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TRANSACTIONS (TM)

NORTH SEA WELL CONTROL EQUIPMENT — DESIGN AND CERTIFICATION DEVELOPMENTS

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North Sea Well Control Equipment — Design and Certification Developments

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SYNOPSIS

Well control equipment is a convenient term used by the oil industry to describe the family of devices and systems which control flow from an oil or gas well during both drilling and subsequent operations. From January 1983 the Department of Energy has required this type of equipment to be surveyed if it is intended for use in the exploitation of hydrocarbons within the UK sector of the North Sea. Although the equipment has historically been designed to codes laid down by the American Petroleum Institute (API), both the UK Department of Energy and the Norwegian Petroleum Directorate have issued additional requirements based on local conditions and practices. Additionally, API are engaged in a substantial programme to upgrade their standards, particularly as equipment is being deployed to a much greater extent on the seabed. The application of new higher standards to equipment already in use presented problems for equipment being deployed in the UK sector of the North Sea. Guidance on the application of new procedures has been put forward in a Memorandum of Understanding. This paper outlines what well control equipment does, discusses some environmental considerations and reviews design codes and inspection procedures.

BACKGROUND

Oil is found in reservoirs formed of source rocks buried below impermeable cap rock. In the North Sea one of the principal source rocks, the Kimmeridge clays, and the exploitable reservoirs are found at depths ranging from 500 to 4000 m below the seabed in water depths ranging from 20 to over 5000 m. The oil in the reservoir is found at pressures of up to 1034 bars (15 000 lb/in^2) and while these pressures are largely a function of reservoir depth and can thus generally be estimated,[1] abnormal pressures are stated to be common throughout the North Sea necessitating careful planning of a well if it is to be drilled in a safe and efficient manner.[2]

The methods by which well fluids can be controlled within the well bore are documented in industrial recommended practices compiled by the American Petroleum Institute (API)[3,4] and the equipment by which this control is exercised may be referred to as well control equipment.

To appreciate the demands of well control equipment it is necessary to have some knowledge of drilling, oil production and well maintenance systems. The oil industry, like many others, uses its own distinct terminology. For the guidance of those not familiar with oil operations, a short list of terms in common use, and their definitions, is given in Appendix 1. A good description of offshore drilling operations can be found in an earlier paper read before this Institute.[5] In summary, the various activities can be categorised as follows:

- Exploratory (wildcat) drilling.
- Completion, when a successful exploratory well is opened for commercial production.
- Work-over, the expression used when maintenance operations are being carried out on the well.

WILDCATTING

Exploratory wells are drilled in the North Sea by both jack-up and semi-submersible rigs. A semi-submersible rig may be secured by anchors above the drill site or in deep water a dynamic positioning system may be utilised to maintain position. Drilling commences with the generation of a 36 in diameter hole which is lined to a depth of about 80 m by 30 in diameter steel conductor pipe.

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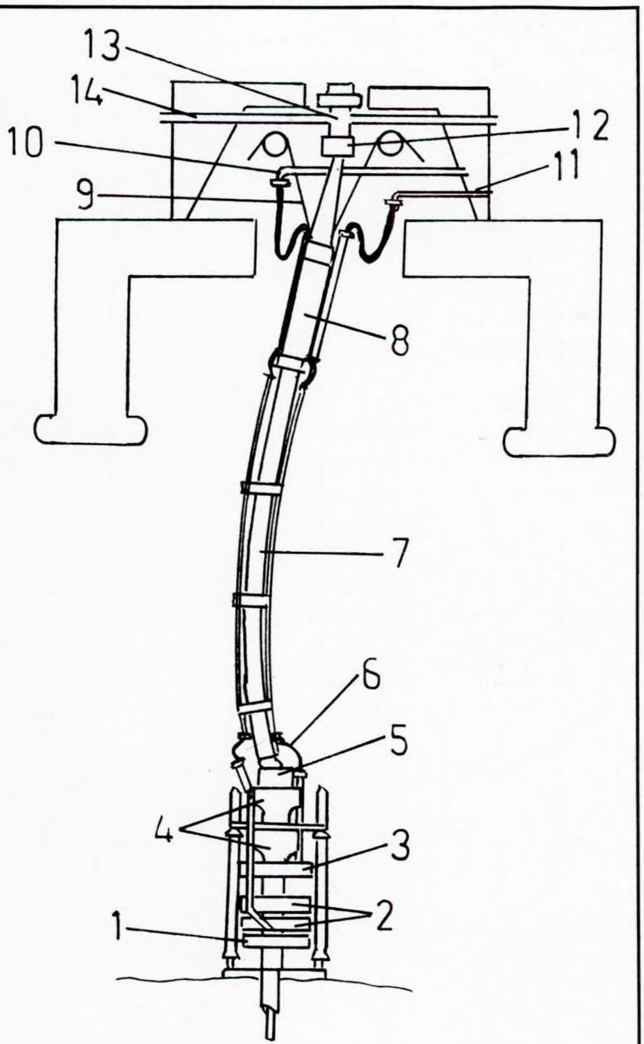
The hole is drilled by bits rotated by a drill string consisting of pipe through which a drilling fluid, mud, is circulated. The drill string turns within a larger diameter pipe, the marine riser, which allows the mud to be brought back to the surface bringing with it cuttings from the bit. The marine riser also carries the choke and kill lines through which fluids or gases released from the penetrated reservoir can be brought to the surface urder control. It thus acts as an important link in the well control equipment used at this stage of drilling (Fig. 1).

The conductor will eventually be cemented into the well and will prevent the sides of the hole caving in. When the next string of casing, the surface string, is cemented in place a blowout preventer (BOP) can be lowered by the drill string and attached to the top of the casing. This device provides a means of sealing the annular space around the drill string and/or the hole so that when the reservoir is penetrated, or if a pocket of gas is encountered in a fault in the cap rock, the well pressure can be controlled. In the early stages of drilling however and before the surface string has been set, it is common practice to protect the rig by installing a diverter sytem.

The BOP is built up from a number of separate hydraulically operated devices, each being a blowout preventer in its own right but providing flow shut off in different ways. Ram type BOPs consist of diametrically opposed rams which can be pushed in to grip the drill string or if necessary cut it. Annular BOPs close diametrically around the drill pipe. A BOP stack is built up of several BOPs



The figure shows an arrangement comprising a blowout preventer stack unitized with shear rams (1), two pipe rams (2), a blind ram (3) and two annular preventers (4). A lower ball joint (5) provides flexibility at the lower end of the riser which is assembled from several riser joints (7). A telescopic joint (8) accommodates any heave and riser tensioner lines (9) attached to hydraulic cylinders (not shown) keep a constant tension on the top of the riser. Choke (10) and kill lines (11) run down the outside of the riser and are attached to the BOP via jump hoses (6) and connectors located above the lower-most closing rams. An upper ball joint (12) provides lateral flexibility at the top of the riser and the diverter (13) provides a means of sealing off the annular space around the drill string and diverting flow away from the rig via diverter lines (14)

FIG. 1: Marine riser system

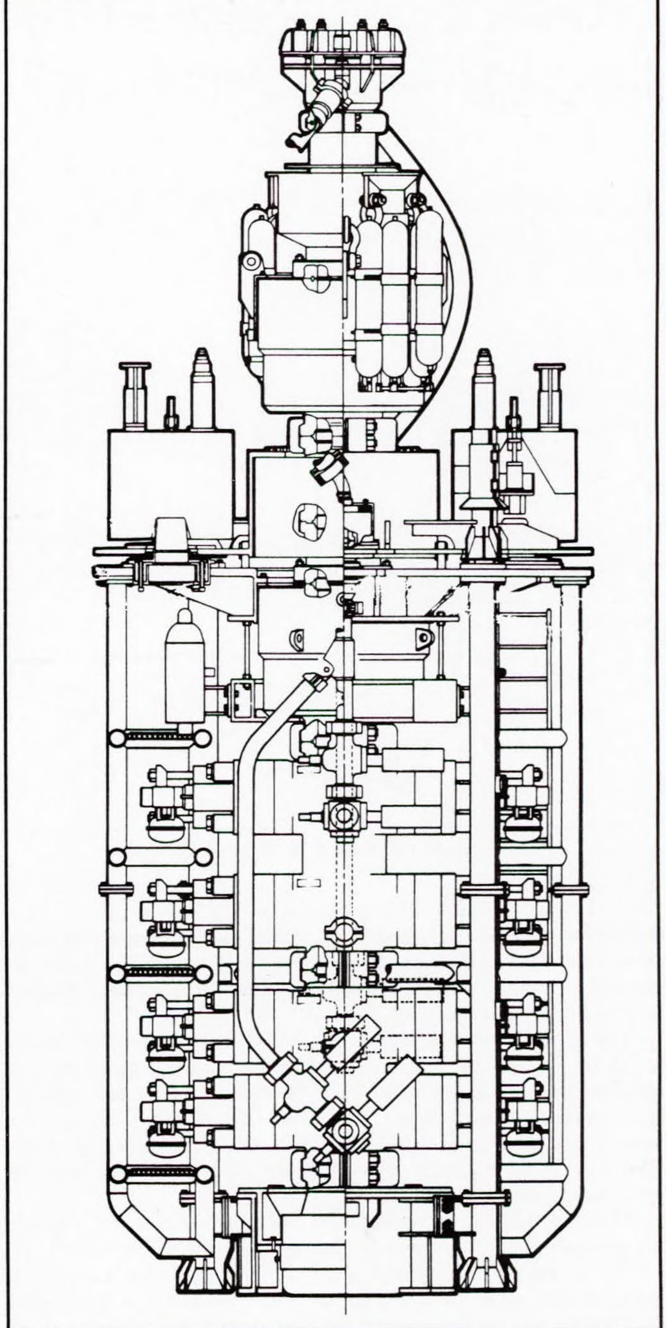


FIG. 2: Side view of a 10 000 lb/in^2 working pressure Cameron BOP stack assembly

'unitized' to provide the driller with several options when operated. (Fig. 2).

A diverter is a device located at the top of a marine riser and its object is not to stop the back flow from the annular space around the drill string but to provide a means of diverting it to a safe area of the rig. It does this by sealing off the space around the drill string (or its driver the kelly) and providing an alternative route at right angles to the drill string (Fig. 3). The object of using a diverter at this stage of the operation instead of closing off the well with a BOP is to prevent an uncontrolled flow of fluid bursting out underground around the outside of the casing which would make the well uncontrollable.

On platforms and jack-up installations the BOP is located at the top of the riser on the drill floor.

Although the BOP plays an important part in securing an installation from the effects of kick (an uncontrolled flow of reservoir fluids into the well) or a blowout, the principal means of preventing well fluids coming up the bore of the well is by carefully balancing the specific gravity of the drilling mud used during the drilling operation. Should a blowout occur, after the well has been secured by closing the diverter or the BOP a high-density mud will be pumped into the well through the drill pipe. (If it is not possible to introduce the mud through the drill pipe it may be pumped in via a kill line connection on a spool piece located immediately below the BOP. In the case of a subsea BOP it is usual to arrange a kill line connector on the BOP itself below the ram most likely to be closed.)

It may be necessary to arrange back pressure in the flow line to prevent formation fluids entering the well. This is done by locating an adjustable choke on to a connection on the BOP via an arrangement of valves, fittings and lines known collectively as the choke manifold. In a subsea

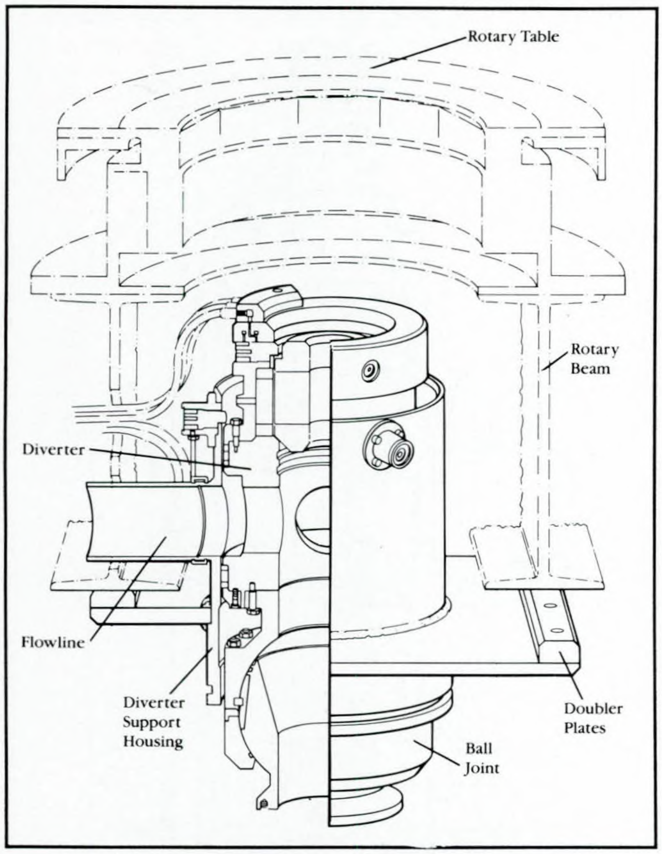


FIG. 3: Sectional view of a Hughes diverter

installation the choke and kill lines are arranged so that either line can be used for either function. Each choke is normally arranged with double shut-off valves located immediately upstream.

The marine riser is built up in sections known as joints and must be able to withstand any forces due to the motion of the floating rig. A flexible joint located at the seabed end of the riser accommodates angular movement. Heave is accommodated via a telescopic joint at the top of the riser. The riser is kept under tension below the telescopic joint by a tensioning system.

When a wildcat or exploration well is found to be capable of producing in commercial quantity it might be sealed by killing it with drilling mud and cement plugs and capping it until such time as it is to be completed. Successful exploration wells are sometimes developed for production. It is frequently more cost effective to abandon the exploration well and drill production wells in the most convenient places once the geographical limits of the reservoir have been established.

PRODUCTION WELLS FROM FIXED PLATFORMS

To complete a well for production it is necessary to install a large bore conductor, typically 30 in for the North Sea. This will be installed using the drill string and attached to the top of the conductor will be a wellhead of smaller bore, typically 21.25 in for the North Sea. The wellhead supports the inner casings and the tubes used to transport fluids from the well bore to the production facility. These are arranged in a telescopic manner through the conductor to various levels within the reservoir (Fig. 4).

When the conductor is firmly established and cemented in, the 21.25 in BOP will be replaced by another BOP of higher

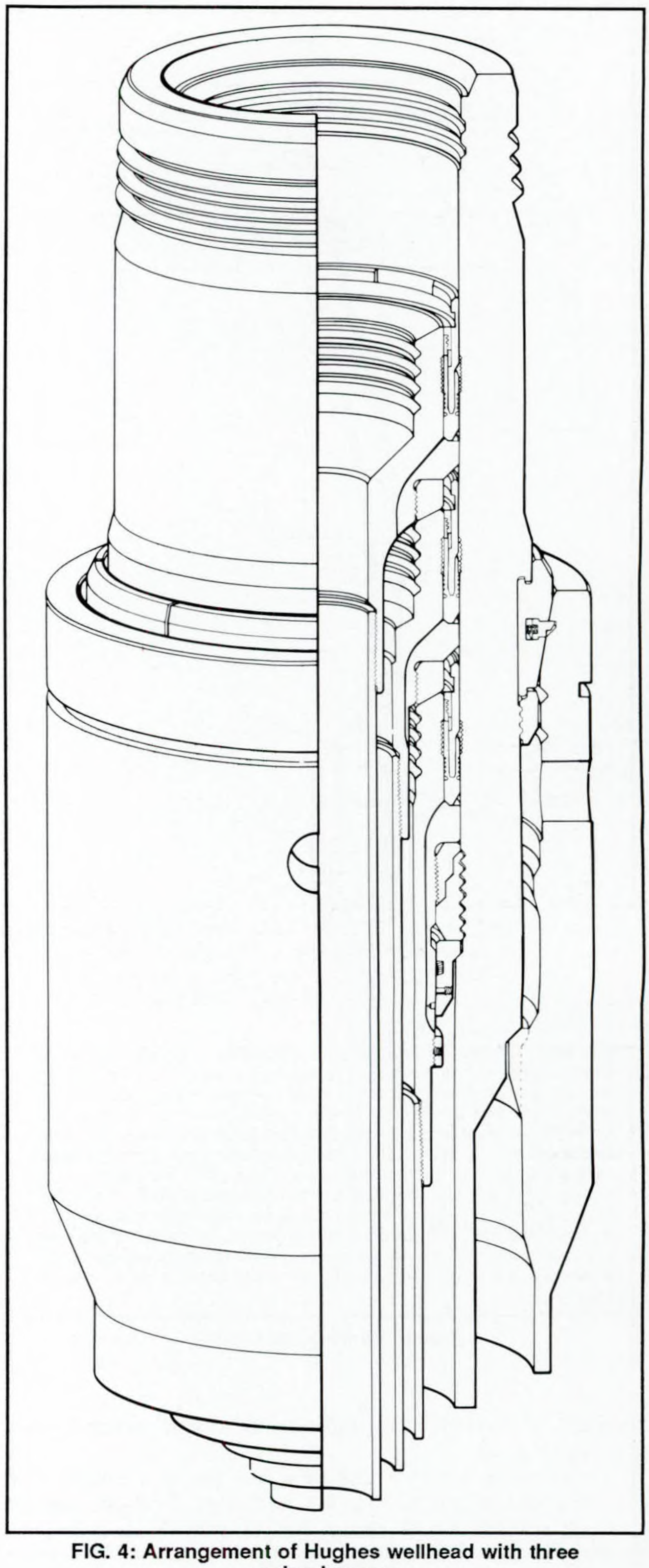


FIG. 4: Arrangement of Hughes wellhead with three casing hangers

pressure rating but smaller bore, typically 10 000 lb/in^2 and 13.625 in bore through which lengths of casing (typically 9.625 in diameter) will be run by the drill string and hung in the wellhead on a casing hanger. Finally, lining tubing of about 7 in diameter will be run within the casing and supported on a tubing hanger.

Once the well has been completed it will be temporarily filled with mud and a temporary plug installed. The BOP will

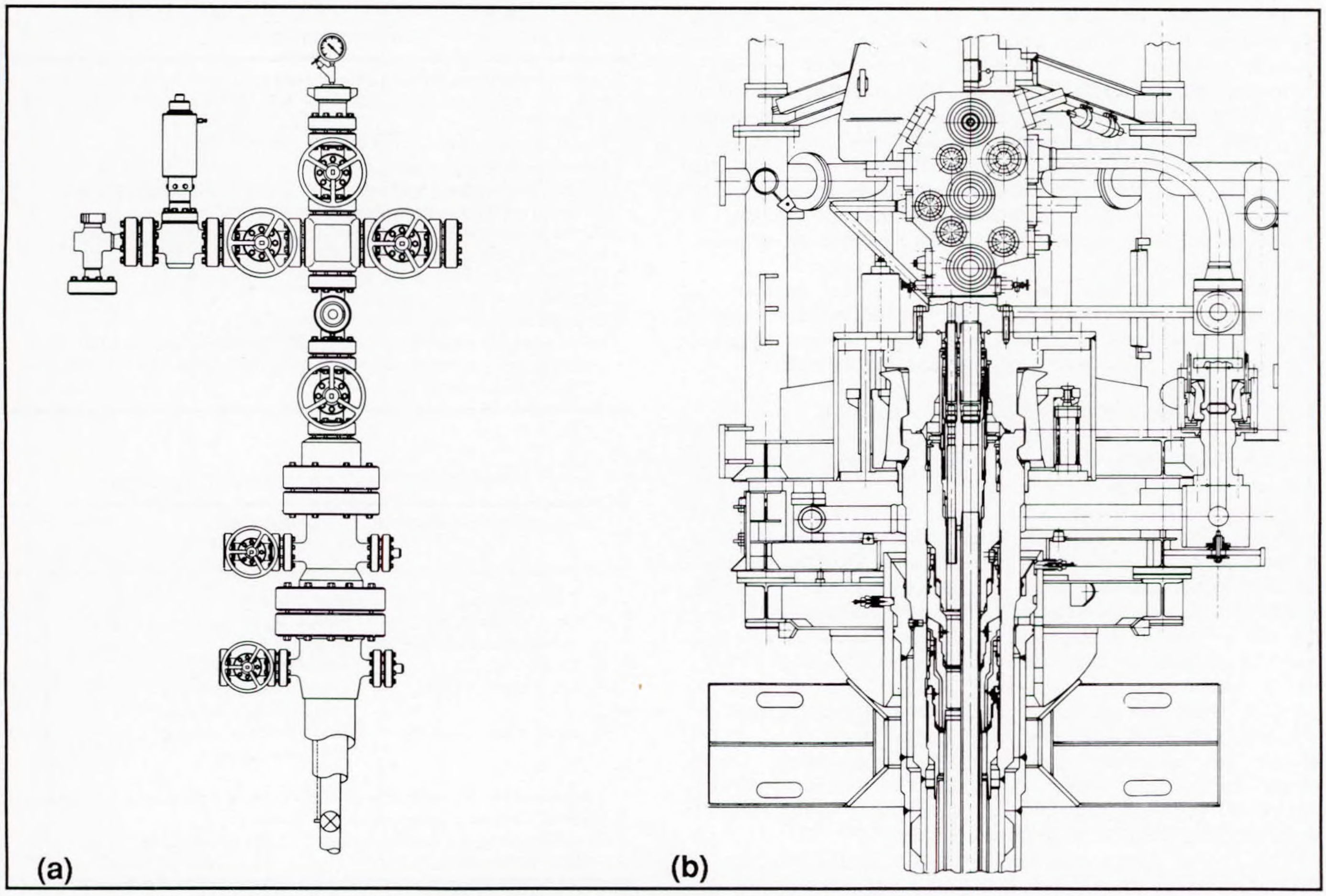


FIG. 5: (a) A typical arrangement of a platform-mounted christmas tree. In this Vetco Gray assembly the tree is assembled from several flange-coupled valves and spools. Arrangements are also available from the same manufacturer with solid block valves. (b) A Cameron subsea solid block christmas tree and wellhead part sectioned to show the collet connector casing hangers and dual tubing strings

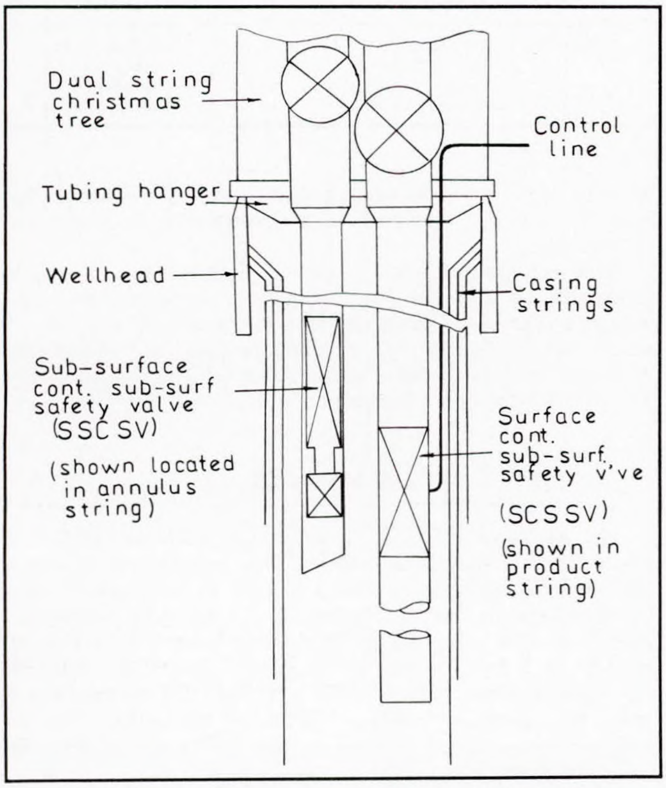


FIG. 6: Schematic arrangement of a sub-surface safety valve showing location in tubing strings

then be removed and replaced by a collection of valves at the wellhead. This collection of valves (master valves and wingvalves) is known as the christmas tree (Fig. 5) and is used to control fluids into and out of the reservoir and provide instrumentation connection points and access to the well for maintenance tooling. With the christmas tree installed (either subsea or on the platform depending on the method of completion) and hooked up to the flow line, the well can be penetrated and production flow started. Penetration will be by shaped explosive charges.

In addition to the christmas tree, safety protection will be provided by a safety valve located in the tubing string, below the mud-line (sub-surface safety valve (SSSV)) to protect against loss of surface control if say the platform is destroyed by fire or collision (Fig. 6). These devices can also be arranged to close automatically as a result of excessive downhole pressure or by remote control from the platform.

MATERIAL SELECTION AND THE ENVIRONMENT

In designing well control equipment due consideration must be given to the corrosive/erosive nature of the conducted fluids and of the marine environment. Conducted fluids include drilling mud, drilling debris, hydrocarbon gases, sand, hydrocarbon liquids, stimulation chemicals (acids etc.), and seawater. Drilling muds often include sodium, calcium and potassium chlorides and where high density is required will be heavily laden with barites, which effectively increase the specific gravity of the mud to 2.1-2.3.

The mud can be water based or oil based (usually a special low-toxicity oil). Drilling muds can be highly corrosive but will be modified by the addition of corrosion inhibitors. Different types of drilling muds can have a detrimental effect on rubber sealing elements. Drilling debris (rock cuttings, clays and sand), while highly abrasive, are provided with adequate lubrication by the drilling mud and are not necessarily a problem. The hydrocarbon gases are not highly corrosive but hydrogen sulphide and carbon dioxide, if present in sufficient quantity and in the presence of moisture, are very corrosive.

Hydrogen sulphide or sour gas when present in concentrations greater than 0.34 kPa partial pressure causes hydrogen stress corrosion cracking in many ferrous materials. The hydrogen sulphide reacts with any ferrous oxide thus:

$$FeO + H_2S + \text{moisture} \rightarrow FeS + H_2$$

and the steel, being anodic to ferrous sulphide, continues to react and deep scab pitting is formed

Research has shown that some alloy steels are less susceptible to this problem than others and standards of material selection have been laid down by NACE (Standard MR-01-75) for materials to be used in sour service. The NACE standard is referenced both in the Industry Standard API Spec 6A and in the UK Department of Energy guidance on Design and Construction of Offshore Installations.[6] According to MR-01-75 special consideration needs to be given to material selection when the gas being handled is at a total pressure of 448 MPa (65 lb/in^2) or more and if the partial pressure of H_2S in the gas is greater than 0.34 kPa (0.05 lb/in^2). Useful charts are provided within the standard to facilitate working out partial pressures and show pressure ranges where sulphide stress cracking (SSC) is liable to be a problem.

One of the criteria specified by NACE in the selection of material resistant to SSC is a suitable heat treatment of the material and the controlling method selected is that of surface hardness testing. Thus NACE specifies a maximum Rockwell C Hardness (HRC) value for carbon and low alloy steels after any prescribed heat treatments. The Standard lists acceptable alloys and some unacceptable ones, giving full details of any heat treatment required and, where applicable, hardness criteria. The Standard also provides a test procedure for determining if materials are suitable. A brief summary of alloys acceptable by NACE for sour gas is shown in Table I.

Carbon dioxide forms carbonic acid in the presence of water and reacts with ferric oxide to form iron carbonate:

$$CO_2 + H_2O \rightarrow H_2CO_3$$
$$FeO + H_2CO_3 \rightarrow FeCO_3 + H_2O$$

Corrosion rates have usually been found to be higher with high wellhead pressures and the criteria used to determine the probability of unacceptable rates of corrosion is the partial pressure of CO_2 (Table II). It has been found that the top portion of tubing and surface flow lines are most susceptable to CO_2 corrosion but it is also found in christmas trees and other areas. The presence of salt water has been found to accelerate CO_2 corrosion. One source[7] lists the alloys shown in Table III as acceptable for CO_2 and O_2 service.

Sand is particularly abrasive and it is significant to note that the API Spec 6A specifically states that it is not valid for sand-bearing fluids.

In a production well sand can be fairly well controlled by downhole management but when exploration wells are being drilled sand can be present in sufficiently high quantities to cause severe erosion problems (Fig. 7). This is especially true in gas-producing wells where the sand is transported by the gas flow. With the high velocities prevelant, failure can be rapid. When a BOP has not yet been installed in the riser system, if a gas pocket is penetrated there is no alternative but to close the diverter and allow the gas flow to be vented to a safe area (circulated out). In such cases gas flow rates can be very high and associated erosion rates spectacular. It has been reported that erosion rates can sometimes be as high as 1-2 mm/min.

Well stimulation fluids (chemicals injected into a well to clean sand or mud from semi-permeable structures) are acidic in nature. For wells producing at temperatures of over 250 °F acetic acid or formic acid is used. Sulfamic and hydrofluoric acids are used to dissolve rocks. Acids are usually used in a 3% to 28% by weight concentration in water.

Table I: Selection of metals suitable for H_2S environment (NACE)

Carbon steels eg ASTM A194 Gr2HM, AISI 1010-1045, API 6A Type 1 & 4
Low alloy steels eg AISI 4130-4145, API 6A Type 2 & 3, AISM A193 GrB7M
Ferritic stainless steels eg AISI 406, 430, ASTM A268
Martensitic stainless steels eg AISI 410, 501, ASTM A217 GrCA15
Precipitation hardening stainless steels eg ASTM, Gr660, UNS 517400
Austenitic stainless steels eg AISI 300 series
Duplex stainless steels eg DIN 1.4462, 26CNDU 20.08M, NF A 320-55
Ni-Cr-Fe eg ASTM-B163, B166, B167
Ni-Cu eg ASTM - B127, B163, B564
Ni-Cr-Mb eg ASTM Gr4, B334, B626
Overlays eg Co-Cr-W alloys, Ni-Cr-B alloys, Ni-B alloys
N.B. The above examples are extracted from NACE Standard MR-01-75. Certain heat treatment restrictions may be applied. The Full Standard should be consulted

Table II: API Spec 6A retained fluid ratings

	Retained fluid classification[a]	*Characteristics*	*Constituent ranges* CO_2[b]	H_2S[c]
A	General service	Non-corrosive	<7	<0.05
B	General service, low CO_2	Moderately corrosive	7 to 30	<0.05
C	General service, high CO_2	Highly corrosive	>30	<0.05
D	Sour service	Sulphide stress cracking	<7	>0.05
E	Sour service, low CO_2	Sulphide stress cracking and moderately corrosive	7 to 30	>0.05
H	Sour service, high CO_2	Sulphide stress cracking and highly corrosive	>30	>0.05

a All retained fluid classifications include oil, water and hydrocarbon gases
b Partial pressure of carbon dioxide (in lb/in^2)
c Hydrogen sulphide partial pressure (in lb/in^2) as defined by NACE MR-01-75

Table III: Selection of metals suitable for CO_2 and O_2 environments

Carbon dioxide	*Oxygen*
Stainless steels (except free machining)	Stainless steels
Monels (Ni-Cu)	Monels
Nickel-iron (Ni-resist)	Nickel-iron
Al-bronze (Cu-Al)	Al-bronze

SEAWATER

The corrosive effect of seawater has been the subject of much research and documentation. One comprehensive source[8] identifies the differing problems related to equipment located in salt-laden air, in the splash zone and fully submerged. Additional data are given for equipment located in or near the bottom mud layer which is frequently anaerobic. Sediments can produce gases such as NH_3 and H_2S. The oxygen supply may be depleted, creating particular difficulties for the stainless steels which rely on oxygen to replenish protective corrosion films.

Seawater cannot be considered as a simple salt solution in its corrosive behaviour. Oxygen content, salinity, temperature, velocity and biological content all play important parts in the overall corrosive effect.

Different metals react in various ways depending on whether they are located in a salt-laden environment (rig deck), the splash zone (rig structure) or fully immersed (subsea wells, riser etc.). The martensitic stainless steel AISI 410 (En 56A) for example shows good corrosion resistance in a salt-laden environment but suffers from deep pitting and crevice attack when submerged, unprotected, in seawater.[8]

High chloride content in well fluids or injection fluids can promote stress corrosion, noticeably in some austenitic stainless and other high alloy steels. Metallurgical considerations have long played an important role in corrosion investigation as attested by the classical intergranular attack of (some) austenitic stainless steels due to precipitation of chromium carbides resulting in an homogeneous condition at the grain boundaries, facilitating dissolution by corrosive attack.[9] This can be obviated by limiting carbon content to 0.03% in the case of 316 stainless[10] (the 316 L Grade) or by solution heat treating in water (or air). Some of the new duplex stainless steels have shown good resistance to crevice attack in seawater, have greater tensile strength and toughness than the ferritics and at least one (DIN 1.4462) is listed by NACE as suitable for direct exposure to sour environment.

Materials must not only be selected for their suitability to exist in the above environments but they must also have various mechanical and physical qualities such as suitable strength, ductility, notch toughness, hardness and where applicable weldability. In many respects the manufacturer is guided by the requirements of the API standards. API Spec 6A lays down chemical composition and tensile strength for pressure-retaining and load-bearing parts and in some cases notch toughness (Tables IV and V). NACE MR-01-75 dictates maximum hardness values for sour gas service.

To meet the conflicting requirements of these various factors when corrosion is a serious problem most manufacturers have turned to cladding or overlay procedures whereby internal parts requiring specific protection are clad or overlaid with expensive corrosion resistant alloys. Alternatively internal cylindrical parts may be sleeved. Externally protection can be afforded by suitable coating and cathodic protection although some alloys require such a high density current to promote passivation that there is a danger of hydrogen bubbling and consequently further coating breakdown.[8]

CLADDING

Cladding is normally used for internal parts exposed to corrosive fluids and sealing ring grooves. Valve seats may be stellited.

The materials most used for cladding sealing ring grooves are 316 stainless steel and Inconel 625 (the latter because of its excellent resistance to crevice corrosion). According to Koshy[11] the varying sections and small internal diameters of equipment used in the petrochemical industry make weld cladding the preferred procedure although HIP cladding is also used by some manufacturers.

NACE MR-01-75 does allow overlays by spray metallizing processes provided the substrate does not exceed the lower critical temperature during application or, in cases where the lower critical temperature is exceeded, by subsequent heat treatment or thermal stress relieving (base metal must return to a hardness value of HRC 22). The standard also permits the use of ceramic overlays and of cobalt-bonded carbides. Elsewhere it is suggested that certain cobalt-bonded carbides do not perform particularly well in seawater because of leaching of the cobalt and subsequent loss of strength and performance.[12] On the other hand, electroplating is not permitted under this standard.

Another process for depositing corrosion-resistant alloys internally is known as hot isostatic pressing (HIP). This process is used to deposit Inconel 625 in powder form onto the internal bores of low alloy steel forgings and requires a pressure of about 1000 bar at temperatures of up to 1100 °C.[13]

CODES AND STANDARDS

Historically the design and manufacture of well control equipment, in common with other oil field processes, has been governed by Standards and Recommended Practices compiled by the American Petroleum Institute. In addition the major oil companies have laid down supplementary 'in-house'

Table IV: API Spec 6A property requirements for body, bonnet and flange material (PSL 1-4)

API material designation	*0.2% yield strength, minimum* (lb/in^2)	*Tensile strength, minimum* (lb/in^2)	*Elongation in 2 in, minimum* (%)	*Reduction in area, minimum* (%)
36 K	36 000	70 000	22	No requirement
45 K	45 000	70 000	19	32
60 K	60 000	85 000	18	35
75 K	75 000	95 000	18	35

Table V: API Spec 6A steel composition limits for body, bonnet and flange material (wt %) (PSL 1-4)

Alloying elements	*Carbon and low alloy steels composition limits*	*Martensitic stainless steels composition limits*[a]	*45K material for weld neck flanges composition limits*[b]
Carbon	0.45 max	0.15 max	0.35 max
Manganese	1.80 max	1.00 max	1.05 max
Silicon	1.00 max	1.50 max	1.35 max
Phosphorus[c]			0.05 max
Sulphur			0.05 max
Nickel	1.00 max	4.50 max	NA
Chromium	2.75 max	11.0-14.0	NA
Molybdenum	1.50 max	1.00 max	NA
Vanadium	0.30 max	NA	NA

a Non-martensitic alloy systems are not required to conform to this table
b For each reduction of 0.01% below the specified carbon maximum (0.35%) an increase of 0.06% manganese above the specified maximum (1.05%) will be permitted up to a maximum of 1.35%
c Phosphorus and sulphur concentration limitations (wt%) (PSL 1-4)

	PSL 1-2	PSL 3-4
Phosphorus	0.040 max	0.025 max
Sulphur	0.040 max	0.025 max

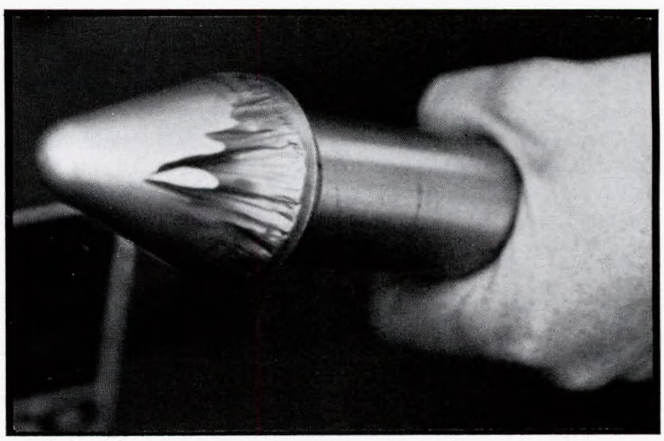


FIG. 7: Valve plug eroded after short exposure to sand-bearing fluids

standards imposed on manufacturers through contractural agreements and purchasing procedures. Over and above these Industry Standards, national legislation plays a significant role either by insisting that the Industry Standards are applied or by providing additional rules and standards based on particular local need and/or on the latest available state of the art information.

Within the UK sector of the North Sea offshore certification activities are governed by an Act of Parliament — the Mineral Workings (Offshore Installations) Act 1971. Similar arrangements for pipelines come under the Petroleum and Submarine Pipelines Act 1975. The primary legislative Statutory Instrument by which government defines regulations for the design and maintenance of equipment used for the exploitation of minerals (with the exception of dredgers) is the Offshore Installations (Construction and Survey) Regulations 1974 (SI 1974/289).

The Secretary of State for Energy is responsible for the enforcement of these two Acts and he discharges this through the Department of Energy Petroleum Engineering Division Operations and Safety Branch and the Pipelines Inspectorate. Matters dealt with by the Pipelines Inspectorate are outside the scope of this paper.

To comply with SI 289 an offshore installation concerned with exploration for, exploitation of, or associated with the conveyance by pipeline of petroleum products within the territorial sea adjacent to the UK requires a Certificate of Fitness. The procedure by which a Certificate of Fitness is obtained and maintained is broadly known as Certification and the Secretary of State has appointed six Certifying Authorities, of which Bureau Veritas is one, to issue such certificates. A Certificate of Fitness is issued after a design appraisal and after surveyors appointed by a Certifying Authority have surveyed and assessed an installation and concluded that it is fit for purpose.

To aid designers, owners, manufacturers and Certifying Authorities to work together to ensure that an installation is fit for purpose, the Department of Energy, with the aid of representatives from the Certifying Authorities and industry, has published Guidance which outlines procedures and standards by which an installation may be assessed in areas where there is doubt or conflict of opinion.

As a matter of policy well control equipment was considered during the first decade of certification to be part of the well and not part of an installation. A production installation was considered to terminate at the outlet from the christmas tree (wing valve) and a mobile drilling rig (installation) to be a machine to drill through well control equipment and receive flow from a well. In a January 1983 amendment to Part 1, Section 1 of the Department of Energy Guidance Notes the Department of Energy changed the boundary of the certifiable installation to include the christmas tree and BOP. On 10 January 1983 the Department of Energy clarified its policy on the extension of SI 289 to include BOPs and christmas trees (ie well control equipment) and particularly drew attention to the way in which existing well control equipment might be dealt with and requiring all such equipment to be brought into the scheme of certification as soon as possible but not later than 1 January 1985.

This policy statement was felt by industry to require some guidance, particularly bearing in mind the way in which industry moves such equipment from one installation to another, and to allow for the acceptance of significant stockpiles of equipment held by manufacturers produced under the previous regime. Following lengthy discussions a Memorandum of Understanding (MOU) between the Department of Energy, UKOOA, IADC and BROA on the subject of Certification of Well Control Equipment was released in April 1985 (see Appendix 2).

It was also considered that the nature of the equipment justified a new Chapter in the Department of Energy Guidance Notes. This became Part V 'Well Control Equipment' and a large portion of the proposed section dealing with well control while drilling was published in April 1985 under Amendment No. 2.

The section was expanded with the publication of Amendment No. 6 in January 1986 to include production well control equipment. Additional work remains to be done on marine risers and more particularly on systems. Several recognised standards are referenced in Part V of the GN and are shown in Appendix 3.

INSTALLATION BOUNDARY

Part V of the Guidance Notes has been written within the general context defined by Part 1 'Principles of Certification and Surveys and Inspections'. Parts of Part IV 'Mechanical Equipment' and Part VI 'Emergency Shut Down Systems' are also relevent to well control equipment.

The broad outline of the boundaries of an installation can be found in Part 1, Section 1 of the Department of Energy Guidance Note as amended in January 1983, thus:

> 1.3.1.(a) Production Installations. Any part of the equipment including the christmas tree but not including the casing heads, conductor or casings, should be treated as part of the installation. Where principal well control equipment is situated on the seabed the christmas tree, its control system and actuators, subsea manifolds, any device to protect against physical damage and any other equipment will form part of the installation. The casing heads, conductor, casings and well re-entry guide equipment should not be treated as part of the installation. The seabed connection for a disconnectable riser, eg for a floating production installation or any similarly placed manifold is part of the installation.
>
> 1.3.1.(b) Drilling Installations. Any part of the equipment from the casing head, including the marine riser and BOP but excluding the casing head, conductor, casings and well re-entry equipment should be treated as part of the installation.

In 1.3.2. of the Department of Energy Guidance Note it is explained that casing heads, conductor pipes and casings are governed by the licence conditions contained in the Petroleum and Submarine Pipelines Act 1975 or the Petroleum (Production) Regulations 1976 and subsequent licencing regulations, whichever is relevant. The application of these regulations to such devices is outside the scope of this paper, assessment of the well design and downhole equipment being carried out directly by the Department of Energy Petroleum Engineering Division.

Because of the variety of types of christmas trees and wellhead configurations, cases have arisen where the above boundary definitions have given rise to confusion. In such cases the interface should be clearly agreed by the Certifying Authority and the owner. Where agreement cannot be reached then the Department of Energy Petroleum Engineering Division should be consulted by both parties. The boundary between installation and pipeline has historically been agreed by discussion between the owner and the Department of Energy Pipelines Inspectorate.

In the introduction to Part V of the Guidance Note a short list is given of examples of equipment to which the section applies. Manufacturers and owners do need to bear in mind however that, regardless of whether equipment is mentioned in Part V of the Guidance Note, if the equipment is considered to be part of the installation it will come under the scrutiny of the Certifying Authority; if it constitutes part of the pipeline then it will come under the scrutiny of the Pipeline Inspectorate. The Pipeline Inspectorate has, on occasion, accepted survey reports of the appointed Certifying Authorities in lieu of its own inspection providing that prior agreement has been reached.

CERTIFICATION REQUIREMENTS

Although a full reading of SI 289 is essential for all directly concerned in the Certification of Offshore Installations, a reasonable summary of the requirements of certification with regard to equipment is that the Certifying Authority must be satisfied that:

1. The design has taken account of established codes and practices.
2. An independent check has been made on major design calculations.
3. The equipment has undergone a satisfactory survey by a surveyor appointed by the Certifying Authority before being put into use and subsequently at regular intervals during service.

Elsewhere[14] it has been pointed out that in discharging its duties a Certifying Authority is not expected to scrutinize every detail of an installation. The Certifying Authority is expected to be selective in items given close attention. Close attention will be given to those items essential to the integrity and safety of an installation.

From regular application of SI 289 and common use of the Guidance Notes it has become recognised that the primary role of the Certifying Authority is that of technical audit. This theme has been developed elsewhere[15] but it must be stated that in this context it is important to note that the Certifying Authority applies professional judgement and does not just scrutinise paper. Its responsibilities to ensure that a survey of the installation is made clearly require an intimate examination of major aspects of hardware by appointed surveyors.

Equally however, it has been made clear by the UK Government that the application of modern quality assurance systems is to be encouraged.[16]

This is further developed in Part V of the Guidance Note which makes clear reference to the requirement for well control equipment manufacturers to employ quality assurance systems equivalent to BS 5750.[17]

SCOPE OF PART V OF THE GUIDANCE NOTES

Part V of the Department of Energy Guidance Note indicates:

- list of recommended standards
- requirements for a defined service environment specification
- recommendation to mark equipment to show environmental limitations
- design parameters
- material selection criteria for major load-bearing and pressure-containing parts, covering ultimate tensile and yield strength, hardness, weldability, corrosion resistance (including sour service), and notch toughness (it notes that API Spec 6A toughness requirements are not adequate)
- material test requirements
- storage of elastomers
- limitations of ring joint gaskets
- inspection during manufacture
- quality assurance standards
- material documentation including material source report comprising chemical and mechanical properties for each heat, heat treatment temperatures and associated periods, Charpy temperatures and impact values, hardness test readings, and manufacturing processes comprising welding, post-weld heat treatment, NDE results, hardness test results, hydrostatic pressure test, and dimensional check results
- performance testing
- repair welding controls
- in-service survey requirements

MEMORANDUM OF UNDERSTANDING

Although this document was drawn up primarily to draw attention to an acceptable procedure for the survey of well control equipment it has a deeper significance in so far as it defines some of the survey procedures which could, and have been, applied to other portable equipment in the body of the main Guidance Note.[14] In short the MOU shows how items of equipment constituting part of an installation can be demonstrated as fit for purpose by:

1. An independent assessment of the design justification.
2. Acknowledgement that quality procedures are an inherent part of design and must be taken into account in its assessment.
3. Inspection during manufacture by a competent body independent of the manufacturing function.
4. Full cognisance of the above by the Certifying Authority when surveying the equipment for deployment within an installation.

To effect the above the MOU outlines the following procedure:

1. A Specification for Manufacture is drawn up by a manufacturer, designer or owner.
2. A documented acceptance of the Specification for Manufacture is made by an independent competent body.
3. The Specification for Manufacture and the assembly is assessed by the Certification Authority.
4. Assessment of individual manufactured items by an independent competent body which issues a Certificate of Conformity.
5. Documents to facilitate in-service deployment and movement between locations and Certifying Authorities are issued.

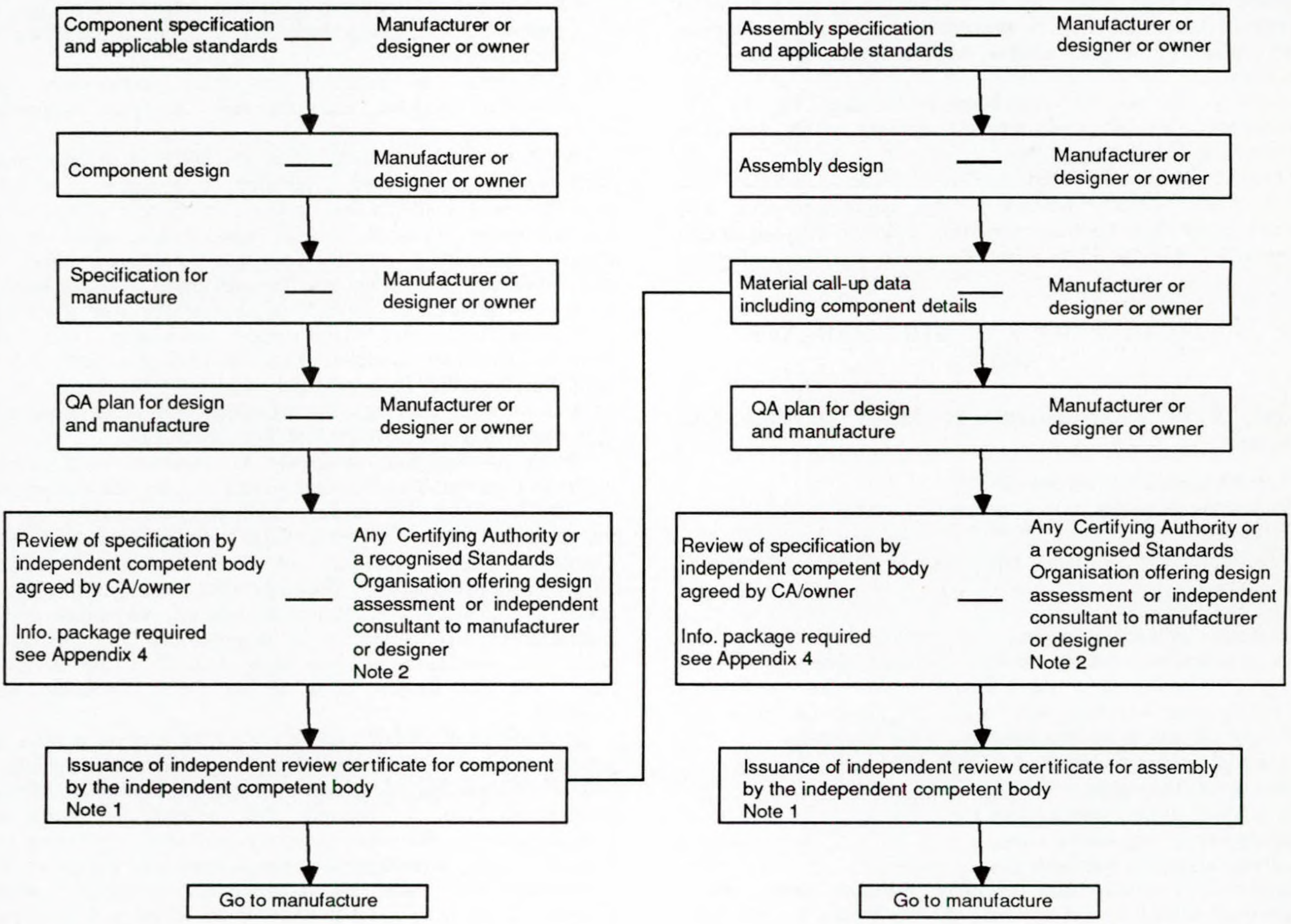
While the procedure outlined in the MOU is of great value when applied to standard assemblies it is found in practice that the more complex installations, especially subsea trees, are invariably 'one-off' designs and design detail is not always available as a complete package prior to commencement of manufacture. In such cases it is not easy to apply the procedure outlined in the MOU and alternative procedures can be considered, providing that the manufacturer/owner complies with SI 1974 No. 289 and in particular Part VII, Para la: 'such work will be carried out in accordance with drawings, specifications and other documents approved or recognised by the Certifying Authority'.

When a Certifying Authority is assessing well control equipment assemblies for deployment on an installation (or in the case of a subsea facility, conceivably as an installation) the accompanying Independent Review Certificates and Certificates of Conformity must indicate which main constructional drawings have been generated as a result of calculations justifying the design. Moreover design justification must clearly have demonstrated that all loads have been considered as required by Part V of the Guidance Note, and not simply loads arising from containing well pressure.

In applying the MOU and Part V of the Guidance Note the procedure followed by Bureau Veritas is summarised in Figs 8 and 9. Within Fig. 8 the two footnotes are worth further elaboration. Note 1 indicates that when components are manufactured by the same company and under the same QA controls as the assembly, separate independent design review certificates will not be compulsory. Complex subsea christmas trees may have in the region of seventy or eighty sub-assemblies — spool pieces, elbows, crosses, actuators, connectors etc. Some components will in fact be outside the scrutiny of the Certifying Authority although in terms of the order they will be part of the tree. In such cases it is clearly burdensome to the manufacturer and independent competent body to produce packages and certificates for each component and it should suffice to provide a single certificate for each major assembly.

Table VI: A Comparison of BS 5750 and API Q1

BS 5750		API Q1		Comment
4.1	Documented system	3.2	Organisation	5750 does not specify need for QA manual, API Q1 does
4.2	Organisation – responsibilty	3.2.1.		5750 requires management rep with responsibility, API Q1 does not
	Identify, evaluate and resolve problems			
	Management and purchaser's representative			5750 allows specifically for puchaser's rep, API Q1 does not
4.3	Review – periodic Internal audit	3.4.2/3.1.8	Quality program	
4.4.	Planning – to be documented			API Q1 does not provide for planning in the sense of 5750
4.5	Work instructions	3.7/3.8	Process control	
4.6	Records	3.20	Quality records	API Q1 does not provide for availablility of records to customer
4.7	Corrective action	3.19	Corrective action	API Q1 is not as explicit as 5750
4.8	Design control, 11 sub-headings	3.6	Design control	API Q1 requires an independentcheck, 5750 does not
4.9	Documentation & change control , 5 sub-headings	3.6	Design control	
4.10	Control of insp., meas. & test equipment	3.14	Measuring & test equipment	
4.11	Control of purchased material services	3.9	Proc. control of critical items	5750 includes all purchased materials, API Q1 only requires critical items
4.12	Manuf. control – special processes	3.8.2.	Process control	
4.13	Purchaser supplied material			API Q1 does not cover
4.14	Completed item insp. & test	3.16	Acceptance status	API Q1 does not specify final insp. but qualifies in 3.16
4.15	Sampling procedures			
4.16	Control of non-confirming material	3.17	Non-conformance	
4.17	Indication of inspection status	3.16	Acceptance status	
4.18	Protection & pres. of product quality	3.15	Handling, storage & shipping	
4.19	Training	3.3	Quality of personnel	API Q1 only deals with QA personnel



Note 1: When coponents are manufactured by the same company and under the same QA controls as the assembly, separate design review certificates will not be compulsory

Note 2: Under certain circumstances a truly independent department within a manufacturing or design company may be accepted

FIG. 8: Flow chart depicting certification procedure related to component and assembly design

With regard to Note 2, some manufacturers and their clients have indicated a desire to use the QA department of the manufacturer to act as the independent competent body especially during the manufacturing stage. This may be acceptable but the responsibilities of the QA department must be clearly recognised. The Guidance Note and the MOU already impose a quality system equivalent to BS 5750 on the manufacturers. The independent competent body needs to be sure that all aspects of specification for manufacture have been fulfilled and where components or material are being provided from a sub-contractor additional intervention by the QA department, acting as independent competent body, seems necessary over and above simply demonstrating that the supplier has been vendor-assessed.

While this additional load may be logistically difficult for the manufacturer, acting as an independent body does free the manufacturer from delays caused by waiting for outside inspection to attend for certain stage inspections. It also frees the Certifying Authority's surveyor from attending at nominated hold points thus giving the Certifying Authority more freedom to inspect (audit) on a random basis and pin-point possible ommissions or weak internal inspecting procedures.

Under the more traditional system it was not unusual for a hydrostatic body test to be witnessed by several inpectors, all of whom might for example have missed a poorly finished internal passageway which could have given rise to early in-service failure.

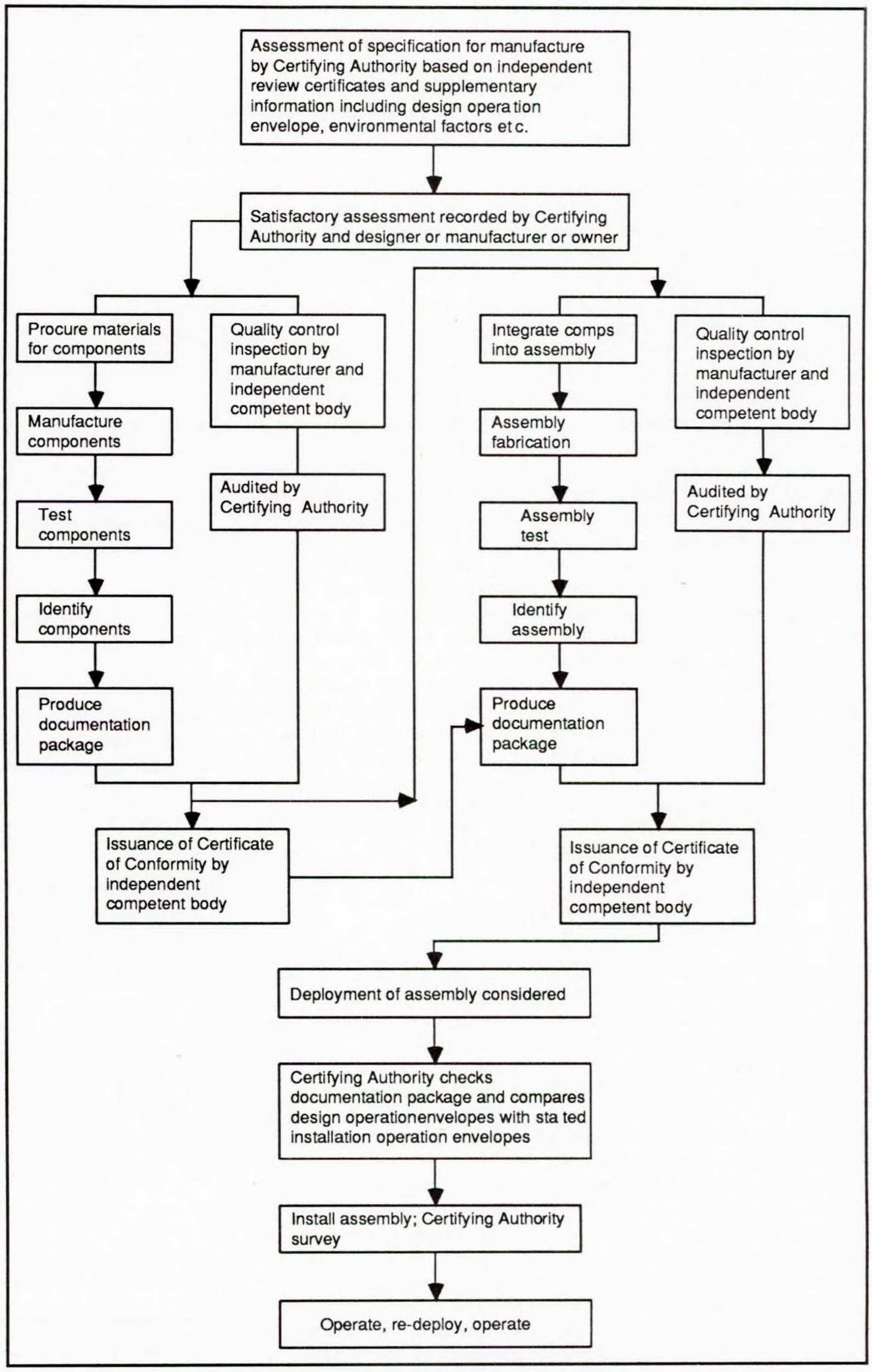


FIG. 9: Flow chart depicting certification procedure related to component and assembly manufacture

CHANGES IN API STANDARDS

As well as the introduction of UK legislation well control manufacturers are also having to take into account recent changes in API requirements. Of these the most significant is the requirement for licencees to meet stringent new quality procedures. All manufacturers seeking to retain or apply for API Monogram licences must have in force a quality programme conforming with API Spec Ql. This new specification was published in January 1985 but, recognising the monumental task of auditing existing API licencees, a staggered period of introduction was suggested.

The procedure by which API Ql is implemented, and its range of topics, is not dissimilar to that used in the UK in registering as a company applying BS 5750. A general comparison of these two standards is given in Table VI but full consultation of both standards is advised.

Prior to the introduction of the fifteenth edition of API Spec 6A in April 1986 previous editions had dealt with BOPs, christmas trees and wellheads. The new API Spec 6A only addresses wellhead and christmas tree equipment leaving drill-through equipment such as BOPs to the new Spec 16A.

The 15th edition of Spec 6A is much more of a manufacturing specification than previous editions. It lays down allowable design stresses and specifies quality control procedures and levels of traceability absent from previous editions but it has remained a disappointment to bodies implementing UK and Norwegian legislation principally in its failure to call for notch toughness testing except for material operating at temperatures below –29 °C (–20 °F) and its shortfall in manufacturing records relative to Part V of the Guidance Note for most equipment.

The 15th edition of API Spec 6A graded equipment into five product specification levels (PSLs). The lowest range was PSL0 which defined equipment designed to the previous editions of Spec 6A while the highest, PSL4, applies to equipment with a rated working pressure of 10 000 lb/in^2 and upwards when used in close proximity. The PSL0 range was subsequently discontinued. The Spec 6A definition of close proximity includes wells located in state or federal waters.

Using this definition of close proximity, selection of equipment from the 15th edition of API Spec 6A for use in the North Sea would require PSL1 for primary parts with rated working pressures of 5000 lb/in^2 and above and PSL3 for working pressures of 10 000 lb/in^2 and above, assuming there were no H_2S difficulties anticipated in the well. It is also significant that Appendix A of Spec 6A (purchasing guidelines) gives recommended specification levels for primary parts defined as tubing head, tubing hanger, tubing head adapter, and lower master valve and says that the specification level for secondary parts may be the same or less than the level for the primary parts.

With regard to quality control it is interesting to note that traceability is only required for PSL3 and PSL4, and PSL3 does not make impact testing of welds mandatory except for low temperature service. The 15 min hold period for hydrostatic body tests required by the Guidance Note is also not required until PSL3 and the heat treatment charts and dimensional records required by the Guidance Note are not required until PSL4. On the other hand while the Guidance Note does not exclude welding, PSL4 excludes all welding except for overlay work.

Having established which PSL should be applied Spec 6A then requires temperature and retained fluid classifications to be specified and defines four material types.

NOTCH TOUGHNESS

In some respects the choice of a single minimum Charpy value aimed at all conceivable applications in the North Sea would simplify the specification of mechanical tests but the resulting figure might well then exclude the use of some materials with other equally desirable qualities. Some correlation has been found between K_{IC} values and Charpy values[18] and valuable work has been done to relate the results of these studies to the probability of rupture occuring from linear faults of a predetermined size.[19]

Based on this work, and in order to consider fully the effects of increased thickness, stress level and design temperature, Bureau Veritas uses a two-stage process in its Guidance Note on Well Control Equipment[20] to assess whether a manufacturer's proposed Charpy values are acceptable.

The first stage derives, from Table VII, an 'intermediate' temperature TI °C based only on wall thickness and the design temperature TD °C. This design temperature is taken as 0 °C for equipment installed permanently on the seabed or below sea level. For equipment operating above sea level TD is taken as the mean air temperature of the coldest day anticipated in the operating area. Having established TI the thoerectical test temperature TA °C is then derived from Table VIII, which takes into account the stress level. In Table VIII Y is the material yield stress and S is the maximum value of actual stress in the component under the most severe load combination liable to be encountered during service.

For a component with a design temperature of –5 °C, wall thickness 35 mm and with a stress ratio of 0.61:

$$\text{theoretical test temperature TA °C} = (\text{TD} - 15) = -5 - 15 + 20 = 0\ \text{°C}$$

The derived test temperature given above is basically applicable to forgings without welding. If welds are performed (either for construction or repair purposes), the energy values quoted at the test temperature should be achieved after stress relieving heat treatment in the parent and filler metal and in the heat affected zone. The temperature at which the tests are performed should be lower or equal to the theoretical test temperature (TA) as computed above but must never be above the design temperature (TD) except in those cases where the material transition temperature can be clearly defined.

These figures relate to the acceptable average energy value of 28 J from three 10 x 10 mm specimens and an individual minimum value of 19 J and generally from samples taken in the longitudinal direction.

DRILL THROUGH EQUIPMENT

As in the case of wellheads covered in API Spec 6A the new API Spec 16A also provides far more detailed specifications for BOPs and related equipment than that provided in the 14th edition of Spec 6A which also covered drill through equipment. Again, however, notch toughness requirements would not at the moment be considered adequate in all cases.

SUBSEA PRODUCTION SYSTEMS

A new API recommended practice covering the design and operation of subsea production systems, RP 17A, was introduced late in 1986. While this provides valuable background descriptions it produces little in the way of manufacturing guidance.

FURTHER ACTIVITIES

Much work requires to be done in both API and the GN to define equipment suitable for sandy service. Following the failure of the diverter system on *West Vanguard* in October 1985, additional legislation and guidance can be expected on diverter systems.

The question of fire-safe trees, already a requirement in the Norwegian sector, may yet come under further consideration by the Department of Energy for equipment deployed in the UK sector.

At the moment Part V of the Guidance Note only refers to the use of fire-safe trees as one of several options to meet the overall fire protection requirements of SI 1976/611. While the trend towards subsea installations would negate any value

Table VII: Intermediate temperatures based on wall thickness

Thickness (mm)	*Temperature, TI* (°C)
less than 30	TD – 5
31 to 40	TD – 15
41 to 50	TD – 25
51 to 100	TD – 30
101 and over	TD – 40

Table VIII: Theoretical test temperature

Stress ratio (*S/Y*)	*Theoretical test temperature, TA* (°C)
0.66 to 0.60	TI + 20
0.59 to 0.50	TI + 30
0.49 to 0.40	TI + 40
0.39 to 0.35	TI + 50
less than 0.35	TI + 60

in developing this aspect of design, it can be assumed that platform installations will continue to be installed and despite the increased fire safety claimed by manufacturers of solid block trees it is highly likely that the question of fire-safe trees will be re-opened by the Department of Energy.

The section of Part V relating to risers needs some development although providing that API Spec 16B (currently being drafted) proves adequate then it will suffice to add this to the referenced standards.

CONCLUSIONS

The development of well control equipment in the marine environment and in areas where shipping activity is high and the ecological and safety aspects of a massive oil leak are sensitive has inevitably led to the introduction of more stringent manufacturing standards and legislative proceedings. This is only correct.

It is important however that industry, already facing difficulties caused by falling oil prices, is not burdened with unnecessarily diverse quality procedures and specifications. It is essential therefore that API, Industry and the Certifying Authorities work together to develop realistic standards which are relevant to the environmental demands and operational needs of areas like the North Sea.

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APPENDIX 1

Definitions

Part V of the Department of Energy Guidance Notes uses definitions contained in API 6A and RP 53. The Memorandum of Understanding (MOU) on well control equipment has within its attachment a further list of definitions. Yet more definitions appear in SI 289. Listed below are those related definitions together with their reference sources. Other definitions considered useful are also included and their source indicated.

Assembly: the complete well control equipment (eg a christmas tree, a BOP stack etc. which are made up from a number of components) (MOU).

Blowout Preventer (BOP): a unit attached to the casing or to a unit of wellhead equipment installed on the casing for the purpose of controlling pressures in the annular spaces between the casing and an inner string of pipe during drilling and completion operation (API 6A) or a device attached to the casing head that allows the well to be sealed to confine the well fluids in the well bore (API RP 53).

Certificate of Conformity: a document signed by a qualified party affirming that, at the time of assessment, the product or service met the stated requirements (MOU sub ref BS 4778). Note that in terms of the MOU a qualified party can only mean an independent competent body.

Choke: a device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas (API RP 53).

Choke Line Valve: the valve(s) connected to and a part of the blowout preventer stack that controls the flow to the choke manifold (API RP 53).

Christmas Tree: an assembly of valves and fittings used for production control and including all equipment down to the tubing head top connection (API 6A).

Clamp Connection: a pressure sealing device used to join two items without using conventional bolted flange joints. The two items to be sealed are prepared with clamp hubs. These hubs are held together by a clamp containing two to four bolts (API RP 53).

Competent Body: a Certifying Authority or another organisation agreed to be competent by the Certifying Authority and owner of an installation (MOU).

Components: the individual parts which go to make up a complete assembly of well control equipment (eg a valve, a BOP, etc.) (MOU).

Cross: a pressure containing fitting with a minimum of four openings. Usually all four openings are at 90° to one another. Crosses may be threaded or flanged (API 6A).

Diverter: a device attached to the wellhead or marine riser to close that vertical access and direct any flow into a line away from the rig. Diverters differ from blowout preventers in that flow is not stopped but rather the flow path is redirected away from the rig (API RP 53).

Drilling Spool: a connection component with ends either flanged or hubbed. It must have an internal diameter at least equal to the bore of the blowout preventer and can have smaller side outlets for connecting auxiliary lines (API RP 53).

Independent Reveiw Certificate: a document (or documents) which will describe the scope of the independent review of the specification for manufacture in a form acceptable to the Certifying Authorities (MOU).

Kill Line: a high-pressure line between the mud or kill pumps and some point below a blowout preventer. This line allows fluids to be pumped into the well or annulus with the blowout preventer closed (API RP 53).

Marine Risers: those used for the purposes of drilling and workover (Department of Energy Guidance Note).

Operating Envelope: the range of individual operating conditions for which the component or assembly is suitable and which also defines acceptable boundaries for combinations of operating conditions within the acceptable ranges of individual conditions/components, eg the combination of offset, water depth and mud weight for a marine drilling riser (MOU).

Operating Envelope – Design: the operating envelope for which a component or assembly has been designed.

Operating Envelope – Installation: the operating envelope stated by an owner, operator or designer to be the estimated worst conditions which a particular installation is likely to experience during its remaining operational life.

Quality Plan: a document derived from the quality programme (extended if necessary) setting out the specific quality practices, resources and activities relevant to a particular contract or project (MOU sub ref BS 4778).

Quality Programme: a documented set of activities, resources and events serving to implement the quality system of an organisation (MOU sub ref BS 4778).

Specification for Manufacture: a comprehensive document specifying the requirements necessary to manufacture the well control equipment including the design specification, manufacturing and quality plan (MOU).

Surface Safety Valve: an automatic wellhead safety valve which will close upon loss of power supply (API 14B).

Survey: an examination conducted by a surveyor of an offshore installation or any part thereof or any equipment, including the scrutiny of any document relevent thereto, and the conducting of any tests which a surveyor considers necessary in order to assess the integrity or safety of any item and whether any requirements of the Regulations (viz. SI 289) have been complied with (SI 289).

Surveyor: a surveyor appointed by a Certifying Authority (SI 289)

Swab Valve: the uppermost valve on the vertical bore of the christmas tree above the flowline outlet (API 6A).

Wellhead: a composite of equipment used at the surface to maintain control of the well. Included in wellhead equipment are casing heads (lowermost and intermediate), tubing heads, christmas tree equipment with valves and fittings, casing and tubing hangers and associated equipment (RP 14B).

APPENDIX 2

Memorandum of Understanding between the Department of Energy, UKOOA, IADC and BROA

The objective of this Memorandum of Understanding is to amplify the Department of Energy policy statement on the application of the construction and survey regulations to well control equipment (PEA 14/584/4 of 10 February 1983) especially to item 10 which is quoted below:

> 'All equipment to which this policy applies should be brought into the scheme of certification as soon as is reasonably practicable at the discretion of the Certifying Authority but not later than 1 January 1985. CAs will be expected to use initially the standards and codes of practice which are in general use in the industry as they have done with other equipment as the criterion for assessment of Installation equipment. Exisiting Installations will be reviewed against the standards and codes of practice etc. prevailing at the time the equipment was purchased unless these can be shown to be unsuitable. Retrospective application of higher standards should only be considered where there is a history of failure or other evidence of serious deterioration. The higher standards will apply to new equipment'.

It is now agreed that the following guidance shall be given in addition to item 10 of the policy statement.

1. Well control equipment manufactured after 1 January 1985 should be addressed by the Certifying Authorities in the manner outlined in the attachment to this Memorandum in conjunction with the current Guidance Notes on the Design and Construction of Offshore Installations.
2. Well control equipment in use or manufactured prior to 1 January 1985 was manufactured according to the standards and codes used by the offshore oil industry at the time. Historical experience may largely determine the acceptability of this equipment, since sufficient documentation may not be available to identify and verify all the codes and standards which were used in its design and fabrication.
   The equipment should be deemed fit for purpose unless reference to any manufacturer's 'bulletins' or 'official' defect records or other information indicates a history of failure of this or similar equipment and subsequent inspection, examination or test of the unit in question confirms the presence of these problems. The reference to higher standards quoted in item 10 of the Department of Energy Policy Document should be interpreted as revised standards.
   For the purpose of assessment the owner should submit to the Certifying Authority as far as is reasonably practicable a list of the available codes and standards to which the equipment was designed, manufactured and tested, together with any other relevant information to assure the Certifying Authority that the equipment is fit for its intended purpose.
3. The extension of the existing Certificate of Fitness for an Installation to include well control systems by 1 January 1985 is in some ways similar to the procedure for introducing new equipment (see SI 289 Regulations 7(3) and 8(3)) except that the equipment is already installed and functioning. When a Certifying Authority reviews the information submitted by the owner and determines the scope for the additional survey of the well control system, consideration should be given to the following:
   (a) the length of time since the equipment was opened up for internal examination.
   (b) the condition of the equipment and recent maintenance records.
   (c) additional surveys, if required, are to be carried out at a time mutually agreed between the owner and the CA.
   (d) full dismantling to the extent associated with a major overhaul by the manufacturer will not normally be required.
   (e) the role of pressure testing as an assessment of the integrity of equipment must be taken into account.
4. When a Certifying Authority assesses well control equipment in connection with Certificates of Fitness a Certificate of Conformity (defined in para 2.7 of the attachment) issed by the Certifying Authority or another independent competent body would normally be accepted by another Certifying Authority unless that Certifying Authority has evidence that the equipment does not conform to the Certificate of Conformity or that there is some discrepency in the Certificate itself.

Attachment to Memorandum of Understanding between the Department of Energy, UKOOA, IADC and BROA

Guidance on the certification of well control equipment

1.0 INTRODUCTION
This paper amplifies the Memorandum of Understanding and describes in general terms the method by which the components and assemblies of well control equipment on offshore installations may be assessed by a Certifying Authority and/or other independent competent body as part of the Certification required by SI 289 The Offshore Installations (Construction and Survey) Regulations 1974.

2.0 DEFINITIONS
For the purpose of this paper the following definitions apply:

2.1 Assembly
The complete well control equipment (eg a christmas tree, a BOP stack etc. which are made up from a number of components).

2.2 Component
The individual parts which go to make up a complete assembly of well control equipment (eg a valve, a BOP, etc.).

2.3 Specification for Manufacture
A document specifying the requirements necessary to manufacture the well control equipment including the design specification, manufacturing procedures, and quality plan.

2.4 Operating Envelope
This is a definition of the range of individual operating conditions for which the component or assembly is suitable and which also defines acceptable boundaries for combinations of operating conditions within the acceptable ranges of individual conditions (eg the combination of offset, water depth and mud weight for a marine drilling riser).

2.5 Quality Programme (BS 4778)
A documented set of activities, resources and events serving to implement the quality system of an organisation.

2.6 Quality Plan (BS 4778)
A document derived from the quality programme (extended if necessary) setting out the specific quality practices, resources and activities relevant to a particular contract or project.

2.7 Certificate of Conformity (BS 4778)
A document signed by a qualified party affirming that, at the time of asessment, the product or service met the stated requirements.

2.8 Independent Review Certificate
A document (or documents) which will describe the scope and results of the Independent Review of the Specification for Manufacture in a form agreed to and accepted by the Certifying Authorities.

2.9 Competent Body

Either a Certifying Authority or another organisation agreed to be competent by the Certifying Authority and owner of an Installation.

3.0 OBJECTIVES

To establish a scheme for the assessment of well control equipment for the purposes of issue renewal or maintenance of Certificates of Fitness issued in accordance with SI 289.

To ensure that the scheme is practical and manageable and reflects good industry practice in line with procurement and deployment of other proprietary and manufactured items.

The pricipal features of the scheme are:

(a) The establishment and presentation of a 'Specification for Manufacturer' covering the operating envelope, specification, design, manufacture and quality control.

(b) A review of the 'Specification for Manufacture' by a competent body and the issue of an Independent Review Certificate.

(c) Assessment of the 'Specification for Manufacture' and of the assembly by the Certifying Authority.

(d) Assessement of individual manufactured items by a competent body, who would issue a certificate of conformity.

(e) In-service deployment and movement between locations and Certifying Authorities.

These points are amplified in the next sections.

4.0 ASSESSMENT SCHEME

Assessment of well control equipment for the issue renewal or maintenance of a Certificate of Fitness for an installation should be effected by a procedure which assures the Certifying Authority that the equipment conforms with an assessed specification for manufacture.

A means for assuring the Certifying Authority that the equipment is fit for purpose is the submission of a certificate of conformity to an approved 'Specification for Manufacture'.

A 'Specification for Manufacture' should be developed by a manufacturer, designer or owner. This 'Specification for Manufacture' should be reviewed by a competent body, who will issue an Independent Review Certificate. This Independent Review Certificate along with the supplementary information necessary to reach the appropriate standards should be made available to the Certifying Authority. The Certifying Authority should assess the 'Specification for Manufacture' for the assembly, a record of which would be maintained by the Certifying Authority and by the manufacturer, designer or owner. Any number of items can be manufactured to this assessed 'Specification for Manufacture' without additional assessments. Any change to an assessed 'Specification for Manufacture' should be submitted to the Certifying Authority which carried out the original assessment.

Manufacture of individual items to an assessed 'Specification for Manufacture' should be monitored by a competent body who will issue a certificate of conformity for each item. The Certifying Authority will audit this monitoring as necessary.

When items of well control equipment are moved onto an Installation the owner of the installation should make the certificate of conformity available to the Certifying Authority for the installation. The Certifying Authority which assessed the 'Specification for Manufacture' need not be the same as the Certifying Authority for the Installation.

5.0 COMPONENT AND ASSEMBLY MANUFACTURE

5.1 Components

Specification for Manufacture

All well pressure containing components should be manufactured to a 'Specification for Manufacture'. This should be produced by the manufacturer, designer or owner and should consist of:

operating envelope
specifications and standards
design justification procedures
quality plan

The 'Specification for Manufacture' and supporting evidence should be reviewed. A number of alternative approaches may be available, the main requirement being that the review is undertaken by an independent and competent body, eg Certifying Authority, National Standards Organisation, professional engineers independent of the design function, specialist consultants etc. The competent body who undertakes the review would issue an Independent Review Certificate, a record of which will be maintained by the manufacturer, designer or owner.

An acceptable Quality Assurance standard is BS 5750. This should be used as the basis for determining the principal features of a Company's Quality Programme. Alternative standards such as CA type approval, ASME SPPE 1 or the proposed API monogram control programme may be acceptable if augmented by the necessary additions required to meet the appropriate standards.

Manufacture

Manufacture of a component should be monitored by a competent body, who should also ensure that a record of inspection reports, material certificates etc. is being maintained. The competent body will issue a certificate of conformity for each component manufactured.

5.2 Assemblies

Specification for Manufacture

All well pressure containing assemblies should be manufactured to an assessed 'Specification for Manufacture'. This should be produceed by the manufacturer, designer or owner and should consist of:

operating envelopes
specifications and standards
design justification
manufacturing procedures of additional items such as spool pieces etc.
quality plan

The 'Specification for Manufacture' and supporting evidence should be reviewed. A similar approach to that for components should be used which should result in an Independent Review Certificate being issued by a competent body.

Certifying Authority Approval

The Independent Review Certificate with the supplementary information necessary should be made available to the Certifying Authority, for assessment of the 'Specification for Manufacture'. A record of this approval should be maintained by the Certifying Authority and the manufacturer, designer or owner.

Unitisation

Unitisation of an assembly should be monitored by a competent body, who should also ensure that a record of certificates of conformity of components, inspection reports etc. is being maintained. The competent body will issue a certificate of conformity. The Certifying Authority will audit as required.

6.0 INSTALLATION

When an assembly is moved on to an Installation, the owner should provide sufficient information so that the Certifying Authority can evaluate the compatability and safe disposition of the equipment on the Installation. This information should typically comprise of:

operating envelope of the Installation
approved operating envelope of the assembly
certificate of conformity of the assembly to an assessed 'Specification for Manufacture'
report of pressure test undertaken on the Installation

Those items that remain in situ on an Installation should be considered as part of that Installation and treated as other equipment for the purpose of SI 289.

6.1 Installation Operating Envelope

The owner should define the operating envelopes of assemblies on an Installation. The operating envelope should define the interface criteria such as size, working pressure, structural capacity and range of wellbore fluids. This information would normally be contained in the operations manual for the Installation.

If the operating envelop of an assembly does not conform to the operating envelope for the installation, the assembly cannot be used above the lowest criteria common to both operating envelopes. For example, if a 15 000 psi BOP stack is connected to 10 000 psi pipework the stack can be used up to 10 000 psi working pressure.

6.2 Assembly Operating Envelope

Assemblies made up of components must have their integrity considered in their own right. The owner is responsible for specifying the operating envelope of the assembly, and ensuring that the 'Specification for Manufacture' reflects these considerations. This information should be developed in concert with the designer and manufacturer.

6.3 Component Operating Envelope

The owner is responsible for determining the component operating envelope and specifications and standards that are suitable for the desired deployment. This information should be contained in an assembly's 'Specification for Manufacture' determined by direct reference to designer or manufacturer's specifications or developed by the owner. The level of detail of such a specification should be a function of the non-standard nature of the component.

7.0 COMPONENT/ASSEMBLY MOVEMENT

Movement of components or assemblies between Installations is made possible by this assessement scheme. Movement of an assembly between Installations requires the Certifying Authority to be notified and the necessary information to be made available.

If components in an assembly are replaced by an equivalent component then it is the responsibility of the owner to ensure that the replacement component has a certificate of conformity.

8.0 EQUIPMENT WHICH IS NOT A PERMANENT PART OF AN INSTALLATION

Equipment regularly in use on offshore installations, but not permanently located on any one installation eg surface test trees, is defined as mobile equipment. It may be included in a current Certifying Authority 'Mobile Equipment Survey Report'. This Survey Report may apply to either a single item of equipment or, by monitoring the owner's system, an Inventory of Equipment.

When the owner of an installation notifies a Certifying Authority that the equipment has been deployed on an installation, the owner may certify that the equipment is included within a current Certifying Authority Mobile Equipment Survey Report which should be available for inspection. In these circumstances, the Certifying Authority for the installation should normally confine any Survey requirements to the compatability and safe disposition of the mobile equipment on the installation. (Refer Section 6.0).

Equipment which is included within this category will have been assessed and surveyed as fit for use on an offshore installation certified under the provisions of SI 1974 No. 289, Offshore Installations (Construction and Survey) Regulations.

Owners of equipment should provide a system of control of use which recognises the pattern of deployment and utilisation of the equipment. These arrangements should provide for:

(a) Identification of individual components and assemblies.

(b) Certificates of conformity (as referenced in Section 5.2).

(c) Definition of general purpose, connecting components which may be used as parts of different assemblies from time to time.

(d) Appropriate routine inspection which will satisfy the requirements for survey.

(e) Notification of changes, failures and repairs to the Certifying Authority who issued the Certifying Authority Mobile Equipment Survey Report. If the changes, failure or repair occurs while the equipment is on an installation, the Certifying Authority for the installation must also be informed by the owner of the installation. SI 1974 No. 289 Regulation 7 refers.

APPENDIX 3

Referenced standards

In July 1985 the Department of Energy indicated that the References listed in Part V, Section 2.0 of its Guidance Notes should be understood to relate to specific issues referenced when the section was compiled. Bureau Veritas accepts that manufacturers may refer to later editions of these standards or indeed any other relevent standards but in such cases it is advisable to consult the Society at an early stage so that any unforeseen difficulties of interpretation may be resolved. The relevant issues as listed by the Department of Energy are as follows.

Basic codes

General

API Spec 6A	Wellhead equipment (14th edn, March 1983, + supplement 1, June 1984)

Pressure Vessels

BS 5500	Unfired fusion welded pressure vessels (1985)
ASME	Section VIII, Div. 1 and 2. Rules for construction for pressure vessels (1977)

Piping

BS 3351	Specification for piping systems for petroleum refineries and petrochemical plants (1971, + amendment 3448, March 1981)
ANSI B31.3	Chemical plant petroleum refinery piping (1984)
API RP 14E	Recommended practice for design and installation of offshore production platform piping systems (4th edn, April 1984)

Material

NACE -01-75	Sulphide stress cracking resistant metallic material for oilfield equipment (January 1984)
NACE TM-01-77	Testing of metals for resistance to sulphide stress cracking at ambient temperature (July 1977)

Drill though and related equipment

Blowout preventers

API RP 53	Blowout prevention equipment systems (1st edn, February 1976, reissued February 1978)

Marine riser and telescopic joints and riser adapters

API RP 2K	Care and use of marine drilling risers (2nd edn, January 1982)
API RP 2Q	Design and operation of marine drilling riser systems (2nd edn, April 1984)
API Bul 2J	Comparison of marine drilling riser analysis (1st edn, January 1977)
API RP 2R	Design, rating and testing of marine drilling riser couplings (1st edn, May 1984)

Christmas trees and similar equipment

Well completion equipment

API Spec 14D	Wellhead suface safety valves and underwater safety valves for offshore service (6th edn, April 1984)
API Spec 6FA	Fire test for valves (1st edn, May 1985)

Other subsea equipment

API Spec 6D	Pipeline valves, end closures, connections and swivels (18th edn, January 1982, + supplement 2, June 1984)
API Spec 6G	Through flow line (TFL) pump down systems (3rd edn, January 1982)

Other codes and standards

During design, construction and testing due consideration should be paid to the follwing codes and standards:

API RP 14 B	Design, installation and operation of subsurface safety valve systems (2nd edn, November 1981, + supplement 1, January 1983)
API RP 14 C	Analysis, design installation and testing of basic surface safety systems on offshore production platforms (3rd edn, April 1984)
API RP 14 H	Use of surface valves and underwater safety valves offshore (2nd edn, April 1984)

General Information

BSI Handbook 22, Quality Assurance (1983)
API Bulletin S1 Policy and Materials (12th edn, April 1983)

Additional codes and standards

BS 4570: Fusion welding of steel castings: Part I: 1970: production, rectification and repair; and Part II: 1972: fabrication welding.
BS 4870: Approval testing of welding procedures: Part I: 1981: fusion welding of steels (including amendment AMDT. 4322 July 1983 and amendment 4730 September 1984).
BS 4871: Approval testing of welders working to approved welding procedures: Part I: 1982: fusion welding of steel.
BS 5750: Quality systems: Part I: 1979: specification for design manufacture and installation; Part 2: 1979: specification for manufacture and installation; Part 3: 1979: specification for final inspection and test; and the corresponding guides to implementation, Part 4: 1981; Part 5: 1981; and Part 6: 1981.
API RP 6G, Recommended practice on through flowline (TFL) pump down systems (3rd edn, January 1982).
API Spec 6FA, Fire test for valves (1st edn, 1 May 1985).
ANSI/ASME Section IX, Welding and brazing qualifications, Article II welding procedure qualifications and III welding performance qualifications (June 1980).
ASTM A 757-81, Standard specification for ferritic and martensitic steel castings for pressure containing and other applications for low temperature service (1981)
ASTM E165, RP and liquid penetrant inspection method (1980).
ASTM E709, Practice for magnetic particle examination (1980).
ASTM RP No SNT-TC-1A (Personnel qualifications and certification on NDT) (June 1980).
ASTM A609, Specification for ultrasonic examination of carbon and low alloy steel castings (1980).
ASTM A38, RP for ultrasonic examination of heavy steel forgings

In addition to the foregoing it may also be useful to refer to some sections of the latest issue of Bureau Veritas Rules and Regulations for the construction of steel vessels and offshore units:

- for pressure vessels — Chapter 16
- for electrical equipment — Chapter 18
- for materials — separate volume
- for flexible hoses carrying hydrocarbons up to 100 mm diameter — Guidance Note 540 D.CN2 MEV and Chapter 15 of the latest issue of Bureau Veritas Rules
- flexible hoses over 100 mm diameter carrying hydrocarbons will be dealt with on a case by case basis.

APPENDIX 4

Typical list of documentation requested by Bureau Veritas and tests to be performed

Surface equipment	*Documentation*	*Tests*
Subsea wellhead control unit	System specification with components ref Logic Diagram Reliability study Fault mode analysis	Prototype test Inspection after completion Operation tests
Electrical power unit	Specification of circuit breakers, transformers, cables Calculation of circuit breakers capacity	Type tests of components Inspection after dielectric tests Operation tests
Hydraulic power unit	Specification of components Bill of material Safety electrical equipment Certificates General arrangement Pressure parts calculation	Inspection after completion Pressure test Insulation and dielectric test Operation tests
Hydraulic backup system	See Hydraulic power unit	
Umbilical Terminations	Bills of materials Review of design Specifications and assembly drawings	Type test Inspection after completion Insulation and dielectric test of electrical connectors Tightness test of hydraulic connector Operation tests
Umbilical	Review of design loads Bills of materials Review of the factory acceptance test programme Specification and assembly drawings	Components acceptance test Factory acceptance test as agreed On shore integration test Inspection after completion Operation tests
Pilot electro valves	Assembly drawing Specifications Operation test reports	Type tests Tightness tests Dielectric tests Operation tests
Hydraulically operated valves (backup system)	Specifications Inspection reports	
Hydraulic Subassemblies (main & backup)	General arrangement Bills of materials	Operation tests
Accumulators	General arrangement Welding procedure Bills of materials NDT programme NDT operators certificates Filler and parent metal certificates Calculation note	NDT of welds Welders qualification Welding procedure qualification Pressure tests
Sensors	Specification	Type tests including tightness test, insulation and dielectric test Calibration Operation tests
Electrical connectors	Detailed drawings Bills of materials Specification	Type test including tightness mechanical tests Dielectric test Operation test
Hydraulic connectors	Detailed drawings Bills of materials Specification	Type test including tightness test Mechanical test Pressure test Operation tests
Electronic package	Pressure shell bill of materials Electronic components specification logic diagram Reliability study of electronics Specification Pressure calculation rate of container NDT procedures	Components type tests Electronic systems operation test Dielectric Electronic system operation system Container pressure test
Christmas tree or similar wellhead pressure containing part	General assembly drawing Detailed drawing of valves and components Stress calculations of pressurised parts Bill of materials Prototype tests reports of components Certificates of materials NDT programme NDT operators certificates Welding procedures specification Filler and parent metal certificates Builders construction file	NDT of welds and components Pressure tests Leakage tests Functional tests Welders qualification Welding procedure qualification Production tests (if any)
Supporting structure	General assembly drawings Wedling procedure Stress calculation	NDT of welds

Discussion

T. A. P. HAMILTON (Department of Energy): I should like to congratulate Mr Smith on his paper which proves a useful summary of the background to and present arrangements for 'Certification' of well control equipment on offshore platforms and mobile drilling rigs.

My first comment enlarges on the key reasons for the change in Department of Energy policy in 1982 which brought blowout preventers and the well control equipment installed on production wells (christmas tree) into the scope of installation certification. In particular exploration and development was being extended to deeper horizons and higher pressure reservoirs in the North Sea. The equipment available was being used much closer to its rated working pressure and reservoir pressure maintenance schemes would ensure that production well control equipment would be exposed to these pressures for a greater part of its life than in the past.

The North Sea was also the focus for developing very high pressure (15 000 lb/in^2) blowout preventer and other related well control equipment for use on floating rigs. Routine testing of installed equipment at these high pressures could be expected. The changes taking place demanded the use of more sophisticated materials, eg higher strength, which were likely to be less damage (or defect) tolerant and would not be easily repairable in the field. The increase in weight of equipment was also giving cause for concern and could lead to design for higher working stress levels than in older equipment. Already the need to proof test forgings and castings at 1.5 times the working pressure during manufacture and testing high pressure systems on installation was presenting difficulties.

There were some other complicating factors in the development of guidance. The manufacturers of most of the equipment and most drilling contractors were American firms. The main standard maker, the American Petroleum Institute, was for many reasons primarily interested in writing standards for domestic use. Furthermore, almost by definition standards cannot be written until after equipment is proven in service. During the period of development Certifying Authorities were in a unique position to help ensure quality and fitness for purpose in the broadest sense but they needed guidance.

Some equipment, unlike the majority of equipment on fixed platforms, was not the property of the installation owners or permanently installed on the installation and required special arrangements for Certification. There was initially controversy about the need for and scope of the certification but eventually a good consensus on the essential guidance and supporting memorandum was obtained.

I wish to record the help we obtained from the International Association of Drilling Contractors in the field of drilling well control equipment and the Association of Well Head Equipment Manufacturers on production well control equipment as well as that from the Certifying Authorities and oil companies. The United Kingdom Offshore Operators Association played an important and vital role coordinating the input of advice to the Department.

In looking to the future, I believe the work has contibuted to the development of higher standards for the integrity of individual components and assemblies. One area where we have identified a need for further guidance is in the fitness of systems. We are working on one important aspect of this now, that of diverter systems.

System certification is in my view more complex, adding another level of complexity to guidance on amongst other aspects location of equipment, its interconnection and control. Guidance on system fitness may also have to take account of other complementary systems. The question of the combination of active and passive fire protection in wellhead areas has been addressed in our present guidance. Another important related feature is the possible use of equipment standards with specific operational restraints and limitations to achieve adequate levels of safety, without imposing unnecessary economic penalties.

I am very encouraged by the developments in API standards and an increasing preparedness to consider international requirements as well as US domestic needs. Nevertheless the North Sea remains the focus for high volume production development offshore in a hostile if not extreme marine environment. We shall seek to avoid duplication of standards by working with API but anticipate there will probably still be a need for some guidance to suit the conditions in North European waters and the type of development of the oilfields in the area.

Dr D. A. BRIARIS (Consultant): The author is to be congratulated for attempting the difficult task of documenting the developing certification process for well control equipment, which was never going to be an easy undertaking.

The following comments are made in a constructive vein in the hope that certain misunderstandings may be corrected, and are based on my involvement with the development and implementation of Guidance Notes in the North Sea, initially in the capacity of an equipment manufacturer and laterally as UKOOA's representative on a number of the API Subcommittees.

Nowhere in the author's presentation is there mention of the Department of Energy's willingness to reduce the need for Guidance Notes if API Specifications in conjunction with Quality Specificiation Q1 can meet all of the North Sea's requirements. This is also the wish of UKOOA and AWHEM (Association of Well Head Equipment Manufacturers) and hopefully that of the Certifying Authorities as well. Since the Department of Energy will not, quite rightly, adopt such a policy whilst gaps exist between the requirements, urgent co-ordinated effort from all parties, including the Certifying Authorities, is needed in order to influence API to change.

The author is correct in stating that API Specification 6A does not cover equipment for sandy service. However, API Specifications 14A and 14D do cover sandy service operation for safety valves. What is the author's view as to the likely impact the use of these Specifications will have when interfaced with the 15th edition of Specification 6A?

The author states that the Specification for Manufacture is to be assessed by the Certifying Authority. However, Section 5 of the Memorandum of Understanding states that the 'main requirement is that the review (of the Specification) is undertaken by an independent competent body', the Certifying Authority being one of those on the list which also includes National Standards Institutions, Professional Engineers independent of the design function, specialist Consultants etc.

The Memorandum of Understanding goes on to state that a Certificate of Conformity issued by an independent competent body 'would normally be accepted by the Certifying Authority issuing the Certificate of Fitness for the installation unless there is evidence that the equipment does not conform to the Certificate or that there is some discrepancy in the Certificate itself'.

This is an important point because it allows a manufacturer and equipment owner jointly to agree the most effective and economic method of presenting equipment for inclusion into the Certificate of Fitness without necessarily involving a Certifying Authority, provided the competent body has been agreed to be competent by the Certifying Authority and the owner. Any inference that only Certifying Authorities are permitted to review Specifications for Manufacture or issue component and assembly Certificates of Conformity would be incorrect and unnecessarily restrictive to the industry.

Whilst API Specification 6A excludes specific reference to subsea wellhead and christmas tree equipment, like Part V Section 4 of the Guidance Notes, API Specification 6A requirements may be equally applied to appropriate subsea equipment, particularly in terms of technical and quality requirements. Even the imminent publication of API RP 17A is unlikely to affect this situation since, as the author points out, it will include little manufacturing guidance.

The author's disappointment in API's apparent failure to recognise North Sea notch toughness requirements is probably equally matched by API's disappointment that, until recently, there has been little or no co-ordinated input from bodies representing North Sea interests, including the Certifying Authorities. Surely if we wish to use the API Specification and furthermore expect them to reflect our needs we must be prepared to provide information to the voluntary Specification-generating Task Groups which exist?

AWHEM is continuing in its efforts to influence API regarding notch toughness requirements and has succeeded in establishing an API Materials Toughness Task Group. This Group has actively been seeking to determine technical requirements, based on all relevant published literature, which would have world-wide acceptability. Only UKOOA, with the support of AWHEM, has participated in this work on behalf of the North Sea industry and so unfortunately, despite the author's comment that 'it is essential that API, Industry and the Certifying Authorities work together', this is one area where the Certifying Authorities have not participated.

Certifying Authorities have, regrettably, continued to develop their own acceptance criteria in isolation from each other, leading to serious confusion within the industry and thereby encouraging manufacturers and owners to 'shop around' to obtain the least stringent assessment. The adoption of API's new proposals, soon to be balloted, as a common standard becomes more meaningful and urgent when one considers that under the present system a Certificate of Conformity, which includes the least stringent notch toughness requirement supported by an approved independent component body, would normally be accepted into the Certificate of Fitness by all the Certifying Authorities, irrespective of their own possibly more stringent requirements.

It is misleading to assume that PSLs apply to specific pressure ratings and proximity definitions. API Specification 6A seeks to define a graded structure for equipment wherein specific design, quality and other technical requirements within each level are made compatible with each other. PSL Selection Guidelines, whilst included, are not a requirement of the Specification, and the North Sea industry has, for some time, selected the appropriate PSL in accordance with historical practice and sound engineering judgement.

Regarding detail requirements such as traceability and hydrostatic testing, UK requirements were not included into Specification 6A because there was no request to this effect. UKOOA, supported by AWHEM, has now presented to API amendments which it believes will 'bridge the gap' between Specification 6A and the Guidance Notes, and hopefully these changes will be reflected in the 16th edition of Specification 6A. To date at least, API is to be commended for its enthusiastic support of the North Sea industry's initiative.

I would like the author to comment on what is seen in the industry as the Certifying Authorities' apparent lack of willingness to co-operate together to provide a more unified and widespread representation on the various Specification-generating bodies or Task Groups in order to help bring about the development of realistic Standards for the UK North Sea. Such co-operation should be in addition to the Well Control meetings held at the Department of Energy, the primary purpose of these meetings being to agree previously generated technical submissions.

Dr P. TERRY (Cameron Iron Works Ltd): In the absence of any recorded data on brittle fracture of oil well equipment, suppliers and many users have difficulty in accepting many of the severe impact test requirements demanded by some users and Certifying Authorities.

It is accepted that there is a requirement within the Department of Energy Guidance Notes for an impact test to be carried out but there is no universally accepted approach to the determination of the absolute requirements. The Sanz relationship used by Bureau Veritas for determination of impact toughness requirements is one of many such approaches to which could be added inter alia BS 5500, Barsom and Rolfe and Sailors and Corten. All these approaches give different requirements, mostly less onerous than the Sanz method.

The Sanz approach is as valid as many of the others but unfortunately Bureau Veritas have in their adoption of the method had to make various assumptions which are required within the method to take account of factors such as yield strength, loading rate etc. and the approach itself is based on one assumed initial defect size. Different choices of such parameters leads to varying Charpy impact requirements.

Taking for example the case of a component designed to operate at –40 °C with a wall thickness in excess of 101 mm and stressed to half yield, the Bureau Veritas method would require 28 J at –40 °C whereas an alternative interpretation would give 28 J at –10 °C.

One further point regarding Bureau Veritas' procedure is the requirement that except in specific cases the Charpy test temperature should never be higher than the design minimum temperature. The work of Sanz is simply a mathematical relationship between Charpy properties and the results of fracture toughness K_{IC} tests. There is no absolute relationship in physical terms and if the approach shows Charpy test temperature requirements above the design minimum temperature then they are still as equally valid as situations where the Charpy test temperature is below the minimum design temperature.

The main purpose of this comment is simply to say that we need to be careful not to over-specify a requirement against a failure mode which has never shown itself to be a problem in the type of equipment we are discussing.

Author's reply

I should first like to thank Mr Hamilton for his comments on my paper.

With respect to Dr Briaris' comments on the desirablility of reducing the volume of the Guidance Note, I believe that Mr Hamilton's contribution has covered this point. I note that sandy service conditions are covered elsewhere in API standards. Suitable interfacing of API Spec 6A with Specs 14A and 14D would cover this area but Dr Briaris no doubt recalls that some members of the Working Group, particularly Operators, expressed a strong desire to see 'stand alone' specifications.

While I understand Dr Briaris' point that industry wishes to avoid any unnecessarily restrictive practices, I do not believe that my paper infers that only Certifying Authorities are permitted to review Specifications for Manufacture or issue component and assembly Certificates of Conformity. The

Certifying Authority must however retain the ability and flexibility to discharge its statutory responsibility under SI 1974/289. I attempted to cover this point under 'Certification Requirements'. In case that paraphrasing of the objectives of the Memorandum of Understanding has given rise to misinterpretation, the complete memorandum and attachment has now been added to the paper as Appendix 2.

Dr Briaris refers to Section 5 of the Attachment to the Memorandum but the phrase quoted by him cannot be taken in isolation.

I am not in a position to comment on Dr Briaris' feeling that there is a lack of willingness by the CAs to co-operate together with regard to helping bring about the development of more realistic Standards for the UK sector of the North Sea, except to observe that in addition to the Well Control Working Group, with which Dr Briaris is familiar, the CAs also participate on Department of Energy working groups covering Mechanical, Electrical, Stability, Structural and Mooring matters, as well as attending annual liaison meetings chaired by the Department of Energy. All of this places demands on the available manpower of the CAs.

Both Dr Briaris and Dr Terry refer to the lack of a universal approach to the determination of notch toughness requirements. Because industry sought guidance from the Certifying Authorities on this matter Bureau Veritas, like the other Certifying Authorities, put its views forward. Not unnaturally the Society's view reflected current work in France in which it had participated.

Dr Terry's contribution neatly summarises the difficulties. While many recognise that notch toughness testing is a requirement there appears to be some division of opinion at an International level with regard to levels of testing. With regard to the Sanz approach, several studies have confirmed the accuracy of this method, including for example work carried out on the IIS sub-commission IX-F where good correlation between the Sanz method and the George method was demonstrated.

Notwithstanding the above, I believe that notch toughness is only one aspect of material quality which needs to be taken into account when assessing a Specification for Manufacture. Too great an emphasis on notch toughness might result in a loss of other qualites of equal or greater relevance.