# Design and integrity management of mobile installation moorings

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# Design and integrity management of mobile installation moorings


**P. J. Donaldson, B.Sc. Master Mariner, MRINA**
**M. Brown B.Sc., M.Sc., M.B.A., C.Eng., MRINA**
**M. Pithie, Master Mariner**
Noble Denton Europe Ltd
Noble House
131 Aldersgate Street
London
EC1A 4EB



The design of semi-submersible moorings that operate in the UKCS are assessed against Codes which are continually being modified and updated to deal with technological changes taking place in the industry. The report reviews and compares current documents put forward by Class and Regulatory Bodies and provides guidance on individual features common to each of the Codes considered. In general the report does not deal with Floating Production Installations although reference is made in the section dealing with line fatigue

Semi-submersible units operate in a number of different modes. Although the functions vary between drilling, accommodation and lifting, the basic make-up of their mooring systems comprises chain and wire. Man-made fibre ropes are beginning to be deployed within the industry but at the time writing their application is mostly limited to permanent mooring systems, and those being outside the UKCS.

The inspection and successful maintenance of a unit's mooring system are costly and balances are constantly being sought to keep inspection times to a minimum yet maintaining a high degree of reliability and integrity through regulatory requirements. In this respect connecting links come under close scrutiny since many instances of line failure can be attributable to these items of equipment.

The report addresses current practice in the event of line failure and also the low indicative reliability of emergency disconnect systems.



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# 1 EXECUTIVE SUMMARY

This report encompasses a review of the main aspects of a mobile offshore unit (MOU) mooring system, including the mooring analysis whilst located within the area of the United Kingdom Continental Shelf.

## 1.1 CODES

The areas covered in this report include a review of the Codes and the reasons that one Code should be used in preference to another. This section highlights the reasons for each Code. For example, API RP 2SK is a recommended practice, DnV's E301 is described as an offshore standard specifying Class Society requirements. The review of the Codes takes into account the main features of the mooring system, how it should be analysed, which extremes should be considered and when set up, how it should be maintained. Wherever possible the information has been tabulated for ease of data extraction. The ISO Standard ISO/TR 13637 First Edition is currently being modified and brought up to date. Although still in Committee Draft stage, the changes are discussed in this document.

Return periods to be used in analyses together with the proof loading of anchors, the use of line optimisation and safety levels are discussed in the Commentary to this section.

## 1.2 PRACTICE AND PROCEDURE IN THE EVENT OF LINE FAILURE

The reasons for line failure in MOU's are discussed together with practice and procedure in the event a mooring line parts. The procedures for such an event are to be found contained in the Operations Manuals of units, but more importantly in the Emergency Response Manual that may form part of the Safety Case. Although there are basic rules and procedures for dealing with such an incident the variables (such as weather, if in close proximity to subsea and surface assets etc) determine that a Hazop followed by a risk assessment between senior personnel must be carried out.

As an adjunct to this section, the reasons for the failure of chain or wire mooring lines are discussed including the problems associated with brittle fracture of chain.

## 1.3 IN-FIELD TENSION MONITORING

Although not specific to the Scope of Work In-Field Tension monitoring is nevertheless relevant to this report. The discussion derives from recent research on the effect that unbalanced lines may have on the mooring system as a whole. Causes of imbalance include the possibility that the tension meters may not be reading accurately or that the fairleads may not be running freely.

The discussion also deals with methods of determining true values of tension in a unit's mooring lines.

Checks on the rotation and azimuth of fairleads should be carried out whenever possible to avoid potential wear on mooring wires or chains. Such checks may be carried out during the move of the unit but should also be incorporated as part of the unit's PMS system.

## 1.4 MOU LINE INSPECTION

Current mooring inspection policies were found to be based around Class requirements with respect to the frequency of surveys. These include annual, biennial and 5 year inspections. Rig owners are very conscious of the physical and commercial effects a broken mooring can have upon their operations and, assisted by the Field Operators take great care to ensure that the correct equipment is being utilised.

Rig owners mobilize to their proposed location with the basic mooring equipment on board. Should the water depths or the features of a location require a particular design of mooring, then the Operator provides the extra equipment, which is compatible in strength to the existing on-board system. Owners, as a matter of good practice check chain and wire moorings at the time of retrieval although it is noted that in the case of chain, such an inspection is of limited value. This said, older chain and chain with a large number of connecting shackles should be identified and given greater scrutiny.

The merits of offshore inspection as against an onshore inspection are discussed. For chain a dockside inspection is preferable. For wire an offshore inspection may be more effective. A useful facility retained by some rigs is the ability to resocket their own wires. Such measures provide a useful adjunct to units that deploy full length wire mooring lines.

The essential need for maintaining records, particularly when chain has a large number of connecting links is also discussed. Class Societies keep their own mooring line records but this should not detract from the need for the rig crew to maintain records as a matter of good practice.

## 1.5 MOU LINE FATIGUE

Given the relative short-term nature of most MOU individual deployments, fatigue during the deployment period is unlikely to be a key issue. However, over the course of a number of deployments, particularly in similar water depths, fatigue may start to be a problem. Unfortunately, it is very difficult to generate and keep up to date records of the cumulative degree of fatigue damage experienced by individual lines. This is less worrying than might be the case for a permanent moored system, since in air inspection can take place at regular intervals when the lines are recovered. To have reasonable confidence of detecting defects adequate time and resources must be assigned to the inspection process, taking into account the shortcomings that may be experienced at the time of chain retrieval.

Owing to the fact that connecting links are a significant source of mooring line failures the Commentary to this section contains a note on the use of Kenter links. The purpose of the note is to raise the awareness amongst operating personnel of the exposure these links have to fatigue and the need to have a removal and replacement programme in place.

## 1.6 ANCHORS AND RIG BASED EQUIPMENT

This section covers a short review of anchors and the inspection of rig based equipment. Anchors used in the North Sea today are of a high holding design with weight to holding power ratios in excess of 10, and in the case of the Stevpris Mk 5 and the Bruce FFTS designs, in excess of 30.

Because of the anchor types available and their effectiveness, the use of piggyback anchors has been reduced. In certain areas of the North Sea they may still be required although piggyback anchors tend to be not so effective as a result of the way they are laid.

Windlasses and fairleads are generally checked on anchor retrieval. Their condition and operation is intrinsic to successful anchor running operations. Windlasses and fairleads have the potential for serious damage to chain and wires if not checked or maintained.

## 1.7 EMERGENCY RELEASE SYSTEMS

Section 11 deals with emergency release systems, which on most units comprise a number of individual systems.

The purpose of an emergency release system is to release the leeward lines to allow the rig to move upwind in case of blow-out.

Windlasses are fitted with a number of braking systems and it is a combination of at least two of these brakes, which not only hold the chain but also are designed to release in an emergency situation.

The different combinations of brake described deploy a number of subsystems, electrical, pneumatic or hydraulic. The more components deployed in an emergency release system the less the probability of a successful release. Tables lifted from Report OTO 98.086 show the probability of successful releases in cases of pneumatic or hydraulic systems. The derived probabilities demonstrate that preventive maintenance is an essential feature of any system, including a full programme of testing.

It is practice when initially set up at a location to perform a "move off" drill and function test each of the individual systems without actually releasing lines.

Report OTO 98.086 also identifies a difference in the effectiveness of release systems due to the variance in water depth.  We would endorse the recommendations that owners identify how far the rig will move after release in a given water depth, and if necessary prepare contingency plans to cover the shortfall.

# 2 INTRODUCTION

This report examines the design and integrity management of mobile installation moorings. A mobile installation can have a number of functions from drilling and accommodation to platform support work. Other functions for mobile installations include Floating Production Installations (FPI's) but these have been specifically excluded from this study and the work centres on the monitoring of moorings for Mobile Offshore Units (MOU's). Accommodation and platform support units including crane vessels are included.

Fibre ropes are a relative innovation into the mooring of MOU's. At the time of writing we have no knowledge of fibre rope mooring applications in the UK sector of the North Sea and for this reason they have been omitted from this report.

An executive summary to the report is provided but additionally, commentary is provided at the end of each section.

# 3 INSTRUCTIONS

Instructions were received contained within the Offer of Agreement No. D5096 dated 3rd December 2003. The Agreement contained the Scope of Work together with the time schedule within which the work was to be performed. The instructions were confirmed to the Research Procurement Officer with the return of the signed Agreement on 17th December 2003.

# 4 SCOPE OF WORK

Guidance to NDE for the proposed scope was provided in a discussion document contained in an e-mail dated 7th August 2003. Further guidance was provided in an e-mail dated 4th September 2003. The scope of work for this study will include as a basis the following,

- Review of the Codes used in mooring analyses, the differences between them and to provide insight into why one Code should be preferred over another.
- To review current practice, procedures and actions in the event of a MOU line failure. To assess the results with a view to providing guidance on best practice.
- To determine and review current mooring inspection policies, practices and methods. To provide guidance on the differences between practices and the confidence of the results from each of the applied methods.
- To examine how fatigue analyses are factored into mooring inspections and to provide guidance on how such analyses may be applied (if appropriate) to MOU's with differing mooring regimes and patterns.
- To provide guidance for hardware inspections of rig based mooring equipment for MOU's.
- To examine current methods of moorings release in the event of an uncontrolled blow-out and provide insight into the effectiveness of different systems.

# 5 REVIEW OF CODES

## 5.1 GENERAL

Industry Codes are in place to provide good practice methods for the assessment of the mooring of Mobile Offshore Units (MOU's) when either operating or stacked. The function of these Codes is to issue guidance when assessing a unit's moorings and also to provide factors of safety for compliance purposes. Some Codes perform this function through the requirements of Class others through a recommended practice document.

The Department of Energy document *'Offshore Installations: Guidance on Design, Construction and Certification, 4th Edition'* was withdrawn in 1998. The information contained within this document has now been provided in the Health and Safety Executive's *'Offshore Technology Report – 2001/050'*. The guidance contained within this report is mainly applicable to mobile units, and may not be directly applicable to FPI's where issues such as heading control and fatigue are relevant.

### 5.1.1 API RP 2SK: "Recommended Practice for Design and Analysis of Station keeping Systems for Floating Structures", Second Edition, December 1996

The Code provides a Recommended Practice to determine the adequacy and safety of a mooring system. Detailed and specific recommendations are made where adequate data is available. In other areas, general statements are used to indicate the points where consideration should be given.

#### *5.1.1.1 Analysis Guidelines*

This Code provides for a Quasi-static analysis normally used for MOU's, however, if required the Code also provides for a more detailed or dynamic analysis of a mooring system.

Design conditions: at least 5-year return conditions for the wind, wave and current extremes should be used if away from other structures. If in the vicinity of other structures at least 10-year return conditions should be used. The Code gives examples of "*Operations in the vicinity of other structures*"; where lines are deployed over a pipeline or where the unit is moored close to a platform.

| Type of Mooring | Analysis Method | Return period for Extremes | Conditions to be analysed |
|---|---|---|---|
| MOU away from other structure | Quasi-static or Dynamic | 5 Years | Intact |
| MOU with mooring lines over pipeline | Quasi-static or Dynamic | 10 Years | Intact / Damaged |
| MOU next to other structures | Quasi-static or Dynamic | 10 Years | Intact / Damaged / Transient |

Table 1 Analysis Guidelines

The Code allows for the slackening of leeward lines to reduce line tensions and offsets as long as it is carried out in a regulated and controlled manner on the MOU.

#### *5.1.1.2 Fatigue Analysis*

Fatigue analysis is dealt with in the Code recommending only that the extreme response analysis is required for MOU's. For short-term moorings therefore, fatigue analysis is not required. (Many fatigue sensitive mooring components such as Kenters are replaced before they reach their fatigue limits - see Commentary to Section 9)

#### *5.1.1.3 Allowable Offset.*

The allowable offset is directly related to the mean ball joint angle of the drilling riser sometimes known as the flexjoint. The joint itself is found at seabed level located immediately above the Lower Marine Riser Package (LMRP) and should the offset be exceeded then damage may occur to the joint. The mooring analysis is used therefore to determine the maximum offset in the storm conditions, but only the intact condition needs to be used.

Guideline: The allowable mean offset is usually between 2% and 4% of the water depth (lower bound for deepwater, upper bound for below 300 feet)

Allowable maximum offset usually between 8% and 12% of the water depth (lower bound for deepwater, upper bound for below 300 feet)

#### *5.1.1.4 Line Tension Safety Factors*

The Code recommends that the safety factors as shown below should be satisfied.

| Condition | Analysis Method | Tension Limit (Percent of line breaking strength) | Safety Factor |
|---|---|---|---|
| Intact | Quasi-static | 50 | 2.00 |
| Intact | Dynamic | 60 | 1.67 |
| Damaged | Quasi-static | 70 | 1.43 |
| Damaged | Dynamic | 80 | 1.25 |
| Transient | Quasi-static | 85 | 1.18 |
| Transient | Dynamic | 95 | 1.05 |

Table 2 Equivalent Factors of Safety for Wire or Chain Systems

The Code describes the table above as a departure from the earlier API RP 2P Code where a lower tension limit is recommended for the maximum operating environment.

#### *5.1.1.5 Line Lengths*

API RP 2SK states that the outboard mooring line length should be sufficient to prevent uplift at the anchor, especially when fluke penetration is anticipated to be shallow. Generally speaking conditions in the Central and Northern part of the North Sea, including West of Shetland, seabed conditions comprise clays and fluke penetrations tend not to be shallow.

#### *5.1.1.6 Proof Loading Moorings*

The Code states that preferably, the test load at the winch should be at the same level as the *maximum* line tension in the maximum design condition. Should this not be achievable for operational reasons then the test load should not be less than the *mean* line tension under the maximum design condition, or the maximum line tension under the maximum operating condition, whichever is the higher.

#### *5.1.1.7 Line Optimisation*

Line tension optimisation is permitted provided such an operation is well defined in the operation manual and is routinely carried out by trained personnel. However, for units operating in the North Sea and West of Shetland storms can arise with little warning with sudden change in wind direction. Such an operation is therefore not practical and should not be considered in the analysis.

#### *5.1.1.8 Thruster Assistance*

The use of thrusters to help reduce environmental loading on the unit is permitted based on the following guidance.

| Mooring System Status | Manual Remote Control (TA) | Automatic Remote Control (ATA) |
|---|---|---|
| **All Lines Intact** | 70% of net thrust after failure of any one thruster | Net thrust after failure of any one thruster |
| **One Line Broken** | 70% of net thrust from all thrusters | Net thrust from all thrusters |

Table 3 Guidance on use of rig thrusters

### 5.1.2 DNV Posmoor 1996

This Code is part of the DNV Rules for Mobile Offshore Units. It contains criteria, technical requirements and guidance on the design and construction of position mooring systems. The Code is predominantly focused on the Classification of floating mobile offshore units, which employ a short-term mooring spread. However it also includes Floating Production Installations (FPI's).

The Code has been replaced by DNV's Offshore Standard E301 (June 2001). The guidance given by DNV on the transition between the two Codes is that DNV MOU Rules Pt.6 Ch.2 January 1996 (POSMOOR) has been withdrawn. However, the Class accepts that the rules valid when a unit was built are applied, when the unit is not going through major reconstruction. In this specific case the old POSMOOR rules may be applied if accepted by the national authority.

#### *5.1.2.1 Analysis Guidelines*

The design conditions specify: the most unfavourable combination of 100-year wave and wind with 10-year current or 10-year wind with 100-year wave and current. Fatigue analysis is not required for a MOU. A table of safety factors is shown below.

| Operating Condition | | Quasi-Static Analysis | | Dynamic Analysis | |
|---|---|---|---|---|---|
| | | POSMOOR | POSMOOR V | POSMOOR | POSMOOR V |
| 1 | **Intact System** | 1.80 | 2.00 | 1.50 | 1.65 |
| | **Transient Motion** | 1.10 | 1.10 | 1.00 | 1.00 |
| | **Temporary mooring after single line failure** | 1.25 | 1.40 | 1.10 | 1.25 |
| 2 | **Intact System** | 2.70 | 3.00 | 2.30 | 2.50 |
| | **Transient Motion** | 1.40 | 1.40 | 1.20 | 1.20 |
| | **Temporary mooring after single line failure** | 1.80 | 2.00 | 1.50 | 1.65 |

Table 4 Posmoor and Posmoor V safety factors

The use of POSMOOR V safety factors is intended for use whilst mooring in the close proximity of another structure, for lines in the so called 'critical sector'. These are lines which, if they were to fail would result in an excursion of the moored unit towards the nearby structure.

An additional factor of 1.1 should be applied to the above safety factors if fibre ropes are to be utilised.

**Consequence Class 1:** where mooring system failure is unlikely to lead to unacceptable consequences such as loss of life, collision with an adjacent platform, uncontrolled outflow of oil or gas, capsize or sinking.

This is the situation where the MOU is in survival condition with the riser or gangway disconnected.

**Consequence Class 2:** where mooring system failure may well lead to unacceptable consequences of the type described in Consequence Class 1.

In this case the MOU is operating with the riser or gangway connected.

#### *5.1.2.2 Allowable Offset*

The Standard confirms that the maximum horizontal offset whilst connected to a rigid riser is dictated by the maximum allowable riser angle at the BOP flex joint. A safety margin of 2.5% of the water depth is required by the Code. In other words:

*Allowable Offset = Offset from BOP Flexjoint – 2.5% of water depth*

#### *5.1.2.3 Line Lengths*

The Standard considers both the question of minimum and maximum line lengths. The mooring line lengths are required to have enough length to avoid uplift of the anchors in all conditions. However, in Operating Condition, Consequence Class I vertical forces on the anchor in the transient and single line failure cases may be acceptable if it can be shown that the holding power of the anchor being deployed is not diminished as a result.

Guidance in respect of maximum line length states that the maximum length to be deployed is given by the suspended length of the line at the breaking strength of the line, plus 500m.

#### *5.1.2.4 Proof Loading Moorings*

The anchor holding capability can be verified by applying an installation line tension equal to the maximum line tension expected at the location. If this tension cannot be achieved, a tension that has been proved sufficient from previous experience with the same type of anchors at the same location should be applied.

#### *5.1.2.5 Line Optimisation*

Line tension optimisation is permitted in the intact condition only, as long as the operation of doing so is easily achievable onboard. If such an operation is used in the mooring system design the procedure for doing so should be included in the units operation manual.

#### *5.1.2.6 Thruster Assistance*

Thrusters may be taken into account in the analysis. Two types of systems are allowed for, Thruster Assist (TA) and Automatic Thruster Assist (ATA).

TA allows for 70% of net total thrust to be employed, whilst ATA allows 100%. It should be noted that in Operating Condition, Consequence Class 2, with TA no thrust shall be accounted for.

### 5.1.3 DNV Offshore Standard DNV-OS-E301: "Position Mooring", June 2001

The Code is described as an Offshore Standard containing criteria, technical requirements and guidelines on the design and construction of position mooring systems. The Code may therefore be considered as Class Rules that contain Recommended Practices.

This Code is an updated version of the DnV Posmoor Code. Since the inception of the original Code, permanently moored installations have become more common. The updated Code seeks to address this with the statement that the design procedure is intended to be equally applicable to mobile drilling units, floating production units, loading buoys and floating accommodation units.

#### *5.1.3.1 Analysis guidelines:*

The design conditions specify: 100-year return wave and wind conditions with 10-year return current. Fatigue analysis is also required.

| Type of Mooring | Analysis Method | Conditions to be analysed |
|---|---|---|
| MOU | Quasi-static or Dynamic | Ultimate Limit State (ULS)<br>Accidental Limit State (ALS)<br>Fatigue Limit State (FLS |

Table 5 Analysis Guidelines

| | | Consequence Class 1 | | Consequence Class 2 | |
|---|---|---|---|---|---|
| **Condition** | **Analysis Method** | **Safety Factor on Mean Tension** | **Safety Factor on Dynamic Tension** | **Safety Factor on Mean Tension** | **Safety Factor on Dynamic Tension** |
| ULS | Quasi-static | 1.70 | | 2.50 | |
| ULS | Dynamic | 1.10 | 1.50 | 1.40 | 2.10 |

Table 6 Line Tension Factors of Safety in Ultimate Limit State (ULS)

| | | Consequence Class 1 | | Consequence Class 2 | |
|---|---|---|---|---|---|
| **Condition** | **Analysis Method** | **Safety Factor on Mean Tension** | **Safety Factor on Dynamic Tension** | **Safety Factor on Mean Tension** | **Safety Factor on Dynamic Tension** |
| ALS | Quasi-static | 1.10 | | 1.35 | |
| ALS | Dynamic | 1.00 | 1.10 | 1.00 | 1.25 |

Table 7 Line Tension Factors of Safety in Accidental Limit State (ALS)

**Consequence Class 1:** where mooring system failure is unlikely to lead to unacceptable consequences such as loss of life, collision with an adjacent platform, uncontrolled outflow of oil or gas, capsize or sinking.

**Consequence Class 2:** where mooring system failure may well lead to unacceptable consequences of the type described in Consequence Class 1.

These consequences are unchanged from Posmoor 1996.

The Standard also prescribes items to be taken into account when performing a quasi-static analysis or dynamic analysis.

#### *5.1.3.2 Fatigue Analysis*

The Code recommends that fatigue calculations are carried out for units positioned at a location for less than 5 years when the in service experience has shown anchor line fatigue damage.

#### *5.1.3.3 Allowable Offset*

The Standard confirms that the maximum horizontal offset is dictated by the maximum allowable riser angle at the BOP flex joint. A safety margin of 2.5% of the water depth is required by the Code. In other words:

*Allowable Offset = Offset from BOP Flexjoint – 2.5% of water depth*

#### *5.1.3.4 Line Lengths*

The Standard considers both the question of minimum and maximum line lengths. The mooring line lengths are required to have enough length to avoid uplift of the anchors in all design conditions in the ULS. In the ALS, vertical forces can be accepted provided that the performance of the anchors is not significantly reduced.

Guidance in respect of maximum line length states that the maximum length to be deployed is given by the suspended length of the line at the breaking strength of the line, plus 500m.

#### *5.1.3.5 Proof Loading Moorings*

The code states that the anchor holding capability can be verified by applying an installation line tension equal to the maximum intact line tension expected at the location. If this tension cannot be achieved, a tension that has been proved sufficient from previous experience with the same type of anchors at the same location should be applied.

#### *5.1.3.6 Line Optimisation*

The running of winches shall only be employed to set relevant pretension for the particular operating condition. When at a particular operating condition the winches shall not be run in order to reduce line tensions. This is a significant change compared to POSMOOR which may have implications for units operating close to their maximum allowable line tensions.

An operating state may specify different pretensions in individual mooring lines, based on knowledge of the long-term directionality of the environmental effects at a particular mooring site.

#### *5.1.3.7 Thruster Assistance*

The effect of thruster assistance (TA and ATA) may be used in analysis. The ALS analysis shall be carried out for both loss of one mooring line and loss of a single thrusters' assistance.

TA allows for 70% of net total thrust to be employed, whilst ATA allows 100%.

### 5.1.4 ISO TR 13637 "Petroleum and natural gas industries - Mooring of mobile offshore drilling units (MOUS) - Design and analysis"

This document is currently being modified and will become ISO/CD 19901-7.E.3 *"Petroleum and natural gas industries - Specific requirements for offshore structures - Part 7: Station keeping systems for floating offshore structures and mobile offshore units"*. The document is at Committee Draft stage and is expected to be issued shortly. The new document is likely to reflect API requirements, i.e. similar environmental criteria, similar safety factors and a similar position regarding fatigue requirements for MOU's (no analysis required). Changes in the new document from ISO TR 13637 include the following.

- **Mooring line tensions** may be controlled by active mooring line tension adjustments. However, this technique shall not be considered in the evaluation of mooring line tensions in the ultimate limit state (ULS) design event.
- **The installation test load** at a winch shall not be less than the maximum line tension for an intact mooring under the design event for the serviceability limit state (SLS).
- **The installation test load** at the anchor shank shall not be less than three times the anchor weight.
- **For moorings in the vicinity of other installations** the installation test load at a winch shall not be less than the mean line tension for an intact mooring under the design event for the ULS.

ISO TR 13637 adopted "*API Recommended Practice 2SK, 2nd edition, 1996*". as the technical report forming the basis of development of the ISO Code see para 5.1.1.

### 5.1.5 NMD document "Regulations of 4th September 1987 concerning Anchoring/Positioning Systems on Mobile Offshore Units":

These regulations shall be satisfied in order to meet the requirements of the Norwegian Maritime Directorate (NMD).

#### *5.1.5.1 Analysis Guidelines*

The general requirements of these guidelines are as for DNV Posmoor 1996, with several supplementary requirements with respect to the following issues. Required safety factors are greater than in the Posmoor Code, with greater consideration given to the consequence Class of the unit.

Both quasi-static and dynamic analyses are outlined, however for dynamic analysis no formal safety factors are stated. Direct contact should be made with NMD to establish safety factors on a case-by-case basis.

For MOUs with production plants it is necessary to perform a double failure analysis with a reduced environmental criteria.

Line tension optimisation through adjustment of the length of anchor lines is permitted, given suitable procedures to be included in the operations manual.

| Condition | Analysis Method | Safety Factor |
|---|---|---|
| Intact | Quasi-static | 2.00 |
| Damaged | Quasi-static | 1.40 (2.0 if in the vicinity of other structures) |
| Transient | Quasi-static | 1.00 |

The Code does not prescribe fatigue analysis in any condition.

## 5.2 SUMMARY TABLE OF CODES

For the purposes of this report, six Codes plus the ISO Code at Committee Draft stage have been considered with the summary points tabulated below.

| Code | Analysis method | Return Period | Analysis Conditions | Proof Loading | Allowable Offset | Line Optimisation | Fatigue analysis | Thruster Assistance |
|---|---|---|---|---|---|---|---|---|
| **API RP2SK** | Quasi-static<br>Dynamic | 5 Year / 10 Year | Intact, Transient & Damaged | Maximum intact load | Connected: approx. 8-12% water depth (WD) (to be assessed wrt ball-joint limits)<br>Disconnected: No limit | Yes | Not required for MOUs | TA (70% Net Thrust)<br>ATA (100% Net Thrust) |
| **DNV Position mooring (Posmoor) January 1996** | Quasi-static<br>Dynamic | 100yr/10yr Combination | Intact, Transient & Damaged | Max line tension expected at location (NTE 40% MBL) | Connected: (Rigid Riser) Max BOP ball-joint minus 2.5% WD margin. (Rigid Riser)<br>Disconnected: No Limit | Yes | Not required | TA (70% Net Thrust)<br>ATA (100% Net Thrust) |
| **DNV-OS-E301** | Quasi-static<br>Dynamic | 100 Year | Intact & Damaged | Max characteristic line tension, intact mooring. | Connected: (Rigid Riser) Max BOP ball-joint minus 2.5% WD (Rigid Riser)<br>Disconnected: No Limit | As part of changing Operating State only | Normally required | TA (70% Net Thrust)<br>ATA (100% Net Thrust) |
| **ISO TR 13637 & Committee Draft of ISO 19901-7.E.3** | Quasi-static<br>Dynamic | 5 Year / 10 Year | Intact, Transient & Damaged | Maximum intact load for SLS | Connected: approx. 8-12% WD (to be assessed wrt ball-joint limits)<br>Disconnected: No limit | No allowance | Not required for MOUs | TA (70% Net Thrust)<br>ATA (100% Net Thrust) |
| **NMD** | Quasi-static<br>Dynamic | 100yr/10yr Combination | Intact, Damaged & Transient | No Guidance | Connected: (Rigid Riser) Max BOP ball-joint minus 2.5% WD margin. (Rigid Riser)<br>Disconnected: No Limit | Yes (if easily achievable) | Not Required | TA (70% Net Thrust)<br>ATA (100% Net Thrust) |

## 5.3 COMMENTARY ON CODES

### 5.3.1 Return Period

The debate on the applicability of 100-year return vs 5/10-year return period for use in assessment of MOU moorings has been present for many years. The use of 100-year return period in the assessment requires a considerable number of arbitrary assumptions to be made about individual inputs into the analysis in order to allow typical semi-submersibles that have successfully operated in the UKCS, to continue to do so. These are discussed later. In a comparative analysis performed as part of a Code Comparison JIP, it was demonstrated that the use of 5/10 year return individual extremes of wind, wave and current when applied concurrently and collinearly will produce an adequately stringent test of the mooring system for MOU's. The ISO document has adopted this approach pioneered by API. Furthermore, from risk arguments, it is generally conceded that floating production installations (FPI) ought to be designed to one order of magnitude greater in reliability than MOU's should be assessed for survival conditions. Given that it is universally accepted that 100-year return conditions provide a sufficient return period for FPI's it is reasonable to conclude that when the same analysis recipe is used, MOU's could be assessed for some lower return period. Based upon these arguments it is concluded that MOU's should be assessed to 5/10 year return period as described by ISO.

### 5.3.2 Proof Loading of Anchors

A number of different descriptions of proof loading requirements to ensure adequate embedment of anchors are available in the different codes reviewed. Essentially, they all reduce to the position that proof loading on site for an MOU is limited to the stall capacity of the winches. These are typically required by class to be about 30-35% of break strength. There are two arguments in support of why this level is adequate despite the fact that tensions may be allowed to go to 50% of break quasi-statically and 67% of break dynamically in the assessment. Firstly, other operating restrictions; drilling riser ball/flex joint angle restrictions or accommodation/tender support: gangway connection would take precedence, would require moving to survival anyway and therefore, the consequence of further drag is mitigated. Secondly, both the 50% and 67% figures include dynamic tension components that occur infrequently and therefore cannot directly be compared with the proof loading approach that essentially establishes on site, the sustained (15-20 minutes) capacity of the anchor.

In the UKCS, the practice is to proof load to about 150-175t, which is indeed about 30-35% of break strength of a typical 3” ORQ chain. This practice based upon the above arguments is acceptable for MOU’s.

### 5.3.3 Line Optimisation

The unrealistic demands placed upon MOU owners by ill-conceived code development in the mid 80s to mid 90s meant that the analyst evaluating a mooring system was using line adjustments (or optimisations) which were completely unrealistic, impractical and if implemented on site would have been counter productive. Most recognise that there is a place for line optimisation when operating with line tensions that are below the stall capacity of the winches (typically, the drilling rig operating condition or tender/accommodation rig with gangway connected condition). However, it is wholly inappropriate to perform these optimisations when in survival conditions and in practice it is not undertaken on site. Therefore, such optimisation should not be accounted for in the analysis.

Line optimisation could be counter-productive if the environmental heading changes. Furthermore, the safety of the rig and crew could be endangered if lines are adjusted under very high tensions.

On the basis that in extreme survival conditions where line tensions exceed 35-40% of break strength, no prudent operator will be adjusting line payouts/pull—in on windward lines, such an approach must be excluded from analysis practice.

This is in line with the ISO recommendations, which exclude line optimisation in survival, but recognises that this can be successfully and safely performed when operating.

### 5.3.4 Safety Level

In line with discussion under “***Return Period***”, it is important to note that the MOU in survival inherently presents an order of magnitude of less consequence as a result of ***system*** failure than an FPI. Whilst there is industry-wide consensus on this position, there have been two schools of thought on how this can be implemented in code. The Norwegian approach has been to adjust the safety factors (typically, in mooring systems 30-40% increase in safety factors would raise reliability by an order of magnitude) whilst the API approach has been to change the return periods. Both can be argued at length.

However, the API/ISO approach for floating production systems has found the greatest favour with industry internationally. If one therefore starts from the principle that the safety levels established by the API/ISO requirements for FPI are adequate, it follows that MOU’s in survival condition can adopt one order of magnitude less reliable set of safety factors or return periods. Such an approach will still result in an acceptable level of reliability.

### 5.3.5 Analysis Recipe

Any mooring analysis in search of a site assessment of an MOU incorporates many steps in which decisions have to be made with regard to input parameters and methods. The more stringent the criteria, the greater the temptation for the analyst to incorporate as many of the assumptions which assist the case for approval.

# 6 PRACTICE AND PROCEDURE IN THE EVENT OF LINE FAILURE

## 6.1 GENERAL

Mooring lines fail in different conditions and for different reasons. The most common modes of line failure are described further in this section. The effects of line failure and initial response to the failure are addressed in the rig's Operations Manual and also in the Emergency Response Manual (or similar which may form part of the Safety Case). Due to the differing circumstances surrounding each line break such documents can only provide guidance.

### 6.1.1 Actions following line failure

As there will be an immediate reaction from the rig due to mooring line failure it is likely that the rig will have progressed through the transient condition and returned to equilibrium before any intervention from the Rig's crew can be initiated. For this reason operations are conducted within limits that allow for a single line failure.

The response from the rig's crew to a mooring line failure will be governed by the equipment and systems available. Although most units operating within the North Sea UKCS have thrusters of some degree fitted there are a number of units operating that have none. For such rigs the ability to compensate for a failed mooring line is limited to the manipulation of line tensions only.

For all units the immediate response will be to reduce the tension on the line adjacent to the failure as this line will have a significantly increased load. Reduction of tension is achieved by the slacking of lines diagonally opposite the failed line and the use of thrusters where fitted.

### 6.1.2 Use of thrusters

Thrusters vary greatly from rig to rig. They can be any number from 2 to 8, may be fixed or azimuthing and have different levels of automation e.g. manual or fully automatic. . The ability of the thrusters to compensate for the failed line will therefore depend on the system design. A non-rotating thruster will clearly not be able to compensate for a beam mooring as well as a fully azimuthing thruster. Rigs fitted with a fully azimuthing automated system that is running at the time of the line failure will immediately respond to the failure and in cases of heavy weather will greatly limit the unit's excursion. In all other cases the thrusters will have to be brought on line before use.

### 6.1.3 Hazops

With the initial reaction in terms of line manipulation and thruster application completed the OIM will be in a position to consider further options which will include:

- Maintain thrusters at the level required either in TA or ATA mode
- Determining if there has been any threat to the integrity of sub sea assets from the failed mooring line
- Conducting a Hazop with the senior toolpusher and the Operator's representative to determine the risk to the flexjoint.
- Determine which operations can and cannot be conducted in the single line failed condition (risk assessment)
- Call for a suitably sized anchor-handling vessel (AHV) that is equipped for recovery and re-attachment of the mooring
- Obtain weather forecast and assess effect on rig

If the rig is operating at an open location without sub sea assets and the weather is good then the hazop carried out may show that the system is capable of maintaining equilibrium and that operations may be carried on as normal

Should the rig be operating over sub sea assets, the Field Operator is likely to confirm the unlatching of the riser until the mooring line can be replaced or until a risk assessment has been conducted to show which operations can be continued in safety

In heavy weather it may not be possible for the AHV to recover and re-attach the failed mooring line. In such cases however it may still be possible to attach the AHV to the Tow Bridle and assist in relieving line tensions.

## 6.2 MODES OF LINE FAILURE

### 6.2.1 Common Modes of Failure in chain

Historically, chain manufactured in the 1980's, especially Grade 4 chain suffered with quality control problems and subsequent brittle fracture problems. Brittle fracture is the term used for a rapid failure of material, which involves low ductility. It is partly dependent on the type of steel used, or the processing that it has been subject to, and is exacerbated by stress-raisers or cracks in the material. It can result in the failure of chains at relatively low tensions. The problem with brittle fracture is that the propensity of the material to fail in this way is not obvious to the naked eye and can only be quantified by destructive testing. Steel is more susceptible to brittle fracture when the yield strength is high or where the operational temperatures are low. The welding process, and subsequent heat treatment, used to form the chain link during manufacture must be very carefully controlled to prevent brittle fracture problems with chain. This said the metallurgical and manufacturing issues appear to have been largely resolved such that modern high strength chain can now be consistently produced.

Much of this problematic chain has now been removed or scrapped but mention has been made in this report since the associated problems have had an impact on the industry over the years. It is also possible that there is a residual amount of this chain around.

The prime cause of line failure now appears to be with the connecting shackles or with links that have been mechanically damaged. Common modes of failure in chain systems therefore include

- Mechanical damage to links
- Missing or loose studs
- Failure of connecting links (See Commentary to Section 9)
- Brittle fracture of links (not so common with improved quality control of chain)

### 6.2.2 Common Modes of Failure in Wire

Failure of wire in mooring lines is caused by one of three causes:

- Mechanical damage to the wire
- Corrosion/Wear
- Fatigue

Chasing operations can also cause bends and kinks in mooring wires. Bends may not be serious enough to replace the wire, however kinks will seriously reduce strength.

## 6.3 COMMENTARY

Section 6 discusses practice, procedure and the options to senior personnel following the failure of a single line. In all cases a Hazop and risk assessments need to be performed, taking into account the variables of weather and exposure to both subsea and surface assets. Thrusters, if fitted may assist but are most effective if they have azimuthing characteristics. The use of anchor-handling vessels was discussed in the context of assisting by connecting to the tow bridle.

- The most common reasons for chain link or connector failures were identified.

- The types of damage to wire were identified but it was noted that chasers are a major cause of damage to rope wires.

# 7 IN FIELD TENSION MONITORING

When a Mobile Offshore Unit (MOU) mooring analysis is undertaken the pre or working tensions are set at specific values, which are often identical. This is a reasonable approach as long as the MOU in the field can set their line tensions to comparable values. If the set up line pre-tensions on a MOU are unbalanced, this can lead to *increased maximum line tensions and reduced fatigue lives*. In addition, in case of a single line failure this can lead to an increased transient excursion, which might exceed the allowable watch circle.

Recent research reported by Noble Denton's on going JIP on FPI Mooring Integrity, has shown that in some instances the belief that the meter readings on the rig are similar to the real line tensions may be misplaced.

In one particular case studied by the JIP the Operator doubted the tension readouts on one of their semi-submersibles because:

- Sometimes the wire becomes partially bedded into, and/or damages the lower wrap on the winch drums
- When grappling for certain components on the mooring line they were not found at the expected depth.

An underwater ROV survey was taken of the flounder plate connectors on the mooring lines to obtain their x, y and z co-ordinates. From these positions and knowing the submerged weight of the chain it was possible to undertake a catenary line calculation to determine the actual line tension. The calculated tensions could then be compared to the tension readouts on the rig at the time that the ROV position check was made. It was found from this process that the calculated tensions and the measured tensions were out by up to <u>160%</u> in the worst case.

There are a number of potential reasons why the tension meters can be so far out. These include:

- The meters have not been calibrated or the calibration has drifted over time
- The gypsy wheels may be seized
- The instrumentation is not sufficiently sensitive
- The tensions are measured at the base of the winches in board of the fairleads

Historically semi submersible drilling units have been subject to relatively frequent mooring line failures. Sometimes these failures cannot be attributed to obvious causes. The work reported in this section shows that it is possible for a carefully set up Rig to have a seriously unbalanced mooring pattern, which may well not be detected by the owners. Such a rig would thus be in greater danger of mooring line failures, which equate to approximately one failure per three operating years.

If the tension meters are well positioned, working properly and their calibration is in date, a likely cause of unbalanced line tensions is partial seizure of the gypsy wheels. A simple line Payout/Pull-In test can confirm this. If this reveals that some of the gypsy wheels are partially seized an attempt should be made to free them up. However, if the unit is on station it may not be feasible to undertake such work in situ. In such a case the line tensions out with the fairlead should be determined by other measures.

At present it is not known how common a problem this could be for other operating semi-submersibles. Hence it is recommended that a similar Payout/Pull-In test be repeated for a number of different ages and designs of semi-submersibles. If this confirms the results reported by Noble Denton's JIP on FPI Mooring Integrity, it will be important to distribute this result through out the industry.

If a fairlead is partially seized with respect to rotation it may also be seized relative to azimuth rotations. Hence, as well as checks on the free running of fairleads, the ability of the fairlead assembly to freely slew or azimuth should also be confirmed. If the fairleads cannot azimuth freely increased chain wear is likely to occur. Because of this criticality of the fairleads with respect to the performance of the mooring system, it is vital to ensure their working operation through the rig's Preventive Maintenance System (PMS).

## 7.1 CHECK OF PULL IN AND LOCKED OFF LINE TENSION READINGS

It is important that both the pull in and locked off line tension readings are comparable. This can be checked fairly simply by dropping the stopper when you have, say 120 tonnes tension reading on the line during line pull in and see how the tension reading from the base of the windlass compares.

It is recommended that such a tension comparison test should be undertaken during the course of the Pay Out/Pull-In tests on all mooring lines.

## 7.2 COMMENTARY

Section 7 is a short section putting forward recent research on the effect that unbalanced lines may have on the mooring system as a whole. The reasons for the imbalance are summarized below.

- Tension meters may not be reading accurately
- Fairleads may not be running freely

The industry has not paid much attention to detailed line tension monitoring because it has faced a great deal of difficulty in installing systems that work in harsh conditions offshore. In particular for mooring systems, the key difficulty has been to place a strain-gauge system on a chain in a location that can provide reliable indication of tension. As has been discussed in this section, tension monitoring at a point near the winch has its drawbacks and for reliability require fairlead gypsy wheels to be frictionless. Installing a strain gauge outboard of the fairlead gypsy provides a difficult environment for the strain gauge to operate. Finally, mooring line tension in a dynamic environment in deepwater cannot be established by geometry information such as fairlead angle alone.

Because MOU's normally have some degree of line tension monitoring, knowledge about line breakage is instantaneous. The same cannot be said for FPI's. Given that line break information is known immediately, the primary purpose of the mooring line monitoring is better understanding of mooring response which may help to improve safety and/or give confidence in the feasibility of using cheaper rigs in more demanding environments where they would have been otherwise rejected on the basis of analysis predictions.

Technology has moved forward on data sensors and loggers and therefore it is recommended that the industry take advantage of recent monitoring technology advances to enhance the safety and operability of MOU's.

# 8 MOU MOORING INSPECTION

This section discusses the composition of mooring lines, how they are commonly inspected and how examination is carried out to best effect. Chain mooring lines are maintained by the rig owner but under the control of Class. The inspections carried out are those recommended by Class at specified periods, annually and 5 yearly for the Special Survey. Guidance with respect to inspection areas is provided by API *Recommended Practice for in service inspection of mooring hardware for Floating Drilling Units* ($2^{nd}$ Edition 1996) (Ref [4]).

## 8.1 MAKE-UP OF MOORING LINES

Chain used for MOU moorings may be supplied to a unit in sections or in complete lengths, and this is becoming common practice with newer rigs or rigs which are renewing mooring lines. However, there are still a large number of rigs, which are equipped with varied lengths of chain using connector links, Kenter shackles or Baldt links to form a full-length mooring line.

The make up of mooring chains on drilling rigs throughout the North Sea shows no consistent pattern. However, complete chain lengths should expect to suffer failure rates less than those chains made up of a number of sections due to the lack of connecting links.

Chain varies in size, grade and type although most chain moored MOU's operating around the UK Continental Shelf have chain of either ORQ+20% or K4 both with a diameter of 76mm. To enable rig owners to have stronger chain and still use current fittings e.g. fairleads and winches, manufacturers have increased the strength of their product over the years to produce chain that has increased breaking loads without an increase in size.

Composite moorings are also in evidence primarily consisting of chain and wire. The advantage of such systems is of course the weight, which assists a unit in respect of variable loads, particularly in deeper water locations. The advantages of such a system include the following:

- Lower catenary weight and subsequent lower winch loadings.
- Good catenary departure angle that allows a sufficiently stiff system to be deployed that is able to maintain the unit within acceptable limits.
- Wire can be compactly stowed on reels containing up to 10 000 feet of cable.

Fibre rope inserts are also in use in a number of units but at the time of writing this report, not on MOU's in the North Sea. Owing to their susceptibility to mechanical damage fibre ropes are not commonly used on MOU's. We have not dealt with such ropes in this report but believe that it will only be a matter of time before handling problems are overcome and that they will become available for use with MOU's on predeployed moorings in deep or ultra deep water.

## 8.2 CHAIN

### 8.2.1 Intervals of Inspection

Chains are inspected not only at major inspection periods but also certainly at each retrieval operation. API provides a recommended schedule for the inspection of chain (Ref [1]) as shown below.

| Years in Service | Maximum Intervals between Major Inspections |
|---|---|
| 0 - 3 | 36 Months |
| 4 - 10 | 24 Months |
| Over 10 | 8 months |

Table 8 Chain inspection periods

The table above is recommended practice, however chain that forms part of the MOU's mooring system is subject to Class requirements that may differ from the above. DnV for example, require annual surveys, intermediate surveys and a major inspection every five years.

### 8.2.2 Methods of Inspection

Class and API both make recommendations in respect of the inspection methods for chain and wire. The distinction in documentation is that Class determine when the surveys are carried out and which items require inspection; API provide a recommended practice as to how inspections are to be performed.

#### *8.2.2.1 Inspection during Retrieval*

It is common practice to inspect chain as it is retrieved when moving away from a location. Class carry out their intermediate surveys in this manner. Loose or missing studs can be detected together with bent or twisted links whilst the value of inspection of the chain as it goes over the windlass can be limited since cracks, unless very apparent in the stud area are not detectable. A problem that may be experienced with this type of inspection is not logistical but human. It is difficult for a single inspector to maintain the required levels of concentration for long periods particularly in the winter season. Although considered good practice therefore, unless there is a requirement as noted above, the limits on the value of such an inspection should be recognized (See Commentary to Section 9).

However, taking the above into account it follows that if chains are of differing vintage or equipped with a large number of connecting shackles then more careful scrutiny should be given to those mooring lines that would be considered more vulnerable. Previous inspection records should be compared to ensure that any new and obvious degradation of the chain is captured.

Annual surveys for Class inspect the mooring system in situ without interference to the unit's operations.

#### *8.2.2.2 Major Inspections*

When major inspections are undertaken, for example the Class 5 year special survey or a major structural repair, a thorough survey of the chain is carried out either on the dockside or offshore. The areas covered for a major inspection include the following:

- Splitting the connecting links, cleaning the component parts and carrying out Magnetic Particle Inspection (MPI). Attention should be given to reassembly to ensure there are no gaps in the mating surfaces and that lead plugs are properly inserted
- Thorough cleaning of the chain either by water or sandblasting followed by 100% visual inspection of the full length of the mooring chain including the length normally stowed in the chain locker.
- Dimensional checks of the links in two planes 90º to each other, length of the link and length over 5 links
- MPI of anchor jewellery, 5% of links in the chain as a whole and 20% of links in the working area of the chain, i.e. where it runs through the fairlead but not at the sea-bed thrash zone.

If problems are uncovered the degree of inspection should be increased.

#### *8.2.2.3 Offshore inspections*

Major inspections can be carried out either offshore or on the dockside. When the work is carried out offshore the chain is inspected from both the back of the anchor-handling vessel, from the deck of the rig at the windlass position or a combination of both. No single one of these options offers ideal conditions. The disadvantage of offshore inspection is the time/cost element with respect to both the rig and the anchor-handler. The time taken for the inspection is increased when disassembling and MPI of the connecting links is taken into account. This said, it is often the practice to simply change the connecting links out for new ones.

#### *8.2.2.4 Onshore or dockside inspection*

By this method, the line to be inspected is taken from the rig and is taken to a dockside location for inspection under controlled conditions. The mooring analysis prepared for a unit for a given location provides for a minimum number of mooring lines being in place. Removal of a line for inspection purposes for any length of time requires a replacement line to be put in place. For the reasons above, many owners carry or hire a spare chain to replace the line requiring inspection.

The checks carried out are exactly the same as those offshore with the advantage that any remedial work to be carried is not at the expense of rig and anchor-handler time.

The links are discarded should studs be missing and replaced with connecting links. If there is a gap between stud and the link, this may be closed up by pressing the stud to expand it. However, this process can only be effectively implemented approximately three times.

#### *8.2.2.5 Records*

On completion of any survey Class will maintain records of the inspection and any replacement or remedial work carried out. The chain is also banded every 100 links for identification purposes. Inspection records are also passed to the rig to maintain with the unit's own records on the mooring system. Details of records held should include;

- Details of inspections carried out, time, date and purpose
- Details of the particular mooring line, certification, location etc.
- Details of connecting links inserted together with certification.
- Findings of inspections, condition, deterioration or damage including any recommendations.
- Service history of the mooring line.

## 8.3 WIRE ROPE

### 8.3.1 Intervals of Inspection

The recommended intervals for wire rope in service are shown in the table below (Ref [1]). Formal assessments such as Class require Annual, biennial and 5 year surveys.

| Years in Service | Maximum Intervals between Major Inspections |
|---|---|
| 0 - 2 | 18 Months |
| 3 - 5 | 12 Months |
| Over 5 | 9 months |

Table 9 Recommended inspection period for wire rope in service

### 8.3.2 Methods of Inspection

Although wire can be inspected during mooring deployment, the winch speeds associated with wire deployment are such that a thorough inspection is unlikely to be achieved and inspection on mooring recovery is the preferred method. Wire is considerably easier than chain to inspect due to being stored on reels, thus allowing an inspector the opportunity to view the wire on a wrap until this wrap is covered. Mechanical damage, which tends to be the biggest problem for wires, is also much easier to spot than say a chain defect. Due to this susceptibility of wire to mechanical damage it is good practice to inspect the wires at every recovery and record the data for future comparisons. As with any inspection process the competence of those carrying out the inspection will have a significant bearing on the results. If rig personnel are to be used for such purposes they should have training to a suitable standard.

Inspection by Class of the mooring system is covered by Annual, biennial and at Special Survey periods (5 Years), similar to that for chain.

API *Recommended Practice 2I* (Ref [4]) provides comprehensive guidance on the inspection of both chain and wire. For both types of material the Code has recommendations and comments on inspection both at the dockside and offshore. For wire a workboat is needed in both cases since the construction and protection of the wire mooring line discourages laying out on the quay. Further, the workboat is used for maintaining adequate tension on the wire whilst laying back onto the winch drum. Generally, wire inspection at offshore locations at the time of anchor retrieval is preferred.

#### *8.3.2.1 Major Inspections*

When major inspections are undertaken, for example the Class 5 year special survey or a major structural repair, a thorough survey of the wire is carried out either on the dockside or offshore. The areas covered for a major inspection include visually checking 100% of the mooring line for the following:

- Broken wires and the cause, whether by fatigue tension, chasing or crushing.
- Wear and Corrosion.
- Change in rope diameter (usually indicating internal corrosion).
- Deformations, bends, kinks and protrusions and damage through torsion.
- Damage to sockets, ferrules and swivels.

A short piece of rope (15-20 feet) is taken from one end and inspected for internal corrosion. Should internal corrosion be found then a further short piece is cut until good material is found. Provided the inspector is satisfied and there is adequate length in the remaining rope, the wire is re-socketed.

The Recommended Practice also advises that a break test would provide guidance as to the condition of the wire, especially one that is older.

#### *8.3.2.2 Records*

As with the inspection of chains, records are maintained of the inspection and any replacement or remedial work carried out. All mooring rope inspection reports should be retained on the unit, in addition to those maintained by the rig personnel themselves, and made available each time the wires are inspected. Details of records held should include;

- Details of inspections carried out, time, date and purpose
- Details of the particular mooring line, certification, location etc.
- Findings of inspections, condition, deterioration or damage including any recommendations.
- Service history of the mooring line.

## 8.4 COMMENTARY

This Section 8 deals with the inspection of mooring chains, wires and the connecting links. The main points identified are noted below.

- Most chain currently found in the North Sea is of ORQ+20% or K4 grade and 76mm diameter.
- Mooring lines are typically made up of different lengths of chain connected by a Kenter or Baldt Link.
- Wire inserts are used when the weight of a line crossing a sub sea asset needs to be reduced. The use of wire moorings in deep water assists in maintaining variable load.
- Class require inspections annually, biennially and a major inspection every 5 years.
- Good practice determines that wires and chains should be inspected on retrieval.
- Chain inspections at retrieval can detect only serious mechanical damage and missing or loose studs.

- The advantages of dockside inspections as against offshore inspections for wire and chain were discussed.

Wire is more vulnerable to damage than chain and for that reason close inspection should be carried out during retrieval. In contrast to the limited value of chain inspections during retrieval, damage to wire, especially major damage is more easily detectable.

The testing of a short length of wire was discussed. There is no specified period for carrying out this test, only when circumstances dictate. However the older the wire becomes the greater the need for performing proof load tests that would both maintain confidence in the integrity of the wire and allow estimates to be made of the remaining in-service period.

Where wire failures have occurred or where mechanical damage has rendered part of the wire unfit for use it is possible to crop and re-terminate. Rigs with wire moorings should have the ability to re-terminate their own moorings and therefore will require equipment, competent personnel and appropriate procedures for this purpose. "Socketing platforms" have been constructed on some units and these have significantly enhanced the safety and efficiency of re-socketing operations.

The need to keep records of the history of mooring lines is not only a requirement but also good practice. Inspectors carrying out work on behalf of Class Societies maintain records that are also passed to the rig. This procedure should not take away the responsibility for the rig maintaining their records. Such a practice provides justification for the close scrutiny of older or more vulnerable (large number of connecting shackles) mooring lines during retrieval.

# 9 MOU MOORING LINE FATIGUE ASSESSMENT

In the previous section, an item raised was whether the carrying out of a fatigue analysis was required for short term MOU moorings. This section examines how fatigue analyses are factored into mooring inspections and provides guidance on how such analyses may be applied (if appropriate) to MOU's with differing mooring regimes and patterns.

All mooring systems are subject to cyclic loading and hence are potentially liable to fatigue damage. Thus DNV's Offshore Standard E-301 requires a fatigue analysis to be performed for Long term Moorings which will be in use for a period in excess of 5 years, such as found on Floating Production Installations (FPI's).

MOUs such as drilling rigs, flotels and crane barges tend to be moored up for shorter periods of time. At each location there are a different set of parameters affecting the chain; water depth, differing environment, change of heading and different catenary shape. These changes in parameters assist in varying the loadings on each of the chains. However, for a long drilling programme or an extensive hook up/decommissioning project, a unit may be at the same location for several months. Hence, over the years, taking into account the time spent at different locations, fatigue can become an issue for MOU mooring lines.

To perform a mooring line fatigue assessment it is necessary to know the number and the respective amplitudes of the tension cycles experienced. It is not easy to obtain this data. The best way is to have an instrumented system in which the tensions are logged just out with the fairlead where accurate line tensions can be obtained. To date, such systems have not been fitted to MOUs.

Before a new FPI goes on station, a fatigue assessment is typically undertaken taking into account the unit's behaviour and anticipated wave amplitudes and directions based on historical data. In such a case the line tension ranges are estimated rather than actual. Since most FPI's start their deployments with new mooring lines there is no need to take into account any existing fatigue damage.

For a MOU it would be feasible to undertake a similar analysis taking into account the anticipated deployment period. However, since the period tends to be a matter of months the fatigue damage will not normally be high. But since the mooring lines are normally not new, it would be necessary to know how much fatigue damage they have already been subjected to. This data is not normally available and to generate it from scratch would require a separate fatigue analysis for each location the rig has worked on. Unless the Rig is fairly new or good records are available this is unlikely to be feasible.

Because of these difficulties DNV do not require fatigue assessments to be performed for short-term moored units. Although it would be helpful to have fatigue assessments for the lines, the criticality is somewhat reduced since in air mooring line inspections are possible from time to time.

## 9.1 FATIGUE AND MOORING LINE INSPECTION

A key difference between a MOU and a Long Term Moored system is that the moorings on a MOU will be recovered fairly regularly. This gives a limited opportunity to undertake an in air inspection on the chain that may reveal fatigue cracks or other evidence of wear or damage. It should be noted though that it is not easy to detect cracks around the stud footprint on studded chains or in the grip area if lapping has occurred. Lapping is the result of two mating links rubbing together, which causes folds on the material surface. From an MPI perspective laps look like cracks. Although it is difficult from chain inspection to be confident that a line is 100% free from fatigue cracks, this is perhaps somewhat less critical than might be expected. This is because a chain that has had a hard life may be condemned for other factors before fractures due to fatigue become likely. For example MOU's tend to use studded chain and after time the studs come loose. There is a limit to the number of times a stud can be re-pressed into place. Also Classification Societies apply a limit to the extent of material wastage due to wear and corrosion. Since the lines are recovered and redeployed on a fairly regular basis, the danger of mechanical damage during this operation increases.

## 9.2 COMMENTARY

Given the relative short-term nature of most MOU individual deployments, fatigue during the deployment period is unlikely to be key issue. However, over the course of a number of deployments, particularly in similar water depths, fatigue may start to be a problem. Unfortunately, it is very difficult to generate and keep up to date records of the cumulative degree of fatigue damage experienced by individual lines. This is less worrying than might be the case for a permanent moored system, since in air inspection can take place at regular intervals when the lines are recovered. However, to have reasonable confidence of detecting defects, adequate time and resources must be assigned to the inspection process.

### 9.2.1 Kenter Links

It has been well established that Kenter links provide a weakness in a chain mooring system. The API/ISO codes imply that given identical load conditions, a Kenter link has less than a quarter of the fatigue life of a corresponding common stud chain link. Calculation of fatigue life is riddled with uncertainty and a factor of 4 reduction is a warning sign against the use of

Kenters for long-term moorings. However, in MOU moorings where routine installation and retrieval of mooring lines is a must, any repair of a chain at the broken location requires the insertion of a Kenter link so that the line can travel through the 7 pocket gypsy fairlead. Therefore it is a matter of fact that Kenters will continue to be used.

Given this is the case, mooring integrity of MOU's will be well served if careful records are kept of the presence of the Kenters in mooring lines so that they are replaced at 4-5 times the frequency at which common chain links are replaced. It is granted that some MOU's still operate with >20 year old mooring chains and Class Societies do not have a particular requirement to discard chain when they reach a pre determined age. This makes it difficult to prescribe a particular age as the maximum permissible for Kenters.

However, the above discussion highlights the need to raise awareness amongst operating personnel who inspect lines equipped with large numbers of Kenters. Careful visual inspection with such lines is required during mooring retrieval.

Similarly, if a common link failure is attributable to fatigue, then in combination with the records of Kenter installation, consideration must be given to the removal and replacement of Kenter shackles which have been in place for longer than 0.2 - 0.25 of the time of the common link

# 10 ANCHORS AND THE INSPECTION OF RIG BASED MOORING EQUIPMENT

Section 8 has discussed the make up of typical mooring lines and how inspection methods are put to best effect. This section discusses the inspection of hardware on board the rig including anchors, how this equipment is inspected and over what intervals.

## 10.1 ANCHORS

Mobile offshore units working on the UK Continental Shelf almost invariably are equipped with high holding anchors. Those most commonly used include, but are not limited to the following.

| Anchor Type | Efficiency |
|---|---|
| Stevpris MK5 & Bruce FFTS | 33-55 |
| Bruce TS | 17-25 |
| Flipper Delta | 14-26 |
| Danforth | 8-15 |
| LWT | 8-15 |
| Offdrill | 8-15 |

Table 10 Anchor Types and their efficiency (Ref [7])

The table above is not exhaustive but tabulates those types of anchors most commonly found on Mobile Offshore Units. The above anchors are termed as embedment or drag anchors; pile anchors and suction anchors operate in a different manner to the embedment type and are therefore not generally seen on Mobile Offshore Units. The efficiency of the anchor varies according to the soil profile, the fluke angle and whether chain or wire is used. Other factors include the use of anchor soaking, which may increase soil resistance thus affecting the performance of the anchor.

### 10.1.1 Anchor failure

Anchors themselves tend to be robust with a history of structural failure virtually unknown. This said, mechanical damage can occur, particular in areas where retrieval is difficult. The usual mode of failure of an anchor is due to its behaviour in the surrounding soils, which cause the anchor to drag. In the process of dragging load is transferred from the most heavily loaded line to the adjacent moorings. This load transfer can in some cases be beneficial since it may bring the mooring system into equilibrium. Such a load transfer is not controllable however and the process may throw unacceptable loads into the adjacent lines producing line failure. To ensure the holding capacity of each of the anchors proof loading of the lines is carried out at the time of platform installation

### 10.1.2 Piggyback Anchors

Piggyback anchors are a means of providing additional holding power to the main anchor. The circumstances for using piggyback anchors are generally where very soft soils are encountered and the main anchor is unable to hold against the pretensioning loads. Piggyback anchors are used in many parts of the world but with the introduction of high-holding design of anchor piggybacking has been become less of a feature in the North Sea. There is the suggestion that if an anchor does not hold, then either the incorrect design of anchor has been used or the anchor is of incorrect size. Of course seabed conditions in situ may be different to those that were expected or surveyed.

The running of piggyback anchors is not always efficient since the pendant from the main anchor to the piggyback may affect its penetration into the soils and hence its stability and performance.

## 10.2 WINDLASSES AND FAIRLEADS

Windlasses and fairleads are subject to regular Class surveys, but it is good practice to carry out checks during anchor running operations. It is important to check that the chain runs smoothly over the windlass and the fairleads and that horizontal links lie properly supported on the shoulders of the links. Normally fairleads and windlasses are fitted with between 5 and 7 chain pockets but it follows that the greater number of pockets, the less stress on the links as they pass over. Lower fairleads should be checked that they not only run freely but also move in azimuth between their design limits. Lower fairleads are often water lubricated but other designs require the use of greases.

## 10.3 COMMENTARY

This section covers a short review of anchors and the inspection of rig based equipment. Anchors used in the North Sea today are of a high holding design with weight to holding power ratios in excess of 10, and in the case of the Stevpris Mk 5 and the Bruce FFTS designs, in excess of 30.

Because of the anchor types available and their effectiveness, the use of piggyback anchors has been reduced. In certain areas of the North Sea they may still be required although piggyback anchors tend to be not so effective as a result of the way they are laid.

Windlasses and fairleads are generally checked on anchor retrieval, which is an optimum time for visual monitoring of the operation of this equipment. Such inspections should not take away from the need for routine maintenance under the rig's PMS system. The condition and operation of the fairleads and windlasses is intrinsic to successful anchor running operations and have the potential for serious damage to chain and wires if not checked or maintained.

# 11 MOORINGS RELEASE IN THE EVENT OF BLOWOUT

The need to provide an emergency release system is contained in *"Health and Safety* Executive *'Offshore Technology Report – 2001/050"* (Ref [9]). Detailed information on Quick Release Systems for Moorings may be found in Offshore Technology Report Nº.OTO 98 086. This section of the report provides a synopsis of the Offshore Technology Report and also discusses current practice with respect to these systems.

## 11.1 PURPOSE

The intent in fitting a quick release system is to move the rig away and upwind from a well in the event a blow-out occurs.

The way the system works is through the release of the leeward moorings that allows the unit to move away from the well and upwind under the effects of the windward lines.

The Emergency moorings release should operate in conditions of no power on board

## 11.2 DESCRIPTION OF SYSTEM

Reference [10] contains details of windlass brake systems, discussing the how the windlass commonly has three types of brake; a pawl, a band brake and a disc brake which operates when the clutch is engaged. For normal mooring operations the main brake to be used would be the disc brake with the either the pawl or the band brake used for back up. On the completion of mooring operations the pawl is engaged with the band brake in support although a number of different combinations have been identified depending on the windlass manufacturers design.

- Single pawl
- Pawl and band brake
- Pawl and disc brake
- Disc brake and band brake
- Pawl, disc brake and band brake.

Although providing a higher reliability factor, the use of a single pawl is not popular since failure of the pawl, without backup, and for whatever reason, would lead to release of the mooring line. Such an approach by rig owners is understandable particularly if the unit is operating close to sub sea assets. It is however essential that any additional brake to the single pawl falls within the emergency release system.

Activation of the emergency release system is achieved remotely, usually from the ballast control room or bridge by the pressing of protected buttons. Electric signals are sent to the hydraulic or pneumatic systems, which release the brakes.

The pawl is activated either hydraulically or pneumatically and is operated such that pawl collapses and is taken away from the fairlead area.

Windlass manufacturers do have different designs and a feature of some systems is a time delay and opportunity to "change your mind", through alarms and interlocks.

## 11.3 RELIABILITY

OTO Report 98.086, which discusses emergency release systems in detail, identifies a variable rate of successful release. Figures taken from this report indicate that the probability of a successful release can vary as shown below.

| Quick Release System | P (Successful Release) Best Case | P (Successful Release) Worst Case |
|---|---|---|
| Single Pawl | 0.9523 | 0.4260 |
| Pawl and band brake | 0.8111 | 0.1318 |
| Pawl and disc brake | 0.8111 | 0.1318 |
| Band and disc brake | 0.8504 | 0.2049 |
| Pawl, band & disc brakes | 0.7371 | 0.0562 |

Table 11 Probability of Successful Release with Pneumatic Power

| Quick Release System | P (Successful Release) Best Case | P (Successful Release) Worst Case |
|---|---|---|
| Single Pawl | 0.9219 | 0.4471 |
| Pawl and band brake | 0.8104 | 0.1267 |
| Pawl and disc brake | 0.8104 | 0.1267 |
| Band and disc brake | 0.8504 | 0.1964 |
| Pawl, band & disc brakes | 0.7364 | 0.0582 |

Table 12 Probability of Successful Release with Hydraulic Power

It may be noted that pneumatic systems are marginally more reliable than those hydraulic systems. This is believed to be due mainly to the complexity of hydraulic systems. Methods of maintaining probabilities on the best-case side are discussed in the next section.

## 11.4 FAULTS AND MAINTENANCE

Emergency release systems are not simple in the sense that as a whole they comprise a number of separate systems which when operated together deploy the emergency release of the mooring chains. Many rigs operating in the North Sea and UKCS are equipped with emergency release systems, a number of which are retrofitted to the windlass manufacturer's specifications. Systems are operated either hydraulically or pneumatically and since the system is required to work without power a number of reserve systems are put in place; in the case of a pneumatic system, local air reservoirs; in the case of hydraulic systems, a local hydraulic accumulator that uses an internal nitrogen bag. Pumps operated from the emergency switchboards normally charge each accumulator. Both systems are independent of the rig's main systems.

Electrical power for activating the emergency release system is low voltage and is provided by batteries, one set per pair of windlasses. The batteries are charged using supply from both the main and emergency switchboards.

Identified faults through Failure Mode Effect Analyses previously carried out are shown below together with their effects. The final column shows means of prevention

| Fault | Effect | Prevention |
|---|---|---|
| Loss of air in local reservoir. | Unable to release brakes as required | Regular checks on integrity of air reservoirs through preventive maintenance (PM) |
| Loss of hydraulic pressure to local accumulator | Unable to release brakes as required | PM, fitting of pressure gauge locally |
| Failure of UPS | Unable to release brakes as required | PM, routing of wires through safe areas. UPS system fitted local to each pair of windlasses |
| Accidental activation | Brake and hence chain release | Careful arrangement of control wiring.to avoid vibration areas |

Table 13 Basic fault chart for emergency release system

A difficulty with emergency release systems is that they can only be function tested in the field. In other words only the component parts of the system can be tested. Emergency release systems as a whole may be tested but rig owners prefer to carry out this exercise during standby periods and in sheltered waters. In order to improve the reliability of the component systems incorporation into the rig's PMS system is essential with a regime of regular testing

Notwithstanding the above a number of field operators are now asking for "move off" drills to be held to test the component systems and to assist in training personnel in the procedures.

## 11.5 EFFECT OF WATER DEPTH

Report OTO 98.086 states that owing to the difference in mooring stiffness, the effectiveness of the emergency release systems is less in shallower water than in deeper water. A check on the mooring analysis will provide an indication of how far the rig will move when the release system is activated. If the excursion is considered insufficient then contingency arrangements should be put in place to ensure the required excursion is achieved.

## 11.6 COMMENTARY

Section 11 deals with emergency release systems, which on most units are multi-facetted.

The purpose of an emergency release system is to release the leeward lines to allow the rig to move upwind in case of blow-out.

Windlasses are fitted with a number of braking systems and it is a combination of at least two of these brakes, which are designed to release in an emergency situation. Unfortunately, Report OTO 98.086 shows that the probability of a successful release decreases with the number of brake systems deployed. This is mainly due to the different make-up of components and sub-systems that make up the system as a whole.

Preventive maintenance and the incorporation of the emergency release system into the rig's PMS play a crucial part in providing the degree of confidence needed in the systems operability. Incorporation into the PMS system must include a full programme of testing.

It is also practice when initially set up at a location to perform a "move off" drill and function test each of the individual systems without actually releasing lines. Again, such procedures assist in both identifying hardware problems and giving confidence to personnel operating the system.

Report OTO 98.086 also identifies a difference in the effectiveness of release systems due to the variance in water depth. We would endorse the recommendations that owners identify how far the rig will move after release in a given water depth, and if necessary prepare contingency plans to cover the shortfall.

# 12 REFERENCES


| | |
|---|---|
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| 3. DnV-OS-E301 | DnV Position mooring (June 2001) |
| 4. API RP 2I | American Petroleum Institute Recommended Practice for in service inspection of Mooring hardware for Floating Drilling Units (2nd Edition 1996) |
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| 9. Health & Safety Executive | 'Station Keeping – OTO 2001/050' |
| 10. Health & Safety Executive | 'Quick release systems for moorings' OTO 98 086 |

# 13 GLOSSARY OF TERMS

| | |
|---|---|
| ALS | Accidental Limit State: Analyses are conducted to this state to ensure that the mooring system has adequate capacity to withstand the failure of one mooring line, failure of one thruster or one failure in the thruster system for unknown reasons. |
| Anchor Efficiency | The multiplication factor that can be applied to the anchor weight to give an indication of holding power. |
| Chain Brittle Fracture | The rapid catastrophic failure of a chain link into two or more pieces. |
| Chasing Operations | The running of a ring collar or J Hook along the length of a mooring line in order to deploy or recover anchors. |
| Damaged Condition | One or more of the lines has failed. In a mooring analysis one line will typically be deliberately failed to assess the loads on the remaining lines. |
| Down Rating | The practice of reducing the SWL of a mooring line – mainly due to mechanical damage |
| Drag Anchor | An anchor designed to penetrate into the seabed when load is applied horizontally to the mooring line lying on the seabed |
| Dynamic Analysis | A more refined analysis in which all six degrees of freedom motions are included. Drag loads on the lines as they follow the Rig's movement are included. |
| Extreme Response Analysis | A dynamic analysis will reveal statistics on line tensions and vessel offsets. If an extreme response analysis is considered this means looking at the maximum values, rather than say the most probable maximums. |
| Fatigue Analysis | An analysis that evaluates the cumulative damage to the mooring lines due to the tension cycles experienced while on location. |
| Ferrule | A swaged joint used on the termination of a wire eye |
| Fluke Penetration | The depth to which an anchor fluke will penetrate in a given soil condition. |
| Hazop | A technique for the identification of hazards and operability problems. |
| Intact Condition | All the mooring lines are in place without damage. |
| Kenter | A connecting link for connecting two chains of equal diameter. |
| Line Tension Optimisation | The manipulation of mooring line tensions to reduce individual line tensions and spread the load evenly throughout the mooring system |
| Mobile offshore unit (MOU) | A floating structure intended to be frequently relocated to perform a particular function. Examples include crane vessels, accommodation vessels and mobile offshore drilling units (Ref [6]) |
| Mooring System | The total combination of mooring lines, anchors, thrusters and associated equipment used for station keeping |
| Offset | Mean offset is defined as the vessel displacement due to the combination of current, mean wave drift and mean wind forces (Ref [5]) |
| Pear Link | A chain connecting link suitable for connecting two chains of different diameters. |

| | |
|---|---|
| Pee-Wee Socket | Wire socket with a rounded nose and also known as a snub nose socket. |
| Piggy Back Anchor | An additional anchor deployed behind and attached to the main anchor in order to provide extra holding power to the mooring line. |
| Pile Anchor | A pre-installed generally permanent vertical pile sunk into the seabed and capable of being used by MOU's. Capable of withstanding some vertical loading |
| PMS System | Planned Maintenance System which may be class approved. |
| Proof Loading | The practice of raising tensions on mooring lines after installation to ensure that adequate holding power exists within the mooring system, i.e. checking that they will not drag. |
| Quasi-Static Analysis | A relatively simple mooring analysis in which only horizontal offsets of the Rig are considered. Drag loads on the mooring lines as they move through the water are excluded. |
| Return Period | The average time (usually expressed in years) between occurrences of events or actions of a specified, or larger magnitude Ref [1]. |
| Safety Case | A document prepared by the Operator of an Offshore Installation to give detailed information on arrangements for managing health and safety and for controlling major hazards on the installation |
| Short Term Mooring | The opposite to a permanent or long term mooring such as a floating production system that may be on station for 15+ years. |
| Spelter Socket | Wire socket with a flat "U" bar nose. |
| Suction Anchor | A suction caisson with open bottom and enclosed top. Water is sucked out of the top causing penetration into the seabed. Holding power of the caisson is generated by suction force and weight of the soil captured inside. These anchors allow for vertical loading |
| SWL | Safe Working Load |
| Transient Condition | When a line fails the Rig will move so that the applied environmental forces come into balance again. Initially the Rig will overshoot its equilibrium position. However, during the course of a few oscillations the Rig will settle down at this position. The maximum offset during line failure is known as the transient offset. |
| ULS | Ultimate Limit State. Analyses are conducted to this state to ensure the individual mooring lines have adequate strength to withstand the load effects imposed by extreme environmental actions. |
| Wire Insert | A length of wire mooring line inserted between two lengths of mooring chain |

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