4-D seismic monitoring of an active steamflood[1]

David E. Lumley[2], Michel Bee[3], Steve Jenkins[3], and Zhijing Wang[4]

SUMMARY

Multiple 3-D seismic surveys have been acquired at time-lapse intervals over a heavy oil reservoir in the Duri field, Indonesia, to monitor the progress of an active steamflood. Time-lapse 3-D seismic images show dramatic and complex changes in the reservoir zone over a wide area, compared to baseline seismic data recorded prior to steam injection. Careful consideration of steamflood fluid-flow, rock physics measurements, finite-difference seismogram modeling, 3-D seismic imaging and velocity analysis leads to an integrated interpretation of the 4-D data set.

Anticipated large decreases in seismic P-wave velocity V_p near the injection well correlate with the presence of a hot steam-saturated zone. Unanticipated large *increases* in V_p and reflectivity changes in an annulus around the steam zone are consistent with a high-pressure front, in which initial free gas in pore space is raised above the bubble point pressure and dissolves into liquid oil. Horizontal and vertical anisotropy in flow directions inferred from these seismic observations correlate with two temperature monitor wells, and in situ measurements of upper and lower reservoir permeability. Since the pressure front propagates out from the injector at least one order of magnitude faster than either the thermal or steam fronts, monitoring it may be useful for predicting future flowpaths of heated oil and steam, months in advance.

INTRODUCTION

The steamflood process is a common method of enhanced oil recovery (EOR) in heavy oil reservoirs. However, steam flow directions, rates and sweep efficiency can be unpredictable in the presence of reservoir heterogeneity. This uncertainty can lead to expensive changes in injection well placement, intervals of perforation, and facility planning. Spatial changes in pressure, temperature and fluid saturation in the reservoir during steamflooding can cause dramatic changes in rock physics properties, and hence seismic wavefield attributes, e.g., Ito et al. (1989), Wang and Nur (1989). In principle, detecting and measuring changes in the seismic response as a function of time can lead to a better understanding of the steamflood fluid-flow dynamics, and in turn, can help optimize the production strategy for an EOR project (Nur, 1989).

Although the concept of time-lapse seismic reservoir monitoring is relatively new, a few notable pilot projects have been attempted at EOR steam sites. Pullin et al. (1987) collected two 3-D seismic surveys before and after a steam pilot at an Athabasca tar sands site. By comparing traveltime delay and amplitude attenuation maps between the two stacked surveys, they were able to qualitatively map the

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[1] Originally presented at the 1995 Annual International SEG Conference, Houston.
[2] Chevron Research, San Ramon, CA; formerly Stanford University.
[3] CalTex Pacific Indonesia, Rumbai, Indonesia.
[4] Chevron Research, La Habra, CA.

location of heated versus unheated zones. Their observed vertical traveltime delays and attenuations through heated sections of the reservoir compared qualitatively well with rock physics studies of the predicted thermal effects on seismic data. Eastwood et al. (1994) performed a similar analysis on a 3-D seismic monitor of an Alberta cyclic steam stimulation (CSS) project. They used two 3-D seismic surveys recorded at separate production and injection cycles, integrated with crosswell data, thermal reservoir simulations, and rock physics measurements. They state they can fit the magnitude of changes between two surveys, but less so the spatial distribution of changes. Non-steam seismic monitoring projects of interest include an in-situ combustion study by Greaves and Fulp (1987), and a gascap monitoring study in the Oseberg field by Johnstad et al. (1993).

FIELD DESCRIPTION

The 4-D seismic monitor data used in this study were recorded over a 7-spot production pattern, as shown in Figure 1, in the Duri field, Indonesia. Bee et al. (1994) give an excellent review of the field's history and current production, and discuss the 4-D experiment and first interpretation. The Duri field contains 5.3 billion barrels (bbls) of original oil in place (OOIP). Primary production was expected to produce only about 400 million bbls, 8% of OOIP, because the Duri oils are very viscous. With steamflooding, about 60% of OOIP is expected to be recovered, representing an additional 2.7 billion bbls of oil over primary production. Currently, about 40% of the field is undergoing steamflooding. The first steamflood patterns were drilled in 1985 and have increased the field production from about 40,000 bbls per day (BPD) to currently over 350,000 BPD. Over $1.2 billion has been invested in steamflooding to date, and the project is expected to encompass the entire field over the next 25 years.

However, clay layers at Duri can cause flow barriers, and heterogeneity can make steam flow directions unpredictable. For these reasons, a 4-D seismic monitor experiment was conducted on a small steam injection pattern to see if vertical and lateral steam flow could be mapped from seismic data. If seismic monitoring can increase the total field production by only 1% of OOIP, an extra 53 million bbls of oil will be gained, which makes the financial incentive favorable to try 4-D seismic at Duri.

4-D SEISMIC FIELD DATA

Figure 6 shows a 3-D migrated inline section from the baseline survey, a monitor survey after 5 months of steam injection, and the difference between the two. The location of the inline section passes through two temperature observation wells and the steam injector. The difference section shows that data above the reservoir top (160 ms) are highly repeatable. A major difference above the reservoir is the effect of a probable steam leak, labeled "B", at the borehole casing in the center of the profile. Major changes in the seismic data have occurred near the injection well (center) within the reservoir zone from 160–200 ms. The bright reflections labeled "S" are due to the presence of steam, and cause traveltime delay (velocity decrease) below the reservoir at the injector location.

An anomalous polarity change has occurred along the reservoir base at 200 ms, labeled "P" in the seismic sections. This strong reflectivity change is asymmetric in that it occurs to the east of the injector, but not to the west. Additionally, there appears to be a large traveltime pull-up (velocity increase) to the west of the injector, which gives a sinusoidal shape to the reflector at 200 ms, most visible in the monitor migration. The difference section shows that *within* the reservoir zone only a narrow

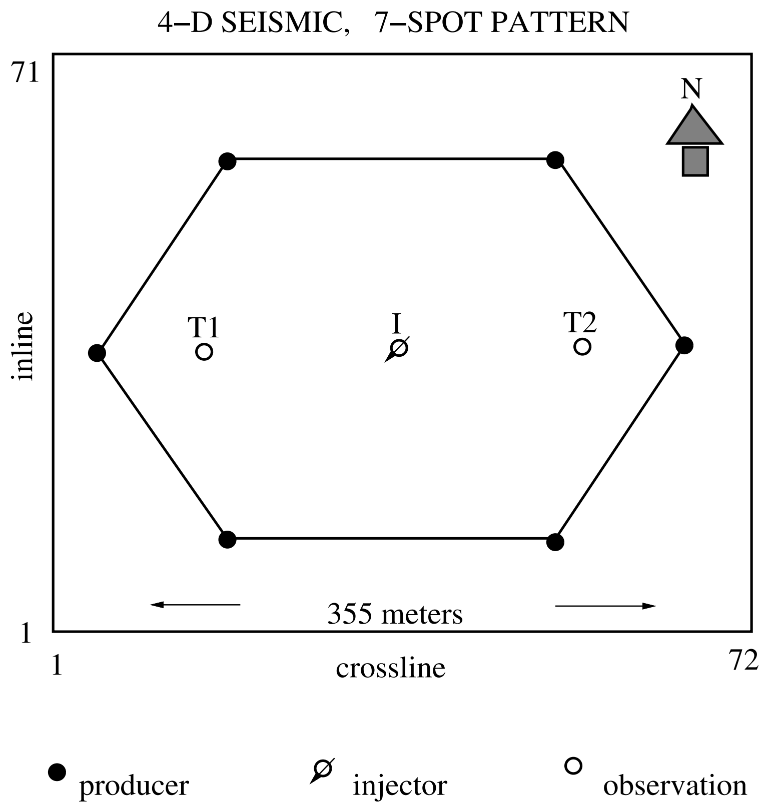

Figure 1: Duri 4-D seismic coverage over a 7-spot steamflood pattern. The steam injection well "I" is at the center, flanked by two temperature monitor wells "T1" and "T2".

width of about 50 m is affected by steam injection. However, *below* the reservoir base, large traveltime and reflectivity changes have occurred in the seismic data for at least 350 m out to the edges of the survey. Figure 7 shows a time slice near the base of the reservoir (204 ms) before and after steam injection. The time slices show dramatic change at the base of the reservoir. A bright reflective disk of diameter 50 m, labeled "S", is centered at the injector and correlates with the presence of steam. The steam disk is surrounded by a thin (20 m) dark gray annulus which correlates with a ring of condensed steam (hot water). A larger black "front" extends out to the edge of the survey to the east and south, labeled "P", and corresponds to the polarity reversal seen in the inline sections. The cause of this reflectivity change is uncertain, but may be due to steam override in the lower reservoir, near the base of the upper reservoir.

Since reflections from the region above the top of the reservoir are very repeatable in both surveys, we can be assured that changes in and below the reservoir are due to the steamflood process. These dramatic changes in seismic data during 5 months of steam injection raise many interesting questions. Do the bright reflections and traveltime delay in the reservoir indicate the presence of steam, or merely hot fluid? What is the cause of traveltime pull-up and the polarity reversals? Why are changes within the reservoir confined to a width of only 50 m, whereas changes below the reservoir extend at least 350 m out to the edge of the survey area? Answers to these questions may be obtained by carefully considering steamflood fluid-flow physics, core measurements, finite-difference seismic modeling, 3-D migration and velocity analysis.

RESERVOIR MODEL

The main oil reservoirs consist of highly unconsolidated sands and silts at depths of 140–230 meters. Sand porosities and permeabilities are high and range from 30–38% and 1–8 darcies respectively. Oil saturation ranges from 29–69%, with an estimated initial gas saturation of about 10% due to pressure drawdown during primary production. Duri oils have an API gravity of 22, and viscosities of 100–1000 cp. Overburden pressure is 530 psi, initial pore pressure is 100 psi, and ambient reservoir temperature is 100 F.

Core measurements

Core measurements were made by Zhijing Wang at Chevron's research facility. Six core samples were taken from the injection well location prior to steamflooding. The samples range from clean fine sand, to clay/silt/sand. The samples show highly unconsolidated sedimentary material. Some samples show coarse sand pockets which might represent potential high-porosity, high-permeability micro channels. The core samples were found to be very sensitive to temperature and saturation conditions, as shown in Figures 2 and 3. V_p decreases of 10–19% were measured for temperature increases from 25 C to 177 C at fixed overburden pressure for core samples saturated with 30–70% oil. An additional V_p decrease of 12–28% for the same temperature increase was measured on samples in which fluid had been replaced with steam (gas). At fixed overburden pressure and temperature, V_p decreases 3–9% as pore pressure increases from 100 psi to 400 psi in saturated samples. This is due to grain matrix compaction alone, not any phase change in the pore fluid. The effect of a decrease in gas saturation from 10% to 0% results in a velocity increase of 19–26%. An increase in gas saturation from 10% to 25% or more results in a 10–15% decrease in velocity.

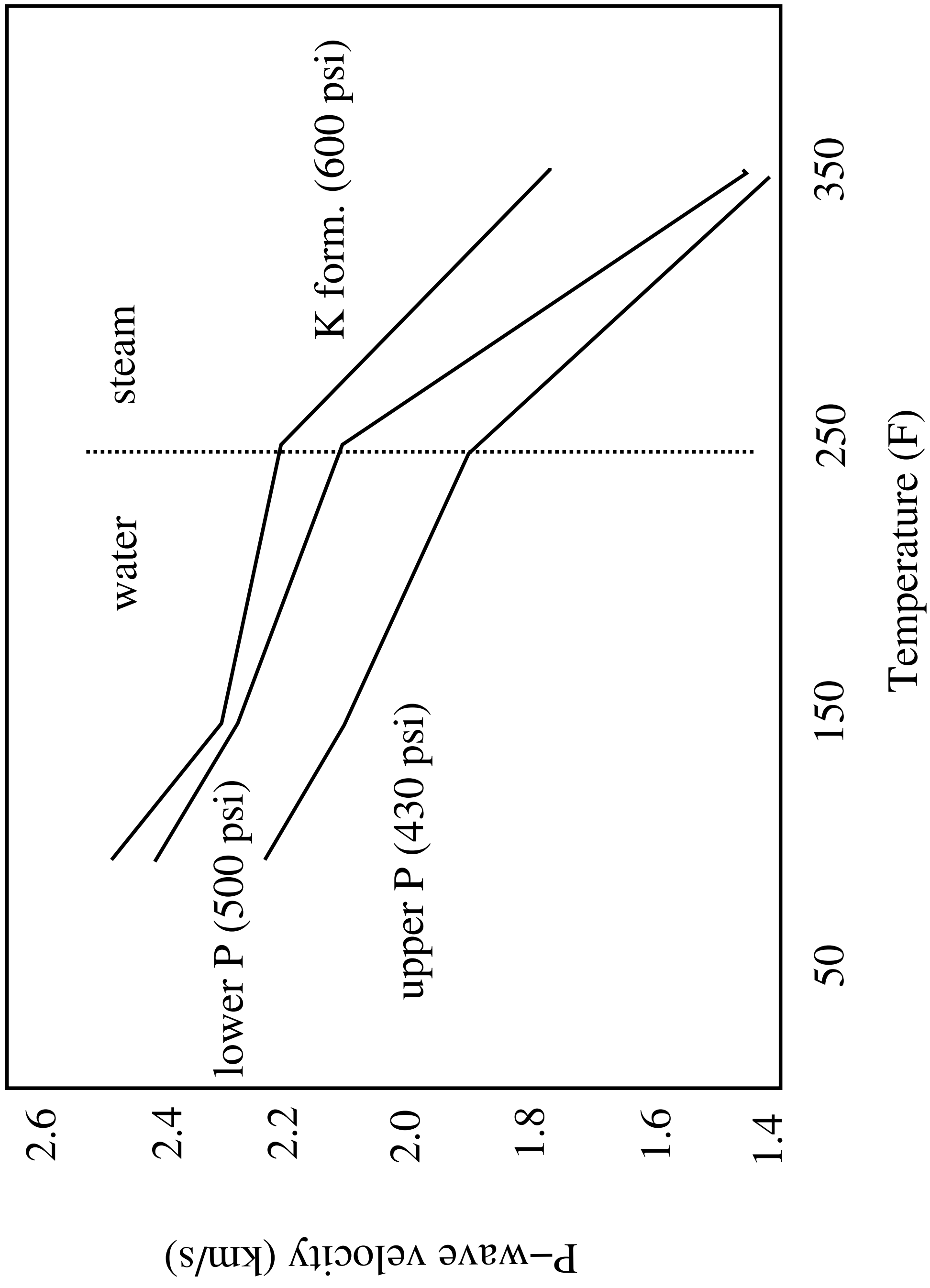

Figure 2: P-wave velocity as a function of temperature and overburden pressure for three saturated samples from the upper P, lower P, and K formations.

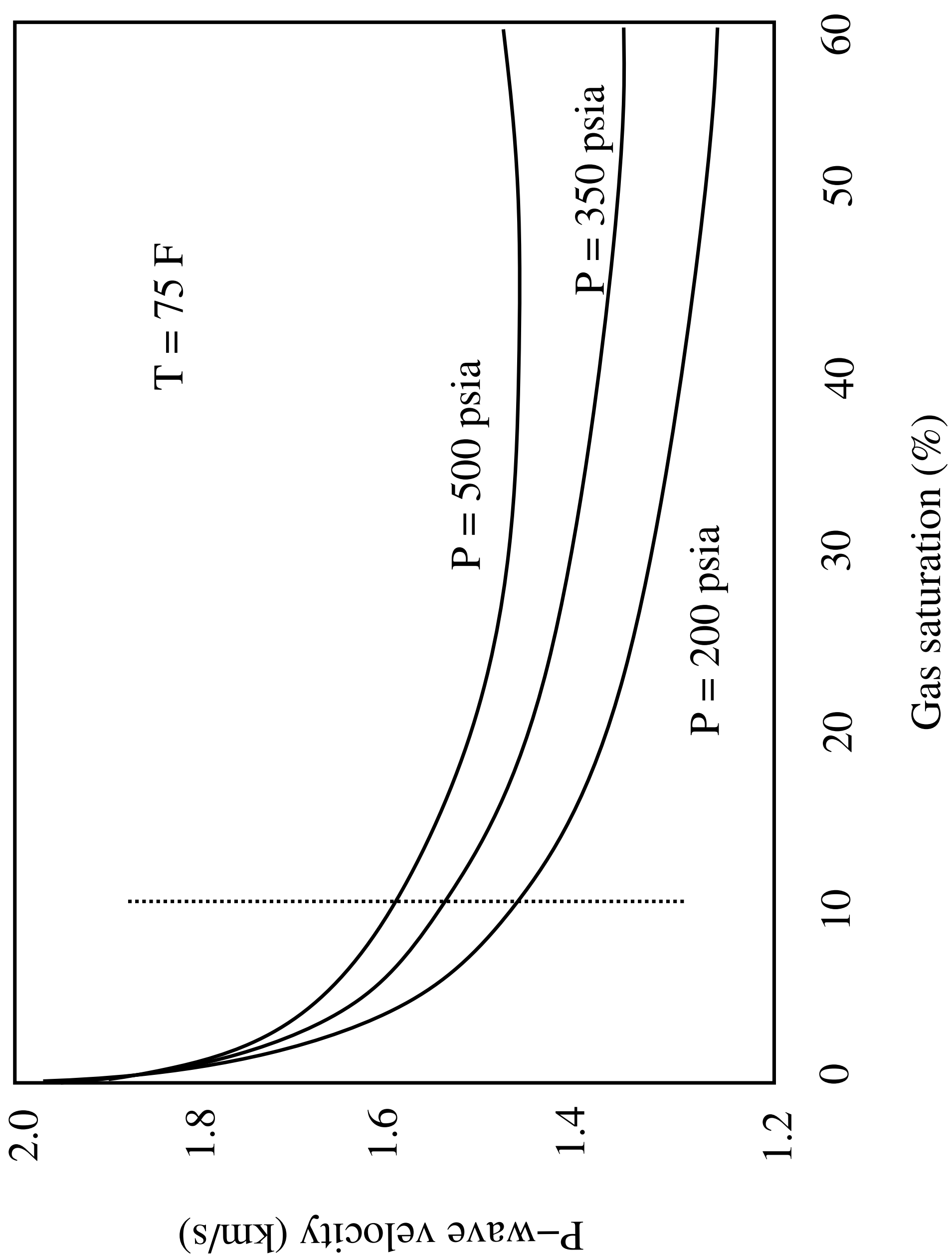

Figure 3: P-wave velocity as a function of gas saturation for a saturated sample at differential pressures of 200, 350 and 500 psia.

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. We consider four separate zones associated with the steamflood: (1) a high-pressure, low-temperature oil zone, (2) a high-pressure, high-temperature oil zone, (3) a high-pressure, high-temperature water zone, and (4) a high-pressure, high-temperature steam zone. This simple model is sketched in Figure 4. It does not account for more complex features such as oil fractionation, emulsions, fingering and gravity override (Lake, 1989).

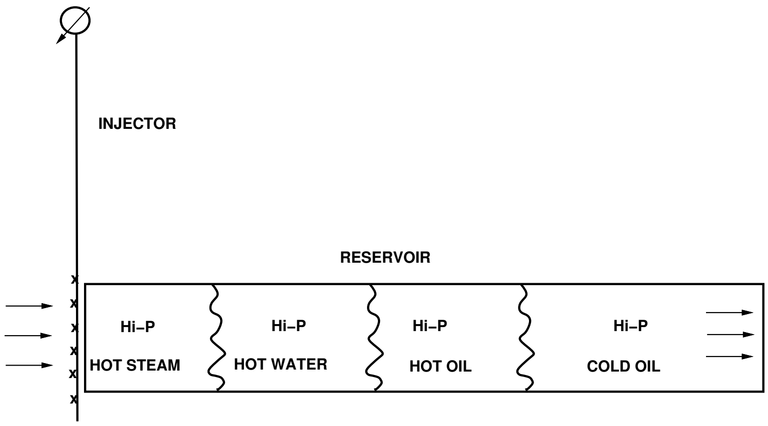

Figure 4: An idealized model of steamflood fluid flow. A rapid high-pressure cold front is expected to lead the injector flow, trailed by hot oil, hot water and hot steam zones. The relative dimensions of each zone are not to scale, and complexities such as mixed phases and gravity overrides are neglected.

Pressure front

The first change caused by steamflooding at a distant point in the reservoir should be an increase in pressure but not temperature. Empirically, a pressure front propagates at least one order of magnitude faster than thermal or steam fronts, which rely on the slower processes of conduction and advection to transport heat. Given that pore pressure at the injector is 350-400 psi, and initial pore pressure is 100 psi, the pore pressure associated with the pressure front may be about 150 psi. Bubble point at Duri is estimated to be about 110 psi, and so the initial 10% gas saturation is likely to dissolve into liquid oil behind the pressure front. Temperature in the pressure front is constant at an ambient 100 F. Combining these effects with the core measurement data, a velocity *increase* of 20% is expected in the propagating pressure front zone, compared to initial conditions, as shown in Figure 5. This velocity change suggests that the pressure front should be visible in seismic monitor data as large traveltime pull-ups and reflectivity changes.

Hot oil zone

A hot oil zone should trail the pressure front, where heat from the steam injector has heated initially cold oil. Wang and Nur (1989) demonstrated that heavy oil-saturated core samples exhibit strong velocity variation as a function of temperature, since heavy oil becomes more compressible when heated. This is confirmed by core measurements at Duri in Figure 2. A temperature increase to 250 F is expected in the hot oil zone, accompanied by a pore pressure increase to 200 psi. Since this pressure is above bubble point, a reduction in gas saturation from an initial 10% to 0% should occur. Combining these effects with the core measurement data, a net velocity change of $\pm 5\%$ is expected compared to initial conditions, depending on initial oil saturation and rock type as shown in Figure 5. The small magnitude and sign variation of these changes suggest that the hot oil zone is likely to be seismically transparent. This zero seismic response is explained in that the velocity increase caused by decreased gas saturation is approximately balanced by an equal velocity decrease caused by the heating of oil.

Hot water zone

A hot water annulus of condensed steam should trail the hot oil zone. The hot water zone is characterized by a temperature increase to 250 F and a pressure increase to 250 psi, compared to initial conditions. Water-saturated rock samples show small velocity decreases during heating (Wang and Nur, 1989). Assuming gas is displaced by hot water in the pore space, the gas saturation drops from an initial 10% to a final 0%. Combining these effects with the core measurement data, a net velocity *increase* of 10% is expected compared to initial conditions, as shown in Figure 5. This velocity increase is due mainly to the decrease in initial gas saturation, as opposed to thermal effects. This result implies that an annulus of hot water, if distinct from an oil-water emulsion, may be visible in seismic as small traveltime-pullups and weak reflectivity changes.

Steam zone

A steam-saturated zone may exist closest to the injector. Pore pressure in the steam zone may be as high as 250–400 psi. Temperature will range from 300–350 F. Steam will drive nearly all fluid out of pore space, so that the gas (steam) saturation in the steam zone is expected to be 90%. Combining these effects with the core measurement data, a net velocity *decrease* of 30% is expected compared to initial conditions, as shown in Figure 5. This implies a zone of steam would be visible in seismic as very bright reflectivity changes and large traveltime delays caused by velocity decrease. Note that the steam zone has seismic properties which allow it to be distinguished separately from the hot oil, hot water, or the pressure-front regions.

DISCUSSION

Figure 7 shows that after 5 months of steam injection, a disk of steam, centered on the steam injector, is visible in the seismic data that extends to a diameter of about 50 m, surrounded by what appears to be a 20 m annulus of hot-water steam condensate. A hot oil annulus does not appear to be seismically visible. Beyond that, a fast-propagating high-pressure cold oil front has propagated to the northwest, causing strong velocity increases by driving initial gas saturation above the bubble point. The evidence for the pressure front includes reflectivity changes along the base of reservoir reflector, and wide-spread seismic velocity increases within the reservoir out to the northwest edges of the survey, as seen in Figure 6. Figure 8 shows in time-slice form that after 19 months of steam injection, the steam front has followed the initial pressure front to the northwest, as confirmed by the presence of steam in temperature observation well "T1", but only small heating in "T2". Since the pressure front travels faster than the thermal or steam fronts, monitoring it could be a powerful technique for predicting future flowpaths of oil and steam, months in advance.

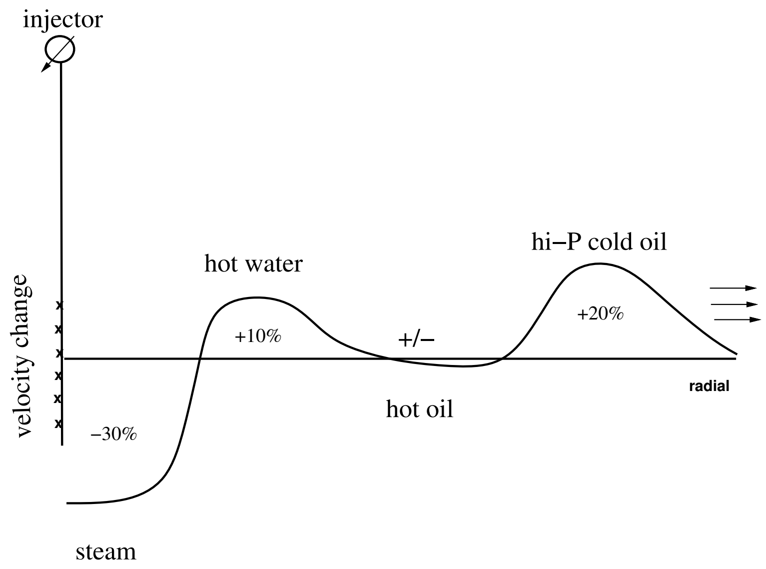

Figure 5: Predicted steamflood P-wave velocity changes compared to initial reservoir conditions as a function of dimensionless radial distance.

CONCLUSIONS

At the presentation, we will show how pressure, temperature, and saturation fronts can be monitored with six time-lapse 3-D seismic data sets at the Duri field 4-D pilot study. Our analysis combines field data observations with a steamflood fluid-flow model, rock physics analysis, seismic modeling, imaging and velocity analysis.

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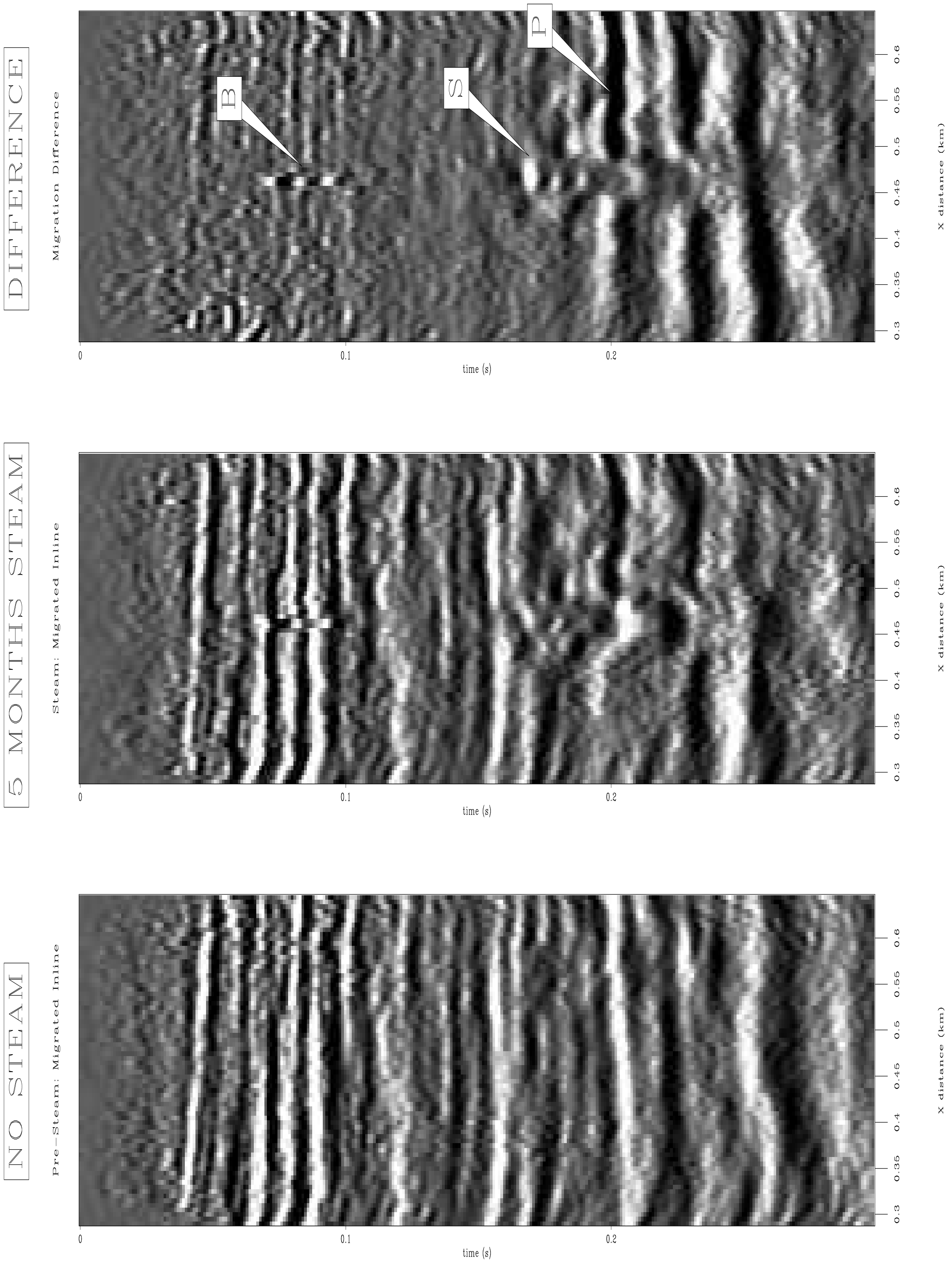
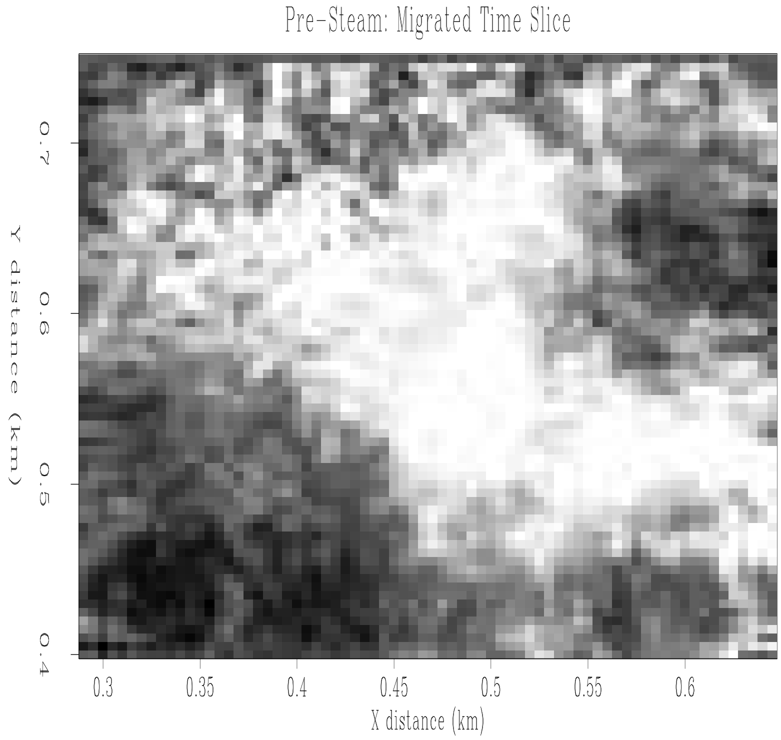


Figure 6: 3-D migrated inline sections: before steam injection (left), during steam (center), and the difference (right). "S" marks a steam zone, "B" marks borehole heating by a probable steam leak, and "P" marks a polarity reversal.



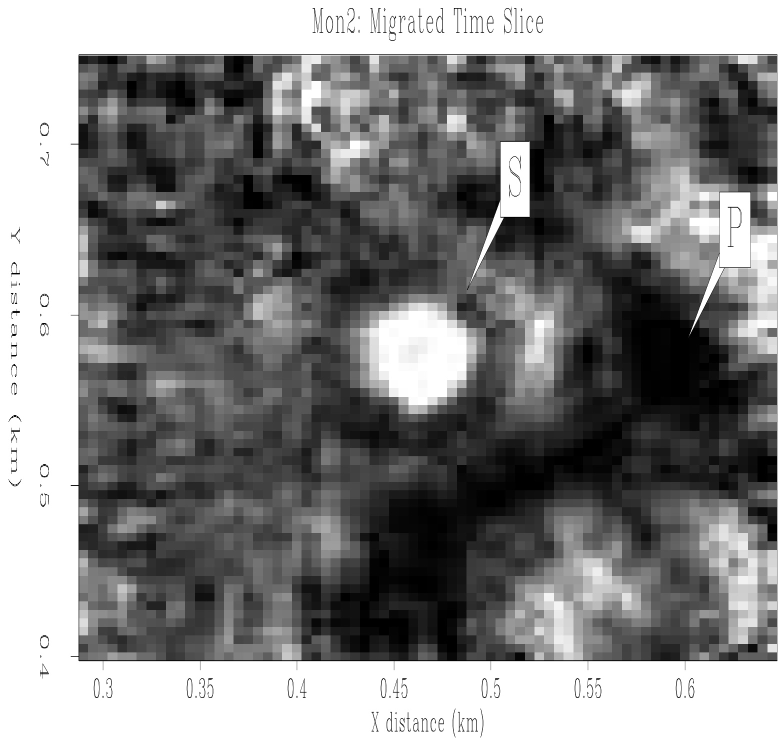


Figure 7: 3-D migrated time slices at the base of the reservoir (204 ms): before steam injection (top), and after 5 months of steam injection (bottom). "S" marks the steam zone, and "P" marks the polarity reversal associated with a possible steam override in a lower reservoir.

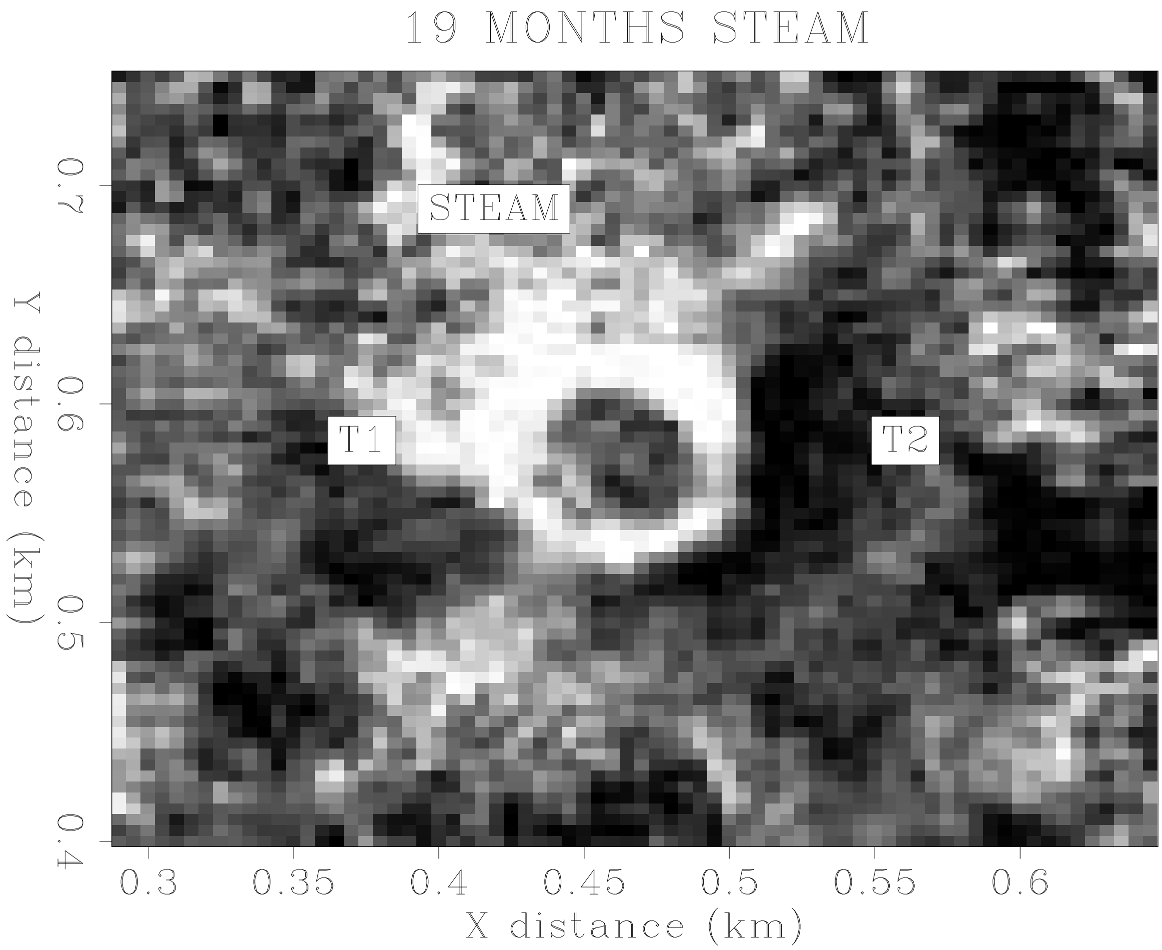


Figure 8: 3-D migrated time slice at the base of the reservoir after 19 months of steam injection. Steam has propagated preferentially to the northwest, as predicted by the path of the early pressure front, and confirmed by the presence of steam in temperature observation well “T1”, but only modest heating in “T2”.