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The Use of Fiber-Optic Distributed Temperature Sensing and Remote Hydraulically Operated Interval Control Valves for the Management of Water Production in the Douglas Field

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Abstract

Unwanted water production has long been one of the biggest problems that the oil and gas industry has had to address in efficiently producing hydrocarbons. This paper describes how fiber-optic-distributed temperature sensing (DTS) has been used in conjunction with remotely operated hydraulic interval control valves (ICVs) as an economical management tool for controlling water encroachment. Used with intelligent well technology, this method provides interventionless control and selectivity of producing intervals using surface-actuated hydraulic ICVs so that unwanted water production can be managed more effectively to maximize oil recovery. Distributed temperature measurements at one-meter intervals in the wellbore provide data that assists in the determinations of zonal contribution and the identification in the change of fluid properties or water ingress.

This method was installed on the Douglas Platform in Liverpool Bay, United Kingdom. The completion was comprised of an ESP pump, hydraulic on/off disconnect, retrievable packers with hydraulic feed throughs and hydraulic ICVs. An optical fiber that acquires continuous distributed temperature data is installed into one of the hydraulic control lines that operate the hydraulic ICVs. Opto-electronic instrumentation on the platform allows distributed temperature data to be transmitted in real-time to a shore-based asset team.

The combination of fiber optics and hydraulic interval control valves provides a number of benefits:

- The number of penetrations through tubing hangers and packers are reduced if required
- The fiber optic sensor is capable of gathering real-time logging data from multiple intervals without intervention
- The ICVs provide interventionless zonal control
- The disconnect system facilitates ESP workover and recompletion.

Introduction

Field Background. The Douglas Field is a shallow low-pressure, under-saturated oil reservoir situated offshore in the Liverpool Bay area of the East Irish Sea on the west of Great Britain. The Triassic sandstone reservoir lies at depths between approximately 2,250- and 3,000-ft. MD.

The reservoir is made up of a number of geological facies; i.e., aeolian dune, aeolian sandstone, sandy sabka, fluvial channel, partial fluvial and mudstone and consists of a number of distinct zones with varying reservoir qualities. These are shown in **Table 1.**

The wells are drilled from a central wellhead tower and because of the shallow nature of the reservoir, the wells are highly deviated as shown in the deviation survey in **Fig. 1**. It can be seen that the wells extend up to approximately 12000 ft. The oil producers are all completed with ESP's that provide the necessary artificial lift to obtain economic production rates. There are other features of the completion, notably the formation saver valve (FSV), which allows the ESP to be worked over without excessive fluid loss to the formation.

Water Production and PLT Results. The Douglas Field is produced under a combination of natural aquifer support and water injection, to maintain reservoir pressures and manage oil sweep efficiency. Over five years into the producing life of the field, water cuts in the Douglas producers have reached as high as 80% in some cases. Water cut development has followed very similar trends in all these wells with the timing of water breakthrough and the current level of watercut being a function of the well's structural elevation and the cumulative oil produced. With the existence of constraints on handling water at surface, it was recognized that downhole water management could provide opportunities to maximize oil production, optimize oil recovery and add project value.

Studies were conducted to identify and screen technical solutions, and to develop a business case and recommendation for implementation. Data to confirm the water breakthrough mechanism is critical to this process, and it was not until this data had been gathered that the final recommendation could be made. **Fig. 2** is a typical production log showing where the water is entering the wells. This water production is due to edge-water drive from the western flank of the structure. Production logging has indicated that the majority of the water production in each well is originating in either Zone 1A or Zone 1C - little or no water is being produced from Zone 2.

This water is over-running laterally extensive sheet flood shale intervals that occur within Zone 1B and at the top of Zone 2. Within Zone 1A and Zone 1C there are no major shale layers, and it is likely that there is full communication vertically. The data shows that any water management scheme must be able to isolate water production from the middle of the reservoir interval, while allowing continued production from lower and higher zones. Based on these studies and data, the selected option for the Douglas Field was to install a completion that allowed selective isolation of the major reservoir zones, and would allow zones to be returned to production.

Since previous wells on BHP Petroleum's Douglas Field had experienced early water ingress, BHP felt that future well development should be reviewed to address the water issue. Therefore, when a new completion project was initiated, the following issues were reviewed to determine methods to resolve the problems:

- Reasons why e.g. rapid changes in reservoir leading to water production then relatively dry-oil production after a period of shut-in
- Limited water-handling facilities on the platform
- Cost-benefit analysis
- Designing for the complete life-cycle so that potential problems could be identified early instead of later when the well can ill afford to pay for rework
- Typical Liverpool Bay well design issues which involve traditional limitations, wellhead penetrations, logging issues, and ESP Issues

Case History

The first well planned for completion using the new water control techniques was Well D17, drilled during the second half of 2000.

Completion design objectives. Completion options for D17 were reviewed with the following objectives:

- Provide the facility to conduct water shutoff as a means to optimize production from both individual Douglas wells and the field in total.
- Reduce well intervention costs by use of remotely operated sliding sleeves.
- Allow the collection of distributed temperature (DTS) data throughout Douglas completion interval to enhance abilities to monitor watercut development from each reservoir zone and to demonstrate the capability to replace PLTs with interventionless data acquisition.
- Allow replacement optical fiber for distributed temperature data acquisition to be pumped in place and removed in future.
- Allow the upper ESP completion to be worked over while leaving the lower completion in place.

On the basis of the production logging results, future water shutoff was to be focused on isolation of each of the major producing intervals; i.e., Zone 1A, Zone 1C, and Zone 2.

Water shutoff would benefit field production by optimization at two levels:

1. At each individual well where the dry oil production is constrained by optimal operation of the ESPs, there is an opportunity to offset water volumes with increased oil production.
2. Once either the gross liquid handling or the water-handling limit would be reached within the Douglas processing facility, net oil production could be maximized through closing off the highest watercut intervals.

Whichever shutoff technique was adopted, the capability to reopen closed zones at a later date would be of value as watercut progressively had increased in other wells. In addition, recent production performance had shown that with gravity separation, water-cut would recede with time. This phenomenon suggested that there might be an added benefit from cycling high water producing intervals.

Completion Economics Screening

A number of completion design options were developed and a cost benefit analysis carried out to rank them. The key factor in performing the cost benefit analysis was the capability of the design to reduce operating costs. The following are typical costs associated with several of the routinely performed operations:

1. Coiled tubing entry to set sliding sleeve: £100,000 (US$134,000)
2. Standard production logging operation: £200 to £250,000 (US$268,000 to US$335,000)
3. Water shutoff operations in standard wells: £250 to £500,000 (US$335,000 to US$670,000)

Initial Completion Design Considerations

Fiber-optic-distributed temperature systems (DTS) installed elsewhere[1,2,3] had been used to identify water breakthrough in horizontal wells, and therefore, had been able to pinpoint the zone in which the water was being produced. Prior to the D17 installation, DTS optical fibers had been successfully installed in more than one hundred wells using fluid drag (the Sensor Highway ™ system). This system relies on the frictional drag of a liquid pulling an optical fiber along a ¼-in. hydraulic control line. The use of this system allows the optical fiber to be installed in one continuous length and avoids the need for complex tubing hanger and packer connectors in the well. The system will also allow the optical fiber to be removed in the event of an ESP workover by opening the hydraulic isolation tool and reversing the fiber back up the hydraulic control line.

If a Sensor Highway TM could obviate the need for production logging, then an immediate cost saving would result. In order to reduce the number of penetrations at the tubing hanger and allow conventional downhole monitoring equipment to be installed as in previous wells, the D17 completion was designed such that optical fiber that measures distributed temperature was installed in the hydraulic line that operated the hydraulic sliding sleeves

Above this, if there were any intentions to shutoff water producing zones, there would clearly be a cost saving in installing a system that would allow multiple remote-sleeve closing and opening operations at minimal operational cost.

There were also other considerations, which are listed below:

1. Avoiding excessive loads on the ESP
2. Maintaining access below the ESP
3. Handling the loads that the completion would sustain with improved bypass tubing
4. Providing adjustment below the hanger to allow for accurate space-out

After investigating all the issues, BHP chose to have well D17 address the water issue by using a DTS system and intelligent well completion technology[4,5,6] to remotely actuate sliding sleeves to shut off water as it broke. Since BHP Petroleum had already installed a DTS system on the D16 well to assist in improving ESP performance in 1998, and since the surface monitoring equipment was already installed on the Douglas Platform, it could be readily re-configured to accept additional wells. This would resolve the ESP issues**. Fig. 3** shows the proposed completion schematic that was finally adopted for D17.

Description of Completion Components and their Functionality

Several state-of-the-art well completion components were chosen for the D17 completion.

Hydraulic Line-Operated Interval Control Valve. This is a remotely manipulated well control device that activates via a single ¼-in. hydraulic tube. The valve configuration is of the annular sliding sleeve or sliding sleeve circulating device and is used to establish communication between tubing and annulus. A balanced actuator piston is attached to the sliding sleeve and strokes it up or down via hydraulic signals applied from the surface to the ¼-in. tube or control line. The valve contains “smart” miniature hydraulic components, used throughout the aircraft industry, to decode the signals and stroke the sliding sleeve to the desired position.

The valve has been developed for use where remote selective production or shut off is required. The remote activation aspect holds significant value for operators where wireline operations are difficult, expensive, or impossible. This typically occurs in horizontal or deviated wells, subsea wells, ESP applications, heavy oil or paraffin situations, etc.[7,8] The features of this valve are shown in **Table 2.** The control line hydraulic circuit permits one control line to drive the sleeve open or closed without the use of a power spring in the wellbore. This circuit incorporates a custom designed 4-way, 2-position shuttle valve to direct fluid flow, as a function of upstream pressure, to either side of a balanced piston which operates the sliding sleeve. The hydraulic line operated interval control valve is shown in **Fig. 4**. The valve has 2 operating positions and 3 operating modes, which are described below.

Normal Position (closing valve):

P = Pressure or Inlet Port flows to
A = Stroke Valve Closed Port
and
B = Stroke Valve Open Port bleeds to
R = Return or Outlet Port

Activated Position (opening valve):

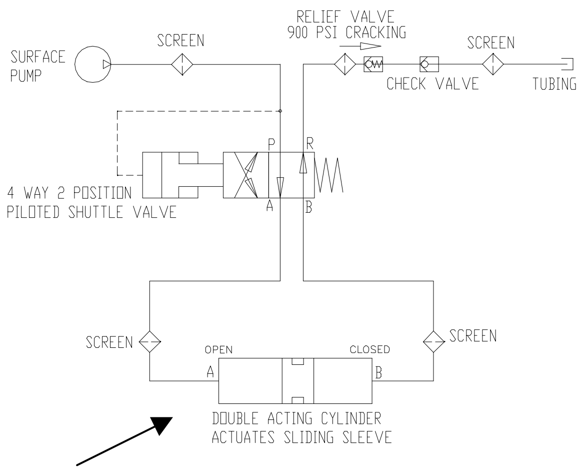
P = Pressure or Inlet Port flows to
B = Stroke Valve Open Port
and
A = Stroke Valve Closed Port bleeds to
R = Return or Outlet Port

Valve operating modes:

0 - 900 psi. Differential. No sliding sleeve movement occurs because the pressure relief valve stops tubing fluid from circulating into the wellbore tubing. Shuttle valve is in the normal position (P to A and B to R).

1,200 - 4,000 psi. Differential. The 4-way, 2-position shuttle valve remains in the normal position (P to A and B to R). Once the pressure relief valve opens at approximately 1,200 psi, then the sliding sleeve strokes closed until the piston bottoms out. Flow rates between 0.1 and 1.0 liters per minute may be employed during stroking, but the differential pressure must remain between 1,200 and 4,000 psi. Once the piston bottoms out, the surface pump flow rate will eventually drop to near zero. The control line pressure must be bled to zero to hold valve in closed position.

4**,500 - 7,500 psi. Differential**. The 4-way 2-position shuttle valve shifts to the activated position (P to B and A to R). The sliding sleeve strokes open until the piston bottoms out. Flow rates between 0.1 and 1.0 liters per minute may be employed during stroking, but differential pressure must be kept between 4,500 and 7,500 psi. Once the piston bottoms out, the surface pump flow rate will eventually drop to near zero. The control line pressure must be bled to zero to hold the valve in open position.



Hydraulic Schematic

Hydraulic Isolation Tool. The hydraulic isolation tool is used in a completion design comprising a combination of optic fiber and control-line operated devices (sleeves or valves) and allows two control lines, one for controlling each device, to communicate with each other. This enables an optic fiber to be pumped down one of the control lines taking returns up the other. Once the fiber has been successfully installed, a sleeve in the isolation tool has to be shifted, which will isolate the control lines from each other. This allows independent actuation of the sleeves or valves. The isolation tool also ensures that there is no control line-to-tubing communication. The tool is run as part of the isolation string.

The Hydraulic Packer with Control Line Bypass and Sleeve Release. The packer chosen for this application is a cased-hole packer with the added facility to bypass electrical and hydraulic lines. The application of tubing pressure against a plugging device below the packer allows setting. A body lock ring stores the compressive force, keeping the packer set. Several versions were considered but the packer chosen for this application was designed to be released and retrieved by straight pull on the tubing. Designed for tandem setting, the packer will set properly without tubing movement or pressure-induced tubing forces. The setting action will not impart loads or damage into any of the penetrations or lines. The packer may be released only after the release mechanism is activated by a an upward jarring to create 15,000 lb. by a selective release tool run on wire line or coiled tubing. Provision for emergency release by mechanical cutting of the mandrel is included. Provision is made for the passage of three ¼-in. control lines, which may include hydraulic lines or instrument wires.

The Fiber Optic Orientating Disconnect Head (FOD) provides a means of aligning and connecting two smooth-bore dual hydraulic control line conduits running between an upper and lower completion. Once connected, the joint provides a continuous bore through which a fiber optic line can be installed without snagging at the connections. The joint provides a pressure-tight seal around connected lines, which are used to operate hydraulic devices. The design also allows a 2-ft downward space-out after the mating faces of the disconnect head make contact.

This connector is used in two trip completions where the lower completion contains hydraulically operated devices such as Interval Control Valves (ICVs). The ICVs are operated by “Mini Hydraulics” where two lines can operate two sleeves independently. The design of the FOD also facilitates the installation of fiber optic line, which is used for well temperature monitoring. If the upper completion needs to be removed for maintenance, such as failure of an ESP, the FOD allows the upper completion to be pulled then re-installed with the hydraulic lines precisely reconnected and sealed.

The Distributed Temperature Sensor

Principles of distributed temperature sensing (DTS). DTS with optical fibers is based on optical time-domain reflectometry. **Fig. 5** illustrates the principle of operation. A pulsed laser is coupled to an optical fiber that is the sensing element. The light is backscattered as the pulse propagates through the fiber owing to density and composition as well as to molecular and bulk vibrations. A portion of the backscattered light is guided back to the light source and split off by a directional coupler to a receiver. Under ideal conditions, the intensity of the backscattered light decays exponentially with time. As the speed of the light within the fiber is known, the distance that the light has passed through the fiber can be derived from the time along the decay curve.

The backscattered light includes different spectral components; i.e., Rayleigh, Brillouin and Raman bands (**Fig. 6**). The Rayleigh component is independent of temperature but is useful in identifying breaks and inhomogeneities along the fiber. This is the main tool used by the telecommunications industry to check the condition of optical fiber communication links.

The Raman spectral band is caused by thermally influenced molecular vibrations. These are naturally occurring phenomena in glass as well as in fluids, gases and solids. The Raman spectral band can be used to obtain information about distribution of temperature along the fiber. The Raman backscattered light has two components, Stokes and Anti-Stokes, one being only weakly dependent on temperature and the other being greatly influenced by temperature. The relative intensities between the Stokes and Anti-Stokes are a function of temperature at which the backscattering occurred. Therefore, temperature can be determined at a remote point in the optical fiber.

Operating the distributed temperature sensor. A DTS system suitable for use in the field comprises an opto-electronic unit containing the laser source and receiver and a portable PC. The sensor can be either a loop of optical fiber having both ends connected to the opto-electronic unit or a single length of optical fiber with just one end connected. In either case, the total length of the optical fiber can be up to 32,000 ft long.

During downhole data acquisition, the opto-electronic unit is coupled to the downhole fiber via a junction box and cable near the wellhead. Data acquisition software then manages the process of gathering Raman backscattered light and converting this to time-dated binary files of temperature data. This is usually placed in a software spreadsheet format for further analysis. There is a trade off between response time, spatial resolution, sample resolution and sensor length. Generally speaking, the longer the measurement time, the better the resolution of the data. For example, a measurement time of 4 minutes 30 seconds results in an accuracy of 0.5 °F and resolution of 0.2 °F with a spatial resolution of 1 meter. This gives a data point every meter point along the wellbore from wellhead to the tubing or pump shoe.

Overview of the D17 Completion

Once the completion had been run, coiled tubing was run to open the hydraulic isolation tool. This was done so that fluid could circulate around the completion to allow the installation of the optical fiber by fluid drag. Experience in earlier installations had shown that it is critical to remove any hydraulic oil from a control line prior to attempting to install optical fibers with a water-based solution. If hydraulic oil is present, it will "wet" the optical fiber, causing it to stick to the wall of the control line. Therefore, before installation could commence, the hydraulic fluid had to be removed from the system by flushing with a detergent. Samples of returns were taken at frequent intervals to determine what levels of hydraulic oil remained. Once tests indicated that the detergent had removed the hydraulic oil, the detergent was removed by flushing with water. The optical fiber was now installed using fluid drag down the hydraulic sliding sleeve control lines. Despite the precautions taken, the fiber was deployed only to the uppermost hydraulic sliding sleeve where it became lodged. A decision was made to complete the fiber installation at this point so that production could commence immediately. Water was displaced to oil once more before closing the hydraulic isolation tool. The DTS system in well D17 was then set up to log the well during the start-up of the ESP.

Problems Encountered During Completion

The completion was successfully installed and operated as planned; however, the optical fiber that gathers distributed temperature information was not fully deployed along all three intervals in the completion. It is believed that the optical fiber became lodged at a point in the circuit where a T-piece is present to take hydraulic fluid to one of the hydraulic sliding sleeves. The flushing process did not fully remove all the hydraulic oil, and this had subsequently seeped into the main control line circuit and prevented further deployment.

DTS Data Logged

The system has been logging DTS data from D17 continually since the well started up. **Fig. 7** shows the recorded temperatures at the ESP during a start-up on 12/14/00. Temperatures of 52°C were observed in the annulus during the start-up phase. The temperatures reduced to 37°C once normal operating conditions had been reached. **Fig. 8** shows DTS data from 12/19/00 to 12/28/00. The three-dimensional plot records data from the top of the ESP pump to the uppermost hydraulic sliding sleeve. The heating effects are shown in **Fig. 9** and again can be clearly observed. The section of optical fiber below the ESP pump shows that reducing temperatures were recorded with time lapse.

Conclusions

The value of the distributed temperature sensor in determining which zone is contributing water will be greatest when the optical fiber is placed along all three zones in the well. A series of tests have been conducted as part of a post-operation review to determine the true cause of the fiber becoming lodged in the control line at the upper hydraulic valve. Small quantities of hydraulic fluid were introduced through a T-piece during a simulated deployment. The fiber was observed to stick at this point. It was also demonstrated that flushing with isopropynal (IPA) removed the hydraulic oil, and fiber-installation could take place. A procedure has been established to remove the optical fibers and install length of fiber across all three intervals when coiled tubing is available to open the hydraulic isolation tool and re-establish circulation through the system.

Fiber-optic distributed temperature sensing (DTS) has been used in conjunction with remotely operated hydraulic Interval Control Valves (ICVs) as a simple and cost effective enhancement to intelligent well technology to enhance production potentials on the Douglas Platform. Interventionless control and selectivity of producing intervals using surface actuated hydraulic ICVs allowed unwanted water production to be managed more effectively to maximize oil recovery. Distributed temperature measurements at one-meter intervals in the wellbore provide data that assists in the determinations of zonal contribution and the identification in the change of fluid properties or water ingress.

An optical fiber that acquires continuous distributed temperature data was installed for the first time into one of the hydraulic control lines that operate the hydraulic ICVs. Opto-electronic instrumentation on the platform allowed distributed temperature data to be transmitted in real-time to a shore-based asset team.

The combination of fiber optics and hydraulic interval control valves provided a number of benefits:

- The combination of hydraulics and fiber optics avoids the use of electronic components downhole, giving a simple, cost effective and inherently reliable system.
- Distributed temperature data can be gathered at 1-meter intervals along all the zones without intervention identifying the precise point of water

entry to within a meter. This will assist in the understanding of the layering or permeability variations within a single zone.

- Distributed temperature data can be acquired without increasing the number of cables in the well or penetrations through tubing hangers and packers.
- The ICVs provide interventionless zonal control,
- The disconnect system facilitates ESP workover and re-completion.

Acknowledgments

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SI Metric Conversion Factors

°F	(°F – 32)1.8		= °C
ft	x 3.048*	E - 01	= m
in	x 2.54*	E + 00	= cm
md	x 9.869 233	E - 04	= m^3
psi	x 6.894 757	E + 00	= kPa
bbl	x 1.589 873	E - 01	= m^3

*Conversion factor is exact

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Table 1

Zone	Geological Facies	Average Thickness (ft)	Core zone porosity from mapping (%)	Core permeability (mD)	Reservoir Quality
IA	Aeolian sandstone	80	18.7	50 - 10,000	Excellent
IB	Thinly inter-bedded fluvial	35	13.2	50 - 2,000	Fair
IC	Aeolian sandstone	45	17.4	50 - 10,000	Excellent
II	Fluvial deposits	250 - 350	13.7	20 - 1,000	Fair
III	Aeolian sandstone	200	19.3	n/a	Excellent

Table 2 —Special Hydraulic-Operated Interval Control Valve Features

Features:	**Benefits:**
Surface controlled opening and closing	The valve does not require a power spring to open or close. The actuator piston is hydraulically stroked in either direction by pressure applied at surface.
Requires only one control line	Miniature hydraulic components in the valve permit dual activation of the piston, with only one hydraulic input. This simplifies tool deployment, reduces the number of feed throughs in the tubing hanger, and limits the number of potential leak points.
Premium check valves	Tubing to control line communication is prevented by means of a premium metal to metal check valve.
Total loss control fluid system	Unlike safety valves, hydraulic fluid is ejected into the well bore tubing with every stroke of the piston. This keeps fresh fluid in the control system and permits small scale and sediment to flush through the system.
Minimal moving parts	Valve has been designed such that the mechanics and hydraulics of the valve mechanisms are both simple and reliable, which is also reflected in the compact size.
Positive high force actuation	The system is not dependent on spring force to operate. Actuation forces as high as 20,000 lb. to open, are available.
Fail safe AS IS operation	Unlike safety valves, which are fail-safe closed devices, the valve maintains position in the event of a hydraulic system failure.
Reliable operation	Unlike safety valves, all hydraulic system dynamic seals contain no pressure differential, except during stroking.
Backup Operation	Model B shifting tool may be used to manually operate the valve if desired. Normal hydraulic activation may be resumed after manual shifting.

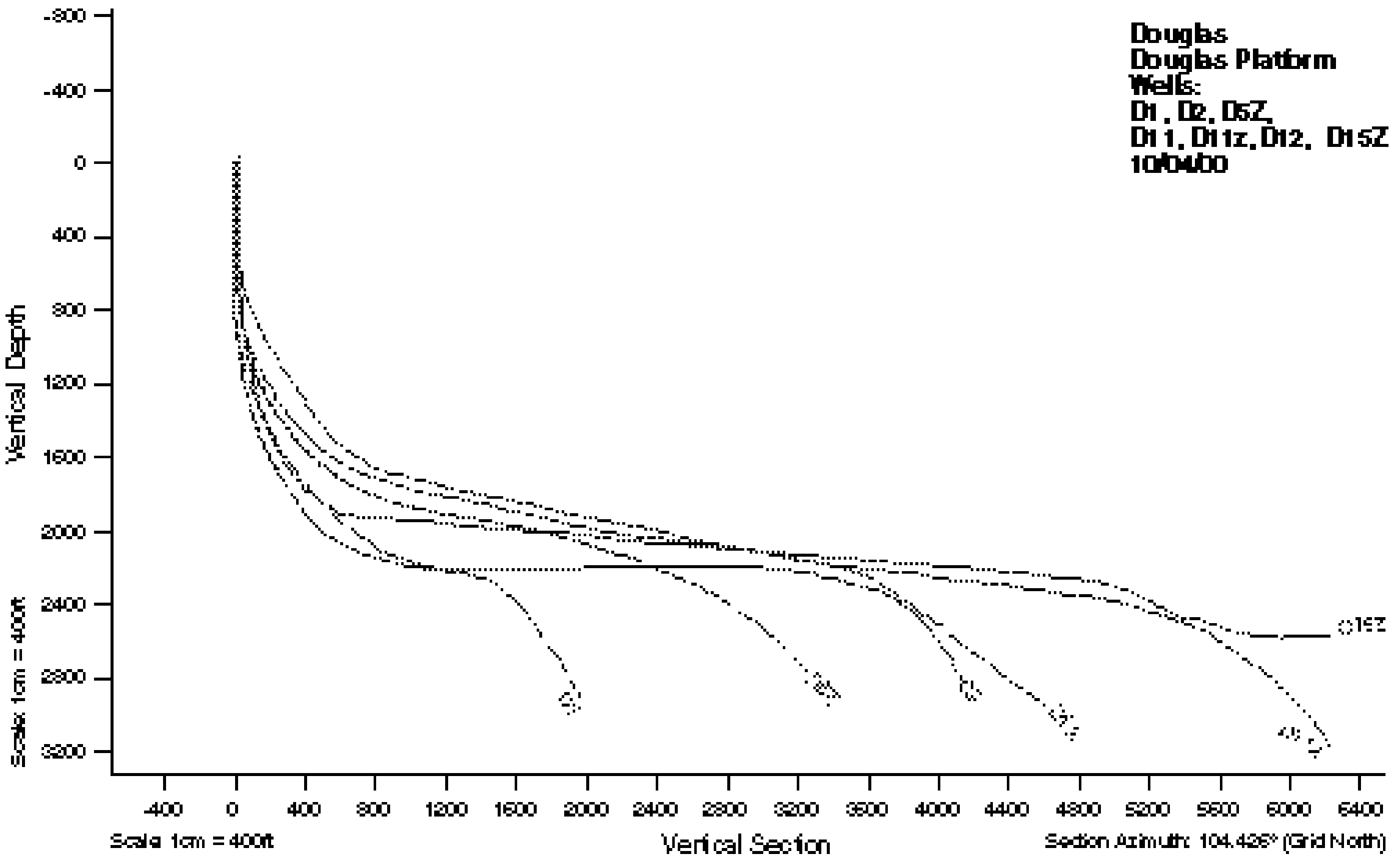

Fig. 1 — Deviation Surveys

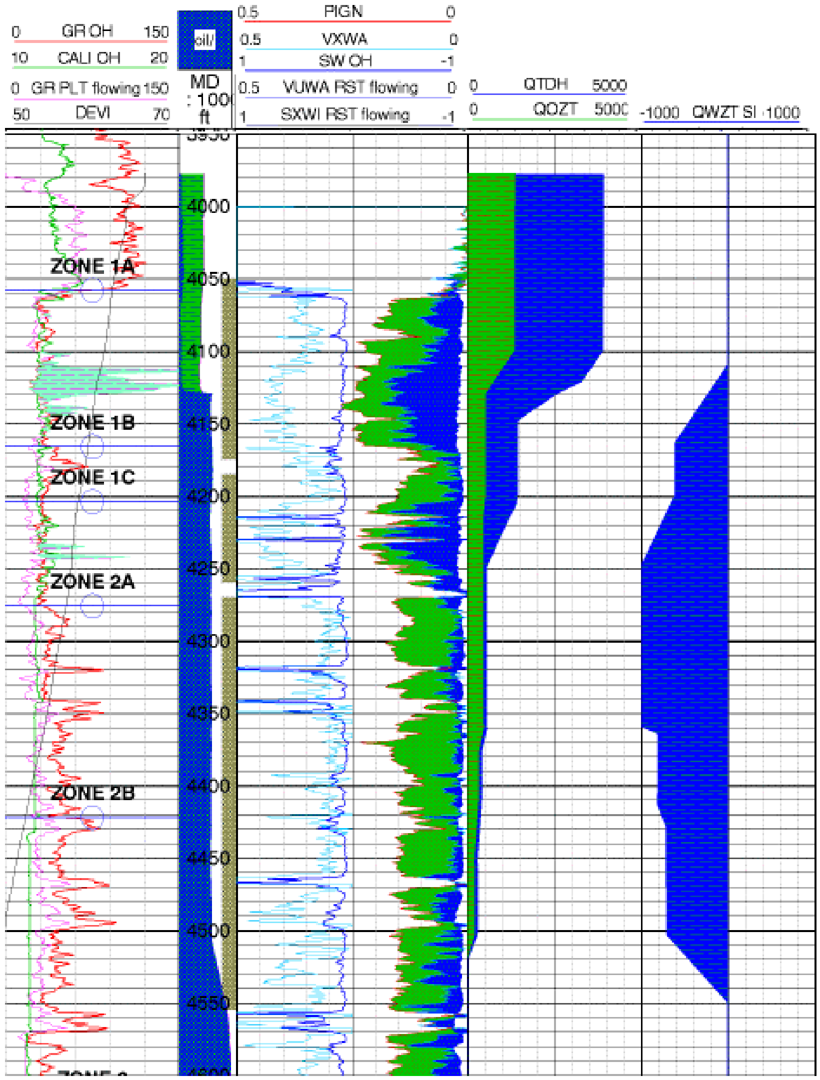

Fig. 2 — Typical production log from high water cut producer

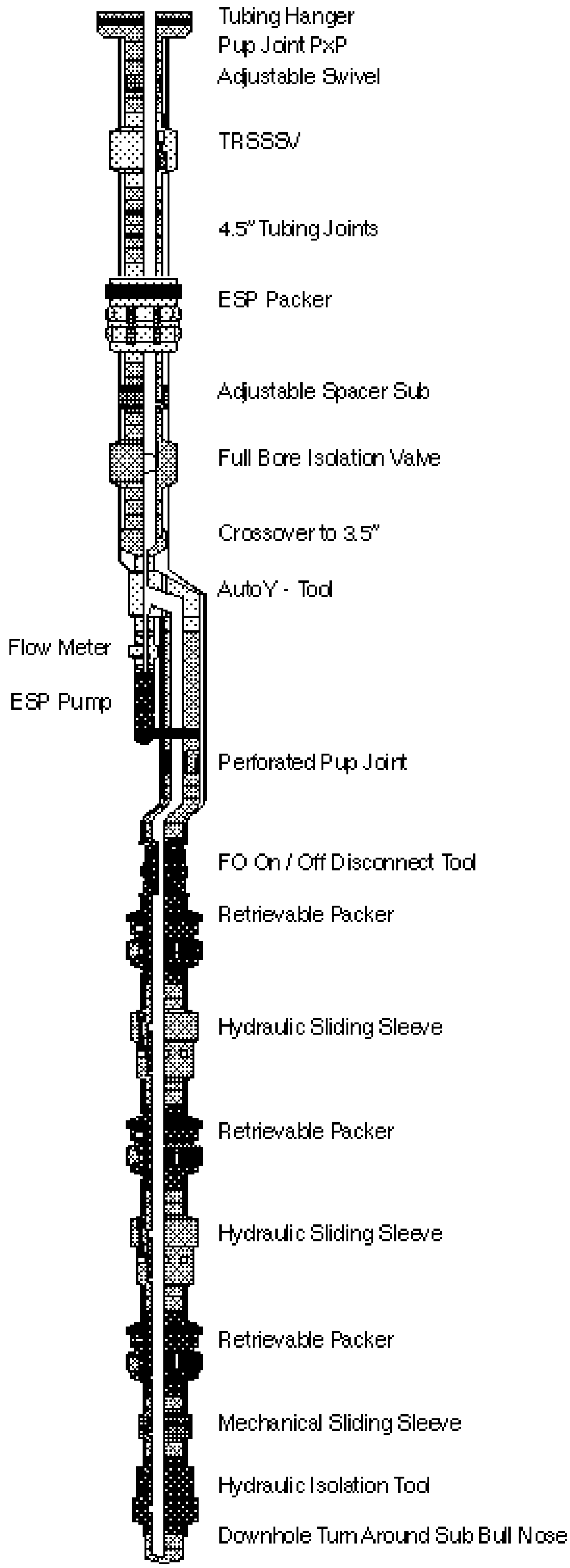

Fig. 3 — Completion Configuration for the D17 Well

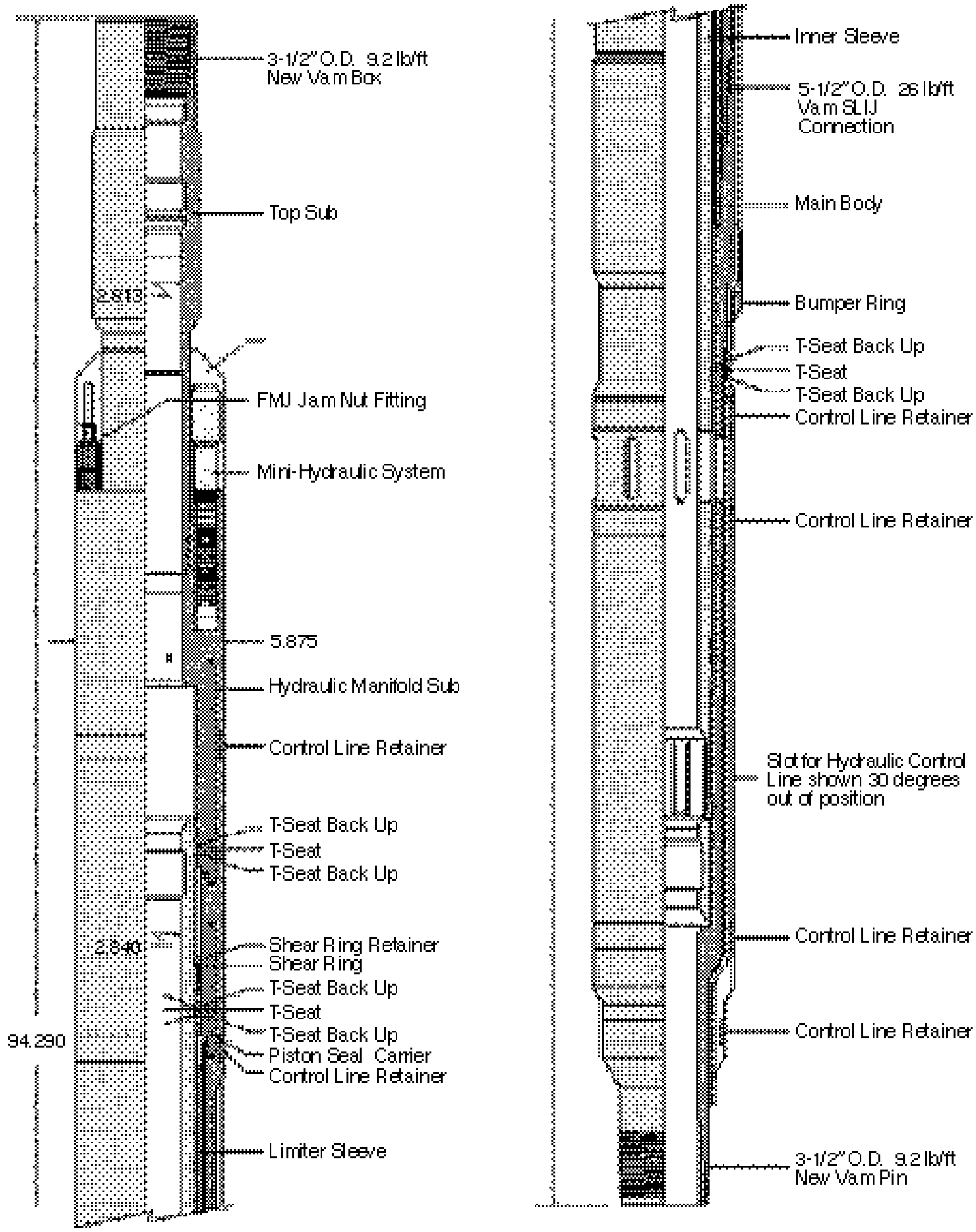

Fig.4 — Hydraulic- Line-Operated Interval Control Valve

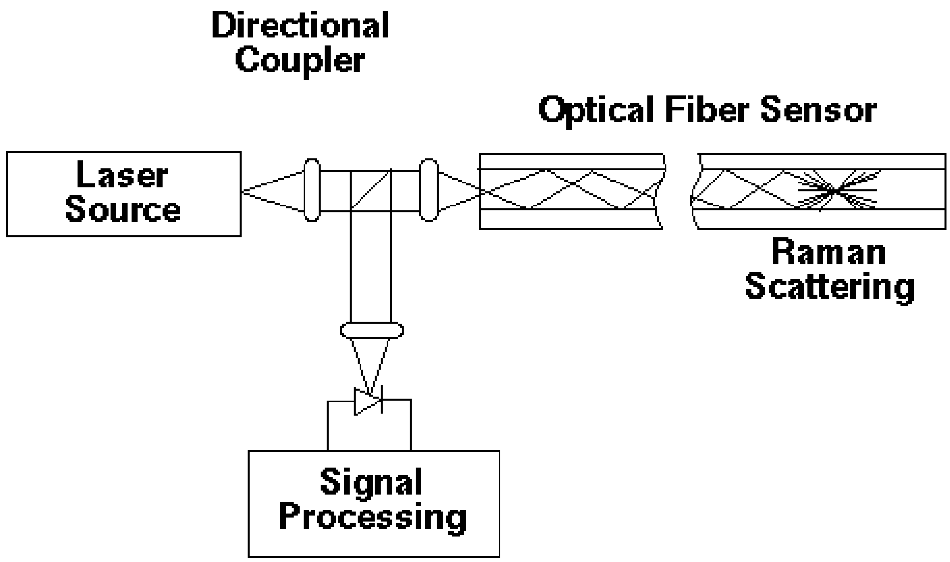

Fig. 5 — Principles of Distributed Temperature Sensing

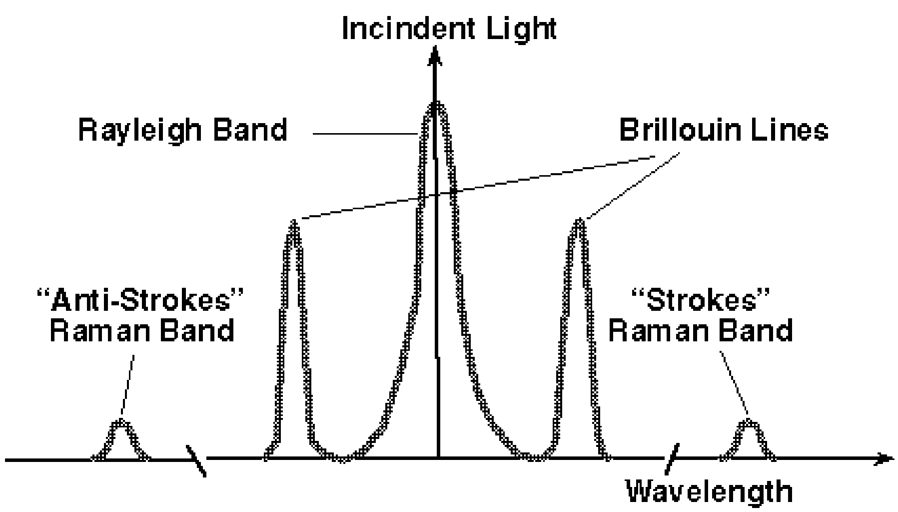

Fig. 6 — Backscattered Light Spectrum

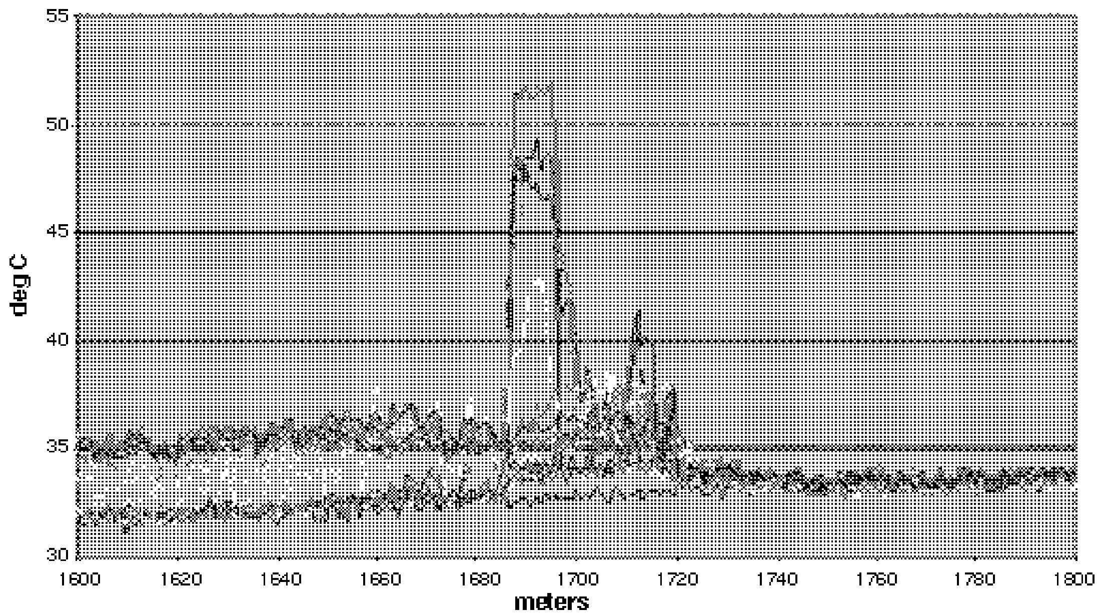

Fig. 7 — DTS data taken during pump start-up on 14 Dec. 2000

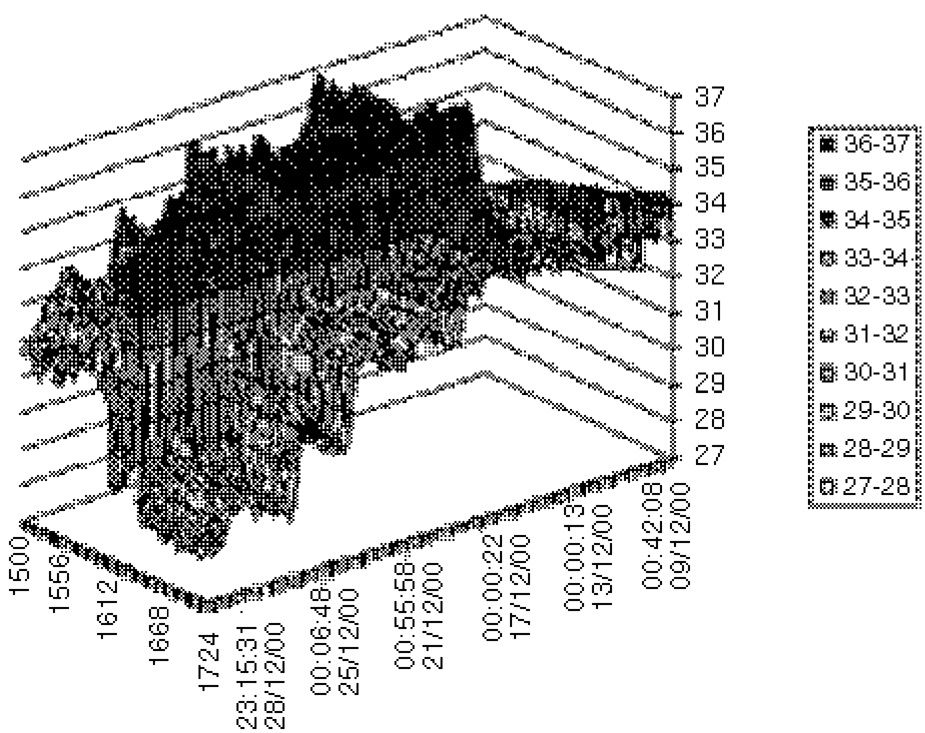

Fig. 8 — DTS data from 19 to 28 December 2000