Stanford Exploration Project, Report 80, May 15, 2001, pages 1–268

3-D seismic monitoring of an active steamflood

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ABSTRACT

I present an idealized physical model of steamflood fluid-flow and make rock physics predictions of seismic impedance changes that might be observable in 3-D surface seismic monitoring data. Four distinct fluid-flow phases are considered. Closest to the steam injection well, a small hot steam zone should be very visible in seismic data due to a predicted 30% decrease in P-wave velocity (Vp) compared to pre-steam reservoir conditions. With increasing radial distance from the injector, an annulus of hot water is likely to be seismically transparent due to a weak (5%) decrease in Vp, but a larger radial annulus of hot oil may be visible due to a predicted 10–15% decrease in Vp. A high-pressure cold oil front is predicted to propagate away from the injector one order of magnitude faster than the thermal fronts. If the increased pore pressure due to steam injection forces the high-pressure cold oil to cross the bubble point, a large *increase* in Vp of at least 15% may be visible in seismic monitor data. This model is currently being tested on a 3-D field data set. Preliminary results are exciting and will be published later this year.

INTRODUCTION

The steamflood process is a common method of enhanced oil recovery in tertiary production. However, steam flow patterns and sweep efficiency can be unpredictable in the presence of reservoir heterogeneity. Recently, a few experiments have been conducted that consist of shooting several 3-D surface seismic "monitor" surveys in time-lapse mode during steam injection (e.g., Pullin et al., 1987, and Eastwood et al., 1994). The spatial changes in pressure, temperature and fluid saturation in the reservoir during steamflooding can cause dramatic changes in rock physics properties and seismic wavefield attributes (e.g., Ito et al., 1979; Wang and Nur, 1988). In principle, detecting and measuring changes in seismic response as a function of time can lead to a better understanding of the steamflood dynamics, and in turn, an optimized strategy for enhanced oil recovery (Nur, 1989). A first-order goal is to simply "detect" changes in the reservoir due to steam injection. This may appear in the form of velocity pull-down in seismic images associated with thermal effects, and amplitude focusing or attenuation. However, a more elusive goal is to use the seismic measurements to make quantitative statements about the steamflood fluid-flow process. Surface seismic monitoring could be extremely valuable in optimizing reservoir development and production if it could "resolve"

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individual steamflood fluid-phase fronts, and predict preferential directions for future oil production flow. To achieve this goal, I intend to integrate fundamental physics from fluid-flow simulation, rock physics, and seismic modeling, imaging and inversion. In particular, I hope to demonstrate that the seismic monitor surveys contain enough information to distinguish the spatial advance of: (1) a high-pressure, low-temperature heavy oil zone, (2) a high-pressure, high-temperature heavy oil zone, (3) a high-pressure, high-temperature water zone, and (4) a high-pressure, high-temperature desaturated steam zone. This model is currently being tested on a 3-D field data set. Preliminary results are exciting and will be published later this year.

AN IDEALIZED STEAMFLOOD MODEL

It is convenient to have an idealized model of the steamflood fluid-flow physical properties in order to make some predictions about the nature of rock physics and seismic responses during steam injection. I consider four separate fluid zones associated with the steamflood: (1) a high-pressure, low-temperature heavy oil zone, (2) a high-pressure, high-temperature heavy oil zone, (3) a high-pressure, high-temperature water zone, and (4) a high-pressure, high-temperature desaturated steam zone. This simple model is schematically diagrammed in Figure **??**. This model is slightly more complicated than the conventional block model of a heated zone and a cold zone, but does not try to incorporate the complexity of mixed fluid phases, emulsions, fingering, gravity overrides, etc., as described by Lake (1989) for example. This model is qualitatively supported by a common observation: pressure fronts travel faster than thermal fronts. In well-to-well pressure transient tests, it takes on the order of hours to days for a pressure pulse at one well to propagate to an adjacent well. Pressure is transmitted through the fluid in the connected pore space at a relatively fast rate because it does not require fluid transport or conduction to diffusively propagate. On the other hand, temperature monitoring wells show that thermal fronts take on the order of weeks to months to propagate similar well-to-well distances. This is because heat transfer must occur through a combination of conduction through the rock matrix and transport of heated fluids through the permeable pore space, both of which tend to be relatively slow processes. Therefore, to first approximation, a steam-induced pressure front will travel about one order of magnitude faster than the associated thermal front. This implies that to a distant observer in the reservoir, the first front to arrive will be a high-pressure cold oil front. The next zone to arrive will be high-pressure heated oil as the thermal effects propagate outward from the steam injector. A hot water zone of condensed steam follows that heats the oil ahead of it, lowering the oil viscosity enough to displace oil with water as it propagates radially away from the injector. Finally, closest to the injector, a hot steam zone with negligible fluid saturation exists as the heat source that drives the total fluid-flow process. It is likely that the steam zone would reach steady-state equilibrium conditions fairly quickly and maintain a stable but slowly expanding disk of growth. In contrast, the pressure front is likely to be large and may propagate rapidly to remote sections of the reservoir. The hot oil and water zones are probably intermediate in size between the steam and high-pressure cold zones.

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Figure 1: An idealized model of steamflood fluid flow. A rapid high-pressure cold front is expected to lead the injector flow, trailed by hot oil, hot water and hot steam zones. The relative dimensions of each zone may not be to scale, and complexities such as mixed phases and gravity overrides are neglected.

ROCK PHYSICS PREDICTIONS

Based on the simple steamflood model of Figure **??**, some rock physics analysis can be made to give approximate estimates of seismic impedance changes that may occur in the reservoir during the steamflood. These rock physics predictions give an indication as to what might be observed in time-lapse 3-D surface seismic monitor surveys. The effects of pressure, temperature, gas/fluid saturation, lithology, and hydrocarbon P-T phase diagrams are considered for each of the four steamflood zones described above.

Hi-pressure cold oil front

It has been experimentally observed that dry-rock measurements of P-wave velocity (Vp) and S-wave velocity (Vs) vary with differential pressure. Since the differential pressure P_d is equal to the overburden confining pressure P_c less the pore pressure P_p, and overburden pressure remains constant in a reservoir during production time scales, Vp and Vs can be graphed from dry rock measurements as a function of pore pressure. Han (1986) made core measurements on unconsolidated Ottawa sand (porosity 33%) that is structurally similar to many shallow reservoir rocks that are subject to cyclic steam soaking and steam injection drive. Han measured dry Vp and Vs as a function of confining hydrostatic stress, which can be converted into velocity as a function of pore pressure, as shown in Figure **??**. In many sedimentary basins, the overburden pressure increases approximately linearly with depth at 1 psi/ft. For a shallow reservoir at 200 m depth, the overburden pressure would be about 4.5 MPa (670 psi). After some time of primary and secondary production, the reservoir may have a pore pressure as low as 0.7 MPa (100 psi). During steam injection, the pore pressure at the injector may be as high as 2.4 MPa (350 psi), and would decay logarithmically with radial distance from the injector. This pore pressure increase of a few MPa due to steam injection decreases the P-wave velocity by only a few percent, as suggested by Figure **??**. The decrease may be slightly slightly more than Figure **??** suggests, because a shallow steamflood reservoir has an overburden pressure of about 5 MPa, whereas Han's data are more suited to a reservoir at 2 km depth and 51 MPa overburden pressure. In summary, the steamflood pore pressure effect at constant fluid saturation should not have a significant velocity impact. However, consider the situation where the

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Figure 2: Compressional and shear wave velocities in dry Ottawa sandstone versus pore pressure at 51 MPa overburden pressure (after Han, 1986).

reservoir is just below the bubble point pressure, such that the the oil saturation relative to gas is about 90%. If the bubble point pressure is 240 psi, then the 10% free gas in the reservoir is dissolved back into liquid oil as the high-pressure front passes by. This situation is depicted by the path A–B in the hydrocarbon phase diagram of Figure **??**: an increase in pressure at fixed temperature crosses the bubble point line. The change from an oil saturation of 0.9 to 1.0 can cause a dramatic effect in Vp, as first described by Domenico (1977). Figure **??** shows Domenico's experimental results that Vp can increase by at least 10% in this regime of fluid saturation contrast. Domenico's results were for brine/gas saturation, but they are equally applicable to oil/gas for our purposes. Combining the effects of pore pressure increase and gas saturation decrease across the bubble point, a net increase of at least 10% is expected in the high-pressure cold oil front compared to initial reservoir conditions, as shown in Figure **??**.

Hot oil zone

Now that we know that the dry-rock effects of pore-pressure increase alone cause a negligible decrease in Vp, we can focus on the hydrocarbon phase diagram and temperature effects. Wang and Nur (1988) performed experiments which showed the effects of temperature and oil/water/gas saturation on Ottawa sandstone, as diagrammed in Figure **??**. Assuming hot oil displaces original cold oil, in the hot oil zone of the advancing steam front, Figure **??** shows that this effect can cause Vp to decrease by as much as 15%. However, when both pressure and temperature increase, the gas saturation level may also change. To predict the latter, the bubble point pressure needs to be known for the reservoir oil as a function of temperature, which is

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Figure 3: Hydrocarbon phase diagram with contours of liquid oil saturation relative to gas. CP is the critical point, P-T is the pressure-temperature plane (after Dake, 1978).

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Figure 4: Vp and Vs versus brine saturation for Ottawa sandstone at a differential pressure of 10 MPa (after Domenico, 1977).

the uppermost contour in Figure **??**. Without knowing the exact shape of the phase space, an increase in both P and T can lead to total gas dissolution (path A–C), or can actually result in an increase in gas saturation (path A–D). Normally, one would expect the bubble point to increase slowly with temperature, such that a large pore pressure increase from 100 psi to 300 psi at hot oil temperatures of about 100 C would reduce the gas saturation, or totally dissolve it (path A–C). This would again increase the velocity by about 0-10% by the Domenico effect of Figure **??**. The net effect of temperature increase and some reduction in gas saturation might make a net impedance decrease of about 10% in the hot oil zone, as shown in Figure **??**.

Hot water zone

The hot water zone should have a simpler physical behavior compared to the case of hot/cold high-pressure oil at or near the bubble point. In this case, both hot oil and any residual gas saturation is largely driven out by a hot waterflood bank. The Vp contrast should be similar to moving from the cold oil curve to the hot water curve in Figure **??**. A net impedance decrease of about 5% is expected in the hot water zone, as shown in Figure **??**.

Hot steam zone

When the steam zone arrives, nearly all fluid is driven out of the pore space, and is the primary mechanism for driving the hot water zone forward. Figure **??** shows that the change from initial cold oil to hot steam causes a dramatic decrease in Vp by about 30%. Note that about 25% of this decrease is due to the gas saturation change effect, and only a a further decrease of 5% is added by the thermal effect. The net effect is an impedance decrease of approximately 30% in the steamed zone, as shown in Figure **??**.

Impedance contrast profile

Figure **??** shows the predicted impedance contrast profile in the radial direction away from the injector, obtained by combining the rock physics results above. The rapidly outward-propagating pressure front leads the thermal fronts, and if the reservoir is initially just below the bubble point pressure, the pressure front will appear seismically as an increase in Vp by at least 10%, marked by velocity pull-ups and a positive reflection coefficient. The thermal fronts are likely to lag behind the leading pressure front by many months of steam injection. The outermost thermal front is likely to contain hot oil and be characterized by a decrease in Vp of about 10%, including seismic velocity pull-down and a negative reflection coefficient. Just behind the hot oil front, a hot water front is likely to exist. Its decrease in Vp is marginal at 0–5% depending on residual gas saturation after waterflood, and may be very difficult to observe in the seismic monitor data. Finally, a small stable steam zone should surround the injector, perhaps growing in diameter at a very slow rate. This steam zone has a net decrease in Vp of about 30% and should be very visible in the seismic monitor data by strong velocity pull-down and very bright negative reflection coefficient polarity.

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Figure 5: Vp measurements as a function of temperature and saturation with air, water and heavy crude in Ottawa sandstone (after Wang and Nur, 1988).

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Figure 6: Predicted steamflood P-impedance changes compared to initial reservoir conditions as a function of dimensionless radial distance.

SEISMIC PREDICTIONS

A most interesting prediction from this analysis is the possibility of observing a rapid, outward-propagating pressure front in 3-D seismic monitoring data. If the flow path of the trailing thermal front is established by the leading pressure front, then a map of any current pressure-front distribution would give not only a picture of where the pressure front is today, but also which path the hot oil is likely to follow over the next several months. If observable, this phenomenon would make a case for predicting future fluid flow using a current map of the pressure front distribution. Prediction time would be on the order of months in advance of the anticipated oil production, since hot oil would follow the slow thermal front, not the fast pressure front. If observable, this phenomenon could be very useful for interactively redesigning the field development and production plan for the reservoir in “real time”, using repeated 3-D seismic monitor surveys as a diagnostic tool. I am currently working with a 3-D seismic monitoring data set associated with an active steamflood project. 3-D seismic surveys are being acquired at regular intervals to monitor the effects of steam injection. The dataset includes a suite of well logs, temperature measurements and VSP surveys. The preliminary results are exciting, and I expect to report on the field data analysis later this year.

CONCLUSIONS

I have presented an idealized physical model of steamflood fluid-flow and made rock physics predictions of seismic impedance changes that might be observable in 3-D surface seismic monitoring data. A simple model of steamflood was proposed that distinguishes four fluid-flow phases: (1) a high-pressure, low-temperature heavy oil zone, (2) a high-pressure, high-temperature heavy oil zone, (3) a high-pressure, high-temperature water zone, and (4) a high-pressure, high-temperature desaturated steam zone. Seismic impedance contrast estimates were predicted for the steamflood fluid-flow model using experimental results from rock physics. I have predicted that seismic images might show the presence of a rapid outward-traveling high-pressure front due to steam injection. This pressure front could map reservoir heterogeneity and offer a prediction several months in advance of the future hot oil flowpath. I am currently testing these ideas on a 3-D field data set. Preliminary results are exciting and will be published later this year.

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