Four-D seismic monitoring: Blackfoot reservoir feasibility

Laurence R. Bentley, John Zhang and Han-xing Lu

ABSTRACT

The Blackfoot reservoir has been analysed to determine the feasibility of monitoring changes in reservoir conditions using time-lapse seismic monitoring (four-D seismic monitoring). The results indicate that the change in the seismic response will be mild to moderate, depending on the assumptions of the fluid distribution. The largest difference in a difference section created from the 1997 2D-3C seismic survey and a contiguous line extracted from the 1995 3D-3C data volume is found to be in the Blackfoot reservoir zone. The difference results are consistent with mild to moderate changes in the seismic response. The results indicate that water flood areas should have observably different changes in seismic response than the non-water flood areas.

INTRODUCTION

The Blackfoot reservoir is located southeast of Calgary. In the following, we investigate the potential for using four-D seismic surveys to infer changes in the pressure and fluid distribution within the reservoir due to production and injection. The goal of four-D surveys is to provide information useful to reservoir engineers in their production decisions. Since the Blackfoot reservoir is a representative of the glauconitic incised-valley system, the study also provides useful information as to the value of conducting four-D surveys over an important class of Alberta hydrocarbon reservoirs.

The Blackfoot reservoir is an incised channel filled with porous cemented sand. In the area of interest (Figure 1), the reservoir consists of three cross cutting channels at an approximate depth of 1550 m below ground level (Dufour, et al., 1999). From top to bottom they are the upper channel, the lithic channel and the lower channel (Figure 2). The lithic channel is more cemented and pressure data indicate that it is a hydraulic barrier between the upper and lower channels. At the location of well 09-08, the thickness of the layers are approximately 25 m, 5 m and 12 m for the upper, lithic and lower channels, respectively. The average porosity of the producing pools is approximately 0.20. The area of interest appears to be isolated from other reservoirs in the channel system by shale plugs to the north and south.

EXPLORATION AND PRODUCTION HISTORY

The first three-D seismic survey was conducted over the area in 1993. Subsequently, the discovery well 09-08 was drilled and it was first tested on August 31, 1994. The original pressure in the reservoir was 11,770 KPa. The interpretation is that the upper channel contained an oil leg of approximately 9 m underlying a gas cap of 16 m. The lower channel was interpreted as oil filled. Subsequently wells 08-08, 00/09-08, 02/09-08 01-08, 16-05 and 09-05 were put on production. In December, 1994 the gas oil ratio (GOR) began to rise rapidly, indicating that the bubble point had been reached. Consequently, water injection was started in 08-08 in August, 1995 with 00/09-08, 02/09-08 and 01-08 continuing as production wells.

In November of 1995, a 3D-3C seismic survey was completed over the area (Yang et al., 1996). At this time the pressure in the upper pool was 11,474 KPa, but the lower pool pressure had been reduced to 8,722.1 KPa. As production and injection continued, the upper pool maintained its pressure and the lower pool continued to decline in pressure. Water breakthrough was not observed at the producing wells. Finally, a two-D seismic line was shot through the location of 09-08 in 1997 (Stewart, et al., 1997). By September 28, 1998, the pressure in the lower pool had declined to 6,046 KPa while the upper pool maintained a pressure of approximately 11,200 KPa.

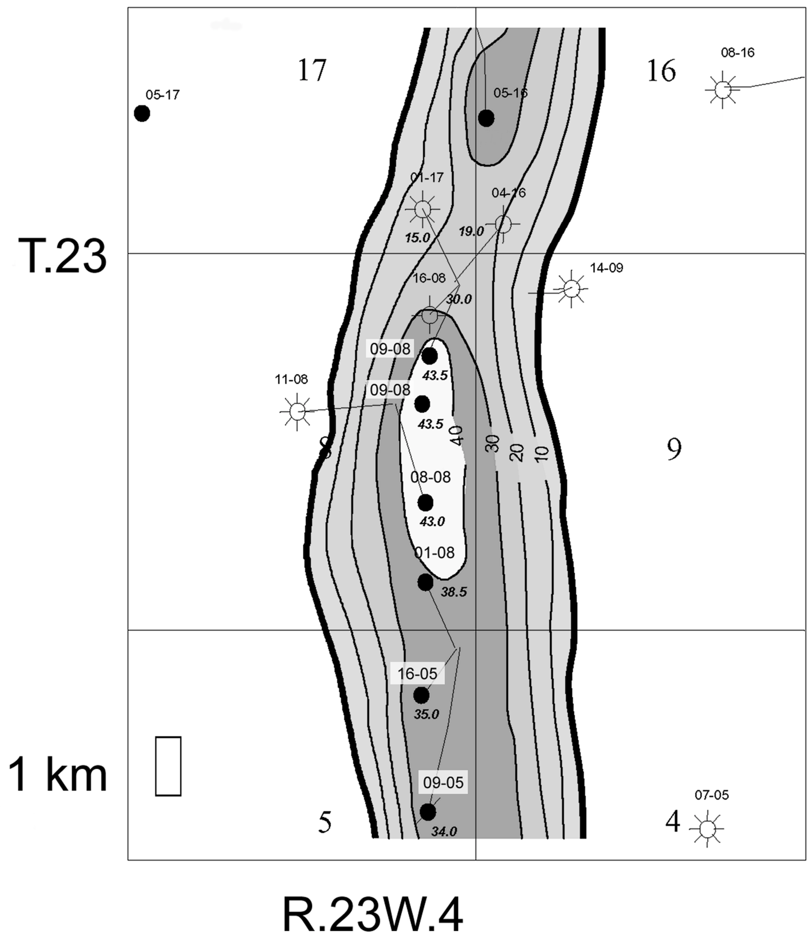


Figure 1. Blackfoot Reservoir Isopach (Courtesy of J. Dufour, PanCanadian Petroleum).

PROCEDURE

The procedure described by Bentley, et al. (1999A) is used to evaluate the predicted change in seismic response. The bulk modulus and density of the formation gas, oil and water are required in order to calculate the fluid bulk modulus and density.

Reservoir Conditions

The reservoir temperature was measured at 45.9°C and was assumed constant during production. Original reservoir pressure was 11,830 KPa. The pressures in the upper and lower pools evolved during production, and were set according to the best estimates obtained from DST tests.

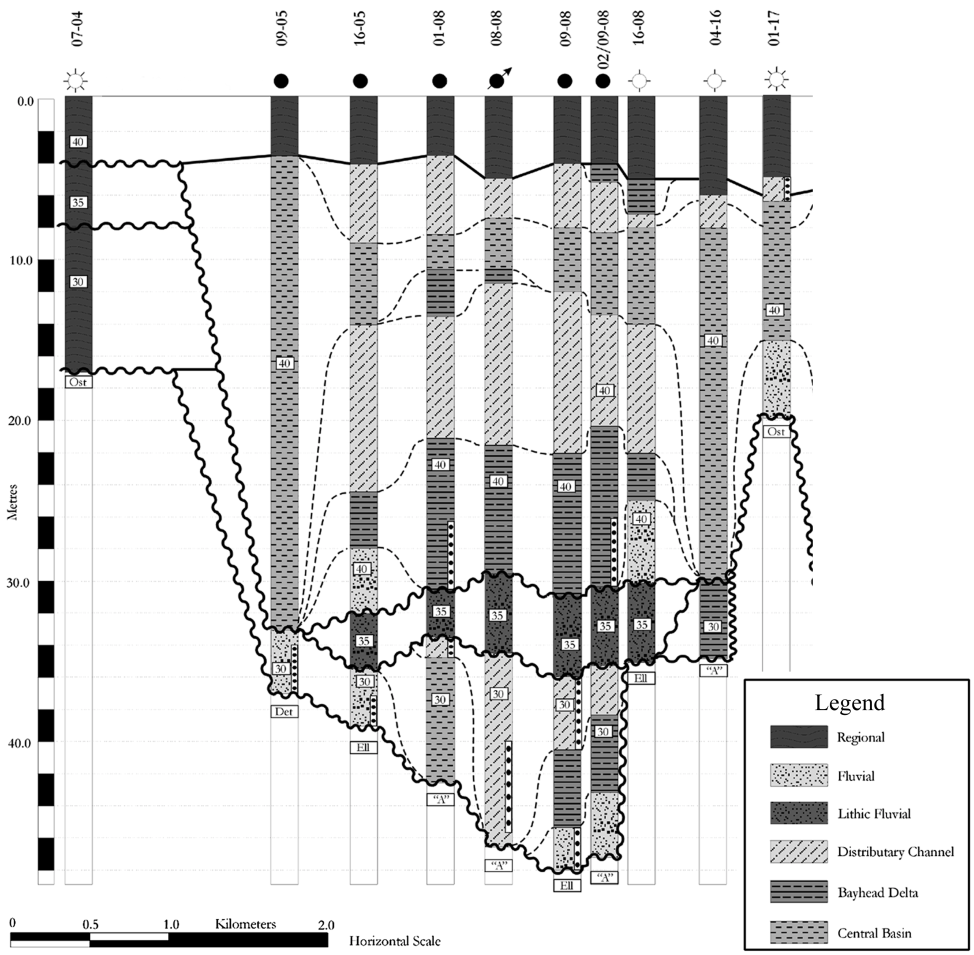


Figure 2. North-south cross section of Blackfoot reservoir showing lower channel (30), lithic channel (35) and upper channel (40) (courtesy of J. Dufour, PanCanadian Petroleum).

Fluid Properties

Gas

Measured values of the Blackfoot specific gravity of gas at standard conditions were not available, so the specific gravity of the Rockyford upper Manville formation gas (.786) was used as a surrogate (Galas, et al., 1995). The specific gravity of gas needs to be corrected for separator pressure and temperature. An assumed separator pressure of 689.5 KPa and an assumed temperature of 15.6°C were used with equation (1) from Vasquez and Beggs (1980) to obtain a corrected specific gravity of 0.772. The bulk modulus (K_G) and density (ρ_G) of the gas at specified reservoir pressures and reservoir temperature of 45.9°C were estimated using the corrected specific gravity and equation (10), Batzle and Wang (1992) (Table 1).

Table 1. Fluid Properties

Pressure (KPa)	K_G (GPa)	ρ_G (kg/m^3)	K_O (GPa)	ρ_O (kg/m^3)	K_W (GPa)	ρ_W (kg/m^3)
11,830.	0.0213	143.	0.565	764.	2.53	1,011
11,200.	0.0196	134.	0.562	768.	2.53	1,011.
6,046	0.0089	64.8	0.0606	798.	2.49	1,009

Oil

Three measurements of the Blackfoot oil yielded an average 37.0° API (839.8 kg/m^3 at standard conditions). The oil formation volume factor (B_o) and solution gas oil ratio (R_S) at selected reservoir pressures were provided by PanCanadian Petroleum (Table 2, Jacques Millette, pers. com.). Equation (5), Vasquez and Beggs (1980) for an undersaturated oil is used to compute the compressibility and bulk modulus (K_O). The density of the oil at reservoir conditions (ρ_O) is derived from mass balance:

$$\rho_O = \frac{\rho_O^{std} + R_S \rho_G^{std}}{B_O} \tag{1}$$

Table 2. PVT Values

Pressure (KPa)	B_O(Rm^3/Sm^3)	R_S(Sm^3/Sm^3)
11,830.	1.1876	71.2
11,200.	1.1786	67.6
6,046	1.0917	32.16

where $\rho_G{}^{std}$ and $\rho_O{}^{std}$ are the densities of gas and oil at standard conditions. Results are found in Table 1.

Water

The connate water salinity is approximately 25,000 ppm (Galas, 1995). Water density (ρ_W) was approximated using equation (27), Batzle and Wang (1992). The water bulk modulus (K_W) was approximated using equations (28) and (29), Batzle and Wang (1992). Results are found in Table 1.

Fluid Mixture Properties

In general, gas oil and water will exist in the pore spaces with saturations S_G, S_O and S_W, respectively. The density of the fluid mixtures were calculated using the insitu density of gas, oil and water and equation (3), Bentley, et al. (1999A).

The bulk modulus of the fluid mixture depends on the details of the fluid distribution. The lower bound is calculated with the isostress model, equation (4), Bentley, et al. (1999A), and the upper bound with the isostrain model, equation (5), Bentley, et al. (1999A).

Reservoir Properties

Reservoir properties were estimated using core and well log data from 08-08. A full wave form sonic log and a density log were run on October 1, 1996 (check date). The average density of the solid grains as determined from core data is 2.65 gm/cm^3. The assumed fluid saturations are S_G=0.75 and S_W=0.25 in the gas zone of the upper channel, S_O=0.75 and S_W=0.25 in the oil zone of the upper channel and S_O=0.75 and S_W=0.25 in the lower channel. The porosity at each point of the density log was calculated as per the procedure described by equation (6), Bentley, et al. (1999A).

The undrained bulk modulus was obtained from the full wave form compressional and shear wave velocities and the corrected bulk density derived from 08-08 logs. The solid bulk modulus (K_S) is assumed to be 40 GPa, a typical value for quartz. The porosity was calculated above. The fluid mixture bulk modulus was estimated from the assumed fluid saturations using the harmonic average. The harmonic average was used because the pre-production fluids were assumed to have been in place long enough so that the homogeneous fluid distribution condition would apply. The Gassmann equation was used to estimate the dry bulk density. This procedure leads to an upper bound on K_D, and is consequently conservative in the sense that it will tend to reduce the magnitude of change due to fluid substitution.

RESULTS

Synthetic Seismograms

Three scenarios will be compared (Figure 3). The first scenario represents the original conditions in the reservoir. The upper channel has a gas zone and an oil zone. The lower channel has an oil zone.

Scenario 2 represents condition in November, 1995 away from the water flood zone. The lower channel has reached bubble point, and now contains all three fluid phases, gas, water and oil. Gas and oil saturations were computed from production data and mass balance given estimated reservoir volume. Water is at residual saturation. The upper channel is assumed to have no change in saturation or gas-oil contact location, but the density and bulk modulus have bee corrected for change in pressure. The dry moduli has been corrected for effective pressure changes.

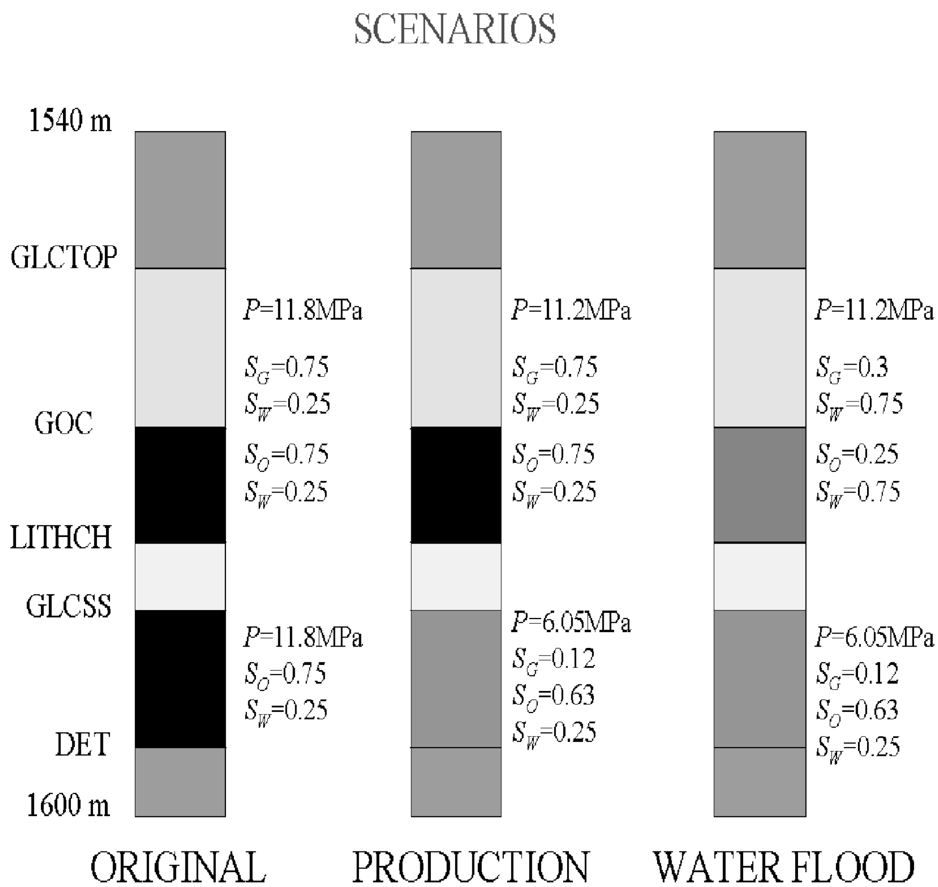


Figure 3. Reservoir condition scenarios used in comparisons of seismic responses.

Scenario 3 represents conditions in November, 1995 in the water flood zone. Since pressure has not been maintained in the lower channel, we assume that no water is in this zone. The zone is assumed to have the same conditions as in the area away from the water flood, that is a mixture of gas, oil and water. Within the upper channel in the water flood zone, we assume that water has displaced gas and oil to residual saturations of S_G=0.3 and S_O=0.25, respectively. Densities and dry moduli have been corrected for changes in fluid pressure and effective pressure.

Figure 4 shows the comparison of synthetic seismograms calculated for the original conditions versus scenario 3, in the water flood zone. The fluid mixture bulk modulus was calculated using the arithmetic average. NMO corrected shot gathers for the original conditions, water flood conditions and their differences are displayed. In addition, trace one of the original condition shot gather is plotted against trace one of the difference plot. In this case, a large percentage change in the trace amplitude is created by the change in conditions. In addition, there is a noticeable difference in the AVO response between original and water flood responses.

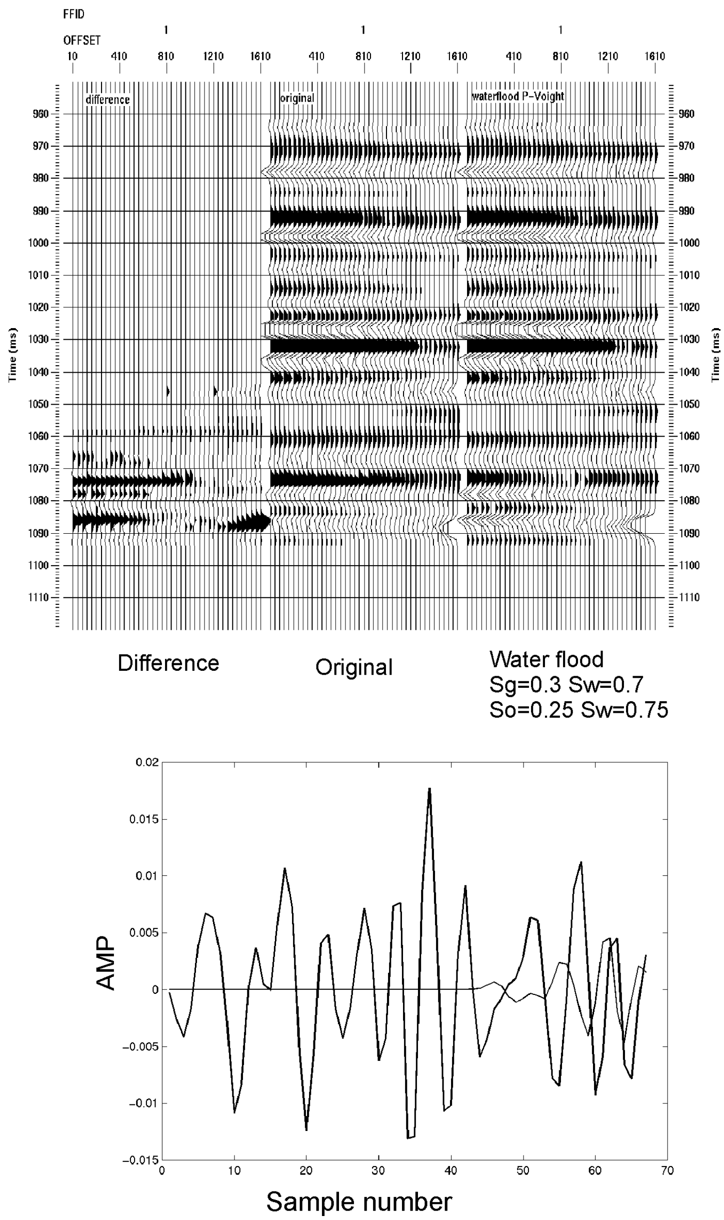


Figure 4. Comparison of an NMO corrected synthetic shot gather seismogram of the original reservoir conditions with that of post-production inside of the water flood area. Fluid mixture bulk modulus was calculated with the arithmetic average. In the lower portion of the figure, trace one of the original response is plotted with trace one of the difference.

Figure 5 shows the difference between original conditions and the post-production conditions outside of the water flood area. As in the calculations in Figure 4, the arithmetic average has been used to calculate the fluid mixture bulk modulus. The change in response is not as great as within the water flood area. Also, the character of the AVO response change is different. Although reduced, the proportional change in the response of trace one is significant.

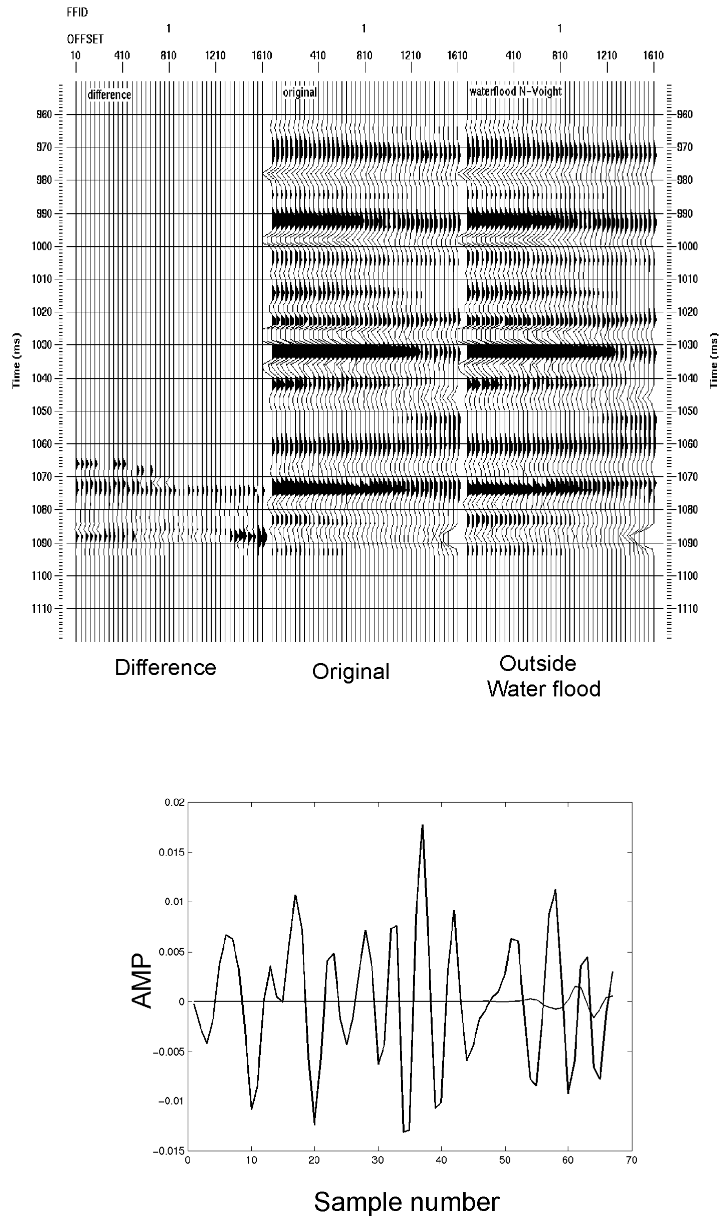
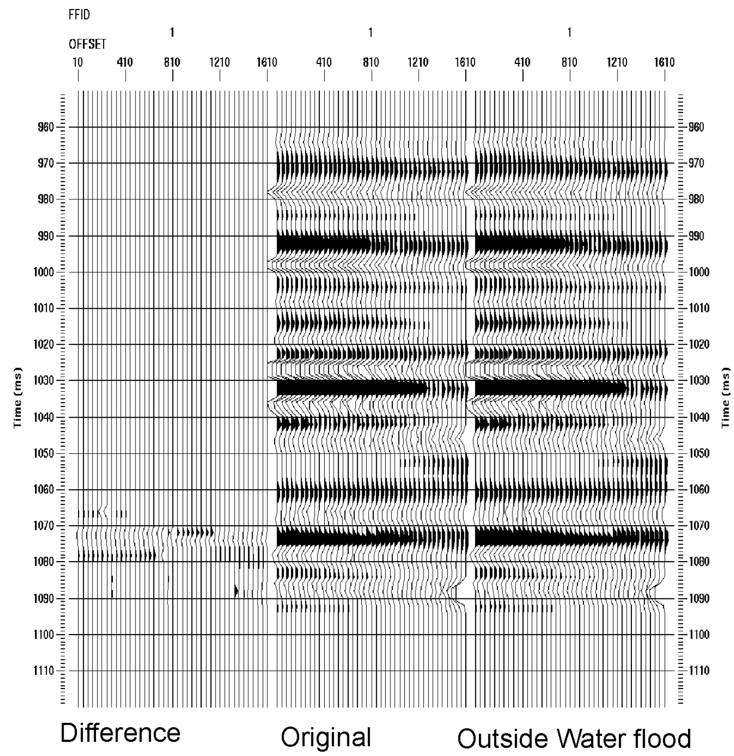


Figure 5. Comparison of synthetic seismogram of the original reservoir conditions with post-production conditions outside of the water flood zone. Fluid mixture bulk modulus is calculated with arithmetic average. In the lower portion of the figure, trace one of the original response is plotted with trace one of the difference.

Figure 6 also shows the difference between the original conditions and the post-production conditions outside of the water flood area. In contrast to the results presented in Figure 5, the fluid mixture bulk modulus was calculated with the harmonic average. Only a minor change in the seismic response is produced, and it is significantly less than the response predicted using the arithmetic average. The harmonic average has emphasized the low bulk modulus of the gas in the mixture, so the fluid mixture bulk modulus will not change much if gas is present.



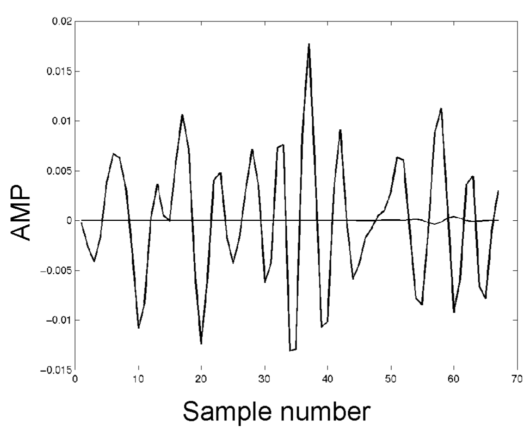


Figure 6. Comparison of synthetic seismogram of the original reservoir conditions with post-production conditions outside of the water flood zone. Fluid mixture bulk modulus is calculated with harmonic average. In the lower portion of the figure, trace one of the original response is plotted with trace one of the difference.

Figures 7 and 8 show the difference in response for areas within and outside the water flood zone. In Figure 7, the fluid mixture bulk modulus is calculated with the harmonic average and in Figure 8, the fluid bulk modulus is calculated with the

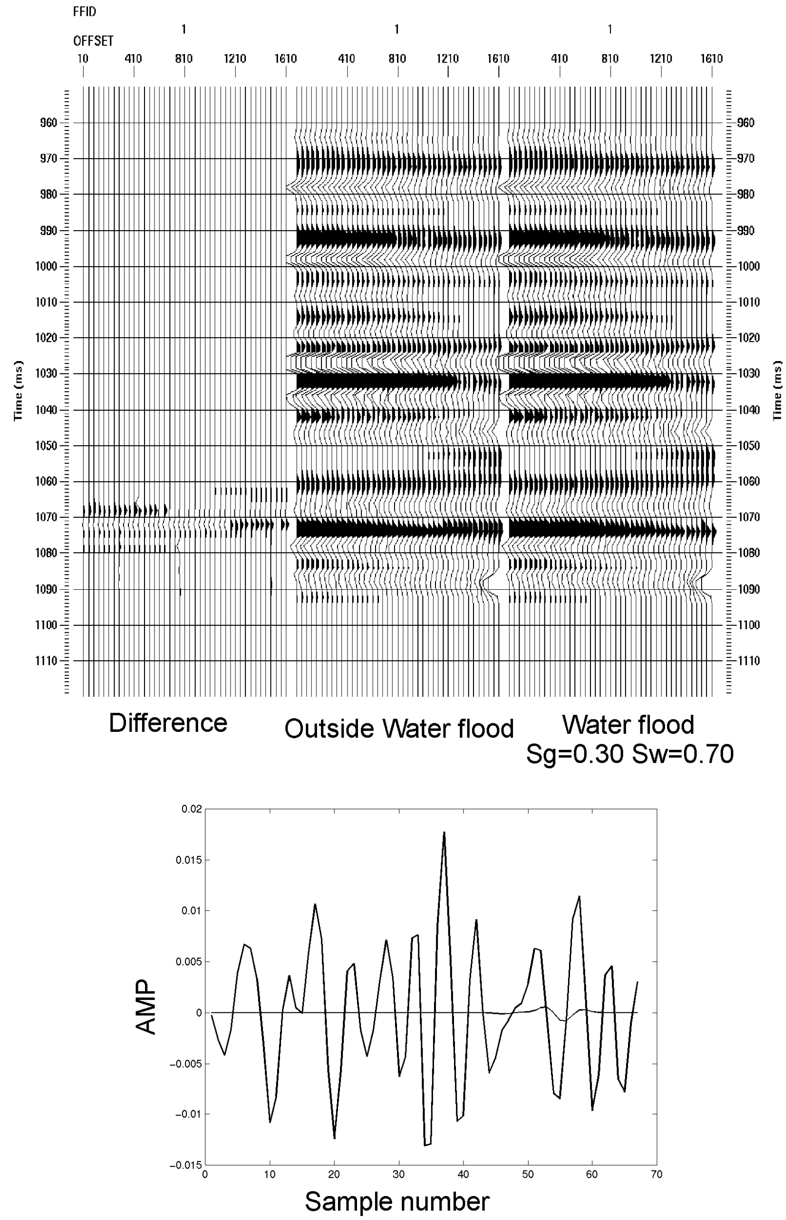


Figure 7. Comparison of synthetic seismogram of outside the water flood with inside the water flood zone. Fluid mixture bulk modulus is calculated with harmonic average.

arithmetic average. These figures represent the upper and lower limits of the difference in seismic response between inside and outside the water flood area. In the case of the harmonic average, the results indicate that it would be very difficult to distinguish the water flooded areas. The arithmetic average results indicate that a reasonably strong difference should exist between the two areas. The harmonic average is appropriate for homogeneous fluid distributions and the arithmetic average is appropriate for patchy fluid distributions. It is speculated that the evolution of gas in the lower reservoir and the invasion of water in the upper reservoir cause some loss of fluid homogeneity, so that the harmonic average is not appropriate. It is not clear that all of the conditions required for the arithmetic average would be met. Consequently, the actual change in fluid mixture bulk modulus is most likely in between the two extreme values and the difference in seismic response between the water flood and non-water flood areas will be between those of Figure 7 and 8.

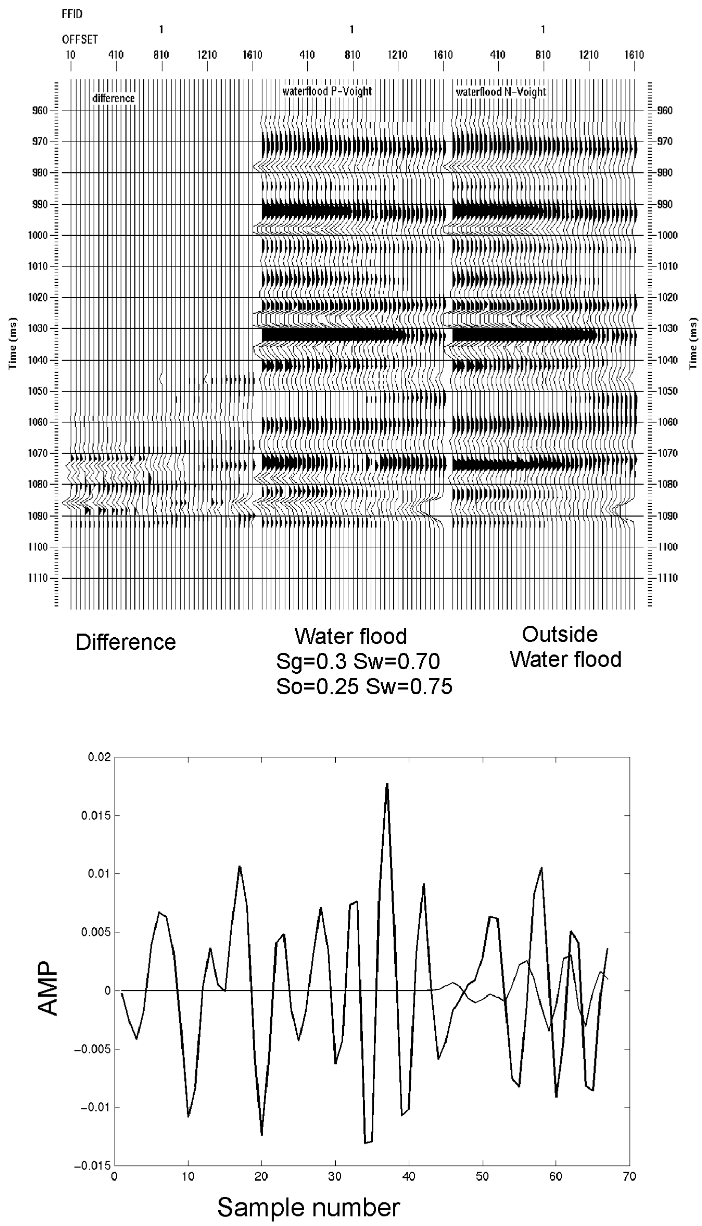


Figure 8. Comparison of synthetic seismogram of outside the water flood with inside the water flood zone. Fluid mixture bulk modulus is calculated with arithmetic average.

Difference Between 1995 and 1997 Surveys

The 1997, 2D-3C high-resolution line was shot across the location of well 00/09-08. A line was extracted from the 1995 3D-3C data volume that was contiguous with the location of the 1997 2D-3C high-resolution line. A match filter was applied to the 2D-3C data. The match-filtered output was subtracted from the extracted line from the 1995 3D-3C data volume and the results are shown in Figure 9. Several anomalies of the same magnitude exist, but the largest anomaly on the section is in the Blackfoot reservoir zone.

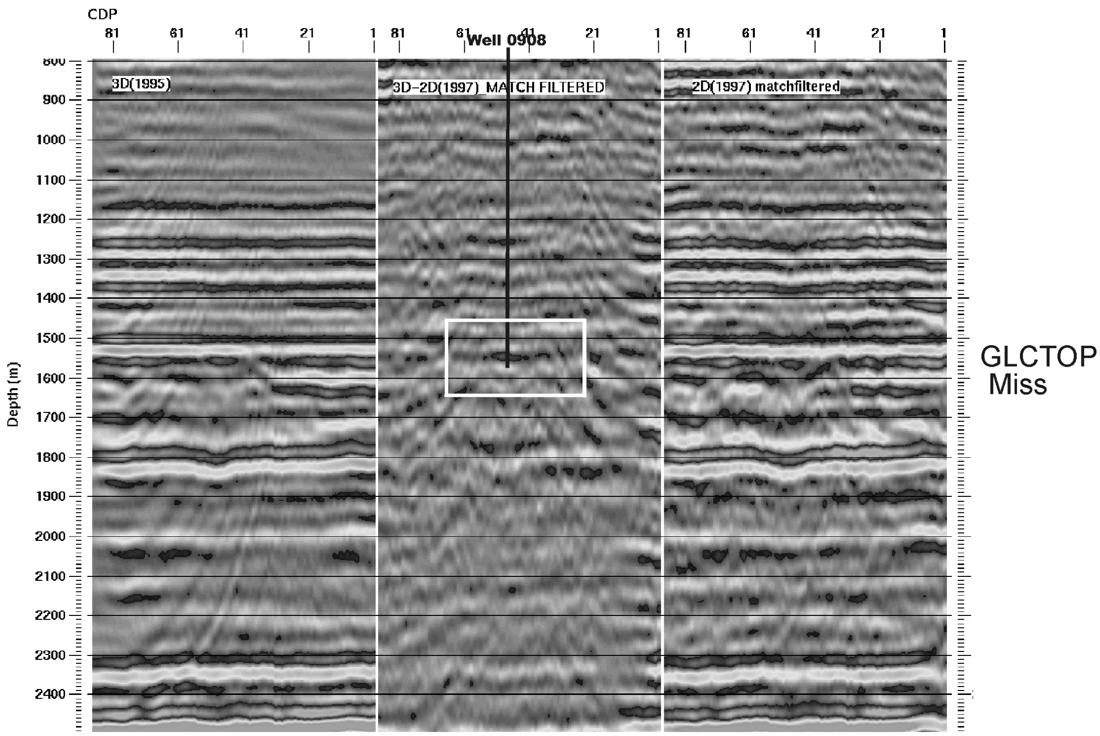


Figure 9. Difference Section. The left section was extracted from the 1995 3D-3C seismic data volume across the same location of the 1997 2D-3C seismic survey. The 1997 match filter profile is shown to the right. The difference between the two sections is shown in the center. The highest amplitude anomaly is located in the Blackfoot reservoir zone.

The cause of the difference in seismic response is unclear. Water has not been produced from 00/09-08, indicating that the water flood front had not arrived at the well location. By the time of the 1995 survey, the lower reservoir had already reached the bubble point, so gas would be present in the lower reservoir during the acquisition of both surveys. Pressure was maintained in the upper reservoir during the interval between the surveys. One difference between the surveys is that the pressure in the lower reservoir had declined between 1995 and 1997.

An explanation for the differences between the surveys and an analysis on whether or not the seismic response differences are significant remain issues for future work. However, the fact that an apparently observable change in seismic response is located in a region where the reservoir conditions had not changed dramatically is encouraging.

CONCLUSIONS

Three scenarios of fluid and pressure distribution within the Blackfoot reservoir have been tested for differences in seismic response. The method of Bentley, et al. (1999A) was used to calculate the bulk modulus, shear modulus and bulk density of vertical profiles within the reservoir. Synthetic shot gathers were generated for each scenario and were compared.

If the fluids were assumed to be homogeneously distributed and the harmonic average was used to calculate the fluid mixture bulk modulus, predicted changes in seismic response were minor. If the fluids were assumed to have a patchy distribution and the arithmetic average was used to calculate the fluid mixture bulk modulus, then the predicted changes in seismic response were significant. The actual change in seismic response is expected to be between these two results.

The seismic response of the 1997 2D-3C was compared with a contiguous line extracted from the 1995 3D-3C seismic data volume. Only moderate changes in the reservoir pressure were expected. Nevertheless, the largest change in the difference section is found at the location of the Blackfoot reservoir zone. The change is only slightly larger than some other changes in the difference section, but the results are encouraging, given the moderate change in the reservoir conditions.

The results indicate that small to moderate changes in the seismic response would be observed in time-lapse seismic monitoring of the Blackfoot reservoir. The results also indicate that the water flood zone would be seismically distinct from the non-water flood areas.

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