Wellhead Fatigue Analysis

Surface casing cement boundary condition for subsea wellhead fatigue analytical models

By

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Preface

Dynamic loading of subsea wellheads was first identified as a failure load in 1981 when a gross structural fatigue failure of a surface casing/wellhead weld was experienced west of Shetland. Subsea development of offshore fields was in its infant stages at this time and since then the subsea technology has evolved into an established technology.

In 2005 Hydro Oil and Gas experienced a structural fatigue failure of a conductor/conductor housing weld on a North Sea subsea well. The failure investigation which followed led to the development of a company specific analysis method and subsequently the launch of an international Joint Industry Project (JIP) "Structural Well Integrity" supported by 14 international operators[1]. The aim of this JIP is to issue international Recommended Practice (RP) reports for a unified fatigue analysis methodology. The JIP RP-3 wellhead fatigue analysis methodology report is currently (2012) open for industry review [1].

Wellhead fatigue seems to have been an area of concern when subsea well technology was a new technology. But through the 1990s and 2000s little attention has been devoted to this problem. The last few years several operators have expressed concerns and the topic has again gained attention.

As a Statoil employee I was involved in the company specific wellhead fatigue analysis methodology developments. At the time of the JIP launch I ventured off to do this PhD study related to wellhead fatigue. My employer funded this PhD project and allowed me to dedicate time to conduct this study.

[1] BG Group, BP, Det Norske, Eni, ExxonMobil, GFD Suez, Lundin, Marathon, Nexen, Shell, Statoil, Talisman, Total and Woodside. DNV is the facilitator of the JIP.

Preface

This thesis consists of 2 parts. Part I presents the thesis summary providing more context and background of the work. A new boundary condition modelling of lateral cement surface casing support is postulated herein. In chapter 5.2 the results from laboratory testing of the lead cement early strength cured at low temperatures is discussed. Some evidence supporting a localised cement failure due to casing movements hypothesis are presented in section 5.2 and 5.3. A new boundary condition modelling of lateral cement surface casing support is postulated and described in chapter 5.5. By applying this modified cement modelling to a well case analysis the estimated fatigue life of the surface casing weld was increased 32 times.

Part II consists of 7 articles related to various aspects of subsea wellhead fatigue analysis. Article I was presented at The 30th International Conference on Ocean, Offshore and Arctic Engineering (OMAE2011) and Article II at the 2011 SPE Arctic and Extreme Environments Conference. Article III through Article VII have been accepted for presentation at the 31st International Conference on Ocean, Offshore and Arctic Engineering (OMAE 2012). The OMAE2012 has devoted an entire session to the wellhead fatigue topic.

Abstract

Material fatigue is a failure mode that has been known to researchers and engineers since the 19th century. Catastrophic accidents have happened due to fatigue failures of structures, machinery and transport vehicles. The capsizing of the semisubmersible rig Alexander L. Kielland in Norwegians waters in 1980 killed 123 people, and investigations pointed at the fatigue failure of a weld as one of the direct causes. This accident led to a number of improvements to the design of offshore structures. The noticeable safety principle ”No single accident should lead to escalating consequences” has since been adopted in a widespread manner. Since 1992 the Petroleum Safety Authority in Norway has enforced a risk based safety regime.

Wells are designed to hold back reservoir pressures and avoid uncontrolled escape of hydrocarbons. In other words a well is a pressure containing vessel. Norwegian safety regulations require a dual barrier construction of wells. This safety principle ensures that one “barrier” is preventing an escalating situation should the other barrier fail. A wellhead is a heavy walled pressure vessel placed at the top of the well. The wellhead is part of the second well barrier envelope during drilling.

The subsea wellheads are located at sea bottom and during subsea drilling the Blow Out Preventer (BOP) is placed on top of the subsea wellhead. The drilling riser is the connection between the BOP and the floating drilling unit. Waves and current forces acting on the drilling riser and drilling unit will cause dynamic movement. Flexible joints at top and bottom of the drilling riser protects the drilling riser from localised bending moments.

The subsea wellhead is both a pressure vessel and a structurally load bearing component resisting external loads transmitted from a connected riser. These external loads can be static and cyclic combinations of bending and tension (compression). Cyclic loads will cause fatigue damage to the well. The well can take a certain amount of fatigue damage without failing. A fatigue failure of a WH system may have serious consequences. Should the WH structurally fail its pressure vessel function will be lost and for this reason WH fatigue is a potential threat to well integrity. The structural load bearing function will also be affected.

Wellhead fatigue analysis can be used as a tool to estimate the accumulated fatigue damage. Analysis results then compares to a safe fatigue limit. This thesis addresses selected aspects of fatigue damage estimations of subsea wellheads and surface casings. The presented work is a contribution to the fatigue analysis methodology currently being developed within the industry. The well cement role as a boundary condition for surface casings in analytical models is particularly addressed.

The majority of research focuses on the casing shoe and formation sealing, which is the primary objective of well cementing. Recent research focus on the cement limits conditions e.g. elevated temperatures. The "near-seabed" conditions of lead cements have seen less scrutiny. Some researchers have shown interest in this issue related to deep water cementing. Deep water bottom temperature is low all year round regardless of location latitude.

Low sea water temperatures will depress the normal thermal gradient of the upper parts of the soil. Subsea wells are typically cemented using a lead and tail cement system, and the lead top casing cement will be pumped all the way to seabed. This lead cement will then be left curing in a low temperature environment. Hydration of cement is an exothermic chemical reaction, and the reaction rate is dependent on temperature. Laboratory measurements of low temperature early compressive strength of typical lead cement slurries are presented herein.

In the North Sea the duration between placement of surface casing lead cement and installation of BOP/drilling riser will typical be around 24 hrs. Then dynamic riser loads will start acting on the upper part of a subsea well. Bending of the well causes relative motions between the conductor and surface casing. The cement around these casings will experience these relative motions. The combination of delayed cement setting due to low temperature and surface casing motions will cause localized failure of cement bonding in the upper part of the well.

In subsea wellhead fatigue analysis finite element models are used. Boundary conditions in analytical models are important in ensuring similar behaviour of model and reality. One boundary condition in wellhead models is the lateral cement support of the surface casing. Modelling this cement support as infinitely stiff with a discrete vertical transition is the existing solution. In this work a modified boundary condition is presented based on low curing temperatures in combination with “premature” loading of the supporting cement.

An overall analysis methodology approach has been suggested. Using a detailed local model of the well to define the lower boundary condition for the global riser load analytical model is one of its features. The implementation of a modified cement boundary condition will change the global stiffness of the local well model. The possible effect on global riser load from variations to the lower boundary condition has been studied. The conclusion supports the suggested analysis approach.

Overall well ultimate structural strength will be reduced by the presence of a fatigue crack in a non pressurised load bearing part of a subsea well. An analysis methodology with case results are presented and indicate that the location of a fatigue crack affects the reduction in ultimate strength. Cases of significant reduction are expected to impact normal operating limitations.

To be able to include the wellhead fatigue failure mode in an overall risk management system, the failure probability needs to be estimated. This can be done by applying a structural reliability analysis methodology to the problem. A suggested structural analysis methodology approach is suggested and notational failure probabilities are presented.

Future improvements to wellhead fatigue analysis may emerge from calibrations from measurements of the reality. A comparison between analytical fatigue loading and measured fatigue loading has been presented and results indicate that the analysis results are conservative. This is evidence that analytical estimate on acceptable fatigue limits can be trusted from a safety point of view. It also indicates the monetary potential that measurements can present to the well.

Acknowledgments

Since 1999 I have been an employee by Statoil ASA and have received invaluable support and funding from my employer for the presented work. The work has been carried out as a part time PhD research fellow at the University of Stavanger, Faculty of Science and Technology, Department of Petroleum Engineering. The work initially started in 2005, but came to almost full stop 2007-2010 during the development of a company specific analysis methodology. My managers Kristian Sirevåg and Gustav Rundgren have supported me through this project and their positive attitude and patience has truly lifted my spirits. I have been overwhelmed by the persistent support from Statoil.

My supervisor Professor Bernt Sigve Aadnøy with the Department of Petroleum Engineering has endured numerous discussions willingly sharing his multi-disciplinary experiences. I want to express my sincere gratitude towards Bernt for always been supportive and positive to me and this project. I hope he has appreciated my gradual transformation from an eager problem-solving engineer into a research minded engineer.

Professor Ove Tobias Gudmestad with the Department of Mechanical and Structural Engineering and Material Science has been my co-supervisor. He lectured me as a M.Sc. student in offshore technology and sparked my interest for knowledge and new ideas then. He holds great responsibility for me returning to the university as a PhD student after several years with the industry. I know that he still remembers my looping dynamic amplification solution to one of his homework. Ove Tobias deserves great thanks for his support and advice.

This project evolved into laboratory testing of oil well cement. Associate Professor Helge Hodne with the Department of Petroleum

Engineering willingly put his cement test laboratory, and not to mention, his knowledge and multiple advice at my disposal. I owe him many thanks for his contributions and steady support. A pleasant spinoff into the wonders of fermentation has made me a believer in the law of purity.

Thanks to Quentin Whitfield for sharing data from Infield Systems unique database of high level subsea indicators. The enthusiasm from B.Sc students Mirkamil Ablikim Turkel and Vibeke Henriksen in performing cement laboratory work as part of my test program has been inspiring and my thanks are herby extended.

Much of the work has been carried out in co-operation with DnV personnel and colleagues in Statoil. Invaluable support and input has been provided by industry co-authors. My colleagues Morten Sæther and Massimillano Russo have willingly devoted their time to complete several articles. Johan Svensson with Validus Engineering has shared his knowhow on FE modelling and analysis. Torfinn Hørte DnV Norway and Guttorm Grytøyr DnV USA has been committed towards my articles on wellhead fatigue. Harald Holden with 4Subsea has been a unique resource in many a way. I thank Tore Geir Wernø for his collegial support and Tor Henry Omland for showing me that this is possible …I look forward to keep working with you all.

No man is an island, and my ability to conduct this project has relied on the endless love and support from my wife Kari Helene. From the start of this project in 2005 until now we have been blessed with 3 children and she has patiently accepted my numerous hours devoted to this project. Without her by my side I would not have finished this long-term project. Spending time with my family has been an urge and strong motivation during work intensive times. Kids, here is daddy's "book".

List of Articles

I. *Wellhead Fatigue Analysis Method*
Presented at OMAE2011, Rotterdam, the Netherlands, 2011

II. *Hindered Strength Development in Oilwell Cement due to Low Curing Temperature* Presented at SPE Arctic & Extreme Environments Conference, Moscow, Russia, 2011

III. *Wellhead Fatigue Analysis Method: A new boundary condition modelling of lateral cement support in local wellhead models*
Presented at OMAE2012, Rio de Janeiro, Brazil, 2012

IV. *Wellhead Fatigue Analysis Method: The Effect of Variation of Lower Boundary Conditions in Global Riser Load Analysis*
Presented at OMAE2012. Rio de Janeiro, Brazil, 2012

V. *The Effect of a Fatigue Failure on the Wellhead Ultimate Load Capacity*
Presented at OMAE2012. Rio de Janeiro, Brazil, 2012

VI. *Wellhead Fatigue Analysis Method: Benefits of a Structural Reliability Analysis Approach*
Presented at OMAE2012. Rio de Janeiro, Brazil, 2012

VII. *Fatigue Damage Estimation of Subsea Wells from Riser Load Measurements*
Presented at OMAE2012. Rio de Janeiro, Brazil, 2012

To Kari Helene

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Part I – Thesis Summary

In 1905, the philosopher **George Santayana** said:

"*Those who do not remember the past are condemned to repeat it*"

1. Introduction

1.1. Background

Fatigue - the process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points and that may culminate in cracks or complete fracture after a sufficient number of fluctuations. [2]

Mechanical fatigue is a time dependant failure mechanism, or more precisely, number of load cycles dependant. Defining fatigue as only a material or structural problem may be difficult. The inter material processes that take place in forming a nucleus crack are covered by material science. These material processes are driven by global structural loading of a structure resulting in local stresses within the material. The design of the structure and its ability to distribute load within the structure control the stress level within the construction material [3]. Determining structural load effects is a structural engineering problem.

In a subsea wellhead application the presence of mechanical fatigue loading is synonymous with drilling activities conducted from a floating vessel with a temporal conduit connected to the well. Given a finite stiffness of the conduit system its motions hence load, will be transmitted to the subsea well. The subsea well will then react external loads into the surrounding soil. During this force transmittance material stresses will cause fatigue damage. The damage will be concentrated to certain structural details often referred to as hotspots in the well.

The well consists of several tubular members which can be classified as structural load bearing. Structural failure of the upper load bearing components of the well structure can have serious consequences. Failure can be the result of a load that surpasses the ultimate load capacity of the structural well components. This load can arise both from internal (e.g. pressure) or external (e.g. bending) loads. In the events of mechanical fatigue failure the loads have been repeated in cycles, with loading amplitude below the ultimate load capacity of the well. It is the accumulated amount of loading that eventually will lead to the development of a fracture in the material. At some point the cross-sectional area left to carry load will be reduced such that the cyclic load amplitude will be in excess of the residual capacity and a failure will be the result. The challenge with fatigue as failure mechanism is twofold; estimation of the accumulated loading cycle history and estimation of the fatigue capacity.

Inspecting for fatigue fractures is generally useful to get confirmation of safe operating conditions. Fatigue inspection methods can be visual, but in most industrial applications Non Destructive Testing (NDT) methods other than visual are required. In the case of subsea wellhead fatigue no applicable inspections methods exist for a wellhead while in service. The main challenge is lack of access to fatigue hotspots while the wellhead is operational.

Without any means for inspection one is left with the option to estimate the fatigue damage based on loading history. The subsea wellhead fatigue damage accumulation has to be estimated from load derived from analysis models or measurements, then accumulated and compared to the fatigue resistance. Analogies to this approach are present for several other technical systems in offshore applications e.g. offshore structures.

The use of Load and Resistance Factor Design (LRDF) approach is frequently used in comparable applications. For offshore structures fatigue design a Design Fatigue Factor (DFF) of 10 is recommended for safety critical components that cannot be inspected [4]. The subsea wellhead is a safety critical component without the option of fatigue inspection while in service and for that reason a DFF of 10 is applied by the industry. This is upheld in the current methodology report from the JIP [1].

The main focus has been on the load-to-stress relationship between external loading at the wellhead and the resulting stress at a specific location within the upper part of the well. This relationship is derived from analytical model representation of the wellhead. A unique load-to-stress relationship exists for each location of interest. An overall analysis methodology was suggested in Article I.

Different modelling approaches can effectively be compared by comparing the load-to-stress relationship at a unique location within a wellhead system. Models can differ both in modelling approach and in Boundary Condition (BC) description. Article III compares two boundary condition definitions applied to two different modelling approaches. The key argument in Article III is a suggested new approach on how to model the lateral support from cement on the surface casing. The suggested modified boundary condition is derived from results obtained by laboratory testing of lead cement cured at low temperatures. Article II and section 5.2 presents these lead cement laboratory results in more detail.

In evaluating subsea wellheads exposed to dynamic loading a scatter of challenges arises. Little research is available on this topic. Additionally it has become clear from various analytical works carried out in the industry that a consistent modelling approach is lacking. Article I is outlining a more consistent modelling approach for the industry. The safety level of existing codes and standards applicable for components of the global system where dynamic global loads work, are not easily comparable. The current situation is not suited for ensuring a uniform safety level throughout the global system[5, 6].

1.2. System Description

By nature a deepwater subsea well can only be accessed from a mobile drilling unit (MODU). It is inherent to a MODU that it is subject to dynamic motions behaviour. In connecting a drilling unit to a subsea well by the use of a marine riser system, the wellhead will be acting as a foundation for the riser preventing its lower end from moving. Figure 1 gives a graphic presentation of the key elements that constitutes the system involved in the problem of subsea wellhead fatigue loading.

From operational and well integrity reasons marine riser systems need to undergo dynamic analysis in order to check the loading of the riser system against the risers own structural integrity and to establish the MODU's operational limitations set by the riser system's structural capacities. The MODU and riser are subject to environmental loads from waves, current and wind. The MODU will have station keeping provisions (i.e. mooring or thrusters) and will experience dynamic motions as the environmental loads are reacted by the station keeping forces. As dynamic motions of the drilling unit and its marine riser system will transfer dynamic loads into the wellhead, surprisingly little attention have been placed on investigations of the integrity of the wellhead due to dynamic loading.

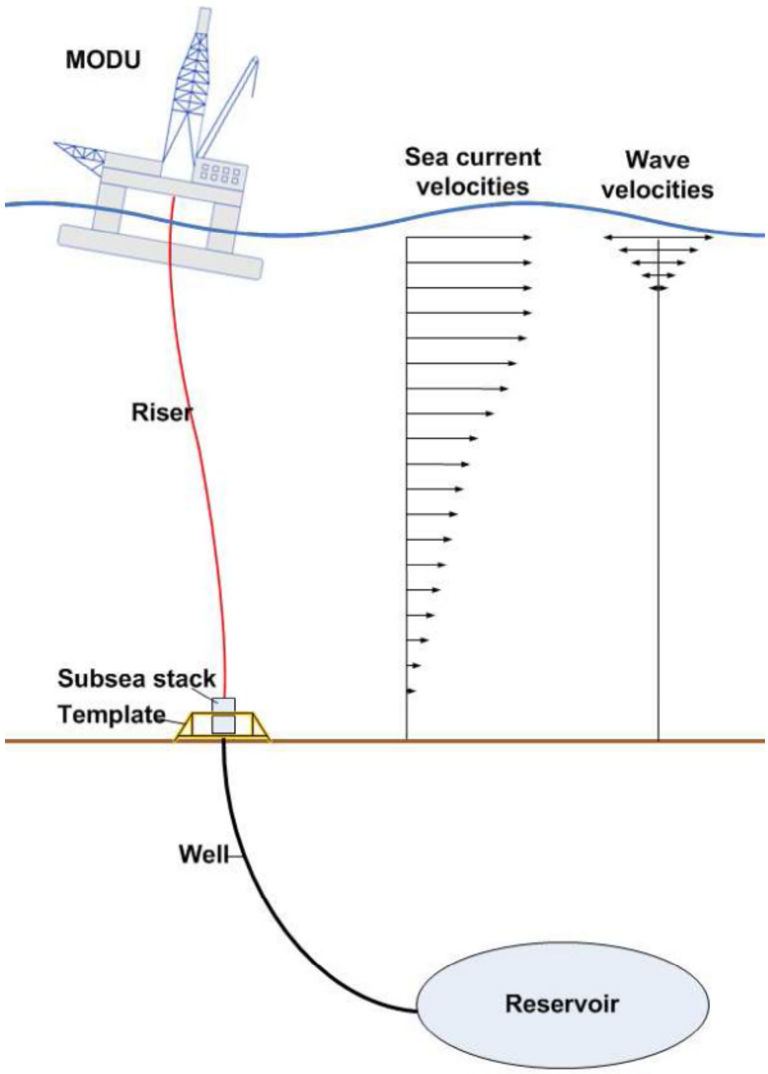

Figure 1 System description

1.3. From topside to subsea

The world first subsea well was completed in 10 m water depth as early as 1943 in Lake Erie. It was done using land type tree equipment and diver assisted operations. In the 1960s the first subsea well was installed in Gulf of Mexico, still relying on diver assistance. Development was slow until the early 1990s when the development of cost efficient diver less subsea building block technology was made available to the market [7]. The building block idea entails introduction of standardized interfaces within a subsea production systems one being that of the subsea wellhead interface against the drilling system and the X-mas production tree. From the mid 1990s a number of large subsea field developments were realized. Since then the number of subsea wells has increased rapidly (see Figure 2)[8].

The subsea technology matured rapidly and water depth technical limitations were continuously extended. In the beginning of the subsea area the deep water limit was seen as water depths beyond 500 ft (152 m) of water depth, but over the years this limit[2] has been lifted to a 1000 ft (304 m). Describing technological frontiers of deep water drilling today the expression Ultra Deep water has been introduced. The current deep water record (2934 m/ 9627 ft) was set at late as fall of 2011 in the Gulf of Mexico (GOM) [9].

It is apparent that subsea wellheads have evolved on the basis of dry offshore equipment, and since the standardization in size (18 3/4" OD) and mechanical interface (the Vetco H4 profile) the principle layout of subsea wellheads has not changed fundamentally. An important change

[2] No official definition for the term deep water exists. The deep water drilling moratorium imposed by the US authorities following the Deepwater Horizon drilling rig accident in 2010 defined drilling beyond 500ft(152m) as "deep water".

seems to have been introduced following the fatigue failure reported by Hopper [10]. Subsea wellhead systems have since been equipped with 2-point contact interference between conductor housing and wellhead housing. For installation purposes there will still be some geometric tolerances present for one of these 2 contacts. With the development towards deepwater drilling, pre-loaded wellhead systems have been introduces to the market. This seems to have been driven by the need for increased ultimate load capacity of the wellhead system, rather than fatigue considerations [11]. Some authors claim that the accident reported by Hopper has driven subsea wellhead designs toward the modern lock-down solutions [12].

Improving structural load capacity on a subsea wellhead does not guarantee an increased fatigue resistance. Pre-loaded wellhead systems still have a wall thickness reduction in combination with a welded connection to the casing tubular which can make the wellhead/surface casing transition sensitive to dynamic loading.

1.4. Subsea drilling development

In offshore field development there has been a trend towards subsea developments with the increase in water depth. Subsea wells represent an increasing fraction of offshore wells completed today. About 100 of 507 giant oilfields have been discovered offshore and 27 in deep water. 10 of 17 giant oilfields planned developed during 2007 to 2012 will be at deep water [13]. By the end of 2011 there were a total of 4046 subsea wells in operation worldwide [8]. The development of the world's accumulated population of subsea wells has been shown in Figure 2 and it portraits a nearly exponential growth from start until today.

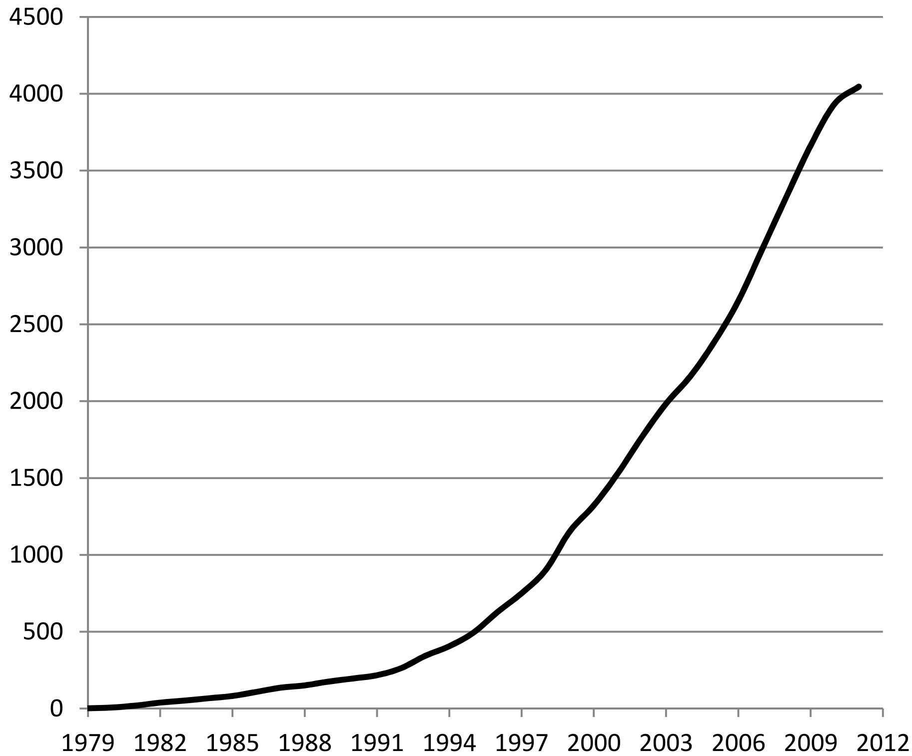

Figure 2 Historic development of the world's population of subsea wells in service [8]

Several technology steps enabled this development besides the development of the subsea technology itself. Most importantly is the advances in seismic imaging of deep lying reservoirs and the advances in deep water drilling units making large scale exploration possible. A thorough analysis of the growth and enabling technology steps making deep water drilling and production possible can be found in the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling's report to the president [14].

The subsea wells average oil recovery factor are 10-15 percentage points lower compared to wells with platform well access, according to a study presented by the Norwegian Petroleum Directorate [15]. A huge production potential is presented by the option to increase the oil recovery factor performance on subsea wells. Current trend towards increased intervention in existing subsea wells are driven by this production potential. In the future one can expect more well intervention work to be carried out on subsea wells. From a well integrity point of view it is important to verify safe operation with respect to fatigue during the entire life of the well. Increased oil recovery has made design life extensions of existing production infrastructure an important exercise in Norwegian waters. A recent report delivered to the Norwegian PSA have identified documentation of subsea wellhead fatigue damage as an life extension requirement [16]. This requirement has been included in the NORSOK N009 [17] standard that was issued in 2011.

Initial drilling of subsea wells have become more time consuming today compared to the beginning of deep water drilling; activities in subsea wells have increased in complexity, measured depth of subsea wells has increased and subsea wells are drilled at deeper waters. All these factors are indicating that the duration of operations has increased per well. This development is partly identified by Osmundsen et al. [18] who analyzed the productivity parameter “meters drilled per day” on 642 exploration wells on the NCS from 1965 till 2008. In particular Osmundsen et al. shows that increased water depth has a negative effect on drilling productivity. Is has been stated by others [5] that the design premises for today’s wellheads and connectors were made when typical durations of a drilling operation were 30-60 days. Today we may see subsea wells exposed to 200-300 days of drilling activities [19]. In sum there is evidence of increased duration of fatigue loading of subsea wellheads.

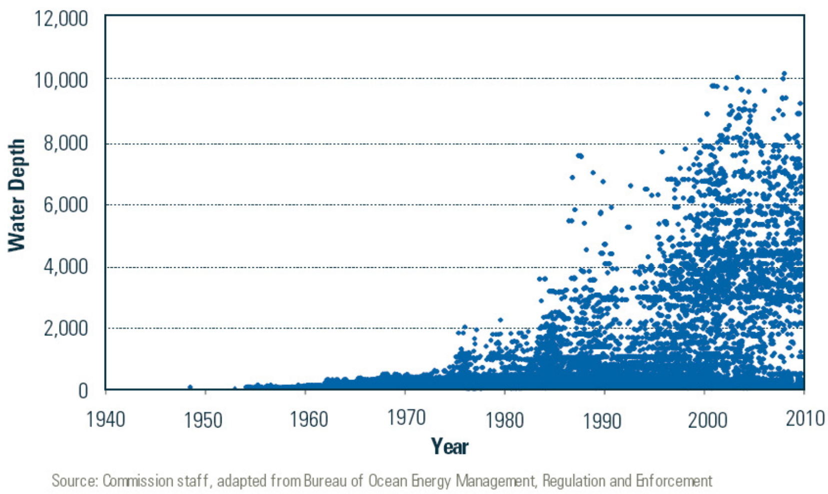

Figure 3 Wells drilled in US GOM has increased in water depth (given in ft) 1940-2010[14]

Figure 3 shows the development in water depth for wells drilled in US waters of Gulf of Mexico (GOM). As shallow water drilling still is ongoing, the increase in deep water drilling has been impressive. This development is mimicked by the development in the world's number of active subsea wells as seen in Figure 2. The shift towards deeper waters has driven MODU designs, and current design of offshore drilling rigs is classified as 6th generation. The subsea well equipment had its design limitations set at a time when 3rd generation drilling rigs where the state of the art. Subsea structures design drilling loads in the national standard NORSOK U-001 [20] are based on a typical 3rd generation drilling rig with a BOP air weight of 250 metric tonnes. Deep water 6th generation drilling rigs may have BOP weights in excess of 400 metric tonnes. NORSOK U-001[3] is currently under review and increased

[3] Note that the NORSOK U-001 standard does not specify any dynamic design loads for subsea wellheads.

drilling design loads are currently expected. At the time when subsea wellheads seem to have been standardised by the industry Dykes et al. [21] published a design load histogram used as a design load in their evaluations for establishing a standard subsea wellhead. In Figure 14 (presented at page 33) a comparison between the Dykes et al. and a typical North Sea annual load histogram of today are presented (see also Article I).

The typical subsea wellhead systems of today are in principle similar to the systems analyzed by Hopper and Dykes et al.[10, 21]. They differ in details, material and size, but are still characterized by a welded connection between the rigid wellhead housing and the less rigid casing pipe extending down into the well [22]. Conventional wellhead systems still include some radial tolerances between wellhead and conductor housing in order for it to be installable. The internal load path is in principal similar.

The development in subsea technology has been driven by the ability to discover hydrocarbons in deep lying reservoirs at increasingly deeper waters. Duration of each drilling operation has increased with water depth and well construction complexity. The increased water depth capability of MODUs has led to larger sized drilling systems that again may impose larger fatigue loads than before [23]. The combination of increased duration, size and forces is one that will make fatigue damage failure more possible.

1.5. Subsea wellheads systems

The subsea wellheads are located at sea bottom and during subsea drilling the Blow Out Preventer (BOP) is placed on top of the subsea wellhead. Figure 4 may serve as an illustration of a subsea wellhead with a BOP on top. The drilling riser is the connection between the BOP and the floating drilling unit. Waves and current forces acting on the drilling riser and drilling unit will cause dynamic movement. Flexible joints at top and bottom of the drilling riser protects the drilling riser from localised bending moments.

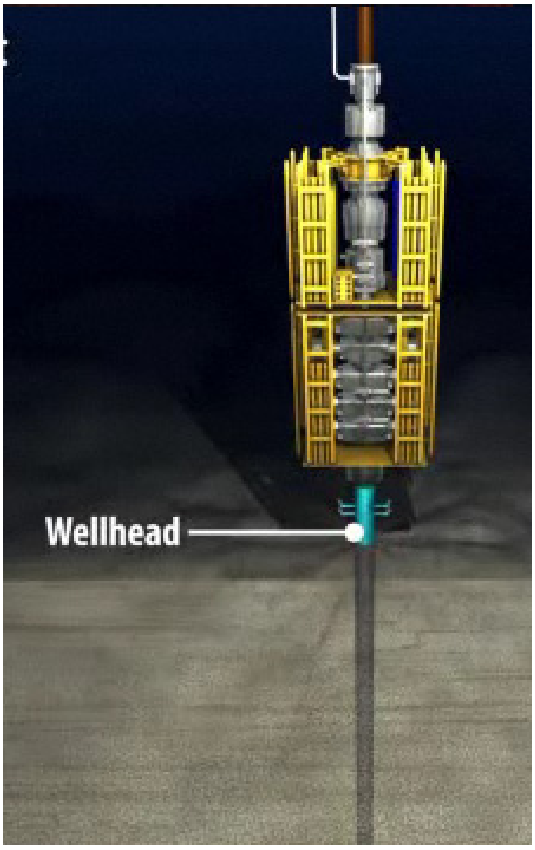

Figure 4 BOP on top of a subsea wellhead protruding the seabed [24]

Structurally a well construction terminates at the wellhead which includes a standardized interface towards the drilling and production systems. A well will be subjected to external and internal loads. Loads generated by reservoir fluids would be internal, i.e. reservoir pressures and thermal growth during production. External loads will be imposed from the surroundings. Typically well construction activities such as installation of casings or pressure testing during different stages of the well construction process introduces loads of significant magnitude.

The subsea wellhead is both a pressure vessel and a structurally load bearing component resisting external loads transmitted from a connected riser. These external loads can be static and cyclic combinations of bending and tension (compression). Cyclic loads will cause fatigue damage to the well. The wells can accumulate a limited amount of fatigue damage without failing. A fatigue failure of a wellhead system may have serious consequences. Should the wellhead structurally fail its pressure vessel function will be lost and for this reason wellhead fatigue is a potential threat to well integrity. The structural load bearing function will also be affected.

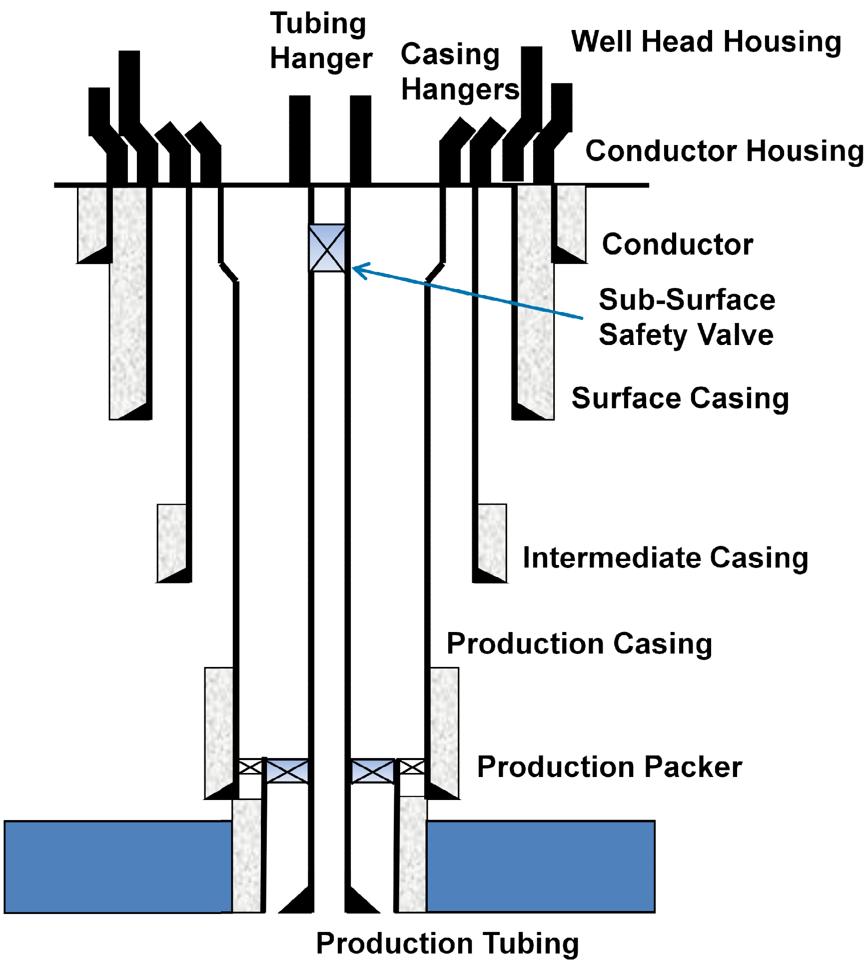

Figure 5 Schematic of typical subsea well construction in the North Sea

A subsea well is constructed similar to other type wells. The subsea wellhead and the adjoined surface casing represent the second well barrier envelope, either in certain phases of the well's life or in all phases thus making it a main well barrier element of the well construction. The subsea wellhead also serves as the mechanical interface towards the drilling units' pressure control equipment (BOP) and/or as the interface towards the production valve assembly (i.e. X-mas tree). A subsea well will structurally be supported by the upper soil either directly or partly indirectly through a template structure.

Figure 5 shows a typical subsea well casing program for the North Sea with naming conventions used in this work. Primary load bearing components are the conductor and the surface casing strings. The conductor housing is joined to the conductor casing by welding. Others refer to this casing string as the structural casing or the low-pressure casing string [20, 25]. The wellhead housing is similarly welded to the surface casing string, and may be denoted the high pressure housing [25].

Subsequent casing strings are the intermediate casing and the production casing. Finally the production tubing is introduced. Variations to the layout in Figure 5 exist; most commonly 2 casing strings have been made into one by introducing a crossover element. This will be done when reservoir drilling conditions permits and are more frequently used in exploration drilling than in production drilling.

1.6. Bend loading of a subsea wellhead

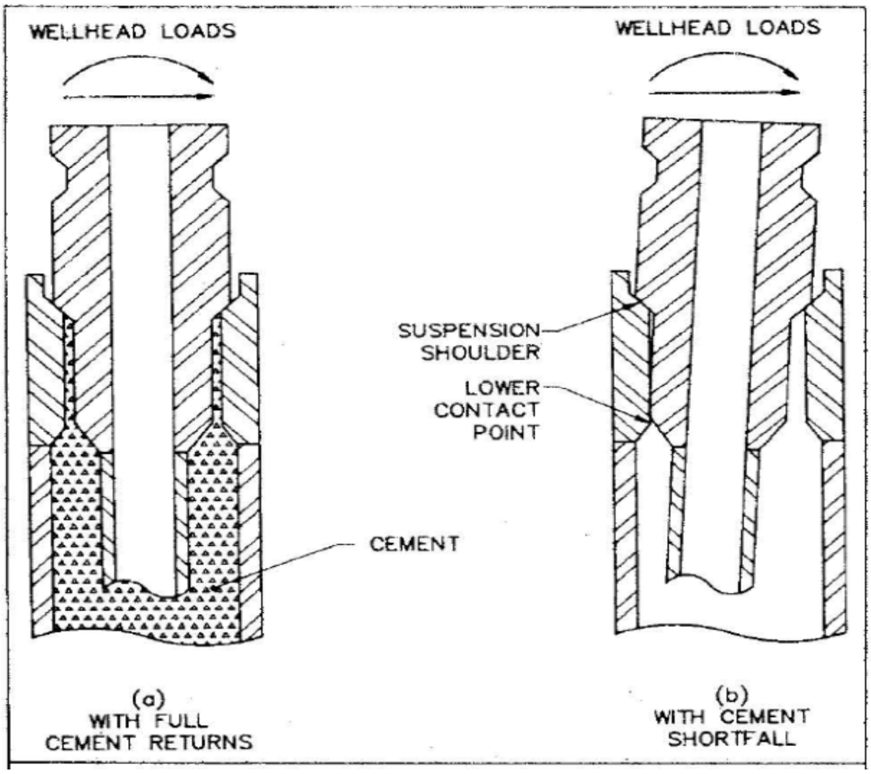

Figure 6 Illustration of wellhead rotation from bending [26]
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As a subsea well experiences bending it will tend to rotate with the bending force. Figure 6 shows an illustration of the rotation of a wellhead due to bending (reprinted with permission) by Britton and Henderson [26]. Global resistance to this rotation will be provided by the inherent bending resistance of each structural well element. Primary load bearing components is the conductor and surface casing strings. The wellhead housing is directly connected to the BOP and will be the receiver of external bending loads. The surface casing is welded to the wellhead housing and will be loaded by rotation of the wellhead housing and the global rotation of the well. From Figure 6 we can see that the wellhead housing needs some degree of rotation to engage lateral mechanical contact to the conductor housing. As this occurs the conductor and surface casing will resist bending as a rigid body.

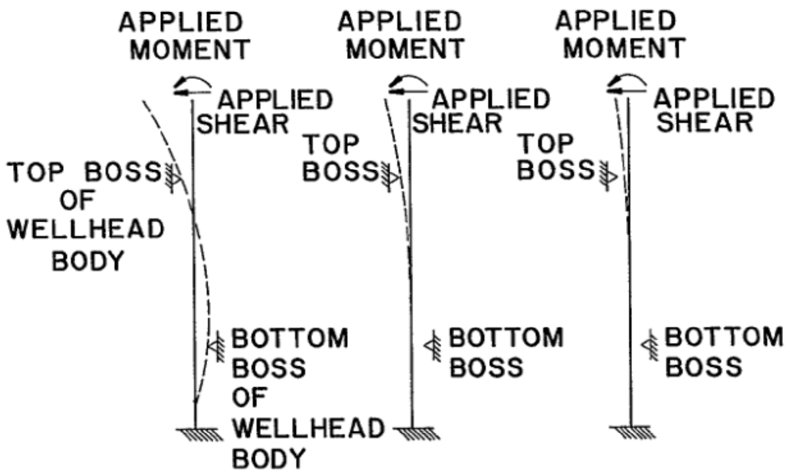

Figure 7 Wellhead body idealized as a cantilever beam [27]
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Valka and Fowler [27] discussed this behaviour of a conventional subsea wellhead. In Figure 7 a simple beam representation of the wellhead housing with interaction to the conductor housing as the system bends is shown as a reprint from Valka and Fowler [27]. It can be seen from this simple representation that the boundary conditions for the wellhead changes with the degree of rotation, which is controlled by the bending force magnitude. Eventually the wellhead “beam” gets interlocked by the mechanical interference to the conductor housing.

From this stage the 2 items; wellhead and conductor housing, behaves as a composite beam.

The course of events seen in Figure 6 and Figure 7 are illustrated in Figure 9 (reprinted from Valka and Fowler) as a relationship between the applied bending load and the stress in the surface casing (due to the bending curvature). We see that the curve in Figure 8 has 3 sections with different rates of change. A load-to-stress curve like this can be generated for different locations in the well. Load to stress curves derived from different models of the same well can be compared. If there are differences then a fatigue accumulation based on identical loads will be different.

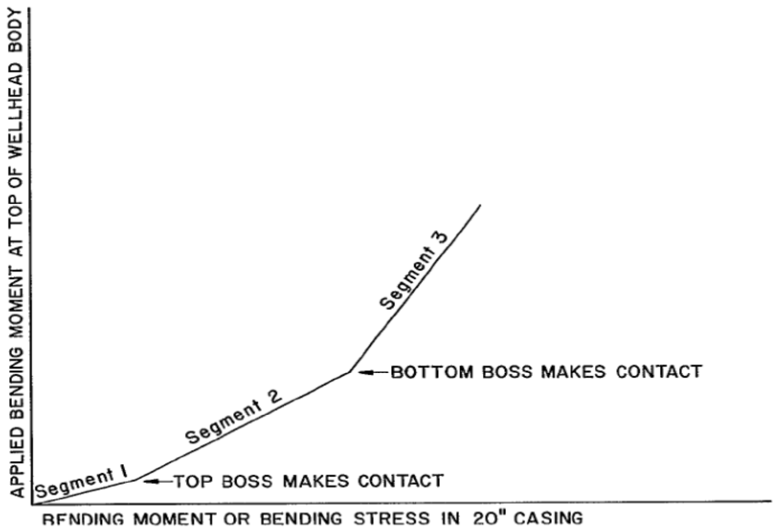

Figure 8 Load-to-stress curve for a surface casing with wellhead body idealized as a cantilever beam [27]
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Uncertain modelling input parameters may be varied and the resulting stress-to-load curves compared. We know that some input parameters affect the load-to-stress curve significantly. One of these inputs is the cement level in the surface casing annulus. Valka and Fowler [27] illustrated the effect of a reduced cement level by use of their simplified beam representation of the wellhead as shown in Figure 9. It is evident from Figure 9 that as the “point-of-fixity” i.e. the cement level falls short of the mud line the radius of the curvature in the surface casing will increase.

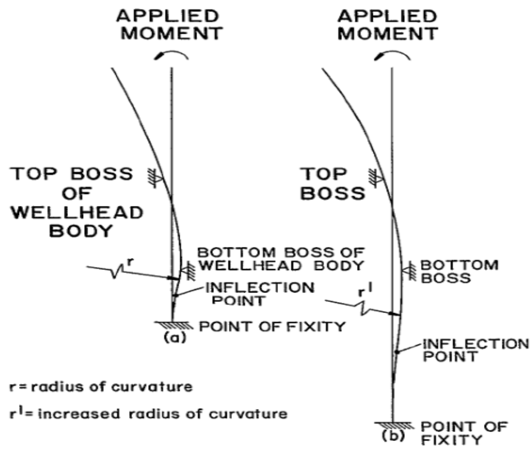

Figure 9 Wellhead body idealized as cantilever beam showing the effect of the "point of fixity" [27]
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Applied bending causes the wellhead to rotate relative to the conductor housing until 2 point contact has been achieved with the conductor housing. Mechanical interference between wellhead and conductor housing will cause these to behave as a composite stiff beam under the influence of more bending. The surface casing welded to the bottom of the wellhead housing will be bent out of vertical plane while being held in place by the presence of lateral cement support. This parabolic bending of the surface casing is illustrated in Figure 9. In practical terms the surface casing will have to enter slight deformations in order for the conductor string to start reacting to the bending load. Several authors have stated that a relative movement between the surface casing string and the conductor string will be present when wellhead bending action is present [10, 25-27].

In order to understand how the curvature or bending radius of the surface casing below the wellhead housing impacts the material stresses the relationship between stress and curvature is investigated.

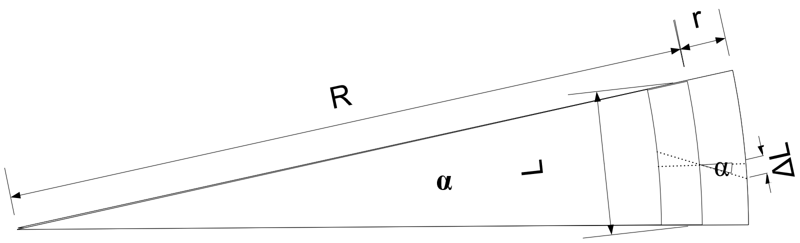


Figure 10 Side view of a section of casing in pure bending

If we simplify the bending of a section of casing and study a small section of the casing like what is shown in Figure 10, we can state the following based on simple geometry.

$$\sin\alpha = \frac{L}{R} \qquad (1.1)$$

Where α is the associated sector angle of our small casing element. L is the segment length; R is the midwall bending radius. Assuming α is small we can simplify this expression. (The angular rotation of wellheads relative to the conductor housing will typically be less than 1 deg.)

$$\alpha = \frac{L}{R} \tag{1.2}$$

Similarly from Figure 10 we can see:

$$\alpha = \frac{\Delta L}{r} \tag{1.3}$$

Here ΔL is the elongation of the outer fibre of our segment, r is the segment radius. The strain ε of the outer surface caused by the bending can then be written as

$$\varepsilon = \frac{\Delta L}{L} = \frac{\alpha r}{\alpha R} = \frac{r}{R} \tag{1.4}$$

Assuming a linear-elastic material and substituting into Hooks law (E is the modulus of elasticity) we get:

$$\sigma = E\varepsilon = E\frac{r}{R} = Er \cdot \frac{1}{R} \tag{1.5}$$

As a result we get a linear relationship between the stress σ in a pipe segment due to bending and the curvature κ (reciprocal of curvature radius):

$$\sigma \sim \frac{1}{R} = \kappa \tag{1.6}$$

Consider the surface casing welded to the bottom of the wellhead housing. From this simple consideration above we can conclude that the load to stress curve will be significantly affected by the bending radius of the casing. As shown by Valka and Fowler (Figure 9) the vertical spacing of “point of fixity” from the centre of wellhead rotation will control the curvature of the surface casing. The stresses in the surface casing will be reduced with increasing spacing for the same bending load applied to the wellhead. In a SN fatigue evaluation a reduction in stress (range) will affect the allowable number of cycles to the power of 3-5[4]. Assuming a SN curve with a inclination of -4, a 10 % reduction in stress range (due to a increase in bending radius of the casing) will mount to a increase in allowable fatigue cycles, everything else constant.

$$S_a^k N = Constant \qquad (1.7)$$

This relationship (1.7) is known as the Basquin relation [3]. SN curves are often presented using logarithmic scales for the number of cycles N (fatigue life) and for the stress range S_a. This is convenient because it will present a logS-to-logN curve with an approximately linear relationship. A mathematical expression for such a line is given by the Basquin equation (1.7). It represents the linear SN relationship in a log-log scale diagram.

As an example we assume a 10% reduction in stress in a surface casing hotspot due to an increase in bending radius from a lower “point-of-fixity”. The k value is assumed to be 4. Then by substitution of (1.7) we get the following:

[4] Depending on the inclination of the SN curve.

$$S_1^4 N1 = S_2^4 N2$$

A 10% reduction in stress range yields

$$Given\ S_2 \ = S_1 \ \ x\ 0.9$$

We substitute S_2 and solve:

$$S_1^4 N1 = (S_1 \ x\ 0.9)^4\ N2$$

$$\frac{S_1^4}{(S_1 \ x\ 0.9)^4} = \frac{N2}{N1} \approx 1.524$$

Thus we see that a 10% reduction in stress range will result in a 52% increase in allowable fatigue life. If the k-value is 3 the increase reduces to 37%. A k-value of 5 yields a fatigue life increase of 69%.

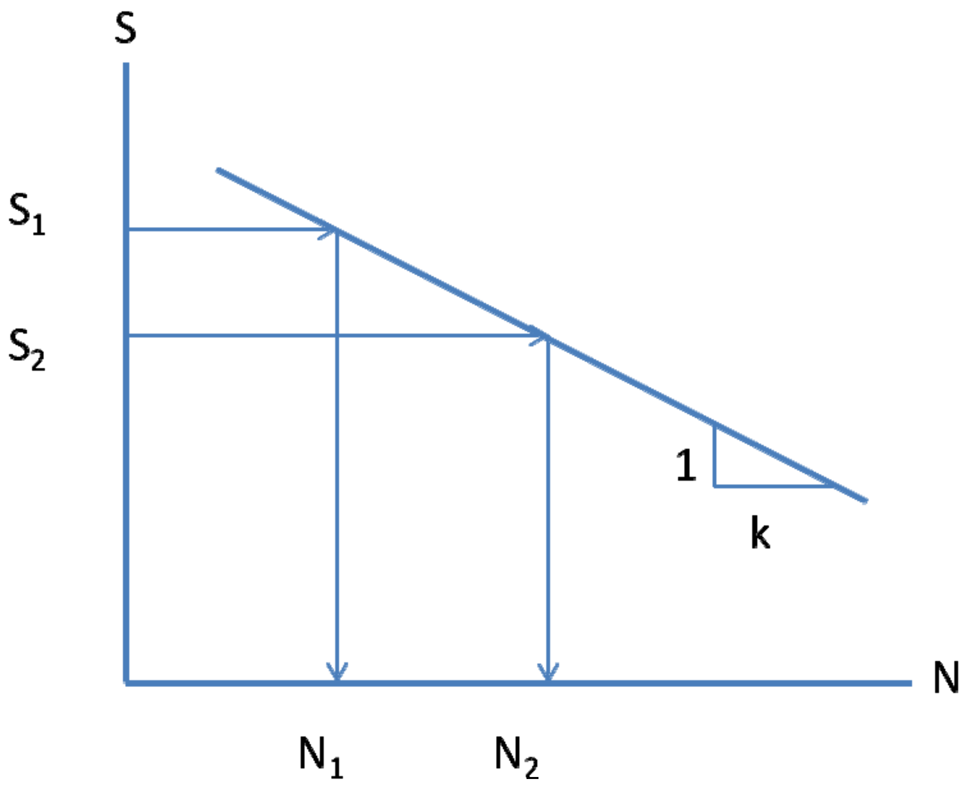


Figure 11 Reducing stress range improves fatigue life

Figure 11 is a graphic illustration of the example. The Basquin equation is presented as a straight line. Lowering the point of fixity of a surface casing will increase the bending radius which again reduces stresses and thus improves fatigue life.

1.7. Fatigue capacity in subsea wells

The conventional fatigue analysis of offshore structures is essentially a Load and Resistance Factor Design (LRDF) approach that bears similarities to static strength analysis. It involves comparison of load vs. resistance with some margin. The most frequently used fatigue limit (resistance) is the SN approach. The SN limit is fundamentally empirical as it is derived from testing (observations). A recent textbook on fatigue life analysis of welded structures states that "*...fatigue design is experimental, empirical and theoretical – and in that order*" [28]. It is essential to any fatigue life analysis to establish the correct SN limit curve from standards or by testing. Factors that generally will influence subsea wellhead system fatigue limits are listed below.

- Welded or non welded hotspot
- Environment (temperature, corrosion)
- Type of loading (tension, bending, shear, combinations)
- Mean stress
- Geometry, notches, defects
- Surface condition (roughness, material condition)
- Size
- Residual stresses
- Material

The term hotspot refers to a construction detail that will see more fatigue damage than the surrounding parts. Several hotspots may exist in the same construction. There is an important difference between welded and non welded hotspots as the welded hotspots are assumed to have no crack initiation phase as part of the total fatigue life. Subsea wellhead systems are recognised by having a welded connection between casing string and the conductor and wellhead housings. This means that any wellhead system will have at least 2 load bearing welds, typically girth welds. This is important since it is assumed that fatigue cracks starts forming and crack growth is present from the first load cycle.

$$N_{total} = N_{initation} + N_{propagation} \qquad (1.8)$$

An important difference between welded and non welded details related to fatigue limit can be explained by the equation 1.8. Generally N_{total} denotes the total limiting number of cycles for constant amplitude loading. This limit is the sum of $N_{initation}$ number of cycles to initiate a fatigue fracture and $N_{propagation}$ which is the number of cycles necessary for crack propagation until the crack reaches its critical size. In the case of welded structures the contribution from the crack initiation to the N_{total} can be discarded due to imperfections that prevail in the weld matrix [29].

Everything else being identical in comparing a welded and non welded detail this will imply less fatigue capacity in a welded structural detail. Fatigue capacity in the form of SN curves can be found in international standards and codes.

1.8. Typical hotspots in a wellhead system

The conductor casing may sometimes be referred to as the structural casing [30] or low pressure casing [25]. The assumption in wellhead design is that the outermost casing string, the conductor, which is attached to the conductor housing by welding, is the primary load bearing component of a subsea well [20][5]. As a consequence the next casing string, the surface casing, welded to the wellhead housing as well, should see no loads but what global bending of the well generates. This assumption implies that the 2 concentric casing strings behave as a composite beam.

Any structures outside the conductor add to an overall global stiffness of the well. Such structures could be wash pipes or template. The stiffness of these components with their foundation properties will

[5] NORSOK U-001, Appendix A, table A1:" *Horizontal load to be carried by template/TGB and conductor*."

introduce a lateral conductor support just above mud line level. This lateral support will resist a wellhead systems ability to globally bend. In the present work (Article III, Article IV, Article VII) the case of a satellite well is studied, and focus is placed on the surface casing/wellhead structural member as it is the first receiver of external loads, and the reminder of the well system can be seen as a support of the surface casing/wellhead string.

Figure 12 shows a FE Model of the upper part of a well, and the 3 most critical hotspots details has been highlighted. The surface casing string may have several fatigue hotspots, but the welded connection between the wellhead housing and the surface casing extension has been the focus of this work. Several authors suggest this to be one of the more critical hotspots in a subsea well [10, 21, 25]. Article V shows that a failure of the surface casing string due to fatigue will affect the overall ultimate strength of the well less than a failure in the conductor.

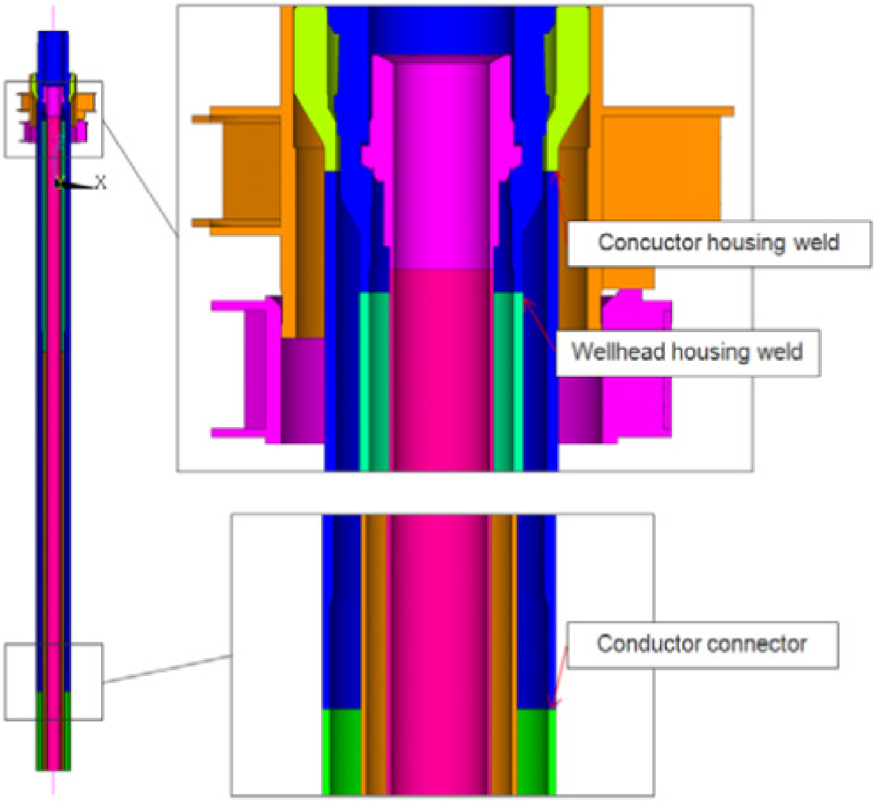


Figure 12 Well model showing hotspots that are reported to have failed in service

1.9. Fatigue failures reported in the literature

Subsea wellhead fatigue failures during service are reported in the literature. In 1989 Singeetham [31] claimed that "*The industry has experienced multiple field failures in the last 10 years, primarily at the bottom of the high pressure housing (wellhead housing)...*"when discussing fatigue capacity on subsea wellhead systems. Further evidence of specific field failures can be found in a 1991 paper by Milberger et al. [25] who stated that two wellhead failures had occurred in the field. They referred to the failure investigation presented by

Hopper in 1983 and to a non published report dated 1980 as references for these 2 failures. In a 1990 paper addressing experiences from the subsea development on the UK Beryl field King [32] identified a fatigue failure of a subsea development well that had to be abandoned for this reason. This failure was confirmed at the 1st conductor threaded connector and large BOP/wellhead movements resulted as the symptom of the failure. Norsk Hydro Oil and Gas experienced abnormal BOP movements on a north sea subsea wellhead due to a fatigue failed conductor weld in 2005 [33].

These reported fatigue failures all happened on subsea wells in service during drilling activities involving a connected drilling riser and highlight fatigue as a failure mechanism relevant to subsea wells. These failures have occurred in both surface casing-wellhead welds, conductor-conductor housing welds and in conductor casing connectors. Figure 12 show an upper subsea well with indications of the fatigue hotspots that are reported to have failed.

The first 2 failures happened in the early 1980ies, and then a decade later King reports a new fatigue failure. Then 15 years and 2200[6] new operational subsea wellheads later a fatigue failure happened again in the North Sea. A major Norwegian operator has since suspected[7] 5 cases of subsea wellhead system failures due to fatigue. A presentation of the first of these failures was given at the Underwater Technology Conference in Bergen, Norway in 2006 [33] and has been referred to in Article I. This incident showed that subsea wellheads can still fail structurally from fatigue loading by a connected drilling riser. The consequence of structural failure of a wellhead system can be

[6] Based on data presented in Figure 2
[7] Final verification has not been obtained since the wellheads have not been retrieved yet.

detrimental to well integrity and are discussed in more detail in section 3.2 and Article V.

In Figure 2 the development of the accumulated number of subsea wells are presented from 1979 until today. Reviewing published work on dynamic lateral loading of subsea wellhead systems, one interesting observation is that the majority of work identified has been published during the period from 1983-1993. This series of published works appear to be a response to a wellhead fatigue failure reported by Hopper [10] to have happened west of Shetland in 1981. It appears that fatigue of subsea wellheads has been discussed at a time when the subsea technology was on the verge of becoming an international industry. Since then the subsea technology has developed and is now used under a wider range of conditions than was the case around 1990. The increase in service conditions for subsea wellhead systems has caused wellhead suppliers to develop new products to satisfy the market e.g. preloaded wellhead systems [11]. An interesting question then becomes; have fatigue loading increased with time?

1.10. Have fatigue loading increased with time

The subsea industry has gradually extended its operational boundaries into deeper water depths and today operations in ultra deep waters are underway. Offshore drilling units have increased their capacities accordingly. Table 1 offers a listing of drilling rig categories and the water depth at which they can perform drilling activities. The first subsea wellhead specification was released in 1992 [34]. 6^{th} generation deep water drilling rigs are larger in size than when subsea wellheads were standardized in the first part of the 1990s.

Table 1 Listing of Semi Submersible drilling rig generation classification [35]

Rig Generation	Water Depth(m/ft)	Dates
First	200 m / about 600 ft	Early 1960s
Second	300 m / about 1000 ft	1969–1974
Third	500 m / about 1500 ft	Early 1980s
Fourth	1000 m / about 3000 ft	1990's
Fifth	2500 m / about 7500 ft	1998–2004
Sixth	3000 m / about 10000 ft	2005–2010

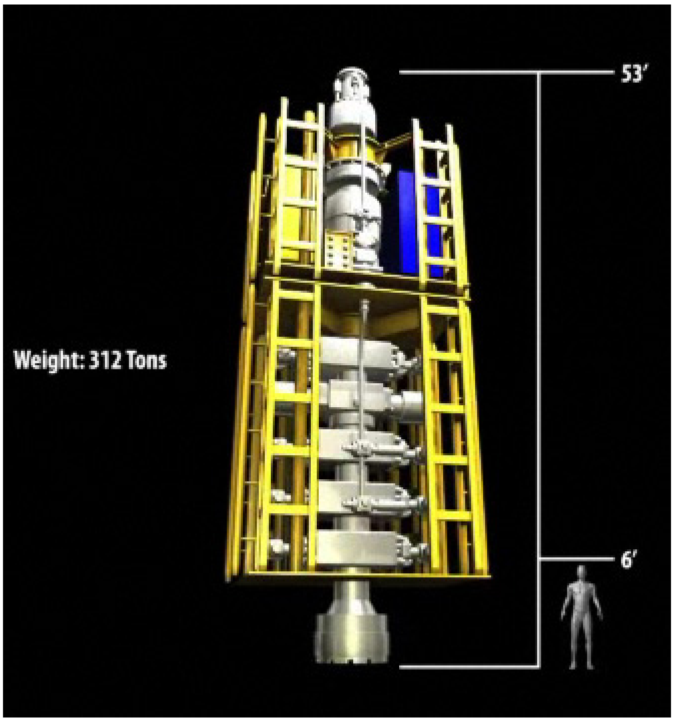


Figure 13 Illustration of the Deepwater Horizon BOP size [24]

Suspended drilling riser weight will increase with water depth. A minimum applied top tension is necessary to ensure the stability of the drilling riser. The minimum top tension should be set such that efficient tension is positive in all parts of the submerged riser[8]. The Lower Marine Riser Package (LMRP) can disconnect from the Subsea BOP when needed. To ensure successful disconnecting, drilling riser tension should ensure positive tension at the LMRP connector.

The new 6th generation drilling rigs are equipped with larger BOPs (larger weight and height, same bore diameter). An illustration of the size of deep water BOP can be seen in Figure 13. As a consequence the deep water LMRP weights have increased too. The top tension needed for deep water rigs are higher as a consequence of increase in riser and LMRP weights. Increased riser tension has caused the structural capacity at both upper and lower flex joints to be reinforced. Flex-joints need a structural tension and pressure rating with a ball joint angular stiffness as a bi-product. This angular rotational stiffness of a lower flex joint will transfer the drilling riser bending moment into the top of the BOP. The riser tension will have a horizontal component dependent on the angel of the lower flex joint. With increased tension settings for deep water rigs this horizontal component will increase too.

Generally the rig hull size is governed by needed volume of drilling fluids to be handled and stored and the need for variable deck load. Deep water well drilling fluid volumes increases as drilling riser volumes increase with water depth. Variable deck load limitations can impact operational efficiency negatively [36]. The 6th generation drilling rig hulls are generally larger than before due to increased need for variable deck load and space [23]. Performing subsea well completions operations in harsh environments like in the North Sea during the winter season have become standard practice. The original development plan for the Åsgard field (1996) held a restriction to only do subsea well completion during the summer season. During the

[8] ISO 13624-1, 5.3.2 Recommended guidelines for design

development of this subsea field this restriction was lifted [37] and year round operations has since been regarded as standard practice.

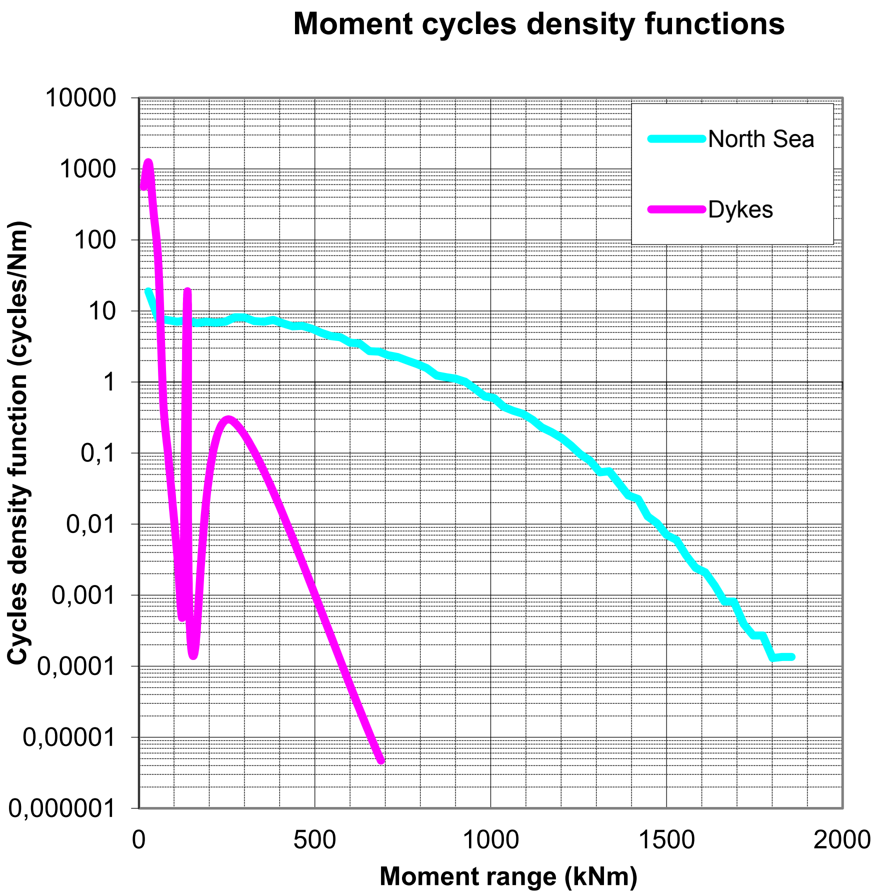


Figure 14 Comparison of moment cycles density functions (Article I)

Article I discusses the increase in dynamic wellhead loading from a typical North Sea case as presented by Dykes et al. [21]. This comparison is presented in Figure 14 and it illustrates the increased occurrence of higher cyclic wellhead bending moments in the North Sea today.

2. Methodology

The following section discusses methodological aspects of this work.

2.1. Objective

Wellhead fatigue is a well integrity problem that is not fully understood. Before design improvements can be successful there is a need to fully understand the problem. Establishment of a unified analysis methodology is the first step en route to successful equipment design guidance or to establish a design fatigue load. The overall goal of this work has been to contribute to a unified analysis methodology from a research point of view. One of the goals of the JIP is to establish a unified analysis methodology

The subsea technology has been growing strongly over the last 2 decades and a high number of subsea wells are currently operational (see Figure 2 at page 8). There will be a need to document the fatigue damage accumulation on operational subsea wells. Industry experience indicates that a simplified and conservative analysis approach may return fatigue damage in excess of safe operation limits. Simplified models should result in conservative analysis results due to model simplifications and its inability to utilize detailed information about the specific problem.

By refining the analysis methodology a potential for a reduced level of conservativism exists. This is possible both from the use of more complex calculation methods and by using more detailed information as input to the calculations. This potential will have monetary value to any operator as the risk of wellhead fatigue failure can then be correctly quantified and included in a risk management system. Research into ways for refinement of the analysis methodology has been an important objective of this work.

2.2. Limitations

The majority of the present work is based on results obtained from analytical models and has been limited to effects on the surface casing (high pressure casing) welded hotspot. Some results can be applied to the other parts of the well (i.e. the conductor hotspots) but quantified results may be different.

One important difference between the surface casing and the conductor casing is that the latter interacts with soil. Another difference is that the surface casing receives external riser loads directly and reacts forces to the conductor, either through mechanical interfaces or through cement. This cement interaction has received detailed attention in this work.

Detailed analysis of wellhead fatigue is not possible in a generic manner due to large impact on the final result from variation to input parameters. The quantified results herein are case specific; numbers will change with details in each case. The use of a case and varying input parameters in the analytical model has been used to be able to illustrate the effect of these model variations. The results are theoretically only validity for the case, but the relative effects that have been obtained should have a wider application. The case descriptions are relevant to North Sea subsea well conditions.

The only fatigue loading discussed here is external loading from a drilling riser connected to the well. Other causes of mechanical fatigue in wells or well components are not included. A drilling riser is the conduit for drilling fluids and a drill string. The presence of a drill string inside the drilling riser is known to increase the riser systems stiffness. Pipe in pipe effect has not been included in any load estimates. Load contributions from Vortex Induced Vibrations (VIV) have not been included.

Any cyclic loading of a well or a part of a well can in theory cause fatigue failure e.g. pressure cycles. The number of pressure cycles and the associated stress range are normally too small to cause concern. Exceptions may be found in Water-Alternating-Gas (WAG) and Geothermal wells where higher number of pressure cycles combined with cyclic thermal effects amplifying the stress ranges may bring the hotspots into a low cycle fatigue area. Such loading is not stochastic and the load estimation may be less challenging. Hotspots would be different than for the problem of subsea wellhead fatigue and these fatigue issues involves onshore wells.

Some examples of drilling and well related technology areas where fatigue is recognised as a failure mode is listed below.

- Coiled tubing
- Drill pipe
- Sucker rods
- Roller cone bits
- High pressure work over risers

2.3. Verification

Comparing analytical results to measurements of the real system is an effective method to verify the analysis, model and methodology. In wellhead fatigue analysis three analytical steps are involved as further explained in section 4.2. Each of these analysis steps has different verification statuses.

Local wellhead modelling is based on detailed and exact geometric data from manufacturer drawings. The software typically involved in the modelling has been thoroughly verified over the years. The modelling aspects that has not been properly verified relates to boundary conditions selected for the wellhead. Example of such model boundary condition is top casing cement lateral support and soil spring representation.

Global load analyses of slender marine structures have been done since the early 1970ies and the complexity in the analysis software has increased with computational progress. The software tools used for load analysis in a wellhead fatigue context are developed to model and analyse slender marine structures in general. The verification of the software has been done through model tests and full scale measurements on various types of slender marine structures involved in offshore engineering. A substantial amount of research effort has resulted in verified software that is available to the industry and the academia.

Figure 15 gives an illustration of the variety of slender marine structures involved in the offshore petroleum industry. Full scale verification on any one of these applications has merit, but does not ensure correct use of boundary conditions and modelling assumptions in the case of well fatigue load analysis.

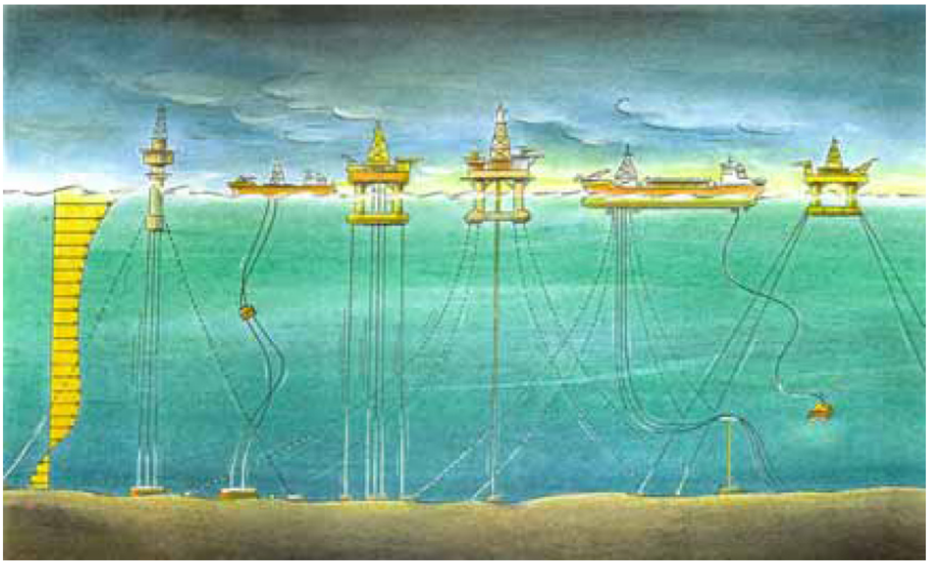


Figure 15 Slender marine structures [38]

King et al. [39] states that several of the analytical methods involved in wellhead fatigue analysis are verified on a sub-component level, but as coupled systems an overall verification is missing. They later released work on verification and analysis correlation against full scale measurements for a subsea well in the North Sea. They concluded that "*Several aspects of the measured behaviour are consistently at variance with the theoretically predicted behaviour, and further investigation is required*" [40].

In Article VII analytical riser loads are substituted by direct measurements with a reduction in the estimated fatigue damage as a result. Results presented in Article VII can be seen both as a validation for conservative analytical results and as a critic of a pure analytical method's ability to correctly estimate fatigue loads. The reduction in fatigue damage results based on measured loads as presented in Article VII has a monetary significance. Improving the analytical ability to predict fatigue damage to subsea wells whilst ensuring conservative (i.e. safe) analysis results will require correlation by measurements.

The SN approach used in variable amplitude fatigue loading is based on assumptions, the Miner-Palmgren rule being one such assumption. According to the Miner-Palmgren rule failure occurs when $\Sigma\ n_i/N_i=1$.[9] As discussed by Schijve [3] this is not always the case as deviations has been seen in experiments. The failure of a fatigue hotspot will be determined by the S_{max} of the last load cycle which is difficult to predict in variable amplitude loading regimes. SN limit curves are based on failure experiments and are associated with a scatter in data. All together the use of relatively large DFF in safety critical evaluations has proven necessary. There are no particular issues with the use of the SN method in wellhead fatigue, the limitations and weaknesses are generic to the method.

2.4. A note on scientific method

The problem of wellhead fatigue analysis is complex and multi disciplinary. Drilling engineering science is traditionally empirically inclined. A fundamental problem in drilling and well research is the inability to observe what happens in a well. The wellheads are the structural termination of the well, but the subsea wellheads still have limitations for directs observations. The costs involved in subsea well constructions are high due to MODU rates.

In the present work most conclusions are drawn on the basis of analytical results. These results are "observations" of analytical model behaviour, and not observations made on a real system. These models are merely representations of the reality and the conclusions are technically correct for the models and the analysis. The models ability

[9] See equation 3.7

to capture the real physical behaviour of the well will determine how representative analytical results are.

In modelling the nature, analytical choices and model simplifications are done for the ease of analysis and understanding. The models ability to capture the physical behaviour of the real system is controlled by the model and the boundary conditions. Considering the models ability to represent the reality can be done by mapping of analytical results with real measurements. Measurements of wellhead fatigue loads have not been available for a full scale system. Measurements on scaled down systems for the purpose of verification of analytical models have not been done, as the total costs are expected to be approximately the same as for adding instrumentation to full size wells.

King et al. [40] discussed this fundamental problem and did a field measurement campaign with the purpose of calibration of the analytical approach in the mid 1990ies. They concluded that calibration was difficult to achieve and forwarded some advice for future instrumentation campaigns. Article VII has shown that the use of measured loads combined with an analytical model of the wellhead predicts significantly less fatigue damage compared to a pure analytical approach. It is likely that future measurements with the intent of calibration of analytical models will enhance the analytical results. Possibly there will be future simplifications to the current state of the art analytical approach as a result.

It could be argued that the findings in Article VII will discard conclusions based on purely analytical results. However, the industry will tend to make analytical choices deemed to yield conservative results. In the quest for true fatigue damage on a wellhead it is important to consider the possible consequences of an error in the analytical results. If results underestimate the damage compared to the reality a serious well integrity situation could occur earlier than the analytical prediction. The opposite situation has merely economic consequences and possible accidents have thus been avoided. This approach can be acceptable in an industry application as long as these conservative results are not impractically limiting. As indicated in Article VI the level of conservativism may be very high, resulting in a failure probability far less that the target[10] of 10^{-4}. There are corresponding results between Article VII and Article VI as both points on the surplus conservative choices done in the current state of the art analytical approach.

From a scientific view this may not be satisfactory, as a scientific aim is to understand and model the nature precisely. Further measurements in order to improve modelling are needed in order to satisfy scientific goals. The industry will not invest into measurement in order to improve the scientific validation of analytical model, but will be inclined to do so from a need to reduce the conservativeness of the analytical results.

As the ability to model the reality is likely to improve from future validation experiments history has taught us that further simplifications can be done by support of measurements. Then we should keep the famous words of Albert Einstein in mind:" *Everything should be made as simple as possible, but not one bit simpler*."

Fatigue failures have happened to subsea wellheads in service and are evidence that the fatigue failure mode is relevant. By designing against fatigue one would not expect high failure rates. In discussion of deep water drilling riser fatigue the following statement reads "*The lack of failures to date in deep water should not therefore be taken as evidence of a lack of problem for the new generation of ultra-deep water wells (water depth > 1000m)*" [12]. This statement will be true for wellhead

[10] A annual failure probability of 10^{-4} is generally accepted by the PSA, Norway.

fatigue as well; the low number of in service failures should not be taken as evidence of a nonexistent fatigue problem.

3. Wellhead Design Specifications

3.1. Subsea wellhead as a well barrier

The Norwegian Petroleum Safety Authority (PSA) [41] acknowledges the NORSOK D-010 standard [42] as a guideline. Here well integrity is defined as "*an application of technical, operational and organizational solution to reduce risk of uncontrolled release of formation fluids throughout the life cycle of the well*" [42]. The expression "life cycle of the well" covers all stages of design and planning, initial drilling, completion, production, intervention and the permanent plugging and abandonment of the well. Any operations during these stages shall be performed in a safe manner. Fatigue is a time dependant degradation mechanism that can cause an increased probability for a wellhead failure with time, or rather with use[11].

There are overall principles advocated by the Norwegian PSA[43]:

- The well barriers shall be designed, manufactured and installed to withstand all loads they may be exposed to and to maintain their function throughout the life cycle of the well.
- The operational limits need to be defined and evaluated during the life cycle of the well.
- The operational limitations should also consider the effect of corrosion, erosion, wear and fatigue

[11] Some fatigue failures of wellheads reported in the literature has happened during initial well construction activities [18, 32].

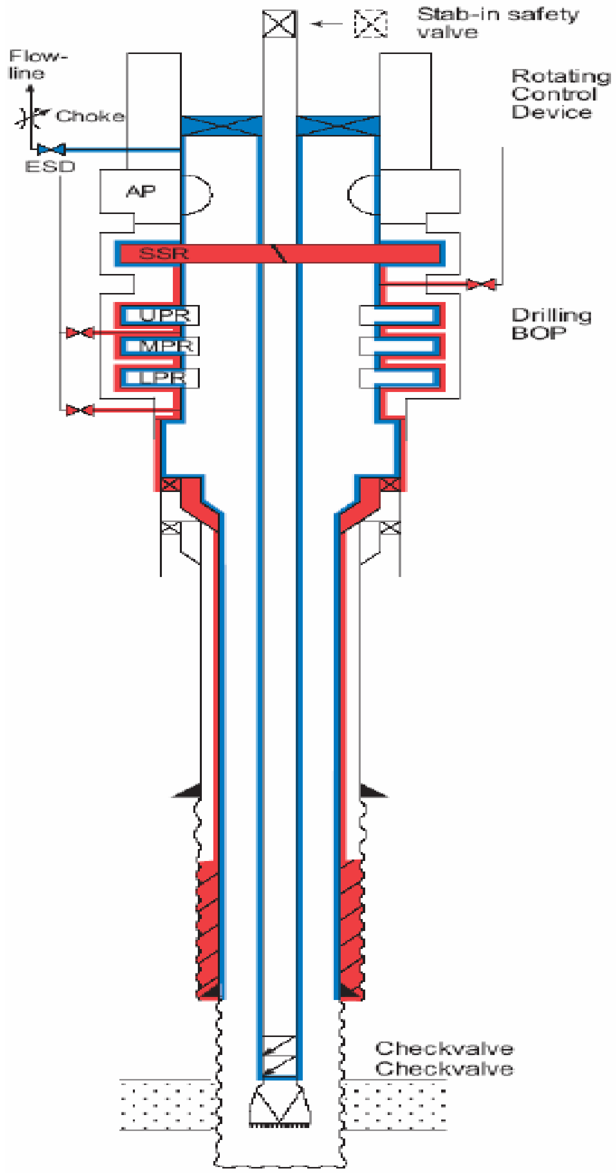


Figure 16 Well barrier schematic for the case of underbalanced drilling or tripping (NORSOK D-010 section 13.8.1)

The need for planning the permanent Plugging and Abandonment (P&A) while the well is being designed is one finding in a recent research survey on well integrity on the Norwegian continental shelf [43]. NORSOK D-010 [42] gives an array of well barrier schematics examples showing the 1st and 2nd well barrier envelope and the well barrier elements. In most cases (part of) the wellhead is classified as an element of the 2nd well barrier envelope. In under balanced operations the wellhead is defined as a shared barrier element, i.e. part of both the 1st and 2nd barrier envelope. This is illustrated in Figure 16. Article V discusses the potential reduction of the well global structural capacity due to a fatigue fracture in selected hotspot locations. It identifies that reduction in the structural bending capacity of a subsea well is dependent on the location of the fatigue failure. The main implication from Article V is that normal operational limitations will be reduced by assuming a possible fatigue fracture in a subsea well.

As a fatigue crack is growing in size it may become a through-wall crack without being structurally critical. A through-wall crack may be detected by a leak if present in the pressure barrier envelope of the well.

Should the fatigue crack become critical in size a structural failure will occur and the overall structural strength of the well will then be reduced as discussed in Article V. In an overbalanced drilling situation the welded transition between wellhead housing and surface casing will not see any pressures and are thus not part of the 2nd barrier envelope. Exceptions are drilling activities without an intermediate casing/ casing hanger installed. The reduction in overall structural capacity still imposes an indirect threat to the barrier envelope. A structural overloading by external loads may cause the well to structurally fail breaking the barrier envelope. As shown in Article V the potential reduction in overall structural capacity is sensitive to the hotspot location. This implies that the well integrity criticality of different hotspots in the wellhead system will vary.

A reduction in ultimate structural load capacity from the presence of a fatigue crack would not necessarily affect the well barrier envelope. Fatigue hotspots will most likely be below the intermediate casing hanger seal assembly. However a reduction in ultimate strength in the load bearing part of the well may indirectly pose a threat to the pressure containing barrier elements. Figure 16 shows the wellhead as a pressure containing barrier element.

3.2. Life cycle of a well

The Norwegian PSA well barrier definitions as cited in section 3.1 includes the" life cycle of the well" expression. As with any well, there are some typical stages in a subsea wells life as illustrated by Figure 17. This is an idealised situation where production follows initial drilling and well construction activities until the well is permanently plugged and abandoned (P&A). The duration of the production phase is dominating the lifespan.

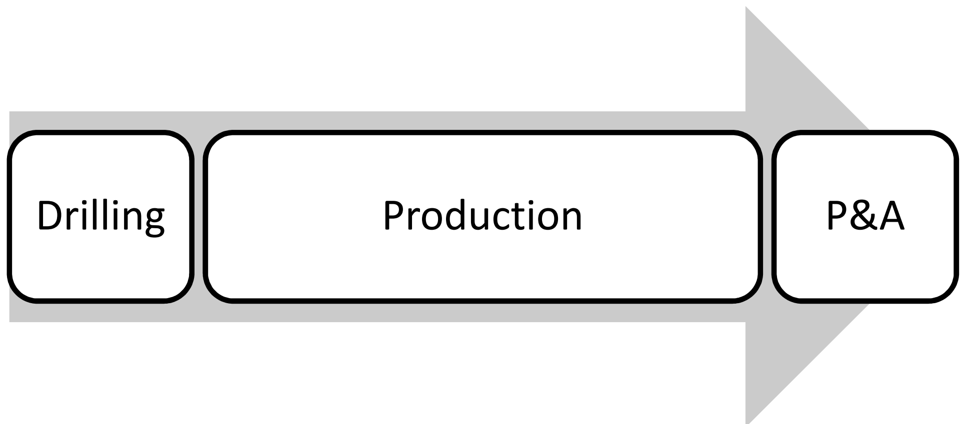


Figure 17 Life phases of a well

Few drilling and well engineers around the world will recognise the idealised lifecycle of a well as presented in Figure 17. A more likely scenario is shown in Figure 18 and involves well interventions and drilling of a sidetrack with a reuse of the wellhead/top casing program. Keeping in mind that fatigue damage affects the wellhead and top casings as a result of connected riser loads, the fatigue hotspots will see increased fatigue damage. There are wellheads in the North Sea that have seen up to a full year of accumulated time with a riser system connected. It was a well of this category that failed in 2005 [33].

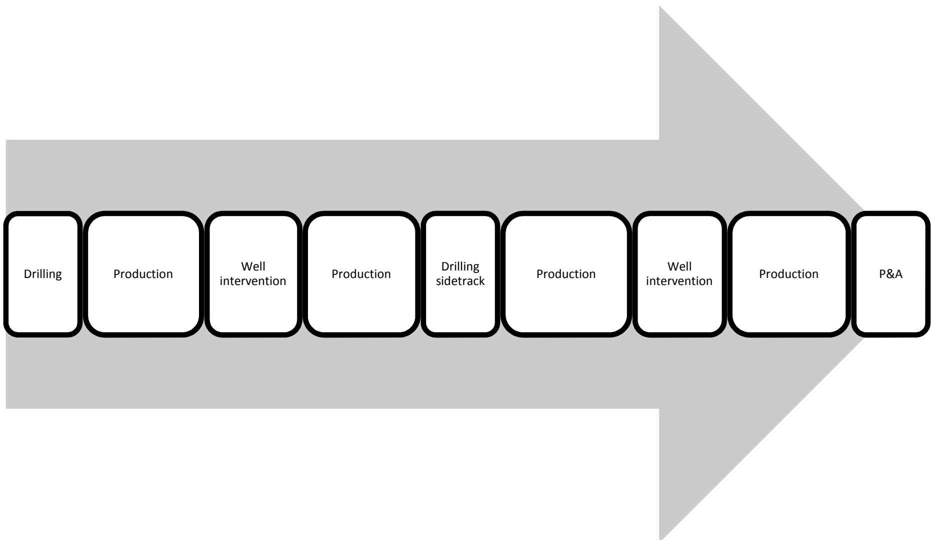


Figure 18 Life of well with re-use of wellhead

The fact that initial drilling and completion has increased in duration has been recognised by several authors. Howell and Bowman [44] argued in 1997 that if the initial drilling of a well in harsh environments were estimated to 2 months of continued riser operations, minimum 4 months of fatigue life should be expected from the wellhead allowing for some well intervention and P&A work. Farrant et al. [45] gave some typical connected riser life cycle durations for different types of wells, ranging from 3 months for exploration wells to 11.2 months for complex exploration wells converted to production. Farrant et al. also identified the trend towards increased connected riser durations, and gave extreme example of exploration wells with up to 2 years of accumulated connected riser duration. They also gave examples of a remote location well fatigue assessment where they used a target fatigue design life of 8.3 years.

The extent of connected riser life cycle time can be difficult to estimate during planning of a well. The planned well production life may be as high as 20-25 years and the need for riser connected well interventions are ideally planned to be avoided. In reality there is a need for drilling riser work on most subsea wells during their producing life. Such interventions can be needed to increase oil recovery or to rectify problems e.g. barrier leaks. Well intervention with a riser and BOP on top of a subsea XT will increase the bending moment seen by the wellhead. The vertical height of the subsea XT will add to the BOP height, increasing the flex joint shear force bending leverage arm. Then the wellhead fatigue damage will accumulate faster compared to work directly onto the wellhead [45].

The subsea well access technology is still developing, and one of the latest trends that have proven successful in the North Sea is the increasing use of riser less well interventions from DP vessel [46]. The wellhead fatigue benefits of such operations are huge since no riser is attached to the well during these operations. The development of a purpose built rig intended for riser based well interventions are underway for the North Sea, expected to be operational in 2014. This concept will be utilising a slim bore high pressure riser and a significantly lower and lighter “BOP”. This concept will be able to handle well returns and through tubing drilling operations [46]. A significant fatigue loading reduction can be expected from such work, compared to performing the same work by a conventional MODU.

3.3. Consequences of a failure

A gross structural failure of a subsea wellhead system may be the result of an accidental loading or accumulated fatigue damage. The consequence of either failure mode may be identical, and will depend on the barrier situation of the well at the time of such an incident. As discussed in section 3.1 parts of the wellhead system are elements in the barrier envelope during drilling operations. A gross structural failure outside of the barrier envelope will involve two aspects.

Firstly the failure location will no longer be able to contain pressures and well fluids may escape. In a fatigue failure situation the loss of pressure integrity may occur prior to that of a structural failure. Then the critical fatigue crack size is larger than that of a leaking through wall crack. This situation can be referred to as “leak before failure”. A “leak before failure” can be used in a deductive manner. Positive leak testing of the well will confirm that no through wall crack (nor any other leak) is present at that point in time. If “leak before failure” condition has been confirmed no leak may be seen as evidence of some margin of failure.

If, on the other hand, the through wall crack is confirmed to be larger than the critical crack size, a “failure before leak” situation exists. A positive leak test result will not give any support for judging the margin of safety to potential fatigue failure. This type of consideration may be relevant during a permanent P&A operation of a subsea well, as the upper part of surface casing string will be accessible for leak testing at the final stages of the operation. In the case of a “failure before leak” condition periodically testing of BOP may introduce failure loads from huge pressure end cap loads. Then the analytically derived fatigue service life estimates should be conservative.

Secondly an indirect threat to the barrier envelope may be present in the case of a fatigue failure at a location outside the barrier envelope. A fatigue failure will happen during the first stress cycle above the structural capacity of the remaining material cross sectional area. This loading can be assumed to be within the normal operating loads of the well. As discussed in Article V a global structural capacity reduction may result from this situation. The ability to identify the presence of this situation will be key to drilling operations on subsea wells with a previous fatigue accumulation close to the limit. Inability to detect the presence of a fully developed fatigue failure may cause the operator assuming full structural capacity of the well. In Article V we conservatively argue that the associated reduction of global structural capacity should be assumed and that operational limitations should be adjusted based on a renewed weak-point analysis. This approach will be the safest and in many cases the only viable option. The main reason is that otherwise the barriers may not be independent, as a fatigue failure may cause the hole well to structurally fail under accidental or extreme loading.

Well casing programs are typically as presented in Figure 5, but modifications to this design exist. Modification involving reduction of the number of casing strings (e.g. combining the surface casing and the intermediate casing into one string) may increase the criticality of the welded hotspot just below the wellhead housing. This will expose the surface casing string to well fluids and pressures for a larger fraction of the well construction process. Likewise it will be more critical in a permanent P&A operation. Well intervention activities involving removal of the production string or sidetrack drilling may do the same. Additionally the reduction in steel weight suspended from the wellhead as a result of this modification, will make the surface casing hotspots more susceptible to fatigue accumulation.

Periodical leak testing of the BOP/wellhead area are part of the Norwegian safety regime. In P&A and work over operations exposing the surface casing hotspots such testing will result in a significant separation force. This separation force may be associated with a critical fatigue crack size less than for normal operations. If fatigue accumulation is estimated close to a fatigue limit this loading need to be checked as a possible failure mode.

3.4. Current design specification

The current subsea wellhead design code is ISO 13628-4 [47] with an identical US national adoption that is code API 17D [48]. The ISO code is part of the 13628 series of subsea relevant standards. ISO has a large portfolio of standards that apply to the oil and gas industry as illustrated by Figure 19.

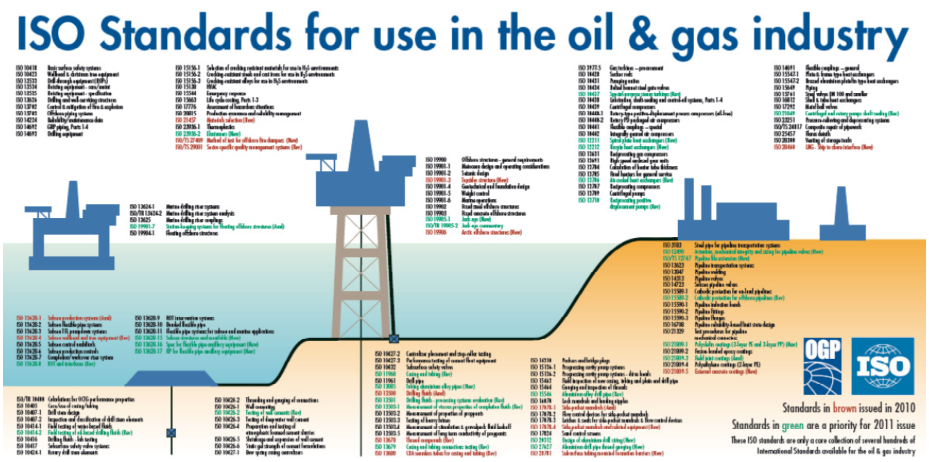


Figure 19 Large portfolio of ISO standards for use in the oil and gas industry [49]

In Table 2 some of the most relevant specifications that apply to the components relevant for wellhead fatigue analysis are listed. It should be noted that the non-subsea wellhead equipment is covered by ISO 10423 [50] which are referenced by the subsea wellhead specification and in a similar way the API 17D refers to the API 6A.

Table 2 Relevant wellhead design specifications

Equipment	ISO	API	Approach
Subsea general	ISO 13628-1	API 17A	
Subsea wellhead	ISO 13628-4	API 17D	Rated Pressure
Dry wellhead	ISO 10423	API 6A	Rated pressure
Drilling Riser	ISO 13624-1/2	API RP 16	Rated pressure
HP riser	ISO 13628-7	API RP 17G	Limit state

Several of the above mentioned standards are based on a rated pressure design approach. It involves designing component capacities to a rated pressure load, derived from a Rated Working Pressures (RWP) of 5, 10 or 15 ksi, (345, 690 or 1035 bars) using the Working Stress Design (WSD) method for checking the design capacity against the rated pressure class of choice. The ISO 13628-4/API 17D design codes have adopted the rated pressure design practice from API 6A (non subsea wellhead equipment).

There is a fundamental difference between the ISO 13628-4 and ISO 13628-7 codes. The ISO 13628-4 are based on a rated pressure design approach and the ISO 13628-7 is based on a limit state design approach [6]. They both use the Working Stress Design (WSD) method. In the following a brief discussion of these methods are included.

3.5. Working Stress Design

The Working Stress Design (WSD) method may also be referred to as permissible stress design or allowable stress design. It is a design approach that ensures that stresses developed in a structure due to design loads do not exceed the elastic limits of the material with some margin, expressed by one central safety factor. This may be expressed as a utilisation ratio U. Notation follows Muff [6].

$$U = \frac{S_d}{R_d} = \frac{Design\ Load\ Effect}{Design\ Capasity(Resistance)} = \frac{S_d}{F_d \times R_{uc}} \leq 1.0 \qquad (3.1)$$

Where

- U is the utilization;
- S_d is the design load effect upper fractiles or maximum values;
- R_d is the design capacity (resistance);
- F_d is the design factor (inverse of safety factor);
- R_{uc} is the characteristic capacity (resistance) lower fractiles or minimum values (mean – 2SD) e.g. structural, preload and leakage capacities.

3.6. Load and Resistance Factor Design

Load and Resistance Factor Design (LRFD) is a design approach that uses partial safety factors applied to each load effect and resistance term respectively to ensure a target safety level. This methodology is capable of separating the influence of uncertainty and variability to characteristic load and resistance values by means of partial safety factors. Thus this method enables designers to adopt a unified safety level regardless of variations in type of load or uncertainty in load effect modelling. Similarly the resistance safety factor may be partial. Note that a safety factor is the reciprocal to a design factor.

The DNV-OS-F201 [51] offshore specification for design of dynamic risers have issued a general LRFD expression 3.2:

$$g\left(S_P;\gamma_F \cdot S_F;\gamma_E \cdot S_E;\gamma_A \cdot S_A;R_k;\gamma_{SC};\gamma_m;\gamma_c;t\right) \leq 1 \tag{3.2}$$

Where g(•) is the generalised load effect. g(•)<1 implies a safe design and g(•)> 1 implies failure. Notation;

- S_P = Pressure loads
- S_F = Load effect from functional loads
- S_E = Load effect from environmental load
- S_A = Load effect from accidental loads
- γ_F = Load effect factor for functional loads
- γ_E = Load effect factor for environmental loads
- γ_A = Load effect factor for accidental loads
- R_k = Generalised resistance
- γ_{SC} = Resistance factor to take into account the safety class (i.e. failure consequence)
- γ_m = Resistance factor to account for material and resistance uncertainties
- γ_c = Resistance factor to account for special conditions
- t = Time

If we consider a slender marine construction like a marine drilling riser, the loads may be a combination of effective tension and bending. The effective tension load effect is governed by the submerged weight of the riser and contents, and is know with a high degree of certainty, and may be precisely translated to a material stress σ_T. Bending will be the load effect caused by hydrodynamic environmental loads, again caused by waves and current. Estimation of the environmental load effects into a materials stress σ_B will be associated with more uncertainty compared to the case of tension. We can then express the design condition as follows:

$$(\sigma_T \cdot \gamma_T) + (\sigma_B \cdot \gamma_B) \leq \frac{R_d}{\gamma_M} \tag{3.3}$$

Where $\gamma_T \neq \gamma_B$ such that the higher uncertainty of bending load effects will only apply to the partial utilisation caused by bending. If a central design factor is to be used (as in the WSD approach) this refinement in design will be lost.

According to Muff [6] a LRFD approach expression applicable for pressure containing primary load bearing components within the scope of ISO 13628-1(API 17A) may be expressed as

$$S_d(\gamma_F \cdot S_k) \leq \frac{R_d}{\gamma_M} \tag{3.4}$$

Where

- S_d is the design load effect upper fractal or maximum values;
- S_k is the design load effect
- γ_F is the load effect design factor for functional, environmental or accidental loads
- R_d is the design capacity (resistance);
- γ_M is the design resistance factor to account for uncertainty in resistance;

The LRFD approach can be found in several fields of engineering today, and has been adopted within civil engineering. In offshore structural design the API RP 2A has been used worldwide, and it is available in 2 versions, the API RP 2A WSD and the API RP 2A LRFD. Within the field of slender marine structural design e.g. flexible risers the LRFD approach is considered superior to the WSD approach [51]. One reason for this is the use of limit state design approach (see section 3.8) where LRDF is beneficial.

3.7. Rated Load Design Method

This is a design approach based on a load associated with the normal or planned use of the structure. If the load considered is pressure, it can be termed Rated Pressure Design method (RPD). In the current version of the wellhead specification[47] it reads *"For the purpose of this part of ISO 13628, pressure ratings shall be interpreted as rated working pressure* [12]." Specifically for wellhead equipment it states "*The standard RWP (Rated Working Pressure) for subsea wellhead shall be 34,5 MPa (5000 psi), 69 MPa (10 000 psi) and 103,5 MPa (15 000 psi)*[13] "In the case of subsea wellhead equipment the design specifications has laid out the appropriate design pressure classes; 5000, 10000 and 15000 psi. Then the pressure vessel components of the wellhead system can be designed to withstand loads (or rather stresses) arising from such pressure loads. By application of the WSD approach a central design factor is applied. This design process has not addressed any failure scenario of the construction.

The benefits of the rated pressure approach are several, and in particular the use of rated pressure classes isolates the process of design and qualification of wellhead equipment components from the scatter of well pressures in service. This has enabled the manufacturers of wellhead equipment to perform and complete their component design, qualification and manufacturing according to a rated pressure as per API 17D and offer their product to the industry. End users need to select products for their specific well application that has a rated pressure equal to or above the Maximum Anticipated Wellhead Pressure (MAWP). No further engineering, design or qualification efforts are needed but ensuring that well specific loads i.e. pressures are within the rated pressure of the selected wellhead product.

Rated pressure design has been an efficient approach, and has served the industry well in terms of easy access to equipment deemed "fit for

[12] ISO 13628-4 section 5.1.2 Service Conditions: sub section 5.1.2.1.1 General
[13] ISO 13628-4 section 5.1.2 Service Conditions: sub section 5.1.2.1.4 Subsea Wellhead Equipment

purpose". A subsea (wet) wellhead will operate under different conditions compared to a surface (dry) wellhead, thus the industry issued a specification particularly addressing the subsea wellhead application. This first edition of API 17D [34] was released in 1992 and the current API version of this specification was released May of 2011 and are still a rated pressure design approach. It does not disregard external loadings, but refers to ISO 13628-7 for operability and system load issues. Further it reads[14]: *"The user is responsible for ensuring subsea equipment meets any additional requirements of governmental regulations for the country in which it is installed. This is outside the scope of this Specification".*

3.8. Limit state design method

The limit state design method is a design approach considering the stresses in the structure at different limit states. A limit state is a condition of the structure beyond which it no longer satisfies the design criteria. Generally limit states can be divided as listed below[15].

- Ultimate Limit States (ULS) corresponding to the ultimate resistance for carrying loads. For operating condition this limit state corresponds to the maximum resistance to applied loads with 10^{-2} annual exceedance probability
- Accidental Limit States (ALS) corresponding to damage to components due to an accidental event or infrequent loads with annual probability of occurrence less than 10^{-2}
- Fatigue Limit States (FLS) related to the possibility of failure due to the effect of cyclic loading
- Serviceability Limit States (SLS) corresponding to the criteria applicable to normal use or durability

[14] ISO 13628-4, Section 1, Scope
[15] Based on DNV OS-F201 Dynamic Risers

In a subsea engineering context load contributions may be several and the object of design may experience loads classified as listed below [51].

- Permanent loads (static loads, mass, buoyancy) invariant in magnitude, direction and position during the period considered
- Environmental loads (hydrodynamic loads e.g. wind, waves, current, inertia forces, wind) expected from normal use that varies in magnitude, direction and position during the period considered
- Accidental loads (dropped objects, loss of position, extreme[16] environmental loads) related to abnormal and unplanned incidents or technical failures. Typical accidental loads will have an annual probability occurrence of 10^{-2} or less.

Our ability to estimate loads precisely will depend of type of loading as listed above. The estimation of permanent loads will be more precise than environmental loads. In a WSD approach the margin of safety towards the uncertainty of the combination of functional and environmental loads still have to be ensured by the use of a central safety factor. In the LRFD approach the estimated permanent loads will be combined with a partial safety factor specified for permanent loads. Similarly the environmental load will be combined with a partial safety factor yielding a design environmental load. In this way our ability to estimate different loads effects will be captured by the design method.

[16] The classification “Extreme loads” are sometimes used, it can be regarded as Accidental loads with a return period less than that of accidents.

3.9. Probabilistic design

As stated the WSD or LRDF methods can both be applied to the different design approaches of rated load design or limit state approach. We have discussed conventional design approaches which assume deterministic values of load and resistance. If we accept that the nature is not deterministic we may include a probabilistic design approach. The LRFD approach is suitable in a probabilistic design approach.

$$\boxed{S_d \leq R_d}$$

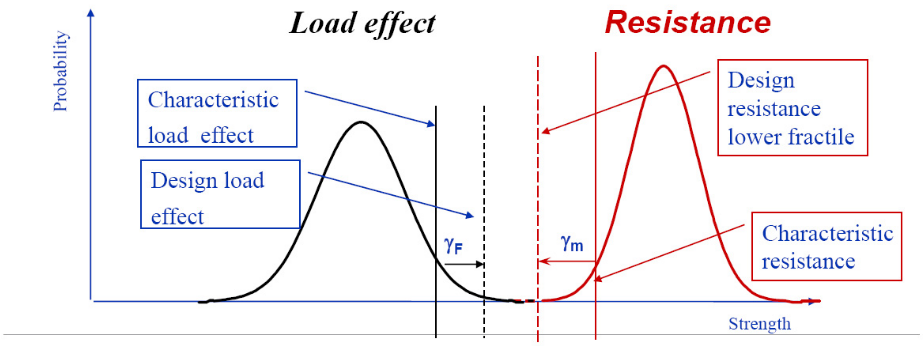


Figure 20 Load effect and resistance as probabilistic entities [52]

In Figure 20 the load and resistance of a given structure is shown as probability density functions. The characteristic value would correspond to the design load or resistance determined by a deterministic design. In a LRFD approach partial safety factors combined with the characteristic value establishes a design load effect or resistance. The strength of a probabilistic approach is that it enables quantification of the probability of failure given the design values. No design has zero probability of failure and deciding an acceptable probability of failure can be done from economic and safety considerations. Other uses of probabilistic analysis (e.g. Structural Reliability Analysis) are in code safety/design factor calibration.

In Article VI a probabilistic structural reliability analysis methodology have been applied to the problem of wellhead fatigue, with the intention to estimate the probability of fatigue failure. Again the benefit of the LRFD methodology clearly stands out. The current design methodology for subsea wellheads are WSD based. There is no evidence of any probabilistic central safety factor calibration for the design code for subsea wellheads. Results presented in Article VI shows indications of highly conservative deterministic fatigue limits.

As discussed the rated load design method uses loads endured from normal use as a design limit. Application of a safety factor ensures margin of safety against failure during normal service. In the case of wellhead the load is a rated pressure load.

A limit state design method uses various loads with associated utilisation factors (the reciprocal to safety factors) defined both by normal operation, extreme and accidental loading. Margin of safety is achieved by claiming a utilisation less than material limits. Such limit state may refer to the structural integrity or other aspects e.g. fitness for use, durability, gas tightness, loss of preload, endurance, erosion, corrosion, unlatch and fatigue.

A failure mode may be the cause of several degrading mechanisms. A PSA technical report addressing aging and life extension methodologies for offshore structures illustrated this by the table shown in Figure 21 [16].

FAILURE MODE		DEGRADATION MECHANISM													
No	**DESCRIPTION**	**A- Blockage**	**B- Corrosion**	**C- Creep**	**D- Metal loss**	**E- Fatigue**	**F- Hyd.rel.cracking**	**G- M.deterioration**	**H- Overload**	**I- Phys.damage**	**J- Temp.embrittlem**	**K- Wear**	**L- Temp.expans.**	**M- Q.press.change**	**N- Accumulated plastic deformation**
1	Cracking and fracture	X	X	X	X	X	X	X	X	X	X	X	X	X	X
2	Physical deformation	X		X					X	X			X		X
3	Burst	X	X	X	X	X	X	X	X	X	X	X	X	X	X
4	Collapse		X	X	X	X		X	X	X			X	X	X
5	Leakage		X		X	X	X		X	X		X			
6	Wall-thinning		X	X	X			X				X			
7	Delamination		X					X						X	
8	Malfunction	X	X		X							X	X		

Figure 21 Failure modes and degrading mechanisms relevant for ageing offshore structures[16]

Failure mode 1-7 will be relevant to passive components, but failure mode 8 is a general failure mode referring to loss of functionality on active components e.g. valves and actuators.

Operational parameters and conditions influence the degrading mechanisms and an overview of these conditions are necessary in order to assess the state of a component in the event of life extension. During design of new components, a similar consideration should be done to ensure the components ability to resist degrading mechanisms and failure.

Currently the design codes for subsea wellheads use the WSD method to satisfy a rated load design method. The ISO 13628-7 code addressing work over risers and associated equipment utilizes the WSD approach to satisfy a limit state design method. Cross referencing[17] between these standards is somewhat meaningless as these two approaches have fundamentally different design targets (Normal loads vs. ULS).

The WSD method utilises a central safety factor in ensuring a margin of safety. The LRFD method includes partial safety factors applied both to load and resistance parameters. The benefit of the LRFD over WSD method is that it enables use of diversified safety factors. The WSD methodology has some shortcomings as outlined by Lewis et.al. [53]. The most important drawbacks listed by Lewis et. al. are:

- It is overly conservative
- It does not give the engineer any insight into the degree of risk or safety
- It has no risk based risk balancing capabilities
- It treats every well the same way
- There is little justification in the safety factors
- The design equations lack basic engineering mechanics
- Many times the design guidelines cannot be followed for critical wells.

Structural design can be done in a deterministic manner or in a probabilistic manner. Both the WSD and LRFD can be used in a probabilistic design, but the LRFD method is by default more suitable.

3.10. Fatigue Limit State

As discussed in section 3.8, Fatigue Limit State (FLS) can be a limit state condition included in a design evaluation. If cyclic stresses in a structure caused by dynamic service loads exceed the fatigue limits of

[17] Currently the ISO 13628-4 refers to ISO 13628-7 on ULS and FLS guidance (see section 5.1.1.5/5.1.3.1/5.1.3.6)

the material, a structural failure may be the result. By application of a central safety factor , the Design fatigue factor D_F the FLS may be expressed as [6]:

$$\frac{Calculated\ fatigue\ Life}{Design\ fatigue\ factor} \geq Fatigue\ service\ life \qquad (3.5)$$

$$\frac{L_F}{D_F} \geq L_S \qquad (3.6)$$

Establishing the calculated fatigue life L_F in a SN context is done by categorisation and subsequent selection of the appropriate design SN curve. Such SN curves are results of fatigue testing until failure at different stress levels, and are thus empirically derived [3]. Principally SN curves[18] are linear relationship in a double logarithmic diagram. The linear section of the regression line may be expressed by the Basquin equation (1.7). Alternate methods for establishing the fatigue limit may be fracture mechanics using Paris law or by testing.

Establishing the fatigue service life F_S is less straight forward in the subsea wellhead case. Ideally the SN method assumes constant amplitude stress variations as a basis for each test results. To counter these limitations by the SN test results, Pålmgren in 1924 postulated a linear cumulative damage hypothesis. In 1945 Miner introduced a derivation to Pålmgren rule as he assumed that the applied work W that could be consumed until failure was constant. The higher stress ranges the lower number of cycles until failure, and vice versa. Applied to variable amplitude loading fatigue problem by the use of Pålmgrens

[18] An example of SN curves from DnV RP-C203 has been show in Figure 54 in section 6.1

linear damage hypothesis, Miners work resulted in the following failure criteria, often called the Miner- Palmgren[19] Rule [3]:

$$\sum \frac{n_i}{N_i} = 1 \qquad (3.7)$$

Where N_i is the limit number of cycles (fatigue life) and n_i is the actual/experienced number of stress cycles.

In order to evaluate a fatigue damage of a structure under influence of variable amplitude loading a load histogram or a load spectrum is necessary. Different load cycle counting algorithms exists, but the one most frequently used is the Rainflow counting method that was suggested by Matsuishi and Endo in 1968. The work presented has been using this load range cycle counting method. Once a load histogram has been established it allows the application of the Miner-Palmgren rule in order to accumulate the total fatigue damage L_S.

The design fatigue factor D_F is typically found from a design specification. As discussed there are no such recommendations given in the specific design codes for subsea wellheads, but a D_F of 10 has been suggested in Article I and by the draft JIP RP-3 report[1]. The selection of a D_F value is supported by guidance in NORSOK N-004 [4] table 8.1 shown in Figure 22.

Probabilistic design approaches are typically used for establishment of design/safety factors in design specifications, as is the case for NORSOK N-004. In Article VI we have employed Structural Reliability Analysis methodology to the problem of a wellhead fatigue problem. Then failure probabilities can be mapped with an associated D_F.

[19] The Pålmgren name is normally written Palmgren for ease, as it is internationally recognised in connection with variable amplitude fatigue damage accumulation

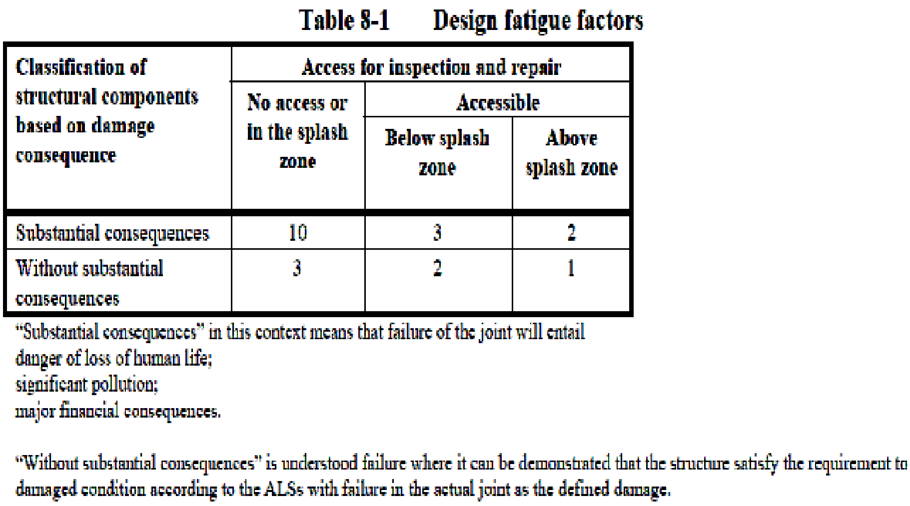


Table 8-1 Design fatigue factors

Classification of structural components based on damage consequence	Access for inspection and repair		
	No access or in the splash zone	Accessible	
		Below splash zone	Above splash zone
Substantial consequences	10	3	2
Without substantial consequences	3	2	1

"Substantial consequences" in this context means that failure of the joint will entail
danger of loss of human life;
significant pollution;
major financial consequences.

"Without substantial consequences" is understood failure where it can be demonstrated that the structure satisfy the requirement to damaged condition according to the ALSs with failure in the actual joint as the defined damage.

Figure 22 Design fatigue factors as suggested by NORSOK N-004[4]

As noted in Article VI the design fatigue factor D_F is the reciprocal of the utilisation factorF_{DF}.

$$D_F = \frac{1}{F_{DF}} \tag{3.8}$$

Having applied the SRA methodology to a wellhead fatigue problem we were able to generate the notational probability of failure-DFF-relationship by means of 2 approximate calculations as shown in Figure 23. The results were supported by 2 cases of Monte Carlo simulations. The implications of these results are that given a target probability of failure of 10^{-4} we could derive a D_F of 3-5 to be used in deterministic fatigue limit state evaluations. The effect on the limit state criteria will be significant, as the acceptable fatigue limit characteristic value (see Figure 20) would be 2-3 times higher[20] than as per NORSOK N-004

[20] $\frac{DFF(NORSOK)}{DFF(\text{Article VI})} = \frac{10}{3} \approx 3, \frac{DFF(NORSOK)}{DFF(\text{Article VI})} = \frac{10}{5} \approx 2$

recommendations(see Figure 22). In other words it may seem like the current deterministic analytical results are overly conservative as a D_F of 10 is used.

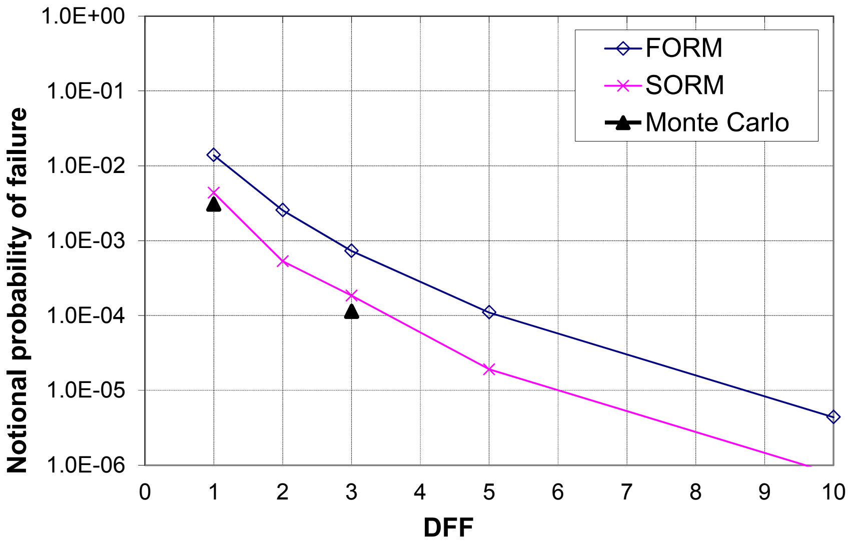


Figure 23 Notional probability of failure using the FORM, SORM and Monte Carlo methods (Article VI).

3.11. Will wellhead design approach change

Several works reviewed has been published during the decade during which the subsea technology advanced. In 1989 BP issued the results from a subsea wellhead standardisation program and the 18 ¾" wellhead-BOP interface we know today was chosen [21]. In Figure 2 the historic development of the worlds accumulated population of operational subsea wells has been shown based on information received from Infield Systems Ltd [8].

As the subsea technology was in an early development phase sceptics would raise concerns with the approach, and combined with some actual in service failures the natural reaction from the industry was to identify and deal with the problem of wellhead fatigue. Both representatives for equipment suppliers and users (operators) were engaged in work presented. Some focused on specific aspects of the problem (e.g. advocating controlled cement short fall [26]) others on more general subsea wellhead aspects while recognising wellhead fatigue as important (e.g. the listing of fatigue loading as one design load case [21]). It may appear that the industry has been convinced that the wellhead fatigue was "taken care of" after a decade of attention and discussions. Several patent applications were supplied at the end of these discussions, as the subsea technology gained momentum. During the 1990ies a consolidation happened on the supplier side and today a few international suppliers are sharing this worldwide market.

After the presentation of a conductor weld fatigue failure in 2006 [33] the attention amongst operators has been increasing. Apart from establishment of the JIP "structural well integrity" articles discussing the issue of wellhead fatigue have again started to come out. In 2012 at least 9 wellhead fatigue relevant articles are expected to emerge.

Additionally we see the contours of fatigue analysis requirements emerging, one example being the balloting version of the all new API RP 96 [54] includes requirements for performing fatigue assessment of the subsea wellhead. However it does not state how such assessment should be done.

Most operators when developing a subsea field utilizes Engineering, Procurement and Commissioning (EPC) type contracts leaving the supplier with a "system responsibility" for the Subsea Production System, including wellheads. The wellhead is a component within such a "system responsibility" that has several interfaces to the operators "responsibilities". The wellhead needs to interface the well casing programs, pressures, temperatures and fluids. Additionally external loading during drilling are imposed by the MODU, typically on contract with the operator.

The fact that wellhead systems are engineered in accordance with international codes with a rated pressure design approach any static or dynamic external load interfaces are not part of the design premises [55].

In 1989 Dykes et al. [21]published an article on the development of a unified subsea wellhead designs under which they considered wellhead fatigue due to external riser loads as an important design load to the subsea wellhead. They were aware of previous field failures and published the load histogram they used as a design load. Indirectly Dykes et al. argued that the subsea wellhead needs to be designed for the intended use and associated loads. They employed a fatigue limit state approach as fatigue loads was identified as a type of load that impacted the design of wellheads. In 2007 a paper by Farrant et al. [45] showed how this operator still were considering the fatigue of wellheads on a regular basis.

At this time subsea wellheads and MODU BOP size and pressure ratings were not standard, and their effort was strongly motivated by the need to increase the well –MODU flexibility by standardization of the wellhead interface. A specific subsea wellhead standard was not present and BP conducted a project to unify their wellhead designs. From this work the 18 ¾” OD and Vetco H4 mechanical profiles were selected. As it turned out this has evolved into an international standard today. In 1993 the first version of API 17D were released embedding the BP choice of wellhead. This standard was in principle a rated pressure design code, and relied on the code for “dry” wellheads, API 6A.

A rated pressure design approach basically views the wellhead as a pressure vessel and states pressure (and temperature) levels that the designer could rate his equipment to. Implicitly this approach assumes that loads are pressure loads or that other loads are pressure equivalent, and can be related to the rated pressure capacity. Dykes et al. [21] regarded fatigue loading from bending was a design load case. There is no such design load case considerations in the subsea wellhead design codes of today [55].

It is meaningful in light of the Norwegian PSA mandatory requirements to well barriers to argue that the design and qualification of any well barrier element should be done against realistic loads [43]. This is in other words an argument for employing a limit state design approach on wellhead systems. This is also advocated by McKie et al.[55] in their discussion of the limits of established pressure vessel design method as they state:"*A working knowledge of Fracture Mechanics encourages engineers to think about what might cause a Pressure Vessel to fail, not just does it meet a code*"

Shortly after the devastating Macondo blow-out in GOM in 2010, The Interior Department issued a moratorium on "deep water drilling" in the US. As a justification of this intervention a governmental spokes person was quoted saying *"I am basing my decision on evidence that grows every day of the industry's inability in the deepwater to contain a catastrophic blowout, respond to an oil spill, and to operate safely."*[56].

The moratorium was countered by legal actions by the industry and after 2 court rulings the administration changed the moratorium to no longer be based on water depth, but rather on drilling configuration and technology. The moratorium was lifted before 6 months had passed, but new requirements were in place.

Early 2011 the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling submitted their report to the president [14]. The report discusses systemic root causes to why the Macondo accident could happen. The commission puts emphasis on the difference between the US “prescriptive” safety regulatory regime and the Norwegian/UK/Canada risk based regulatory regime. They discuss how API had acted both as an advocate for the industry lobbying their interests and at the same time acting as the issuing body of prescriptive safety standards and guidelines. The commission showed how API had resisted a translation in the regulatory regime as had happened in Norway/UK/Canada. This API critic made one reporter state that API had been “*compromised*”[57].

The JIP gap analysis report [5] identifies that the various component and sub-systems specifications do not address system design load and failure modes. Different component design approaches are also employed in different codes. As a consequence it states that a unified target safety level cannot be achieved by the current standards and codes [5] . This is implicitly in line with a report presented by Muff [6]. Muff showed how the individual design specifications consider components, and no system design loads are addressed. Muff also addresses the incapability presented by rated pressure component design in a system limit state design evaluation.

Wellhead equipment is designed and manufactured for a worldwide marked by a few US controlled supplier companies. GOM prescriptive safety regulatory regime has allowed subsea wellhead technology that may not have been accepted under a risk based regulatory scheme.

The API/ISO specification writing process has strong influence from equipment manufacturers and suppliers, and is a consensus based process. History has shown that the specification writing process can take 5-10 years to conclude. As criticised by the Macondo commission the API safety standards has increasingly failed to reflect " *best industry practice*" and have instead expressed the" *lowest common denominator*" [14]. This would imply that consensus based process end up including specifications that every industry partner can achieve.

The petroleum industry has seen an international shift from operators being the system engineering responsible to a large degree of outsourcing the system engineering responsibility by use of EPC contracts. The operator in-house engineering and R&D capacities has reduced, and grown amongst key system responsibility suppliers. The fundamental interest among system suppliers towards unified analysis methodologies set by specifications is low. Also these system suppliers are not in control of system design loads and failure modes as now are being targeted by the JIP[21]. The rated pressure design approach has been the path of least resistance to the system suppliers, and operators have accepted this situation.

The industry has shown ability to respond and change its ways as a response to accidents in the history. The fatigue failure reported by Hopper seemed to have caused a debate and subsequent standardisation of subsea wellhead concept designs. Then 15 "quiet" years passes and now the industry of subsea wellheads is faced with a growing concern with operators over the unknown fatigue limit state of their subsea wells. It is likely that this situation will change in the future; the question is how and in what directions this change will occur.

Wellheads intended for subsea applications should comply with the current design codes which are ISO 13628-1 (general requirements) and ISO 13628-4 (equivalent to API 17D). Section 5 of ISO 13628 calls for internal and external static loads to be evaluated. These are pressure loads and riser loads such as tension and bending.

[21] The JIP "structural well integrity" is formed by operators only

In essence this design code is based on a pressure vessel design approach, focusing on temperature and pressure rating of wellhead equipment. The current design standard does not provide any guidance on cyclic loading, but suggests using ASME Boiler and Pressure vessel code (BPVC), Section VIII, Division 2, appendix 5 or that "other recognised standard may be used when calculating fatigue".

In ISO 13628-4, section 5.1.3 Design Method, it reads: "*The effects of external loads (i.e. bending moments, tension etc.) on the assembly or components are not explicitly addresses in this part of ISO 13628 or ISO10432. As equipment covered by this part of ISO 13628 are exposed to external loads, ISO 13628-7 may be used to define the structural strength design.*"

The standard ISO 13628-7 undertakes a fundamentally different design approach than ISO 13628-4 by employing limit state design principle.

The Norwegian Petroleum Safety Authorities (PSA) has focused on life extension activities, particularly related to offshore structures. In late 2008 PSA received a report from SINTEF where multiple offshore systems had been considered fit for life extension considerations. One technical area that was highlighted as least fit for life extension was wells. The findings where related to lack of knowledge on the following main areas relevant to life extension:

- Knowledge of degradation mechanisms,(e.g. wear; fatigue of subsea wellhead)
- Methods for down hole inspection and monitoring of material behaviour
- Knowledge of loads during drilling, production and workover
- Modelling of erosion caused by sand particles

None of the above considerations are covered in the relevant design codes for subsea wellheads of today. This raises the concern that subsea wells currently in production and wells being constructed now will not have the necessary design premises for life extension methodologies that can be accepted by PSA.

In 2011 the national standard NORSOK U-009 was issued regarding life extension of subsea production systems. It covers subsea XT, but not the well construction (which includes the wellhead housing). However in appendix B, section B 7.5 condition based reassessment considerations of fatigue loads are listed as a requirement when doing life extension exercises. There the fatigue of wellhead and wellhead connectors are specifically mentioned. The statement reads:*" Fatigue of XT is relevant for the wellhead connector interface and for interface with the BOP/LRP connector. This is a fact experienced after well operations of long duration when there is alternating bending moment transferred from the riser. Some wellheads have cracked and wellhead connectors have revealed failures. It has not been the tradition to design against fatigue. Therefore this issue must be assessed for life extension."* Thus a life extension requirement for performing fatigue assessments of the wellhead and XT connector is now in effect in Norway.

As discussed in detail in this section there are no industry specifications for designing subsea wellheads against a fatigue failure. Applying a fatigue failure mode check in design of subsea wellheads would imply a move from a rated pressure design to a limit state design methodology. I believe that the business benefits to the industry from the rated pressure design have helped conserving this methodology until now. There are potential business drawbacks, at least in a short perspective, with the limit state approach. Obviously most product designs at the market would need a costly and resource drawing exercise to document its ULS, FLS and SLS capacities to the buyers. Secondly the presentation of such data could potentially reveal “less favourable” designs, clearly bad for business for the supplier of such designs. Comparison between products on other indicators than pressure rating could impact business and market share statuses of today. The outcome of a transition from rated pressure design to limit state design of subsea wellheads are unknown and thus represents a risk to all suppliers of such equipment. In the short term they are all best of not changing today’s approach. But there is mounting pressure for a change in the design approach, and it points in the direction of a limit state approach.

The question then remains; do the current design specifications satisfy current regulatory expectations?

3.12. Do current standards meet regulatory expectations

In The Norwegian Petroleum Safety Authority (PSA) Regulations relating to design and outfitting of facilities, etc in the petroleum activities (the facility regulations)[58][22] it reads: “*Well barriers shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime*.”

The PSA recognises the NORSOK D010[23] as a guideline and it states the following: *“Static and dynamic load cases scenarios for critical equipment installed or used in the well shall be established. Load calculations shall be performed and compared with minimum acceptance criteria/design factors. Calculations performed and selection performance ratings for material and equipment can be based*

[22] §48 Well barriers
[23] Section 4.3.3 Load Case Scenarios

on deterministic or probabilistic models. All calculations shall be verified and documented".

There is reference to "safeguarding of barriers" during the "wells lifetime". D010 specifies static and dynamic load cases, and calls for such load cases to be established. Possible interpretation of these requirements is the use of a limit state approach and that time dependant failure modes are required to be addressed. Thus fatigue as a possible failure mode will then be a requirement under the Norwegian regulations. We should remind ourselves that the current design regime of subsea wellhead is a rated pressure approach. There is no requirement for any fatigue assessments under the current design codes applicable for subsea wellhead equipment. This has been stated by McKie et al. [55].

In the lasts revision of the design code for subsea wellheads released after the Macondo accident a new statement has emerged. It reads: "*The user is responsible for ensuring subsea equipment meets any additional requirements of governmental regulations for the country in which it is installed. This is outside the scope of this part of ISO 13628*" [47][24].

Thus the answer to the question whether the international design code for subsea wellhead equipment meets regulatory expectations in Norway is no. There is a need for placing additional requirements if an operator is purchasing subsea wellhead equipment for use in Norwegian waters.

Currently such additional requirements must be of a company specific type, but the future might bring more unified additional requirements that can help satisfying the expectations of a risk based governmental

[24] Section 1-Scope

regulatory regime, such as in Norway. Such work towards recommended practice documents is underway with the ongoing JIP.

3.13. JIP “Structural Well Integrity”

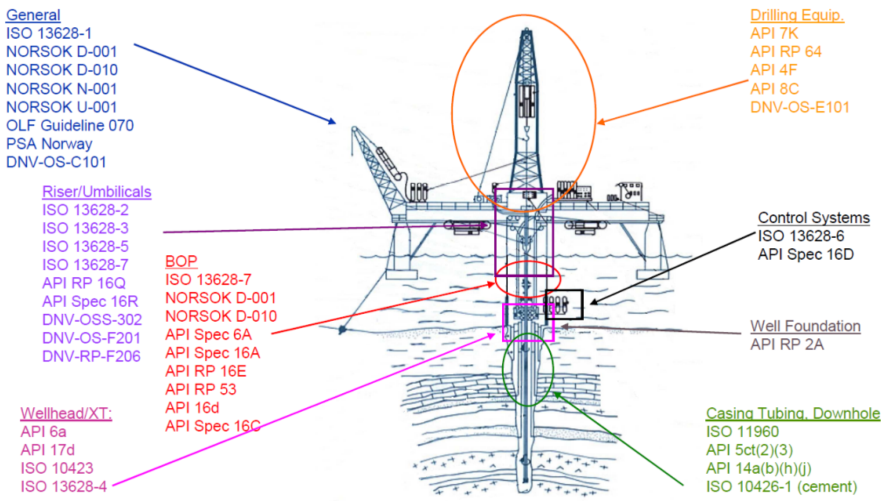


Figure 24 Drilling system relevant standards and codes [1]

In 2010 the international Joint Industry Project (JIP) named “Structural Well Integrity” was launched and is now supported by 14 operators. DnV holds the secretary role and one activity of this JIP is to establish a Recommended Practice (RP) document “Wellhead fatigue method statement” outlining a unified analysis methodology on wellhead fatigue estimation. The JIP has investigated the safety level on all the international standards applicable to the vertical drilling system, as illustrated in Figure 24. One finding from this work is” *There is no uniform definition of dynamic drilling loads, normal, extreme, accidental or fatigue loads*” across the various scopes of these standards. This has led to the conclusion that “*As a consequence, the knowledge of the margin to failure on the drilling and well system cannot be uniformly described for existing operations*”[5].

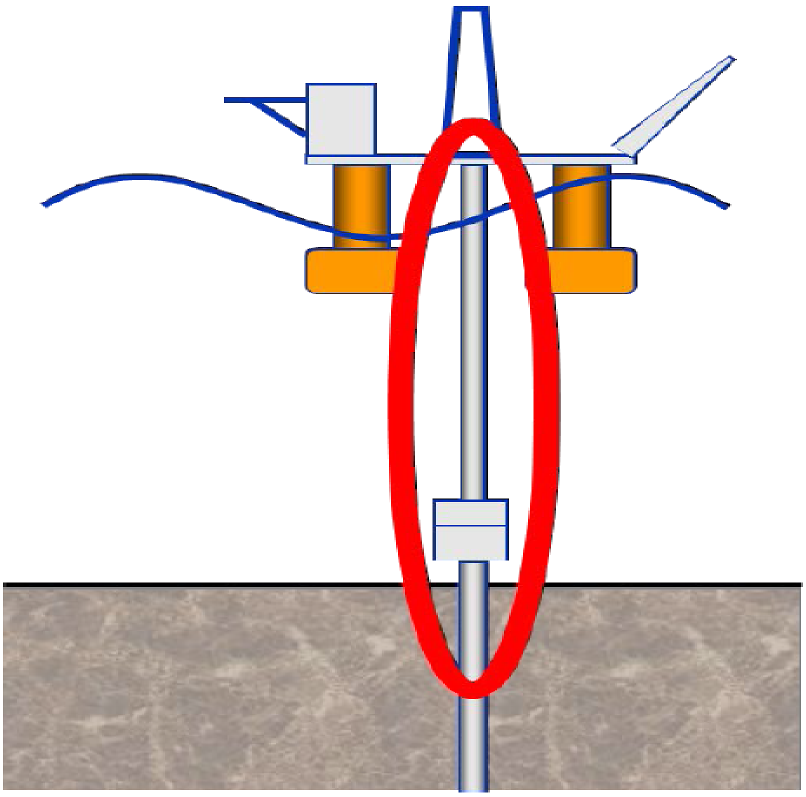


Figure 25 System scope for the JIP “Structural Well Integrity” [59]

As a response to the current situation on lack of a unified analysis approach for the upper part of a subsea well, an international JIP “Structural Well Integrity” was established and are now supported by 14 international operators [60]. The fatigue limit state was the first issue that the participants agreed to address, and by default a limit state approach towards ensuring safe design implies checking all relevant failure modes. Thus the scope of the work under the JIP covers ULS, ALS and FLS limit states. This is planned as a series of Recommended Practice (RP) documents that can be an amendment to the existing component specifications. These documents are intended to ensure a system design approach and thus ensure a unified safety level throughout the entire well/drilling system. The system approach scope for the JIP has been graphically shown inside the red circle in Figure 25.

Table 3 JIP suggested RP documents list

No	Title	Status (2012)
RP-1	Structural Integrity Philosophy of Drilling and Well Systems	In drafting
RP-2	Capacity Design of Drilling and Well Systems	In drafting
RP-3	Fatigue Design and Analysis of Drilling and Well Systems	Draft issued for comments
RP-4	Integrity and Information Management of Drilling and Well Systems	In drafting

As discussed in the introduction, the topic of wellhead fatigue caused by external loads from drilling risers seems to have caused some public debate after Hopper launched his article on a wellhead fatigue failure in 1983 [10]. At this time subsea technology was an emerging technology and this failure introduced some design improvements improving the load sharing between conductor and surface casing.

For the purpose of comparison unified analysis methodology is the key, ensuring that variations in results are not due to analytical model variations, but rather to the case input parameters. This is fundamental in increasing the understanding of the problem. In this way the designers of wellheads may be able to design more fatigue resistant wellheads in the future. Likewise the operators will become better equipped to ensure loading and boundary conditions that promotes fatigue resistant well designs. Fatigue beneficial operational aspects can also be judged better this way.

Muff [6] showed that there is no system loads included in component design specifications for wellhead equipment. McKie et al. [55] made the following statement regarding the use of fatigue system design loads;"*Without knowing the frequency and magnitude of loading we have no way of determining the life of our products in years*".

The operators of each subsea well are in control of these system design loads, not the component supplier (designer). With the ongoing JIP operators are working towards recommended practises documents that will address these system design load issues.

4. Subsea Wellhead Analysis

4.1. Intent of analysis

The intent of the fatigue analysis may impact analytical preferences when making decisions affecting methodology and assumptions while applying a conservative approach. Figure 26 gives a graphical illustration of how different analysis intent may not completely cover the same area of interest.

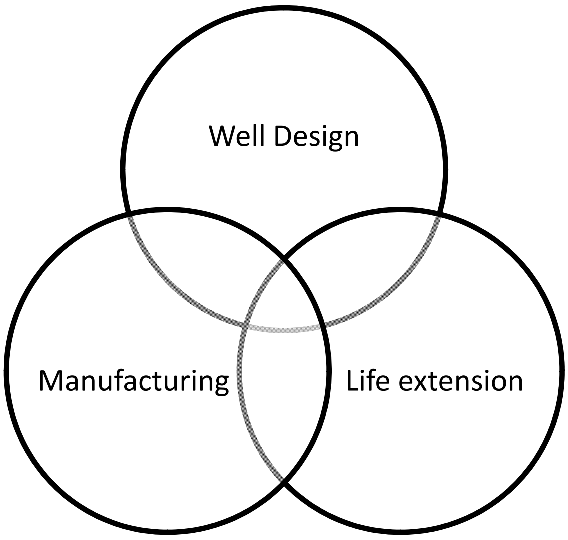


Figure 26 Modelling purpose affecting the analysis approach

As an example of this we can address the difference in intentions behind a well design motivated fatigue analysis of a subsea wellhead and an analysis that are called out for the purpose of life extension exercises on an existing subsea well. In the case of a design exercise there will be design impact options but not in the life extension case. The main purpose of a well design analysis becomes one of selecting the well design with sufficient or optimum fatigue service life. If a simple and conservative analysis approach is chosen results can be reached in a rapid manner. Several design options may be present that all needs analysis and important input parameters may not have been selected yet. Sensitivity analysis may be needed and the scatter of results will be input in a well design process in due time before operations. Thus the design can be impacted by the analysis findings. Such design analysis processes are iterative and comparison between different design options is needed.

In the analysis case where an existing well construction in service needs documentation for the purpose of life extension, the main objective of the analysis work is to document whether acceptable service life is present. The object of modelling is a specific well which has already been constructed, and fatigue loading from historic and planned operations need to be included in the load analysis. The option of changing the well design is not present. A simple and thus conservative approach will return a lower estimate of remaining service life than a more sophisticated analysis approach.

As a wellhead equipment design has been established manufacturing can commence. The analytical model then can provide useful guidance on manufacturing tolerances and manufacturing QA acceptance criteria. From such QA processes discrepancies will be identified and further engineering may be needed on specific individual wellheads to consider if that individual wellhead still satisfies the design requirements. The analytical model will then be a useful tool for the manufacturing engineering consideration.

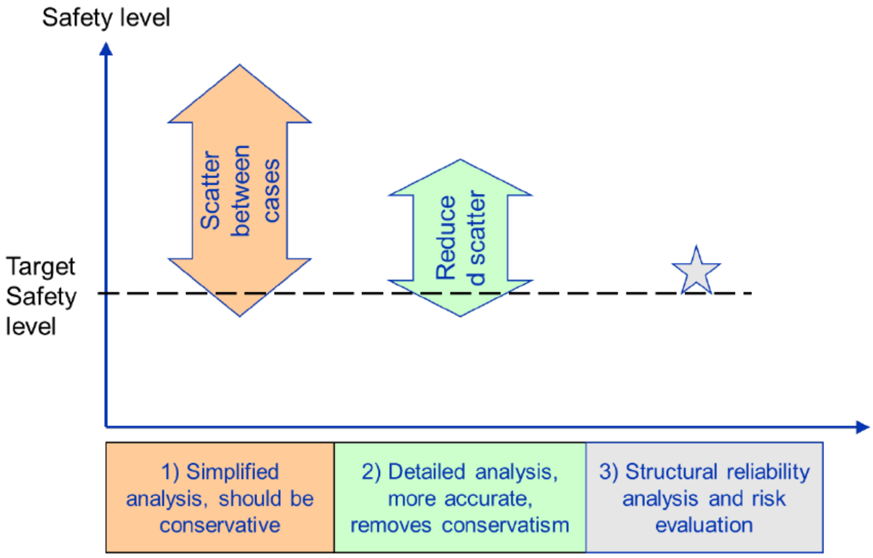


Figure 27 Analysis method impact safety level [1]

The wellhead local modelling approach suggested in Article I has been derived from analysis intent of life extension. A comparison of different analysis simplifications levels has been shown in Figure 27 and places the work in Article I in category 2. This will be the basis for understanding the simplifications that has been introduced. Such a model will not be fit for detailed component analysis as in the case of manufacturing. Article VI employs a probabilistic analysis approach and could be classifies as group 3 according to Figure 27.

4.2. Overall analysis methodology

There is no support in any international standard or code on how analysis of wellhead fatigue damage should be done. The ongoing JIP “Structural well Integrity” is planning to issue a DnV Recommended Practice on wellhead fatigue analysis methodology. The intention behind this JIP is that the RP documents will be a guideline on how wellhead fatigue analysis should be performed.

The JIP methodology will honour the main structure as outlined in Article I. In this section the main contents of the Article I methodology will be outlined. Further details can be seen in Article I or in the JIP report[25] currently out for industry review [1].

It can be seen from the analysis flowchart outlined in Figure 28 that a total of 3 analysis steps are included in the methodology as presented in Article I. These analysis steps are;

1. Local response analysis
2. Global load analysis
3. Fatigue damage assessment

There is an implicit requirement that the analysis steps are performed in the order as listed. The first analysis is the local analysis of the upper part of the well including the wellhead. The methodology asks for a rather detailed model, and the static solution is done with an stepwise increasing unit load. The global finite flexibility of the well subject to local response analysis is then used to define the lower boundary condition of the global load analysis. Additionally the local response analysis will provide the analyst results for selecting critical hotspots and associated Stress Concentration Factors (SCF). The purpose of the global load analysis is to establish a load history on the wellhead system, which essentially is the lower boundary condition in the global load riser model. This load history will then be combined with the results from the local response finite element analysis in a fatigue assessment.

[25] Industry response has called for a tiered analysis methodology, where a more conservative and simplified analysis can be performed as a first iteration.

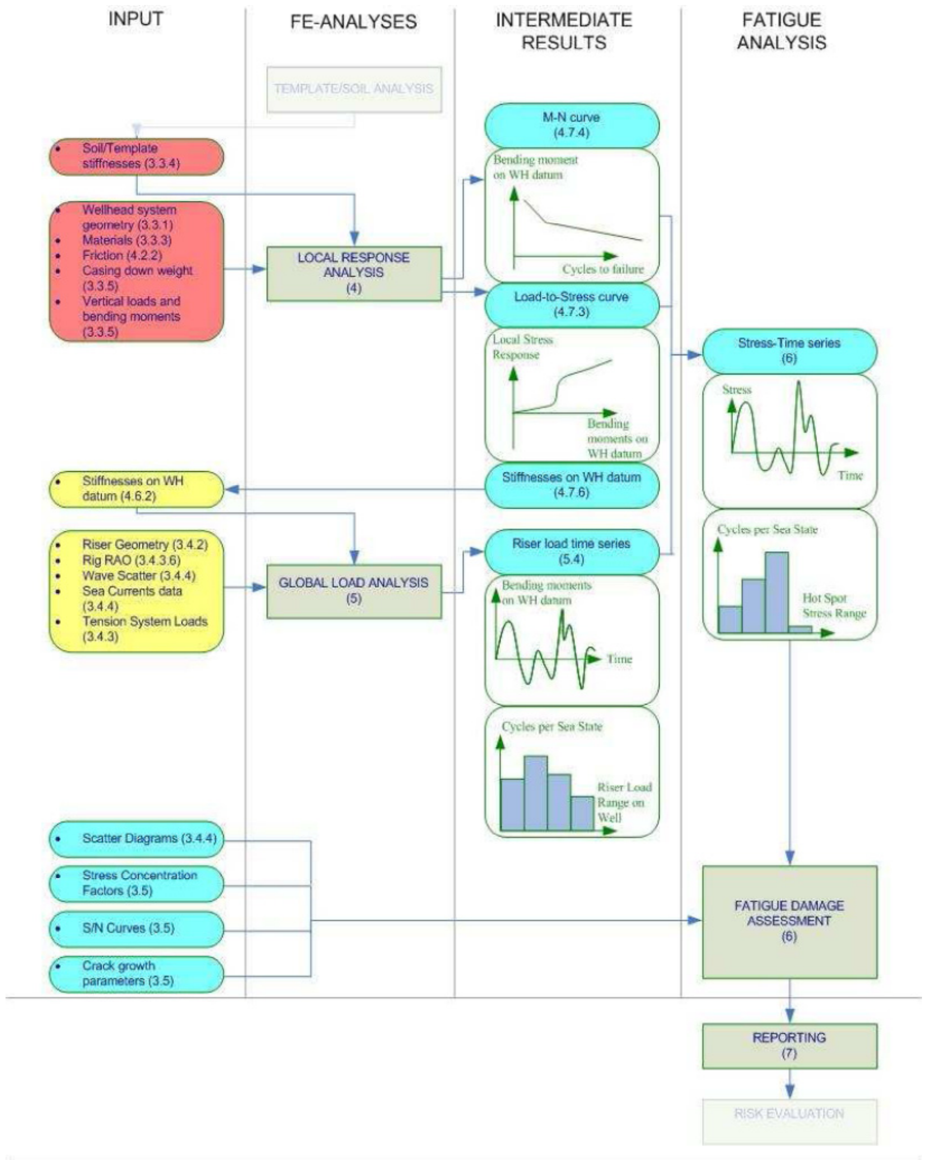


Figure 28 Overall analysis methodology flowchart (Article I)

4.3. Local response analysis

The local response modelling methodology proposed in Article I have been used for analytical results in Article III - Article VII. The analysis methodology describes in detail how to build a fully parametric 3D, 180 degree symmetric FE-model of a subsea wellhead for the only purpose of fatigue calculation using the SN approach. The model is not intended for any other structural evaluations than fatigue[26]. This assumption allows simplification where only the hotspots of interest needs to be modelled and meshed accurately; the rest of the wellhead components are intended to behave structurally correct. Details important for the load transfer through the system must be detailed accurately and meshed accordingly. The FE wellhead model shall extend to a depth such that the stresses are not influenced by the model termination. As rule of the thumb this may be at 50 m below mud line, or to 20 m below the lowest relevant hotspot. This approach allows a transition from solid to beam elements at the lower part of the model. The main result from the static local response analysis is

- A load-to-stress-curve describing the relation between stresses in a hotspot and the bending moment applied on the wellhead datum
- Lower boundary conditions input for the global load analysis
- Geometrical Stress Concentration Factor (SCF)

The analysis methodology statement report [1] gives detailed guiding on selection of element types, mesh sizing, contact definition, modelling of cement, soil spring representation, reference elevation, X,Y,Z convention, boundary conditions, friction, model loading and solution.

[26] The analysis work in Article VII addresses ULS capacities, and modifications to the modelling approach was necessary and has been outlined in that article.

The main result from this analysis is the load-to-stress relationship between applied wellhead bending load and the corresponding stress at any number of locations in the local model. The locations are the fatigue hotspots of the well which are the target of the analysis.

Figure 8 is a load-to-stress curve for the cantilever idealized wellhead model as presented by Valka and Fowler [27]. Another example is showed in Figure 29 and has been derived from a local analysis of a real well using the methodology as presented in Article I. That involved loading the well model to a relatively high wellhead bending moment to ensure the load-to-stress curve has stress values for infrequent occurrences of high bending moments.

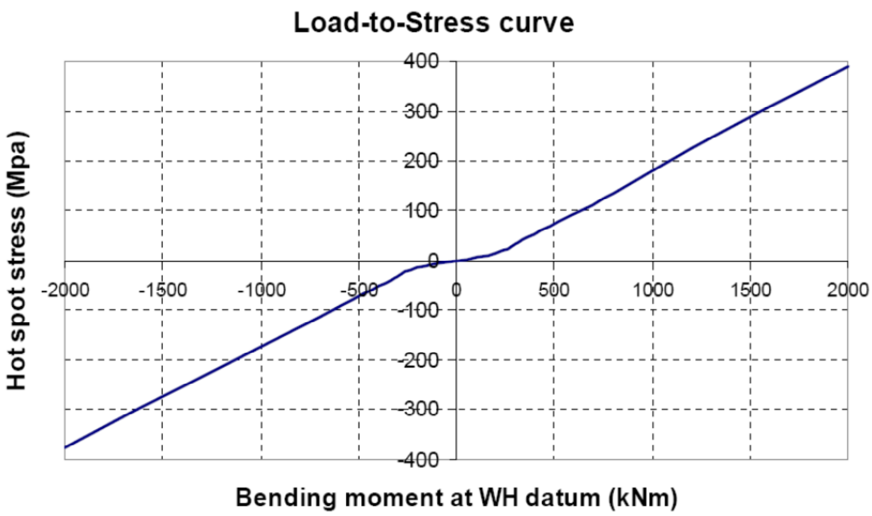


Figure 29 Example of load-to-stress curve. (The moment range set relatively high in order to cover all relevant cases.) (Article I)

A second result from the local response analysis is the global well stiffness behaviour under influence of bending moment and shear used to derive the parameters for the lower boundary condition to be used in the analysis step 2, the global load analysis. A discussion of the global load analysis sensitivity towards different types of lower boundary conditions models is the objective of Article IV.

Without breaching the overall methodology from Article I, a modified lateral cement casing support boundary condition was suggested in Article III. This modified boundary condition can be used in local response analysis modelling given fulfilment of certain well specific criteria as discussed in section 5.6. The basis of the modified cement boundary condition is outlined in detail in section 5.5.

A typical subsea wellhead and an interpretation as a mechanical system are presented in Figure 30. The mechanical system can be modelled in any multipurpose FEM software, but several modelling choices must be made. The model can be made as interacting beams with cross-sectional properties equivalent to the real system. The model may also be generated as a meshed structure in 2-D, with various mesh refinement and element definitions. There is also possibility to model the construction using solid elements in 3D representation of the structure. In solid 3D modelling the presence of symmetry is frequently used to reduce model size and calculation efforts without losing precision. The selection of mesh refinement and type of elements is completed by a segment refinement selection. The local modelling approach advocated by Article I is a 180 degree[27] solid 3D model. In addiction the modelling approach is suggested to be parameterised, the new models can easily be generated when doing sensitivity studies or shifting analysis target from one well system to the next.

In Figure 30 the type of mechanical contact between casing strings has been suggested. The wellhead conductor housing mechanical contacts

[27] A 180 degree modelling will capture ovalisation effects if present

should be modelled using contacts elements with a static friction value. Conductor to tailpipe (if present) should be modelled as a gap with friction. Template lateral contact should be modelled friction less with a gap.

In Article III the effect of a modified boundary condition modelling of lateral surface casing cement support is compared to the conventional approach currently suggested by the JIP Draft RP [1]. The comparison is presented as differences to the load-to-stress relationship for the surface casing weld. In addition this difference has been studied using two modelling approaches, one 3D solid element model as suggested by the JIP and one simplified 2D beam element model. The effect from the modified boundary condition was identified by both modelling approaches, but the results also showed that the less sophisticated model returned higher stresses. This was true for all loading levels and different cement shortfalls. Additionally results showed the modified boundary condition to return lower stresses regardless of the modelling approach.

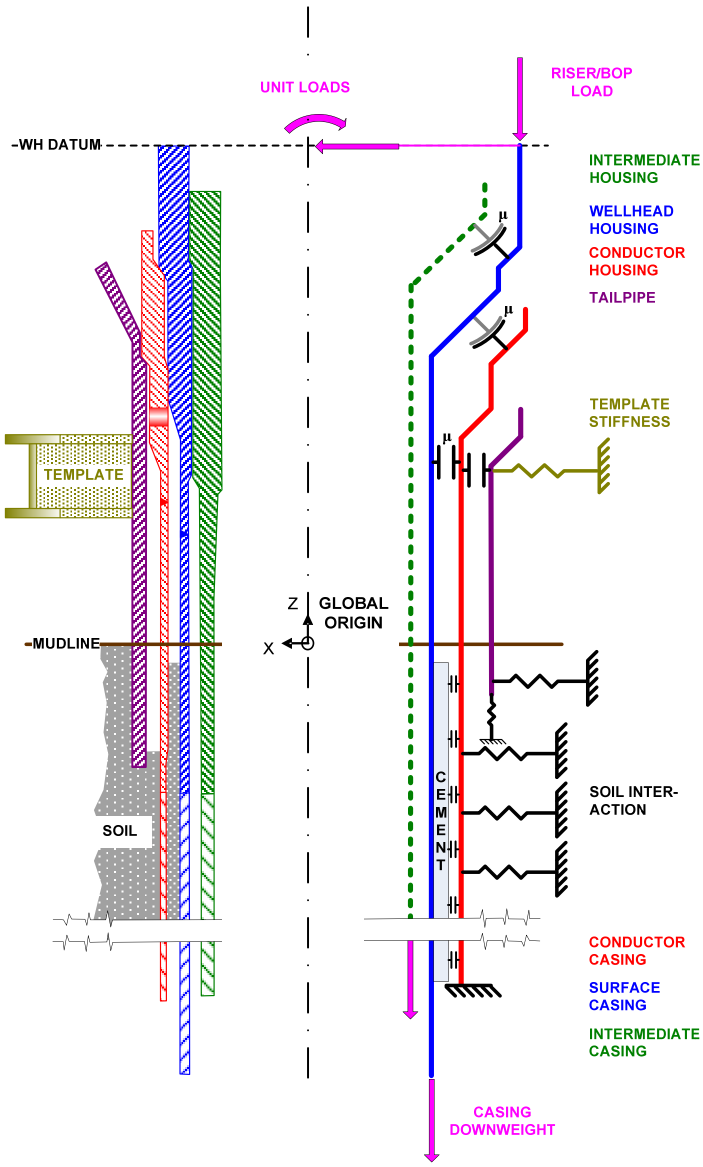


Figure 30 Typical wellhead system and a mechanical interpretation of the wellhead system (Article I)

4.4. Global load analysis

The analytical results from the global load analysis are time series of the bending moment at the wellhead datum. The analysis methodology [1] gives detailed guiding on modelling of upper and lower boundaries, rig motions, non linear flex joint stiffness, heave compensation systems and hydrodynamic coefficients. A guiding on the level of current loading is also included. This dynamic analysis provides:

- Time series of bending moment at wellhead datum
- Bending moment load range histograms, presenting the number of cycles for each load range by use of RFC

The overall load-response methodology is a decoupled one, combining analysis step 1 and 2 while assuming quasi-static behaviour of the well. The global load analysis however is performed in a coupled manner with a lower boundary condition modelling that couples non-linear rotational and lateral stiffness's of the well. The effect of a well-like boundary condition approach has been outlined in more detail in Article IV. Results from this research indicate that more dynamic behaviour is captured by the global load analysis from using a lower boundary condition with actual well flexibility.

The standard ISO 13624-2 [61] which adopted the works of the JIP DEEPSTAR IV project discusses the choice of a coupled (Figure 31)[28] or decoupled (Figure 32) analysis methodology for the global riser analysis.

By using a coupled analysis approach King et al. [39] showed that there is a interdependence between riser response and well stiffness, which again were impacted by soil and cement levels. The findings from King

[28] If a fully coupled approach is chosen ISO 13624 states no need for a local wellhead analysis, as the wellhead structures will be an integral part of the global model.

et al. are included by the current methodology by using a coupled model approach in the global load analysis.

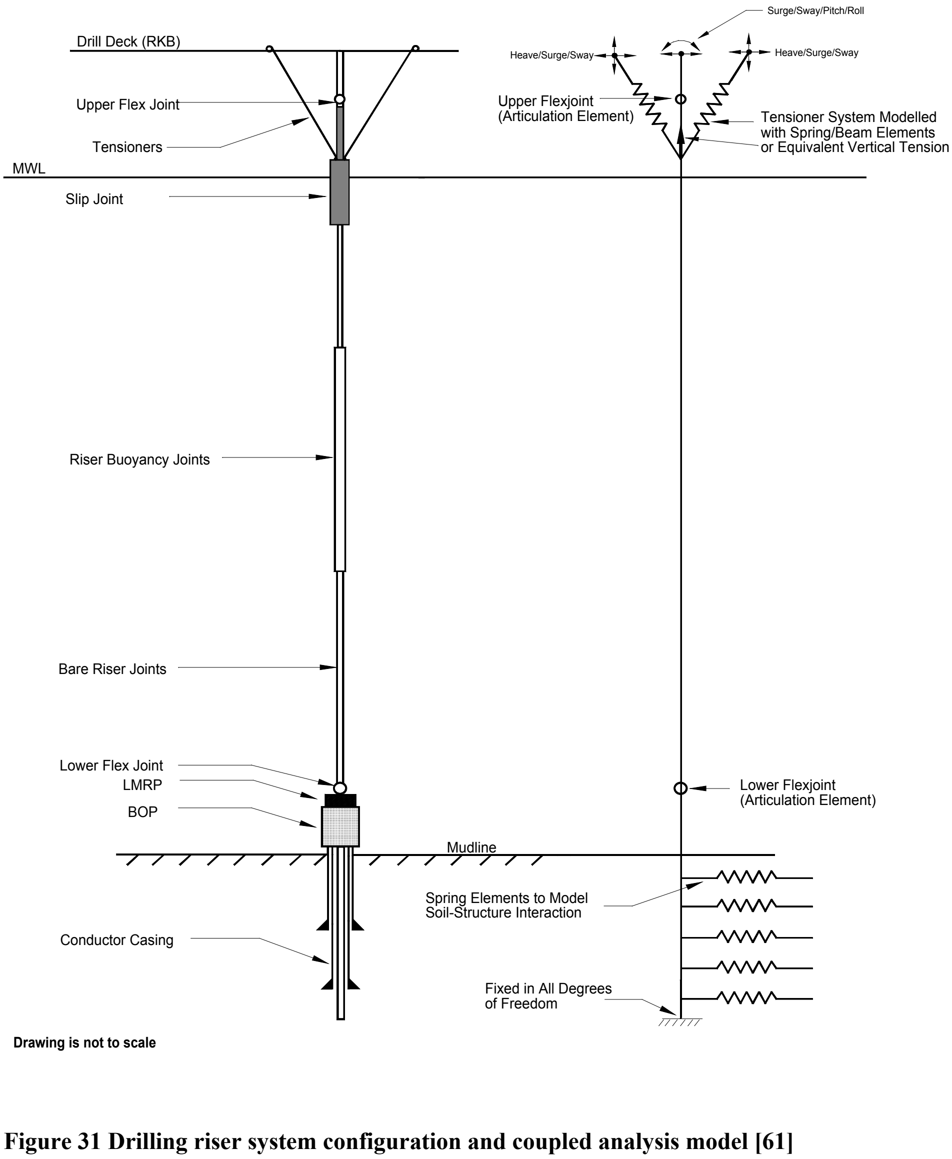


Figure 31 Drilling riser system configuration and coupled analysis model [61]

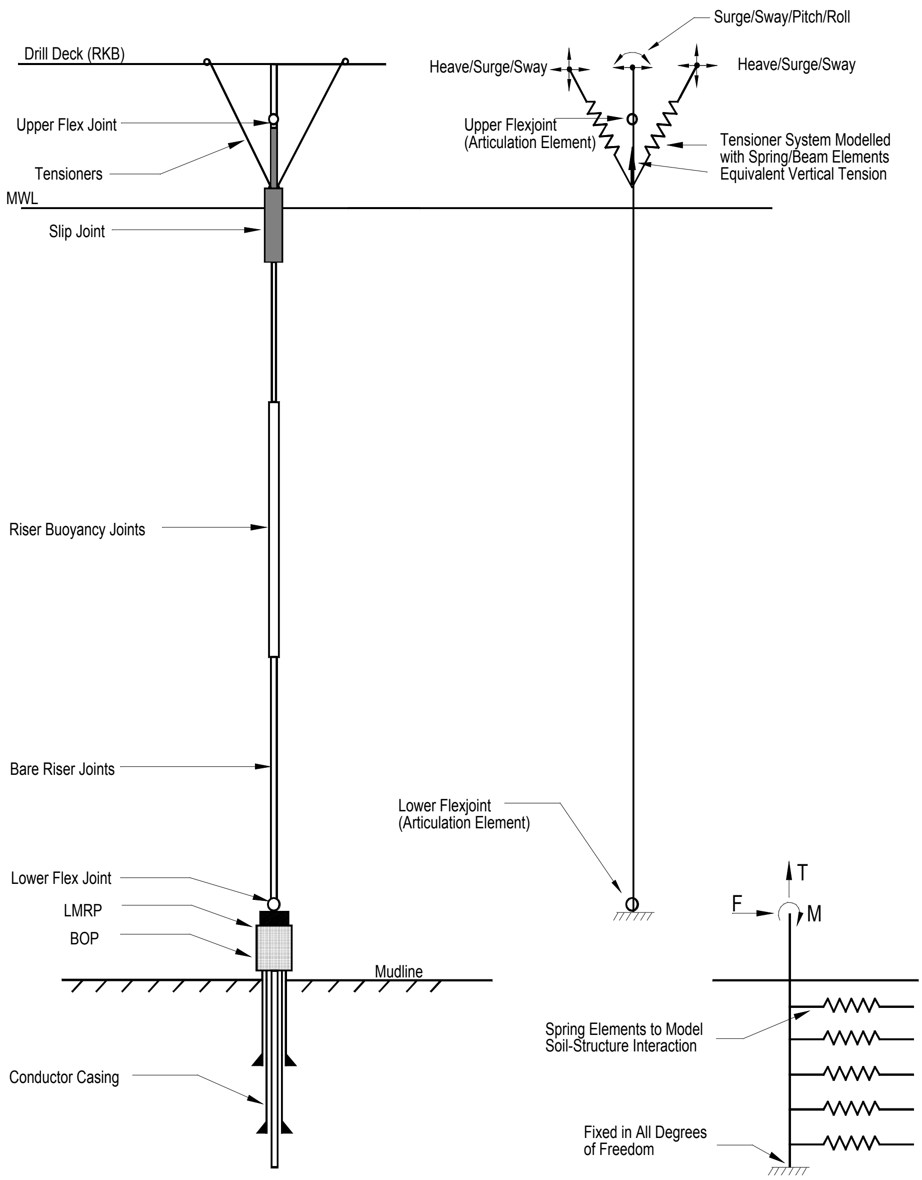


Figure 32 Drilling riser system configuration and decoupled analysis models [61]

4.5. Fatigue damage assessment

The fatigue assessment is based on the conventional principle using SN curves and the Miner-Palmgren hypothesis for linear fatigue damage accumulation.

The damage assessment is done per hotspot by mapping the time series of the loads acting on the well with the load-to-stress curve to obtain the stress time series. If relevant, additional hotspot stress concentration factors may be applied before these stress-time series are subjected to Rain Flow Counting (RFC). Relevant SN curve is then selected according to DnV recommended practice for fatigue calculations for offshore structures [62][29]. The fatigue calculation is carried out for the number of sea states as specified in the relevant scatter diagram, and the accumulation reflects the probability of sea state for the duration of the operations that contribute to the fatigue damage.

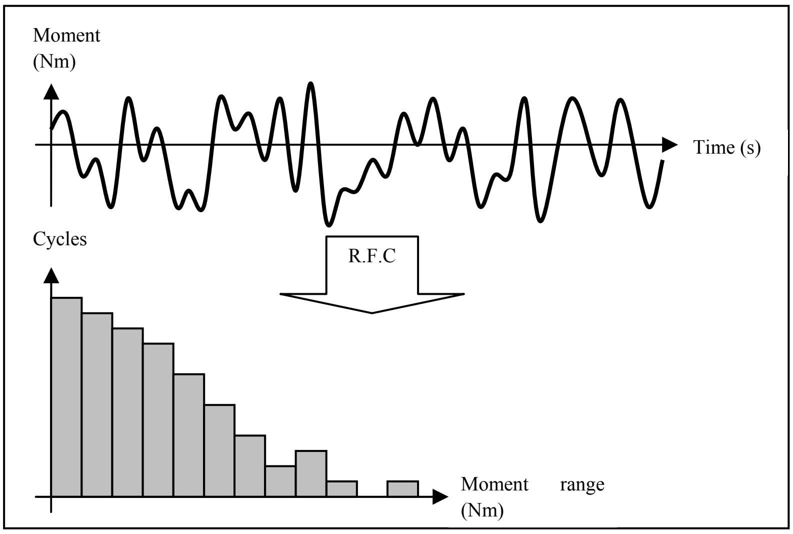


Figure 33 Principle sketch of calculation of short term bending moment load histograms. Note that the number of bins in the figure is very low for illustrational purposes (Article I)

[29] This document is available for free download from the publisher.

Instead of computing the time series of stress, one may as an alternative use the global analysis results in terms of histograms of the load ranges acting on the well. In this case the load histograms obtained from rain flow counting of the load-time series are assessed for each individual sea state. Each load range in the histogram is then mapped with the load-to-stress curve with the same amplitude to the positive and negative side. This provides a histogram of stress ranges that is evaluated against the SN curve for damage accumulation.

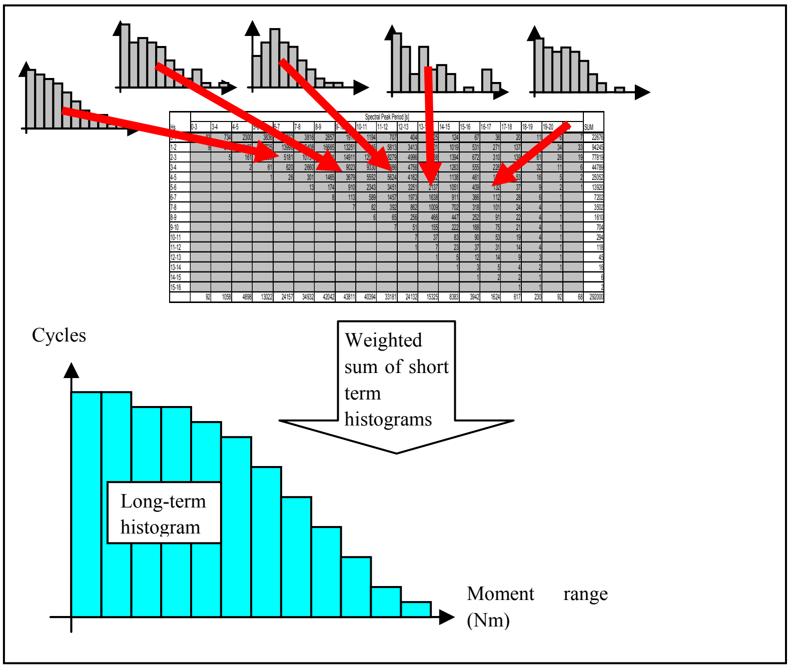


Figure 34 Principle sketch of calculation of long term histograms as a weighted sum of short term histograms, using the probability of occurrence of each sea state as weight. Note that the number of bins in the figure is very low for illustrational purposes (Article I)

Damage accumulation

The total accumulated fatigue damage D_{Total} is a summation of the damage from all relevant phases that contribute, and may be written on the form:

$$D_{Total} = \sum_{all\ phases} D_i \qquad (4.1)$$

Where D_i is the accumulated damage during operational stage i. The accumulation comprises operation stages that occurred in the past, and stages that are planned in the future.

Equation 4.1 is to be calculated a number of times at each hotspot in order to cover:

- Results for all cement levels as required
- Results with estimated hang-off weights of casings
- Results with hang-off weights set to zero.

This latter case may be of interest if the extent of down weight is uncertain or if temperature effects[30] are significant. Results are also calculated as a function of time, and the relative contribution from the various operational phases can then be seen. The following assumptions should be noted:

- Stress variation at the hotspot is uniquely expressed by the variation in moment and associated shear force at the wellhead datum; i.e. no other loads contribute to the fatigue.
- The weld and cross-sectional properties are constant around the circumference.

[30] Temperature increase during drilling may cause “landing shoulder” lift-off again affecting the load sharing within the wellhead system

- Hotspot stress is calculated on the compression and on the tension side, and the load to stress curve may be unsymmetrical in compression and in tension.
- The load-to-stress curve is the same for loading and unloading; i.e. potential hysteresis effects are not accounted for.

4.6. Important input parameters

Cement shortfall

Recognition of the importance of cement shortfall is the reason for a suggested method to operationally control the level of cement shortfall [26]. This work suggest that by ensuring a programmed cement shortfall during well construction conventional wellhead surface casing extension welds will suffer less damage during dynamic loading. Several authors [21, 25, 27, 31, 63] have emphasises the importance of cement shortfall on the load-to-stress relationship. They all based their conclusions on analytical models where the top of cement was modelled as a discrete local introduction of lateral support. This approach yields a parabolic relationship between cement shortfall and fatigue life for a wellhead housing welded transition to the surface casing extension.

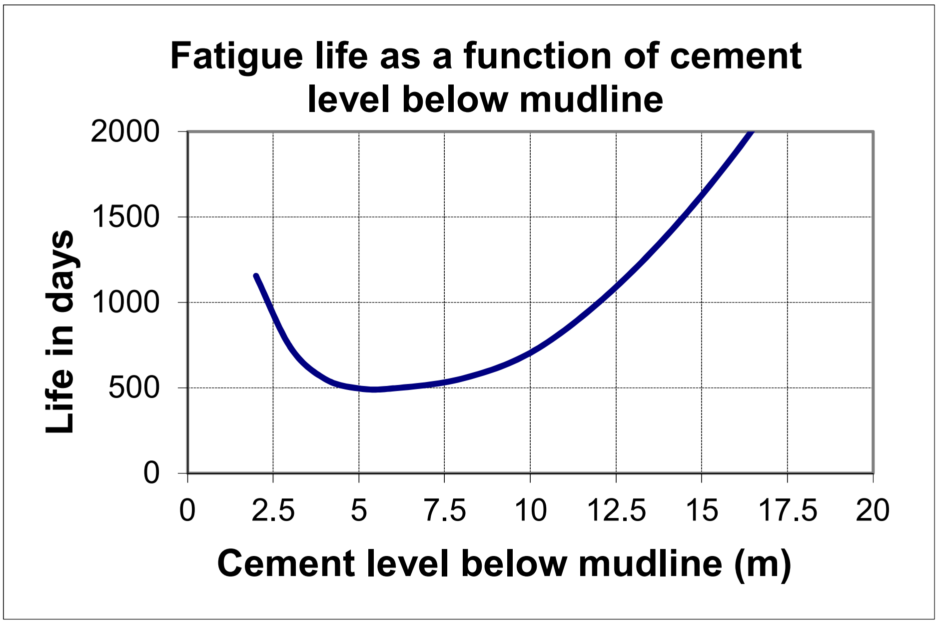


Figure 35 Fatigue life as a function of cement level variations (Article VI)

Figure 35 is an example on the effect of cement shortfall on the calculated fatigue life of a surface casing weld. The aim for cementing of the surface casing is to place cement all the way to the cement exhaust port of the wellhead housing, typically just above mud line elevation. There are multiple reasons to why this aim might not be achieved in a particular cementing operation [26]. A more detailed discussion on causes of cement level shortfall can be found in section 5.1.

From a probabilistic methodology applied to the problem of wellhead fatigue a input parameter uncertainty factor listing can be extracted. (Article VI). Having modelled the top of cement location with a uniform probabilistic density function we got the results as seen in Figure 36. We see her that the importance factor of the cement level accounted for 23% of the total.

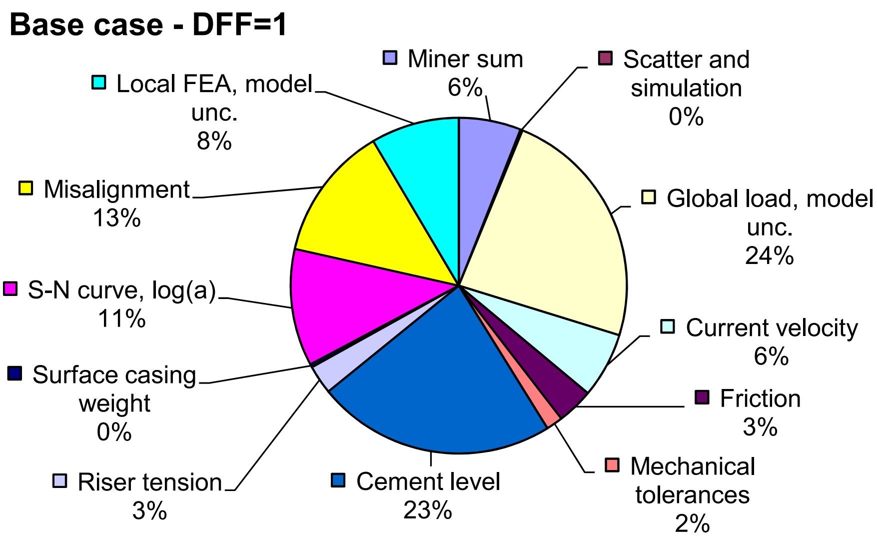


Figure 36 Input parameters Importance factors comparison (Article VI)

Supported casing weight

The presence of a down force excreted by the wellhead suspended casings will increase the friction force in the landing shoulders interference between wellhead housing and conductor housing. The friction force will resist slipping and liftoff at the landing shoulders, as can be seen in Figure 6 b) at page 16.

Typical well constructions as previously presented in Figure 5 consist of multistring casings with reduced radial size from outside to centre. Casing strings and production tubing are typically supported from the wellhead area. These strings will represent a downward force that is ultimately supported by the Conductor casing. Some authors have identified the level of such downweight to affect the load sharing between conductor and surface casing when the wellhead system is subjected to bending. Bohem [63] states that other string weights but the conductor and surface casings has little effect on the load sharing in the wellhead, excluding any thermal "lift-off" effects from these strings. Valka and Fowler [27] stated that these inner strings bear little or no load during global bending of the wellhead system.

With reference to Figure 36 we see that the casing down weight input parameter have zero contribution to the uncertainty of the problem, even if it will affect the final numbers if varied. The reason for this is that it can be estimated with more certainty, and that the impact on the uncertainty of the analytical result is less pronounced.

As stated by Article I an analytical case of no applied casing down weight should be included for consideration of possible thermal lift off effects.

Global Load

As seen from Figure 36 the global load modelling uncertainty accounts for 24 % of the total. That implies that the global load estimate is the single largest contributor of uncertainty. This is a result supported by the results presented in Article VII. There a load estimate was “replaced” by direct measurements and it resulted in less accumulated fatigue damage.

5. Surface Casing Cement Lateral Support

5.1. Top casing well cementing

In top casings cementing for subsea wells the objective is to provide foundations for conductor and surface casing towards formations, to ensure formation support and pressure integrity. Top casing cementing operations typically aims to place cement all the way to the subsea wellhead cement outlet port, and volumes are calculated with a degree of excess to ensure cement returns at seabed. Typically top casings are cemented by first pumping a lead cement slurry of reduced density (W/C[31] ratio higher than optimum) followed by tail cement slurry with higher density and a more engineered chemistry. In Figure 37 this cement placement technique is schematically indicated. It should be observed that the lead cement (2) is pumped first into the well followed by the tail cement (1). Once the cement is in place the high W/C ratio lead cement will be placed all the way to seabed and any excess cement will be exhausted into the sea since the cement pumping sequence is done in an open system. It is important during such cementing operations to avoid exceeding the lowest formation fracturing pressure to avoid subsequent lost circulation (cements slurry will then be pumped into the formation fracture rather than following the channel leading to seabed). Avoidance of excessive pressures is commonly done by using low density lead cement slurries [64].

[31] The water to cement ratio (W/C ratio) helps categorise different cement slurries. A certain cement will be associated with a optimum W/C ratio for ideal hydration.

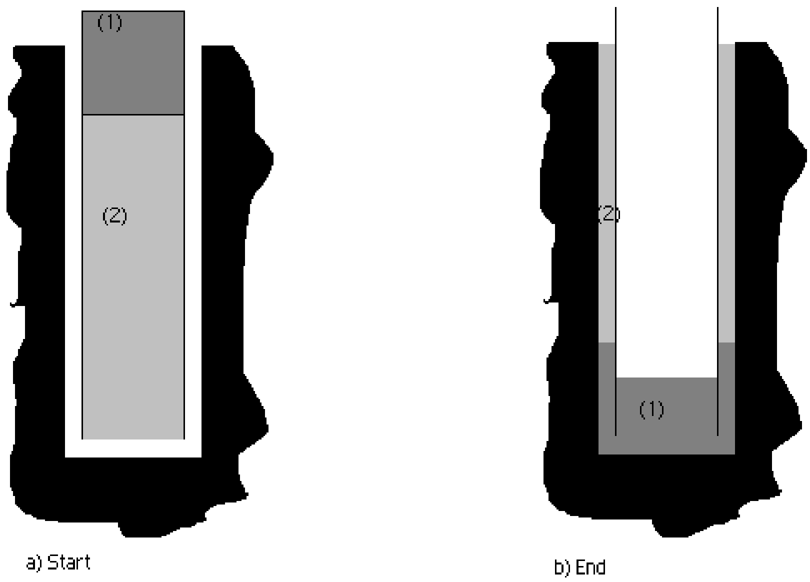


Figure 37 Well cementing with lead and tail cement (Article II)

An unexpected shortfall of cement level can occur despite visual confirmation of a full cement return at seabed. Cement shortfall can be caused in 2 ways; first by the cement slurry hydrostatic pressure on exposed formations could break down a weak formation zone resulting in a drop in the unsettled cement level. Such an event is difficult to detect subsea. Secondly the cement near the top may fail to form an adequate bonding between the conductor and surface casing resulting in an “effective” cement level below the “actual” cement level of that well. A combination of the 2 reasons is possible as they are caused by independent events [26].

The test results presented in Article II is relevant to the latter effect and will be helpful in assessing existing subsea wells which have already been cemented in place and where fatigue life evaluation is necessary.

Moreover these results should also be relevant to design and planning of new subsea wells, particularly in arctic and deep water environments. Other applications could be the emerging industry of offshore wind turbines when foundations are cemented in place in a similar manner.

5.2. The effect of low temperature on early strength development

In subsea well cementing near seabed curing temperature conditions may be different compared to onshore cementing and laboratory conditions. The importance of curing conditions during deep water cementing is known to be significant. Temperature affects subsea deep water cementing design more than what is generally recognized [65].

The near seabed water temperature is low compared to surface conditions, and in deepwater conditions the near seabed seawater temperature will be low and nearly constant year round and will suppress the normal thermal gradient of the upper formations [66]. Then top casing cement placed close to seabed will experience cooling from the surroundings both during pumping and curing. This leads to low cement curing condition temperature. Others have shown that this cooling effect is present and affects top casing cement curing conditions [65, 66]. Article II reports laboratory test results for cement initial setting and strength development under low temperature conditions for cement slurries with W/C ratios other than optimum.

The resulting level of cement in the annulus between conductor and surface casing of subsea wells has a strong influence on wellhead mechanical fatigue performance as has been shown by several authors [21, 25, 26, 63, 65-67]. All this work documents dynamic lateral loading and motions of surface casing relative to conductor casing that leads to fatigue loading of the surface casing and wellhead assembly. Hopper [67] reported a gross structural failure of a surface casing and related this failure to Vortex Induced Vibrations (VIV) fatigue loading from the drilling riser. Further he showed that the maximum stress seen by the surface casing is nonlinear dependant on the level of cement surrounding it. Wellhead housing is joined to the surface casing by welding, and the location of this weld is below and close to the landing shoulders in the wellhead. Fatigue loading of a wellhead is a result of bending moment's actions. In analytical models of a subsea wellhead used for fatigue evaluations, the lateral support exerted by the cement present between surface and conductor casing is a key boundary condition. The presence of solid cured cement makes analysts assume rigid body movement between these 2 casing strings [26]. A possible cement shortfall becomes a key model input. A surface casing cement level just a few meters below the subsea cement outlet elevation is reported to yield minimum fatigue life for the surface casing weld [26].

5.3. Evidence of local cement failure

During instrumented monitoring of a subsea conductor in the North Sea differential pressure sensors revealed pressure communication with sea water 10m below mud line 6-7 days after the cementing operation [40]. Stain gauges installed on the wellhead and conductor gave positive indications of riser induced cyclic bending. King and Soloman [40] concluded that the sudden pressure communication was due to cracking of the cement supporting the conductor, and that seawater pressure was communicating with the pressure gauge through these cracks. King and Soloman gives indications of approximately 1.2 days of curing to establish a gel structure and that initial setting started after approximately 1.5 days of curing. The BOP was landed on the well approximately 4 days after cementing of the Conductor. This is consistent with the time analysis presented by Aadnøy [68]. Further it implies that the cement cracks[32] happened after 2-3 days of connected riser operations. The cement shortfall was estimated from the pressure readings to be 3-4 meters below seabed. The lead cement used was 1.44 sg and the well was a North Sea well. No information on water depth or location has been given, but the well was drilled from November to January. The fact that it was done in the North Sea and during winter should call for a sea bottom water temperature of 6-7°C or lower. From the 1.4 sg results in Article II we can estimate that the equivalent curing temperature of the cement may have been 7-9°C based on an estimated 36-48 hours to reach 50 psi compressive strength. Near seabed water temperatures for subsea fields in the Norwegian part of the North Sea can be seen from Table 4.

Table 4 Mean, minimum and maximum near seabed sea temperature at different offshore fields in Norway [69]

Offshore Field	Block	Mean temperature (ºC)	Min temperature (ºC)	Max temperature (ºC)
Alve	NO 6507/3	7.1	1.0	9.0
Fram	NO 35/11	6.7	1.7	9.9
Glitne	NO 15/5	7.3	4.0	11.7
Gjøa	NO 35/9	6.7	1.7	9.9
Gullfaks Sør	NO 34/10	8.3	6.1	10.7
Skinfaks	NO 33/12	8.3	6.1	10.7
Heidrun	NO 6507/7	7.1	1.0	9.0
Heidrun	NO 6507/8	7.1	1.0	9.0
Kristin	NO 6406/2	7.1	1.0	9.0
Kristin	NO 6506/11	7.1	1.0	9.0
Mikkel	NO 6407/6	7.1	1.0	9.0
Morvin	NO 6506/11	7.1	1.0	9.0

[32] Observed as pressure communication though the cement

Njord	6407/7	7.1	1.0	9.0
Norne	NO 6608/10	7.1	1.0	9.0
Oseberg	NO 30/9	7.8	4.9	11.2
Oseberg Sør	NO 30/9	7.8	4.9	11.2
Sleipner Øst	NO 15/9	7.3	4.0	11.7
Sleipner Vest (Alpha Nord)	NO 15/9	7.3	4.0	11.7
Snorre SPS	NO 34/7	7.1	1.5	9.9
Snorre B	NO 34/4	7.1	1.5	9.9
Snøhvit	NO 7121/4	6.5	0.0	8.0
Statfjord Nordflanken	NO 33/9	8.3	6.1	10.7
Sygna	NO 33/9	8.3	6.1	10.7
Tordis	NO 34/7	7.1	1.5	9.9
Vigdis	NO 34/7	7.1	1.5	9.9
Troll B	NO 31/2	7.4	3.0	8.9
Troll B	NO 31/5	7.4	3.0	8.9
Troll C	NO 31/2	7.4	3.0	8.9
Troll C	NO 31/3	7.4	3.0	8.9
Tune	NO 30/8	7.8	4.9	11.2
Tune	NO 30/9	7.8	4.9	11.2
Tyrihans	NO 6407/1	7.1	1.0	9.0
Urd Svale	NO 6608/10	7.1	1.0	9.0
Vale	NO 25/4	7.5	4.2	11.5
Vega	NO 35/8	6.7	1.7	9.9
Vega South	NO 35/11	6.7	1.7	9.9
Vilje	NO 25/4	7.5	4.2	11.5
Visund	NO 34/8	7.1	1.5	9.9
Yttergryta	NO 6507/11	7.1	1.0	9.0
Åsgard A	NO 6506/12	7.1	1.0	9.0
Åsgard B	NO 6507/11	7.1	1.0	9.0
Åsgard B	NO 6407/2	7.1	1.0	9.0

From Table 4 we see that the dominant mean temperature is in the range 6-7°C and that minimum observed temperature as low as +1°C is observed at the Haltenbanken area. The maximum temperature observed is 11.7 °C, albeit most locations have maximum observation below 10°C. These temperature statistics tells us that the near bottom seawater temperatures in the Norwegian part of the North Sea is low.

Curing shallow water flow and conductor movements by grouting cement repair operation of a North Sea exploration satellite well revealed visual confirmation of mechanical failure of the conductor cement top. Opseth et al. [70] assume that cement fractures were the cause of shallow water flow and that observed conductor motion resulted. An alternative explanation postulated here is that the failure may be evidence of cyclic conductor motions failing the cement then leading to shallow water flow. The authors state that there was a lag time between cement failure and observation of water flow. This statement supports the postulate that shallow water flow was a symptom of cement failure rather than the cause.

Figure 38 ROV image showing the first conductor cement failure [71]

The conductor and the failed cement can be seen in Figure 38.

Then a grouting cement job was performed successfully sealing off the shallow water flow. The cement used was an industrial blend with accelerator to counter the prolonged curing times expected from low water temperatures. Figure 39 shows the result of the grouting job.

Figure 39 Conductor after grouting cement job [71]

Soon after this repair cement cracks was again observed around the conductor. Figure 40 shows the cement again cracking 12 days after the cement grouting job. The authors claim these cracks to be due to conductor movements.

Figure 40 Conductor cement 12 days after the grouting job [71]

Two papers [40, 70] have been identified that provide some evidence of localised top conductor cement failure due to cyclic top casing bending. The curing conditions can be assumed to be similar for the conductor and surface casing. The casing motions will be different if we compare the conductor and surface casing. The cement in the annulus formed by the conductor and surface casing will only be impacted by the radial displacement of the surface casing relative to that of the conductor casing.

The presence of relative radial casing displacement has been confirmed by the analytical results presented in Article III. The radial displacement of the surface casing relative to the conductor casing is shown in Figure 41. It shows that the surface casing will tend to make an impress into its annulus cement close to seabed. The modified boundary condition modelling of lateral cement surface casing support is based on the creation of a small annulus from the persistent motion of the surface casing riser.

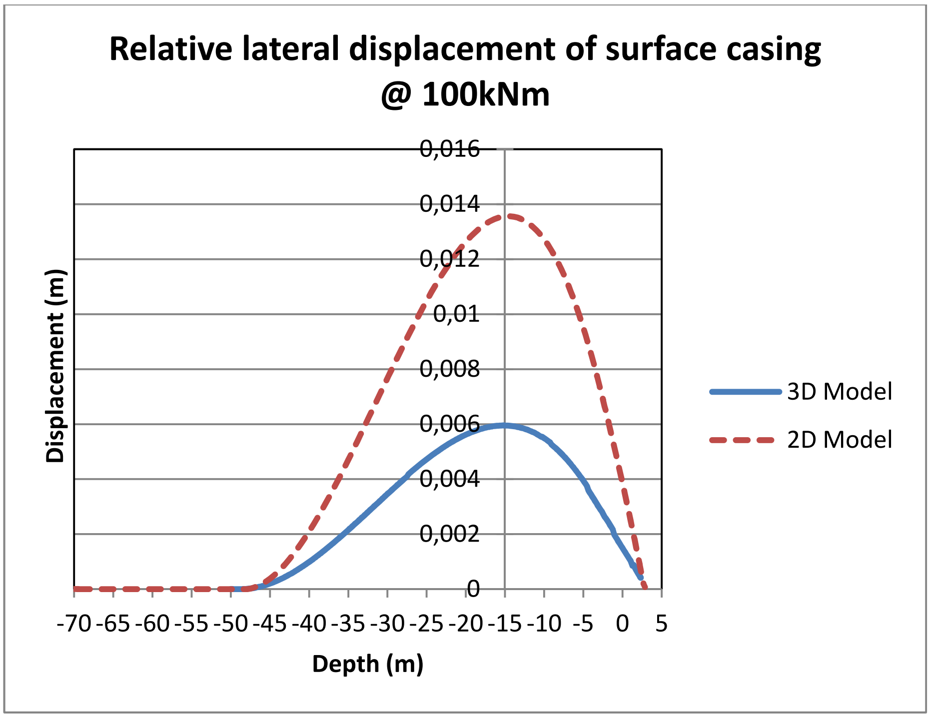


Figure 41 Relative lateral displacement of a surface casing with 100kNm bending (Article III)

Further evidence can be found by the quantified initial setting times for lead cement cured at low temperatures in the laboratory as described in Article II. By comparing these results to typical operational durations between the end of cementing the surface casing until landing of BOP the criteria for assuming a small annulus can be obtained. This time interval is the time the cement close to the seabed is allowed to cure without any casing movements. Generally for North Sea operations duration of 24 hours should be expected based on time analysis performed by Aadnøy [68]. Costs associated with subsea drilling gives strong incentives to reduce time spent for Wait On Cement (WOC) to a minimum [72]. In deep water drilling prolonged curing time for top casing cement due to low seawater/seabed temperatures cooling of cement as it is being pumped and during curing, has received attention [64-66, 73]. In the North Sea basin there are a high number of subsea wells in shallow water (less than 500m water depth) where the seabed temperatures are low year round based on the latitude of this basin [74].

With the near bottom seawater temperatures presented in Table 4 and the initial curing times presented in Figure 44 and more detailed in Article II it is likely that a majority of subsea wells in the North Sea will have a surface casing annulus gap close to seabed. Such wells will be candidates for using the modified cement boundary condition presented in Article III. Analysis of the effect of a modified boundary condition has showed a significant impact on fatigue life as discussed in Article IV.

The creation of a annulus cement gap due to relative casing movements were supported by model trials in the laboratory. A scaled down model of 2 concentric tubular were cemented[33] and left curing in ambient conditions for 5 hrs. The inner tube was then set into a reciprocal motion for 1 week. Then the test was stopped and the setup was left curing for yet another week. Then the model was cut along its length in 2 half's. The picture seen in Figure 42 gives visual confirmation of a annulus gap that was generated during this illustrative test.

[33] 1.56 sg commercial cement slurry was used

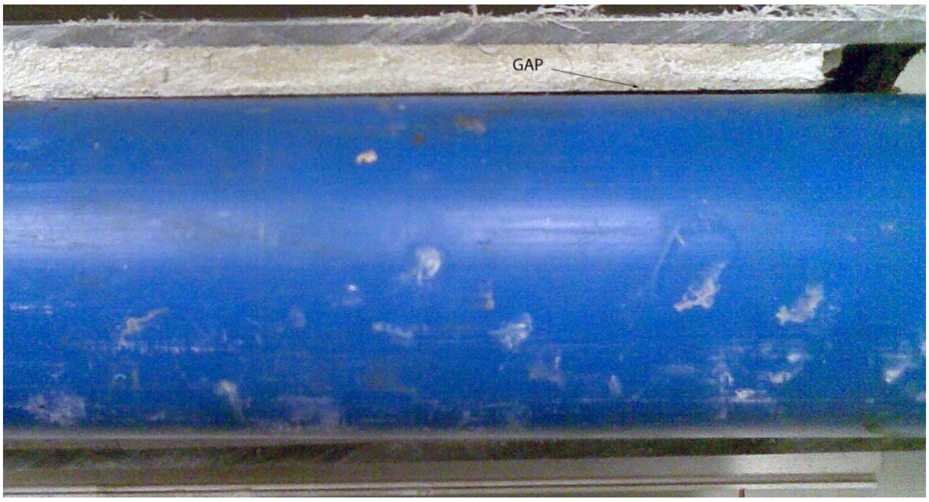


Figure 42 Picture of cut through model showing the presence of a small annulus after bending during curing

The evidences presented above supports the postulate that cement lateral surface casing support is affected by a small annulus.

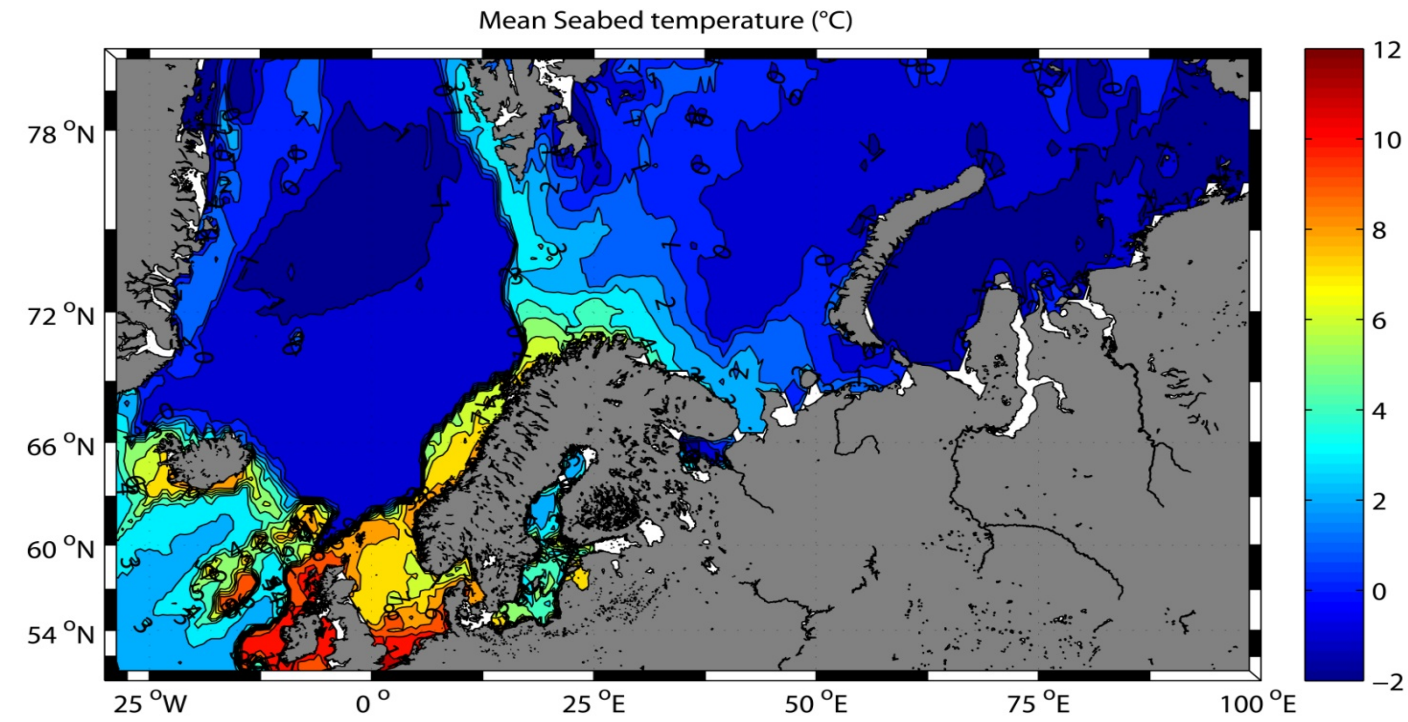


Figure 43 Map showing mean seabed temperature (created based on data from World Ocean Database 2009)[75]

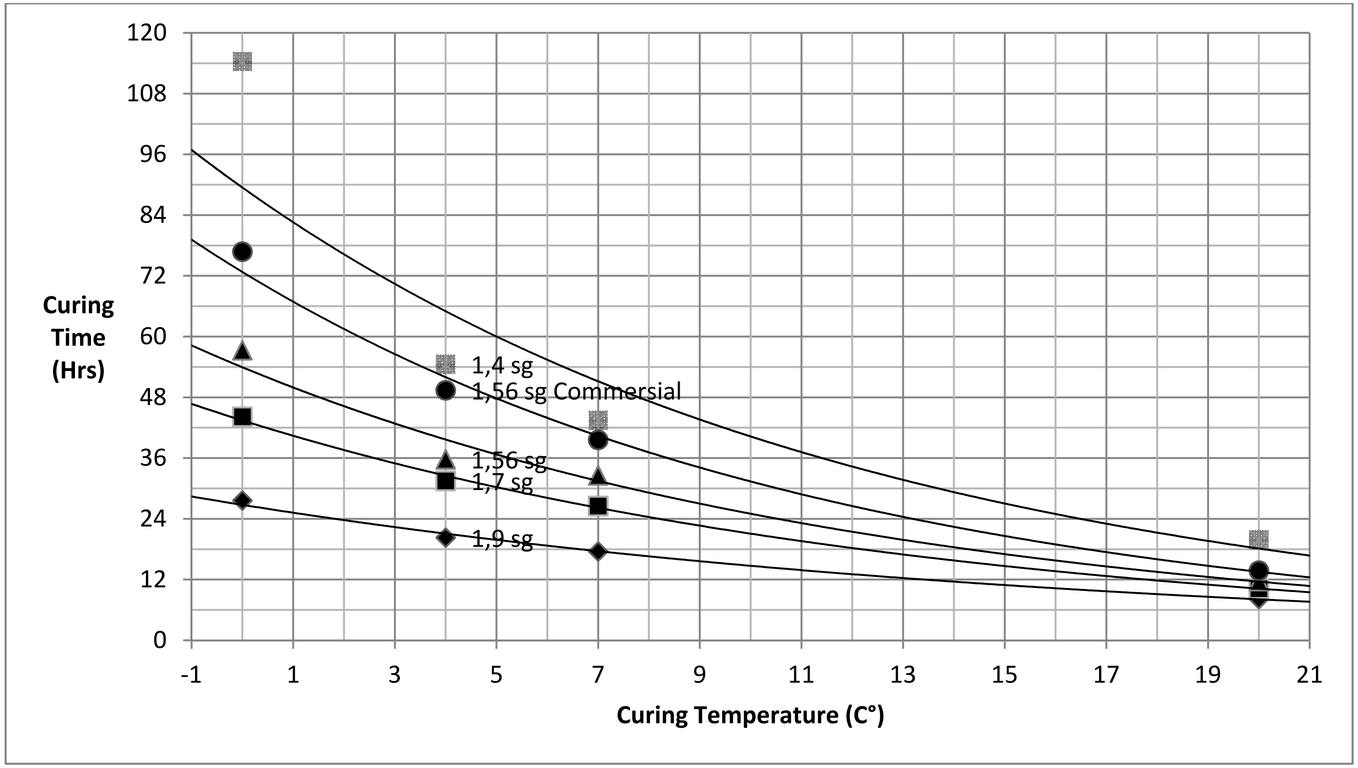


Figure 44 Development of 50 psi (0.345 MPa) compressive strength with time and temperature (Article II)

5.4. Discussion

In the literature for early strength characterization of oil well cement slurries the focus is mainly on tail cement slurries (see Figure 37) and bottom well curing conditions, and not on lead cement slurries used for top casing cementing [76]. Some authors have shown concerns with the low temperature conditions for top casing cement in deep water applications. The top of cement (TOC) level in the annulus between the conductor and surface casing is an important boundary condition in modelling subsea wellhead systems exposed to lateral loads and bending moment. In the case of dynamic loads acting on subsea wells the cement boundary conditions has an impact on estimated fatigue resistance of surface casing hotspots. Britton and Henderson [26] proposed a ported sub to be included in the surface casing to enable circulating out the upper part of the cement column to ensure TOC below the depth of the ported sub. Ensuring TOC is not close to seabed/wellhead cement exhaust port will ensure acceptable fatigue conditions for the wellhead/surface casing. Subsea wellhead fatigue is a localized effect which potentially presents a problem at the upper 10-50 meters of the well (ref Article I).

Pressure testing of casings is known to potentially cause micro annulus and cement failures [64]. It is well known that cement is a bimodular material; it is stronger in compression than in tension. In the pressure testing loading of casing (expansion of the casing outer diameter) the load exerted on the cement will be compressive in the radial direction, and subsequently tensional in the tangential direction. Mueller and Eid [76] have shown that in the event of pressure testing casings such loading may cause cement to fail in tension. For neat cement Mueller and Eid states that the bimodularity is strongly pronounced; compressive strength is 8-10 times the value of tension strength. The development of 50 psi (0.345 MPa) compressive strength as seen in

Figure 44 shows that with curing temperatures less than 9°C 24hrs or more of curing time should be expected for lead cement slurries (slurries with W/C ratio higher than optimum). The commercial slurry will reach 50 psi (0.345 MPa) compressive strength in 24 hrs for a curing temperature of 13°C. For curing temperatures below 13°C more than 24hrs is needed to reach 50 psi (0.345 MPa) compressive strength.

After cementing of surface casing the next operational step is to connect the drilling riser to the subsea wellhead. Once this connection is made lateral movements of surface casing relative to conductor should be expected. When a casing is radial moving towards the surrounding cement it resembles pressure testing of a casing which is known to potentially cause micro annulus and cement failures [64].

Water depth affects the time from placement of cement until drilling riser is attached to the subsea wellhead. In North Sea operations water depths are typically less than 500m and 24 hrs will be a typical duration between placement of cement until drilling riser is attached [68]. Compared to a typical curing duration of 24hrs our results indicate that the lead cement lateral casing support is not yet fully established due to hindered compressive strength development. In 24 hrs the commercial lead cement slurry will not have formed compressive strength of 50 psi (0.345 MPa) if curing temperature have been less than 13°C. With low curing temperatures high W/C ratio lead cement will need curing time that could be in the range of several days before drilling riser is connected. Connecting the drilling riser too early will impose loads to the cement that can cause failure to the lead cement surrounding the uppermost part of a surface casing.

Any such failure would be a local effect as the relative movement of the surface casing will diminish quickly with depth. The failure of bonding and effective lateral support due to casing movements will not affect the main purpose of the cementing operations. But in wellhead fatigue modelling the cement interface with surface casing will experience this phenomenon, and models should disregard “effective” cement levels close to the wellhead cement exhaust port. Estimation of the elevation of the uppermost effective TOC is a well specific problem. It is a result of actual curing temperature, type of cement used, wellhead design and tolerances and the time between placement of cement and connection of riser (start of casing movements).

5.5. Modified cement modelling

At the time when the BOP/riser is landed and connected to the wellhead dynamic loading will be imposed to the well. The bending moment will cause the upper part of the surface casing to move in a radial direction. Depending on the cement curing time and temperature conditions the lead cement surrounding the surface casing may not have developed sufficient strength to resist surface casing movement. In such cases continues casing movement will create a small annulus as the cement eventually cures into a solid material. In doing so it passes through a state of plastic/gel like behaviour and finally starts to develop the characteristic of a solid material, with a gradually improving compressive strength. The development of compressive strength in typical lead cement slurry cured at +4°C have been monitored using an Ultrasonic Cement Analyser (UCA). Figure 45 shows the compressive strength development of 1.56 sg lead cement[34] cured at +4°C. A compressive strength of 50 psi is regarded as the initial setting of well cement. The time to reach 50 psi compressive strength is 49:20 (hrs:min) judging from the example in Figure 45. Aadnøy [68] has showed that 24hrs is a typical duration from cementing until loading starts (BOP landed on wellhead).

[34] The slurry design is typical for lead cements used in the North Sea.

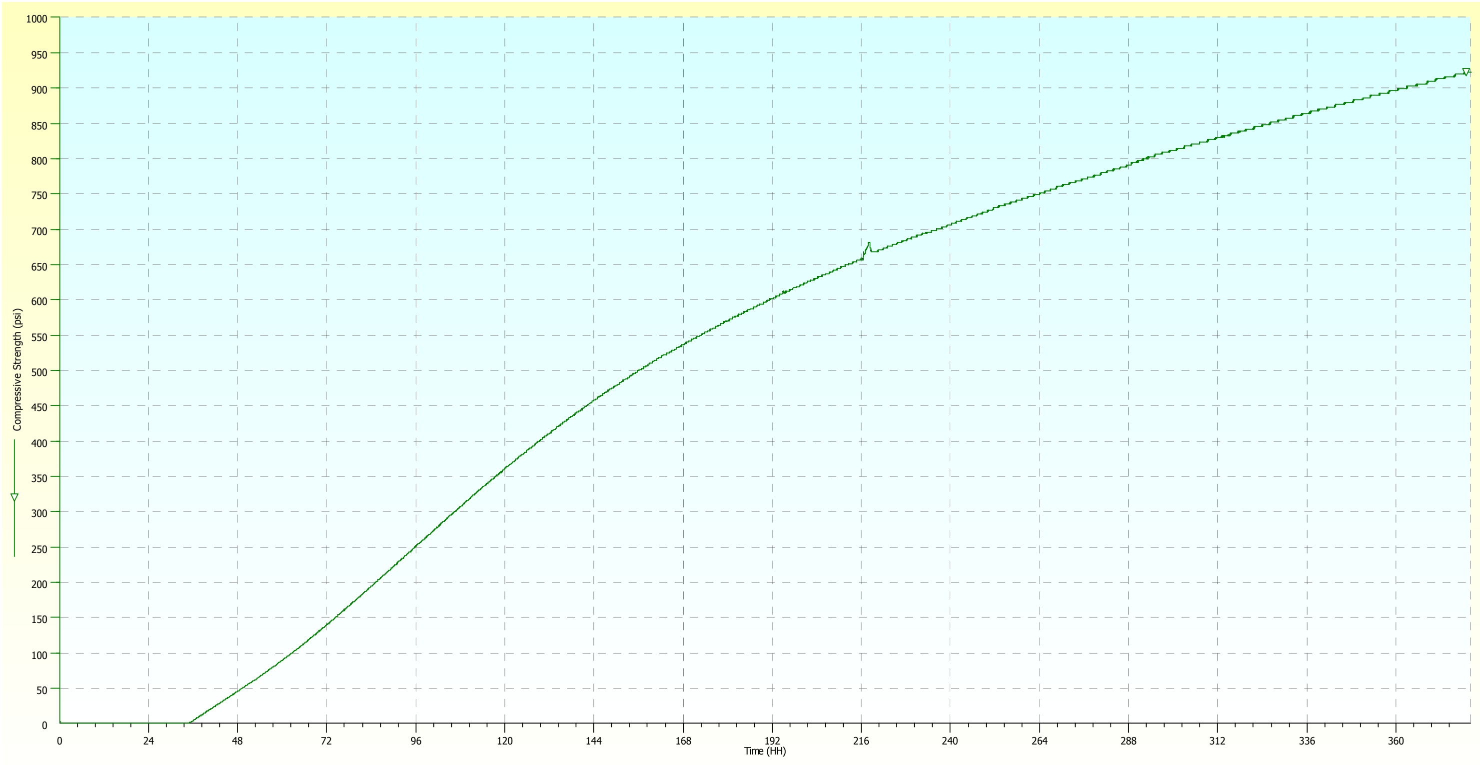


Figure 45 Development of compressive strength 1.56 sg lead cement cured at 4°C

Given that curing has not resulted in a solid material before commencement of casing movements the local response analysis model should include a modified lateral cement support for the surface casing. Figure 46 is an modelled illustration of how such a modified model might look like. The Top of Cement (TOC) may still encounter a shortfall. The modelling and analytical steps related to this modified cement modelling approach have been outlined in detail in Article III.

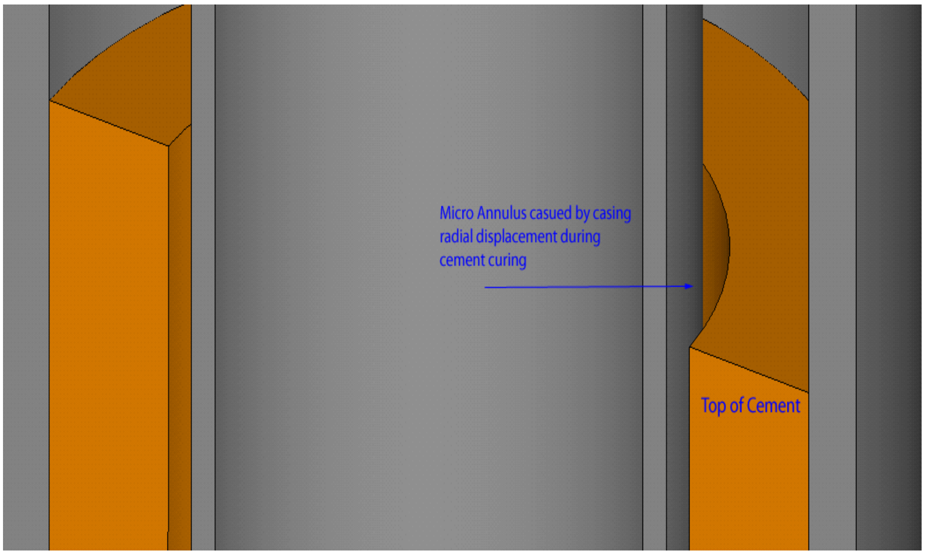


Figure 46 Modified surface casing lateral support cement boundary condition

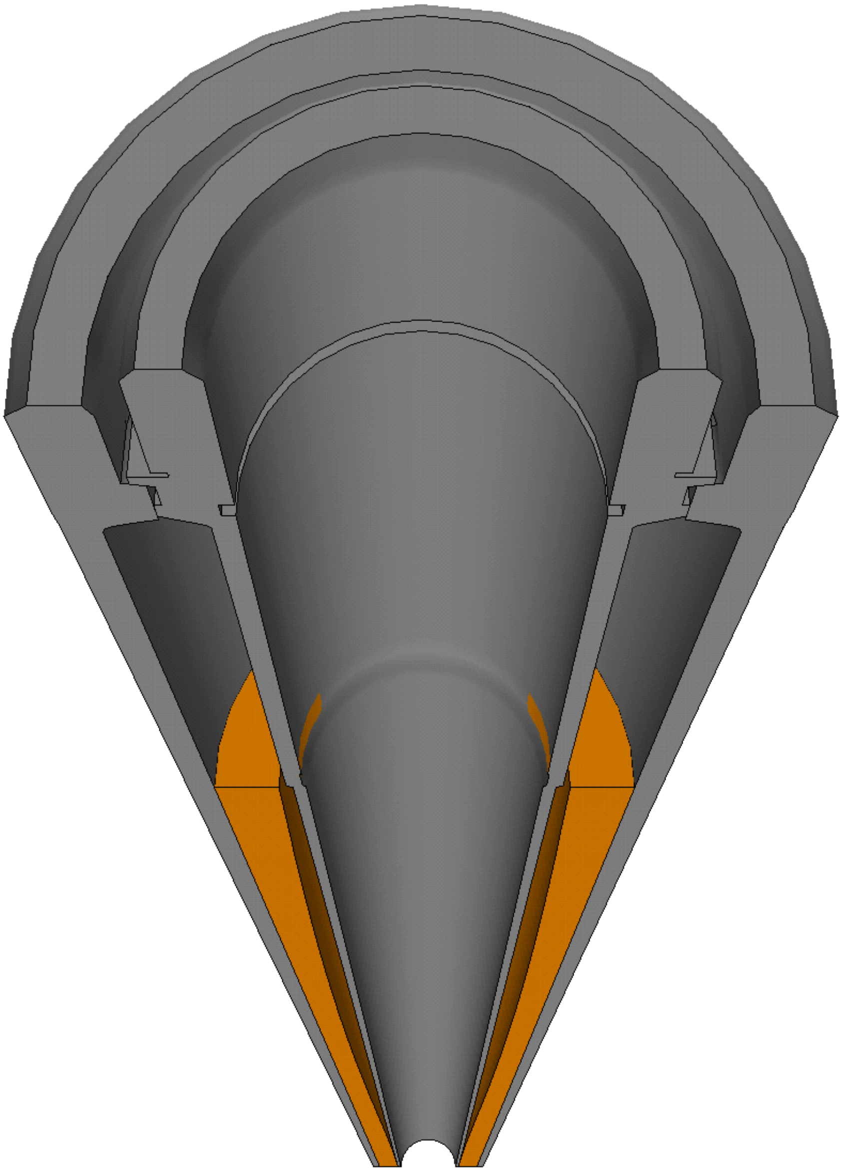


Figure 47 Top of well with indications of the cement small annulus (NOTE the radial size of the annulus gap has been enlarged 10 times its size)

In Figure 47 an illustration of the top a well with a modified cement model is shown. Cement is shown with a 5 meters cement shortfall, and the annulus crated by surface casing motions relative to the conductor casing movements is visible. It should be noted that the annulus radial gap has been enlarged 10 times its size for illustration purpose. Now this well model is ready for conventional local response analysis as per the methodology presented by Article I.

As the casing moves sideways displacing cement slurry/gel a void will be established. The gap used to obtain the analytical results in Article III spans a void as can be seen from Figure 47. This void volume has been estimated to be 273 litres in the 3D model and 631 litres in the 2D model. The annular volume capacity is 316 litres / meter. A subsequent increase of the TOC due to the creation of an annulus cement gap is thus small, less than 1 meter in a 3D model case. The model used in Article III is typical and the consideration of void volumes should be typical as well.

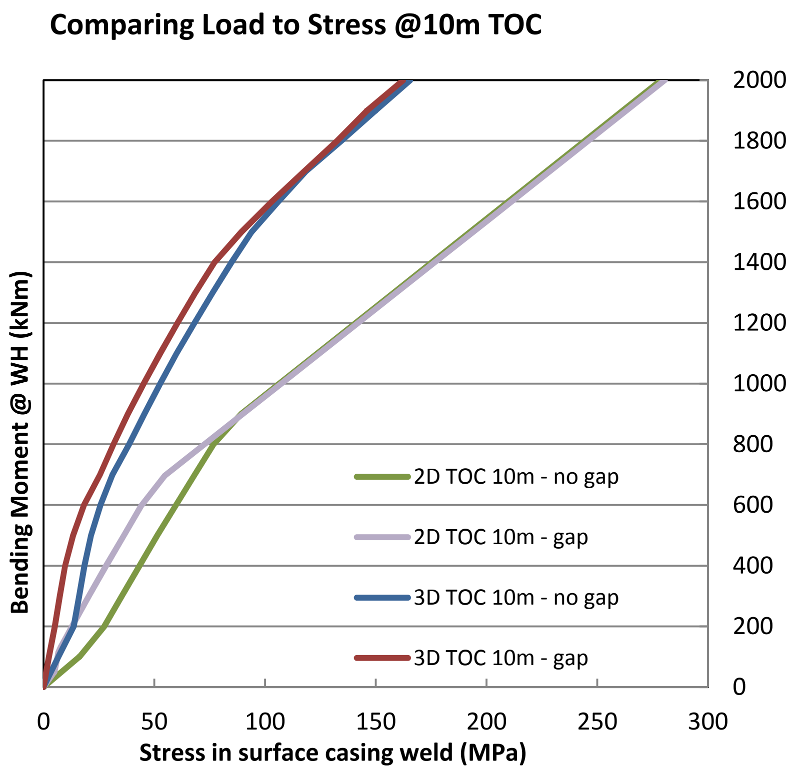


Figure 48 Comparing Load-to-stress for different models 10m TOC (Article III)

By such an analysis we establish the load-to-stress relationship as seen in Figure 48. The load-to-stress relationship is presented for a simplified 2D beam element FE model and a 3D solid element FE model, both with and without the modified cement modelling. The modified cement results are labelled –gap- in Figure 49. The results are derived for a TOC shortfall of 10 m. We see that the stress in the surface casing weld is estimated lower for any applied load less than 1600 kNm[35] when using the modified cement model.

[35] Applies to the 3D soild model, for the 2D beam model this statement is true for applied loads below 800 kNm

From a global load analysis performed using the associated well stiffness as a lower boundary condition a long term loading histogram can be established. The load histograms will be slightly impacted by the increased surface casing flexibility allowed by the modified cement modelling. Article IV discussed the impact of lower boundary condition variation on the fatigue load histogram. King et al. [39] found that "*The interdependence of the riser response and conductor foundation is significant; the stiffness of the foundation not only affects the loads applied to the foundation but also influences the stresses within the riser*".

Figure 49 illustrates the potential effect of the modified cement model on calculated fatigue life (fatigue capacity). The fatigue accumulation has been conducted using a load-to-stress curve related to TOC of 10m. A load histogram created on the basis of a well flexibility of a modified cement model has been used with a load-to-stress curve of the same case. Similarly for the conventional cement model case. Thus the effect of the modified cement model is captured both in the local response analysis as well as in the global load analysis.

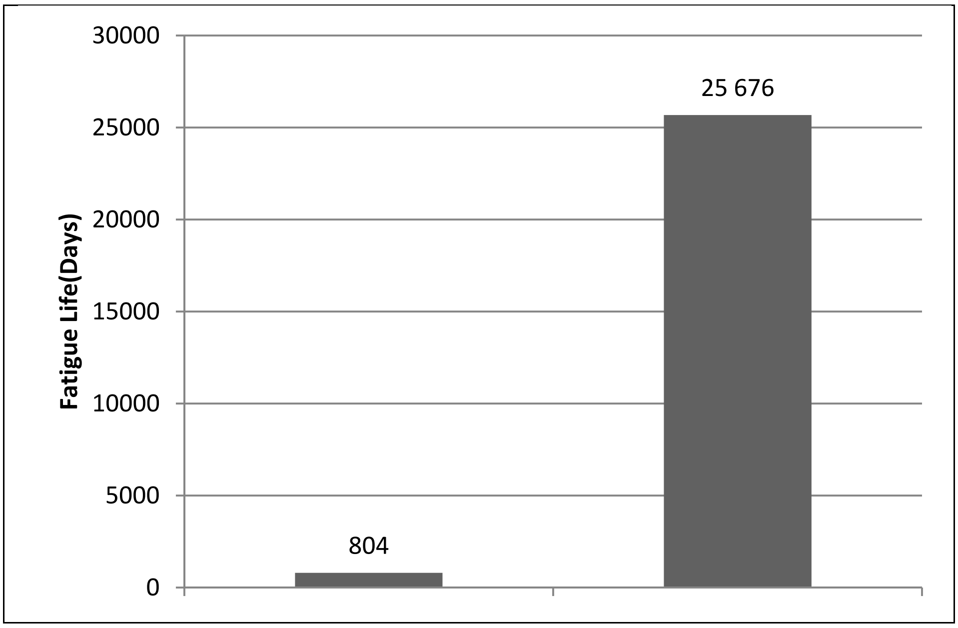


Figure 49 Fatigue life of a well with conventional and modified cement modelling using the stress-to-load relationship from the associated local FEM model (Article IV)

Figure 49 illustrates the difference in unfactored fatigue life obtained in a calculated well case only from imposing a modified cement boundary condition. We see that the fatigue life has increased 32 times from the introduction of a small annulus gap between cement and casing. By default a DFF of 10 is recommended. The situation then becomes 80 days allowable for the entire life of the well. Introducing the modified cement boundary condition results in an allowable fatigue life of 2567 days. This is equivalent to an unlimited fatigue capacity in practical life. It is unlikely that any operator would keep a MODU working 7 years on an individual well. In this case the use of the suggested boundary condition entails acceptable fatigue capacity or not.

5.6. Criteria for applying the modified cement modelling

The decision of applying a modified cement boundary condition in a local response model for the purpose of fatigue analysis will return a "favourable" load-to-stress relationship for the welded hotspot in the surface casing string. Thus it must be proven as a realistic assumption on an individual well basis. A caution principle should apply, if there is doubt if the conditions have been in favour of generating such a annulus cement-casing gap.

The criteria for applying a modified cement boundary condition in modelling and analysis of a specific well can be found in the operational log of the well[36]. A discussion and presentation of such criteria are presented here. First information from the operational log is needed:

1. The time between placement of cement in the annulus to the landing and connection of a riser system on the well needs to be identified.
2. The weather condition during the first week after connecting the riser.
3. Has the riser stayed continuously connected for the first week or not?
4. Confirm cement volumes that were aimed to cement to surface
5. Was the cement pumping operation successful?
6. Establish the lead cement composition used.
7. What is the sea bottom temperature data at this location?
8. Was the actual sea bottom temperature recorded at time of cementing?

[36] Alternatively in the operational plan for a well not yet drilled. The risk of not being able to follow the plan should then be assessed.

From the gathered information we can answer the following questions:

Was the time of stationary curing less than the initial setting curing time for the lead cement used?

If the answer is positive the modified cement boundary condition can be applied in the subsequent fatigue damage assessment. The modified cement modelling applies to the local response modelling and will apply both to an analytical or measured load damage accumulation.

Based on the cement slurry information and local temperature conditions a specific UCA re-test can be done to establish well specific curing time data. The same logic still applies.

6. Improving Wellhead Fatigue Life

The fatigue limit state expression as presented in section 3.10 will serve as a basis for discussing fatigue life improvment:

$$\frac{Calculated\ fatigue\ Life}{Design\ fatigue\ factor} \geq Fatigue\ service\ life \qquad (6.1)$$

$$\frac{L_F}{D_F} \geq L_S \qquad (6.2)$$

The calculated fatigue life L_F is synonymous with the physical limit or fatigue capacity that cannot be exceeded. This capacity is reduced by a design fatigue factor D_F and then compared to a loading or fatigue usage named fatigue service life L_S. Improving the fatigue life should be understood as actions that will result in increased capacity or reduced usage or both. Reducing the value of the design fatigue factor will have the same effect on the numbers without any real changes to the physical system. Determining the appropriate DFF value is a matter of acceptable safety levels, and has been discussed more detailed in section 3.10 page 68. A discussion of D_F value is therefore not included here.

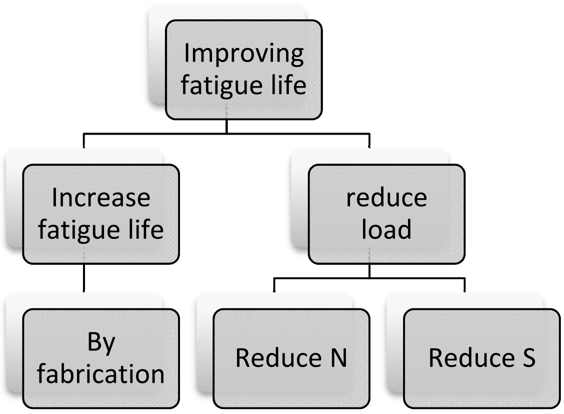


Figure 50 Reducing fatigue damage options

6.1. Increasing calculated fatigue life

Under the concept of the SN approach improving the calculated fatigue life is all about qualifying for using of a SN curve returning a higher fatigue capacity. As indicated by Figure 12 the welded connection between the wellhead and the surface casing is a fatigue hotspot that is reported to have failed from fatigue in service. In analytical fatigue assessments this weld tends to be critical, meaning that the combination of loading and limitation returns the least number of load cycles.

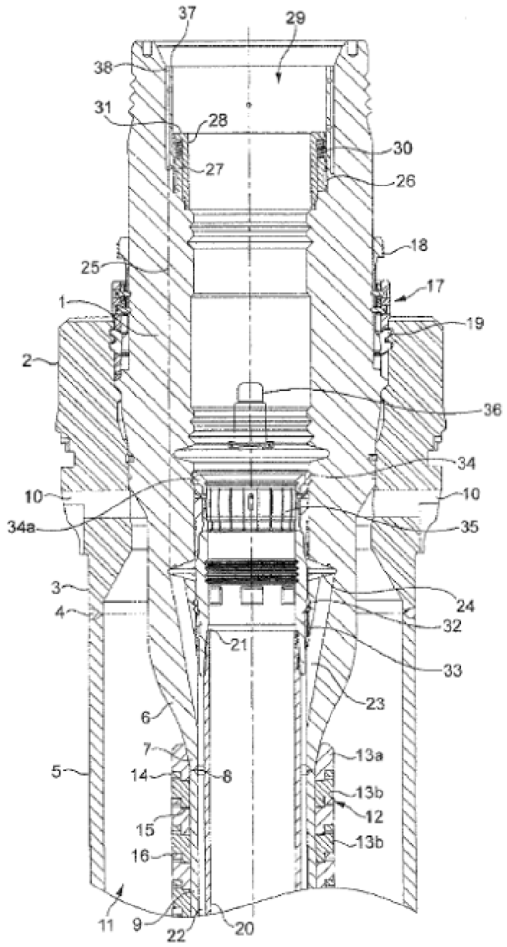


Figure 51 US patent drawing with fatigue optimized wall thickness transition (Item 6)[77]

Appropriate SN curve selecting criteria for a one sided girth weld refers to fabrication aspects. The post weld treatments are important e.g. NDT inspection and flush grinding and polishing. Additionally the degree of misalignment and ovality between the 2 adjoined cylinders is important.

Improvements of fatigue life capacity of the welded transitions between the housings and the casing extensions can be done during fabrication. The DnV RP C203 section 7 [62] provides guidance on welding fabrication improvements that will improve SN limit. Weld fatigue resistance can be improved by alignment and tolerance improvements.

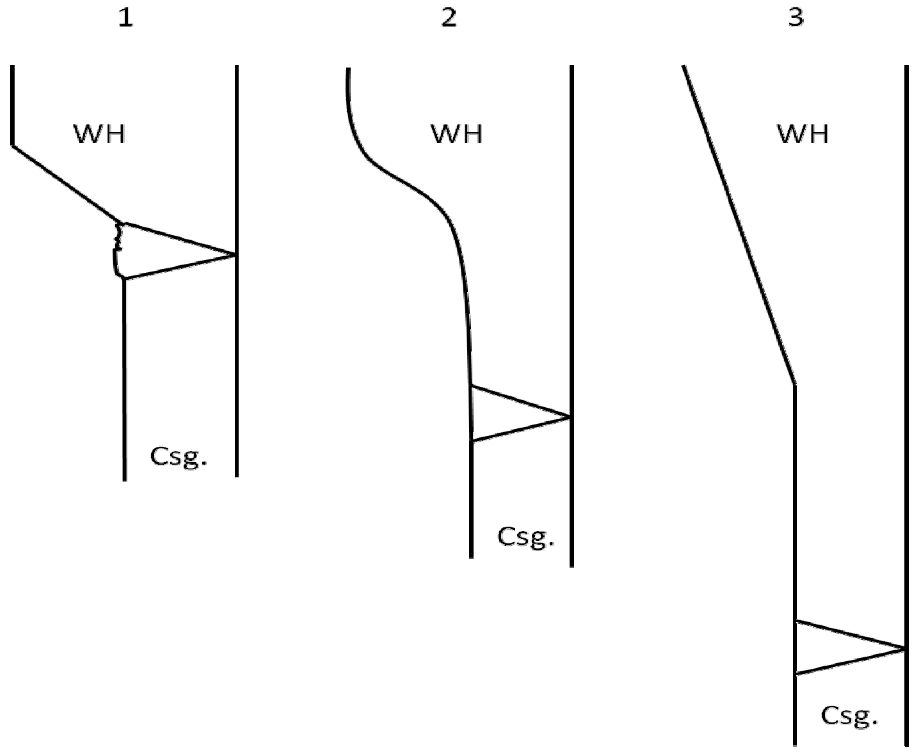


Figure 52 Examples of wellhead housing transition with different fatigue performance

The local wall thickness transitions of a wellhead to the casing extension weld can be done such to reduce the geometric stress concentration factor. Figure 52 indicates 3 examples of wall thickness transitions that will perform very different with regards to fatigue due to local stress amplification effects. Case 1 is the typical transition seen in most products of today. It is recognised by a sharp transition down to a casing wall thickness and the load bearing weld placed close to the transition. Case 2 in Figure 52 resembles the example of a fatigue optimised wall thickness transition that can be found in a wellhead fatigue relevant patent application of 2010 [77]. The wellhead illustration is shown in Figure 51 can serve as a good example on a design improvement. Item 6 in Figure 51 is the lower part of the wellhead housing (item 1) where the wall thickness transition down to the casing extension weld prep (item 8) is done. This transition has been made in a geometrically optimised manner in order to minimise local stress amplifications to the weld location. The case 3 in Figure 52 follows recommendations in DNV RP C203[37] [62] of a preferred transition of welded tubular.

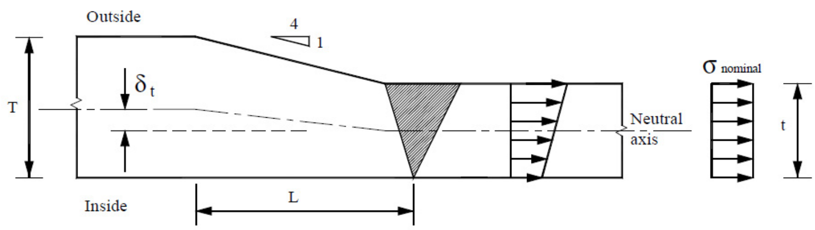


Figure 53 Preferred outer transition of tubular welded from the outside [62]

Additionally the weld has been moved from the transition to avoid the localised stress amplification effects. Both case 2 and 3 are indicated as flush grinded welds.

The weld quality will impact the SN curve that is applicable for the FLS evaluation. If the weld is designed as a static structural weld, as the current design codes do, no post weld treatments are likely to be implemented. If the weld is regarded as weld exposed to dynamic loading, which is the case in reality, the weld is likely to be specified

[37] Section 3.3.7 Stress concentration factors for tubular butt weld connections

with post weld treatments. Most efficiently this would include grinding and NDT inspections. DnV RP C203 [62] appendix A provides guidance on classification of welded details. With attention to the underlying requirements a subsea well weld may at best satisfy the requirements of a class C1 girth weld. Unless it will typically be rated as a F1 weld.

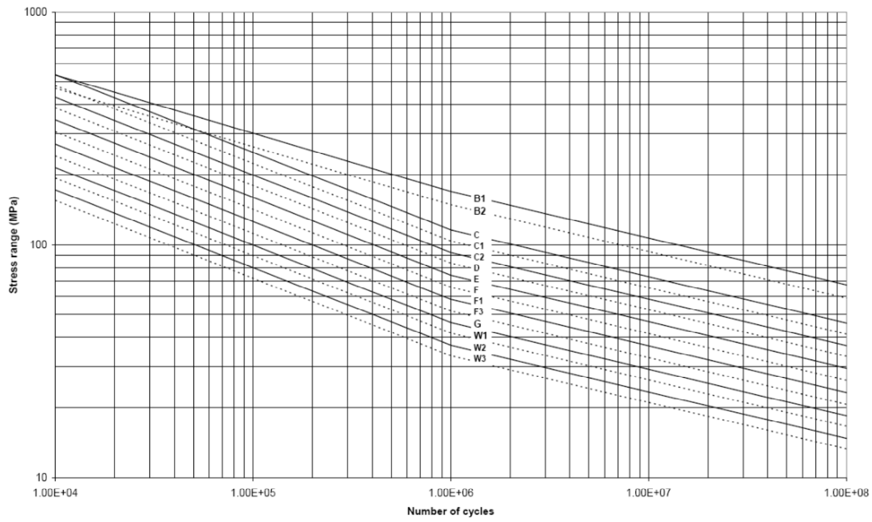


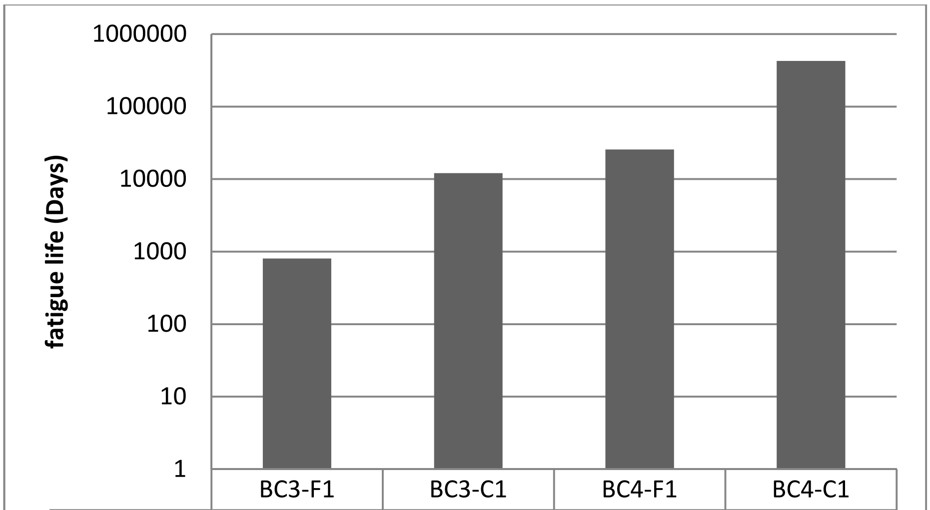
Figure 54 SN curves in seawater with cathodic protection [62]

Weld improvements from F1 →C1 will have significant effect on the limit. A weld quality improvement from F1 to C1 to the case presented in Article IV[38] will give the results presented in Figure 55. The improvement is significant, regardless of the cement modelling approach. The relative increase in life is 15 times for BC3[39] and 16.6 times for BC4. The reason why the increase is different is due to different load-to-stress curves between BC3 and BC4. In a practical

[38] See Figure 15 in Article IV

[39] BC3 and BC4 refer to notations used in article IV. BC3 is conventional cement modelling. BC4 is the modified cement modelling.

term the BC3-F1 will be unacceptable and the BC3-C1 will be acceptable[40].



	BC3-F1	BC3-C1	BC4-F1	BC4-C1
Fatigue Life	804	12062	25676	426327

Figure 55 The effect on unfactored fatigue life by improving the weld quality from F1 to C1 (note the use of logarithmic scale on the axis).

6.2. Reducing fatigue service life

The first step of improving the fatigue situation is to perform a FLS evaluation. From that the fatigue limit is known. Increasing the fatigue limit of a subsea wellhead is possible if you have design impact. The improvements are related to each hotspot, but the fatigue performance is affected by the details of the hotspot (e.g. thickness, weld quality, SCF) as well as the global design of the upper part of the well (e.g. cement level, casing down weight, tolerances).

Reducing the fatigue loading can be done in 2 ways, either by reducing the amount of cycles N or reducing the stress range S per cycle. A

[40] The allowable service life would be 80.4 days and1206.4 using a DFF of 10.

combination will have ample effect. Again there is a fundamental difference to design and planning or during operations.

Some examples of planning parameters that can help reduce fatigue loading are listed below.

- In harsher environments taking advantage of seasonal weather variations will help reduce loading [45].
- Imposing operational disconnect criteria related to high loading conditions will help reduce high stress loading.
- Reducing the height of the subsea stack will help reduce stress ranges[45].
- Use tailor made MODU designs[78].
- Avoid/reduce planned connected riser time with BOP on top of Subsea XT[45]
    - VXT has a benefit over HXT systems in this respect
    - LWRP/HP riser operations has lower fatigue loading benefits compared to the alternative SSTT Landing string operations

Reducing the number of cycles most typically involves reduction of down hole well plans in order to reduce the overall duration of connected riser/BOP. Additionally increasing the operational efficiency of operations by planning and training ensures spending minimum time in connected mode. The high day rates of MODUs gives operators an incentive for ensuring that this is already as low as reasonable practical. The potential for improvements are thus small.

Existing wells with a need for well interventions work has the highest potential for reducing the fatigue load. A reduction potential exists by planning well intervention work typically done from a MODU to be done by riser less vessels operations. The rise less well intervention technology is currently increasing its scope of work in the North Sea [46].

In the presented methodology the local response analysis provides a load-to-stress relationship that ensures mapping from applied wellhead loading to the resulting stress in the hotspot in consideration. During planning of a well construction we may impact the relationship between load and stress in a hotspot. Some examples of well construction considerations that may affect the load-to-stress relationship are:

- Maximising net down weight from suspended casings
    - Using heavy walled casings will increase the mass of the casing string
    - Avoid combining 2 strings into 1 even if formations permit.
    - Displacing the cement by weighted fluid will counter the buoyant effect of cement
- Programmed cement shortfall will reduce the fatigue damage of the surface casing [26].
- Ensuring BOP is landed on wellhead prior to setting of lead cement close to seabed will reduce fatigue damage of surface casing (Article III)
- The use of a preloaded wellhead system will reduce the fatigue damage of the surface casing [11, 45]
- Improving conductor fatigue capacity
    - Increasing Outer Diameter from 30” to 36”
    - Ensuring heavy wall conductor
    - Ensuring use of fatigue proven preloaded conductor connectors, particularly for the first connector
- Casing weld improved by fabrication

  - Avoid use of quick-lock type conductor with no preload. Such connectors are not suited for dynamic bending loads[32]

Approach to reducing fatigue of subsea wells: one can reduce loading per cycle, reduce number of cycles, or improve fatigue capacity. In more layman's terms this can be converted into: use smaller and lighter rigs during summer, make it quick and grind your welds.

7. Conclusions

Low sea water temperatures will depress the normal thermal gradient of the upper parts of the soil. Subsea wells are typically cemented using a lead and tail cement system, and the lead top casing cement will be pumped all the way to seabed. This lead cement will then be left curing in a low temperature environment. Hydration of cement is a chemical reaction, and the reaction rate is dependent on temperature. Laboratory measurements of low temperature early compressive strength of typical lead cement slurries are presented herein. These results show that more than 24 hours curing time is needed for lead cement to reach initial setting in a low temperature environment.

In the North Sea the typical duration between placement of surface casing lead cement and installation of BOP/drilling riser will be around 24 hrs. Then dynamic riser loads will start acting on the upper part of a subsea well. The cement around these casings will experience cyclic casing motions due to BOP/riser loads. The combination of delayed cement setting due to low temperature and surface casing motions will cause localized failure of cement bonding in upper part of the well.

With the near bottom seawater temperatures presented in Table 4 and the initial curing times presented in Figure 44 and more detailed in Article II it is likely that a majority of subsea wells in the North Sea will have a surface casing-cement gap close to seabed. Such wells may be candidates for using the modified cement boundary condition presented in Article III. Analysis of the effect of a modified boundary condition has showed a significant impact on surface casing fatigue life as discussed in Article IV. The fatigue life has increased 32 times from the introduction of the modified cement model.

The effect of a well-like boundary condition approach has been outlined in more detail in Article IV. Results from this research indicate that more dynamic behaviour is captured by the global load analysis from using a lower boundary condition with actual well flexibility. Results are presented in detail in Article IV and show an increase of 76% in the number of load cycles estimated by the load analysis, compared to a fixed well model.

The subsea wellhead is both a pressure vessel and a structurally load bearing component resisting external loads transmitted from a connected riser. Cyclic loads will cause fatigue damage to the well. The well can take a certain amount of fatigue damage without failing. A fatigue failure of a WH system may have serious well integrity consequences. Overall well ultimate structural strength will be reduced by the presence of a fatigue crack in a non pressurised load bearing part of a subsea well. An analysis methodology with case results is presented and the studied case indicates that the location of a fatigue crack affects the reduction in ultimate strength. A residual strength of 44% of the intact well strength was found if the conductor has failed. Cases of significant reduction are expected to impact normal operating limitations.

Knowing the failure probability of the wellhead fatigue failure mode enables operators to include wellhead fatigue in an overall risk management system. A structural reliability analysis methodology approach is suggested and notational failure probabilities are presented in Article VI. This approach may be used to establish case specific design fatigue factors that correlates to a target safety level specified by the operator. The results indicate that a DFF of 10 returns over-conservative results. The first real well case specific structural reliability analysis is now (2012) underway in the industry.

Future improvements to wellhead fatigue analysis may emerge from calibrations from measurements of the reality. A comparison between analytical fatigue loading and measured fatigue loading has been presented and results indicate that the analysis results are conservative. This is evidence that analytical estimate on acceptable fatigue limits can be trusted from a safety point of view. It also indicates the monetary potential that measurements can present to the well.

The present work has several contributions to the building of a unified analysis methodology which is currently underway in an industry JIP "structural well integrity". An overall analysis methodology has been suggested and is currently included in the JIP draft recommended practice document on wellhead fatigue analysis. The draft is now (2012) out for industry comments.

8. Contributions

The main contribution from the research presented is a modified boundary condition modelling of lateral cement support on the surface casing as presented in section 5.5 and Article III.

This is based on laboratory work that gives guidance on the timeline vs. typical operations during initial well construction work. This will not only apply to future wells but also to all existing subsea wells that satisfy the criteria for using such modified modelling which was discussed in section 5.6.

Other contributions is the more general knowledge of who low temperature significantly affects the development of early compressive strength and initial setting of lead cement (cement slurries with a higher than optimum w/c-ratio). This knowledge can be utilised in all arctic and deep water foundation designs, possible beyond the scope of the petroleum industry e.g. offshore wind turbines.

The ongoing JIP will establish a Recommended Practice document that will be internationally available. The document is expected to be made contractual by the participating operators. This work includes contributions that will be relevant for establishing such a methodology.

Lower Boundary conditions for global load analysis will affect the dynamics of the problem and return a higher number of fatigue load cycles. The use of fixed boundary condition is not a conservative choice. The research results presented in Article IV forms a basis for deviation from the prescribed boundary condition definitions as specified by the current design specification for drilling riser analysis [61]

When planning drilling activities on a well with a previous load history it is important to verify conditions for safe operations. If this is not the case the possibility of a fatigue fracture may significantly affect the residual strength of the wellhead. This reduction may have caused the well to be the weak-point under the given operational limitations, and new operational limitations have to be implemented. This has been closer described in Article V.

Current analysis methodology returns conservative results. The modified boundary condition may be a possible explanation to why previous operational practices have been beneficial to wellhead fatigue.

9. Further work

There are several aspects that affect our ability to model a subsea well for the purpose of fatigue damage estimation that will need further research. Thermal growth of steel tubular due to the increase of temperature during production is a well known phenomenon. During drilling activities the bottom hole temperature will increase as the well construction progresses deeper. The drilling fluid constantly circulating within the well will heat up and bring thermal energy towards surface. Drilling fluids will sweep casing strings suspended from the wellhead area and possibly impose an increase in steel temperature above the normal thermal gradient. Such thermal effects may affect the load sharing between the surface casing and the conductor and be important in wellhead fatigue modelling. Thermal effects from circulating drilling fluid during initial well construction have not been fully understood in a wellhead fatigue context and should be further investigated.

Thermal analysis on transient behaviour in upper part of a subsea well during top casing cementing in low temperature conditions should be evaluated to address the concerns raised by Romero and Lozzio [73]. They recommended against performing UCA testing on a constant temperature equal to the seabed temperature arguing that this could result in too conservative WOC. Investigations into what would be a more correct curing temperature or temperature profile will be beneficial to ensure optimum WOC and for better estimation of time until initial setting of lead cements.

The current analysis methodology assumes an abrupt introduction of annulus cement lateral support. There may be a potential for the industry to keep this modelling approach by use of an equivalent cement level that would return equivalent fatigue life as the modified boundary condition modelling. Further research work is needed to establish an accepted way of defining the equivalent cement shortfall

Modelling of conductor cement as a boundary condition could potentially have important impacts on the local wellhead behaviour. Employing the presented knowledge on curing time for lead cements in a low temperature condition could result in updated recommendations on conductor cement modelling. The effect of grouting of conductor and recommendations on how to model these remedial cementing jobs will impact several subsea wells.

Ultimate load capacity of a subsea wellhead may be affected by the basic knowledge presented with respect to cement boundary condition modelling. Any such effects have not been investigated herein, and are suggested as future work.

Finally there is future needs for full scale measurements for the purpose of calibration and improvements to the analytical tools used in wellhead fatigue damage estimation. The potential of direct measurements has been shown by the result presented in Article VII.

10. Nomenclature

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BC	Boundary Condition
BOP	Blow Out Preventer
DFF	Design Fatigue Factor
E&P	Exploration and Production
FEA	Finite Element Analysis
FORM	First Order Reliability Method
GOM	Gulf Of Mexico
HPHT	High Pressure High Temperature
ID	Internal Diameter
LMRP	Lower Marine Riser Package
LRFD	Load and Resistance Factor Design
MODU	Mobile Offshore Drilling Unit
MRWP	Maximum Rated Working Pressures
NDT	Non Destructive Test
NPD	Norwegian Petroleum Directorate
SCF	Stress Concentration Factors

SN	Allowable Stress Amplitude 'S' - Number of Design Cycles 'N'
SORM	Second Order Reliability Method
UCA	Ultrasonic Cement Analyser
VIV	Vortex Induced Vibrations
WAG	Water-Alternating-Gas
WH	Well head
WSD	Working Stress Design

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Part II - Articles

Summary of articles

This part contains reprints of the articles as published and a brief description of each article.

Article I outlines a fatigue analysis methodology involving 3 analytical steps;

1. Local response analysis
2. Global load analysis
3. Fatigue damage assessment

The proposed methodology is prescriptive in order to promote benchmarking of analysis results based on well design and input parameters. There is no guidance on how to perform fatigue analysis of subsea wells in international standards or codes today.

Article II presents the quantified results from laboratory work on early strength development in lead cement slurries cured at low temperatures. Curing temperature affects the hydration rate of cement slurries is a fact recognised by most textbooks on cement hydration. The effect is governed by W/C ratio and temperature. This article presents data for compressive strength for high W/C slurries cured at low temperatures. The sea bottom water temperature in deep water will be low year round. Sea bottom temperatures in North Sea will be low, with some seasonal variation. Thus top casing cementing operations in Arctic will have similarities to the curing temperature conditions as seen in deep water drilling. The findings presented in this article forms an important basis for the modified cement modelling.

Article III presents a modified modelling of the surface casing lateral support boundary condition in local response analysis. The article presents case studies of 2D ad 3D FEM models with and without the modified modelling approach. Results clearly indicate the stress reducing effect from a more realistic cement modelling. The article indirectly supports the modelling choice of using 3D FEM as stated by Article I, as 2D FEM yields higher stresses compared to a 3D FEM approach.

Article IV addresses the impact on global load analysis by variations of the lower boundary condition of the riser model. The article supports the recommended lower boundary condition definition suggested in Article I and indicated that the stress reduction obtained by a modified cement boundary condition as suggested in Article III is not outweighed by changes in loading.

Article V addresses the reduction in ultimate structural strength of a subsea well given a fatigue fracture at 3 different hotspot locations. Results show that the residual strength is largely dependent on the location of the fracture. Potential operations on a wellhead where unacceptable fatigue damage has been estimated should honour this reduction by rechecking the weak-point analysis, ensuring that the wellhead is not the weak point in an accidental loading case. Reduction of normal operating limitations can be expected.

Article VI outlines a methodological approach on how to perform Structural Reliability Analysis of the problem of wellhead fatigue. Notational probabilities of failure and parameter uncertainty impact factor results are given. This approach may form the basis for establishing wellhead fatigue failure probability needed as input in a risk management system.

Article VII outlines an approach where riser load measurements has replace the analytical load estimation in the overall wellhead fatigue damage methodology as presented in Article I. It further elaborates on how such measurements can be used to estimate past and future operations fatigue damage. The accumulated fatigue damage from a fully analytical approach is compared to damage derived from direct load measurements. This comparison shows that the analytical approach is conservative and largely so.

Article I

Title: Wellhead Fatigue Analysis Method

@ OMAE2011, Rotterdam, the Netherlands, 2011

Authors:

Lorents Reinås

Torfinn Hørte

Morten Sæther

Guttorm Grytøyr

Article II

Title: Hindered Strength Development in Oilwell Cement due to Low Curing Temperature

@SPE Arctic & Extreme Environments Conference, Moscow, Russia, 2011

Authors:

Lorents Reinås

Helge Hodne

Mirkamil Ablikim Turkel

Article III

Title: Wellhead Fatigue Analysis Method: A new boundary condition modelling of lateral cement support in local wellhead models

@OMAE2012, Rio de Janeiro, Brazil, 2012

Authors:

Lorents Reinås

Morten Sæther

Johan Svensson

Article IV

Title: Wellhead Fatigue Analysis Method: The Effect of Variation of Lower Boundary Conditions in Global Riser Load Analysis

@OMAE2012. Rio de Janeiro, Brazil, 2012

Authors:

Lorents Reinås

Guttorm Grytøyr

Massiliano Russo

Article V

Title: The Effect of a Fatigue Failure on the Wellhead Ultimate Load Capacity

@OMAE2012. Rio de Janeiro, Brazil, 2012

Authors:

Lorents Reinås

Morten Sæther

Bernt Sigve Aadnøy

Article VI

Title: Wellhead Fatigue Analysis Method: Benefits of a Structural Reliability Analysis Approach

@OMAE2012. Rio de Janeiro, Brazil, 2012

Authors:

Torfinn Hørte

Lorents Reinås

Jan Mathisen

Article VII

Title: Fatigue Damage Estimation of Subsea Wells from Riser Load Measurements

@OMAE2012. Rio de Janeiro, Brazil, 2012

Authors:

Massiliano Russo

Morten Sæther

Harald Holden

Lorents Reinås

Student work

During the preparation of this work I have assisted in the design of experiments, laboratory work and supervision of the following student work:

I. Vibeke Henriksen, BcS Thesis,
"Rheological Development of Top Hole Cementing Slurries",
UiS 2011

II. Mirkamil Ablikim Turkel, BcS Thesis,
"Time and Strength Development of Cement mixtures due to low temperature ", UiS 2011