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Innovative ESP Completions For Liverpool Bay Development

D. R. Stewart, SPE, and B. Holland, SPE, BHP Petroleum Ltd.

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Abstract

This paper presents a review of the ESP completions installed in the Douglas Field in Liverpool Bay. A number of innovations were successfully introduced into the completion design, these are discussed along with the completion procedures and the excellent operational performance which was achieved. ESP runlife performance and the steps taken to maximise runlives are also discussed.

Introduction

The Douglas Oil Field, part of the Liverpool Bay Development, off the west coast of the United Kingdom, requires artificial lift to achieve economic production rates. Low reservoir temperature and a low GOR make Douglas an ideal application for electrical submersible pumps, ESP's and all producers will be completed with an ESP.

In a Field dependent on ESP's, runlives and workover costs play a critical part in project economics. On Douglas, a number of steps have been taken to maximise runlives and minimise completion and workover costs. The completions have been designed to be reliable and quick to install without compromising productivity.

A number of innovations have been introduced into the completion design to help achieve these objectives and the operational performance on the original completion campaign was very good.

The ESP system has been designed to maximise runlife, with the selection of fit-for-purpose, cost-effective equipment. Systems have been put in place to ensure comprehensive monitoring of the operation of the ESP's, further increasing the probability of long runlives.

Oil production started in January 1996; by the end of June 1996 when the paper was written, all ESP's were still operating despite having been subjected to a high number of starts.

Liverpool Bay Development

Development Overview. The Liverpool Bay Development comprises four fields in two separate license blocks. The Hamilton and Hamilton North gas fields and the Douglas oil field are located 15 miles off the North coast of Wales in Block 110/13 and the Lennox oil and gas field is located 5 miles off the West coast of England in block 110/15. BHP operates the development on behalf of a partnership including Lasmo, Monument and Powergen.

Figure 1 shows an overview of the development which includes a total of six platforms offshore. On Douglas there are three bridge linked structures: an Accommodation platform, a process platform and a wellhead platform. Smaller unmanned platforms on Lennox. Hamilton and Hamilton North pump oil and gas to the Douglas complex via subsea pipelines. The oil is exported via an offshore storage barge and shuttle tankers. The gas is exported via a pipeline to an onshore terminal in North Wales.

Plateau production rates from the development are expected to be around 75,000 barrels per day of oil and around 200 mmscf/day of gas.

Douglas Field Details. The Douglas reservoir contains a low GOR, low energy oil which requires artificial lift to achieve economic production rates. The reservoir parameters are listed in Table 1. The 11 production wells on the field will all be completed with Electrical Submersible Pumps, ESP's. There will also be 7 water injection wells to provide pressure support.

The reservoir is a clean and productive Triassic sandstone at a depth of only 2400 ft TVD. The formation is well consolidated and, based on core tests, sand production is not expected to be a problem throughout field life.

The reservoir temperature is low at 85 deg F, combined with the low GOR this makes Douglas an ideal application for ESP's.

Well productivities are in the range 6 to 20 bpd/psi and typical pumped production rates will be 3,000 to 15,000 bpd. Although the oil is relatively light at 45 deg API, it contains significant quantities of wax. It also contains high quantities of H_2S, 46,000 ppm.

Drilling Considerations. The reservoir is divided into 3 fault panels, **Figure 2** shows the reservoir top structure map. The field extends over a wide area at a shallow depth, drilling the high step-out development wells is technically challenging.

The reservoir cross-section in **Figure 3** shows how the production wells are drilled into the updip part of the fault panel, parallel to the fault and as close to it as possible. The water injectors are drilled into the down dip section of the fault. To achieve the high step-outs most wells are drilled to deviations of 85 to 90 degrees.

To reduce mechanical stresses when running an ESP, dog-legs should be minimised. An ESP should be set in a straight section of hole to minimise stresses on the rotating pump sections. In order to accommodate the ESP's on Douglas, the wells are drilled to place a 300 ft long tangent section, with a dogleg of less than 0.5 degrees/100 ft, in 9-5/8" casing, as deep as possible. In addition, there should be no dogleg greater than 7 degrees/100 ft in the well above the ESP setting depth.

Table 1 - Douglas Reservoir Parameters

Depth	-	2400 ft TVD @ OWC
Pressure	-	1100 psi @ OWC
Temperature	-	85 deg F @ OWC
GOR	-	60 scf/stb
Bubble Point	-	230 psi
Well Productivity Index	-	6 - 20 bpd/psi
Oil Gravity	-	45 deg API
Oil H2S Content	-	46,000 ppm

Selection of ESP's for Artificial Lift. In the early stages of planning for the Liverpool Bay Development both gas lift and ESP's were considered as potential artificial lift systems. Gas lift was considered more reliable than ESP's; it had a potentially lower operating cost and it offered higher production uptime.

Well performance studies showed that ESP's could achieve significantly higher production rates than gas lift, particularly after the onset of water production. A review of ESP runlives in the North Sea area led BHP to believe that runlives of 2 to 3 years could be achieved on Douglas.

Economic modelling based on higher production rates and long runlives for ESP's led to the decision to select ESP's as the artificial lift system for Douglas.

ESP Completion Design

Design Objectives. The Douglas ESP completions were designed with the following objectives :

- To have a completion design life greater than the maximum anticipated ESP runlife, 5 years.
- To be simple and quick to install and work-over.
- To maximise well productivity and minimise formation damage potential.
- Not to compromise the ESP runlives.
- To achieve the most cost effective solution with respect to equipment and material selection within the stated design objectives.

Completion Overview. **Figure 4** shows an overview of a Douglas ESP completion. It is a fairly standard North Sea ESP completion in that it includes a surface controlled subsurface safety valve, an ESP packer, and a logging bypass. However, there are a number of significant innovations that have been introduced into this design.

(1) Horizontal christmas trees were used for the first time in a platform application to improve work-over efficiency. Horizontal tree are discussed in more detail below.

(2) A newly developed fluid loss device was incorporated in the completion string to address formation damage and operational integrity concerns during work-over. The fluid loss device is discussed in more detail below.

(3) To eliminate coiled tubing from work-over operations the ESP packers were adapted to allow setting through a capillary line from surface. Packer setting is discussed in more detail below.

(4) The high wax content of the crude led to the requirement for a downhole chemical injection system. The injection point is at the pump intake to ensure the earliest possible treatment of the crude, with the downhole check valve set in a side pocket mandrel at a wirelineable depth to facilitate easy changeout.

(5) The possibility of wax build-up in the tubing raised concern over the ability to run wireline or coiled tubing to open a circulating device or perforate the tubing for well kill. To overcome this concern an annulus pressure operated circulating device is installed immediately above the packer.

Horizontal Christmas Trees. The main advantage of a horizontal tree for the Douglas ESP wells is the ability to carry out a work-over without breaking out flowlines and nippling down the tree. This will result in significant time savings during well interventions.

The horizontal tree is significantly smaller than a conventional tree. The height from the wellhead deck to the top of the tree cap is only 88 inches, this allowed the mezzanine deck to be eliminated from the wellhead platform. The savings in platform weight and associated construction costs were significant and the concept was extended to the other Liverpool Bay Fields.

The Douglas horizontal christmas tree is shown in **Figure 5**. The body of the tree contains an integral production master valve, a bolt on valve block houses the production wing valve and a service wing valve. The production choke bolts directly onto the tree.

The tubing hanger straddles the full length of the tree, at the lower end the tubing connection is eccentric to accommodate the ESP power cable. Flow exits the hanger horizontally into the master valve. In the vertical direction the well is sealed by two wireline plugs set in the hanger body, there is a port to monitor the pressure between the plugs.

The tree, which is common to all wells in Liverpool Bay, contains four penetrations through the tree into the hanger. There are penetrations for an ESP cable, a downhole safety valve control line, a chemical injection line and an instrument cable. On Douglas the instrument cable penetration is redundant

For re-entry into the wells intervention valves are rigged up on the tree prior to pulling the plugs. The advantage of this feature is that wireline or coiled tubing are never run through tree valves, reducing the potential for damage to safety critical equipment.

Fluid Loss Device. When considering work-over operations on the Douglas ESP wells, two potential problems were anticipated. Severe losses when killing the wells could result in well control difficulties and in significant formation damage. In addition, as a result of the well profiles sour crude would remain in the wellbore even after extensive circulating and it would percolate to surface during the work-over.

The solution to these problems was a valve which would isolate the formation during work-over, preventing losses or percolation. However the valve could not be allowed to compromise the main function of the completion.

The selected valve, shown in **Figure** 6, is a self piloting check valve. The valve incorporates a ball which provides the main barrier and flappers which provide the closing force for the ball. When the ESP is shut down the hydrostatic pressure of the column of fluid above the valve is greater that the bottom hole pressure. Fluid will tend to fall down the wellbore and a differential pressure will build up on the flappers which are lightly sprung to close. The flappers then exert the force necessary to rotate and close the ball. When the ESP is restarted the pressure differential above the flappers is lifted and the ball is forced to rotate into the open position.

The valve is installed and operated independent of the ESP completion. It is suspended in the well from a retrievable packer with a sliding sleeve in between to provide bypass in the event of a valve problem. The valve can be locked open to allow coiled tubing access to the reservoir.

The wells are perforated and cleaned up through the drillpipe string used to install the valve. In this way the fluid loss device allows the perforations to be fully cleaned up and isolated prior to installing the ESP completion.

Packer Setting. In order to simplify completion operations and to maximise efficiency every attempt is made to minimise wireline or coiled tubing operations in these highly deviated, 85 degrees plus, wells. As an alternative to setting the hydraulic set packer against a tubing plug, which would require a coiled tubing run to retrieve, it was identified that an alternative packer setting conduit was the chemical injection line which ran through the packer. The packer was modified to allow it to be set by the application of pressure down the chemical injection line against a rupture disc at the discharge point. This feature saved approximately 20 hours per completion and eliminated the complication of high angle plug retrieval operations.

Operational Completion Performance

Completion Installation Programme. An outline of the procedure adopted for the installation of the Douglas ESP completions is as follows:-

1. Skid rig over suspended well.
2. Install horizontal christmas tree and nipple up BOP.
3. Make up sump assembly comprising: perforating guns, fluid loss device, sliding sleeve and packer.
4. Run assembly in on drillpipe, locate guns on depth and set packer.
5. Deploy coiled tubing through the drillpipe to lock open fluid loss device, circulate in nitrogen cushion and install mechanical firing head in guns.
6. Fire guns and back flow well to clean-up perforations.
7. Unlock the fluid loss device and circulate the well to kill weight brine. Pull the drillpipe.
8. Make up completion BHA comprising ESP, logging bypass, nipple, packer and circulating device.
9. Run completion tubing installing chemical injection mandrel, downhole safety valve and tubing hanger.
10. Land hanger. Test hydraulic systems and electrical connections through tree.
11. Set packer by applying pressure to downhole chemical injection system. Shear out rupture disc
12. Set plugs in DHSV and christmas tree to suspend well.

Throughout this procedure, every effort was made to ensure the maximum integrity of the ESP electrical system.

Performance. The first 6 ESP producers were completed as part of an 11 well tieback and completion campaign. An operational target of 7 days per ESP completion was set. **Figure 7** shows the performance achieved.

The completion times shown in the figure include skidding onto the well, nippling up the BOP, pulling the suspension plugs, running the completion, suspending the well and nippling down. The operational target was achieved in all except the first two wells where problems were encountered pulling the suspension plugs.

The average time to complete the last four wells was 5.25 days with less than 8% non-productive time. The six wells were completed consecutively over a 37 day period. This continuous period of focusing on ESP completion operations, as well as pre-operations training, contributed to the excellent performance achieved.

Problem Areas. The main causes of lost time on wells D1 and D2 were problems pulling suspension plugs and killing the well. These problems were overcome by procedural changes.

The only other significant problem was a failure of the coiled tubing hydraulic running tool to release from the ESP bypass plug. The running tool was disconnected and subsequent fishing attempts were unsuccessful. The solution to the problem was a change to procedures to allow the plug to be run in place. The wells were cleaned up through the drillpipe after running the guns and fluid loss device rather than through the ESP completion.

Minor wireline problems did occur and these could generally be attributed to debris in the wellbore. Procedures were implemented to improve the cleanliness of the wellbores during subsequent operations.

ESP Runlife Optimisation

To maximise ESP runlives three main areas must be addressed; 1)Fit for purpose equipment must be selected, 2) it must be installed without introducing system weaknesses and 3)it must be operated correctly. For the Douglas ESP completions efforts were directed into each of these areas.

Equipment Selection. Pump sizing in a new development where there is still significant reservoir uncertainty can be difficult. On Douglas ranges of reservoir parameters were considered and pumps were selected to be suitable over a wide range of operating conditions. The use of variable speed drives greatly improved this flexibility.

In the selection of materials for the ESP equipment it is important to manage the selection of fit for purpose materials without introducing excessive and unnecessary costs.

On Douglas, the high levels of H_2S made material selection vital. However, the low temperature, which reduces the H_2S corrosion rates, and the relatively short design life meant that it was not necessary to select the highest level of metallurgy. Premium elastomers were used throughout but only critical sealing areas utilised high specification alloys.

Pump abrasion due to high sand production is not expected to be a major problem. Fit for purpose materials, which offer a reasonable level of abrasion resistance, were selected. Higher specification equipment will be introduced at a later date as actual operating conditions dictate.

Completion Installation. In order to ensure high quality completion installations significant effort was put into training and teambuilding. The training was focused on personnel involved with the installation of the completion but who had limited experience of ESP's. This included the drilling crew and contract service hands. The initial training took the form of a teambuilding event at which all aspects of the completion programme were discussed. Contractor and participant input/feedback was utilised throughout the session to further optimise and "trouble shoot in advance" completion operations. The event included a visit to the ESP suppliers facility to gain an understanding of the design and operation of ESP's and to witness the assembly of an ESP system in a test well. This training provided a significant boost up the learning curve prior to the start of operations.

ESP Operation and Monitoring. In order to minimise the possibility of operator error the ESP supplier provides experienced ESP operators to assist in the running of the pumps.

Optimum operation of an ESP can only be achieved based on adequate information on the downhole operating conditions. On Douglas a downhole monitoring system records, flowrate, inlet and discharge pressures, fluid and motor oil temperatures and insulation resistance. This data together with surface and process parameters are monitored by the offshore operators and transmitted to the ESP suppliers office for further evaluation.

In addition, the contract for ESP supply includes a significant incentive element which rewards the achievement of runlives in excess of an agreed threshold. The monitoring procedure described is a key element for the supplier to achieve the threshold runlife.

ESP Performance

The first 6 Douglas production wells were completed in July and August 1995 but the ESP's were not powered up until the end of December 1995. First oil production from Douglas was on 17 January 1996.

ESP utilisation was generally low during the commissioning period up to the end of March 1996. In April utilisation reached 84%. By end June 1996 all ESP's were still operating. The number of starts per unit was high during the commissioning phase, typically in excess of 100 by the end of June 1996.

The ESP performance in the first 5 months of production has been good, in particular the avoidance of any short runlife failures has been excellent.

Conclusions

The integration of innovative downhole and surface equipment, focused training of operations personnel, detailed procedures and incentivised contract philosophy was used to maximise both the initial installation efficiency and long term reliability of the Liverpool Bay Development ESP Completions

1. A number of technical innovations were successfully introduced into the Douglas ESP completion design. Innovative techniques improved the efficiency of the completion campaign and will be beneficial during subsequent workovers.
2. An effective completion procedure has been developed and excellent performance was achieved. Most problems have been eliminated by procedural modifications.
3. The steps taken to maximise ESP runlives through equipment selection, training and ESP monitoring and operation have proved successful to date.

Nomenclature

ESP	=	electric submersible pump
GOR	=	gas oil ratio
mmscf/d	=	million standard cubic feet per day

ft TVD	=	feet true vertical depth
psi	=	pounds per square inch
OWC	=	oil water content
bpd	=	barrels (US) per day

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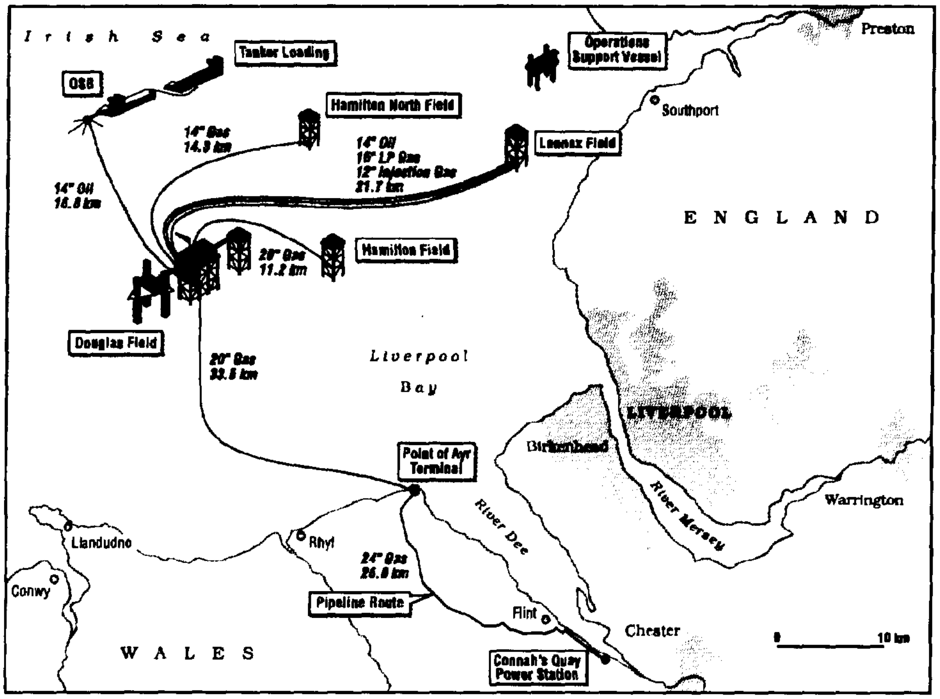

Figure 1 - Overview of Liverpool Bay Development

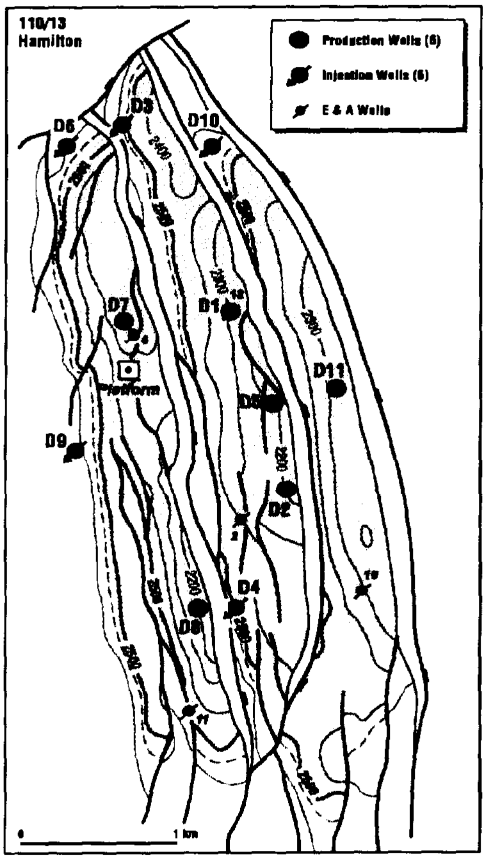

Figure 2 Douglas Reservoir Top Structure

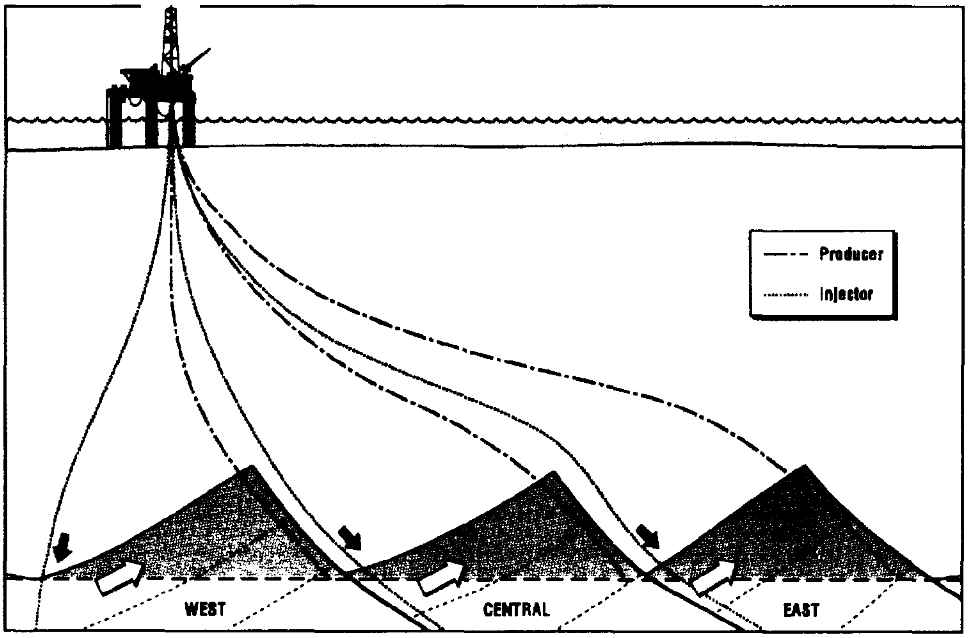

Figure 3 Cross Section of Douglas Reservoir

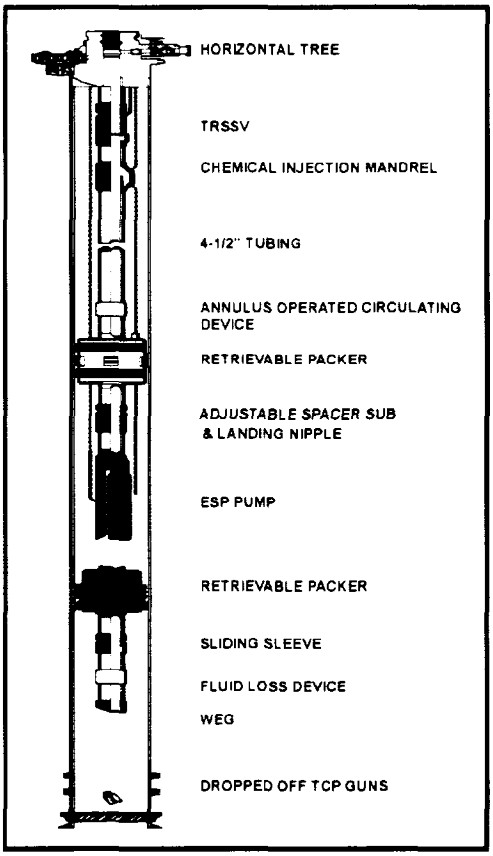

Figure 4 Douglas ESP Completion Schematic

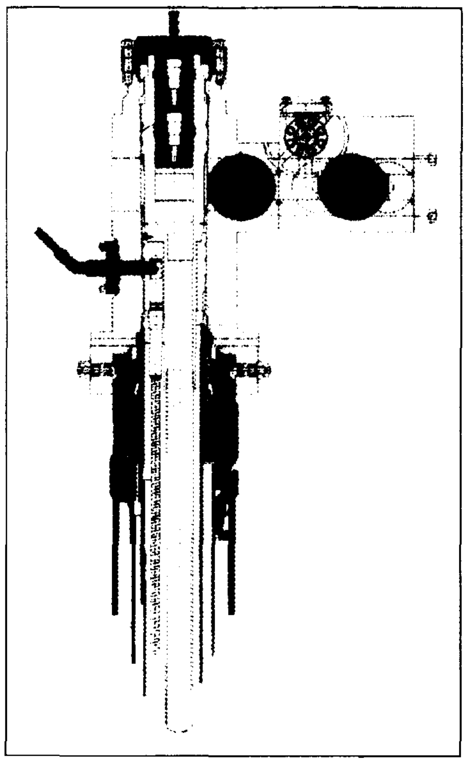

Figure 5 Horizontal Christmas Tree

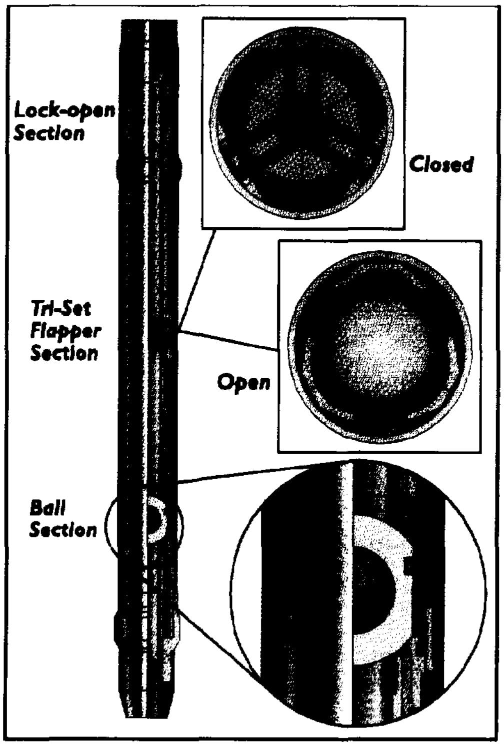

Figure 6 Fluid Loss Device

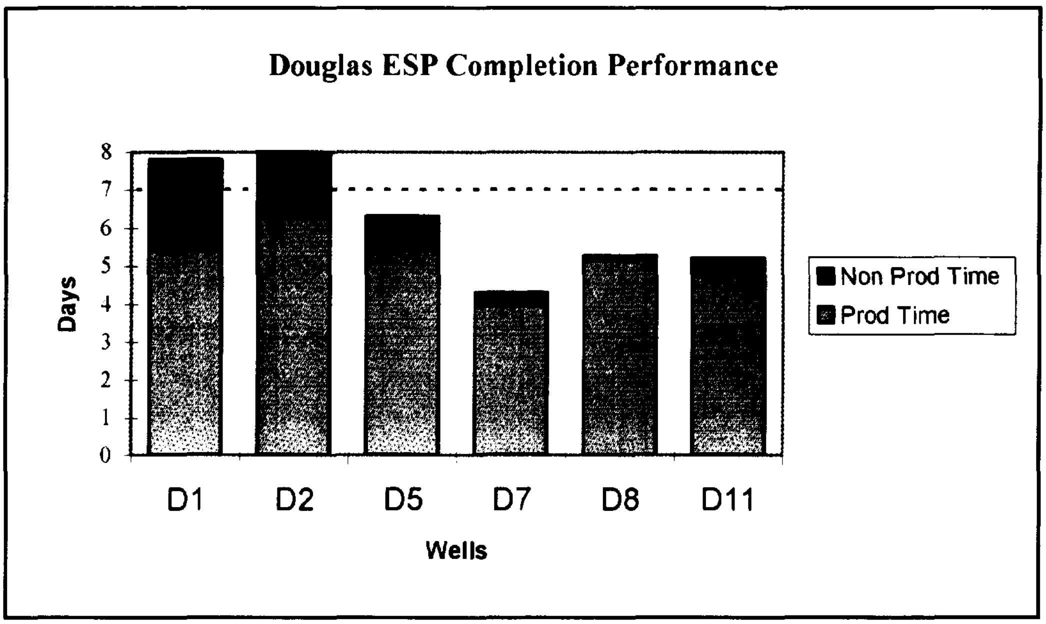

Figure 7 Operational Completion Performance