GEOPHYSICS, VOL. 56, NO. 10 (OCTOBER); P. 1614–1623, 10 FIGS., 4 TABLES.

# Seismic monitoring of water floods?—A petrophysical study

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**ABSTRACT**

Seismic velocities were measured in the laboratory on 67 samples as a function of pressure and temperature when saturated with gas and a 35° API [°API = 141.5/(density at 1 atmosphere and 60°F) − 131.5] mineral oil and flooded with pentane and fresh water, respectively, using an ultrasonic pulse transmission method. The rock samples consisted of 39 carbonate cores from eight reservoirs, 22 sandstone cores from six formations, and six unconsolidated samples from three origins. The results show that water flooding increases the compressional velocity $V_p$ by more than 5 percent in most of the gas-saturated cores at effective pressures (overburden pressure minus pore pressure) less than 20 MPa. Such $V_p$ increase is less than 5 percent in about half of the carbonate cores and some of the sandstone cores with normal pentane and in all the consolidated cores (both carbonates and sandstones) saturated with the 35° API oil. However, in unconsolidated samples saturated with gas, pentane, or oil, water flooding increases the $V_p$ substantially.

Both the laboratory results and theoretical analysis show that seismic methods may succeed in monitoring water floods in some reservoirs under certain conditions, while they may fail in others. It is thus important to carry out petrophysical and feasibility studies prior to the implementation of in-situ seismic monitoring of water-flood processes.

## INTRODUCTION

In recent years, seismic methods have found successful applications in petroleum production assessment, reservoir characterization, and in monitoring enhanced oil recovery (EOR) and production processes. In seismic monitoring applications, the impedance contrast caused by various EOR and production processes is the physical basis of the method. Laboratory results have shown that large velocity decreases are found in heavy oil- or tar-sands as temperature increases (e.g., Tosaya et al., 1987; Wang, 1988), in oil-saturated rocks when flooded with carbon dioxide ($CO_2$) (Wang and Nur, 1989), and in oil-saturated rocks when flooded with gas and a hydrocarbon solvent (Hirsche et al., 1990). Furthermore, laboratory results also show large differences between the compressional velocities in gas- (e.g., air) and liquid- (e.g., water or oil) saturated rocks (e.g., Nur and Simmons, 1969; Gregory, 1976). These results are the petrophysical basis for using seismic methods to monitor EOR and production processes.

It has not been proven, petrophysically, that seismic methods can be used to monitor in-situ water-flood processes. Although the effect of water saturation on velocities in rocks has been well documented (e.g., King, 1966; Nur and Simmons, 1969; Gregory, 1976), few petrophysical data or reports have been published on the effect of water flooding on seismic velocities in a variety of rocks saturated with reservoir oils. Furthermore, prior to the in-situ monitoring of an enhanced oil recovery process, it is important that a complete feasibility study, including laboratory investigations and theoretical analysis, be carried out to estimate the effect of the EOR process on seismic impedances and/or reflection amplitudes. The objectives of this study are (1) to ascertain if seismic methods can be applied to monitoring water-flooding processes, (2) to provide a petrophysical basis for such seismic monitoring and its interpretation, and (3) to determine types of reservoirs and reservoir conditions in which seismic methods are likely to succeed in monitoring of in-situ water-flood processes.

In the literature, Dunlop et al. (1988) reported success in using high-resolution, high-frequency seismic methods to monitor water-flood processes. However, their field monitoring survey lacked petrophysical support and was carried out over a shallow (564 m) live oil (oil with significant

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amount of gas in solution) reservoir. As will be shown, our laboratory results and analysis verify that shallow, unconsolidated reservoirs saturated with live oils (with low velocities) are always better candidates for seismic monitoring of in-situ water-flood processes. Thus it is dangerous to extend the success reported by Dunlop et al. to other reservoirs for seismic monitoring of water floods without petrophysical measurements and analysis. Our laboratory results and theoretical analysis, as reported in this paper, provide a petrophysical basis on the applicability of seismic methods to monitoring of in-situ water floods.

## EXPERIMENTS

### Apparatus

An ultrasonic pulse transmission method was employed in the experiments. Figure 1 shows the schematic diagram of the experimental apparatus. The transmitting transducer, with both compressional and shear piezoelectric crystals of 500 kHz, converts the ultrasonic pulses generated by the pulse generator to elastic waves. The receiving transducer, identical to the transmitting transducer, converts the elastic waves traveling through the rock sample back to electrical signals. The received waveforms are displayed and digitized by an oscilloscope and then stored for further processing and traveltime analysis using a small computer. the waveforms stored in the computer can be retrieved and amplified (in both horizontal and vertical directions) so that accurate traveltimes can be picked. The velocities were calculated using the measured sample length and the picked traveltimes. The total uncertainty in the calculated velocities is estimated to be less than ±1 percent.

Overburden $P_c$ and pore $P_p$ pressures are controlled separately. The difference between these two pressures gives the effective pressure $P_e$ on the rock sample. A pump with a step motor-drive controls pore pressure and achieves fluid displacement. The back-pressure controller allows for fluid displacement at a constant pore pressure.

### Physical properties of the rock samples

Thirty-nine carbonate samples were selected from eight oil-producing reservoirs in Alberta, Canada. About 60 percent of these rocks are limestones, with the remaining being dolomites. The reservoir temperature for these rock samples ranges from 21 to 105° C. Table A-1 in the Appendix lists the physical properties of these carbonate samples.

Twenty-two sandstone samples were selected from six formations, all of which are from British Columbia and Alberta, Canada, except Berea sandstone. Their physical properties are listed in Table A-2 in the Appendix.

Six unconsolidated samples were prepared in the experiments: two Ottawa unconsolidated sand, two blend sand, and two glass bead samples. The Ottawa sand is a clean quartz sand with grain size ranging from 100 to 300 μm. The blend sand is extracted from two tar-sands and blended together, with grain size ranging from 50 to 200 μm. The glass bead has grain size ranging from 300 to 650 μm. Their physical properties are also listed in Table A-2 in the Appendix.

### Physical properties of the pore fluids

The pore fluids used in the experiments are air, a refined mineral oil, normal pentane, and fresh water. Air-saturation was used to simulate natural gas-saturation and dry condition. The oil is a nonpolar white mineral oil with an equivalent API gravity of approximately 35 degrees. Normal pentane is a pure hydrocarbon with chemical formula of $C_5H_{12}$ and API gravity around 92 degrees. It was used to simulate extremely light oil (gas condensate) or live oil [the velocity in pentane is similar to that in many high gas-to-oil-ratio (GOR) live oils]. Physical properties of the pore fluids are listed in Table 1.

The compressional velocities ($V_p$) in pure water and the mineral oil are shown in Figure 2 versus temperature at room pressure. As temperature increases, the $V_p$ in water increases until the temperature reaches 73° C then decreases slowly, while the $V_p$ in the oil, like that in all other petroleum oils, decreases monotonously. This means that at higher temperatures, the $V_p$ difference between water and oil is greater. The effect of pressure on $V_p$ in both water and oil is small ($V_p$ increases with pressure at a rate of 4 (m/s)/MPa in the oil, approximately).

### Experimental procedure

The rock samples were cut to appropriate lengths, cleaned in toluene/methanol extractors, and dried in an oven. The lengths of the samples ranged from 5 to 10 cm and the diameters were all 3.8 cm. Porosity, gas permeability, and grain density were measured on each sample after cleaning and before velocity measurements.

The sample was first jacketed in a high-temperature plastic sleeve to separate pore pressure from overburden pressure and

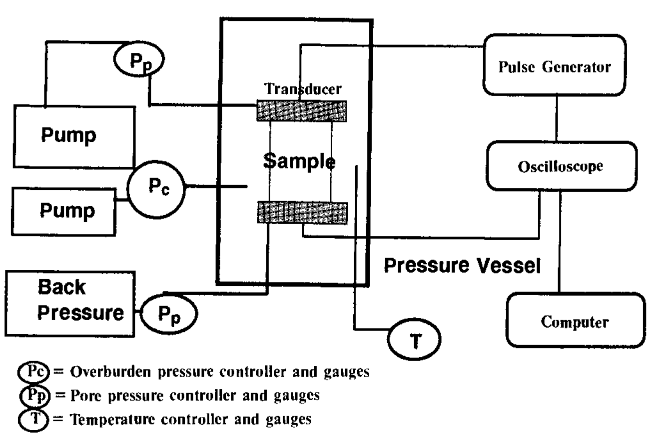



FIG. 1. Schematic diagram of the acoustic measurement system.

**Table 1. Physical properties of the pore fluids.**

| | Room condition | | | 70°C and 13.8 MPa |
|---|---|---|---|---|
| Fluid | Density (g/cm$^3$) | Viscosity (mPa.s) | Velocity (m/s) | Velocity (m/s) |
| Air | — | — | 340 | 350 |
| Oil | 0.835 | 17.0 | 1410 | 1285 |
| Pentane | 0.626 | 0.2 | 1030 | 860 |
| Water | 0.997 | 1.0 | 1492 | 1581 |

then loaded into the hydrostatic pressure vessel. Overburden pressure was increased to 48.3 MPa and then lowered to 6.9 MPa with zero pore (fluid) pressure to eliminate compaction effects and velocity hysteresis. Temperature was raised to reservoir temperature through a heater in the pressure vessel.

When the rock sample was heated and temperature had reached equilibrium, velocities in the dry (with air in the pores) rock were measured versus overburden pressure. Afterwards, the rock sample was evacuated and saturated with oil. The sample was left overnight for saturation at overburden pressure 20.7 MPa and pore pressure 13.8 MPa.

After the velocities were measured in the oil-saturated sample, about 25 pore volumes of normal pentane ($C_5H_{12}$) was flooded through the sample at a flow rate of 0.1 − 0.5 $cm^3$/minute (only the carbonate samples and some selected sandstone and sand samples were subjected to pentane flood in the experiments). The pore pressure was controlled at a constant 13.8 MPa by the back-pressure regulator throughout the flooding. The pentane-flooded sample was left for about 16 hours before the velocities were measured. Since the oil is soluble in pentane, the residual oil in the rocks is usually less than 25 percent after pentane-flood.

Finally the sample was flooded with fresh water under the same conditions as in the pentane flood. Typically 30 to 50 pore volumes of water was forced through each rock sample. The water-flooded sample was also left in the pressure vessel for about 16 hours before the velocities were measured. After the final velocity measurement, residual oil (oil or oil-pentane mixture) saturation in the core was determined which ranged from 47 to 54 percent.

## EXPERIMENTAL RESULTS

### Carbonate cores

The effect of water flooding was measured in 39 carbonate core samples. Figure 3 shows, as an example, the velocities versus effective pressure in a limestone sample from the West Pembina reservoir at reservoir temperature. The compressional velocity $V_p$ increases significantly as the gas in the core is replaced by the 35° API oil, especially in the low effective pressure range. The shear velocity $V_s$ is only slightly affected. This $V_p$ increase is more than 5 percent in the majority (about 75 percent) of the carbonate cores at effective pressures below 20.7 MPa. When the oil-saturated core is flooded with pentane, $V_p$ decreases, usually by 1 to 10 percent, depending on the sample. However, when the oil-saturated core is flooded with fresh water, $V_p$ increases by only a small amount. In fact, some cores show lower $V_p$ in the water-flooded cores than in the oil-saturated cores because of the increased density of the overall rock.

For the complete suite of carbonate cores, water-flooding changes the $V_p$ in the oil-saturated cores by −2 to 3 percent at an effective pressure of 20.7 MPa and reservoir temperatures (Figure 4). At lower effective pressures, this $V_p$ change is still less than 5 percent. In cores with oil-pentane mixture, water flooding increases the $V_p$ by less than 5 percent in over 65 percent of the measured carbonate cores (Figure 4).

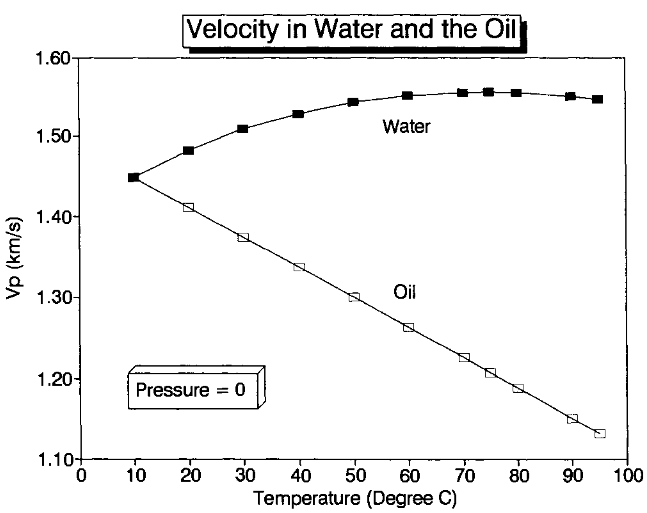



FIG. 2. Velocities in pure water and the mineral oil (35° API) versus temperature at ambient pressure.

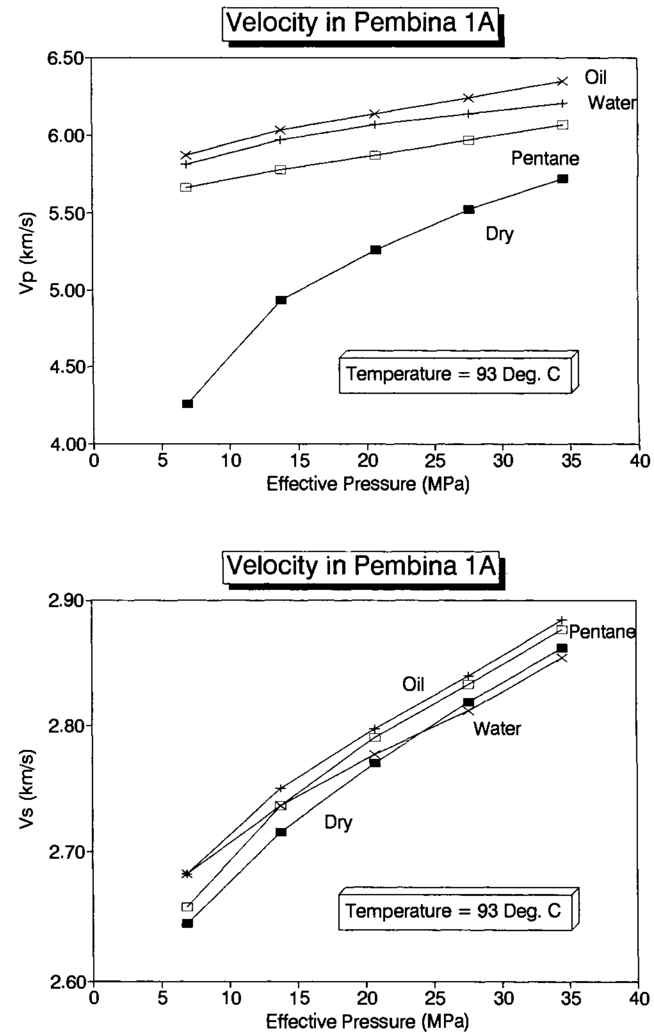



FIG. 3. Compression $V_p$ (a) and shear $V_s$ (b) velocities in Pembina sample 1A. In the figures, "Oil" represents the measured velocities in the oil-saturated core; "Water" and "Petane" represent the velocities measured after the oil-saturated core was flooded by water and pentane, respectively; and "Dry" represents the velocities measured at the air-saturation condition.

### Sandstone cores

The effect of water flooding on the velocities was measured in 22 well-consolidated sandstone cores. Figure 5 shows the velocities, for example, in a Karr sandstone sample. As in the carbonate cores, the $V_p$ increases significantly when gas in the pores is replaced by the oil. This $V_p$ increase is more than 5 percent in over half of the sandstone cores at an effective pressure of 20.7 MPa (Figure 6). As the sandstone cores are flooded with pentane, $V_p$ decreases by 2 to 13 percent, depending on the effective pressure and temperature. When the oil-saturated sandstone cores are flooded with water, the $V_p$ changes by less than $\pm 3$ percent. The negative $V_p$ change means that the $V_p$ in the water-flooded core is actually lower than the value measured for the same core saturated with the oil (Figure 6). As observed in the carbonate cores, shear velocities in the sandstone cores are also insensitive to the pore fluid changes.

In the experiments, we also tried to first saturate the cores with fresh water then displace water with oil. $V_p$ is always higher in the water-saturated core than in the "oil-flooded" core (oil displacing water). However, in the case of water-displacing oil, more than 60 percent of the cores show that $V_p$ is lower in the water-flooded core than in the oil-saturated core, which means that water flood in rocks saturated with the 35° API oil may either increase or decrease the $V_p$.

### Unconsolidated samples

Figure 7 shows the velocities in an unconsolidated Ottawa sand versus effective pressure at 70° C. As the sand is saturated with the oil, the $V_p$ increases dramatically, by 21 percent at 34.5 MPa and up to 48 percent at 6.9 MPa effective pressures. When the oil-saturated sand is flooded with pentane, $V_p$ decreases by 8 to 16 percent. In contrast, when the oil-saturated sand is flooded with fresh water, $V_p$ increases by 8 to 14 percent. Furthermore, the $V_p$ difference between the dry and water-flooded sand ranges from 31 percent at 34.5 MPa up to 68 percent at 6.9 MPa effective pressures. As seen in the carbonate and sandstone samples, the $V_s$ is again insensitive to the pore-fluid changes. The $V_p$ in the other 5 unconsolidated samples saturated with the oil also shows a 7 to 15 percent (depending on the effective pressure) increase as the oil-saturated samples are flooded by water (Figure 6).

## GASSMANN ANALYSIS

Gassmann (1951) developed an equation which relates the moduli of the fluid-saturated rock to those of the frame and matrix of the rock and the pore fluid. The Gassmann equation is a low-frequency approximation to wave propa-

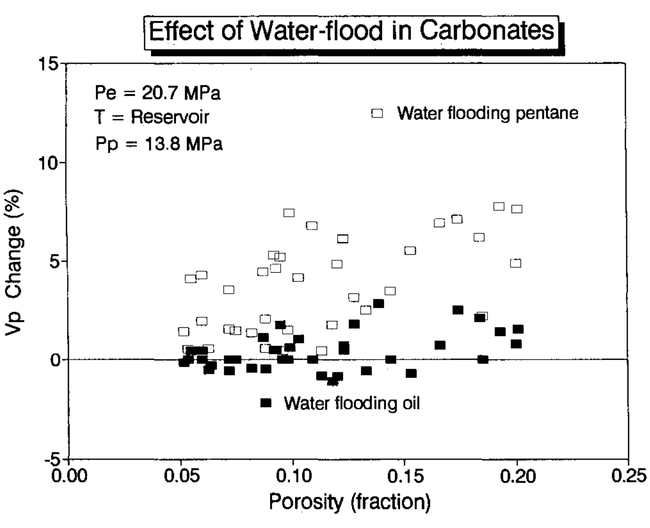



FIG. 4. Effect of water flood on $V_p$ in the carbonate samples. The solid squares represent the $V_p$ change after the oil-saturated cores were flooded with water, while the open squares represent the $V_p$ change after the pentane-flooded cores were further flooded with water. $P_e$ = effective pressure, $T$ = temperature, and $P_p$ = pore pressure ($P_e + P_p$ = overburden pressure).

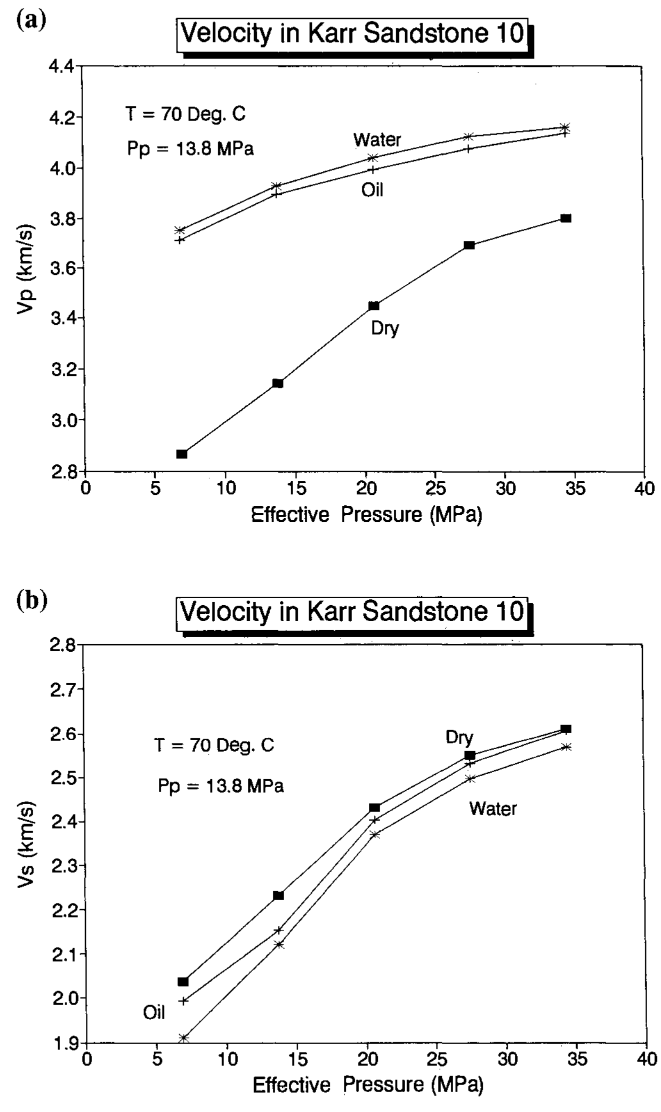



FIG. 5. Compressional $V_p$ (a) and shear $V_s$ (b) velocities in Karr sandstone sample 10. In the figures, "Oil" represents the measured velocities in the oil-saturated core; "Water" and "Petane" represent the velocities measured after the oil-saturated core was flooded by water and pentane, respectively; and "Dry" represents the velocities measured at the air-saturation condition.

gation in a porous medium. If the dry rock and fluid properties are known, the velocities in the fluid-saturated rock can be calculated. The equations are:

$$V_p^2 = \frac{1}{\rho_c}\left[\frac{(K_s - K_d)^2}{K_s\left[1 - \varphi - \left(\frac{K_d}{K_s}\right) + \varphi\left(\frac{K_s}{K_f}\right)\right]} + K_d + \tfrac{4}{3}\mu\right], \tag{1}$$

and

$$V_s^2 = \frac{\mu}{\rho_c}, \tag{2}$$

$K_d = \rho_d\,(V_{pd}^2 - \frac{4}{3}V_{sd}^2)$ and $\mu = \rho_d V_{sd}^2$ are the bulk and shear moduli of the dry rock, and $\rho_d = (1-\varphi)\rho_s$ is the density of the dry rock. $V_{pd}$ and $V_{sd}$ are the compressional and shear wave velocities in the dry rock; $\varphi$ is porosity; $\rho_s$ is density of the solid matrix; $K_f$ is bulk modulus of the pore fluid; $K_s$ is bulk modulus of the solid matrix; $\rho_f$ is density of the pore fluid; and $\rho_c = (1-\varphi)\rho_s + \varphi\rho_f$ is density of the saturated rock. In the calculations, the bulk modulus of the mineral matrix is assumed to be 80 GPa for limestone, 96 GPa for dolomite, and 40 GPa for sandstone and sand. The bulk and shear moduli of the dry rock are derived from the measured gas-saturated velocities. The bulk modulus of the pore fluid is also derived from the measured velocity. The density and porosity are measured directly.

Figure 8 shows the Gassmann-calculated effect of water flood on the $V_p$ in 39 carbonate cores saturated with the 35° API oil at an effective pressure of 20.7 MPa. The Gassmann equation predicts only 1 to 3 percent $V_p$ increases as the oil in the pore space is replaced by water. As with the measured velocity changes, the calculated effect of water flood on $V_p$ in these 39 cores is slightly higher at lower effective pressures. For example, at 6.9 MPa, the $V_p$ increase ranges from 1 to 4 percent in the same oil-saturated cores when flooded with water.

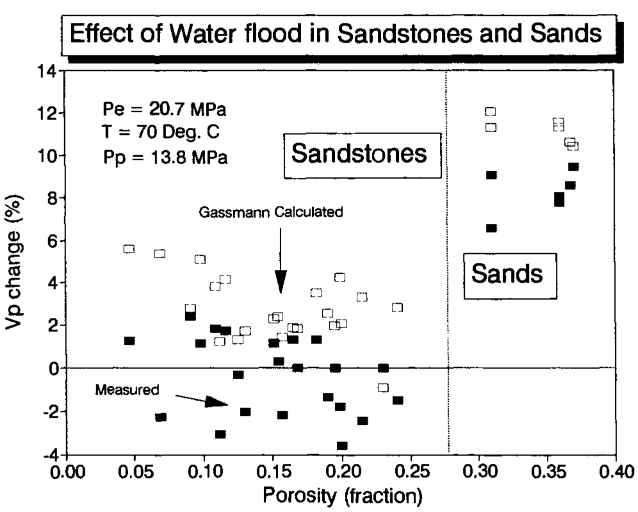



FIG. 6. Effect of water flood on $V_p$ in the sandstones and unconsolidated sands. The solid squares represent the $V_p$ change in the oil-saturated cores after water flood, while the open squares represent the Gassmann predicted $V_p$ change.

For consolidated sandstones (Figure 9), the $V_p$ increase calculated by the Gassmann equation is less than 5 percent in the majority of the oil-saturated cores when the saturating oil is substituted by water: Only three of the 22 sandstone samples show a 5 percent or more $V_p$ increase at a 20.7 MPa effective pressure. At 6.9 MPa, the $V_p$ increase exceeds 5 percent in seven of the oil-saturated sandstone samples when the oil is replaced by water.

Figure 9 also shows the effect of water flood on the $V_p$ in the oil-saturated unconsolidated samples calculated by the Gassmann equation. As the 35° API oil in the unconsolidated cores is replaced by water, the Gassmann equation predicts that the $V_p$ increases by 10 percent or more at 20.7 MPa. Furthermore, this calculated $V_p$ increase amounts to over 20 percent as pentane is replaced by water, and up to 58 percent as the gas in the pore space is replaced by water in the samples. This increase in $V_p$ is particularly large at low effective pressures. For example, water flooding results in a

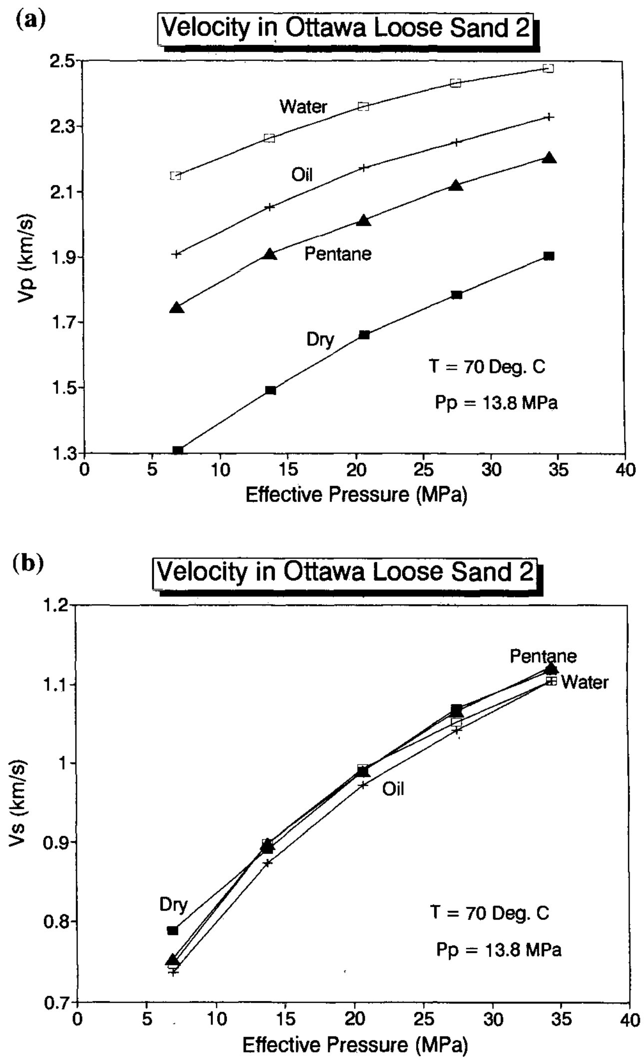



FIG. 7. Compressional $V_p$ (a) and shear $V_s$ (b) velocities in Ottawa unconsolidated sand sample 2. In the figures, "Oil" represents the measured velocities in the oil-saturated core; "Water" and "Petane" represent the velocities measured after the oil-saturated core was flooded by water and pentane, respectively; and "Dry" represents the velocities measured at the air-saturation condition.

14 to 15 percent $V_p$ increase in the oil-saturated unconsolidated cores at a 6.9 MPa effective pressure.

The magnitude of the calculated $V_p$ increase by the Gassmann equation when the oil in the rocks is replaced by water is usually higher than the measured $V_p$ increase. This is because, in the Gassmann calculation, a full oil or water saturation is assumed, while in reality the cores have approximately 50 percent residual oil saturation after water displacement. The combination of water and oil in the pore space may result in a lower $V_p$ value than that of the same core saturated with either oil or water, because the oil-water combination has a higher density than oil.

## DISCUSSION: FEASIBILITY OF IN-SITU SEISMIC MONITORING OF WATER FLOODS

Seismic modeling has shown that a minimum of 5 percent change in $V_p$ is needed in order to use seismic methods to monitor a specific EOR process (Hirsche et al., 1990). Our laboratory results show that high-frequency, high-resolution seismic methods may succeed in monitoring water-flood processes in some reservoirs under certain reservoir environments, while they are likely to fail in many other reservoirs under other reservoir environments. In this section, we analyze the feasibilities for seismic monitoring of water-flood processes.

(a)

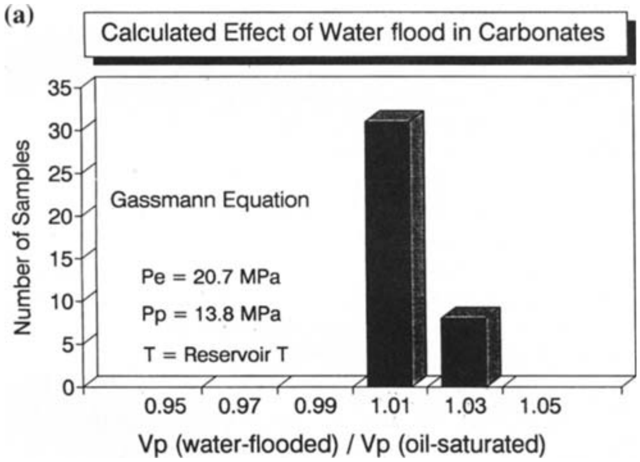



FIG. 8. Effect of water flooding on $V_p$ in the carbonate samples saturated with the oil calculated by the Gassmann equation. Gassmann equation predicts very small $V_p$ changes caused by water-flood in the oil-saturated carbonates.

(b)

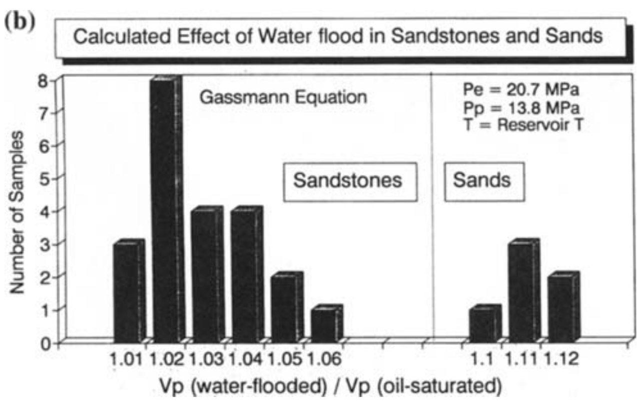



FIG. 9. Effect of water flooding on $V_p$ in the sandstone and unconsolidated samples saturated with the oil calculated by the Gassmann equation. According to the Gassmann equation, only three of the 22 sandstone samples, compared to all the unconsolidated core, show a 5 percent or more $V_p$ increase when the oil-saturated cores are water-flooded.

### Effect of reservoir depth and pressure

The experimental results show that the $V_p$ difference between gas- or oil-saturated and water-flooded rocks is greater at shallower reservoir depths (lower effective pressures). At lower effective pressures, the thin cracks, microfractures, or elongated pores in the rock, which contribute to most of the rock's compressibility, are still open. The rock's overall compressibility, and hence compressional velocity, is very sensitive to the compressibility change of the fluid in these thin pores. As the hydrocarbon (oil or gas) in the rock's pore space is replaced by the less compressible water, the $V_p$ increases in the overall rock. At higher effective pressures or greater reservoir depths, the thin compliant pores are closed and the rock's overall compressibility and hence compressional velocity are less sensitive to pore fluid changes because the round pores, which are still open, are relatively incompressible.

Decreasing effective pressure always decreases seismic velocities (e.g., Nur and Simmons, 1969). In water floods, the injection pressure of water must be higher than the formation pore pressure. This higher pore pressure caused by water injection decreases both the compressional and shear velocities, which further complicates the situation of seismic monitoring of water-floods in-situ. The velocity decrease caused by the higher pore pressure is offset by the compressibility decrease when the hydrocarbons in the reservoir rock are displaced by water. Therefore, the magnitude of the velocity change caused by water-flood in-situ may be less than that observed in the laboratory due to the higher pore pressure in water-flooded zones. In addition, seismic frequency content and signal to noise ratio generally degrade with increasing depth. Thus seismic monitoring of water floods has a better chance of success in shallower reservoirs.

### Effect of reservoir temperature

The $V_p$ in water shows a maximum at about 73° C (atmospheric pressure) on the velocity-temperature curve (Figure 2). As pressure increases, this maximum shifts to higher temperatures and the dependency of the velocity on temperature decreases (Lawson and Hughes, 1963). In all hydrocarbon oils, $V_p$ always decreases with increasing temperature (Wang et al., 1990). This means that at higher reservoir temperatures, the difference between the $V_p$ in water and oil is higher. For example, at a 13.8 MPa pore pressure, the $V_p$ difference between water and the 35° API oil is only about 50 m/s at 21° C but almost 300 m/s at 75° C. Intuitively, when a rock is saturated with this oil and then flooded with water, the $V_p$ change in this rock will be greater at higher reservoir temperatures. Therefore, seismic monitoring of water-floods in-situ will have a better chance to succeed at higher reservoir temperatures. The water to be injected into the wells, however, is usually at surface temperature, while the reservoir temperature is higher. The cooling effect of the injected water will generally decrease the $V_p$ difference between the oil-saturated and water-flooded rock, because the $V_p$ difference between water and oil is smaller at lower temperatures.

### Effect of the original pore fluids

The magnitude of the velocity difference between the rock with injected water as opposed to the original pore fluids depends on the type of the original pore fluids in the reservoir (gas, light oil, or heavy oil, etc.). In gas reservoirs, as the injected water displaces the hydrocarbon gases and then saturates the reservoir rocks, the compressional velocity increases substantially if the water saturation reaches 100 percent. In light and medium oil reservoirs, the velocity contrast between oil and water may be large enough to increase the $V_p$ in the oil-saturated reservoir rocks when flooded with water.

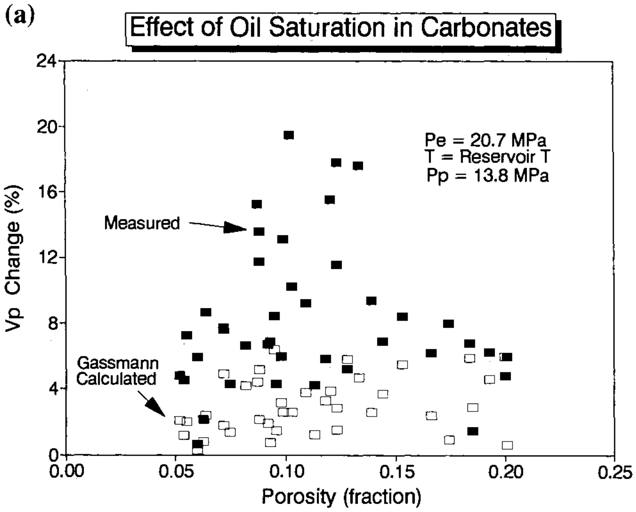
Figures 10a and 10b show the $V_p$ changes as the carbonate, sandstone, and unconsolidated cores are saturated with the 35° API oil, respectively, at an effective pressure of 20.7 MPa (overburden pressure = 34.5 MPa, pore pressure = 13.8 MPa). Thirty of the 39 carbonate cores (77 percent), 12 of the 22 sandstone cores (55 percent), and six of the six unconsolidated cores (100 percent) show a 5 percent or more $V_p$ increase as the gas in the cores is replaced by the oil. The magnitude of this $V_p$ increase is generally independent of porosity, especially in the carbonate cores. If the dry cores were saturated with water, more of them would show a 5 percent or more $V_p$ increase because the velocity in water is higher than that in this oil.

Figures 10a and 10b indicate that in most gas reservoirs, the $V_p$ will increase by 5 percent or more as the gas in the reservoir rocks is replaced by oil. Furthermore, at lower effective pressures (smaller reservoir depth), the magnitude of the $V_p$ increase is higher. For example, at an effective pressure of 6.9 MPa, about 90 percent of the measured carbonate and sandstone cores, and all the measured unconsolidated cores show a 5 percent or more $V_p$ increase as the dry cores are saturated with the oil. This suggests that gas reservoirs are always good candidates for seismic monitoring of water-flood processes.

The $V_p$ will increase more in live oil (oil with significant amount of gas in solution) reservoirs than in dead oil (oil without dissolved gases) reservoirs (with the same API gravity) when the reservoir rock is flooded with water because $V_p$ in a live oil is lower than that in a dead oil with similar gravity (Wang et al., 1990). Therefore, shallow live oil reservoirs are also good candidates for seismic monitoring of water flooding in-situ.

Water-flood may be monitored in conjunction with the monitoring of the gas cap's movement in live oil reservoirs. In live oil reservoirs, gas caps may form due to formation pressure depletion caused by production. As water is injected into the reservoir, the gas cap will move and shrink due to the increasing reservoir formation pressure (gas is produced). Because large $V_p$ contrast exists between gas- and fully water-saturated rocks, water-flooded zones may be seismically monitored through monitoring the gas cap's movement.

(a)




(b)

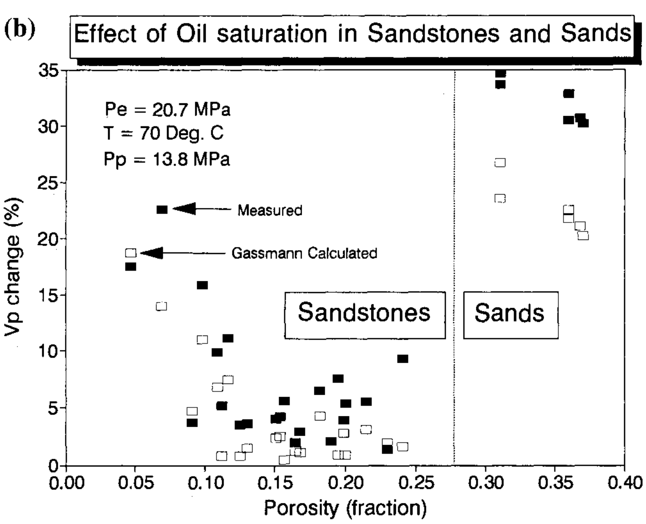



FIG. 10. Effect of the oil-saturation on $V_p$ in the carbonate (a) and sandstone and unconsolidated samples (b). The solid squares represent the $V_p$ change in the dry cores after oil-saturation, while the open squares represent the Gassmann predicted $V_p$ change.

### Effect of reservoir lithology

The effect of lithology is simply that in oil-saturated rocks, $V_p$ in carbonates are significantly less sensitive to water-flood than that in sandstones and sands. Thus seismic methods are likely to fail in monitoring water-flood processes in carbonate reservoirs. For most sandstone reservoirs, seismic monitoring of water floods requires that the oil be very light (API gravity >45 degrees) or have high gas-to-oil ratio (GOR) and the reservoir be shallow (<1 km). Both the laboratory results and theoretical analysis show that unconsolidated sand reservoirs are good candidates for seismic monitoring of water floods in-situ, especially when the API gravity of the reservoir oil is higher than 30 degrees.

### Effect of wave frequency

It has been shown that seismic waves can be considered nondispersive in dry rocks in the range from seismic (10–200 Hz) to laboratory (0.1–1.5 MHz) frequencies (Spencer, 1981; Jones, 1986). Laboratory-measured velocity values should be very close to those at seismic or log frequencies in dry or gas-saturated rocks.

In the local flow mechanism (O'Connell and Budiansky, 1977; Mavko and Nur, 1978), some parts of the pores in the rock are considered more compliant than others, e.g., thin pores or cracks are more compliant than round pores. A passing seismic wave deforms the pore space and thus induces the pore fluid in the more compliant parts to flow to the less compliant parts. At high frequencies, the pore pressure does not have enough time to reach equilibrium during the half period of the wave so that the rock-liquid system is at an "unrelaxed" state and the rock's moduli appear to be higher (Winkler, 1985; 1986). This local flow mechanism is related to the viscosity of the pore fluid, the presence of thin pores, and the connectivity of the thin pores to the round pores.

In gas reservoirs subjected to water flood, the magnitude of the $V_p$ increase is overestimated in the laboratory at 500 kHz because the $V_p$ has no dispersion in the gas-saturated rock but a few percent (usually below 3 percent) dispersion in the water-saturated rock from seismic to the laboratory frequencies. In the seismic frequency band in-situ, the effect of water flood on the $V_p$ in gas reservoirs should be slightly lower than that observed in the laboratory.

In light to medium oil-saturated rocks, the amount of velocity dispersion is usually slightly higher than, but very close to, that in the same rocks saturated with water. Thus the $V_p$ increase in light to medium oil-saturated rocks when flooded with water should be higher in the seismic frequency band than in the laboratory band. However, the difference between the effects of water flood on $V_p$ at low and high frequencies is usually small. Besides, the $V_p$ increase caused by water floods in light to medium oil-saturated rocks cannot exceed that in gas-saturated rocks: if there is not enough $V_p$ difference between gas-saturated and water-flooded rocks, there will not be enough $V_p$ difference between light to medium oil-saturated and water-flooded rocks, to monitor the water-flood process in-situ.

### Effects of other factors

Some other parameters may affect the effect of water floods on seismic velocities. These parameters include reservoir heterogeneity, displacement efficiency, degree of connate water saturation, viscous fingering, wettability, and pore geometry.

Reservoir heterogeneity may cause water channeling. Because of the high viscosity ratio between oil and water, viscous fingering may also occur. Both reservoir heterogeneity and viscous fingering will decrease the displacement efficiency in water floods and make in-situ seismic monitoring of water floods more difficult. As connate water saturation increases, the effect of water flood on seismic velocities decreases. In water-wet reservoirs with connate water saturation, the small and thin pores are occupied by water and the injected water displaces the oil in the big and round pores. Since the pore fluid in the thin pores are not changed, the $V_p$ will not be dramatically affected by water flood because the thin pores actually control most of the compressibility of the rock. In oil-wet reservoirs, the displacement efficiency of water flood is small and the oil occupies the small and thin pores which is usually not displaced by the injected water so that the $V_p$ is unlikely to be dramatically affected.

**Table 2. Feasibility of seismic monitoring of water floods.**

| Reservoir Rocks | Reservoir Fluids | Seismic monitoring of water flooding? |
|---|---|---|
| | Gas | Yes in many reservoirs. |
| Carbonate | Light Oil | Probable in some shallow reservoirs. |
| | Medium Oil | No. |
| | Heavy Oil | No. |
| | Gas | Yes in most reservoirs. |
| Sandstone | Light Oil | Probable in some shallow reservoirs. |
| | Medium Oil | No in most reservoirs. |
| | Heavy Oil | No. |
| Unconsolidated Sand | Gas | Yes in most reservoirs. |
| | Light Oil | Yes in most reservoirs. |
| | Medium Oil | Yes in many reservoirs. |
| | Heavy Oil | No. |

## CONCLUSION

Both laboratory results and theoretical analysis show that seismic methods may be applied to monitor water-flood processes in some reservoirs under certain conditions. This emphasizes the importance of petrophysical investigations and measurements of the rock and fluid properties prior to in-situ seismic monitoring. Furthermore, petrophysical results can serve as a tool to guide in interpreting the seismic data. In the literature, Donlop et al. (1988) successfully monitored an in-situ water flood over a shallow, high-porosity, and perhaps unconsolidated, reservoir. It is dangerous, however, to extend their success to other reservoirs without thorough petrophysical studies. Since the properties of a reservoir (both rock and fluid properties) can vary substantially from reservoir to reservoir, a complete feasibility study should be implemented prior to attempting in-situ seismic monitoring. This feasibility study should include a thorough understanding in reservoir geology, rock and fluid properties, reservoir parameters, laboratory measurements and theoretical calculations of the effect of water flood on the seismic properties of the reservoir rocks saturated with the reservoir pore fluids, and an economic assessment.

Table 2 summarizes the feasibilities of using seismic methods to monitor water-flood processes in reservoirs of various lithologies with different pore fluids.

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## APPENDIX
### PHYSICAL PROPERTIES OF THE ROCKS

Tables A-1 and A-2 list the physical properties of the rocks used in the water-flood experiments.

**Table A-1. Petrophysical properties of the carbonate samples.**

| Sample Formation | Sample Number | Depth (m) | Porosity (%) | Permeab (mD) | Grain Density (kg/m3) | Displacing Fluid |
|---|---|---|---|---|---|---|
| Kaybob | 3A | 2997.4 | 13.9 | 26.3 | 2700 | water |
| | 10B | 3015.4 | 9.9 | 2.3 | 2700 | water |
| | 19A | 3012.9 | 12.3 | 42.3 | 2700 | water |
| | 33A | 3026.5 | 5.5 | 0.11 | 2710 | water |
| | 40B | 3012.2 | 9.3 | 34.6 | 2690 | water |
| | 45A | 3014.3 | 17.4 | 122 | 2690 | water |
| | 109H | 3047.9 | 6.0 | 1.5 | 2700 | water |
| Boundary Lake | A | 1316.8 | 20.1 | 9.2 | 2820 | water |
| | B | 1338.7 | 18.5 | 16.5 | 2730 | water |
| | C | 1344.0 | 14.4 | 1.1 | 2740 | water |
| | D | 1329.6 | 18.4 | 5.1 | 2740 | water |
| Pembina | 1A | 2877.3 | 8.7 | 0.46 | 2840 | water |
| | 28A | 2893.0 | 8.8 | 6.8 | 2840 | water |
| | 94A | 1796.4 | 12.0 | 8.2 | 2840 | water |
| | 153A | 2932.7 | 13.3 | 968 | 2830 | water |
| Judy Creek | 9 | 2555.4 | 12.8 | 14.1 | 2700 | water |
| | 22 | 2565.5 | 20.0 | 22.7 | 2700 | water |
| | 39 | 2562.8 | 9.5 | 15.3 | 2700 | water |
| | 57 | 2567.6 | 19.3 | 190 | 2700 | water |
| | 77 | 2572.9 | 5.2 | 18.2 | 2700 | water |
| Leduc | 15H | 1561.3 | 5.4 | 0.87 | 2820 | water |
| | 15V | 1561.3 | 6.3 | 0.04 | 2820 | water |
| | 44H | 1572.7 | 11.3 | 35.2 | 2820 | water |
| | 44V | 1572.7 | 9.6 | 1.1 | 2820 | water |
| | 46H | 1573.1 | 10.3 | 9.2 | 2830 | water |
| | 46V | 1573.1 | 7.2 | 6.8 | 2830 | water |
| | 47V | 1573.3 | 8.8 | 1.6 | 2830 | water |
| | 81H | 1584.4 | 9.8 | 34.4 | 2850 | water |
| Norman Wells | 68 | 527.5 | 11.8 | 3.6 | 2720 | water |
| | 218 | 547.0 | 8.2 | 1.1 | 2700 | water |
| Golden Spike | C3-26 | 1743.8 | 16.6 | 65.3 | 2700 | water |
| | D3-26 | | 15.3 | 18.2 | 2700 | water |
| | A9 | | 7.2 | 1.8 | 2700 | water |
| | A11 | 1710.6 | 7.5 | 3.5 | 2700 | water |
| | 328 | 1748.1 | 9.2 | 8.0 | 2700 | water |
| | 342 | | 12.3 | 157 | 2700 | water |
| Rainbow Lake | 179 | 1813.0 | 6.0 | 0.07 | 2770 | water |
| | 233 | 1825.2 | 10.9 | 0.41 | 2800 | water |
| | 166B | 1838.9 | 6.4 | 0.19 | 2800 | water |

Table A-2. Petrophysical properties of the sandstone and sand samples.

| Sample Formation | Number | Depth (m) | Porosity (%) | Permeab. (mD) | Grain Density (kg/m$^3$) | Displacing Fluid |
|---|---|---|---|---|---|---|
| Berea | 5 | — | 24.1 | 237 | 2650 | water |
| Sandstone | 9 | — | 20.0 | 61 | 2650 | water |
| | 9-2 | — | 23.0 | 198 | 2650 | water |
| Viking | 5 | 1465.5 | 15.7 | 573 | 2660 | water |
| Sandstone | 7 | 1483.2 | 11.2 | 34 | 2670 | water |
| | 8 | 1483.6 | 19.5 | 1310 | 2670 | water |
| Ring | 7 | 807.8 | 19.9 | 6.77 | 2650 | water |
| Gething | 12-2 | 809.2 | 15.1 | 1.42 | 2640 | oil |
| Sandstone | 17 | 810.9 | 12.5 | 2.03 | 2640 | water |
| Ring | 38 | 820.3 | 19.0 | 1.78 | 2680 | water |
| Montney | 46 | 822.9 | 18.2 | 0.36 | 2670 | oil |
| Sandstone | 53 | 825.1 | 21.5 | 1.90 | 2650 | water |
| | 56 | 826.9 | 13.0 | 0.06 | 2690 | water |
| Karr | 2 | 2303.2 | 6.9 | 0.07 | 2700 | water |
| Bluesky | 10 | 2308.0 | 9.8 | 0.27 | 2650 | oil |
| Sandstone | 11 | 2308.2 | 10.9 | 0.52 | 2660 | oil |
| | 12 | 2308.4 | 11.6 | 0.94 | 2650 | oil |
| | 16 | 2311.2 | 4.7 | 0.02 | 2680 | water |
| Brassey | 1 | 3068.6 | 16.8 | 3.62 | 2650 | water |
| Artex | 3 | 3068.8 | 16.5 | 1.71 | 2670 | oil |
| Sandstone | 5 | 3069.0 | 15.4 | 2.76 | 2620 | water |
| | 6 | 3069.1 | 9.1 | 0.02 | 2560 | oil |
| Ottawa | 1 | — | 37.0 | ~3000 | | water |
| Sand | 2 | — | 36.8 | ~3000 | 2650 | water |
| Blend | 1 | — | 36.0 | ~2500 | 2620 | oil |
| Sand | 2 | — | 36.0 | ~2500 | 2610 | oil |
| Glass | 1 | — | 31.0 | ~1700 | 2530 | oil |
| Beads | 2 | — | 31.0 | ~1700 | 2530 | oil |