NORSOK STANDARD U-001

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Subsea production systems

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Foreword

The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding 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 recognised 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 Subject to development and publication of international standards, the relevant NORSOK standards will be withdrawn.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 supported by OLF (The Norwegian Oil Industry Association) and TBL (Federation of Norwegian Manufacturing Industries). NORSOK standards are administered and published by NTS (Norwegian Technology Centre).

Annex A is normative.

Introduction

This NORSOK standard is based on ISO 13628, *Petroleum and natural gas industries – Design and operation of subsea production systems – (Part 1 through Part 9)*, and includes specific national requirements and recommendations that are not covered by ISO 13628.

This NORSOK standard shall therefore be read in conjunction with all parts of ISO 13628.

This NORSOK standard refers to the first edition of ISO 13628-1, which is currently being revised. When this revision work is completed this NORSOK standard will be revised to reflect the latest edition of ISO 13628-1.

This NORSOK standard is completely rewritten and it replaces Rev. 2 of this NORSOK standard, NORSOK U-002, *Subsea Structures and Piping System*, Rev 2, NORSOK U-006, *Subsea Production Control Umbilicals*, Rev 2, and NORSOK U-007, *Subsea Intervention*, Rev 2, which were issued in June 1998.

The EU Pressure Equipment Directive (PED 97/23/EC) has been implemented in Norway by the ”Forskrift om trykkpåkjent utstyr” which applies exclusively from 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".

Other pressurized parts of the subsea system (e.g. pressure vessels) needs to be accounted for during the development of a subsea production system and certain amendments may be required for this NORSOK standard in order to comply with the essential requirements of the PED.

For further interpretation of the PED please consult with NPD.

1 Scope

See ISO 13628-1.

2 Normative and informative references

The following standards include provisions and guidelines which, through 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.

ASME B31.3,	*Process Piping*
ASME B31.8,	*Gas Transmission and Distribution Piping Systems*
DNV,	*Rules for Planning and Execution of Marine Operations*
DNV–OS-F101,	*Submarine pipeline systems*
EU Directive 98/37/EC,	*Safety of machinery*
EU Directive 97/23/EC,	*Pressure Equipment Directive (PED)*
IEC 60885,	*Electrical test methods for electrical cables*
IEC 60811,	*Common test method for insulating and sheeting materials of electric and optical cables*
IEC 60794,	*Optical fibre cables*
ISO 10423,	*Petroleum and natural gas industries – Drilling and production equipment - Specification for valves, wellhead and Christmas tree equipment*
ISO 13628-1,	*Petroleum and natural gas industries - Design and operation of subsea production systems – Part 1: General requirements and recommendations*
ISO 13628-2,	*Petroleum and natural gas industries – Design and operation of subsea production systems – Part 2: Flexible pipe systems for subsea and marine applications*
ISO 13628-3,	*Petroleum and natural gas industries – Design and operation of subsea production systems – Part 3: Through Flow Line (TFL) systems*
ISO 13628-4,	*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 control umbilicals*
ISO 13628-6,	*Petroleum and natural gas industries - Design and operation of subsea production systems – Part 6: Subsea production controls*
ISO 13628-7,	*Petroleum and natural gas industries - Design and operation of subsea production systems – Part 7: Completion/workover riser systems (currently DIS)*
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 (currently FDIS)*
ISO 13628-9,	*Petroleum and natural gas industries - Design and operation of subsea production systems – Part 9: ROT intervention systems*
ISO 14313,	*Petroleum and natural gas industries – Pipeline transportation systems- Pipeline valves*
ITU-T G.652,	*Characteristic of a single-mode optical fibre cable*
NMD,	*Regulations for mobile offshore units*
NORSOK J-003,	*Marine Operations*
NORSOK M-001,	*Material selection*
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 datasheets 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,	*Structural design*
NORSOK Z-010,	*Electrical, instrumentations and telecommunication*

3 Definitions and abbreviations

3.1 Definitions

3.1.1
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

3.1.2
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

3.1.3
may
verbal form used to indicate a course of action permissible within the limits of the standard

3.1.4
can
verbal form used for statements of possibility and capability, whether material, physical or casual

For other definitions, see ISO 13628 (Part 1 through Part 9).

3.2 Abbreviations

BOP	blow out preventer
FAT	factory acceptance test
ID	internal diameter
NMD	Norwegian Maritime Directorate
NPD	Norwegian Petroleum Directorate
PE	polyethylene
PED	Pressure Equipment Directive
PGB	permanent guide base
PLS	plastic limit state
PVC	polyvinylchloride
QT	qualification test
ROV	remotely operated vehicle
TGB	temporary guide base
ULS	ultimate limit state

4 Technical requirements

ISO 13628 (Part 1 through Part 9) apply in full.

The following requirements shall be read in conjunction with the relevant part of ISO 13628 and supersede and/or add to the provisions listed therein. The provisions in this NORSOK standard are presented sequential as listed in the applicable part of ISO 13628.

It is considered favourable that a design basis covering typically the following areas is developed as early as possible for a specific field development:

a) operational requirements;
b) process flowcharts;
c) wellstream composition;
d) injection requirements and media;
e) simultaneous operations;
f) intervention strategy;
g) test requirements;
h) condition monitoring;
i) control system design data;

j) flowline data;
k) thermal expansion data;
l) ROV torque tools;
m) guidewire anchor and guidepost locking mechanism.

5 ISO 13628 – 1 additions

5.1 To 5.4.1 General

Drilling loads default values are tabulated in Annex A.

The following dropped object and fishing gear loads shall apply:

Dropped objects

Impact loads from dropped objects shall be treated as a PLS condition. The impact force from actual objects that will be handled over the structure should be used as initial design loads. Alternatively the following loads may be used:

Group	Impact energy kJ	Impact area	Object diameter mm
Multi well structures	50	Point load	700
	5	Point load	100
Other structures	20	Point load	500
	5	Point load	100

Fishing gear loads

Design load type	Design load figure		
Trawlnet friction	2x200 kN	0° to 20° horizontal	ULS
Trawlboard overpull	300 kN	0° to 20° horizontal	ULS
Trawlboard impact	13 kJ		ULS
Trawlboard snag	600 kN	0° to 20° horizontal	PLS (If not overtrawlable/snagfree)
Trawl ground rope snag	1000 kN	0° to 20° horizontal	PLS (If not overtrawlable/snagfree)
Trawlboard snag on sealine	600 kN		PLS (If not overtrawlable/snagfree)

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

5.2 To 5.4.2 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 in the conductor. An arrangement for correction of the cement level (e.g. a cementing stinger) should be considered.

5.3 To 5.5.8.3.2

5.3.1 Snagging shall be considered as an abnormal operation (PLS), while impact and frictional loads caused by passing fishing gear shall be regarded as normal operation (ULS). This applies unless the frequency of trawling allows it to be considered as a PLS condition. Specimen loads for a typical North Sea location are given in 5.1.

5.3.2 Model tests may be used to document smaller loads. Loads from beam trawls shall, in addition, be considered for areas where such equipment is used.

When an overtrawlable/snagfree 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 investigate the overtrawlability of the structure and quantify the trawl loads to which it may be subjected. 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;
- minimum breaking strength of warp lines;
- bobbins and ground ropes.

5.3.3 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 For overtrawlable structures the following design requirements shall apply:

a) the protective structure shall deflect all fishing equipment;
b) structural corners shall have maximum true angle of 58° from the horizontal to assist trawl and trawl wire deflection;
c) corners, ramps and equivalent structures shall penetrate the seabed to avoid snagging from trawl warp lines and ground rope. Effects from installation tolerances and expected scouring shall be accommodated;
d) the overall geometry of the structure and the size of openings, shall be such that trawl doors are prevented from entering into the structure;
e) if vertical side bracings are included, these shall be spaced to prevent intrusion and rotation of trawl equipment, without restricting subsea structure access for the intervention systems;
f) all protuberances shall be designed to prevent snagging of nets;
g) all external edges/members which are not part of a closed protection structure shall have a minimum radius of 250 mm;
h) minimum trawl speed shall be 3,0 m/s.

5.4 To 5.5.8.3.3

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 maximum 1,6 m/s shall apply. For drillpipe deployed running tools, the landing speed shall be maximum 0,8 m/s.

5.5 To 5.5.8.5 Manifold and piping

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

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

5.5.3 Manifold piping joints shall be butt-welded.

5.5.4 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.

5.6 Manifold valve design

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 damages thereof. Means for ensuring correct position, fully open, shall be provided.

5.7 Manifold piping system

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 centerline 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.

5.8 To 6.1 Material evaluation

Material selection and corrosion protection shall be in accordance with NORSOK M-001.

5.9 To 6.1.3

Requirements to materials shall be in accordance with NORSOK M-630.

5.10 To 6.2.1 Corrosivity evaluation in hydrocarbon systems

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

5.11 To 6.2.3 Design considerations

All sealing materials and sealing areas shall be resistant to all specified fluids that may get in contact with the seals during testing, commissioning or operation. This also applies to the secondary barriers.

For material selection special considerations shall be made to avoid galling. The qualification test shall demonstrate that acceptable materials have been selected.

Weld overlay UNS N06625 shall be applied in all critical areas such as seat pockets and all surfaces forming crevices between mating parts. Weld overlay is not required for super-duplex material.

The spring material in seats and seals shall be UNS R30003, UNS R30035, Alloy 625, Alloy C276 or NiAl bronze.

The bearing/bushing base material shall be corrosion resistant.

Body and bonnet for subsea valves shall be made of forged, wrought or hot isostatic pressed materials unless otherwise agreed.

5.12 To 6.3 Non-metallic materials

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.

5.13 To 6.5.1

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.

5.14 To 7 Manufacturing and testing

5.14.1 General

Manufacturing of subsea equipment shall be in accordance with NORSOK M-601, NORSOK M-630 and the relevant design and fabrication codes.

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.

5.14.2 QT of subsea production equipment

If required, prototype QT shall be in accordance with ISO 10423, PR2.

The correctness of the estimated torque/trust force shall be documented in the qualification test. For gas valves all moving parts 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 slow pressure increments and at all pressure levels.

5.14.3 Factory acceptance testing (FAT) of subsea production equipment

FAT of tree valves and actuators shall be conducted following ISO 10423, PSL 3, with gas test, if relevant.

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

5.15 To 8 Operations

The recommendations and requirements given in NORSOK J-003 shall apply.

Design and arrangement of structural elements including those not being rigid members of the overall structure (e.g. hatches) shall take 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.

Use of wire or soft rope lashing should be avoided.

5.16 To 8.1 Transportation and handling

Seafastening of equipment for offshore shipment shall be designed according to NMD "Regulations for mobile offshore units" and DNV "Rules for Planning and Execution of Marine Operations".
Before any lifting can take place, a certificate of compliance (samsvarserklæring) and certificate for usage (brukererklæring) shall be issued in accordance with EU Directive 98/37/EC.

5.17 To 8.5 Well intervention

5.17.1 Subsea system design

5.17.1.1 General

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

5.17.1.2 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.

5.17.1.3 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

5.17.1.4 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.

5.17.2 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.

During normal production the X-mas tree, as a complete unit, is defined as one of the two barriers. The other barrier is normally the downhole safety valve.

5.17.3 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 ISO 13628 – 5 additions

NOTE - The following amendments are based on ISO/FDIS 13628-5.

6.1 To 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 behavior 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.

6.2 To 7.2.1 General

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 filled with dielectric gel/ jelly as petroleum jelly or similar.
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.

6.3 To 7.3.2 Insulation resistance

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. Consistancy in measurements should be aimed at since the result is dependant on test voltage and period as well as method used.

6.4 To 7.8.1 General

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

The fibres shall be loosely contained in a metallic tube.

The cable design shall ensure that no strain is exerted on the fibres during normal operation.

6.5 To 7.10.1 General

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

6.6 To 8.2 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 electrical cables shall be terminated to ensure that the electrical conductors are protected against water ingress by minimum two individual barriers. The individual barriers shall be demonstrated by testing that each barrier is capable to handle the extreme environmental combinations, to which the umbilical is exposed. Cable conductors, insulation or sheathing shall not introduce critical strain.

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

Sufficient length for re-termination of pigtails shall be included.
Components above 30 kg shall be prepared for handling.

6.7 To 8.2.3 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.

6.8 To 8.2.4 Topside hang-off

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

6.9 To 8.3.1 Joint box

Relevant parts of ISO 13628-5, 7.9.3.4, is also valid for joint boxes.

6.10 To 10.2 Verification tests

Same provision as 6.1

6.11 To 11.1 General

Final FAT shall be performed with the end termination, couplers and connectors included.

6.12 To Annex B Umbilical testing

The following tests are required to be carried out on sample lengths taken from the production lengths:

a) dimensional checks;
b) insulation and sheath materials to be checked in accordance with the requirements of IEC 60811 or equivalent standard. Documentary evidence is required to prove that the cable materials are compatible with the specified hydraulic fluid and any other fluids that is specified for the system;
c) tensile strength and elongation at break before and after ageing in oven shall be checked for each core size and each sheathed cable.

7 ISO 13628 – 8 additions

NOTE - The following amendments are based on draft ISO/FDIS 13628-8.

7.1 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.

7.2 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.

Annex A
(Normative)
Default drilling loads

A.1 Drilling loads - for water depths up to and including 750 m			
Phase/activity	**Loadcase**		**Design load (template/TGB)**
Lowering/cementing of 762 mm (30 in) conductor	1.1.1	Weight (load) of 762 mm (30 in) conductor shall be carried by template (TGB).	Vertical load 600 kN (ULS) (temporary)
Drilling of 610 mm (24 in), lowering and cementing of 473 mm (18 5/8 in) casing	1.2.1	The vertical load from weight of 762 mm (30 in) (partly) and 473 mm (18 5/8 in) casing will be transferred to soil via the cement, assume settling of the structure/TGB.	Vertical load 450 kN (ULS) (permanent)
	1.2.2	Normal pull off stuck drill string (2 000 kN) and rig offset 4,5° (flex joint angle), including misalignment of ± 1,5°. Vertical load will be carried by conductor. Horizontal load to be carried by template/TGB and conductor.	Vertical load 0 kN (ULS) Horizontal load 160 kN (ULS)
Drilling of subsequent sections	1.3.1	A BOP with riser attached landing on TGB ($250x10^3$ kg at 0,5 m/s). This impact load will mainly be taken up by the conductor casing.	Vertical 31 kJ impact load (ULS)
	1.3.2	Normal pull of stuck drill string (2 000 kN) and rig offset 4,5° (flex joint angle), including misalignment of ± 1,5°. Vertical load will be carried by conductor. Horizontal load to be carried by template/TGB and conductor.	Vertical load 0 kN (ULS) Horizontal load 160 kN (ULS)
	1.3.3	Tension from riser (300 kN) will be taken up by TGB/conductor casing weight. Horizontal component to be carried by TGB/template and conductor.	Vertical load 0 kN (ULS) Horizontal load 25 kN (ULS)
	1.3.4	Guideline tension maximum is 200 kN. Vertical load will be taken up by TGB/template weight. Horizontal component from 4 off lines at 4,5° to be carried by TGB/template and conductor.	Vertical load 0 kN (ULS) Horizontal load 15 kN (ULS)

The loads defined above shall be combined based on relevant combination of activities resulting in the following design loads:

A. Loadcase 1.2.1: Vertical load 450 kN (ULS);
B. Loadcase 1.3.1: Vertical impact load 31 kJ (ULS);
C. Loadcase 1.3.2 + 1.3.3 + 1.3.4: 200 kN horizontal load (ULS).

B and C above shall not be combined with each other or other loads from drilling operations or fishing gear. A above shall be combined with B and with C as well as with other relevant operational and function loads including loads from fishing gear etc.

A BOP moving sideways into the structure when lowered shall be considered for guidelineless systems. The template drilling sequence used for structural design shall be dictated by the worst case combination of loads.
Drilling and well live loads should be combined when simultaneous operations are assumed.

The loads induced on the PGB/bottom frame from the well systems shall depend upon the following:
- soil conditions, bending and axial stiffness of wellsystem;
- structural design and stiffness of bottom frame against vertical deflection;
- structure/well interface design. The loads shall represent the worst case situation

A.2 Drilling loads - for deep water applications deeper than 750 m

Phase/Activity	Loadcase		Design load (template/TGB)
Lowering/ cementing of 762 mm (30 in) conductor	2.1.1	Weight (load) of 762 mm (30 in) conductor shall be carried by template (TGB).	Vertical load 600 kN (ULS) (temporary)
Drilling of 610 mm (24 in), lowering and cementing of 473 mm (18 5/8 in) casing	2.2.1	The vertical load from weight of 762 mm (30 in) (partly) and 473 mm (18 5/8 in) casing will be transferred to soil via the cement, assume settling of the structure/TGB (heavier conductors may be required).	Vertical load 450 kN (ULS) (permanent)
	2.2.2	Normal pull off stuck drill string, rig offset 3,5° (flex joint angle), including misalignment of ± 1,5°. Vertical load will be carried by conductor. Horizontal load to be carried by template/TGB and conductor.	Vertical load 0 kN (ULS) Horizontal load 155 kN (ULS)
Drilling of subsequent sections	2.3.1	A BOP with riser attached landing on TGB (250 x 10^3 kg at 0,5 m/s vertical/0,15 m/s horizontal). Vertical impact load will mainly be taken up by the conductor casing, horizontal impact load will be taken by guiding structure.	Vertical impact 44 kJ (ULS) Horizontal impact 2 kJ (ULS) (*) Horizontal impact load 33 kN (ULS)
	2.3.2	Normal pull off stuck drill string, rig offset 3,5° (flex joint angle), including misalignment of ± 1,5° + drilling riser tension. Vertical load will be carried by conductor. Horizontal load to be carried by template/TGB and conductor.	Vertical load 0 kN Horizontal load 155 kN + 75 kN (750 m) Horizontal load 155 kN + 160 kN (1 500 m) Bending moment 95 kNm (ULS)
	2.3.3	Extreme operating at 5,5° (flex joint angle) including misalignment of ± 1,5°. Drilling riser tension (2 300 kN/750 m, 3 200 kN/1 500 m). Vertical load will be carried by conductor. Horizontal load to be carried by template/TGB and conductor.	Vertical load 0 kN Horizontal 220 kN (750 m) Horizontal 310 kN (1 500 m) Bending moment 150 kNm (PLS)
	2.3.4	Guideline tension maximum is 200 kN (750 m), 0 kN (1 500 m). Vertical load will be taken up by TGB/template weight. Horizontal component from 4 off lines at 4,5° = 20 kN to be carried by TGB/template and conductor.	Vertical load 0 kN Horizontal 20 kN (750 m) Horizontal 0 kN (1 500 m) (ULS)
	2.3.5	Workover riser in open sea mode (750 m and 1 500 m). Vertical load (600 kN) will be carried by conductor. Horizontal load to be carried by template/TGB and conductor.	Vertical load 0 kN Horizontal 70 kN (750 m/1 500 m) Bending moment 500 kNm (ULS)

Load combinations: **A:** 2.2.1, **B:** 2.3.1, **C:** 2.3.2 + 2.3.4, **D:** 2.3.3 + 2.3.4, **E:** 2.3.5. Loadcase A shall be combined with B, C, D and E.
Loadcase A shall also be combined with other relevant operational and functional loads including fishing loads etc.

(*) For satellite wells