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Monitoring Horizontal Producers and Injectors During Cleanup and Production Using Fiber-Optic-Distributed Temperature Measurements

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Abstract

This paper describes the application of fiber-optic-distributed temperature systems installed in several long horizontal open-hole completion intervals of production and injection wells in Oman. We demonstrate how distributed temperature data, from both types of wells, was used to optimize completion procedures and improve knowledge of the reservoir and its performance.

The Shuaiba reservoir produces 44° API oil from a low permeability micritic lime mudstone, typically 3 md. Initially, gas injection in vertical wells was selected to enhance oil recovery, but producing wells commonly experienced gas breakthrough, gas flaring was undesirable, and surface-compression constraints were encountered. For these reasons the operator decided to phase out gas injection and use line-drive water injection from horizontal wells. Wells were drilled horizontally, with up to 5,000-ft open-hole completions, but varied in effectiveness.

Fiber-optic distributed temperature measurement systems were installed in a horizontal water injector and several horizontal oil producers during 2002 to monitor the long open-hole reservoir intervals during well startup, production, and injection. Data from the fiber optic water injector showed that the intervals flooded slowly from the heel to the toe over a period of months, giving the operator improved knowledge of reservoir sweep from this type of completion. The first oil producer exhibited slow cleanup from the heel, enabling a change in pre-production well stimulation procedures to improve cleanup.

The results demonstrate that it is possible to monitor long horizontal open hole intervals continuously, during both clean-up and production, without the need for multiple well interventions. This has proved a safe and cost effective solution to improve the operators understanding of the performance of horizontal wells drilled in the Shuaiba reservoir. Substantial savings are expected through DTS surveys, with a one-time installation costs comparable to a coiled tubing run production log. Following the installation, DTS is available to provide survey data for life of the completion. It is not only cost effective, but also data acquisition operation is much less risky.

Geological Background

Safah field is producing from the Upper Shuaiba Formation of lower cretaceous age at around 6,010 ft subsea. The best reservoir is lightly cemented and the rock is dominantly skeletal wackestone/packstone. Porosities in the Shuaiba Reservoir typically range 20 to 25%, but permeability's are low, rarely exceeding 5 mD.

The Safah field has been divided into a vertical series of flow units, baffles and dense limestone layers making up the main and minor reservoir units. The top five flow units are classified as Main reservoir and the rest is Minor reservoir. The baffles are limestone layers with low porosity that have developed in local areas of the field. In parts of the field they are reservoir rock and form no barrier between overlying and underlying flow units. Most of the water injectors are completed across the main reservoir flow unit 3. The monitoring concept is to survey patterns consisting of producer-injector pairs in different areas of the field. Thereafter, the experience could be extrapolated to wells with similar properties in the area.

Fiber Optic Distributed Temperature Installations

Fig. 1 is a typical Safah completion showing how the fiber optic control line is installed in the well. Two ¼ inch control lines are strapped to a 2 7/8th inch tubing stinger hung below the production tubing and connected to a turn-around-sub located at the toe of the well. The control line and stinger are installed with the completion and once this has been achieved

the fiber is pumped around the ¼ inch control line without impeding other surface operations.

Once the fiber has been installed in the well it is connected to the Distributed Temperature System (DTS) acquisition box. This uses laser light to interrogate the backscatter properties of the fiber and compute a temperature measurement every meter along the fiber every ½ hour.

Occidental has not acquired data on continuous basis for the Safah wells, they planned periodic monitoring intervals such as during a shut-in, or over short time intervals, to provide data that represents stable flowing conditions.

Safah A Injection Monitoring

The first well that the fiber optic temperature monitoring system was installed on was Safah A, a planned water injector. This well produced mainly gas during the very short period of cleaning up and in November 2001 the well was worked over and converted to a water injector.

Thermal analysis of water injectors^{1,2} conventionally requires monitoring the well when it is shut-in, after a period of injection, and relating the thermal warm-back response of the reservoir intervals to permeability changes along the reservoir. Intervals that have high permeability take more water and are preferentially cooled with respect to lower permeability intervals, so they warm back slower. **Fig. 2** shows the warm-back response of the reservoir interval after 39 hours injection at an estimated rate of 4,500 bwpd. Note the interval from 7,000-8,000 ft has a very slow warm-back and that the reservoir below 10,000ft has not been cooled by injection at all, indicating no flow below this point.

Detailed analysis of this data can be performed using thermal modeling software. The reservoir is divided into zones of constant permeability and water is flowed into each zone as a function of total injection rate, the zones permeability and friction pressure drop between the zones. The far field reservoir pressure is assumed constant. By varying the permeability of each layer, and thus its inflow during injection, the warm back response of each layer can be varied and compared to the measured warm back response of the fiber optic system. Once a match between measured and modeled data is obtained the reservoir permeability's can be used to calculate the injection profile.

The reservoir permeability's so derived are relative, not absolute values, and indicative only of changes in near well injectivity rather than true petrophysical values.

Two further shut-ins with warm back monitoring took place in March and November 2002 and the results of all three analyses are shown in **Fig. 3**. The data indicated that the water was injecting further along the horizontal section with time, and had flooded virtually the whole horizontal section by November 2002. This is an important finding since one of the main objectives of the fiber optic installation was to define if drilling longer laterals (the least expensive drilling

section in terms of \$/ft) can be justified versus shorter laterals and more wells.

Whether this extension of the injected interval with time is due to well clean-up, injection pressure distribution along the horizontal section or higher reservoir pressures towards the toe is not known, however the data confirmed Occidental's decision to drill long horizontal injectors and that with sufficient injection time they will flood along the whole reservoir interval.

Safah B Injector Monitoring

During the sequence of shut-in and warm backs in Safah A in 2002 it was observed that the water in the tubing and casing, immediately above the reservoir, always warmed up quickly on shut-in. This was due to conduction from the surrounding formation and resulted in a large thermal step between the fluid in the casing and the temperature of the flooded intervals in the well bore.

We determined to take advantage of this hot slug of liquid in the casing in Safah B in early 2003 by pumping it down the reservoir and tracking its velocity with the fiber optic temperature measurement system. **Fig. 4** shows the hot slug as it moves down the reservoir once injection had been recommenced. Note that the slug loses heat to the surroundings as it traverses the reservoir so it would not be possible to inject a slug of hot fluid from the surface and have a measurable signal once it had reached the reservoir.

The hot slugs speed, as it moves down the reservoir, is a measure of the velocity of the water injection at that depth. **Fig. 5** compares the results of the injection flow distribution calculated from both the warm back technique and that of the hot slug tracking. This showed good agreement except at very low velocities, where the warm back measurement is most likely to be in error.

The difference between the two techniques is that warm back analysis requires increasingly longer warm back periods during the life of the well because the formation is cooled deeper with time, whilst the hot slug injection technique only requires a short warm back period to heat up the slug of water in the casing above the reservoir irrespective of the time of injection.

Safah C Producer Clean-up Monitoring

The temperature monitoring system was installed in July 2002 in Safah C, a newly drilled horizontal well. **Fig. 6** shows typical temperature data acquired along the reservoir interval after installation of the completion and again in July, August and October once the well was being produced. This well initially produced at a rate of 1,800 bopd but by October 2002 had dropped to 900 bopd and the GOR has increased to about 7,000.

Comparing the June data, before the well was put on production, to a geothermal gradient calculated from the well

trajectory we can see that cooling had taken place during the drilling process, mainly towards the heel, and that the well had not quite yet warmed back to the expected geothermal gradient at the time the temperature data was acquired. However, by August the thermal response of the well shows a significant decrease in temperature, below the geothermal gradient, down the reservoir to approximately 9,000 ft with little change below this. By October 2002 the interval 9,000 to 11,000 ft was also exhibiting significant cooling. After a few weeks of production any drilling-induced cooling should have completely dissipated.

The reason for this response is the Joule Thomson effect^{3,4}. As oil with a high gas content flows towards the well in this low permeability formation the near well bore pressure drop causes the fluid to cool and this can be observed as a temperature drop in the well bore itself. The temperature response indicates that the well was only producing down to 9,000 ft in August and had cleaned up down to 11,000 ft by October 2002.

The thermal response of the well can be modeled using Schlumberger's Pipesim software which can calculate the near well bore Joule Thomson effects due to flow through zones of varying permeability. **Fig. 7** shows the measured and modeled temperature data and associated flow distribution for the August and October data sets. The analysis confirmed that less than 100 bopd was flowing from below 9,000 ft in August and that this had increased to over 200 bopd by October even though the total production from the well had dropped. This was taken as evidence that the well was cleaning up over time and Occidental modified their well stimulation procedures on subsequent wells in order to improve further the clean-up rate.

Safah D Gas Lift Optimization and Cleanup

Safah D was the next well the temperature monitoring system was installed on and was completed in August 2002. Production wells are usually gas lifted and so in order to bring in Safah D gas was injected at a rate of 0.5 MMScfd down the annulus. The temperature data showed that when gas lift commenced gas was circulating through a mandrel at 3,600 ft from the Joule Thomson cooling effect caused by the pressure drop through the mandrel, rather than the mandrel at 6,200 ft needed to lift the well **Fig. 8**. Because Occidental were able to identify which mandrel was operating in real time they could rapidly replace it and re-commence gas lift. Unfortunately, the replaced gas lift mandrel failed again soon after installation and this too was easily recognized from the temperature response and the mandrel was replaced once more.

By being able to identify which mandrel is operating in real time significant savings on commissioning can be made, because the alternative is to pull the mandrels sequentially until the problem is fixed.

In order to improve well clean up Safah D was treated with mud enzyme just prior to initial well flow. The enzyme

penetrates the filter cake, breaking down the starch components, and the residual calcium carbonate portion of the filter cake can then easily be dispersed and flowed back without compromising the open hole completion. It was hoped that this would result in quicker well clean up and thus the well was monitored with the distributed temperature system during start-up. The temperature data indicated that the well flowed from the whole horizontal section during start-up, suggesting that the mud enzyme treatment had been successful.

Distributed temperature data was acquired again in November once the expected reservoir Joule Thomson cooling had reached steady state conditions and **Fig. 9** shows the data together with the Pipesim modeled temperatures and flow profile. In order to match the modeled to the measured data the permeability towards the heel of the well needed to be reduced and this resulted in a flow distribution along the reservoir section biased towards the toe. Whether the permeability towards the heel was actually lower, or the reservoir pressure towards the toe was higher than expected was not known, since both would give the same thermal response. However the data did confirm satisfactory clean-up down to the toe and confirm that the whole horizontal section was producing.

Safah E Response to Nearby Gas Injection

Safah E was drilled with its toe close to a vertical gas injector, and completed with a distributed temperature monitoring system in October 2002. Data acquired before the well was flowed again showed drilling induced cooling towards the heel of the well that had not had sufficient time to dissipate. However, the toe temperature was close to 106 Degrees Centigrade that was similar to the geothermal temperature of the reservoir from previous temperature data.

Repeat temperature measurements in November exhibit a similar profile to Safah D suggesting flow biased towards the toe of the well with about 2 Degrees Centigrade Joule Thomson cooling along the reservoir interval **Fig. 10**.

In this well we expected the toe to have a higher reservoir pressure than the heel because of the influence of the nearby gas injector, consequently the Pipesim model was run with reservoir pressure increasing towards the toe and constant reservoir permeability. These results gave a better match to the temperature data than when the reservoir pressure had been kept constant. The production profile produced by Pipesim by matching the calculated and measured temperature profiles is also shown on **Fig. 10** and is biased towards the toe, as result of the improved clean-up procedure and the influence of the nearby injector.

Discussion

Five DTS fiber optic temperature monitoring systems have been installed to date and have a trouble free track record of operation in wells where the open hole horizontal reservoir sections have extended up to 6,000 ft. We have found it necessary to limit installations of DTS to new wells since old and tortuous well paths have proved to be problematic in getting the tailpipe and fiber-optic conveyed down to TD.

After 9 months of water injection the warm back time for Safah A is now too long to allow it to be analyzed to see future changes in reservoir permeability, say due to pore plugging. This is because the cooled thermal front has now extended well beyond the near well bore region. The solution to future monitoring of this well is to perform a short warm back to create a slug of hot water in the casing directly above the reservoir and monitor the velocity of this slug as it is pumped down the reservoir.

The key to success for the producing wells is the fact that this is a low permeability reservoir with high GOR oil that produces significant Joule Thomson cooling on inflow from the reservoir. Thus the thermal changes as a result of production are directly related to the flow rate from the formation and a thermal model that can account for the reservoir Joule Thomson effect can be used to simulate the reservoir and estimate the flow profile. If the reservoir had high permeability with low GOR the Joule Thomson effects would be much smaller.

Using a "double ended" DTS fiber installation means that the light losses down the fiber are automatically compensated for by the processing system and the accuracy and resolution of the measurement is maximized. Consequently there is greater confidence that the small thermal events observed are indeed thermal effects and not fiber light losses. Also accuracy becomes very important (in terms of repeatability) when measurements are only made on an occasional basis.

The cost of a one-time DTS installation, including associated wellhead equipment, is comparable to a coiled tubing production log. Hence, substantial savings are expected through repeat DTS surveys and the system is available to provide survey data for life of the completion. It is not only cost effective, but also data acquisition operation is much less risky.

The main downside is the requirement to install the ¼ inch control line on a stinger along the reservoir interval. Whilst not a significant problem in the Safah open hole completions where intervention will be minimal, in cemented and perforated completions this would prevent intervention to facilitate re-perforating and squeeze off's etc.

Conclusions

The results achieved so far from the use of the fiber optic distributed temperature monitoring on Safah injector and producer wells proves that it is a cost effective and less risky than conventional production logging in horizontal wells. It has allowed Occidental to confirm the effectiveness of their long horizontal wells and demonstrate that they do clean up with sufficient time.

Analysis of the data provided has facilitated the understanding of inflow sweep in the horizontal injectors and the evaluation and effectiveness of clean up stimulation.

It has also enabled Occidental to monitor key events such as the effectiveness of nearby gas injection and to optimize the operation of the gas lift valves on well start up with considerable commissioning time saving.

Acknowledgements

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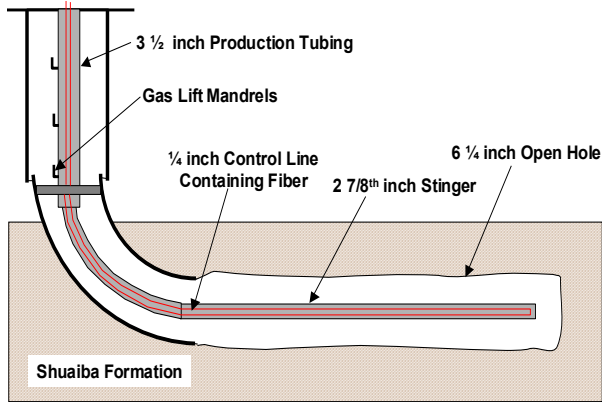


Fig. 1 - Schematic of a Shuaiba horizontal completion with a DTS system installed along the horizontal section mounted on a 2 7/8th inch stinger.

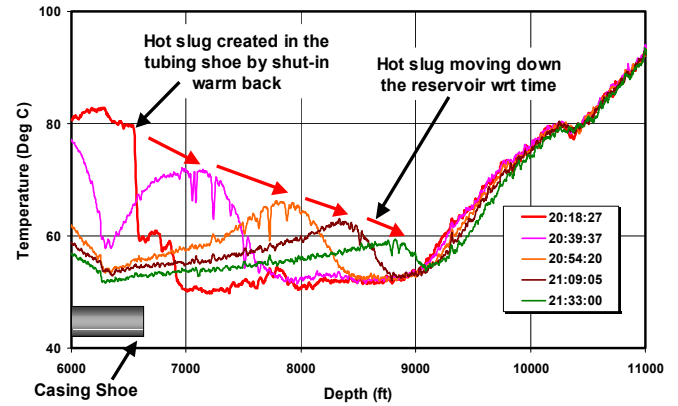


Fig. 4 - Hot slug injection in Safah B shows the movement of the slug of hot water created in the production tubing by warm back as it traverses the reservoir once injection has been re-commenced.

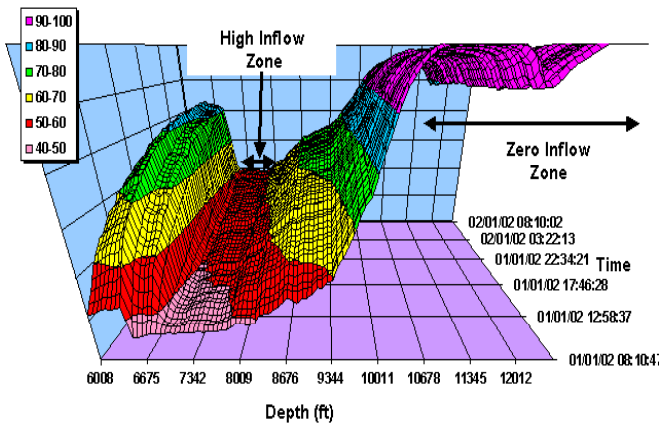


Fig. 2 - Thermal warm back of Safah A reservoir interval showing the interval of high inflow and the zone at the bottom of the well where no inflow occurred.

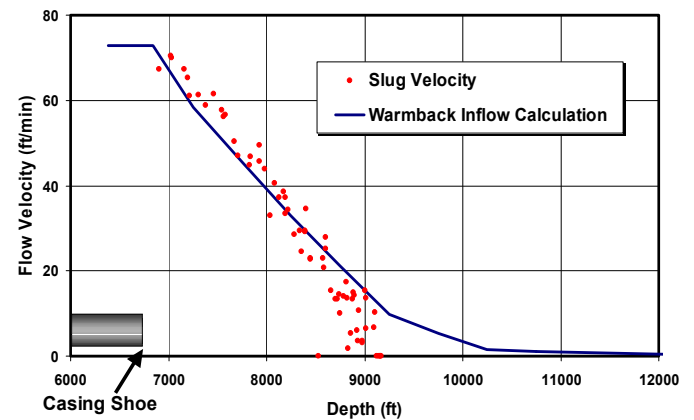


Fig. 5 - Comparison of the water injection flow velocity calculated by both the hot slug injection and shut-in warm back techniques.

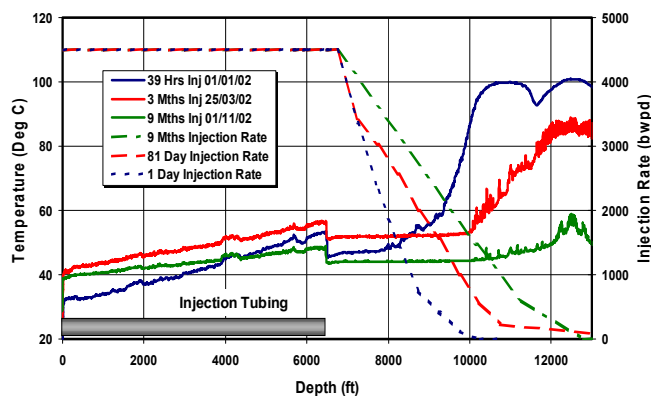


Fig. 3 - Temperature warm back data and computed injection profiles for the January, March and October 2002 injection warm back tests on Safah A.

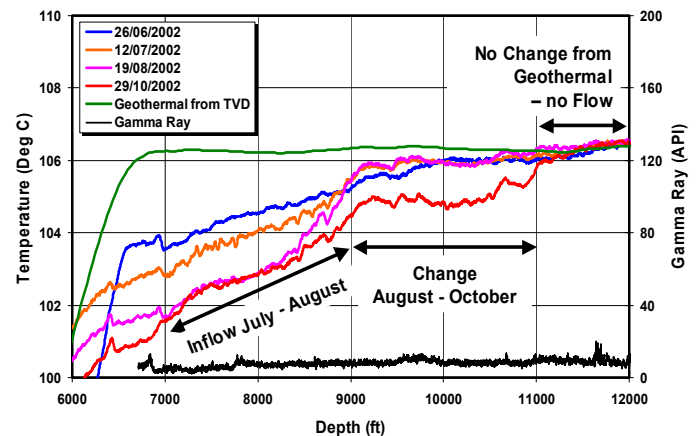


Fig. 6 - Safah C producing well showing the Joule Thomson cooling increasing and extending down the reservoir with time.

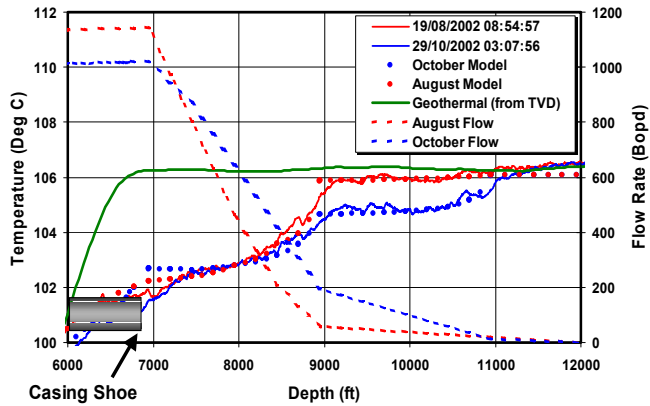


Fig. 7 – Measured and calculated temperature profiles along the reservoir and the associated inflow profile of Safah C.

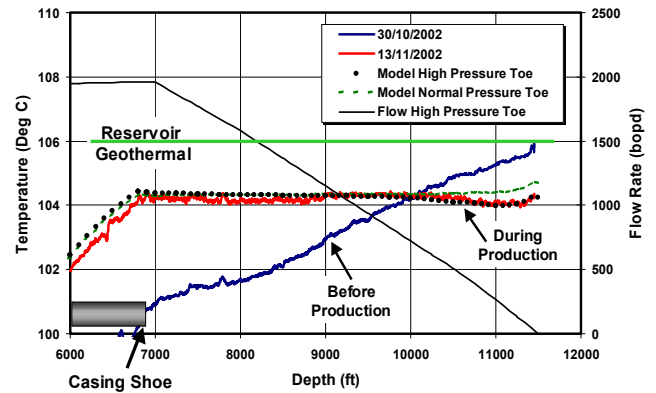


Fig. 10 – Safah E measured and computed temperature profiles showing Joule Thomson cooling along the reservoir section during steady state production.

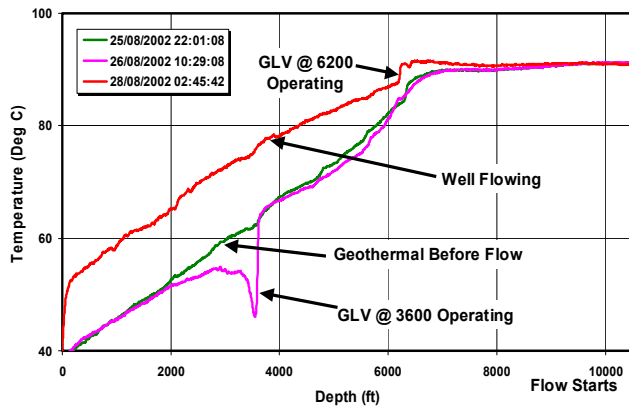


Fig. 8 – Safah D temperature profiles showing operating gas lift valves at 3600 ft and 6200 ft.

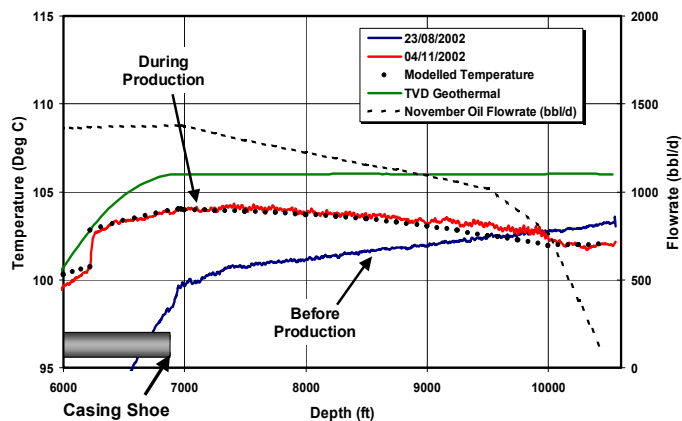


Fig. 9 – Safah D measured and computed temperature profiles showing Joule Thomson cooling along the reservoir section.