# Effects of Water Depth on Offshore Equipment and Operations
# Topic #1: Review of Surface BOP Equipment and Operations

## General Purpose

This white paper presents a baseline of the current technology of Surface BOP drilling and its *Effects of Water Depth on Offshore Equipment and Operations*. The paper is meant to provide a brief background of the topic and identify current trends and challenges. This paper is intended to address:

- Current technologies and challenges with implementing those technologies
- Trends and/or notable technologies envisioned for the near and long-term
- Coordination and communication to help align the efforts of industry and regulatory agencies

## Acronyms and Abbreviations:

| | |
|---|---|
| AADE | American Association of Drilling Engineers |
| AFE | authorization for expenditure |
| APD | application for permit to drill (BOEM/BSEE) |
| API | American Petroleum Institute |
| ASME | American Society of Mechanical Engineers |
| Bull | technical bulletin (API) |
| CAPEX | capital expenditure |
| CFR | Code of (US) Federal Regulations |
| DDCV | deep draft caisson vessel; Other citations reference to a Spar |
| DIV | drilling (or drill pipe) induced vibration |
| DnV | Det Norske Veritas (Norway) |
| DP | dynamically positioned (stationkeeping) |
| HAZMAT | hazardous material (identification and mitigation analysis) |
| HAZOP | hazard operation (identification and mitigation analysis) |
| HSE | health, safety, and the environment |
| IADC | International Association of Drilling Contractors |
| ksi | 1000 psi |
| MODU | mobile offshore drilling unit (BOEM/BSEE) |
| Mr/I | bending moment x pipe radius / pipe moment of inertia |
| NACE | National Association of Corrosion Engineers |
| NTL | notice to lessees (BOEM/BSEE) |
| OCTG | oil country tubular goods |
| PD/2t | internal pressure x pipe outside diameter / 2 x pipe wall thickness |
| ROV | remotely operated vehicle |
| RP | recommended practice (API) |
| SBOP | surface blowout preventer |
| SID | seabed isolation device (IADC); Other citations refer to it as the environmental safe guard |
| SPE | Society of Petroleum Engineers |
| SX | saturation exploration |
| TLP | tension leg platform |
| VIV | vortex induced vibration |
| WSD | working stress design |
| $\sigma$ | material stress |
| Ys | material yield strength |

## Background and History

The interest in surface BOP (SBOP) systems on floating MODUs has been primarily to find novel ways to drastically reduce the amount of time and CAPEX associated with drilling a well.

The first recorded instance of the use of a SBOP stack on a MODU was in Nigeria on the *Sedco 135* in 1967. Since then, the concept languished until mid-1992 when **Unocal** introduced a radical low-cost strategy for exploration drilling, called Saturation Exploration (SX), in Indonesia. The SX strategy was to drill as many low cost prospects as possible using the same amount of AFE funds that would otherwise drill fewer wells using floating drilling operations involving a subsea BOP stack and low pressure marine drilling riser. By saturating the prospect area with far more wells, the statistical likelihood for success in finding new reservoirs was greatly improved.

The key to SX was to minimize the time to drill each well, use a smaller MODU vessel, and minimize the riser/hardware, both to reduce overall cost. The majority of hardware cost lies with the high pressure riser pipe. To offset this investment, the riser is put to use for the first well, then becomes the casing program for the second well. New casing pipe is then employed as the riser for the second well which becomes the casing for the third well and so on. Unocal realized early on that hydrodynamic forces and drilling wear might limit the riser's practical life. So by limiting the pipe's exposure to one well, and finding a subsequent use for it, reduces overall costs through its double duty.

- The initial program was with an 18 ¾-in. BOP suspended in the moonpool from the *Sedco 602*.
- The second phase utilized a 13 $^{5}/_{8}$-in. BOP used from the *Sedco 601* and when additional riser uplift (tension) was required an air can was installed. Using a 13 $^{5}/_{8}$-in. SBOP system the *Sedco 601* could work in 6,700 ft water depth.
- The third phase was using the *Ocean Baroness* semi-submersible with and 18 ¾-in. BOP suspended in the moonpool using line hydraulic tensioners.

The other savings initiative was the minimal use of hardware. It was argued that Indonesian waters are relatively benign with respect to metocean conditions. Therefore a moored semi-submersible in these waters would be a very stable platform from which to work, especially if SX drilling time to drill a well was on the order of days rather than weeks (for wells in Gulf of Thailand). From this premise, it was determined that a single string high pressure riser's bending fatigue and tension requirements would be manageable and situations which might lead to damaging to the riser were extremely remote. It was further surmised that an additional well control barrier at the sea floor, a seabed isolation device (SID) (beneath the high pressure riser) was unnecessary (no SID or control system to operate it – further cost savings).

As the nuances of using SBOP drilling and the SX strategy became clearer, **Unocal** was able to work its way up to drilling 16,000 ft wells in less than 18 days.

Since **Unocal** first utilized SBOPs, other operators in 2002-2005 followed suit, including **ConocoPhillips** in China, **Total** and **Santos** in Indonesia, and **Shell** in Brunei, Brazil and Egypt. SBOP capability grew under these campaigns to water depths over 8,000 feet and pressure containment up to 10,000 psi. However, the extension of SBOP capability was viewed by these operators to carry more technical risk, and adopted SIDs to the hardware configuration. Other notable milestones include:

- In 2009 **Murphy Oil** installed a Floating Drilling Production Storage and Offloading (FDPSO) system in West Africa (Azurite project). A SID was deployed during this campaign.
- In 2011 **ATP Oil & Gas** deployed the first in the Gulf of Mexico SBOP/SID drilling system from the *ATP Titan*, a deepwater floating drilling and production facility. The SID is equipped with two blind/shear rams.

As mentioned, the most obvious incentive to using SBOP high pressure riser technology is ***cost.*** The potential to use smaller, less expensive rigs to drill the same well continues to spur interest. There is also the opportunity to increase fleet size by improving a smaller rig's water depth capability. The smaller loads and less volumetric requirements associated with a SBOP's high pressure riser lower variable deck load requirements and riser tensioning capacities of the MODU back within those of second and third generation rigs. The smaller loads and riser diameter in turn makes the SBOP smaller in size and weight and makes it feasible to handle and suspend from the rig's substructure.

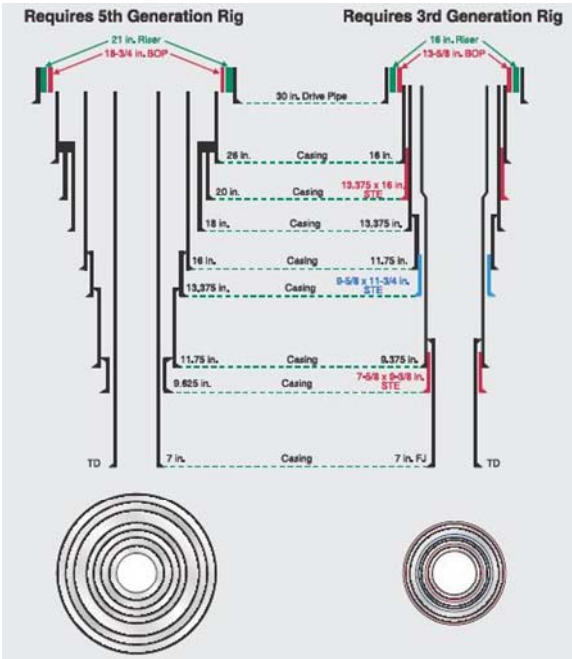
Many operators feel the BOP at the surface rather than on the sea floor means more predictable well control can be handled quickly and safely, since choke and kill lines are shorter (to the SBOP) and boost lines are not needed.

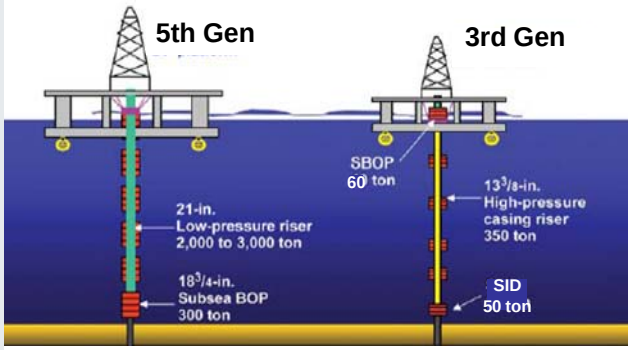
There are some limitations to SBOP, the foremost of which is operating environment. To date, SBOP operations have been conducted in benign sea and weather conditions and containment pressures below 10,000 psi.

Also, the riser diameters in an SBOP system are smaller than the conventional 21-in. marine riser, limiting the hole size drilled and the number of casing strings in the well. Typical riser sizes may range from 10 ¾-in. to 16-in., meaning conventional 18 ¾-in. subsea wellhead casing hangers will not pass through the SBOP or high pressure riser;, requiring special wellheads with smaller through bore and hanger profiles. Additionally, the number of casing strings that can be run in a well may be limited.

With a smaller bore riser system, "slimbore" drilling techniques can be employed, adding to the overall cost savings. But slimbore well design has its limits with respect to reservoir depth and pressure, and using a smaller MODU and high pressure riser may be limited to working in relatively benign metocean environments. The smaller diameter wellbore also makes well completion and flow testing difficult because of the smaller completion string sizes and equipment, both with inherent flow capacity restrictions. This is why SBOP-high pressure riser drilling has been better suited for exploration drilling than production drilling.

So SBOP is not for every possible scenario worldwide.



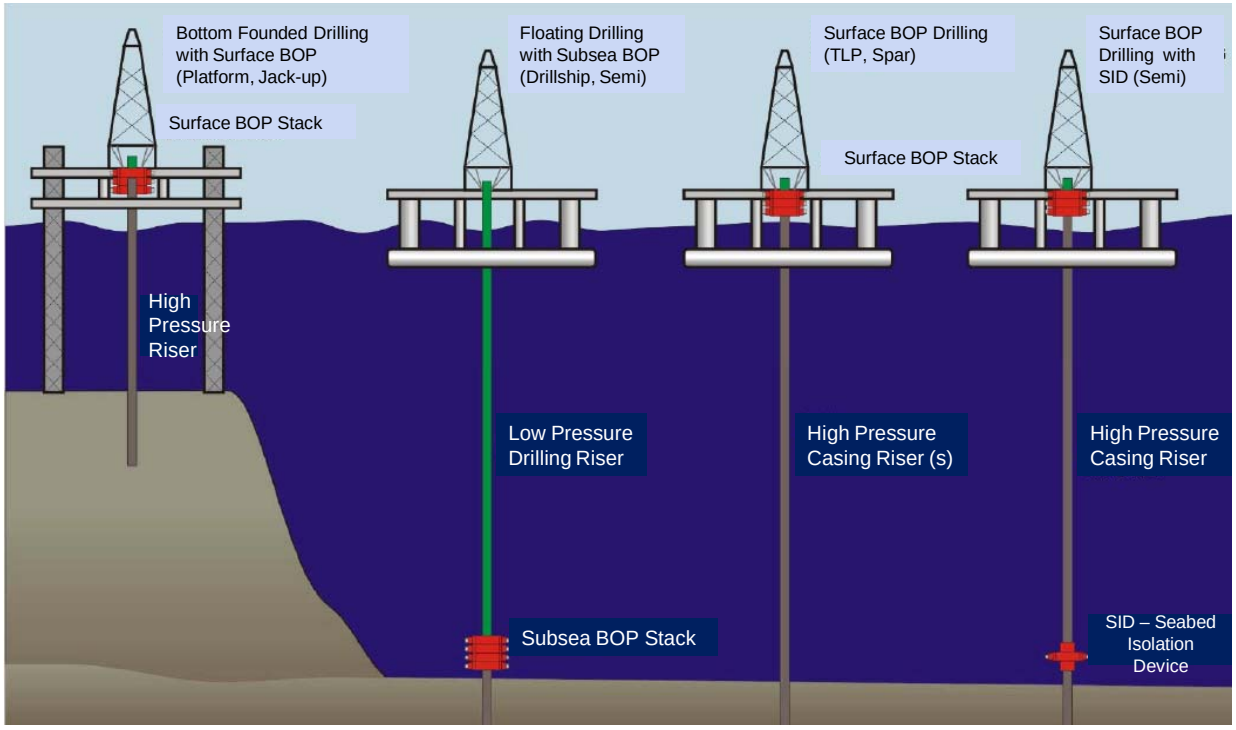

*Subsea BOP vs. SBOP Systems*
*Approx. 3000 m WD*

| | |
|---|---|
| $450k / day | $250k / day |

The other outgrowth of SBOP drilling technology has been employed as a part of tension leg platforms (TLPs) and Spars. TLPs and spars are floating, permanently moored vessels with deep drafts and a fair amount of tonnage displacement (positive buoyancy). As such they become extremely stable platforms in a variety of metocean conditions. This premise lead to a modified form of the traditional SBOP practices on platforms and jack-ups. In the bottom founded platform design, a new riser string is run and landed inside the previous casing string, as the well gets deeper and the working pressures increase. For TLPs and spars, the number of casing strings that make up the riser is limited to two: an outer environmental barrier riser, and an inner pressure barrier riser. The first dual casing string drilling riser system was first implemented on the **Shell** *Mars* TLP. The minimizing of riser strings to two optimized the hang off weight the floating TLP or spar had to support; allowing the structural draft/displacement of hull to remain within acceptable technical and economical boundaries. The two pipe riser approach is seen as having additional benefits. First, the outer riser serves as a back-up barrier, should the inner riser lose structural or pressure integrity. If there were only a single riser that leaked, the drilling mud below the SBOP would drain out to the environment until enough hydrostatic head was lost to invite a kick from the well pushing wellbore fluids upwards in an uncontrolled manner. Second, the annular area between the two riser pipes could be monitored for any pressure build-up, signaling the potential of an inner riser breach to rig personnel earlier. Third, the two risers separated the loads acting on the system; the outer pipe only seeing environmental loads, the inner pipe pressure end loads. Fourth, the use of SBOP riser technology on dry tree floaters such as TLP/Spar prevents clashing of a subsea BOP with the installed production risers. The use of a subsea BOP, such as was used on the **Shell** *Auger* TLP, required a very large spacing of the wells on the sea floor. This resulted in the need for a lateral mooring system to move the entire platform over the well to be drilled. In the case of a Spar, even though well spacing and lateral mooring is common, the restriction at the keel is very limited. A single pipe high pressure riser sees a combination of both external hydrodynamic loads combined with internal pressure loads. To meet both criteria, the pipe has to be designed with added strength (which usually means added wall thickness – and weight, or the use of higher strength materials, or both) and is more susceptible to fatigue damage because of the cyclic loading at higher amplitudes. In the dual riser case, the cyclic loads acting on the external riser are much less since they are not coupled to the high pressure loads, and the inner pipe is free of cyclic loads altogether since the outer riser pipe shields the inner pipe from the metocean environment. Fifth, the two risers basically constitute the “dual barrier” design rule common throughout the oil industry. With two risers in place, technical risk is minimal to the point where a SID is not required.

The larger vessel draft and riser weight management also affords the drilling engineer the possibility of larger diameter hole access, or higher well count when SBOP technology is used.

SBOP systems also come in three varieties. The traditional configuration for bottom founded structures such as fixed platforms and Jack-up MODUs, a second configuration for moored floating structures such as TLPs and Spars, and a third configuration for Floating MODUs such as semi-submersible MODUs. This paper focuses on the latter two.




## SBOP Components *(from IADC Surface BOP Guidelines)*

The components that make up the SBOP system, described below, are pretty much universal. Some variation of hardware location depends on the SBOP location, the method of handling and riser tensioner attachment and the number of drilling riser strings employed. The descriptions are for equipment starting at the rig floor, working toward the sea floor.

**Diverter Adapter**
An adapter flange may be required to interface the top of a telescopic joint with the rig's diverter element.

**Flex (or Ball) Joint**
The flex joint is a low pressure dynamically sealing ball and cup arrangement that decouples the physical alignment between the rig floor, the diverter adapter structurally affixed to the rig floor's structure, and the telescoping pipe below. It usually has a minimum 10 degrees range of operating envelope. The flex joint here is nearly identical to those used in floating drilling operations.

On TLP/Spars flex joints are not commonly used. Instead, the upper portion of the riser (above water) is held vertically by two sets of roller guides spaced vertically part. The rollers may be found in the riser tensioner frame. For some Spars, the rollers were incorporated with the riser's air can buoyancy system.

**Telescopic Joint**
The telescopic joint provides a means to allow the drilling fluid to return to the mud pits and guides drilling tools into and out of the wellbore at relatively low pressure conditions. As its name implies, it extends or contracts on itself with the changing relative height between the fixed portion of the drilling riser and the vessel (heave). Its design too is nearly identical to those used in floating drilling operations, except that it is connected directly to the SBOP. Depending on where the SBOP stack is located (below the splash zone or above the splash zone in the moonpool area) will determine the length and available stroke. Sometimes, a purpose built multiple barrel telescopic joint is required to accommodate extremely short stack-up height constraints when SBOPs are closer to the rig floor. The stroke of the telescopic joint should be sufficient to accommodate the design rig offset in the event of a loss of station keeping, and the full range of dynamic

motion due to rig motions, tides and storm surge. The outer barrel(s) of the telescopic joint may also be used as an attachment point for the riser tensioner lines either by means of padeyes or a load ring.

Alternative methods of returning the mud to the flow line are possible thus eliminating the need for a telescopic joint. These would include rotating heads, mud return pumps and other means. In selecting and locating these components in the system it is important to determine if they form part of the well control system that needs to contain full working pressure or if they are simply low pressure mud return devices. With alternative mud return devices consideration should be given to observing the well fluid level and preventing fluid spills when no pipe is in the hole and during the passage of large size tools such as bits and stabilizers.

**Surface BOP Stack**
A minimum of one annular BOP is required in the SBOP system. This is a key component and is the often the first well control device employed when primary control is lost. It also facilitates other well control procedures such as stripping.

If stripping is considered, the closing pressure and stripping surge accumulator configuration should permit stripping without landing off significant weight on the SBOP system. The riser tensioner system must support any weight added. If significant use of the annular BOP is anticipated, consideration should be given to the accessibility to this component for change out of the element. A second annular may be considered but note that this adds weight and height to the SBOP.

In the SBOP configuration ensure that any tension loads in combination with internal pressure and bending are taken into account on the annular flanges and structure.

A minimum of three rams are required in the SBOP stack. At least one of the rams should be configured as a shear/blind ram for closing open hole or for containing an uncontrolled flow in the drill pipe. The remaining rams should be configured to close and seal on all tubular sizes used in the well program.
.
Note that if pipe is hung off on the rams that this weight must be supported by the riser tensioners. Typically it is not feasible to support all the drill pipe weight on the tensioners.

If a SID is used, the shearing requirement may assigned to the SID fitted with shear/bind rams instead of placing them in the SBOP stack. In either case, shear rams should be equipped with means to lock the ram closed in the event of loss of hydraulic supply pressure.

Spacer spools may be required between ram or annular preventers to ensure the proper spacing between the ram preventers, particularly the shear/blind rams. Spacer spools are also used to adjust the height and clearance of the SBOP above the riser tensioner support ring or support frame depending on the configuration. Spools may also be used to provide additional outlets for alternative mud return methods.

In some rig configurations, the SBOP may be installed below the splash zone. If so, additional components will be required. Many of these will be standard subsea drilling riser components. To install the SBOP below the splash zone, the riser must be hung off and the SBOP and stress joints installed in the string.

A significant benefit of this installation method is the ability to retain a full 50-ft stroke on the telescopic joint which may extend the suitability of SBOP operations into more severe environments.

**SBOP Connector**
The SBOP connector attaches the SBOP to the top joint in the riser string. This is usually a transition or stress joint. The transition joint will have a suitable hub at the top for the SBOP connector to latch and seal. The connector may be a mechanically or hydraulically actuated device.

The connector must contain full wellbore pressures and support the weight and bending imposed by the SBOP and telescopic joint above and riser below. In some cases the connector must also support the entire

riser string during installation and the riser tension loads in operation. Selection of a connector shall take into account all tension loads that are to be applied during the handling, installation, testing and operation of the SBOP system.

The loads may be in combination with internal pressure and bending. Physical access to the connector location, personnel safety and handling efficiency should be considered when selecting a connector configuration.

**SBOP Choke and Kill Lines**
The choke and kill lines may be positioned in different configurations depending on the intended service. These lines are connected to outlets on the ram cavity bodies of the rams within the SBOP (just like land and platform SBOPs are connected). This short distance is one of the SBOP drilling's advantages over floating drilling operations with a subsea BOP. In floating drilling, the choke and kill lines are extended to the surface via individual (3 or 4 inch diameter) lines strapped to the exterior of the low pressure drilling riser. Should a well kick occur, well control operations dictate circulation and exchange of heavier fluids into the well as wellbore fluids and gasses are passed out. This circulation transfer occurs at a nominal flow rate while the wellbore fluid/gas is in the well below the subsea BOP. As the wellbore fluids enter the choke and kill piping, the cross-section area of the pipe drastically reduces, speeding up the circulation rate, and requiring special well control procedures to be followed during this time. For the SBOP with shorter choke and kill lines, this extra procedure is not needed and simpler well control practices can be maintained the kick is completely circulated out at the SBOP.

Each choke and kill outlet features isolation valve(s) rated for the full SBOP working pressure. Due to the limited access to the SBOP the choke and kill valves are typically hydraulically operated.

**Tapered Stress Joint for Single Pipe High Pressure Riser**
The connection point between the SBOP connector and the high pressure riser is an upper tapered stress joint. At the top, the joint has an upset lip with either a flange or clamp hub to allow the SBOP connector to structurally lock and seal around. Below the upset lip, the riser pipe features a thick walled cross section, which tapers down thinner and thinner until it reaches the nominal wall thickness of the rest of the riser. It provides a connection between the riser and the SBOP and controls stresses and in particular bending and fatigue at the top of the riser string. The tapered stress joint is uniquely designed to withstand the increased bending stresses induced in the riser pipe as it sways from a lateral offset (from ocean waves and current) to a forced vertical orientation with the SBOP stack. The wall thickness increases with the increased bending moment, keeping the cross sectional stress in the pipe the same.

Upper and lower tapered stress joints are employed at the top (under the SBOP) and the bottom connecting to the top of the SID, to control bending moment induced stress as the riser pipe is "forced" back into a vertical orientation. Use of tapered stress joints replaces the flex joint used between the subsea BOP stack and the low pressure marine drilling riser. Flex (and ball) joints are very efficient means to de-couple bending moment loads in the riser to structurally founded end connections, but are also very low pressure designs, unsuitable for high pressure riser SBOP applications. Tapered stress joints are more common on subsea completion/workover risers and rigid production tieback risers on TLP and spar well completions. These high pressure riser designs and their tapered stress joints are manufactured in accordance with API 2RD or 17G.

**Surface Wellhead (alternate to a tapered stress joint) for Single Pipe High Pressure Riser**
In some case the connection between the riser and the SBOP will be by means of a wellhead rather than a tapered stress joint. This is generally used in cases where a smaller riser is run through a larger SBOP. The wellhead is installed on the bottom of the SBOP which in turn is set below the rotary prior to casing riser running operations.

The high pressure riser pipe is run through the SBOP and eventually lands a load shoulder designed end coupling (hanger) to a landing shoulder within the wellhead body. After landing, the hanger engages a surface element between wellhead and the supporting wellhead hardware. If a surface wellhead is used it must contain full wellbore pressures in combination with riser tension and bending loads. Particular attention

should be paid to potential movement of the hanger and seal inside the wellhead due to riser, SBOP and vessel movement. Any small movement of the seal could cause a seal failure so the seal and landing surfaces must be correctly centralized and laterally constrained within the wellhead.

**Surface Wellhead for Dual Pipe High Pressure Riser**
TLP and spar SBOPs are connected to a purpose-built wellhead body that performs three functions. First, the wellhead has the requirement and features for a landing shoulder design found in the single riser design through which it passes the inner drilling riser pipe and shoulders its hanger. Second, the wellhead's exterior features a hub or flange bottom end connection which is attached to the upper tapered stress joint of the outer drilling riser. The wellhead is designed with same rated working pressures to withstand either the inner or outer pressure ratings. Third, the wellhead body features an annulus access outlet and isolation valve for monitoring and venting the annular space between the two riser casing strings.

The wellhead is installed between the upper tapered stress joint and the bottom of the SBOP. Once the SBOP is secured, the smaller inner riser is run through the SBOP.

**SBOP Handling and Riser Tensioning**
The configuration of the SBOP is closely dependent on the handling and tensioning method. The following are the main methods for handling and supporting the SBOP.

- Tension from the top - In this case the SBOP and riser system is supported from the top through a structural frame constructed around the SBOP stack, or by means of a tension ring on the telescopic joint. If any tension and bending loads are transmitted through the SBOP flanges the combination of internal pressure, tension and bending must be considered.
- Tensioning joint (or ring) – In this case the SBOP frame only has to support the weight and movement of the SBOP; not the riser. The riser is tensioned through separate tensioner lines connected to a specialty joint with a swivel ring (tension ring) and padeye/shackle connections. Alternatively the riser tensioners may be attached to a load bearing frame (in which case careful attention should be paid to the load transfer method from the frame to the riser to ensure that all components are independently supported).
- SBOP installed below the splash zone – In this case, the SBOP stack itself must be capable of fully transmitting the riser loads through the SBOP body (rather than through a structural frame) and flanges or this must be accomplished by a load bearing frame that isolates the SBOP from tension and bending loads. Above the SBOP will be a flex or stress joint and a cross over to marine riser. Several marine riser joints perhaps some with buoyancy will connect back to the rig. A conventional telescopic joint and riser tensioner attachment may be used. Note that on older or shallow water rigs adapted for SBOP service the riser and telescopic joints may not be rated for the higher tensioner loads in deepwater SBOP operations.
- For TLP/Spars, direct acting hydraulic-pneumatic riser tensioners (hydraulic cylinders directly attached to the riser) are the most commonly employed. These tensioners couple the riser directly to the deck structure.

**Seabed Isolation Device (SID)**
The seabed isolation device (SID) is intended as a back-up device to seal the wellbore and disconnect the riser. As such, it is not considered as a primary well control device.

The control system for the SID should comply with API Specification 16D and API Standard 53. In particular, the control system should incorporate a means to continuously monitor and display accumulator pressure. For moored vessels, a single set of controls, and ROV intervention capability, rather than dual, independent controls specified in API Specification 16D is considered adequate for SBOP applications. For SBOP operations from DP vessels, consideration should be given to dual, independent controls as specified in API Specification 16D. The control system for the SID could comprise a number of different options all providing redundancy should the primary system fail.

It is likely however that any system designed will only require one control system at the seabed. The SID control system subsea accumulators may be provided with hydraulic power replenishment by means of an umbilical (hot line) strapped to the casing riser or from a ROV pump package and fluid reservoir. The system should be designed in such a way that the controls will both open and close the shear ram and the riser connector. In normal operation the SID will be operated only for connecting and disconnecting from the well. This may be powered by the ROV. Emergency operations will commence should the riser fail or the SBOP control systems fail to operate. For DP rigs, should the DP system fail the SID will be the primary means for shearing the drill pipe, sealing the wellbore and disconnecting the riser. Consideration should be given to the use of deadman, auto-shear and emergency disconnect functions should the riser need to be disconnected in a stationkeeping emergency. The auto-shear and emergency disconnect should perform in a required sequence to secure the well and release the riser in a timely manner to avoid damage to the riser or other MODU equipment.

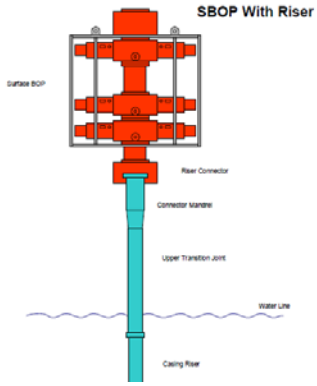
The SID configuration contains two subsea connectors and at least one shear/blind ram all manufactured in accordance with API 16A. The upper connector is an emergency disconnect connector that locks and seals around the upset lip of the high pressure riser's lower tapered stress joint. The connector may be unlocked to release the riser in an emergency situation where riser angle or MODU position over the well is compromised to the point that the SID must be closed and the riser released to head off any collateral damage to the subsea well, or the riser and rig above. The shear/blind ram is there to close the open wellbore and shear drill pipe if in the well when the emergency arises. A second subsea connector oriented downward locks and seals to the high pressure housing of a smaller bore subsea wellhead. Note that for a SID, the subsea well must be of the subsea wellhead design with a high pressure housing, internal casing hangers and annular packoff assemblies manufactured in accordance with API 17D. All of the well's casing strings have to be hung off and sealed inside the subsea wellhead's high pressure housing below the SID's ram. Casing strings cannot contiguously run up to the SBOP since the SID has no casing shear capability.

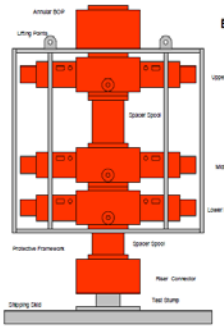
All three components in the SID are designed to withstand anticipated tension loads in combination with internal pressure and bending.

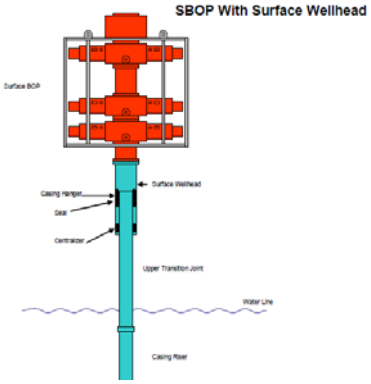
In some instances, a second pipe ram is added to the SID above the shear ram. This added ram may be used in conjunction with the re-installed high pressure riser and a drill pipe (rams closed around the drill pipe) to assist in circulating a gas pocket underneath the SID's shear ram after a disconnect event, and well control through circulating drilling mud needs to be re-established before drilling can continue.

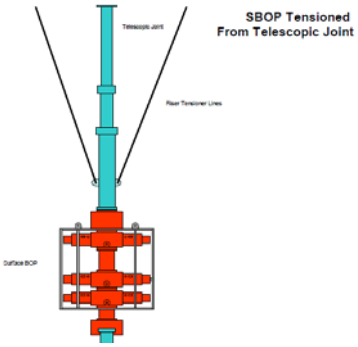
**Note:** The seabed isolation device (SID) has been called (in other citations), the emergency safe guard (ESG), or the subsea disconnect system (SDS).

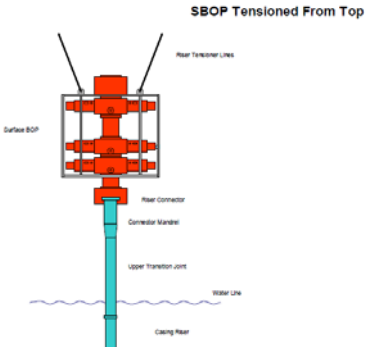
**For tensioning support suspended from the derrick's substructure over a large open moonpool, commonly found on MODUs, the following tensioning configurations may be found:**

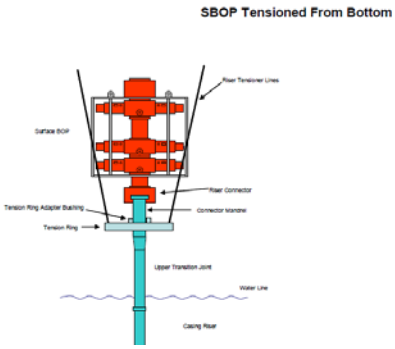


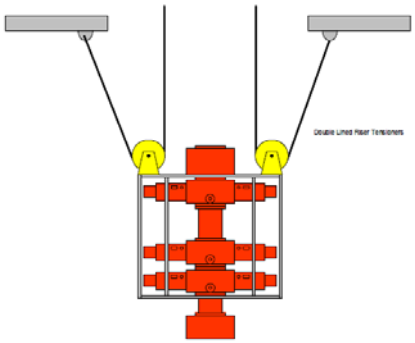



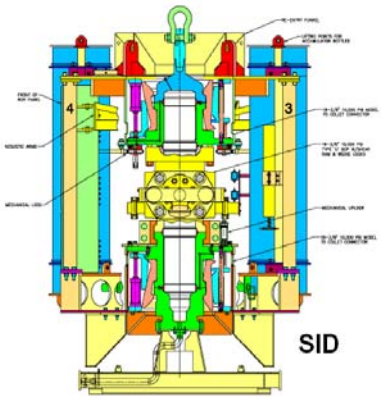



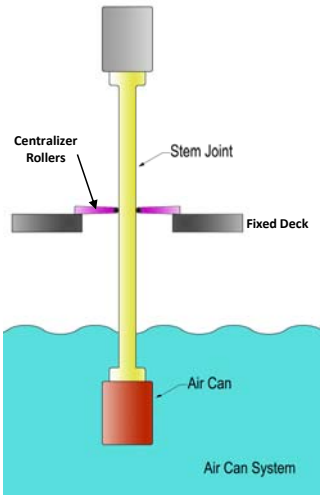



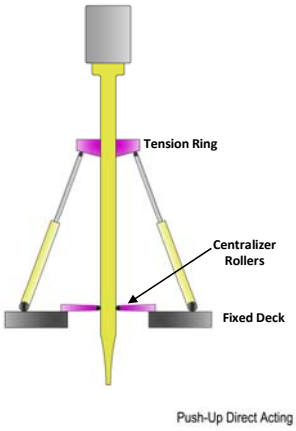



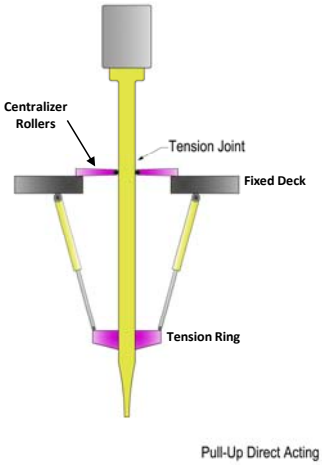



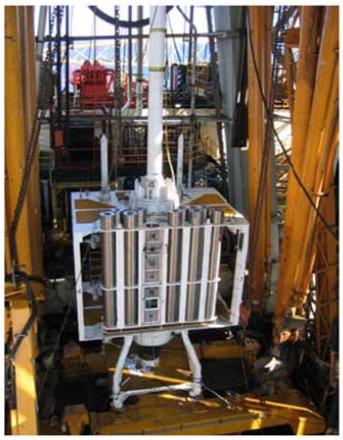



**For fixed (cellar) decks that surround each well slot instead of a large open moonpool, commonly found on TLPs and Spars, the following tensioning configurations may be found:**



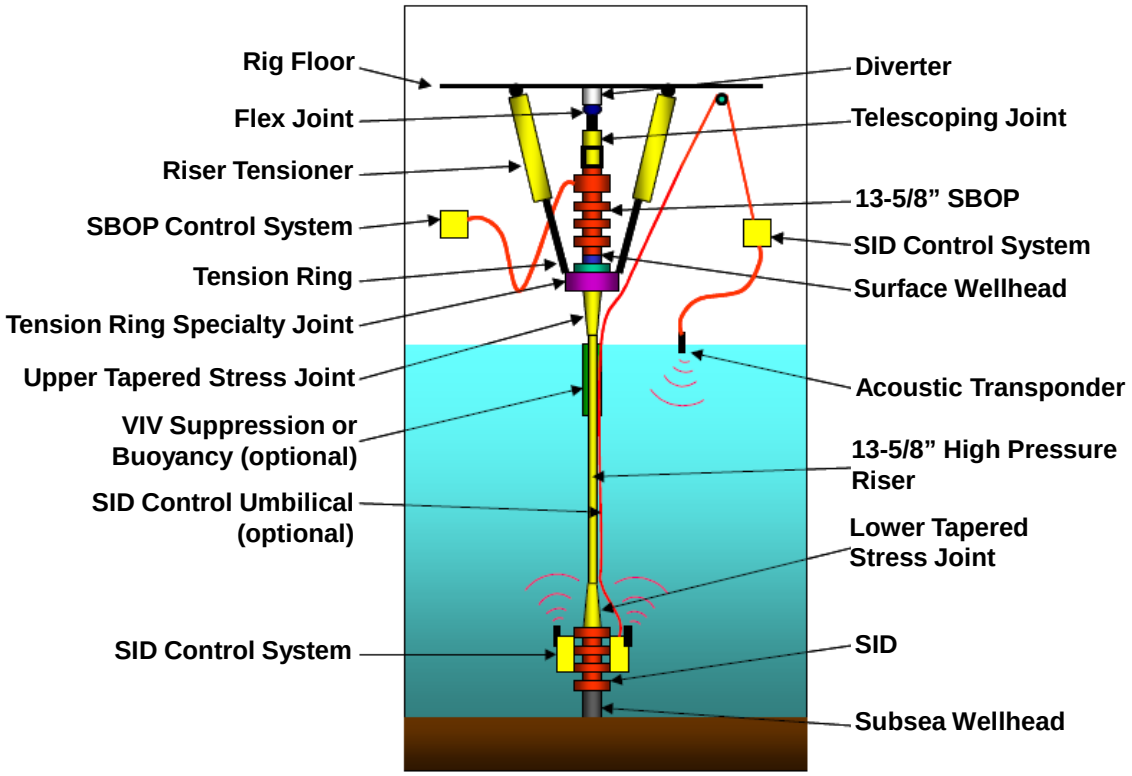



**Surface BOP (SBOP) shown with Riser Tensioner and Tension Ring (Stena Tay) →**

**Subsea Isolation Device (SID) shown in Moonpool ←**

**Titan – Floating Drilling And Production Facility ←**

**Titan's Subsea Isolation Device (SID) lifted off a workboat →**




## Reference Standards

**Government Regulations and NTLs:**

- 30 CFR 250 Subparts A thru S
- NTL drafts t-256h and t-259c on SID, June 2011
- NTL 2008-G07, 2008-G09, 2009-G10, on managed pressure drilling and hurricane fitness

**Industry Standards:**

- API Specifications 16 A-C-D-E-F
- API Specifications 6A, 17D
- API Specifications 5CT, 5L
- API RP 5C1, 5C2
- API Bull 5C3, 5C5
- API RP 2RD
- API RP 2SK
- DnV OS-F101, OS-F201, OS-E301, on pipeline, dynamic risers, and mooring designs
- API RP 17G
- API RP 17H
- API Standard 53
- API RP 59
- API RP 64
- API RP 90, Annex C
- API RP 96
- API RP 1111
- NACE MR0175
- IADC SBOP Guidelines
- NORSOK D-010

**Engineering Bulletins and Brochures:**

- Cameron ESG
- *Stena Tay*
- Helix *Q4000*
- Ocean Riser Systems
- 2H and Subsea Riser Systems
- Weatherford Managed Pressure Drilling Services

### Issue #1 – General Pros and Cons

Offshore operations Surface BOP operations is the traditional time tested standard when evaluating hardware and practices associated with land and fixed platform well control operations. Floating drilling operations were developed to offset the dynamic effects and cyclic loads associated with vessel movement, by moving the BOP and wellhead to the sea floor, away from the vessel motions, and then further isolate this equipment by adding flexible joints that decouple bending moments which otherwise build tremendous stresses at either end of the riser pipe. However the trade off for structural stability is the operational lag time and excessive pressure drop/area reduction associated with extra long choke and kill lines and control system umbilicals. In addition some deepwater oil and gas reservoirs are located in areas with narrow margins between pore pressure and fracture gradients or in shallow formation depths below the mudline. Well control using floating drilling operations are far from ideal under these conditions. Surface BOP operations for deepwater floating drilling and access activities are more straightforward, because of the simpler and shorter lines to the BOP (and less onerous hydraulic characteristics).

Other advantages of SBOP operations in deepwater include:

- Larger vessel watch circles are possible for drilling envelope (but very short watch circle distance for shut down and disconnect)
- Far less mud is required (18 ¾-inch bore vs. 13 $^{5}/_{8}$-inch bore)
- Less chemicals needed and consequently less HAZMAT exposure
- Less exposure to heavy lifting and tensioning requirements
- Less waste requiring disposal
- Less risk of gas expansion in the riser
- Reduced risk of hydrate formation
- More efficient hole cleaning characteristics (better mud circulation characteristics and less need for a booster line)
- Smaller riser diameter changing VIV and DIV characteristics
- Smaller rigs required, extended use of fleet capabilities – more availability
- Ability to use rotating control head on top of the SBOP to utilize managed pressure drilling techniques through tight pore/fracture pressure zones common in deepwater

But raising the BOP from the sea floor wellhead to the surface moves the risk to the high pressure pipe in between. Should anything happen there, there are few options left to regain control of the well. So far the solution has been to either: utilize dual concentric drilling riser strings, employ a SID to close in the well and disconnect before emergency conditions manifest themselves. In addition, the high pressure riser must deal with a unique set of design and operation issues associated with dynamically supporting the BOP structure in air, the combined pressure and environmental loading acting on the riser pipe suspended in the water column.

Many will argue that SBOP has its place given the right circumstances. Although its use has been in relatively benign metocean environments, it has been demonstrated to be useful in more severe conditions, provided sufficient HAZOP and additional safeguards (such as a SID or dual riser strings) are employed with the full understanding operating within the technology limits of the high pressure riser pipe.

**A Different World**
The SX program had to deal with a couple of blowout wells during its campaigns in the Gulf of Thailand; exposing the vulnerability and riskiness of SBOP drilling without some sort of contingency in place. Since then, the safety-conscious and blowout-averse culture of today demands a complete HAZOP review identifying all contingency plans and mitigation hardware. As a result, SBOP-high pressure riser systems since 2000 either feature: a dual string drilling riser, or a single high pressure drilling riser with a SID.

Hurricanes Ivan, Katrina, and Rita also pointed to MODU mooring vulnerability. Rigs that utilized permanent or preset moorings survived and stayed on location. However these three storms destroyed 10 jack-up rigs and sent 24 jack-ups and semi-submersibles adrift or foundering on shoals. Metocean return period storm criteria had to be revised downward by almost an order of magnitude; resulting in new mooring systems designed nearly twice as strong. DnV OS-E301 and API 2SK may need to be reviewed in concert with tight watch circles needed for adequate high pressure riser operation.

These added constraints further limit the locations and economic viability of SBOP-high pressure riser drilling to a smaller niche of opportunities.

### Issue #2 – It's all about the riser.

The primary technical limitation of SBOP drilling technology is the load management and metallurgical properties of the high pressure pipe. Because of the high pressure containment requirements below the SBOP, flex and telescoping joints cannot be used in the riser design. Instead tapered stress joints are used to deal with bending and lateral loads at constrained locations at either end of the riser. Their tapered wall thickness is calculated to grow commensurate with the corresponding increase in resulting stress as one gets closer to the fixed constraint. Hence, the tapered design and its end connections are designed around an assumed maximum limit of metocean conditions and vessel movement that in turn dictates the window in which the MODU can safely operate.

A further constraint is the material that physically makes up the high pressure riser joints and how they're fabricated and connected. It is easy to assume that the higher the loads and stresses imparted on the riser, higher strength materials should be employed. However, there are metallurgical and fabrication limits. High strength materials are uniquely susceptible to embrittlement and stress cracking when exposed to corrosive media such as hydrogen sulfide or salt water (chloride) infused fluids. Higher strength materials are more prone to premature failure under these conditions. Steel mill techniques that form pipe, have increasing manufacturing problems maintaining a uniform wall thickness and concentricity as wall thickness increases relative to pipe diameter (D/t ratio). If the thickness and ovality tolerances are too lax, the pipe may be prone to external pressure or buckling collapse; too tight and the manufacturing costs associated with scrap rates will make it too expensive and scarce.

Material selection must be made as to whether it is a "NACE" (sour) or "non-NACE" environment, as defined by NACE MR-01-75. As a general rule of thumb, carbon steel grades with yield strengths on the order of 80,000 psi (or lower) are less susceptible to embrittlement or stress corrosion cracking. Higher material strength, increased temperature, or cyclic loading may exacerbate the problem. Heat treatment or work hardening steels to increase strength ($\sigma$) makes the pipe stronger but also makes it more prone to embrittlement failure. If one restricts material strength, $\sigma = PD/2t$ dictates a greater wall thickness (t) is required to withstand the pressure (and environmental) loads; hence the design conundrum. Increasing material strength increases the likelihood of metallurgical failure; increasing wall thickness increases overall weight, reduces the accessible bore available for drilling, and reduces either water depth or deck load capacity of the MODU. The only other alternative is going to a more exotic alloy that provides higher strength while resisting embrittlement (cracking) failure. Unfortunately their raw material cost may be an order of magnitude higher than carbon steel and they are usually more difficult to fabricate (threading, welding, forming [forging, drawn over mandrel, etc.]).

Some have argued that the exposure to a sour (or $H_2S$ environment) is a time dependent function and the detrimental effects of stress cracking can be mitigated or controlled by limiting the pipe's exposure through

chemical scavengers in the drilling mud, restricting load conditions or just lowering the overall useful service time (similar to **Unocal's** limit of short drilling times and using the pipe one time). However, this strategy may involve an excessive amount of monitoring and data collection activity beyond what's practical on the rig; not to mention how accurate or accessible the data has to be in order to make appropriate assessments when to curtail the riser's use.

**Dual Riser Pipe Configuration – Divide and Conquer?**
A dual riser pipe design in a sense splits the loads acting on the overall system. The outer pipe is inherently larger in diameter and as such can withstand higher structural loads ($\sigma = Mr/I$), while limited to lower pressures ($\sigma = PD/2t$). That's okay in this instance since the inner riser which is smaller is shielded from the structural loads (outside) and is better equipped to deal with higher pressure loads inside. By splitting the loads, each pipe string deals with less combined stress, thereby making wall thickness and ovality issues less severe. In addition the environment is also split. To the outside, sea water is the corrosive agent acting on the outer pipe, while wellbore fluids are contained and dealt with inside the inner string. It is not uncommon to have two different materials, with differing coatings, make-up connections and methods of construction customized for the specific riser pipe string. HPHT raises another interesting point. The inner riser may see much higher temperatures (in addition to pressure) relative to the outer riser, adding thermal growth into the design mix.

As mentioned earlier, other drawbacks to a dual pipe drilling riser include: the added weight per foot of riser itself, the increased support requirements imposed on the riser tensioners, plus the added complexity to hardware design, running and operating procedures. These plus the added stiffness associated with locking two concentric pipes (greater moment of inertial (I)) make the riser much less compliant. Therefore the watch circle of the MODU has to be restricted so as not to overload the riser tensioner or the subsea wellhead from excessive loads. For these reasons, dual pipe drilling risers are better suited for TLPs and spars.

**Large Bore wells vs. Slimbore wells**
One last dual string riser configuration needs to be mentioned. As mentioned earlier, SBOP-high pressure drilling evolved from the notion of using a smaller casing approach to save time and consumables in drilling the well. Yet some of the larger TLPs and Spars have sufficient displacement capacity to support larger bore (more conventional) casing well programs. The most common approach starts with a nominal 21 inch outer riser string (similar to the marine drilling riser used in floating drilling) with a pressure rating up to 3000 psi. Then large casing (at lower pressure ratings) are installed through the outer riser with either a 21-$^{1}/_{4}$ 3ksi BOP or an 18-$^{3}/_{4}$ 5ksi BOP for well control. This allows standard casing hangers to be run and set while keeping the wellbore large for deeper drilling depths. Then as the well is drilled further and higher pressures are encountered, the second inner high pressure riser is installed with an adaptor and a 13-$^{5}/_{8}$ 10ksi BOP. This involves splitting the stack, but keeps hardware weight down and is easier to handle. Subsequent casing strings land in either nested casing hangers, or a liner hanger down hole. The next most common method is to use an 18-$^{3}/_{4}$ 10ksi BOP and run everything through it. This has the advantage of not having to split the stack and allowing standard hangers to be used for all strings. However, the BOP is much heavier and running operations and equipment is more complex.

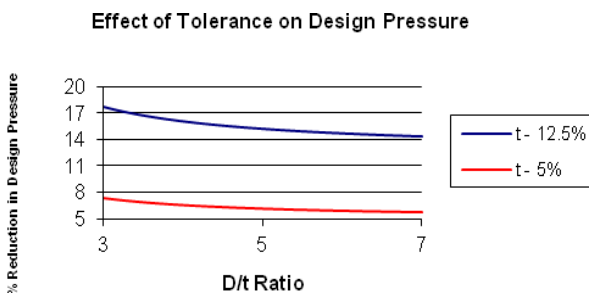
**Which Code to Use – Is there another way?**
The SBOP drilling riser is often deemed "rigid high pressure piping", and therefore subject to the design codes commonly used by the oil industry for piping design (ASME Pipeline Design Codes – B31.3, B31.4 and B31.8). But the pipeline design guidelines are based on quasi-static design conditions, not dynamic. And wall thicknesses are based on 67% and 83% of material yield strength for normal operating and test pressure conditions. API 16Q addresses marine drilling risers; but its design philosophy assumes short-duration exploratory drilling. So there are no provisions for fatigue limiting criteria or safety factors for extended drilling. Rather it focuses on extreme and survival conditions, resulting in a very conservative design.

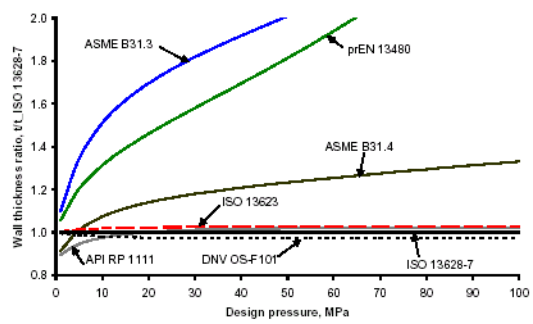
API 2RD takes another step closer to the SBOP riser case and has become more prevalent design code in the Gulf of Mexico, partly because it has been written for the production risers, but more importantly that, "the design of risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) requires

recognition that risers form a subsystem that is an integral part of the total system." Its design methodology still uses the conservative approach of allowable stresses based on a percentage of yield strength. But API 2RD eases the design restrictions by employing multiple working stress design (WSD) limits for different load cases (normal operating – 67% of Ys, pressure test – 90% of Ys, and survival – 100% of Ys). This allows the allowable stress to be higher in low probability events, maintaining conservative calculations without driving to a single over the top condition. API 2RD is the most widely accepted steel riser code in the industry, and it is the required code for riser design in the Gulf of Mexico referred to by BOEM/BSEE.

However, there is another design philosophy whose acceptance is growing, especially in Europe, "Limit State" theory. Pipeline design codes DnV OS-F101 and API 1111 use Limit State theory for deepwater pipeline designs when ASME pipeline codes values lead to pipe designs that no longer make sense from either from an installation or on-bottom in-situ case. DnV OS-F201 has a similar design method for dynamic risers, and uses Limit State API 17G for designing completion/workover risers that access subsea wells.

Limit State theory follows the same stress calculations as WSD, but sets its acceptance criteria based on two design criteria: a "pipe-burst" failure mechanism (ultimate limit state) and a serviceable limit state (the traditional "leakage" or pressure loss criteria). Both Limit State and WSD formulas closely track to one another at low pressures. However, at higher pressures, their results diverge, with WSD providing a more conservative result than what is actually required and observed from pipe failure testing. API 17G is accepted as the standard for high pressure workover and completion/workover risers and are finding their way into light duty and limited sidetrack drilling applications in the North Sea. So it might be argued that API 17G might be a plausible alternative to API 2RD. Government regulation has been silent on accepting Limit State, as an alternative to WSD, making this a relevant discussion point.




A second criterion that is becoming more and more crucial to deepwater riser design, is the wide band of allowances in manufactured geometry (wall thickness, ovality, etc.). Much of oil country tubular goods (OCTG) follow the criteria established in the API 5 series of specifications (5CT, 5L, etc.). OCTG manufactured to API 5CT allows variations in wall thickness up to 12-1/2% below the nominal thickness. For most well and static pipeline applications with high D/t pipe ratios (i.e. thin walled pressure vessels), reductions in design pressure rating remain relatively constant around 14%. However as D/t drops below 8 (the range needed for riser applications), the reduction in pressure rating increases by an additional 2-3%. Normally, the 14-17% reduction in strength can be offset by increasing wall thickness. But adding wall thickness causes all sorts of collateral design problems. However, narrowing OCTG tolerances by half nearly doubles the pressure rating performance. Similar improvements in reducing ovality and pipe straightness allowances gives the riser designer more room to optimize pipe thickness for the best possible riser weight and load support.

SBOP drilling differs from conventional floating drilling operations in that the well control components (i.e., the BOP stack) are not located at the seabed. Instead, the BOP stack is located at the surface just below the drill floor of the MODU. A further key difference is the SBOP drilling riser is designed to contain wellbore pressure whereas a conventional marine riser does not contain wellbore pressure and is isolated from wellbore pressure when the BOPs are closed.

There are numerous standards and guidelines for conventional drilling operations. Some of these cover many parts of the SBOP system design, configuration and operation. However, there are at present no SBOP specific guidelines that the industry can use in the planning and implementation of an SBOP operation. Consequently, the approach to SBOP operations within the industry has been driven by specific circumstances, individual operator requirements, and by IADC's SBOP guidelines.

### Issue #3 – Other Issues

Possible discussion points include thoughts on:

- What is the recommended number of rams; what type and in what order for the SBOP and SID? If a shear/blind ram is put on the SBOP, could a fish drop and damage the SID barriers?
- For design purposes, what pressure should be used within the ram wellbore? The current requirement is for the maximum anticipated surface pressure (MASP) – typically for a SBOP, but what should that be for the SID?
- What is mechanism for regaining well control over a shut in SID with gas? With hydrocarbon liquid? (dealing with bottoms up effect) (Murphy Azurite considered a pipe ram in addition to a shear/blind ram (dual stack) as part of its lessons learned)
- What is the most cost-efficient, yet safe control system for the SID? Electro-hydraulic multiplex? Acoustics, "Deadman" systems, ROV intervention, ROV hydrophone? If acoustics for SID control, how does one deal with the noise and shielding associated with a blowout plume?
- API 17H "high flow (HF)" receptacles with 1" bores have been specified for the subsea ROV interface. Hydraulic lines between these stabs and the function may be smaller and more restrictive. Is this right standard? Should there be hydraulic isolation to the disabled control system to prevent back flow?
- What types of MODUs are going to be allowed to use SBOP? Moored vs. DP vessels? TLPs/Spars only? What will be the allowed high pressure riser configuration for these (dual string, single string – SID)? Is there a water depth preference? Where should "Deadman", auto-shear, and emergency disconnect functions be required for these configurations?
- Are there different maintenance and protocols associated with well control equipment for SBOP-high pressure riser drilling vs. Subsea BOP and floating drilling equipment?
- Are there different reliability and redundancy requirements associated with well control equipment for SBOP-high pressure riser drilling vs. Subsea BOP and floating drilling equipment? How does one determine the efficacy level for maintenance of other SBOP/SID well control equipment?
- Are personnel easier to train in operating, maintaining and use of well control equipment for SBOP-high pressure riser drilling than Subsea BOP and floating drilling operations?
- Are personnel currently trained in operating the high pressure riser and monitoring its performance in the metocean environment?
- How does one inspect for premium threads and couplings during make-break and re-use? Are re-cuts required? Can they only be re-used once and only in a static condition (like SX)?
- How does one determine the fatigue life for maintenance of high pressure riser?
- How does one determine the fatigue life for maintenance of subsea wellhead? Are there any well foundation design or subsea wellhead rigid-lock requirements?
- Is IADC's *SBOP Design Guidelines* adequate for all other aspects of SBOP planning and operations? Should there be separate guidelines for shallow water vs. deepwater? Should there be separate guidelines for TLP/Spar vs. MODU?
- Should Standard 53 address SBOP-high pressure riser drilling? Does RP 96 properly address SBOP-high pressure riser drilling with respect to well design?
- Are there different well survivability issues (using the BOEM/BSEE well screening tool) that should be addressed in HAZOPs because of the SBOP-high pressure riser drilling?
- What should be done to address and minimize the effects of mechanical wear on adjacent production risers next to the drilling riser in the case of TLP/Spar well spacing?
- What are the current mechanisms for aligning the Industry and the Regulatory Agencies?
- Gaps in regulations, standards, industry practices, collaboration and technologies.

**Findings:**

- Note areas that could benefit from workshop discussion
- Include any preliminary recommendations to BOEM/BSEE

**Bibliography:**

1. American Petroleum Institute, RP1111, *Design Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines – (Limit State Theory)*, 3rd Edition, July 1999.

2. Bates, J.B., Kan, W.C., Allegra, A.P., Yu. A., "Dry Tree and Drilling Riser System for Hoover DDCV", Paper # 13084, Offshore Technology Conference, May 2001.

3. Brander, G., Magne, E., Newman, L., Taklo, T., "Drilling in Brazil in 2887m Water Depth Using a Surface BOP System and DP Vessel", IADC/SPE Paper # 87113, March 2004.

4. Claassen, L.C., Hendriks, S.M., Zijderveld, G.H.T., "Newbuild Compact Deepwater Drillship Designed for Surface BOP System", Paper # 20635, Offshore Technology Conference, May 2010.

5. DeLuca, M., "Breaking the Surface", Asian Oil & Gas Magazine, pp. 26-27, July-August 2004.

6. Denison, E.B., Howell, C.T., Ju, G.T., Gonzalez, R., Meyers, G.A., Ashcombe, G.T., "Mars TLP Drilling and Production Riser Systems", Paper # 8514, Offshore Technology Conference, May 1997.

7. Eyles, T., "Single / Dual Barrier HP Drilling Risers", Acteon HPHT Subsea Community Breakfast Meeting, (Presentation Slides), March, 2011.

8. IADC, *Surface BOP Guidelines for Floating MODUs*, IADC - Houston, October 2004.

9. IADC, "Workshop Examines Surface BOP Ops From Floaters", Drilling Contractor Magazine, pp 21, July-August 2002.

10. IADC, "SBOP Technology Results in Better Efficiency Safety", Drilling Contractor Magazine, pp 53-54, January-February 2005.

11. Kirkemo, F., Holden, H., "Burst and Gross Plastic Deformation Limit State Equations for Pipes: Part 2 - Applications," ISOPE JSC-249B Publication, 2001.

12. Koeck, F., MacFarlane, D., Skeels, H.B., "Future Considerations For HPHT Equipment and Systems", Paper # 18076, Offshore Technology Conference, May 2006.

13. Kozicz, J., Newman, S., "Reconfigurable Riser – Enabling Drilling Solutions for the Future", AADE Paper # AADE-05-NTCE-23, April 2005.

14. Mason, D.L., Wilie, C.L., Tharp, W., "Surface BOP: Testing and Completing Deepwater Wells Drilled with a Surface BOP Rig, IADC/SPE Paper # 87111, March 2004.

15. MCS, "Risk Analysis of Using a Surface BOP", Technology Assessment & Research (TA&R) Program, Project # 640, MCS Paper # PR-09-0433/SR01, Rev. 2, April, 2010.

16. Pallini, J., Wong, S., "HPHT Riser System", World Oil HPHT Drilling and Completions Conference September 2010.

17. Simondin, A., MacPherson, D., Touboul, N., Ragnes, G., "A Deepwater Well Construction Alternative: Surface BOP Drilling Concept using an Environmental Safe Guard", IADC/SPE Paper # 87108, March 2004.

18. Skeels, H.B., Broussard, D., Byrd, M., "Challenges Associated with HPHT Intervention Equipment", Paper # 15181, Offshore Technology Conference, May 2003.

19. Smith, T., Allen, T., Yu, A., "Holstein Spar Supported Vertical Riser and Dry Tree System", Paper # 17254, Offshore Technology Conference, May 2005.

20. Whooley, A., Deegan, F.J., Goldsmith, R., Botto, A., "Tools and Techniques for the Selection and Design of Safe Deepwater Riser Systems for Mobile Offshore Drilling Units", Paper # 22714, OTC – Brasil, October 2011.

### Other References on Risk Analysis:

1. Hull, M.E., Rees, J.C., Botto, A., Deegan, F.J., Whooley, A., "Risk-Based Case Study of Floating Facility Drilling Riser Design Concepts in Deepwater Gulf of Mexico", Paper # 31873, Offshore Technology Conference May, 2011.

2. Melendez, J., Schubert, J.J., "Risk Assessment of Surface vs. Subsurface BOP's on Mobile Offshore Drilling Units", Technology Assessment & Research (TA&R) Program, Project # 540, Texas A&M University, August, 2006.

3. Sattler, J. Lewis, E., "Qualitative Risk Analysis of Emergency BOP Control Systems to Ensure Availability", IADC/SPE Paper # 87157, March 2004.

4. Taklo, T., Magne, E., Brander, G., "Risk Management Process for Ultra-deepwater Surface BOP Operations from a DP Drilling Rig", IADC/SPE Paper # 87112, March 2004.