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Development of a New Stratigraphic Trap Exploration Using Elastic-Wave Seismic Technology

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Abstract

Vecta acquired 9 square miles of 9-C seismic data in Mountrail County, North Dakota with the Mission Canyon shoreline as a primary target. Vecta contracted the Institut Français du Pétrole in order to co-develop a more rigorous multicomponent seismic interpretation product. The final interpretation was very unique in that it utilized not only the 9-C seismic data but also the new jointly developed software. A Mission Canyon anomaly was developed in 2006; however, it was of insufficient size to be a commercial target at the time. Therefore, Vecta analyzed the shear data for anisotropy within the Bakken formation and successfully reentered an abandoned producer within the project area and drilled a horizontal leg through the anomalous zones of the middle member of the Bakken formation. The well was open hole completed, swab tested, sand fraced, and swab tested some more. No shows of oil were ever seen from the Bakken formation, but the well yielded considerable amounts of formation water. The well has been abandoned as non-commercial. From the swab tests, one may conclude considerable permeability exists in the formation, thus confirming the utility of the shear wave to detect fractures within the targeted formation.

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Introduction

The Mission Canyon formation was selected for exploitation using 9-C seismic because of the depositional complexity of its shoreline system and the inability of conventional seismic techniques to discriminate reservoir from nonreservoir facies. This survey proved an excellent dataset on which to apply and extend to pure-mode shear data the joint inversion techniques developed by Tonellot et al (1999). A Mission Canyon anomaly was found by the joint inversion work but was of insufficient size to support drilling a well at the time. Also at the time the Bakken formation had become a very desirable target in the area. Fractures were thought to be a critical component needed to make commercially producing wells in the Bakken, and with shear waves being ideal for fracture detection, Vecta requested a revision from the DOE to use the full waveform data set to generate an interpretation of the anisotropy at Bakken depth and then to drill a horizontal well through the middle member of the Bakken formation in order to test such interpretation. The DOE granted such request, so Vecta generated an interpretation of the anisotropy of the Bakken formation, and subsequently drilled and tested the Bakken formation with a single horizontal well.

Executive Summary

This report summarizes work performed between February 2003 and February 2008 under DOE research contract DE-FC26-03NT15421. The project was performed by Vecta Exploration, Inc and the Bureau of Economic Geology at the University of Texas under the auspices of the National Energy Technology Laboratory (NETL).

The objective of the project is to develop a new seismic technology that will reduce industry exploration risk for stratigraphic traps. The technology was tested in Mission Canyon oolitic limestone traps in the Williston Basin of the Rocky Mountain Frontier. Nine component (9-C) seismic data was utilized in order to obtain images of the compressional wave (P-wave) and also the shear wave (S-wave) reflectivities and, using the joint inversion methodology more fully described below, impedances.

Vecta acquired approximately 9 square miles of 9-C seismic data over the project area in an attempt to unlock the reservoir complexities of the Mission Canyon shoreline facies. The Mission Canyon formation is characterized by a set of connected depositional environments including restricted shelf limestones, ooid shoals and shoal islands, hypersaline lagoons, and sabkhas. Considerable overlap exists in the seismic response of these facies, particularly between the grainstone shoals which are the main exploration objective and the hypersaline lagoon facies that form the updip lateral seal in the play. Because of this subtle, ambiguous seismic response, new technology to analyze and interpret multicomponent data to discriminate the aforementioned shoals from the lagoons was desperately needed. Vecta contracted with Institut Français du Pétrole in order to extend the pure-mode shear data to the joint inversion techniques developed by Tonellot et al (1999). Integrating well information with simple elastic attributes such as impedances and the V_p/V_s ratio from prestack elastic inversion of 9-C data over an exploration prospect allowed detailed mapping of the lateral facies changes which form both the reservoir and trap in the Mission Canyon carbonates. Although no new well has been drilled to the Mission Canyon to provide further evidence of the utility of the joint prestack inversion, based on the interpretation's correlation with existing well control, one may conclude it to be a powerful tool for stratigraphic prediction in complex, heterolithic depositional environments which are characterized by rapid lateral facies changes. Analysis of rock properties indicated that the changes interpreted here using 9-C data are too subtle to image using only P-wave AVO, even if combined with prestack inversion of the P-wave data. Multicomponent, particularly 9-C, joint inversion has broad application to reservoir prediction in a variety of depositional styles in consolidated environments that have proven difficult to characterize using P-wave data alone.

Unfortunately, Vecta was unable to generate industry interest in drilling the Mission Canyon anomaly and therefore analyzed the shear data for anisotropy within the Bakken formation. An abandoned well was successfully re-entered within the project area and a horizontal leg was drilled through the anomalous zones of the middle member of the Bakken formation. The well was open hole completed, swab tested, sand fraced, and swab tested some more. No shows of oil were ever seen from the Bakken formation, but considerable amounts of formation water were recovered. It appears that the well is

slightly east of the area where the Bakken is thermally mature and hydrocarbon productive. The well was therefore abandoned as non-commercial. However, from the swab tests, one may conclude that considerable permeability exists in the formation, thus providing a reasonable inference that the shear wave analysis did accurately detect fractures within the targeted formation.

Experimental

Vecta acquired an approximately 9 square mile 9-C 3D seismic survey in October, 2003 in the Williston Basin using Dawson Geophysical as the seismic contractor, as more fully described herein below.

The joint inversion software, which was co-developed by Institute Français du Pétrole and Vecta, was the first time this software was used on a 9C-3D dataset. The dataset was actually used to Beta test the software by Institute Français du Pétrole, and then once the software was shown to run smoothly, further work was performed by Vecta resulting in the final interpretation.

Results and Discussion

This report summarizes work performed between February 2003 and February 2008 under DOE research contract DE-FC26-03NT15421. The project was performed by Vecta Exploration, Inc and the Bureau of Economic Geology at the University of Texas under the auspices of the National Energy Technology Laboratory.

The objective of the project is to develop a new seismic technology that will improve upon the current industry exploration risk for stratigraphic traps. The technology was tested in Mission Canyon oolitic limestone traps in the Williston Basin of the Rocky Mountain Frontier. Nine component (9-C) seismic data was utilized in order to obtain images of the compressional wave (p-wave) and also the shear wave (s-wave) reflectivities.

Geological Background

Stratigraphic traps in the Mission Canyon formation in the eastern Williston Basin have long been attractive exploration targets. Oil accumulations are trapped by updip pinchout of porous, permeable shoals into nonreservoir rocks, which include a variety of facies. A series of small and large oilfields extends for over 60 miles along a paleoshoreline from the Canadian border to near the town of Dickinson.

Subsurface mapping has been the predominant exploration tool in the Mission Canyon play but has had a success rate of less than 10%. Geophysical techniques using P-wave seismic have also had limited success because of the depositional complexity of the Mission Canyon shoreline system and the inability of conventional seismic techniques to discriminate reservoir from nonreservoir facies.

The Williston Basin is an oval-shaped intracratonic sag underlying northwestern North Dakota, northeastern Montana, and southern Saskatchewan. The North Dakota portion of the Williston Basin has produced over 1.3 BBO, predominantly from Mississippian and older sediments which dominate the basin fill (Figure 1). The primary objective of the 9-C 3D survey was the Mississippian-aged Mission Canyon formation.

Mississippian dips on the broad eastern shelf of the basin are very shallow, averaging much less than one degree (Figure 2). This lack of structural complexity greatly facilitates seismic reservoir prediction.

In contrast to the structural simplicity evident from Figure 2, the Mission Canyon itself exhibits great stratigraphic complexity. The Mission Canyon interval is informally subdivided into a series of “beds” that represent individual, probably fourth-order depositional cycles (Figure 3). An idealized cycle comprises a basal limestone shelf or shoreline interval, which may include porous grainstone shoals or tight shelf skeletal mudstones; a mudstone lagoonal facies that is usually dolomitized; and a cap of sabkha anhydrites. The most prolific beds within the Mission Canyon interval are the Sherwood beds, which are the primary reservoir objective within the survey area. The overlying

Blueell is also an important reservoir in the area. A schematic depositional model for the Sherwood is shown in Figure 4, which gives some idea of its stratigraphic complexity. The most important Sherwood reservoir facies are grainstone strandline shoals (Figure 5). The shoals form excellent reservoirs, with porosities up to 15% and permeabilities greater than 100 md.

It appears that most Sherwood shoreline fields are stratigraphic traps. With the shoals grading updip into mudstones were deposited in hypersaline lagoons. Interestingly, these dolomites often are more porous than the limestone shoal reservoirs immediately downdip which are usually tight and form the updip seal in the play. Figure 6 shows core photographs of a sample of the dolomitized mudstone lagoon facies that form the trap at nearby Wabek Field. High porosity in the dolomites creates difficulties in unambiguously separating them from the reservoir limestones (Figure 7) on impedance-porosity crossplots. As Figure 7 demonstrates, a good correlation between limestone porosity and acoustic impedance is present, but there is considerable overlap between the porous limestones and the porous (but tight) dolomites. As will be seen below, the dolomites have a higher Vp/Vs ratio than any other facies present, allowing them to be separated from the adjacent reservoir limestones if multicomponent data are available.

Survey Acquisition and Processing

A 9 mi² 9C 3-D survey was acquired in late 2003. Sets of three or four vertical and horizontal vibrators were used at each source point, with orthogonal shot and receiver lines, a 1760 foot shot line interval, 660 foot receiver line interval and 220 foot shot and group interval. The vertical vibrators shook up-sweep frequencies from 6 to 150 hertz and horizontal vibrators shook up-sweep frequencies of 3 to 55 hertz. Two strings of analog geophones were deployed. The first string had only vertical geophones with each receiver point having a six phone array clustered ten feet apart. The second string had three component geophones with arrays of three clustered 6 feet apart.

Processing of the data was performed by two different companies using a variety of processing techniques. A conventional processing flow was applied to the P data, including prestack time migration. A similar flow was employed on the shear data, except that an early vector rotation from field coordinates to radial-transverse (SV-SH) coordinates was performed. The reasons behind this were twofold: firstly, the refraction statics solution is much more robust on SH data than in field (or any other) coordinates; and secondly, the assumptions for amplitude interpretation on the shear data, particularly for the joint prestack multicomponent inversion, require an SV-SH frame. During processing, a small but detectable amount of anisotropy was noticed, and a conventional Alford analysis was also performed on the data, as described more fully below. As expected, the P data were of excellent quality, with a usable bandwidth from approximately 8 Hz to about 50 Hz at the Mission Canyon. The shear data were of good quality but had disappointingly low frequency content, the usable spectrum extending only to about 20 Hz at the high end. The reasons for the relatively poor bandwidth are unclear but probably are related to the presence of boulder-rich glacial till in this portion

of the Williston Basin. Despite these limitations, however, the shear data were usable for further analysis.

Anisotropy analysis in processing (Stevens and DeVault, 2005) indicated that the subsurface is weakly orthorhombic with very little shear-wave splitting. The prestack amplitudes for the SH mode are stable across all offset ranges employed for analysis and match isotropic amplitude models for SH propagation. Consequently, a radial-transverse frame was chosen for further analysis and processing of the data. The joint inversion methodology can include converted waves as well, so we examined the converted wave datasets to see if they could be used for analysis. Unfortunately, these were of extremely poor quality and could not be used.

Well to Seismic Match

To assist in depth registering the P-wave data to the S-wave data, Vecta requested from the NETL a revision to the work tasks to acquire a dipole sonic log in a nearby well in place of drilling the second demonstration well. The request was granted, and so on October 22, 2004 Vecta ran a dipole sonic log in the Whiting Oil and Gas Torgerson 11-27 well in the adjacent Lucky Mound Field. Vecta felt strongly that modern wireline shear data was critical to aid interpretation of the multicomponent data. The only existing dipole sonic in the area was acquired at Plaza Field in 1985 and was of very questionable quality. The information gathered from the Torgerson log proved critical in the subsequent interpretation of the shear data. Geostatistical prediction of the shear slownesses in the survey wells using this log allowed confident synthetic ties (described) to be made with the shear data. Another important contribution of this log was that it demonstrated that the dolomitic mudstones that form the updip lateral seal in the play have a very high (>2.0) V_p/V_s ratio, contradicting the old log which indicated a low V_p/V_s ratio for these same sediments. Readily visible on the joint inversion output, this high V_p/V_s ratio first apparent on the Torgerson dipole proved to be the most important discriminant of the lagoon facies.

Accurate well to seismic calibration is essential to derive robust elastic parameters through the inversion process. The tie procedure determines a wavelet that provides the best possible match between synthetic and real seismic traces in the wells' vicinity. The well tie successfully derived a wavelet valid for the whole survey. The well-to-seismic calibration process is divided into two main steps:

- a multi coherence analysis using seismic information only. This evaluates the wavelet amplitude spectrum for each angle stack by using generalized trace-to-trace correlations.
- a multi-well wavelet estimation analyzing seismic and synthetic traces' correlation in a neighbourhood around each well. This procedure serves to effectively calibrate the impedance and density logs, delivering the logs' time, inline, and crossline shifts that optimize the well to seismic calibration.

The angle dimension is taken into account by using linearized Zoeppritz equations. An example of a seismic to well calibration is shown in Figure 8. One can observe the relatively good match between observed and synthetic traces for the Alenco-Nordquist well (the single producer in the survey). As expected, the P bandwidth was much greater than the SH bandwidth, the latter extending from 4 Hz to slightly more than 18 Hz.

Joint Inversion

The prestack joint inversion methodology for the P and SH modes is derived from the one presented in Agullo et al. (2004). It consists of three steps aimed at estimating an optimal elastic model in P and S impedance which best explains the multicomponent amplitudes in their own time scale, through an optimal P to SH time rule.

In the first of these steps, the P and SH data are sequentially inverted, using the prestack inversion methodology described in Tonellot et al. (2001), to estimate two optimal 3D elastic models, $\mathbf{m}^{PP} = (\mathbf{I}_P^{PP}, \mathbf{I}_S^{PP}, \rho^{PP})$ expressed in PP time and $\mathbf{m}^{SH} = (\mathbf{I}_S^{SH}, \rho^{SH})$ expressed in SH time. As with the well to seismic match described above, each sequential inversion computes the synthetic data associated with a given model by convolution of the P (SH for the respective mode) Aki-Richards reflection coefficient series at this incidence angle by an angle wavelet derived from the well-to seismic calibration step. The joint inversion was performed on nine P wave angle stacks and three SH angle stacks.

The second step of this approach comprises estimating a 3D P to SH time correspondence which minimizes the difference between $\mathbf{I}_S^{SH}$ transformed in PP time and $\mathbf{I}_S^{PP}$ in P time. This inverse problem is solved using a technique derived from the one proposed by Kybic et al. (2003) for image registration, in which the P to SH time match function is parameterized using cubic splines.

Under this assumption the spline parameters c_j are determined by minimizing the cost function:

$$W(\{c_j\}) = \left\| \mathbf{I}_S^{SH}(t^{SH}(t^{PP})) - \mathbf{I}_S^{PP}(t^{PP}) \right\|_{C_D^{-1}}^2 + \left\| t^{SH}(t^{PP}) - t_0^{SH}(t^{PP}) \right\|_{C_M^{-1}}^2$$

where C_D and C_M are covariance operators describing the uncertainties on $\mathbf{I}_S^{PP}$, $\mathbf{I}_S^{SH}$ and t_0^{SH} , defined in the same way as in Tonellot et al. (2001). t_0^{SH} is usually defined by pairing interpreted events in the P and SH domains, allowing a quite accurate estimation of the very low frequency of t^{SH} , and thereby removing the main source of nonlinearity. The function W is then minimized using a conjugate gradient technique.

An important practical advantage of using impedance instead of raw seismic traces in the P-S registration is that the inversion process removes phase differences between the datasets, allowing a more accurate registration. The registration routine allows the interpreter to vary several registration parameters, such as the number of spline parameters and the degree of lateral and vertical constraint applied to the registration's

inverse computation. The registration function is sensitive to warping parameter selection, requiring careful evaluation of the warping result. Because there are numerous low-impedance evaporites and shales above and below the objective section, mapping the time difference between the two I_s estimates at the warped time for these events and visual comparison of their times in section view provided straightforward ways to select the best warping function for the joint inversion. Throughout the interval chosen for inversion, times for the evaporite and shale markers matched within three samples almost everywhere and usually within one or two samples. The joint inversion result using the warped P to SH time transform proved superior to one made conventionally using a time transform constructed by correlating key marker horizons on the P and SH datasets and creating a Vp/Vs function by merely pinning these key marker horizons. A comparison of the warping result using two spline parameters with a pinned Vp/Vs volume using three marker horizons with no warp is shown in Figure 9. The two-spline warp aligns the two shear impedance estimates better at the Mission Canyon (at about 4.1 s in SH time) than the pinned function. The performance of the warp in the underlying Lower Lodgepole and Bakken interval, a low impedance shale section at about 4.3 s, is markedly superior to the pinned result, highlighting the importance of the warping step.

The final step of the approach consists of estimating a unique elastic model $\mathbf{m}$, expressed in PP time, which minimizes:

$$\begin{aligned} J(\mathbf{m}) = & \sum_{\theta} \left\| \mathbf{R}_{\theta}^{\text{PP}}(\mathbf{m}) * \mathbf{w}_{\theta}^{\text{PP}} - \mathbf{D}_{\theta}^{\text{PP}} \right\|_{(\mathbf{C}_{\mathbf{D}}^{\text{PP}})^{-1}}^2 + \\ & \sum_{\theta} \left\| \mathbf{R}_{\theta}^{\text{SH}}(\mathbf{m}(t^{\text{SH}})) * \mathbf{w}_{\theta}^{\text{SH}} - \mathbf{D}_{\theta}^{\text{SH}} \right\|_{(\mathbf{C}_{\mathbf{D}}^{\text{SH}})^{-1}}^2 + \\ & \left\| \mathbf{m} - \mathbf{m}_{\text{prior}} \right\|_{\mathbf{C}_{\mathbf{M}}^{\text{PP}}}^2 \end{aligned}$$

where $\mathbf{R}_{\theta}^{\text{PP}}$, $\mathbf{w}_{\theta}^{\text{PP}}$, $\mathbf{D}_{\theta}^{\text{PP}}$ and $\mathbf{R}_{\theta}^{\text{SH}}$, $\mathbf{w}_{\theta}^{\text{SH}}$, $\mathbf{D}_{\theta}^{\text{SH}}$ are the Aki-Richards reflection coefficient series, the seismic wavelet and the observed data at incidence angle θ for respectively the PP and SH modes. $(\mathbf{C}_{\mathbf{D}})_{\text{PP}}$, $(\mathbf{C}_{\mathbf{D}})_{\text{SH}}$ and $\mathbf{C}_{\mathbf{M}}$ are covariance operators describing the uncertainties on P and SH observed data and on an a priori model $\mathbf{m}_{\text{prior}}$.

A common I_p , I_s , and density background model, highcut to the bottom of the seismic bandwidth, was used as the initial model for the inversion. Slightly modified noise estimates from the multicoherence analysis described above were used to provide data signal-to-noise estimates for each individual P and SH angle stack. As with the warping, we experimented considerably with the vertical and lateral constraints. Unequal inline and crossline lateral constraint values proved very useful in suppressing acquisition footprint in the data. Additionally, we tested the joint inversion using several different P-SH registration functions, including a function that merely time aligned user-picked marker events on both datasets, performing no warping between them. We obtained a somewhat inferior joint inversion result using this marker-only registration function, highlighting the importance of the warping step.

Examination of the residuals for each P and SH angle stack indicated mostly low amounts of coherent energy compared to the input angle stacks (Figure 10). While not guaranteeing a unique inversion result, the lack of coherent energy on both P and SH angle stacks indicates that both modes are consistent with each other and can be inverted against a common impedance and density model in P-wave time.

Interpretation

Because it is not a strong boundary, the Sherwood is difficult to map seismically on any dataset. However, a marker only about 20 ms above it in P-wave time, the base of the last Charles salt, is a strong, easily picked event. Fortunately, the Sherwood top and base appear at a constant time (within a 2 ms sample) below this marker on all seven wells in the survey area, allowing windowed extractions below the last Charles salt to reliably characterize lateral variations in the Sherwood reservoir interval. A windowed extraction of average P-wave impedance (I_p) in a short time window containing the Sherwood is shown in Figure 11. Sherwood lithologies encountered in the wells are shown as colored circles, and the subsurface interpretation of the shoreline, lagoon, and sabkha positions is shown in heavy colored lines. A prominent low-impedance anomaly probably caused by a porous grainstone shoal is visible just west of the single producer. However, a well only about 1300 feet northwest of the producer which had a tight drill stem test and mostly dolomite in the Sherwood and overlying Bluell interval is also in an area of relatively low I_p . That area extends northwest of the well a considerable distance into the interpreted lagoonal facies tract. Given the low impedances associated with the porous but tight hypersaline lagoon facies (Figure 7), this is not a particularly surprising result. Because the nonreservoir hypersaline lagoon forms the updip seal for grainstone shoal stratigraphic traps, it is critical to distinguish the two facies.

Mapping V_p/V_s by ratioing the I_p and I_s extractions from the joint inversion in a common time window proved useful in resolving this ambiguity and aided our interpretation of Sherwood depositional environments. Figure 12 is a map of Sherwood V_p/V_s with the well lithologies and facies tracts interpreted from changes in the V_p/V_s ratio. As described more fully above, the dipole sonic log acquired in Lucky Mound field indicates that the lagoonal dolomites have higher V_p/V_s values than any other lithology in the Mission Canyon. The boundary between the lagoon and paleoshoreline observed in the two adjacent Nordquist wells only 1300 feet apart is clearly visible on the V_p/V_s map, as is the shoal itself, which has the low V_p/V_s values expected for porous limestones. Intermediate values of V_p/V_s (1.7-1.85) characterize the tight restricted-shelf or cemented shoal-island limestones and sabkha anhydrites. The joint inversion V_p/V_s map allows a much more detailed map of the shoal, lagoon, and sabkha environments to be made than is possible using the subsurface data alone. A crossplot of the Sherwood and Lower Bluell dolomite fraction in wells with the V_p/V_s from the joint inversion is shown in Figure 13. An excellent correlation is observed, providing confidence in the facies map of Figure 12. To assure ourselves that this correlation is driven by the seismic data and not the inversion background model, we extracted I_p/I_s from the background model over the same window used to create Figure 12 and crossplotted it against dolomite fraction in the wells (Figure 14). No correlation is visible, indicating that the

correlation results from information in the seismic data, not details in the background model, which was highcut at 10-15 Hz in any event.

One advantage of including pure mode (9-C) shear data in the joint inversion is that the structure of the pure-mode shear reflection coefficients allows the density term to be unambiguously separated from the impedances, allowing a unique if noisy solution for density if pure-mode shear data are available for the prestack inversion (see DeVault, 1997). This is not possible using P-wave data, even if converted waves are also included in the inversion, for typical real-world values of V_p/V_s . In our case, the V_p/V_s ratio proved a much better lithology indicator than density because of the overlap in density between the grainstone shoals and the porous hypersaline lagoon facies immediately updip. In carbonate environments, this is a somewhat anomalous situation: an unambiguous density estimate is of great value in characterizing porosity development usually associated with production. Joint inversion would be very useful in such circumstances if one acquires long enough offsets to allow a reasonably good density estimate from the SH mode.

A location was picked to be drilled in the west half of section 26, but due to the limited extent of the reservoir, Vecta was unable to economically justify drilling the well. Since the Mission Canyon anomaly was of insufficient size to be drilled, Vecta personnel analyzed the shear data for anisotropy in the Bakken formation. After the discovery of Parshall Field immediately northwest of the prospect, the Bakken formation had become a highly commercial target in the industry and the project area was on the eastern edge of much drilling activity. Typically, the Bakken consists of three zones: an upper shale zone, a middle non-shale interval, and a lower shale zone. The middle non-shale zone can be clastic or carbonate and typically has some storage capacity and when fractured will have good permeability.

Shear waves are the best tool for remotely detecting open fractures in the subsurface. Shear-wave polarization information gives a highly accurate, unambiguous estimate of fracture strike, while shear-wave amplitudes give a high-resolution estimate of open fracture intensity.

Using the Alford diagonalization procedure to determine the orientation of fractures, Figure 15 shows how all the energy in the cross components is transferred to azimuthally aligned components when the data is rotated from a zero azimuth to an azimuth of $N60^\circ E$. This $N60^\circ E$ direction is the fast direction for the shear waves and is believed to be the direction of open fractures. Figure 16 is an $S_1 - S_2$ shear-wave amplitude map at the Bakken level. The hotter colors are indications of greater shear wave splitting and thus great concentrations of open fractures. The $N60^\circ E$ azimuth direction is overlain with the white lines.

Test Well

Vecta again requested a revision from the NETL to drill a demonstration well to test the concept of using shear data to detect open fractures in the Bakken in place of the

demonstration well to test the Mission Canyon formation. Again the NETL granted the request and so Vecta and its industry partners re-entered the Alenco Nordquist #43-23 42 well. Griffon & Associates, LLC was the operator of the well, and it was renamed to the Vecta-Nordquist 34-23. After re-entering the old vertical hole, the well was kicked off and drilled 3,567 feet horizontally in a southeasterly direction as shown on Figure 17, being nearly perpendicular to the fracture orientation and through the amplitude anomaly in Sections 23 and 26. The horizontal leg was drilled predominately through the Middle Bakken section as planned and as can be seen in Figure 17. The well was open hole completed, swab tested, then fraced and swab tested some more. Figure 18 is an abbreviated completion report. Prior to abandoning the well, it was swabbing 30 to 70 barrels of formation water per day. The Bakken formation never yielded any hydrocarbons. Although difficult to quantitatively analyze the amount of open fractures through only swab testing, the well yielded sufficient fluids to conclude that some permeability was present in the completed interval. The Middle Bakken member in this area is a dolomitic siltstone with less than 6% porosity and almost no matrix permeability, so it is reasonable to conclude that the fluid recovery from the wellbore results from natural fracturing intersected by the borehole.

Conclusions

Integrating well information with simple elastic attributes such as impedances and the V_p/V_s ratio from prestack elastic inversion of 9-C data over an exploration prospect allowed detailed mapping of the lateral facies changes which form both the reservoir and trap in these Williston Basin carbonates. Joint prestack inversion proved to be a powerful tool for stratigraphic prediction in complex, heterolithic depositional environments which are characterized by rapid lateral facies changes. Analysis of rock properties indicated that the changes interpreted here using 9-C data are too subtle to image using only P-wave AVO, even if combined with prestack inversion of the P-wave data. Multicomponent, particularly 9-C, joint inversion has broad application to reservoir prediction in a variety of depositional styles in consolidated environments that have proven difficult to characterize using P-wave data alone.

Additionally, the 9-C data appears to be useful in detecting open fractures in the Bakken formation; although, with only a single test well in the project area and with the unlikelihood of any other wells being drilled to test the Bakken formation, we will never really be able to draw any concrete conclusions regarding its effectiveness on this dataset

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Systems	Rock Units		Permian	Minnekahta
Quaternary	Pleistocene			Opeche
	White River		Pennsylvanian	Broom Creek
	Golden Valley			Amaden
				Tyler
				Otter
Tertiary	Fort Union Group			Kibbey
			Mississippian	Charles
				Mission Canyon
				Lodgepole
	Hell Creek			Bakken
	Fox Hills			Three Forks
	Pierre			Birdbear
	Judith River			Duperow
	Isipile		Devonian	Souris River
	Niobrara			Dawson Bay
	Carlile			Prairie
	Greenhorn			Winnipegosis
	Belle Fourche			Ashern
	Mowry			
	Newcastle		Silurian	Interlake
	Skull Creek			Stonewall
	Inyan Kara			Stony Mountain
	Swift		Ordovician	Red River
Jurassic	Rierdon			Winnipeg Group
	Piper			Deadwood
Triassic	Spearfish		Cambrian	
Permian			Precambrian	

Figure 1: Eastern Williston Basin stratigraphic column. Mississippian Mission Canyon is primary 9-C 3D survey objective.

Figure 2: Location map for 9-C 3D seismic survey with Mission Canyon subsea depth contours

Figure 3: Mission Canyon facies subdivision into “beds” representing individual fourth-order depositional cycles

Figure 4: Schematic Sherwood depositional model.. Sherwood reservoirs are strandline shoals, with oil trapped updip by dolomitized mudstone facies in lagoon.

Figure 5: Core photomicrograph from porous grainstone shoal at Wabek Field, immediately north of study area. Note high porosity and permeability of productive interval, with abundant preserved primary interclast porosity.

Figure 6: Core photomicrograph from hypersaline lagoon backstopping Wabek Field. Note high porosity but low permeability of dolomites, which are updip seal

Figure 7: Porosity-impedance crossplot for Sherwood interval at a Wabek Field well and a well in survey area. Note good correlation between impedance and porosity except for porous dolomites.

Figure 8: P-wave well tie with extracted wavelet for Alenco Nordquist 43-23 well

Figure 9. Comparison of P-SH impedance time registration result using two spline functions (left) with time alignment made by pinning three marker events (right). Wiggles are I_s estimates from P and SH data, stretched to SH time; color background is I_s estimate from P data. Note better performance of warp between reference horizons, particularly at Bakken (blue ovals) and in Mission Canyon interval (dark green)

Figure 10. Input SH angle stacks and residuals from joint inversion: 15 degrees (left two panels) and 20 degrees (right two panels). Displays are commonly gained.

Figure 11: P-wave impedance from joint inversion in Sherwood interval with well test recoveries and production, Sherwood lithofacies, and inferred depositional environments from subsurface data only

Figure 12. Vp/Vs map from Sherwood-interval Ip/Is ratio from joint inversion result showing well lithologies and interpreted facies tracts combining subsurface and seismic data.

Figure 13. Sherwood dolomite fraction crossplotted against joint-inversion Vp/Vs ratio from Figure 12.

Figure 14. Vp/Vs ratio from Sherwood window extracted from initial inversion background model crossplotted against well-derived Sherwood dolomite fraction; X axis is scaled identically to Figure 13.

Alford rotation to find polarization directions

Shear wave polarizations recovered by Alford diagonalization procedure, best done on *stacked shots and receivers*: compare 0 azimuth...

S1/S1

S1/S2

Azimuth - 0° S2/S1

S2/S2

Alford rotation to find polarization directions

...with 60-degree azimuth

S1/S1

S1/S2

Azimuth - N60E S2/S1

S2/S2

Figure 15. Alford rotation demonstrating a 60 degree orientation of anisotropy

Fast azimuth is N60E, ie 060.

Figure 16. Amplitude Map of the Bakken Interval.

Figure 17. Path of Horizontal Leg of the Vecta-Nordquist 34-23 well.

9/29/07 Drill out float shoe.

10/10/07 Start Swabbing

10/10/07-10/26/07 Recovered 498 bbls water over load, 9.85 lb/gal water at end.

11/15/07 Ran in hole with 2-3/8 tubing and set packer at near casing shoe.

11/16/07-11/19/07 Swabbed with very little fluid entry.

11/21/07 Treated open hole section with surfactant, bactericide, and scale inhibitor.

11/26/07-11/28/07 Swabbed with little fluid entry.

1/9/08-1/15/08 ran 3-1/2 inch frac string with packer, fraced well with 269,000 lbs of 20/40 sand and 139,000 gal of gelled water.

1/21/08 Pulled 3-1/2 inch frac string, ran 2-7/8 inch tubing with packer.

1/23/08 – 2/2/08 Swabbed 2267 bbls load water, 1569 bbls of load left to recover.

2/3/08-3/25/08 Swabbed 1284 bbls load water, 285 bbls of load left to recover. Swabbing 30 to 60 bbls per day. Released swab unit.

4/16/08-4/28/08 Move on swab unit, swabbed 324 bbls load and formation water. Have recovered 39 bbls over load. Swabbing 30 to 70 bbls water per day. No show of oil. Temporarily abandon well.

Figure 18. Vecta Nordquist 43-23 Completion Report

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