— fluid properties and their variation throughout field life (density, GOR, watercut, viscosity, etc.),

— tie-back distance,

— water depth.

A.7.2.4 The well depth (true vertical depth from seabed) has a significant influence on the best location of pumping equipment. In shallow wells, the performance difference between downhole and wellhead-located pumps tends to be small, and the increased intervention cost and complexity of downhole equipment means that mudline-located pumps are generally favored. On the other hand, deep or under-pressured reservoirs can require downhole pumps to be technically viable.

A.7.2.5 Produced fluids and solids properties, and their variations throughout the life of a development, have a significant impact on the design and performance of SSP equipment. Often, it is late-life conditions that require the use of processing to boost production. Increasing watercut and GOR make seabed separation an attractive method for increasing production. A single, fixed-system design might not be appropriate for the full field life-cycle. Modular, flexible processing designs might be the preferred solution. A number of suppliers are currently developing modular SSP systems.

A.7.2.6 In general, locating the processing equipment as close as possible to the reservoir is the preferred option because of the following:

— increased hydraulic efficiency for pumping, due to lower GVF;

— easier separation, due to lower phase viscosities;

— reduced system back pressure if water is removed;

— improved inflow performance;

— improved flow assurance.

A.7.2.7 For example, an under-pressured reservoir might not have sufficient energy to produce fluids to the seabed where they can be boosted by a multiphase pump. In this situation, downhole pumping is necessary to produce the well.

A.7.2.8 In most cases, consideration of fluid properties, thermodynamic and mechanical efficiencies favour placing pressure-boosting and separation as close to the reservoir as possible, while consideration of engineering factors and maintenance favour equipment placed as far downstream as possible. These two conflicting requirements need to be balanced to arrive at a field development solution that is both technically viable and gives optimum economic benefit.

A.7.2.9 In deepwater developments and at short tie-back distances, there is little difference in hydraulic performance between wellhead and riser base locations for SSP systems. In this situation, locating equipment at the riser base can be beneficial if it allows intervention for repair and maintenance to be performed from the host facility, rather than requiring the use of a separate intervention vessel.

A.7.3 Separation

A.7.3.1 General

A.7.3.1.1 Subsea separation can be performed for a variety of reasons that are frequently different from the reasons for topside separation. Subsea separation is typically used as a method to increase production rates, maximize total recovery and overcome limitations of topside facilities. This can be achieved by removal and disposal of unwanted products (such as water) near the reservoir or at the mudline, hence reducing back-pressure on the production system. Separation can also allow the use of more efficient single-phase pressure-boosting methods, and compensate for limitations of topside facilities, e.g. water-handling capacity. Another important purpose of subsea separation is to overcome flow assurance problems (e.g hydrate formation, corrosion and slugging) arising from the transport of untreated multiphase well fluids.

A.7.3.1.2 Depending on the requirements for separation, the efficiency of subsea separation techniques might not have to be as stringent as that normally expected in topside separators. For example, if the purpose of separation is to allow efficient pressure-boosting for a long-distance tie-back, then high efficiency gas-liquid separation might not be required or provide any significant benefit over a design giving moderate efficiency. This is because pressure and temperature losses in the export pipelines can cause phase changes, leading to gas evolution in the liquid line and liquid dropout in the gas line. The quantities of liquid and gas generated by the phase change are frequently significantly higher than those carried into the lines due to moderately efficient separation. However, the performance of any separation system needs to be specified as accurately as possible, in order to allow efficient design of the downstream processing facilities.

A.7.3.1.3 Management of produced solids (e.g. sand) in an SSP system is a significant issue, and can drive the design towards the use of downhole sand-control techniques. Use of devices to monitor sand production subsea should be seriously considered.

A.7.3.2 Hydrocarbon/water separation

A.7.3.2.1 Hydrocarbon/water separation involves removing most or all of the produced water from the well fluids. The produced water can then either be discharged subsea or re-injected into a suitable formation. Water separation subsea at/near the wellsite can provide significant economic benefits to certain field developments by

— reducing well back-pressure, thus increasing production rates and/or total recovery,

— reducing the volume of fluid that needs to be transported to topsides, thus allowing the use of smaller diameter flowlines,

— de-bottlenecking existing topside facilities, thus freeing up additional production capacity,

— eliminating or minimizing the need for topside water separation, clean-up and disposal.

A.7.3.2.2 Removal of the bulk of the water from the produced fluids can also help in the mitigation of a number of flow assurance problems, especially corrosion and hydrate formation. This can also reduce the requirement for chemical injection and/or flowline insulation.

A.7.3.2.3 Subsea seabed separation can be achieved either via a conventional gravity separator, with the separated oil and gas phases recombined and transported in a single pipeline, or by using compact separation, usually in two stages, with the first stage involving gas-liquid separation and the second stage separating the water from the oil. Compact separators are usually based on cyclonic or centrifugal designs. Some hydrocyclone designs are limited to operation with water-continuous feeds, which require a produced fluid with a high water cut or a pre-separation stage to remove the bulk of the oil.

A.7.3.2.4 An alternative to seabed separation of water is the use of a downhole hydrocyclone-type separator in combination with a submersible pump.

A.7.3.2.5 In general, it is the oil-in-water content of the separated water that is the critical performance specification. The water-in-oil content of the separated hydrocarbons is typically less important, and an acceptable specification may be as high as 20 %. In general, this level of water-in-oil does not generate high viscosity emulsions and remains as an oil-continuous system, reducing water-pipewall contact and hence corrosion inhibitor requirements. However, if the goal of subsea separation is to reduce the cost of hydrate inhibition, then the requirement to reduce the water content in the separated hydrocarbons to a significantly lower level will be a more critical design parameter.

A.7.3.3 Gas/liquid separation

A.7.3.3.1 Gas-liquid separation can be achieved by either conventional (gravity) or compact (usually cyclonic) separator designs. Gas-liquid separation allows efficient single-phase pumping of the separated liquids and can also assist in overcoming flow assurance problems, especially hydrate formation and corrosion, by separating the acid gas and hydrate-forming hydrocarbons from the water. Slugging can also be reduced or eliminated by gas/liquid separation at/near the wellsite.

A.7.3.3.2 The primary aim of gas-liquid separation is to increase production rates and recoverable reserves by reducing back-pressure on the reservoir and allowing a lower field-abandonment pressure. Subsea gas-liquid separation systems have commonly been developed in conjunction with a liquid pumping system. Control of the liquid pump speed is used as the primary method of separator liquid level control. The two types of gas-liquid separation systems are

— gravity separation systems, which can be of either vertical or horizontal design, and may incorporate inlet devices to augment the separation. Separator design is generally based on existing codes for topside units for both separator residence time and pressure vessel design,

— cyclonic separation systems, which allow the use of vessels smaller than gravity separators by using some of the fluid energy to generate high separation forces between the gas and the entrained liquids.

A.7.3.3.3 It is possible to locate the separator either at/near the wellsite or at the riser base. Generally, there is always a trade-off between optimizing the performance and minimizing the cost of the system. Optimal performance favours placing the processing system closer to the reservoir, but minimal cost favours placing the system closer to the host facility. The optimum location depends on the production system characteristics and the primary reason for performing the separation. The following are typical considerations that need to be evaluated on a case-by-case basis:

— for long distance tie-backs, wellsite separation may be the preferred option, based on hydraulic considerations. This is because the bulk of the production system pressure loss is most likely in the multiphase pipeline, and reducing this significantly decreases the back-pressure on the reservoir;

— for deepwater applications, with small elevation changes between the wellsite and the riser, and relatively short tie-back distances, separation at the riser base may be the preferred solution. This location is attractive, as most of the system pressure-drop and problems such as slugging and low temperatures are generated in the riser. Additional operating cost benefits can be gained if intervention on the separator can be performed from the host facility without the need for additional vessels.

A.7.3.4 Three-phase separation

Three-phase subsea separation is also possible; however, significant challenges to obtaining reliable performance of such systems include

— accurate and reliable measurement of the water, emulsion, oil, foam and gas interface levels within the separation vessel (for further information see A.7.7),

— provision of a reliable variable-dosage chemical injection system to be used to minimize the amount of emulsion and foam in the separator, thus making measurement of the interface levels easier while also maximizing the useful volume available for separation of the fluids,

— provision of high reliability subsea-level control valves to control the flowrates of the various fluids from the separator,

— accurate on-line measurement of the oil-in-water content of the produced water stream,

— methods for removing sand and other solids from the separation vessel.

A.7.4 Pressure-boosting

A.7.4.1 General

A.7.4.1.1 Pressure-boosting (pumping) in subsea applications can be applied downhole or on the seabed. Such multiphase pumps (MPPs) are used to boost production above natural flow conditions by adding energy to the system, with the following potential benefits:

— accelerated production (reduce field life) and increased recovery;

— lift provided to wells with low natural production (low pressure, low GOR, high water-cut, deep water);

— increased flowline inlet pressure to enable long-distance tie-backs to an existing host or to shore;

— increased pressure from the low pressure wells to balance the flowing wellhead pressures (“positive choking”).

A.7.4.1.2 A typical subsea pumping unit consists of the following sub-systems:

— pump, including impellers or screws, casing, radial/thrust bearings, shaft seals, valves and piping;

— driver, i.e. an electric motor or hydraulic turbine;

— mechanical coupling between the pump and the driver;

— power transmission (electric or hydraulic);

— control and monitoring, including a control unit with power supply, instrumentation and valves;

— lubrication and motor cooling systems, including a reservoir, pumps, filters, valves, cooler, seals and oil.

A.7.4.1.3 In general, the service of subsea pumps is more demanding than it is for topside liquid pumps and gas compressors. The feed composition in subsea applications is likely to be less well controlled, with the potential for significant gas in the liquid stream and liquid carryover into the gas phase. The fluids also frequently contain small amounts of abrasive solids. These considerations lead to the design of subsea pressure-boosting systems that are tolerant to varying multiphase flow conditions and solids-laden fluids. This generally results in machines with lower efficiencies than conventional topside pumps and compressors.

A.7.4.2 Submersible pumps

A.7.4.2.1 Both downhole ESPs and hydraulic subsea pumps (HSPs) have been extensively used for many years in onshore applications and more recently have been deployed in subsea wells.

A.7.4.2.2 Downhole submersible pumps are basically multistage progressing cavity pumps driven either by an electric motor or a hydraulic turbine.

A.7.4.2.3 In terms of hydraulic performance, pumping is generally more effective the closer it is placed to the reservoir. This is because pumping becomes less efficient as the gas fraction increases and the inlet pressure drops. Thus, downhole pumping is the preferred solution from the perspective of increased production and system efficiency. However, a number of factors need to be taken into account when considering the use of downhole pumping, including

— the cost of providing one pump per well,

— the potential requirement for a fluid and/or downhole tool bypass around the pump,

— the impact of the pump dimensions and fluid bypass on the casing size selected,

— the impact of the use of a downhole pump on the subsea tree design (e.g. the need for wet mateable electrical power connectors to provide power to an ESP, the requirement for additional hydraulic lines downhole to control flow through the fluid bypass, and the tradeoffs between vertical and horizontal trees with respect to the ease of access for maintenance and replacement of the pump),

— the cost of the power generation, distribution and control system for the pumps,

— the predicted reliability and cost of intervention for pump maintenance and replacement.

A.7.4.2.4 While many of these factors can weigh against the use of downhole submersible pumps in subsea wells, there are certainly particular scenarios where downhole submersible pumps are a more attractive alternative than seabed-based pumps. Consideration of the above factors should form part of a balanced assessment of the equipment alternatives, to assist in identifying the optimum equipment configuration for any given development.

A.7.4.2.5 Submersible pumps can also be deployed at the wellsite at seabed level in a can or at the base of the production riser adjacent to the host facility, depending on the exact nature of the field requirements.

A.7.4.3 Seabed multiphase pumps (MPP)

A.7.4.3.1 Seabed MPPs are generally classified into the following two categories:

— hydrodynamic pumps, which work on the principle of transforming kinetic energy into static energy (head), e.g. helico-axial pumps;

— positive displacement pumps, which simply enclose a defined volume from the low-pressure side, compress it, and release it to the high-pressure side, e.g. twin-screw, piston and progressive cavity pumps.

A.7.4.3.2 Both types of pump have their own inherent advantages and disadvantages, and these should be clearly understood prior to selecting a pump for a given application.

A.7.4.3.3 For deepwater developments with short tie-back distances, an acceptable alternative to locating the seabed MPP at/near the wellsite can be to locate them at the riser base adjacent to the host facility, so that intervention for repair and maintenance can be performed from the host facility.

A.7.4.4 Wet gas compressors

A.7.4.4.1 Wet gas compressors are designed for the same basic service as MPPs, but with higher gas volume fractions (GVFs). The normal operating range for a wet gas compressor is expected to be approximately 95 % GVF to 100 % GVF. Particular types of multiphase pump can in fact handle multiphase flowstreams up to and including very high GVFs, at least for short durations.

A.7.4.4.2 The volume decrease and pressure boost derived from compression of the wet gas can result in the need for a smaller diameter flowline between the subsea facilities and the host, thus saving significant capital expenditure.

A.7.5 Water disposal

A.7.5.1 Produced water is typically either disposed of to the environment or re-injected into a suitable formation, consistent with local regulatory requirements and accepted local practices.

A.7.5.2 Disposal of water directly to the environment requires an accurate on-line method of measuring the oil-in-water content of the water stream, to ensure that the oil content is within the pre-defined acceptable limit. Given the practical difficulties of achieving this objective in a subsea environment and the desire for zero discharge facilities, it is usually a better option to re-inject the produced water back into a suitable formation.

A.7.5.3 The requirements for successful produced water re-injection are

— chemical compatibility between the injection water and the formation, such that scale does not form,

— monitoring and control of oil-in-water and solids content levels to ensure they are suitable for long-term re-injection into the particular formation selected.

A.7.5.4 If water injection is needed for reservoir pressure maintenance, re-injection of the separated water into the appropriate formation can reduce the water injection requirements on the host facility. However, re-injection of the separated produced water does not provide all of the water required for total voidage replacement, as it will not replace the produced oil volume.

A.7.5.5 Re-injection of the produced water normally requires drilling and completion of additional wells unless downhole separation technology is employed.

A.7.5.6 Injected water can cause reservoir souring. Originally sweet reservoirs can sour if subjected to seawater injection (water flooding). The most plausible cause of reservoir souring is the growth of sulfate-reducing bacteria (SRB) in the zone where seawater mixes with formation water. Fatty acids and sulfate both need to be present in the mixing zone in order for SRB activity to exist. Treatment is not possible, so the only remediation is to design for sour service.

A.7.6 Electrical power management

A.7.6.1 Many of the SSP systems that are currently in use require significant quantities of electrical power, typically several megawatts. Electrical power is generally used for operating pumps either to dispose of produced water by re-injection or to boost the pressure of production fluids, allowing an increase in production rates. Additional subsea electrical power consumers can also include electrostatic coalescers, wet gas compressors and centrifugal separators.

A.7.6.2 Considerable ancillary equipment is required to distribute, connect and control the electrical power that is supplied to SSP systems, such as subsea electric motors, transformers, high voltage wet-mateable connectors, frequency converters and VFDs.

A.7.6.3 DC power transmission systems have some advantages over AC power transmission systems for long step-out distances, including

— lower transmission losses in DC systems,

— DC systems are inherently less complex and more flexible, particularly with respect to changes in configuration and load mode,

— system harmonics and resonance are likely to be significant issues for AC systems, whereas they are not for DC systems,

— cable sizing for DC systems is straightforward and is based on power and voltage drop, whereas for AC systems a compromize is required between a number of competing factors, including an acceptable level of harmonic distortion, the voltage profile and the transmission losses.

A.7.6.4 It should be noted however, that DC motors are more likely to require regular intervention for maintenance of various components than AC motors. High-voltage conversion of DC voltages to AC is currently not available for subsea installations. Selection of a system for a given application is usually based on an assessment of life-cycle costs.

A.7.7 Monitoring of SSP systems

A.7.7.1 Optimization of systems involving SSP equipment requires monitoring of both the process conditions and the condition of the processing equipment itself.

A.7.7.2 In addition to conventional pressure- and temperature-monitoring that is routinely performed for subsea production systems, additional process variables that may need to be monitored/measured in SSP systems include

— flow rates, either single-phase and/or multiphase,

— the position of the oil, water, emulsion and foam interfaces in subsea separators (nucleonic-type level detectors are thought to provide the best solution for subsea separation systems),

— oil-in-water content of separated water (an accurate on-line monitor is required to confirm that the water quality is consistently acceptable either for discharge to the environment or for reinjection into a suitable downhole formation),

— water cut of the separated oil.

A.7.7.3 While it may be possible to infer something about the condition of the SSP equipment indirectly from monitoring the trends of the process variables, it is preferable to also directly monitor the condition of the SSP equipment in order to be able to optimize performance and to establish reliability/wear trends accurately. Such condition monitoring could include

— pump suction and discharge, pressure and temperature,

— pump/motor speed, shaft run-out and bearing temperature,

— axial and radial vibration of rotating components,

— electrical power supply characteristics, e.g. driving current and its harmonics,

— correct functioning of critical components, such as level detectors, level control valves, the oil-in-water monitor, the chemical-dosing system, fluid barrier systems, etc.,

— sand production/buildup in process vessels (for fields where significant sand production is anticipated, a sand removal mechanism is required).

A.7.7.4 Methods for performing all the required process/performance/integrity monitoring need to be incorporated into the overall SSP system design from the outset. The high electrical noise environment in which the sensors will operate should be taken into consideration, together with the communications system bandwidth required for transmission of all data back to the host facility.

A.8 Production control systems (PCSs)

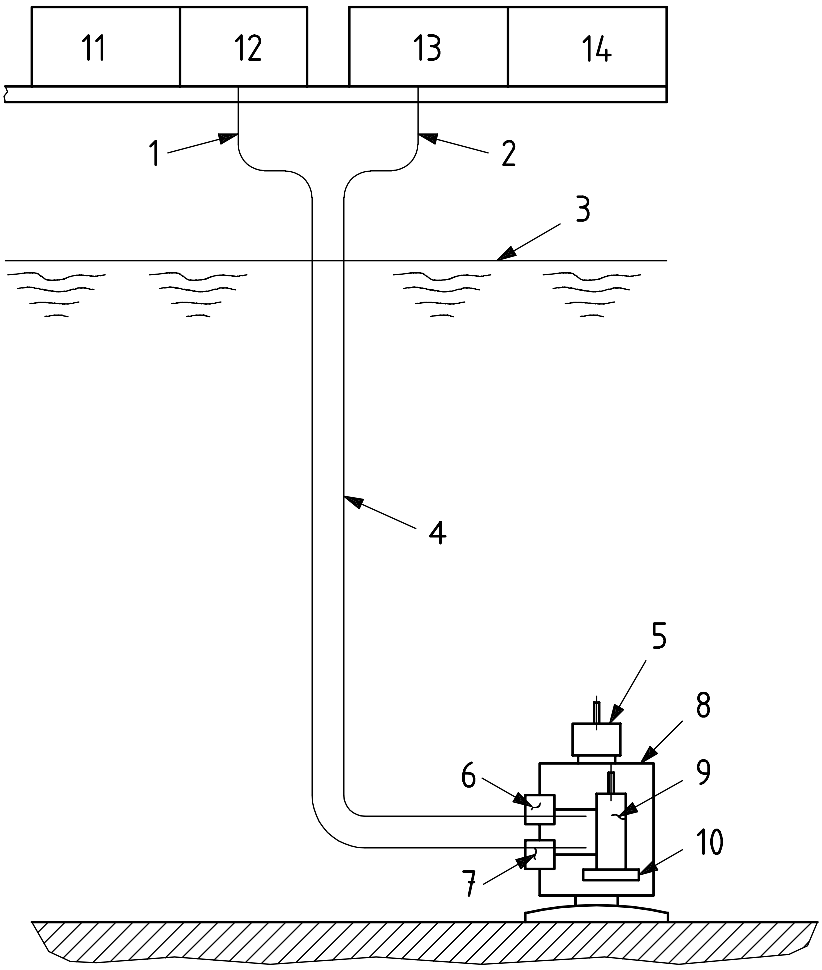
A.8.1 General

A.8.1.1 A PCS provides the means to control and monitor the operation of a subsea production or injection facility from a remote location.

A.8.1.2 The PCS consists of both surface and subsea equipment, see Figure A.23.

A.8.1.3 Depending on system design and field-specific requirements, the design of the surface equipment can range from simple hydraulic power-packs with integrated control panels, through to more advanced systems including signal multiplexing, with the operator interface integral with the control system for the surface-processing equipment. The control system may interface with the actuated subsea equipment directly or via a subsea control module. The subsea control module(s) may be configured to operate/monitor functions on each or several subsea XTs, downhole functions and/or manifold functions.

A.8.1.4 Several types of PCS are used for production operations. General characteristics of common systems based on the use of an umbilical from the host facility to the subsea production system, through which to provide power, communications and fluid conduits, are shown in Table A.1. Because of the large number of variables and the high degree of operator preference in choosing control systems, only relative comparisons of systems are possible. Important features of each system are described in the following subclauses. Common to each is the requirement to provide high-pressure hydraulic fluid to subsea-controlled functions. This is accomplished by an HPU normally located on the surface, but may alternatively be located subsea.



Key

1 hydraulic control line(s)
2 electrical control line(s)
3 sealevel
4 electrical and hydraulic control lines combined into a single umbilical (optional)
5 tree cap
6 electrical control line termination
7 hydraulic control line termination
8 subsea tree
9 control pod
10 control pod baseplate
11 hydraulic power unit
12 control panel
13 electrical control panel
14 data read-back system

Figure A.23 — Schematic diagram of typical satellite-well PCS

Table A.1 — Characteristics of different types of control systems

System	Features							
	Complexity	Response rate		Discrete control of subsea functions	Data readback	Umbilical(s)		
		Signal	Actuation			Type	Size	Command distance
Direct hydraulic	Low	Slow	Slow	Yes	Separate if desired	Hydraulic	Large	Short
Discrete piloted hydraulic	Moderately low	Slow	Fast	Yes	Separate if desired	Hydraulic	Moderately large	Moderate
Sequential piloted hydraulic	Moderate	Slow	Fast	No	Separate if desired	Hydraulic	Small	Moderate
Direct electrohydraulic	Moderate	Very fast	Fast	Yes	Separate if desired	Hydraulic and electric or composite	Moderate	Long
Multiplexed electrohydraulic	High	Very fast	Fast	Yes	Integral	Hydraulic and electric or composite	Small	Long

A.8.1.5 The most common systems currently employed are multiplexed electrohydraulic systems, as these provide very fast shutdown response times combined with an integral ability to monitor a significant number of subsea parameters.

A.8.1.6 In order to reduce the complexity of the following descriptions of a typical PCS, only features consistent with a multiplexed electrohydraulic control system are described, unless otherwise specifically noted. Further details on the other types of subsea PCSs can be found in ISO 13628-6.

A.8.1.7 Typical multiplexed electrohydraulic systems utilize a multicore electrohydraulic umbilical with dedicated or common copper conductors to transmit control signals (usually multiplexed digital data) and power for the operation of various subsea functions. Electronic encoding and decoding logic is required at the surface and subsea. This approach reduces electrical cable and subsea electrical connection complexity. Source filtering of data at the individual end devices can also be used to limit the amount of data routinely transmitted.

A.8.1.8 In addition to the conductors to transmit control signals and power, the multicore electrohydraulic umbilical usually contains various fluid conduits to provide control fluid and chemicals to the subsea facilities as required. Individual hoses or tubes making up the fluid conduits may be manufactured from carbon steel, corrosion-resistant steels or thermoplastic materials. See A.9 for further details on umbilicals.

A.8.1.9 Some electrohydraulic systems superimpose the control signals on the power circuit. This is commonly referred to as “comms on power”, and eliminates the need for a separate communications cable thus reducing umbilical cost.

A.8.1.10 Alternatively, signals can be transmitted by fibre optic cable or acoustic methods, as described in A.8.2 and A.8.3 respectively.

A.8.1.11 Given the high level of functionality available via multiplexed electrohydraulic control systems, they can execute all of the following:

— open/close all downhole, tree, manifold and flowline valves during normal operations;

— shut in production due to abnormal conditions, such as evidence of hydrocarbon leaks and high/low pressures;

— shift the position of TFL tool diverters;

— control the position of subsea and/or downhole chokes;

— operate miscellaneous utility functions, such as the chemical injection system;

— monitor subsea parameters such as valve positions, temperature, pressure, sand production and the condition of SSP equipment;

— monitor control system variables and housekeeping parameters such as hydraulic fluid pressures, communications status and system voltages;

— transmit data from multiphase meters and downhole sensors to the control system on the host facility.

A.8.1.12 PCSs are seldom provided with means of controlling installation functions such as latching of subsea hydraulic connectors or operating vertical access valves and pressure test ports.

A.8.1.13 A subsea control module (colloquially referred to as a “control pod”) is normally mounted directly on the facility to be controlled, such as a subsea tree/manifold, on a base from which it can be removed for maintenance if necessary. The control pod is the interface between the control lines, supplying hydraulic and electric power and signals from the host facility, and the subsea equipment to be monitored and controlled. The control pod contains pilot valves powered by hydraulic fluid, electric power or both, that is supplied from the host facility. The pod also contains electronic components that are used for control, communications and data-gathering.

A.8.1.14 Pressurized control fluids are used to actuate subsea functions; they are designed to lubricate and to provide corrosion protection to wetted parts. The hydraulic control circuit may be either open or closed, i.e. it may either vent to sea or return the fluid to the host facility when various subsea functions are actuated. Either biodegradable water-based, petroleum or synthetic mineral fluids can be used as control fluids. Only biodegradable water-based fluids may be used in open systems in which spent fluid is exhausted subsea. Petroleum-based fluids should only be used in closed systems in which exhausted fluid is returned to the fluid reservoir. Information on the required properties and testing of control fluids is contained in ISO 13628-6.

A.8.1.15 Test stands, etc., are used to ensure that the control system equipment is functioning in accordance with all operational specifications prior to installation.

A.8.1.16 A dedicated running tool is usually provided with the PCS, so that the pod can be retrieved and reinstalled subsea for maintenance if necessary.

A.8.1.17 Locally sited control buoys, as described in A.8.4, are also an alternative to traditional multicore seabed umbilical control systems.

A.8.2 Fibre optics

A.8.2.1 Fibre optic cables are also an option for transmission of control and monitoring signals between the host facility and the subsea equipment. For subsea production systems involving downhole pressure/temperature gauges and/or multiphase flowmeters, large amounts of data need to be transmitted to the MCS on the host facility. For these applications, the high data transmission rates and wide bandwidth offered by fibre optics provide a significant advantage over traditional copper wire communications cables.

A.8.2.2 Other advantages of fibre optic communication systems are

— freedom from electromagnetic interference and cross-talk,

— low mass compared to copper cable,

— elimination of electrical sparking and fire hazards,

— lower transmission losses than in coaxial cables at high frequency, thus reducing the need for repeater stations over long distances.

Further information on fibre optic cables is provided in A.9.1.3.

A.8.3 Acoustic control systems

A.8.3.1 Acoustic through-water control systems are currently only in limited use, due to limitations on their effective range and their requirement for power generation at the wellsite. Relatively low power requirements can be achieved through the use of highly directive, narrow-beam systems.

A.8.3.2 The performance of acoustic systems is significantly influenced by the properties of the seawater, including the salinity, temperature, depth and surface noise from waves. The water depth is a particularly significant factor, as in relatively shallow water (e.g. the North Sea) the acoustic waves tend to bend toward the surface of the water, thus dramatically limiting the range of communication.

A.8.3.3 The speed of response of acoustic systems also needs to be taken into account, bearing in mind that signals can only be transmitted as fast as the speed of sound in seawater and that a cyclic redundancy check is required for each message, as specified in ISO 13628-6.

A.8.3.4 Acoustic control systems that transmit and receive data via the pipewall of the flowline/pipeline are also possible, but these are not currently in general use.

A.8.4 Control buoys

A.8.4.1 One alternative to the use of a multicore umbilical which runs between the host and the subsea facilities is the use of a locally sited control buoy.

A.8.4.2 A control buoy can be anchored within the immediate vicinity of the subsea facilities and can be used to provide a communications link with the subsea facilities, typically via radio telemetry from the host to the control buoy and thence, via a relatively short dynamic umbilical, from the control buoy to the subsea facilities. The control buoy can also be used as a site from which to provide electrical and hydraulic power to the subsea facilities, as well as chemicals such as hydrate inhibitor, corrosion inhibitor, etc.

A.8.4.3 A number of factors should be taken into account when making a choice between a multicore umbilical from the host versus an onsite control buoy, including

- health and safety considerations, including the risks to personnel when transferring to/from the buoy, emergency escape from the buoy, hazards presented by storage of chemicals on the buoy and normal working conditions/constraints inside the buoy, e.g. confined space entry-type hazards, handling of large equipment items inside the buoy and propensity for motion sickness,

- environmental considerations, including the potential for leakage of chemicals from a dynamic umbilical and spillage of chemicals during reloading operations,

- risks to shipping and prevention of unauthorized access to the buoy,

- overall system availability, including an assessment of the ability to access the buoy in various weather conditions for emergency maintenance,

- life-cycle cost comparison, including operating costs for inspection and periodic maintenance of the control buoy and its associated anchoring system and the dynamic umbilical.

A.8.5 Multiphase flowmeters (MPFM)

A.8.5.1 MPFMs are in-line meters designed to measure the relative flows of gas, oil and water in a flowline, without requiring prior separation of the phases. However, some MPFMs do require some form of flow conditioning upstream of the meter. Measurements of the flowstream are made by two or more sensors, and the resultant data are processed to yield the individual phase flowrates.

A.8.5.2 The potential benefits of MPFMs in subsea field development applications can include