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Optimizing pressure in subsea pipes with HIPPS

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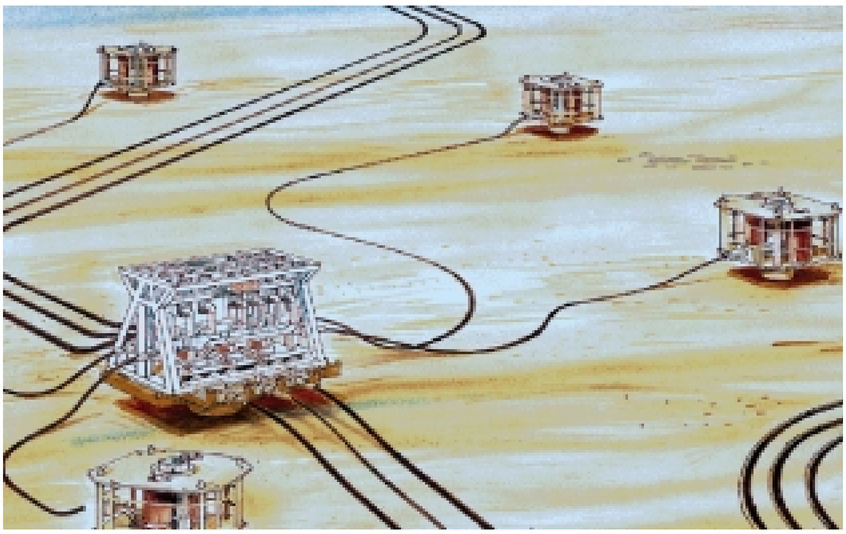
Most of the 'easy' oil fields have now been discovered, making it likely that new fields will be more difficult to develop than in the past. For those fields where high pressure is the main technical challenge, ABB offers a subsea High Integrity Pipeline Protection System (HIPPS) which, by confining the high pressures to the wellhead area, allows existing infrastructure to be used. When subsea HIPPS is installed, the flowline and riser pipe wall thickness can be rated to just the flowing pressure. A modularized, flexible system, subsea HIPPS helps oilfield operators to reduce the cost of developing pipeline solutions without compromising safety.



1 A typical subsea situation with connection to the production facility on the ocean surface

Subsea oil wells are commonplace in today's oil industry. The wells are normally spread out on the sea floor, with subsea pipelines, known as flowlines, connecting them to a gathering manifold that transports the produced oil to process facilities on the surface (called topsides) 1. The flowlines from the manifold to the topsides can be tens of kilometers long.

When the wells are producing, the pressure in the pipeline is determined by the process pressure topside and the dynamic losses along the pipeline. If the flow is shut off topside, the well will continue to produce into the pipeline until the pressure is in equilibrium with the static reservoir pressure. Pipelines are traditionally designed to handle the shut-

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in pressure, which is substantially higher than the flowing pressure.

The usual practice is to design the topside process equipment for a lower pressure than the shut-in pressure. The point along the process line where a lower design pressure is allowed is called a pressure specification break. An emergency shut-down valve (ESV) is installed here, with a process relief valve downstream to bleed off any excess pressure in the form of combustible fluids to a flare boom, where it is burnt.

Increased environmental awareness throughout the oil industry has led to flaring having to be reduced to a bare minimum. Since the safety of the personnel on the installation obviously has to take first place, any alternative to flaring must operate at least as safely as the present solution. The solution favored until now has been to install HIPPS topside, where the flowlines are taken onboard the process facility, in series with the ESV. In such a case, HIPPS has one or more fast-

Pressure management with HIPPS

A large part of the total budget for subsea oil and gas developments goes on pipeline costs. The reason is that production flowlines from the wellhead to offshore processing or storage facilities are usually built to withstand the high wellhead 'shut-in' pressures, even though the pressure in the pipeline is much lower under normal operating conditions. Building this pressure 'buffer' into the system can be costly and jeopardize the economic feasibility of such developments.

ABB's High Integrity Pipeline Protection System (HIPPS) gets around this problem by safely downrating the pipeline pressure. Since it automatically monitors the pressure, HIPPS is able to instantaneously close the pipeline the moment a preset level is exceeded. This is done using a choke to maintain a continuous pressure drop, with barrier valves that close if the pressure increases. A control module activates the protection system.

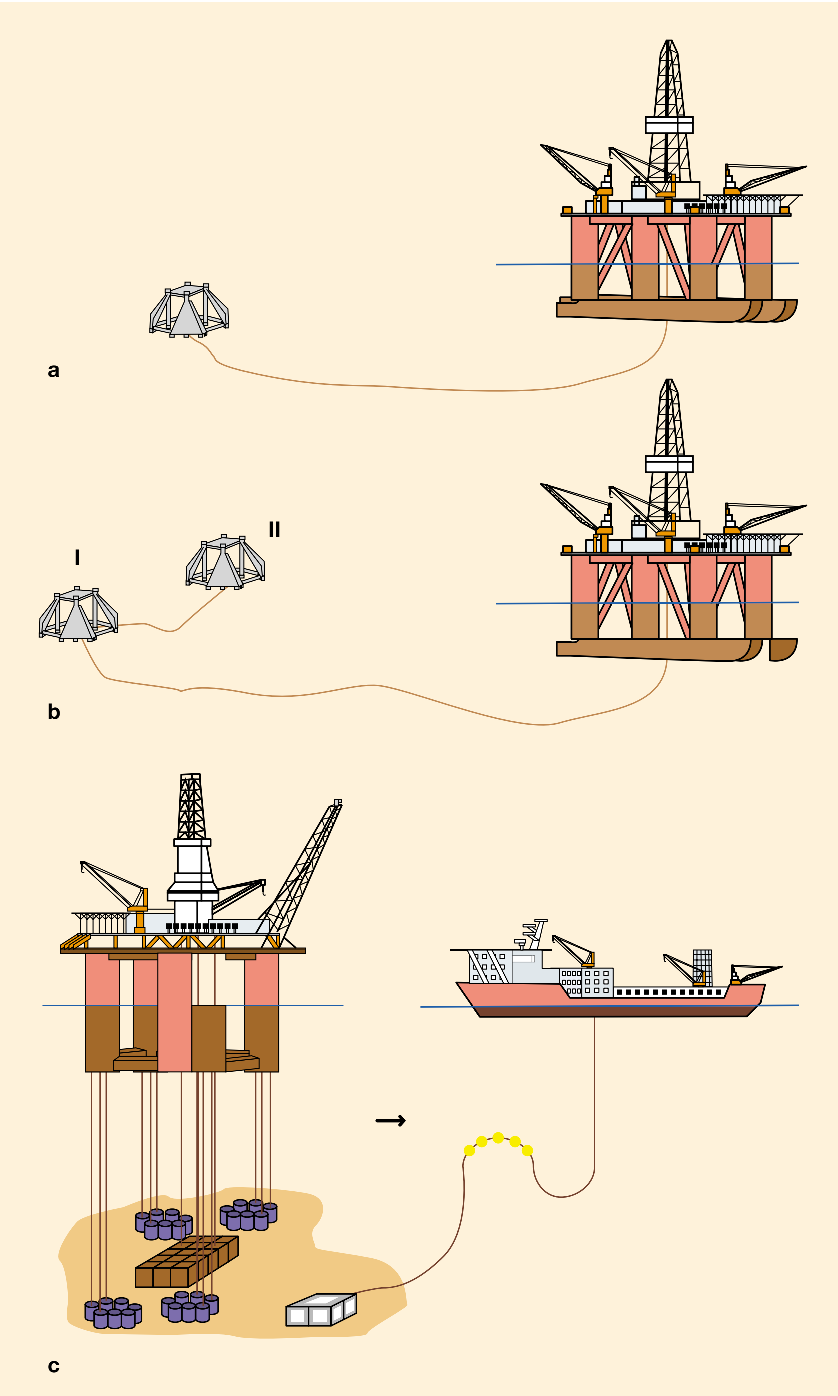
HIPPS, which has a modular structure, can be equipped with valve and control systems to suit a wide range of conditions. In all, HIPPS and its associated concept evaluation software, which can compare the grade of material needed for any pipeline, can save producers as much as 30 percent of the capital costs of a project.

2 Different scenarios for HIPPS application:

a *High-pressure well tied back to a processing facility more than 20 km away*

b *High-pressure well 'II' tied back into an existing low-pressure flowline from well 'I'*

c *An expensive tension leg platform can be replaced by a less expensive floating vessel with flexible risers. Subsea HIPPS protects the flexible risers from high pressure*



acting shut-off valves and an autonomous safety control system that shuts the valves if the pressure rises beyond the allowable limit.

A natural next step in the evolution of offshore pressure protection will be to move HIPPS closer to the wellhead, where it will also protect the flowlines and risers.

Benefits of subsea HIPPS

HIPPS protection of the subsea flowlines and risers from the shut-in pressure may even offer the only viable means of developing some fields. Studies of the application of subsea HIPPS technology indicate three scenarios where the economic benefits are significant **2** :

- Long-distance tie-back of a marginal high-pressure field to existing topsides.
- Tie-back of a marginal high-pressure field into existing subsea infrastructure.
- High-pressure fields where a Floating Production Storage and Offloading (FPSO) vessel with flexible risers is preferred.

In the case of long-distance high-pressure tie-back, the cost of the pipeline is high due to the combined effect of the thick pipe wall and the length of the pipeline. Added to this is the cost of corrosion resistant alloys when the reservoir fluids are corrosive. A reduction in wall thickness of about 30% can often be achieved when HIPPS is used, so when the pipeline is long the savings are substantial. As a rule of thumb, the break-even point for HIPPS is a tie-back length of about 20 km (12 miles) and pressures greater than 5,000 psi with corrosive fluids. (Break-even in this context means that the savings more than offset the life cycle cost of installing HIPPS). For a 30-km (19 miles) 300 mm (12-inch) tie-back of a 700-bar (10,000 psi) field with corrosive fluids, the saving in pipeline costs with subsea HIPPS could be in the order of US$ 25 million.

In the scenario with tie-back to existing subsea infrastructure, a pipeline already leaving the area is rated at less than the pressure required for a new discovery. With HIPPS the new well can be produced through the existing line. The material cost of the pipeline as well as the cost of the laying operation are saved.

The last scenario considers a high-pressure reservoir being developed in water too deep for a fixed platform, making a floating vessel necessary (either a tether-moored floater or a chain-moored floater). FPSO vessels are less expensive and often preferred, but they move significantly with the motion of the sea, so that flexible risers are needed to get the well flow from the sea bed. If the pressure is high, the flexible risers cannot be made strong enough to withstand it, and the operator is left with only the tether-moored option. This is where subsea HIPPS comes in: by protecting the flexible risers from high wellhead pressures, it makes the less expensive chain-moored structure a viable alternative.

In all three scenarios the cost saving offered by HIPPS is high enough to sway the decision when looking for alternative methods of cost-effective production.

Operating principles

Subsea HIPPS is assembled in the subsea flowline close to the wellhead, and the production flows unrestricted through it under normal conditions. The flowline pressure at this location is continuously monitored and compared with the safe operating pressure level. If it rises above this level, HIPPS triggers fast-acting valves 3, which shut the inflow to the flowline. A two out of three voting logic is used for the pressure readings to ensure maximum safety and minimize spurious tripping.

Causes of pressure increases may be flow restrictions occurring further downstream or an increase in flow somewhere upstream of HIPPS (*see Table*).

Blockages in the downstream flowline may demand a very quick response from HIPPS. If the distance to the blockage is short and the pressure increases rapidly, HIPPS has to act fast. The present design has a response time of approximately two seconds from fully open to fully shut. In terms of distance to the blockage, this corresponds to approximately 200 meters, depending on the compressibility of the fluid. Within this short distance – referred to as the fortified zone – the flowline must be rated to the full pressure to ensure safe operation. Downstream of the fortified zone the flowline wall thickness may be significantly reduced.

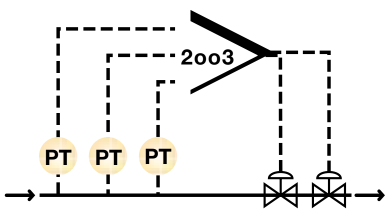
Like any other safety system, HIPPS must be tested periodically to verify that it performs properly. A set of auxiliary functions enables the tests to be performed smoothly, so that production is disturbed as little as possible:

- The electronics are continuously monitored by watchdog functions.
- System functionality can be tested by partial closing of the valves.
- Valve integrity can be tested by closing and subsequent barrier testing.

HIPPS: 'made-to-measure'

System services

ABB's offshore portfolio includes complete subsea production systems, and HIPPS is an important building block in the systems designed for high-pressure fields. The establishment of procedures for assessing



3 Schematic of the overall system configuration

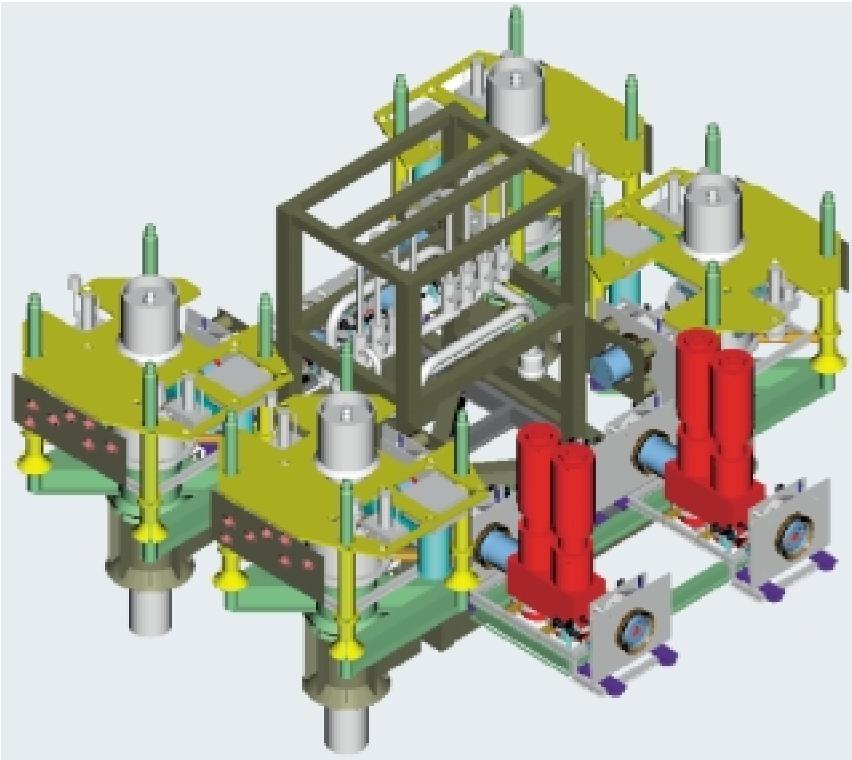
PT *Pressure transducer*

2oo3 *Two out of three voting logic and comparison of pressure with trigger limit*

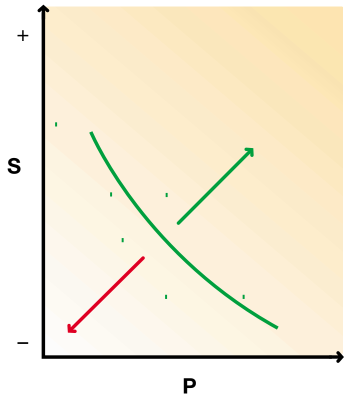
Table

Events that may cause an undesired increase in flowline pressure and require action by subsea HIPPS

⇧	**Events upstream of HIPPS**	Production choke ruptured Sand screen ruptured or similar
⇩	**Events downstream of HIPPS**	Valve shut topside Flowline blocked due to hydrates or similar



4 A subsea production station with four wells and HIPPS mounted on the manifold headers



5 Performance of subsea HIPPS with respect to safety (S) and production availability (P)

Green arrow *Higher system efficiency*

Red arrow *Lower system efficiency*

how these systems and HIPPS perform together was therefore an important part of the development program.

Subsea systems are modular to allow the replacement of parts using underwater intervention tools. A multitude of field architectures is thus possible by connecting the modules in new patterns, while the number of module variations from project to project can be minimized. HIPPS has been designed to fit into this concept. One example of its implementation can be seen in 4, which shows a subsea production station with four wells and HIPPS on the manifold headers. The HIPPS equipment, red in the diagram, is cantilevered off the bottom structure of the gathering manifold. Each HIPPS block, with two barrier valves in series, can be retrieved separately by subsea intervention tools for repair if required. The production flowlines are connected to the outboard hub of each block.

Two critical parameters for finding the best subsea HIPPS variant are the technical safety of the system and the production availability. The safety of the system is determined by means of a quantitative assessment of the Critical Safety Unavailability (CSU), the production availability being found by analyzing the Reliability, Availability and Maintainability (RAM). The production system architecture must be optimized with respect to both of these parameters.

To be as safe as a process safety valve or a flowline wall for the full pressure rating, HIPPS must have a CSU of the order of 10-4 failures per year. As this performance has to be documented, a significant effort has gone into establishing the reliability performance of the system components through analysis and development of in-house databases. System performance, with respect to safety and availability, is simulated using these data as input, and the results used to recommend what ABB believes to be the best solution 5. The scatter shows point estimates of various system configurations. A trend line is included to show the optimum existing between safety and production availability for a given set of equipment. Higher safety means that the system is optimized more towards shut in, which in turn will lead to more production shut-downs. Finding the right balance is important when analyzing how the system should be configured. A performance shift in the direction of the green arrow indicates increased system efficiency, whereas a shift in the direction of the red arrow indicates the opposite.

Barrier valves

The function of the barrier valves is to shut off the inflow to the flowline when the control system signals a high pressure. Since the flow is normally routed from several wells into a gathering manifold before entering the flowline, the valves can be located on the header or in the branches from the individual wells.

The HIPPS valves are built using the proven 'fail safe close' slab gate valve design. All process seals are metal-to-metal with elastomer backup on the seat-to-body and stem seals. This is the state of the art for sealing technology for subsea valves and will ensure high sealing integrity over a long design life.

During normal production, the valve is kept open by hydraulic pressure applied via the control system. If a high pressure is detected the pressure is equalized over the actuator piston and the process pressure will close the valve by acting directly on the stem. This method of actuation ensures that a minimum number of components are used in the control loop, thus enhancing safety. The actuators have large control ports for fast operation.

At the time the HIPPS project was started, gate valve designs for high pressure, eg 1035 bar (15,000 psi), were only available for bore sizes up to 7". This size is suitable for the flow from one or two wells, but is often too small for more wells. A safety study was therefore performed to see if it would be feasible to distribute the barrier valves on the well branches, and cases were identified where it would be necessary to have valves on the manifold header, ie with a large bore. To find out what size valves would be required, a market survey was carried out to look into potential high-pressure field developments. The study indicated that a 10-inch bore valve would cover most of the scenarios. Being within the practical limitations of present-day gate valve technology, it was decided to design and qualify this valve 6.

Shut-in pressures will obviously decrease in time, until at some point HIPPS protection is no longer required to operate the flowline safely. It must therefore be possible to disable the functionality of the system without compromising safe operation. The valve actuator has a special type of mandrel at the end for this. A lock open device can be inserted into this mandrel using a remotely operated vehicle when the HIPPS valves are no longer required.

Qualification of this new barrier valve has now been completed, enabling subsea HIPPS to be optimized by distributing

6 Gate being fitted into a 10-inch, 15,000 psi prototype valve

barrier functionality between the individual production wells and the manifold headers.

Choice of control system

In most cases the HIPPS control system is hosted in the form of add-on functionality in one of the modules used for the subsea production control. The type of control technology used for HIPPS will be dictated by the rest of the control system. Electro-hydraulic technology is currently used for most production control systems where the offset distances are long enough to justify HIPPS, so this technology is the most obvious one to use. However, due to the flexibility of HIPPS it could also be used with electrically operated valves, which are found widely in modern process plants but not yet in subsea operations.

Subsea production control systems are generally configured to 'fail as is' in the event of electrical power or communication failures. The idea is to maintain production in cases where a temporary loss of control functionality has no safety implications. However, such an approach cannot be used with HIPPS. The control system must be configured so that the barrier valves close in the event of a safety function failure, ie it must be fail-safe.

Certain failures in non-safety critical parts of the system need not trigger barrier valve closure. For example, a temporary loss of communications, shorter than a set time limit, can be tolerated as the pipeline is still protected by the subsea part of the system. This example shows that to achieve high safety availability, pressure sensing, decision-making (comparison, voting, etc), and valve control should be located near the barrier valve, thereby removing complex communications equipment and subsea umbilicals from the safety critical heart of the system.

The subsea HIPPS control system comprises the following elements:

- Pressure transmitters for converting pipeline pressure into electrical signals.
- Threshold comparison and voting logic, which goes into action when a certain number of pressure transmitter signals exceed the set level.
- Solid-state switches for the solenoid-operated control valves, triggered by the voting logic.
- Solenoid valves to control the barrier valves (replaced by circuit-breakers in an all-electric system).
- Non-safety critical functions for monitoring, testing, communications and power supply.

Pressure transmitters

Pressure signals are obtained using conventional pressure transmitters of proven design and employing strain gauge techniques. Detailed studies, backed up by extensive field experience, prove the good reliability of these devices. Flush diaphrams replace the small ports found on some transmitters, thereby preventing blockages associated with hydrates, waxing and sand.

Threshold and voting hardware

The pressure transmitter signals are processed by a Safety Critical Control Board (SCCB). This unit compares each pressure signal with a pre-set value and, when sufficient inputs exceed the setpoint, switches off the current to the solenoids controlling the barrier valves.

After considering several voting regimes, the two out of three (2oo3) and three out of five (3oo5) regimes were short-listed. The pressure transmitters are considered to be the least reliable part of the voting system and have a Mean Time Between Failures (MTBF) of the order of 50 years. A 2oo3 voting system can tolerate one failure, this being likely to happen in 16.7 years. A 3oo5 system can tolerate two faults, the first fault being likely to happen in 10 years and the second after 20 years. The move from 2oo3 to 3oo5 affords an improvement of 3.3 years MTBF for the system. Since this slight improvement will probably be eroded by the increased complexity of the voting unit, leading to higher unreliability, the unit is designed for 2oo3 voting.

Careful design enabled the parts count to be kept to a minimum. The small number of components and the fact that only proven parts are used ensure maximum reliability. All the SCCB functions are monitored continuously. The monitoring circuits are designed such that failures elsewhere in the system cannot cause incorrect operation of the SCCB. The voting logic latches after a trigger event, and an external signal from the surface is required to reset the system before the barrier valves can be reopened. It is not possible to use the reset to inhibit correct functioning of the SCCB.

Safety critical control valve

The safety critical control valve is essentially a solenoid-operated, spring-return hydraulic valve. When the solenoid is energized, the hydraulic valve feeds fluid to the barrier valve actuator to open the pipeline: loss of solenoid power makes the barrier valve close. The large swept volume of the 10-inch barrier valve actuator makes fast operation essential. For this reason, a large control valve with 1.5-inch ports is used.

High Integrity Pipeline Protection System (HIPPS) under test in the laboratory

Non-safety critical functions

The SCCB fits into one of the card slots in a standard subsea electronics module, which provides a one-atmosphere environment as well as the required power supplies, monitoring and communications. These are the non-safety critical 'house-keeping' functions which are necessary for operation of HIPPS. A failure in this area cannot cause HIPPS to fail and become unsafe.

Non-safety critical tasks carried out by the system include:

- Control of vent and methanol injection valves around the barrier valves.
- Continuous monitoring of safety critical functions.
- Periodic test routines, such as partial closure tests and barrier integrity tests, plus reporting of results.
- Provision of a reset signal to the safety critical logic after a HIPPS trigger event.

Production chokes

Although chokes are not normally part of the HIPPS system, reliable high-performance choke valves are required for high-pressure developments. Operations such as starting and stopping flow from the wells must be performed by the subsea choke when the flowline cannot take the shut-in pressure. Compared with current practice, in which subsea chokes are operated at lower pressures and adjusted only occasionally, HIPPS makes considerably higher demands on the chokes. It was therefore decided to include a new choke design in the development program.

The new production choke is based on the retrievable insert subsea choke design and has a plug-and-cage type trim with dual pressure let-down. To ensure that the choke can take the high pressure and handle the large number of operations, all the process seals are metal-to-metal; also, a new stem seal, based on the gate valve design, has elastomer back-up for maximum reliability over the design lifetime.

The pressure rating is the same as for the barrier valves, ie 1035 bar (15,000 psi), while the temperature capability is high at up to 200 °C (392 °F).

An advantage of using the choke with HIPPS is that it may be used to actively counter pressure increases in the system. Every high-pressure situation that is avoided by operating the choke is one less situation that needs to be handled by HIPPS. The choke therefore has a high-speed motor-driven actuator rather than the usual stepping actuator. Both hydraulic and low effect electric motors can be used with this actuator.

Outlook

Subsea HIPPS is beginning to gain acceptance in the highly conservative oil industry. The equipment has now been qualified and it is regarded to be only a matter of time until the right field is identified for the implementation of ABB's subsea HIPPS solution.

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