Monitoring fluid injection using time-lapse analysis: a Rainbow Lake case study

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ABSTRACT

The Rainbow B pool, a carbonate reservoir, is undergoing gas and solvent injection to extract the remaining oil. Although not commonly done because the expected changes are small, time-lapse or 4D processing and interpretation are applied to two sets of 3D data to detect the locations of the injected fluids. The presence of gas and solvent were best interpreted with the time-delay results, as opposed to the amplitude change results. Fluid related changes were detected in the vuggy or a crack-like low pore aspect ratio area but changes were not detectable in the intergranular area even though there may be the same amount of fluid present. Because the reservoir is extremely heterogeneous and the pore geometry greatly affects the results, this study could detect changes but not detect the amount of fluid present nor detect bypassed oil. This study also confirmed that the Gassmann equation underpredicts velocity changes. The seismic time-delay results matched the engineering simulation data fairly well.

INTRODUCTION

An ideal reservoir for time-lapse analysis would be an unconsolidated, highly porous sand reservoir with a high GOR (gas-oil-ratio) that is undergoing steam injection. According to this criterion, the Rainbow B pool does not appear feasible for time-lapse analysis. The Rainbow B pool is a carbonate pool where gas and solvent are injected into the reservoir. The fluid related seismic changes expected in this type of reservoir, using the Gassmann (1951) equation, are subtle. Fortunately, the changes are bigger than expected due to the pore geometry of the Rainbow B pool. The significance of this study is that the Rainbow B pool is one of the few carbonate case studies done using time-lapse analysis. Another carbonate case study is the Weyburn field in Saskachewan where CO_2 is injected into the carbonate reservoir (Brown et al., 2002; Terrell et al., 2002; Davis et al., 2003; Li, 2003)

Gas and solvent are injected into the Rainbow B pool to extract the remaining oil. The locations of the injection wells are known but where the gas and solvent has moved to is not known. Fortunately, time-lapse seismic is able to detect changes in between wells. Two 3D surveys were acquired. The first survey was acquired in 1987 while the second survey was acquired in 2002. The objective of this study is to use the time-lapse analysis results to infer locations where gas and solvent are present. Then the results are interpreted with respect to the geological data and the engineering data.

GEOLOGICAL BACKGROUND

The Rainbow B pool is an atoll reef located in northwest Alberta, township 108-109, range 8 W6M. The reef is 5.6 km long and 2.1 km wide at its widest point. The average thickness of the reef is 200 m and it is located at a depth of approximately 1800 m. The pool is producing oil from the Middle Devonian Keg River formation. The Keg River formation is overlain by the Muskeg member, which is made of impermeable evaporites, and is underlain by calcareous shales and argillaceous limestones (Hirsche et al., 1998). The average porosity within the B pool is 8% while the average permeability is 460 mD. The majority of the reef is dolomitized. There are various porosity types identified in the reef but the vuggy porosity type dominates (Laflamme, 1993). The vuggy type porosity is mainly located at the reef margins. The lower porosity and the intergranular type porosity are located mainly within the interior of the reef. This is because the depositional environment in the interior of the reef is in a quieter lagoonal setting. This reef is fairly heterogeneous. The facies and the porosity type vary both vertically and laterally within the reef.

RESERVOIR BACKGROUND

Husky Energy is the operator of the pool and this pool has been producing oil since 1965. The OOIP (original oil in place) is 43.7 * 10^6 m^3. During primary production, 1.6% of the oil was recovered while 36.5% was recovered during secondary production (Nagel et al, 1990). The pressure in the reservoir during production never reached bubble point, which is at 10 845 KPa, so the dissolved gases in the oil did not come out of the solution. Also, the pressure in the reservoir remained relatively stable, about 17.2 MPa, from 1987 to 2002.

To further enhance oil recovery, miscible gas and solvent are injected into the top of the reservoir. The solvent helps remove residual oil from the reservoir. The solvent is injected first and then a lean gas is injected into the top of the reservoir to push the solvent bank down. Time-lapse analysis will help determine the injected fluid locations in the reservoir. There are currently 11 injection wells in the reservoir. Table 1 shows the timeline of the Rainbow B pool.

Table 1. Rainbow B pool timeline

Date	Process	Description
1965, November	Primary Production	Oil produced by natural drives
1968, March	Secondary Production	Pool waterflooded
1984, June	Tertiary Production begins	Solvent injected first into the north lobe, then through south lobe
1987, January	3D seismic data acquired	10 m solvent bank formed
1991, October	Tertiary Production continued	Solvent injection stopped, miscible gas injected
2002, January	3D seismic data acquired	30 m solvent bank formed

RESULTS & DISCUSSION

Two 3D seismic surveys were recorded over the Rainbow B pool. A comparison of the two surveys will reveal seismic differences that can be attributed to the production related changes within the reservoir. This will help determine any inefficiencies of the production process. Before the two surveys can be compared to one another, they must be made to match each other in terms of geometry, time, phase, and frequency. This can be accomplished with time-lapse processing, which was done for this study. Then the differences between the two 3D surveys should only reveal production changes. Processing details will be available later (Ng, in prep.).

From 1987 to 2002, the porosity and the pressure within the reservoir remained the same. Therefore, the only changes from 1987 to 2002 are due to the injection of gas and solvent or possibility due to the opening of new fractures as gas and solvent were injected. Then the areas where there are time delays or amplitude changes can be interpreted as areas where gas and solvent are injected.

Three different seismic changes were analyzed: time-delays and amplitude changes, and impedance changes. To infer the location of gas and solvent, we need to understand the effect gas and solvent have on seismic data. Figure 1 is a schematic showing the reservoir prior to and after gas and solvent injection. The replacement of oil with gas and solvent would cause a velocity and density decrease. Hence, a time-delay or a time-sag should occur below the production zone. The Cold Lake horizon is a strong reflector below the reservoir and so time-delay measurements are taken near that horizon. Also, the presence of gas and solvent would cause an amplitude increase at the top of the Keg River horizon. In addition, the impedance should decrease within the zone of gas and solvent. Impedance is the velocity multiplied by the density. These results can be displayed in map form.

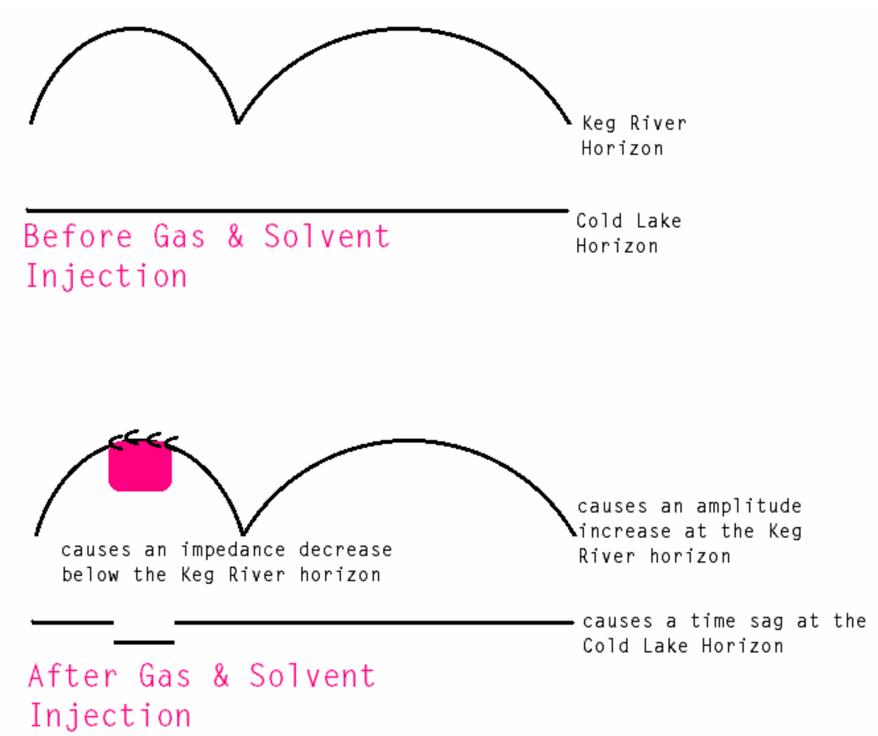

FIG. 1. Schematic diagram of seismic results expected after the injection of gas and solvent.

The amplitude change map

An amplitude difference map is displayed in Figure 2. The injection of gas and solvent replacing oil should cause an amplitude increase at the top of the reservoir. A difference map is made between the 1987 and the 2002 survey. Figure 2 shows a map of the normalized RMS amplitude differences with a window of 20 ms centered at the Keg River horizon. The purple/pink areas could be interpreted as areas where there are a presence of gas and solvent. Unfortunately, this map does not correlate well to the injection wells. Another factor to be aware of is that the amount of gas and solvent injected may not affect the reflection amplitude. For example, 5% gas saturation and 100% gas saturation can have the same reflection amplitude (Domenico, 1974). Also, there were already gas and solvent in the reservoir prior to the first survey in 1987. Any additional gas and solvent may not have a significant affect on the amplitude. Tracking changes in amplitude does not seem to be a useful way of tracking the solvent and gas distribution.

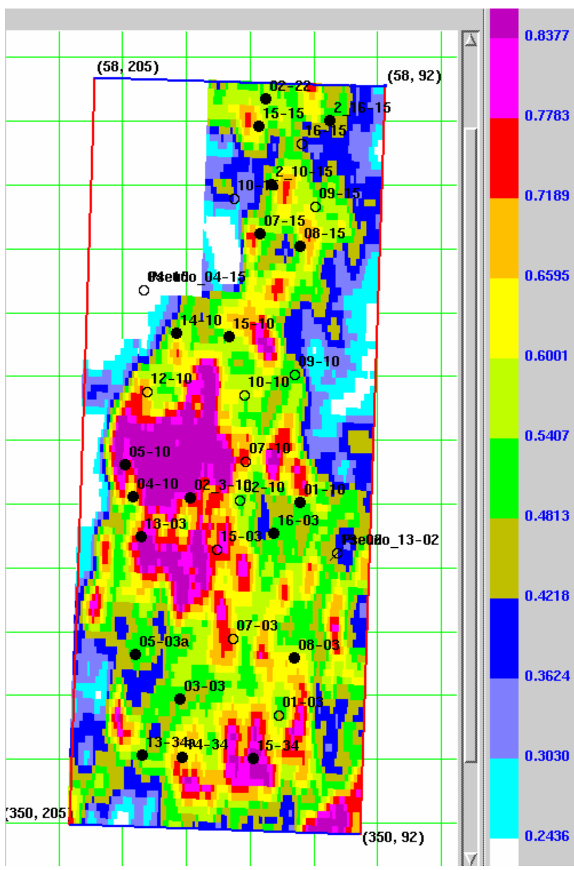

FIG. 2. Difference of Normalized RMS averaged amplitude between 1987 and the 2002 with a window centered at 20 ms on the Keg River horizon. (fractional units)

The time-delay map in comparison with the isochron map

The presence of gas and solvent causes a velocity decrease in the reservoir resulting in a time-delay below the reservoir. The time-delay map is shown next to the isochron map in Figure 3. The isochron map, of the Keg River horizon to the Cold Lake horizon, indirectly represents the thickness of the reservoir. The time-delay map was made by crosscorrelating the two surveys at a window below the reservoir at 1200-1250 ms. This window centers around the Cold Lake horizon because time-delays can easily be detected because the Cold Lake horizon is a strong amplitude event. The time-delay map depicts the time-shift that is required to match the Cold Lake horizons in both surveys. The injected fluids are interpreted to be in the locations where the time-delays are coloured pink/purple. It is very similar to the isochron map. Note that the injection wells (coloured white) mostly correspond to the perceived injected fluids found in the time-delay map.

a) b)

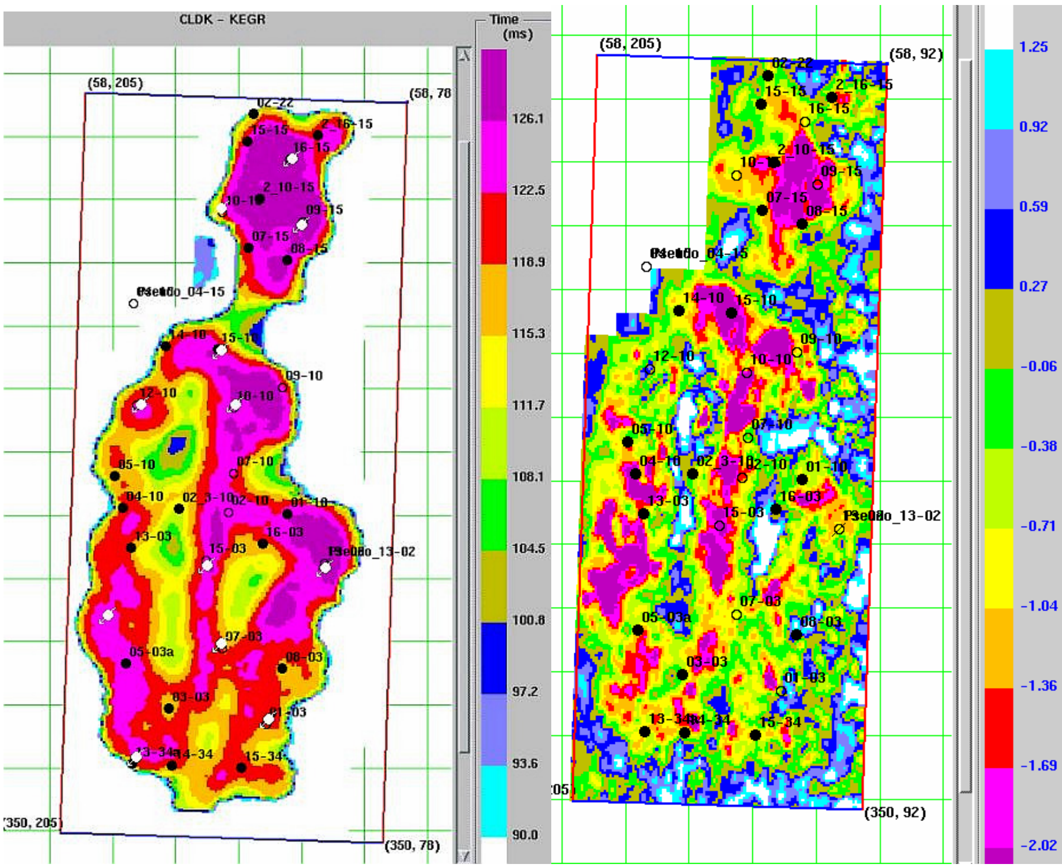

FIG. 3. a) Isochron map of the Keg River horizon to the Cold Lake horizon. The map represents the thickness of the reservoir. b) Time-delay map (milliseconds).

The time-delay map in comparison with the Gassmann calculated time-delay map

Time-lapse analysis is not commonly done for carbonate pools because the dry bulk modulus of the carbonate matrix is very high. The high bulk modulus of the carbonate will greatly exceed the low modulus of the fluids within the pore space. Thus, the fluid effects seen in seismic data after gas injection are small and difficult to detect. Hirsche et al. (1998) applied time-lapse analysis on two seismic lines in the Rainbow B pool and discovered that the velocity changes, from pre- to post-tertiary production, are bigger than Gassmann predicted. This is because the Gassmann equation does not take into account the shape of the pores. The Gassmann equation is used for calculating the effects of fluid substitution on the bulk modulus, which is then related to the velocity. The pore geometry of the Rainbow pool affects the velocity. A lower pore aspect ratio rock would cause a higher velocity change than a higher pore aspect ratio rock (Kuster & Toksoz, 1974). The pore aspect ratio is defined as the length of the short axis divided by the length of the long axis in a 2D pore space and the ratio is always less than or equal to one (Wang, 2001).

a) b)

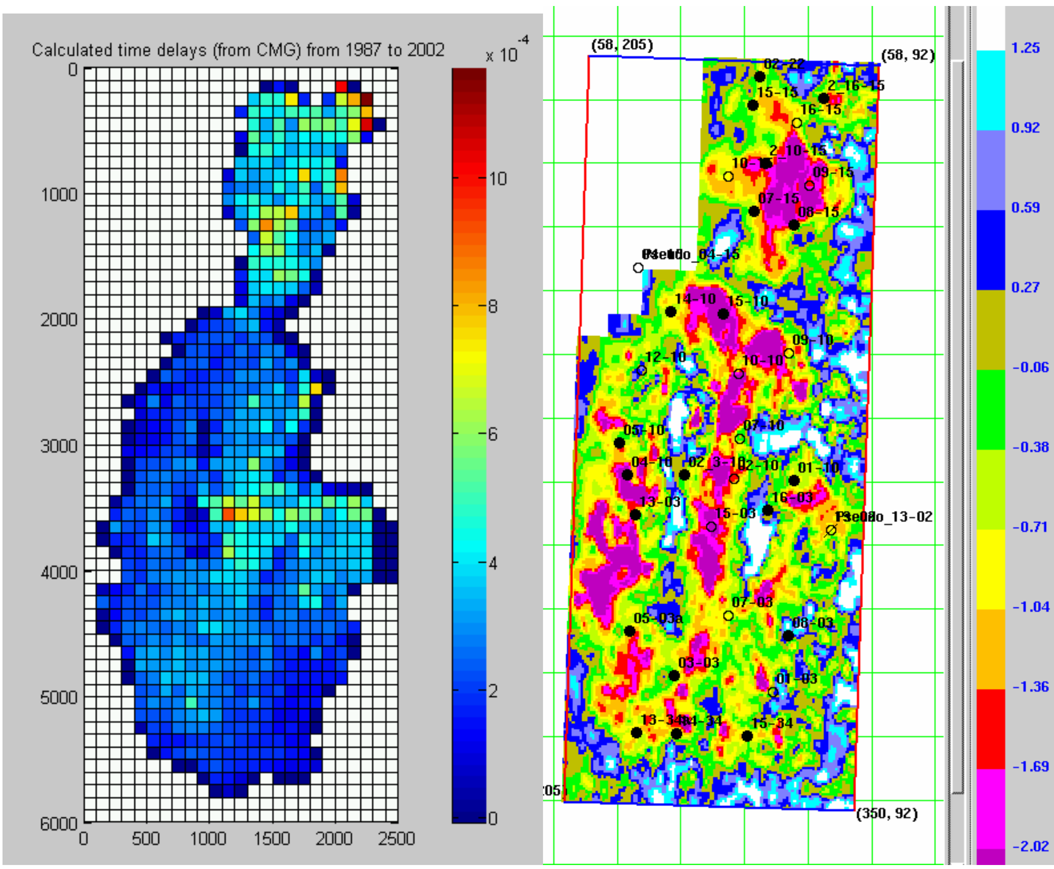

FIG. 4. a) Gassmann calculated time-delay map (seconds) based on saturation and porosity results from the reservoir simulation. These results are calculated using the Gassmann equation and the Batzle and Wang (1992) derived fluid properties. b) Time-delay map for comparison (milliseconds).

Husky engineers simulated the Rainbow reservoir using reservoir simulation software. The reservoir simulation is used to predict the reservoir parameters in the future and to determine how long it will take for the hydrocarbons to be depleted. There are 60 000 grid blocks in the flow model grid with different fluid saturation values in each grid block, as well as different porosity values. These values were used to calculate the fluid change results that should be expected in seismic data. The values were calculated using the Gassmann equation and the Batzle and Wang equations (1992). The results were converted to time values and displayed in map view. The Gassmann calculated time-delay map is compared to the observed seismic time-delay map. The calculated time-delay map represents the engineering results and the time-delay map represents the geophysical results.

On the Gassmann calculated time-delay map, there are more time changes found in the north lobe and in the northeastern/central part of the south lobe. The changes found there are at an average of 0.6 ms to a maximum of 1 ms. The changes are even smaller elsewhere in the reservoir. A side-by-side comparison of the Gassmann calculated time-delay map (Figure 4) and the seismic time-delay map show that they are mainly similar in the north lobe. They are different because the calculated time-delay map shows fewer changes than the seismic time-delay map. This implies that the Gassmann equation underpredicts the changes found in seismic data. Again, the reason for this difference is because the Gassmann equation does not take into account the pore geometry, which greatly affects the velocity changes. The pore aspect ratio of the reservoir is fairly low and so the velocity changes seen on seismic data are bigger than expected. These results are similar to the results found by Hirsche et al. (1997, 1998)

The time-delay map compared to the engineering thickness map

a) b)

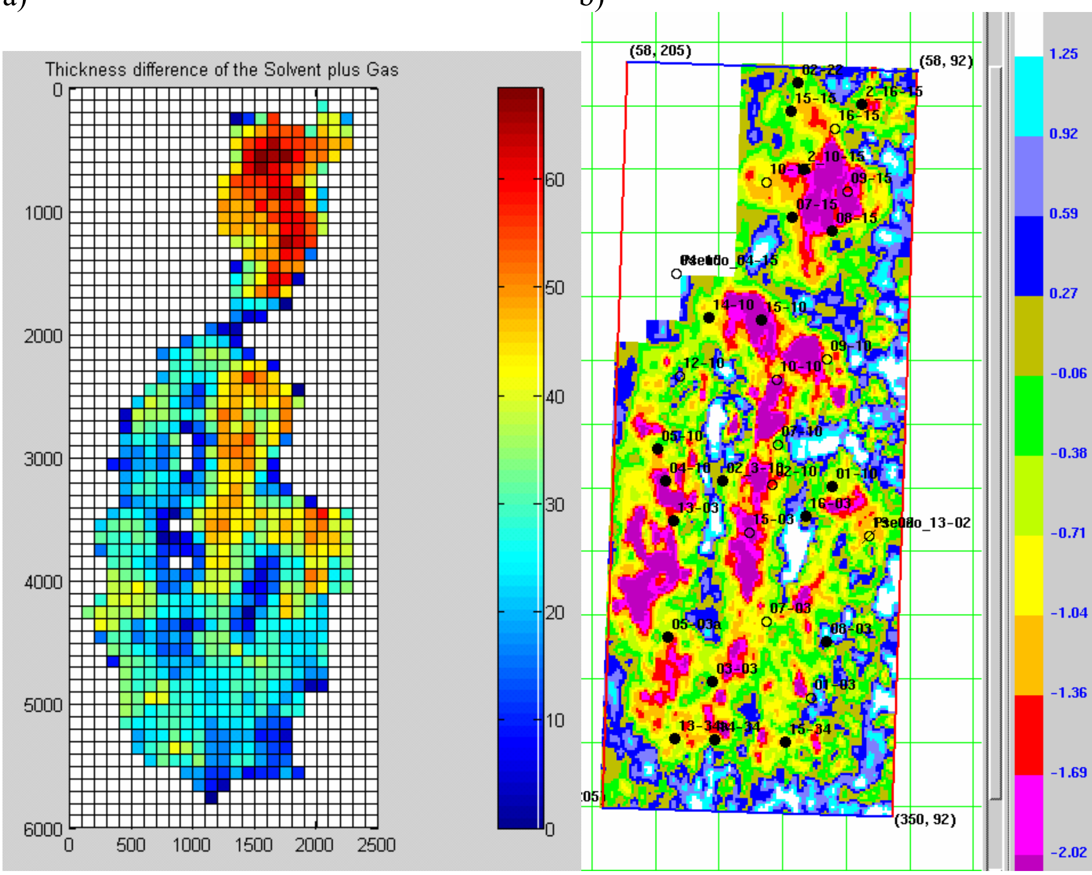

FIG. 5. a) Difference of gas and solvent thickness between 1987 and 2002 (metres). Data from the reservoir simulation. b) Time-delay map for comparison (milliseconds)

Figure 5 shows a map of the thickness difference from 1987 to 2002 of the solvent plus gas amount. This map is produced from the reservoir simulation and represents the amount of gas plus solvent thickness believed to be in the reservoir. These are the results that the engineers have at this point of the simulation. The north lobe and the northeastern south lobe contain 50 m thickness of gas plus solvent. Elsewhere in the reservoir, the gas plus solvent volume is at approximately 30 m thickness. The shape of this map resembles the isochron map.

We can compare this map to the time-delay map. The geophysical time-lapse results and the results from the reservoir simulation have similarities and differences. Again, the north lobe and the northeastern part of the south lobe show big changes in both maps. But, the changes are greater on the western side of the reservoir in the time-delay map. There are a few other places where the engineering thickness map shows locations of injected gas but the seismic data does not. Nevertheless, the results are generally similar.

The time-delay map compared to the porosity type map

The porosity and the porosity type vary both vertically and horizontally within the reservoir. The porosity type has been averaged vertically and displayed in map view in order to be compared to the time-delay map. The porosity type map (Figure 6) shows that the edges of the reef are mostly vuggy and the northwest corner of the south lobe has a zone that is mostly intergranular. Well 12-10 is believed to contain a high amount of injected gas and solvent even though the time-delay map does not indicate this situation (L.Carr, personal communication, 2003). This may be related to the porosity type, which is intergranular and has a high pore aspect ratio. Fluid changes are not very detectable in areas with a high pore aspect ratio because crack-like pores are more compressible than sphere-like pores. Thus, areas of the reservoir without time-delays may still have gas and solvent but the changes are not detectable due to the porosity type. Therefore, this study cannot determine the locations of bypassed oil but can only confirm that there indeed are production related fluid changes.

According to the time-delay map, there are relatively large time-delays within certain zones of the reservoir. One might say that those zones will have a higher amount of gas and solvent present. Unfortunately, the porosity and the porosity type will influence the time-delay results. Thus, the magnitude of time-delay would not correlate with the amount of solvent and gas injected. For example, the time delay through a vuggy porosity type area is different than the time delay through an intergranular porosity type area even though there may be the same amount of gas and solvent present. Time-delays or velocity changes are detected more strongly in some porosity types than in other porosity types. Thus, the magnitude of the time-delay does not determine the thickness amount of gas and solvent present.

Overall, if there is a time-delay at a certain location, then there are gas and solvent present regardless of the amount present. If there is no time-delay, then we do not know if there are gas or solvent present because time-lapse seismic cannot detect changes in certain porosity types. We cannot use this study to detect bypassed oil but we can interpret vuggy type zones with more confidence than the intergranular type zones.

a) b)

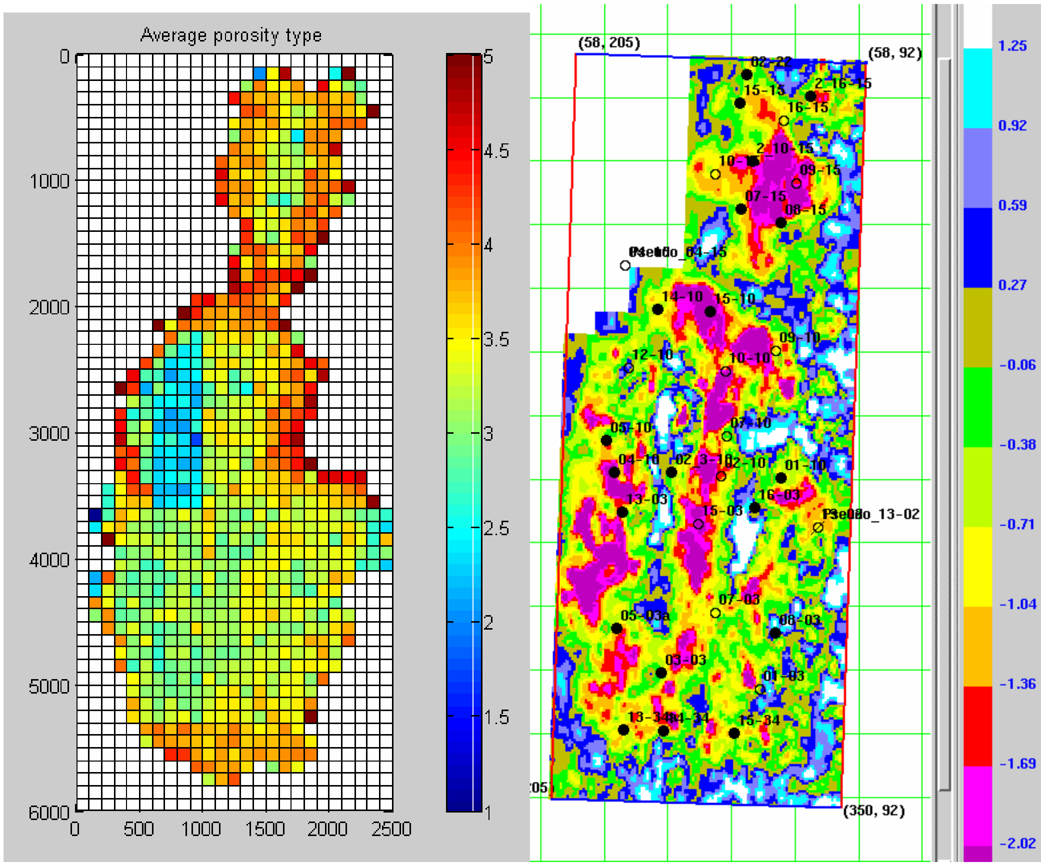

FIG. 6. a) Porosity type map: average of all the layers. Data taken from the reservoir simulation. b) Time-delay map for comparison (milliseconds)

POROSITY TYPE LEGEND
Porosity type 5: mostly large vugs
Porosity type 4: medium vugs
Porosity type 3: Predominantly vuggy with secondary intergranular matrix
Porosity type 2: Predominantly intergranular with reservoir quality porosity
Porosity type 1: Entirely intergranular with downgraded porosity

CONCLUSIONS

1. The presence of gas and solvent were best interpreted using the time-delay map. The porosity in the Rainbow B pool is very heterogeneous and so the time-delay map had to be interpreted with respect to the porosity. The factor that most affects fluid related seismic changes is the pore geometry. The changes are greater for a rock with a low pore aspect ratio than for a rock with a high pore aspect ratio. Similarly, an area of the reservoir with vuggy type porosity showed more changes than an area with intergranular type porosity. In fact, there were no time-delays at well 12-10, which is an intergranular type porosity area, even though the engineers knew that there were gas and solvent present. It appears that the time delays are visible at locations where the porosity type is vuggy but not

visible at locations where the porosity type is intergranular. Where there is a time-delay, regardless of the magnitude of the time-delay, that area is interpreted with having the presence of gas and solvent. Where there is not a time-delay, that area may have an intergranular porosity type and so changes are not detectable. Also, there may not be much time-delay detected if there were already a very thick gas and solvent bank in the reservoir prior to the first survey. We can be more confident of our interpretation in areas where the porosity type is vuggy and where the pore aspect ratio is low because reservoir fluid changes will show up on the time-delay map. Time-lapse analysis for this study is useful in confirming the presence of gas and solvent with the reservoir simulation but is not useful in detecting bypassed oil.

2. The amplitude change results do not appear as trustworthy as the time-delay results. There may not be any amplitude changes detected if there already were gas and solvent in the reservoir prior to the first survey. This is because the presence of 5% gas saturation and the presence of 100% gas saturation can display the same reflection amplitude. Thus, if there were any gas and solvent in the reservoir originally, any additional gas and solvent would not cause any significant reflection amplitude change. Also, the amplitude change data do not match the geology and the engineering data as well as the time-delay data.

3. This study has also confirmed that the Gassmann analysis underpredicts changes due to solvent and gas injection as Hirsche et al. (1997, 1998) has shown. The time-delays found in this study is fairly low, at approximately 2 ms, but is still much higher than the changes the Gassmann analysis predicts. Although the changes in this study are small, they are still useful and anomalous in interpreting the production related changes.

4. The reservoir appears mostly flooded. According to the time-delay map, there are gas and solvent at the saddle point, the area in between the north and the south lobe. The time-lapse data matches the injection well, isochron map and the engineering fluid thickness data fairly well.

Time-lapse analysis is not commonly done for carbonate reservoirs but this case study showed fluid changes that were bigger than expected. With the increasing use of enhanced oil recovery methods, the use of time-lapse analysis could also increase. Overall, time-lapse analysis seems to work better and for more case studies than we expect (I.Jack, personal communication, 2003).

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