodology would not have recommended these locations. Both of these wells are in regions of low gas saturation and low lineament density.

Selected Prospects

Prospects are developed by overlaying the Lower Dakota phase gradient attribute with the seismic lineament map (Figure 10). A prospective fairway is defined where Lower Dakota gas saturation is between 37 to 62 percent (phase gradient –65 to –15 degrees) and clay volume is less than 13 percent. Three prospects (Wells 52, 28E and 31E) are chosen to drill on swarming / intersecting lineaments in the fairway. Well 52 tests attributes near the northeast part of the fairway, Well 28E tests attributes near the central region of the trend, and Well 31E tests attributes near the southwest part of the prospective fairway. The fourth prospect, Well 53 is selected to test a swarm of seismic lineaments close to the southwest / central edge of the 3D seismic coverage. However, Well 53 does not have favorable AVO attributes. GeoSpectrum advised the Unit Operators that this drill location did not appear to have significant Lower Dakota gas before the well was drilled. The four prospect locations (Wells 28E, 31E, 52, and 53) are shown in the phase gradient and seismic lineament map (Figure 10). All four wells are spotted on or near lineaments or intersection points of the lineaments. (Note that depending on drilling results, a number of other locations would justify drilling if we can relax the reservoir constraints and pick locations based mainly on the gas sensitive phase gradient (AVO) attribute.)

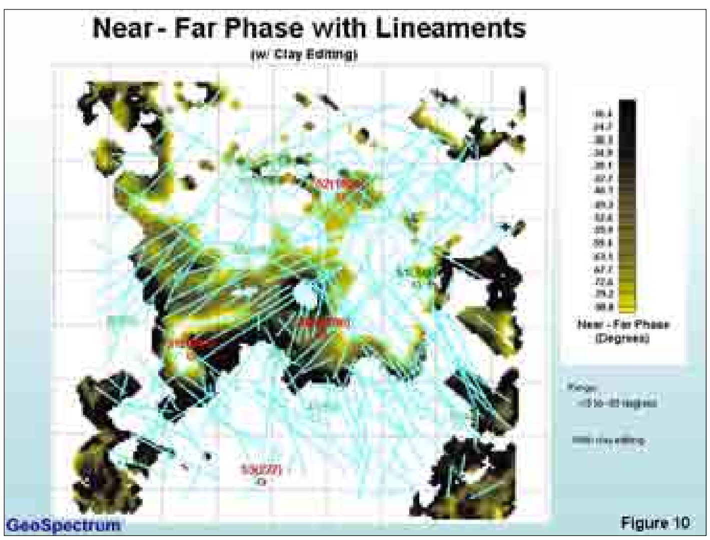

Figure 10. Low clay and gas bearing prospective fairway with seismic lineaments. New drill locations Well 52, 53, 28E, and 31E are shown.

Drilling Results

In 2004, Burlington Resources and Huntington Energy completed four wells defined by GeoSpectrum's 3D seismic interpretation method. Results indicate a success ratio of nearly 100 percent using the exploration method. The 52 prospect drilled and completed in January 2004 had an initial potential of nearly 4,000 Mcfg/d and a best of 12 month production estimate of 1652 Mcfg/d. The 28E well drilled and completed in May 2004 has a best of 12 month production estimate of 2106 Mcfg/d and has produced steadily near this rate making it one of the best wells in the Unit so far. The 31E well was drilled and completed in June 2004 and has a best of 12 month production estimate of 941 Mcfg/d. The fourth well, the No. 53, was drilled and completed in April 2004 and initially produced about 2,000 Mcfg/d but has a best of 12 month production estimate of 227 Mcfg/d. This prospect had favorable seismic lineament (fractured) reservoir attributes, however it did not have a good AVO (gas) attribute. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon sandstone, located underneath the productive Encinal sand found in the Lower Dakota wells. It is interpreted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

Tables 1 and 2 summarize drilling results with reservoir attributes used in GeoSpectrum's methodology for targeting drilling locations. Table 2 shows the 2004 outstanding drilling results for the four wells spotted using GeoSpectrum's exploration methods. Table 1 shows the results for the last three wells drilled earlier in the same gas Unit not using GeoSpectrum's 3D seismic interpretation methods. Note that each of these three wells have poor AVO attributes and modest gas saturation.

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)
52	01/2004	Low	High	High	High	1652
53	04/2004	High	High	No AVO Attribute	High	227
28E	05/2004	Low	High	High	Low	2106
31E	06/2004	Low	Low	High	Low	941

GeoSpectrum Table 2

Table 2. Conclusions / Prospect drilling results 2004.

Conclusion

The three productive Unit Wells (28, 55 and 31) and the new prospect Wells (28E, 31E, 52, and 53) completed in 2004, appear to be predicted with nearly 100 percent success using the following methodology to explore for Lower Dakota gas:

1. Locate well in or near alluvial sand channels,
2. Lower Dakota Clay content less than or equal to roughly 13 percent,
3. Phase Gradient (AVO) attribute indicating a phase difference between -15 to -85 degrees (gas saturation about 37 to 62 percent),
4. Spot well near intersecting or swarming seismic lineaments, and

5. Look for up hole fracture potential using Upper Dakota interval velocity anisotropy.
We interpret that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the four prospect wells and the economic discovery of gas in three prospects (Wells 28E, 31E, and 52) and the predicted result of the poor producing prospect (Well 53) validates the results of our Phase I, U. S. Department of Energy study. These outstanding drilling results confirm the value of GeoSpectrum's applied methodology in detecting commercial and prospective targets in fractured tight gas sands. Future work should include an automated approach to map seismic lineaments and to apply the new technology.

For more information contact GeoSpectrum's Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

Acknowledgements

Most of the funding for the study came from the U. S. Department of Energy, the gas Unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations provided by the operators, their employees, and associates. Dakota play geology was abstracted from Burlington Resources well and prospect files by Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, Mark Gygax prepared many of the graphics used in our publications, and Hoxie Smith assisted in preparation of the original project proposal and review of project reports and papers. Dr. James Reeves is the Principal Investigator in the project, he designed and managed all phases of the research, and is the primary author of the project proposal, all technical project reports and publications. A special thanks is extended to all the technical societies and publishers, including, GasTIPS, Midland Reporter Telegram, Permian Basin Geophysical Society, Petroleum Technology Transfer Council, Society of Exploration Geophysicist, Society of Petroleum Engineers, Strategic Research Institute, West Texas Geological Society, World Oil, and others, who have published our technical project papers and results, portions of which may have been reprinted in this paper. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

APPENDIX 7
New Advances in 3D Seismic Interpretation Methods for Fractured Tight Gas Reservoirs

(Permian Basin Geophysical Society 46th Annual Exploration Meeting, Midland, Texas, Reeves, 2005)

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Expanded Abstract

Natural fractures are often responsible for enhancing production in oil and gas reservoirs. They play an important role for defining sweet spots especially in the Permian Basin of west Texas and New Mexico, and in the Rocky Mountain Region of the United States. For the last 5 years, Dr. James J. Reeves, Principal Investigator, and GeoSpectrum, an oil an gas technology company in Midland, Texas, have worked for the U. S. Department of Energy to develop a 3D seismic interpretation method for tight gas fractured reservoirs in the San Juan Basin of New Mexico. The Department of Energy has spent over a million dollars in developing this program. Burlington Resources contributed the 3D seismic and well data to the study. An additional three million dollars in drilling cost was invested by Huntington Energy to test new prospects. Drill locations are defined from an overlay of three key reservoir attribute maps, seismic lineaments, clay volume, and gas saturation (Figure 1).

Lead areas are screened by seismic attributes, such as seismic amplitude or acoustic impedance, indicating brittle reservoir rock that are more likely to be highly fractured (Figure 2). Seismic attributes are calibrated to clay content measured in existing well control by wire line logs (Figure 3). Further screening of the lead areas may also be done based on reservoir thickness and stratigraphy interpreted from the 3D seismic data.

Gas sensitive seismic attributes such as the phase gradient (an AVO attribute first developed by GeoSpectrum) or frequency dependent seismic amplitude may be used to define a prospective fairway to further screen drill locations having high gas saturation (Figure 4). These attributes are calibrated to gas saturation determined from existing well control by wireline logs (Figure 5). The importance of gas sensitive attributes cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they also may penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Natural fractures are predicted using seismic lineament mapping in the reservoir section (Figures 6). A seismic lineament is defined as a linear feature seen in a time or horizon slice through the seismic volume that has a negligible vertical offset. Seismic attributes investigated may include coherency, amplitude, frequency, phase, and acoustic

impedance. Volume based structural curvature attributes may also be computed. It is interpreted that areas having high seismic lineament density with multi-directional lineaments define areas of high fracture density in the reservoir.

In a gas field previously plagued with poor drilling results, four new wells were spotted using the methodology and recently drilled. The wells have estimated best of 12-months production indicators of 2106, 1652, 941, and 227 MCFGPD (Figure 7). The later well was drilled in a region of swarming seismic lineaments but had a poor gas sensitive AVO attribute. GeoSpectrum advised the Unit Operators that this location did not appear to have significant Lower Dakota gas before the well was drilled. The other three wells are considered good wells in this part of the basin and among the best wells in the field. A prospect rating system is developed indicating either a “good”, “average”, or “poor” grade (Table 1). The new interpretation method is ready for commercialization, and gas exploration and development. The technology is adaptable to conventional lower cost 3D seismic surveys.

For more information contact GeoSpectrum's Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

Dr. James J. Reeves, Ph.D., P.G., P.E.

Dr. James J. Reeves earned a BS in mineral engineering-physics (1976), MS in geophysical engineering (1979) and a PhD in geophysics (1984) from the Colorado School of Mines. He is a registered Professional Engineer and Geoscientist with the State of Texas. He started his career with Gulf Oil as a seismic interpreter, exploring the Delaware and Midland basins of west Texas. After graduation, he worked for Pecten International Co., coordinating seismic-data acquisition and processing for eastern Syria. Subsequently, Dr. Reeves served as a geology professor at the University of Texas of the Permian basin, as a research professor at Texas Tech University's Center for Applied Petrophysical Studies, and as the co-founder-Chairman of the West Texas Earth Resources Institute (WTERI). In 1992, Dr. Reeves formed GeoSpectrum, Inc. processing and interpreting 3D seismic and subsurface well data, and identifying oil and gas prospects for the last 13 years. (www.geospectrum.com)

Figures

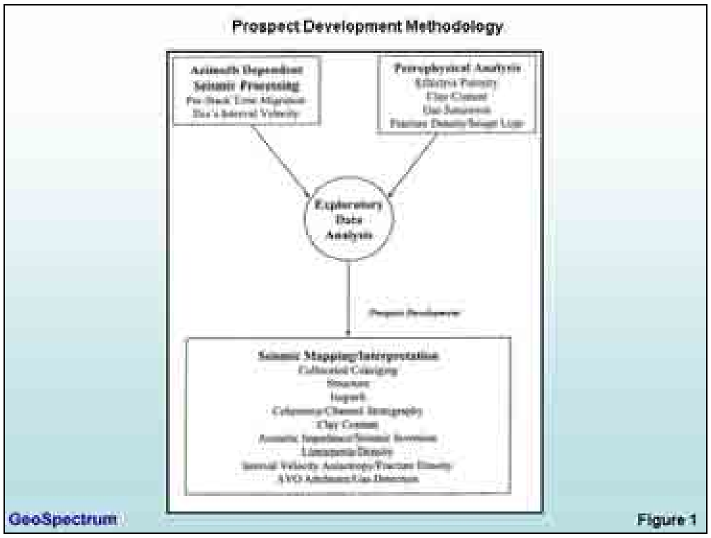

Figure 1. Prospect development methodology.

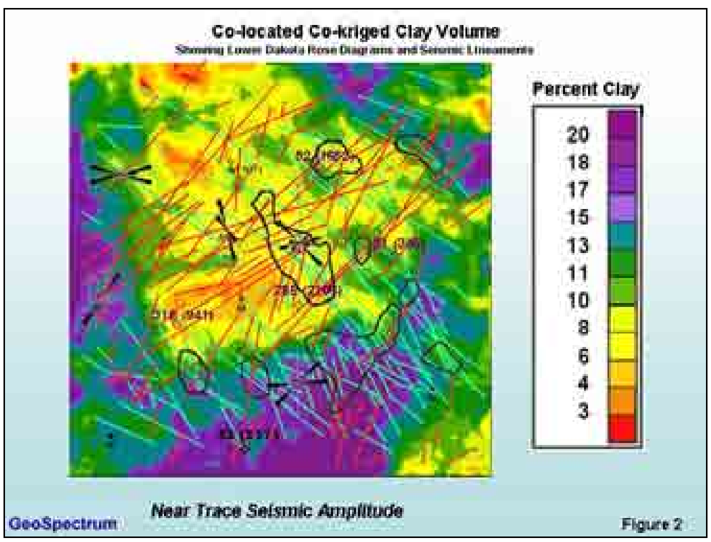

Figure 2. Collocated cokriged clay volume map.

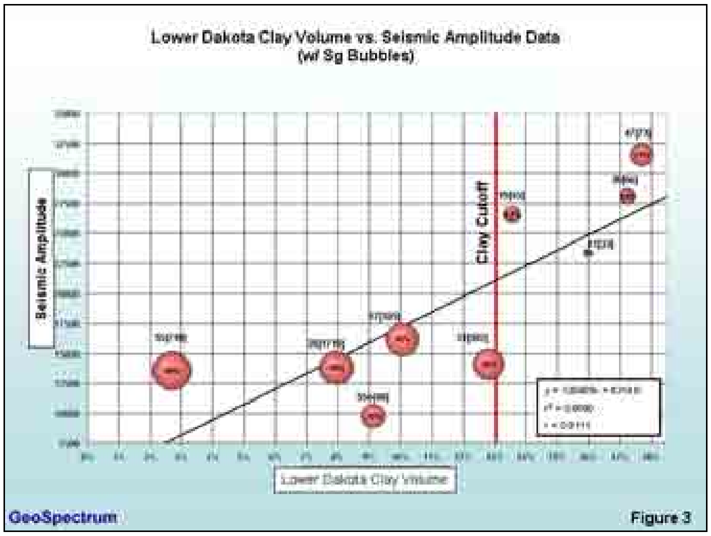

Figure 3. Clay volume versus near-trace seismic amplitude (AVO attribute).

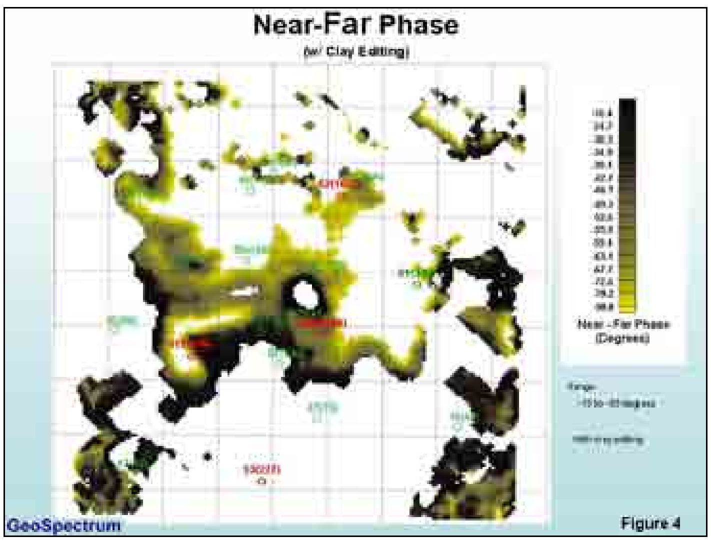

Figure 4. Lower Dakota seismic phase gradient map.

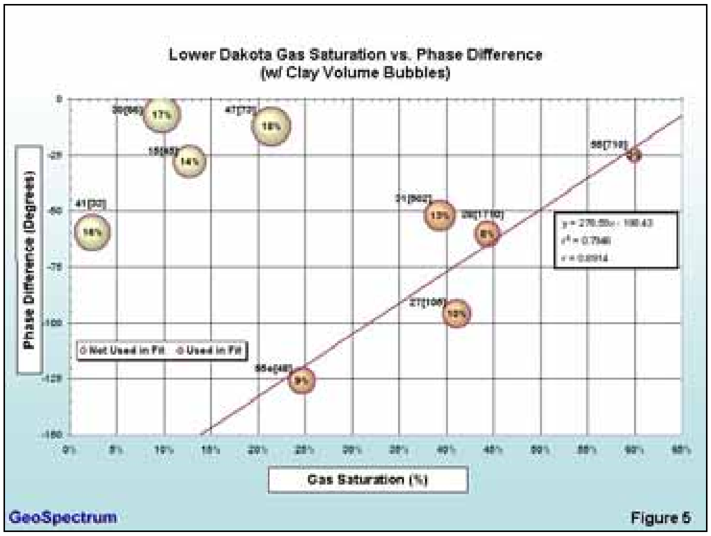

Figure 5. Gas saturation versus phase gradient (AVO attribute).

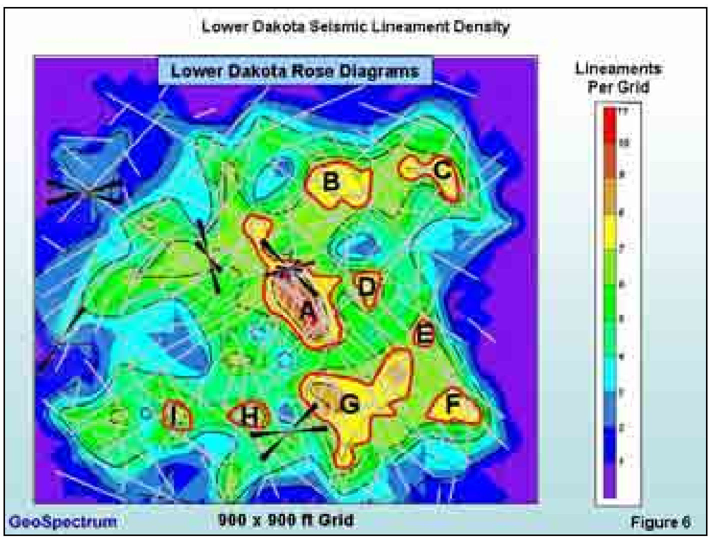

Figure 6. Lead areas (A through I) associated with regions of high lineament density.

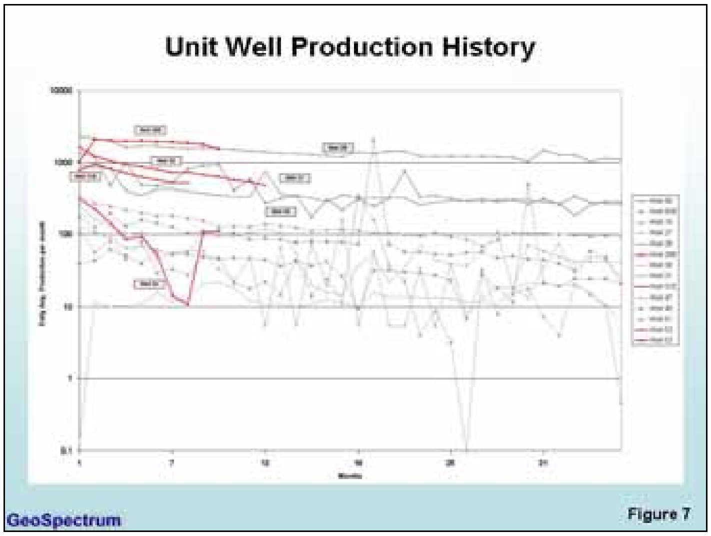

Figure 7. 2004 prospect drilling results.

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
62	01/2004	Low	High	High	High	1652	Good
63	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 1

Table 1. Prospect rating system.

APPENDIX 8
An Integrated 3D-Seismic Exploration Method for Fractured Reservoirs in Tight Gas Sands

(Society of Petroleum Engineers 2005 Latin American Caribbean Petroleum Engineering Conference, Rio de Janeiro, Brazil, Reeves, 2005)

James J. Reeves/GeoSpectrum, Inc.

Introduction

In a tight gas exploration and development study conducted for the U. S. Department of Energy by GeoSpectrum, Inc., a 3D seismic interpretation method for fractured sandstone reservoirs is developed. The method is based on a comprehensive reservoir characterization of the Lower Dakota Sandstone in a gas producing Unit, Rio Arriba County, New Mexico.

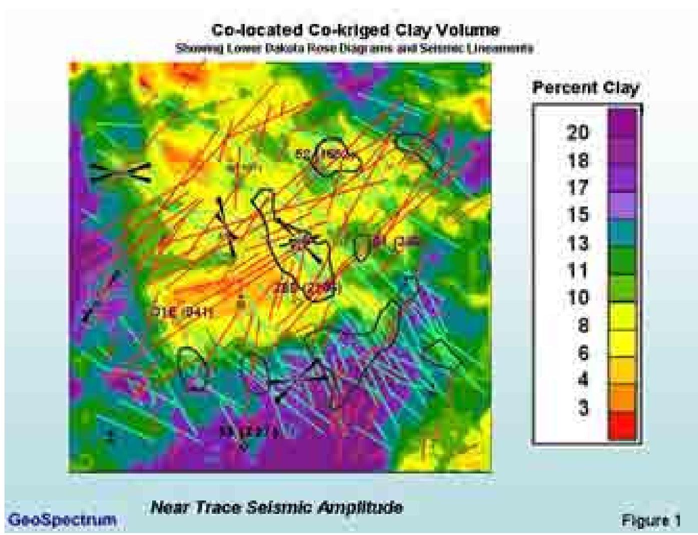

Figure 1. Collocated cokriged Lower Dakota clay volume map from Unit Wells drilled pre 1999. Prospective regions are defined by low clay reservoir in areas of swarming / intersecting lineaments. Also note the unique directional distribution of seismic lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths).

The following reservoir attributes are used:

1. Lead areas containing brittle reservoir rocks are defined by geologic attributes such as acoustic impedance and a **collocated cokriged clay volume map** for the Lower Dakota.
2. A gas sensitive AVO seismic attribute, near-trace stacked phase minus far-trace stacked phase, **phase gradient**, is used to further define drill locations having high gas saturation.

3. Reservoir fractures are predicted using **seismic lineament mapping** in the reservoir section.
4. A seismic **interval velocity anisotropy** attribute is used to investigate fractured reservoir potential in tight sands up hole from the main reservoir target.

A four well drilling program was recently completed to test GeoSpectrum's fractured gas reservoir prospects and exploration technology. The nearly 100 percent success ratio of the drilling program indicates GeoSpectrum's fracture detection method is ready to be applied on a commercial basis.

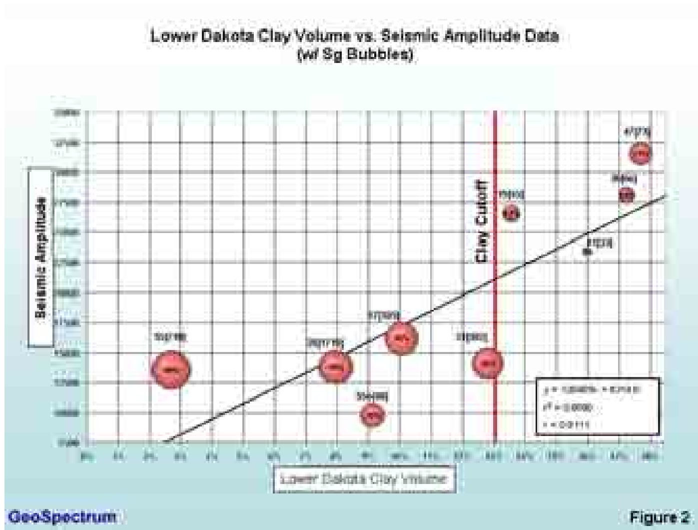

Figure 2. Clay volume versus near trace amplitude (AVO attribute) for Unit Wells drilled pre 1999. Characteristic curve to compute collocated cokriged seismic clay volume map (correlation coefficient 0.8).

Fractured Tight Gas Reservoir Characteristics

Lower Dakota Clay Volume / Seismic Amplitude AVO Attribute. Potentially gas bearing lead areas are defined by reservoir attributes, including reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; and a **collocated cokriged clay volume map** computed from near-trace seismic amplitude (an AVO attribute). A comprehensive petrophysical analysis of the well data is used to determine discrete values of clay volume at each well. We interpret that clean/low clay reservoir rock is brittle and more likely to be highly fractured.

In Figure 1, a seismic guided Lower Dakota clay volume map based on petrophysical analysis of log data from 9 wells drilled pre 1999 is shown. For the purpose of anonymity, the names of the wells referred to in this paper have been truncated to the last two numerical digits. Seismic guided mapping is done using collocated cokriging using the average near-trace instantaneous seismic amplitude from a narrow zone (3 msec thick) in the Lower Dakota (measured cross correlation = 0.8, Figure 2). (The horizon defining this zone is the same horizon used to define the phase gradient AVO attribute described later in the paper.) Both the phase gradient and the near-trace amplitude are AVO attributes.) Two distinct rock types are defined by the map, low clay (less than about 13 percent) shown by hot colors and high clay (greater than about 13 percent) shown by cooler colors. We focus our attention to the low clay reservoir rock.

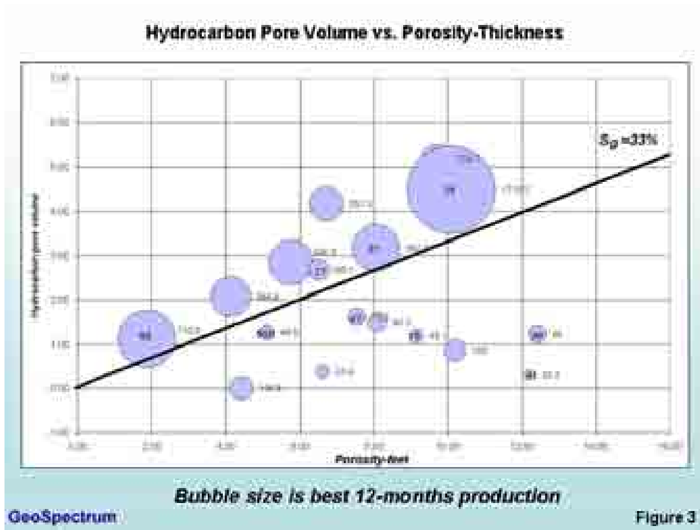

Figure 3. Advanced petrophysical analysis of Lower Dakota well log data from Unit Wells drilled pre 1999 and other surrounding wells. Notice that all significant wells have a gas saturation greater than 33 percent. The random distribution of production quality (bubble size) above the gas cutoff line is indicative of fractured Lower Dakota reservoir.

Gas Prediction / Seismic Phase Gradient AVO Attribute. Gas production data is analyzed using a cross plot showing hydrocarbon pore volume versus porosity-thickness and the best of 12-months of gas production (Figure 3). Significant / good wells in the study area are distinguished by a gas saturation cut-off of about 33 percent. There appears to be a random correlation between the best of 12-months production indicator for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality does not increase linearly with reservoir volume.)

A Lower Dakota gas sensitive AVO seismic attribute, near-trace stacked phase minus far-trace stacked phase, **phase gradient**, is used to further define drill locations having low clay and high gas saturation (correlation coefficient 0.9, Figure 4). The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Figure 5 shows seismic guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than roughly 13 percent. Seismic guided mapping is done using collocated cokriging and the empirical trend line for low clay reservoir (phase difference vs. gas saturation) from Unit Wells drilled pre 1999. Gas saturations between about 33 - 60 percent define a prospective trend for Lower Dakota fracture controlled gas production in the Unit. The lower end gas cutoff (33 percent) is interpreted from the cross plot of hydrocarbon pore volume versus porosity thickness and best of 12-months production indicator (Figure 3). The high-end gas cutoff (60 percent) comes from the hydrocarbon pore volume determined for the significant gas producing Unit Wells (No. 28, 55, and 31). A model switching routine could be used to map gas saturation through the higher clay rock, by pulling an empirical trend line through the high clay cluster in the cross plot (Figure 4).

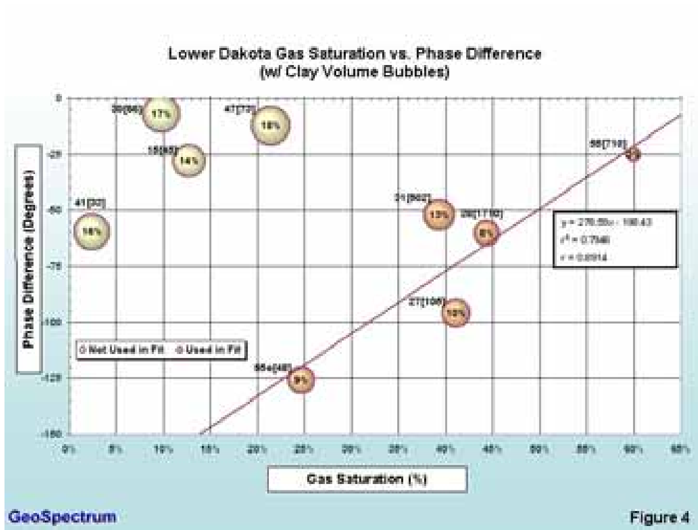

Figure 4. Gas saturation versus phase gradient (AVO attribute) for Unit Wells drilled pre 1999. Cross plot groups wells into low (less than 13 percent) and high (greater than 13 percent) clay clusters. Note the empirical red trend line through the low clay cluster (correlation coefficient 0.9).

Two prospective trends that correspond to regional Dakota production are indicated in the northwest and northeast directions (Figure 5). Notice that more favorable gas / AVO attributes are typically found regionally on the updip side of the map, Figure 6. The Well 52 prospect has nearly identical phase difference attributes or a computed "gas saturation" as the Well 28 indicating similar AVO characteristics. In practice, it is recommended the AVO attributes should be reviewed in the common midpoint (CMP) offset domain before any prospect is drilled to confirm the phase gradient mapping has selected a drill location having positive gas bearing AVO attributes. Well 55E, which was drilled between the productive 31 and 28 Wells, is not shown to be prospective which collaborates with its poor completion results, Table 1. The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir.

The empirical relationship of the seismic phase difference attribute and gas saturation has not been confirmed by seismic modeling. Additional work should be done using full wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 5 should only be used to define prospective trends for gas production, not for actual gas saturation values.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon. (This is near where the gas is!) The interpretation should provide important additional information as to the role of channel stratigraphy and trapping mechanism.

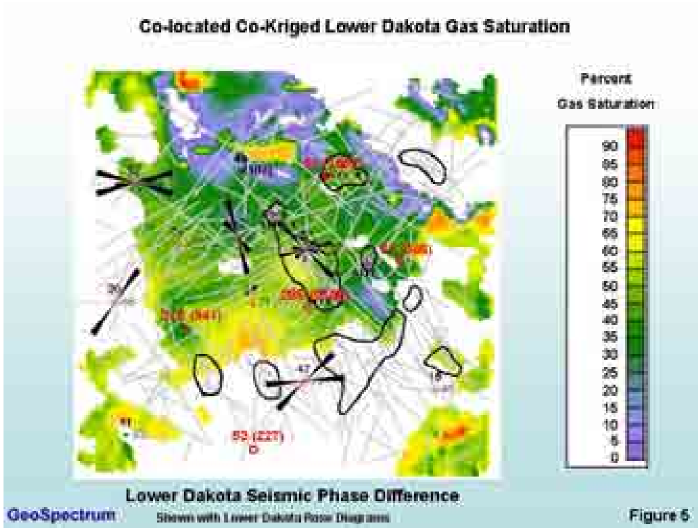

Figure 5. Collocated cokriged Lower Dakota gas saturation map from Unit Wells drilled pre 1999. The Well 52 prospect nearly has the same phase gradient response / gas saturation as Well 28, a significant gas producer, indicating similar AVO attributes. The phase gradient / computed gas saturation explains the poor production encountered by the 55E well (Table 1).

In summary, the phase gradient attribute shows all three pre 1999 significant Unit Wells (28, 31, and 55) in the Encinal Sand as gas bearing and it explains the poor results of the nearby 55E well as gas not being present (Figures 3 and 5). The gas sensitive AVO attribute has defined a prospective fairway through the Unit in the Lower Dakota Sandstone.

Fracture Detection Methodology

Lower Dakota Fractures / Seismic Lineaments. Reservoir fractures are predicted using multiple azimuth **seismic lineament mapping** in the reservoir section. A seismic lineament is defined as a linear feature seen in a time slice or horizon slice through the seismic volume that has negligible vertical offset. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir (Figure 6).

The application of azimuth dependent pre-stack time migration is used to increase spatial resolution to enhance our ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at Well 28, one of the most prolific wells in the Unit. Borehole breakout indicates present day maximum horizontal tectonic stress in nearly a north-south direction. This orientation of tectonic stress does not preferentially close any fractures oriented in the northeast or northwest directions. Both of these fracture orientations should be available for fluid or gas flow in the Unit. (However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.)

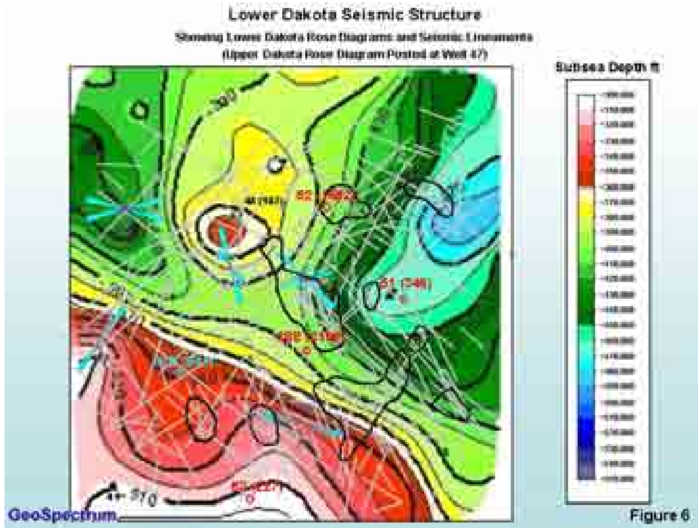

Figure 6. Seismic lineaments are used to infer a network of northeast and northwest fracture zones in the Lower Dakota. Notice the strong correspondence between the multi-directional character of many of the seismic lineaments in the Unit with structural troughs and noses mapped in the Lower Dakota. Structural mapping is based on 3D seismic and Unit Wells drilled pre 1999.

In the Lower Dakota, notice the unique directional distributions for seismic lineaments as a function of rock type, low versus high clay (Figure 1). Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction and high clay rocks are associated with lineaments in the northwest direction. The highest lineament density is found in low clay rocks. It is not surprising that the two rock types have differing distributions of lineaments. Fractures in these two rock masses are controlled by their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses, and how the two interact with each other during their tectonic stress history. Results could be tested by modeling the state of stress underground using a finite element or finite difference method. We would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

In summary, the low clay and high clay rock types (good versus poor reservoir quality) in the Lower Dakota are distinguished in three different but integrated seismic attributes that confirm and unify our interpretation:

1. Near-trace seismic amplitude (Figure 2)
2. Seismic lineament density and orientation (Figure 1)
3. Phase gradient / AVO characteristics (Figure 4)

Upper Dakota Fractures / Interval Velocity Anisotropy. Seismic **interval velocity anisotropy** is used to investigate reservoir potential up hole from the main Lower Dakota reservoir target. We interpret that large interval velocity anisotropy is associated with fracture-related anisotropy.

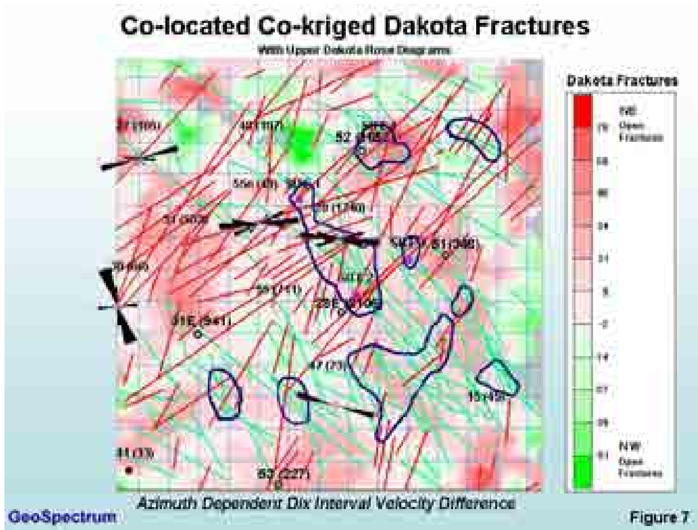

Figure 7. The large interval velocity anisotropy in the Upper Dakota / Green Horn at the Well 52 prospect may indicate additional fracture potential of reservoir up hole. Note the differing fracture distributions indicated by the seismic lineaments in the Lower Dakota (Figure 6) and by interval velocity anisotropy in the Upper Dakota / Green Horn. Collocated cokriging is done using Dakota fracture counts from borehole image data measured in Unit Wells drilled pre 1999 (correlation coefficient 0.6, Figure 8).

Figure 7 shows a seismic guided Upper Dakota fracture density map modeled from fracture counts (interpreted Lower Dakota plus interpreted Upper Dakota) from borehole image logs for 5 wells. Fracture density mapping is done using collocated cokriging using interval velocity anisotropy (correlation coefficient 0.6, Figure 8). Interval velocity anisotropy is computed as Dix's interval velocity for 145 ± 22.5 degree azimuth data minus the interval velocity for 55 ± 22.5 degree azimuth data. The increase in signal to noise ratio obtained by pre-stack time migration greatly improved our ability to do this analysis. Interval velocities were computed for a zone between two strong seismic reflectors including most of the Upper Dakota from the top of the near Lower Cubero to the top of the near Green Horn, located immediately above the Dakota. This analysis is used to infer prospective Upper Dakota fractures.

In the Upper Dakota, note the orientation of fractures inferred from the interval velocity anisotropy, Figure 7. Most of the anisotropy values are shaded in red on the map that may indicate an abundance of northeast trending fractures. If the anisotropy is related to fracture counts, we conclude that northwest trending fractures (shaded in green) simply are not as common as northeast trending fractures. If so, the distribution of fractures in the Upper Dakota over the study area appears to be more similar to the distribution of seismic lineaments or fractures in the Lower Dakota for the clean low clay rock type,

Figure 1. The differences between the Upper and Lower Dakota fracture distributions should be explained by their differing depositional environments and tectonic history. The Lower Dakota are non-marine fluvial-deltaic and braided channel sands whereas the Upper Dakota are mostly marine shoreline sands. Each of these units should have differing rock types and geometries that effect fracture distributions.

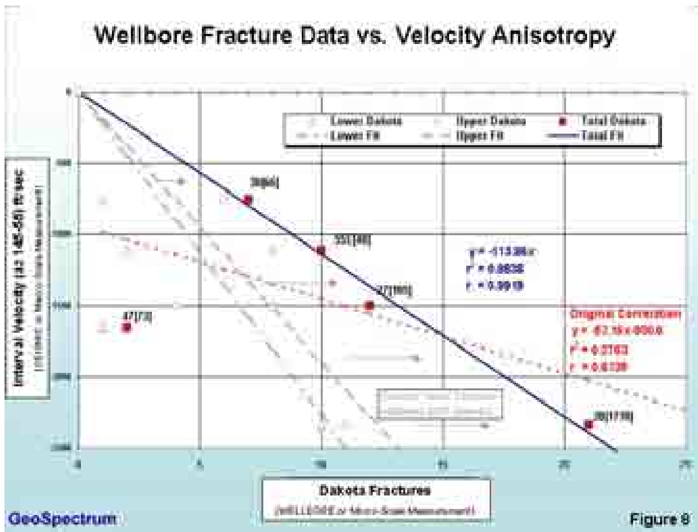

Figure 8. A near perfect response curve is obtained by removing Well 47 as an outlier and passing the curve through the origin (correlation coefficient 0.99). Dakota fracture counts (interpreted Lower Dakota plus interpreted Upper Dakota) are from borehole image data measured in Unit Wells drilled pre 1999.

Fracture Detection Results

Figure 9 defines fracture-related reservoir anisotropy on three different scales of data, 1.) A localized scale / rose diagrams show Lower Dakota fracture orientations interpreted from borehole image logs, 2.) A field level scale from seismic lineaments, and 3.) A regional scale from Dakota cumulative production trends (Dakota Interval Production, San Juan Basin, New Mexico, Burlington Resources Proprietary Map, prepared by Charles F. Head, 2001). Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales.

A number of fractured reservoir leads can be interpreted from the seismic lineament map (Figure 6) from the anomalous clusters of multi-directional lineaments. Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments are associated with structural troughs and noses seen in the Lower Dakota corrected seismic structure map. At the same time lineament distributions and productive reservoir are also controlled by rock types, low versus high clay content (Figure 1).

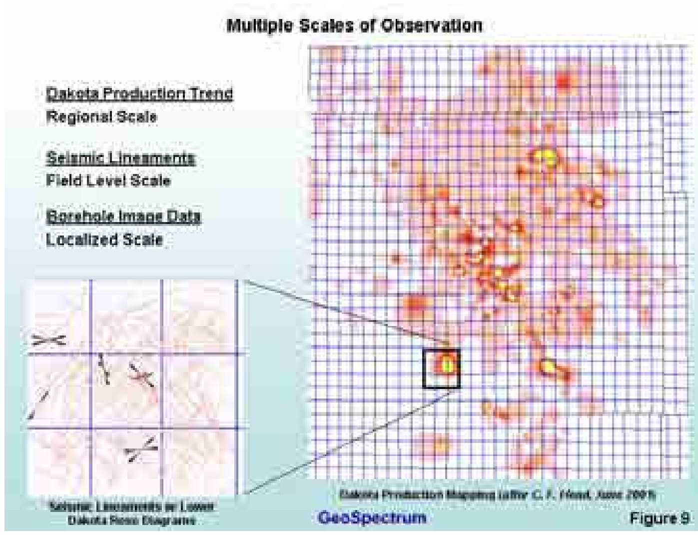

Figure 9. Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales. Borehole image data was obtained from Unit Wells drilled pre 1999. Dakota cumulative production trends are from Dakota Interval Production, San Juan Basin, New Mexico, Burlington Resources Proprietary Map, prepared by Charles F. Head, 2001.

Selected Prospects

Prospects are developed by overlaying the Lower Dakota clay volume, phase gradient and seismic lineament maps. A prospective fairway is defined where Lower Dakota gas saturation is between 37 to 62 percent (phase gradient –65 to –15 degrees) and clay volume is less than 13 percent (Figure 10). Three prospects (Wells 52, 28E and 31E) are chosen to drill on swarming / intersecting lineaments in the fairway. Well 52 tests attributes near the northeast part of the fairway, Well 28E tests attributes near the central region of the trend, and Well 31E tests attributes near the southwest part of the prospective fairway. The fourth prospect, Well 53 is selected to test a swarm of seismic lineaments close to the southwest / central edge of the 3D seismic coverage. However, Well 53 does not have favorable AVO or clay volume attributes. GeoSpectrum advised the Unit Operators that this drill location did not appear to have significant Lower Dakota gas before the well was drilled. The four prospect locations (Wells 28E, 31E, 52, and 53) are shown in the phase gradient and seismic lineament map (Figure 10). All four wells are spotted on or near lineaments or intersection points of the lineaments. (Note that depending on drilling results, a number of other locations would justify drilling if we can relax the reservoir constraints and pick locations based mainly on the gas sensitive phase gradient (AVO) attribute.)

Drilling Results

Validation / Blind Wells 48 and 51. After presenting GeoSpectrum's methodology for fractured Dakota reservoir exploration to Burlington Resources, GeoSpectrum learned that Burlington had drilled two “blind Wells” (No. 48 and 51) in the gas Unit. The results of these wells were not used in this study. Unfortunately, Wells 48 and 51 are poor wells (Table 1). Spotting the wells on the Lower Dakota gas saturation and seismic lineament map (Figure 5 and 10) shows that GeoSpectrum's methodology would not have recommended these locations. Both of these wells are in regions of low gas saturation and low lineament density.

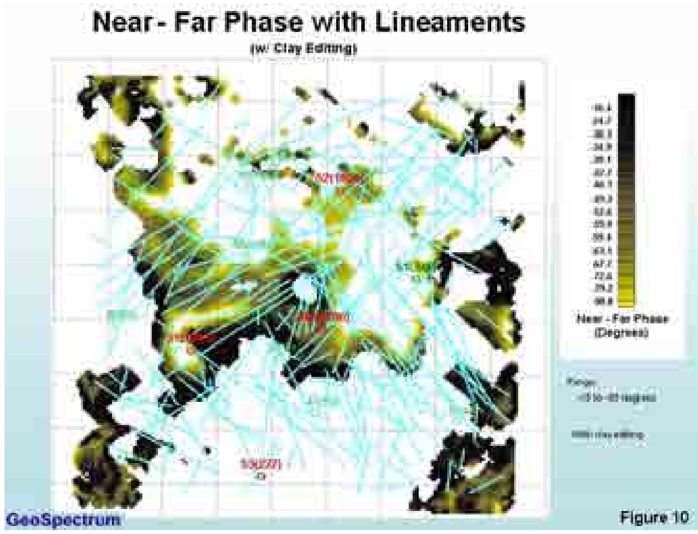

Figure 10. Low clay and gas bearing prospective fairway with seismic lineaments. New drill locations Well 52, 53, 28E, and 31E are shown.

2004 Prospects

Burlington Resources and Huntington Energy recently completed four wells defined by GeoSpectrum’s 3D seismic interpretation method. Results indicate a success ratio of nearly 100 percent using the exploration method. The 52 prospect drilled and completed in January 2004 had an initial potential of nearly 4,000 Mcfg/d and a best of 12-month production estimate of 1652 Mcfg/d. The 28E well drilled and completed in May 2004 has a best of 12-month production estimate of 2106 Mcfg/d and continues to produce near this rate making it one of the best wells in the Unit so far. The 31E well was drilled and completed in June 2004 and has a best of 12-month production estimate of 941 Mcfg/d. The fourth well, the No. 53, was drilled and completed in April 2004 and initially produced about 2,000 Mcfg/d but has a best of 12-month production estimate of 227 Mcfg/d. This prospect had favorable seismic lineament (fractured) reservoir attributes, however it did not have a good AVO (gas) or clay volume attributes. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon Sandstone, located underneath the productive Encinal Sand found in Lower Dakota wells. It is interpreted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

The GeoSpectrum Prospect Rating System assigning either a "good", "average", or "poor" grade to the prospects is illustrated in Tables 1 and 2. Table 2 shows the 2004 outstanding drilling results for the four wells spotted using GeoSpectrum's exploration methods. Table 1 shows the results for the last three wells drilled earlier in the same gas Unit not using GeoSpectrum's 3D seismic interpretation methods. Each of these three wells have poor AVO attributes, modest gas saturation, and poor best of 12-month production indicators, less than 350 Mcfg/d, proving the value of our new technology. The Lower Dakota production results of 15 wells drilled in the Unit are all reasonably predicted by the methodology.

Recent Drilling Results
Not Using GeoSpectrum's Recommendations
1998 to 2001

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
55E	05/1998	Good	Low	Poor	Good	48	Poor
48	04/1999	Good	Low	Poor	Good	195	Poor
51	10/2001	Poor	Low	Poor	Excellent	346	Poor

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 1

Table 1. Recent drilling results not using GeoSpectrum's recommendations, 1998 to 2001.

Conclusion

The three productive Unit Wells (28, 55 and 31) and the new prospect Wells (28E, 31E, 52, and 53) completed in 2004, appear to be predicted with nearly 100 percent success using the following methodology to explore for Lower Dakota gas:

1. Lower Dakota Clay content less than or equal to roughly 13 percent,
2. Phase Gradient (AVO) attribute indicating a phase difference between -15 to -85 degrees (gas saturation about 37 to 62 percent),
3. Spot well near intersecting or swarming seismic lineaments, and
4. Look for up hole fracture potential using Upper Dakota interval velocity anisotropy.

We interpret that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the four prospect wells and the economic discovery of gas in three prospects (Wells 28E, 31E, and 52) and the predicted result of the poor producing prospect (Well 53) validates the results of our U. S. Department of Energy study. These outstanding drilling results confirm the value of GeoSpectrum's applied methodology in detecting commercial and prospective targets in fractured tight gas sands. Future work should include the development of an automated approach to map seismic lineaments and to apply the technology.

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 2

Table 2. Conclusions / Prospect drilling results 2004. GeoSpectrum advised the Unit Operators that the Well 53 location did not appear to have significant Lower Dakota gas before the well was drilled.

For more information contact GeoSpectrum's Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

Acknowledgements

Most of the funding for the study came from the U. S. Department of Energy, the gas Unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations provided by the operators, their employees, and associates. Dakota play geology was abstracted from Burlington Resources well and prospect files by Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, Mark Gygax prepared many of the graphics used in our publications, the GeoSpectrum Prospect Rating System was recommended by Dr. John Reeves, Jr. and Kory Razaghi, Waveland Capital Group, and Dr. Emilio Mutis-Duplat reviewed the final project report and made many useful suggestions. Hoxie Smith assisted in preparation of the original project proposal and review of project reports and papers. Dr. James Reeves is the Principal Investigator in the project, he designed and managed all phases of the research, and is the primary author of the original project proposal and all technical project reports and publications. A special thanks is extended to all the technical societies and publishers, including, the American Association of Petroleum Geologists, GasTIPS, Permian Basin Geophysical Society, Rocky Mountain Association of Geologists, Society of Exploration Geophysicist, Saudi Aramco, Society of Petroleum Engineers, Strategic Research Institute, West Texas Geological Society, World Oil, and others, who have published our technical project papers and results, portions of which may have been reprinted in this paper. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

APPENDIX 9
Advancing 3D Seismic Interpretation Methods for Unconventional Fractured Gas Reservoirs

(Balkan Geophysical Society 4th Congress, Bucharest, Romania, Reeves, 2005)

Dr. James J. Reeves/GeoSpectrum, Inc.

Fractures are often responsible for enhancing production in oil and gas reservoirs. They play an important role for defining sweet spots in many producing regions of the world. For the last 5 years, Dr. James J. Reeves, Principal Investigator, has worked for the U. S. Department of Energy to advance a new 3D seismic interpretation method for tight gas fractured reservoirs in the San Juan Basin of New Mexico (see Reeves and Smith, World Oil, September, 2002 and GasTIPS, Fall, 2004). The Department of Energy has outlaid over a million dollars in developing this program. Burlington Resources contributed the 3D seismic and well data to the project. An additional three million dollars was invested by Huntington Energy to drill new prospects. Locations are spotted from an overlay of three key reservoir attribute maps: seismic lineaments, clay volume, and gas saturation.

Lead areas are developed by seismic attributes, such as seismic amplitude or acoustic impedance, indicating brittle reservoir rock that are more likely to be highly fractured (Figure 1). Seismic attributes are calibrated to clay content determined in existing well control by wireline logs (Figure 2). Further screening of the lead areas may also be done using reservoir thickness and stratigraphy interpreted from the 3D seismic data.

Gas sensitive seismic attributes such as the phase gradient (an AVO attribute first developed by GeoSpectrum) or frequency dependent seismic amplitude may be used to model the prospective fairway to further screen drill locations having high gas saturation (Figures 3a and 3b). These attributes may be used to estimate gas saturation determined from existing well control by wireline logs (Figure 4). The importance of gas sensitive attributes cannot be understated, as natural fractures enhance reservoir permeability and volume, they also can penetrate water-saturated zones and be responsible for the reservoir being water-wet and ruined.

Fractures are predicted using seismic lineament mapping in the reservoir section (Figure 5). A seismic lineament is a linear feature seen in a time or horizon slice through the seismic volume that has a negligible vertical offset. Seismic attributes investigated may include amplitude, frequency, phase, coherency, and acoustic impedance. Structural curvature attributes may also be computed. It is interpreted that areas having high seismic lineament density with swarming multi-directional lineaments define areas of high fracture density in the reservoir.

In a gas field previously burdened with poor drilling results, four new locations were spotted using the methodology and recently drilled. The wells have estimated best of 12-months production indicators of 227, 941, 1652, and 2106 MCFGPD (Figures 6 and 7).

The first well was drilled in a region of swarming seismic lineaments but had a poor gas sensitive AVO attribute. The Unit Operators were informed that this location did not appear to have significant Lower Dakota gas before the well was drilled. The other three wells are good wells in this part of the basin and among the best wells in the field. A prospect rating system is developed defining either a "good", "average", or "poor" grade (Table 1). The new interpretation methods are ready for commercialization and gas exploration and development. The technology is adaptable to lower cost 3D seismic surveys.

Figures

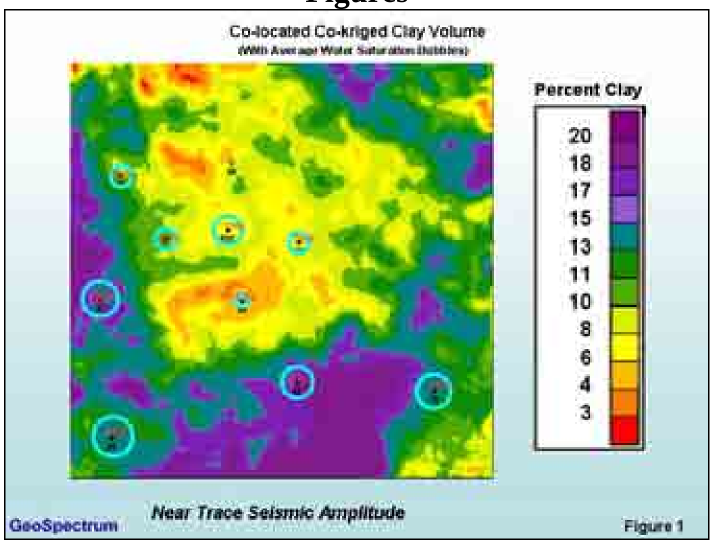

Figure 1. Collocated cokriged clay volume map using Unit Wells drilled pre-1999. Low clay rock types (hot colors) tend to have lower water saturations than high clay rock types (cool colors).

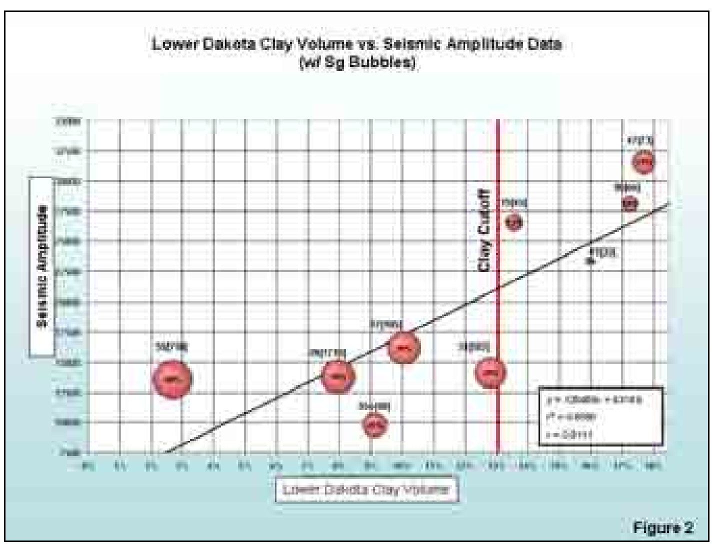

Figure 2. Clay content versus near-trace seismic amplitude (AVO attribute) for Unit Wells drilled pre-1999. The linear regression line is used to compute the collocated cokriged seismic clay volume map (correlation coefficient 0.81).

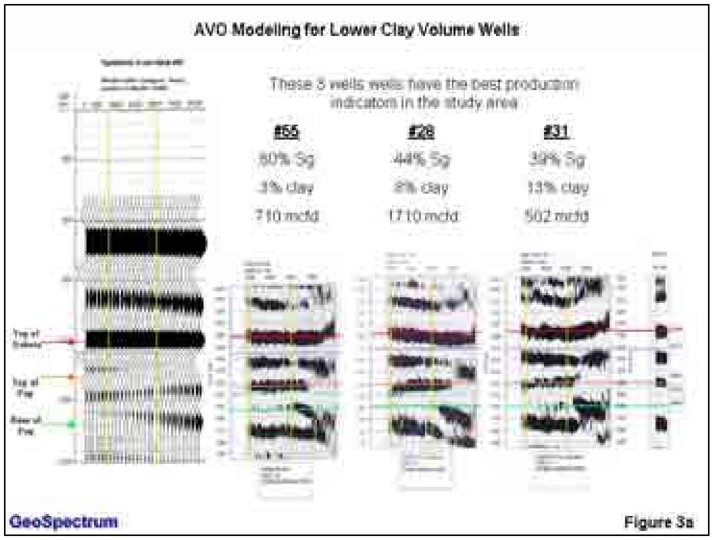

Figure 3a. Significant gas producing Lower Dakota wells with low clay have a diagnostic AVO response (green horizon) compared to poor wells (Figure 3b).

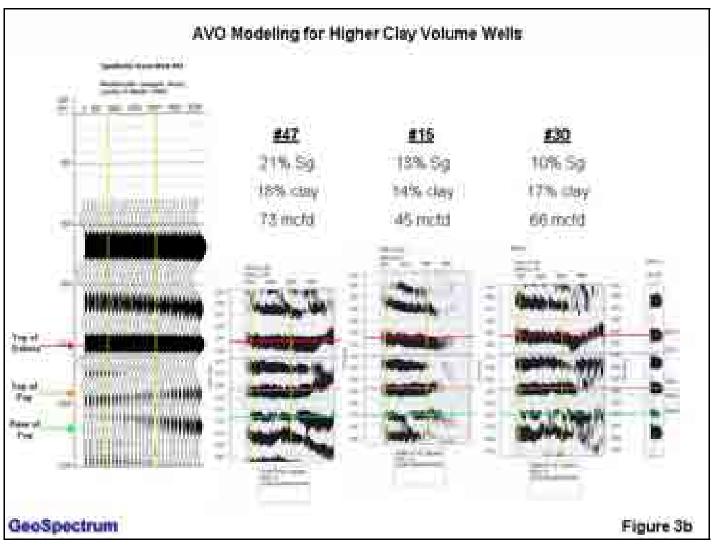

Figure 3b. Poor producing Lower Dakota wells with high clay have a diagnostic AVO response (green horizon) compared to significant production (Figure 3a).

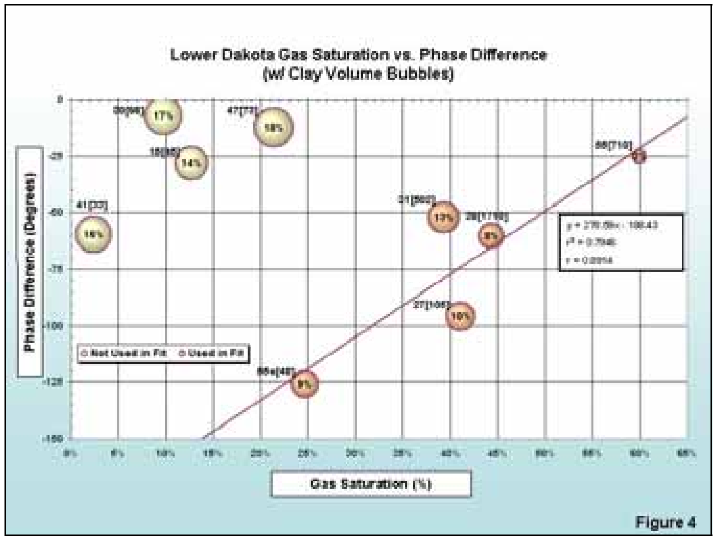

Figure 4. Gas content versus phase gradient (AVO attribute) for Unit Wells drilled pre-1999. Cross plot groups well into high and low clay clusters. Note the red linear regression line through the low clay cluster (correlation coefficient 0.89).

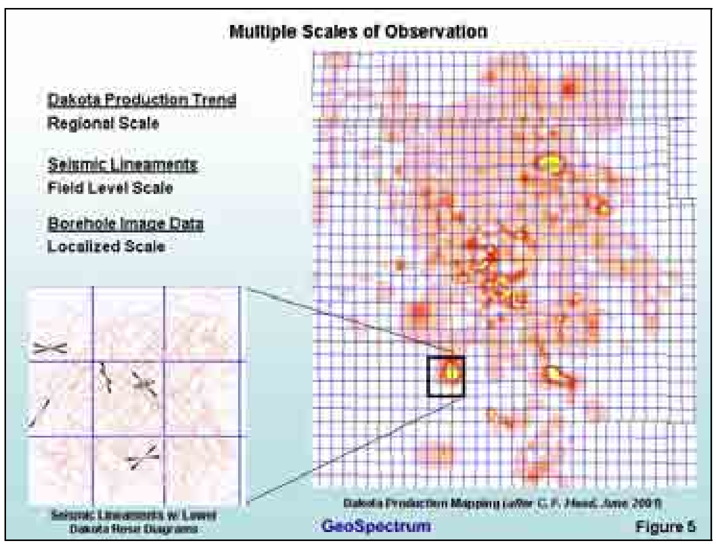

Figure 5. Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales.

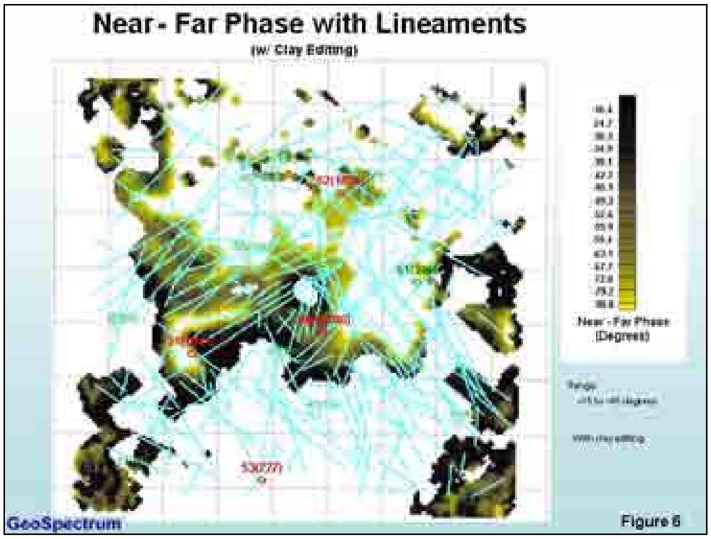

Figure 6. Overlay of low clay and gas bearing prospective fairway with seismic lineaments. New drill locations are shown (Wells 52, 53, 28E, and 31E).

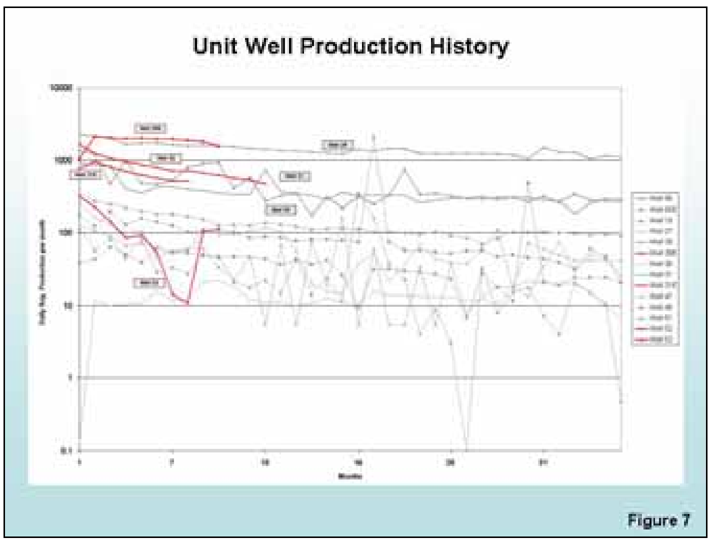

Figure 7. Production for new drill locations are shown in red (Wells 52, 53, 28E, and 31E). The new fractured reservoir exploration method has nearly doubled gas production and the value of the unit.

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	841	Average

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 1

Table 1. Prospect rating system. The Unit Operators were notified that the Well 53 location did not appear to have significant Lower Dakota gas before the well was drilled.

For more information contact the Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

APPENDIX 10
Interpreting 3D Seismic Data For Fractured Unconventional Gas Reservoirs

(West Texas Geological Society 2005 Fall Symposium, Midland, Texas, Reeves, 2005)

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INTRODUCTION

Natural fractures are often responsible for enhancing production in oil and gas reservoirs. They play an important role for defining sweet spots especially in the Permian Basin of west Texas and New Mexico, and in the Rocky Mountain Region of the United States. For the last 5 years, Dr. James J. Reeves, Principal Investigator, has worked for the U. S. Department of Energy to develop a 3D seismic interpretation method for tight gas fractured reservoirs in the San Juan Basin of New Mexico (Reeves and Smith, 2002 and 2004). The Department of Energy has spent over a million dollars in developing this program. Burlington Resources contributed the 3D seismic and well data to the study. An additional three million dollars in drilling cost was invested by Huntington Energy to test new prospects. Drill locations are defined from an overlay of three key reservoir attribute maps: seismic lineaments, clay volume, and gas saturation (Figure 1).

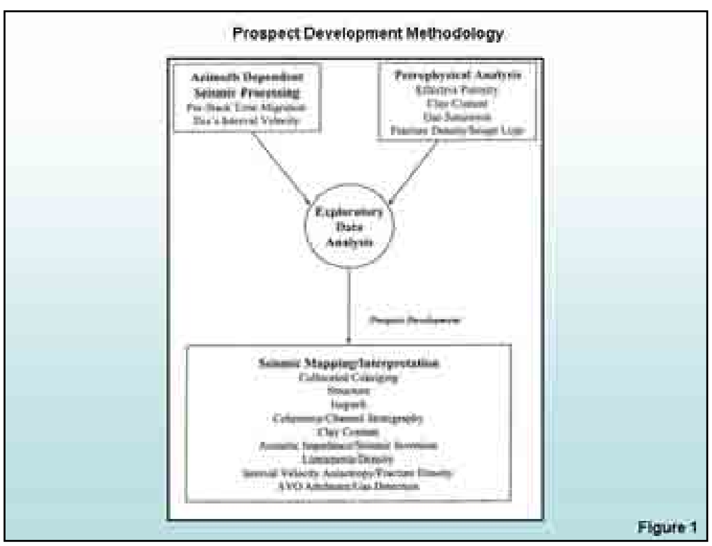

Figure 1. Prospect development methodology.
Steps:
1. Seismic lineament mapping
2. Seismic isopach mapping and channel imaging
3. Collocated cokriged clay volume
4. Phase gradient / AVO attribute map
5. Seismic interval velocity anisotropy

METHOD

Natural fractures are predicted using seismic lineament mapping in the reservoir section (Figure 2). A seismic lineament is defined as a linear feature seen in a time or horizon slice through the seismic volume that has a negligible vertical offset. Seismic attributes investigated may include coherency, amplitude, frequency, phase, and acoustic impedance. Volume based structural curvature attributes may also be computed. It is interpreted that areas having high seismic lineament density with multi-directional lineaments define areas of high fracture density in the reservoir.

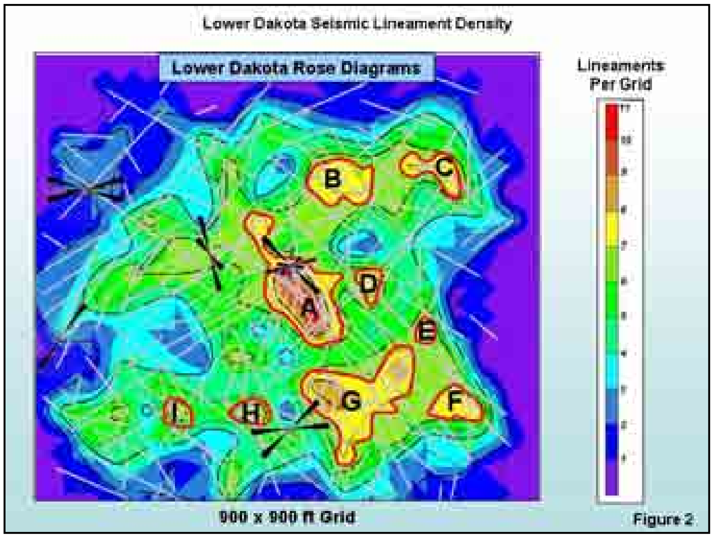

Figure 2. Lead areas (A through I) associated with regions of high lineament density. Notice the outstanding agreement between orientation of fractures in wells drilled pre-1999 (rose diagrams) and seismic lineaments.

Lead areas are screened by seismic attributes, such as seismic amplitude or acoustic impedance, indicating brittle reservoir rock that are more likely to be highly fractured (Figure 3). Seismic attributes are calibrated to clay content measured in existing well control by wireline logs (Figure 4). Further screening of the lead areas may also be done based on reservoir thickness and stratigraphy interpreted from the 3D seismic data.

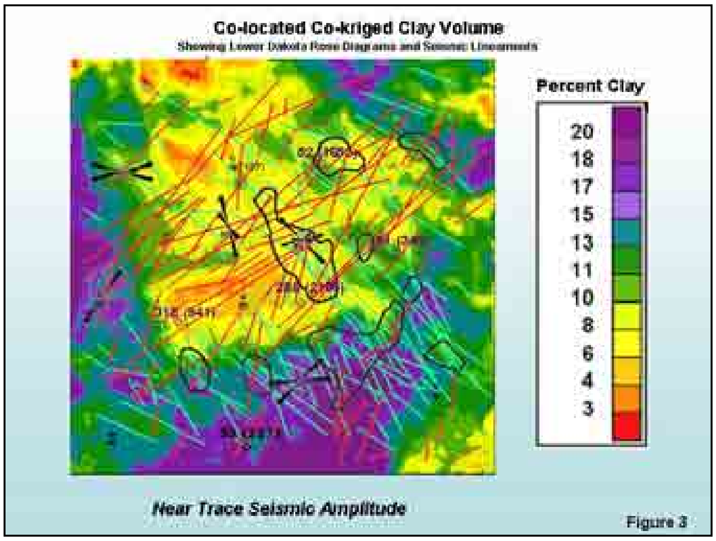

Figure 3. Collocated cokriged clay volume map using Unit Wells drilled pre-1999. After applying the low clay volume constraint (less than 13 percent), only three leads remain to be investigated (leads A, B and D). Notice the unique directional distribution of lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths).

Gas sensitive seismic attributes such as the phase gradient (an AVO attribute first developed by GeoSpectrum) or frequency dependent seismic amplitude may be used to

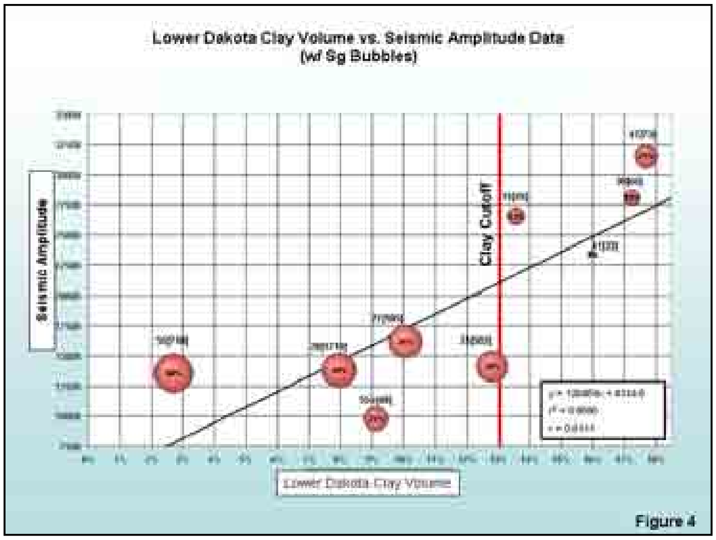

Figure 4. Clay volume versus near-trace seismic amplitude (AVO attribute) for Unit Wells drilled pre-1999. Characteristic curve used to compute collocated cokriged seismic clay volume map (correlation coefficient 0.81).

define a prospective fairway to further screen drill locations having high gas saturation

(Figure 5). These attributes may be calibrated to gas saturation determined from existing well control by wireline logs (Figure 6). The importance of gas sensitive attributes cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they also may penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

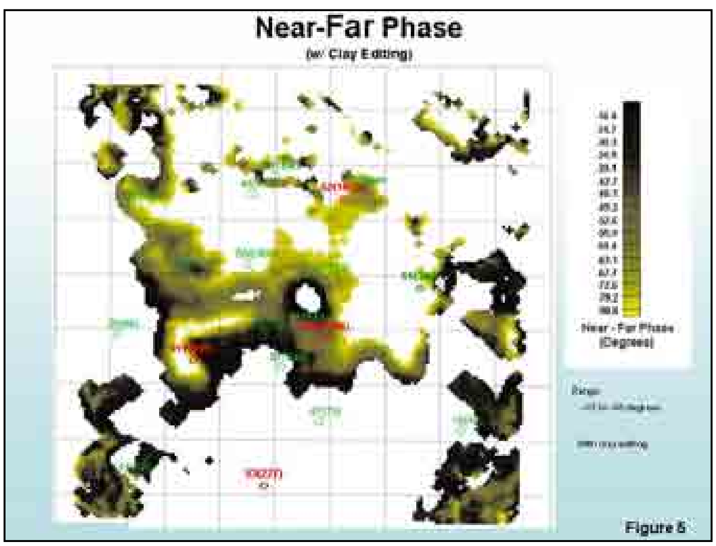

Figure 5. Lower Dakota seismic phase gradient map (near minus far-trace stack) showing values between –15 to –85 degrees with estimated clay less than 13 percent (near-trace seismic amplitude less than 2000, Figure 3).

CONCLUSIONS

In a gas field previously plagued with poor drilling results, four new wells were spotted using the methodology and recently drilled. The wells have estimated best of 12-months production indicators of 2106, 1652, 941, and 227 MCFGPD (Figure 7). The latter well was drilled in a region of swarming seismic lineaments but had a poor gas sensitive AVO attribute. The Unit Operators were advised that this location did not appear to have

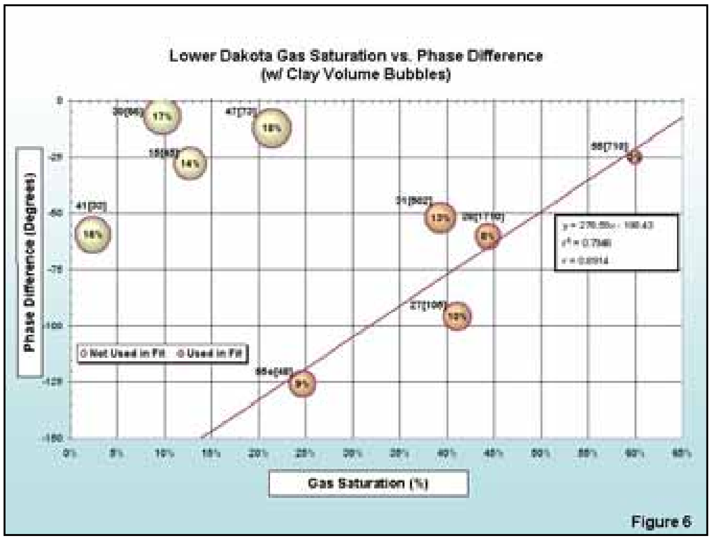

Figure 6. Gas saturation versus phase gradient (AVO attribute) for Unit Wells drilled pre-1999. Cross plot groups wells into low (less than 13 percent) and high (greater than 13 percent) clay clusters. Note the empirical red trend line through the low clay cluster (correlation coefficient 0.89).

significant Lower Dakota gas before the well was drilled. The other three wells are considered good wells in this part of the basin and among the best wells in the field. A prospect rating system is developed indicating either a "good", "average", or "poor" grade (Table 1). The new interpretation method is ready for commercialization, and gas exploration and development. The technology is adaptable to conventional lower cost 3D seismic surveys.

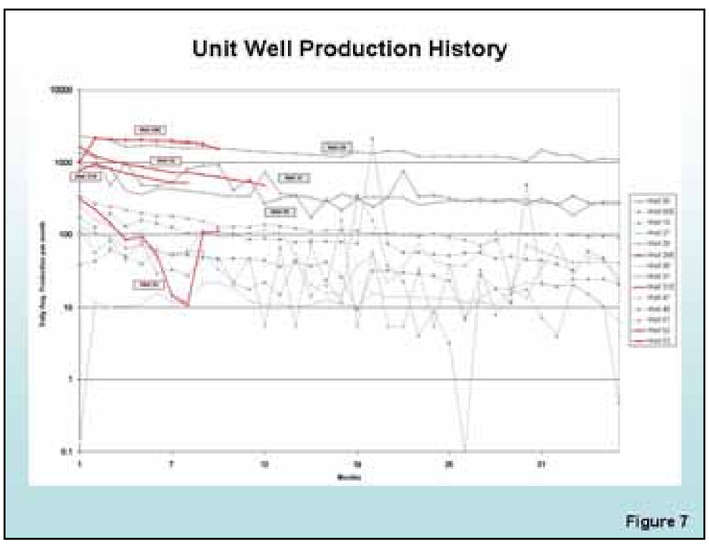

Figure 7. Unit Well Production History. Production for new drill locations Well 52, 53, 28E, and 31E are shown in red. The new fractured reservoir exploration technology has nearly doubled the production and value of the unit.

ACKNOWLEDGEMENTS

Most of the funding for the study came from the U. S. Department of Energy, the gas Unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

Table 1

Table 1. Conclusions / prospect drilling results 2004. The Unit Operators were advised that the Well 53 location did not appear to have significant Lower Dakota gas before the well was drilled.

provided by the operators, their employees, and associates. Dakota play geology was abstracted from Burlington Resources well and prospect files by Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, Mark Gygax prepared many of the graphics used in our publications, the Prospect Rating System was recommended by Dr. John Reeves, Jr., and Dr. Emilio Mutis-Duplat reviewed the final project report and made many useful suggestions. Hoxie Smith assisted in preparation of the original project proposal and review of project reports and papers. Dr. James Reeves, the Principal Investigator, designed and managed all phases of the research, and is the primary author of the original project proposal and all technical project reports and publications. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

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APPENDIX 11
New 3D Seismic Interpretation Methods to Characterize Fractured Gas Reservoirs

(Society of Petroleum Engineers 2005 International Petroleum Technology Conference, Doha, Qatar, Reeves, 2005)

James J. Reeves/GeoSpectrum, Inc.

Abstract

Reservoir fractures are predicted using multiple azimuth **seismic lineament mapping** in the Lower Dakota reservoir section. A seismic lineament is defined as a linear dislocation seen in a time slice or horizon slice through the seismic volume. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include: coherency, amplitude, frequency, phase, and acoustic impedance. We interpret that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir.

Lead areas defined by regions of "swarming" multi-directional lineaments are further screened by additional geologic attributes. These attributes include reservoir isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; and a **collocated cokriged clay volume map** for the Lower Dakota computed from near trace seismic amplitude (an AVO attribute) and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present.

A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient** (an AVO attribute first developed by GeoSpectrum), is used to further define drill locations having high gas saturation. The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they may also penetrate water saturated zones in the Dakota and/or Morrison intervals and be responsible for the reservoir being water saturated and ruined.

Seismic **interval velocity anisotropy** is used to investigate reservoir potential in tight sands of the Upper Dakota up hole from the main reservoir target. We interpret that large interval velocity anisotropy is associated with fracture related anisotropy in these tight sands.

Results from a four well drilling program to test GeoSpectrum's fractured gas reservoir prospects show that the fracture detection methodology is ready to be applied on a commercial basis.

Introduction

GeoSpectrum has successfully completed a project funded by the U.S. Department of Energy (DOE) to develop an integrated 3D seismic fracture interpretation method to explore for tight gas reservoirs. Four prospects were developed by the work and selected to be drilled by GeoSpectrum, the operator, and the U. S. Department of Energy to test the new methodology (GeoSpectrum, 2003).

Three of the four prospects drilled have been very successful, each having initial potentials ranging near 1 to 4 MMCFGPD from the Lower Dakota. These wells are some of the best wells in the Unit so far, and good wells for this area of the San Juan Basin, New Mexico. The fourth well was drilled in an area predicted not to contain significant gas.

Lower Dakota Encinal Sand fractured reservoir prospects are predicted by a method of applying modern seismic processing techniques including prestack time migration, followed by a rigorous analysis of azimuth dependent and all azimuth seismic attributes and well log data, to quantify areas of high natural fracture density and potential high gas saturation.

In the study, GeoSpectrum, Inc. reprocessed a nine square mile 3-D seismic data set acquired with an omni-directional receiver array to provide broad offset azimuth statistics. The processing was focused on prestack analysis of amplitude variation with offset (AVO) and after stack analysis of anisotropy using multiple azimuths. The processed 3-D seismic data volume and subsequent statistical analysis of seismic attributes were interpreted for identification of fractures prospective for commercial gas production. Relationships between seismic attributes and measured reservoir properties, such as clay content, and Dakota fracture density (or counts) interpreted from borehole image logs, are presented.

The following reservoir attributes are used,

1. Reservoir fractures are predicted using **seismic lineament mapping** in the reservoir section.
2. The lead areas defined by regions of "swarming" multi-directional lineaments are further screened by additional geologic attributes including a **collocated cokriged clay volume map** for the Lower Dakota.
3. A gas sensitive AVO seismic attribute, near trace stacked phase minus far trace stacked phase, **phase gradient** (a new AVO attribute), is used to further define drill locations having high gas saturation.
4. A seismic **interval velocity anisotropy** attribute is used to investigate fractured reservoir potential in tight sands up hole from the main reservoir target.

Play Geology

The gas Unit used to develop the methodology is located in Rio Arriba county, New

Mexico in the central portion of the San Juan Basin (Figure 1). The well numbers in this paper are truncated to use the last two numerical digits of the actual unit well number. Gas production in this region is mainly from the Cretaceous Dakota and Gallop Sandstones. The most significant Dakota production occurs in the Lower Dakota mainly from the Encinal and Burro Canyon Sands.

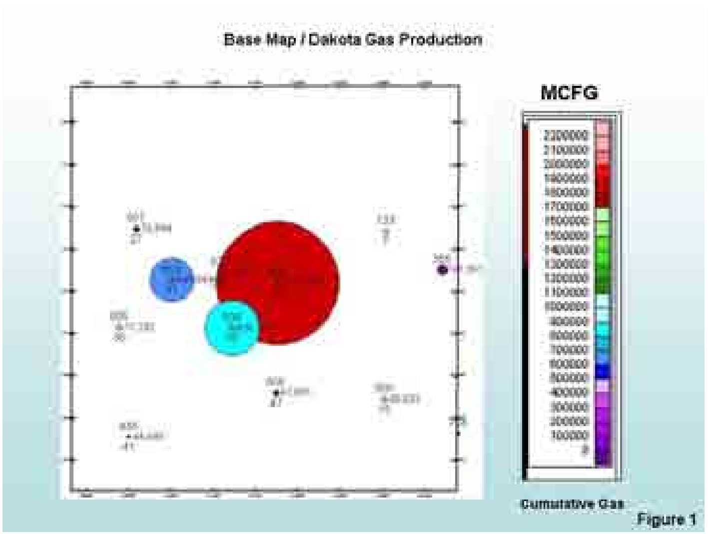

Figure 1. Cumulative gas production map for wells drilled pre-1999. The number below each well symbol has the last two numerical digits of the Unit Well No. The number to the right is cumulative gas production (MCFG).

Prospective Dakota horizons include both tight (Upper Dakota) and permeable (Lower Dakota) sandstones. Reservoir stratigraphy of the Dakota producing interval is complex, with production potential in five individual sandstones. Dakota sandstone depositional environments range from (near marine) fluvial-deltaic to marine. A summary of both the Upper and Lower Dakota producing zones follows.

Upper Dakota. The Upper Dakota is comprised of both near shore marine (Two Wells, Paguate, and Oak Canyon) and fluvial-deltaic (Cubero) members.

Two Wells and Lower Paguate. The Lower Paguate and Two Wells sandstones are northwest trending marine shore faces exhibiting classic coarsening upward sequences. Porosity ranges of 8 – 13 percent characterize both sandstones with matrix permeability between 0.5 – 0.20 md. These sandstones require stimulation to achieve commercial rates.

Cubero Sandstone. The upward fining fluvial-deltaic Cubero, which is oriented essentially perpendicular to these marine flow units (Lower Paguate and Two Wells), exhibits log porosity up to 10 percent and is typically a lower permeability reservoir than the marine Dakota units. It was deposited in a delta where combined fluvial and wave processes were dominant.

The Upper and Lower Cubero sandstones have the best reservoir potential of the several Upper Dakota sandstones that are typically completed (e.g. Well 15). However, only the middle Cubero sandstone has significant potential in Wells 25 and 31 (northwest portion of the Unit).

The deepest prospective, conventional Upper Dakota reservoir is the Lower Cubero Sandstone (Well 77). The reservoir was deposited as a northeast trending lobe of a fluvial deltaic system and is characterized by average porosity of 9.5 percent and average matrix permeability of approximately 0.10 md. This "clean", brittle sandstone is prone to natural fracturing; however, hydraulic fracturing is required to achieve commercial production.

Lower Dakota. The Lower Dakota reservoirs are comprised of the fluvial Burro Canyon and Encinal Canyon sands that are typically thick and relatively permeable but lithologically and petrophysically complex.

Encinal Canyon Sandstone. The Encinal Sandstone is near the base of the Dakota Formation and was deposited by braided streams in topographic valleys.

In 1993, commercial Lower Dakota gas production was established in the Unit with an Encinal Canyon sand pay-add in Well 55 essentially a "new field" discovery. A three well priority program followed this initial success in 1994 to define reservoir limits and upside potential. Of those three wells, Well 31 was a commercial success; Well 15 was wet and unsuccessful; and Well 25, a reservoir boundary (edge) well, was marginal.

As part of the 1994 priority program, data was collected to characterize the Encinal Canyon reservoir. Core taken from Well 15 indicates that this sandstone has exceptional reservoir quality compared to "conventional" tight Dakota reservoirs. Key differences include greater permeability (up to 200 md at reservoir stress), greater porosity (8 – 18 percent), and lower shale volumes.

In 1995, four additional wells were recommended. Well 30 and Well 28 were developmental extensions, and Well 27 and Well 47 were exploratory extensions. In addition to the basal Dakota Encinal Canyon Sandstone, conventional tight Dakota sandstones were secondary targets in all four proposed wells. This stacked pay zone possibility reduced the dry hole risk and increased the upside potential gas reserves.

The four additional Lower Dakota new wells were programmed to further define the productive limits and extent of the "new field", and to test a geological valley fill reservoir model. Well 28 is one of the most significant Unit Dakota wells drilled with a best of 12-months production of 1710 MCFGPD. Wells 47, 30, and 27 had various degrees of calculated Lower Dakota pay, but each of these wells proved to be unsuccessful.

A significant risk in Encinal completions is water invasion from sandstones either above or below the gas reservoir. Water can encroach vertically through both natural and hydraulic fractures. A highly fractured reservoir may be responsible for excellent gas production or it may be ruined by fractures providing a plumbing system to nearby Dakota and/or Morrison water reservoirs. Also, within an Encinal structural / stratigraphic trap there is increased risk of Encinal water downdip. Unlike the Burro Canyon, the Encinal Canyon sand is more typically hydrocarbon bearing.

Burro Canyon Formation. The Burro Canyon Sandstone is legally defined as part of the Dakota producing interval, but is stratigraphically distinct from the overlying Dakota Formation.

The Cretaceous Burro Canyon Sandstone was deposited by fluvial (river) systems on top of an irregular surface formed by erosion of the Jurassic Morrison Formation. The unconformity separating these two formations represents a hiatus of approximately 23–37 million years. A thicker Burro Canyon interval was deposited in Morrison valleys and thinner Burro Canyon on higher areas. The Burro Canyon represents the base of the Cretaceous in the San Juan Basin.

Burro Canyon sandstones were deposited in braided streams, far from marine influences; whereas Dakota sandstone depositional environments range from (near marine) fluvial-deltaic to marine. This difference in depositional environment explains why hydrocarbon source shales (rich in organic matter) are present in the Dakota, but not in the Burro Canyon. Burro Canyon sandstones generally have larger grain size, higher porosity, and higher matrix permeability than typical Dakota sandstones.

The Burro Canyon Sandstone is separated from the overlying Dakota Formation by an erosional unconformity, representing 3–6 million years. Irregularities in the amount of erosional down-cutting combined with the inherently irregular nature of Burro Canyon sandstones (braided stream deposits) create hydrocarbon traps where individual sandstones are truncated updip by the unconformity.

Within the Burro Canyon Sandstone there are many individual sandstone units, each with it’s own reservoir boundaries. These are too irregular to be individually mapped. They pinch out laterally, coalesce with other sandstones, and/or down-cut into underlying sandstones. Although the Burro Canyon is known as a "sandstone", interbedded shales and siltstones are common. This bewildering stratigraphic complexity has formed permeability barriers that, in conjunction with erosional truncation and structure, have trapped hydrocarbons.

The Burro Canyon is a fine-to-coarse grained, upward fining deposit that is frequently characterized by wet porosity, often when porosities exceed 15 percent.

Fracture Detection Methodology

Reservoir Characteristics. Several potential new Encinal Sand prospect/exploratory extensions of the Unit have been developed. The prospects are based on an integrated methodology using geologic as well as seismic attributes determined from advanced petrophysical and seismic data analysis.

The Unit consists of about 10 wells that were drilled pre-1999, 7 of which are marginal producers. Three of these Wells (Nos. 28, 55 and 31) each have a cumulative gas production of greater than 700 MMCFG and are good producers. However, the close proximity of poor Wells (e.g. Nos. 55E and 27) to within one mile of the good producers is an indication of the Dakota reservoir complexity within the boundaries of the Unit.

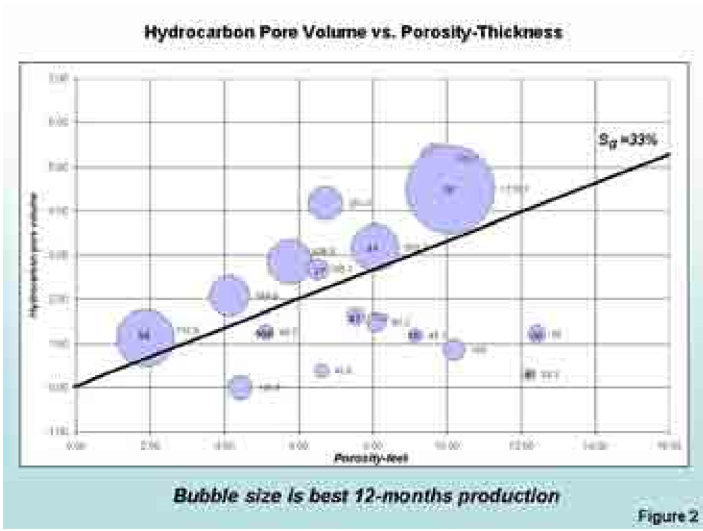

Figure 2. Advanced petro-physical analysis of Lower Dakota well log data for Unit Wells drilled pre-1999. Notice that all significant wells have a gas saturation greater than 33%. The random distribution of production quality, the best of 12-months production indicator (bubble size) above the gas cutoff line is indicative of fractured Dakota reservoir.

Figure 2 shows for Unit Wells drilled pre-1999, hydrocarbon pore volume versus porosity-thickness and the best of 12-months of production. Note that all of the significant / good wells in the study area are distinguished by a gas saturation cut-off of about 33 percent. Also notice the apparent random correlation between the best of 12-months production indicator (bubble size) for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. [In other words, production quality (bubble size) in the cross plot does not increase linearly with reservoir volume.]

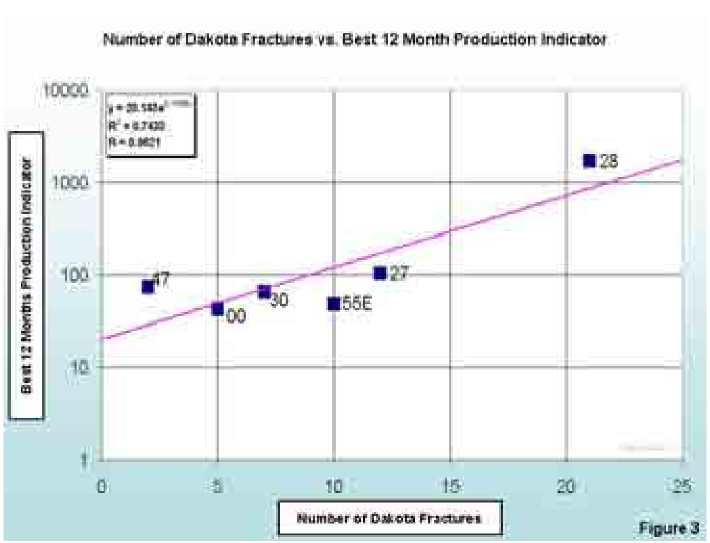

Figure 3. Number of Dakota fractures (Lower Dakota counts plus Upper Dakota counts) measured from borehole image logs versus best of 12-months production indicator (Unit Wells drilled pre-1999). Well No. 28 is one of the most significant wells in the Unit.

Figure 3 shows Dakota fracture counts (Lower Dakota counts plus Upper Dakota counts) interpreted in Unit Wells drilled pre-1999 from borehole image logs versus the best of 12-months production indicator. Note that most of the fracture counts occur in Well 28, one of the most productive wells in the Unit (best of 12-months production of 1710 MCFGPD). This well is one of the most significant Dakota discoveries drilled in the area.

Figure 4 shows a seismic record section after prestack time migration containing Wells 30, 31, 55E, and 28. After applying prestack time migration, the correlation of the synthetic seismograms computed at each well is excellent. The Lower Dakota seismic section analyzed in this study is between the top of the Encinal Sandstone, ENSS horizon (blue), and the top of the Morrison, MRSN horizon (yellow). Note the varying seismic response associated with the Dakota-Morrison unconformity (yellow). All seismic attributes used in this paper are computed from data within the Lower Dakota interval except for the interval velocity seismic attributes. The latter attributes were computed for an interval roughly near, the first positive reflection (Lower Cubero) above the ENSS horizon (blue) in the Upper Dakota to the first positive reflection (Green Horn) above the DKOT horizon (yellow), top of the Dakota.

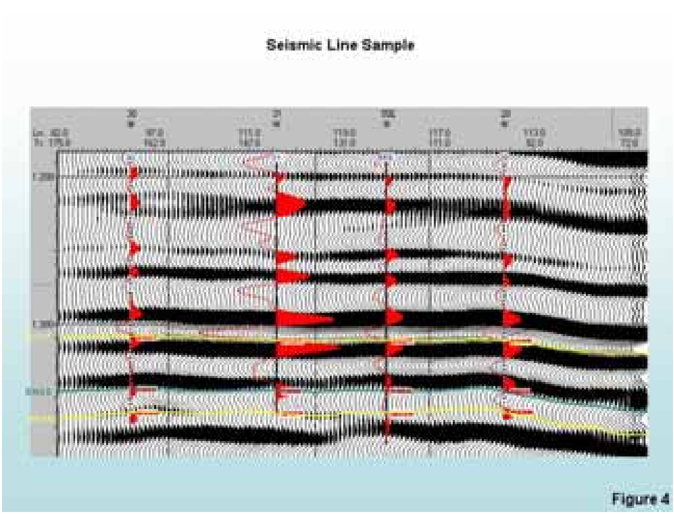

Figure 4. The Lower Dakota reservoir section is located between the top of the Encinal Sandstone, ENSS (blue), and the top of Morrison, MRSN (yellow) horizons.

Seismic Lineament Analysis. Lower Dakota lineaments are interpreted from azimuth dependent and all azimuth seismic attribute volumes. Seismic attributes include azimuth dependent and all azimuth instantaneous amplitude, frequency, phase, coherency, prestack time migration, and difference attributes (one azimuth attribute subtracted from another azimuth attribute separated by about 90 degrees). Seismic attribute volumes were computed roughly along the same preferred azimuths that the seismic lineaments have themselves, and perpendicular to those azimuths, N 10 degrees E, N 55 degrees E, N 100 degrees E, and N 145 degrees E (each azimuth ± 22.5 degrees).

Seismic lineaments are most easily seen in horizontal cross section. We interpret these lineaments to correspond to fracture zones in the reservoir. Figure 5 shows a composite map of all seismic lineaments interpreted in the Lower Dakota. Only seismic lineaments that are observed in two or more different seismic attribute volumes are mapped. The application of azimuth dependent prestack time migration to increase spatial resolution should have significantly enhanced our ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at Well 28, one of the most prolific wells in the Unit. The rose diagrams in Figure 5 show borehole breakout indicating present day tectonic stress in nearly a north-south direction. This orientation of tectonic stress does not preferentially close any fractures oriented in the northeast or northwest directions. Both fracture orientations should be available for fluid or gas flow in the Unit.

However, borehole breakout data in a well to the southeast and off the map indicates a change in stress orientation to a NE direction.

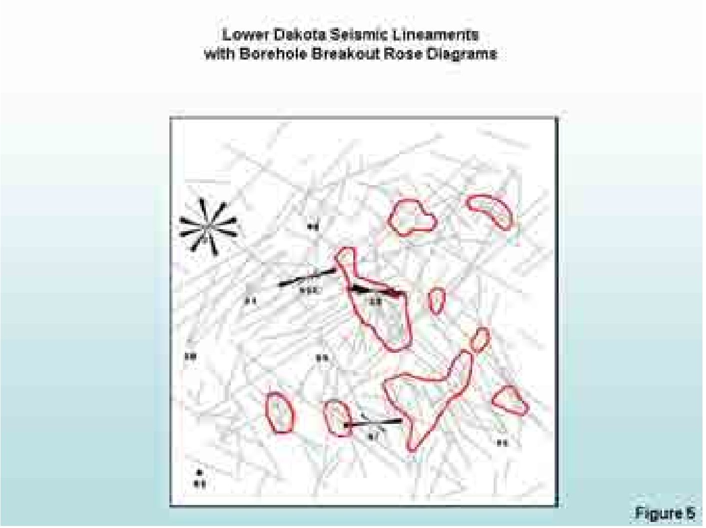

Figure 5. Seismic lineaments are used to infer a network of northeast and northwest fracture zones in the Lower Dakota. Present day north-south tectonic stress inferred from borehole breakout (Unit Wells drilled pre-1999) does not preferentially close any of these fracture orientations. (However, borehole breakout data in a well to the southeast and off the map indicates a change in orientation of tectonic stress to a NE direction.)

Lower Dakota lineament density (Figure 6) is computed assuming a well drainage area or pixel size of about 900 sq ft and from the lineaments in Figure 5. The hotter colors (regions of high lineament density) are interpreted to indicate fracture-developed reservoirs showing nine different lead areas (A through I). Notice a number of other leads could be distinguished from the seismic lineament map itself (Figure 5) from the anomalous clusters of multi-directional lineaments. The rose diagrams in Figure 6 show Lower Dakota fracture orientations interpreted from borehole image logs. Considering the different scales of measurement between the well data and the seismic images, the agreement in orientation between fractures measured in wells and orientation of seismic lineaments is quite good.

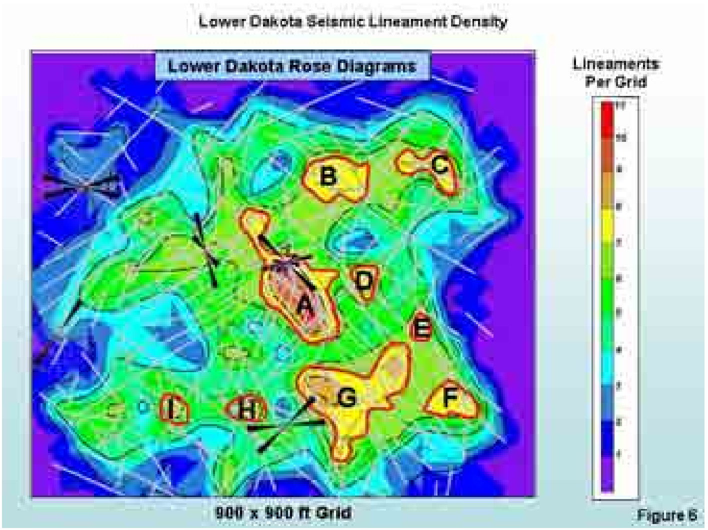

Figure 6. Lead areas (A through I) associated with regions of high lineament density. Notice the outstanding agreement between orientation of fractures in wells drilled pre-1999 (rose diagrams) and seismic lineaments.

Figure 7 defines fracture related reservoir anisotropy on three different scales of data, 1.) A localized scale from borehole image data, 2.) A field level scale from seismic lineaments, and 3.) A regional scale from Dakota production trends (after C. F. Head, 2001). Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales.

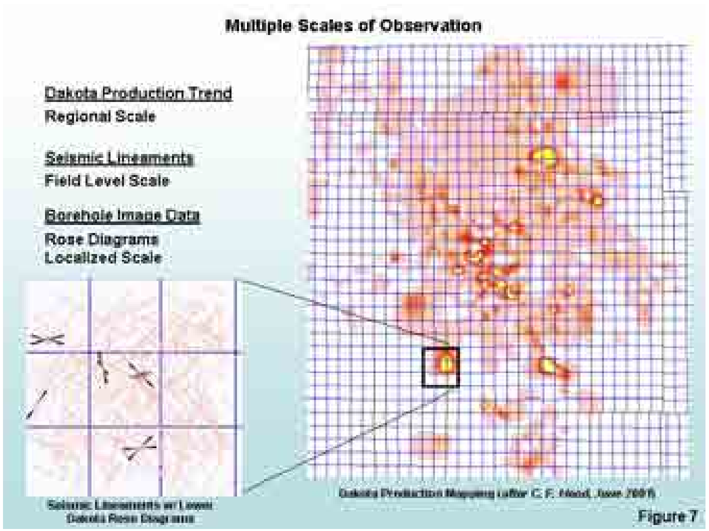

Figure 7. Inferred fracture orientations from all three scales of data are in excellent agreement showing a classic "fractal-like" dependence of the data at different scales. Borehole image data was obtained from Unit Wells drilled pre-1999. (Dakota production mapping after C. F. Head, 2001)

Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments are associated with structural troughs and noses mapped in the Lower Dakota (Figure 8).

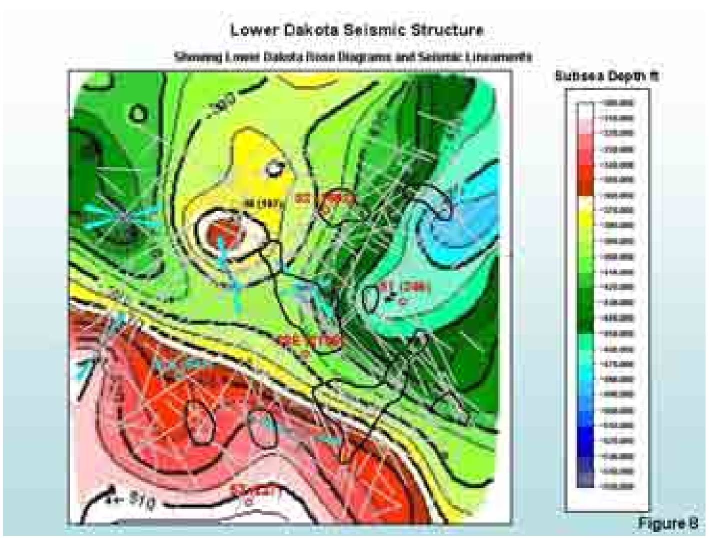

Figure 8. Notice the strong correspondence between the multi-directional character of many of the seismic lineaments in the Unit with structural troughs and noses mapped in the Lower Dakota. Structural mapping is based on Unit Wells drilled pre-1999.

Upper Dakota Fracture Density. Figure 9 shows a seismic guided Upper Dakota fracture density map modeled from Dakota fracture counts measured from borehole image logs for 5 wells. Fracture density mapping was done using collocated cokriging using interval velocity anisotropy. Interval velocity anisotropy is computed as Dix's interval velocity for 145 ± 22.5 degree azimuth data minus the interval velocity for 55 ± 22.5 degree azimuth data. The increase in signal to noise ratio obtained by prestack time migration greatly improved our ability to do this analysis. Interval velocities were computed for an interval roughly near the first positive reflection (Lower Cubero) above the ENSS horizon (blue) in the Upper Dakota to the first positive reflection (Green Horn) above the DKOT horizon (yellow), top of the Dakota (Figure 9). This analysis is used to infer prospective Upper Dakota fractures.

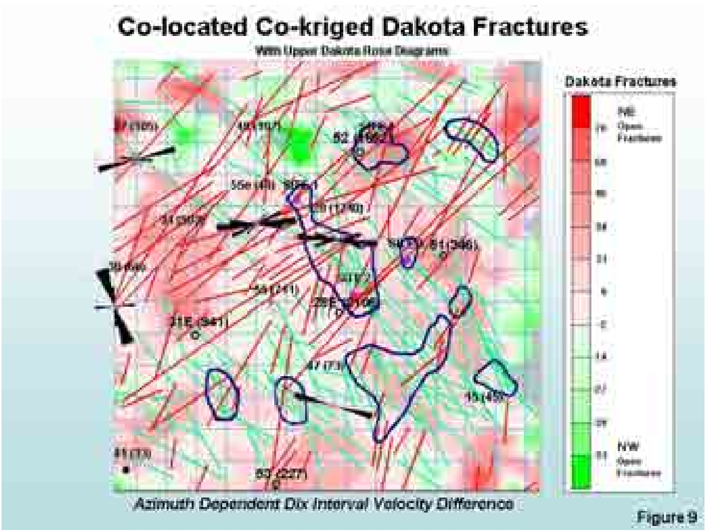

Figure 9. The large interval velocity anisotropy in the Upper Dakota/Green Horn at the Well 52 prospect may indicate additional fracture potential of reservoir up hole. Note the differing fracture distributions indicated by the seismic lineaments (Lower Dakota, Figure 5) and interval velocity anisotropy (near Upper Dakota / Green Horn). (Collocated co-kriging is done using Dakota fracture counts from borehole image data measured in Unit Wells drilled pre-1999.)

Figure 10 shows a cross plot of interval velocity anisotropy versus Dakota fracture counts (Lower Dakota counts plus Upper Dakota counts, correlation coefficient .61) and was used to model Upper Dakota fracture density / counts. A better correlation coefficient (.99) is obtained if Well 47 is considered an outlier and the characteristic curve is passed through the origin, however this improved response was not used.

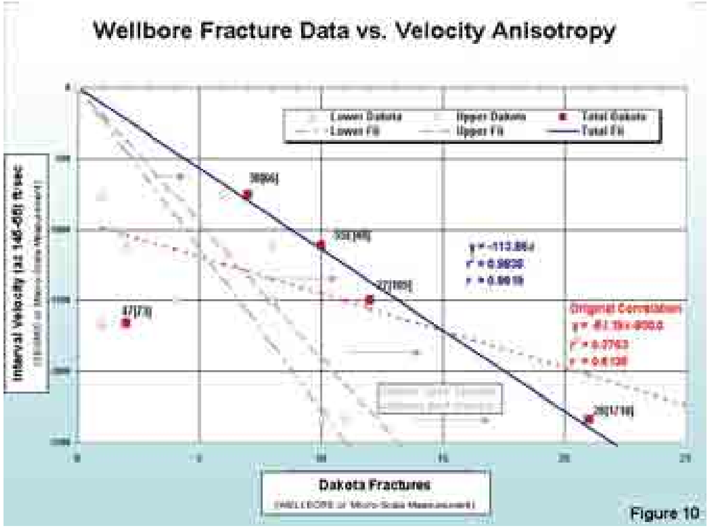

Figure 10. A near perfect response curve is obtained by removing Well 47 as an outlier and passing the curve through the origin (correlation coefficient 0.99). Dakota fracture counts (Lower Dakota counts plus Upper Dakota counts) are from borehole image data measured in Unit Wells drilled pre-1999.

Note the trend of high interval velocity anisotropy associated with the prolific Well 28 that may be associated with fractures. Other prospective regions of possible high fracture density are also seen to the northeast of Well 28 at the proposed Well 52 prospect. This anomalous interval velocity anisotropy may correspond to fractured reservoir potential up hole in the Upper Dakota.

Fractured Reservoir Prospects

Reservoir Mapping. The lead areas defined by the seismic lineament mapping should be further screened using appropriate reservoir quality attributes. A data driven approach is used. We identify leads that have similar reservoir attributes as the significant Unit Wells (No. 28, 31, and 55). Several different attributes should be considered including channel stratigraphy (interpreted from isopach mapping and seismic horizon slices) and clay volume. Clay volume is one of the main attributes used in our reservoir analysis to indicate where good/clean reservoir rock is located. We interpret that clean/low clay reservoir rock is brittle and likely to be highly fractured when seismic lineaments are present. Also, clays typically have high water content increasing the likelihood of a clay rich reservoir being water-wet.

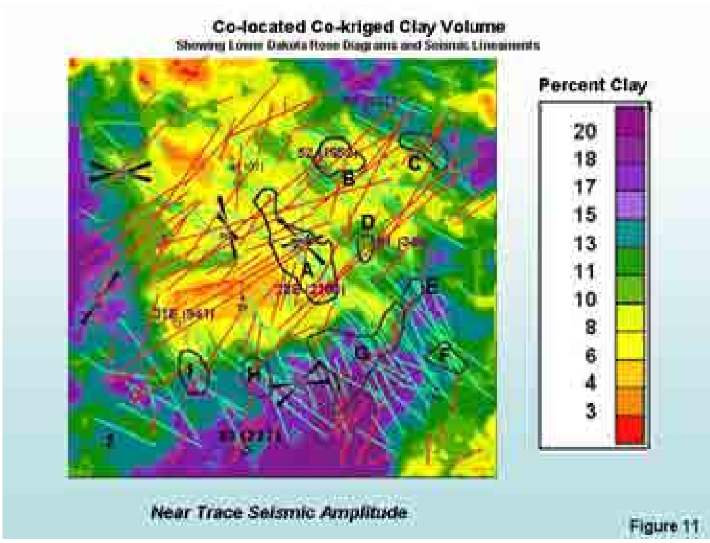

Figure 11. Collocated cokriged clay volume map for Unit Wells drilled pre-1999. After applying the low clay volume constraint (less than 13 percent), only three leads remain to be investigated (leads A, B and D). Notice the unique directional distribution of lineaments associated with low clay (northeast azimuths) and high clay (northwest azimuths)

In Figure 11, a seismic guided Lower Dakota clay volume map based on petrophysical analysis of log data from 9 wells drilled pre-1999 is shown. Seismic guided mapping was done using collocated cokriging using the average near trace instantaneous seismic amplitude from a narrow zone (~ 3 ms thick) in the Lower Dakota (measured cross correlation 0.81, Figure 12). (The horizon defining this zone is the same horizon used to define the phase gradient AVO attribute described later in the paper. Both the phase gradient and the near trace amplitude are AVO attributes.)

Figure 11 shows Lower Dakota clay volume, seismic lineaments, and lead areas (A through I). Two distinct rock types are defined by the map, low clay (less than about 13 percent) shown by hot colors and high clay (greater than about 13 percent) shown by cooler colors. If we focus our attention only to low clay reservoir we have eliminated all lead areas except for leads A, B, and D.

Notice the unique directional distributions for seismic lineaments as a function of rock type, low versus high clay. Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction and high clay rocks are associated with lineaments in the northwest direction. It's not surprising that the two rock types have differing distributions of lineaments. Fractures in these two rock masses are controlled by their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses, and how the two rock masses interact with each other during their tectonic stress history.

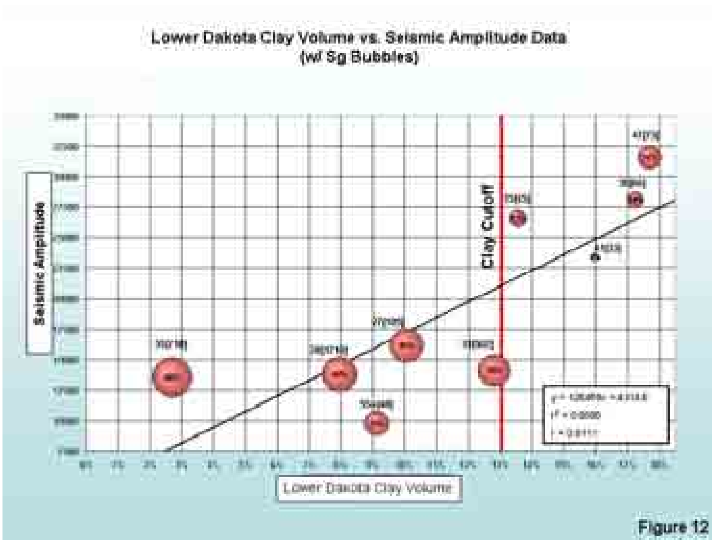

Figure 12. Clay volume versus near trace amplitude (AVO attribute) for Unit Wells drilled pre-1999. Characteristic curve to compute collocated cokriged seismic clay volume map.

These results should be tested by modeling the state of stress underground using a finite element or finite difference method. We would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

Note the orientation of fractures inferred from the Upper Dakota interval velocity anisotropy, Figure 9. Most of the anisotropy values are shaded in red on the map that may indicate an abundance of northeast trending fractures. If the anisotropy is related to fracture counts, we conclude that northwest trending fractures (shaded in green) simply are not as common as northeast trending fractures. If so, the distribution of fractures in the Upper Dakota over the study area is more similar to the distribution of seismic lineaments or fractures in the Lower Dakota for the clean low clay rock type, Figure 11. The differences between the Upper and Lower Dakota fracture distributions should be explained by their differing depositional environments and tectonic history. The Lower Dakota are non-marine fluvial channel sands whereas the Upper Dakota are non-marine fluvial-deltaic and marine shoreline sands. Each of these units should have differing rock types and geometries that effect fracture distributions.

Gas Prediction Seismic Attribute / Phase Gradient

We can not underestimate the importance of a seismic attribute to help predict gas saturation. Just as reservoir fractures can increase the drainage area of a gas productive well, they also can provide a plumbing system to aquifers for the reservoir to become water saturated. This is quite common for the Dakota, because of complex stratigraphy water charged zones can be found both above and below gas bearing zones.

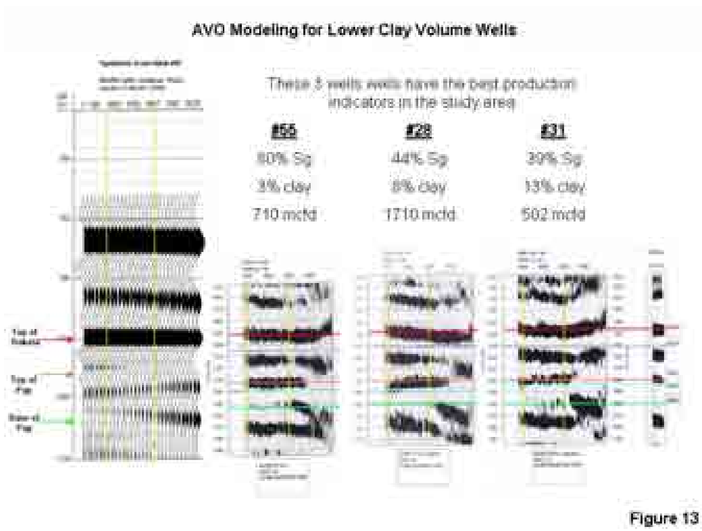

Figure 13. Significant gas producing Lower Dakota wells with low clay have a diagnostic AVO response compared to poor wells (Figure 14). (AVO modeling from Castagna et. al., 1998)

In Figures 13 and 14, normal move out corrected 25-fold supergathers, after prestack time migration, are extracted for significant gas producers drilled pre-1999, Unit Wells 55, 28, and 31 (Figure 13) and for poor producing Unit wells drilled pre-1999, the 47, 15, and 30 that have higher clay in the Lower Dakota (Figure 14). Note the apparent Lower Dakota class 2 AVO anomaly near the base of pay / top of Morrison Formation. A class 2 AVO anomaly typically exhibits a low amplitude near offset response and a phase reversal with increased amplitude at far offsets.

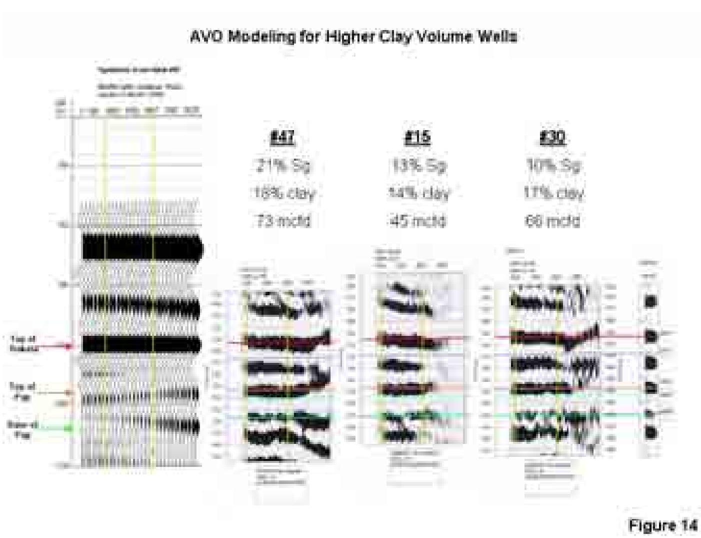

Figure 14. Poor producing Lower Dakota wells with high clay have a diagnostic AVO response compared to significant production (Figure 13). (AVO modeling from Castagna et. al., 1998)

Figures 13 and 14 also show a Dakota AVO model computed using dipole sonic and density logs for Well 47 (Castagna et. al., 1998). Comparison of the modeled response of the AVO anomaly in the Lower Dakota to the AVO supergather from the field data at Well 47 is excellent (Figure 14). Lower Dakota gas saturation averages about 23 percent in this well.

A closer look reveals that the characteristic differences between the AVO gathers at each of the endpoints, gas producing wells versus high clay / poor producing wells, are very distinguishable and diagnostic. An interpreter could evaluate the entire seismic volume for potential gas producing targets and eliminate clay rich poor producing regions on a gather by gather basis. In this study, we accomplish the same task through development of an automatic computer driven routine.

After reviewing the supergathers at each well showing the AVO anomaly, a special horizon was interpreted through the Lower Dakota to compute an AVO attribute. (This is the same special or AVO horizon used earlier to compute near trace seismic amplitude for clay mapping.) The cross plot in Figure 15 shows Lower Dakota phase gradient (near trace phase minus far trace phase, a new AVO attribute) computed for the special/AVO horizon versus Lower Dakota gas saturation for Unit Wells drilled pre-1999. The outlying wells with gas saturations less than 24 percent have Lower Dakota clay contents greater than 13 percent. The red trend line (correlation coefficient 0.89) is based on the remaining five wells that have clay contents less than 13 percent, and gas saturations greater than 24 percent. Note that three of these five Wells (28, 55 and 31) are the most productive wells in the Unit, and are associated with a phase difference range between -15 to -85 degrees. It is important to note that the phase gradient AVO attribute is sensitive to both clay volume and gas, whereas the near trace amplitude AVO attribute is sensitive to mostly clay (Figure 11).

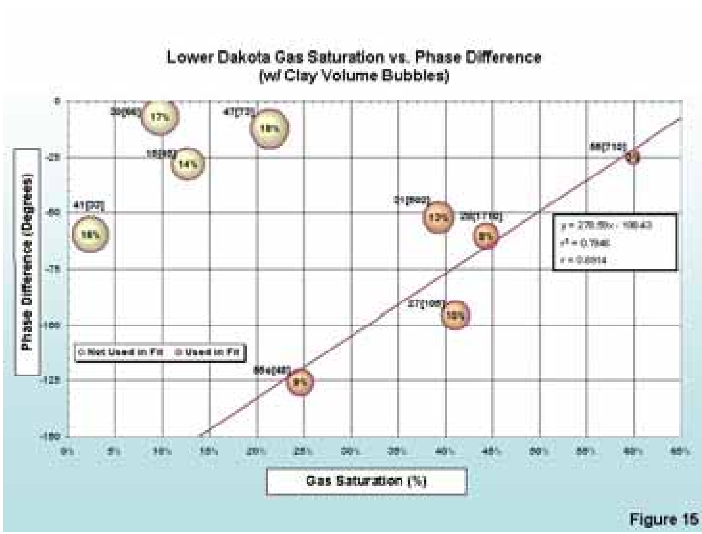

Figure 15. Gas saturation versus phase gradient (a new AVO attribute) for Unit Wells drilled pre-1999. Cross plot groups wells into low (less than 13 percent) and high (greater than 13 percent) clay clusters. Note the empirical red trend line through the low clay cluster (correlation coefficient 0.89).

Figure 16 shows seismic guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than about 13 percent. Seismic guided mapping was done using collocated cokriging and the empirical trend line (phase difference vs. gas saturation) in Figure 15 for Unit Wells drilled pre-1999. (A model switching routine could be used to map gas in the higher clay rock type.) Modeled gas saturations between about 33–60 percent define a prospective trend for Lower Dakota fracture controlled gas production in the Unit. The lower end gas cutoff (33 percent) comes as a result of the petrophysical analysis shown in the hydrocarbon pore volume versus porosity thickness and best of 12-months production indicator (Figure 2). The high-end gas cutoff comes from the petrophysical analysis of the significant Unit Wells (Figure 15, Well 55).

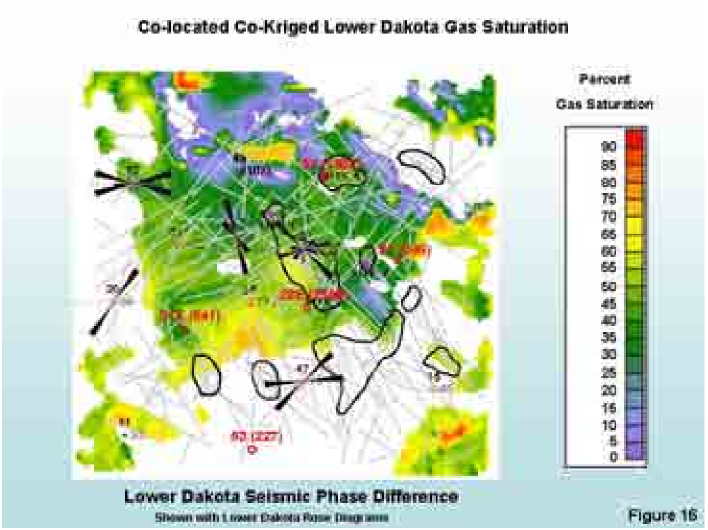

Figure 16. Collocated cokriged Lower Dakota gas saturation map for Unit Wells drilled pre-1999. The Well 52 prospect nearly has the same phase gradient response / gas saturation as Well 28, one of the most significant well, indicating similar AVO attributes. Most importantly the phase gradient / computed gas saturation does not support the 55E well location (Table 1).

Two prospective trends that correspond to regional Dakota production are indicated in the northwest and northeast directions. Notice that more favorable gas / AVO attributes are typically found regionally on the updip side of the map. The Well 52 prospect has nearly identical phase difference attributes or a computed "gas saturation" as the Well 28 indicating similar AVO characteristics (Figure 17, AVO modeling from Castagna et. al., 1998). In practice the AVO attributes should be reviewed in the common midpoint (CMP) offset domain before any prospect is drilled to further confirm the AVO phase gradient mapping. Well 55E, that was drilled between the productive 31 and 28 Wells, has poor AVO attributes and is not shown to be prospective which collaborates with its poor completion results (Table 1). The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir.

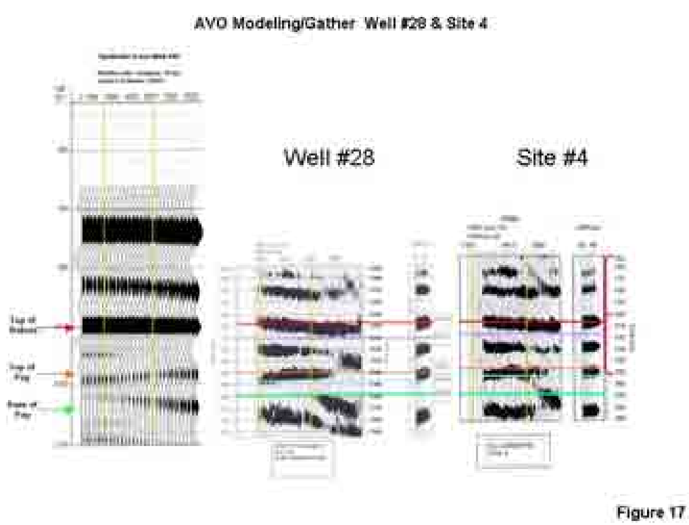

Figure 17. The equivalent AVO response for Site 4 (Well 52 prospect) and Well 28 (one of the most significant wells in the Unit) indicates that Site 4 has low clay and is gas producing (Figure 13). (AVO modeling from Castagna et. al., 1998)

The empirical relationship of the seismic phase difference attribute and gas saturation has not been confirmed by seismic modeling. Additional work should be done for full wave equation AVO modeling to analyze the observed relationship. The gas saturation mapped in Figure 16 should only be used to define prospective trends for gas production, not for actual gas saturation values.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon. This is near where the gas is. The interpretation should provide additional information as to the role of channel stratigraphy and trapping mechanism.

Recent Drilling Results
Not Using GeoSpectrum's Recommendations
1998 to 2001

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
55E	05/1998	Good	Low	Poor	Good	48	Poor
48	04/1999	Good	Low	Poor	Good	195	Poor
51	10/2001	Poor	Low	Poor	Excellent	346	Poor

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 1

Table 1. Recent drilling results not using GeoSpectrum's recommendations, 1998 to 2001.

In summary, the phase gradient attribute shows all three pre-1999 significant Unit Wells (28, 31, and 55) in the Encinal Sand as gas bearing. It explains the poor results of the nearby 55E Well as gas not being present. Also note that the low clay and high clay rock types (good versus poor reservoir quality) in the Lower Dakota are distinguished in three different seismic attributes confirming our interpretation:

1. Near trace seismic amplitude (Figure 11)
2. Phase gradient / AVO characteristics (Figure 15)
3. Seismic lineament orientation (Figure 12)

Selected Prospects

Prospects are developed by overlaying the Lower Dakota clay volume, phase gradient, and seismic lineament maps. A prospective fairway is defined where Lower Dakota gas saturation is between 37 to 62 percent (phase gradient –65 to –15 degrees) and clay volume is less than 13 percent (Figure 18). Three prospects (Wells 52, 28E and 31E) are chosen to drill on swarming / intersecting lineaments in the gas bearing fairway. Well 52 tests attributes near the northeast part of the fairway, Well 28E tests attributes near the central region of the trend, and Well 31E tests attributes near the southwest part of the prospective fairway. The fourth prospect, Well 53 is selected to test a swarm of seismic lineaments close to the southwest / central edge of the 3D seismic coverage. However, Well 53 does not have favorable AVO or clay volume attributes. GeoSpectrum advised the Unit Operators that this drill location did not appear to have significant Lower Dakota gas before the well was drilled. The four prospect locations (Wells 28E, 31E, 52, and 53) are shown in the phase gradient and seismic lineament map (Figure 18). All four wells are spotted on or near lineaments and/or intersection points of the lineaments. (Note that depending on drilling results, a number of other locations would justify drilling if we can relax the reservoir constraints and pick locations based mainly on the gas sensitive phase gradient (AVO) attribute.)

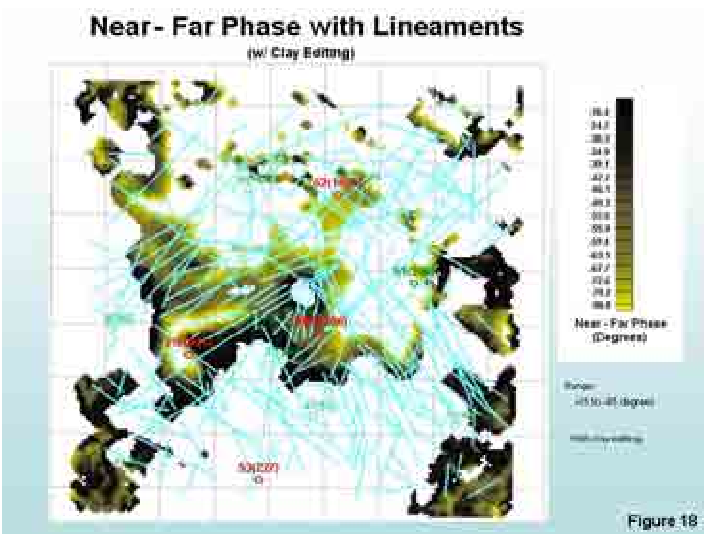

Figure 18. Low clay and gas bearing prospective fairway with seismic lineaments. New drill locations Well 52, 53, 28E, and 31E are shown. (Note the phase gradient AVO attribute does not support the 55E well location, Table 1.)

Drilling Results

Validation / Blind Wells 48 and 51. While presenting GeoSpectrum's methodology for fractured Dakota reservoir exploration to Burlington Resources, GeoSpectrum learned that Burlington had drilled two "blind Wells" (No. 48 and 51) in the gas Unit. The results of these wells were not used in this study. Unfortunately, Wells 48 and 51 are poor wells (Table 1). Spotting the wells on the Lower Dakota gas saturation and seismic lineament map (Figure 16 and 18) shows that GeoSpectrum's methodology would not have recommended these locations. Both of these wells are in regions of low gas saturation and low lineament density.

2004 Prospects / Drilling Results

Burlington Resources and Huntington Energy recently completed four wells defined by GeoSpectrum's 3D seismic interpretation method. Results indicate a success ratio of nearly 100 percent using the exploration method (Figure 19, Table 2). The 52 prospect drilled and completed in January 2004 had an initial potential of nearly 4,000 MCFGPD and a best of 12-month production estimate of 1652 MCFGPD. The 28E well drilled and completed in May 2004 has a best of 12-month production estimate of 2106 MCFGPD and continues to produce near this rate making it one of the best wells in the Unit so far. The 31E well was drilled and completed in June 2004 and has a best of 12-month production estimate of 941 MCFGPD. The fourth well, the No. 53, was drilled and completed in April 2004 and initially produced about 2,000 MCFGPD but has a best of 12-month production estimate of 227 MCFGPD. This prospect had favorable seismic lineament (fractured) reservoir attributes, however it did not have a good AVO (gas) or clay volume attributes. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon Sandstone, located underneath the productive Encinal Sand found in Lower Dakota wells. It is interpreted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

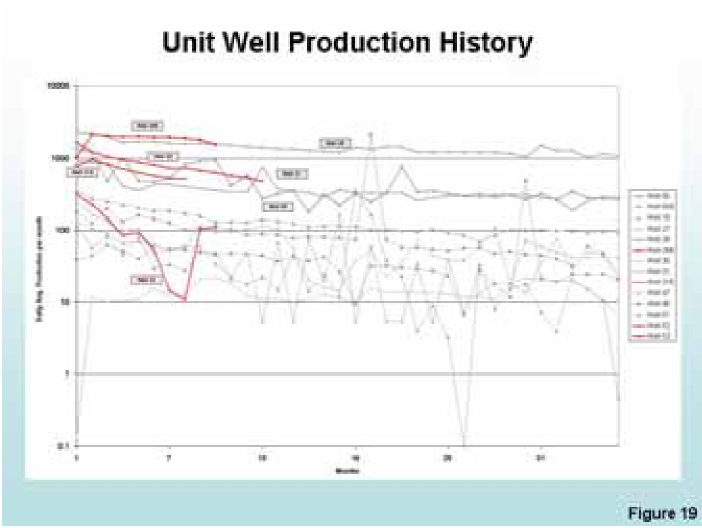

Figure 19. Unit Well Production History. Production for new drill locations Well 52, 53, 28E, and 31E are shown in red. The new fractured reservoir exploration technology has nearly doubled the gas production and value of the unit.

The GeoSpectrum Prospect Rating System assigning either a "good", "average", or "poor" grade to the prospects is illustrated in Tables 1 and 2. Table 2 shows the 2004 outstanding drilling results for the four wells spotted using GeoSpectrum's exploration methods. Table 1 shows the results for the last three wells drilled earlier in the same gas Unit not using GeoSpectrum's 3D seismic interpretation methods. Each of these three wells have poor AVO attributes, modest gas saturation, and poor best of 12-month production indicators, less than 350 MCFGPD, proving the value of our new technology. The Lower Dakota production results of 15 wells drilled in the Unit are all reasonably predicted by the methodology.

Conclusions / Prospect Drilling Results 2004

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 2

Table 2. Conclusions / Prospect drilling results 2004. GeoSpectrum advised the Unit Operators that the Well 53 location did not appear to have significant Lower Dakota gas before the well was drilled.

Conclusion

The three productive Unit Wells (28, 55 and 31) and the new prospect Wells (28E, 31E, 52, and 53) completed in 2004, appear to be predicted with nearly 100 percent success using the following methodology to explore for Lower Dakota gas:

1. Lower Dakota Clay content less than or equal to roughly 13 percent,
2. Phase Gradient (AVO) attribute indicating a phase difference between -15 to -85 degrees (gas saturation about 37 to 62 percent),
3. Spot well near intersecting or swarming seismic lineaments, and
4. Look for up hole fracture potential using Upper Dakota interval velocity anisotropy.

We interpret that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the four prospect wells and the economic discovery of gas in three prospects (Wells 28E, 31E, and 52) and the predicted result of the poor producing prospect (Well 53) validates the results of our U. S. Department of Energy study. These outstanding drilling results confirm the value of GeoSpectrum's applied methodology in detecting commercial and prospective targets in fractured tight gas sands. Future work should include the development of an automated approach to map seismic lineaments and to apply the technology.

For more information contact GeoSpectrum's Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

Acknowledgements

Funding for the study came from the U. S. Department of Energy, the gas Unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations provided by the operators, their employees, and associates. Dakota play geology was abstracted from Burlington Resources well and prospect files by Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, Mark Gygax prepared many of the graphics used in our publications, the GeoSpectrum Prospect Rating System was recommended by Dr. John Reeves, Jr., and Dr. Emilio Mutis-Duplat reviewed the final project report and made useful suggestions. Hoxie Smith assisted in preparation of the original project proposal and review of project reports and papers. Dr. James Reeves is the Principal Investigator in the project, he designed and managed all phases of the research, and is the primary author of the original project proposal and all technical project reports and publications. A special thanks is extended to all the technical societies and publishers, including, the American Association of Petroleum Geologists, GasTIPS, Permian Basin Geophysical Society, Rocky Mountain

Association of Geologists, Society of Exploration Geophysicist, Saudi Aramco, Petroleum Development Oman, Society of Petroleum Engineers, Strategic Research Institute, West Texas Geological Society, World Oil, and others, who have published our technical project papers and results, portions of which may have been reprinted in this paper. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

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APPENDIX 12
Advancing 3D seismic interpretation methods to find the sweet spots in tight gas reservoirs

(Society of Exploration Geophysicists 76th Annual Meeting, New Orleans, Louisiana, Reeves, 2006)

James J. Reeves, GeoSpectrum, Inc.*

Summary

Natural fractures are often responsible for enhancing production in oil and gas reservoirs. Drill locations are defined from an overlay of three key reservoir attribute maps. Seismic attributes are calibrated to clay content measured in existing well control by wire line logs to define fracture-prone brittle reservoir. Gas sensitive seismic attributes such as the phase gradient (an AVO attribute first developed by GeoSpectrum) are used to define a prospective fairway. Natural fractures are predicted using seismic lineament mapping in the reservoir section. Successful drilling results from 5 new wells indicate the new interpretation method is ready for commercialization, and gas exploration and development.

Introduction

Natural fractures are often responsible for enhancing production in oil and gas reservoirs. They play an important role for defining sweet spots especially in the Permian Basin of west Texas and New Mexico, and in the Rocky Mountain Region of the United States. For the last 5 years, Dr. James J. Reeves, Principal Investigator, and GeoSpectrum, an oil an gas technology company in Midland, Texas, have worked for the U. S. Department of Energy to develop a 3D seismic interpretation method for tight gas fractured reservoirs using conventional P-wave seismic data (Reeves and Smith, 2002 and 2004). The Department of Energy has spent over a million dollars in developing this program. Burlington Resources contributed the 3D seismic and well data for a study conducted in the San Juan Basin of New Mexico. An additional three million dollars in drilling cost was invested by Huntington Energy to test new prospects. Drill locations are defined from an overlay of three key reservoir attribute maps, seismic lineaments, clay volume, and gas saturation (Figure 1).

Method

Lead areas are screened by seismic attributes, such as seismic amplitude or acoustic impedance, indicating brittle reservoir rock that are more likely to be highly fractured (Figure 2). Seismic attributes are calibrated to clay content measured in existing well control by wire line logs (Figure 3). Further screening of the lead areas may also be done based on reservoir thickness and stratigraphy interpreted from the 3D seismic data.

Gas sensitive seismic attributes such as the phase gradient (an AVO attribute first developed by GeoSpectrum) or frequency dependent seismic amplitude may be used to define a prospective fairway to further screen drill locations having high gas saturation (Figure 4). Seismic attributes may then be calibrated to gas saturation determined from existing well control by wireline logs (Figure 5). The importance of gas sensitive attributes cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they also may penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Natural fractures are predicted using seismic lineament mapping in the reservoir section (Figures 6). A seismic lineament is defined as a linear feature seen in a time or horizon slice through the seismic volume that has a negligible vertical offset. Seismic attributes investigated may include coherency, amplitude, frequency, phase, and acoustic impedance. Volume based structural curvature attributes may also be computed. It is interpreted that areas having high seismic lineament density with multi-directional lineaments define areas of high fracture density in the reservoir.

Conclusions

In a gas field previously plagued with poor drilling results, four new wells were spotted using the methodology and recently drilled and completed in 2004. A fifth well was also drilled in 2005. The wells have estimated best of 12-months production indicators of 2106, 1652, 941, 227, and 231 MCFGPD (Figure 7). The latter two wells did not have good positive AVO and clay volume attributes. The other three wells are considered good wells in this part of the basin and among the best wells in the field. A prospect rating system is developed indicating either a “good”, “average”, or “poor” grade (Table 1). The new interpretation method is ready for commercialization, and gas exploration and development. The technology is adaptable to conventional lower cost 3D seismic surveys.

For more information contact GeoSpectrum's Principal Investigator, Dr. James J. Reeves, Tel. (432) 686-8626 Ext. 101, Email jreeves@geospectrum.com or the U. S. Department of Energy, Technical Contract Officer, Frances C. Toro, Tel. (304) 285-4107, Email frances.toro@netl.doe.gov.

References

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Acknowledgements

Most of the funding for the study came from the U. S. Department of Energy, the gas Unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations provided by the operators, their employees, and associates. Dakota play geology was abstracted from Burlington Resources well and prospect files by Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, and Mark Gygax prepared many of the graphics used in our publications. The Prospect Rating System was recommended by Dr. John Reeves, Jr., and Dr. Emilio Mutis-Duplat and many others in the oil and gas industry have reviewed and improved the quality of this report with their questions and comments. Hoxie Smith assisted in preparation of the original project proposal and review of project reports and papers. Dr. James J. Reeves, the Principal Investigator, designed and managed all phases of the research, and is the primary author of the original technical project proposal and all technical project reports and publications. A special thanks is extended to all the technical societies and publishers, including Balkan Geophysical Society, GasTIPS, Permian Basin Geophysical Society, Petroleum Development of Oman, Saudi Aramco, Society of Exploration Geophysicists, Society of Petroleum Engineers, Strategic Research Institute, West Texas Geological Society, World Oil, and others, who have published our technical project papers and results, portions of which have been reprinted in this paper. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

Figures

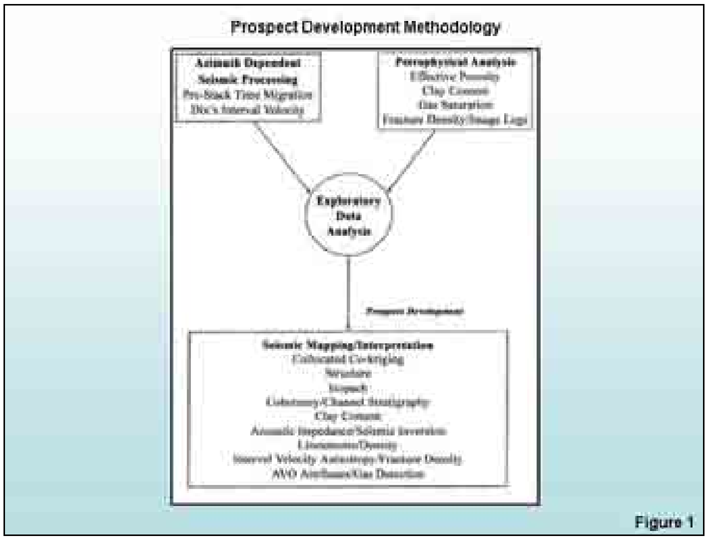

Figure 1. Prospect development methodology.

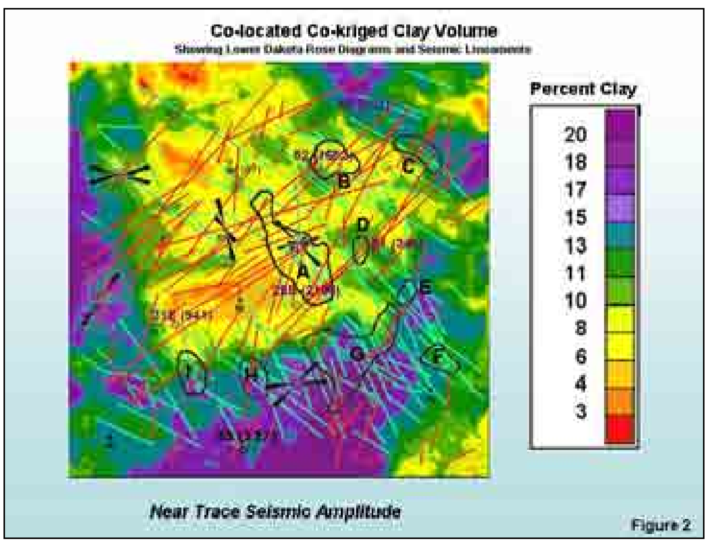

Figure 2. Collocated cokriged clay volume map.

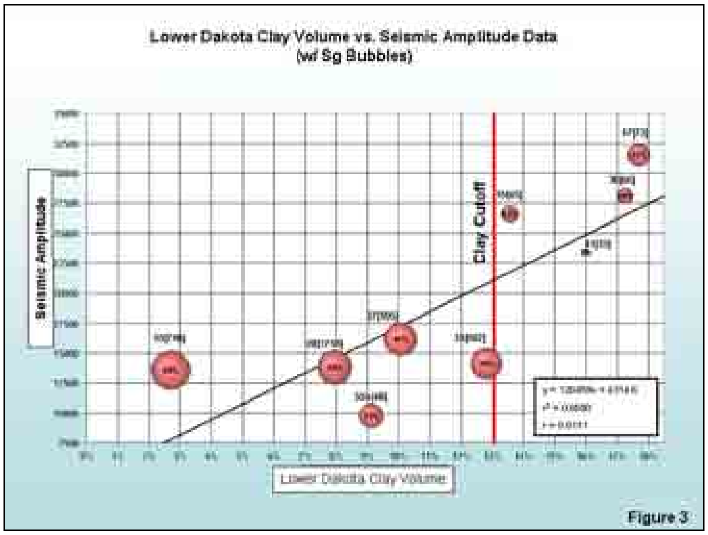

Figure 3. Clay volume versus near-trace seismic amplitude (AVO attribute).

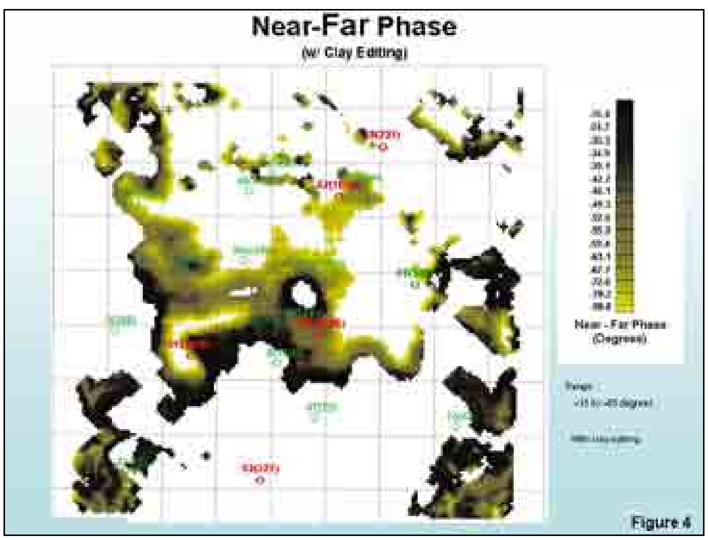

Figure 4. Lower Dakota seismic phase gradient map.

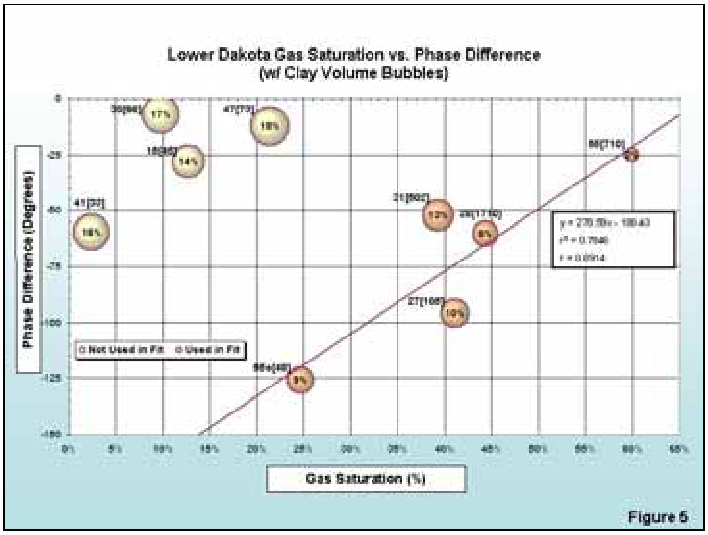

Figure 5. Gas saturation versus phase gradient (AVO attribute).

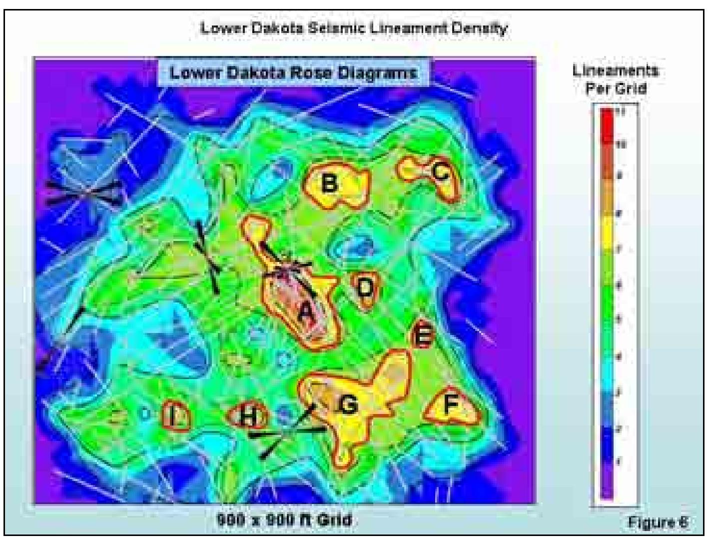

Figure 6. Lead areas (A through I) associated with regions of high lineament density.

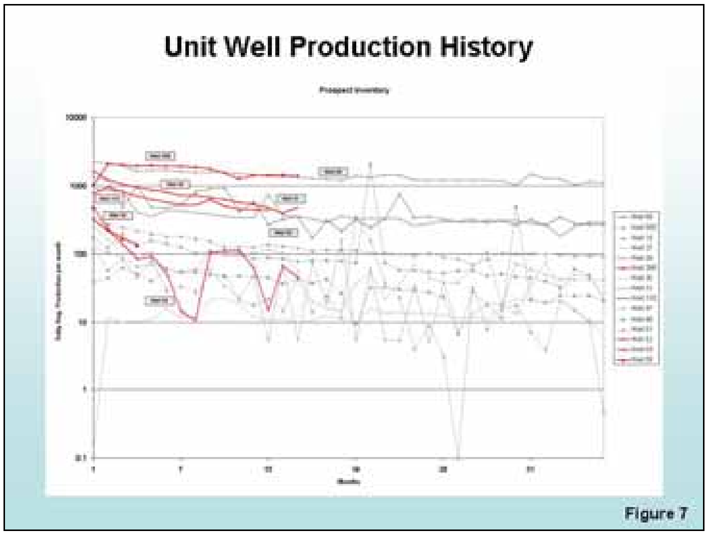

Figure 7. 2004/2005 prospect drilling results.

Conclusions / Prospect Drilling Results 2004/2005

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average
59	04/2005	High	Low	No AVO Attribute	Low	231	Poor

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

Table 1

Table 1. Prospect rating system.

APPENDIX 13
Developing New 3D Seismic Fracture Interpretation Methods for Tight Gas Reservoirs

("The Leading Edge," Reeves, 2006, in press)

By James J. Reeves, Ph.D., P.G., P.E.
GeoSpectrum, Inc., Midland, Texas

GeoSpectrum, Inc. is finishing a tight gas exploration and development study establishing 3-D seismic interpretation methods for fractured sandstone reservoirs.

The interpretation method is based on a comprehensive reservoir characterization of the Lower Dakota sandstone in a gas-producing unit in Rio Arriba County, NM.

This article reviews the following reservoir attributes from a 3 mi by 3 mi P-wave 3D seismic survey which are used in characterizing the reservoir:

- a collocated cokriged clay volume map for the Lower Dakota, along with additional geologic attributes, define regions of brittle reservoir rock prone to fracturing
- seismic lineament mapping in the reservoir predicts fractures;
- seismic interval velocity anisotropy investigates fractured reservoir potential in tight sands up-hole from the main reservoir target; and
- a gas-sensitive amplitude variation with offset (AVO) seismic attribute, near trace stacked phase minus far trace stacked phase, phase gradient, is used to further define drill locations having high gas saturation.

A four-well drilling program recently was completed to test the fractured gas reservoir prospects and exploration technology. The nearly 100% success ratio of the drilling program indicates the fracture detection method is ready for commercial application.

Fracture detection methodology

Lower Dakota clay volume/instantaneous seismic amplitude

Fractured reservoir leads are defined using important reservoir attributes for seismic rock typing: isopach thickness, indicating thicker reservoir section; seismic horizon slices, imaging potentially productive reservoir stratigraphy; a collocated cokriged clay volume map computed from near trace instantaneous seismic amplitude; and a comprehensive petrophysical analysis of the well data to determine discrete values of clay volume at each well. It is interpreted that clean/low clay reservoir rock is brittle and more likely to be fractured.

Figure 1 shows a seismic-guided Lower Dakota clay volume map based on petrophysical analysis of log data from nine wells drilled pre-1999. Note that for the purpose of anonymity, the names of the wells referenced in this paper have been truncated to have two numerical digits. Seismic-guided mapping is done with collocated cokriging using the average near trace instantaneous seismic amplitude from a narrow zone about 3 milliseconds thick in the Lower Dakota (measured cross correlation = 0.8). Similar results are seen for a zone thickness about twice as thick. The horizon defining this zone is the same as that used to define the phase gradient AVO attribute described later in this paper. The map defines two distinct rock types: low clay (less than about 13%) shown by hot colors and high clay (greater than about 13%) shown by cooler colors. The clay volume map divides the region into low and high clay cluster groups or rock types to define prospective trends for low clay reservoir prone to fracturing.

Lower Dakota fractures/seismic lineaments

Reservoir fractures are predicted using multiple azimuth seismic lineament mapping in the reservoir section. A seismic lineament is defined as a linear feature seen in a time or horizon slice through the seismic volume with negligible vertical offset. For lineament mapping, each lineament must be recognizable in more than one seismic attribute volume. Seismic attributes investigated include coherency, amplitude, frequency, phase and acoustic impedance (Figure 2). We interpreted that areas having high seismic lineament density with multi-directional lineaments are associated with high fracture density in the reservoir.

The application of separate prestack time migrations for each azimuth dependant seismic volume increases spatial resolution significantly enhancing our ability to accurately map seismic lineaments. Note the concentrated number of lineaments found at well 28, one of the most prolific wells in the unit. Borehole breakout in three wells indicates present-day maximum horizontal tectonic stress in nearly a north-south direction.   This orientation does not preferentially close any fractures oriented in the northeast or northwest directions. These fracture orientations should be available for fluid or gas flow in the unit. However, borehole breakout data in a well to the southeast and off the map indicates a change in maximum horizontal stress orientation to the northeast.

A number of leads can be distinguished from Figures 1 and 2 from the anomalous clusters of multidirectional lineaments in regions of low clay fracture prone reservoir rock. Lower Dakota structure appears to play a strong role in lineament orientation. The swarming effect of many of the seismic lineaments is associated with structural troughs and noses seen in the Lower Dakota depth converted seismic structure map.

Figure 3 defines fracture-related reservoir anisotropy on three different scales of data:

- localized scale/rose diagrams show Lower Dakota fracture orientations interpreted from borehole image logs;
- a field-level scale from seismic lineaments; and
- a regional scale from Dakota cumulative production trends.

Inferred fracture orientations from all three scales of data are in general agreement indicating a “fractal-like” dependence of the data at different scales.

In Figure 1, notice the unique directional distributions for seismic lineaments as a function of rock type, low vs. high clay. Lineaments in the northeast direction are shown in red and in the northwest direction in green. Low clay rocks are associated with lineaments in the northeast direction, and high clay rocks are associated with lineaments in the northwest direction. A similar rock typing relationship is seen in an acoustic impedance slice from a seismic inversion. It is not surprising that the two rock types have differing distributions of lineaments. Their differing strength characteristics, rock fabric, regional geometry or shape of the rock masses and how the two interact with each other during their tectonic stress history control fractures in these two rock masses.

Modeling the state of stress underground using a finite element or finite difference method should test results. One would expect to see an appropriate change in stress trajectory in moving from one rock mass to another that would yield the different fracture distributions.

Upper Dakota fractures/ interval velocity anisotropy

Seismic interval velocity anisotropy is used to investigate reservoir potential in the Upper Dakota above the main reservoir target. It is interpreted that large interval velocity anisotropy is associated with fracture related anisotropy.

Figure 4 shows a seismic-guided Upper Dakota fracture density map modeled from Dakota fracture counts measured from borehole image logs for five wells. Fracture density mapping is done with collocated cokriging using interval velocity anisotropy (correlation coefficient 0.6). Interval velocity anisotropy is computed as Dix's interval velocity for 145 ± 22.5° azimuth data minus the interval velocity for 55 ± 22.5° azimuth data. The increase in signal to noise ratio obtained by prestack time migration has improved the ability to perform this analysis. Interval velocities were computed for a zone between two strong seismic reflectors, including most of the Upper Dakota from the top of the Lower Cubero to the top of the Green Horn immediately above the Dakota. Prospective Upper Dakota fractures are inferred using this analysis.

The orientation of the Upper Dakota interval velocity anisotropy is of interest. If the anisotropy is related to natural fractures, the map indicates an abundance of northeast trending fractures (shaded in red). We conclude that northwest trending fractures (shaded in green) simply are not as common as northeast trending fractures. The distribution of fractures in the Upper Dakota in the study area is observed to be similar to the distribution of seismic lineaments or fractures in the Lower Dakota. The northwest striking lineaments mapped in the Lower Dakota are associated with the green and light pink colors in the interval velocity anisotropy map (Figure 4), and may correspond to an increase in Upper Dakota fractures in the northwest direction. The darker red areas in the map seem to correspond to the northeast striking lineaments.

Differing depositional environments and tectonic history could explain any differences between the Upper and Lower Dakota fracture distributions. The Upper Dakota are non-marine fluvial–deltaic and marine shoreline sands whereas the Lower Dakota are non-marine fluvial-deltaic and braided channel sands. Each of these units has different rock types, geometries, and tectonic histories that will affect fracture distributions and orientation.

Gas prediction/seismic phase gradient AVO attribute

Gas production data is analyzed using a cross plot showing hydrocarbon pore volume vs. porosity-thickness and the best of 12 months of gas production. Significant or good wells in the study area are distinguished by a lower gas saturation cut-off of about 33%. There appears to be a random correlation between the best of 12 months of production indicator for the good wells and reservoir volume (porosity-feet), indicating a fracture-controlled reservoir. (In other words, production quality does not increase linearly with reservoir volume determined from log analysis.)

A gas-sensitive AVO seismic attribute, near trace migrated stacked phase minus far trace migrated stacked phase, the phase gradient is used to further define drill locations having high gas saturation. An exploratory data analysis of gas saturation and the phase gradient indicates a correlation coefficient of 0.9 for low clay reservoir (less than ~ 13%). The importance of this attribute cannot be understated, as reservoir fractures enhance reservoir permeability and volume, they also may penetrate water-saturated zones and be responsible for the reservoir being water wet and ruined.

Figure 5 shows seismic-guided Lower Dakota gas saturation computed from the phase difference attribute where estimated Lower Dakota clay content is less than roughly 13%. Seismic-guided mapping is done using collocated cokriging and the empirical trend line for low clay reservoir (phase difference vs. gas saturation) from unit wells drilled pre-1999. Gas saturations between about 33% to 60% (determined from petrophysical analysis) define a prospective fairway for Lower Dakota fracture-controlled gas production in the unit. The lower end gas cutoff (33%) is deduced from the cross plot of hydrocarbon pore volume vs. porosity thickness and best of 12 months of production indicator. The high-end gas cutoff (60%) comes from the hydrocarbon pore volume determined for the significant gas-producing unit wells (28, 55 and 31).

Two trends shown by the prospective fairway that correspond to regional Dakota production are indicated in the northwest and northeast directions. Notice that more favorable AVO/gas attributes are typically found regionally on the updip side of the map in the fairway. The well 52 prospect has nearly identical phase difference attributes or a computed “gas saturation” as well 28, indicating similar AVO characteristics. In practice, it is recommended the AVO attributes should be reviewed in the common midpoint offset domain and compared to AVO gathers near good wells before any prospect is drilled to further confirm the AVO attributes indicate gas. Well 55E, which was drilled between the productive wells 31 and 28, is not in the prospective fairway, which collaborates with its poor completion results. The fractures at this well may have been responsible for providing a plumbing system for water to get into the Lower Dakota reservoir. The phase gradient gas saturation map is used to define a prospective fairway for gas production to upgrade fractured reservoir leads to prospect status.

Future work should include evaluation of channel images from horizon slices through the seismic volume near the AVO horizon, which is near the gas. The interpretation should provide important additional information as to the role of channel stratigraphy and trapping mechanism.

In summary, the phase gradient attribute shows all three pre-1999 significant unit wells (numbers 28, 31 and 55) in the Lower Dakota Encinal Sand as gas bearing. It explains the poor results of the nearby well 55E as gas not being present. Also note the low clay and high clay rock types (good vs. poor reservoir quality) in the Lower Dakota may be distinguished in four different seismic attributes that confirm and unify the interpretation:

- near trace instantaneous seismic amplitude (Figure 1);
- seismic lineament orientation (Figure 1);
- phase gradient/AVO characteristics (Figure 5); and
- in an acoustic impedance attribute from seismic inversion.

The integration of seismic attributes to interpret seismic rock types prone to fracturing, reservoir fractures from seismic lineaments and interval velocity anisotropy, and the direct detection of gas from an AVO attribute, has resulted in successful recent drilling results.

Selected prospects

Overlaying the Lower Dakota phase gradient attribute with the seismic lineament and seismic rock type maps defines prospects (Figure 5). A prospective fairway is defined where Lower Dakota gas saturation is about 37% to 62% and clay volume is less than 13%. Three prospects (wells 52, 28E and 31E) are chosen to drill near swarming/intersecting lineaments in the fairway. Well 52 tests attributes near the northeast edge of the fairway, Well 28E tests attributes near the central region of the trends, and well 31E tests attributes near the southwest edge of the prospective fairway. The fourth prospect, well 53, is selected to test a swarm of seismic lineaments close to the southwest/ central edge of the 3-D seismic coverage. However, well 53 does not have favorable AVO and clay volume attributes. The four prospect locations (wells 28E, 31E, 52 and 53) are shown in Figure 5, and are spotted on or near lineaments or intersection points of the lineaments. Note that a number of other locations would justify drilling if the reservoir constraints can be relaxed and locations picked based mainly on the phase gradient AVO attribute.

Drilling results

In 2004, Burlington Resources and Huntington Energy completed the four wells defined by GeoSpectrum's new 3D seismic interpretation method (Table 1). Results indicate a success ratio of nearly 100 percent using the exploration methodology. The well 52 prospect drilled and completed in January 2004 had an initial potential of nearly 4000

MCFGPD and a best of 12-month production estimate of 1652 MCFGPD. The 28E well drilled and completed in May 2004 has a best of 12-month production estimate of 2106 MCFGPD and continues to produce near this rate making it one of the best wells in the unit so far. The 31E well was drilled and completed in June 2004 and has a best of 12-month production estimate of 941 MCFGPD. The fourth well, the no. 53, was drilled and completed in April 2004 and initially produced about 2000 MCFGPD, but has a best of 12-month production estimate of 227 MCFGPD. This prospect had favorable seismic lineament (fractured) reservoir attributes, however, it did not have good AVO (gas) and clay volume attributes. Based on Neutron Density log crossover, the well may be producing most of its gas from a different reservoir, the Burro Canyon Sandstone, located underneath the productive Encinal Sand found in Lower Dakota wells. It is interpreted that reservoir fractures initially enhanced the gas production in this well, but its rapid decline is caused by the predicted lack of gas in the reservoir.

An additional well (no. 59) was drilled and completed in January 2005. This well is located to the northeast and on trend with productive wells 31E and 52 but in an area of poor seismic (AVO) phase gradient and clay volume attributes (Figure 5). As predicted by the new exploration methodology, this new well has a poor estimated best of 12 month production indicator of 231 MCFGPD (Table 1). The reservoir does not appear to contain significant gas.

Figure 6 shows early production histories for 16 wells completed in the unit. Production histories for the prospects (wells 28E, 31E, 52, 53 and 59) are shown in red. Note that the best well in the unit is now the new well 28E. New wells 31E and 52 are also among the better producing wells. The new fractured reservoir exploration technology has nearly doubled the production and value of the gas unit.

To date, a total of 12 new wells have been drilled in the unit and initiated by this study. Six of these wells were drilled within the 3D seismic survey. Production results from five of these wells (28E, 31E, 52, 53, and 59) were described earlier in the paper. The sixth well in the 3D seismic survey (no. 63) was completed in February 2006 in the northwest corner and near the boundaries of the 3D survey. This well appears to be a poor producing well. The analysis of the drilling and production results of this prospect has not been completed.

Conclusions

A new 3D seismic interpretation methodology for fractured reservoir exploration has been developed for conventional P-wave seismic data. An automatic picking routine using a new phase gradient AVO attribute is used to find gas bearing reservoir. Seismic rock types defined by clay content are identified to interpret brittle reservoir rock prone to fracturing. Seismic lineament mapping in the reservoir zone is used to predict fracture zones.

The three productive unit wells (28, 55 and 31) and the new prospect wells (28E, 31E, 52, and 53) completed in 2004, appear to be predicted with nearly 100 percent success using a new method to explore for Lower Dakota gas.

Prospects are developed where:

1. Lower Dakota Clay content from seismic rock typing is less than or equal to roughly 13 percent,
2. Lower Dakota phase gradient (AVO) attributes indicate a phase difference between -15 to -85 degrees (corresponding to gas saturation of about 37 to 62 percent),
3. Intersecting or swarming Lower Dakota seismic lineaments are present, and
4. Fractured reservoir potential in the Upper Dakota may be interpreted from Upper Dakota interval velocity anisotropy.

We interpret that natural fractures indicated by seismic lineaments have enhanced gas production. The drilling of the four prospect wells and the economic discovery of gas in three prospects (wells 28E, 31E, and 52) and the predicted result of the poor producing prospects (wells 53 and 59) validates the results of our U. S. Department of Energy study. The results of 16 wells in the unit are reasonably explained by the interpretation methodology. These drilling results confirm the value of GeoSpectrum's applied methodology in detecting commercial and prospective targets in fractured tight gas sands.

Future work should include an automated approach to map seismic lineaments and to apply the new technology.

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Acknowledgments

Portions of this paper appear in our Fall 2004 GasTIPS publication. Most of the funding for the study came from the U. S. Department of Energy, the gas unit operators, Burlington Resources and Huntington Energy, and the primary contractor, GeoSpectrum, Inc. The project also benefited greatly from data and interpretations provided by the operators, their employees, and associates. Dakota play geology was abstracted from Burlington Resources Prospect and Well files by Roger Smith, seismic data processing was done by Don Zimbeck, Jim Oden did the seismic interpretation, Jeff Kane did the petrophysical analysis, Sylvia Chamberlain was responsible for exploratory data analysis and AVO analysis/modeling, Dr. Mark Semmelbeck did the production data analysis, and Mark Gygax prepared many of the graphics used in our publications. Hoxie Smith assisted in contract administration. Dr. James J. Reeves, the Principal Investigator,

designed and managed all technical work and research resulting in the new 3D seismic interpretation methodology, prospect development, and drilling plan. Dr. Reeves is the primary author of the original technical project proposal and all technical project reports and publications. Finally, the timeliness and assistance of the U. S. Department of Energy technical contract managers, Fran Toro and Jim Ammer, is greatly appreciated.

Figures

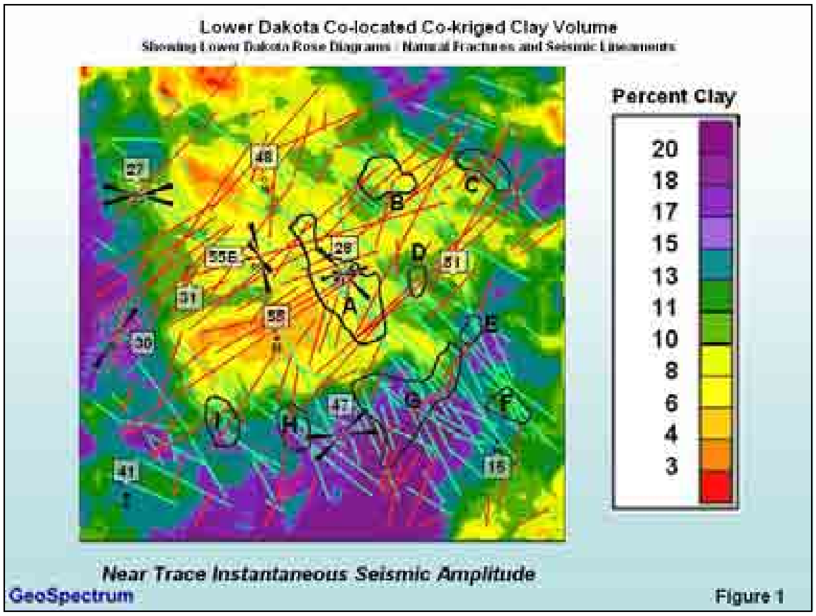

Figure 1. Collocated cokriged Lower Dakota clay volume from unit wells drilled pre-1999 indicating prospective regions defined by low clay reservoir in areas of swarming/intersecting Lower Dakota seismic lineaments shown in bold red (northeast direction) and bold green (northwest direction).

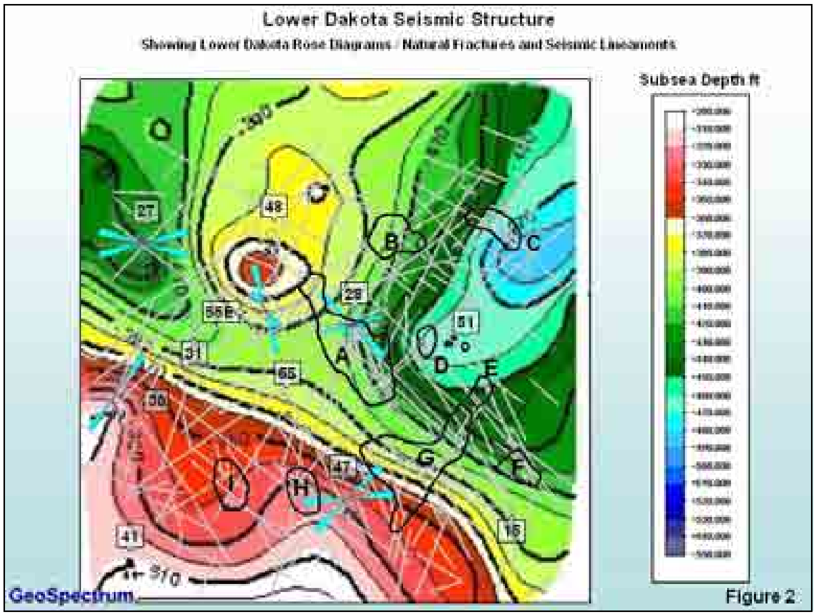

Figure 2. Lower Dakota seismic lineaments (silver lines) superimposed on structure contour map of the Lower Dakota (based on 3-D seismic and unit wells drilled pre-1999). Blue rose diagrams indicate fracture orientation determined from borehole image logs in the Lower Dakota.

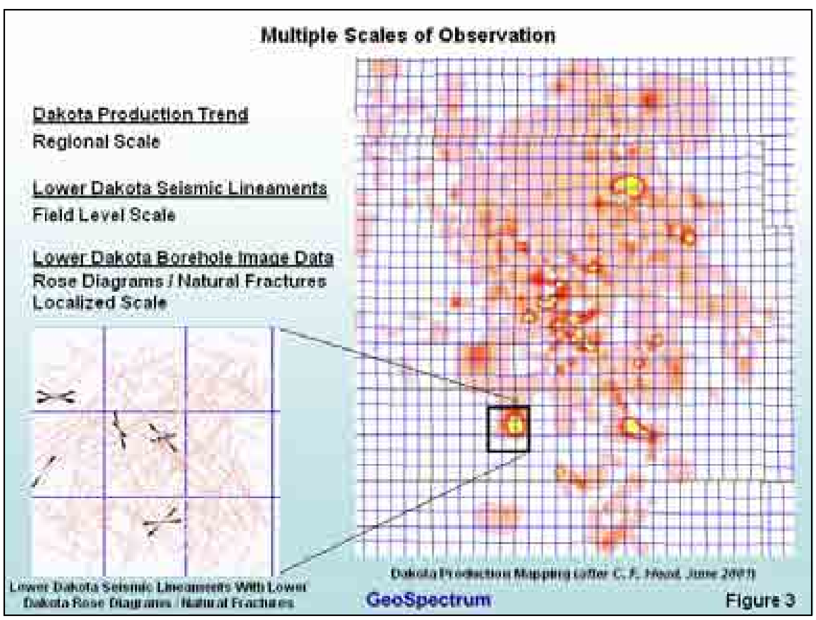

Figure 3. Dakota production map with inset showing Lower Dakota lineaments (pink lines) and rose diagrams (black symbols) indicating Lower Dakota fracture orientation interpreted from borehole image logs. Fracture orientation from all three scales of data is in general agreement indicating a “fractal-like” dependence of the data at different scales. (Dakota production map courtesy of Charles F. Head, Burlington Resources, 2001.)

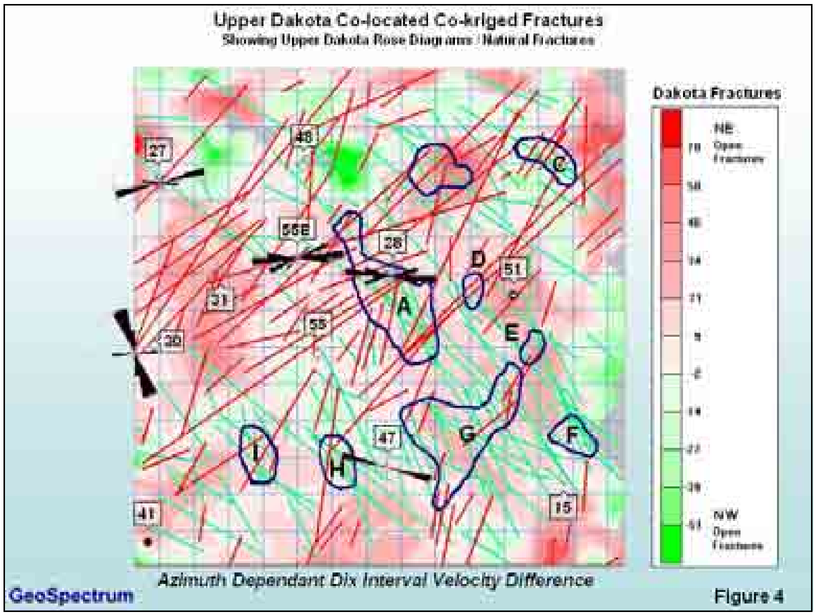

Figure 4. Collocated cokriged Upper Dakota fracture map using seismic interval velocity anisotropy in the Upper Dakota/Green Horn and Dakota fracture counts from borehole image data measured in unit wells drilled pre-1999. Black rose diagrams indicate fracture orientations determined from borehole image logs in the Upper Dakota. Red (northeast) and green (northwest) bold lines are Lower Dakota seismic lineaments.

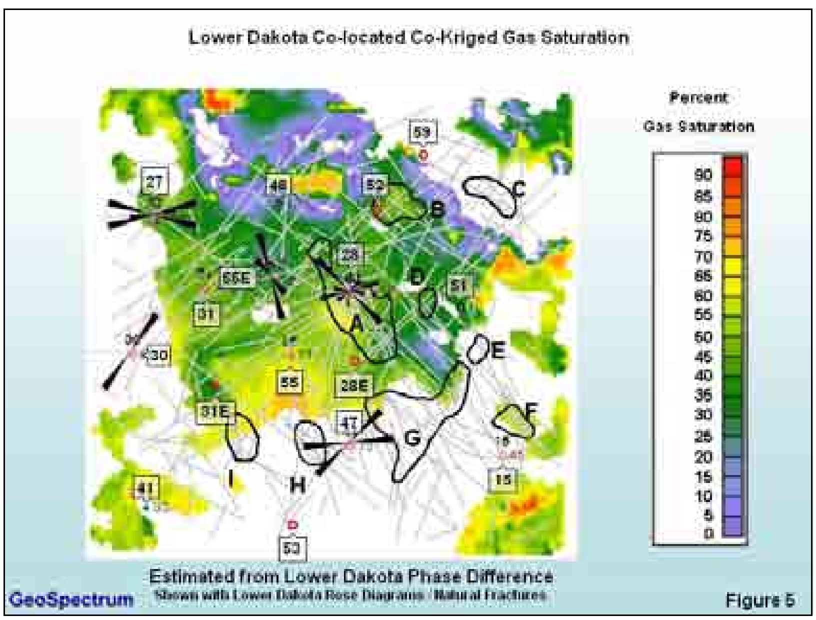

Figure 5. Collocated cokriged Lower Dakota gas saturation from unit wells drilled pre-1999 showing the well 52 prospect to have nearly the same phase gradient AVO response/gas saturation as well 28 (a significant Lower Dakota gas producer). Recent well 28E, 31E, 52, 53, and 59 prospects are shown.

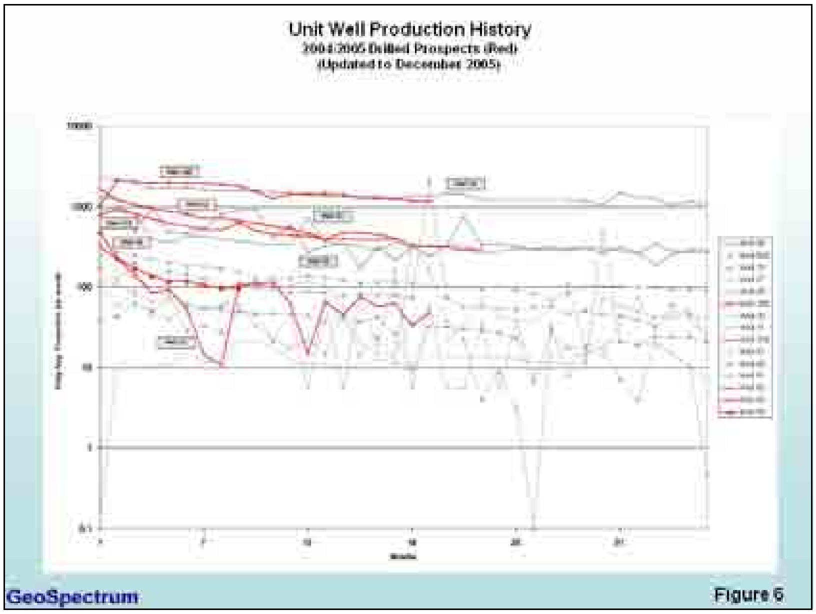

Figure 6. Unit well production histories (updated to December 2005). Production for new drill locations well 52, 53, 28E, 31E and 59 are shown in red. The new fractured reservoir exploration technology has nearly doubled the production and value of the gas unit.

Conclusions / Prospect Drilling Results 2004/2005

Well No.	Date Completed	Clay Volume (AVO Attribute)	Seismic Lineament Density	Gas Saturation (AVO Attribute)	Seismic Velocity Anisotropy	Est. Best of 12 mo. Prod. (MCFGPD)	Prospect Rating
52	01/2004	Low	High	High	High	1652	Good
53	04/2004	High	High	No AVO Attribute	High	227	Poor
28E	05/2004	Low	High	High	Low	2106	Good
31E	06/2004	Low	Low	High	Low	941	Average
69	04/2005	High	Low	No AVO Attribute	Low	231	Poor

Note: The three rating classifications are interpreted as follows:
Clay Volume (AVO Attribute) – A low clay volume is good and conversely a high clay volume is poor.
Seismic Lineament Density – A high seismic lineament density is good and conversely a low seismic lineament density is poor.
Gas Saturation (AVO Attribute) – A high gas saturation is good and conversely a low gas saturation is poor.

If all three rating classes are good, the prospect is classified as good. If two of the three rating classes are good and the prospect has positive AVO attributes indicating gas, the prospect is classified as average. If two or more of the three rating classes are poor or the prospect has negative AVO attributes, the prospect is classified as poor.

GeoSpectrum Table 1

Table 1. Conclusions/prospect drilling results.