HSE
Health & Safety
Executive

High pressure, high temperature developments in the United Kingdom Continental Shelf

Prepared by **Highoose Limited**
for the Health and Safety Executive 2005

RESEARCH REPORT 409

High pressure, high temperature developments in the United Kingdom Continental Shelf

A W Glass
Well Engineering Consultant
Highoose Limited
5 Millden Road
Cults
Aberdeen AB15 9LJ

In 2004 the UK Health & Safety Executive (HSE) commissioned research in respect of high pressure, high temperature (HPHT) developments in the UK Continental Shelf (UKCS).

Part 1 of the report summarizes the scope for future HPHT developments possible in the UKCS. It is concluded that the price of HPHT exploration could be bigger than previously thought.

Part 2 of the report reviews the HPHT incidents and defines the associated safety issues. Well control incidents are by far the most frequently occurring but there appears to be an increasing occurrence of incidents related to catastrophic failure of well tubulars and hangers manufactured from premium steels or alloys

In Part 3 the engineering and management solutions implemented by the UKCS industry are reviewed. Where appropriate the risk associated with specific technical measures and concepts is highlighted. In a separate section a number of future technical developments are discussed.

In Part 4 it is concluded that although the UKCS industry is on the right track a number of issues will still need to be solved. Based on the discussions with stakeholders in a workshop a number of Joint Industry Type projects are identified, in addition to other issues that require attention.

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the author alone and do not necessarily reflect HSE policy.

HSE BOOKS

First published 2005

Acknowledgements

The author is grateful for the opportunity and time given by industry representatives and experts to discuss HPHT related matters and for the contributions, comments and suggestions received from:

Grady Ables	Total
Fred Algie	HSE
Jules Borm	Shell
Jan Brinkhorst	Frontier
Trevor Butler	Nexus
Graham Carson	Baker
Frank Close	Chevron
Margaret Copland	HSE
Jim Cowie	BP
Norman Day	BP
William Gill	Talisman
Alan Humphreys	Total
Philip Imperiale	Shell
Matt Inglis	Vetcogray
David Jamieson	Cameron
Eric Low	Nexus
George Lorgen	Baker
Alf Massie	Vetcogray
Mike Marray	Retired ex Shell
Mike McLean	BP
Richard Milton-Worssell	Dti
Ivor Palmer	ConocoPhillips
Chris Robins	HSE
David Scott	HSE
Dave Seymour	Shell
Clint Smith	ConocoPhillips
Bruce Tunget	ConocoPhillips
Fraser Tavendale	Talisman
Bill White	Nexus
Duncan Watt	Nexus
David Wilson	Nexus
Dave Woodland	Shell
Claas van der Zwaag	PSA

CONTENTS

EXECUTIVE SUMMARY

In 2004 the UK Health & Safety Executive (HSE) commissioned research in respect of high pressure, high temperature (HPHT) developments in the UK continental shelf (UKCS) with the objective to:

- Research the full range of HPHT developments possible in the UKCS.
- Define the full range of safety issues associated with HPHT developments to date.
- Review the competence and validity of solutions implemented to date.
- Identify any significant areas of uncertainty and sensitivity.
- Prepare a recommendation on the potential for a Joint Industry Project (JIP) to address any areas of significant uncertainty identified.

The Yet-To–Find HPHT reserves have increased with a factor 3 to 6 since 2001. In a current study the Department of Trade and Industry (Dti) will attempt to put a more accurate figure to that estimate but there seems little doubt that the prize of HPHT exploration could be bigger than previously thought.

Using the Dti definition some 227 wells drilled in the UKCS in the period 1987-2003 were identified as HPHT wells. To identify the HPHT safety issues a comprehensive search of the HSE databases was carried out.

On basis of the information obtained from 130 HPHT-related well incidents and the scant information about HPHT problems encountered in other areas, a number of apparent safety issues and uncertainties have been identified:

- ♦ Well control incidents are by far the most frequently occurring of all HPHT well safety concerns although the hazard related to kick incidents is limited. In the UKCS the probability that well control problems will be encountered in a HPHT well has been successfully reduced from more than 45% to about 17%.

- ♦ The number of incidents involving blow out preventers and ancillary equipment is low. These failures in combination with well control incidents could have catastrophic consequences.

- ♦ Some potential safety issues with perforating and production packers reported in other areas of the world have not (yet) become apparent in the UKCS. It is possible that this will become a future problem.

- ♦ There appears to be an increasing occurrence of incidents related to catastrophic failure of well tubulars and hangers. In most of these cases the failed equipment was manufactured from premium steels or alloys. In most - but not all - cases the root cause of the failure has been attributed to metallurgical flaws. There is no obvious correlation between the specific metallurgical problems and it is believed that there may be a common contributory cause that has not yet been identified. The hazard related to well integrity failures of HPHT production wells is very significant.

The design and construction of a HPHT well – as any other well -- needs to comply with the general duty of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 (DCR)

Operators have demonstrated that this is generally possible with the available materials, equipment and technology. However an increased risk of failure continues to exist as a result of the:

- High stress environment – both tension and compression
- High operating temperatures
- High temperature gradients in the well especially near surface.
- High-end metallurgy susceptible to specific environments
- Chemical activity of well fluid components enhanced by the high temperature
- Massive initial flow rates of most wells
- Narrow margin between the boundaries presented by loading uncertainties and material property variations.

The validity and competence of the technical solutions implemented to date is reviewed under two separate headings:

The Well Construction and Maintenance Operations

The main issue is the high-pressure regime that exists in the prospective zone and more specifically the narrow margin between the required borehole pressure to control the reservoir pore fluid pressures and the allowable pressure to retain borehole competence. Operators are employing the following methods to prevent well control problems:

- Accurate recording of minor influxes from detailed measurements of flows and rig movements.
- Using PWD equipment to obtain complete information on the ECD at any time.
- Employing 'fingerprinting' techniques to demonstrate to the rig personnel the correct procedures for minimizing pressure surges.
- Refining the knowledge of jack up movements in deep water.

In addition sophisticated pore pressure predictions are carried out during well planning to design an optimum drilling control programme that will avoid loss of borehole competence. The latter has a high priority as kick and loss situations are agreed to be the most hazardous.

The problem of well control is amplified when there is a need to penetrate partly depleted reservoirs within the overpressured sequence. The available method involves borehole strengthening by selective pore blocking.

It is concluded that the industry is on the right track to keep the HPHT well control risk as low as reasonably possible. The Health & Safety Executive believes that the frequency of kicks can be reduced further by continued close attention to the available pore/frac pressure window for each individual well. It is expected that development and eventual application of some potential new techniques may also assist in reducing the kick incidence.

The Quality of the Well Construction

During production, HPHT well constructions have given rise to the concerns about the following hazards:

- Catastrophic failure of well tubulars and hangers
- Failure of sealing elements
- Inability to contain the gasbearing Hod and Frigg Chalks
- Erratic well growth

- Inability to withstand reservoir compaction
- Inability to inject chemicals for continuous downhole scale inhibition

Many of above safety concerns involve the loss of one barrier from the well control arrangements.

The industry has been very active to prevent future failure situations by:

- The introduction of intensive quality assurance procedures
- The introduction of design changes to the well configuration
- The introduction of new inspection processes
- The introduction of special handling and installation procedures
- The selection of experienced design and operating teams.
- The use of supply and services resources with a proven track record
- The open exchange of information between HPHT operators.

Each and everyone of these measures is valid and competent if applied consistently and will undoubtedly lead to an overall reduction of the number of safety related incidents in HPHT wells and hence to a reduction of the risk of producing HPHT wells.

It is concluded that the UKCS operators and service/supply industry have been only partly successful in designing and constructing all North Sea HPHT wells right first-time. Although failures generally occurred in fields at the most severe end of the well productivity scale there remains a general concern that not all HPHT hazards have been identified yet. Thanks to the open exchange of information by the industry, the causes of failures and their remedies have been well publicized. This will be of great benefit to future HPHT developments.

In a workshop held in Aberdeen in April 2005 stakeholders' views on the continuing and future challenges from HPHT developments were discussed and the potential areas that will require attention highlighted. The following opportunities for Joint Industry type initiatives were identified:

Compaction

Work required

Geomechanical modelling by industry rock mechanics experts.

The Use of Exotic Materials

Work required

The metallurgists of the various operators and service companies should consider exchanging information on an informal basis. They should consult with metallurgists from other industries (e.g. refineries, pipelines) who may have long experience in using the materials in environments similar to HPHT wells.

Shock Loading

Work required:

Study the effects of (sudden) load variations on well completions. This could involve looking at experiences of other industries.

Model Code of Practice Part 17 (IP now EI)

Work required

The Code of Practice should be updated to regain its status as the prime reference for HP operators.

INTRODUCTION

The UK Health & Safety Executive (HSE) commissioned Highoose Ltd to undertake research in respect of high pressure, high temperature (HPHT) developments in the UKCS. The objectives of the project were as follows:

- Research the full range of HPHT developments possible in the UK continental shelf (UKCS) with particular emphasis on the anticipated reservoir conditions.
- Define the full range of safety issues associated with events that have occurred on HPHT developments to date, taking into account the lifecycle of the well through drilling, construction, completion, production and maintenance.
- Review the competence and validity of solutions implemented to date with regard to existing developments anticipated developments and available technology.
- Identify any significant areas of uncertainty and sensitivity in assessment methods and conclusions reached.
- Produce a report on the work outlined above which would serve to review current knowledge for HPHT wells and identify areas of improvement throughout the lifecycle of the well; drilling, construction, completion, production and maintenance.
- Manage an HSE sponsored workshop, which would consider operators' experiences and reflect on the continuing challenges from the HPHT developments.
- Update the report with the results of the workshop and prepare a recommendation on the potential for a Joint Industry Project (JIP) to address and remedy any areas of significant uncertainty identified.

HPHT developments are defined for this research as developments of reservoirs with a pressure exceeding 69 MPa (10,000 psi) and a temperature above 150 ^{o}C (300 ^{o}F) This is the definition used by the Department of Trade and Industry (Dti). It should be noted that many of the issues will affect wells, which meet either the pressure or the temperature criterion.

Some other industry bodies use a different definition e.g. the Norwegian Petroleum Directorate (NPD) defines HPHT wells as deeper than 4000m true vertical and/or having an expected wellhead shut in pressure exceeding 69 MPa (10,000 psi) and/or having a temperature exceeding 150 ^{o}C. The Institute of Petroleum defines a high pressure well as one having an anticipated surface pressure requiring pressure control equipment with a rated working pressure in excess of 69 MPa (10,000 psi). These definitions are more restrictive and require a more extensive technical interpretation of potential well conditions for each well.

The results of the study are reported in three distinct parts dealing respectively with the future development potential, the safety issues identified to date and the well engineering solutions.

PART 1

FUTURE HPHT DEVELOPMENTS IN THE UKCS

1 INTRODUCTION

Development economics are the key to future HPHT potential in the UKCS area while technical challenges keep intensifying with time in terms of the subsurface conditions encountered i.e.:

Maximum pressure gradient: 22 kPa/m (0.97 psi/ft)
Maximum overpressure: 55 – 62 MPa (8000 – 9000 psi)
Maximum bottom hole temperature: 188 ^{o}C (371^{o}F)

At the time of completing this report the Dti is engaged in a more detailed study to improve the estimates of 'Yet-To-Find (YTF)' HPHT reserves. The information in this section is based on preliminary work done during 2004[1] with the total study not expected to be completed until well into 2006.

2 PROSPECTIVE AREA

The HPHT development area in the North Sea area is an 'overprint' on the complex geology rather than a separate 'play'. There are several basins involved, i.e. apart from the Central North Sea and Fisher Bank there are finds in the Outer Moray Firth, the Viking Grabens, the Magnus Embayement and West of Shetland. Also the HPHT accumulations are found in many different reservoirs: e.g. the Kimmeridge turbidites, the Fulmar sands, the Pentland/Hugin, Skagerrak, Triassic, Rotliegendes sandstones, the Rhum turbidite sands and the Zechstein carbonates.

The HPHT overprint area has increased considerably in recent years. In 2001 the outline enclosed an area of 14 000 km^2, in 2004 the total area, including the Magnus Embayement and West of Shetlands was almost 38 000 km^2 (see table 1).

Table 1 Quadrants and blocks included in preliminary HPHT overprint

Quadrants	Blocks
3	4,5,8,9,10,13,14,15,18,19,20,23,24,25,28,29,30
4	21, 26 (all)
9	3,4,5,8,9,10,13,14,15,18,19,23,24,28,29
10	1 (all)
15	16 to 30
16	2,3,7,8,12,13,17,18,22,23,24,26,27,28,29,30
21	1 to 15,18,19,20,24,25,29,30
22	1 to 30 (all)
23	6,11,16,17,21,22,26,27 (all)
28	5
29	1 to 10, 12,13,14,15
30	1,2,3,6,7,8,11,12,13,14,16,17,18,19,20,24,25
31	21,26,27 (all)
204	4,5,8,9,10,13 to 30 (all)
210	4,5,10,13,14,15
211	1,2,7,29,30

3 FIELDS AND DISCOVERIES

Some twelve UKCS HPHT fields are in production or under development. There is a mixture of large independent jacket based operations - generally gas-condensate fields - and small - generally oil - fields, producing sub-sea to nearby infrastructure. The USGS class reserves of these fields cover a wide range, varying from 0.6 to 81.3 Mm^3 oil equivalent (4 to 512 million boe = barrels oil equivalent). Dti reports a further 34 undeveloped discoveries with reserves of 0.6 to 20.3 Mm^3 oil equivalent (4 to128 million boe).

4 PROSPECTS

The 'Yet-To-Find' reserves have increased by a factor 3 to 6 since 2001 and the current Dti study will attempt to put a more accurate figure to the estimate. The study is designed to qualify the estimates by reservoir, area and geological risk but there seems little doubt that the prize of HPHT exploration could be bigger than previously thought

Important elements in the context of the study are:

- Pressure prediction from better seismic imaging from the Long Offset seismic surveys both 2D and 3D.
- Pressure prediction from better velocity interpretation.
- Pressure prediction from gravity measurements using a better depth model – one case study world-wide so far.
- A better understanding of "column height prediction and fill factors".
- Determination of the pressure cell boundaries through identification of the trap seal integrity
- Identification of deeper targets

Previous YTF reserve estimates show prevalence of accumulations of less than 5.1 Mm^3 oil equivalent (32 million boe). In 2004 the economic field development cut-off was thought to be in the order of 4.3 Mm^3 - 5.6 Mm^3 (27 – 35 million boe) but with the oil price exceeding $50/bbl this economic cut-off may have dropped to 3.2 Mm^3 (20 million boe) now.

Any reduction in the costs of drilling HPHT Exploration and Appraisal wells, by technological advances or added knowledge, would increase the number of exploration wells that may be drilled in this area of complex geology thus increasing the finding chance.

Reduced drilling cost would also lower the cost of field exploitation. This would act to lower the economic reserves cut-off and smaller reserves would be developed.

5 FUTURE EXPLORATION DRILLING COSTS

HPHT Exploration wells are currently designed to be 'Keepers' although very few are actually used for production after the field is developed. Designing these wells as expendable 'Finders' is possible with the current technology and would present a cost reduction to the tune of £ 7 – 8 million. However, the cheaper design could affect the amount of information that may be obtained and would also increase the risk that the well would not reach its target.

Although one operator is seriously looking at applying the Finder principle, other operators are concerned that 'Finders' will not satisfy the information requirements of the Dti. The advice of Dti is 'ask' – they have a flexible "well by well" approach to these matters and the first priority is to get an exploration well drilled safely and discover hydrocarbons.

6 FUTURE FIELD DEVELOPMENT CONCEPTS

Assuming that the more detailed information that will emanate from the current Dti YTF study would not significantly change the overall size distribution of the prospects, it could be expected that many of the future finds will be in the 2.5 – 5.1 Mm^3 oil equivalent (16 – 32 million boe) range with a very good chance of finding considerably more.

The development concept applied to future fields will be strongly dependent on their location in relation to the existing infrastructure and it is expected that the Dti study will fill in much of this detail. In general it may be stated however that the North Sea development trend for the smaller and medium size fields is towards sub-sea completed wells either producing to an existing facility or to a dedicated floating facility. The equipment to apply the sub-sea concept to HPHT wells is now available and it should be expected that many operators will find this the most economic and safe solution to exploit future reserves.

PART 2

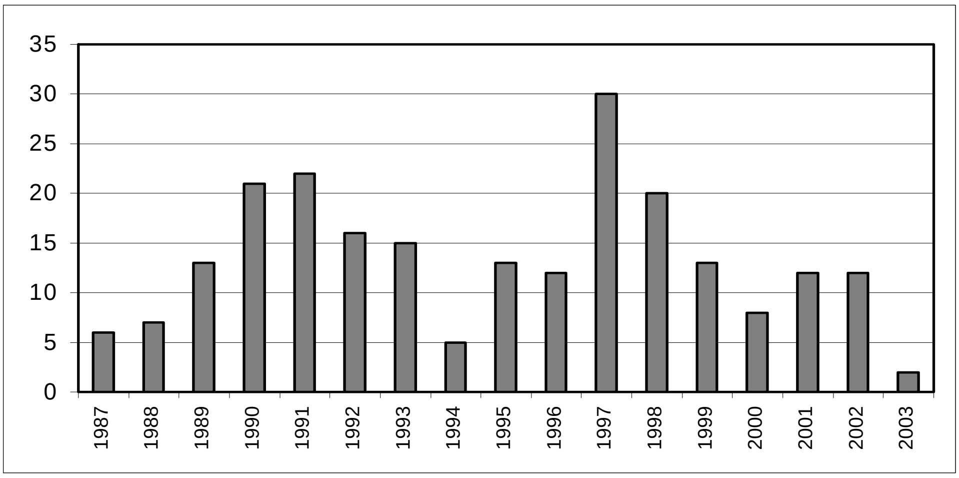
HPHT WELL SAFETY ISSUES IDENTIFIED TO DATE

1 INCIDENTS ON THE UKCS

1.1 Introduction

Using the Dti definition some 227 wells drilled in the UKCS in the period 1987-2003 were identified as HPHT. The number of well spuds varies strongly over the years, ranging from 30 to 2, as shown in figure 1.

Figure 1: HPHT Well Spuds



In the following sections of this part of the report the number of wells per year is used to obtain incident rates. For this purpose the correct denominator i.e. the number of wells exposed to risk was derived from the number of well spuds by assuming that 25% of the wells spudded would carry over to the next year.

As a first approach to identify the safety issues with HPHT wells to date – i.e. to achieve objective 2 above - a comprehensive search of the HSE databases was carried out. A total of 130 HPHT related well incidents have been recorded from the start of HPHT drilling on the UKCS, up to the end of 2003.

To obtain insight into the safety issues involved it may be important to establish

- The type of incident and the basic cause(s)
- The well type i.e. exploration/appraisal or development
- The type of installation involved i.e. semi-submersible, jack-up, fixed platform or none (i.e. for a sub-sea completion)
- The phase of the well life cycle i.e. drilling, testing, suspension, completion, production, maintenance, workover, abandonment

The full HSE well incident classification indicating the type of incident is shown in the relevant Regulation: RIDDOR [2]. For this review only HPHT related incidents were considered. Incidents during tophole drilling were excluded. No HPHT related incidents involving interaction of wells or coiled tubing operations were reported during the period concerned. As a result the incidents reviewed were limited to the following types:

- Control of unplanned influxes or flows (i.e. kicks)
- Failure of the blow-out preventer (BOP) and ancillary equipment after initial installation
- Detection of H_2S during operations or in samples of well fluids
- Mechanical failure of a safety critical component of a well
- Uncontrolled flow from a well

The incidents are reviewed by type in the following sections.

1.2 Control of unplanned influxes or flows: Kicks

Kicks are defined as incidents when a BOP or diverter is operated to control the flow from a well. These incidents are further classified in relation to the volume of unplanned inflow from subsurface reservoirs into the hole. This criterion provides a direct indication of the level of risk incurred. Kicks are defined as 'major' if the influx is more than 3.2 m^3 (20 bbl) while drilling an 216 mm (8 1/2 inch) or smaller diameter hole. For other hole sizes this volume is adjusted to reflect an equivalent length of hole filled and thus producing an equivalent loss of head in the well.

The occurrence of the 77 incidents reported over the period 1987-2003 is shown in figure 2. It is clear from this figure that the incidence of the more serious major kicks is reducing, the last one reported in 2001.

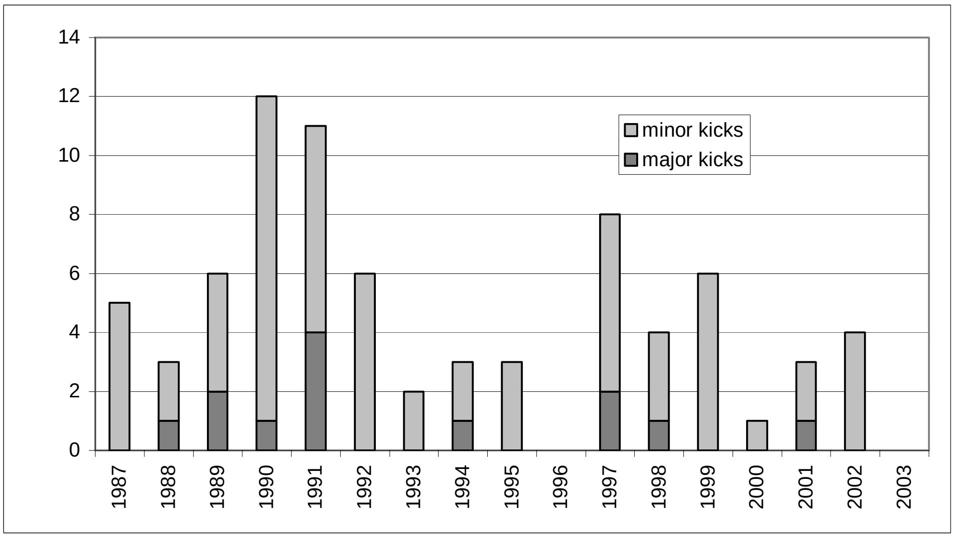


Figure 2: HPHT kicks

To obtain the relative incident rate for kicks the data presented in figure 2 have been set against the number of wells drilled during the year concerned in figure 3. For this purpose the risk factor was expressed as the number of wells incurring kicks (56) rather than the number of individual kicks (77), i.e. reducing the effect of multiple deep kicks incurred in the same well. As mentioned in section 1.1 above, the correct denominator i.e. the number of wells exposed to risk was derived from the number of well spuds by assuming that 25% of the wells spudded would carry over into the next year. In order to show trends more clearly the data are presented as a three-year moving average.

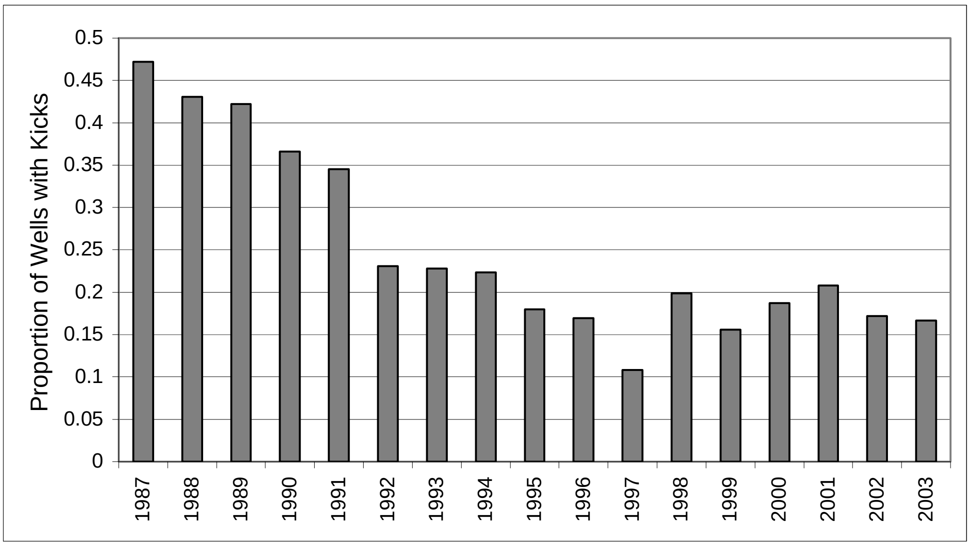


Figure 3: Kick incident rate

Hinton [3] reported that over the period 1989-1998 kicks were taken in 22% of all HPHT wells drilled with no discernible trend. This compared to 11% when looking at all wells drilled on the UKCS. The HPHT well data collected for this study include 28 additional wells as a result of using the slightly different Dti definition for HPHT wells. It is clear from the presentation in figure 3 that the kick incidence rate has actually reduced sharply from more than 45% to less than 15% over the period 1987 to 1997. This trend has not continued over the more recent years and a level of about 17% i.e. one well in about six wells is shown for 2003. The reduction over the early years may be an indication that improved Operator procedures and training programmes instituted after the Ocean Odyssey accident in 1988 have been effective. The reason for the lack of further improvement since 1997 is not clear.

The majority of the reported incidents concerned unplanned influxes into the wellbore often coinciding with losses of drilling fluid in other permeable zones in the open hole.
The basic cause of this type of incident is the requirement to control reservoir fluids with heavy drilling muds exerting a gradient up to 22.7 kPa/m (1.00 psi/ft), close to the formation strength gradient at depth. See figure 4 for a summary of the required gradients as reported for these incidents. An added complication is that isolated high-pressure sand lenses may occur in the Kimmeridge directly below the X-unconformity i.e. in the top part of the prospective section to be drilled.

In 19 of the 77 incidents (25%) the leak off strength of the intermediate casing string – usually set just above the X-unconformity – or the formation strength in deeper open hole proved insufficient resulting in a kick and loss situation. In a few cases this led to abandonment of the open hole – at times with great difficulty.

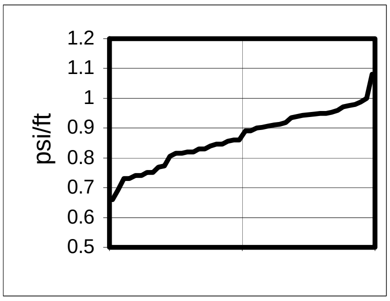


Figure 4: Fluid gradient required

1.3 Failures of blow-out preventers and ancillary equipment

Eleven incidents with BOP's or ancillary equipment were reported. The equipment failures involved the annular element, the control line, the choke line, the kill line, and the BOP seals. Functional failures of the yellow pod, the choke valve and the total system were also experienced.

There is no trend of failures pointing to a particular item or part of the equipment being particularly vulnerable. It should be noted that the Ocean Odyssey accident of 1988 was ultimately caused by failure of a wellhead component.

The relative incident rate for this type of failure is shown in figure 4. There is no indication that this type of incident is being eliminated and no clear trend can be observed - probably as a result of the low absolute number of occurrences.

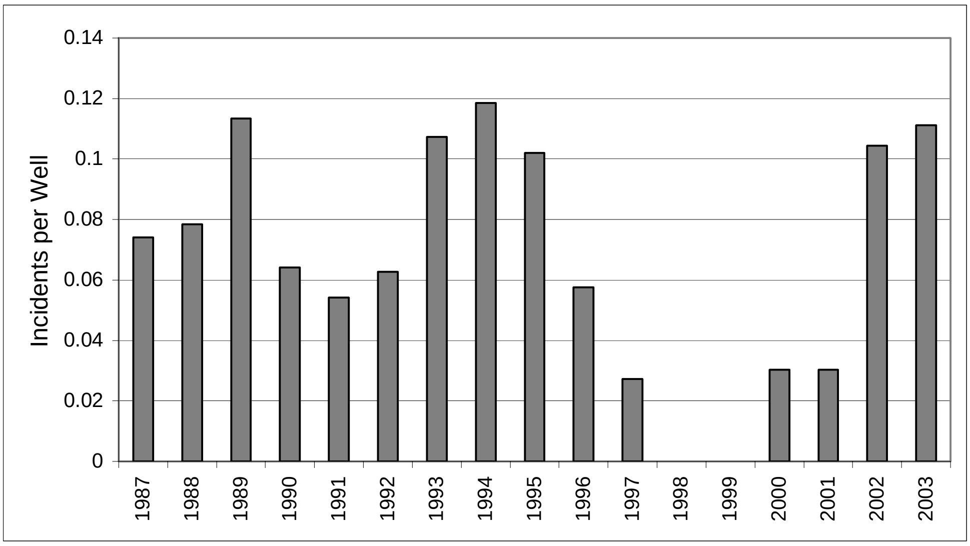


Figure 5: Incident rate of BOP equipment failures

1.4 Detection of H_2S

Reports concerning detection of H_2S were only submitted during the first ten years of HPHT drilling, see figure 5. After 1995 the new reporting Regulations (RIDDOR [2]) required submission of an incident report only when the H_2S concentrations observed were higher than expected.

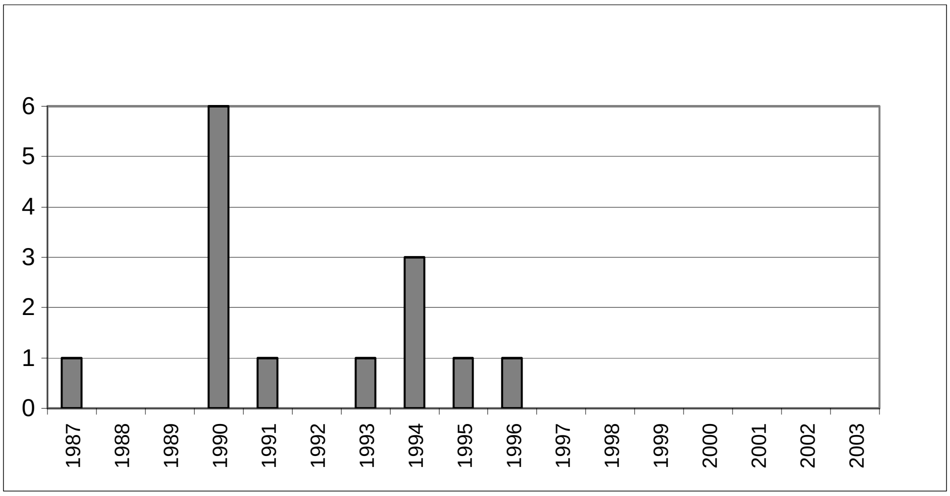


Figure 6: H_2S related incidents

Fourteen incidents were recorded. Initially the sour gas was noticed during drill stem or production testing or when recovering wireline samples. Concentrations were generally low, 15 –200 ppm but on one occasion 8000 ppm was recorded. Later incidents concerned H_2S gas observed during pulling out with the corebarrel or while recovering the cores. Concentrations up to 4000 ppm were recorded in those cases. As H_2S contingency plans are normally included in all HPHT well programmes, these incidents were handled expertly and caused no significant risk.

1.5 Mechanical failures of a safety critical component

This type of incident includes all failures of equipment other than those related to the blow out preventer stack. The occurrence of these incidents is reported separately for exploration/appraisal and development wells. A total of 25 incidents were recorded, initially on E/A wells but recently increasingly on development wells - see figure 7. Because several of the latter incidents occurred in the production phase of the wells, it is less meaningful to derive an incident rate per well drilled.

The early failures were mainly due to leaking seals and seal assemblies or washouts of surface equipment. One case of a parted conductor near surface and a worn through casing at kick-off depth were also reported.

The early development wells showed problems with mudline casing hanger installation, leaking production and liner packers, collapsed tubing and leakage of wellhead and flowline equipment. Recently a broken slickline incident was reported under this heading.

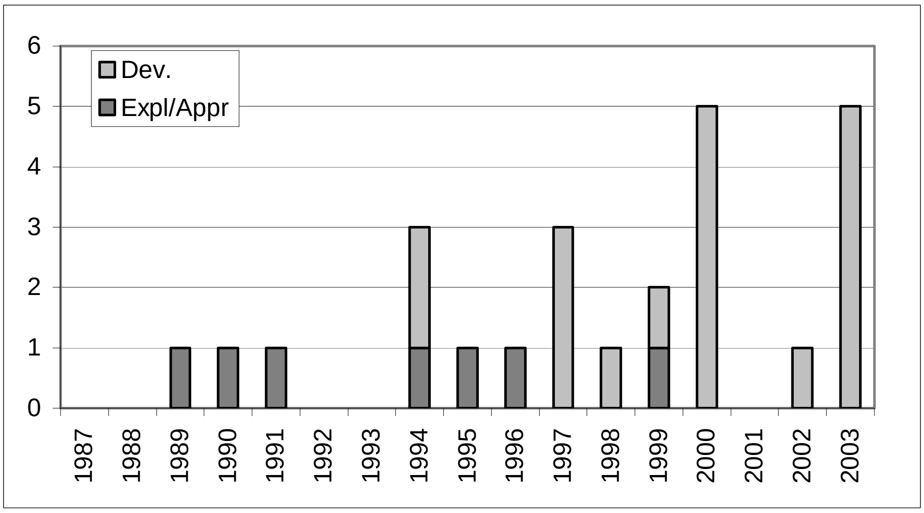


Figure 7: Mechanical failures

Since 1998 a different type of mechanical failure has become apparent in HPHT wells:

Incident 1 (1998) In this platform well communication was established between the 127 mm (5") tubing and the annulus within 12 months after being taken into production. The well was closed in and the tubing recovered during a subsequent workover.
A long bursting split had developed in the pipebody of the 127 mm (5”) 25CR-130 duplex stainless steel tubing joint at 59 m (194’) below the tubing hanger. The topmost eleven joints of the tubing string were all found to be suffering, to varying degrees, from extensive pitting attack and in some cases, severe stress corrosion cracking. The pitting severity increased from either end of this section towards the central region where the failure occurred. The corrosion was only found on external surfaces of the pipe.
The prime cause of the pitting attack and subsequent stress corrosion cracking is thought to be oxygen ingress into the annulus. The heating of the annulus fluid (inhibited calcium chloride brine) during production generated steam and suppressed the liquid level down to 122/213 m (400/700 feet). Several blow-downs had been required. During subsequent cooling off periods air could have been drawn into the annulus via a small leak. The failure occurred at the annulus fluid liquid/vapour interface, a zone subject to frequent washing and vapour phase exposure. Once the cracking had reached a critical level the tubing burst due to internal pressure.
This incident highlights the importance of strict control of the annulus integrity and the choice of annulus fluid. One potential concern is that the brine appeared to be treated for the protection of carbon steel. There did not appear to be consideration of the possible effects on duplex stainless steel.

Incident 2 (1999): While pressure testing the production casing with an inflatable packer the packer failed and pressures equalized across the strings. It was found that the production-casing hanger had parted at 100 mm from the bottom of the box thread. The well was still suspended with cement plugs and not yet perforated and the failure was not generating the level of risk that would be experienced with similar failures in a producing well. The stainless steel hanger was recovered and was found to be very brittle (7J versus normal

30J). This could have been the result of inadequate heat treatment of the component.

Incident 3 (2000): This development well was completed, perforated and cleaned up before being closed in until start up of platform production. After being opened up for commissioning well growth exceeded the model forecasts resulting in production lines being moved. It is suggested that the excessive growth was partially due to movement of the marine conductor and hence the fixed point of well support.

Difficulties were also experienced in stabilising the annulus pressures. It was concluded that there was communication between the A and B annuli i.e. across the production casing and the well was closed in awaiting workover.

After being closed in for 16 days an integrity failure occurred in the production-tubing conduit above the subsurface safety valve and full well pressure was seen on the A-annulus. The B annulus - in communication with the A annulus - was not designed to withstand reservoir pressure and there was the potential for pressurization of weaker formations which were open to the B annulus below the casing shoe. This could lead to an underground blow out and subsequent cratering around the platform foundation.

Hydraulic control of the safety valve was lost and the valve closed as designed, thus shutting off flow from the HPHT reservoir. It should be noted, however, that subsurface safety valves are not normally used for long term isolation as they have an allowable leak rate and hence the double failure of the well completion created a very serious risk for the platform and personnel on board. The platform was shut down until the well was killed by pumping oil/brine/mud and re-entered for abandonment.

It was found that the production conduit failure was due to the Alloy 718 tubing hanger parting at the root of the box thread. The cause of the material failure was identified as hydrogen embrittlement predisposed by the presence of delta phase material in the alloy structure. Delta phase is a feather-like effect among the grains created prior to forging, which is usually removed during subsequent heat treatment. It was established that the heat treatment temperatures/procedures of batches of hangers had been subject to variation.

The issue of delta phase material was known about by metallurgists but not generally thought to be a problem in Alloy 718. The manufacture of these unusually large and thick components of the alloy appears to have created a cooling problem that exacerbated the phenomenon.

When recovering the casing it was found that a coupling at about 1006 m (3300’) had washed out. The coupling had damaged threads and had not been made up properly. This has led to significant changes in the running procedures and the torque-turn graph acceptance procedures.

This incident was serious because of the occurrence of two independent failures of critical components.

Incident 4 (2003): After producing intermittently for two years this well was additionally perforated, flowed for one day on commingled production then shut in. After 16 days the integrity of the production tubing conduit was suddenly lost and the A annulus pressurized. The subsurface safety valve remained closed on fail-safe when hydraulic control was lost. After a further five days there were indications of a leak path developing between the B and A annuli and the well was killed. All other wells on the platform were shut down and the platform hydrocarbon inventory reduced for safety reasons.

Upon recovering of the tubing it was found that the body of the 25 Cr Super Duplex pupjoint below the tubing hanger had split longitudinally then had parted close to the tubing hanger connection. The failure is thought to have been initiated by a short (120 mm) brittle crack starting from the outside. Apart from some high hardness anomalous microstructure on the surface of the pipe along a longitudinal grinding line no significant deviations of the material specifications were found. The precise cause(s) and mechanism(s) of failure have not been established, but it is postulated that the initial crack could have been caused by chloride stress cracking.
The leak from the B annulus to the A annulus was identified to have been caused by incomplete setting of the production casing hanger pack-off assembly. The upper shear ring of the seal assembly had not been sheared and the upper seal had not been set.
Although no leakage in the critical direction from the A annulus to the B annulus had been established, this incident had the potential to become equally serious as incident 3 above. In that case two independent failures of critical components lead to sole reliance on the subsurface safety valve integrity to prevent an underground blow out.

Incident 5 (2003): This newly completed production well was closed in after a 30-hour production test prior to suspension. After 4 hours a pressure build up in the A annulus was observed. When this pressure could not be bled off, tubing to annulus communication was evident and the subsurface safety valve of the well was closed. All other wells on the platform were closed in and the platform was shut down until the well was killed with brine. Upon recovery of the tubing the cause of the communication could not be established and the completion operations were resumed.
While re-testing the production casing with water pressure communication with the B annulus was suddenly established. The well was suspended and the platform shut down.
It was found that the Alloy 718 production-casing hanger had partially failed at the root of the box thread. Less than half of the total circumference had cracked, the central 50 mm in brittle failure, the remainder in ductile failure. The crack could have been initiated as a brittle failure during the make-up of the hanger to the first casing joint. The lower than normal forging ratio applied (2 : 1 instead of 3 : 1) was also suspect. After further investigation the main fracture was attributed to a low energy hydrogen assisted cracking process in cold condition. The hydrogen may have originated from the thread plating process or from a corrosion process between the Alloy 718 hanger and the C110 casing pup joint. The arrest of the ductile crack is considered a typical strength of the Alloy 718 material.

These incidents have in common that a critical component of the production tubulars failed catastrophically while under tensional axial and/or hoop stress conditions. In none of the cases did investigators find indications that the loads applied to the equipment had exceeded their design specifications and the cause of the failure was attributed to environmentally assisted cracking perhaps initiated by material flaws or imperfections.

Increased quality control during the manufacturing and installation process is an obvious measure that could reduce the incidence of these failures in future. However the case for the material quality to be root cause of these incidents is plausible but not strong for either incident. It is also alarming that in each case a different aspect of the material composition appears to have played a role. It is believed that there might be another common as yet unidentified explanation for these failures. This explanation could be related to additional tensional and/or rotational forces caused by the extreme temperature/pressure conditions.

1.6 Uncontrolled flows

Two HPHT related cases were reported since 1987.

The first incident occurred in September 1988 and concerns the blow-out of well 22/30b-3 drilled by the Ocean Odyssey. The ultimate direct cause of the incident was a failure of the sub-sea wellhead equipment after a prolonged period of kick control. Miraculously only one fatality was suffered as the crew abandoned the rig on fire. The well killed itself after a few days.

The accident demonstrates the relative magnitude of the hazard connected with incidents involving HPHT kick control when these are accompanied by failures of BOP's or ancillary wellhead equipment.

The occurrence of one major accident against 77 controlled kicks in 56 wells and, more significantly, in a total sample of 227 wells - largely Exploration/Appraisal wells - compares with the following blow out frequencies for HPHT wells derived by the Blowfam system in February 2004:

HPHT Development Wells:	4.3×10^{-3} per drilled well (or 1 in 233)
HPHT Exploration Wells	1.7×10^{-3} per drilled well (or 1 in 588)

The second incident in this group concerns a sour gas escape after cutting the production casing without removing the seal assembly during well abandonment operations. Fortunately the uncontrolled flow was not connected to a major reservoir and could be killed from surface. This incident, which could have led to a major accident, demonstrates the potential consequences of reducing surface control capability of a well before all conduits are inflow tested conclusively.

2 HPHT INCIDENTS IN OTHER AREAS

Schofield and Pickering [4] concluded in 2001 that

- Much of the information in the public domain relates to the UKCS
- The publicly available literature provided very little information pertaining to failures and incidents.

They concluded that operators might have chosen not to publicize this information in view of possible negative ramifications.

A review of more recent publications available in the databases of the Society of Petroleum Engineers and the Offshore Technology Conference largely confirmed these observations although some additional information could be extracted:

.

Hahn *et al* [5] suggest a number of potential incidents in California wells:

Bellevue ELH #1R Sidetrack

- Well control 'concerns' when encountering top pay (the original, discovery well had experienced uncontrolled flow)
- The liner was not cemented due to lost circulation and the inflow test failed leading to the setting of an additional bridge plug
- Definitive well integrity could not be achieved
- The tubing string got plugged over 762 m (2500 feet) with perforating debris

Berkley ELH # 2

- Complications during cementing of the liner resulting in a drillpipe fish at the linertop.
- Tubing to annulus communication during tubing pressure test – Several tubing joints partly backed off and signs of washouts. Anchor was not latched correctly.

Gordon *et al* [6] report costly well control problems because of severe lost circulation in depleted zones in South Texas.

Al-Saeedi *et al* [7] report severe loss and gain situations in the fractured Najmah/Sargelu source rock in North Kuwait.

McDermott *et al* [8] report that in the sour Norbet gas wells offshore Alabama

- Several minor seal failures of the Alloy 718 tubing hangers were attributed to extreme temperature cycling. The upper plastically deformed metal-to-metal seals and the elastomeric seals at the hydraulic control line port were replaced with elastically deformed metal-to-metal seals.
- Alloy 625 appears to have a better resistance to stress corrosion cracking in the high-temperature sour gas environment.
- Perforating has been the most unreliable and troublesome of all aspects of the completion operations although no specific safety incidents were mentioned. In some cases detonation failure resulted in gun body destruction and costly fishing operations.
- Numerous production packers failed to hold pressure during negative differential testing and several packers failed during displacement to a non-kill weight fluid. The latter situation could have resulted in a safety incident.

These reports indicate that the well control and kick and loss incidents experienced in the UKCS are certainly not unique to the area. Some of the non-well-control related occurrences are due to operational mishaps and point to a requirement for better specification of equipment in particular in relation to the high temperature resistance.

Of specific interest is the problem with production packers in Alabama, which so far has not occurred in the UKCS.

3 CONCLUSIONS

On basis of the information obtained from the HPHT incidents reported to HSE and the scant information about HPHT problems encountered in other areas, a number of apparent safety issues and uncertainties can be identified:

- It is clear that well control incidents are by far the most frequently occurring of all well safety concerns in the UKCS and most likely the same applies to other areas. It should be noted that the hazard related to kick incidents is limited by the fact that usually the hydrocarbon inventory on board of dedicated drilling units is low and often no other live wells are in the vicinity. In the UKCS the probability that well control problems will be encountered in a HPHT well has been successfully reduced to 1 in 6. HSE believes that further improvement is possible, especially as the problem may aggravate when drilling through depleted zones in future.

- The number of incidents involving blow out preventers and ancillary equipment is low and no clear trend regarding vulnerable items can be identified. It should be borne in mind that these failures in combination with well control incidents could have catastrophic consequences..

- Some potential safety issues with perforating and production packers reported in other areas have not (yet) become apparent in the UKCS. It should be ascertained that this will not become a future problem.

- There appears to be an increasing occurrence of incidents related to catastrophic failure of well tubulars and hangers. In most of these cases the failed equipment was manufactured from premium steels or alloys. In most - but not all - cases the root cause of the failure has been attributed to metallurgical flaws. The hazard related to well integrity failures of HPHT production wells is very significant. The number of people at risk on production platform is usually substantial and the hazard is aggravated by the presence of hydrocarbon processing facilities and other live wells. The extreme production conditions of HPHT wells place exceptional demands on the well components. This will not only lead to the use of exotic, less commonly applied materials but it may also increase the probability of mechanical equipment failures and hence may increase the potential for double jeopardy as encountered in one of the incidents. There is no obvious correlation between the specific metallurgical problems encountered and it is believed that there may be a common contributory cause that has not yet been identified.

PART 3

HPHT WELL ENGINEERING AND MANAGEMENT SOLUTIONS

1. INTRODUCTION

The UK offshore oil & gas industry has experienced a number of potentially hazardous events during the drilling, completion and production phases of HPHT field developments. The ultimate consequence of these events could have been a loss of hydrocarbon containment. All major incidents reported on HPHT wells were reviewed in part 2 of this report.

Part 3 identifies the current and future technical solutions available to the Industry. This information was obtained through interviews with staff of several of the main HPHT operators and service companies in the UKCS. In addition discussions were held with HSE staff and information available to the HSE was studied. Some of the leads were obtained from open literature sources and private sources. A workshop in April 2005 served to obtain a reality check on the information collated and to consider stakeholders' views on the future challenges from HPHT developments.

2. RISK CONSIDERATIONS

The obvious factors contributing to the risk of HPHT wells are the extreme surface pressures combined with very high temperatures and the generally corrosive and toxic composition of the produced fluids. The design and construction of a HPHT well – as any other well -- needs to comply with the general duty of the DCR [9] which requires that a well is so designed, modified, commissioned, constructed, equipped, operated, suspended and abandoned that,

- so far as reasonably practicably, there can be no unplanned escape of fluids from the well and
- risks to health and safety of persons from it or anything in it, or in the strata to which it is connected, are as low as reasonably practicable.

Operators have demonstrated that this is generally possible with the available materials, equipment and technology. However the occurrence of a number of serious incidents is causing concern that an increased risk of failure resulting from the exposure to the extreme subsurface conditions could exist.

In table 2 an analysis is presented of the basic design requirements and the related complicating factors of HPHT wells. The increased risk appears to result from

- High stress environment – both tension and compression
- High operating temperatures
- High temperature gradients in the well especially near surface.
- High-end metallurgy susceptible to specific environments
- Chemical activity of well fluid components enhanced by the high temperature
- Massive initial flow rates of most wells
- Narrow margin between the boundaries presented by loading uncertainties and material property variations.

It is suggested that the critical areas of risk are the consequence of the high temperatures combined with corrosivity of the well environment.

Table 2 Basic design considerations for HPHT wells

Overall DCR requirements:

- Well designed, constructed and equipped so that, so far as is reasonably practicable, there can be no unplanned escape of fluids.
- Well designed, constructed and equipped so that risks to persons from it or anything in it or in strata to which it is connected as low as reasonably practicable.
- Every part of the well to be composed of material suitable to achieve the above.
- Well control equipment to be provided that is suitable to protect against blowouts

Well condition	*Basic technical requirements*	*Complicating HPHT factors*
High Well Pressures	Wellhead body to withstand burst loads. Wellhead valves to withstand pressure differentials. Well tubular bodies to withstand radial and axial loads. Pipe connections to withstand radial and axial loads. Safety valve to withstand pressure differential. Bodies of all downhole equipment to withstand radial and axial loads. Seals to withstand pressure differentials frequently in both directions. Wells designed with two permanent pressure barriers between reservoir and environment.	Additional wall thickness results in higher axial loads to be supported. Manufacturing of high strength materials is complex. Installation of tubulars, equipment and seals is partly a remotely controlled downhole process, which could lead to faults due to misinterpretation of surface data. .
High Well Temperatures	Material of wellhead, tubulars and equipment to retain sufficient mechanical strength after downgrading for temperature effects. Seals to retain shape and effectiveness at high temperatures. Pipes, connections and hangers to withstand axial and buckling loads caused by thermal expansion and contraction of constrained pipe strings. Annular fluids to remain stable at high temperatures.	Uncertainty about fixidity and support provided by cement sheet around pipes. Uncertainty about temperature differentials at critical depth levels during heating up and cooling down phases. Chemical activity of well fluids may be enhanced

Corrosive Fluids	Material of wellhead, tubulars and equipment to be resistant to all possible corrosive attacks. Exposure of the wellhead, tubulars and equipment to corrosive elements to be prevented	Manufacturing of corrosion resistant high strength metals requires specialised mills. Metallurgy of corrosion resistant high strength metals is complex. Shaping of corrosion resistant high strength metals into thick walled units is new territory. Rough handling of equipment and pipes during transport and installation may cause surface defects that would trigger corrosion. Thread compounds may generate hydrogen gas Different corrosion mechanisms are effective at different temperatures. Completion fluids may be/become corrosive.
Toxic Gases	Wells designed with two leakproof barriers between reservoir and environment.	Consequences of containment failures are seriously amplified.

Operators are required to demonstrate that risks in HPHT wells are as low as reasonably practicable (ALARP) in spite of the extreme subsurface conditions. Guidance on the ALARP demonstration is available from the HSE [10, 11, 12, 13] and from UKOOA [14].

The HSE guidance places much emphasis on prevention of risks by incorporating inherently safer design features where appropriate. In well design this principle is usually applied, as the alternative, safety through monitoring and operational procedures, is often not available. In HPHT wells the inherent safe design solution is close to the limits of available technology and procedural defences and precautions may have to be applied to safeguard the design. Safe design limits must be established in advance of operations, as some HPHT wells may not be able to be drilled using conventional technology.

The HSE guidance also indicates that the application of relevant good practice may be acceptable as sufficient demonstration of ALARP. Good Practice is defined as:

> The generic term for those standards for controlling risks which have been judged and recognised by HSE as satisfying the law when applied to a particular relevant case in an appropriate manner.

The relevant guidance [12] defines a number of possible sources for ‘good practice’ e.g. Approved Codes of Practice, HSE technical guidance and Guidance agreed by other Government bodies, standard-making organisations or representative trade/professional organisations.

Worldwide there are many HPHT developments and there is a line of effective industry practice that may be derived from the experience obtained in these fields. It should be noted however that most HPHT projects (and many HPHT wells) are unique in character - even more so than ‘normal’ field developments - and there is a continuous trend to develop ever deeper and hotter accumulations. This will lead to a strong evolution of practices in time as operators rely on technical innovation to cope with the more severe demands.

In the following sections a number of measures and technologies are discussed that are currently employed or contemplated to help satisfy the ALARP requirement. Where appropriate ‘*Risk Comments’* will highlight the relevant risk element of actual, possible or potential practices to provide linkage to the ALARP demonstration.

3. INDUSTRY SOLUTIONS TO DATE

3.1 Well construction

3.1.1 Foundation and growth

In basic terms a well is a construction consisting of a set of concentric pipes locked together and upheld at surface by a wellhead, and supported in the borehole by a number of cement collars. Offshore wells which are not completed with a sub sea wellhead (see next section) have as a characteristic complexity that several hundreds of feet of the construction from the seafloor to the surface above sea level have no lateral support from the borehole. This support is provided by the marine conductor pipe drilled or driven from the platform or jacket deck level into the sea bottom

Most North Sea operators employ a traditional casing scheme for their HPHT wells. Starting through a 762 mm (30”) marine conductor, the wells will be drilled with a nominal 508/344/273 mm (20”/$13^5/_8$”/$10^3/_4$”) casing scheme to the top of the overpressured section, then completed with a 127 mm (5”) production liner. In completions with a 127 mm (5”) production tubing a nominal 191 mm ($7^5/_8$”) tie back casing string is sometimes installed. Except for the 508 mm (20”) all casing strings are sized up in the surface section to allow for tubing accessories. A 200 mm ($7^7/_8$”) contingency liner is available should pressure conditions in the prospective section require a deeper set intermediate shoe.

Some operators prefer to drill the wells with a slimline scheme, starting from a 762x508 mm (30”x20”) marine conductor, then setting the nominal 344 mm ($13^5/_8$”) and 273 mm ($10^3/_4$”) or 251 mm ($9^7/_8$”) strings as deep as possible before completing as in the traditional scheme. The 200 mm ($7^7/_8$”) contingency drilling liner is also available in this scheme. This contingency may have to be used more often than with the traditional scheme especially if subsurface conditions are not well known. The slim-line scheme is less costly although the drilling liner will probably have to be included as a likely cost, rather than as a contingency item. The scheme has as an additional advantage that it is easier on the surface casing design as it does results in much lower loads to be supported by the wellhead.

Risk Comment: Choosing the slim-line scheme will not change the risk situation significantly provided a firm drilling strategy is adopted to set the contingency liner immediately if required to maintain borehole integrity, and to accept an early TD if this would be dictated by subsequent subsurface conditions. It will be an advantage to reduce these probabilities if the subsurface conditions are reasonably well predictable.

The well foundation principles for surface completed wells employed by the various operators differ. Most operators will use the marine conductor fully as the main foundation pile for the well by ensuring that the first well casing string is cemented completely to the surface and that the wellhead is directly supported by the marine conductor. However, some operators will cement the next casing string to the seabed only and will keep the wellhead free of the marine conductor. This has the effect that the well tubulars and the wellhead are mainly supported by the next casing string – usually called the surface string - leaving the marine conductor free to provide lateral support and protect the well from environmental loads.

HPHT wells are usually deep and the severe subsurface conditions may call for heavy casing strings. This may result in well loads higher than can be safely supported by the surface string from deck level to the seafloor and part of the load needs to be transferred to the marine conductor at a deeper level. Usually a set of landing collars is installed just below seafloor level to achieve this transfer.

An additional complication in producing wells is that the various casing strings and the production tubing, heat up and expand at different rates when the well is flowing. This is most pronounced in the surface section where the production tubing and wellhead of HPHT wells are heated up from the ambient temperature (0 – 10^{o}C) to around 150 ^{o}C. There is a strong radial temperature gradient especially above the seabed, as the marine conductor will remain at near ambient seawater temperature at all times. All strings are locked in and depending on the pre-stress applied during installation, the system may become subjected to strong axial forces generated by differing thermal expansions. During the well commissioning process these forces are difficult to predict especially in the short surface section between the landing collar at seabed level and the wellhead. The solution chosen by some operators is to transfer only the weight of the outer two casing strings to the marine conductor at sea floor level. The production casing string which will be most affected by thermal loading will then be free to expand over its full length from wellhead to the cement top at considerable depth.

Risk Comment: Although there is no evidence for this from incident reports, it would appear that the practice of landing the production casing string at seabed level as well as in the wellhead would create the potential for extreme thermal loading of the short upper section of the string. This could lead to mechanical or sealing failures and loss of a pressure barrier.

The configuration of the well support and its foundation also determines the amount of well growth – i.e. the rise of the wellhead experienced when the well is heated up. Most operators found that the actual well growth exceeded predictions, sometimes by as much as 100%.

This under-estimation of the growth was caused by optimistic assumptions regarding the fixidity of the marine conductor, the main foundation column in the seafloor. The thermal forces made the subsoil yield and move upward with the pipe from a much deeper level than had been predicted especially in areas where the drilling of earlier wells had disturbed the subsoil. This caused the conductor to rise above the seafloor taking the well along. It is currently assumed that in practice the conductor will not be restrained in its thermal expansion for most of its length below the seabed.

It was found that prevention of wash-outs when drilling-in the marine conductor – using mud – had a positive effect on the fixidity resulting in a reduced well growth.

Risk Comment: Thermal forces – like gravity and buoyancy forces – are mass forces rather than single point loads and their effects are often misunderstood. Under estimation of well growth could prove hazardous as wellheads and flowlines may rise more than allowed for in the design of the surface facilities causing damage and leakage.

In some Norwegian fields burst disks have been installed in casing strings to alleviate extreme pressure build-ups in enclosed annuli due to strong temperature increases during production. The burst disks are themselves hazardous components that could be damaged during installation. Recent completions have avoided this potential problem and the burst disk solution by not cementing the production casing up into the previous shoe thus allowing a natural pressure leak-off into the open formation. Special spacers are run ahead of the cement slurry to prevent settlement of solids from the annular fluid onto the leak-off zone.

3.1.2 Sub sea completions

The choice between sub sea completions and surface completions for wells is part of the development concept selection process, which falls outside the scope of this report. There are, however, a number of risk related issues that may weigh heavily when the field development includes HPHT wells.

+ Sub sea completed wells have the advantage that the wellheads are usually at some distance from other wells and a catastrophic failure would not affect any offshore installation or personnel except in the recovery stage.
+ The thermal loading complications that may be experienced in casing sections from sea bottom to the surface will be avoided.

– Even the simplest remedial work will require time-consuming mobilisation of special vessels with HPHT capabilities, which may not be available widely.
– Sub sea wellheads are not easily accessible for routine monitoring.
– Sub sea flowlines and gathering lines need to be designed to HPHT specifications and may have to be insulated to avoid strong cooling of the well stream and consequent liquid hold ups.

One HPHT field on the UKCS and one field offshore Norway are currently being completed with 15k sub sea wellheads. Wellhead suppliers have been using their standard 15k drilling wellheads with newly upgraded and thoroughly tested 15k side outlet valves to allow well completion with ‘horizontal’ or low profile production trees.

Risk Comment: Continuous monitoring of wellhead pressures of sub sea wells is usually limited to the tubing head and the A-annulus. The pressure integrity of the second barrier, i.e. the production casing string can therefore only be derived from its internal pressure behaviour, not from the B-annulus pressure. If hydrocarbon bearing zones would be present in the higher strata (e.g.. the Hod), it would be necessary to monitor their shut off by checking the pressure of the outer annuli periodically. In areas where no hydrocarbons are present above the HPHT prospect, sub sea wells would appear to present an option with less risk of major accidents involving injuries or loss of human life.

3.1.3 Intermediate casing cementation

In part of the HPHT areas in the North Sea the Hod formation at about 14 000 ft presents an additional well engineering problem. The formation is a gas bearing chalk and cementations across the zone – as part of the intermediate/production casing string installation have so far been rarely successful in obtaining a full shut off. As a result the B-annulus in these wells is permanently pressurized although it may take as long as two years after the start of production before the Hod pressures are seen..

Fortunately the zone has proved to be of very low productivity to date and on platforms or jackets the annulus pressure can be easily controlled to maintain well integrity by bleeding off at regular intervals or continuously - if this is designed for initially.

Trials with foam cement and flexible cement – a well-accepted methods to control gas influx into cement columns – have been reported as unsuccessful so far. Installing an inflatable collar above the gas zone might be prohibited by pressure/temperature considerations and the fear that the collar could impair the integrity of the production casing string.

Risk Comment: The Hod pressure on the B-annulus, although controllable, remains a matter of concern in HPHT well completions that must be dealt with at the design stage.

3.1.4 Reservoir compaction

Most HPHT wells with a production history of three to four years have shown considerable pressure depletion – as could be expected in these overpressured accumulations that generally lack an external drive mechanism. As a result the reservoir rock will lose some of the support originally provided by the highly pressured pore fluids and will compact. This will not always lead to reservoir rock failure. Recent rock tests and model studies [15] have shown that rock compaction may lead to increased resistance to rock break-up owing to the increased friction between the sand grains and arching around the perforations. It is more likely that the compaction will result in the collapse of overlying shale/silt layers or in overburden fault or bedding movement [16].

There are a number of potential effects of reservoir compaction.

- Collapse of the borehole or bedding movement may damage the production liner thus prohibiting re-entry of the well section for repair or clean out.
- The production liner may be damaged above the production packer thus by-passing one of the well's safety barriers. This could lead to pressurization of the A-annulus.
- Collapse of the overlying shales/silts may result in failure of the shut off provided by the liner cementation. This would also remove one safety barrier from the completion and pressurise the A-annulus.
- Silt, sand and shale debris may be produced into the well filling up the sump and eventually blocking the lower perforations. This will become more pronounced when flowrates decline.
- Silt, sand and shale debris may be produced to surface filling up flowline sumps and separators.
- The solids laden fluids may cause cut out chokes, valves and pipe bodies especially in location where the flow direction is diverted – i.e. at the wellhead.

In well design the effects of compaction and the resulting collapse or lateral movement of the overburden are difficult to remedy. In the Gulf of Mexico wells in a field experiencing this problems are completed with liners uncemented in underreamed sections across the overlying layers. The lower completion of the wells was strengthened structurally and hydraulically by a cemented liner tie-back [16].

Risk Comment: With the experience in the Gulf of Mexico now being repeated in producing North Sea HPHT fields, operators may want to consider modifying future well completions to avoid losing the integrity of one of the well's safety barriers permanently as a result of compaction effects on the overburden

3.2 Drilling into the prospective zone

3.2.1 Well control

The majority of the HPHT incidents reported to the Health & Safety Executive relate to 'kicks' i.e. situations when the BOP facilities were operated because primary well control via the mud column had been lost or had become suspect. Currently one in about six HPHT wells incurs one or more kicks, an incidence that has been fairly constant over the last six years.

North Sea operators appear to have become comfortable with the occurrence of HP kicks while drilling through the overpressured sequence but do not foresee that any reduction in the occurrence of kicks can be achieved. Drilling practices and well control procedures have been refined jointly with rig owners and drilling crews are given well-specific training to handle kick situations with confidence. Kick mitigation methods employed include:

- Accurate recording of minor influxes from detailed measurements of flows and rig movements.
- Using PWD equipment to obtain complete information on the ECD at any time.
- Employing 'fingerprinting' techniques to demonstrate to the rig personnel the correct procedures for minimizing pressure surges.
- Refining the knowledge of jack up movements in deep water.

The main threat from kicks is that the risk will be amplified considerably if losses would be incurred as a result of the kick or during the killing process. Operators have become more effective at achieving good leak-off strengths at the last casing shoe thus greatly reducing the chances of losses at that – most vulnerable – level. In addition a number of practices to avoid losses have been introduced in recent drilling operations i.e.:

- The mud weight design is based on the most likely anticipated reservoir pressure rather than the maximum
- The drilling overbalance is kept very small compared with standard levels.
- There is a general reluctance to increase the mud weight during drilling and when circulating out kicks.

Risk Comment 1: Although the above practices should not be interpreted as 'drilling for kicks' they could jeopardize any reduction in the HPHT kick frequency resulting from the procedure and training improvements and the sophisticated techniques introduced over the last decade. Operators claim that it is not the number of kicks but their size and especially the occurrence of kick and loss situations that determine the overall risk picture. Statistics seem to confirm that view, as influxes over 20 bbl and kick and loss situations appear to have occurred less frequently during the last five years.

Risk Comment 2: The Health & Safety Executive are not convinced that the frequency of kicks cannot be reduced further. Close attention to the available pore/frac pressure window for each individual well is necessary to ensure that the risks are ALARP.

In traditional well design the geological, fluid, temperature and accumulation predictions are fed into the design assumptions and the drilling program based on experience. For the critical designs of HPHT wells this procedure is not always satisfactory.

A key element in the design of the mud weight strategy for a HPHT exploratory or appraisal well is the prediction of the pore pressures in the prospective zone. The interpretation of seismic velocities from surface seismic in the area is hampered by the presence of thick chalk above the overpressured strata. Better seismic interpretation methods and the use of gravity measurements are part of a recent Dti study (see part 1 of this report).

With a probabilistic 'mechanical earth model' it is possible to combine seismic information with other geological parameters as attributes to a pore pressure prediction [17]. Going one step further, one North Sea operator has developed an overall approach in which the independent geological uncertainties are combined with the well design requirements in a single simulation model.

The output requirements of this model are defined on basis of their impact on the well (casing) design and that on the well construction and evaluation support i.e.

- Pore pressure (absolute and gradient)
- Kick tolerance
- Maximum well head pressures
- Shoe strength requirements
- Pressure regime and overbalances
- Mud weight criteria
- ECD management
- Well control failure mode analysis

With this simulation model a mud weight strategy can be derived showing the failure probabilities for specific mud weights when used in various operating modes.

During drilling of a well models and interpretations can be adjusted using acoustic surveys and pore pressure information at depth. This will reduce the uncertainty of predictions as the well progresses [18].

3.2.2 Depleted zones

The most recent problem experienced by operators of HPHT fields is the need to drill into or through partly depleted reservoirs within the overpressured sequence. This amplifies the problem of well control as the margin between the controlling and loss-inducing mud gradients has disappeared or even reversed.

The positive aspect of the situation is that, as the problem arises generally while penetrating reservoirs of producing fields, the subsurface conditions are well known. The well control hazard has changed to a situation with 'anticipated' kicks instead of 'unexpected' kicks. This allows operators to programme the operations accurately and reduce the exposure to risk from hazardous situations to a minimum.

Operators have little experience with these conditions to date. The available method is to drill into the depleted reservoir for the minimum distance (say 20 ft) with a heavy mud system then improve the fracture strength of the borehole wall by a squeezing a specially designed chemical treatment [19, 20, 21, 22]. This will allow setting of a liner or casing string into the depleted zone before reducing mud weight.

In the past operators took no account of bridging or blocking of the formation pores although, unknowingly, strengthening of the wellbore walls took place. The current methods attempt to achieve optimum pore blocking by design, using particle size selection criteria derived from frac design technology.

The technique has been applied in some 30 wells worldwide to date. In the UKCS the method was applied in two wells west of Shetlands although this was not to drill through depleted reservoirs. Further application is planned for a non HPHT well in Magnus.

Three field trials are planned to apply the technique in shallow wells.

Risk Comment: There is a pay-off here between the increased risk to induce a loss situation followed by a kick and the operational confidence to handle the situation based on the available subsurface information from neighbouring wells. An in-depth risk assessment will be required in each case.

3.3 Wellhead hangers and seals

3.3.1 Material selection

The most critical wellhead hangers, usually those for the production casing string and the tubing string, need to take considerable axial and radial loads. In addition the lower connection is subject to high hoop stresses due to the make up force. The material of the hanger also needs to comply with the NACE sour service specifications and be resistant to chloride induced stress corrosion cracking and hydrogen induced cracking.

Almost without exception UKCS operators have selected the nickel-base alloy 718 for the critical hangers. This material (50-55% Ni and 17-21% Cr) is very expensive: 25x the cost of normal steel. It has a tensile strength compatible to the casing/tubing steels employed in these wells and can be forged and machined as required.

In spite of the material’s excellent corrosion resistance on tests, two alloy 718 hangers have failed in service during the past five years. Hydrogen embrittlement was identified as the probable direct cause of both failures. In each case the hanger box failed at the root of the first full thread where the stress concentration is the highest. In the case of one failure the presence of delta phase, needle-like brittle phase at grain boundaries was found in the microstructure due to inadequate heat treatment. However the second hanger had no apparent pre-existing metallurgical defects.

The most likely source of the hydrogen was identified as the copper plating used on the box threads of the hanger. Operators are considering the use of a re-designed hanger with a pin down connection. The box of the connecting casing or tubing is not alloy 718 and hence would not require copper plating. This design would also avoid exposing the alloy 718 material to the high stress concentrations that occur in a pipe box and to which the material appears to be more susceptible. Additional costs may be involved, as the pin down hanger needs to be longer to accept the make-up tongs.

The record of failures of critical hangers in North Sea HPHT completions has become a cause for concern and operators have been adopting the most rigorous quality assurance procedures for these items of equipment to prevent future (costly) failure incidents. The common factor to the failures appears to be hydrogen. Prevention (alternatives to electroplating) or removal (bake-out) prior to the use of components could be considered for items where hydrogen pick-up during manufacture may have occurred. It should be noted that no components that have survived the initial temperature cycles have failed.

It is understood that research is underway into fracture propagation in alloy 718 material and into the possible use of 11.6 – 12.3 MPa (80 – 85 ksi) steels for HPHT hangers.

Risk Comment 1: The production casing and tubing hangers are critical parts of the first and second pressure barrier of the well and failure of either will immediately create a potentially hazardous situation. As long as the remaining barrier remains intact the well construction would be within its design parameters and there would be no serious immediate risk. Experience has shown however that the probability of subsequent failure of the remaining barrier in these highly stressed well constructions is not negligible. It would be required to plug or to kill the well as soon as possible in order to maintain the ALARP status.

Risk Comment 2: It appears that minor flaws in the metallurgical composition of the nickel-base alloys can become an initiating factor for destructive corrosive attack. Quality control can reduce the chance that equipment machined from imperfect material is installed but there will always remain a small probability that defects – possibly unrecognised as with the delta phase effect – remain.

3.3.2 Seal type

The well head hanger seals are critical elements of the permanent pressure barriers of the well construction and failure will have the same consequences as described for the hangers in the section above.

Generally metal to metal seals are used in HTHP wellheads. The installation sequence of wellheads and seals is fairly complex and in one case the setting of the seals remained incomplete, resulting in the complete loss of the barrier at a later stage. In the event the well head design included a feature that allowed height adjustment of the landing collar by rotation. This made it impossible to provide the sealing collar with a testing port and hence it was impossible to ascertain full activation of the metal seal lips by pressure testing. The operator has now elected to install the contingency sealing ring – with a single hydrogenated nitrile seal - as a first choice.

The choice of elastomers for use in HPHT wells is limited. Subsurface packers are usually equipped with Aflas elements. This material has a high temperature rating (232^{o}C) but results in a very close OD tolerance. Replacement of the Aflas packer element with Nitrile elements (which would allow a larger OD tolerance) is impossible due to the latter material’s limited tolerance of exposure to Caesium Formate.

Risk Comment: This incident highlights the importance of being able to test the wellhead seals for pressure integrity in both directions after they are installed. Mechanical indications that the setting has been completed according to design may not provide the assurance that the seal is actually in place and holding. In the extreme HPHT conditions it would constitute good operating practice to obtain that assurance directly by pressure testing.

3.4 Production tubing

3.4.1 Material selection

The production tubing is the well conduit that will be continually exposed to the reservoir fluids and the reservoir conditions. Selection of the correct material for this conduit is therefore considered of utmost importance by UKCS operators to ensure the safe operation of a HPHT well.

Factors taken into account are:
- Stresses induced by tensile loading, internal and external pressures, bending and buckling.
- Downgrading of material strength due to high temperature.

- Resistance to Corrosion / Erosion
- Resistance to Stress Corrosion Cracking
- Resistance to Sulphide Stress cracking
- Resistance to Hydrogen Embrittlement
- Resistance to Crevice Corrosion
- Resistance to Impingement Attack
- Resistance to Microbial Corrosion.

Operators have generally selected stainless steels for this application. Most wells are equipped with duplex or super-duplex stainless steel tubing with 20 to 25% chromium. The duplex steels have a high resistance to stress corrosion cracking and sulphide corrosion cracking due to its dual austenitic/ferritic microstructure.

The failure of a 25%Cr super-duplex steel tubing pupjoint in one of the UKCS HPHT wells demonstrates that the duplex material also needs to be of a near-perfect composition to realise its high resistance to cracking corrosion. The failed joint had suffered surface disturbances during cold working in the mill. The surface marks had been removed but deeper anomalies in the microstructure remained. These led to the formation of shallow external cracks, which in turn allowed a concentrated corrosive attack from the A-annulus environment. Eventually the joint failed due to through-wall stress corrosion cracking.

This experience has led to the development of an in-line electromagnetic inspection process that can detect microstructural anomalies of the pipe body. Acceptance criteria are based on the electromagnetic response patterns. This additional quality control requirement may prevent future corrosion failures of this high performance material.

One operator has chosen sour-service stainless steel with 13%Cr ('Superchrome') and a minimum of 2% molybdenum for the production tubing as this material was considered acceptable for the field's operating conditions and more resistant to hydrogen embrittlement than the more expensive duplex steels [23]. To date their choice has proven to be correct. It should be noted that the field's operating conditions are at the more benign end of the UKCS HPHT scale.

Risk Comment 1: It appears that the duplex stainless steels suffer from a similar sensitivity to imperfect conditions as the alloys discussed in chapter 3.3.1 above. Quality control can reduce the chance that joints drawn from imperfect material are installed in the well but there will always remain a small probability that defects remain. Use of simpler less sensitive materials, if possible, would remove some of the risks of prime barrier failure.

Risk Comment 2: HPHT completions may require detailed inspection of individual pipe joints on physical measurements to allow selective positioning in the string. In this context it was noted that the production casing string is as critical as the tubing string and would command the same inspection standards.

3.4.2 Supply and installation procedures

It is recognised by the industry that the handling procedures during transportation of stainless steel casing and tubing joints from the mills to the rig floor and then during installation into the well, are a possible source of surface marking that could initiate corrosive attack and cracking.

Although normally the passive film of Cr_2O_3 to which stainless steels and alloys owe their corrosion resistance, heals almost immediately when damaged, this is not necessarily happening in sharp pits and crevices. Handling of pipe with tools equipped with metal dies and knocks during transportation may generate these sharp surface defects or even shallow stress cracks in the material.

One operator has implemented the following measures to avoid this problem [23]:
– Transporting pipes from the mill in plastic scalloped frames
– Transporting pipes to offshore using a specially designed hoisting system
– Using a collar support landing system on the rig floor
– Using non-metallic fluid-grip rotary tongs to make up joints on the rig floor.

The 273 mm (10¾”) production casing in one HPHT well failed during commissioning due to a washed out connection. The original make-up of the connection had been incomplete, leading to leakage and massive erosion of pin and box. This incident has led to a complete review of the operator’s running procedures. The very strict procedures that were until that time only used for production tubing strings (considered more critical) are now also applied to the running of HPHT production casing strings.

Risk Comment: The rough environment of a traditional oilwell drilling rig may not be automatically suited to the handling of pipes and equipment manufactured of stainless steels and exotic alloys. Operators appear to accept that drilling and completing HPHT wells may require ‘hospital type’ procedures to avoid marking the well equipment during installation that could lead to future failure due to corrosion.

3.5 Commissioning and production

3.5.1 Operational procedures

The commissioning process is a critical stage in the well-life as this is the first time that all tubulars, seals and well equipment are exposed to increasing pressures and temperatures at differing rates until an equilibrium state has been reached for the full well construction. Operators have been paying much attention to these operations, monitoring wellhead pressures and temperatures and the relative movement of the wellhead continuously. It was found that generally the actual rise of the wellheads as a result of the heating up of the well construction exceeded the predicted rise considerably – by up to a factor two – and this has formed an important consideration in the safety management during commissioning.

Once HPHT wells are successfully commissioned the production operations generally proceed very smoothly with chokes and separators working without trouble in spite of the enormous initial throughputs of most wells. Bean up and bean down procedures are designed to avoid shock loads on the well construction. The only shock loads that could be experienced by producing wells are due to automatic emergency shut downs. Shock loads may also occur during perforating, well testing and commissioning of wells.

Risk Comment 1: Commissioning of wells is normally considered a relatively high risk operation and this is particularly the case for HPHT wells in which extreme production conditions generate extreme loads on the well construction. Detailed planning and risk assessment is essential. Staff – offshore and onshore – must be made fully aware of the risks and the contingency plans in place.

Risk Comment 2: It is considered that the effects of shock loads on the well construction are relatively unexplored by operators. Emergency shut down valves are activated regularly on production facilities, on average possibly at least once per quarter and this will result in a hard *shut down of the well stream. Peak loads experienced may be several magnitudes higher than the static loads and their effect on exotic alloys may be different from that on steels.*

Risk Comment 3: It is noted that shockloading during perforating, initial well testing and commissioning may be more hazardous as connections, seals etc have not yet been exposed to high loads in anger (as would be the case during emergency shut downs later in the producing well life).

3.5.2 Killing practices

Killing of HPHT wells is usually only required for well repair after failure of the well equipment, the well construction or the borehole integrity. If the failure has resulted in the loss or suspected loss of one of the pressure barriers of the well, the killing operations will have to be initiated as soon as possible to reinstate the well to a safe condition (see 3.6.3 below).

Usually there are few options to kill a well and the preferred killing method is by bullheading. This will avoid the handling of large quantities of well fluids being circulated to surface. Most HPHT wells produce gas and condensate and some operators prefer to use base oil as the first batch of killing fluid. Once all well fluids have been dissolved the killing is completed with a heavy brine and/or mud to displace the base oil into the formation. The use of solid free brines (e.g. expensive caesium formate) would reduce the chance of washing out any existing leak paths in the well construction.

The key to a successful HPHT killing operation is in the detailed preparation. Operators are aware that HPHT well events can escalate very rapidly and that killing operations should not start until all aspects of the job have been thoroughly assessed and all teams and equipment – including that on a service vessel - are positively tested ready to go.

The design and programming of the well kill should be done by staff with a good understanding of the wellhead jacket/platform lay-out, the well construction details and the requirements for equipment preparation and rig up. The loading of the well tubulars during a high pressure killing operation using cold fluids is often the one of more severe cases that should be included in the initial well design. The design assumptions should be verified

One operator found it very helpful to produce a schematic representation of the principal steps of the programme for the purpose of briefing senior management and other stakeholders prior to and during the operation.

The safety of the offshore staff, whether on a platform, jacket, workover rig or service vessel should be paramount. One operator found that involvement of the offshore staff in all phases of the job preparation is vital to create a good rapport between the various teams and thus minimising interface issues during the execution phase.

The programme should be detailed to leave no room for misunderstanding about the valve operations. One operator produced a detailed diagram of the complete surface set up with all valves numbered to ensure a common understanding of the system.

Risk Comment: It is vital that all steps of the programme are thoroughly assessed for risks and that a detailed action plan is available for each potential event or change of conditions. This should include a clear command protocol with fall-back instructions in case of lost communications.

3.5.3 Sand production

Pressure depletion around the borehole may eventually reach the critical level at which the reservoir rock will desegregate. Taking into account the large drawdowns on the wells, It had been anticipated that this would lead to early catastrophic sand production requiring immediate installation of downhole sand control equipment. Recent experience in HPHT fields in the Louisiana [15] has shown however that the critical depletion level for rock desegregation was much higher than estimated using traditional sanding models and also that initially the sand production will occur in small, controllable bursts. The latter effect has been explained on basis of the grain-to-grain frictional resistance and the capillary cohesion, which binds the individual sand grains. This favourable behaviour has been confirmed in North Sea HPHT fields.

Operators are installing sand filters in the flowlines to prevent erosion damage to the downstream production facilities. In addition in line acoustic sand detectors are used to detect the onset of solids influx and monitor the level with the objective to keep the drawdown on the well at the level at which the influx is controllable.

Risk Comment 1: Sand production creates a number of safety hazards, which are of particular concern in HPHT conditions. It appears that operators can do little else than reduce the well flow to levels at which the sand content of the well stream is acceptably low. It is important that this is done as soon as sand break-through occurs to allow stabilization of the rock around the borehole and to limit the exposure of well and production equipment to the effects of sand laden production.

Risk Comment 2: Operators have commented that monitoring of sand in the well stream with clamp-on sonic detectors has been less satisfactory and may not detect all solids – especially not the larger particles

3.5.4 Water production and scaling

The produced water of one of the older UKCS HPHT fields contains H_2S, H_2SO_4 and Hg. The produced water of many Norwegian fields has also a high Hg content. It has been suggested that mercury salts may sensitize ferrous alloys to corrosive attack but no evidence of this phenomenon is available from the North Sea..

It has also been suggested that duplex steels should also not be exposed to hot salty waters and that the combinations of chemicals in produced water could affect the material.

The calcium carbonate scales deposited in HPHT wells are extremely hard due to the presence of lead sulphide and zinc sulphide. Xmas trees and downhole safety valves are affected and removal with strong acids is not feasible due to susceptibility of duplex materials to these chemicals.

Future requirements are development of a HPHT matrix treatment to prevent scale production and qualified equipment to allow continuous inhibition downhole from the safety valve up. One operator is using the second line of the safety valve for the injection of scale inhibitor.

Risk Comment 1: There appears to be a lack of information regarding the suitability of duplex steels when exposed to hot formation waters.

Risk Comment 2: There is a reluctance to introduce ports in the HPHT hangers to accommodate a continuous injection line on safety grounds. It should be noted that in wells *drilled into partly depleted HPHT reservoirs the risks and the resulting caution could be reassessed*.

3.6 Management

3.6.1 Team selection

Without exception UKCS operators are emphasizing the importance of dedicated and experienced onshore and offshore teams during the planning, programming and execution stages of an HPHT development. This may pose a practical problem as HPHT projects are fairly infrequent occurrences for individual operators and their design is usually unique. Most operators have a small core of staff with HPHT experience and will assemble their teams around them. Additional staff and consultants have also been attracted to complement the in-house expertise of planning teams. Consultants with HPHT experience are employed in offshore teams. Major operators often have the option to draw on experienced staff employed elsewhere in the world. Other operators rely on third party consultants or on the expertise available within the organisation of supply and service companies.

Operators tend to select service companies and equipment suppliers with a proven track record of HPHT work in the UKCS. This will reduce the risks of mishaps due to equipment failures or operational mistakes. As a result a few selected service companies will accumulate HPHT expertise at an increasing rate. This could lead to fears that there will be a lack of incentive for these companies to develop new methods and equipment. Given the small market for HPHT work in the UKCS, it is doubted that the new development effort would have been stronger if a more healthy competition existed. Even more so than for ‘normal’ developments, renewal and change initiatives in the HPHT world are driven by the operating companies.

Wellhead suppliers have generally been relying on operators to ensure that new HPHT developments are included into their specifications. This might be an area of future co-ordination for the Association of Wellhead Equipment Manufacturers (AWHEM)

North Sea Operators have established an informal HPHT Forum to exchange experience and disseminate information across companies. This forum is viewed as a very useful initiative to compensate for the lack of continuity of HPHT projects in each operator’s local organisation. The forum meets approximately once per quarter and its attendance is limited to representatives of operating companies. To promote a free exchange of up to date information, no proceedings or minutes are issued.

Much experience is also available in supply and service companies but this resource is often not easy to draw upon. One of the well equipment suppliers is running an internal, international HPHT group to maintain expertise. This group might be extended to include customers and could then form a valuable facility to build up industry knowledge and experience in this particular area of expertise.

An Aberdeen based quality assurance company has established – together with a HPHT technical consultancy firm -- an extensive on-line catalogue of HPHT best practice guidelines and field experience. This is a good source of practical guidance and a useful point of first reference for well engineers and other HPHT team members. It could benefit from input provided by the users and could become an accepted practice if the majority of North Sea operators would subscribe.

Part 17 of the Model Code of Safe Practice of the Institute of Petroleum – now the Energy Institute – issued in 1992 [24] is still valid and provides a useful general guide to High Pressure drilling and testing. In view of its age a review of the text and completeness of the document should be considered.

Risk Comment 1: HPHT projects occur infrequently and every time a new team is charged with planning and design. The opportunities to establish a complete knowledge bank within a local operating company are scarce and as a result the in-house HPHT design experience is usually nowhere near the level that is available for 'normal' wells. There is also an issue over the competence of well examiners to examine HPHT wells. On the other hand the designers are confronted with extreme circumstances and are forced to use exotic materials. Operators will only avoid increased risks if the utmost attention is paid to the selection and building of design and operating teams and to the competence of its individual members.

Risk Comment 2: There appears to be a number of routes HPHT operators could take to assemble a team of adequate experience and maintain expertise. Differences will always remain between design and operating philosophies of the various operating companies and also between those of the various supply and service companies. These differences need not affect the overall risk level of the solutions achieved, provided that certain DO's and DON'T's are adhered to.

3.6.2 Quality assurance and control

Given the extreme operating conditions and the close design margins for HPHT wells, it should be no surprise that operators are giving much attention to the quality assurance of equipment and operations. This is a vast task involving operator's and suppliers' staff as well as resources from dedicated quality assurances companies.

Operators appear to be organising the quality assurance effort in different ways and using various schemes. In some cases the control is executed as an in-house effort with suppliers providing a dedicated verification service for their equipment. In other cases a third party quality assurance company is employed to provide the verification of company operations and in addition to audit the assurance effort in the supply line for some or all of the components. The latter system benefits from a standard reporting system against specifications for all parts of the operation.

The major question that operators have to address is to what extent quality assurance should be applied. There is the suggestion that operators may be tempted to introduce extreme quality control and an overly cautious approach to offset a lack of expertise in the design and operations team. The level of quality control should be commensurate with the risk of failure of equipment and installation. Once the quality control level is selected it should be applied rigorously.

It is the view of one of the quality assurance companies that effective HPHT QA results from smarter, not more QA. The very specific HPHT designs and material specifications require QA staff with a high degree of experience who can convey the appropriate focus on delivery and risk to the supply chain.

Known risk areas in design and manufacturing should be targeted with deeper (and where appropriate intrusive) QA, i.e. at the Mills. Vendor QA specialists might be included in an integrated QA approach for the well. This would ensure that optimum use is being made of available competence and capabilities.

The focus should be on coaching, i.e. using QA to foster a common understanding of the technical requirements of the end-user all along the supply line, across all interfaces.

Risk Comment: HPHT wells have long lead times with most of the materials and equipment specifically designed, ordered and manufactured for the project. This makes them ideally suited for a dedicated quality assurance system, be it for the basic material, the fabrication or the installation of components. Rigorous application of such verification system would contribute to the containment of risks for these projects.

3.6.3 Response to failures

Failure of the equipment, the construction or the borehole integrity of a HPHT well will not necessarily lead to an emergency but, if it results in the loss or suspected loss of a pressure barrier it should certainly be classified as a crisis situation. The severity of the well conditions and hence the time involved to arrange for corrective measures – usually in first instance a well kill – will give rise to an extended period during which the well pressure integrity is relying on the single remaining barrier. With most well materials being pushed towards the extremes of their operating envelopes a distinct increase of operational risk could be incurred.

After an HPHT failure there is enormous internal and external focus on the problem and its actual and potential consequences. This leads to pressure to move quickly to remedy the situation. One operator's experience has led to the following points of note:

- Assemble the strongest team that can be made available. Crisis management is arduous and demanding.
- A senior representative of the contractor providing the intervention equipment and services will be an important member of the crisis team
- Keep stakeholders fully briefed. This applies in particular to the Health & Safety Executive. Early and open discussion of plans with inspectors will avoid surprises that may cause 'Regulatory' delays.
- After an outline plan has been developed the critical path will run through the process of contracting, preparing and assembling equipment and services. Usually that will make ample time available to prepare and programme the corrective action in detail..
- Never start any aspect of the operations until the preparations are complete and all risks are fully assessed and controlled.

Risk Comment: The risks to plant and people when a failed well is closed in with a single pressure barrier should be assessed realistically and critically. If there are indications that the remaining barrier may not be guaranteed on a long term basis – e.g. when relying on a subsurface safety valve - a potential emergency should be declared, adjoining wells should be closed in and non-essential staff may have to be evacuated.

4. FUTURE TECHNICAL DEVELOPMENTS

4.1 Managed pressure drilling

In its simplest definition 'Managed Pressure Drilling' is a drilling process allowing precise control of the annular pressure profile by maintaining a variable (small) backpressure on the annulus returns. By managing the combined effects of backpressure, borehole fluid density, and circulating friction, the pressure profile may be controlled more accurately within the downhole environmental window set by the formation pore pressures and the available borehole strengths[25].

In comparison to the conventional drilling process the correction of the downhole pressures can usually be much faster as it can be achieved in principle by adjusting the surface chokes rather than adjusting the drilling fluid density and the circulating friction. When circulation is stopped to add a single to the string, adjusting the surface pressure may offset the loss of ECD and the re-starting peak.

The specialized equipment associated with managed pressure drilling include rotating control heads, at surface, at the seabed or within the riser, choke manifolds, surface separation, nitrogen generation equipment, down hole valves and electronic data acquisition and control systems. None of this equipment will be on the drill floor.

For HPHT wells, the managed drilling process appears to offer distinct advantages as it would allow continuous active control of the downhole pressures within the very constrained pressure window that is available

The managed drilling process could lead to underbalanced drilling and in fact this step may be necessary when it is applied for drilling HPHT sections that include depleted zones.

Managed pressure drilling is actively considered by at least two Norwegian operators. UK operators have no plans for introduction of this process – mainly on account of the considerable extra equipment that would have to be installed on the rig for use on a very limited number of wells and the temperature rating of the rotating head.

Risk Comment 1: Managed pressure drilling changes the configuration of the pressure barriers available to the drilling process. The primary barrier is now only partially provided by the mud column, the rotating control head being the closing element. The secondary barrier is unchanged, i.e. the BOP stack. If primary control would be lost the actions to regain control are unchanged from the conventional situation.

Risk Comment 2: Managed pressure drilling will result in the need to operate a rigorous active pressure control process on a continuous basis. This could have beneficial effects on the kick alertness of the drilling crew thus resulting in a lowering of risks, although it could also attribute to an increased tendency to complacency.

Risk Comment 3: Introduction of full underbalanced drilling (as opposed to managed pressure drilling) would introduce considerable additional risk on account of the prolific production potential of the HPHT reservoirs. Considering that underbalanced drilling would only be required when penetrating depleted reservoirs, the increased risk should be set against that of performing the same operation using the conventional drilling process.

4.2 Constant pressure drilling

Jenner et al [26] have reported recent advances in constant pressure drilling i.e. drilling without interrupting circulation while new joints of drillpipe are added to the string. This could be useful while drilling overpressured sections in HPHT wells. Maintaining continuous circulation throughout the hole section would allow utilization of the ECD to control pore pressure in addition to the drilling fluid column. Pressure surges before and after making a connection can be avoided and the overbalance could be minimized with obvious benefits when working in a narrow pore pressure/fracture pressure window.

The system is included in this report as it might have scope for future HPHT development in the UKCS. As far as known, the system is not considered by any of the North Sea operators at present.

Constant pressure drilling utilizes a Continuous Circulation System developed by a joint industry project in the USA. The heart of the system is a ‘Coupler’, effectively a pressure chamber between to sets of piperams situated over the rotary table, through which the drillstring passes and which seal around the drill pipe during the disconnection process. The coupler is divided in two sub-chambers by a set of blind rams. This will allow the pin connection to be removed from the upper chamber while maintaining circulation pressure on the string via the lower chamber. After connecting a new joint of drillpipe to the top drive the pin is re-inserted into the upper chamber, which is then sealed and repressurized before opening the dividing rams and making the connection. The equipment effectively integrates a snubbing unit with powerslips and an iron roughneck.

The prototype equipment used for a field trial in Oklahoma in 2003 was rated to 5000 psi clearly inadequate for application with HPHT drilling. The system is now commercialized and available for hire but there appear to be no plans to develop equipment for high-pressure use. It is possible that this would make the coupler overly heavy, which could slow down operations.

Risk Comment: Provided a high-pressure system could be developed constant pressure drilling would eliminate to a large extent the risks created by kick and loss incidents. This could be partly offset by the introduction of a complex item of rigfloor equipment and additional high pressure piping and manifolding together with involved pumping control operations at every connection.

4.3 Borehole temperature control

A recent discussion on the SPE drilling website highlighted the possible relationship between wellbore temperature and leak-off or fracturing strength and hence the chance of mud losses. The theory proposed is that the localized cooling effect of the mud circulated in a well would reduce the in situ compressive stresses in the rock of the borehole wall. This would result in lower hoop stresses and consequently a lower fracture initiation pressure of the rock.

The corollary of this theory is that circulating with a hot fluid would increase or at least maintain hoop stresses and thereby the capacity of the borehole to withstand higher pressures without leak-off or fracturing.

There is anecdotal evidence that leak–off strengths at casing shoes improve with time. One contributor to the SPE discussion reported that calculations using typical rock parameters and estimated temperature increases confirmed that the observed increases in leak-off strength could be due to thermal effects. Another contributing factor could be that solids entrapped in mini fractures after a leak-off test would lead to increased hoop stresses around the borehole.

One North Sea operating company carried out a well test in the USA with increasing circulating temperatures between 32 and 66 ^{o}C (90 and 150^{o}F). It was found that the leak-off strength of a sand-shale sequence at 914 m (3000’) increased by an average of nearly 0.04 kPa/m for every ^{o}C (nearly 0.01 psi/ft for every 10^{o}F) increase of the bottom hole temperature.

Risk Comment: If operators would intend to apply this method to improve/maintain borehole strength it should be realized that overheating of the borehole wall at higher levels could result in excessive hoop stresses and failure of the rock in compression. This could lead to wash outs and a poor cement-seal around a future liner.

4.4 Expandable liners

Several hundreds of expandable liners and screens have been installed in conventional wells since the advent of the expandable tubular technology in 1999 – 2000. The steel used in expandable pipe has been specially processed for ductility, reduced sensitivity to metallurgical defects and increased fracture resistance, enabling it to be permanently deformed during the expansion process. The primary expansion techniques used in the industry are fixed cone and rotary expansion. The rotary expansion tools impart a radial force on the pipe through one or more rollers. The latter system appears to allow better control of the expansion process requiring much lower axial forces [27].

If expandable pipe is used for drilling or production liners, the sealing against the borehole can be achieved by placing conventional cement slurry before expansion, or by the use of elastomers energised by the expansion process. It is not known if elastomers have already been qualified for high temperature application.

The technology is now also available for 13%Cr stainless steels. This was successfully applied in Sarawak to expand a 191 mm ($7^5/_8$") 13%Cr tubing into the 244 mm ($9^5/_8$") production casing for productivity improvement [28].

One North Sea operator is studying the potential of the expandable tubular technology to install additional drilling liners when drilling through depleted sections of the HPHT prospective zone. The technology would also have application to provide scope for additional drilling liners in exploration wells.

Risk Comment: In HPHT wells expandable tubulars would primarily be applied in the prospective zone where very high temperatures prevail. This places extra conditions on the specifications of the material used for the pipe and – if considered – the elastomers used for sealing off the annulus. The potential risk should be recognised that further uncertainties could be introduced into completions that are already designed on the edge of metallurgical and elastomer knowledge.

4.5 Horizontal borehole sections

Horizontal or high angle (near) HPHT drilling has been carried out in various fields in the UKCS [29] and offshore Norway as well as in other parts of the world [30, 31].

There is anecdotal information that horizontal drilling operations have been carried out in Texas as early as 1990. Some 3000 feet were drilled horizontally at a depth of 16000 feet TVD. Reportedly the drilling process was enabled by the use of an unusual concentric casing design that allowed underbalanced drilling with a solids free brine. The bore hole temperature was said to exceed 400^{o}F and a high solids mud systems would have caused additional problems in the horizontal section. It is assumed that the well productivity was relatively low thus allowing the underbalanced conditions.

Interventionless completion packers have been developed for these highly deviated wells that will require to be completed without wireline intervention.

Risk Comment: The HPHT well control problems will be accentuated when large sections of the well are horizontal. This requires an even more rigorous approach to the operational procedures and could require application of managed pressure drilling to control the risks involved.

4.6 Insulated production tubing

Installing insulated tubing in North Sea HPHT wells is not normal practice. Casings of new wells are usually designed for the high temperatures of the reservoir fluids and there is no need to maintain production temperatures in the well for PVT or flow reasons.

One North Sea operator will be using insulated tubing to complete a suspended HPHT well of which the casing cannot stand the high production temperatures.

4.7 New materials

The proprietary alloy 725 is now also patent free and can thus be manufactured by competing mills. This opens the possibility for operators to use this metal as an alternative to Alloy 718. The composition of alloy 725 includes more nickel, chrome and molybdenum and the material exhibits a somewhat better resistance against sulfide stress cracking. Alloy 725 is also stronger than 718. Operators have so far not indicated an interest in applying this – no doubt more expensive and not field proven – nickel alloy for their completions.

4.8 Deeper HPHT wells

HPHT wells to depths over say 20 000 ft are being planned in the North Sea. The challenge of these wells is that all technical and operational limits will be tested even more severely [32]. Longer casing strings will be heavier and may exceed weight limitations. One operator has selected the option of using a slim well design with drilling liners to overcome these problems in the HPHT section.

The well control problem due to the narrow operating window between the pore pressure gradient and the fracturing gradient is aggravated as a result of the increased circulating friction effects in the longer hole. Operators have not indicated if they will employ alternative control options while drilling the HPHT section of the well.

4.9 HPHT wells in deep water

Deep water conditions will be encountered if HPHT drilling west of Shetlands would be contemplated. The following factors are generally complicating deep water drilling:

- The overburden sediments are often undercompacted and weak thus further reducing the pore pressure-fracture strength window.
- The contrast between the long riser column of heavy circulating fluid and the surrounding seawater column will generally distort the well control options. This will be more severe when circulating with extremely high fluid gradients

Deep water wells will always be drilled in the sub-sea mode and probably be completed sub sea, thus avoiding some of the well construction problems related to strong radial temperature gradients in well sections above the seafloor (ref 3.1.1, page 21). Only recently have sub-sea wellheads with appropriate ratings become available and the first real HPHT field is being developed on the UKCS at present. The experience with this development will undoubtedly inform operators attempting to drill HPHT wells in deep water.

PART 4

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The obvious and defining characteristics of HPHT wells are the abnormally high subsurface pressures and temperatures encountered. There is however another condition - only partly related to the subsurface environment - which is shared by these wells. Individual HPHT well production rates in the North Sea area are high in comparison with field size, hence field developments comprise few wells, often less than ten. This denies HPHT developments the full benefits from:

- Economies of scale, i.e. the potential for development of field specific drilling methods/tools and completion equipment is restrained
- Economies through learning, i.e. the potential for optimization of field specific methods, equipment and techniques is limited.

In many aspects the technical developments and optimizations go hand in hand with the development of solutions to safety issues. For HPHT wells many economic and safety improvements can only be achieved through cross industry learning and equipment/method development and this will slow down the pace at which this happens..

In a discussion of safety issues and validity and competence of the technical solutions implemented to date it will be useful to address separately

- the drilling, completion and re-entry operations on a well, i.e. the process of constructing the well in the first place and to maintain it at a later date.
- the quality of the well construction as demonstrated during its production phase.

The Well Construction and Maintenance Operations

During HPHT well operations the main safety issue is the high pressure regime that exists in the prospective zone and more specifically the narrow margin between the required borehole pressure to control the reservoir pore fluid pressures and the allowable pressure to retain borehole competence. To date well control incidents are by far the most frequently occurring of all well safety concerns in the UKCS. It should be noted that this statistic might be skewed as the UKCS HPHT well drilling history goes back much further than the HPHT field production history.

In the years immediately following the Ocean Odyssey blow-out, the industry has been successful in reducing the probability that well control problems will be encountered in a HPHT well to 1 in 6. This probability has remained virtually unchanged for the last six years despite efforts by operators. The magnitude of the kicks experienced and the occurrence of kick and loss situations has however decreased in recent years. This may be the result of using the most likely subsurface pressure rather than the maximum expected for mud design.

The UK industry holds the strong view that avoidance of losses, i.e. maintaining borehole competence when working in a HPHT environment has the highest priority as kick and loss situations are the most hazardous.

The industry’s efforts to reduce the well control incidence further have been mainly concentrated on better and more sophisticated prediction methods and extensive preparedness training. There are however a number of potential future techniques to avoid kicks and/or losses i.e.

- Borehole fracture strength improvement - This method is actively considered by UK operators specifically for operations involving depleted HPHT reservoir sections when the potential for incurring a kick and loss situation is high
- Expandable liners.
- Managed pressure drilling – Considered by Norwegian operators only.
- Constant pressure drilling – Equipment needs further development.
- Borehole temperature control – Still in the testing stage.

It is concluded that the industry is on the right track to keep the HPHT well control risk as low as reasonably practicable but the Health & Safety Executive believes that the frequency of kicks can be reduced further by continued close attention to the available pore/frac pressure window for each individual well. It is expected that development and eventual application of some of the potential techniques mentioned above may also assist in reducing the kick incidence.

The Quality of the Well Construction

In principle any well construction is designed to be fit for purpose i.e. fit to be produced to full potential with risks as low as reasonably practicable. It is only during commissioning and subsequent full production that the well design premise is put to the test.

During HPHT production there are three main safety issues

- The high pressure regime existing in the well. This will not only lead to the use of exotic, less commonly applied materials and thick-walled pipes but it may also increase the probability of mechanical equipment failures
- The high temperature of the produced fluids resulting in extreme operating temperatures of the total well construction and the adjacent surface facilities. In addition there will be strong temperature changes (and hence thermal forces) and high temperature gradients in the well especially near surface. Chemical activity of well fluid components may also be enhanced by the high temperature
- The massive flowrates of most HPHT wells especially when first opened up.

.
On the UKCS a number of incidents related to the integrity of HPHT well constructions have given rise to the following concerns about the following hazards:

- Catastrophic failure of well tubulars and hangers
  In most cases the failed equipment was manufactured from premium stainless steels or alloys and has the root cause of the failure been attributed to metallurgical flaws. There is no obvious correlation between the specific metallurgical problems encountered and in one case no metallurgical cause has been identified. The failures have invariably led to the loss of one safety barrier of the wells concerned.
- Failure of sealing elements
  Incomplete setting of metal to metal wellhead seals was caused by the complex installation sequence dictated by the selected well foundation arrangement. There is a general uneasiness about the suitability of the available elastomers used for HPHT seals. failure of wellhead or production packer seals will result in the loss of one safety barrier.
- Inability to contain the gasbearing Hod and Frigg Chalks
  Gas channelling has been experienced in the annulus of many wells in spite of optimum techniques having been applied during casing cementation. The problem may be related to the effect of large thermal cycles on cement and/or the underestimation of the pore pressure in the chalk zone. A pressurized and gaseous B or C annulus poses a risk to the outer safety barrier of the well if not continuously monitored and managed. Operationally this would be more problematic for subsea wells than it is for surface completed wells.
- Erratic well growth

The thermal growth of wells during commissioning has been underestimated in many cases as a result of optimistic assumptions regarding the conductor fixidity. Due to variations in subsurface conditions this may remain an element of uncertainty. If the wellhead bay is not designed to accommodate the maximum possible well growth, damage to surface facilities may be incurred.

- Inability to withstand reservoir compaction
  The collapse or lateral movement of rock-layers overlying the HPHT reservoirs has caused damage to the production liner. This may lead to loss of one safety barrier from the completion.
- Inability to inject chemicals for continuous downhole scale inhibition
  On safety grounds there is a reluctance to introduce ports in HPHT hangers to accommodate injection lines. The extremely hard scale deposits experienced in watercut HPHT wells will affect the operation of the safety valve and the wellhead valves, both essential safety barriers in a producing well.

It is clear that several unrelated sections of the HPHT well constructions can be at risk, or could indirectly create a risk. Many of above safety concerns involve the loss of one barrier from the well control arrangements. The severity of the well production conditions and hence the time involved to arrange for and to employ suitable corrective measures will increase the risk that the one remaining barrier could also become ineffective before full control can be re-established. The exceptional demands on the well components thus increase the potential for double jeopardy which would lead to a shut down of all neighbouring wells and initiation of crisis management measures.

The industry has been very active to prevent future failure situations by:

- The introduction of intensive quality assurance procedures
- The introduction of design changes to the well configuration
- The introduction of new inspection processes
- The introduction of special handling and installation procedures
- The selection of experienced design and operating teams.
- The use of supply and services resources with a proven track record
- The open exchange of information between HPHT operators.

Each and everyone of these measures is valid and competent if applied consistently and will undoubtedly lead to an overall reduction of the number of safety related incidents in HPHT wells and hence to a reduction of the risk of producing HPHT wells. The measures appear to be of general applicability to HPHT fields with different characteristics and should apply in addition to field specific design requirements.

It is concluded that the UKCS operators and service/supply industry have been only partly successful in designing and constructing all North Sea HPHT wells right first-time. Although failures generally occurred in fields at the most severe end of the well productivity scale there remains a general concern that not all HPHT hazards have been identified yet. Thanks to the open exchange of information by the industry, the causes of failures and their remedies have been well publicized. This will be of great benefit to future HPHT developments.

RECOMMENDATIONS

In a workshop held in Aberdeen in April 2005 stakeholders' views on the continuing and future challenges from HPHT developments were discussed and the potential areas that will require attention highlighted. The following opportunities for Joint Industry type initiatives.
were identified:

High Priority

Design of Exploration Wells

HPHT Exploration wells are currently designed to be ‘keepers’ although very few are actually used for production after the field is developed. Designing these wells as expendable ‘finders’ is possible with the current technology and would present a cost reduction to the tune of £ 7 – 8 million. However, the cheaper design could affect the amount of information that may be obtained and would also increase the risk that the well would not reach its target. On operator is seriously looking at applying the finder principle. Management of other operators are concerned that finder wells will not satisfy the information requirements of the Dti.

Work required:

Dti will clarify their requirements, which are in principle pragmatic (PILOT?).

Life of Development Wells

The strong depletion of HPHT reservoirs causes a number of subsurface problems in development wells. Damage of the completion liner due to rock movements as a result of compaction is the major problem (see also below)

Work required:

A well design that copes better with compaction and consequent lateral rock movements is required.

Compaction

The effects of the severe reservoir compaction experienced in HPHT wells (up to 15%!) on the overburden and caprock are not well understood.

Work required

Geomechanical modelling by industry rock mechanics experts

Could be a JIP type initiative – there appears to be a global knowledge gap.

The Use of Exotic Materials

The properties of the exotic alloys used in HPHT completions and the effects of various environments have on these metals is not always well understood. This may have led to inadequate specifications, reliance on supply management to select the suppliers and unexplained (potentially serious) failures in service. An example is the effect of mercury – present in varying proportions in well streams - on ferrous alloys.

Work required

The metallurgists of the various operators and service companies should consider exchanging information on an informal basis (a regular meeting?). They should consult with metallurgists from other industries (e.g. refineries, pipelines) who may have long experience in using the materials in environments similar to HPHT wells.

Could be a JIP type initiative

Shock Loading

Production wells are subjected to frequent and abrupt loading changes due to ESD’s. This could be up to 100 times per year. The effect on the well completion and the cement bond is not well known.

Work required:

Study the effects of (sudden) load variations on well completions. This could involve looking at experiences of other industries (c/f ASTM 8).

Could be a JIP type initiative.

Elastomers

Based on field experience it is doubted if the currently available elastomers are good enough for HPHT applications especially as we are exploring deeper and hotter target reservoirs.

Work required:
Suppliers of completion equipment to re-evaluate elastomer and other sealing materials to ensure they are ready for the step change from 450°F to 550 °F.

Model Code of Practice Part 17 (Institute of Petroleum now Energy Institute)
The COP is still valid but has not been kept up to date with industry experience.
Work required
The Code of Practice should be updated to regain its status as the prime reference for HP operators. This could be a task for the Energy Institute or for UKOOA in conjunction with the role suggested below.
By necessity this should be a JIP type initiative.

Medium Priority

Isolation of the Hod/Frigg Formations
The effective isolation of the overpressured Hod or Frigg gas reservoirs behind the intermediate or production casing string is a problem.
Work required:
1. Determine the precise regional occurrence of these formations and where they are gas filled.
2. Devise a technique to isolate these reservoirs and eliminate pressurised B or C annuli in completed wells

Efficient Sharing of Information
Operators can only spend a limited amount of staff time to share essential information with HPHT stakeholders. An efficient vehicle is required. The HPHT Operators Forum provides this but informal body has its limitations.
Work required:
HSE to investigate if UKOOA could play a more active role.

Low Priority

Education of Tubular Suppliers
Most pipe manufacturers and material suppliers are unaware of the service requirements for their goods and the environments to which these will be exposed. This may lead to assumptions and practices in the supply line that could cause unexpected failures in service. In this context it was noted that the production casing string is just as critical as the production tubing and should be subject to the same level of quality assurance.
Work required:
Educate the suppliers

HPHT Operators Forum
Although new North Sea HPHT operators are welcome to join the Forum it is unclear how they would be aware of its existence.
Work required:
Dti to ensure that new operators are briefed on the existence of the informal North Sea HPHT Operators Forum and to provide contact information.

It is recommended that industry representatives take high priority initiatives to address the subjects listed above under:
- *Compaction*
- *The Use of Exotic Materials*
- *Shock Loading*
- *Model Code of Practice Part 17*

REFERENCES

1. Millton-Worssell R et al *Presentation to the Maximizing Hydrocarbon Recovery from the UKCS Seminar 2004* www.og-mrp.com/dissemination/openreports/DTIIOR04/ June 2004
2. HSE L73 *A guide to the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR 95).*
3. Hinton A *An Analysis of OSD's Well Incident Data Base; Results can Improve Well design and Target Well Control Training* SPE 56921 1999
4. Schofield MJ and Pickering P *Review of Operating Experience with HPHT Wells* CAPCIS Ref: HKBMTX/01 2001
5. Hahn DE, Burke LH, Mackenzie SF and Archibald KH *Completion Design and Implementation in Challenging HP/HT Wells in California* SPE 86911 2003
6. Gordon D, Billa R, Weissman M and Fu Hou *Underbalanced Drilling with Casing; Evolution in South Texas Vicksburg* SPE 84173 (highlights) 2003
7. Al-Saeedi M, Al-Mutairi B, Al-Khaldi M and Sheeran T *Fastest Deep Marrat Well in North Kuwait: Case History of Raudhatain 206* SPE/IADC 85287 2003
8. McDermott JR and Martin III BL *Completion Design for Deep, Sour Norphlet Gas Wells Offshore Mobile, Alabama* SPE 24772 1992
9. HSE *Offshore Installations and Wells (Design and Construction, etc) Regulations 1996*
10. HSE OSD 1.5 *Guidance on ALARP for Offshore Division Inspectors - Making an ALARP demonstration* SPC/Enf/38 March 2003
11. HSE *Principles and guidelines to assist HSE in its judgements that duty-holders have reduced risk as low as reasonably practicable* alarp1.htm 13 December 2001
12. HSE *Assessing compliance with the law in individual cases and the use of good practice* alarp2.htm Revised May 2003
13. HSE *Policy and Guidelines on reducing risks as low as reasonably practicable in design* AD/25 alarp3.htm Updated 17 June 2003
14. UKOOA *A Framework for Risk Related Decision Support*
15. Vaziri H, Allam R., Kidd G, Bennett C, Grose T, Robinson P, and Malyn J *Sanding, A Rigorous Examination of the Interplay Between Drawdown, Depletion, Start-up Frequency and Water Cut* SPE 89895 2004
16. Li X, Mitchum FL, Bruno M, Pattillo PD, and Wilson SM *Compaction, Subsidence, and Associated Casing Damage and Well Failure Assessment for the Gulf of Mexico Shelf Matagorda Island 623 Field* SPE 84553 2003
17. Doyen PM, Malinverno A, Prioul R, Hooyman P, Noeth S, den Boer L, Psaila D, Sayers CM, Smit TJM, van Eden C and Wervelman R *Seismic Pore Pressure Prediction with Uncertainty using a Probabilistic Mechanical Earth Model* 73rd Annual International Mtg Soc. of Exploration Geophysicists, 1366-1369 2003
18. Editorial *Ahead of the Bit: Managing Geohazards Proactively* Journal of Production Technology December 2004
19. Sanad M, Butler C, Waheed A and Sweatman R *A new Treatment Increases the Fracture Gradient to Cure Lost Circulation and Control a Flowing HPHT Well in the East Mediterranean Sea* SPE 84318 2003
20. Aston MS, Alberty MW, McLean MR, de Jong HJ and Armagost K *Drilling Fluids for Wellbore Strengthening* SPE 87130 2004
21. Alberty MW and McLean MR *A Physical Model for Stress Cages* SPE 90493 2004
22. Benaissa S, Bachelot A, Ricaud J, Arquey G, Yi X, and Ong S *PreventingDifferential Sticking and Mud Losses Drilling through Highly Depleted Sands – Fluids and Geomechanics Approach* SPE/IADC 92266 2005
23. Palmer IAC *Jade North Sea HPHT Development: Innovative Well Design Generates Best In Class Performance* SPE/IADC 92218 2005

24. The Institute of Petroleum *Well Control During Drilling and Testing of High Pressure Offshore Wells* Model Code of Safe Practice Part 17 May 1992
25. Hannegan DM *Managed Pressure Drilling in Marine Environments – Case Studies* SPE/IADC 92600 2005
26. Jenner JW, Elkins HL, Springett F, Lurie PG and Wellings JS *The Continuous Circulation System: An Advance in Constant Pressure Drilling* SPE 90702 2004
27. Innes G, Metcalfe P and Hillis D *Next Generation Expandable Liner Applications* IADC/SPE 88022 2004
28. Bada I, Maekiaho L, Ain FM, Nijveld E and Tan I *Maximizing Production with 13Cr Solid Expandable Tubulars in Sarawak Gas Fields* SPE 88027 2004
29. Bradley ND, Low E, Aas B, Rommetveit R and Larsen HF *Gas Diffusion – Its Impact on a Horizontal HPHT Well* SPE 77474 2002
30. Shaughnessy JM and Locke HA *20-Plus Years of Tuscaloosa Drilling: Continuously Optimizing Deep HTHP Wells* IADC/SPE 59181 2000
31. Al-Saeedi M, Munger R., Tooms P, Al-Mutari B, Al-Quraini K, Decaire J and Tuncer T *First High Pressure, High Angle Well in Kuwait: Case Study of WMN-2* IADC/SPE 72299 2001
32. Shaughnessy JM, Romo LA, and Soza RL *Problems of Ultra-Deep High-Temperature, High-Pressure Drilling* SPE 84555 2003

BIBLIOGRAPHY

1. HSE *HPHT Wells: Perspective on Drilling and Completion from the Field* OTH 512 1998
2. Wilford J, Rice P and Ray T *Selection of Metallurgy and Elastomers Used in Completion Products to Achieve Predicted Integrity for the HP/HT Oil and Gas Fields of Indonesia* SPE 54291 1999
3. Mowat DE, Edgerton MC and Wade EHR *Erskine Field HPHT Workover and Tubing Corrosion Failure Investigation* SPE/IADC 67779 2001
4. Avila JC, Zerpa E, Rojas L and Salas JG *Drilling HP/HT Wells in Bosque Field, Venezuela – The Aloctono Block Challenge* SPE/IADC 79815 2003
5. Jones JF, Taylor GD and Barree RD *Successfully Managing Drilling-Fluid Losses in Multiple, Highly Depleted Sands* SPE 83713 2003
6. Wilson SM, Edwards S, Heppard PD, Li X, Coltrin G, Chester DK, Harrison HL and Cocales BW *Wellbore Stability Challenges in the Deep Water, Gulf of Mexico: Case History Examples from the Pompano Field* SPE 84266 2003
7. Marketz F, Van Noort RHJ and Baaijens MN *Expandable Tubular Completions for Carbonate Reservoirs* SPE 88736 2004
8. Stevens R, Mingjie K, Javora PH and Qu Q *Oilfield Environment-Induced Stress Corrosion Cracking of CRAs in Completion Brines* SPE 90188 2004

Published by the Health and Safety Executive
12/05

HSE
BOOKS

MAIL ORDER
HSE priced and free
publications are
available from:
HSE Books
PO Box 1999
Sudbury
Suffolk CO10 2WA
Tel: 01787 881165
Fax: 01787 313995
Website: www.hsebooks.co.uk

RETAIL
HSE priced publications
are available from booksellers

HEALTH AND SAFETY INFORMATION
HSE Infoline
Tel: 0845 345 0055
Fax: 0845 408 9566
Textphone: 0845 408 9577
e-mail: hse.infoline@natbrit.com
or write to:
HSE Information Services
Caerphilly Business Park
Caerphilly CF83 3GG

HSE website: www.hse.gov.uk

RR 409