

GENERAL SPECIFICATION

Drilling & Wells

GS EP FP 441

Subsea WCE Specifications & Tests

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1. Scope

This general specification gives configuration, rating, maintenance and testing policy for Subsea Well Control Equipment involved in drilling, work-over and well testing operations.

In general the minimum requirements are dictated by the [API STD 53](#). This general specification retains the main points of this standard but aims to highlight any specific points that diverge from API or are more stringent. Points not addressed shall be in accordance with the above API standard.

2. Reference documents

The reference documents listed below form an integral part of this General Specification.

External Documents

Unless otherwise stipulated, the applicable version of these documents, including relevant appendices and supplements, is the latest revision published at the effective date of this document.

Reference	Title
API RP 17H	Recommended Practice for Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems
API SPEC 6A	Specification for Wellhead and Christmas Tree Equipment
API SPEC 7-1	Specification for Rotary Drill Stem Elements
API SPEC 12J	Specification for Oil and Gas Separators
API SPEC 16A	Specification for Drill-Through Equipment
API SPEC 16C	Specification for Choke and Kill Equipment
API SPEC 16D	Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API SPEC 16F	Specification for Marine Drilling Riser Equipment
API STD 53	Blowout Prevention Equipment Systems for Drilling Wells
ANSI/ASME B36.10M	Welded and seamless wrought steel pipe
DNVGL-OS-E101	Drilling plant
NACE MR 0175	Petroleum and natural gas industries - Materials for use in H ₂ S-containing environments in oil and gas production

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Reference	Title
GS EP COR 170	Materials for upstream sour service application. Specification for selection and design
GS EP SPS 001	Subsea Production Systems General Design Requirements
GS EP SPS 027	WORO spread minimum requirements

3. Foreword

3.1 Definitions

“Deep Water” is defined as the water depths included between 500 and 1,500 meters.

“Ultra Deep Water” is defined as the water depths included between 1,500 and 3,000 meters.

“Abyssal water” is defined as the water depths of 3,000 m and more.

For water depths, refer to [GS EP SPS 001](#).

“HP/HT” is defined as High Pressure/High Temperature Wells with MEWHP above 10,000 psi and bottom hole temperature above 150°C.

3.2 Glossary

API	American Petroleum Institute
BOP	Blow Out Preventer
BSR	Blind Shear Rams
BWM	Between Wells Maintenance
CL	Choke Line
CLV	Close / Lock / Vent
CM	Choke Manifold
CSO	Complete Shut-Off
CSR	Casing Shear Rams
DICV = DIBPV	Drop In Check Valve = Drop In Back Pressure Valve
DMC	Drill Master Cabin
DP rig	Dynamically Positioned rig
EBS	Emergency Back-up System
EDS	Emergency Disconnection Sequence
FOSV	Full Opening Safety Valve

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IBOP	Inside Blow Out Preventer
ID	Inside Diameter
KL	Kill Line
LAP	Lower Annular Preventer
LKL	Lower Kill Line
LMRP	Lower Marine Riser Package
LP	Low Pressure
LPR	Lower Pipe Rams
MEWHP	Maximum Expected Well Head Pressure
MGS	Mud Gas Separator
MOC	Manual Operated Choke
MUX	Multiplexed electro-hydraulic control system
NABM	Non Aqueous Based mud
NSP	Non Shearable Period
OD	Outside Diameter
OEM	Original Equipment Manufacturer
OP	Operating Pressure
PCS	Primary Control System
PMS	Preventive Maintenance System
PR	Pipe Rams
RIW	Run In Water
ROC	Remote Operated Choke
ROV	Remote Operated Vehicle
SCS	Secondary Control System
SEM	Subsea Electronics Module
SHZ	Safe Handling Zone
TP	Testing Pressure
UAP	Upper Annular Preventer
UKL	Upper Kill Line
UPR	Upper Pipe Rams
UPS	Uninterrupted Power Supply
VBR	Variable Bore Rams
WBM	Water Base Mud

WCE	Well Control Equipment
WH	Well Head
WP	Working Pressure

4. Main considerations

4.1 Working pressure of Well Control Equipment

The WCE is one of the main components of the mechanical envelope when drilling or completing a well. WCE can be used at its API WP unless any de-rating applies, for example: temperature limitations, specific points mentioned in inspection reports (wear, existing repair, etc.) or H₂S in fluids. The WP of equipment is equal to its API WP minus any de-rating:

$$WP = API\ WP * K \text{ with } K = \text{de-rating ratio}$$

Constraints due to special pumping operations (acid job, stimulation, etc.) will be taken into consideration if foreseen.

The WP of WCE subject to well pressure shall be $\geq$ MEWHP of the operational phase during which the equipment is used, except for annular preventers where chapter 4.2 applies.

Sea water hydrostatic pressure shall be ignored when choosing the subsea WCE working pressure.

Six WP categories are given by [API SPEC 16A](#):

- 2,000 psi/138 bar
- 3,000 psi/207 bar
- 5,000 psi/345 bar
- 10,000 psi/689 bar
- 15,000 psi/1,035 bar
- 20,000 psi/1,379 bar.

4.2 Annular Preventers

Annular preventers shall have as a minimum a WP rating immediately lower than the WP rating of the ram preventers.

4.3 Ring gaskets

Only pressure-energized metal seal ring gasket shall be used. Ring gaskets shall not be reused.

The ring groove should be checked and cleaned with oil before make-up, but oil should not be left in the groove. Grease should not be used.

RX and BX gaskets (used respectively with 6B and 6BX flanges) as defined in [API SPEC 6A](#) and BX gaskets (used with 16BX hubs) as defined in [API SPEC 16A](#), are the API approved gaskets for WCE.

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Proprietary gaskets (mainly AX, CX, DX or VX) are used in conjunction with WH and LMRP connectors and mini-connectors.

All gaskets that include elastomeric or non-elastomeric inserts (Hycar for example) are not considered as permanent metal-to-metal sealing elements and can only be used in back-up and temporary solutions, after a Risk Assessment has been performed.

4.4 BOP stack installation

Subsea BOPs will not be run on WH at an angle greater than 1.5° to avoid wear and key-seating damage to the bore of the wellhead, BOP and riser.

Connecting the BOP onto the subsea WH should be performed under fair metocean and weather conditions within the operating limitations of the rig to avoid damage to equipment and WH in particular.

For each drilling operation performed with a floating rig, a Safe Handling Zone (SHZ) is defined based on the following parameters:

- Sea bed slope (water depth at SHZ should be equal or deeper than at WH location)
- Prevailing current direction
- Existing subsea facilities
- Shape of potential dropped objects

BOP running/retrieving operations shall always be performed in a defined SHZ.

The LMRP connector shall be pressurized in the closed position (if a hot line is connected) or set in block position (if no hot line). Emergency Back-up Systems and Acoustic Secondary Control System shall not be armed until the BOP is latched on WH.

However, for the specific case of exploration or appraisal wells, BOP running / retrieving operations can be done on the well location under specific conditions:

- If the rig enables dual handling and the running / retrieving of BOP on well location is part of the optimization of the operations
- If no other subsea installation is located in the near vicinity of the well location
- If a dedicated risk assessment has been performed to highlight and mitigate the risk taken (proper securing of equipment while RIW BOP, respud equipment ready, shallow hazards survey done for respud location...)
- Ultimately, the decision is to be taken by the Drilling Manager based on the specificities of the well to be drilled.

4.5 H2S environment

Identification:

WCE components should be marked in accordance with [NACE MR 0175](#) / Section 5.4 to show their suitability for sour service. Temporary marking should be in agreement with [GS EP COR 170](#).

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Compatibility:

The H₂S compatibility of WCE should be thoroughly assessed according to the working programme.

In H₂S environment, metallic components which may be in contact with well fluids, should meet the requirements of [NACE MR 0175](#). Shear rams which involve high strength materials with a high hardness can be susceptible to H₂S cracking, even on H₂S trim BOP's.

In the presence of H₂S, the service life of elastomers shortens as temperature increases. Any elastomeric component on a BOP is recommended to be changed out as soon as possible after exposure to H₂S during a kick circulation.

4.6 Temperature/Fluid compatibility

The temperature rating of all elastomers (ram packers, bonnet seals, valves, annular elements, etc.) and their resistance to NABM and completion fluid should be thoroughly assessed according to the working programme.

4.7 HP/HT wells specific

Specific elastomers need to be planned for HT conditions.

Not only BOP rams, but all HP and LP mud system components need to be checked for compatibility with HT mud. When working in HT environments it is highly recommended to monitor the choke line temperature, upstream of the choke, and on the flow line, with read-out in the DMC.

4.8 Non Shearable Periods

When a non shearable piece of equipment is across the BOP during some time, this period is called "Non Shearable Period" or NSP.

NSP management is especially important for drilling operations from a DP vessel when no riser margin can be included in the mud weight.

Wireline operations, when BOP shear rams are not designed to shear wires or braided cables, are considered as NSP as the shearing and sealing of the well are not guaranteed. Note that the main subsea BOPs' OEMs are proposing BSRs able to shear wires.

5. Functional requirements

5.1 Shear and seal function

The installation of the BSR in the uppermost cavity is considered as the most effective position in all BOP configurations because:

- It limits their exposure to H₂S if any (high-hardness steels required for ram shear blades)
- It minimizes the OP needed for shearing, as the pipe rams closure will avoid the shear rams to be exposed to well pressure (in pressure-in-well condition and well shut on annular)
- It ensures a proper space out to avoid shearing on a tool joint
- It ensures a better centralization of string (effective shearing dependent on centralisation)

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- It avoids dropping the drill string and allow easier fishing operations

Based on the above reasons, it is highly recommended to hang-off the drill string before shearing.

The driller has to know the proper tool-joint position for shearing.

For any operational phase where hydrocarbon layers are foreseen, the shear and seal function shall be available on a BOP stack.

The BSR shall always be installed in the uppermost BOP cavity, whatever the number of cavities. Adequate spacing shall be provided to be able to hang-off the string and shear the drill pipe above the tool joint.

5.2 Casing shear function

Casing Shear Rams (CSR) shall be installed on all BOPs used on DP rigs.

5.3 Shear tests

With all the different types of drill pipes and casing strings used in operations, it is imperative to confirm the BOP capacity to shear the relevant tubulars with the control system in use.

The shearing capability of the installed BOP and its control system shall be verified during the rig acceptance period through a shear test or by giving valid references.

The BSR(s) shall be able to shear the strongest drill pipe in use (not-including landing string and HWDP) and seal the well.

The CSR shall be able to shear the strongest casing set to cover the first expected Hydrocarbons formation (DP rigs only).

It shall be verified that the SCS (Acoustic and ROV) are performing the functions with the same operating pressure as the PCS and that the recorded shearing pressure⁽²⁾ is within the SCS system WP.

The references are valid if a successful shear test has been performed in the industry in equivalent conditions ⁽¹⁾ and if the recorded shearing pressure ⁽²⁾ is within 80% of the rig' shear rams operating pressure.

The shear test(s) performed or the references used to justify not doing shear test(s) have to be fully documented and a dossier prepared (see Appendix 2 for requirements of records).

⁽¹⁾ Equivalent shear test means that the same type of BOP (OEM, model, size, WP, rams) and same control system (operator size, operating pressure) were used to shear the same tubular (size, weight, grade).

⁽²⁾ The recorded shearing pressure (when obtained in surface conditions) has to be corrected with either Mud Weight hydrostatic pressure / ram closing ratio or MEWHP / ram closing ratio whichever value is the highest.

A surface BSR test against "non mono tubular" completion equipment (completion shear sub complete with control lines, Stand Alone Screens with shroud or wash pipe, vacuum insulated tubings, etc...) should be performed whenever possible to confirm the suitability of the BOP with the completion equipment. This shear test can be performed at the BOP OEM facilities.

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5.4 Hang-off

The current NACE requirements for rams (subsea BOPs are designed for service in H₂S environment) often result in the rams being softer than drill pipe tool joints and can limit the pipe hang-off capacity. Manufacturers can be asked for specific applications such as localised metal hardening which can increase hang-off capacity. Depending on the well program, the need for special hang-off rams should be evaluated and possibly included in the call for tender.

VBR hang-off capacity should be verified (refer to manufacturer data) as it is usually lower than fixed rams capacity, particularly in the smaller diameters of their range.

Hang-off shall always be possible, even if using VBR, but never on the lowermost PR.

To improve the ram and line redundancy for well control, the uppermost PR shall be used as hang-off rams when the spacing with uppermost BSR allows shearing the string.

On shallow water wells when disconnection is required for bad weather and enough time is available, it is recommended to use a dedicated emergency hang-off tool to be able to suspend the string and close the BSR above the hang-off rams.

5.5 Stripping

With a subsea BOP, stripping operations are normally performed with the annular preventer(s) and consequently, the installation of a surge bottle on each annular preventer is compulsory.

Stripping using PRs is difficult to implement with a subsea BOP and is not recommended by OEMs, especially with VBRs which are not designed for and are now present in most BOP configurations. Furthermore the stripping procedures using PRs have gained in complexity with the automatic locks fitted on most ram preventers. In addition, as we want to keep the lowermost PR as a mean of shutting the well if other components of the BOP stack fail, these rams should never be subject to the wear and stress of stripping operations.

Each annular preventer shall be fitted with a surge bottle.

At least one annular preventer shall allow a Complete Shut-Off (CSO) of the well and at least one annular preventer shall allow stripping with drill pipe size(s) in use for drilling ⁽¹⁾.

The lowermost PR shall never be used for stripping.

⁽¹⁾ Depending on annulars' OEM specifications and tool-joint sizes, annular packer elements used for stripping may not be Complete Shut-Off (CSO). When selecting packer elements, a compromise may have to be found between rated WP, rated T°, stripping capacity and CSO ability (API SPEC 16A testing requirement in CSO condition is set-up to one-half of WP). Refer to OEM's tables. CSO annular preventer allows closing on cable.

If both annulars cannot respect simultaneously Stripping and CSO conditions, it is recommended to use the UAP for stripping (the UAP is typically used as a "working" annular and usually considered as the primary stripping preventer), the LAP being kept for sealing or CSO.

The use of a stripping tank is recommended on all rigs to facilitate stripping operations. It should be accurate enough and its scale should correspond to the steel displacement volume of a stand of the main drill pipe. Ideally the level indication should be visible from the choke panel and the set up should allow bleeding down straight from the choke manifold into the stripping tank.

5.6 Casing rams

Consideration for the use of casing rams is dependent on the inherent risks of the section to be cased and as a general statement:

- At least one BOP sealing element (ram or annular type) is required to run casing in addition to having the suitable mud weight in the well.
- When running a tubular with an annular being the primary preventer, the collapse rating of the tubular has to be considered. In addition, a table of annular closing pressure versus casing size should be available, known and posted in DMC.

When running casing strings in open holes where hydrocarbon layers are present or suspected, one preventer shall seal on casing and have a WP $\geq$ MEWHP.

When an annular is used as the primary preventer, the WP to consider shall be the packer element WP ⁽¹⁾.

A cross-over and a safety valve shall be available on rig floor to allow internal closure at any time.

⁽¹⁾ The packer element WP may be reduced depending on OEM and type of packer (e.g. stripping packer).

5.7 Ram locking devices

The function of the locking devices is to block any ram in a closed position. It is a recommended practice with a subsea BOP to lock the rams prior to hang-off and to conduct any well control operation (to be noted that numerous BOPs have an automatic locking function after ram closure).

All sealing ram type preventers shall be equipped with locking devices. ([API STD 53](#))

BOP stacks shall be pressure tested with the locks engaged, the lock pressure vented and the ram closing pressure vented (called "close/lock/vent" sequence) during all the pressure tests conducted at surface, i.e. during the acceptance period, at first BOP latch to WH and BWM periods.

5.8 Completion

When running a completion, sub-assemblies and control lines can prevent the appropriate PR to properly seal around the tubing. It is therefore recommended to use special bevelled flat-pack.

5.9 Mud cross / Drilling spool

The use of BOP bodies with lateral outlets below the rams allows:

- The elimination of mud cross / drilling spool with potential leak areas
- The reduction of stack heights

Nevertheless, the use of mud cross / drilling spool is not authorized on subsea BOP stack, only spacer spool without outlet can be used.

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5.10 BOP outlets and lines

5.10.1 Choke and Kill lines

The BOP outlet below the lowermost ram is a potential single point failure. If it gets washed there is no other means to secure the well. Therefore this outlet should never be used to evacuate well influx and should be connected to the KL for ultimate pumping or for pressure monitoring purpose. Only clean fluid (mud or brine) will be pumped down the KL.

The purpose of CL is to evacuate the well effluent during a conventional well control. Consequently there is no benefit to have a CL connected just below the BSR. In addition it is not accepted to have a CL above the BSR as there is a strong possibility of by-passing the BSR if the well control situation deteriorates requiring to close the BSR.

CLs have to be connected below the PRs (but above the lowermost one).

CL and KL shall be designed as per [API SPEC 16C](#).

The line connected below the lowermost ram preventer (i.e. called the LKL) shall never be used as a CL to evacuate an influx.

CL and KL shall never be connected above uppermost BSR.

CL and KL shall be at least 3" ID and equipped with two full bore remotely operated valves (fail safe closed).

For DW / UDW applications, Choke and Kill lines shall be at least 4" ID on the marine riser.

Moonpool Choke & Kill HP hoses shall be fire retardant as per requirement of [API SPEC 16C](#) (i.e. withstand a 30 minute fire test under 1,300°F / 704°C temperature and have no visible leakage during the subsequent testing at WP).

WECO unions and swivel joints are not allowed on CL and KL.

Even if CL and KL could be considered as interchangeable on subsea BOP stacks, it is highly recommended to keep some rigour in the line naming and apply the same rationale for subsea and surface BOP stack. It is however understood that on subsea BOP stacks, both CL and KL have a common part between the upper and lower choke and kill sections.

5.10.2 Gas bleed-off line

Recent DW / UDW rigs are equipped with one gas bleed-off / relief line (isolated with two failsafe valves) connected below the UAP to facilitate the evacuation of effluent which could be trapped above the well control rams. This set-up however makes it possible to by-pass the closed rams during an escalating kick control. Therefore it is reminded that this line should only be used after well control is completed.

The Gas bleed-off line shall never be used to evacuate an influx during a well control situation. Gas bleed-off line shall only be used when the killing mud with the adequate required specific gravity has been circulated in the well.

6. Configuration of BOP

Today only single stack systems are used for all offshore subsea operations, either shallow or DW / UDW.