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Inspection and testing procedures improve BOPs for HPHT drilling

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Blowout prevention (BOP) equipment for high-pressure, high-temperature (HPHT) operations requires consistent, thorough inspection and testing procedures to maintain high performance standards.

A consortium of seven Norwegian operators commissioned WEST Hou Inc. to evaluate the parameters affecting the safety and reliability of BOP equipment for high-pressure, high-temperature operations. This study also analyzed several aspects of BOP equipment for normal temperature and pressure operations.

The study scope included equipment manufacturing specifications; temperature, pressure, and fluid effects on equipment; BOP stack configurations; and methods for inspecting, testing, and maintaining well control equipment.

The data come from audits of BOP equipment on 25 HPHT rigs operating in the North Sea and Southeast Asia, investigations of standard-temperature elastomers in BOPs on 165 rigs, technical material from the original equipment manufacturers, extensive meetings with the manufacturers, and some operator experiences.

Overall, with few exceptions, the study found that BOP equipment built to American Petroleum Institute (API) specifications is fit for purpose when it leaves the manufacturer. Afterward, maintaining the high-performance standard is the responsibility of the equipment owner.

A key finding of the study was that equipment-specific inspection and testing procedures (ITPs) are beneficial to maintain high performance BOP equipment to an acceptable standard. Specific acceptance criteria for each field test are necessary.

Based on a presentation at the International Association of Drilling Contractors Well Control Conference of the Americas, Houston, Nov. 16-17, 1994.

Fig. 1

HIGH TEMPERATURES INCREASE ELASTOMER HARDNESS

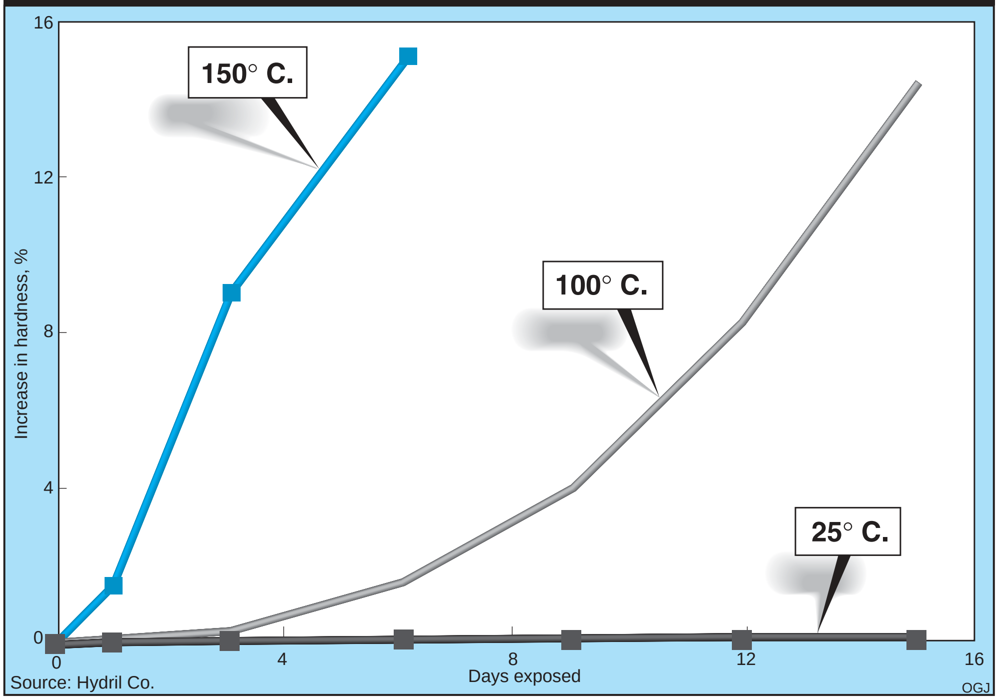
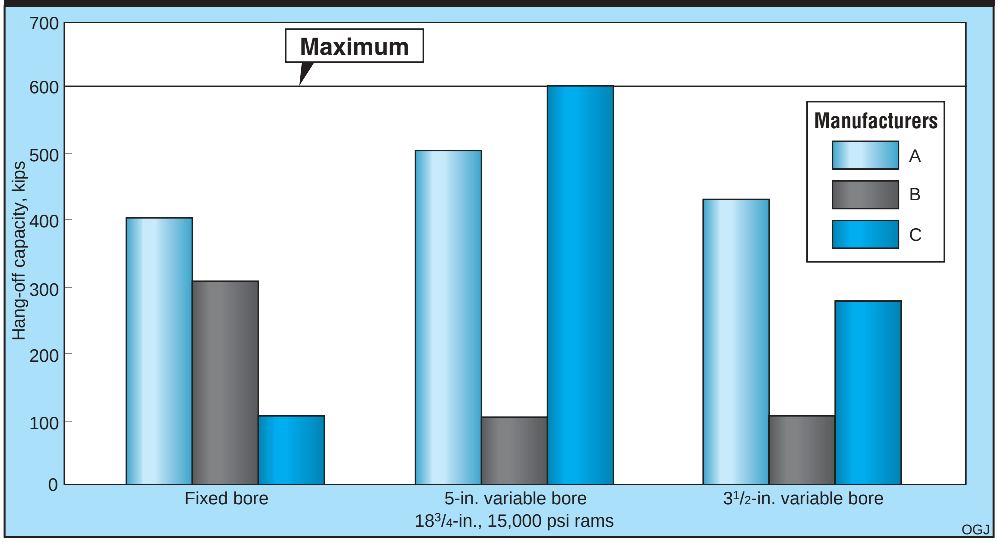


Fig. 2

HANG-OFF TESTS WITH LOCKING SYSTEM ONLY



Equipment in use

Most BOP manufacturers follow high-quality in-house standards and API Specification 16A. Thus, BOP equipment comes from the manufacturer fit for purpose.

Most problems occur with equipment that has been in the field for some time, and not with new equipment. The drilling industry does not have a specification for BOP equipment repair. Used equipment may not perform like new equipment, generally because of a lack of thorough maintenance and testing. In some cases, the most recent repair may not have used parts from the original equipment manufacturer.

If equipment performance does not meet expectations, the problem usually results from a lack of detailed inspection and testing procedures (with specified acceptance criteria) or a lack of quality-control in some non-original equipment manufacturer repair facilities. Adequate specifications and procedures may not be available for third-party maintenance personnel to inspect and test equipment.

This problem usually results because the information is not available from the manufacturer, the information did not reach the service man on the rig, or the maintenance staff did not know the information was available.

Technical information

One of the largest obstacles to proper BOP equipment maintenance today is the poor availability of information. Some manufacturers have made an exemplary effort to publish engineering bulletins to distribute their technical information, and the distribution of this material is an integral part of their quality system.

Although other manufacturers have much technical data in their files, they have not been as diligent about publishing these data. Thus, the information is difficult to retrieve or exists in a format unsuitable for distribution to the customer. Furthermore, many equipment manufactures have reduced staff dramatically during the past decade, leaving fewer engineers to produce technical bulletins.

After the first study meeting for this project, one major BOP equipment manufacturer realized it needed about 20 additional engineering bulletins to support its equipment. This type of reaction was common for other manufacturers as well.

Most equipment manufacturers do not consider BOP equipment inspection standards proprietary, but they do need control over the distribution and revision of information. Each company maintains stringent practices and procedures for the manufacturing process; however, in many cases the manufacturers have not specified an acceptance standard for used equipment.

Although modifying testing and inspection procedures for used equipment is subjective, improving the "if it pressure tests, it's good" inspection philosophy will benefit the industry.

Man on the rig

There are several reasons why the man on the rig may not know about new developments with his company's equipment, even though those developments may have happened years ago:

- The manufacturer's distribution practices may be poor.
- Sales of equipment between drilling contractors and trades between rigs create difficulty for the manufacturers to know who is the current equipment owner.
- Problems exist within the contractors' distribution and implementation programs.

Maintenance staff

In some cases, the maintenance staff did not know the information was available. Even if the information was published by the manufacturer and distributed to the current owner and rig, many of the modifications and developments may have occurred years ago, and recent personnel changes may reduce the understanding of some equipment details.

Documenting changes and making the information available are among the most effective ways of improving equipment reliability. The use of inspection and testing procedures (ITPs) for each component on the stack can improve quality control. ITPs have two benefits: the quality is consistent, and the critical parameters only have to be identified once.

Information transmitted to maintenance staff in the form of ITPs should contain the following:

- Inspection procedures and acceptance criteria
- The technical source of critical specifications.

Information used to inspect and test equipment can come from a variety of sources. Rather than many people being responsible for remembering what the information is and where to find it, it should be recorded in the ITP.

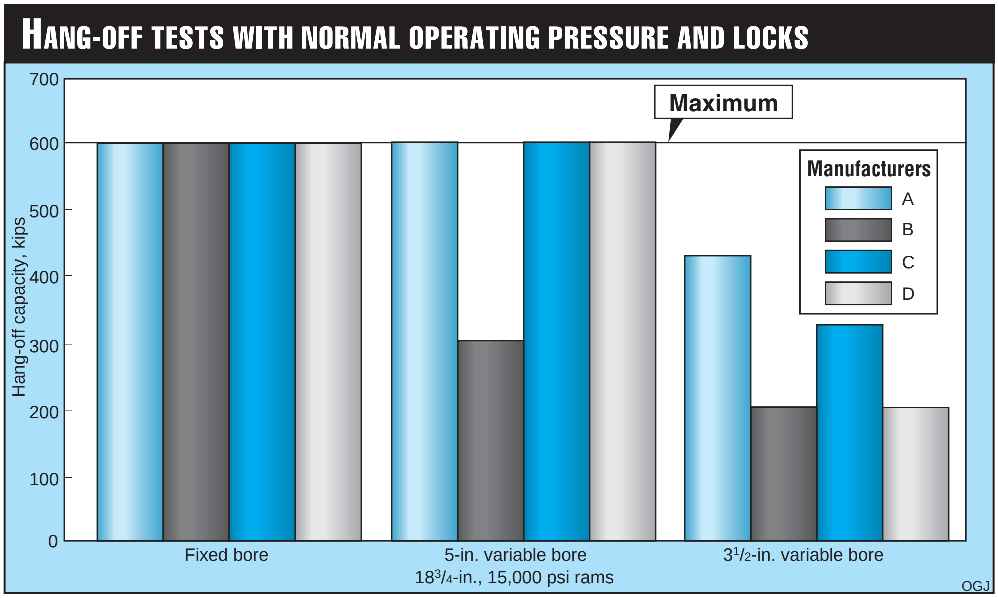
- A procedure to keep the system current.

Once an ITP is written and distributed, controlling changes becomes instrumental in keeping it current. A standard procedure should be developed to distribute new information to the people who need to know. With change control and new procedure distribution procedures, a system can be continually improved when a new method is developed or additional information becomes available.

Equipment performance

Because of the lack of field ITPs for equipment in use, equipment owners must develop their own equipment inspection and testing procedures. These ITPs should have specific acceptance criteria based on the manufacturers' recommendations and be supplemented with experience and good engi-

Fig. 3



neering practices.

The industry can continue to expect to be guided by the manufacturers. Because the manufacturers' capital equipment sales and engineering support staffs have continued to decline over the past 15 years, the contractors and operators must use their own engineering knowledge to improve the reliability of drilling equipment. Relying only on one's own experience, however, does not allow a company to benefit from the experience and expertise of the industry.

The manufacturing process has numerous quality checks, inspections, and tests to ensure the equipment performs as required. The technical objectives of these tests lead to equipment performance criteria.

Marine riser

The following example, using a marine drilling riser, illustrates the importance of testing and performance criteria. Riser problems can significantly affect downtime. A 1987 Sintef (Foundation for Scientific & Industrial Research at the Norwegian Institute of Technology) reliability study reported risers as the second leading cause of equipment downtime on floating rigs off Norway. Petrobras, in an independent study, found risers as a leading downtime cause in the deep waters off Brazil.

The development of an adequate riser test procedure begins with an analysis of its operational requirements, including the following:

- Required surface finish of the Colmonoy No. 5 overlay on the choke and kill line pins
- Minimum allowable OD of the choke and kill pins
- Allowable choke and kill box surface finish on the OD of the choke and kill seals
- Minimum end float of the choke and kill lines (a dynamic seal)
- Different load limits of the telescopic joint in the extended and collapsed position
- Telescopic joint bolting requirements (several stacks have been dropped because of problems in this area),

Manufacturers have made only a small portion of this information available to the equipment owners for riser inspection. Thus, there are three choices in the development of adequate testing procedures:

- Use new equipment inspection standards on used equipment
- Continue to use the pressure test as the only acceptance criteria
- Use good engineering judgment to develop minimum standards.

Although some companies might consider specific data proprietary, such as dimensional data, no inspection standard would be acceptable without it.

With an industry average for subsea BOP stick downtime of 4%, continued use of the pressure test as the sole acceptance criteria is not the most economical choice. Thus, good engineering judgment is a must in the absence of specific manufacturers' recommendations for complete inspection procedures to supplement the standard pressure test.

All marine drilling riser manufacturers use Colmonoy No. 5 on the pins because of the material's hardness and abrasion resistance. Riser manufacturers have not yet published specifications for acceptable choke and kill pin surface finish. Based strictly on experience, WEST Hou's procedures specify 32 rms (root mean square) surface finish as acceptable. In a meeting for the Norwegian study, Greg Childs, drilling products manager for Cooper Oil Tools, stated that 32 rms was an acceptable inspection standard for a Cooper riser in service.

Considering this technical information may be the best available, and all choke and kill pin designs operate on the same engineering principle of a dynamic seal, this specification can be used as the engineering standard for the inspection of other manufacturers' risers. From the experience basis for this specification and the verbal assent of one manufacturer, it is logical to apply similar good engineering judgment to other equipment.

Only mechanical criteria were used in this example. The allowable operating ranges must also be specified. An example of an allowable operating range is the required hydraulic pressures for operating a wellhead or riser connector.

The ITP should include steps to lock the connector to the test stump with 1,500 psi and 3,000 psi hydraulic pressure and record the required unlocking pressures for each case. Unlocking at too low or too high a pressure is equally unacceptable. In the former case, "back-driving" or unlocking of the connector from external forces, such as well bore pressure, tension, or bending, might occur. In the latter case, there may be difficulty in getting the stack or lower marine riser package off the well. (Not being able to disconnect when necessary for inclement weather or a wild well is extremely dangerous.)

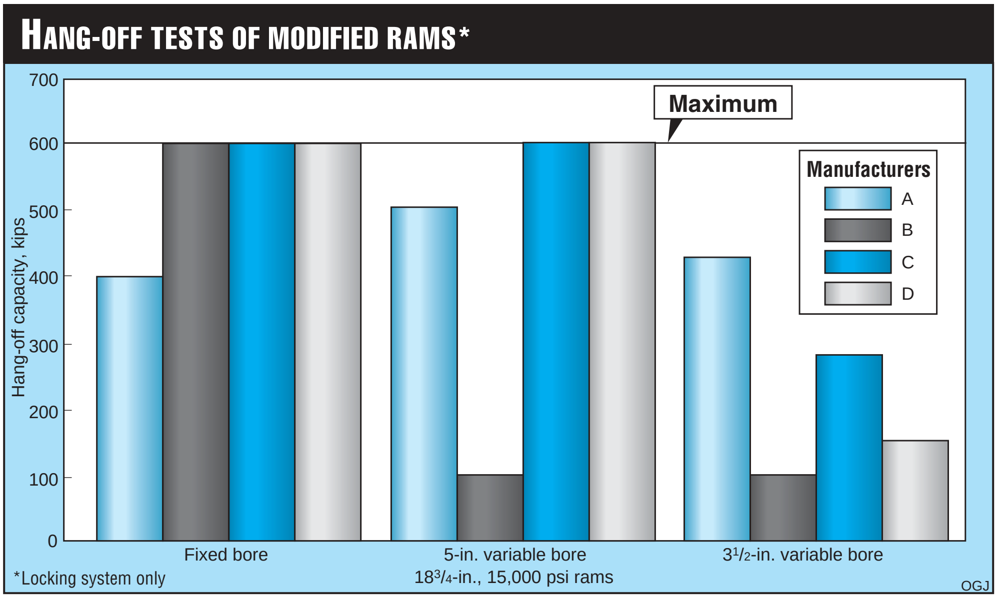
Pressure ratings

A demonstrated safety factor is commonly included in pressure ratings. For example, ram bodies are tested to 1.5 times the rated pressure for pressure ratings ≥10,000 psi and twice the rated pressure for lower ratings.

Not well known, however, is that closed preventer testing on BOPs is only done to the maximum working pressure. (In this type of test, the well control equipment is in the closed position, and the seal is tested at the rated pressure.) Thus, for a 15,000-psi ram, a safety factor for pressures greater than 15,000 psi may not be used, even in the manufacturing facility.

The assurance that the

Fig. 4



rams are fit for purpose at their rated pressure comes from proper maintenance, regular and comprehensive testing, and confidence in the manufacturer's design criteria, fatigue testing, and use of (American Society of Mechanical Engineers) design allowables for working pressure.

There is no industry standard for pressure testing any weld-repaired BOP equipment, even when the original equipment manufacturer does the work. Thus, the equipment owners must have internal quality standards to ensure safe operation of repaired BOP equipment.

Temperature ratings

There is no industry standard for high temperature testing. All of the full-scale testing on ram preventers to date has used operating pressure on the close side of the rams. One industry expert said that this method is necessary to achieve a seal and that well bore testing at high temperatures will not work without operating pressure on the close side of the rams, using only the ram locking device.

An operator should consider that well bore integrity of 5-in., high-temperature packers has never been proven in the absence of operating pressure on the close side of the rams. This issue should be carefully considered during well planning, prior to having to disconnect the lower marine riser package on a floating drilling rig or abandoning a rig.

Some ram packers are rated as low as 200° F. One Southeast Asia operator, contacted for this study, recently "cooked" a set of 5-in. packers while testing a well with a static bottom hole temperature of 268° F., indicating the importance of knowing both the anticipated downhole temperature and the temperature rating of the elastomers.

Many equipment-specific issues must be addressed for a stack dressed for a high temperature well. Many stacks rated at 10,000 psi are used on wells in Southeast Asia, and consequently the rigs may encounter availability problems in acquiring the high temperature elastomers. Additional planning is necessary to provide adequate lead time for acquiring these high temperature elastomers. Some manufacturers do not recommend resilient gaskets for wellhead connectors, and at least one manufacturer provides a special elastomeric compound for resilient gaskets used for high temperature applications.

Another consideration is that some fail-safe valves cannot be upgraded for high temperature applications.

BOP connections

Washed-out ring grooves on BOP connections can cause loss of containment. Manufacturers strongly recommend that hubs or flanges have face-to-face contact for surface and subsea installations, but there is not yet an industry recommended practice that specifies this contact. Also, an operator or contractor needs to verify that the stress loading on the BOP kill and choke line outlet is within the allowable range for the choke and kill line connections.

Washed out ring grooves are avoidable. The ITPs should verify that face-to-face contact has been achieved on all drill-through connections and side outlets. The ITP should specify all aspects of bolt preload procedures, including retorquing to overcome the effects of relaxation embedding and lubricants.

Because of the special exposure to single-point failure loss of containment, side outlets beneath the lower pipe rams on subsea stacks should be given special attention. ITPs should specify procedures to verify that external loads from well bore pressure and bending loads from the handling system are not exerted on these connections.

Elastomers

Because elastomeric properties are particularly sensitive to the time of exposure to high temperatures, performance tests are critical. Obviously, the standard of well bore testing should continue to be used. However, annular preventers can also be visually inspected and drift tested 30 min after closing pressure is released to requalify them for use on an additional well. The combination of these two tests is the best available technology to demonstrate an acceptable level of mechanical properties remaining in the rubber.

When elastomers are exposed to high temperature, the aging rate accelerates. When elastomers age, they lose their memory (ability to return to original condition). An increase in temperature can increase an elastomer's hardness considerably, significantly affecting its ability to seal. Fig. 1, for example, shows how one nitrile elastomer's rate of hardness increases by a factor of four when the temperature is increased from 100° C. to 150° C.

Specific tests (such as sealing characteristics tests for ram preventers or drift tests for annular preventers) can be used to requalify elastomers prior to a drill stem test or during between-well maintenance.

There is an almost infinite combination of drilling fluids, considering the large number of additives on the market and the temperature ranges of operations. It is very difficult and impractical to test all critical elastomers with every drilling fluid combination possible, especially at all the possible temperature ranges.

Thus, when a drilling fluid is selected for a program, the operator should ensure that it is compatible with the specific elastomers in the intended BOP. These tests can best be undertaken by equipment manufacturers (as some already do) to document the effect of temperature on the nitrile elastomers used as sealing components.

Wear

Subject to the pressure ratings limitations noted above, a 15,000-psi ram is good for 15,000 psi and should not be derated.

Shear rams, however, are more affected by cavity wear than pipe rams. Fortunately, with good well bore testing techniques, ram cavity wear can be detected before it leads to an unscheduled repair. Quality well bore testing techniques for early detection of problems pay off handsomely, especially considering that much equipment in use is rather old and that some ram blocks are harder than the cavity section.

BOP stack

In specifying a BOP stack configuration, the operator should consider many factors, including the following: stripping and hang-off capability of the rams, shear capability, choke and kill outlet placement, and use of variable rams.

Rig and equipment operating limits must be known and taken into consideration during well planning. Hang-off capability can vary greatly, depending on the manufacture date of the preventer and whether equipment has been upgraded.

The last major industry study of BOP equipment was in 1985 by a consortium led by Exxon Corp.; $18\frac{3}{4}$-in., 15,000-psi rams were studied, and in some cases deficiencies were found. One such case was with drill pipe hang-off on 5-in. ram blocks. The hang-off capacities show the maximum load that can be applied while maintaining well bore integrity. The study indicated some rams had discrepancies in hang-off capacity, depending on whether locking pressure only or locking pressure and operating pressure together were applied (Figs. 2 and 3).

A well plan must take into account the worst possible case—an event causing loss of operating pressure on the close side of the rams (for example, power loss, drive off, anchors slip, loss of hydraulic pumps, etc.). Thus, actual ram hang-off capacity is critical.

After these hang-off capacity limitations were known, some manufacturers modified the designs of the preventers. Three of the four rams were retested, and the hang-off capacities improved significantly (Fig. 4) .

How can this information be used, and what questions need to bc asked?

Most high temperature wells in Southeast Asia are drilled with 10,000-psi stacks, and a large amount of the equipment in the area was purchased before 1985.

- Has the manufacturer made design improvements for the hang-off capabilities of the $18\frac{3}{4}$-in., 10,000-psi rams, as well as for the rams with other sizes and pressure ranges? (Note: Only one of the three manufacturers included in the test has published technical information about hang-off capacity improvements, listing part numbers, since the 1985 $18\frac{3}{4}$-in., 15,000-psi ram tests.)
- Has the drilling contractor purchased the equipment upgrades?

An operator must learn what the hang-off capacity is for the rig hired and incorporate this capacity into the well plan.

During well planning, the following should be considered:

- Are the manufacturer's data from estimates or actual test results?
- Ask for hang-off capabilities with operating pressure on the close side of the rams as well as using the locking system. If the operator only asks for hang-off capabilities, the number given may only be for operating pressure on the close side of the rams.
- Record the part numbers of the ram blocks and determine their capacity.
- When the string weight reaches the hang-off capacity, including a factor of safety, those rams should be considered hang-off rams only and no longer sealing rams. The well plan should include a second set of rams closed for pressure integrity.

Manufacturers have not performed stripping tests with high temperature packers, so relying on old stripping tests that used standard temperature packers may be misleading.

One manufacturer stated that the required shear force for a given pipe grade and weight can vary by as much as 60%. Therefore, the operator should ask the manufacturer for specific shear data instead of general "yes/no" questions on equipment limitations.

Fail-safe valves

For fail-safe valves, the 1992 Norwegian Petroleum Directorate, "Regulations Concerning Drilling and Well Activities," requires that "..the valves shall be of a 'fail-safe closed' make and shall be capable of closing during dynamic flow conditions."

There is no industry standard for this requirement; some operators regularly require them while others rarely do not. An operator should know the operating characteristics of the fail-safe valves on the BOP stack used and under what flowing conditions they will return to the closed position.

Most valves on BOP stacks are designed according to API Specification 6A. This specification does not require the actuator opening and closing force to operate the subsea valve when the valve is at the most severe design operating conditions. Valves for HPHT applications, at a minimum, should have this capability.

Consideration should be given to upgrading existing equipment to conform with the requirements of API Specification 17D, "Specification for Subsea Wellhead and Christmas Tree Equipment." API 17D, section 908.2b (c) states: "Subsea actuator opening and closing force shall be sufficient to operate the subsea valve when the valve is at the most severe design operating conditions without exceeding 90% of the nominal hydraulic operating pressure...."

The main question is: "Will a valve return to the closed position under dynamic flow conditions?" This situation has not been tested by manufacturers, so hard data are not available. Some valve designs use well bore pressure to assist the gate to the closed position (balanced gate valve), increasing the likelihood that it will close under these conditions. Some valve designs do not use well bore pressure assistance, however. It is important to determine beforehand what type of fail-safe valve is used. ▪

THE AUTHOR

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Michael Montgomery is president of WEST Hou Inc., a BOP equipment consulting and training company. He began his career on the Discoverer III in Singapore as one of the first subsea BOP engineers in the industry. He conducts seminars on drill-through equipment and rig-specific training worldwide. Montgomery earned a BS in engineering from the Tennessee Technological University in 1975. He is a coauthor of the U.K. Department of Energy Guidance Notes, Section 43, which pertains to blowout preventers. He is a member of American Petroleum Institute Committee 16 and is a task group member for API Specification 16, Drill Through Equipment.