EnCana

Weyburn Field

Crosswell Seismic project report

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Overview

The objective of the project was to use crosswell seismic to provide high-resolution reservoir images to assist in diagnosing unexpected CO_2 performance in the Weyburn field. In the area of interest horizontal injection logging and 4-D surface seismic indicate good areal extent to the CO_2, but no response has been seen in nearby production wells. Several possible explanations include lower permeability in the area, slowing the movement of CO_2, upward flow of CO_2 into zones above the reservoir or behind casing leaks that provide an upward migration path for CO_2. The 4-D seismic vertical resolution does not delineate in-reservoir and out-of-reservoir flow of CO_2.

Crosswell seismic conducted between available vertical wellbores offered a means to image along 2-D lines with high vertical resolution to better delineate the path of the CO_2. The expected vertical resolution was a few meters. The survey planning considered operating inside of production tubing. The final profiles were selected to not depend on though-tubing operations. In preparation of the wellbores, a number of problems were encountered that limited the deepest depths that could be logged. The result was reduced, not well-to-well coverage, which made interpretation more difficult. Reflection tomography was used to estimate velocities below the maximum depths logged. Unlike typical crosswell reflection tomography which gives well constrained velocity values down to the depth logged, the depth restrictions required a tomography approach more like surface seismic that did not constrain the velocities accurately enough for optimum high-resolution reflection imaging.

This project was acquired and processed by TomoSeis, a division of Core Laboratories. Since the time of the project, Z-Seis Corporation has been formed to continue the crosswell seismic business of TomoSeis. Z-Seis has prepared this report in support of EnCana's ongoing use of crosswell seismic technology. Please address any technical questions regarding the project to Z-Seis.

Survey Planning

The objective of the survey planning was first to provide a preliminary analysis of the feasibility of crosswell operations to assist in diagnosing unexpected CO_2 performance in the Weyburn field. Crosswell seismic conducted between available vertical wellbores offers a means to image along 2-D lines with high vertical resolution to better delineate the path of the CO_2. The expected vertical resolution should be a few meters. The well separation for the selected wells from 400 to 580 meters is within the window of typical operation for TomoSeis crosswell equipment in carbonate reservoirs. The initial feasibility assessment was performed under the assumption that the operation would be through production tubing in the receiver wells. TomoSeis has unique hydrophone receiver technology configured to operate inside of production tubing. The hydrophone receiver tool is 1-11/16" O.D. and can be operated inside of any tubing from 2-3/8" O.D. and larger. Two versions of the TomoSeis tool are available: a 10-level tool with levels spaced 3 meters apart and a 20-level tool with levels spaced 1.5 meters apart. Both tools are wireline conveyed on multiconductor line and are about 35 meters in length. The TomoSeis source is 4-1/8" O.D. and requires that tubing be pulled for operation. The downside to receiver operation inside of production tubing is signal attenuation due to propagation through another layer of steel. Both the annular region between tubing and casing and the region inside of tubing must be liquid-filled to propagate the seismic energy to the receiver tool.

TomoSeis has operated through production tubing in 3 operational cases:

- Case 1: 537 meters between wells. Clastic formation. 2-7/8"tubing. 12-18 dB signal attenuation.
- Case 2: 100 meter well spacing. Shallow clastic formation. 2-3/8" tubing. 15-20 dB signal attenuation.
- Case 3: 300 meter well spacing. Clastic formation. 2-3/8" tubing 12-15 dB signal attenuation.

In each case, data was recorded at a similar level in the receiver well inside of production tubing and with the tubing removed from the well to make the comparison.

An extensive analysis of attenuation in production tubing has been made at the BEG Devine Borehole Geophysics test site. All smaller tubing diameters (2-3/8", 2-7/8" and 3-1/2" diameter) showed approximately an attenuation of 16 dB. Source generated tube wave arrivals propagating in the source well were attenuated by approximately the same amount as the direct arrival. Source generated tube waves propagating in the receiver well have increased in number and, in some cases, amplitude. The array response of the receiver tools was evaluated and no systematic difference was noted. An example of baseline data in this test at a well spacing of 100 meters is shown in Figure 1. An example of data recorded through 2-3/8" production tubing is shown in Figure 2.

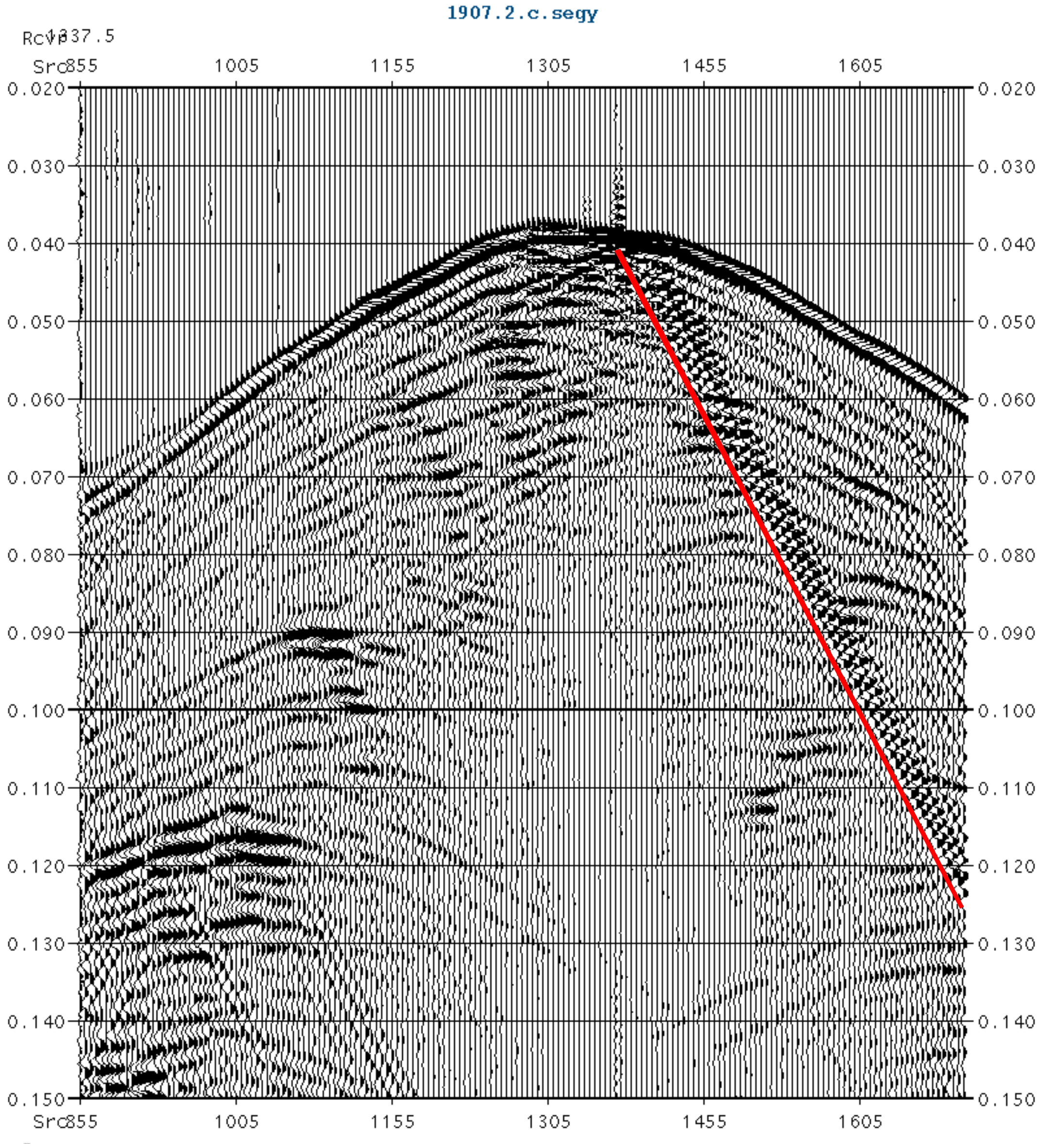

Figure 1. Baseline gather recorded without tubing in the receiver well.

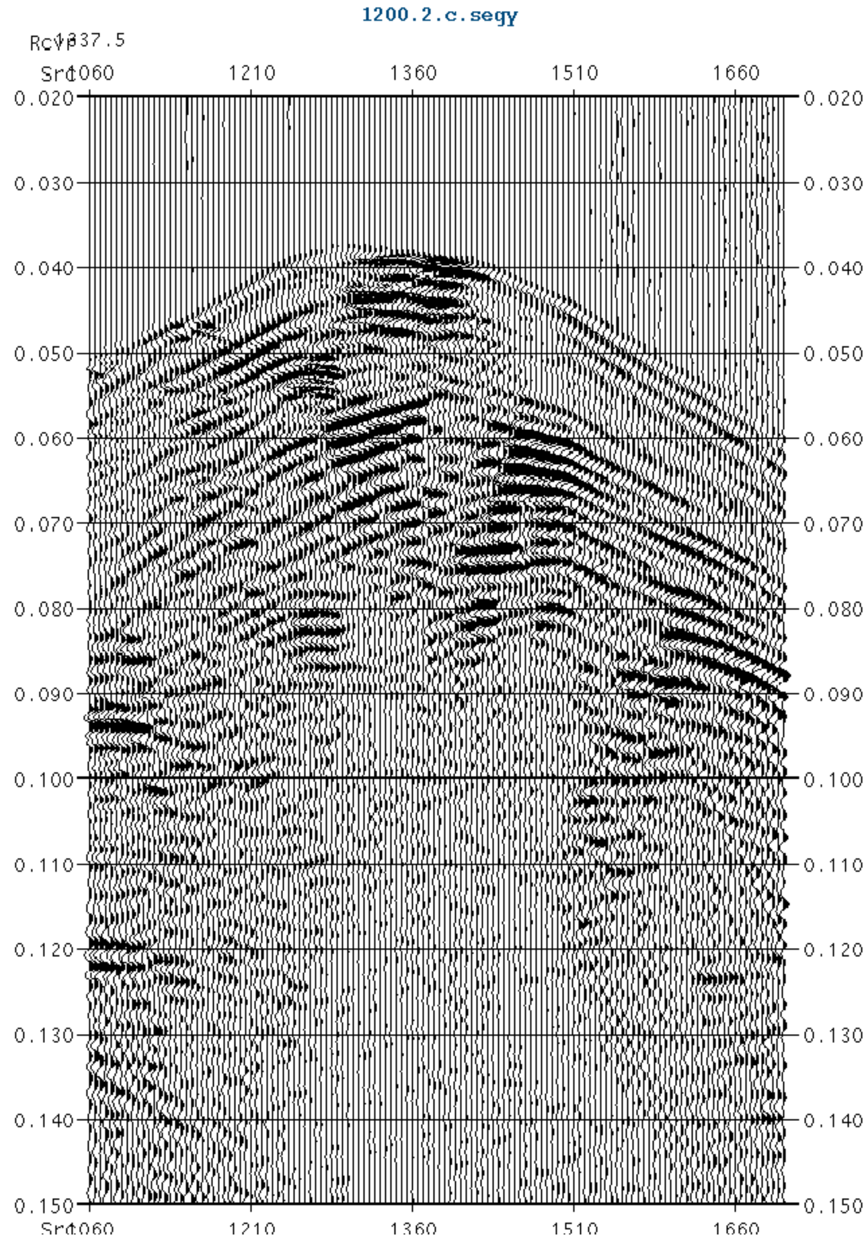

Figure 2. Same gather as in Figure 1, recorded through 2-3/8" production tubing.

With production tubing in the receiver well, 16 dB of SNR must be recovered. One improvement, relative to normal TomoSeis operation, is to deploy a dual X-Series source that can provide a 6 dB signal improvement. The source is specially configured by combining two standard X-Series sources. The remaining 10 to 12 dB of SNR must be recovered by additional signal stacking. Increasing the stack from the stack of 8 in the plan shown above to a stack of 64 to 128 should provide about 9 to 12 dB of SNR enhancement. The shooting time of 9 hours in the baseline plan is increased to an operating time of between 5 and 6 days to acquire two profiles (using 2 receiver tools simultaneously). Operating through tubing also will likely require special pressure control equipment including grease injection and possibly lubricators long enough to house the receiver tools above the wellhead. The difference in operating time and the risk to signal quality eliminated through-tubing operation from the survey plan.

Preliminary Operational Plan

Site Specifications

The operational plan was based on information provided by EnCana for a crosswell seismic project to better delineate the path of the CO_2 in the Weyburn field. The planned crosswell profiles were (1) between wells 111/12-13 and 101/6-13 and (2) between wells 101/6-13 and 101/4-13 as shown in Figure 3.

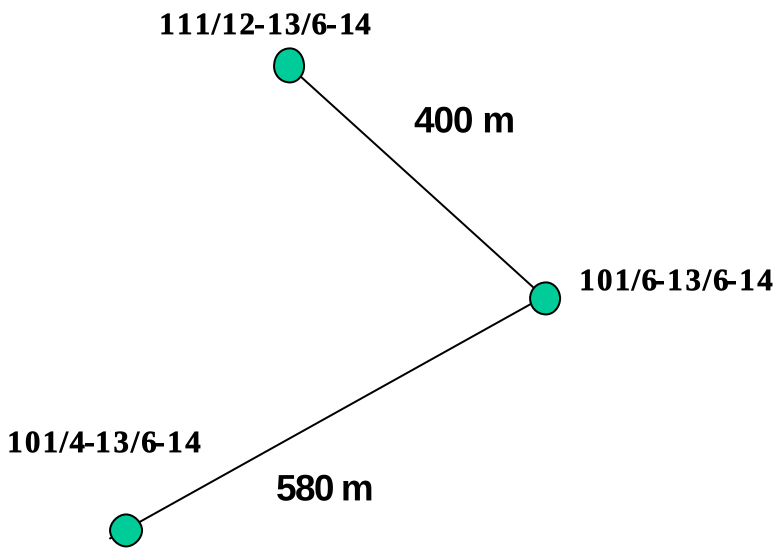

Figure 3. Map view of planned crosswell profiles.

The wells shown were to be used to operate the crosswell source and receiver systems and have TDs in the range of about 1400 meters. No corrosives or pressure control issues were present. The wells were cased with 7” and 5½” O.D. casing and were either producers with rod pumps that were removed prior to crosswell acquisition or water injection wells with the tubing pulled.

Well Preparation

Tubing was pulled on all wells. The two receiver wells (111/12-13 and 101/4-13) were plugged back to 1320 m and 1410 m (top of perforations), respectively. Note the loss of coverage seen in the survey plans below for the target interval from 1400 to 1430 meters. All wells were filled with fluid to 200 meters from the surface. The source well (101/6-13) was killed and plugged back to 1353 m. Flanges were installed on all wellheads with 7” 8-round box looking up to accommodate TomoSeis’ pack-offs. Gyros were recorded on all wells.

Operations Sequence

The three wells were prepared for operations as above. The recommended sequence was for the second receiver well (101/4-13) to be pulled and prepared, followed by the source well (101/6-13). The first receiver (111/12-13) well was then pulled and plugged back. The pulling unit was left over the last well and the wireline sheave hung from it for the first profile acquisition. Acquisition of the first profile was anticipated to take approximately 1.5 days. Following this the first receiver well was put back online while the second profile was acquired. Initial planning indicated the second profile would take approximately three days. Following this the two injector wells were put back in service.

Key Assumptions

From the information provided, the following assumptions were made.

- No surface pressure control will be required beyond wireline pack-offs.
- Operationally, the receiver well will hold liquid and the source well will hold fluid with infrequent addition of fluid and will be filled to approximately 200 meters of surface.
- No hostile conditions exist, including excessive downhole temperature and pressure and corrosive elements (H_2S or CO_2).
- For access, the wellheads will be prepared such that the minimum restriction will allow passage of the TomoSeis source and noise attenuation system (4.5”)
- Source and receiver wells are plugged above the productive interval.
- Noise levels in the well will be important due to the well separation and unknown attenuation characteristics. Therefore, TomoSeis will run its 4.5” O.D. gas can noise attenuation system above and below the receiver system.

Safety

Full safety standards of EnCana and TomoSeis were adhered to. The TomoSeis HSE policy is given below in Figure 4.

HEALTH, SAFETY, AND ENVIRONMENT POLICY

TomoSeis is committed to maintain and enforce an effective Health, Safety, and Environmental Affairs (Operational) program that applies to all employees. This commitment centers on the belief that *all accidents are preventable.*

The safety and health of TomoSeis employees and the protection of the environment are management responsibilities requiring primary consideration in the planning and implementation of all Company activities. The success of any Operational program requires a continuous effort of all TomoSeis employees. Consequently, TomoSeis employees must follow documented work procedures and must act responsibly in the performance of their work activities. Acting responsibly includes taking every precaution to protect individuals and the environment as well as reporting any unsafe act, condition, or equipment to management. All employees are responsible for the implementation of Operational policies and are encouraged to participate in the continuous improvement of the Operational program. TomoSeis will review Operational policies as necessary to ensure that adequate policies are in place.

TomoSeis and TomoSeis employees will at all times adopt and adhere to our clients Safety Policies and Procedures when working at a client location.

Bruce P. Marion, President.
January 1998

Figure 4. TomoSeis HSE Policy.

TomoSeis conducted a wellsite safety meeting prior to commencing operations on location. No lost time or safety incidents occurred.

Critical issues

The survey plans and contingency plans were based on the following critical issues:

- Active CO_2 injection could be a source of wellbore noise. Plugs have been set in potential receiver wells to reduce the possibility of noise generated by fluid movement across perforations. Injections in wells adjacent to the survey area have been suspended. The noise attenuation system will be deployed to further reduce the possibility of unacceptably high levels of borehole noise.
- Acquisition time in well 111/12-13 must be minimized so the well can be put back into production.

Given these operational constraints the following deployment and parameter setting sequence was followed.

- Planned receiver well (111/12-13), planned source well (101/6-13). Final preparations for well 111/12-13 to be completed by mid-day Nov 13th.
- Characterize noise levels in well 101/6-13 on morning of Nov 13th before well 111/12-13 is ready for logging. Measure and characterize background noise level (N). <u>No noise attenuation equipment on this test</u>.
    - N < –35 dB relative to 1 Pa (TomoSeis calibrated noise scale) then rig noise attenuation system and prepare to acquire survey with receivers in well 101/6-13. Rig source in well 111/12-13.
    - N > -35 dB relative to 1 Pa then prepare to rig up receivers with noise attenuation system on well 111/12-13. Rig source in well 101/6-13.
    - N < -50 dB then deploy w/o noise attenuation system.
- If receivers are deployed in well 111/12-13, characterize noise levels before proceeding to parameter setting procedure (below).
    - N > -20dB then well 111/12-13 is markedly noisier than 101/6-13. Inform EnCana of time impact (12-14 hours) and suggest swapping source and receiver wells back to 111/12-13 and 101/6-13 respectively. Swap wells with EnCana's agreement.

VSP acquisition outline

A VSP was also recorded with the hydrophone receivers and the initial plan called for 12-15 hours logging with a 10 level/3 meter spaced logging tool. Survey design was made to meet the following criteria as close as possible.

- Receivers in well 101/6-13
- One Zero offset VSP
- Five offset VSP
    - 2 offsets along profile # 1 line
    - 3 offsets along profile #2 line.
- 400 meter logged interval (900-1300 meters)
- 14 second records (12 sec sweep + 2 sec listen) @ 2 ms sample period** (High frequency of acquisition system at 150 hertz)
- 8 sweeps per level per component (3 component vibrator)

** Recorder supports record lengths up to 12,000 samples. To record data to 300 hertz recommend 12 second records (10 sec sweep + 2 sec listen) @ 1 ms sample period.

Survey Plans [X-Plan™]

Survey plans describe in concise form different parameters of a crosswell profile. Outputs such as the estimated seismic coverage and time frame of each profile are used to plan the survey more effectively. Note that survey plans are often updated in the field, as new acquisition information becomes available. All coverage charts are computed assuming straight ray paths.

In this section, a preliminary survey plan for each possible profile has been run. To familiarize the reader with the form and content of the survey plan, below is a description of some of the pertinent plots.

Acquisition parameters/statistics

The planned acquisition parameters are noted in the upper left of the chart. Details such as interval of interest, source shooting parameters, well spacing and other parameters that affect the speed of acquisition are listed.

Shooting Chart

The shooting chart is a graphical representation of the source/receiver positions that are to be occupied during the survey. The horizontal axis is receiver depth and vertical axis is source depth. A tabular form is also created with depth intervals for source and receiver clearly detailed.

Direct Fold

This shows the number of rays crossing each bin (see Fold Cell size) assuming straight raypaths. This shows the approximate coverage that will be possible for this profile using the direct ray incidence angles noted. The horizontal axis extends from receiver well to source well. The vertical axis is depth relative to datum elevation. Sparse apparent coverage near the wells ("scalloping") is an anomaly of subsampling in the coverage calculation and not a true measure of coverage.

Upgoing Reflection Fold

This shows the number of rays incident in each bin for the range of incidence angles noted. Sparse apparent coverage near the wells ("scalloping") is an anomaly of subsampling in the coverage calculation and not a true measure of coverage.

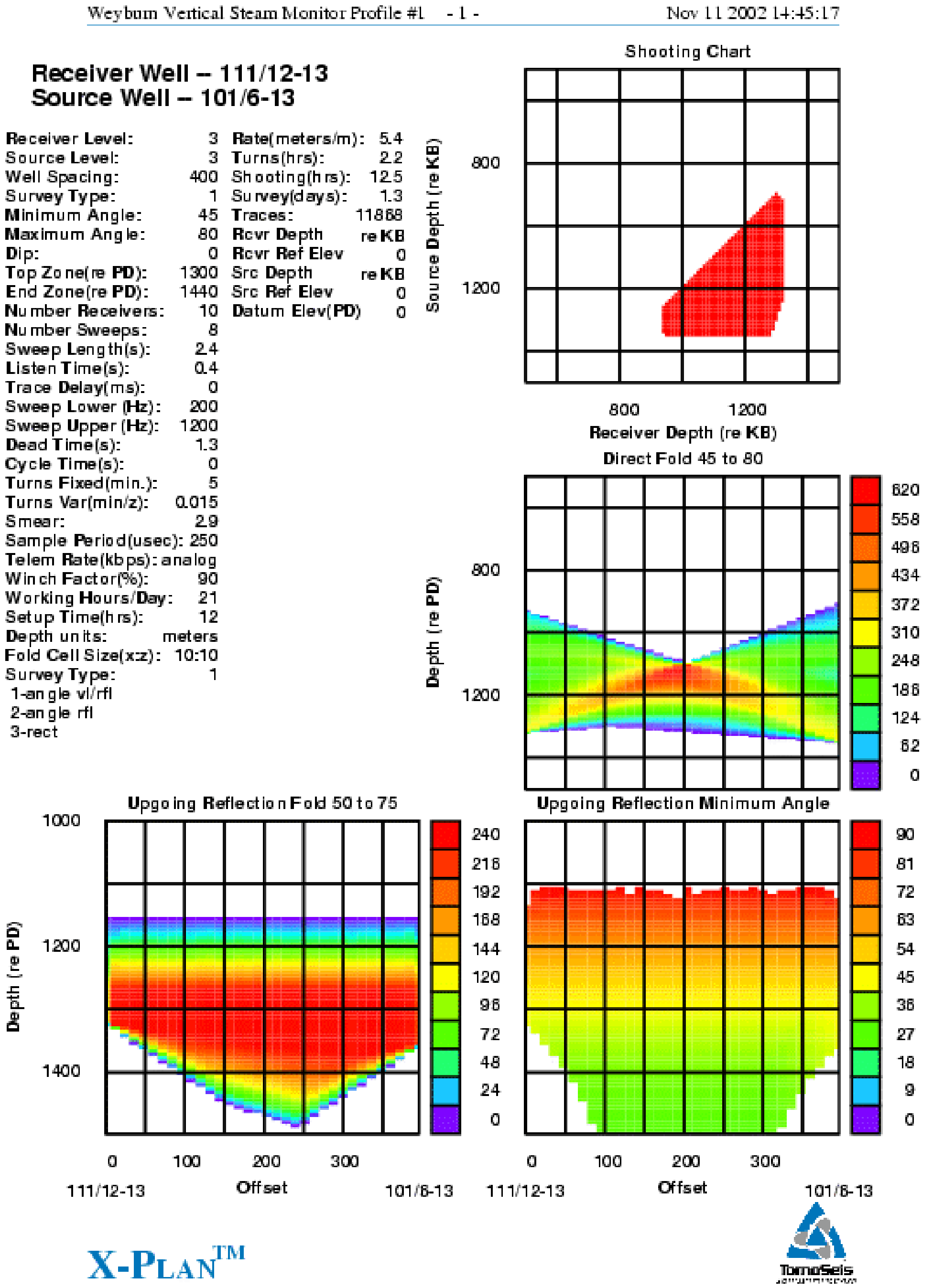

Figure 5. Logging plan #1, profile #1

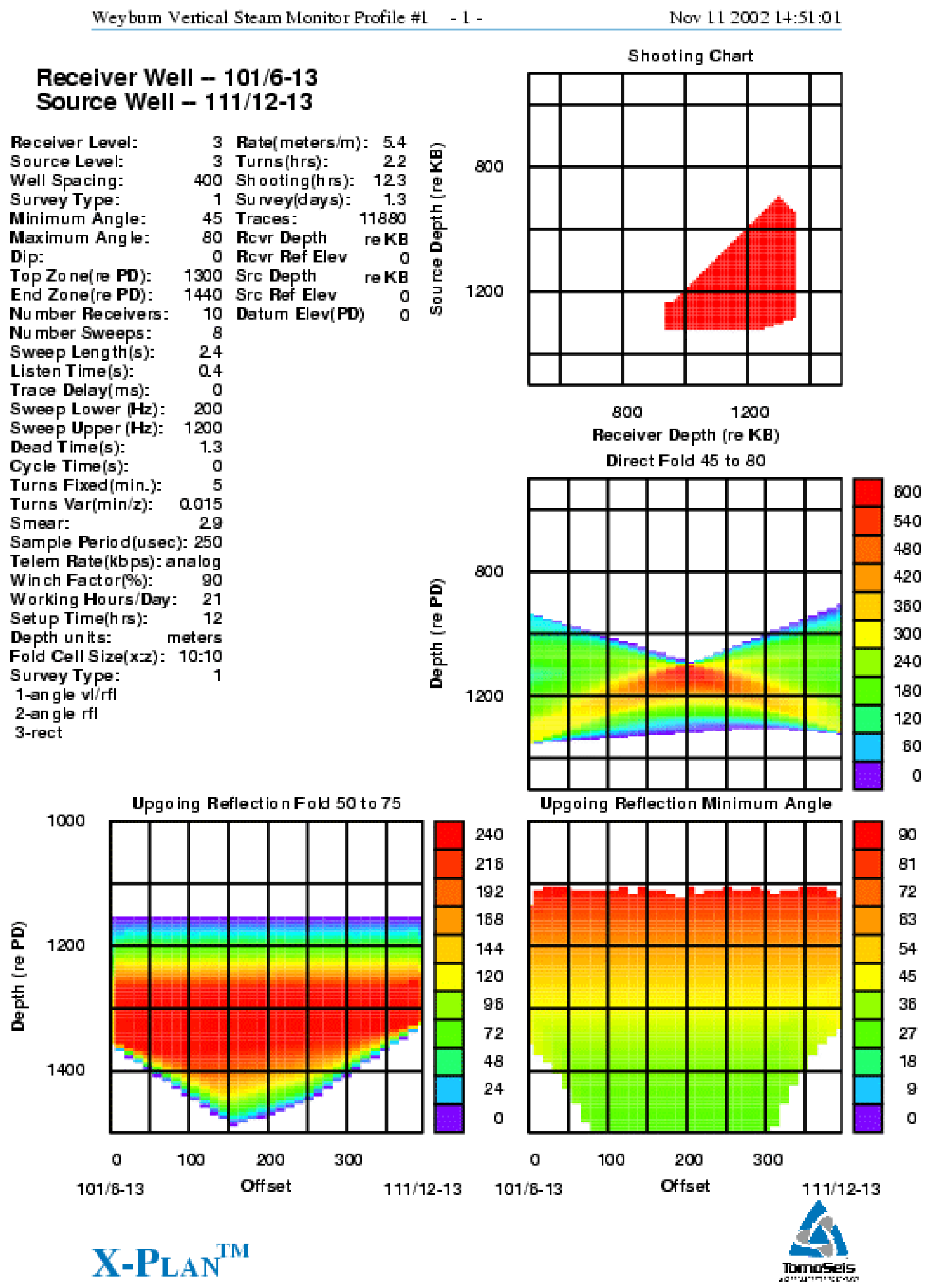

Figure 6. Logging plan #1, profile #1 source and receiver well switched.

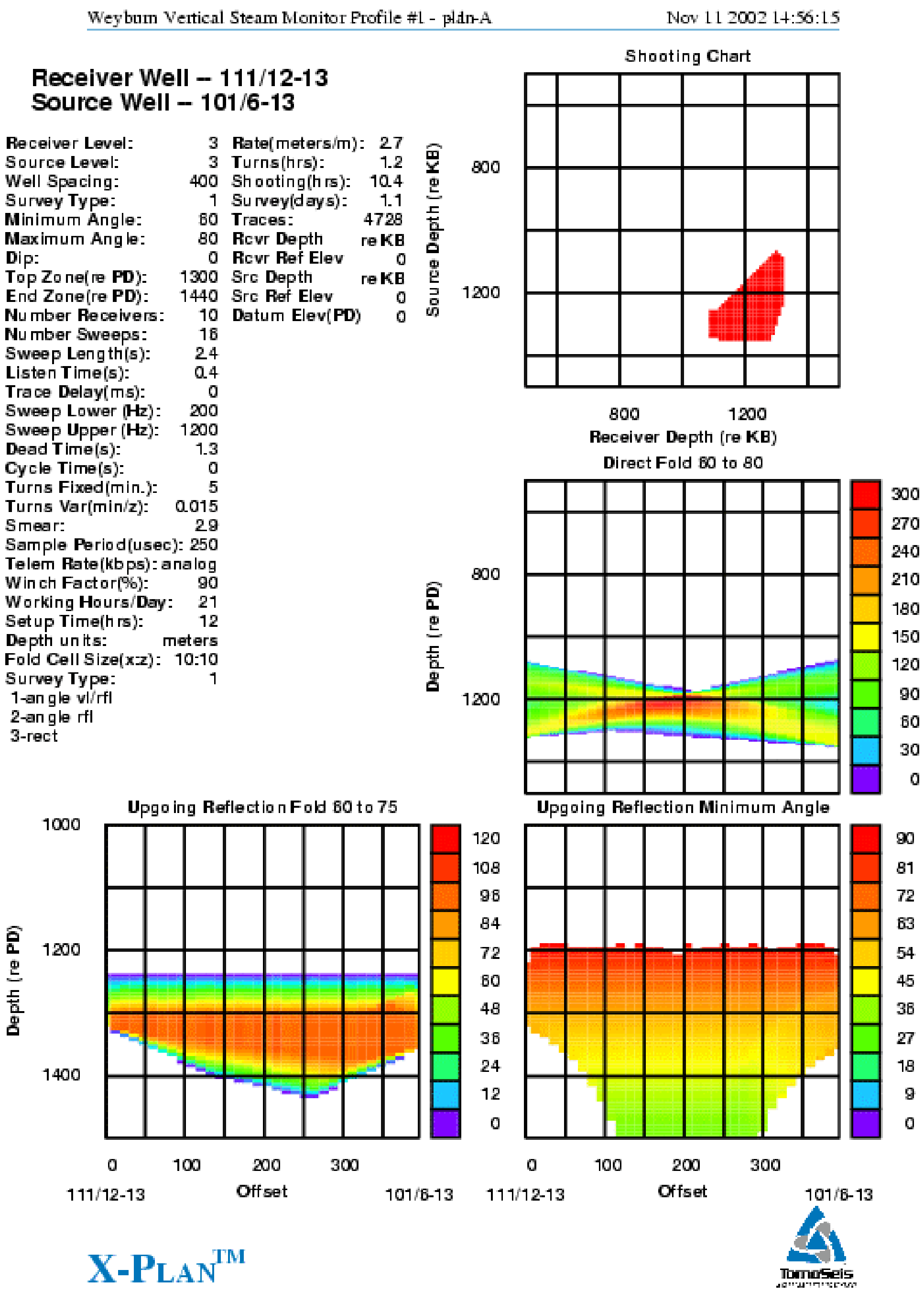

Figure 7. Logging plan #1A, profile #1

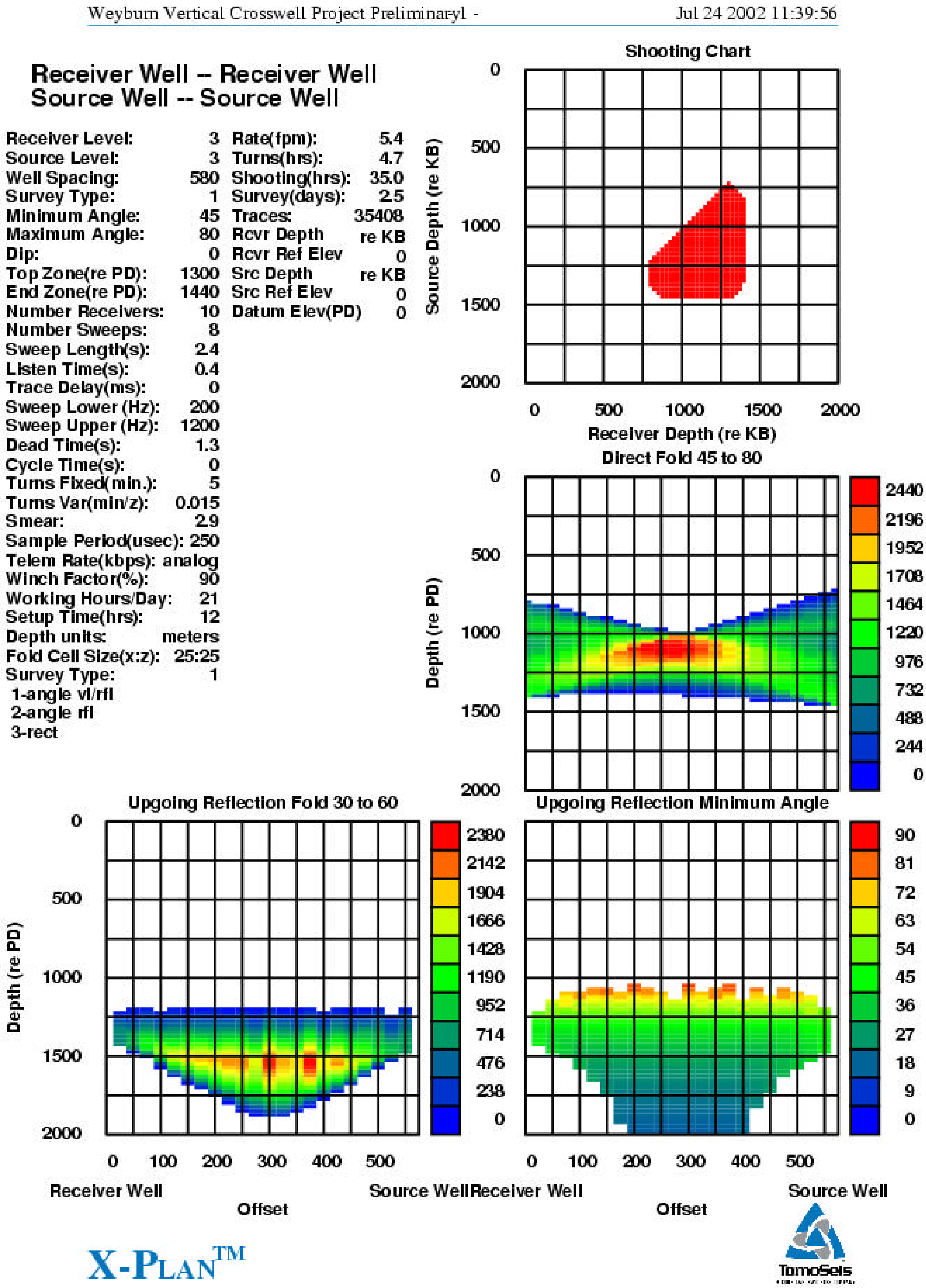

Figure 8. Logging pla n, Profile #2.

Well Information

Well	**111/12-13/6-14 (receiver)**	**101/6-13/6-14 (source)**	**101/4-13/6-14 (receiver)**
Coordinates	X: Y: Z:	X: Y: Z:	
Distance (surface)	400	0	580
Depth (m)	1320 (plug)	1353 (plug)	1400 (plug)
G.L.			
K.B.			
Deviated	Horizontal	Vertical	Vertical
Casing	7 inch O.D.	5-1/2 inch OD	5-1/2 inch O.D
Logs			
Reservoir top (m) Top of Marley Top of Vuggy Base of Reservoir		 1413 1420 1437	 1412 1419 1437

Acquisition Summary

Operations Summary—Profile 101/6-13—111/12-13

Before going to the location, a safety meeting was held at the Encana Field Office in Weyburn. The objectives for the crosswell project were outlined and at the close of the meeting, all requirements regarding safety and operational communication were met.

We deployed the receiver tool in the well 101/6-13 to measure and characterize background noise levels. We found noise levels to be less than –40 dB at all intervals tested with the exception of relatively strong tube wave energy in the range 500 to 700 Hz (see Data Quality section for details). We found the tube wave energy to increase with depth, yet within limits capable of being attenuated by our noise attenuation system. The noise level of less than –35 dB met the criteria established in the operational plan for making 101/6-13 our receiver well.

Data Quality

In order to characterize noise levels our 30 meter, ten level receiver string was run to TD in well 101/6-13. Noise test results showed relatively strong tube wave energy in the frequency range from 500 to 700 Hz as shown in the frequency spectrum of Figure 9.

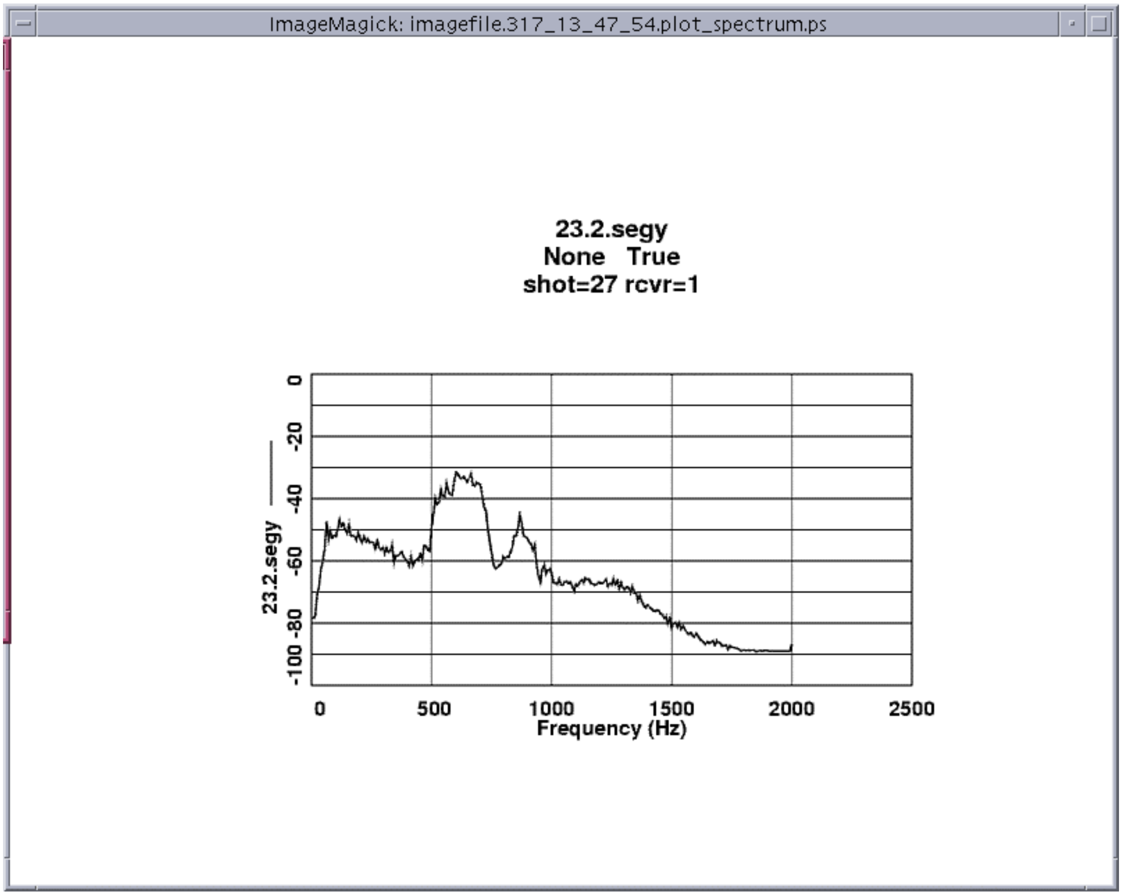

Figure 9. Frequency spectrum from TD

The receiver tool was brought up the hole 100 meters from TD and another test was run. A similar frequency spectrum was generated showing a decrease in spectral magnitude for frequencies between 500 and 700 Hz while the remainder of the spectral display is largely unchanged as shown in Figure 10.

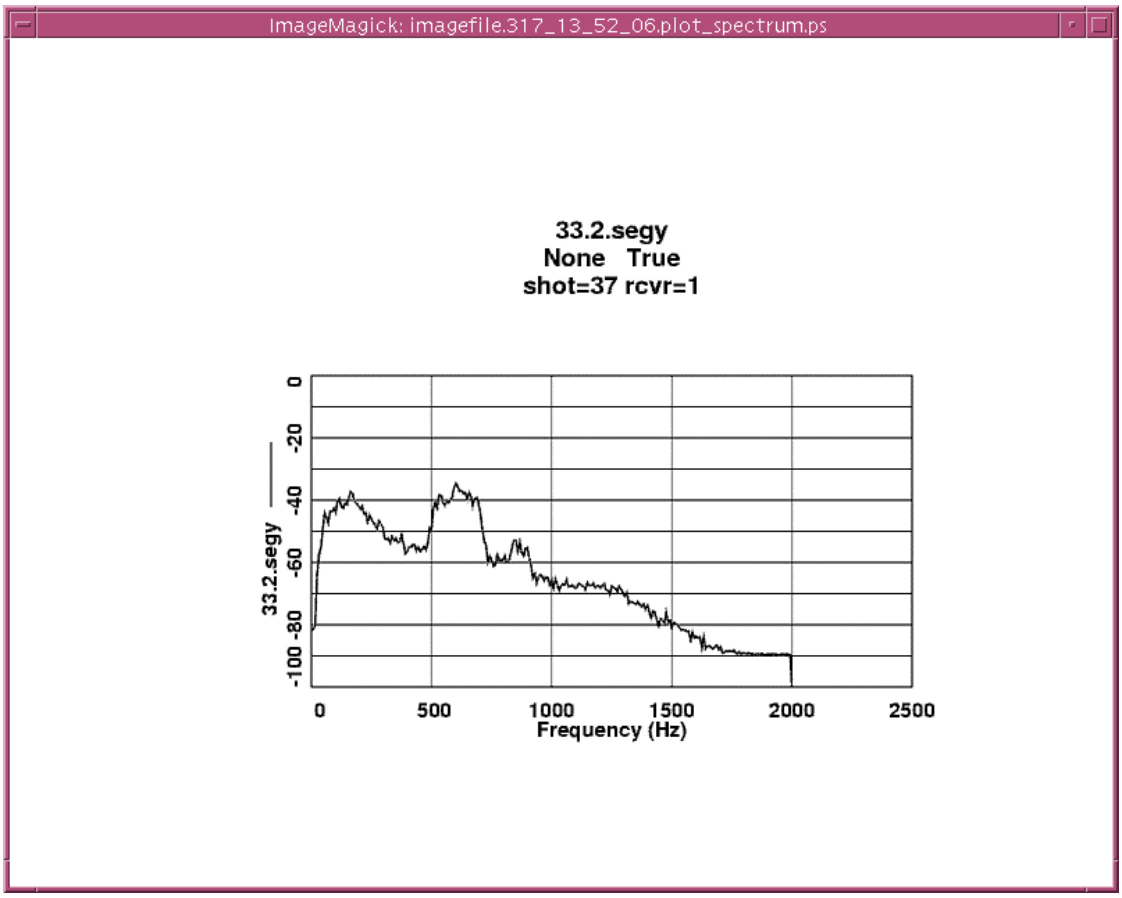

Figure 10. Frequency Spectrum 100m above TD

For the final test, the receiver tool was brought up to 800 meters. The resulting frequency spectrum shown in Figure 11 was again similar to the two previous tests, showing noise in the same frequency range, yet much lower amplitude than before.

These spectral displays show a decrease in the energy between 500 and 700 Hz with proximity to the bottom of the well. This strongly suggests the energy is emanating below the plug in the reservoir interval. Evidence of this fact can be seen in the common shot gather shown in Figure 12. Figure 12 shows the dominance of relatively high frequency upcoming tube waves. The low frequency energy is less frequent and more random in direction whereas the high frequency energy is consistent throughout every record and is coming from below. This suggested that the noise was being generated always from below the receiver tool and likely from within the reservoir interval.

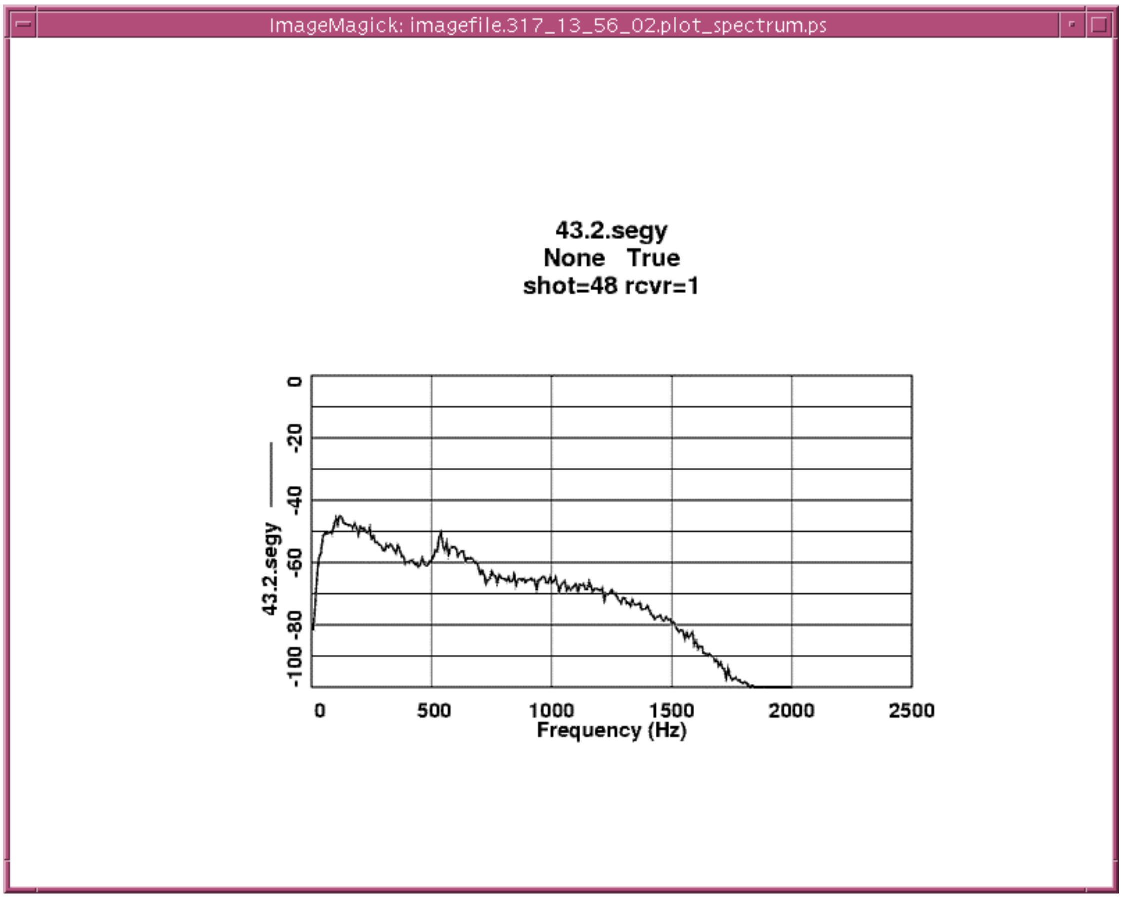

Figure 11. Frequency Spectrum at 800m

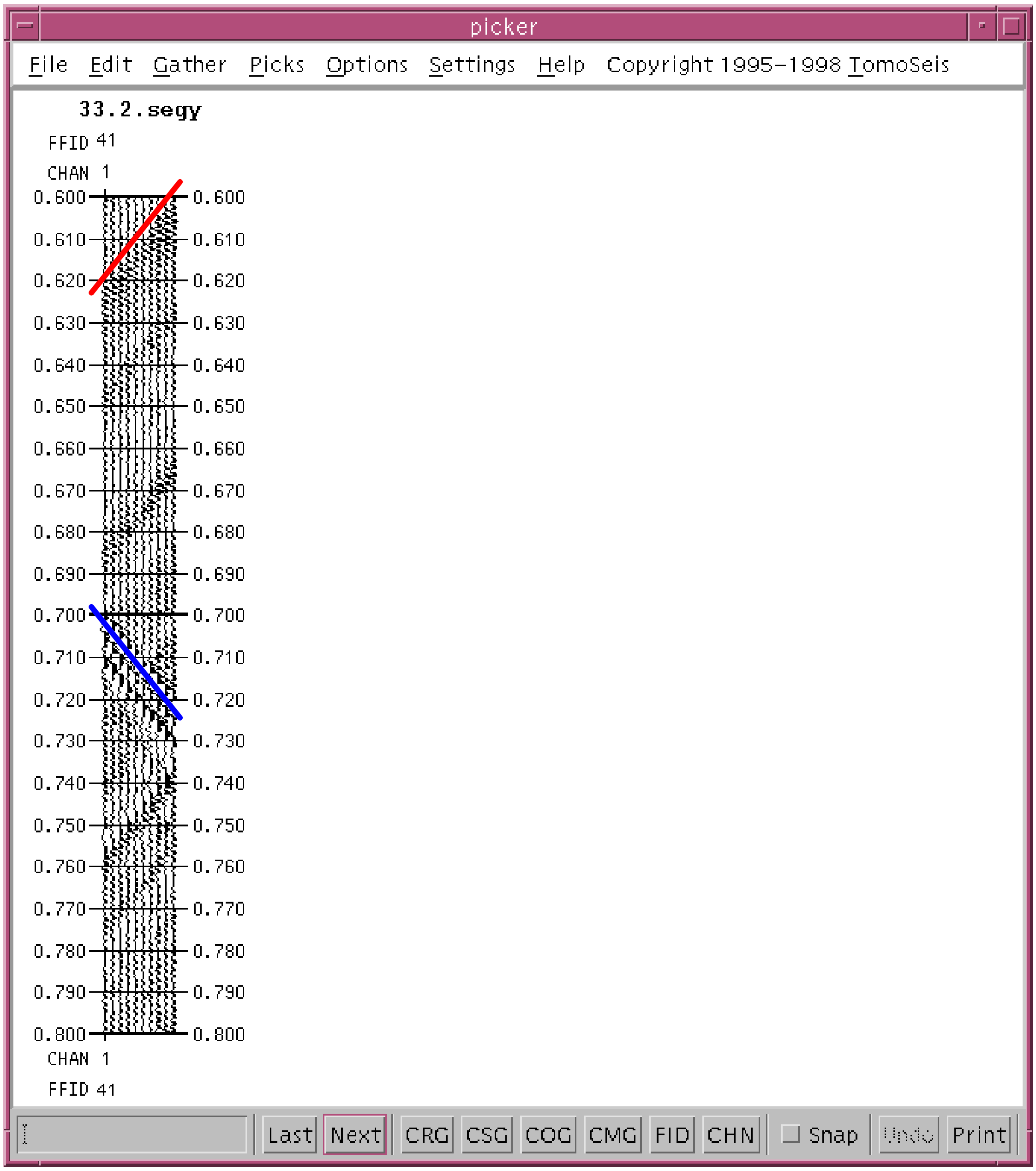

Figure 12. Seismic section of uncorrelated data acquired at 100 m above TD showing high frequency upcoming tube waves (red). The downgoing tube wave (blue) is typical of more random background noises.

The decision was made to deploy the receiver tool along with the noise attenuation system in well 101/6-13 to attenuate some of the observed noise. The tube wave attenuation system reduced the amplitude of the noise spectra by over 10 dB, with the frequencies between 500 and 700 hertz being attenuated by and additional 10 dB (20 dB in total).

The noise attenuation system was found to be very effective in attenuating the energy of the noise, particularly within the frequency range of 500-700 Hz. Amplitude spectra show attenuation of between 10 and 20 dB across the entire frequency band, with the greatest attenuation in the frequency band with the strongest noise.

Figures 13-15 are from depths of 1271, 1196 and 1181 meters. Direct arrival, reflected and tube wave arrivals are visible in these gathers. The signal-to-noise ratio of the data varies from moderate (1271 meters) to good (1196 meters).

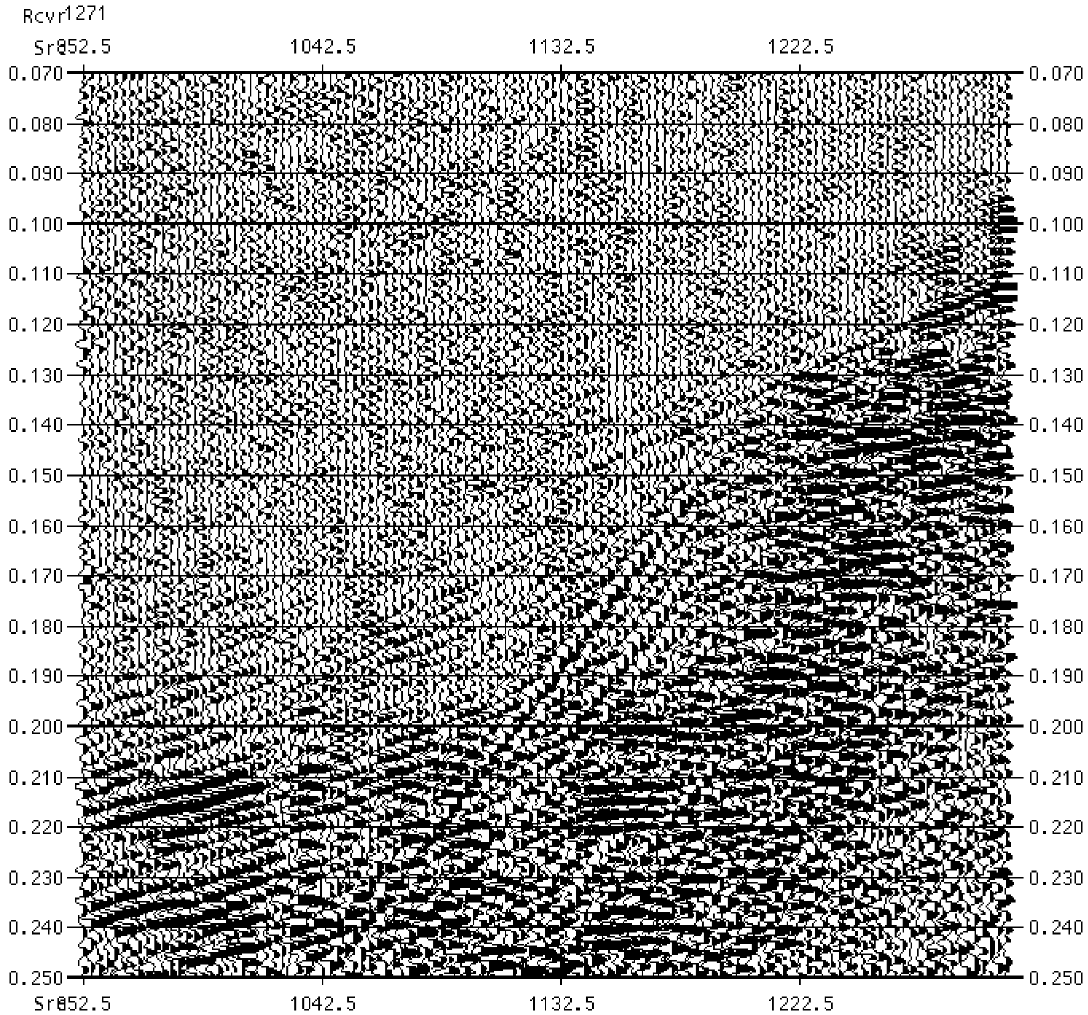

Figure 13. A common receiver gather from a depth of 1271 shows direct arrival energy at the right edge of the gather. Tube wave energy and possible P-wave reflection energy are also visible.

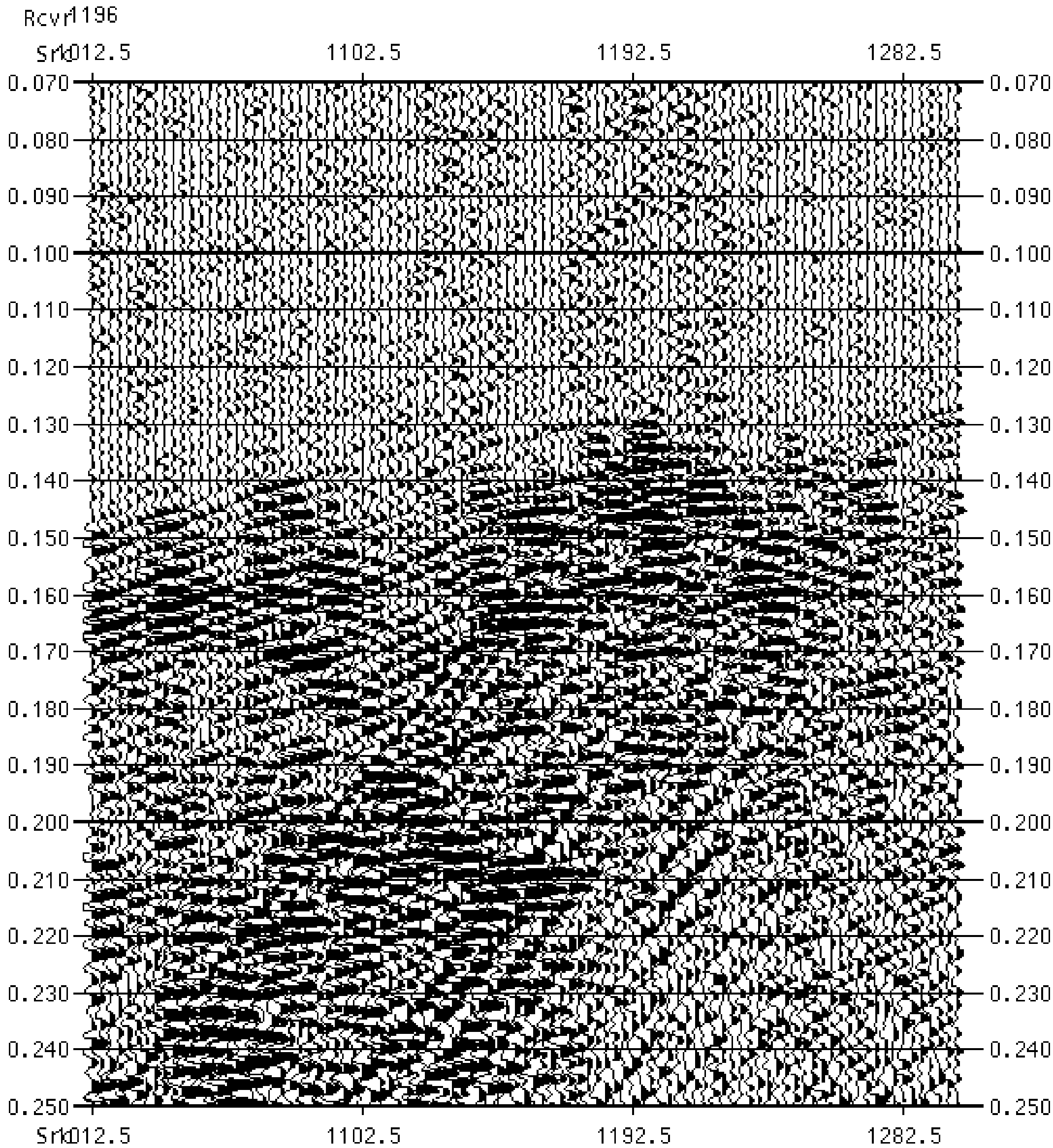

Figure 14. Common receiver gather taken at 1196 meters showing improved direct arrival signal and the presence of upcoming and downgoing tube waves.

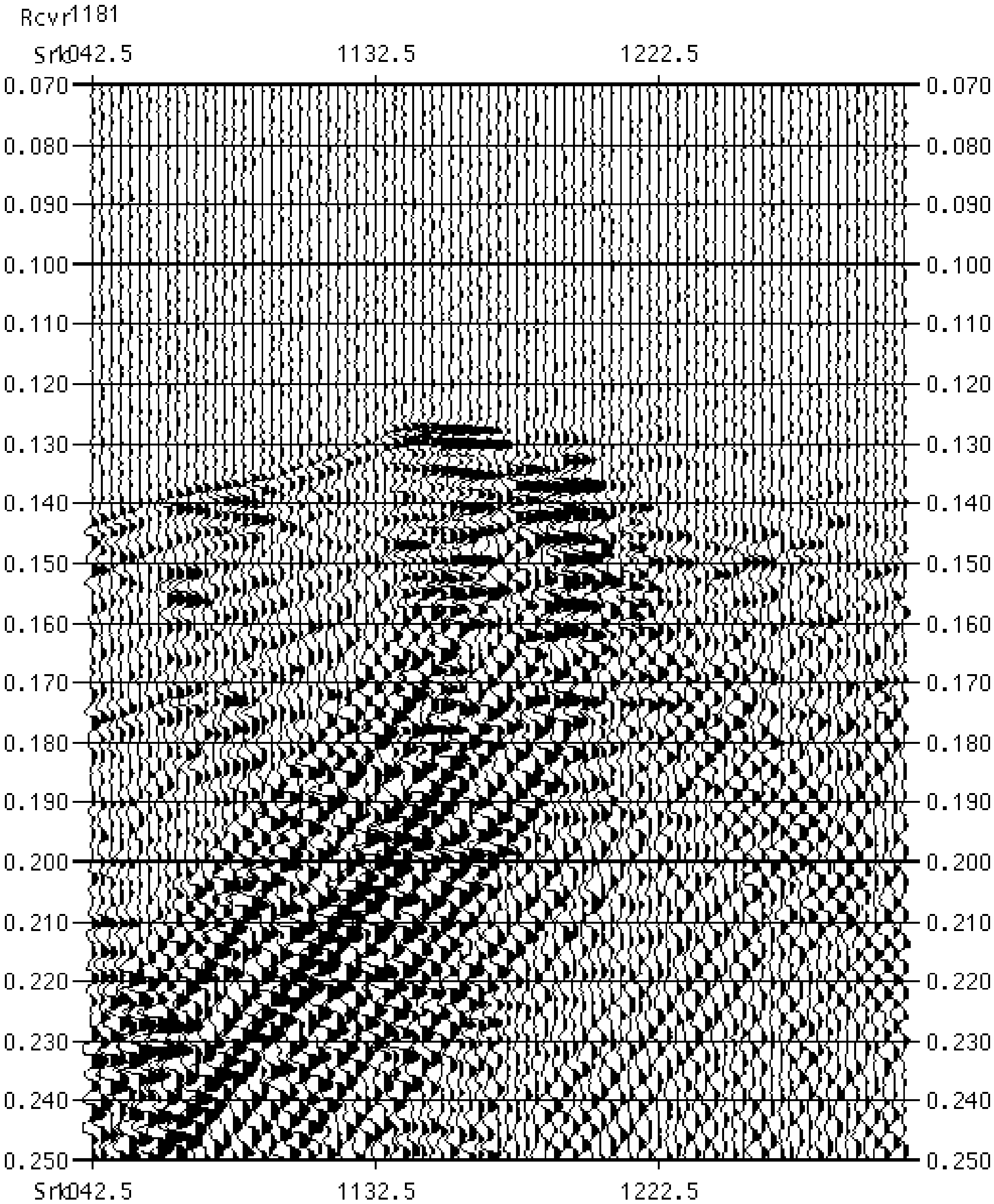

Figure 15. Common receiver gather taken at a depth of 1181 showing some low and high frequency upcoming tube waves as well as a strong direct arrival with clear reflection events. Notice the decrease in direct arrival energy to the right hand side of this gather, along with an increase in wavefield complexity. This change corresponds to a change in formation properties.

Figure 16 (a-d) shows the common receiver gather at 1181 meters band-passed into four different frequency bands. Direct arrival signal can be identified in all four bands with the frequency band of 500-800 Hz being the worst. This is the band that is contaminated by the previously mentioned noise source. With further processing the signal in this band may be improved.

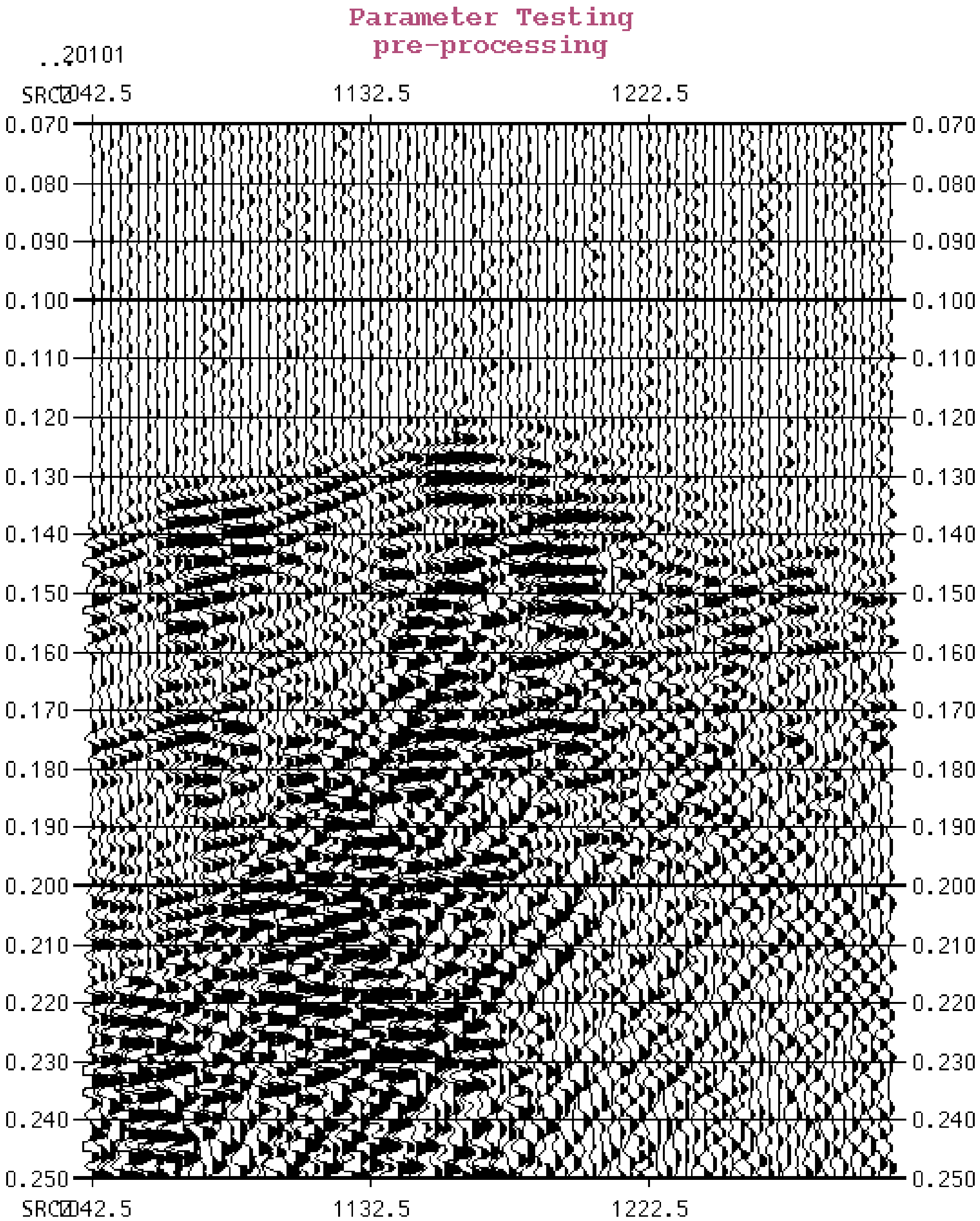

Figure 16. (a) A common receiver gather taken at a depth of 1181 with a band pass filter 100-300 Hz.

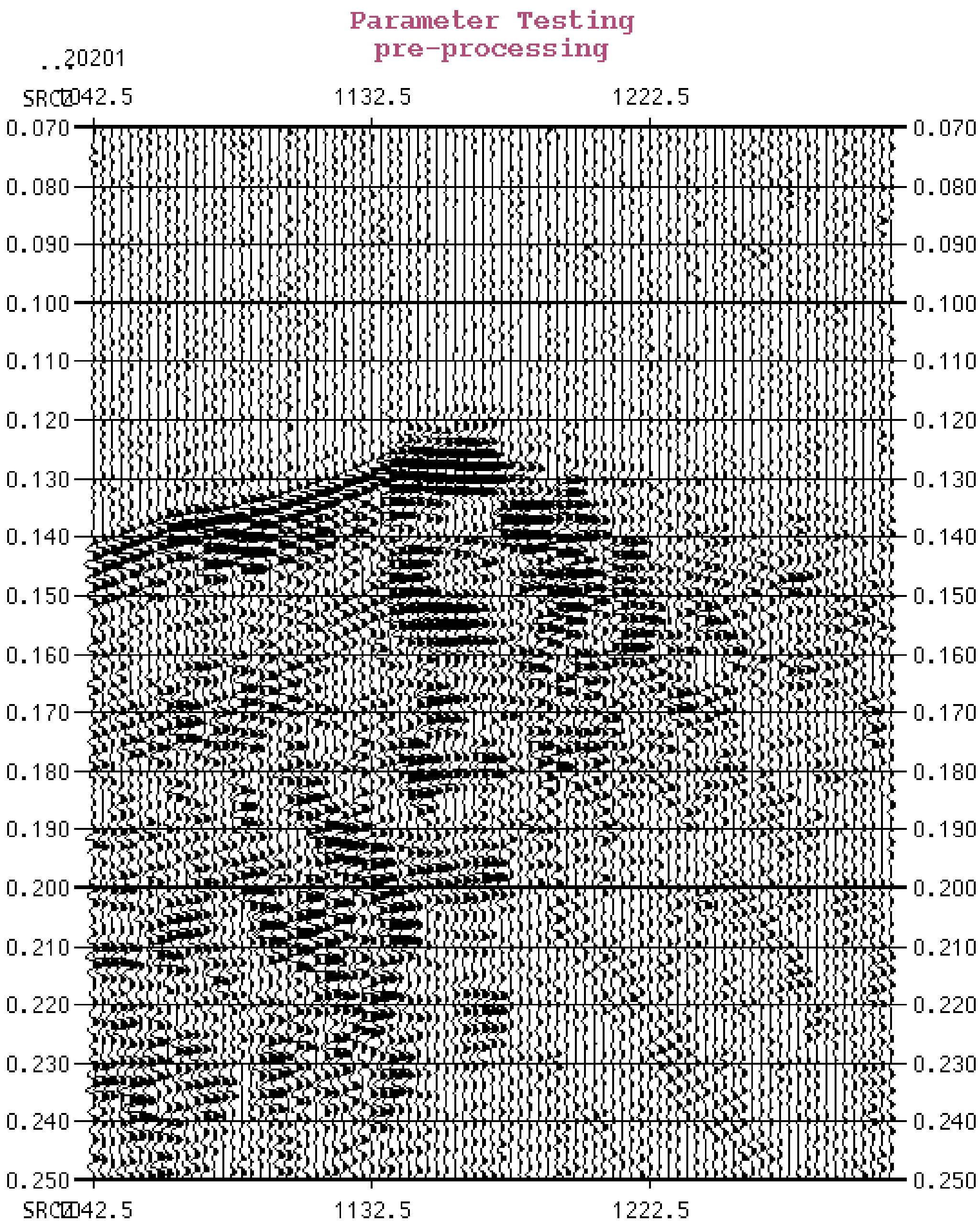

Figure 16 (b) A common receiver gather taken at a depth of 1181 with a band pass filter 300-500 Hz.

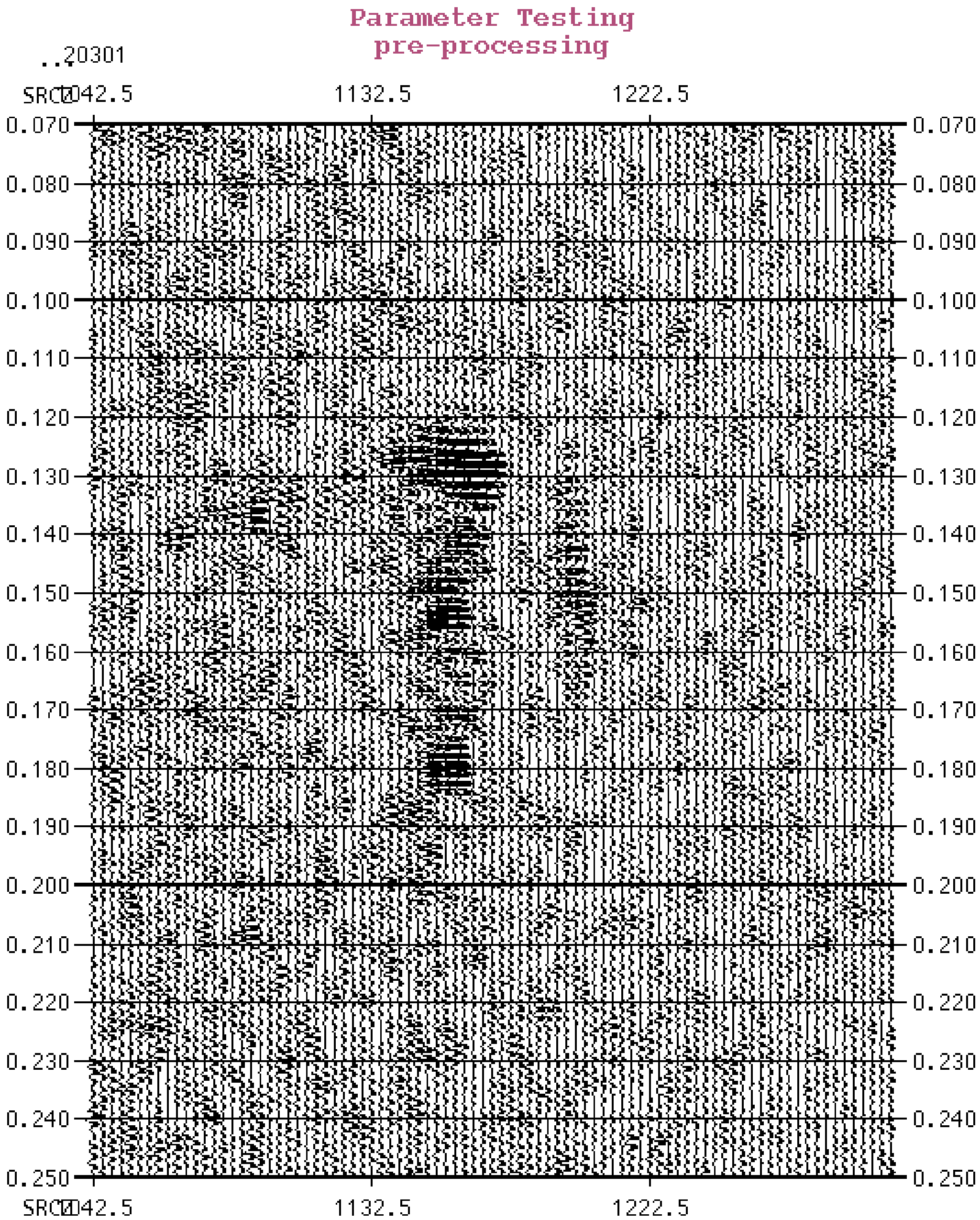

Figure 16 (c) A common receiver gather taken at a depth of 1181 with a band pass filter 500-800 Hz.

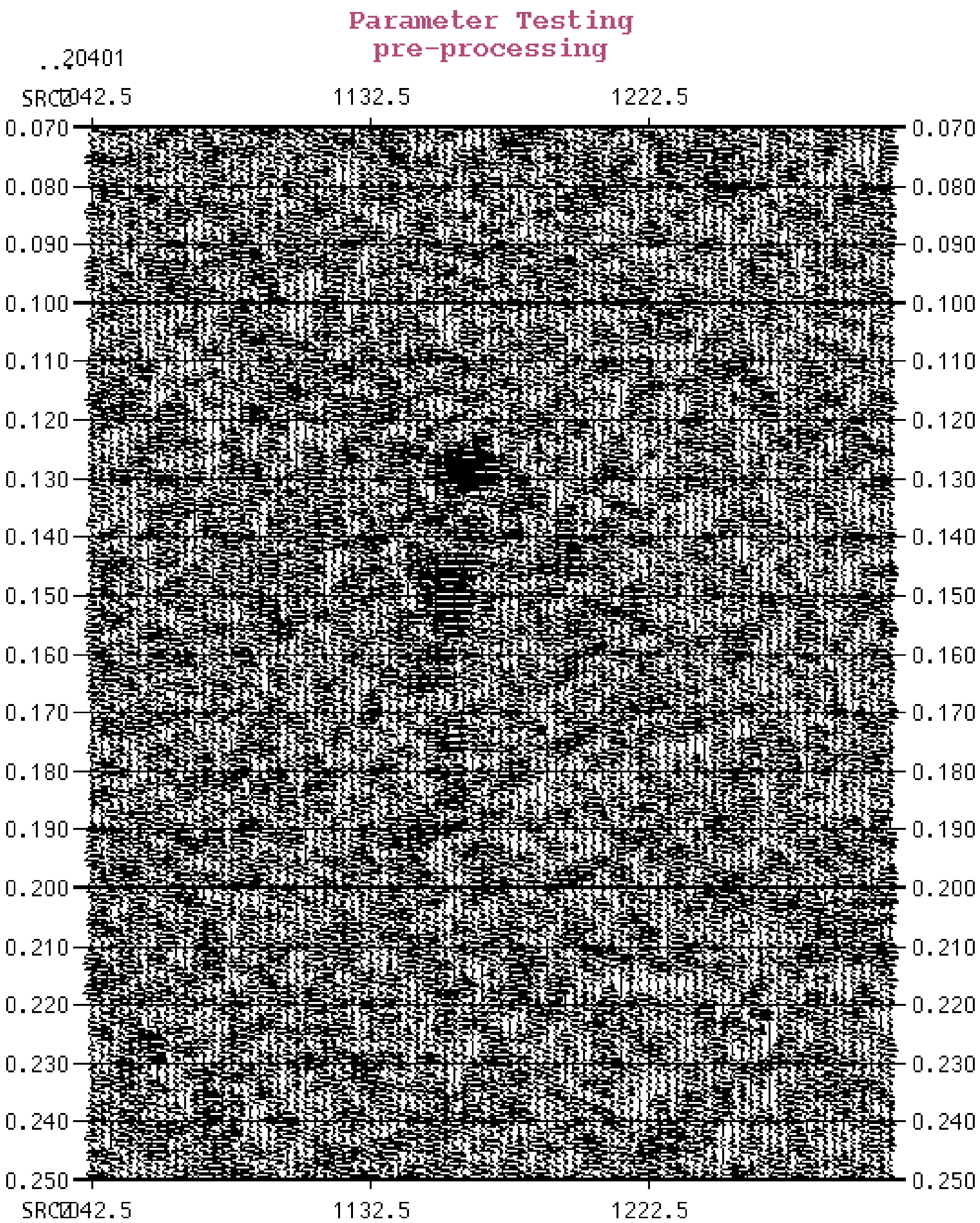

Figure 16 (d) A common receiver gather taken at a depth of 1181 with a band pass filter 800-1200 Hz.

The first 5 fans of Profile #1 were partially repeated to improve signal to noise ratio of those levels. Noise levels in the receiver well had decreased since the start of the survey.

Figure 17 shows one of the repeated common receiver gathers from 1319 meters. Figure 18 shows a spectrum from the initial recording of this level and Figure 19 shows the spectrum from the second recording.

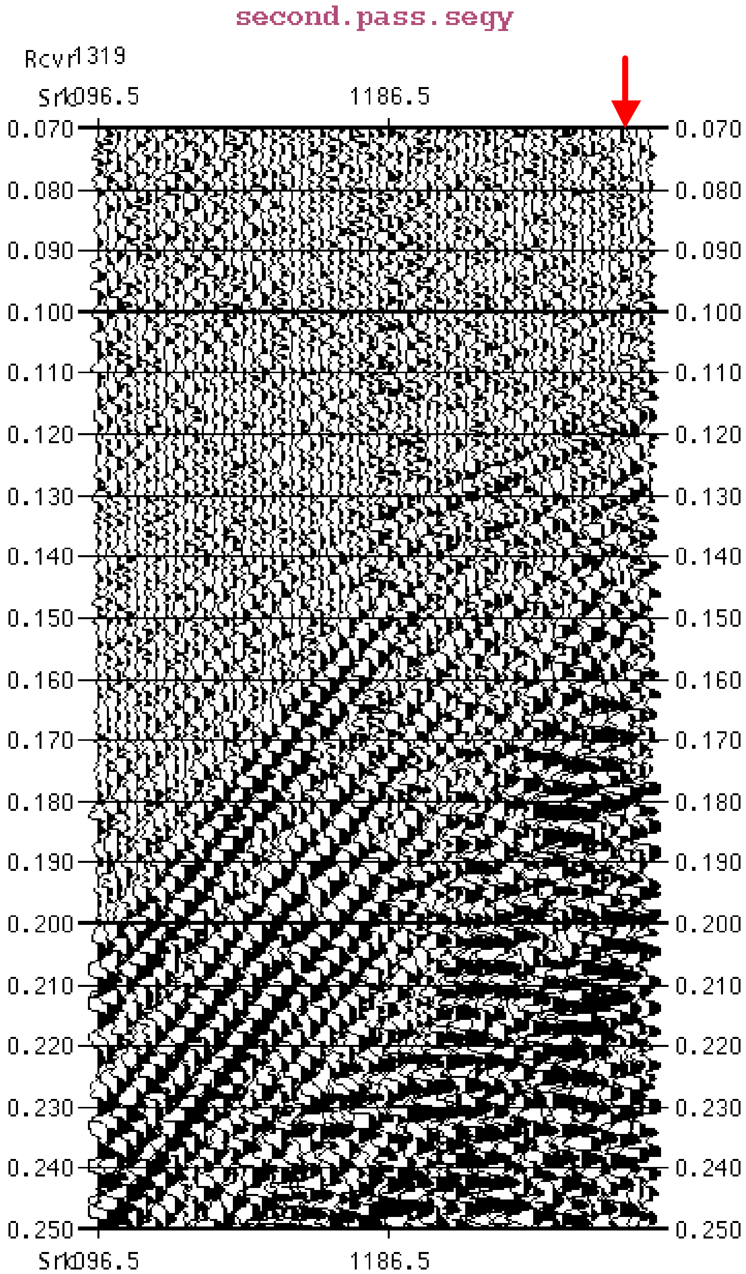

Figure 17. Common receiver gather from 1131 m during the second recording pass. The red arrow indicates the source level used in the following spectral analysis. These data are stacked and cross-correlated with the pilot signal; no additional processing has been performed.

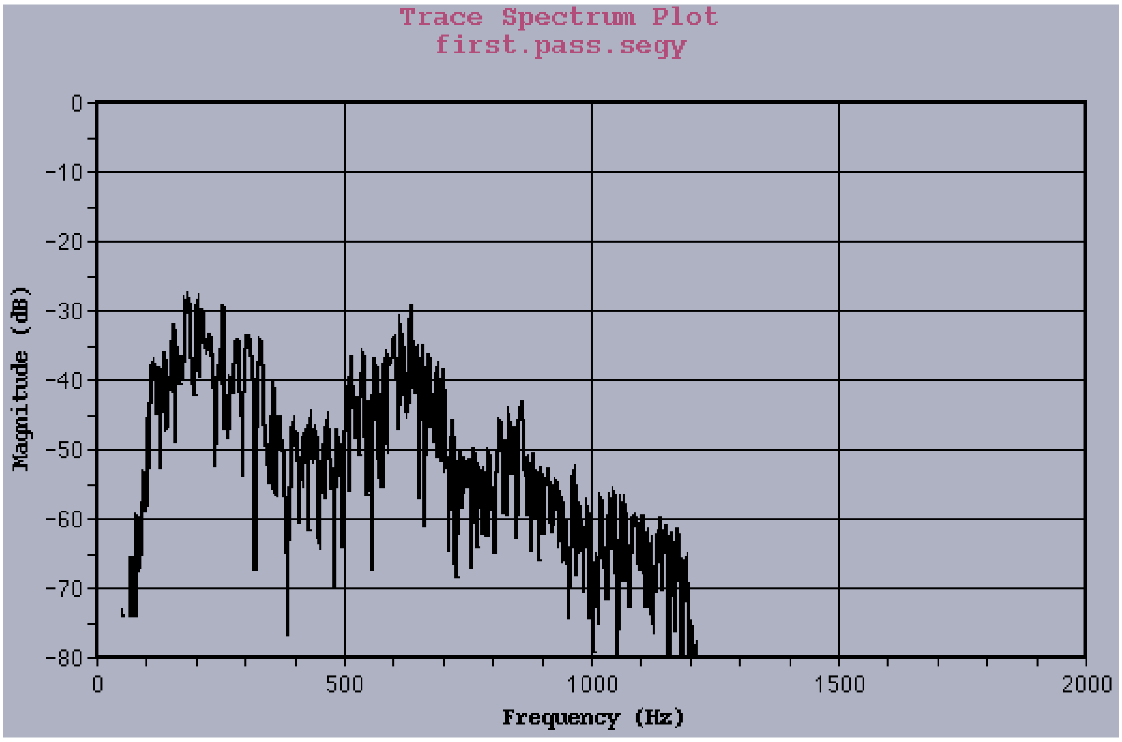

Figure 18. Spectrum computed for a trace recorded earlier in the profile at the location indicated in Figure 17. Note the relatively large spectral amplitude between 500 and 700 Hz.

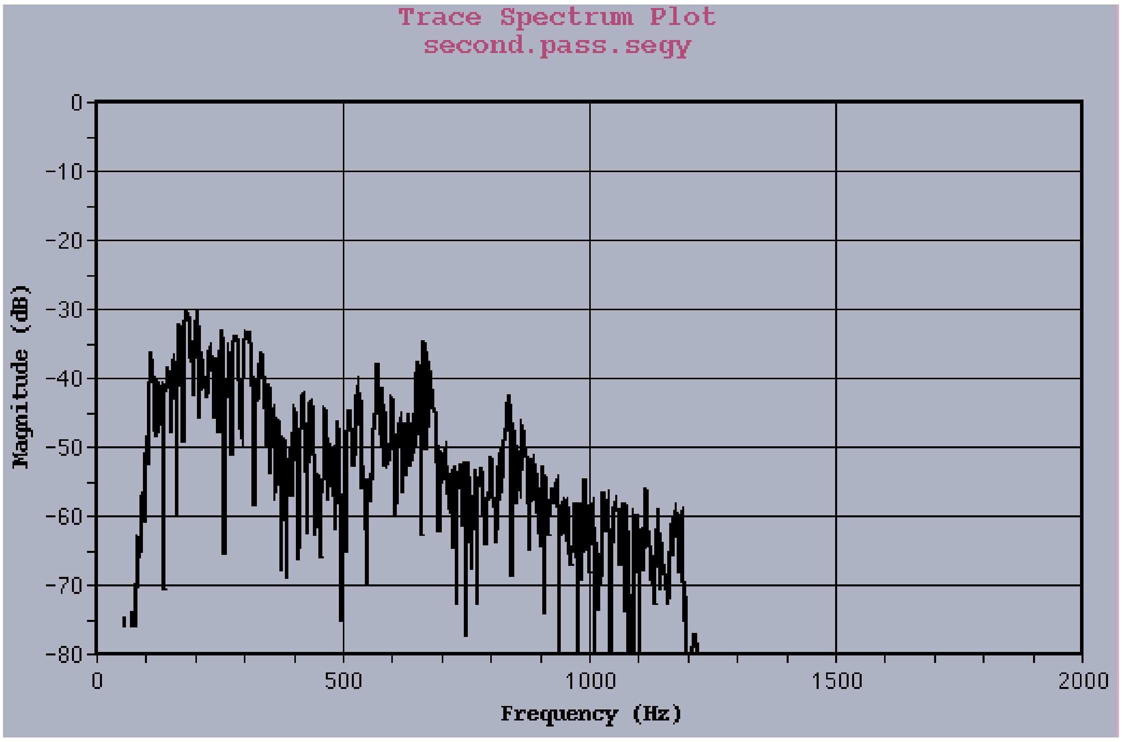

Figure 19. Spectrum for the trace indicated in Figure 17, recorded during the second pass. Note the lower amplitudes in the 500 to 700 Hz range indicating a reduction in noise levels.

Operations Summary Profile 101/6-13—101/4-13

Data quality on the second profile was similar to the first profile. The ability to position the source tool to a greater depth provides acquisition through intervals not possible in the first profile. Figure 20 indicates the increased depth aperture relative to the first profile. Figure 21 shows the noise spectrum for the first fan of Profile #2. Figure 22 shows a common receiver gather from a depth of 1166 meters.

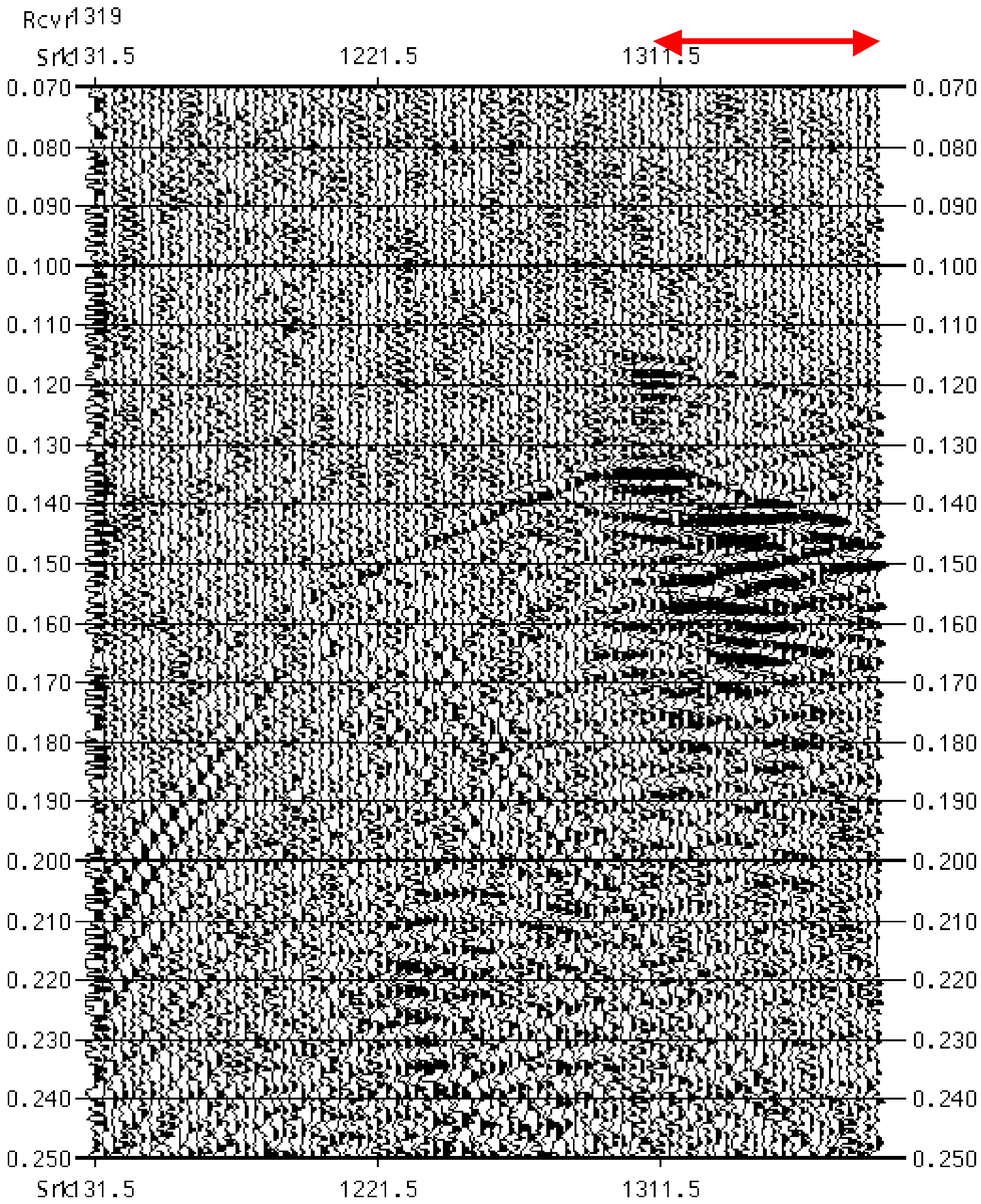

Figure 20. Data from the first fan of Profile #2. The red arrow in the above display indicates the additional depth interval achieved in the 101/4-13 (current source well) over the 111/12-13 (previous source well).

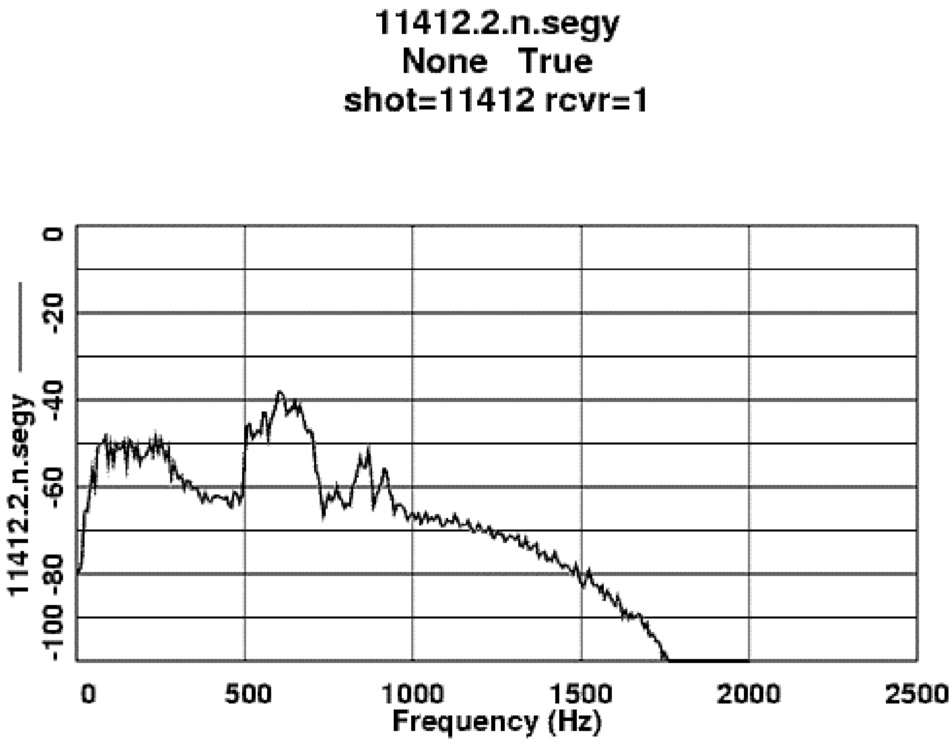

Figure 21. Noise spectrum from first fan of Profile #2 with noise attenuation system deployed.

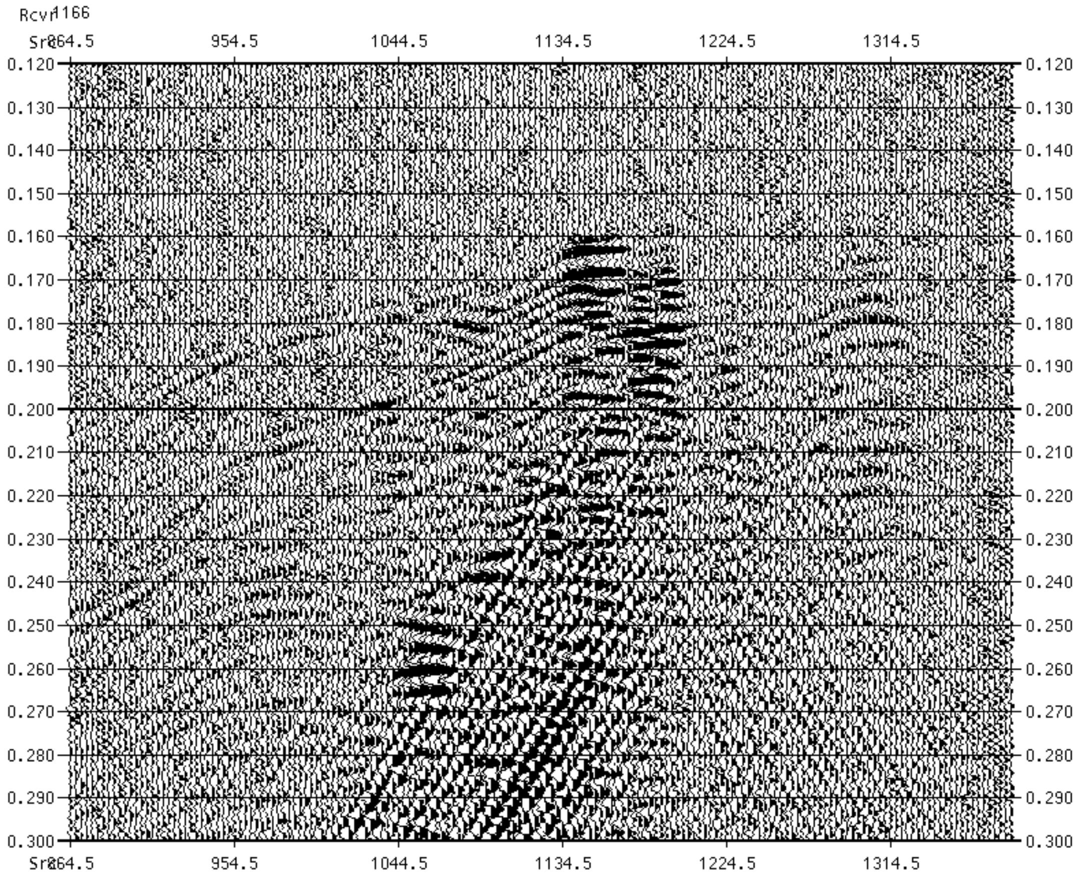

Figure 22. Common receiver gather from 1166 meters. The frequency content present in this gather is mostly below 600 hertz.

Figures 23-25 are examples of gathers from Profile #2. These gathers represent stacked and correlated data with a mild spectral whitening and band pass filter from 100 to 500 Hz. The frequencies above 500 Hz that were present in a number of gathers on Profile #1 are largely absent on Profile #2. This is probably a result of the increased noise and larger interwell distance of Profile #2.

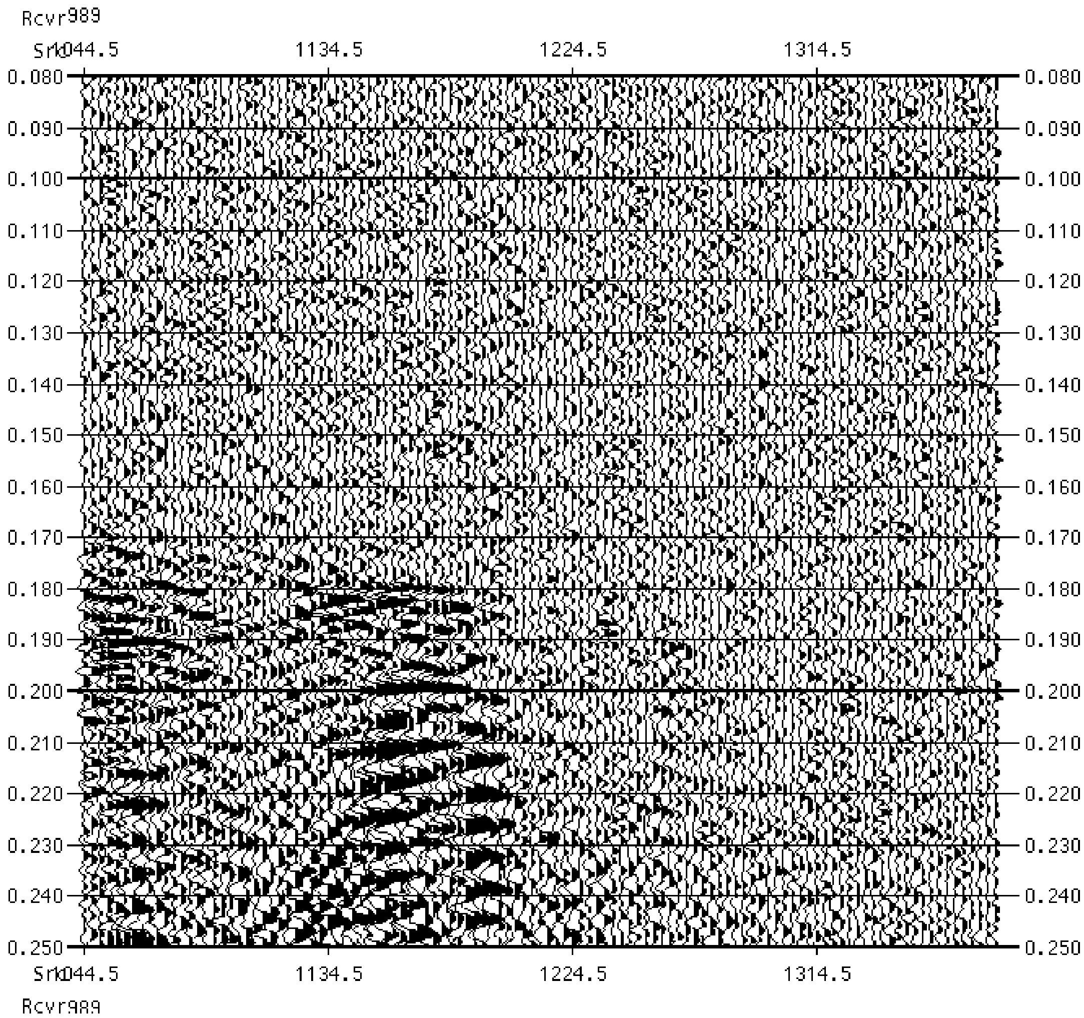

Figure 23. Common receiver gather for Profile #2 from a depth of 989 m.

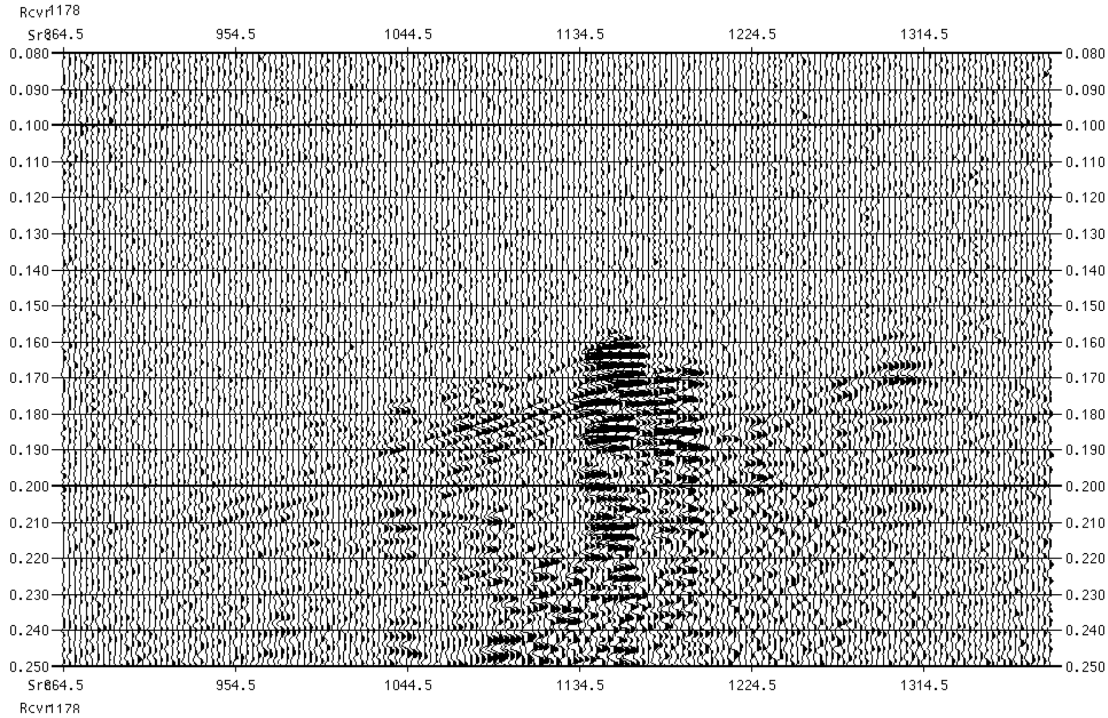

Figure 24. Common receiver gather for Profile #2 from a depth of 1178 m.

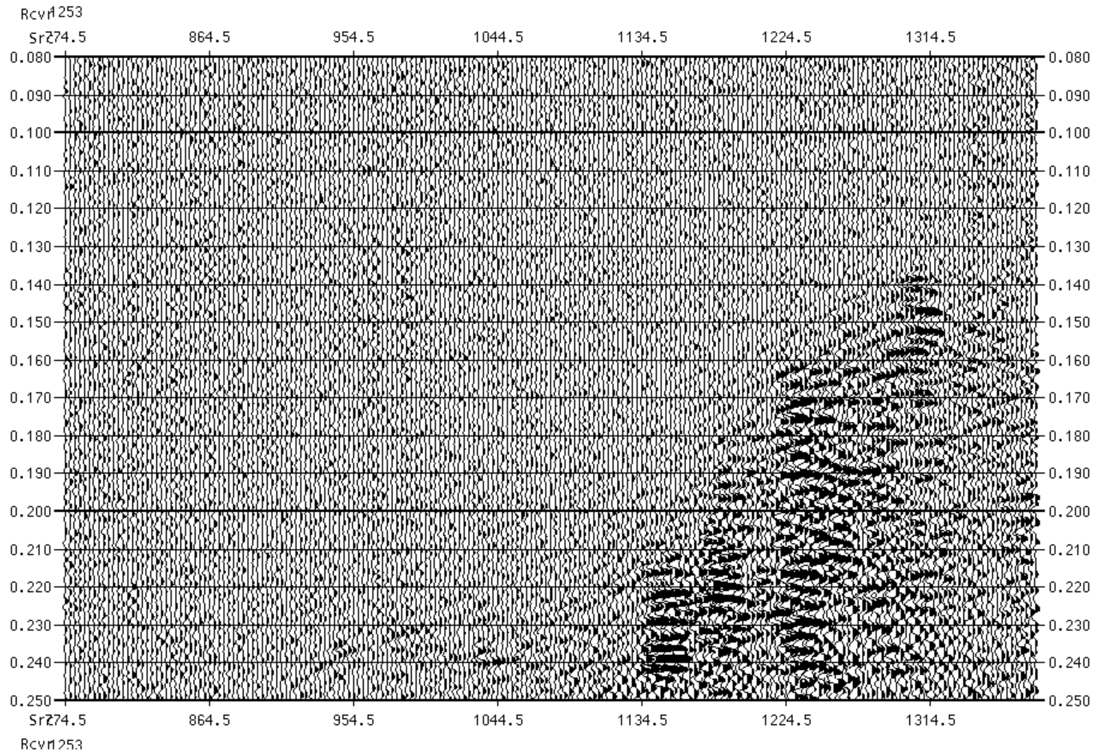

Figure 25. Common receiver gather for Profile #2 from a depth of 1253 m.

VSP Acquisition

Acquisition of a zero offset and 3 offset VSPs were recorded into well 101/6-13 in the Weyburn field following the conclusion of the crosswell seismic operations. The borehole tool was the TARS (TomoSeis Analog Receiver System) hydrophone system and the source was an I/O vibrator. TomoSeis' responsibility in this acquisition was to assist with equipment interface, recording and on-site data QC. The exact surface locations were specified by Dale Cox and were not known exactly by the TomoSeis staff. Approximate locations of the vibe points are given for completeness.

Acquisition

Acquisition operations began at around noon November 18, 2002, and continued uninterrupted through approximately 3:00 a.m. November 19, 2002. The receiver tool was deployed in the 101/6-13 for each profile with receivers spanning from 1337 to 380 meters at a 3-meter level spacing. Depth measured relative to GL elevation

Vibrator points were selected by Dale Cox. Approximate locations of vibe points are given below when known.

Receiver tool description

The receiver tool consists of ten 16 element by 3 meter hydrophone arrays. The array centers are separated by 3 meters for an effective level spacing of 3 meters.

Vibrator description

The vibrator was an I/O device capable of generating both *P*- and *S*- wave energy. The majority of acquisition was performed using *P*-wave source, however some levels were recorded using *S*-wave source. *S*-wave source shots on offset #1 were recorded with the axis of excitation off axis from the direction of the profile. This was corrected and repeated on offset #2.

The table below describes the approximate locations of the vibrator for the 4 offsets acquired.

Offset	Description	Approximate distance (m)
1	Along 111/12-13 to 101/6-13 line.	800
2	Along 101/4-13 to 101/6-13 line.	1200
3	Zero offset	On 101/6-13 pad
4	Along 101/4-13 to 101/6-13 line.	580

A similarity test was conducted prior to the start of acquisition to ensure the vibrator encoder signal and the encoder in the recording unit were producing the same sweep. These test are recorded on shot numbers 31-35. The recorder unit encoder sweep is recorded on channel #1 while the vibrator encoder sweep is recorded on channel 4. Following the similarity test the sweeps from the encoder in the receiver unit were the only ones recorded.

Channel configuration

The VSP recording was performed on an EGG Strataview recorder. This system wrote the SEG-Y data to disk and tape during acquisition. The disk files were QC'd in the field and the tape files (two copies) were archived for delivery.

The channel configuration used during acquisition is described in the table below.

Channel #	Description	Channel #	Description
1	Sweep	8	Depth=Z+9
2	Aux	9	Depth=Z+12
3	Aux	10	Depth=Z+15
4	Aux	11	Depth=Z+18
5	Top receiver (Depth=Z)	12	Depth=Z+21
6	Depth=Z+3	13	Depth=Z+24
7	Depth=Z+6	14	Depth=Z+27

Recorder Timing

The vibrator encoder box was unable to trigger the Strataview recorder as planned so an alternative triggering scheme was used. The time break signal for the vibrator was used as the recorder start trigger for all VSP data.

Data Tapes

Field data tapes (4-mm) were delivered to the TomoSeis Houston processing center at the end of the survey. The 4-mm tapes were transcribed to 8-mm tapes for delivery to LBL. The field tapes are SEG-Y format with trace data as 4 byte fixed-point data (format code 2). The data are as recorded in the field and have not been correlated with the pilot sweep. Important trace header locations are listed below, of which the most useful are high lighted in red. The Reel Identification Header is standard SEG-Y format.

Description	Bytes	Description	Bytes
Trace sequence number	001-004	Number of samples	115-116
Field recorder channel number	005-008	Sample period (us)	117-118
Field file ID	009-012	Gain type	119-120
Sequential channel number	013-016	Instrument gain	121-122
Sequential shot number in file	017-020	Initial gain	123-124
Trace ID code	029-030	Low cut filter corner frequency	149-150
Receiver measured depth.	041-044	Anti-alias filter corner frequency	151-152
Source measured depth.	045-048	Hour of day	161-162
Source depth from encoder	049-052	Minute of hour	163-164
Acquisition delay (milliseconds)	109-110	Second of minute	165-166

Data Quality

Figures 26-29 show one receiver position for each of the offsets. The results are scaled by the RMS level of all traces in the display (panel or section normalization) and processing is a simple mean stack followed by correlation with the recorded pilot. No trace editing prior to stack or subsequent filtering has been performed.

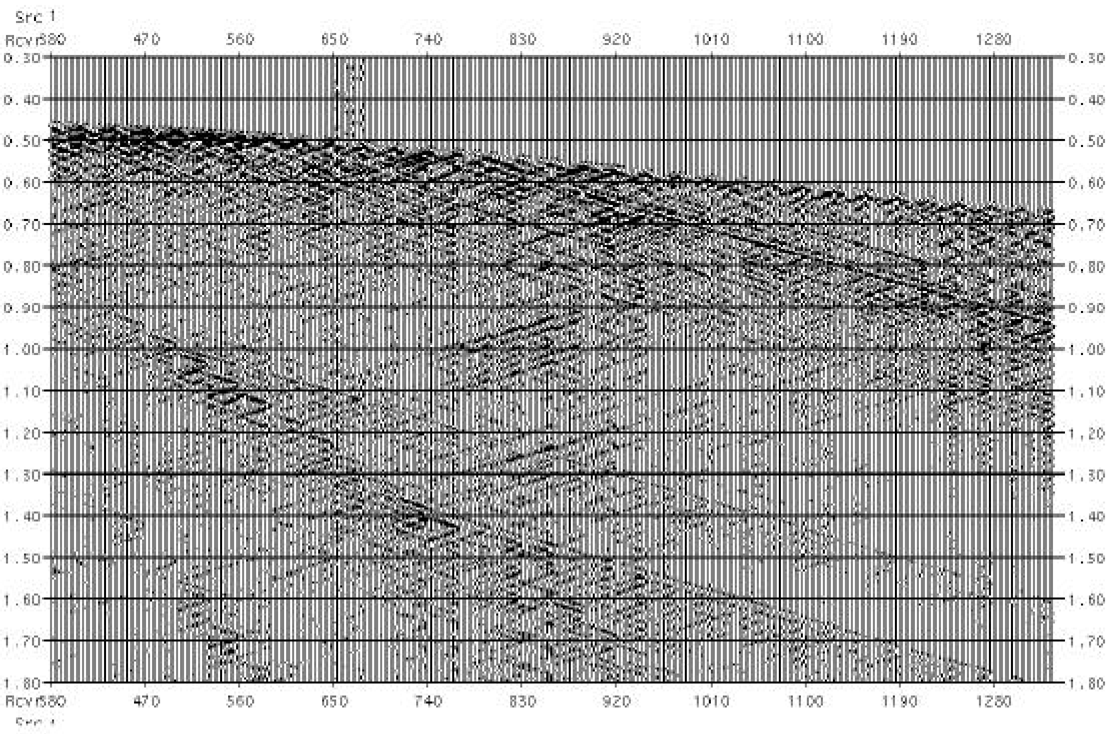

Figure 26. Offset 1 of VSP.

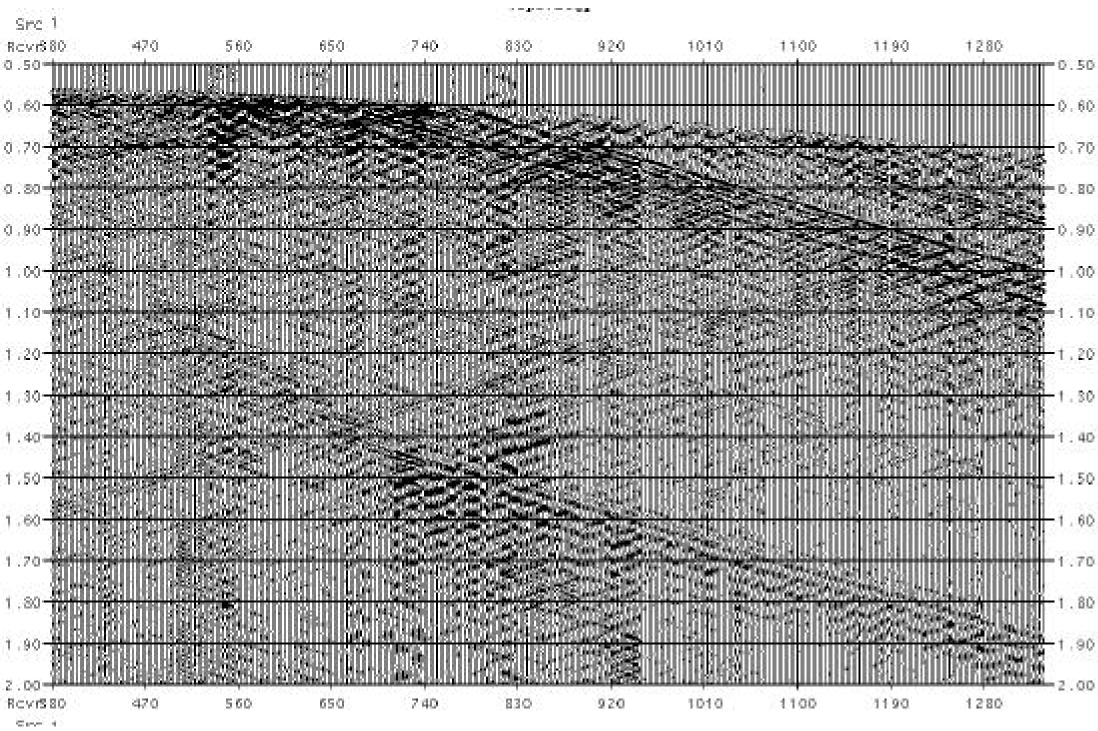

Figure 27. Offset 2 of VSP.

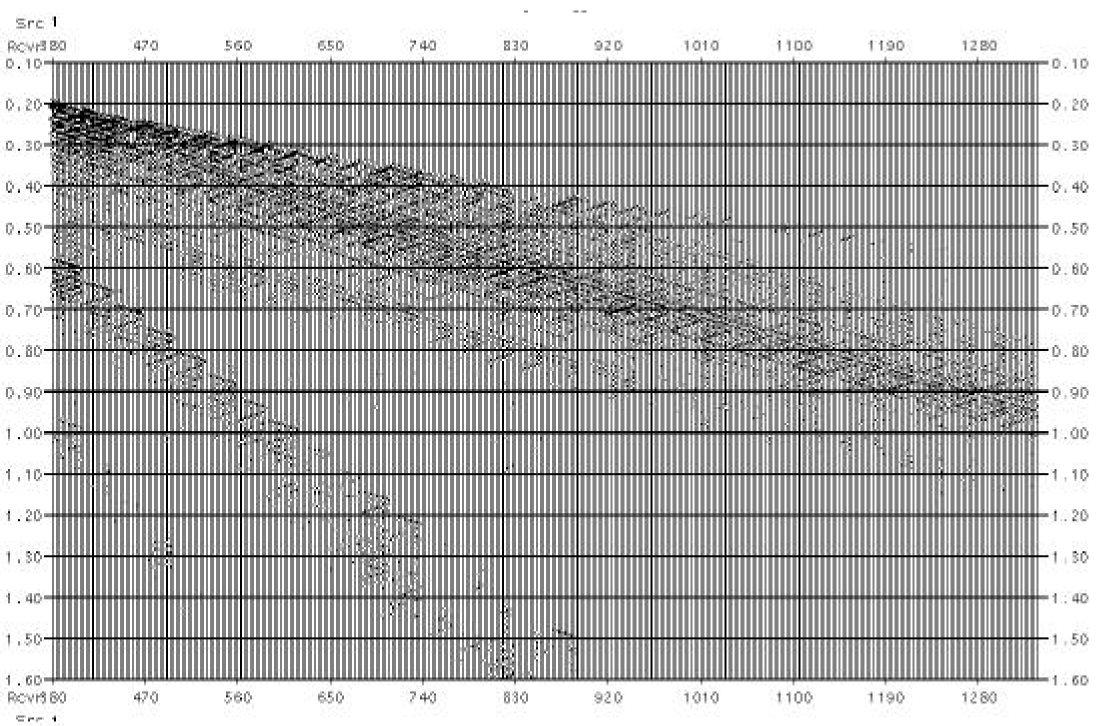

Figure 28. Offset 3 of VSP.

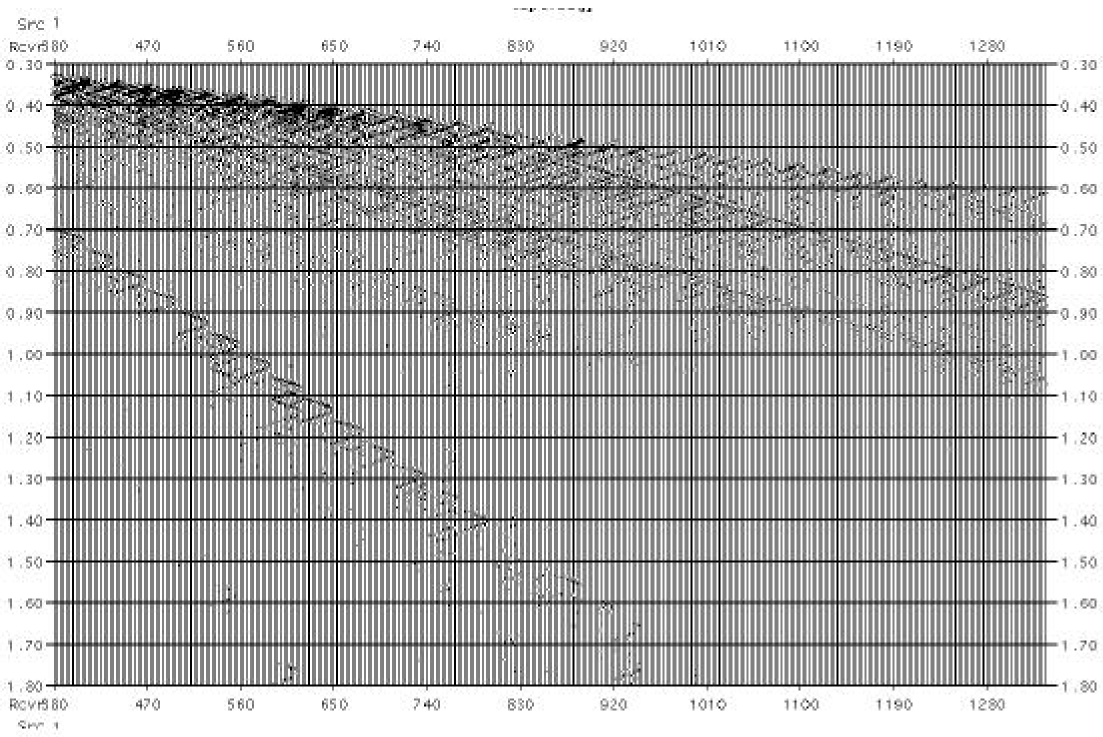

Figure 29. Offset 4 of VSP.

Data Processing

Processing Plan

Objectives

The objective of the data processing is to assist in diagnosing unexpected CO_2 performance in the Weyburn field, Saskatchewan, Canada (figure 30). In the area of interest horizontal injection logging and 4-D surface seismic indicate good areal extent to the CO_2, but no response has been seen in nearby production wells, specifically 121/08-14. Several possible explanations include lower permeability in the area slowing the movement of CO_2, upward flow of CO_2 into zones above the reservoir or below in the Frobisher Marley, or behind casing leaks that provide an upward migration path for CO_2. The 4-D seismic vertical resolution is not adequate to delineate in-reservoir and out-of-reservoir flow of CO_2.

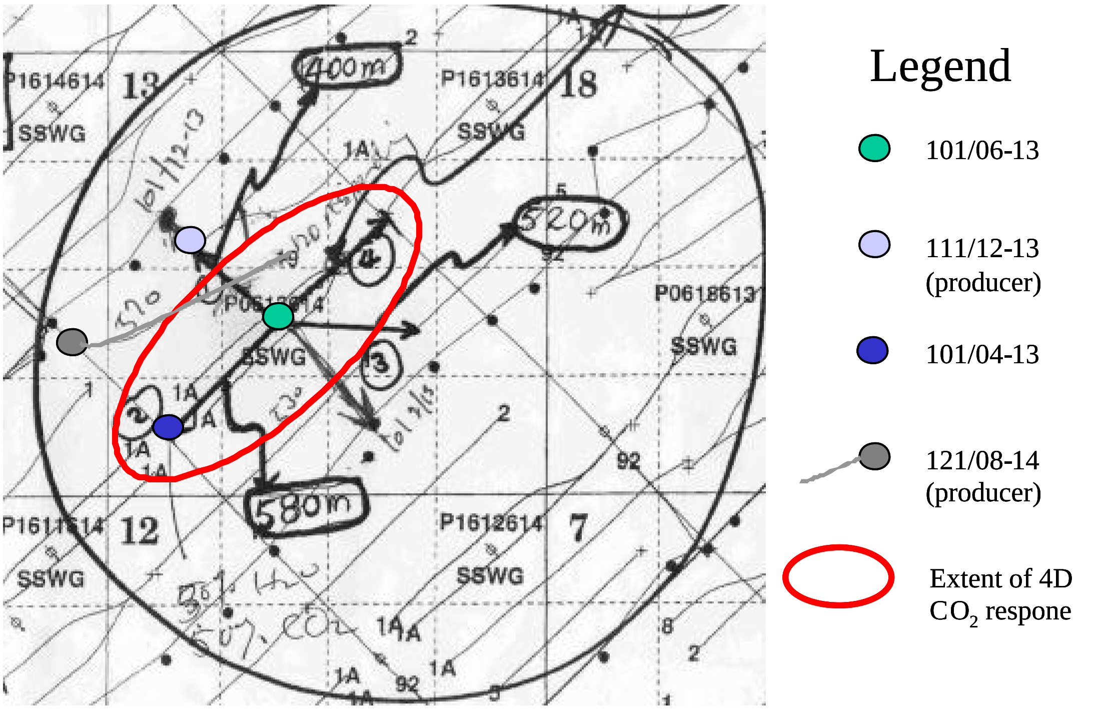

Figure 30. Weyburn field map showing survey area and area of 4-D CO_2 response

Issues

The crosswell acquisition occurs entirely above the intervals of interest so the reservoir interval will be interrogated using reflected *P*-wave energy only. Proper positioning of this energy depends on relatively accurate velocity information. Direct arrival traveltime tomography will be used for intervals covered with direct arrival energy (see Figure 31). Intervals below direct arrival coverage will be imaged using velocities derived from nearby sonic logs. These sonic logs will represent velocities before CO_2 injection began, or baseline velocities for purposes of our interpretation here. Reflection images produced using these velocities will correctly position reflection horizons when the velocities are unchanged since injection began. Based on this assumption any mispositioned reflection events should be the result of velocity changes along individual ray paths. It is through this mispositioning of reflected energy that we hope to infer the presence of CO_2.

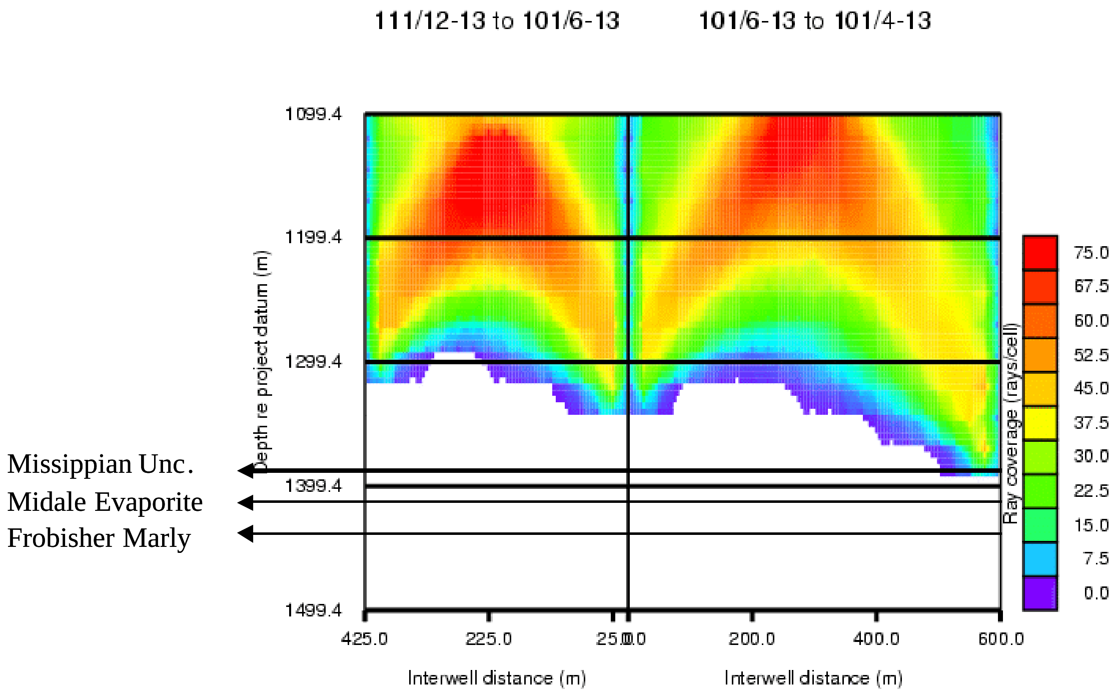

Figure 31. Direct arrival coverage entirely above the interval of interest. Sonic logs will be used to create velocity models for imaging below direct arrival coverage.

Structural features above first detected CO_2 can be interpreted as imaged while features below CO_2 will be mispositioned in depth. Image refinement may be required to improve the stack quality below CO_2. Interpretation of structure below CO_2 will require an analysis of the relative positions of reflection horizons as compared to the formation picks provided by EnCana.

Data Overview

Two profiles were acquired in the Weyburn field beginning November 12 and concluding November 18, 2002. Tests conducted in the field indicated that well 101/6-13 would be suitable as a receiver well and so the receivers were deployed in that well according to contingencies outlined in the Operational Plan for this project.

Noise levels in the receiver well were low with the exception of fairly strong noise energy between 500 and 700 Hz. These particular noises were identified as emanating from the reservoir interval due to their moveout across the receiver array. The noise attenuation device reduced the magnitude of all recorded noises by approximately 10 dB, with the noise between 500 and 750 Hz being attenuated by about 20 dB. The presence of this noise energy may be an impediment to using signal above 500 Hz.

Signal quality on Profile #1 (101/6-13 to 111/12-13) was good with signal quality generally increasing with decreasing depth. Several of the deepest fans were repeated to provide additional stacking gain. The noise level was observed to have decreased during the repeat acquisition of the deeper fans. Signal was observed over the entire range of sweep frequencies (100 to 1200 Hz).

Signal quality on Profile #2 (101/6-13 to 101/4-13) was good for frequencies below 500 Hz. The lower frequencies observed on the second profile are probably a result of the increased well spacing (580 meters versus 400 meters on Profile #1).

Processing Outline

Reflection imaging was used to detect changes in the interval of interest. Traveltime tomography was used to obtain imaging velocities above the reservoir interval. The wells were plugged above the perforations. Since no crosswell data was recorded in the reservoir interval there were no direct arrival traveltimes from which to compute velocities (see Figure 31). Imaging velocities in the reservoir interval were therefore derived from sonic logs interpolated from wells 121/8-14, 101/02-13 and 111/07-13.

A diagram of reflection coverage for the acquisition geometry is shown (see Figure 32) with the approximate locations of the intervals of interest. The reflection coverage on the interval of interest is below the logging interval for both profiles. Imaging below the logging interval was performed using interpolated sonic logs from adjacent wells while imaging within the logging interval was performed using velocities produced from direct arrival traveltime tomography. Subsequent image refinement was performed through semblance analysis of the unstacked reflection data. The stacking velocities were refined to improve reflection semblance.

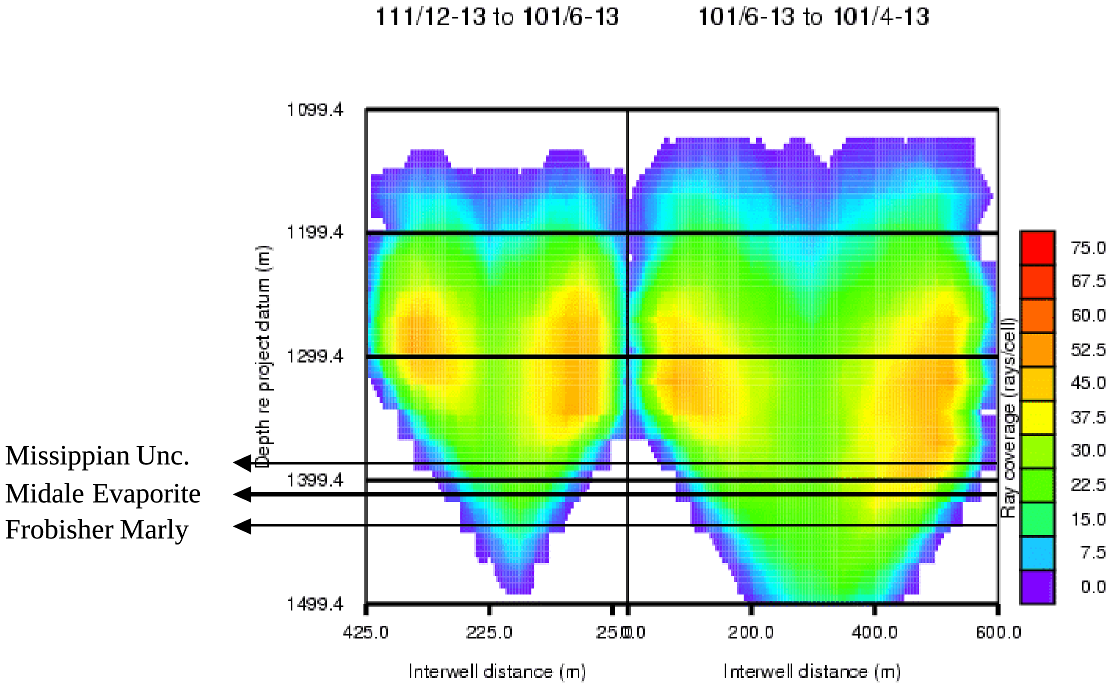

Figure 32 Reflection coverage for crosswell data. Only the reflected arrivals sample the interval of interest.

Processing Flow

A summary of the processing overview is provided below in bullet form.

- Pick direct arrivals and run direct arrival traveltime inversion.
    - Wireline correlation logs were not available in field for depth control. Depth system for processing will be as recorded relative to ground level in well 101/6-13.
    - Band limit data 100 to 500 hertz to eliminate high amplitude noises.
- Prepare velocity models from tomogram results as described above.
- Time/Depth conversion using VSP-CDP transform
    - Images to cover from 1200 to 1500 meters.
    - Evaluate wavefield separation steps using best model.
- Review best reflection stack at this time. Interpret locations of CO_2
- Refine image quality below tomographic coverage as required.

Data Checklist

Following is a list of information provided by EnCana to TomoSeis for processing of this crosswell project.

WELL ID	LOGS	DEPTH RANGE	
101/06-13-006-14W2	GR NEUT	1397-1442 1397-1442	Receiver well, Profiles #1 and #2
101/04-13-006-14W2	GR NEUT	1396-1439 1396-1442	Source well, Profile #2
111/12-13-006-14W2	NONE		Source well Profile #1
101/02-13-006-14W2	GR DT1 DT4P DT4S NEUT	750-1442 1020-1132, 1138-1403, 1407-1417, 1423-1434 1020-1070 1102-1111 1118-1172 1178-1201 1204-1227 1229-1417 1299-1306 1327-1415 1409-1434	 Sonic velocity to use for imaging
111/07-13-006-14W2	DT GR RHOB	1138-1438 1138-1432 1145-1438	Sonic velocity to use for imaging
121/08-14-006-14W2	DT RHOB GR	1136-1428 1139-1431 1400-1424	Sonic velocity to use for imaging
121/12-13-006-14W2	GR NEUT	1383-1414 1383-1414	
121/14-13-006-14W2	GR NEUT	1383-1414 1383-1416	
141/08-13-006-14W2	DT RHOB GR	1140-1438 1395-1434 1395-1434	Sonic velocity to use for imaging
121/02-13-006-14W2	GR RHOB	1400-1430 1223-1437	

Velocity Model Building

One of the initial processing steps was to produce the best model of velocity below the zone logged based on available well log information. This section describes the model building procedure.

Processing Datum

All information used in processing was referenced to a processing datum, which for this project was selected to be ground level elevation of well 101/6-13. Final deliverables can be referenced to any arbitrary elevation.

Baseline model building

The baseline velocity model used to process the crosswell images was constructed from a combination of crosswell velocity observations and sonic velocities in nearby wells. The crosswell survey was conducted entirely above the interval of interest and so a velocity model derived from nearby well control was used to image reflections below direct arrival tomographic coverage.

The following table shows the information input to the model building process. Figure 33 shows the relative well locations at surface. Note: Depth information in the table below is not datum corrected but represents depths as acquired/delivered.

WELL ID	CROSSWELL	SONIC	NEUTRON	FORMATION PICK
111/12-13	to 1290.5 m			no
101/6-13	to 1335 m		1397-1442 m	yes
101/4-13	to 1380.5 m		1396-1442 m	yes
121/14-13			1383-1416 m	yes
121/12-13			1383-1414 m	yes
121/8-14		1136-1428 m		yes
101/2-13				yes
111/7-13		1138-1438 m		yes
121/2-13			1409-1434 m	no
141/8-13		1140-1438 m		no

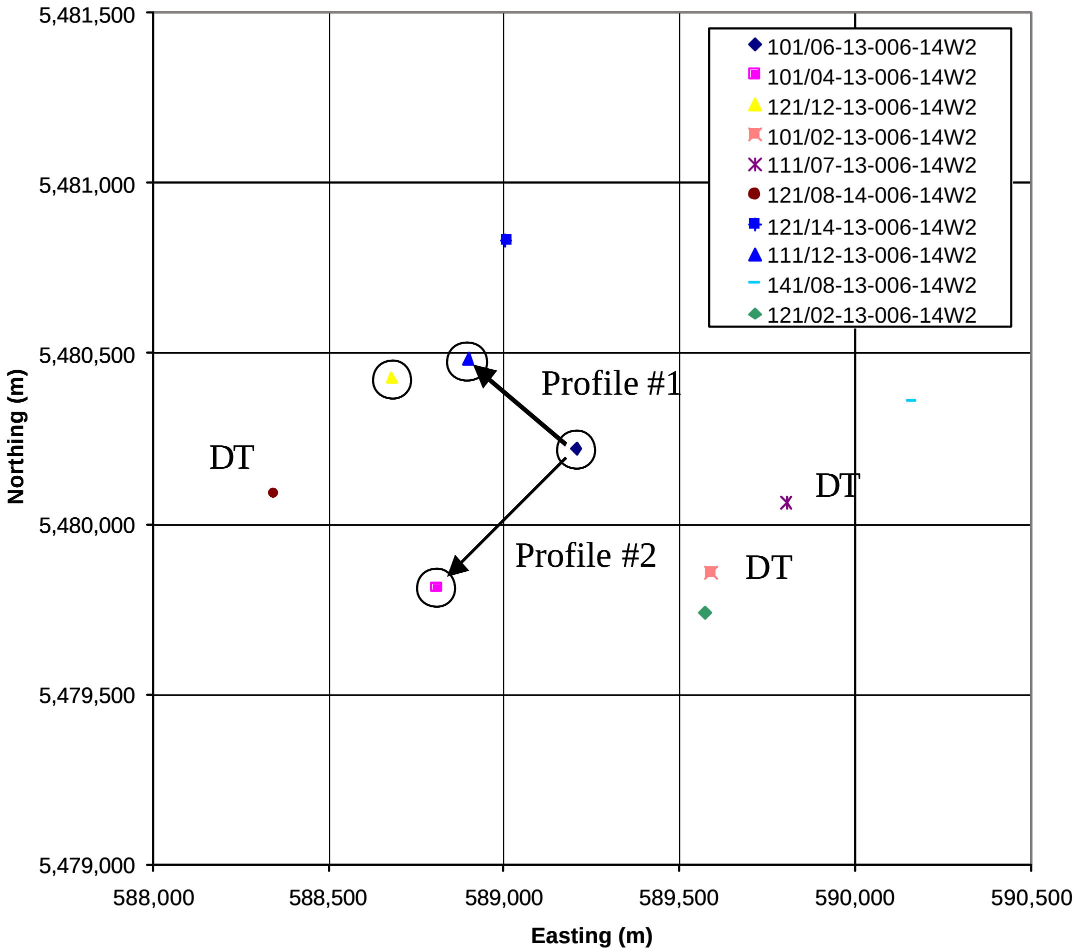

Figure 33. Relative well locations at surface showing locations of crosswell profiles

The procedure used to obtain velocity curves for the wells used in the crosswell survey is described below.

1. A structural model was created using the formation picks provided by EnCana. Model layers were selected to intersect formation picks at the wells with formation picks listed above. See figure 34.
2. A velocity model was constructed based on the structural model created above. Sonic velocities were loaded into the model at the three wells indicated above (121/8-14, 111/7-13 and 141/8-13) and extrapolated along models layers to populate the entire model.
3. Velocity curves were then extracted from the global velocity model at the wells used in the crosswell survey (111/12-13, 101/6-13, 101/4-13).
4. A revised structural model was constructed using formation picks from wells 121/12-13, 101/6-13 and 101/4-13. Picks from 121/12-13 were used, as picks for well 111/12-13 were unavailable. The structural model was updated from step 1 to provide more planar surfaces in the structural model. Variations in depth and thickness of picked intervals resulted in curved surfaces in step 1. This is acceptable for

extrapolating the velocity logs to adjacent well but was not thought to represent the structure in the region. See figure 35.

5. Velocities extracted from the model of step 2 were then used to populate the new structural model of step 4

Figure 36 shows the resulting velocity model for each of the crosswell profiles.

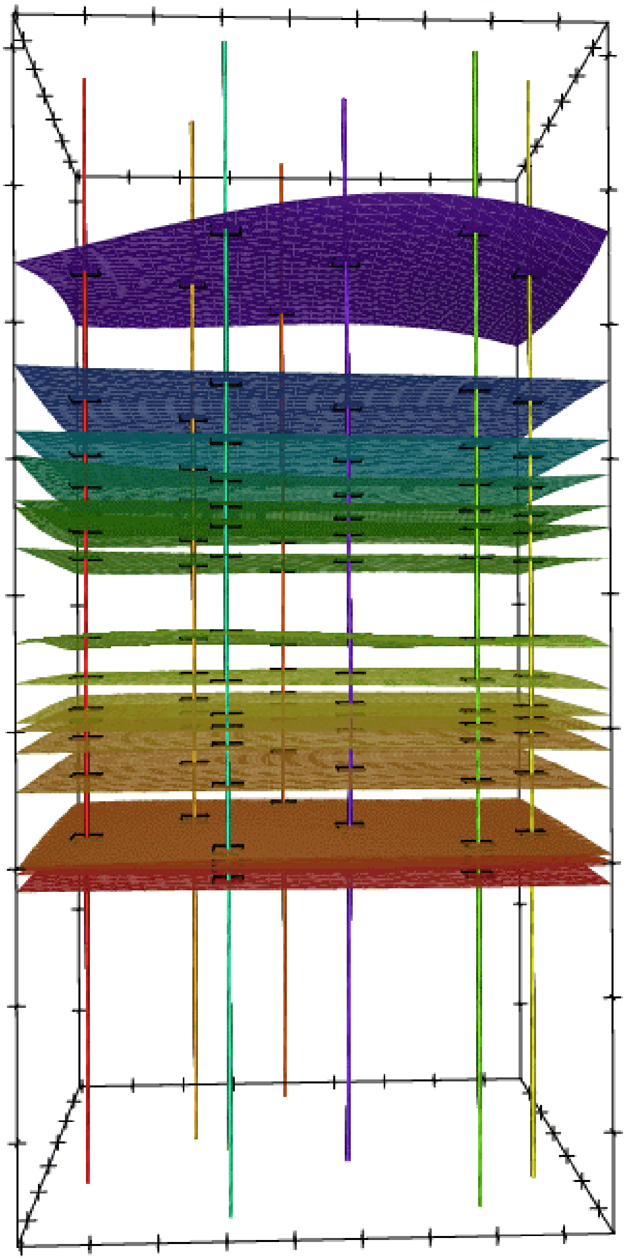

Figure 34. Structural model of all formation picks available from wells of Figure 33. Note curvature of surfaces required to fit all formation picks. These surfaces will be refit using only the wells circled in Figure 33 for the baseline velocity model.

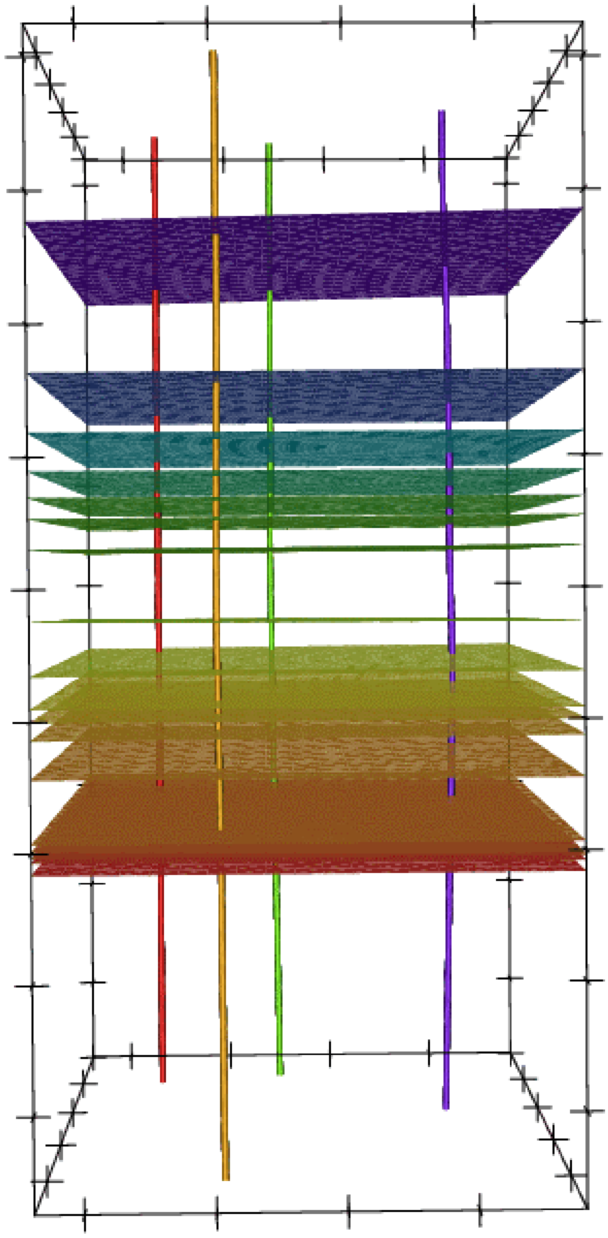

Figure 35. Structural model revised to include only picks from the crosswell observation wells and one other nearby well. This was done to remove unwanted curvature from the surfaces in the structural model

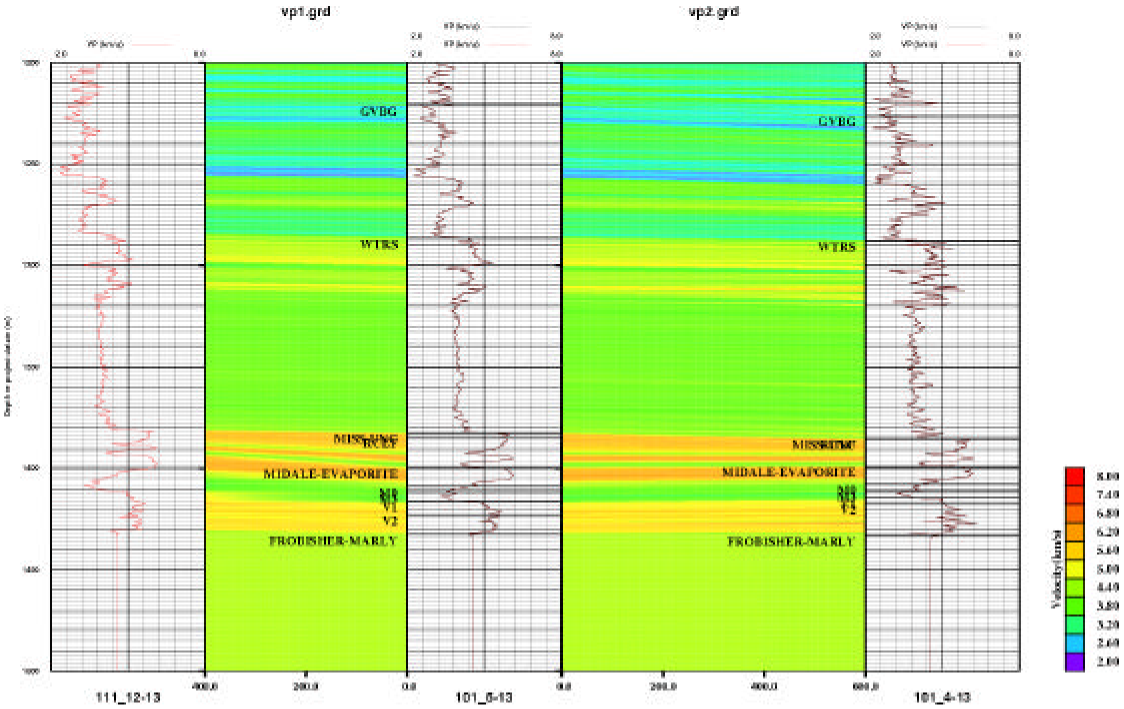

Figure 36. Baseline structural model derived from nearby sonic logs. This figure shows a velocity profile for each crosswell profile as well as velocities for the profile 111/12-13 to 101/4-13 which was not recorded.

Depth corrections

The crosswell data were recorded on a depth system relative to ground level at each wellhead. Our standard operating procedure is to adjust all wireline depths to match client provided logs before correcting to a common datum. In this case there were no GR/CCL logs available over the intervals where crosswell data were acquired. The depth correlation process was done by comparing the TomoSeis GR/CCL to the pseudo velocity logs created for the baseline model (Figure 36). Since the pseudo velocity logs of Figure 36 are already corrected to the processing datum the TomoSeis GR/CCL curves only need to be shifted to tie the pseudo velocity curves. This same shift applied to the crosswell data will depth correct the seismic traces to measured depths relative to processing datum.

Figure 37 shows the pseudo velocity curves along with un-corrected TomoSeis GR curves. The GR curves tie the pseudo velocity curves very well for both the 101/6-13 (-2 m shift) and 101/4-13 (0 m shift). The depth correlation on the 111/12-13 well is much worse. (-10 m shift).

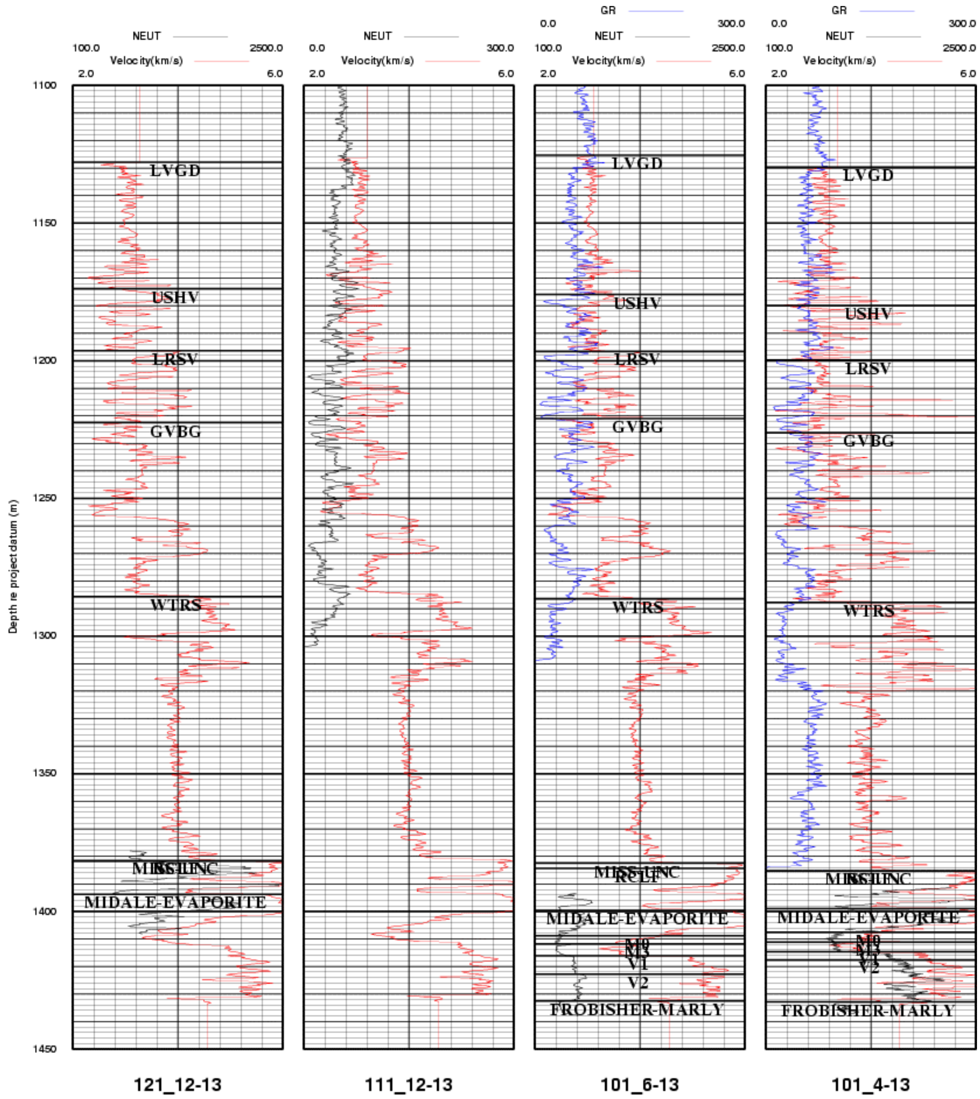

Figure 37. TomoSeis GR logs plotted with pseudo velocity curves of baseline velocity model. All data except the GR curves of this display are corrected to processing datum. Correcting the GR curves to match this data will yield the depth shifts required to put the crosswell data on the same depth system.

Figure 38 shows the same data with the above-mentioned depth shifts applied to GR curves. The depth correlation is now good at each well.

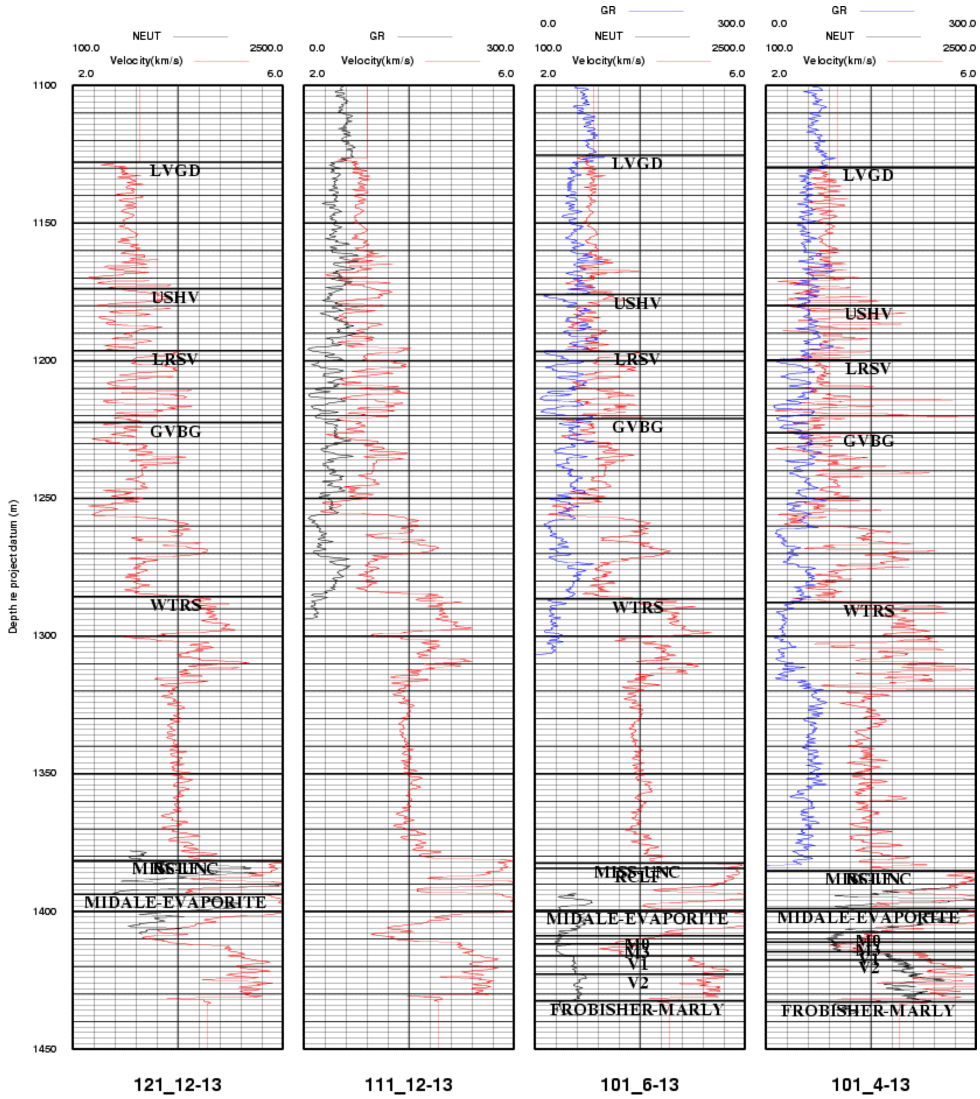

Figure 38. ***GR curves have been corrected for depth shifts between pseudo velocity curves of baseline model. Crosswell data will be similarly shifted in depth before processing.***

Direct Arrival Tomography

The initial velocity model for reflection imaging was a hybrid of the model described in the velocity model building section above and the results of a direct arrival tomographic inversion.

Step 1: 3D Anisotropic Traveltime Inversion

This section describes the traveltime inversion process for the project. See Appendix A for further details on the 3-D anisotropic method.

First arrival identification

Data was prepared for *P*-wave first break identification by:

1. Noise editing in the field (during acquisition
2. Cross-correlation with the recorded source sweep (200-1200 Hz).
3. Stacked to 3 meters source spacing.
4. Datum to project datum .
5. Stacked to 3 meters source and receiver spacing.

P-wave first arrivals were identified and picked in four domains:

- Common receiver.
- Common source.
- Common offset (receiver depth – source depth).
- Common mid-depth (receiver depth + source depth)/2.

Summary description

Accurate spatial positioning is important for processing of the high frequency crosswell data. The 3-D anisotropic travel-time tomography algorithm operates in a rectangular coordinate system with the vertical axis being TVD (true vertical depth). Velocity image values are positioned in the rectangular depth coordinate system. The velocity image is derived using the following input information:

1. *P*-wave direct arrival traveltimes as picked from the data.
2. Receiver and source locations. Without precise well positioning information the resulting velocity model can be used in the VSP-CDP mapping procedure, but the velocities values are not calibrated (distance is not accurately known) and therefore not reliable as absolute values.
3. Structural model. The same structural model described in the model building section above was used.

The starting model is then ray traced and traveltimes are calculated (see example in Figure 39). The calculated traveltimes are compared with the measured travel-times and the starting model is updated through non-linear continuation steps to minimize the travel-time residuals (difference between the *P*-wave first arrival picks and calculated travel-times).

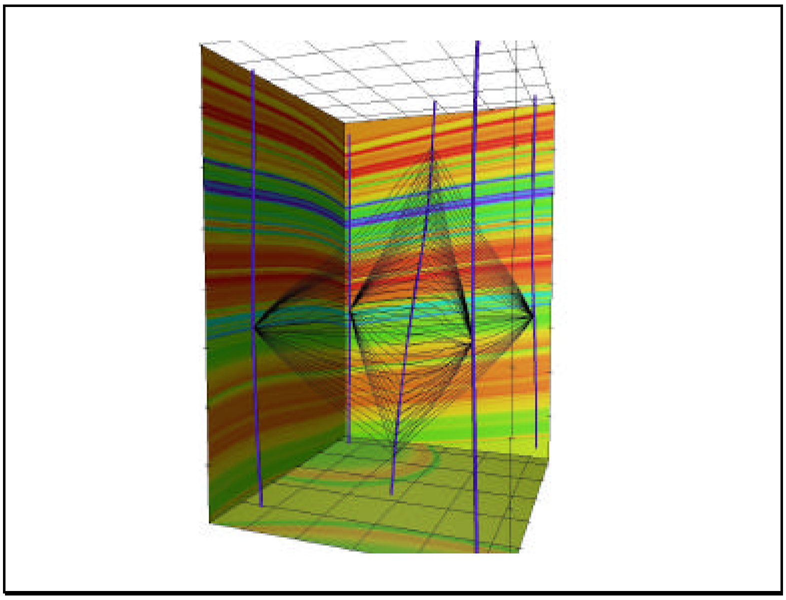

Figure 39. A general example of a velocity model showing multiple raypaths over which the traveltimes are calculated. This example shows multiple source and receiver well pairs.

The final direct arrival only inversion results (velocity models) are shown in the next section in the overlay plots with the initial imaging results.

Reflection Imaging Procedure

For a detailed description of reflection imaging processes please see Appendix B. Figure 40 is a flowchart of the steps involved in crosswell seismic data processing for reflection imaging.

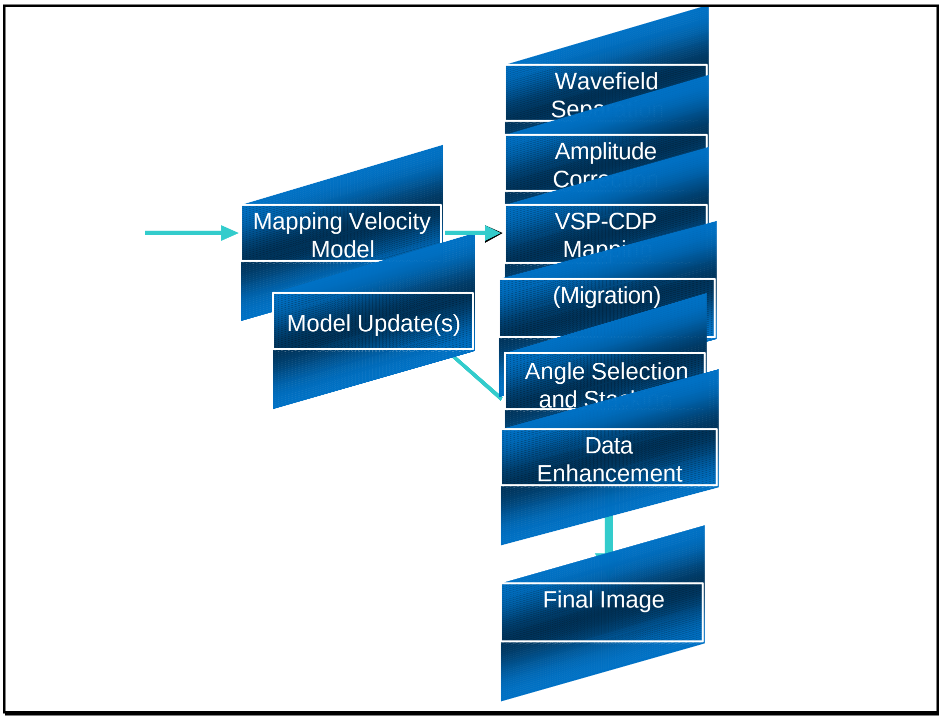

Figure 40. Reflection imaging flow chart.

In crosswell data there are many arrivals present in the wavefield. Direct arrival, *P* and *S* reflections from below (upgoing) and above (downgoing) the receiver, as well as various converted modes and tube waves. For reflection imaging of the reservoir interval the objective was to use the upgoing *P*-wave reflections. All arrivals in the wavefield that contribute coherent noise to the final stacked image are removed through spatial filtering.

Wavefield Separation

Prior to transforming the time domain data into a data volume in depth, the time domain data are filtered to remove coherent modes (which do not stack out of the final image) other than upgoing reflection energy. The unwanted modes are attenuated using spatial filters, usually *f-k* fan filters or variations on median filters, applied in common-receiver (CRG), source (CSG), and offset (COG) gathers.

The general approach is to filter the largest noise mode from the data first. This result is evaluated by mapping and stacking and the next largest noise mode is then removed. This procedure is repeated until all separable noise modes have been attenuated. The final step is to remove the unwanted reflection energy. In the case of upgoing reflection imaging those are the downgoing reflections. This is typically done as the last time domain filter before mapping. The filter used to remove downgoing reflections was a half-space *f-k* fan filter applied in CRG followed by CSG. These filtered data are then amplitude corrected and mapped to depth using a VSP-CDP transform.

VSP-CDP Mapping/Time-Depth conversion

The wavefield-separated data were VSP-CDP depth mapped, as in offset VSP data processing. The velocity model from the traveltime inversion and model building is used in tracing reflection raypaths.

The VSP-CDP mapped data set is a 3-D data cube as shown in Figure 41 with mid-depth and offset (distance between the two wells) as the two domains. Individual depth mapped mid-depth gathers were reviewed and compared to the time domain data to ensure that the stacked image contained only events with reflection moveouts.

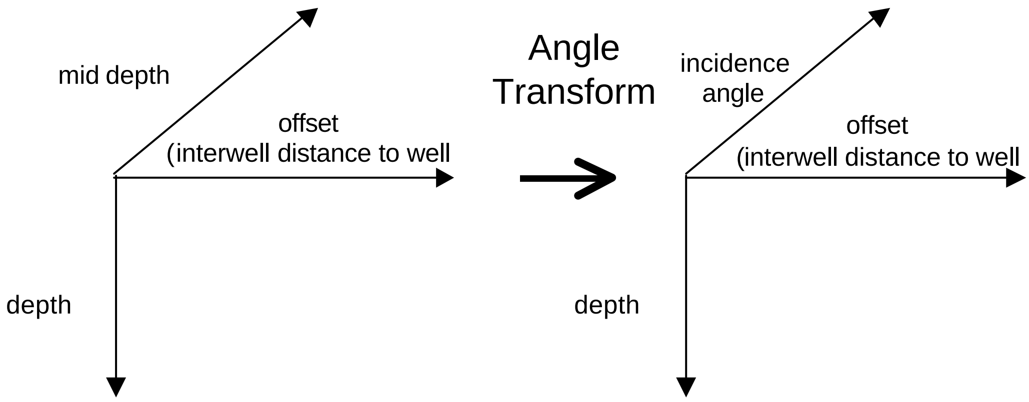

Figure 41. Schematic of the angle transform.

Angle Selection and Stacking

Since there are a wide range of incidence angles present on a crosswell data set and the wavelet and reflection character change with incidence angle, another natural domain for data analysis is the angle-transformed AVA data cube shown in Figure 41

Migration

Post CDP-mapping pre-stack migration was applied to the resulting gathers from VSP-CDP mapping of time-domain mid-depth gathers. For a full description of the crosswell migration applied see Appendix B.

Reflection Imaging with the Initial Model

Processing Datum

All information used in processing are referenced to a processing datum, which for this project has been selected to be ground level elevation of well 101/6-13. Final deliverables can be referenced to any arbitrary elevation.

Preliminary Reflection Image – Profile #1

The reflection image shown in Figure 42 is the result of reflection imaging with the initial model. The image was produced with the following approach

1. Velocity model used is a velocity tomogram supplemented with baseline model below tomographic coverage. Color background of Figure 42 is the velocity model.
2. Depth system is as described above. Depth correlation as describe in previous email (TomoSeis GR correlated to Encana DT curves).
3. Minimal wavefield separation consisting of tube wave removal, downgoing wavefield removal and band-pass filter.
4. Stack over straight ray incidence angles 55 to 65 degrees.

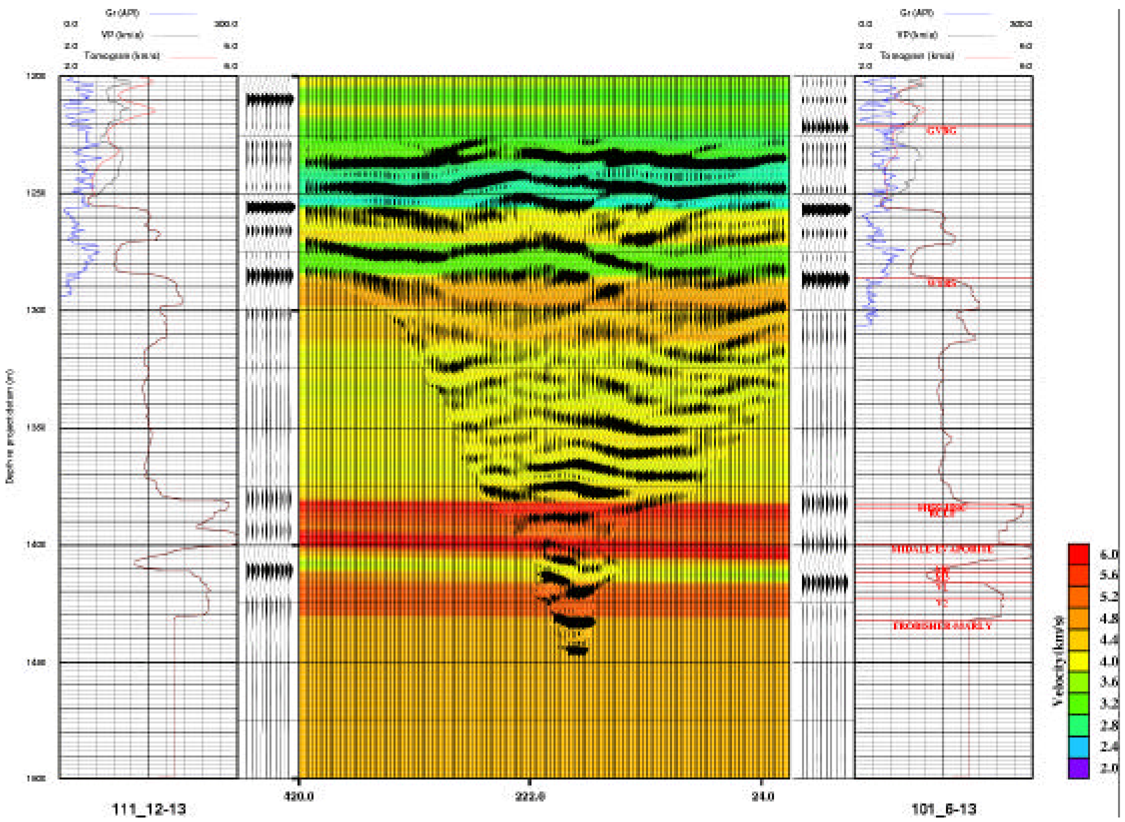

Figure 42. Preliminary reflection image with mapping model overlaid in color. Note the pull up of the strong reflection events positioned at about 1248 meters. This is most likely due to velocity errors present in the mapping model.

The two most noticeable features of this image are the "pull-up" of the reflection event at about 1248 meters, and the apparent mispositioning in depth of this same event where it intersects the wells. Possible causes for these features and recommended solutions are discussed below.

Velocity Errors

The "pull-up" of the shallowest reflection horizon is most likely caused by error in the velocity model used for time/depth conversion. Figure 43 shows the coverage of the direct arrival tomography overlaid on the reflection stack of Figure 42. There is good correlation between the reflector "pull-up" and the decreased direct arrival coverage in the center of the image.

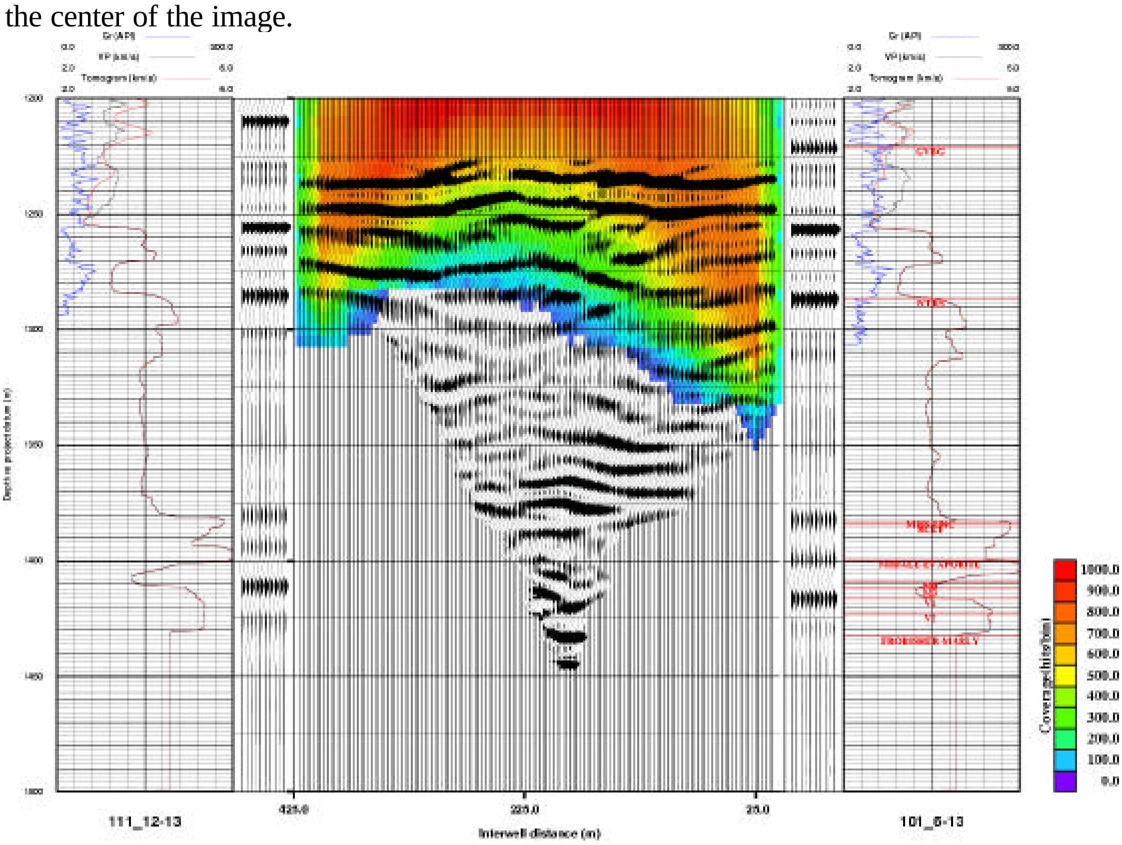

Figure 43. Preliminary reflection image with direct arrival tomogram coverage overlaid in color. Note the correlation between the low coverage interval in the center of the image and the reflector "pull-up". Reflection tomography may be required to improve the velocity model used for time/depth conversion in the imaging process.

Apparent Depth Errors

The synthetic seismograms plotted between the log tracks and the reflection section appear be off depth with the reflection section. Given we suspect errors in the velocity model this can be expected.

In crosswell data the depth of a reflector can be determined from the field records by noting the depth at which the direct and reflected arrivals intersect. When imaging the reflection energy from crosswell data the imaged reflector depth becomes a function of the velocity model. The reflector depth is determined by the intersection of the reflected energy in the wavefield and the direct arrival time predicted by the velocity model.

Figure 44 shows a cartoon of a common mid-depth gather. The black curve shows the actual direct/reflected arrival times. The red curves represent time predicted by a velocity model that is too fast producing times that are too early. The blue curve shows predicted times through a velocity model that is too slow producing times that are too late. When imaging the actual data the blue model would position the actual reflector too shallow while the red model would position the reflector too deep. Note also that with the red model the reflection horizon would not actually extend to the well due to the absence of reflection energy beyond the true direct arrival time.

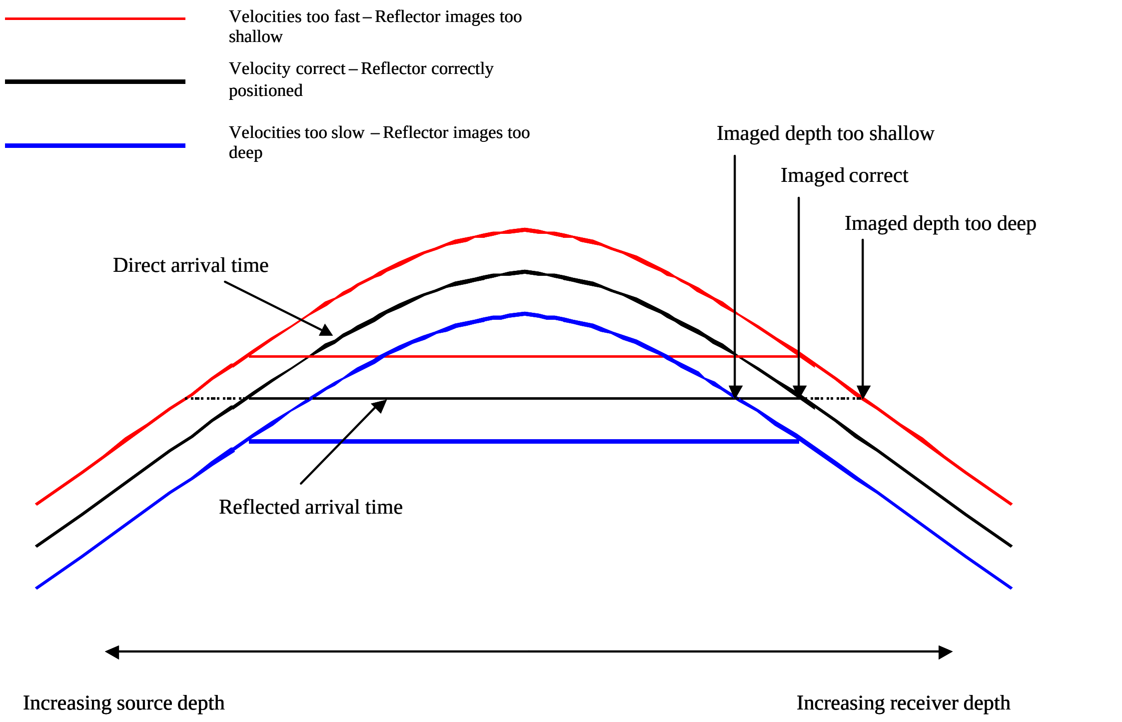

Figure 44. Cartoon showing depth errors at the wells for a common mid-depth gather (average of source and receiver depths are constant.) The actual reflector time/depth is determined from the black curve. The blue (too slow velocity model) and red (too fast velocity model) will misposition the reflector in depth at the wells.

Reflection Tomography

Reflection tomography uses the travel times of reflected energy to augment tomographic coverage below the logging interval. In intervals where the direct and reflected travel times overlap the vertical and lateral resolution of the velocity function can be improved. This improvement should allow improved estimates of velocity above about 1300 meters.

In intervals where only reflected traveltime information are available the vertical resolution will be a function of the number of reflecting horizons for which travel time data can be picked. Several events occur deeper in the section (between 1350 and 1400 meters in Figure 1) that should allow reflected events to be picked for reflection tomography below direct arrival coverage.

The reflected energy below direct arrival coverage will be assumed to conform to the structural model and occur at a known depth. The reflection tomography process will endeavor to solve for the velocity function that positions the reflecting horizon at the specified depth. This is a fundamental departure from the methodology discussed in the original processing plan. Travel paths affected by the presence of CO_2 will now be detected by velocity anomalies produced in the reflection tomogram. Reflector geometry will be largely determined by the assumed baseline structural model.

Since reflection tomography was a new tool at TomoSeis we proposed a two-part approach to its application at Weyburn. Part I involved applying the technique to a synthetic data set developed for this purpose. During this process learned how to parameterize the inversion to optimize the resulting imaging velocity model. Following the completion of the synthetic work we began using velocities derived through application of reflection tomography on Profile #1. Finally, Profile #2 was processed employing the lessons learned from the modeling and Profile #1.

Synthetic Analysis

Reflection tomography has the potential to improve the quality of velocity information in low direct arrival coverage regions by augmenting coverage with observations of reflection times. In addition, reflected energy is the only information available in cross well data that can interrogate intervals that are below the interval logged in the observation wells.

The reflection tomography algorithm used by TomoSeis was run on a synthetic data set to characterize its performance prior to its application to the Weyburn Vertical well cross well data.

Synthetic Data

A velocity model was created with several velocity contrasts with varying lateral extent. The velocity function was forward modeled for direct and reflected arrival times using the same ray tracer employed in the inversion routines. Velocity contrasts were approximately 25 percent

Tomography

A direct arrival tomogram was produced using the direct arrival (DA) times produced by forward modeling. Figure 45 shows the actual velocity model (a), the DA tomogram (c) and the difference between the two (b). The red line across the sections shows the maximum depth for which DA observations were computed, or 300 meters. This would be analogous to a cross well project where the interval of interest occurred at or near well TD. Note the large negative velocity difference in the center of the difference image. This occurs in a zone of low coverage.

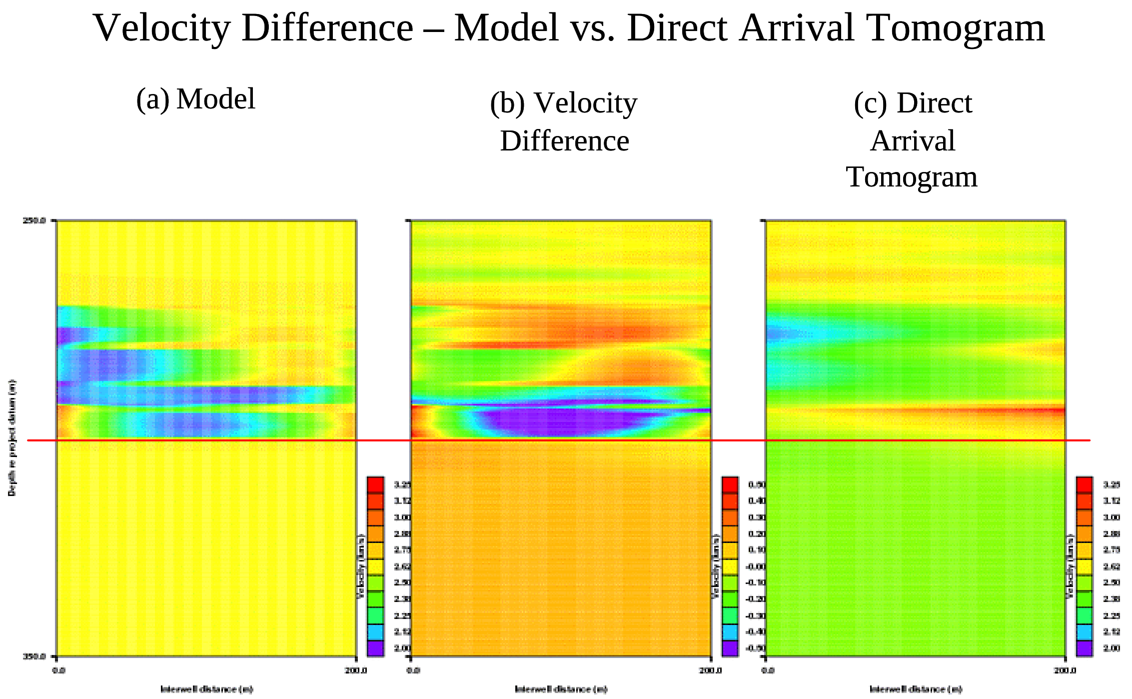

Figure 45. Direct arrival tomography results from synthetic.

The reflection tomography was conducted using the same direct arrival observations employed in the DA only inversion with the addition of reflection times from a horizon at 300 meters. Figure 46 shows the actual velocity model (a), the DA/Reflection tomogram (c) and the difference between the two (b). Again the red line shows the maximum depth for which DA observations were included. The reflection times used in the tomography were for a reflector at 300 meters. Note the greatly reduced difference in the center of the difference image.

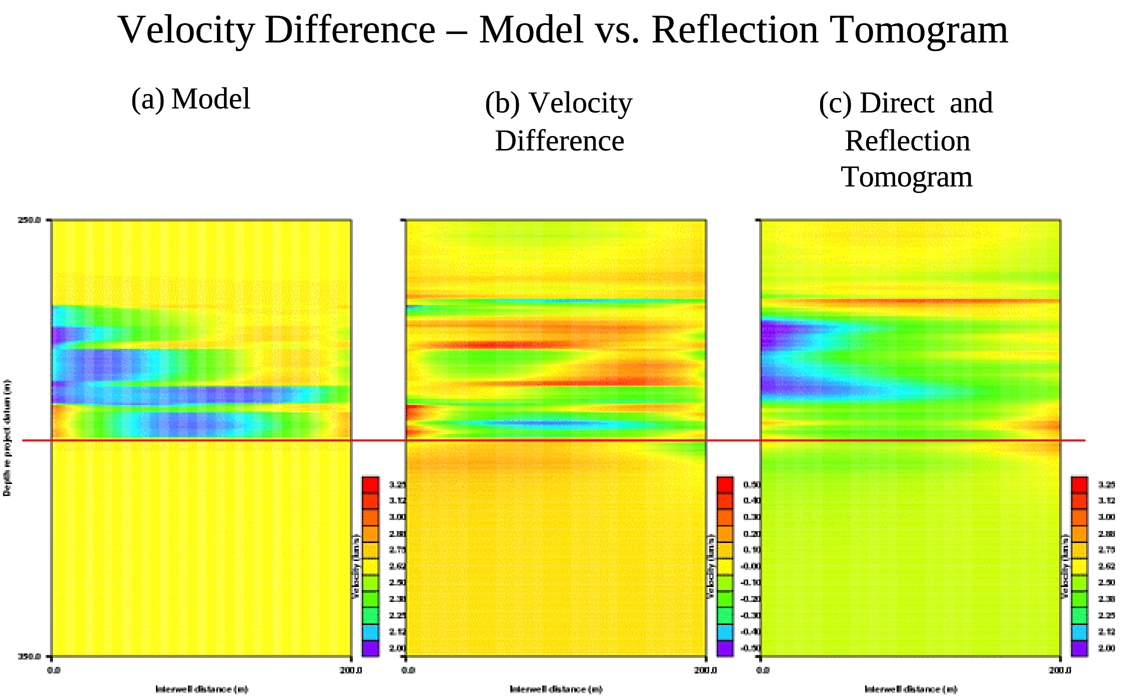

Figure 46. Reflection tomography results using synthetic data.

Another measure of inversion performance is a comparison of actual reflection times to reflection times predicted by ray tracing the tomogram. Figure 47 shows this comparison for (a) the DA tomogram and (b) the DA/Reflection tomogram. The squares in Figure 47 show travel time differences for each source/receiver pair that has an upcoming reflection on a reflecting horizon at 300 meters. The source/receiver positions between the black diagonal lines are those reflection observations that were used in the reflection tomogram. An obvious reduction in the time differences has occurred between the two results indicating an improvement in the velocity model. For the observations with the diagonal lines the time difference was reduced from 2.49 to 0.46 milliseconds RMS.

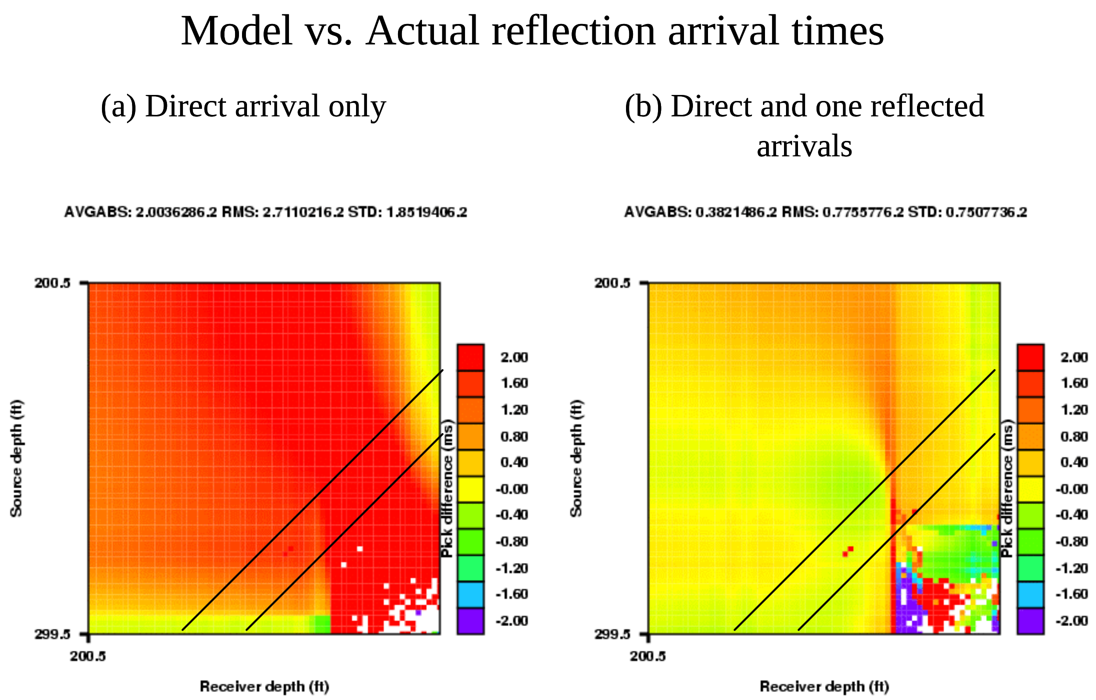

Figure 47. Traveltime residual comparison for direct arrival tomography and direct/reflection tomography.

Reflection Tomography Iteration

A variety of reflection tomography strategies were used to attempt to image 150 meters below the deepest depth logged. A number of issues made the task difficult including:

- Lack of coverage. Below the deepest depth logged, coverage in the crosswell geometry is no longer well-to-well, making tying a seismic event to a log event an interpretive call.
- Lack of sonic and density logs. The lack of sonic and density logs in the wells in which crosswell was conducted made it difficult to determine the expected character of the crosswell at the wells, further enhancing the difficulty of tying the seismic events at the well.
- Low SNR especially on Profile #2 made reflection picking in unstacked data sometimes difficult
- Lack of experience in applying reflection tomography in cases where the reservoir was well below the deepest depth logged.

The final imaging results for the 2 profiles together with well log control are shown in Figures 48 and 49.

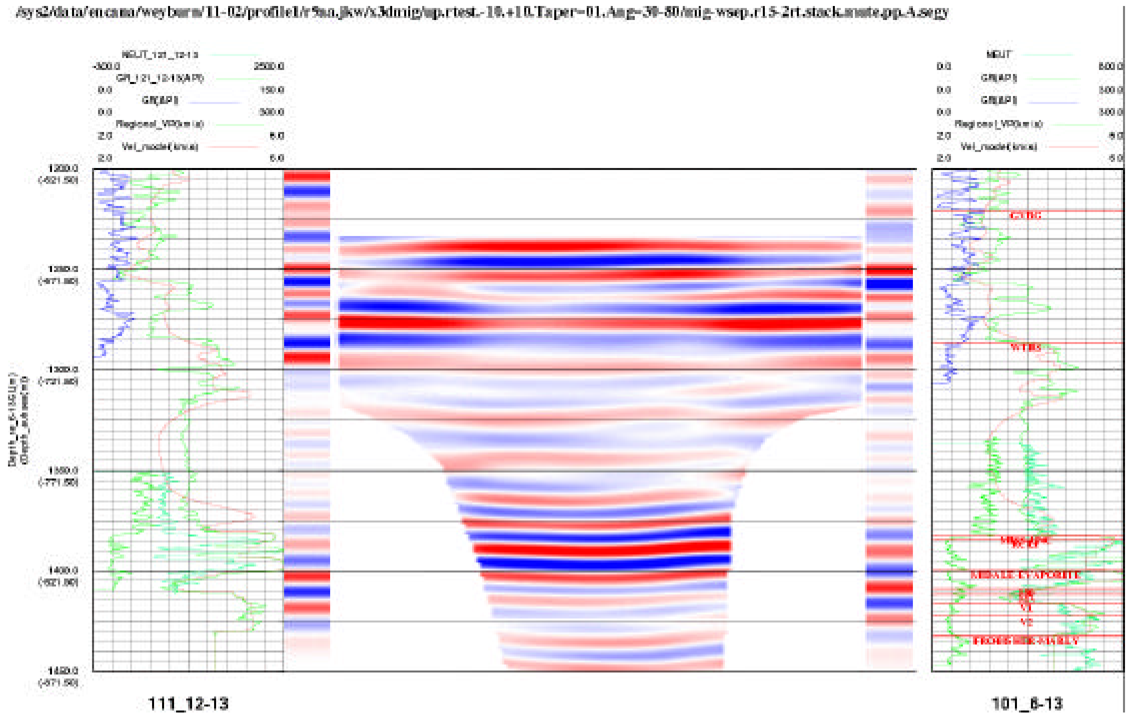

Figure 48. Final reflection image for profile 101/6-13—111/12-13.

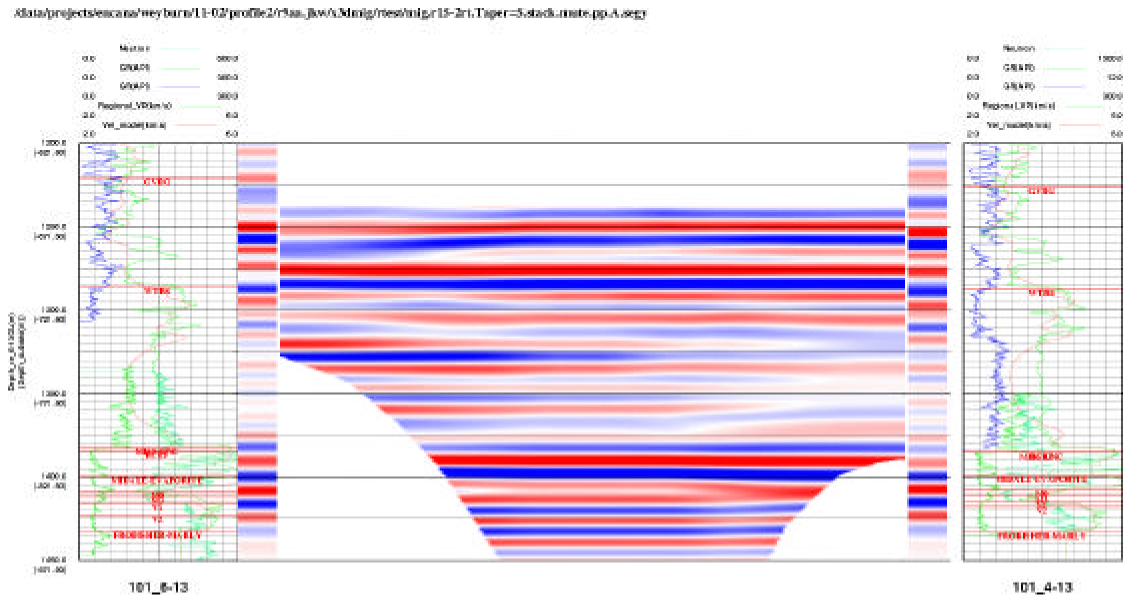

Figure 49. Final reflection image for Profile 101/6-13—101/4-13.

The nature of the reflection tomography iterations is illustrated in Figures 50-52. When a given model was imaged, the resulting event placements were associated to a well depth, the reflection traveltimes of these horizons were picked and a new model was produced using reflection tomography. The difficulties in tying to the well described above are easily seen in these figures.

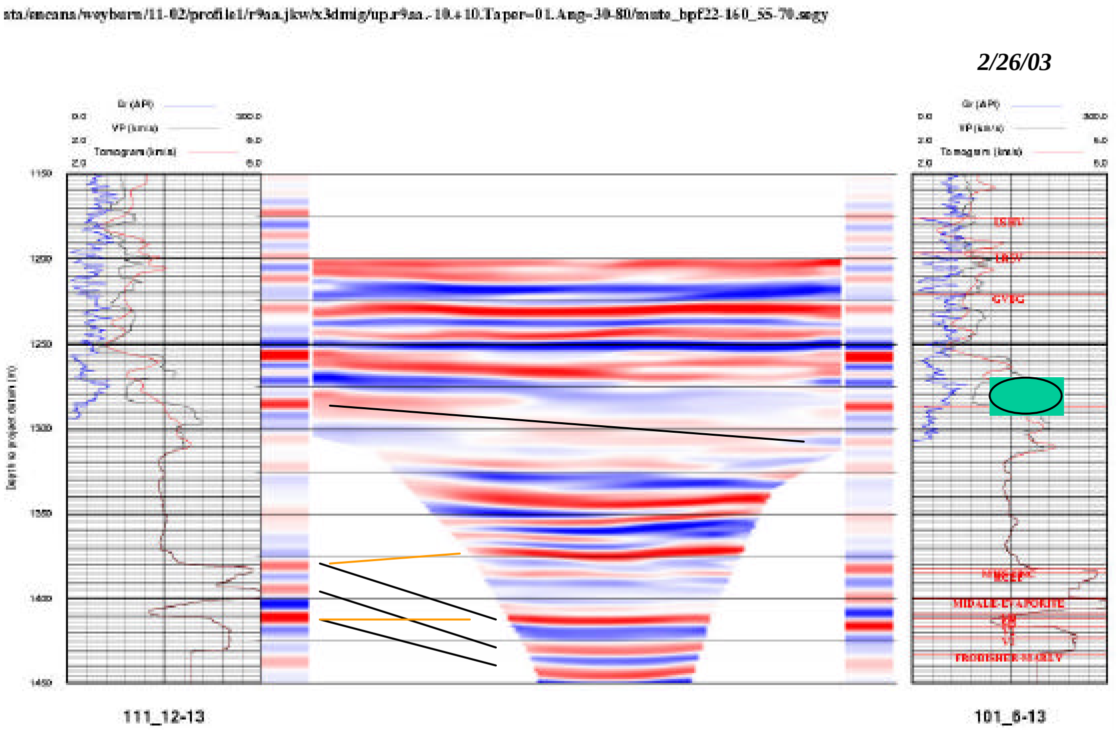

Figure 50. The image from an interim model showing the hypothesized event tie. Note that synthetics are produced from the regional velocity model and not from well logs from these 2 wells.

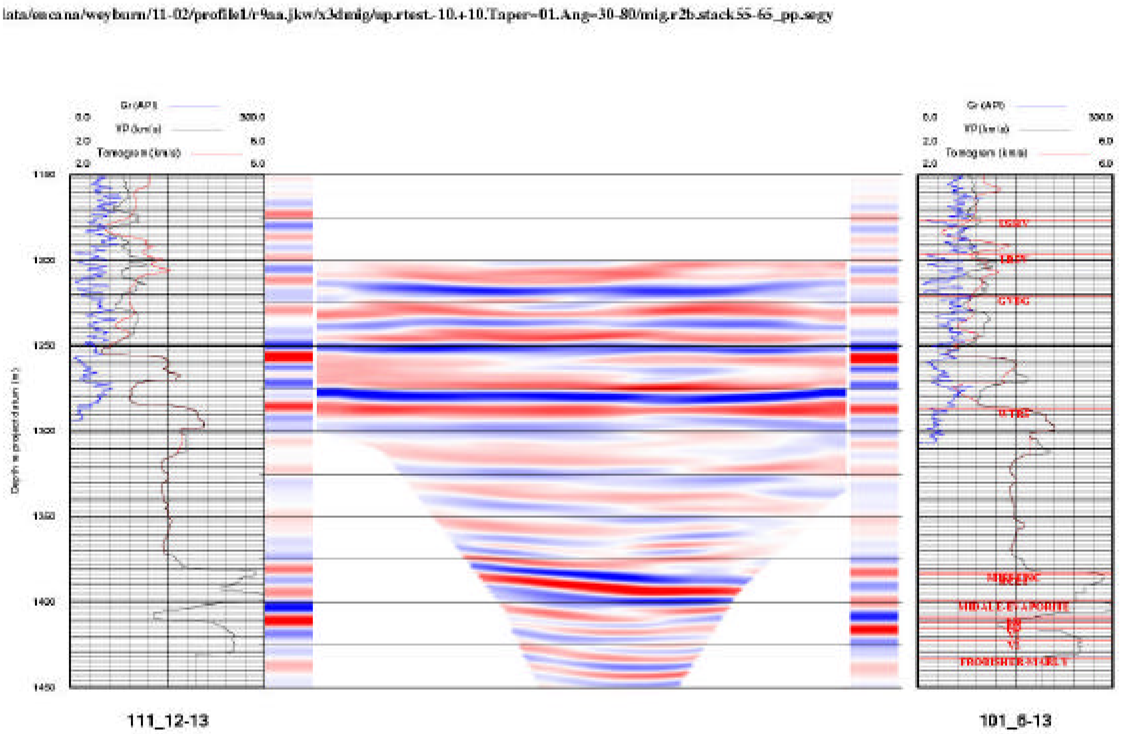

Figure 51. The velocity model after picking the events and tie as shown in Figure 50.

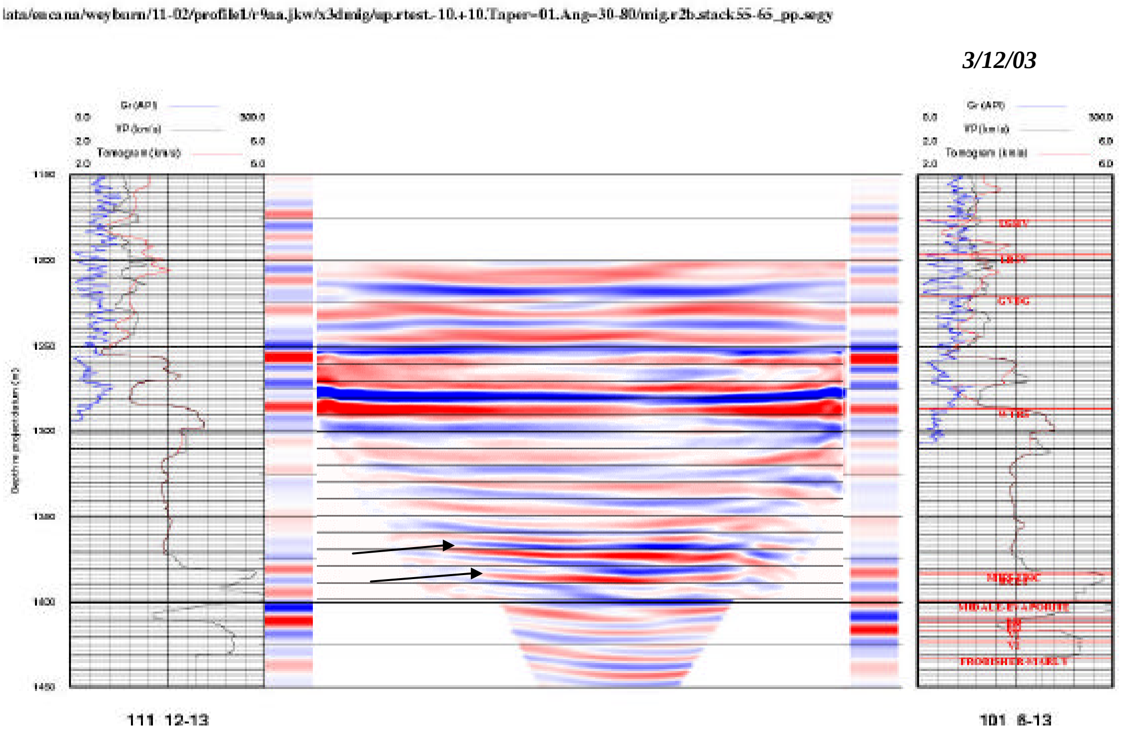

Figure 52. Event character changes in an additional iteration from Figure 51, making a different event tie seem possible.

Results and Conclusions

The final images were inconclusive in their ability to deliver the high-resolution answer needed. The decision to not open the 101/6-13 well deeper limited the crosswell coverage and, therefore, the overall utility of the survey. In addition to the limited coverage, which likely meant any flow barrier to the CO_2 might have existed outside of the image zone covered, a number of issues also made the imaging task difficult. A variety of reflection tomography strategies were used to attempt to image 150 meters below the deepest depth logged. The issues that added to the complexity of the imaging test included:

- Lack of coverage. Below the deepest depth logged, coverage in the crosswell geometry is no longer well-to-well, making tying a seismic event to a log event an interpretive call.
- Lack of sonic and density logs. The lack of sonic and density logs in the wells in which crosswell was conducted made it difficult to determine the expected character of the crosswell at the wells, further enhancing the difficulty of tying the seismic events at the well.
- Low SNR especially on Profile #2 made reflection picking in unstacked data sometimes difficult
- Lack of experience in applying reflection tomography in cases where the reservoir was well below the deepest depth logged.

Reflection tomography is relatively new in crosswell data processing. Much has been learned in the year since the processing reported here was concluded. Crosswell processing of data from Christina Lake has made excellent use of reflection tomography in eliminating the need to log below the base of the target McMurray reservoir formation. Reflection and direct arrival hybrid tomography provides a high coverage velocity model to the depth logged and has enhanced image quality and confidence in time-lapse, velocity–based images of steam. Each new project where reflection tomography is applied adds to our base of knowledge.

Appendix A – Tomographic Inversion

Appendix B – Reflection Imaging

Appendix C – Anisotropic Processing

Crosswell Methods and Glossary