

Subsea production systems

This NORSOK standard is developed with broad petroleum industry participation by interested parties in the Norwegian petroleum industry and is owned by the Norwegian petroleum industry represented by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries. Please note that whilst every effort has been made to ensure the accuracy of this NORSOK standard, neither the Norwegian Oil and Gas Association nor the Federation of Norwegian Industries or any of their members will assume liability for any use thereof. Standards Norway is responsible for the administration and publication of this NORSOK standard.

Standards Norway
P.O. Box 242
N-1326 Lysaker
NORWAY
Visiting address:
Mustads vei 1, 0283 Oslo
Copyrights reserved

Telephone: + 47 67 83 86 00
Fax: + 47 67 83 86 01
Email: petroleum@standard.no
Website: www.standard.no/petroleum

© NORSOK. Any enquiries regarding reproduction should be addressed to Standard Online AS. www.standard.no

Subsea production systems

Content

Foreword 3

Introduction 3

1 Scope..... 5

2 Normative and informative references..... 5

3 Terms, definitions and abbreviations..... 8

4 Technical requirements 9

5 General requirements and recommendations 10

6 Subsea wellhead and tree equipment 15

7 Subsea umbilicals..... 15

8 Completion/workover riser systems..... 16

9 Remotely operated vehicle (ROV) interfaces on subsea production systems 16

10 Subsea structures and manifolds 16

Annex A (informative) Loads for design and selection of subsea trees, wellheads and templates 17

Annex B (informative) Recommendations for structural design, materials, fabrication and testing of subsea wellhead and tree equipment and completion/workover riser systems 29

Copyright Norsk Søkkel Konkursansettisjón
Provided by IHS
No reproduction or networking permitted without license from IHS

Foreword

The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, added value and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to replace oil company specifications and serve as references in the authorities' regulations.

The NORSOK standards are normally based on recognized international standards, adding the provisions deemed necessary to fill the broad needs of the Norwegian petroleum industry. Where relevant, NORSOK standards will be used to provide the Norwegian industry input to the international standardisation process. Subject to development and publication of international standards, the relevant NORSOK standards will be withdrawn.

The NORSOK standards are developed according to the consensus principle, generally applicable standards work and according to established procedures defined in NORSOK A-001N.

The NORSOK standards are prepared and published with support by the Norwegian Oil and Gas Association, the Federation of Norwegian Industries, Norwegian Shipowners' Association and The Petroleum Safety Authority (PSA) Norway.

NORSOK standards are administered and published by Standards Norway.

This fourth edition of NORSOK U-001 is updated with particular attention to loads from fishing gear, riser loads, and recommendations concerning subsea wellhead and tree equipment. See details below.

Annex A and B are informative.

Introduction

This NORSOK standard is based on the ISO 13628 *Petroleum and natural gas industries – Design and operation of subsea production systems* series of standards.

This NORSOK standard includes specific requirements and recommendations that are not covered by ISO 13628 series of standards.

This NORSOK standard replaces U-001 Rev. 3, October 2002.

Revision information

This edition 4 of NORSOK U-001 Subsea production systems standard replaces NORSOK U-001 *Subsea production systems* (Rev. 3, October 2002). This standard is based on the relevant parts of the ISO 13628 series of standards, and provides amendments to fishing gear loads, riser loads, and design of subsea wellhead and tree equipment, and templates. The basis for this NORSOK standard has been the previous version of U-001, combined with general industry experience over the last years.

The main changes are:

- updating reference to relevant parts of the 13628 series of standard;
- updating references;
- updating trawl loads;
- updating Annex A, to provide static and dynamic design riser loads for subsea wellhead connectors, subsea wellheads, and subsea templates (already covered in first paragraph below);
- adding Annex B, to provide recommendations for structural design, materials, fabrication and testing of subsea wellhead and tree equipment and completion/workover riser systems.

Annex A, based on Joint Industry Project, see DNV GL 2014-0783 [NORSOK U001 Well System loads](#). Additional information for; [one typical well load - bending moment- annual fatigue histogram](#) and [all sea state individual annual histograms](#).

Typical template loads are given in Annex A, Table A.8. Template loads for site specific conditions can be calculated by spreadsheet which is available at this link, [Annex A, Table A.8 Conductor dimension and capacity and weight Rev1D](#).

Based upon the enquiry, many comments were given upon the completely revised riser loads in Annex A. The stakeholders from the enquiry agreed upon a verification study. This study was sponsored by Standards Norway. The verification was done as a joint effort by DNV GL, FMC, Aker Solutions, and Statoil.

The recommendations in the verification summary report prepared by Statoil are included in the final edition of NORSOK U-001, see summary below.

Statoil – Verification of riser analyses for revised standard wellhead loads in NORSOK U-001, Annex A.

Work has been carried out to verify the analyses performed by DNV-GL to provide updated standard maximum wellhead loads for NORSOK U-001, Annex A. Main contributors have been Aker and FMC, who have prepared their own reports. Funding has been provided by Statoil. The verification work is summarized as follows:

Summary:

The DNV-GL calculated wellhead maximum loads may not be on the safe side for drilling rigs with high load variations in the riser tensioner system.

It has been shown that the DNV-GL calculated wellhead maximum loads for shallow water (125 m analysed) are consistently over-estimated by 5–10 %. This is due to the applied method for extreme value estimation, which appears not well suited for extrapolation of shallow water wellhead responses.

For deeper water (250 m and more), the applied method for extreme value estimation is considered to provide results without significant bias.

References:

- 1) [Aker Engineering & Technology report 160026-1002-1000-2-REP-01, Rev 02, 25.02.2015, NORSOK U001 Annex A: Verification of Wellhead Loads](#)
- 2) [FMC Technologies report RPT60121280, February 26, 2015, NORSOK U-001 Well system loads verification](#)

1 Scope

A complete subsea production system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells and transfer them to a given processing facility located offshore (fixed, floating or subsea) or onshore, or to inject water/gas through subsea wells.

This standard NORSOK U-001 *Subsea production systems* provides general requirements and overall recommendations for development of complete subsea production systems, from the design phase to decommissioning and abandonment, within the Norwegian continental shelf (NCS).

NORSOK U-001 provides normative reference to the relevant ISO 13628 *Design and operation of subsea production systems* series of standards, and provides *additional* requirements that are applicable to equipment and operations in the NCS.

The ISO 13628 series of standards consists of the following parts, under the general title *Petroleum and natural gas industries – Design and operation of subsea production systems*:

- *Part 1: General requirements and recommendations (*)*
- *Part 2: Unbonded flexible pipe systems for subsea and marine applications*
- *Part 3: Through flowline (TFL) systems*
- *Part 4: Subsea wellhead and tree equipment (*)*
- *Part 5: Subsea umbilicals (*)*
- *Part 6: Subsea production control systems*
- *Part 7: Completion/workover riser systems (*)*
- *Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems (*)*
- *Part 9: Remotely Operated Tool (ROT) intervention systems*
- *Part 10: Specification for bonded flexible pipe*
- *Part 11: Flexible pipe systems for subsea and marine applications*
- *Part 15: Subsea structures and manifolds (*)*

(*) Presently, this NORSOK U-001 provides amendments only to the ISO standards marked with asterisks above.

2 Normative and informative references

The following standards include provisions and guidelines which, by reference in this text, constitute provisions and guidelines of this NORSOK standard.. Latest issue of the references shall be used unless otherwise agreed. Other recognized standards may be used provided it can be shown that they meet or exceed the requirements and guidelines of the standards referenced below.

2.1 Normative references

The following documents, in whole or in part, are normative referenced in this document and are indispensable for its application.

ASME B31.3, *Process Piping*

ASME B31.8, *Gas Transmission and Distribution Piping Systems*

DNV offshore standard DNV-OS-H205, *Loadout, Transportation and Installation of Subsea Objects* (VMO Standard – Part 2-6)

DNV-OS-F101, *Submarine Pipeline Systems*

DNV-OS-H101, *Marine Operations, General*

DNV-OS-H102, *Marine Operations, Design & Fabrication*

DNV-OS-H201, *Load Transfer Operations*

DNV-OS-H202, *Sea Transports*

DNV-OS-H203, *Transit and Positioning of Mobile Offshore Units*

DNV-OS-H204, *Offshore Installation Operations*

DNV-OS-H205, *Lifting Operations*

DNV-OS-H206, *Sub Sea Operations*

IEC 60794-1-2, *Optical fibre cables – Part 1-2: Generic specification – Basic optical cable test procedures*

IEC 60811-202 ed. 1.0, *Electric and optical fibre cables – Test methods for non-metallic materials – Part 202: General tests – Measurement of thickness of non-metallic sheath*

IEC 60811-100, *Electric and optical fibre cables – Test methods for non-metallic materials – Part 100: General*

ISO 10423, *Petroleum and natural gas industries – Drilling and production equipment - Wellhead and christmas tree equipment*

ISO 13628-1:2005, *Petroleum and natural gas industries – Design and operation of subsea production systems - Part 1: General requirements and recommendations*

ISO 13628-4:2010, *Petroleum and natural gas industries – Design and operation of subsea production systems - Part 4: Subsea wellhead and tree equipment*

ISO 13628-5, *Petroleum and natural gas industries – Design and operation of subsea production systems – Part 5: Subsea umbilicals*

ISO 13628-7:2005, *Petroleum and natural gas industries – Design and operation of subsea production systems - Part 7: Completion/workover riser systems*

ISO 13628-8, *Petroleum and natural gas industries – Design and operation of subsea production systems – Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems*

ISO 13628-15, *Petroleum and natural gas industries – Design and operation of subsea production systems – Part 15: Subsea structures and manifolds*

ISO 14313, *Petroleum and natural gas industries – Pipeline transportation systems – Pipeline valves*

ISO 19901-6, *Petroleum and natural gas industries – Specific requirements for offshore structures – Part 6: Marine operations*

ITU-T G.652, *Characteristics of a single-mode optical fibre and cable*

NMD, *Regulations for mobile offshore units*

NORSOK D-010, *Well integrity in drilling and well operations*

NORSOK M-001, *Materials selection*

NORSOK M-120, *Material data sheets for structural steel*

NORSOK M-501, *Surface preparation and protective coating*

NORSOK M-503, *Cathodic protection*

NORSOK M-601, *Welding and inspection of piping*

NORSOK M-630, *Material data sheets and element data sheets for piping*

NORSOK M-650, *Qualification of manufacturers of special materials*

NORSOK M-710, *Qualification of non-metallic sealing materials and manufacturers*

NORSOK N-001, *Integrity of offshore structures*

(PED 97/23/EC) by Pressure Equipment Directive, dated 29 May 2002

2.2 Informative references

API RP 17Q, *Subsea Equipment Qualification - Standardized Process for Documentation*

API Spec 20B, *Open Die Shaped Forgings for Use in the Petroleum and Natural Gas Industry*

API Spec 20C, *Closed Die Forgings for Use in the Petroleum and Natural Gas Industry*

API Std 6X, *Design Calculations for Pressure-containing Equipment*

API TR 6MET, *Metallic Material Limits for Wellhead Equipment Used in High Temperature for API 6A and 17D Applications*

ASM Handbook, *Volume 1: Properties and Selection: Irons, Steels, and High-Performance Alloys*

ASME Boiler and Pressure Vessel Code (BPVC), *Section V, Nondestructive Examination (ASME BPV Code, Section V)*

ASME Boiler and Pressure Vessel Code (BPVC), *Section VIII, Division 2: Alternative Rules, 2015 (ASME BPV Code, Section VIII, Division 2:2015)*

ASME Boiler and Pressure Vessel Code (BPVC), *Section VIII, Division 3: Alternative Rules for Construction of High Pressure Vessels, 2015 (ASME BPV Code, Section VIII, Division 3:2015)*

ASME Boiler and Pressure Vessel Code (BPVC), *Section IX, Welding, Brazing, and Fusing Qualifications: Qualification Standard for Welding, Brazing, and Fusing Procedures; Welders; Brazers; and Welding, Brazing and Fusing Operators (ASME BPV Code, Section IX)*

ASNT ACCP-CP-1, ASNT Central Certification Program

ASTM A194, *Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both*

ASTM A320, *Standard Specification for Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service*

ASTM A370, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*

ASTM A388, *Standard Practice for Ultrasonic Examination of Steel Forgings*

ASTM A508, *Standard Specification for Quenched and Tempered Vacuum-Treated Carbon and Alloy Steel Forgings for Pressure Vessels*

ASTM A962, *Standard Specification for Common Requirements for Bolting Intended for Use at Any Temperature from Cryogenic to the Creep Range*

ASTM E709, *Standard Guide for Magnetic Particle Testing*

ASTM F788, *Standard Specification for Surface Discontinuities of Bolts, Screws, and Studs, Inch and Metric Series*

ASTM F812, *Standard Specification for Surface Discontinuities of Nuts, Inch and Metric Series*

AWS B5.9, *Specification for the Qualification of Welding Supervisors*

BS 7608, *Guide to fatigue design and assessment of steel products, 2014*

BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*

DNV Standard for Certification No 2.7-3, *Portable Offshore Units*

DNV-RP-F-204, *Riser Fatigue*

DNVGL report, Rev B., 20143-0783, NORSOK U-001, *Well System Loads*

DNVGL-RP-0001, *Probabilistic methods for planning of inspection for fatigue cracks in offshore structures*

DNVGL-RP-0005, *Fatigue design of offshore steel structures*

DNVGL-RP-0034, *Steel forgings for subsea applications*

EN 10204, *Metallic products - Types of inspection documents*

FKM Guideline, *Analytical strength assessment, VDM Verlag, 5th revised edition, 2003*

ISO 3183, *Petroleum and natural gas industries – Steel pipe for pipeline transportation systems*

ISO 3834-2, *Quality requirements for fusion welding of metallic materials – Part 2: Comprehensive quality requirements*

ISO 9588, *Metallic and other inorganic coatings – Post-coating treatments of iron or steel to reduce the risk of hydrogen embrittlement*

ISO 9606-1, *Qualification testing of welders - Fusion welding - Part 1: Steels*

ISO 9712, *Non-destructive testing - Qualification and certification of NDT personnel*

ISO 10474, *Steel and steel products – Inspection documents*

ISO 11960, *Petroleum and natural gas industries – Steel pipes for use as casing or tubing for wells*

ISO 14731, *Welding coordination – Tasks and responsibilities*

ISO 14732, *Welding personnel - Qualification testing of welding operators and weld setters for mechanized and automatic welding of metallic materials*

ISO 15609-1, *Specification and qualification of welding procedures for metallic materials -- Welding procedure specification - Part 1: Arc welding*

ISO 15614-1, *Specification and qualification of welding procedures for metallic materials – Welding procedure test – Part 1: Arc and gas welding of steels and arc welding of nickel and nickel alloys*

ISO 15614-7, *Specification and qualification of welding procedures for metallic materials – Welding procedure test – Part 7: Overlay welding*

ISO 17636-1, *Non-destructive testing of welds - Radiographic testing - Part 1: X- and gamma-ray techniques with film*

ISO 17637, *Non-destructive testing of welds - Visual testing of fusion-welded joints*

ISO 17638, *Non-destructive testing of welds - Magnetic particle testing*

ISO 17640, *Non-destructive testing of welds - Ultrasonic testing - Techniques, testing levels, and assessment*

NORSOK U-009, *Life extension for subsea systems*

3 Terms, definitions and abbreviations

For the purposes of this NORSOK standard, the following terms, definitions and abbreviations apply.

3.1 Definitions

3.1.1

can

verbal form used for statements of possibility and capability, whether material, physical or casual

3.1.2

may

verbal form used to indicate a course of action permissible within the limits of the standard

3.1.3

shall

verbal form used to indicate requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted, unless accepted by all involved parties

3.1.4

should

verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required

3.2 Abbreviations

ACCP	ASNT central certification program
ALS	accidental limit state
ASNT	American society for non-destructive testing
BOP	blow out preventer
C/WO	completion/workover
CVN	Charpy V-notch
DST	drill string (pipe) tension
EDP	emergency disconnect package
FAT	factory acceptance test
FSL	forging specification level
HXT	horisontal subsea tree (X-mas tree)

ID	internal diameter
LFJ	lower flexjoint
LMRP	lower marine riser package
MT	magnetic particle testing
NDT	non-destructive testing
NMD	Norwegian Maritime Directorate
PE	polyethylene
PED	Pressure Equipment Directive
PGB	permanent guide base
PSA	Petroleum Safety Authority
PSL	product specification level
PT	penetrant testing
PVC	polyvinylchloride
PWHT	post weld heat treatment
RAO	response amplitude operator
ROV	remotely operated vehicle
RT	radiographic testing
SFC	steel forging class
SMTS	specified minimum tensile strength
SMYS	specified minimum yield strength
SSTT	subsea test tree
ULS	ultimate limit state
UT	ultrasonic testing
WD	water depth
WH	subsea wellhead
XT	subsea tree (X-mas tree)

4 Technical requirements

4.1 General

The EU Pressure Equipment Directive (PED 97/23/EC) has been implemented in Norway by the *Forskrift om trykkpåkjent utstyr* dated 29 May 2002. The following are, however, excluded from the scope of PED and the Norwegian implementation regulation:

- (3.1) "pipelines comprising piping or a system of piping designed for the conveyance of any fluid or substance to or from an installation (onshore or offshore) starting from and including the last isolation device located within the confines of the installation, including all the annexed equipment designed specifically for pipelines. This exclusion does not apply to standard pressure equipment such as may be found in pressure reduction stations or compression stations";
- (3.9) "well-control equipment used in the petroleum, gas or geothermal exploration and extraction industry and in underground storage which is intended to contain and/or control well pressure. This comprises the wellhead, christmas tree, the blow out preventers (BOP), the piping manifolds and all their equipment upstream".

This is a limited normative reference for subsea systems. For subsea equipment, said regulation applies to process vessels only, e.g. separators, when these are permanently located subsea. Other parts of subsea systems are governed by standards and norms specifically established for subsea equipment.

The requirements for the rest of a subsea system are regulated by other standards and norms developed for this specific purpose. The interface to standard pressure equipment will have to be detailed based upon the system layout established during the system engineering phase of a field development.

4.2 Relation to ISO 13628

This NORSOK standard gives additional requirements and recommendations, and shall be read in conjunction with all relevant parts of ISO 13628.

5 General requirements and recommendations

5.1 General

A subsea production system shall be designed to account for equipment and system testing, installation, commissioning, operation, inspection, maintenance, repair, replacement, and removal, see ISO 13628-1, ISO 13628-4, ISO 13628-5, ISO 13628-7, ISO 13628-8, ISO 13628-15. U-001 normative requirements shall prevail over ISO requirements, and other referenced standards and specifications.

The design life should be in accordance with NORSOK U-009.

5.2 Unpressurized primary structural components

Subsea structures shall be designed according to NORSOK N-001.

All guidebases used for drilling shall include a possibility (e.g. grouting funnel) for verification of top of the cement level within the conductor. An arrangement for correction of the cement level (e.g. a cementing stinger) should be considered.

5.3 Design loads

5.3.1 General

See ISO 13628-1:2005 5.4.1.

Relevant loads and load combinations for the actual application shall be defined in the project specific design basis (typical data sheets are presented in ISO 13628-1, Annex F).

5.3.2 Riser loads

Loads for design and selection of subsea trees, wellheads, and templates are tabulated in Annex A.

5.3.3 Dropped objects

Dropped object loads in accordance with ISO 13628-1 Annex F Datasheet No. F5 shall apply.

5.3.4 Fishing gear loads

5.3.4.1 Standard loads and design load conditions

The fishing gear loads in Table 1 shall apply.

Table 1 – Fishing gear loads

Design load type	Design load figure		
Ground rope friction load	2x200 kN	0° to 20° Relative to the horizontal plane	ULS
Trawlboard overpull	450 kN*	0° to 20° Relative to the horizontal plane	ALS
Horizontal impact load	30 kJ	Object diameter 500mm	ALS
Trawlboard snag	600 kN	0° to 20° Relative to the horizontal plane	ALS (If not overtrawlable/snagfree)
Trawl ground rope snag	1000 kN	0° to 20° Relative to the horizontal plane	ALS (If not overtrawlable/snagfree)
Trawlboard snag on sealine	600 kN		ALS (If not overtrawlable/snagfree)

*For closed, smooth protection structures; such as GRP covers, 300 kN shall apply.

5.3.4.2 Snagging

Snagging and impact loads shall be considered as ALS, while frictional loads caused by passing fishing gear shall be regarded as ULS. Loads for a typical North Sea location are given in Table 1.

5.3.4.3 Model tests

Model tests may be used to document and justify use of reduced design loads. Models can be physical small scale test models or computer simulation models. For simulation models, it shall be documented that the model adequately represents the interaction between trawl equipment and subsea structure. Loads from beam trawls shall be considered for areas where such equipment is used. Model test loads shall be ALS or ULS as stated in Table 1.

If an overtrawlable/snag free concept can be documented through model test or a geometric evaluation combined with data from relevant model tests, the following design loads can be disregarded:

- trawlboard snag;
- trawl ground rope snag;
- trawlboard snag on sealine.

A model test shall include an overtrawlability test of the structure, and include measurement of the trawl loads. The model test shall as a minimum simulate the following:

- trawl gear type (otter/cotesi, beam, etc.);
- trawl speed;
- water depth;
- friction on seabed and structure;
- length;
- stiffness and angle of warp lines;
- breaking strength of warp lines;
- bobbins and ground ropes.

5.3.4.4 Test procedure and verification

The test procedure and set-up should be verified by the local fishing authorities and/or a fishing/trawling expert with experience from that particular area. The test set-up may vary to suit local test facilities.

5.3.4.5 Requirements for overtrawable structures

For overtrawable structures the following design requirements shall apply:

- a) the protective structure shall deflect all fishing equipment;
- b) structural corners shall have maximum angle of 58° from the true horizontal plane for truncated pyramid shaped structure, see Figure 1, to assist trawl and trawl wire deflection;
- c) structural corners shall have maximum angle of 50° from the true horizontal plane for trapezoid shaped structure, see Figure 2, type to assist trawl and trawl wire deflection;
- d) corners, ramps and equivalent structures shall penetrate the seabed sufficiently to avoid snagging from trawl warp lines and ground rope. Effects from installation tolerances and expected scouring shall be accommodated;
- e) the overall geometry of the structure and the size of openings shall be such that trawl doors are prevented from entering into the structure;
- f) if vertical side bracings are included, these shall be spaced to prevent intrusion and rotation of trawl equipment, without restricting access for the intervention systems;
- g) all protuberances shall be designed to prevent snagging of nets;
- h) all external edges/free standing members which are not part of a closed protection structure shall have a minimum radius of 250 mm;
- i) minimum trawl speed shall be 2,8 m/s.

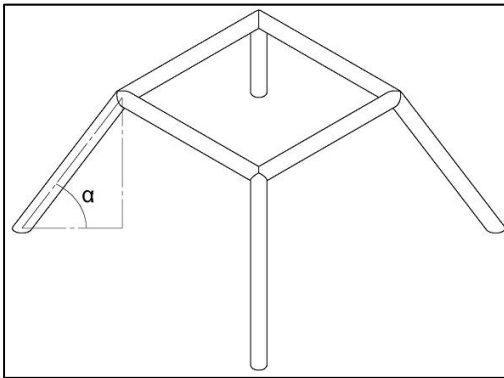


Figure 1 – Truncated pyramid

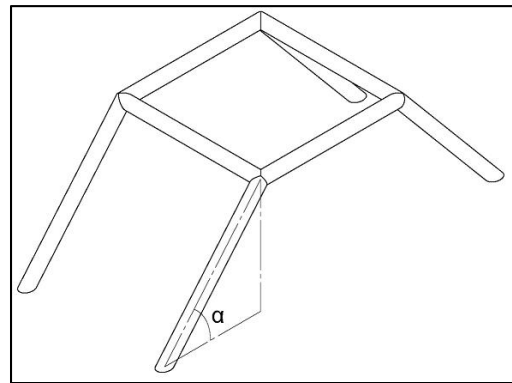


Figure 2 – Trapezoid

5.3.5 Landing loads

The landing and surrounding areas shall be designed to withstand loads imposed by the respective intervention system during landing and operation. For wire deployed running tools, a landing speed of 1,6 m/s shall apply. For drillpipe deployed running tools, the landing speed shall be 0,8 m/s.

5.4 Manifold and piping

Connection/disconnection of flowlines shall not affect other manifold connections.

Installation and retrieval of trees on well supporting structures shall be completed without affecting manifold connections and other trees.

Manifold piping joints shall be full penetration butt-welded.

All applicable loads that may affect the subsea structure and piping system during all phases shall be included in the design. Production and gas injection systems shall be designed according to ASME B31.3 or ASME B31.8 or DNV-OS-F101.

Valve design shall be according to ISO 10423, ISO 14313 and ISO 13628-4.

The design of the valves shall minimise the potential for hydrate formation and damage that could be caused by possible sand, erosion or corrosion. For gate valves with vertical movement of gate, special consideration shall be given to possibility for sand accumulation or hydrate formation in valve cavity.

Valve performance shall be unaffected when the maximum operating load combination from the connected pipe is applied. The valve supplier shall specify the limiting loads. The performance shall be demonstrated by analysis and/or testing.

Penetrations in the valve body and bonnet shall as far as possible be avoided. Any ports used for testing only shall be seal welded after testing.

Valves in piggable lines shall be suitable for running all applicable types of pigs and plugs in both directions. The internal profile of the valve shall minimise accumulation of debris and loose objects and the possible damage thereof. Means for ensuring correct position, fully open, shall be provided.

The following requirements and recommendations shall apply for piggable piping systems:

- a) bends in piggable lines should have a radius of minimum three times the pipe ID;
- b) successive bends, valves, branches and combination of such, should be separated with a straight leg of minimum three times the pipe ID;
- c) branches to piggable lines shall be designed to avoid collection of deposits from the pigging. The branches shall intersect above the centreline of the headers. Fabricated tees and fittings to piggable lines shall be designed for pigging. Barred tees are to be used in the design to eliminate potential damage to gauge plates, etc.;
- d) piggable lines should have constant internal diameter, see DNV-OS-F101.

5.5 Material selection and corrosion protection

5.5.1 General principles

Material selection shall be in accordance with Norsok M-001.

Requirements to pressure containing materials shall be in accordance with Norsok M-630.

Requirements for structural steel shall be in accordance with Norsok M-120.

5.5.2 Corrosivity evaluation

Evaluation of corrosivity shall be in accordance with Norsok M-001.

5.5.3 Corrosion control

A corrosion protection system based on a combination of surface coating and cathodic protection shall be included in the design of subsea structures, manifolds and modules exposed to seawater.

Cathodic protection shall be in accordance with Norsok M-503, surface preparation and coating shall be in accordance with Norsok M-501.

5.5.4 Materials selection

Selection of non-metallic materials shall be in accordance with Norsok M-001 and Norsok M-710.

Qualification and documentation of non-metallic sealing materials and manufacturers shall be in accordance with Norsok M-710.

5.6 Manufacturing and testing

5.6.1 General

Manufacturing of pressure containing subsea equipment shall be in accordance with Norsok M-601, Norsok M-630 and the relevant design and fabrication codes. See Annex B for additional recommendations to ISO 13628-1.

Manufacturers of components in special materials such as 22Cr and 25Cr Duplex stainless steels, 6Mo and other high alloy stainless steels, nickel alloys and titanium castings shall be qualified in accordance with Norsok M-650.

5.6.2 Qualification test of subsea production equipment

The correctness of the estimated torque/trust force shall be documented in the qualification test. For gas valves all sealing surfaces shall be completely free from lubrication oils, etc.

The bonnet and stem seal shall also be tested with external pressure corresponding to the specified water depth plus a safety factor of 1,05.

Where more than one seal is installed, each seal shall be tested individually.

Stepwise seat test shall be performed to demonstrate that the valve seals properly with small pressure increments, referenced in ISO 10423.

5.6.3 Factory acceptance testing of subsea production equipment

FAT and tree valves and actuators shall be conducted in accordance with ISO 10423 PSL 3 as a minimum. FAT gas pressure testing shall be conducted in accordance with ISO 10423 PSL 3G or PSL 4 when specified by purchaser or manufacturer.

Resistance measurements shall be performed to verify electrical continuity between components to be connected to the cathodic protection system, see NORSOK M-503.

5.7 Operation

The recommendations and requirements given in ISO 19901-6:2009, DNV-OS-H101, DNV-OS-H102 and DNV-OS-H201 through DNV-OS-H206 shall apply.

Design and arrangement of structural elements including those not being rigid members of the overall structure (e.g. hatches) shall give special consideration to dynamic forces during lowering into and through the water column. In particular the hydrodynamic added mass and water entry/exit loads are to be considered.

Sea fastening of equipment using wire or synthetic rope should be avoided.

5.8 Transportation and handling

Standard installation operations of equipment from an offshore drilling unit shall be in accordance with NMD "Regulations for mobile offshore units.

Transportation and handling/installation of subsea equipment and modules shall be in accordance with DNV offshore standard DNV-OS-H205 Loadout, Transportation and Installation of Subsea Objects (VMO Standard – Part 2-6).

The design requirements to subsea units in DNV Standard for Certification No 2.7-3, Portable Offshore Units should be considered for subsea equipment that are transported and handled/installed as "portable offshore units" i.e. equipment transported to/from offshore by using standard procedures.

5.9 Subsea system design

5.9.1 General

The subsea system design work should include the definition of procedures/limitations for major operational modes, including installation, intervention and abandonment.

5.9.2 Well completion/testing/killing/intervention/workover

Equipment operational limitations during installation and retrieval shall be defined. Safety with respect to running offset from well location shall be assessed.

5.9.3 Normal production

This mode will include regular remote pressure testing of subsea barriers and routine inspection and maintenance by ROV, and individual well rate testing. Pipelines may be inspected by instrument pigs or other methods. Pipeline system ID, bends and transitions shall accommodate this requirement.

5.9.4 Repair of subsea equipment

During design of the subsea production system the possibility to replace equipment while main parts of the system are in operation should be evaluated.

5.9.5 Barriers

During production activities at least two independent and tested barriers shall be available between reservoir and environment in order to prevent an unintentional flow from the well. The barriers shall be designed for re-establishment of a lost barrier. The position status of the barriers shall be known at all times. Refer to NORSOK D-010 for barrier definition, well barrier selection and construction principles and application.

5.9.6 Instrumentation, valve position indicators and valve overrides

The subsea production system shall be equipped with pressure monitoring at points necessary for a satisfactory functioning of the system, and for pressure testing of the barrier valves. The need for temperature monitoring and leak detection systems shall be considered in each individual case.

6 Subsea wellhead and tree equipment

See Annex A and Annex B for additional recommendations to ISO 13628-4:2010.

Annex B may also be used for:

- 1) surface casing and conductors joints subjected to riser loads;
- 2) pressurised components within the scope of ISO 13628-4;
- 3) upgrading of existing design of components and equipment within the scope of ISO 13628-4.

7 Subsea umbilicals

7.1 General

All parts of the umbilical system assembly shall be qualified for the intended service. The qualification program shall be based on a pre-established fault theory, considering the behaviour of the complete assembly and its individual components, during the service conditions. The qualification activities shall give answers to the questions raised in the fault theory and prove their integrity.

Qualification activities performed on similar components, but considered as less resistant for the intended service than the component in question, can be considered as valid if substantiated by analysis. This also applies to components that have been successfully in service during more severe conditions than the intended service.

Special materials such as 25Cr Duplex stainless steel and other high alloy stainless steels shall be qualified in accordance with NORSOK M-650.

7.2 Electric cables

The electrical cables shall include two barriers against water ingress, i.e. the core insulation and the inner sheath of the electrical cable. The barriers shall be maintained throughout the umbilical system.

The electrical cables shall be designed to block any water ingress either by dielectric gel or other qualified means. Any repair method shall be qualified.

All conductors shall be PE sheathed or equivalent. Insulation thickness proposed shall be in accordance with tabulated values for PVC for PE. Measurements shall be taken in accordance with IEC 60811-202:2012, which gives the methods for measuring thicknesses of non-metallic sheath which apply to the most common types of sheathing compounds (cross-linked, PVC, PE, PP, etc.).

This publication is to be read in conjunction with IEC 60811-100:2012.

Insulation resistance values, during offshore commissioning of a new umbilical system, should result in values typically above 1 Gohm and not less than 500 Mohm (independent of length). Systems in operation should typically stay above 100 Mohm. Consistency in measurements should be aimed at since the result is dependent on test voltage and period as well as method used.

7.3 Fiber optic cables

IEC 60794-1-2 and ITU-T G.652 apply. Measurements shall be performed according to methods recommended by ITU-T G.652.

7.4 Terminations

The fluid line welds shall not be susceptible to hydrogen induced embrittlement or cracking due to cathodic protection or internal fluids. Soldering shall be performed according to a recognized standard or a qualified procedure.

The barriers shall be tested separately during qualification and during final product assembly before FAT. This is also valid for temporary arrangements.

Components above 30 kg shall be prepared for handling.

7.5 Pull-in head

During hook-up at topside facility it shall be possible to bleed off any internal pressure, inside the hydraulic and chemical lines (including the service line) in a controlled manner. The internal pressure will typically be in the range of 5 bar to 10 bar above the hydrostatic seabed pressure corrected by the temperature difference between the seabed and the platform/ vessel deck. Easy access shall be made to ports and valves. The isolation valves shall be removed before the tubing is made up.

7.6 Topside hang-off

Topside junction boxes shall be made according to NORSOK Z-010.

8 Completion/workover riser systems

See Annex B for additional recommendations to ISO 13628-7:2005.

9 Remotely operated vehicle (ROV) interfaces on subsea production systems

9.1 ROV operated electrical connection system

The following requirements and recommendations apply:

- a) parking receptacles should be incorporated as appropriate;
- b) the electrical connectors shall be arranged to enable replacement by ROV;
- c) the electrical connector receptacles in the termination head shall have ROV removable protection caps;
- d) sufficient space shall be left for inspection and possible cleaning of the electrical connectors in the termination head.

9.2 ROV tools

The following requirements and recommendations apply:

- a) ROV mounted equipment shall allow usage of a variety of commercially available ROVs;
- b) the ROV tool handles shall be easy replaceable and be adopted for various types of manipulators;
- c) the ROV tool shall include a reaction plate or similar arrangement preventing rotation of the tool when being held by the ROV;
- d) transport boxes for ROV tools should be robust and suitable for offshore transportation;
- e) the medium torque tool version for ROV operated valve shall be based on a torque range up to 2 700 Nm. The high torque tool version for ROV operated valve shall be based on torque values up to 13 500 Nm;
- f) torque limiting facilities shall be provided;
- g) the valve torque tool shall be designed for valves with non-rising stems.

10 Subsea structures and manifolds

10.1 General

This clause provides normative and informative amendments to ISO 13628-15, concerning subsea structures and manifolds.

10.2 Design requirements

Additional normative requirements are given in Clause 5 in this standard.

10.3 Design guidelines

Standard design loads from riser, standard vertical loads from well construction, and recommended design load combinations, are given in informative Annex A.

Annex A (informative)

Loads for design and selection of subsea trees, wellheads and templates

A.1 Introduction

The wellhead system consists of the subsea tree (XT), wellhead connector and wellhead. During the drilling phase, the drilling vessel is connected to the wellhead by use of a BOP stack (lower marine riser package + lower stack), and a marine drilling riser. When drilling is complete, the BOP is retrieved, and in case of a production well, a XT is installed on the wellhead. On the Norwegian Continental Shelf (NCS), a production wellhead is usually installed through and supported by a template structure fixed to the seabed. However for exploration drilling, the wellhead will typically be free-standing, supported by the soil only and no XT will be installed.

Variable loads from the drilling vessel motions and direct wave loads on the riser system are transferred down into the wellhead, and further down into the conductor and template (if present) and the soil.

This annex provides design loads for selection and design of subsea wellheads and subsea templates subject to loads from such drilling operations. The loads are intended to be representative for NCS conditions.

Maximum single-loads are defined for subsea wellheads for the following design conditions:

- extreme environmental condition, in normal vessel positions (ULS);
- accidental event conditions, including heave compensator failure and abnormal vessel positions (ALS).

The intention is that the design loads shall facilitate the definition of preliminary ULS and ALS load levels for a given well drilling campaign. Hopefully, this will assist the users in the early selection of wellhead system that will satisfy the requirements to operational availability and endurance.

When field specific data are available, these should be used in specific analysis to verify and update initial design concepts and equipment selection as required, and to establish/adjust operating limits reflecting the capacity of subsea trees, wellheads, and templates.

For template structures, standard vertical loads from the well construction process and the production phase are given. It is also shown how riser loads on the wellhead can be converted to loads to the template wellbay area. To account for the great variety of wellheads, template, and soil conditions, a spreadsheet is made available at [this link](#), which allows estimation of the template loads with due account to local conditions.

Loads from “open water” well intervention risers are not calculated. It is assumed that well intervention systems are designed and operated to keep loads induced to XT and wellhead within capacity limits of the selected equipment. Particular attention should be made to intervention risers that provide a rigid and strong link between wellhead and vessel top drive. Top drives can fail (lock) and the system should contain a load limiting device, see B.4.2. The release load should be selected such that well barriers are protected against unacceptable loads.

Wellhead loads with BOP connected to the top of a horizontal subsea tree (HXT) are not analysed specifically. These loads could be covered by applying loads from systems with one size larger BOP (if possible).

The variety of loss-of-position accidental load scenarios is unlimited, and many scenarios generate loads far beyond what can reasonably be accommodated just by increasing the strength of the wellhead systems. Therefore, the following approach was selected:

- a) Standard wellhead design loads are established for conventional drilling with BOP at wellhead, intact station keeping system, but with internal drill-pipe or landing string tension corresponding to none / normal / extreme / accidental tension.
- b) In case of loss-of-station scenarios, the rig operator will ensure that adequate safety systems, emergency procedures, and trained personnel are in place to achieve sufficiently low risk for well barrier damage, with due account for the capacity of the wellhead. Ref. PSA facility regulation.

This approach is assumed valid for conventional drilling and all other modes of operation, as completion (including BOP on HXT), XT installation, well intervention, through-tubing rotary drilling, etc.

The detailed analysis approach, riser model, load cases, analysis methodology, results, and discussions are documented in DNV GL report, Rev. 1, 20143-0783, *NORSOK U-001, Well System Loads*. Verification analyses were performed, and these are reported in FMC RPT60121280, *NORSOK U-001 Well system load verification* and Aker Solutions Norsok U001 *Verification of Wellhead Loads*.

A.2 Drilling riser loads on subsea wellhead systems

A.2.1 Maximum single-load, ULS and ALS

The wellhead tension (compression) is given in Table A.1. Drill string tension is not included in these values.

The shear force at wellhead is given in Table A.2.

The wellhead single design bending loads are given in Tables A.3 to A.7 for the standard operational conditions. The loads are provided for the following load conditions:

- 1) Extreme (ULS), drilling, drill string tension (DST) 150t, extreme operation offsets;
- 2) Extreme (ULS), non-drilling, DST 0t, extreme operation offset;
- 3) Temporary (ULS), stuck drill string, DST 250t, normal operation offset;
- 4) Accidental (ALS), mooring line failure, DST 150t, accidental operation offset;
- 5) Accidental (ALS), top compensator lock-up, DST 450t, extreme operation offset.

There are large differences in wellhead load level between drilling rigs. These differences may be due to flex-joint stiffness/damping, BOP mass/height, tensioner characteristics, riser buoyancy, and probably other effects that we do not yet fully understand. It may be appropriate to allow use of scaling factors F_{stat} and F_{dyn} , to account for documented performance of drilling vessels. (Default value =1,0). Thereby, total design wellhead bending moment (M_W) can be calculated as

$$M_W = F_{stat} * S + F_{dyn} * D \quad (A.1)$$

where

S = tabulated static wellhead bending moment

D = tabulated dynamic wellhead bending moment

F_{stat} = scaling factor for S

F_{dyn} = scaling factor for D

E.g., for the largest drilling facilities (large/heavy BOP, stiff flexjoint, etc), it may be appropriate to use $F_{dyn} > 1,0$, while for smaller rigs, $F_{dyn} < 1$ may be justified. F_{stat} may be adjusted to account for actual BOP height (flex-joint elevation above wellhead), and flex-joint stiffness. Custom values of scaling factors should be properly documented by validated field-specific simulation models or measurement of actual loads. If the lower flexjoint (LFJ) elevation (H_{LFJ}) above wellhead datum deviates from the standard value in Table A.2, the bending moments in Tables A.3 to A.7 can be scaled. The shear force in the wellhead shall then be calculated based on the *actual* value H_{LFJ} see Equation (A.2).

Typically, the accidental loads are high compared to the capacities of available equipment. This means that the presumptions (e.g. operating limits, maximum vessel offset, weak link failure load, etc.) may need to be adjusted to ensure that wellhead loads are always (even in accidental conditions) within the permissible load charts specified by the supplier.

For shallow water depths, in particular, exceeding of the operational weather limitations specified will increase the wellhead loads substantially.

Table A.1 – Wellhead static effective tension

BOP stack mass	200t	300t	400t
Tension (kN)	-600	-1190	-1780

NOTE Negative tension values means BOP downweight (positive load direction is upwards)

The shear force (Q_W) in the wellhead may be assumed to be proportional to the wellhead bending moment (M_W). Based on tabulated values of M_W , Q_W can be calculated as:

$$Q_W = M_W / H_{LFJ} \quad (\text{A.2})$$

where

H_{LFJ} = *actual* lower flex joint elevation above wellhead datum. The standard values for H_{LFJ} given in Table A.2 can be used if actual value is not known.

M_W = the standard wellhead bending moment found in Tables A.3–A.7.

Table A.2 – Wellhead shear force

BOP stack mass	200t	300t	400t
HLFJ (LFJ elevation above wellhead datum)	10,5 m	12,9 m	15,3 m

(*) NOTE: The shear force Q_W in the wellhead should be calculated as $Q_W = M_W / H_{LFJ}$, where H_{LFJ} is the standard value given above, and M_W is the standard wellhead bending moment found in tables below.

Table A.3 – Wellhead bending moments [kNm] for medium vessel, fixed template well, DRILLING MODE (Extreme/ULS)

Operating mode	Drilling								
Vessel offset	Extreme: Minimum of 7 % WD (4 deg), 50 m								
Drill string tension	150t								
Vessel heave limit	+/- 3 m								
Significant wave height limit	Hs=8,5 m								
Load components	STATIC (S)			DYNAMIC (D)			TOTAL (S+D)		
BOP size / Water depth (m)	200t	300t	400t	200t	300t	400t	200t	300t	400t
80	2930	3830	4690	3390	4510	5190	6320	8340	9880
100	3040	3800	4640	3440	4260	5460	6480	8060	10100
125	3070	3860	4700	3290	4120	4540	6360	7980	9240
250	3200	3970	4770	1940	2970	4150	5140	6940	8920
400	3350	4120	4950	1050	1400	2190	4400	5520	7140
750	3100	3820	4540	450	630	820	3550	4450	5360
1500	2230	2650	3080	80	120	160	2310	2770	3240
3000	2210	2550	2860	180	90	90	2390	2640	2950

Table A.4 – Wellhead bending moments [kNm] for medium vessel, fixed template well, NON-DRILLING (Extreme / ULS)

Operating mode	Non-drilling								
Vessel offset	Extreme: Minimum of 7 % WD (4 deg), 50 m								
Drill string tension	0t								
Vessel heave limit	+/- 4,5 m								
Significant wave height limit	Hs=10,5 m								
Load components	STATIC (S)			DYNAMIC (D)			TOTAL (S+D)		
BOP size / Water depth (m)	200t	300t	400t	200t	300t	400t	200t	300t	400t
80	1620	2210	2750	4120	5640	6710	5740	7850	9460
100	1720	2160	2680	3470	4550	5850	5190	6710	8530
125	1740	2210	2750	3440	3890	5130	5180	6100	7880
250	1840	2280	2850	2510	3090	4610	4350	5370	7460
400	2000	2460	2980	1200	1620	2310	3200	4080	5290
750	1800	2200	2630	390	610	850	2190	2810	3480
1500	1550	1730	1940	90	110	150	1640	1840	2090
3000	1750	2320	2440	100	190	260	1850	2510	2700

Table A.5 – Wellhead bending moments [kNm] for medium vessel, fixed template well, MOORING LINE FAILURE (Accidental, ALS)

Operating mode	Mooring line failure while drilling								
Vessel offset	Accidental: Minimum of 13 % WD (7,4 deg)								
Drill string tension	150t								
Vessel heave limit	+/- 3 m								
Significant wave height limit	Hs=8,5 m								
Load components	STATIC (S)			DYNAMIC (D)			TOTAL (S+D)		
BOP Size / Water depth (m)	200t	300t	400t	200t	300t	400t	200t	300t	400t
80	4450	5910	7340	3340	4100	5110	7790	10010	12450
100	4630	5900	7310	3350	4120	5240	7980	10020	12550
125	4800	6130	7540	3190	3950	5010	7990	10080	12550
250	4930	6230	7640	1850	2770	3960	6780	9000	11600
400	5030	6340	7760	1060	1400	2010	6090	7740	9770

Table A.6 – Wellhead bending moments [kNm] for medium vessel, fixed template well, STUCK DRILL-STRING (Temporary / ULS)

Operating mode	Stuck drill-string								
Vessel offset	Normal: Minimum of 3,5% WD (2 deg), 25 m								
Drill string tension	250t								
Vessel heave limit	+/- 3 m								
Significant wave height limit	Hs=8,5 m								
Load components	STATIC (S)			DYNAMIC (D)			TOTAL (S+D)		
BOP size / Water depth (m)	200t	300t	400t	200t	300t	400t	200t	300t	400t
80	2590	3290	3840	3010	3760	4900	5600	7050	8740
100	2650	3250	3880	3250	3970	4930	5900	7220	8810
125	2660	3280	3880	3340	4130	5150	6000	7410	9030
250	2770	3360	3940	2310	3190	4220	5080	6550	8160
400	2950	3550	4170	1380	2150	3200	4330	5700	7370
750	2730	3280	3820	570	770	1140	3300	4050	4960
1500	2170	2550	2900	130	170	250	2300	2720	3150
3000	2240	2590	2910	190	130	80	2430	2720	2990

Table A.7 – Wellhead bending moments [kNm] for medium vessel, fixed template well, TOP COMPENSATOR LOCK UP (Accidental / ALS)

Operating mode	Top compenator lock up								
Vessel offset	Extreme: Minimum of 7,0% WD (4 deg), 50 m								
Drill string tension	450t								
Vessel heave limit	+/- 3 m								
Significant wave height limit	Hs=8,5 m								
Load components	STATIC (S)			DYNAMIC (D)			TOTAL (S+D)		
BOP size / Water depth (m)	200t	300t	400t	200t	300t	400t	200t	300t	400t
80	5380	6820	8200	3010	4020	5320	8390	10840	13520
100	5520	6830	8200	2860	3570	4370	8380	10400	12570
125	5580	6910	8240	3230	4070	4790	8810	10980	13030
250	5800	7120	8420	2590	3430	4550	8390	10550	12970
400	5950	7330	8670	2150	2890	3830	8100	10220	12500
750	5800	7200	8500	1270	1920	2920	7070	9120	11420
1500	2800	3300	3900	1350	1830	2310	4150	5130	6210
3000	2200	2320	2440	1180	1680	2090	3380	4000	4530

A.2.2 Cyclic loads (fatigue)

Cyclic loads for fatigue analysis are not included in the present revision of this standard. However, guidelines and examples of cyclic loads for fatigue analyses may be found in the DNV GL report, Rev. 1, 20143-0783, *NORSOK U-001, Well System Loads*. The report and wellhead bending moment fatigue load histograms typical for the Norwegian continental shelf are provided as electronic files and available for download, see [Revision information](#).

A.2.3 Basis for loads

The magnitude of loads depends on several parameters, and an infinite number of load combinations are possible. Based in industry practice for operation, guidelines in design standards, engineering judgement and sensitivity analyses a limited number of variations were selected, and these are assumed to be representative for the majority of actual cases.

The wellhead loads are calculated based on selected standard combinations of governing parameters:

- water depth: 80, 100, 125, 250, 400, 750, 1500, 3000 m;
- vessel station keeping:
 - moored for water depth ≤ 400 m;
 - dynamic positioning for water depth ≥ 250 m.
- BOP size: small, medium, and large (200t, 300t, 400t) and corresponding heights of lower flexjoint (LFJ);
- wellhead datum stick-up above mudline is 2,5 m;
- RAO for semi-submersible: Small, medium, and large vessel size (displacement);
- current: 1,0 m/s with a standard current depth shape factor (ULS, ALS);
- drill-string tension (DST):
 - non-drilling, DST = 0t;
 - normal drilling, DST = 150t
 - pull to release stuck string, DST = 250t
 - compensator lock and weaklink failure, DST = 450t.
- well inclination 1,5 degrees (ULS, ALS);
- foundation stiffness:
 - rigid template support;
 - soft template support;
 - no template support (exploration well).
- normal operation mean offset of maximum 3,5 % of water depth (2 deg), however not exceeding 25 m;
- extreme operation mean offset of maximum 7,0 % of water depth (4 deg), however not exceeding 50 m;
- accidental offset,
 - dynamic positioning vessel: Full speed drive-off;
 - moored vessel: 13 % of water depth.
- limitations for operations are set as:
 - normal drilling; ± 3 m rig heave and significant wave height $H_s = 8,5$ m;
 - connected, non-drilling; $\pm 4,5$ m rig heave and significant wave height $H_s = 10,5$ m.
- standard tension setting is 40t (effective tension in the LMRP/BOP connector) with almost constant tension (6 kN/m).

A typical drilling riser stack-up with slick joints in wave zone and buoyancy joints further down is used for the simulations.

Waves are modelled as irregular wave histories, with JONSWAP wave spectra, and uni-axial long crested waves.

Sensitivity analyses were initially done for variations of loads, riser system properties and boundary conditions to check the influence of these on the wellhead bending moment. This was then used to select the governing load cases to be analysed and specified for all water depths. More details and loads related to these sensitivities can be found in the DNV GL report, 20143-0783,

The water depth has a significant influence on the characteristics of the loads and load level. Therefore, loads are provided for a wide range of water depths.

The influence of the variations is most dominant at shallow water depths.