Reservoir recovery processes and geophysics

M. Batzle and R. Christiansen, Colorado School of Mines
D-H. Han, Houston Advanced Research Center

The effect of various oil or gas production operations on reservoir conditions and seismic properties is examined in Table 1. The reservoir conditions that most strongly affect seismic properties are emphasized (pore pressure, effective pressure, and gas saturation). Most operations will change pore pressure and effective pressure and so alter the seismic properties. Some operations will lead to evolution of gas saturation or to increasing gas saturation, while others will decrease gas saturation. As demonstrated by the well-known Gassmann equations, seismic velocities decrease rapidly with the first 10% or so of gas saturation. Thus we need quantitative methods to predict even small changes in saturations. As detailed examples, we will look at two processes, carbon dioxide and steam flooding, which can be much more complicated than usually assumed in geophysics.

Hydrocarbons occur in a variety of conditions, in different phases, and with widely varying properties. Figure 1 shows the relation among the different mixtures. Velocities and densities will be high (close to water) for heavy "black" oils and will decrease dramatically as we move right toward lighter compounds. In many cases, the hydrocarbons are above critical pressure and temperature conditions (above critical point). Properties then can vary continuously from liquidlike for oils with gas in solution to gaslike for mixtures of light molecular weight. With changing pressure and temperature conditions, phase boundaries can be crossed, resulting in abrupt changes in fluid properties. Additional components are often injected during production, further complicating the distribution of compositions and properties.

We need enough information on the rocks, fluids, and physical conditions to interpret any velocity changes. In general, formation properties will be sensitive to factors including fluid composition, density, effective pressure, and temperature. Figure 2 shows a typical rock velocity behavior with pressure and saturation during a water flood where brine replaces oil. Near the injection wells, pore pressure may increase enough to lower velocity (a). As the sweep proceeds, brine invasion farther in the reservoir will increase velocity (b). Thus, velocity changes will vary over the length of a flow profile. Such combinations of effects were first described by Nur (*TLE*, 1989). Reservoir simulation is now sufficiently sophisticated to predict

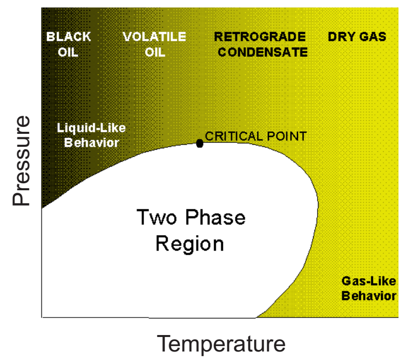

Figure 1. Generalized fluid phase behavior. Hydrocarbon mixtures can have a continuous range of properties from gaslike to liquidlike or mixed phase.

Table 1. General recovery processes and their effects*

Process description	Effect on reservoir conditons	Effect on seismic properties
Primary depletion with weak aquifer	Decrease pore pressure, increase effective pressure. Uniform increase in gas saturation when reservoir pressure falls below bubble point. Gas segregation upward if saturation exceeds critical value. Water saturation relatively constant.	Initial velocity increase with increasing effective pressure; decrease in velocity and density as free gas phase forms.
Primary depletion with strong aquifer	Pore pressure and effective pressure relatively constant. If pressure remains above bubble point, no gas saturation. Increasing water saturation.	Velocity and density increase as water saturation increases.
Water flood of formation with weak aquifer	Increase pore pressure, decrease effective pressure. Decreasing gas saturation spreading from injectors. Increase water saturation	Increasing velocity and density with increased water saturation and loss of gas. Possible velocity decrease near injector.
Pressure maintenance with gas	Pore pressure and effective pressure relatively constant. Increasing gas saturation spreading from injectors.	Velocity and density decrease with expanding gas cap. Oil-water contact relatively constant.
CO_2 flood	Increase pore pressure, decrease effective pressure. Increase CO_2 saturation from injectors. May create a bank of methane ahead of CO_2. Asphaltenes may precipitate.	Velocity and density decrease near injectors depending on pressure and temperature. Low-velocity zone if gas phase in methane bank forms (Figure 4).
Enriched hydrocarbon gas flood	Increase pore pressure, decrease effective pressure. Increase gas saturation spreading from injectors. Methane-rich bank may propagate ahead of oil bank. Asphaltenes may precipitate.	Velocity and density decrease near injectors depending on pressure and temperature. Low-velocity zone if gas phase in methane bank forms (Figure 2).
Steam flood	Increase pore pressure, decrease effective pressure. Increase formation temperature. Liquid water bank propagates ahead of steam.	Velocity drops with temperature rise and steam saturation. Slight velocity increase in water bank (Figure 5).

*For oil production unless otherwise noted.

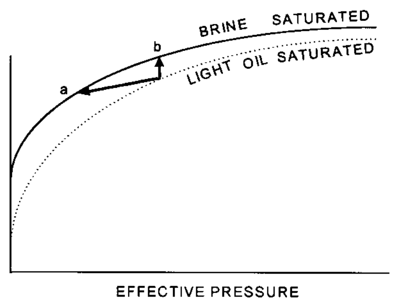

Figure 2. Generalized compressional velocity behavior during water injection. (a) Near an injector well and (b) near center of reservoir.

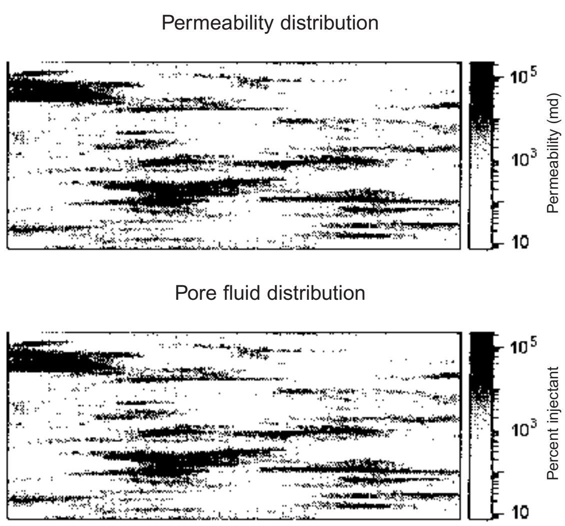

Figure 3. Permeability and pore fluid phase distribution for a modeled miscible gas injection (after Thiele et al., 1997).

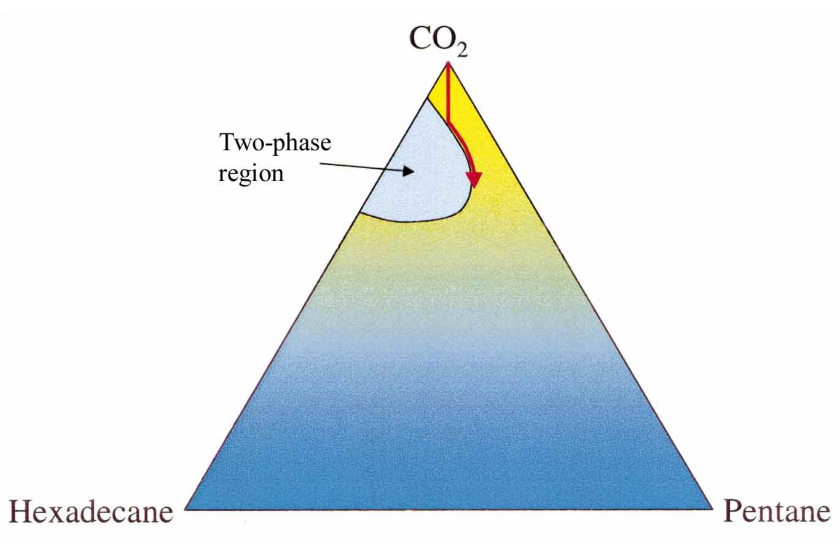

Figure 4. Three-component diagram: carbon dioxide, pentane (C5), and hexadecane (C16) at 160° F and 1200 psi.

pore fluid saturations based on the reservoir models. Figure 3 shows the modeled distribution of an enriched gas during a miscible flood. The flow and pressures will be controlled by the permeability distributions assigned. However, such simulations are primarily used to history-match bulk fluid production and may not correctly model important seismic events such as the development of small gas concentrations.

CO_2 flood example. Unusual conditions can develop during CO_2 flooding to improve oil recovery. Specifically, a methane-rich bank can propagate beyond the CO_2 zone and substantially lower seismic velocities.

Often, prior to CO_2 injection, reservoir pressure is increased by excess water injection. During this period, any in situ gas saturation will be reabsorbed by either hydrocarbon liquids or the brine phase. Furthermore, the increase in pore pressure will "inflate" the pore volume, thus altering the mechanical properties of the formation. Once the desired formation pressure is obtained, CO_2 injection finally begins.

The desired formation pressure is chosen to maximize oil recovery while minimizing compression and other operating costs. Generally, oil recovery from CO_2 injection increases with increasing pressure, but beyond the "minimum miscibility pressure" (MMP), the incremental benefit of increasing pressure is small. Hence, most CO_2 processes operate near the MMP. As the CO_2 displaces oil, a portion of the CO_2 is absorbed by the oil, and a portion of the lower molecular weight components in the oil vaporizes into the CO_2-rich phase. This process can be represented in a simplistic way with a ternary (or three-component) diagram.

Figure 4 shows a ternary diagram for CO_2, pentane, and hexadecane at 71° C and 1200 psi. Each vertex represents a single chemical species. The hill on the CO_2-hexadecane side of the diagram represents a two-phase region. With increasing pressure, the size of this hill decreases, allowing for more effective recovery of oil-pentane and hexadecane in this example. The path indicated by the red arrow shows the change in composition of the CO_2 phase as it moves away from an injector. The CO_2 phase becomes particularly enriched with pentane.

Although ternary diagrams are instructive, they cannot accurately represent the complexities of multicomponent mass transfer when CO_2 displaces a crude oil rather than a two-component idealization. However, much of the complexity can be captured in a quaternary (or four-component) diagram. The quaternary diagram shown in Figure 5 allows for representation of CO_2, methane, an intermediate molecular weight hydrocarbon pseudocomponent, and a higher molecular weight hydrocarbon pseudocomponent. A quaternary diagram is appealing because it allows for more accurate description of the effect of methane, but it is still an incomplete picture of reality. (Engineers capture more of reality with equations of state analysis of the CO_2 process.)

An important result of our analysis of the CO_2 process (as seen in Figure 5) is that a bank of gaseous methane can precede the CO_2-rich phase in a displacement process. The size of the methane bank depends on pressure, temperature, and oil composition in the formation. At pressures above the MMP, the bank should be nonexistent. As pressure decreases below the MMP, the size of the methane bank should increase. Obviously, input from compositional reservoir simulators could be quite

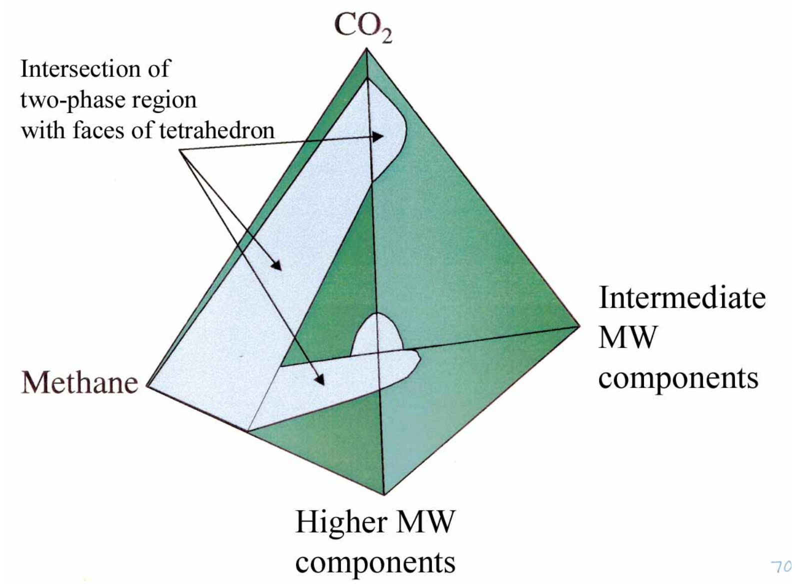

Figure 5. A quarternary (four-component) digram. Intermediate MW compounds consist of C_2-C_8 components. Higher MW contains all the heavier components.

helpful for interpreting the seismic response of a CO_2-invaded formation.

As a result of these chemical interactions, fluid properties will vary substantially along the injection-production profiles. Densities of fluids in the various regions could be quite different. Density of the injected CO_2 at the formation pressure is high, often 0.3-0.5 g/cm^3. Density of a methane-rich gas will be less than 0.1 g/cm^3. Similarly, seismic velocities will vary with the gas content. Figure 6a shows the expected pore fluid profile along a carbon dioxide flood. CO_2 is injected and becomes miscible with oil. As the CO_2 is absorbed, oil swells and viscosity drops. Because of the methane enrichment during sweep, a zone of high dissolved gas content builds following the initial front. Under conditions where sufficient methane is stripped, the zone with a separate gas phase evolves. Since small concentrations of gas make the fluid mixture much more compliant, seismic velocities will drop over this free gas zone, as indicated in Figure 6b.

Steam flood example. In thermal flooding, temperatures are increased to lower viscosities and mobilize oil. Steam flooding is the primary example. Steam quality, or liquid water content, can vary substantially both in time and among different project sites. In any case, the steam eventually condenses into water, often near the injection borehole. Pressures are usually low since this is typically a near-surface process. (A fire flood is a variation on this technique in which air or oxygen is injected and combustion occurs in the formation. Combustion products are then included with the steam.)

As temperatures increase, density and seismic velocities will decrease, primarily due to the temperature effects on the pore fluid. These velocity decreases are followed by a further drop as the pore fluid changes phase from liquid water to steam (Figure 7). However, pressure variations will complicate this relation, as free hydrocarbon gas can go in and out of solution depending on the pressure and temperature conditions. Pressure variations travel much more quickly and will be more extensive than the thermal front. The small variations in gas saturation with pressure may dominate the overall seismic image.

As with the CO_2 flood, compositions and phases vary across the reservoir profile. Both the elevated temperatures and gas (steam) saturation result in low velocities near the injectors. Figure 8 shows the expected pore fluid profile and velocity profile expected across such a steam flood. The initial steam, saturated zone may not be extensive. As heat is dissipated into the formation, hot water condenses and eventually a bank of high water saturation is built up in front of the flood front. A bank of mobilized oil precedes the hot water bank. Just from fluid saturation conditions, we would expect low velocities in the steam zone but higher velocities in the water and oil zones. These types of floods are usually conducted in shallow reservoirs with low pore and effective pressures and rocks will be sensitive to injection pressures (Figure 2). Because of the shallow depths, sensitivity of the rocks, and major changes in fluid properties, steam floods are among the best targets for time-lapse seismic monitoring.

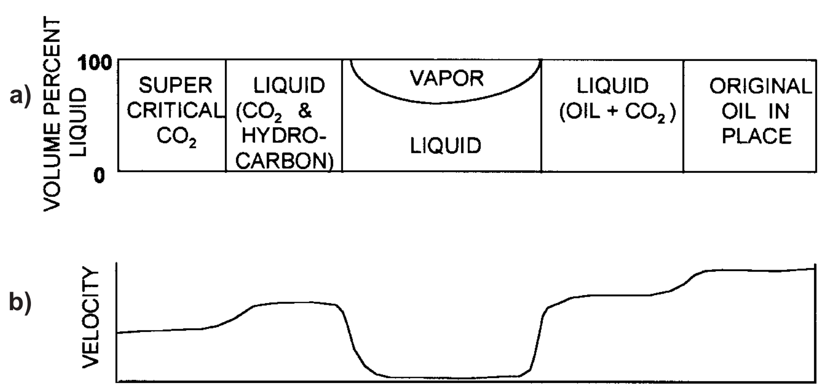

Figure 6. (a) Fluid saturation profile during a CO_2 flood at about 8000 kPa and 71° C. At other pressures and temperatures, a free-gas phase may not occur (from Metcalf and Yarbrough, 1979). (b) Expected compressional velocity and density profile.

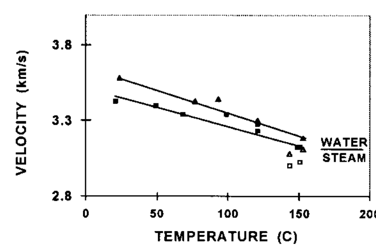

Figure 7. Temperature and saturation effects on Holt sand compressional velocity. Solid symbols = water saturated. Open symbols = steam saturated. (From Greaves et al., 1983)

Conclusions. The wide variety of reservoir processes each can produce subtle and unexpected results on seismic data. Seismic interpretation needs to be done within a context of realistic reservoir properties and conditions. Liquids will be exchanged and gas may appear. Pressures will vary between injectors and producers and can dominate the rock response. Reservoir simulations can predict important factors, but these simulations usually focus on fluid production and must be tuned to emphasize seismic responses. The distribution of properties within the reservoir will be systematic but very heterogeneous. LE

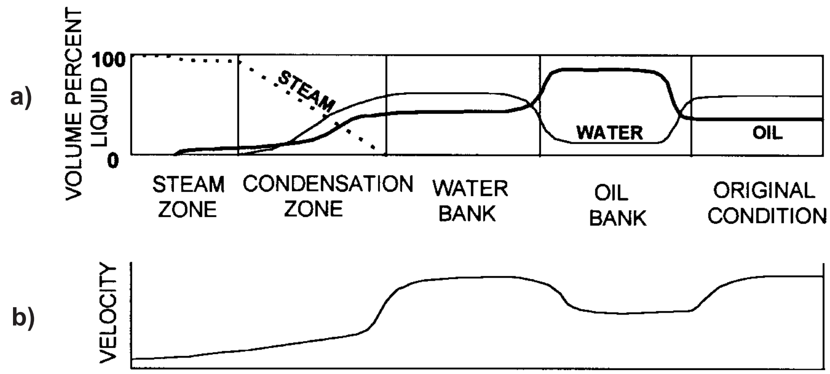

Figure 8. (a) Schematic fluid saturation profile during a steam flood (modified from Tadema, 1959). (b) Expected compressional velocity and density profile

Suggestions for further reading. "Seismic monitoring of steam-based recovery of bitumen" by Eastwood et al. (*TLE,* 1994). "Interpretation and description of in-situ combustion propagation from geologic and seismic data" by Greaves et al. (in *Time-lapse seismic in reservoir management,* SEG, 1998). "Time-lapse monitoring of the Duri steamflood: A pilot and case study" by Jenkins et al. (*TLE,* 1997). "The effect of phase equilibria on the CO_2 displacement mechanism" by Metcalfe and Yarbrough (*SPE Journal,* 1979). "Four-dimensional seismology and (true) direct detection of hydrocarbons: the petrophysical basis" by Nur (*TLE,* 1989). "Mechanisms of oil production by underground combustion" by Tadema (*Proceedings of the Fifth World Petroleum Congress,* 1959). "A streamline-based 3D field scale compositional simulator" by Thiele et al. (1997 SPE annual technical conference).

Corresponding author: M. Batzle, 1-303-384-2067 or mbatzle@mines.edu