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Integration of VSPs with oil sands SAGD operations

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Summary

A VSP using fiber-optic cable was acquired in a Steam Assisted Gravity Drainage (SAGD) operation in an Athabasca oil sands field in Alberta. The VSP interpretation is being integrated into the SAGD operations to help understand the behavior of the reservoir. Check shot information of two VSP wells was used to update the velocity model of the subsurface and assist with time-depth conversion of seismic data. Images of four 2D VSP lines were tested, evaluated and applied to measure time-shifts related to the SAGD steam chamber. Through this study, a baseline and a workflow for future time-lapse studies were built. Recommendations were made, based on data assessment of this project, for improving data quality of future VSP surveys as well.

Introduction

SAGD operations can be significantly enhanced by the accuracy of prediction of a subsurface geological model. The need for a better understanding of the reservoir motivates geophysicists to improve the resolution of seismic and conduct more accurate time-depth conversion. A Vertical Seismic Profile (VSP) is a measurement in which seismic signals are generated at the surface and recorded by receivers that are secured in a wellbore. A VSP has two advantages: first, it records reflection in both time and depth (therefore, it is widely used to calibrate surface seismic data to subsurface geological features). Second, due to its geometry, VSP data usually has higher resolution and signal-to-noise ratio because the seismic wave travels through attenuating near surface strata only once and seismic waves are recorded in the quiet borehole environment.

Since a VSP provides a more detailed image around the borehole than surface seismic data, and a VSP provides accurate time-depth conversion, it has great potential to monitor steam chamber development and identify thin shale layers in SAGD operations.

However, due to the high temperature of steam chambers, traditional geophones are not suitable for VSP’s in SAGD operations. As an alternative, optical fiber was used in this project because the fiber can handle the heat in a steam chamber. For this project, the fiber was permanently cemented behind the casing. The fiber-optic VSP and its deployment make time-lapse surveys more convenient and reduce costs relative to traditional geophone VSPs. However, the signal-to-noise ratio of optical fiber is low, which makes the project very challenging in acquisition, processing and interpretation. In this study, optical fiber VSP data was acquired and integrated into SAGD operations.

Distributed acoustic sensing (DAS) tool and VSP geometry

The study area is a northeastern Alberta Athabasca oil sands field, which is currently undergoing SAGD operations. Traditional geophones would fail due to high temperature of the steam, so optical fibers were used in this project because they allow for high temperatures (up to 300˚ C). One single optical fiber can replace hundreds of traditional sensors, making them very economic. The single mode fiber used is a Distributed Acoustic Sensing (DAS) fiber, which provides continuous acoustic measurements along its length. The DAS fiber can be temporarily deployed via wireline or coiled tubing, semi-permanently attached to production tubing, or permanently cemented behind casing, which is the case for this project.

The permanent deployment is convenient and decreases the cost for time-lapse surveys. This feature makes DAS-VSP's especially suitable for regular steam chamber monitoring.

Two VSP surveys were acquired in February 2015. Both VSPs are walkaway surveys with shots offset at various distance from wellbores (Figure 1). VSP1 produced two 2D lines with offset ranging from 0 - 400m. VSP2 produced two 2D lines perpendicular to each other and with offsets ranging from 0 - 360m. In order to improve S/N (signal/noise), groups of 8 vibrator sweeps were used in VSP1 with receiver type ODH3. In order to improve VSP2 still further, 4 vibrator sweeps were used, combined with a newer version of the receiver instrument: ODH4i. The fiber optic cables were connected to 28 channels, secured at depths ranging from 8 - 228m, with spacing of 8 m. With different combinations, both surveys produced comparable signal-to-noise ratios.

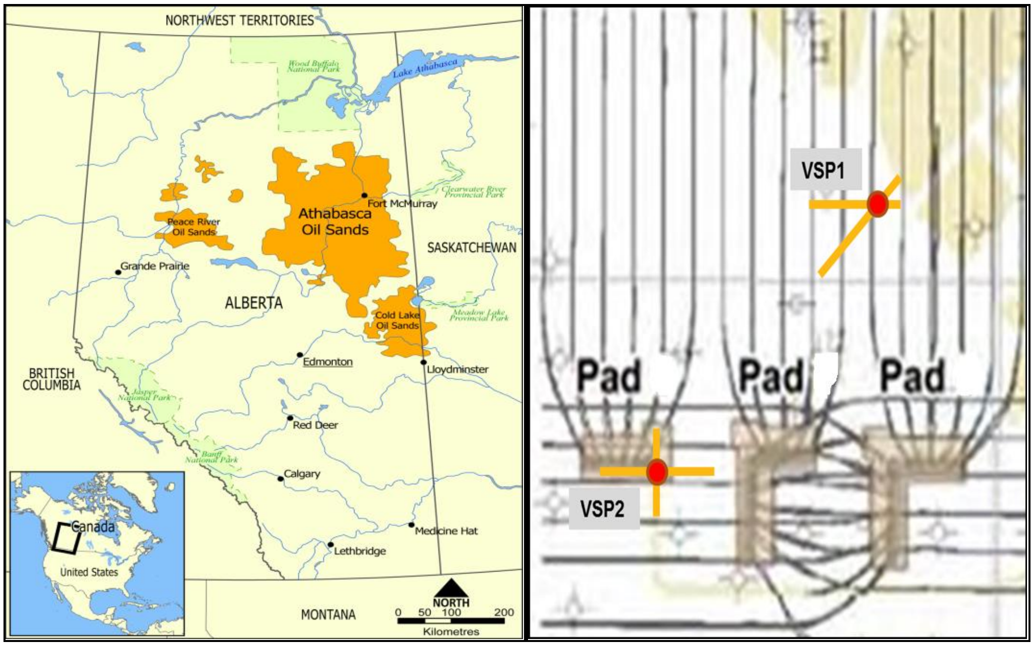

FIG.1. Location map of Athabasca oil sands and VSP surveys (Base map source: National Energy Technology Laboratories; well pad map: AER, 2013).

Quality control and interpretations

The application of optical fiber brought more difficulties in data acquisition, processing and interpretation than conventional geophone VSP surveys. Optical fiber measures strains within a certain length (called the gauge length), but it is less sensitive than traditional geophones. Accordingly, a set of vibroseis sweeps (8 for VSP1 and 4 for VSP2) were applied in order to improve the signal-to-noise (S/N) ratio. Gauge length is a parameter similar to a receiver array in traditional geophone deployment. There is a "gauge length array effect", which filters out higher frequencies in the DAS-VSP as the gauge length increases. The longer the array, the more high frequencies are filtered by it. A large gauge length of 10m was used to improve the S/N in this project. Unfortunately, this long gauge length has an impact in this project because the surface seismic data has frequencies over 200 Hz (Figure 2a, and Gray et al, 2015). A 10m gauge length filtered out high frequency content above 150 Hz (Figure 2b), so the VSP frequencies are lower than the surface seismic frequencies.

An 8m receiver interval does not provide enough spatial samples for the short wavelength signal in this area. Therefore, strong aliasing was observed on raw records and, as usual, aliasing is difficult to remove in processing. Figure 3 shows a comparison of raw data from the optical fiber DAS-VSP and from traditional geophones from another oil sands area. Apparently, DAS-VSP shots show lower resolution and signal-to-noise ratio than a traditional geophone VSP shot. The jagged signal in Figure 3a is aliasing caused by undersampling. Limited data quality makes the interpretation of these images challenging.

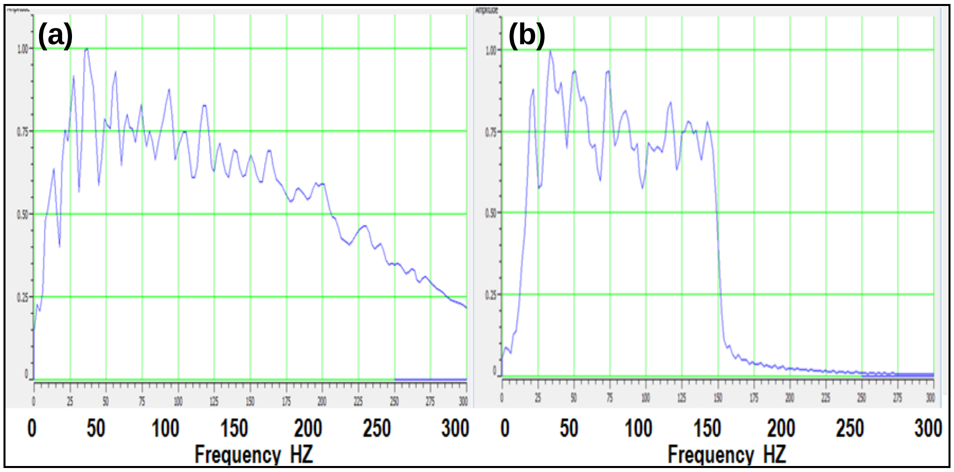

FIG.2. Comparison of frequency analysis of surface seismic and DAS-VSP. (a) Frequency analysis of surface seismic; (b) Frequency analysis of DAS-VSP data, the frequencies above 150Hz are filtered out by the 10m gauge length.

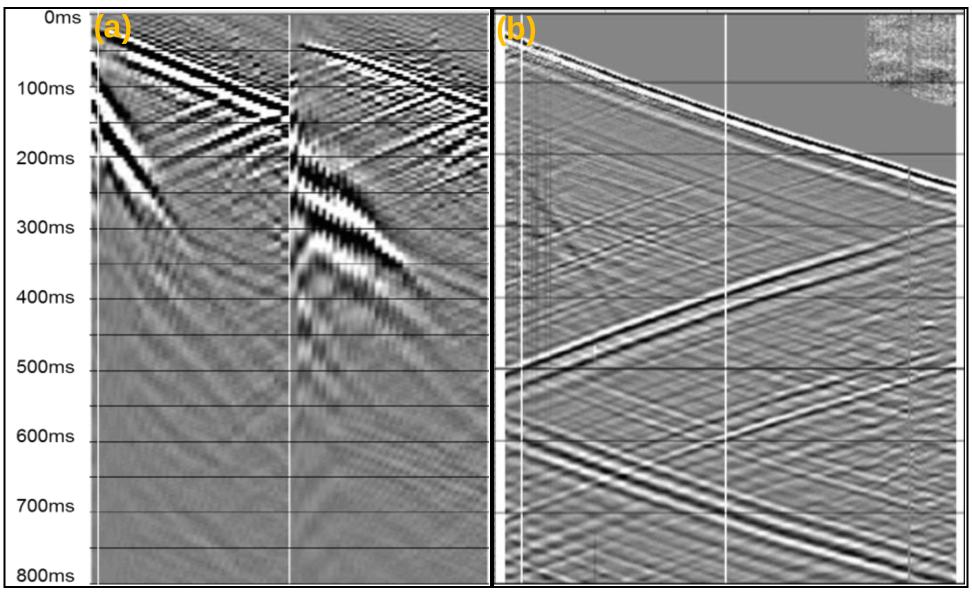

FIG.3. Comparison of DAS-VSP shots and traditional geophone VSP shot. (a) DAS-VSP shots; (b) Traditional geophone VSP shot. DAS-VSP shots show lower S/N, lower resolution, and stronger aliasing.

As discussed above, optical fiber measures strains in the proximity of the fiber, which is similar to velocities measured by geophones. However, the raw records show -90 degree phase rotation. This phase rotation was caused by a combination of the acquisition instruments and attenuation within the gauge length. The phase rotation can introduce mis-ties to other seismic data and small errors in travel time. The phase rotation needs to be carefully corrected in processing and interpretation.

The interpretation of VSP data includes two aspects. First, the check shot information was used to update the subsurface velocity model in the study area. In order to do this, offset and phase shift effects in the check shot tables were removed. The sonic log usually yields higher velocities due to the differences in measurement frequency. Therefore, it was calibrated to the check shot table. Second, we correlated the VSP corridor stack to the synthetic seismogram created with calibrated logs. A corridor stack is the VSP image at the well location which contains minimal artefacts from acquisition and processing. Perfect correlation between corridor stack and synthetic seismogram validates the reliability and accuracy of the VSP check shot table (provided the calibrated acoustic logs are also valid). Check shots with such correlation represents the best estimation of subsurface velocity and time-depth relationships. Figure 4 shows the correlations of VSP corridor stack and synthetic seismogram. After bulk shift correction, a small residual shift and phase rotation are acceptable. Differences are from geometry, acquisition equipment and the processing system and techniques.

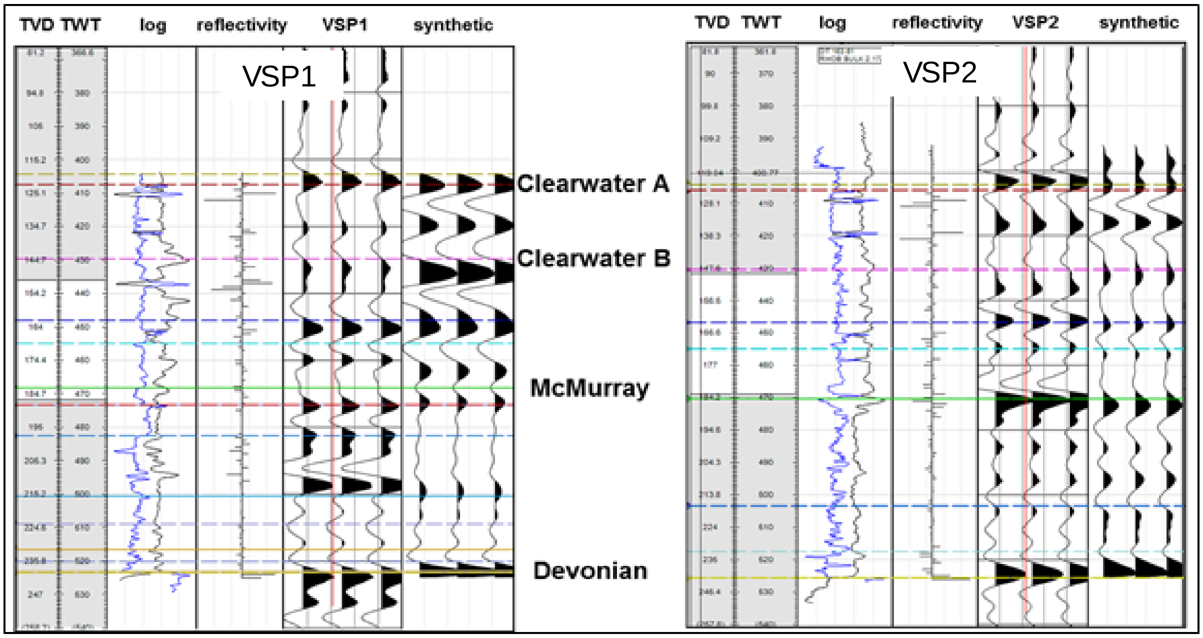

FIG.4. The correlation of VSP corridor stack and synthetic seismogram.

Figure 5 shows the comparison of time-depth relationships from the VSP check shot and a well log, which was calibrated to surface seismic horizons. The red curve is from well log and the blue curve is from VSP check shot. Since the logs were already calibrated to surface seismic, the red and blue curves don't show a big difference in the target interval between the Clearwater A to Devonian. Whereas, above the first well log point, the time-depth relationship extrapolated from the synthetic tie has larger errors and the VSP check shot provides more accurate velocities. For example, the first receiver is at 8m from surface in the VSP but the extrapolated sonic velocity maps it to 28m, which is a 20m error. In addition, the base of drift was mapped by the extrapolated sonic velocity 16m deeper than its true depth, as interpreted from the VSP. From Figure 5, we can see that the differences between the synthetic tie and the VSP checkshot are decreasing with the increasing depth. Below the Clearwater A, the differences are negligible. Therefore, the VSP check shot can be used to update the time-depth relationship, especially for the shallower zone, where there is no log information, and for intervals without the constraints of picked horizons. A more accurate time-depth relationship from the VSP helps us to conduct important SAGD operations, such as mapping caprock layers and placing geological features like mud barriers at their true depth.

Another application of VSP data is monitoring steam chamber development by measuring the time-shift from baseline. We know that a seismic wave travels through steam zones more slowly than through bitumen sands. Therefore, there is a time delay for seismic waves that have passed through the steam chamber. In oil sands, 4D seismic is an effective tool to monitor steam chambers in SAGD operations (e.g. Byerley et al. (2009)). Theoretically, a VSP shot through a steam chamber provides the same image around the borehole, but with higher accuracy. An accurate time-depth relationship from the VSP check shot also helps to build better velocity models for prestack time or depth migration, which improves the reliability of their imaging. For such studies, we acquired a 3D seismic baseline in 2003 and shot a 4D seismic monitor and baseline VSP in 2015. We measured the time shift of the Devonian on these monitors. Figure 6 shows the comparison of the seismic images from the 2003, 2015 and VSP surveys. We observed good alignment of the horizons above the reservoir interpreted from the VSP surveys with the horizons above the reservoir interpreted from the 4D seismic surveys. Then we measured a 5ms time-shift in the Devonian horizon at the well location in VSP1 and saw it increase to 7-8ms farther away from the wellbore. These measurements are consistent with observations from the 2015 4D seismic monitor survey. In VSP2, both the 2015 seismic and VSP do not show any time-shifts from baseline to monitor and we know that the VSP is in a cold zone from temperature logs from the VSP well.

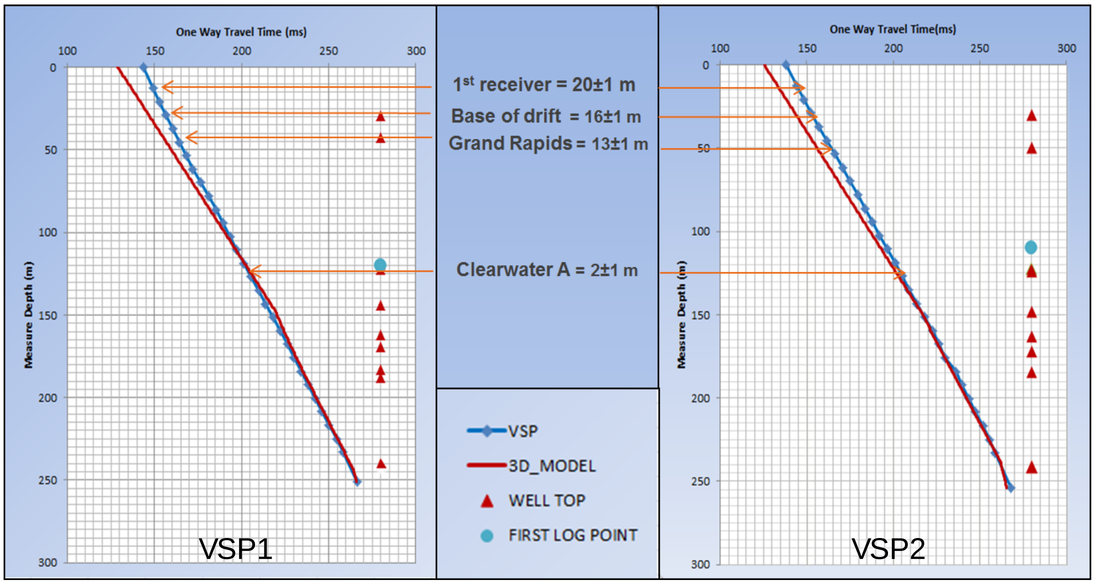

FIG.5. Time-depth relationships plot. Red curve is from calibrated log and blue curve is from VSP check shot after corrections.

In addition to the time-shift, an impedance difference between the baseline and monitor was used as an indicator to monitor the SAGD steam chamber. Considering that the VSP survey has a more limited aperture than the surface seismic, we created limited incident angle stacks for the 4D monitor survey and estimated that the 1-30 degree stack yields the image most comparable to the 2D VSP lines. Then we did post stack inversion on the surface seismic stacks and the VSP lines. Figure 7 shows the comparison of inverted impedance from both. The similar characteristics in both inversions suggest that the VSP is providing the same results as the 4D seismic monitor. Therefore, 4D VSP’s can be a cost effective method to monitor steam chamber development relative to surface seismic 4Ds.

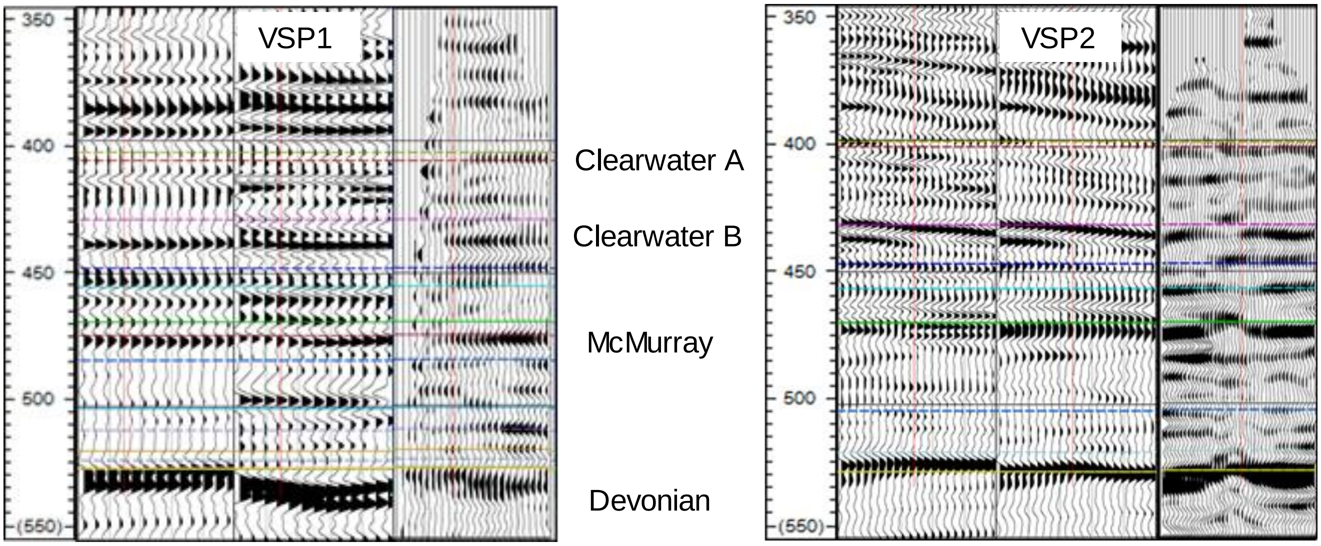

FIG.6. Comparison of surface seismic and VSP images of 4D seismic baseline (left), monitor (center) and DAS-VSP (right) data in time domain. When the horizons above the McMurray target interval are aligned, time shifts between our interpretations of the Devonian horizon in the monitor and baseline surveys are an indicator of steam chamber development. In VSP1, both the 2015 seismic and the VSP line show a 5-8ms time shift indicating steam chamber development around the VSP1 well. In VSP2, both the 2015 seismic and the VSP line show a zero time-shift indicating no steam chamber development around the VSP2 well at the time the VSP was acquired.

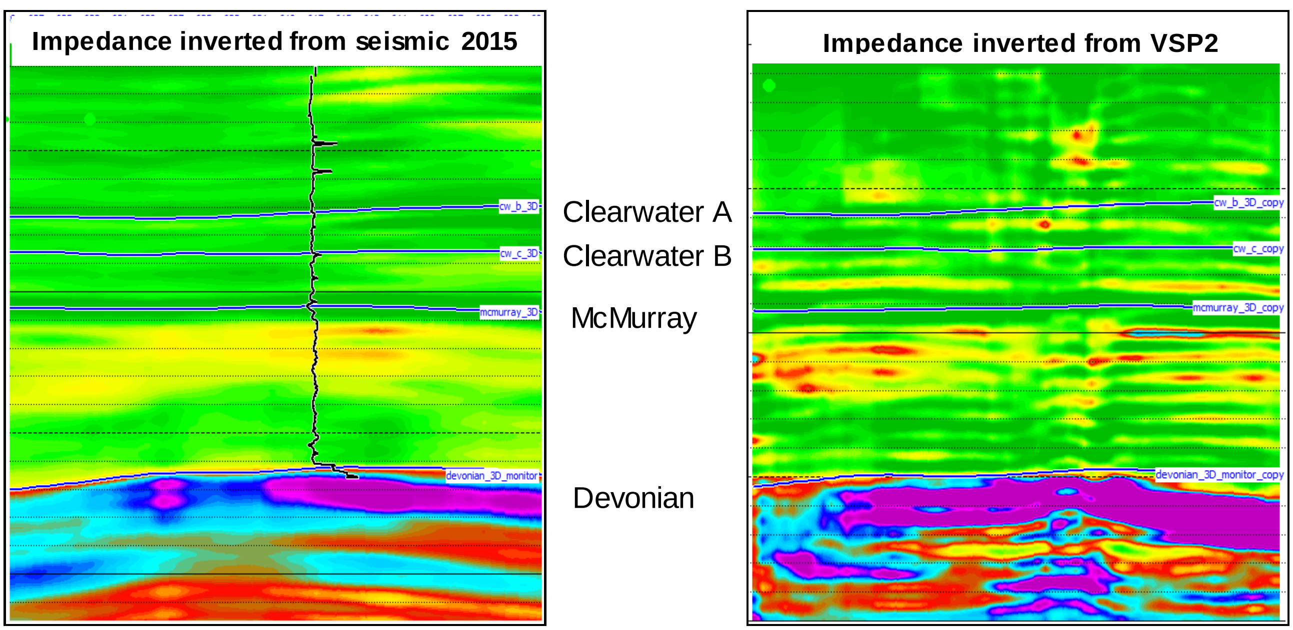

FIG.7. Comparison of inverted impedance from 4D seismic monitor and the VSP image at same location. Similar impedance characteristics seen in the inversion illustrate the promise of using VSPs to monitor steam chambers in SAGD operations.

Discussion

A VSP using optical fiber was acquired in an Athabasca oil sands SAGD operation to monitor steam chamber development. In this project, we have tested and evaluated the fiber-optic VSP approach and we have learned a few lessons: 1) A finer gauge length in a low velocity area, such as a SAGD steam chamber, could improve the frequency bandwidth and prevent aliasing. Shortly after this acquisition, new tools were developed which could better meet the technical requirements in this area. Although the fiber was permanently cemented in the well, technically, it is viable to connect it to this newer acquisition equipment with a finer spatial sample interval, which will improve the VSP images. 2) Because the receivers are in the wellbore, the VSP survey has relatively small coverage aperture within the McMurray reservoir. The aperture depends on maximum incident angle, which is associated with the depth and velocity of the target reservoir. For example, in this project, the image coverage of the reservoir is about 200m. With further development of acquisition and processing techniques, it could potentially be expanded to 250-300m. This pitfall of VSP coverage could be overcome by additional deployment of optical fibers for VSP acquisition in neighboring wells. In order to achieve this solution, additional economical acquisition tools are required. 3) An unrivaled advantage of optical fibers is their flexibility in deployment. They can be deployed in production wells (e.g. Javanbakhti et al, 2016), which are inaccessible to conventional geophones. Permanent cementation of the fiber in the well reduces the cost of time-lapse surveys and helps with the repeatability, which is critical for 4D studies and steam chamber monitoring. Optical fiber also provides the opportunity to monitor well log acoustics and temperatures between 4D surveys.

We also found a few other ways to improve upon this VSP study. During this project, we acquired the 4D surface seismic monitor survey and the VSP separately. Recording the VSP and and the surface seismic at same time and sharing sources would be a more economical solution. The fiber is already cemented in the wellbore; therefore, the cost of the next VSP survey arises only from the deployment of the seismic sources. There are multiple benefits to shooting a monitor 4D VSP in conjunction with a conventional 4D seismic survey (e.g. the downgoing waves of the VSP can be used to design deconvolution operators, which can improve the image from the surface seismic data). With development of the improved acquisition tool, which will allow for higher resolution images, we can optimize the VSP for more detailed interpretations. For example, we can use the corridor stack to check the multiples and phase rotation of the surface seismic image, improve estimates of rock properties, estimate attenuation and more.

Conclusions

DAS-VSPs are being used to monitor steam chamber development in an Athabasca SAGD operation. The VSP check shot information is used to create accurate time-depth relationships, which particularly benefit the depth estimates of shallow zones and any other uninterpreted intervals. The time-shifts in the VSP images and their inversions for P-impedance were used to estimate presence and size of steam chambers. Overall, these estimates from the VSP data are consistent with the 4D surface seismic interpretations. This result suggests that DAS-VSPs can be used to augment and, where appropriate, to replace 4D seismic as a tool to monitor steam chamber development.

The optical fiber used for the VSP is permanently cemented in this wellbore, thus reducing the cost of future 4D VSP surveys by removing the receiver deployment costs in future acquisitions. The DAS-VSP technique is still immature, as shown by some of the issues encountered during this project. However, improvements in acquisition equipment and processing hold a great deal of promise to improve the efficiency of the DAS-VSP technique. We have the potential to acquire DAS-VSP data simultaneously and regularly in neighboring wells or in conjunction with a conventional surface 4D seismic monitor survey.

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