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A Case History: First Real-Time Digital Flow Profiling of a Passive Inflow Control Device (ICD) Completion

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Abstract

While adapting Advanced Well Completions (AWC) in horizontal wells has provided significant improvements in reservoir deliverability and depletion, it has also resulted in increased data gathering challenges for the longer and deeper completions, in particular, the options to perform well logging are reduced, and the costs are high. This is related to both the costs of the more advanced horizontal well logging tools and the more expensive logging methods, such as coiled tubing and tractor systems, used for the conveyance of these tools into the wellbore.

In an effort to acquire high quality downhole data in a timely manner from passive Inflow Control Device (ICD) completions, Saudi Aramco set about investigating the alternatives to traditional production logging methods. A technology gaining greater industry acceptance in recent years, is the permanently installed Distributed Temperature Sensing (DTS) and this technology has become the focus of investigation. The limitations of single point permanent Downhole Pressure Monitoring (PDHM) and DTS technology were soon realized. In particular, the limited temperature resolution from DTS and discrete point PDHM readings, were not sufficient for evaluating horizontal wells. At the time of investigation a new generation of DTS technology became commercially available, providing a ten-fold improvement in measurement resolution. This allowed Saudi Aramco to proceed with field trials for this new technology.

This paper will present the case history from the world's first installation of DTS in a horizontal ICD completion while showing the advanced well completion design and the data from the field trials. The paper will also indicate the future of DTS in advanced well completions.

Background

To understand the flow contribution from AWC, a DTS system was chosen to be deployed with ICDs and Swellable Packers in a horizontal production well. Although previous systems have been run above the production packer and in cased multilateral wells, this was the first attempt worldwide to deploy a DTS system in an openhole completion across a passive ICD system. The objectives for the field trial were to provide real-time information on well unloading, indicate real time compartmental contributions, and reduce the requirement for horizontal flow meter logging and well intervention throughout well life.

The field trial considered in this paper utilized an ICD completion, swell packers with feed-through capability for the DTS cable, and standard cased hole production packer with feed-through. The ICD acts as a known restriction between the annulus and wellbore. **Figures 1a and b** show the flow path through both basic ICD design concepts (Helix & Orifice). The pressure drop across the ICD increases as the square of the flow rate; effectively preventing any one zone/ICD from providing a dominant inflow along the wellbore.

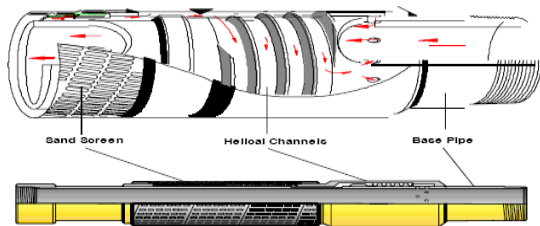


Figure 1a Helix Type ICD

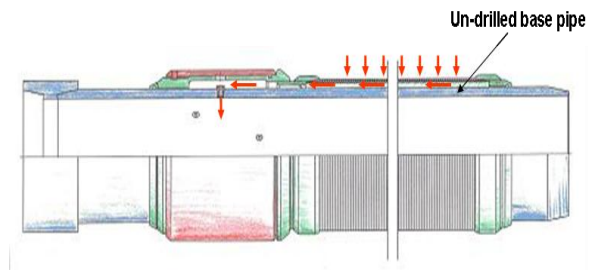


Figure 1b Orifice Type ICD

Over the past 6 years, Saudi Aramco has pioneered the use of advanced well completions (AWC) utilizing passive ICDs in its advanced wells to reduce development costs, prolong unwanted water production and control early gas breakthrough¹. Saudi Aramco's original AWCs included openhole laterals drilled from a 7" completion liner to provide the required contact/reservoir foot print to optimize rate and recovery.

More recent designs have utilized ICD completion technology combined with a DTS umbilical deployed in the 6-1/8" openhole section below a 7" liner to control inflow from each compartment to extend well life and increase recovery, as shown in **Figure 2**. Compartments are created utilizing either swellable or openhole mechanical packers with feed through capabilities for the DTS umbilical. The compartment length is based on modeling and openhole log data in an effort to set even off-take rates per compartment to prolong water break through or unwanted gas production.

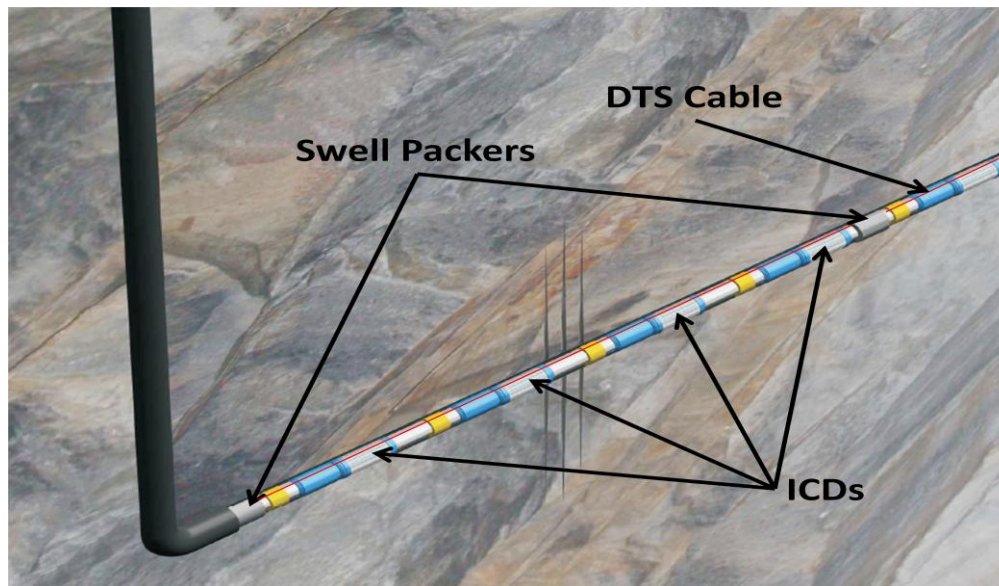


Figure 2 ICD completion with swell packers creating compartments for ICD control and fracture isolation².

DTS system and installation overview

A DTS Fibre Optic Permanent Downhole Monitoring System (PDHMS) was installed successfully in April 2008 in a stable carbonate reservoir. The fibre optic cable was attached and secured to the production tubing utilizing specially designed clamps allowing the cable to pass over the ICD moduals. The DTS system provides a multi-point temperature profile across the whole depth of the well without the need for any form of future intervention. The real time data provided from the DTS can be used for reservoir optimisation and management. Production can be monitored and allocated between the ICD compartments, and cross flow identified during shut-in.

The DTS installation was carried out in three phases:

- Installation of sensing cable up to the production packer
- Installation of sensing cable above the production packer
- Termination of DTS cable and installation of junction box

During installation the DTS cable was monitored continuously using an optical rotary joint. This allowed a considerable reduction in the installation time, as well as providing continuous data during the installation. The data captured during the installation is shown in **Figure 3** below. The benefits of a fixed fiber system are:

- Data was continuously available, allowing field engineers to monitor and confirm the integrity of the monitoring system throughout the installation.
- Completion integrity and operation could be confirmed prior to setting the production packer.
- A baseline Geothermal reference profile was immediately available for use during inflow analysis.

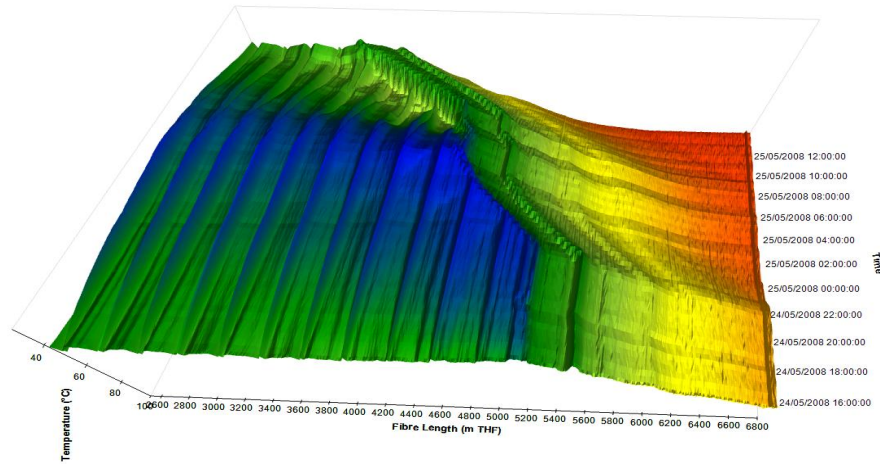


Figure 3 DTS data captured while running in hole

A wellhead outlet, **Figure 4**, was installed and the fiber cable was terminated in a junction box placed temporarily in the cellar, later moved to a junction box on a post near the wellhead.



Figure 4 Surface Junction box for fiber optic terminations

The DTS system was designed to minimize optical loss, allowing the required high resolution performance to be achieved. Despite installation of six in-well packers only a single optical splice was required. A field proven design, allowing dual splices for a double ended system, was utilized, providing very low loss connections.

Unfortunately at the time of installation, only five feedthrough swell packers were available. As result the DTS cable could not be run to the toe of the well. Normally a DTS system would be run below the lowest point of inflow as this provides a useful and stable temperature reference over the production life of the well. See **Figure 5**. This reference point is achieved by isolating the last 100 ft of reservoir with an openhole packer and blankpipe creating a no-flow zone.

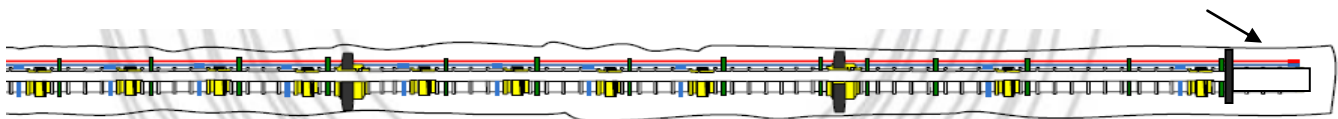


Figure 5 ICDC completion showing no-flow zone

Drilling & deployment best practices include:

1. Plan the openhole section to avoid doglegs greater than 4 degrees per 100.
2. While landing the well, deviation angles should not exceed 88 degrees to avoid inversions and sumps while entering the reservoir section.
3. Utilize rotary steerable system (RSS) wherever possible to improve openhole conditions.
4. Obtain LWD caliper and Image Logs to properly spaceout openhole packers and ICDs.
5. Evaluate torque and drag before and after wiper trips. Final wiper trip with stiff assembly and no rotation to simulate deploying completion.
6. After reaching openhole section, do not stop for tubing drifts. This will reduce sticking problems.

Reservoir Requirements and needs

The field selected for the trial test has been on production since 1954. It is a high permeability, high porosity carbonate reservoir with prolific production. The reservoir is highly fractured, especially in the crest. Water injection into the flank started in 1964, effectively halting any decline in reservoir pressure.

The drilling of horizontal wells in the field commenced in 1990, allowing a significant improvement in reservoir contact. Early horizontal wells were short radius horizontal wells. The high dog leg severity prevented deployment of Logging While Drilling (LWD) tools, making reservoir evaluation difficult. Long radius horizontal wells were introduced later, allowing a full range of LWD tools to be deployed. This allowed the wellbore to be evaluated prior to completing the well (in particular using Image logs to identify fractures); however, little information was used to optimize the reservoir completion.

Although 3D seismic information provides some information on fracture locations seismic data cannot be used with certainty to predict fracture locations and plan drilling trajectories accordingly. This is especially problematic in the crest given the high fracture density. Early horizontal wells drilled in the crest were deliberately restricted to 500-1,000ft horizontal intervals to minimize the probability of intersecting fractures. Despite these attempts crestal wells typically watered out within 6 months to 2 years.

In 2005 ICD completions were introduced to control production from fractures. This allowed horizontal contact lengths to be increased and problems with early water breakthrough to be mitigated. None of the wells installed with ICD technology have watered out thus far, proving the success of using a fracture management tool in the completion.

While there have been major improvements in completion design evaluation of the production profile remains problematic. Early horizontal wells were evaluated using production logging tools (PLTs) and later multiphase PLTs. While these provided effective measurements, deployment along the horizontal interval is difficult. Usually, expensive coiled tubing deployed horizontal production log or tractor run production logs lockup and do not get to bottom, or worse, the tool is lost in the hole for one reason or the other. The cost, risk and disruption involved in intervention based surveys mean that very few surveys are undertaken in relation to the reservoir engineer requirement. To understand the intervention complexity, we have included a photograph of the surface equipment required for the validation of the field trial in **Figure 6** below. Most noticeable is the extensive Coiled Tubing equipment use for conveyance of the logging equipment.



Figure 6 Surface equipment required for the Production Log surveys

Another concern about use of Coiled Tubing for conveyance is the effect on the well production and flow distribution. Introducing a 1.75" restriction in the well, and across horizontal producing intervals, will have a significant effect on the pressure regime and therefore flow distribution. The resulting data from an intervention based production log may not be representative of the normal flow profile. These inaccuracies will result in poor decision making.

DTS provides a cost-effective alternative and provides real-time flow profile without the cost and safety risks of coiled tubing or tractor tractor deployed logs. As the DTS is placed external to the production tubing and liner, it does not interfere with production rates and therefore provides a more accurate picture of the well inflow profile and provides this information in real time.

Test Results and Well Production Performance

Following the workover (Figure 7 shows post workover completion), the well was placed on production in August 2008. Prior to FSI logging, the well was tested fully open at 3 MBOPD 13% watercut on a reduced surface choke and at 7.3 MBOD and 6% water cut on a larger choke setting. One point of notice is the important effect of the ICD completion on controlling watercut³. As the well is produced harder, the water cut drops. This effect is seen again during the multi-rate PLT testing shown below in Table 1. This is a common effect an ICD completion has as it creates increased pressure drop in two-phase conditions.

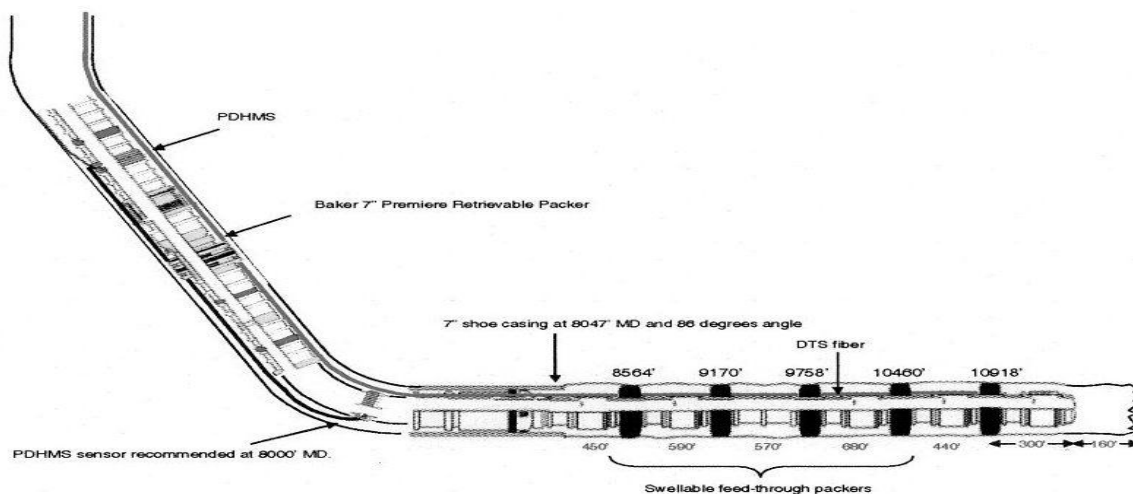


Figure 7: Post workover completion

A production log was run in December 2008 to confirm the effectiveness of the ICD completion and the performance of the downhole DTS system. The FSI-PLT survey was conducted at three different choke settings (26/64", 40/64" and 92/64") while shooting the DTS for evaluation. This data was then be used to evaluate the performance of the DTS system over the entire rang of possible production rates from the well.

In addition, a shut-in pass was run to allow for a complete evaluation of the well. The results are shown in Table 1 below. Detailed analyses of the logs show contribution from the entire lateral, in accordance with the completion design. Some cross-flow, about 0.6 MBD, from toe to heel was observed as expected, during the shut-in pass.

Choke (/64")	Multiphase Meter Rate (SBPD)	Multiphase Meter Water Cut (%)	PLT Rate (SBPD)	PLT Water Cut (%)	PLT Press at Ref Depth (psig)	Ref Depth (ft md)
SHUT-IN	0	0	0	0	3,168.7	8,047
26	2,009	3.35	2,310	7.4	3,149.3	8,025
40	4,019	1.58	4,431	3.4	3,122.1	8,025
92	7,754	1.62	8,011	1.6	3,037.5	8,025

TABLE 1: Production data Post-ICD/DTS

The DTS data captured during the evaluation is shown in Figure 8 below. The data shows some clear differences at each rate; most noticeable is the change in temperature near the surface. At high rates (92/64ths) fluid is travelling rapidly up the wellbore and therefore arrives at surface at a high temperature. At lower rates (26/64ths) fluid travels more slowly and is subject to greater heat loss to the cooler geothermal temperatures in the upper wellbore.

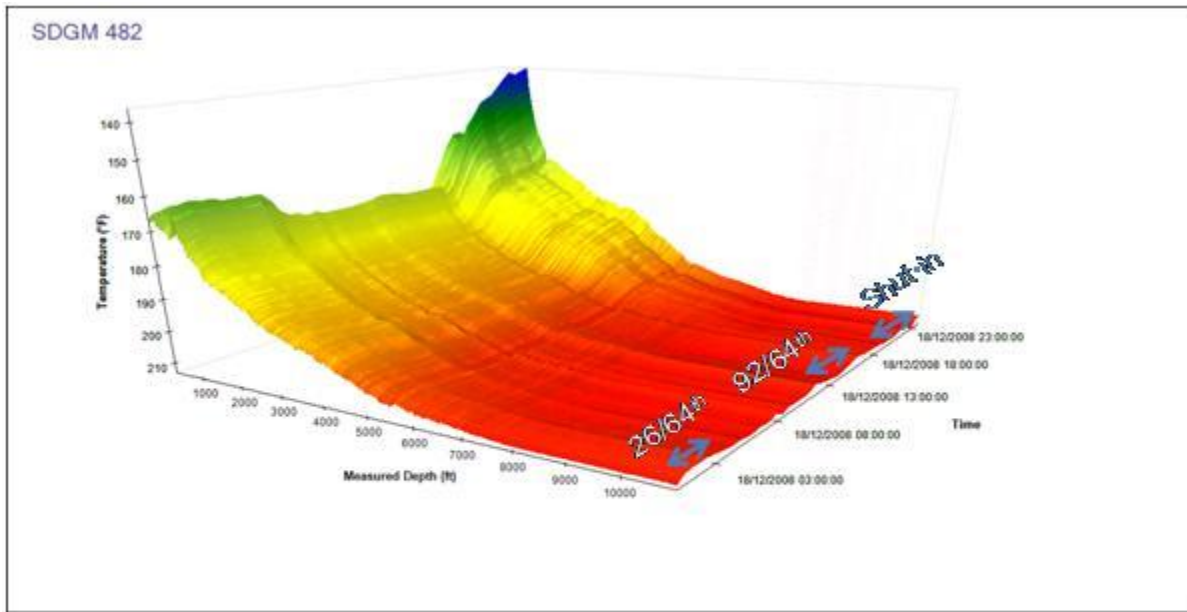


Figure 8: DTS Temperature on 18th December 2008

The production log analysis was performed as a blind test, Sensornet and FloQuest were not provided with any of the log information or results until after presenting the flow prediction using the DTS data. FloQuest was only provided the DTS data, total surface well rates and watercut and the single point pressure and temperature data from the electronic PDHMS. This data was used as a reference to generate the compartmental contributions and watercuts.

The observed actual flow profiles from the FSI data (**Figure 9**) are in close agreement with both the DTS modeling and with the NETool predictions (**Figure 10**); thus, validating both the ICD design, Sensornet™ DTS and FloQuest™ modeling capabilities.

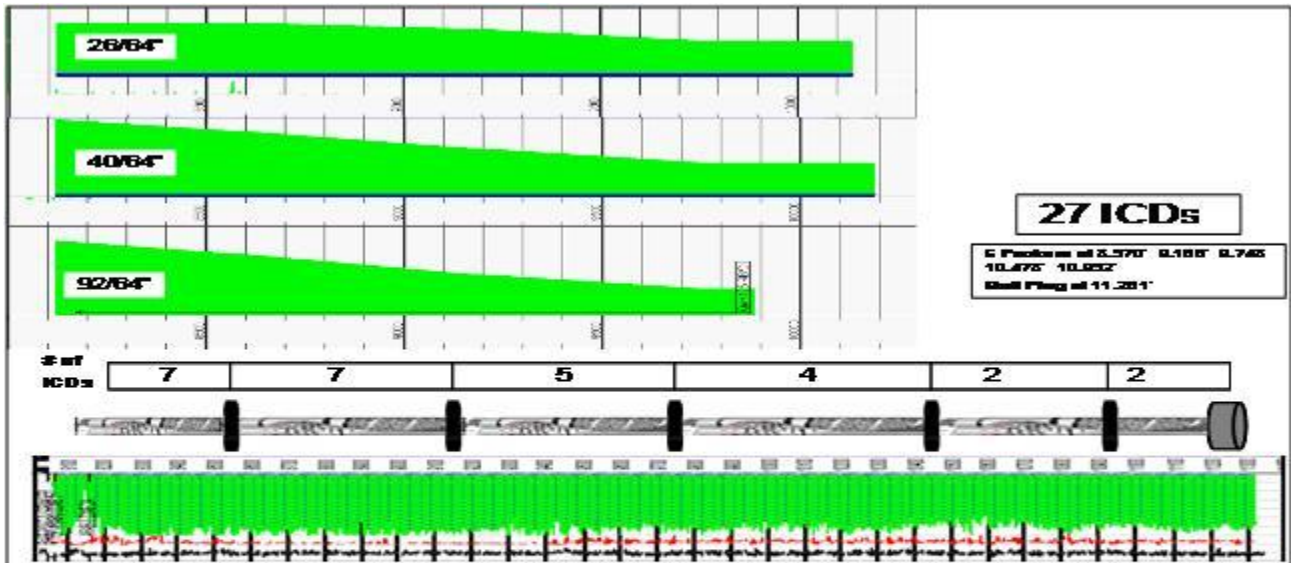


Figure 9: Post ICD/DTS Completion FSI PLT on December 17, 2008.

FSI SPIF1

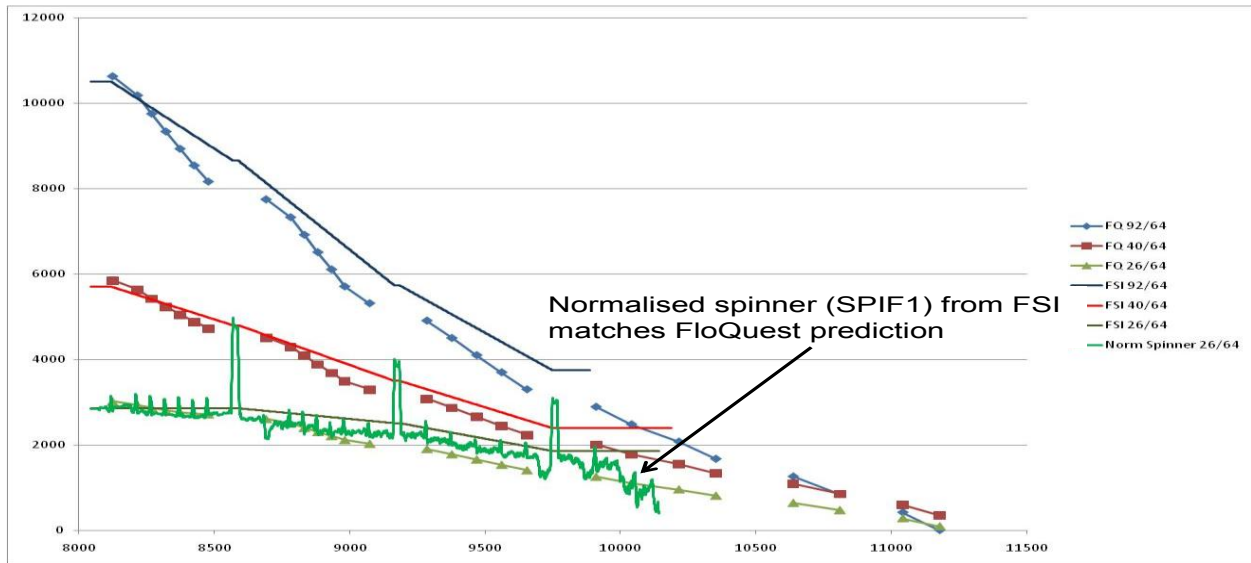


Figure 10 DTS Compared to FSI and Raw Data

Figure 11 below shows a comparison of the actual FSI rates versus both the NETool and Sensornet DTS interpretive profiles for the three flow rates (FL1, FL2, & FL3). These results confirm that the Sensornet DTS system with FloQuest modeling is capable of monitoring inflow profiles and cross flows for horizontal completions with in acceptable accuracies compared to conventional FSI logging on coiled tubing.

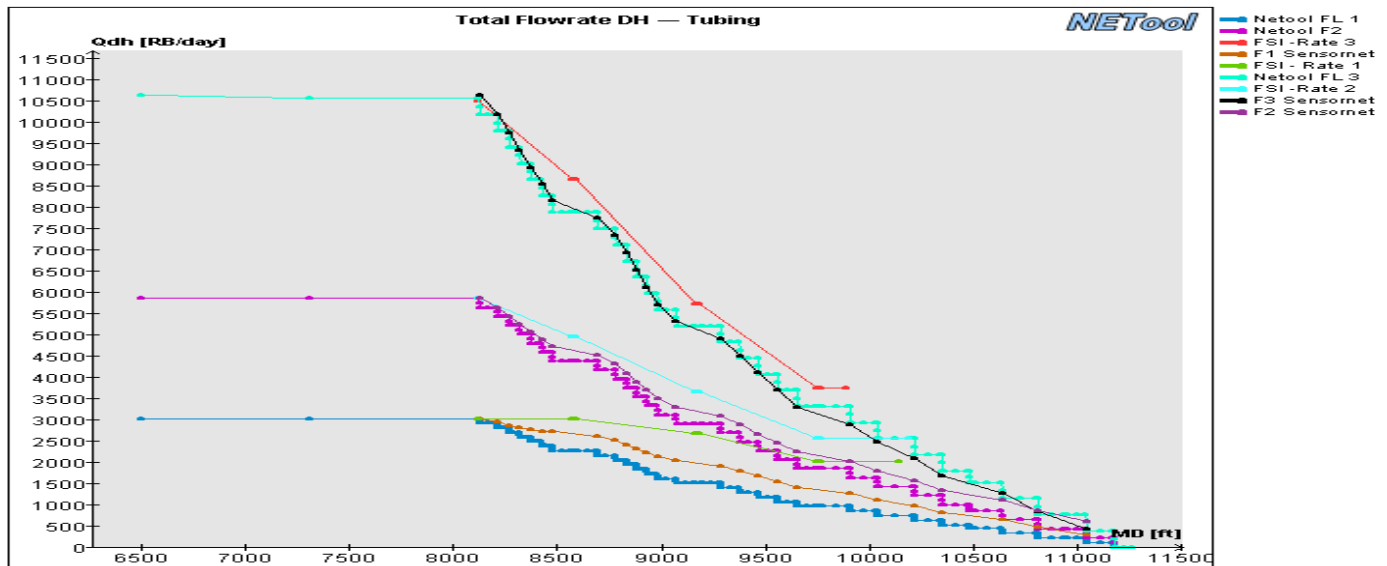


Figure 11: Flow profile comparison at different choke sizes, DTS vs NetTool vs FSI

Conclusions

1. Digital Flow Profiling provides a highly effective means of monitoring horizontal passive ICD completions.
2. Valuable data is provided in real time during well unloading to confirm open-hole packer swelling, ICD performance, and well unloading status.

3. Seeing the well unload to TD in real-time can save expensive rig time during the unloading process and insure damaging fluids are not left in the wellbore.
4. The DTS system clearly shows the placement of wellbore cleanout and breaker fluids improving wellbore displacement and clean-up.
5. Initial data from the installation has proven the required resolution of 0.01°C has been achieved despite the fiber length and three in-well cable splices.

The in-well cables, downhole splices, wellhead outlet and surface hardware required for digital flow profiling can feasibly be integrated into passive ICD completions. No significant delays or NPT related to the monitoring system were observed during the installation.

Implementation Plans

Saudi Aramco plans to implement additional DTS monitoring systems for its future horizontal ICD, multi-lateral MRC, intelligent wells, and into horizontal injection wells to provide real-time monitoring of compartment and lateral contributions. This will initially be done on a controlled number of wells allowing time for integration of data sets to full field modeling and a more complete understanding of value creation. This will allow for optimization of future completion designs and unloading procedures. For horizontal water injectors, real-time monitoring via DTS will allow for injection profiling and improved sweep modeling.

Next generation Systems

Saudi Aramco plans to field test fiber optic multi-point pressure/Temperature (PT) systems with DTS to improve the overall accuracy of the flow profiling, provide real-time compartment PI and skin damage estimates. Phase two of the field testing will include a mandrel design allowing PT measurement both inside the liner and outside per compartment. This enhancement will provide increased ICD performance monitoring and crossflow measurement.

Acknowledgements

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Nomenclature

DTS	=	Distributed Temperature Survey
ICD	=	Inflow Control Device
ICV	=	Inflow Control Valve
PDHG	=	Permanent Downhole Gauge
PDHM	=	Permanent Downhole Monitoring System
SCADA	=	Supervisory Control and Data Acquisition
SSD	=	Selective Shutting Device