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ADDENDUM

Replace the Foreword and Contents with the attached.

Please insert the attached Appendix K after Appendix J.

FOREWORD

This recommended practice is under the jurisdiction of the API Subcommittee on Standardization of Offshore Structures.

Offshore technology is growing rapidly. In those areas where the committee felt that adequate data were available, specific and detailed recommendations are given. In other areas general statements are used to indicate that consideration should be given those particular points. Designers are encouraged to utilize all research advances available to them. As offshore knowledge continues to grow, this recommended practice will be revised. It is hoped that the general statements contained herein will gradually be replaced by detailed recommendations.

Work sites and equipment operations may differ. Users are solely responsible for assessing their specific equipment and premises in determining the appropriateness of applying the Instructions.

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Suggested revisions are invited and should be submitted to the Standards and Publications Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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APPENDIX K—GULF OF MEXICO MODU MOORING PRACTICE FOR HURRICANE SEASON

K.1 Scope

This appendix provides guidance for design and operation of MODU mooring systems in the Gulf of Mexico during the hurricane season. The guidance was developed through a cooperative arrangement with the American Petroleum Instituteís Subcommittee on Offshore Structures RP 2SK Work Group and the Joint Industry Project entitled "US Gulf of Mexico (GOM) Mooring Strength Reliabilty" (MODU JIP). The information presented herein is premised on the existence of a MODU evacuation plan, the intent of which is to assure timely and safe evacuation of all MODU personnel in anticipation of hurricane conditions.

This guidance is supplemental to the following documents:

- API RP 2SK, *Design and Analysis of Stationkeeping Systems for Floating Structures*, 3rd Edition (2005);
- API RP 2I, *In-service Inspection of Mooring Hardware for Floating Structures*, 3rd Edition (2008);
- API RP 2SM, *Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring*, 1st Edition (2001), and the 2007 Addendum.

This guidance replaces API RP 95F, *Gulf of Mexico MODU Mooring Practices for the 2007 Hurricane Season—Interim Recommendations*, 2nd Edition, April 2007.

K.2 Basic Considerations

K.2.1 BACKGROUND

In 2004 and 2005, Hurricanes Ivan, Katrina, and Rita moved through the Gulf of Mexico with extreme winds and waves, causing a number of MODU mooring failures in their paths. Mooring failures have occurred in previous hurricanes, including Hurricanes Andrew and Lili, but the number of failures was much lower.

Assessment of MODU mooring systems for worldwide operations has frequently been based on API recommended practices. The first API MODU mooring recommended practice (API RP 2P), released in 1987, specified a design environment lower than the five to ten year return period specified in 3.1, principally driven by the MODU mooring capacities available at that time. Building on the results of a joint industry project focused on MODU mooring code calibration (Reference 1), this document incorporates increased MODU mooring design return periods. These criteria are as follows:

- 5-year return period (away from other structures);
- 10-year return period (in the vicinity of other structures).

There have been significant modifications in the underlying calibration parameters and Gulf of Mexico operations since the 1995 mooring code calibration study which may influence the applicability to future activities. Differences include the following.

1. There are more floating and subsea installations and pipelines. This may result in higher risk of property damage or environmental impact, should a MODU break loose or drag its anchors under hurricane conditions.
2. The number of deepwater permanent installations has increased significantly. These are high production rate installations that often share a pipeline to shore. Therefore the cost for an incident can be much higher.
3. There are more deepwater MODU operations that typically use taut leg moorings with pile anchors. These systems may respond to hurricanes differently than catenary moorings with drag anchors. These types of mooring systems in deeper water were not part of the 1995 calibration study.

K.2.2 MOORING ISSUES

This appendix supplements 3.1, Section 5 and Section 6 for Gulf of Mexico MODU mooring design and operating practice during the hurricane season. Topics addressed herein that will be part of the overall mooring design and MODU operations include:

- site- and well-specific data;
- design criteria for the mooring;
- indicative Gulf of Mexico hurricane extreme metocean conditions;
- mooring analysis;
- site-specific risk assessment and mitigation;
- mooring hardware issues such as anchor system and mooring system upgrade;
- mooring operation issues such as deployment, hurricane preparedness, and inspection.

K.2.3 SITE- AND WELL-SPECIFIC DATA

When planning a MODU mooring operation, the following site- and well-specific data should be collected:

1. location description;
2. description of planned well operation;
3. site-specific metocean data and source;
4. mooring installation hazards;
5. surface and subsea infrastructure.

K.2.4 STACKED MODUS

These guidelines also apply to MODUs that are "stacked" and not working. MODUs that are not actively working should be moored in accordance with the provisions of this document to minimize the likelihood of breaking free and inflicting damage. Alternate methods of stacking MODUs, e.g., setting on bottom for MODUs that can accommodate bottom founding, may be acceptable provided appropriate engineering is performed to assure performance comparable to or better than that of moored MODUs.

K.2.5 EXCEPTIONAL MODU MOORING OPERATIONS

It is recognized that a MODU may be required to perform exceptional operations, for example, to prevent major losses or pollution. Alternately, it may be necessary to relocate a MODU (e.g., to a low consequence location) with a damaged mooring while it awaits repair. In these exceptional cases a risk assessment should be performed to assess the consequences of not performing the MODU mooring operation and the risks associated with mooring system failure. In these special circumstances an environmental return period of less than 10-years may be acceptable for the particular operation under consideration.

K.2.6 MOORING INSPECTION

Mooring inspection is critical to ensure the integrity of the mooring system and minimize the probability of mooring failure resulting from premature failure of substandard components. Guidance for inspection and reuse of MODU mooring components is contained in API 2I, 3rd Edition, with special reference to Annex B on MODU mooring inspection in areas of tropical cyclone.

K.3 Mooring Analysis

K.3.1 MOORING ANALYSIS METHOD

Following API 2SK, quasi-static or dynamic analyses may be utilized for MODU moorings. Either the 1-hour wind speed with wind spectrum or the 1-minute steady wind speed may be used for the wind force calculation. It should be noted that the wind spectrum approach requires good estimates of low-frequency damping.

Wind, wave, and current forces and vessel motions shall be evaluated using the best available, updated MODU information. Many MODUs have gone through significant modifications, involving additional hull structures and deck equipment, that can change the environmental loads on the vessel. Wind, wave, and current force coefficients and models for hydrodynamic analysis should be adjusted to reflect the changes. The adjustment can be based on new model tests, analysis, or combination thereof.

It is not possible to predict precise wind, wave, and current directions under hurricane conditions; therefore, sufficient environmental directions shall be investigated to capture critical cases for line tensions and anchor load and uplift angle. As a minimum, bow, beam, quarter, down-line, and between-line environmental directions should be analyzed. Analysis for the damaged condition should investigate as many conditions as necessary to capture the critical cases, including, as a minimum, damage of the most highly loaded line and adjacent lines. For mooring systems with lines of unequal strength, damage of the most utilized lines and adjacent lines should also be considered.

K.3.2 IDEALIZED MOORING SYSTEM BEHAVIOR: ROBUSTNESS CHECK OR WEAK POINT ANALYSIS

K.3.2.1 General

In addition to the safety factor check, a mooring sensitivity or weak point analysis should be performed. The objective of this analysis is to determine the probable failure mode of the mooring system. It is a useful tool for comparing different mooring systems for a given design criteria. Such an analysis can provide useful information for risk assessment and mitigation strategies. As such, there are no defined acceptance criteria for mooring analysis results discussed in this section.

The mooring sensitivity or weak point analysis should be conducted for both the intact and the damaged conditions. Performing this analysis does not guarantee MODU mooring survival because of other potential failure modes, such as bending over the fairlead, wire fretting, elasto-plastic fatigue damage, etc.

For line components such as chain, wire rope, and fiber rope, the capacity of the component is normally taken as the break strength [minimum break load (MBL), catalog break strength (CBS), minimum break strength (MBS), as appropriate] adjusted for the condition of the component. For example, API 2I allows a mooring component to remain in use until its break strength is reduced to 90% of its catalog break strength. In addition, wire rope bending around the fairlead experiences further strength reduction; for example, a *D/d* (fairlead diameter/wire rope diameter) ratio of 16 may reduce the strength of the wire rope to 90% of CBS. Strength reduction can also be expected for chain.

K.3.2.2 Illustrative Example

Following is an example demonstrating how this analysis may be used for risk assessment and mitigation. The mooring is a chain/wire rope combination system with high efficiency drag anchors. Based on mooring analysis results, plots of utilization versus return period are generated for anchor load and line tension under intact (see Figure K.1) and damaged (see Figure K.2) conditions. For line tension, utilization is the ratio of the maximum line tension to break strength. For anchor load, utilization is the ratio of the maximum anchor load to anchor holding capacity. These two figures provide the following information.

1. Utilization limits are 0.6 (intact line tension), 0.8 (damaged line tension), and 1.25 (MODU intact anchor load for drag anchor) based on dynamic analysis (see 7.2 and 7.4). These utilization limits are satisfied for environmental return periods of 12 years for the intact mooring system and 10 years for the damaged system. Therefore, this mooring system meets the line tension utilization requirements for a 10 year return period hurricane.
2. As an example, consider a wire rope with a reduced break strength of about 80% CBS (e.g., 10% strength reduction due to wire condition and 10% strength reduction due to bending over the fairlead). If there is no faulty component in the windward lines, the intact mooring system may survive a 20- to 25-year return period hurricane (see Figure K.1). However, the anchors of the most loaded lines are expected to move and bury deeper, resulting in redistribution of the load between the highly loaded lines and a reduction in the maximum line tension and anchor load. For hurricane conditions that exceed the 25-year return period, a complete stationkeeping failure—breaking of a number of lines and dragging the anchors of the remaining lines a large distance—is possible if further reduction in mooring line and anchor load cannot be achieved by anchor movement.
3. If a faulty component results in a premature failure of a highly loaded mooring line, then a complete stationkeeping failure can be expected to occur in about a 10-year return period hurricane, based on Figure K.2. This highlights the importance of keeping the mooring system in good condition through mooring inspection and maintenance.

K.4 Site Assessment Background for MODU Mooring

K.4.1 EXISTING CRITERIA

This document provides the basis for mooring analysis for both site assessment of MODU moorings and the design of mooring systems for permanent installations.

K.4.2 MODIFICATIONS FOR SITE ASSESSMENT OF GULF OF MEXICO MODU MOORINGS

The 2004 and 2005 Gulf of Mexico hurricanes resulted in a number of total and partial failures of MODU mooring systems, but no failures of permanent mooring systems. As a result of these MODU mooring system failures, a risk based method for site assessment of MODUs operating in the Gulf of Mexico during hurricane season was introduced in API 95F, 1st and 2nd Editions, for use in the 2006 and 2007 hurricane seasons.

The most significant change in this appendix, from the previous 5- or 10-year return period environmental conditions used for MODU site assessment in 3.1, is the use of risk assessment methods to determine the adequacy of the MODUs mooring system for the planned operation and location. Other differences between the MODU site assessment method recommended in this appendix and those in Section 3 include the following.

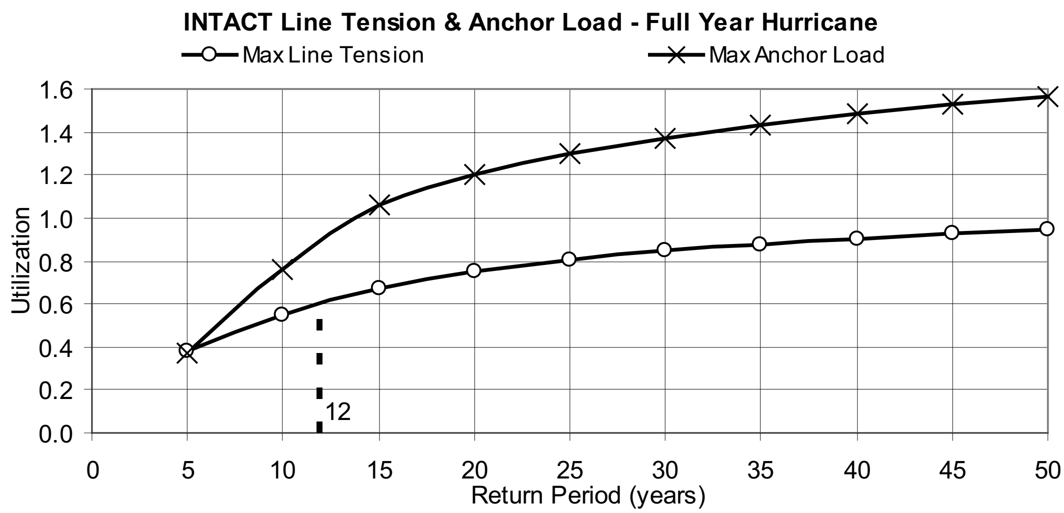


Figure K.1—Utilization versus Return Period for Intact Condition

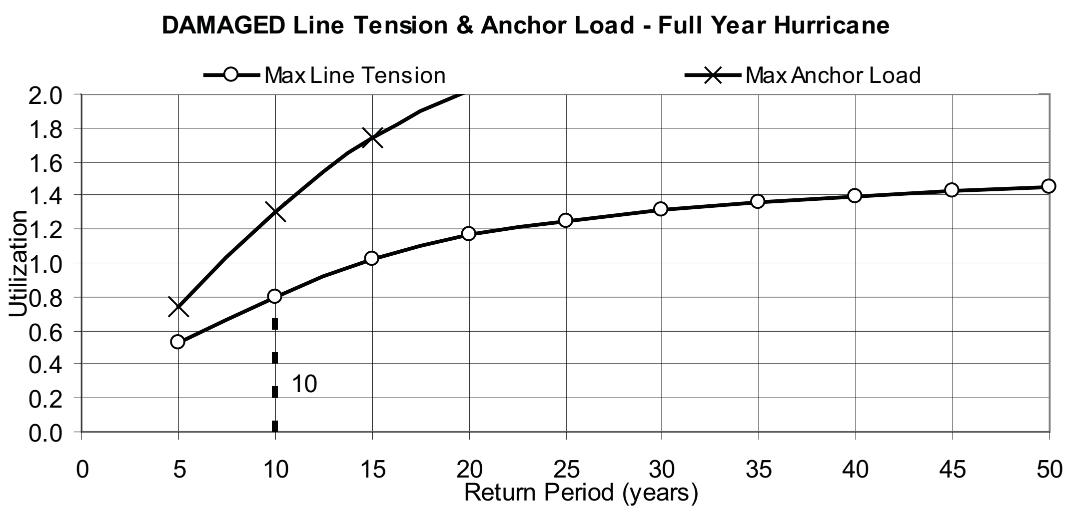


Figure K.2—Utilization versus Return Period for Damaged Condition

1. Recommended design requirements with increased return periods and consequence categories (see K.6).
2. The metocean conditions used for site assessment of MODUs performing typical or atypical operations shall have a return period of not less than 10 years (see K.6).
3. For operations within the peak of the hurricane season (as defined in K.11), the wind, wave, and current conditions used for site assessment of typical or atypical operations shall not be less than those associated with a threshold Category 1 hurricane. During the pre- and post-peak hurricane seasons, the wind, wave and current conditions used for site assessment should not be less than those associated with a threshold Category 1 hurricane unless it can be shown that the overall risk associated with the MODU operations can be significantly reduced with marginally lower metocean criteria.

   Note: In some cases, mitigation methods (the use of alternative mooring line or anchor types) can result in an increase in the probability of system failure (reduction in line or anchor safety factors). In these cases, it can sometimes be shown that despite the increase in probability of mooring system failure, the overall risk of the operation (namely damage to surrounding infrastructure) is substantially reduced.

4. Site and seasonal metocean conditions may be used. Guidance is provided for establishing site and seasonal metocean parameters (see K.11).

5. For typical MODU operations, guidance is provided for performing a financial risk assessment and decision analysis (see K.5, K.6, K.13 and K.14).
6. For atypical MODU operations, an appropriate risk assessment is required to evaluate suitability of the operation (see K.6 and K.14).
7. Mitigation and prevention strategies for reducing the consequences and likelihood of mooring failure should always be considered when designing the mooring system and planning and scheduling the operation (see K.5 through K.10 and K.14).

K.4.3 SITE-SPECIFIC AND MOORING INFORMATION

The general and local site-specific information to be obtained by the Operator should include the following (existing and anticipated during operation):

1. Location description:
   a. Gulf of Mexico Block designation;
   b. location coordinates;
   c. water depth and seafloor bathymetry;
   d. seabed conditions (soils) and hazards;
   e. site characteristics (e.g., chemosynthetics, archeological, etc.).
2. Description of planned well operation:
   a. well type such as exploratory, development, workover;
   b. time of year for the planned operations;
   c. expected duration;
   d. confidence in duration and potential overrun;
   e. possible causes of delay.
3. Site-specific metocean data and source (see K.11).
4. Mooring installation hazards: restrictions to anchor placement and drag.
5. Surface and subsea infrastructure (see K.6, K.13 and K.14):
   a. distances and directions;
   b. other mooring lines, tendons, etc., within mooring pattern;
   c. mooring lines crossing subsea infrastructure (pipelines, umbilicals, wells, etc.).

The information related to the mooring system that affects the consequences, or mitigates the consequences, of mooring failure includes:

1. type of anchors: drag embedment, plate, pile, etc.;
2. types of mooring components that could damage subsea infrastructure, if dragged;
3. other components used to mitigate the consequences of mooring failure (buoyancy, polyester, etc.).

K.5 Risk Based Site Assessment for MODU Mooring Operations

K.5.1 GENERAL

The probability and consequences of a MODU losing station when operating at any location shall be assessed. The intent of the assessment process is to determine the characteristics of the area near the drilling operation and identify options related to mooring component selection, mooring system design, and mitigation opportunities prior to finalizing the mooring design and installing the mooring system. For the planned MODU operation, the mooring system should be associated with an acceptable risk, either by minimizing potential consequences of mooring component or system failure (mitigation) or by reducing the probability of mooring component or system failure (prevention).

K.5.2 RISK AND CONSEQUENCE TYPES

Risk is defined as:

Risk = [Probability of an adverse event occurring] × [The consequences associated with that event]

The risk can be reduced either by reducing the probability of experiencing an incident (prevention) or by reducing the consequences of that incident should it occur (mitigation). A fundamental part of reducing the risk associated with MODU operations is to ensure that all parties, including owners, operators, regulators, etc., have a clear understanding of their "risk exposure."

The different types of consequences that are associated with MODU mooring failures are as follows:

1. health and safety;
2. environmental;
3. financial;
4. corporate reputation and image;
5. industry reputation and image;
6. national interest.

For MODU operations in the hurricane season where the MODU is evacuated and wells and pipelines are shut-in, health, safety, and environmental consequences associated with MODU mooring system failure are relatively low. Assessments of consequence types 4 through 6 will be subject to considerable corporate interpretation, and there will be large variations in risk tolerance. In the case of industry reputation (5) and national interest (6), the consequences depend on the performance of all MODUs operating in the Gulf of Mexico at any one time. The consequences of failure will include public and regulatory perception, which will be influenced by the number of MODUs that fail and the result of those failures on other industry infrastructure in a single hurricane, hurricane season, or few years.

While risk assessments may be performed for all six types of consequences, the one primarily addressed in this appendix is the third, financial. Other types of risk, namely health and safety and environmental, should be evaluated as required for the operation at hand. For example, if there is a significant risk for an environmental release of hydrocarbons from a drifting MODU colliding with a facility that stores hydrocarbons or dragging an anchor over a pipeline resulting in a release, then such possible environmental hazards should be considered in the assessment process. Additional information on the other types may be found in K.14.

K.5.3 OVERVIEW OF RISK ASSESSMENT

The consequences (to infrastructure) of a MODU mooring failure depend on the density and type of subsea and surface infrastructure that surrounds the location of interest and, to some extent, on the type of MODU mooring system (e.g., the consequences of dragging chain over the seabed will be different from those due to dragged polyester). The risk assessment procedures described in this Appendix address the consequences of damage to surrounding infrastructure. For MODU operations in the hurricane season, where the MODU is evacuated, it is the responsibility of the Drilling Contractor and Operator to manage the risk associated with damage to the MODU and its mooring system, and to the Operator's drilling program.

An introduction to risk assessment methods and acceptance criteria (decision analysis) for performing different levels of risk assessment is provided in K.14. Recommended procedures and guidance are provided in K.6.

The potential consequences to infrastructure from a stationkeeping failure depend on:

- financial consequence values (including both the cost of replacement and lost production);
- distances and directions between individual components of infrastructure and the MODU's location;
- mitigation strategies;
- different likelihoods of adverse consequences given a mooring failure.

The probability of MODU mooring system failure decreases with increases in the design return period [the return period for which the mooring system satisfies all of the requirements of this document (intact and damaged line tension, anchor load, and clearance requirements)]. Generally, the management of risk to surrounding infrastructure requires that the design return period increases or additional mitigation measures be put into place as the consequence of failure increases, but the required return period is independent of the duration of the operation and the season of operation. However, for a given return period, the intensity of the environmental conditions (wind, wave, and current) is dependent on the particular site and the season(s) of operations.

The following example serves to illustrate that the return period is independent of duration.

An operator has two wells that need to be drilled near an existing facility with identical consequences. Each well will take one month to complete, and they will be drilled consecutively. If two independent Applications for Permit to Drill (APDs) are submitted, each for a drilling program of one month operation, then the design return period for each well should be the same as for a single APD for a MODU operating on the same location for a duration of two months. Clearly, different return periods for two one month APDs compared to a single two month APD is not a logical solution: the exposure risk for the facility is the same in both cases, so the design return periods should be the same. In effect, the daily risk to the infrastructure should be consistent, so the duration of an operation should not influence the design return period for MODU operations.

Figure K.3 shows the general methodology for carrying out a risk assessment for MODU operations when considering the potential consequences of mooring failure to the surrounding infrastructure.

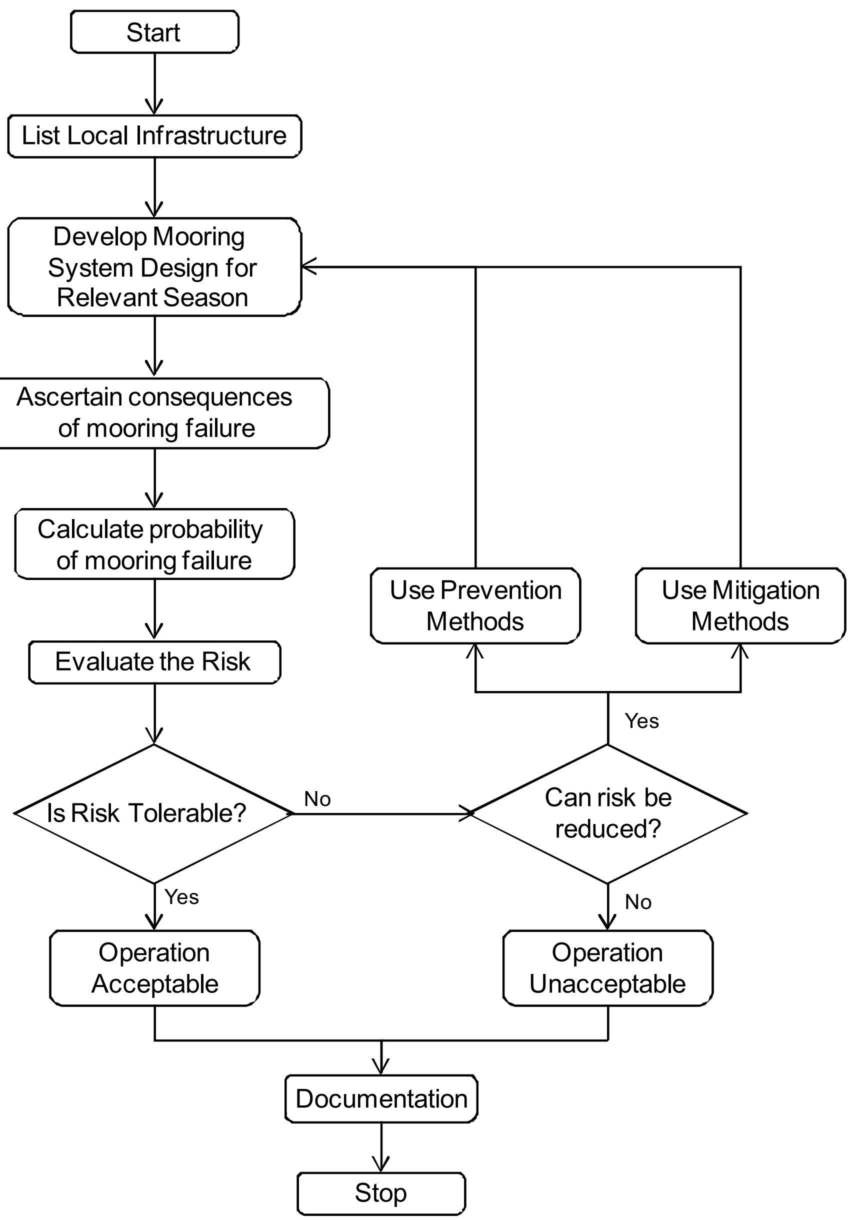


Figure K.3—Financial Risk Assessment—Overall Process

Tolerable risk levels should provide a balance between absolute safety requirements and costs and benefits of proposed risk reduction measures. Additional discussion and guidance on risk acceptance criteria and means to reduce risk are provided in K.14. In particular, changing operating season may be considered a prevention method that can reduce risk to acceptable levels. Documentation is the responsibility of the Operator and should include all necessary information to allow verification of the risk assessment.

K.6 Assessment Procedures and Criteria

K.6.1 GENERAL

This Appendix recognizes five consequence categories that depend on the type of MODU operation being performed and site characteristics. Two of the five consequence categories are associated with exceptional (see K.2.5) and atypical (see K.6.4) MODU operations. Three of the five consequence categories are associated with typical MODU operations and are:

C-1 lower consequences in event of stationkeeping failure;

C-2 intermediate consequences in event of stationkeeping failure;

C-3 higher consequences in event of stationkeeping failure.

For typical operations, an initial assessment and basic risk assessment shall be conducted for all locations as discussed below. A supplemental risk assessment should be conducted when necessary. The results of the basic or supplemental always override the results of the initial assessment.

An outline of the recommended risk based assessment process is as follows.

1. *Initial Assessment (required)*. The initial assessment process determines the unmitigated consequence category for the location to be evaluated based on distance and class of nearby infrastructure. In the initial assessment, the consequences categories listed in Figure K.4 are intended as a starting point for the basic risk assessment of the mooring system.
2. *Basic Risk Assessment (required)*. The basic risk assessment is used to establish the acceptability of the risk and the design return period. A basic risk assessment shall consider each of the following elements.

   a. *Infrastructure and Design Return Period Evaluation*. In determining the design return period, the actual infrastructure proximity shall be considered for a given moored MODU operation. Detailed evaluation of nearby infrastructure and potential to damage such infrastructure shall be conducted for all MODU operations. This evaluation includes assessing the MODU mooring system performance and the weak point analysis per K.3.3.

   b. *Operational Planning and Evaluation*. Additional issues that affect mooring system reliability and risk exposure should be evaluated. During peak hurricane season, lower risk locations should be given priority in operational planning. Adequate contingency plans shall be in place with operations near peak hurricane season if the risk levels during peak season are not tolerable.

   c. *Mitigation Evaluation*. As part of the risk evaluation, possible actions should be evaluated that can reduce the potential for mooring failure and consequence of failure. The design criteria referenced in this document are not intended to preclude reasonable and practical actions that can result in improved mooring systems.
3. *Supplemental Risk Assessment (as required)*. For higher risk locations or areas where more detailed assessment is warranted, a supplemental risk assessment should be conducted to determine suitability to drill with a given mooring system at a specific location. When a supplemental risk assessment is used for a typical MODU operation, it shall include considerations of elements from the basic risk assessment.

Sections K.5, K.13 and K.14 provide more detailed information, discussion, and guidance for evaluating site-specific consequences associated with MODU mooring failure and for assessing the risk of MODU operations.

K.6.2 INITIAL ASSESSMENT PROCEDURE FOR TYPICAL MODU OPERATIONS

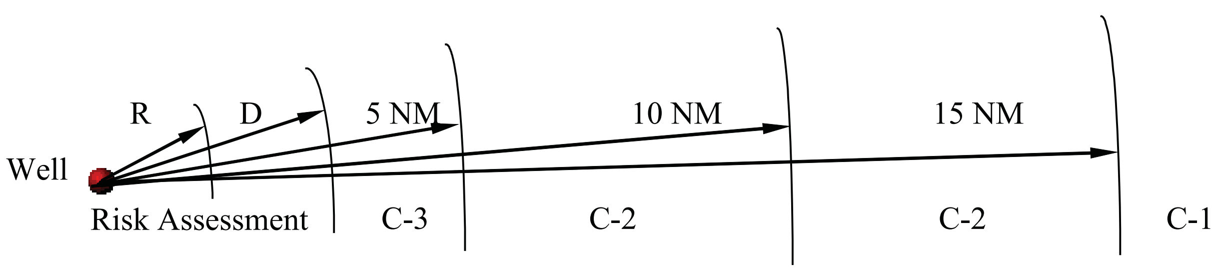
The initial assessment process determines the unmitigated consequence category for the location to be evaluated based on distance and class of nearby infrastructure.

The consequence category from the initial assessment depends on two factors: production rate and distance. A larger facility or pipeline represents a higher consequence at the same distance as a smaller facility or pipeline. Therefore, the design return period for a MODU operating in the proximity of a large facility or pipeline is higher than that of a MODU operating near a smaller facility or pipeline.

The greater initial investment and future tie-in potential for surface facilities dictates that the consequence assessment for surface facilities be based on rated production. Pipelines can be repaired in a shorter time and production potentially rerouted; therefore, the consequence assessment for pipelines may be based on actual throughput rather than rated capacity. If actual pipeline throughput is unavailable, a conservative estimate of pipeline throughput shall be used.

The initial assessment is a process to determine the relative consequence level of MODU operations. The initial assessment process works by determining the consequence category based on distance and capacity of nearby and most important infrastructure and then finding an approximate design return period for that consequence class. However, the initial assessment does not take into account multiple facilities or pipelines which would increase the consequence of a particular MODU mooring operation. Likewise, the initial assessment does not take into account mitigation measures that would reduce the consequence of the operations. The Operator must take these factors into consideration when conducting an initial assessment. The initial assessment may be useful in helping an Operator schedule operations or determine MODU mooring requirements. For example, a location that falls under the C-1 consequence category, the Operator may be able to use, after performing the required basic assessment, a MODU of opportunity at any time of the year. If a location falls under the C-3 consequence category, it is an indication that the Operator may have to take more care in selecting a MODU or in scheduling the operation for a more benign season of the year. Figure K.4 presents recommended unmitigated consequence categories based on distance to surface and subsea infrastructure. The consequence category for a given location may change for other assessment methods, e.g., basic and supplemental.The unmitigated consequence category for the location determined by the initial assessment is the highest consequence category for any facility or pipeline as determined from Figure K.4. The recommended design return period is obtained from Table K.1 based on the consequence category.

Figure K.4—Initial Assessment Unmitigated Consequence Categories for Typical MODU Operations



Note: *d* = distance to well center. *R* = mooring radius = distance between well and most distant anchor; *D* = mooring diameter = 2*R*

Surface Facilities

Rated Capacity	$d \le R$	$R < d \le D$	$D < d \le$ 5NM	$5 < d \le$ 10NM	$10 < d \le$ 15NM	15NM < d
> 75K BOE/D			C-3	C-2	C-2	C-1
25 to 75K BOE/D	Risk Assessment		C-2	C-2	C-1	C-1
< 25K BOE/D			C-1	C-1	C-1	C-1

Active Pipelines

Actual Throughput	$d \le R$	$R < d \le D$	$D < d \le$ 5NM	$5 < d \le$ 10NM	$10 < d \le$ 15NM	15NM < d
> 75K BOE/D	Risk Assessment	C-3	C-2	C-2	C-2	C-1
25 to 75K BOE/D	C-2	C-2	C-2	C-2	C-1	C-1
< 25K BOE/D	C-2	C-1	C-1	C-1	C-1	C-1

Note: An "Active Pipeline" is defined as any pipeline located within the OCS that currently has throughput. Pipelines that are abandoned, cancelled, out of service, proposed, or relinquished are not active. However an active pipeline could be temporarily shut-in. Actual throughput should be based on all active pipelines in a corridor. When selecting the initial consequence category, due consideration should be given to the number of active pipelines and total throughput. Details of active oil and gas pipelines in the Gulf of Mexico are available at: http://www.gomr.mms.gov/homepg/pubinfo/freeasci/pipeline/freepipe.html and http://www.gomr.mms.gov/homepg/pubinfo/PI%20Catalog.pdf

Table K.1—Consequence Category Return Period

Consequence Category	Return Period, Years
C-1	10
C-2	see note
C-3	50

Note: In principle, the return period for C-2 and C-3 categories is a range. It is expected that the C-2 category covers most operations in the GOM and a 20-year return period should be suitable for the majority of locations. When the consequence of the MODU operation is close to the boundary between consequence categories, particular care needs to be taken to ensure that a suitable design return period is used.

K.6.3 BASIC RISK ASSESSMENT PROCEDURE FOR TYPICAL MODU OPERATIONS

The purpose of a basic risk assessment is to facilitate planning and follow-up operations that reduce as much as practically possible the risk exposure from MODU mooring systems, as discussed previously.

A basic risk assessment should, as a minimum, qualitatively assess and fully document the following:

1. potential mooring failure modes (see K.14.2);
2. probability of mooring failure (see K.14.7);
3. nearby infrastructure and the potential for damage with various types of failure and consequence of damage;
4. operations plans and impact on analysis assumptions;
5. mechanical integrity of systems;
6. possible mitigation actions to improve reliability and reduce potential consequence of failure.

A basic risk assessment may be based on a methodology that determines a mitigated consequence score, which allows the stakeholders to assess, on a relative basis, the consequences of MODU mooring failure associated with the proposed operations. The intent of this approach is to be more conservative by comparison to a more detailed risk assessment. However, the basic consequence assessment can be completed with the routinely available information and data that should be available to the Operator and Drilling Contractor.

The basic consequence assessment should be based on:

1. consequence values based on location (infrastructure that could be damaged in the event of a mooring failure);
2. consequence factors based on mooring components and system details.

The Consequence Assessment Methodology, in K.13, is an example of a methodology that can be used to determine the mitigated financial consequences of a given MODU operation as part of a risk assessment. Guidance on acceptance criteria for risk assessment (i.e., acceptable return period) is provided in K.14.

Table K.2 shows a risk matrix based on consequence and probability of occurrence for hazardous events which can be used as part of a qualitative MODU mooring risk assessment. In situations with moderate risk, reasonable and practical actions should be evaluated that reduce the potential of mooring failure and consequences of failure.

Table K.2—Sample Risk Matrix

<table>
<tr><td colspan="2" rowspan="3">Consequences</td><td colspan="4">Probability</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td></tr>
<tr><td>Less Likely</td><td></td><td></td><td>More Likely</td></tr>
<tr><td>IV</td><td>High</td><td></td><td></td><td></td><td>High Risk</td></tr>
<tr><td>III</td><td></td><td></td><td colspan="2" rowspan="2">Moderate Risk</td><td></td></tr>
<tr><td>I</td><td></td><td rowspan="2">Low Risk</td><td></td></tr>
<tr><td>I</td><td>Low</td><td></td><td></td><td></td></tr>
</table>

K.6.4 SUPPLEMENTAL RISK ASSESSMENT

For typical operations, a supplemental risk assessment may always be used to perform a more detailed assessment of specific risk elements of interest associated with the proposed operations.

For atypical MODU operations, a detailed risk assessment of all applicable mooring risk elements shall be performed.

The risk assessment process contains a series of steps to formally assess the risk at any given location. Due consideration should be given to the time required to complete this process. The steps can be summarized as:

1. definition of location and well parameters;
2. identification of local and distant infrastructure;
3. undertaking a hazard identification (HAZID) study;
4. determination of probability of mooring failure (mooring system reliability analysis, anchor holding capacity uncertainty, etc.);
5. quantification of the consequences of failure (e.g., through event tree analysis);
6. risk mitigation;
7. documentation.

Further information on risk assessment methods is provided in K.14.

The risk assessment entails a documented and structured identification of options available, impact of these options, and leads to the selection of the lowest consequence mooring system available, and is a valuable tool in designing the mooring system.

K.6.5 ATYPICAL MODU OPERATIONS

There may be atypical MODU operations associated with exceptionally high consequences that may require very high environmental return periods. MODU operations that may be associated with exceptionally high consequences include but are not limited to:

- MODU offset drilling;
- tender assisted drilling adjacent to a permanent facility;
- MODU operations within a mooring radius of a permanent surface facility.

Such operations are subject to a detailed supplemental risk assessment to determine if the operation is acceptable (see K.6.4).

K.7 Mooring System Improvement

There are various options to improve the survivability of the mooring system and reduce the consequences of a mooring failure under hurricane conditions, such as the use of higher strength components, additional mooring lines, and steel or fiber rope inserts. These options have design and hardware issues that require special attention, as discussed below.

K.7.1 HIGHER STRENGTH COMPONENTS AND ADDITIONAL LINES

Replacement of existing chain and wire ropes with higher strength components may be considered.

Additional lines may also be placed on a MODU to increase mooring system strength. The additional lines may be terminated in a number of ways, such as:

- standard fairlead and tensioning equipment with full tensioning capability;
- alternate fairlead and tensioning equipment with limited tensioning capability;
- fixed terminations with no tensioning capability.

The following items may be affected by the additional lines or the lines with stronger components:

- required anchor holding capacity;
- required stall and brake load capacity of winch/windlass;
- global structural strength of the vessel;
- local structural strength of the tensioning equipment frame and foundation;
- local structural strength of the fairlead foundation and support structure;
- vessel variable deck load and loading conditions;
- vessel stability if new downflooding points are introduced by the mooring modifications;
- available space.

K.7.2 FIBER ROPE INSERT

Fiber rope (polyester or HMPE) sections may be inserted in the existing mooring line to improve mooring performance and mitigate the potential for damage due to lines dropped on or dragged over subsea equipment. The selection and design of such systems shall be based on mooring analysis using a proper fiber rope stiffness model. The rope should be protected by soil blocking devices such as a filter or jacketing since contact with seafloor is possible under hurricane conditions due to large offsets, anchor drag or line failure.

K.7.3 FIBER ROPE AND STEEL WIRE ROPE INTERACTION—STRENGTH AND FATIGUE CONSIDERATIONS

The torque relationship between fiber and steel mooring components requires special consideration to ensure the mooring system performance is not compromised.

K.7.3.1 Strength Considerations

For MODU mooring systems, Reference 2 indicates that neither the strength of a fiber rope nor the strength of a 6- or 8-strand wire would be degraded by any noticeable amount when they are connected in the same line for the duration of a severe hurricane.

K.7.3.2 Fatigue Considerations

Typically, no fatigue design analysis is required for a MODU mooring system. However, laboratory testing demonstrates that a 6- or 8-strand wire rope's fatigue performance, when connected with a torque-neutral fiber rope, could be significantly degraded (Reference 3) although the scale effect of such testing is yet to be quantified. Industry experience indicates that there are at least two viable design approaches to address this issue.

1. **Torque-matched approach**
   A steel wire rope's fatigue life is best preserved by connecting to a torque-matched rope. A rope is considered torque-matched if its torsional characteristics over the design load range are essentially the same as that of the connected wire rope. Due to the inherent difference in material properties, a fiber rope typically can only match a wire rope's torsional characteristics at a pre-determined tension level. The difference between the torque of the fiber rope and wire rope increases as the line tension deviates from the match point with changing environmental loading or heading. Other factors to be considered in the torque-matched design include torque characteristics, lay direction, presence of swivels in the mooring lines, swivel lock-up load, and the presence and length of chain segments.
2. **Non-torque-matched approach**
   Available torque-neutral fiber ropes can be used for short term MODU mooring systems if the dynamic torsion of the steel wire could be restrained at the interface between the fiber rope and wire rope (Reference 2). A properly designed submersible buoy could provide such restraint. Available experience shows that wire fatigue damage in such a system is lower than some of the earlier scaled test data suggests (Reference 2).

The fatigue damage to wire rope tends to be concentrated near the interface with the fiber rope. The wire rope can be returned to service after the damaged end is re-terminated during a MODU move. It is also possible to insert a short connecting wire rope (200 ft to 300 ft) between the MODU mooring wire and the fiber rope to minimize the need for re-socketing wire ropes in the field.

K.8 Anchor System Considerations

K.8.1 GENERAL

The anchor system plays an important role in hurricane survivability of the mooring system and the consequence of mooring failure. Consideration should be given to alternative anchor types, where necessary, to achieve adequate performance and mitigate consequences of failure. Anchor handling vessel and MODU winch system capabilities should be considered in selecting the best anchor option.

Drag anchors are commonly used for catenary moorings, while fixed anchors such as suction piles or normally loaded plate anchors, including drag or direct embedded plate anchors, are often used for taut or semi-taut moorings. Drag anchors of the heavily loaded lines may move a short distance (tens to hundreds of feet), causing redistribution of the mooring load among the mooring lines. This redistribution of load may help the mooring system survive. However, for locations where pipelines, subsea trees, manifolds or other subsea infrastructure exist, excessive anchor movement can cause damage to these infrastructure elements.

The use of fixed anchors may increase the likelihood of mooring line failure under similar conditions because redistribution of mooring load cannot be achieved.

For all types of anchors, behavior and performance under severe loading must be understood to assess and mitigate the risk of moored MODU operations.

K.8.2 ANCHOR HOLDING CAPACITY, SAFETY FACTORS AND INSTALLATION REQUIREMENTS

Anchor holding capacity for the types of anchors being used shall be considered in the design of the mooring system. Anchor installation requirements should be included in anchor type selection consideration, especially when the anchor is to be installed near sea floor infrastructure and where an adequate safety zone should be maintained around the infrastructure during anchor handling. Anchor selection and safety factors should consider capacity, availability, and potential to minimize damage to subsea infrastructure should an anchor failure occur in conditions such as but not limited to:

- a marine installation such as a pipeline lies in the dragging path of an anchor or in the potential dragging path, i.e. a location such that mooring system failure could result in an anchor dragging across the installation;
- a mooring line that can cross another mooring line;
- density or importance of seafloor or water column infrastructure that merits a higher safety factor than those stated in Tables 6 and 7.

Unless site-specific soil data are available, appropriate upper and lower bound soil conditions for the general area of operation shall be considered. Any evaluation of anchor holding capacity should take into consideration the uncertainties of the local soil strength profile and other geotechnical properties.

K.8.3 DRAG ANCHOR

Drag anchors should have a proven performance or be closely similar to an anchor with proven performance. Performance may be proven through scale testing, field tests, etc. Drag anchors should be in an undamaged condition to preserve symmetry and hence holding capacity.

When drag anchors are used for a MODU mooring operation, they should be test loaded to ensure the anchor is right side up and sufficient embedment is achieved.

K.8.3.1 Windward Line Loading

Due to equipment limitations for MODU operations, a drag anchor is typically subjected to a test load below the maximum storm load. When the anchor experiences loads higher than the test load and uplift angles are within the anchor's design tolerance, a properly set anchor will typically penetrate deeper, developing higher holding capacity. When the storm load exceeds the anchor holding capacity and uplift angles are within the anchor's design tolerance, the anchor will stop penetrating and move horizontally below the seafloor. In this process the mooring line either breaks due to overloading or remains intact due to mooring load redistribution or storm passage. If the uplift angle exceeds the anchor's design tolerance, then the anchor may lose holding capacity, lose penetration and may drag to the surface.

Note: In the 2004 and 2005 hurricane seasons, anchor drag distances for the windward lines were typically less than one mile. However, on some occasions, windward anchors dragged over 20 miles off location.

K.8.3.2 Out-of-plane Loading

When several windward lines fail, resulting in large directional changes of the remaining lines, out of plane loading at the anchor shackle may occur. Although anchor behavior under this loading condition is still a subject of research, there is evidence suggesting that drag anchors will rotate to a new orientation and maintain their holding capacities. Under this loading condition, a pipeline or subsea equipment that was not originally in the dragging path of an anchor may become in the dragging path due to change of line direction. Consequently, the site-specific assessment should account for the possibility of anchors dragging in directions other than towards the center of the mooring pattern.

When windward lines fail, some drag anchors on the leeward lines may be subject to reverse loading. These anchors may be pulled out and dragged some distance. Some drag anchors may re-embed, limiting the drag distance.

Note: Industry experience in the 2004 and 2005 hurricane seasons shows that most of the leeward and side anchors stayed in the vicinity of their original locations.

K.8.3.3 Oversized Anchor

When drag anchors are oversized for a MODU operation to protect the surrounding structures, they should be test loaded to ensure the anchor is right side up and sufficient embedment is achieved. If the anchors are conventionally set, the MODU must have sufficient winch capacity to apply the required test load.

K.8.4 PLATE ANCHOR

The behavior of drag embedded and direct embedded plate anchors for MODU operations must be understood in order to determine suitability of the anchor for the intended operation.

K.8.4.1 Fluke Angle Setting

Drag embedment plate anchors may have several options for fluke angle setting: embedment, near-normal, and normal. In the embedment or near-normal fluke angle setting, the plate anchor behaves as a drag embedment anchor. The smaller embedment fluke angle is generally used to obtain initial anchor penetration, changing to the larger near-normal fluke angle allows even deeper penetration. In the near normal setting, the anchor may behave as a plate anchor under design loading conditions, but under overload conditions the anchor can drag, penetrate deeper and reach a new equilibrium depth with a higher holding capacity. In the normal setting, the anchor ultimately behaves as a fixed plate anchor, and overloading will either result in failure of the mooring line or cause the anchor to pull out. Selection of these options should be based on evaluation of the specific MODU operation.

Some direct embedment plate anchors have also demonstrated diving behavior. Diving behavior is a result of an eccentricity between the line of action of the mooring line and the center of soil pressure on the fluke. In an overload condition, plate anchor movement through the soil will cause the fluke to tilt with respect to the mooring line direction developing an effective near-normal shank or fluke angle.

K.8.4.2 Triggering the Anchor and Ultimate Holding Capacity

Drag embedment plate anchors typically have two operating modes: an installation mode and a normal or near-normal loading mode. In the installation mode, depending on the consistency of the soil, the load is applied at an angle of 40º to 60º to the fluke. After failing a shear pin or triggering the anchor, the load becomes perpendicular (normal) or nearly perpendicular (near normal) to the fluke.

Design holding capacity should be based on rigorous anchor design and installation analysis for a defined set of upper and lower bound soil conditions and installation loads. Once a normally loaded anchor is triggered the holding capacity will always be greater than the installation load with relatively small anchor movement. The actual holding capacity will depend on anchor and mooring line dimensions, the sensitivity of the soil, and the change in load direction. Guidance on installation analysis can be found in DNV RP E302 (Reference 4).

K.8.4.3 Out-of-plane and Reverse Loading

Some drag embedment plate anchors for MODU moorings are designed to be retrieved by loading in the reverse direction to operate a release mechanism, permitting low load recovery by the mooring line. These plate anchors cannot resist reverse loading and therefore may also have limited resistance to out of plane loading. However, where the risk of damaging pipelines and subsea equipment by anchors needs to be minimized, the reverse retrieval device can be disabled temporarily to provide reverse loading capability during the hurricane season, with recovery being achieved by means of a drogue tail or submerged buoy attached to the anchor fluke. These anchors may be set from the MODU or preset.

Plate anchors with a normal loading fluke angle setting that have the retrieval device temporarily disabled or do not incorporate a reverse retrieval device will therefore have capability of resisting out of plane and reverse loading.

Care should be taken when using drag embedment and direct embedment plate anchors designed with near-normal features; they may lose capacity if rotated approximately 90º in the vertical plane after windward mooring line failure and leeward line direction change as the MODU drifts off location over a leeward anchor.

K.8.5 SUCTION PILE

Suction piles have been observed to fail at the padeye due to a combination of tension and excessive out-of-plane bending. The out-of-plane bending occurs due to large vessel offset after first and subsequent line failures. Consideration should be given in the padeye design to applying the breaking load of the mooring line at any angle.

K.8.6 SOIL CONDITIONS

Unless site-specific soil data are available, appropriate upper and lower bound soil conditions for the general area of operation shall be considered. However, caution should be exercised at locations where unusual soil conditions beyond the notional bounds may be encountered—e.g., underconsolidated or weak soil, shallow cementation, sand layers and overconsolidated or hard soil. Unusual soil conditions may be identified at specific locations by interpretation of 3-D seismic data, usually analyzed in support of EP submissions for exploration drilling—see 30 *CFR* Part 250, Subpart B, and NTL 2006 G14. Features that may be interpreted from 3-D seismic data that provide evidence for unusual soil conditions include (but are not limited to):

- shallow gas;
- erosion features, such as canyons and furrows;
- shallow mass transport deposits;
- seafloor expulsion features;
- seafloor faults.

Continental shelf areas, where interpretation of 3-D seismic data for shallow geologic features is extremely limited, may warrant dedicated site surveys and soil sampling where data for the general area of operation are sparse.

K.9 Hurricane Preparedness

K.9.1 GENERAL

This section addresses specific mooring related issues that are part of a hurricane preparedness plan. The overall hurricane preparedness plan should include suitable provisions for other activities, such as personnel evacuation and suspension of drilling activities.

K.9.2 PREPAREDNESS OVERVIEW

K.9.2.1 Hurricane Preparedness Plan

The hurricane preparedness plan shall be a written plan and should address as appropriate the following mooring specific items:

- ballasting operations;
- repositioning the vessel to a more favorable storm safe position within the already set anchor positions;
- mooring line payout and/or tension adjustments to optimize the mooring's storm survivability;
- engaging storm survival brakes and stoppers or securing and dogging winches;
- optimum mooring pattern and positions to maximize mooring performance;
- provision of sufficient battery power, computer disc storage space, etc., to ensure that critical systems, including MODU trackers, remain operational from the time the crew disembarks until the time the crew re-boards the MODU;
- confirmation that towing bridles or lines, navigation aids, and position tracking devices are installed and functional.

The hurricane preparedness plan should also include a schedule that reflects the time required to complete necessary mooring activities, operations to secure the well and the MODU, evacuate the crew to a safe location and allow for some contingency time.

K.9.2.2 MODU Recovery

All units should be prepared to the extent feasible for towing. Each MODU should be equipped with a primary and secondary tow line or bridle.

K.9.2.3 Contingency Planning

Contingency plans shall address operations identified as critical to both hurricane survival and resumption of normal activities. The contingency plans shall address the need to have suitable personnel available to respond to the problem at hand. For example, if a mooring winch is inoperable and cannot be repaired, then it is necessary to have a mooring analyst determine suitable payouts and pretensions on the remaining lines in order to maximize survivability.

K.9.3 LOOP AND EDDY CURRENTS

When a MODU is in a loop or eddy current, the drilling contractor or operator shall determine the mooring line adjustments required to abandon the MODU in a condition that provides its best chance of riding out the storm with due consideration to the anticipated surface current velocity and direction.

The drilling contractor or operator should obtain the following information:

- existing line payouts and tensions;
- stall capacity of the winches;
- latest measurements of the currents, particularly velocity and direction at the sea surface;
- forecasts of the loop/eddy current velocity and direction.

The drilling contractor or operator should determine the optimum line payouts and pretensions that serve to maximize intact mooring line safety factors without exceeding equipment limits or endangering human life. The environmental conditions used for analysis should include the following weather combinations:

- omnidirectional hurricane metocean criteria;
- hurricane-driven surface currents vectorially added to the local loop or eddy current;
- the payouts and pretensions updated as surface current velocities or headings change.

K.9.4 MODU TRACKERS

Satellite location transponders should be installed and tested on board all moored MODUs operating in the Gulf of Mexico. These transponder systems should be function tested prior to hurricane season to ensure the system is functioning properly. Sufficient care should be given to ensure these systems have adequate battery backup to enable the transponders to function after the MODU has been abandoned for a minimum period of seven days. Sufficient battery life should allow for reasonable assurance that the system will be operational through a given cyclonic storm event and for a period of time after potential passage of the storm, to allow for speedy recovery operations in the event of mooring failure. The tracker system should be fully operational with seven day capacity within 48 hours of reboarding the MODU.

Redundancy in systems should be considered.

K.9.5 POST-STORM REPORTING

Section K.15 contains a form that may be utilized to capture the MODU particulars and any storm related consequences. Completion of the appropriate sections of this form immediately after installation is recommended.

Every reasonable effort should be made to retain, preserve, and label the failure surface of any failed mooring line component for future examination. The label should include: site name, failure date, MODU name, line number, location along the line, and component serial number if applicable.

K.10 Mooring Installation

K.10.1 MOORING INSTALLATION PLAN

The mooring system for a specific site should be deployed according to an installation plan that specifies a number of items related to the mooring design:

- MODU heading;
- mooring line headings, including installation tolerance;
- anchor locations, including installation tolerance;
- line segment lengths and composition;
- pretensions;
- anchor test loads.

The installation plan should also include information on:

- minimum anchor handling vessel (AHV) specification (bollard pull, winch capacity and pull, and any other equipment requirements);
- maximum sea states for safe operations;
- weather window requirements (i.e., duration of installation activities);
- weather forecast requirements;
- contingency and management of changes to the plan.

K.10.2 AS-INSTALLED MOORING SYSTEM INFORMATION

Once the installation is completed, it is the Operator's responsibility to ensure that the information on the as-installed mooring system is recorded and transmitted, as applicable, in a timely fashion. This information should be provided to all relevant parties, including the drilling contractor, for post installation verification, operating the mooring system, and planning for evacuation. Completion of K.14 may facilitate recording most of this information.

This information can be used for a number of purposes.

- verify that the mooring system is installed within design tolerances;
- verify that any deviations from the design tolerances will not have a negative impact on mooring system performance.

As a minimum, the as-installed information shall include the following:

- Global geometry:
  - MODU heading and global position;
  - individual line headings;
  - initial and final anchor locations.
- Mooring composition:
  - length, general condition, composition and location of all mooring line sections;
  - number, location, general condition, and type of connectors (e.g., shackles, connecting links, subsea connectors, etc.);
  - anchor type, size, general condition, serial number, and fluke angle, as applicable.
- Anchor test load:
  - test load at fairlead;
  - estimated test load at anchor shackle;
  - estimated anchor drag distance.
- Mooring pretension:
  - pretension or line angle at fairlead, and estimation of accuracy.

K.10.3 POST INSTALLATION VERIFICATION

Based on the information specified in K.10.1 and K.10.2, the operator and drilling contractor shall verify that the as-installed mooring meets the original safety factor requirements. If the as-installed mooring system does not meet the design safety factor requirements, then appropriate plans should be developed and implemented in a timely fashion that will provide acceptable mooring safety factors.

K.11 Gulf of Mexico Hurricane Criteria

K.11.1 GENERAL

Guidance on development of metocean extremes are contained in API Bull 2INT-MET, including Addenda A and B. This section provides a summary and parameterization of the deepwater Gulf of Mexico hurricane criteria contained in API 2INT-MET specifically tailored for use in performing site assessments of MODUs. In all cases, the criteria contained in API 2INT-MET take precedence over the summary presented in this section.

K.11.2 SELECTION OF METOCEAN CRITERIA

The consequences to surrounding infrastructure of mooring system failure determine the required minimum design return period. The flow chart shown in Figure K.5 describes a method for selection of metocean criteria. API 2INT-MET provides default metocean criteria that are intended to be conservative for the Gulf of Mexico and may be used instead of site-specific criteria.

For operations during the peak hurricane season, the wind, wave, and current conditions used for site assessment of typical or atypical operations shall not be less than those associated with a threshold Category 1 hurricane. During the pre- and post-peak seasons, this restriction may be eased subject to the constraints listed in K.4.2. This minimum Category 1 hurricane condition is not required if the metocean conditions associated with the required return period are more severe.

K.11.3 BACKGROUND TO DEEPWATER GULF OF MEXICO HURRICANE CONDITIONS

Hurricane season in the North Atlantic Basin officially runs from June 1st through November 30th, with the most severe storm activity generally occurring in August, September and October. The storms which occur in these three months effectively control

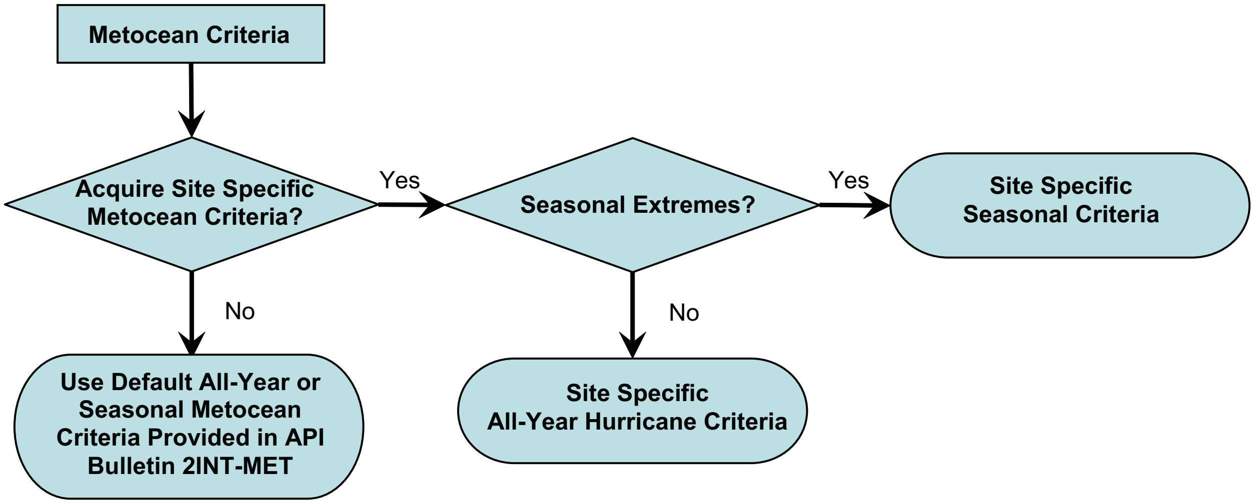


Figure K.5—Metocean Criteria Flowchart

the annual (all-year) hurricane extremes; extremes derived just considering storms which occur in these three months will be essentially identical to extremes derived using the full population of storms irrespective of month. The severe months are preceded by a period of moderate cyclone activity during June and July and then followed by a period of rapidly decreasing cyclone activity from the end of October through November. While rare, tropical storms have formed or entered in the Gulf of Mexico in both May and December, outside the official hurricane season.

The regional conditions presented in API 2INT-MET have been derived assuming an exposure period to hurricane encounters over the full year. Should a facility operate in such a manner as to restrict its exposure to hurricanes in the Gulf of Mexico (or one of the regions in the Gulf of Mexico) to periods less than one year, i.e., a seasonal operation, it would be reasonable to consider the facility subject to hurricane conditions derived from a limited exposure period.

A set of seasonal hurricane conditions for water depths greater than or equal to 300 m (984 ft) are provided in Addendum A to API 2INT-MET, for each of the four Gulf of Mexico regions described in Section 3 of API 2INT-MET. Conditions are provided for a pre-peak season period, covering June 1st to August 1st, and a post-peak season period, covering October 21st through November 30th. Peak hurricane season is considered to cover the period from August 14th through October 7th; during this period, the hurricane conditions from API 2INT-MET, Section 4.5, i.e., the annual full-population conditions, should be used. For the periods between August 1st to August 14th, and between October 7th and October 21st, conditions should be derived by linearly interpolating over two-week ramp periods between the full-population conditions in API 2INT-MET and the pre- and post-peak conditions presented in Addendum A to API 2INT-MET. For the 1-minute mean wind speed at 10 m above mean water level this is illustrated in Figure K.6.

The following conditions apply to the Gulf of Mexico hurricane criteria summarized in this section.

- The conditions presented in this section are for water depths of 300 m (984 ft) or greater in the regions covered by API 2INT-MET. They should not be interpolated or extrapolated to shallow water.
- The seasonal conditions are for the full population of pre- and post-peak tropical cyclones. They do not include winter storms, which should be treated as a separate storm population with its own set of derived extremes. Some of the extremes presented in this section, particularly in the post-peak period, may not represent the highest storm-driven n-year wind or wave conditions which could be encountered in the periods described.
- The pre- and post-peak conditions summarized in this section should be treated as complete load cases, and the wind, waves, and current should be treated as omni-directional. That is, the factors provided in Sections 4.2.2 and 5 of API 2INT-MET should not be used with the seasonal information in this section; however, the seasonal wave conditions should not be higher in any given direction than the appropriate Section 4.5 of API 2INT-MET independent extreme waves adjusted for direction.

For MODU operations planned to take place in the pre-peak (ending before August 1st) or post-peak (starting after October 21st) the following should be considered.

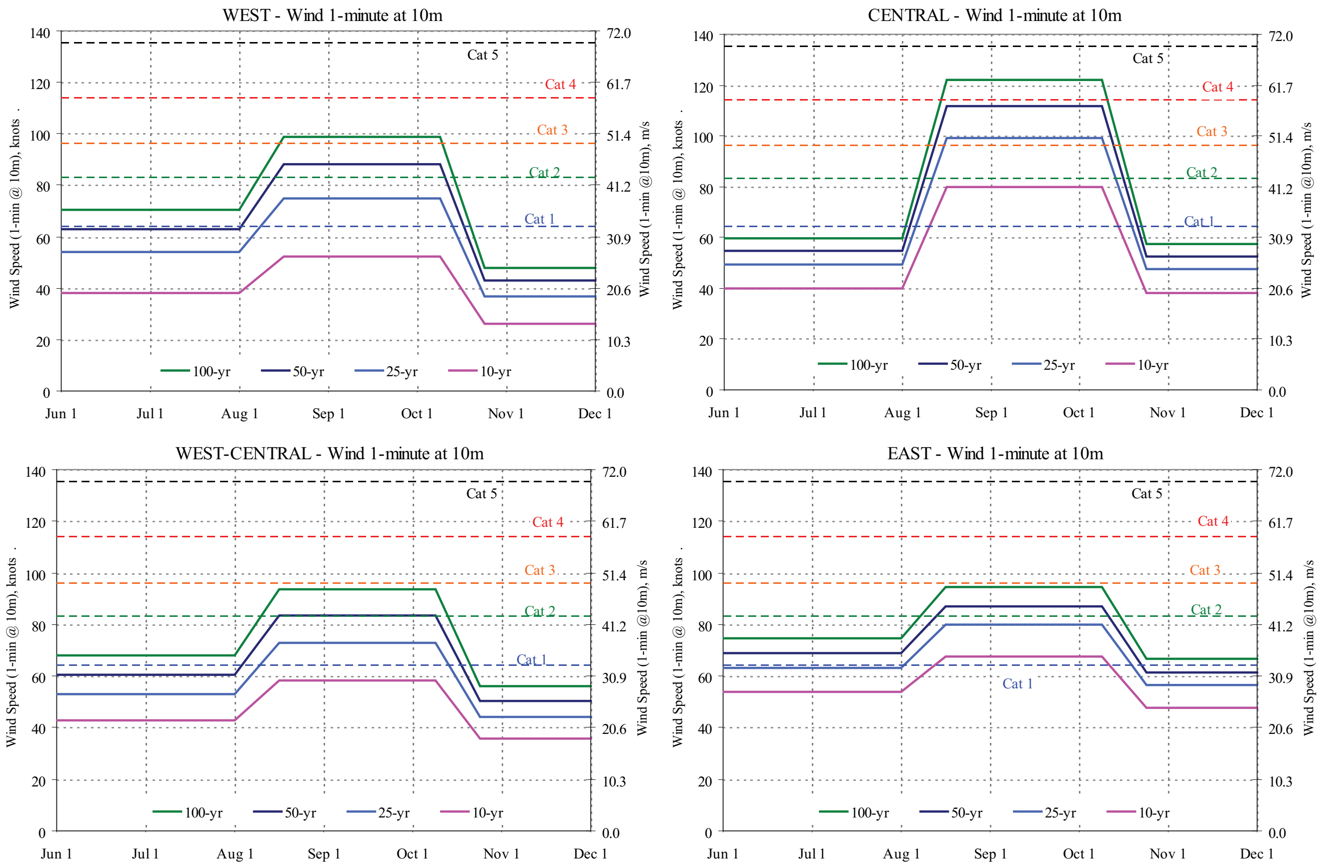


Figure K.6—Deepwater Seasonal Hurricane Wind Speeds (1-minute at 10 m) for Four Regions [API 2INT-MET and 2INT-MET Addendum A]

- Planning for operations in the pre-peak hurricane season should consider the possibility of delayed completion due to late arrival of equipment at the beginning of the operation, delays due to Loop current intrusions, and delays due to tropical storm occurrences. Wind, waves, and current corresponding to the latest likely completion date should be used in planning.
- Planning for operations in the post-peak hurricane season should consider the possibility of an early start due to early availability of equipment. Wind, waves, and current corresponding to the earliest likely start date should be used in planning, or the operator should be prepared to delay the start until it is clear that no hurricane will approach the Gulf in the next few weeks.

Addendum A to API 2INT-MET contains guidelines and recommendations for the derivation of seasonal hurricane conditions in the Gulf of Mexico, and should be followed when a site-specific study is performed.

K.11.4 SUMMARY OF API BULLETIN 2INT-MET HURRICANE CRITERIA FOR DEEPWATER MODU SITE ASSESSMENT

API 2INT-MET provides all-year hurricane criteria for four regions with transition zones between the regions. The four regions are described in Figure K.7 and defined as:

- West, between longitude 97.5° W and 95° W;
- West-Central, between longitude 94° W and 90.5° W;
- Central, between longitude 89.5° W and 86.5° W;
- East, between longitude 85.5° W and 82.5° W.

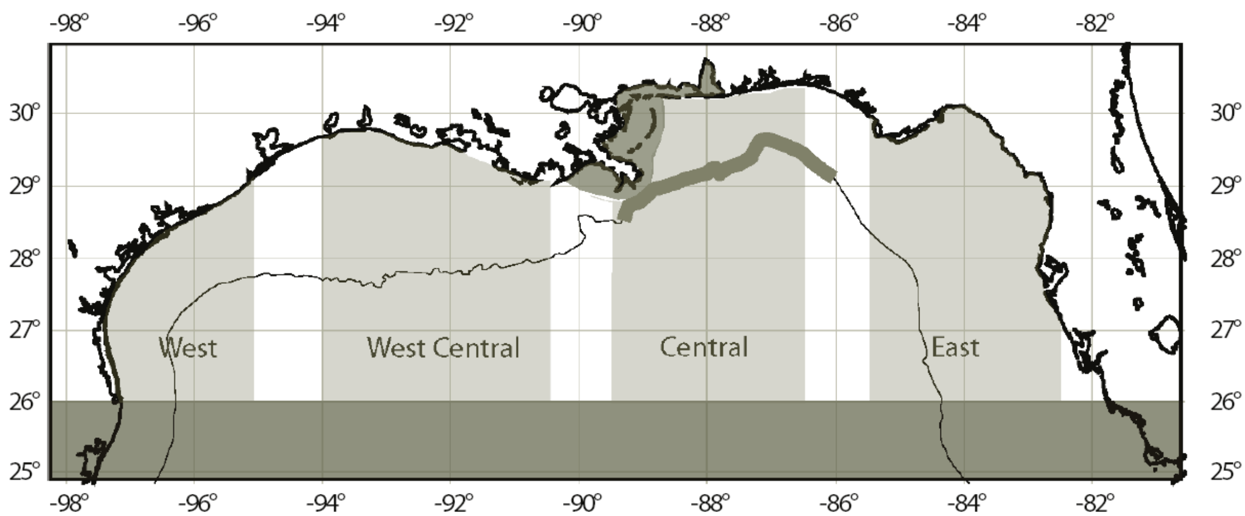


Figure K.7—Four Gulf of Mexico Regions [API 2INT-MET]

Between each region are areas of transition (unshaded), 1º longitude wide. Conditions for these transition areas should be derived by linearly interpolating between the values of the two adjacent regions across the width of the transition, see API 2INT-MET.

In addition Addendum A to API 2INT-MET divides the hurricane season into three parts:

- Pre-Peak hurricane season from June 1st to August 1st;
- Peak hurricane season from August 14th to October 7th;
- Post-Peak hurricane season from October 21st to November 30th.

Two week transition periods separate the pre-peak, peak, and post-peak parts of the hurricane season as shown in Figure K.6.

Tables 4.5.1-1A and 1B, 4.5.2-1A and 1B, 4.5.3-1A and 1B, and 4.5.4-1A and 1B of API 2INT-MET contain the independent extremes for the 10 to 10,000 year return period hurricane winds, waves, currents, and surge. For the site assessment of MODU mooring systems in deepwater a sub-set of the parameters provided in API 2INT-MET are required. Table K.3 illustrates the parameters required for the site assessment of MODU mooring systems in deepwater.

Table K.3—Central Region—All-Year Independent Extremes for Deepwater MODU Site Assessment

Return Period (years)	10	25	50	100	200
$V_{1\text{-}hr}$, 1-hr average wind @ 10 m, knots	64.20	78.00	86.30	93.30	99.10
$V_{1\text{-}min}$, 1-min average wind @ 10 m, knots	79.70	99.30	111.60	122.10	131.00
H_s, significant wave height, ft	32.80	43.60	48.60	51.80	54.10
T_p, peak period, s	13.00	14.40	15.00	15.40	15.70
Surge, ft	1.05	1.71	2.17	2.62	3.05
V_{cs}, current, surface speed, knots	3.21	3.89	4.32	4.67	4.96
V_{cm}, current, mid-depth speed, knots	2.41	2.92	3.25	3.50	3.71
D_0, current, zero speed current depth, ft	227.40	276.20	305.80	330.70	351.40

Table 5-1 of API 2INT-MET contains factors, for deepwater, to be used with the independent extremes for developing peak-wind, peak-wave, and peak-current cases for return periods between 10 and 10,000 years. Table 5-1 also provides the relative directions between wind, wave, and current for the three peak cases, and these are summarized in Figure K.8.

Addendum A to API 2INT-MET contains tables summarizing seasonal (pre- and post-peak) deepwater Gulf of Mexico hurricane wind, waves, currents, and surge for the four regions and for return periods between 10 and 10,000 years.

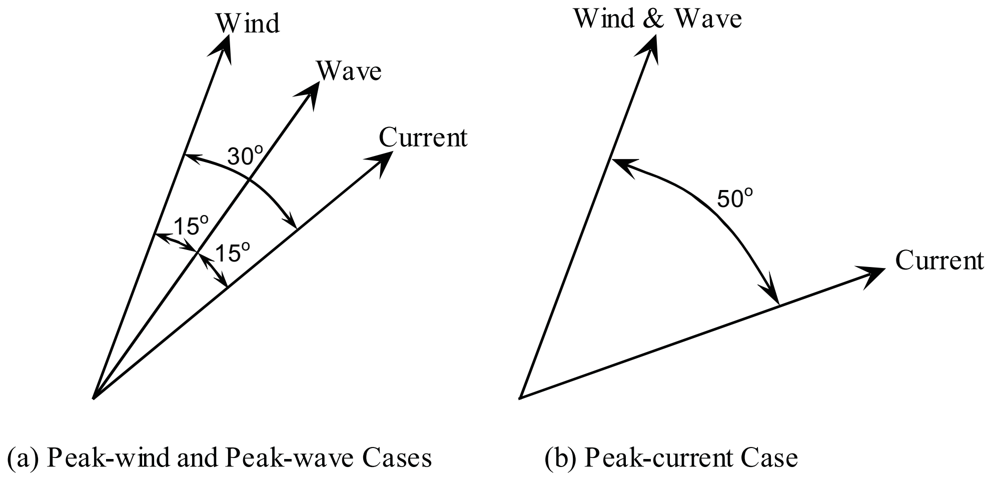


Figure K.8—Directional Relationship for Peak Wind, Wave and Current Cases [API 2INT-MET]

In performing site assessments of MODU mooring systems return periods other than the 10, 25, 50, 100, etc. provided in API 2INT-MET are usually required. To assist in developing metocean parameters of interest for a given return period, the following equation may be used:

$$E_R(\varepsilon, \alpha, \beta) = E_{10}\left\{\varepsilon - \alpha\left[-\ln\left(1-\frac{1}{R}\right)\right]^{\frac{1}{\beta}}\right\} \text{for } 10 \le R \le 200 \quad \text{(K.1)}$$

where

E_R = R-year return period value of environmental parameter,

R = return period (years),

E_{10} = 10-year return period value of environmental parameter,

ε = threshold parameter,

α = scale parameter,

β = shape parameter.

For the various load cases the parameters, ε, α, β, and E_{10} are given in Table K.4.

In all cases, the NPD spectrum shall be used to describe the frequency content of the wind energy, and the JONSWAP spectrum shall be used to describe the frequency content of the wave energy. The peak enhancement factor, γ, should be in the range of 2.0 to 2.5 for hurricane seastates.

The relationship between 1-hour and 1-minute wind speeds at 10m above mean water level, based on the NPD spectrum, is:

$$V_{1\text{-min}} = V_{1\text{-hr}}\,(1.10070 + 0.004331V_{1\text{-hr}}), \text{ where } V_{1\text{-hr}} \text{ and } V_{1\text{-min}} \text{ are in m/s}$$

$$V_{1\text{-min}} = V_{1\text{-hr}}\,(1.10070 + 0.002228V_{1\text{-hr}}), \text{ where } V_{1\text{-hr}} \text{ and } V_{1\text{-min}} \text{ are in knots} \quad \text{(K.2)}$$

$$V_{1\text{-min}} = V_{1\text{-hr}}\,(1.10070 + 0.001320V_{1\text{-hr}}), \text{ where } V_{1\text{-hr}} \text{ and } V_{1\text{-min}} \text{ are in ft/s}$$

Table K.4—Parameters for fits to API 2INT-MET Gulf of Mexico Hurricane Criteria

Season	Load Cases	Parameters	West			West-Central			Central			East		
			Wind 1-hr @10m	Wave Hs	Current Surface	Wind 1-hr @10m	Wave Hs	Current Surface	Wind 1-hr @10m	Wave Hs	Current Surface	Wind 1-hr @10m	Wave Hs	Current Surface
All-year wind, wave, and current (peak season, Aug. 14 to Oct. 7)	Peak Wind Case	ε	**2.439**	6.691	2.038	**6.577**	2.026	2.747	**2.042**	1.766	1.615	**2.126**	4.462	1.481
		α	**3.011**	6.619	2.726	**6.137**	1.762	2.294	**1.804**	2.116	1.449	**1.612**	3.910	1.047
		β	**3.048**	14.903	2.332	**23.526**	4.162	8.262	**4.101**	2.216	2.625	**6.266**	18.477	2.895
		E_{10} (m/s, m, m/s)	**22.5**	6.8	0.90	**24.9**	8.1	1.00	**33.0**	10.0	1.32	**28.4**	8.2	1.14
		E_{10} (kt, ft, kt)	**43.7**	22.3	1.76	**48.4**	26.6	1.94	**64.2**	32.8	2.57	**55.2**	26.9	2.21
		E_{10} (ft/s, ft, ft/s)	**73.8**	22.3	2.97	**81.7**	26.6	3.28	**108.3**	32.8	4.33	**93.2**	26.9	3.73
	Peak Wave Case	ε	2.675	**3.949**	2.038	7.116	**1.856**	2.747	4.419	**1.780**	1.615	7.269	**2.421**	1.481
		α	2.771	**4.231**	2.726	6.585	**2.087**	2.294	3.830	**2.873**	1.449	6.554	**2.126**	1.047
		β	4.473	**6.230**	2.332	30.493	**2.525**	8.262	19.845	**1.726**	2.625	50.590	**5.589**	2.895
		E_{10} (m/s, m, m/s)	22.5	**6.8**	0.90	24.9	**8.1**	1.00	33.0	**10.0**	1.32	28.4	**8.2**	1.14
		E_{10} (kt, ft, kt)	43.7	**22.3**	1.76	48.4	**26.6**	1.94	64.2	**32.8**	2.57	55.2	**26.9**	2.21
		E_{10} (ft/s, ft, ft/s)	73.8	**22.3**	2.97	81.7	**26.6**	3.28	108.3	**32.8**	4.33	93.2	**26.9**	3.73
	Peak Current Case	ε	2.276	3.685	**2.504**	6.139	1.732	**9.257**	1.906	1.661	**2.086**	1.984	2.260	**2.026**
		α	2.544	3.764	**2.989**	5.585	1.643	**8.797**	1.465	2.222	**1.825**	1.324	1.794	**1.534**
		β	3.264	6.663	**3.277**	27.013	2.785	**35.559**	4.681	1.857	**4.333**	7.592	6.370	**5.589**
		E_{10} (m/s, m, m/s)	16.9	5.1	**1.13**	18.7	6.1	**1.25**	24.8	7.5	**1.65**	21.3	6.2	**1.42**
		E_{10} (kt, ft, kt)	32.8	16.7	**2.20**	36.3	19.9	**2.43**	48.1	24.6	**3.21**	41.4	20.2	**2.76**
		E_{10} (ft/s, ft, ft/s)	55.4	16.7	**3.71**	61.3	19.9	**4.10**	81.2	24.6	**5.41**	69.9	20.2	**4.66**
Pre-peak (Jun. 1 to Aug. 1)	All Cases	ε	2.440	4.437	2.594	9.279	1.846	8.545	1.993	1.744	1.962	2.183	2.352	2.085
		α	2.981	4.613	2.971	8.820	2.047	8.080	1.775	3.127	1.793	1.660	2.084	1.589
		β	3.094	7.649	3.615	35.559	2.549	32.820	3.877	1.567	3.615	6.652	5.201	5.900
		E_{10} (m/s, m, m/s)	16.7	4.4	0.84	18.7	5.1	0.94	17.5	4.5	0.87	23.0	5.9	1.15
		E_{10} (kt, ft, kt)	32.5	14.4	1.63	36.4	16.7	1.83	34.0	14.8	1.69	44.7	19.4	2.24
		E_{10} (ft/s, ft, ft/s)	54.8	14.4	2.76	61.4	16.7	3.08	57.4	14.8	2.85	75.5	19.4	3.77
Post-peak (Oct. 21 to Nov. 30)	All Cases	ε	2.420	4.378	2.475	5.804	1.842	8.743	2.048	1.812	2.016	1.981	2.620	2.060
		α	2.998	4.605	2.962	5.371	2.138	8.275	1.818	2.822	1.786	1.503	2.272	1.548
		β	3.013	7.268	3.229	20.154	2.417	33.870	4.087	1.807	3.988	5.276	6.652	5.946
		E_{10} (m/s, m, m/s)	11.7	3.0	0.59	15.7	4.2	0.79	16.8	4.4	0.84	20.7	5.6	1.04
		E_{10} (kt, ft, kt)	22.7	9.8	1.15	30.5	13.8	1.54	32.7	14.4	1.63	40.2	18.4	2.02
		E_{10} (ft/s, ft, ft/s)	38.4	9.8	1.94	51.5	13.8	2.59	55.1	14.4	2.76	67.9	18.4	3.41

Note: For all-year hurricane conditions the independent extremes are calculated by using the parameters in **bold**.

For return periods other than those specified in API 2INT-MET the peak period, T_p in seconds, may be calculated from the significant wave height, H_s, using the following relationship,

$$T_p = A \cdot (H_s)^B \tag{K.3}$$

where

		Peak Hurricane Season				Pre- & Post-Peak
		West	West-Central	Central	East	All Regions
H_s in meters,	A =	5.868	5.719	4.776	4.311	5.427
H_s in feet,	A =	3.763	3.676	2.872	2.466	3.416
H_s in meters or feet,	B =	0.374	0.372	0.428	0.470	0.390

The mid-depth current speed, V_{cm}, may be calculated from the surface current speed, V_{cs}, as follows,

$$V_{cm} = 0.750 \cdot V_{cs} \tag{K.4}$$

And the depth at which the current speed is zero, D_0, is given by,

$$D_0 = C \cdot V_{cs} \tag{K.5}$$

where

D_0 in metres and V_{cs} in m/s, C = 42.00

D_0 in ft and V_{cs} in knots, C = 70.88

D_0 in ft and V_{cs} in ft/s, C = 42.00

Finally the storm surge can be calculated from the 1-hour mean wind speed at 10 m above mean water level, $V_{1\text{-hr}}$, as follows,

$$\text{Surge} = F \cdot V_{1\text{-}hr} + G \tag{K.6}$$

where

	F	G
Surge in metres and $V_{1\text{-hr}}$ in m/s	0.0283	– 0.5171
Surge in feet and $V_{1\text{-hr}}$ in knots	0.0478	– 1.6965
Surge in feet and $V_{1\text{-hr}}$ in ft/s	0.0283	– 1.6965

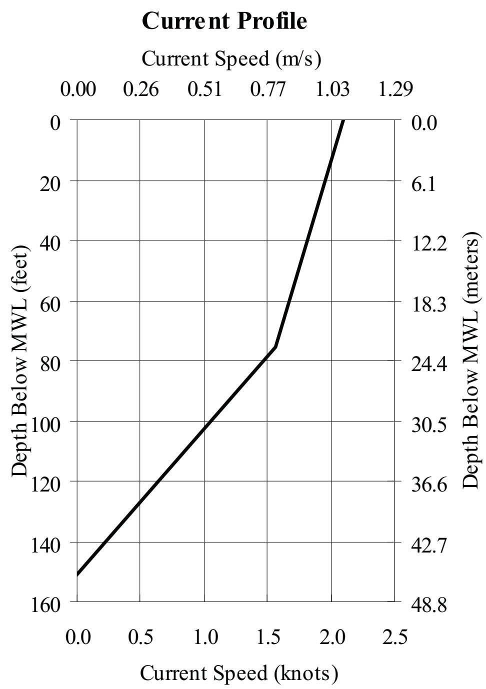
K.11.5 MINIMUM CATEGORY 1 HURRICANE WIND, WAVE, AND CURRENT CONDITIONS

Site and seasonal specific metocean criteria may be used in developing the wave and current conditions associated with a minimum Category 1 hurricane. That is, the wave and current conditions that occur for the same return period as the 64 knot 1-minute wind speed may be determined based on site and seasonal specific hurricane criteria. Alternatively, the wind, wave, and current conditions specified in Table K.5 may be used.

Table K.5—Minimum Category 1 Hurricane Conditions

Wind			
1-hour mean at 10 m, $V_{1\text{-hr}}$	27.0 m/s	52.6 knots	88.6 ft/s
1-minute mean at 10 m, $V_{1\text{-minr}}$	32.9 m/s	64.0 knots	107.9 ft/s
Wave			
Significant Wave Height, H_s	8.0 m	26.2 ft	26.2 ft
Peak Period, T_p	12.2 s	12.2 s	12.2 s
Current			
Surface Speed, V_{cs}	1.08 m/s	2.10 knots	3.5 ft/s
Mid-depth Speed, V_{cm}	0.81 m/s	1.57 knots	2.7 ft/s
Zero Speed Depth, D_0	46 m	151 ft	151 ft

JONSWAP wave spectrum 2.0 < γ < 2.5, and NPD wind spectrum



If the operator has a set of site-specific metocean criteria for the mooring location, the Operator may elect to derive suitable associated waves and current through the following procedure:

1. determine the return period R_{64kt} for a 1-minute average 64kt wind speed;
2. determine the associated significant wave height (H_s) for the return period R_{64kt};
3. determine the peak wave period (T_p) using regression analysis of H_s and T_p;
4. determine the surface current velocity for the return period R_{64kt};
5. determine the mid depth current velocity and zero current depth using regression analysis.

Use of the above procedure should provide an appropriate set of parameters for a minimum Category 1 hurricane at the location of interest.

K.12 References

1. Noble Denton, “Calibration of ABS, API, DnV, HSE (Den), and NMD Mooring Design Codes for Floating Drilling and Production Platforms,” NDAI Rpt No. 92489, December 1995.
2. Shu, H. and Loeb, D.A., “Extending the Mooring Capability of a Mobile Offshore Drilling Unit,” OTC paper 17995, 2006.
3. Chaplin, C.R. Rebel, G. and Ridge, I.M.L., “Tension/Torsion Interactions in Multi-component Mooring Lines,” OTC paper 12173, 2000.
4. DNV-RP-E302, “Design and Installation of Plate Anchors in Clay,” December 2002.

K.13 Consequence Assessment Checklist

Notes regarding usage of the Consequence Assessment Checklist.

1. This checklist contains many of the items that need to be addressed when determining the potential consequences of operating a MODU at a specific location. The list may not be complete, and there may be other items that need to be addressed.
2. A user can base decisions as to preferred mitigation options in the design of the mooring system by use of the checklist, or a similar consequence assessment method.
3. If a user desires to compute numerical scores, a factor of unity may be used as a multiplier on the base value and values less than unity developed for terms such as Slightly Better, Better, Much Better, Significantly Better. “Similar” refers to a factor close to unity, i.e., a value close to the base value. Factors greater than unity may be used for terms such as Worse, Much Worse, etc. User-selected factors allow for rapid sensitivity assessments.
4. Some questions have multiplier ranges provided. The factors provided are indicative of values that may be used in a numerical analysis to account for relative importance or consequence. The user is encouraged to select values and factors commensurate with these items and consistent throughout the evaluation.
5. Some questions concern the number of items (e.g., pipelines, wells, umbilicals, etc.) and may generally be taken to act as a direct multiplier. A response of zero should be equivalent to ignoring the question. In other cases the response is simply “yes/no”: the base can be taken as unity with the other term taken as zero.

K.13.1 OVERVIEW TO CHECKLIST

K.13.1.1 General Information

The checklist approach is a simple consequence ranking methodology that allows the stakeholders to assess, on a consistent relative basis, the likelihood of adverse consequence that the well operations represents. The risks associated with drilling a specific location can be considered to be a combination of the probability that a unit will suffer a mooring failure and the consequences should such a failure occur. The primary purpose of the approach set out below is to help the stakeholders develop a high level overview of the consequences of a mooring failure, and a measure of the likelihood of realizing those consequences. The stakeholders must then determine an acceptable level of risk for the operation by selecting the minimum environmental return period to be used in the design of mooring system, and other mitigation measures that may be suitable.

Some variations of the questions in the checklist set out below are associated with atypical operations, as defined in K.6.5 (e.g., a permanent facility within one mooring radius of the MODU, etc.). The checklist can be used as a method of initially estimating the consequences of atypical operations, but it is not sufficiently refined to assess all the nuances of such an operation. Atypical operations should always be subject to a detailed supplemental risk assessment in addition to any basic assessment.

Note: *Likelihood* is the conditional probability of an event (consequence) occurring, given that a mooring failure has already occurred (i.e., at a minimum the likelihood of an event occurring is conditional on partial or complete mooring system failure). The *probability* of mooring system failure largely depends on the environmental return period for which the mooring system meets the design criteria specified in Section 7.

It is anticipated that any risk analysis would consider the issues set out below, but this does not represent the only approach, and there may be other factors that need to be taken into account that have not been described. Any risk assessment should assess the overall issue to ensure completeness.

K.13.1.2 Definitions

K.13.1.2.1 Within the mooring pattern is taken to be anywhere within a smooth closed curve drawn through all the anchors in a projection on the horizontal plane.

K.13.1.2.2 Within one mooring radius of any anchor can be taken as the area covered by a series of circles, one based on each anchor, having a radius equal to the greatest distance from the nominal center of the mooring pattern to the furthest anchor.

K.13.1.2.3 Crossed moorings are defined as when the smooth curve drawn through the MODU anchors intersect a similar curve for an adjacent permanent facility.

K.13.1.2.4 Surface facility is defined as the platform and its mooring pattern where applicable.

K.13.2 BLOCK AREA

Certain areas of the Gulf of Mexico are more densely populated with both surface and subsea infrastructure. Despite the answers to the questions below about pipelines and permanent facilities close to the proposed location, there is a certain “overhead” consequence for drilling in any given location. A higher consequence designation of some block areas may be chosen to account for the proximity and density of infrastructure that cannot be explicitly calculated within the checklist approach. Due consideration should be given to the infrastructure that is in adjacent block areas, not only that within the block area in question. Size and criticality of the infrastructure should also be taken into account. In some areas there may not be many pipelines, but those that exist are large, service deepwater areas, would be costly to repair, and carry a significant percentage of the Gulf production.

There are metocean variations across the Gulf. The Block Area Value does NOT account for these since they will be accounted for in the site specific metocean criteria used in the design. Use of infrastructure maps, such as the MMS map referenced in the main document (see K.6.2), may be used in evaluating infrastructure importance for a given site and nearby waters.

Areas of high density infrastructure may include Mississippi Canyon, Green Canyon, Eugene Island, Garden Banks, East Breaks, West Cameron, South Timbalier, High Island, Ship Shoal, Viosca Knoll, South Marsh Island, Vermillion, Ewing Bank, and Main Pass.

Areas of low density may include Destin Dome, Desoto Canyon, Henderson, Port Isabel, and Corpus Christi.

If computing numerical values, a Block Area Consequence Value ($Block_v$) in the range of 5 to 20 may be considered appropriate and should be reported as:

$$Block_v = \text{value based on response to Table K.6}$$

K.13.3 WATER DEPTH

The cost and impact of damage to subsea infrastructure in deepwater is often greater than in the shallower waters. In addition, there can be additional delays in contracting the larger marine vessels required to handle repairs in deepwater due to limited availability. This contracting problem can, in turn, further increase the cost and delay production. The checklist accounts for an increase in the subsea damage consequence of failure in deepwater.

If computing numerical values, the Water Depth Factor (WD_f) should be reported as:

$$WD_f = \text{factor based on response to Table K.7}$$

K.13.4 SEABED INFRASTRUCTURE WITHIN THE MOORING PATTERN

K.13.4.1 General

This section, and those that follow, contain specific questions about the local subsea infrastructure. This specific question concerns the subsea infrastructure that actually lies within the mooring pattern of the MODU. “Within the mooring pattern” is taken to be anywhere within a smooth closed curve drawn through all the anchors in a projection on the horizontal plane. Because the infrastructure is within the mooring pattern, mooring failure in any direction could lead to failed mooring components being dragged over, or dropped on the subsea facilities. Since the effective consequence value for a pipeline or umbilical within a mooring pattern is higher than for one outside the mooring pattern, any item that is accounted for in this question does not need to be included in the responses to other questions, unless there is either a significant change in potential consequence of damage, or the size of a pipeline changes (e.g., after picking up production from a subsea well). (Note that the “effective

Table K.6—Block Area

Block Area	Response	Block Area	Response
Alaminos Canyon		Lund South	
Amery Terrace		Main Pass	
Apalachicola		Matagorda Island	
Atwater Valley		Miami	
Bay Marchand		Mississippi Canyon	
Brazos		Mobile	
Breton Sound		Mustang Island	
Campeche Escarpment		North Padre Island	
Chandeleur		Pensacola	
Charlotte Harbor		Port Isabel	
Corpus Christi		Pulley Ridge	
DeSoto Canyon		Rankin	
Destin Dome		Sabine Pass (LA)	
Dry Tortugas		Sabine Pass (TX)	
East Breaks		Ship Shoal	
East Cameron		Sigsbee Escarpment	
Eugene Island		South Marsh Island	
Ewing Bank		South Padre Island	
Florida Middle Ground		South Pass	
Florida Plain		South Pelto	
Gainesville		South Timbalier	
Galveston		St. Petersburg	
Garden Banks		Tarpon Springs	
Grand Isle		The Elbow	
Green Canyon		Tortugas Valley	
Henderson		Vermilion	
High Island		Vernon Basin	
Howell Hook		Viosca Knoll	
Keathley Canyon		Walker Ridge	
Key West		West Cameron	
Lloyd Ridge		West Delta	
Lund			

Table K.7—Water Depth

Response	Subsea Factor
<1000 ft	Slightly Better
1000 ft – 4000 ft	Base
>4000 ft	Slightly Worse

consequence value" implicitly includes such issues as likelihood of drifting over the relevant subsea infrastructure and the "Likelihood Factor" explicitly given in Table K.8. However, this allowed exclusion does not account for the possibility that the pipeline, umbilical, etc. is damaged in more than one location by the drifting MODU which would increase the direct repair costs, but have limited effect on "lost" production.)

K.13.4.2 Likelihood Factor

The Likelihood Factor is a measure of the likelihood that a mooring component will be dragged over the pipeline, umbilical, etc., taking into account where the item is within the mooring pattern. If computing numerical values, a value of 0.5 to 0.7 may be considered as a base for pipelines and umbilicals. There is a lower likelihood that a component will be dragged over a subsea well because of its size. This factor should not be used to account for the likelihood that the subsea item is damaged by the dragged mooring component. That is addressed separately within the checklist.

Table K.8—Subsea infrastructure within Mooring Pattern

	Number of Items	Likelihood Factor	Possible Value[a]	Total Value
ACTIVE PIPELINES WITHIN MOORING PATTERN				
How many pipelines are there within the mooring pattern, and are:				
< 10 in. diameter?		Base: 0.5 to 0.7	Better	
10 in. ≤ D < 15 in.?		Base: 0.5 to 0.7	Base: 15 to 35	
15 in. ≤ D < 20 in.?		Base: 0.5 to 0.7	Worse	
20-in. ≤ D?		Base 0.5 to 0.7	Much Worse	
UMBILICALS				
How many umbilicals are within the mooring pattern?		Base: 0.5 to 0.7	Base: 1 to 15	
SUBSEA WELLS				
How many subsea wells or completions are within the mooring pattern?		Better	Base: 1 to 15	
Total Sum of Subsea Consequences within Mooring Pattern (see note below)				

[a]If computing a numerical value, then the numbers given in this column may be considered suitable values modified, as appropriate, by the expressions "Better," Worse," etc. Additional discussion can be found below the table.

K.13.4.3 Pipelines

If computing numerical values, a value of 15 to 35 may be considered as a base for a pipeline in the range of 10 in. to 15 in. within the mooring pattern. Lines that are less than 10 in. diameter will be of less consequence, i.e., "Much Better" than the base value. Those over 15 in., and particularly those over 20 in., can be considered of high consequence, i.e., "Much Worse" than the base value, particularly as they may be carrying hydrocarbons from a number of wells and facilities. Pipeline values chosen here should be consistently used throughout the checklist as they are modified by "Likelihood Factors," or equivalents, to account for changing locations relative to the MODU. In some cases, it is not known what hydrocarbon is being transported in the pipeline, however, this can be taken into account when assigning values, if it is known. Generally, a gas line will carry less barrels of oil equivalent (BOE) than an equal size line carrying oil. However, due consideration needs to be given to the possibility that damage to a gas line could shut down production through an oil line having the same starting point, but possibly different destination. (If the gas cannot be exported from a facility, and cannot be re-injected, then all hydrocarbon production will be shut down due to losing only the gas export facility.) The flow capacity of a pipeline is approximately proportional to the square of its diameter, although not all lines are flowing at their capacity. Actual pipeline flow rates may be taken into account when computing numerical values: it is permissible to use less than the design capacity if actual flow rates are known.

K.13.4.4 Umbilicals

If computing numerical values, a value of 1 to 15 may be considered as a base for an umbilical, depending on the factors discussed below. Umbilicals are easily damaged, but have a relatively low consequence rating within this approach. While they are important, they generally affect only one well or a small number of wells, and may not have a major impact on the overall production levels within the Gulf of Mexico. However, they can be extremely difficult to replace, and may have long lead times on replacement. Companies may want to increase the significance of umbilicals for their own internal purposes, but from a Gulf of Mexico production perspective, they are less important than pipelines. For umbilicals that service a number of different wells, or a single high production rate well, a value in the upper range may be considered.

K.13.4.5 Subsea Wells

Subsea wells, over and above the well being worked on, should be included if they are active. If computing numerical values, a value of 1 to 15 may be considered as a base for a subsea well within a mooring pattern. The cost and consequences of damage are slightly larger than those for an umbilical within a mooring pattern, although the likelihood of damaging a subsea well is somewhat lower due to its physically smaller size.

K.13.4.6 Computation of Numerical Values

If computing numerical values, the consequence value for Subsea Infrastructure within the mooring pattern, (Subsea-in$_v$) should be reported as:

$$\text{Subsea-in}_v = \Sigma(\text{Number} \times \text{Likelihood Factor} \times \text{Value})$$

See Table K.8 for for guidance on the numerical values for Likelihood Factors and Values for pipelines, umbilicals, and subsea wells.

As discussed in K.13.13, if a more detailed assessment is being undertaken, it may be advantageous to keep separate the calculated values for pipelines and umbilicals as they have different damage probabilities, depending on what mooring component is potentially being dragged over the seabed. Combining the values at this stage will be conservative.

K.13.5 SEABED FACILITIES WITHIN ONE MOORING RADIUS OF ANY ANCHOR

This question is an extension of the previous one relating to infrastructure within the mooring pattern, except that it addresses subsea infrastructure outside the mooring pattern, but within one mooring radius of any anchor. The subsea infrastructure questions are identical, but it would be expected that somewhat lower values would be used since there is an increased likelihood that no mooring component would be dragged over, or dropped on, the pipelines, etc. if the mooring system was to fail. This change in likelihood of having a mooring component dragged over the subsea item should be included through modification of the "Likelihood Factor" if calculating numerical values. The base values for pipelines, umbilicals, etc. should remain the same since their "value" does not alter.

The definition of "within one mooring radius of any anchor" can be taken as the area covered by a series of circles, one based on each anchor, having a radius equal to the greatest distance from the nominal center of the mooring pattern to the furthest anchor. This will tend to be slightly conservative for some asymmetrical mooring patterns, but should generally be followed unless there is good evidence that it would produce unrealistic results. The intent is to cover the entire area that can be "swept" by the MODU should it swing on any anchor, allowing for some limited anchor slippage for drag embedment anchors.

No account has been taken for directionality to this nearby infrastructure as there is a relatively high likelihood of damage due to dragged components over a relatively wide swath.

As with the pipelines or umbilicals within the mooring pattern, any component that is accounted for in this question does not need to be included in the responses to other questions, unless there is either a significant change in potential consequence of damage, or the size of a pipeline increases (e.g., after picking up production from a subsea well).

If computing numerical values, a value of 15 to 35 may be considered as a base for a 10-in. to 15-in. pipelines, 1 to 15 for umbilicals, and 1 to 15 for subsea wells within a mooring radius of any anchor. See K.13.4 on "subsea infrastructure within the mooring pattern" for further discussion of these items.

If computing numerical values, the consequence value for Subsea Infrastructure within one radius of any anchor (Subsea-out$_v$) should be reported as:

$$\text{Subsea-out}_v = \Sigma(\text{Number} \times \text{Likelihood Factor} \times \text{Value})$$

See Table K.9 for for guidance on the numerical values for Likelihood Factors and Values for pipelines, umbilicals, and subsea wells.

As discussed in K.13.13, if a more detailed assessment is being undertaken, it may be advantageous to keep separate the calculated values for pipelines and umbilicals as they have different damage probabilities, depending on what mooring component is potentially being dragged over the seabed. Combining the values at this stage will be conservative.

K.13.6 MOORING LINES CROSSING THE MOORINGS OF OTHER TEMPORARY FACILITY

If the MODU mooring lines cross the moorings of another temporary facility, there is clearly a threat that if either of the mooring systems fail, then there could be an adverse effect on the moorings of the other unit. This would be a high consequence event. There is, however, a relatively high likelihood that even in the worst case, the MODU and other facility will not be irreparably damaged. Crossed moorings are defined as when the smooth curve drawn through the MODU anchors intersect a similar curve for an adjacent temporary facility. See also K.13.9.

Table K.9—Subsea Infrastructure within Mooring Radius of Anchor

	Number of Items	Likelihood Factor	Possible Value*	Total Value
ACTIVE PIPELINES WITHIN ONE MOORING RADIUS				
How many pipelines are there within the mooring radius of any anchor, and are:				
< 10 in. diameter?		Base: 0.4 to 0.6	Better	
10 in. ≤ D < 15 in.?		Base: 0.4 to 0.6	Base: 15 to 35	
15 in. ≤ D < 20 in.?		Base: 0.4 to 0.6	Worse	
20 in. ≤ D?		Base: 0.4 to 0.6	Much Worse	
UMBILICALS				
How many umbilicals are within the mooring radius of any anchor?		Base: 0.4 to 0.6	Base: 1 to 15	
SUBSEA WELLS				
How many subsea wells or completions are within the mooring radius of any anchor?		Better	Base: 1 to 15	
Total Sum of Subsea Consequences within One Mooring Radius (see note below)				
*If computing a numerical value, then the numbers given in this column may be considered suitable values modified, as appropriate, by the expressions "Better," "Worse," etc. Additional discussion can be found below the table.				

K.13.7 SURFACE FACILITIES WITHIN THE MOORING PATTERN

There is a potentially high consequence of a MODU mooring failure to a surface facility within the mooring pattern of the MODU. The primary concern is the loss of the permanent facility. The secondary concern is damage to the facility resulting in lost production. In addition, there is a possibility that the surface facility could suffer a failure and thereby affect the MODU. "Within the mooring pattern" is taken to be anywhere within a smooth closed curve drawn through all the anchors in a projection on the horizontal plane. This question, and the next addressing surface facilities within one mooring radius, has the same drivers, however, the likelihood of interaction decreases with distance between the facilities.

It is important to note that if there are crossed moorings with another temporary facility, as addressed in K.13.6, then it may be advisable to add an additional overall multiplier to both this and the next question to account for the increased likelihood of a MODU mooring failure.

K.13.7.1 Likelihood Factor

The likelihood factor is to account for the likelihood that the MODU, having had a mooring failure, will interact with the surface facility. It should take into account how close the facility is to the MODU, its size, any special features that make it more or less likely to be damaged, etc. If calculating numerical values, a base value of 0.3 to 0.6 may be used. The likelihood factor is higher for spread moored surface facilities since there is a higher likelihood of adverse interaction leading to loss of station, damage to the facility, and damage to the wells.

K.13.7.2 Design Production Capacity

The design production capacity will affect the consequences of an interaction between the MODU and a surface facility. High production facilities both cost more as capital investments and are also likely to have higher "lost production" costs. Although not explicitly included in the table above, if computing a numerical value, the design production capacity should be taken into account. The upper end of the range of base values for a full-size TLP has been estimated for a major TLP with high production rates of approximately 150,000 barrel of oil equivalent (BOE) per day. The cost of a facility is not directly proportional to the design production rate, but there is a close relationship.

Referring to Table K.10, if computing numerical values, the consequence value for Crossed Mooring Lines with a temporary facility ($Cross_v$) should be reported as:

$$Cross_v = \text{“Yes/No factor”} \times \text{Value}$$

Table K.10—Mooring Lines Crossed with Temporary Facility

MOORING LINES CROSSED WITH OTHER TEMPORARY FACILITY Directionality does not matter	Factor	Possible Value
Does the smooth curve drawn through the MODU anchors intersect a similar curve for an adjacent temporary facility?	Yes = 1 No = 0	20 to 30

K.13.7.3 TLP

A TLP is a relatively robust facility, as long as the tendons remain intact. When a TLP is very close to a MODU, and the MODU suffers a mooring failure, then there is a relatively high likelihood that the MODU mooring lines will interact with the TLP tendons. At best this will damage the tendons so that they only need to be replaced. At worst, the tendons will fail during the storm, thereby leading to TLP mooring failure. Generally, TLPs are not stable when tendons are lost, so the damage may be catastrophic and the TLP can capsize. Another possibility is that a tendon pile is damaged by a mooring component being dragged over it. Depending on the specific TLP, this may be an irrecoverable event that requires facility replacement at a new location, necessitating the re-drilling of all the wells. Most of the larger TLPs have dry trees, so loss of the TLP could lead to very expensive P&A operations, with a very low likelihood of well recovery.

K.13.7.4 Spar

A spar is relatively robust from the standpoint of stability: it is possible for them to sustain significant damage and still remain upright. The greater threat to a spar is from damage to the mooring system, thereby possibly leading to loss of stationkeeping and damage to risers. Conversely, subsurface damage to a spar hull would be extremely difficult and costly to repair. Most spars have dry trees, so loss of stationkeeping would result in wells only protected by a sub-surface safety valve. It may be possible to re-enter the wells and get them flowing again once the surface facility has been replaced, but this would be an expensive and relatively high risk operation.

K.13.7.5 Semi-Submersible

A semi-submersible production unit is going to have similar responses to those of a spar, although the cost of recovery from a complete mooring system failure may be lower. It should be possible to either take the unit into a shipyard for repairs, or possibly “dry dock” it on submersible barges although disconnecting and safely laying down the production and export SCRs will be challenging.

K.13.7.6 Synthetic Moored

Synthetic mooring components can be more easily damaged than conventional wire and chain. There is a possibility that dragging MODU mooring components over the steel mooring lines could cause failure, but it is relatively low likelihood. A more likely outcome is that the moorings are damaged and have to be replaced after the storm, but with limited impact on production. Synthetic lines, however, will very likely fail if subjected to interaction with the MODU steel mooring components, thereby letting the permanent facility drift off location resulting in massive repair costs and loss of production. To account for this increased likelihood of damage, there is a possible multiplier of 1.5 to 2.5 that may be used if numerical values are being computed. Redundancy in the mooring system and grouping of mooring legs should be taken into consideration when selecting this factor.

K.13.7.7 Compliant Tower

Compliant towers will tend to be lower consequence than most of the floating facilities as they are reasonably likely to survive in a repairable condition, generally have lower capital investment, and riser damage would likely be more easily repaired.

K.13.7.8 Jacket

Similar to a compliant tower, except for hub jackets. Hub jackets have been included at a higher level to account for the effect on overall GoM production if they were to be damaged.

K.13.7.9 Computation of Numerical Values

If computing numerical values, the consequence values for Surface Facility within the mooring pattern (Surface-in$_v$) should be reported as:

$$\text{Surface-in}_v = \text{Both}_f \times \Sigma(\text{Number} \times \text{Likelihood Factor} \times \text{Synthetic Multiplier} \times \text{Facility Value})$$

where “Both$_f$” is defined below and the “Synthetic Multiplier” is either unity, or adjusted to account for the presence of synthetic moorings.

See Table K.11 for for guidance on the numerical values for Likelihood Factors and Values for TLPs, spars, semi-submersibles, compliant towers and jackets.

Table K.11—Surface Facility within Mooring Pattern

SURFACE FACILITIES WITHIN MOORING PATTERN Directionality does not matter	Number of Items	Likelihood Factor	Synthetic Multiplier	Possible Value[a]	Total Value
Is there a permanent installation(s) within the mooring pattern? If yes, indicate which of the following types;					
Full-size TLP		Base		Base: 400 to 700	
Mini TLP		Base		Better	
Spar		Worse		Similar	
Synthetic moored?			1.5 to 2.5	Similar	
Semi-submersible		Worse		Slightly Better	
Synthetic moored?			1.5 to 2.5	Slightly Better	
Compliant Tower		Base		Better	
Hub Jacket		Base		Better	
Other Jacket		Base		Much Better	
Total Sum of Surface Facility within Mooring Pattern Consequences (see note below)					

[a]If computing a numerical value, then the numbers given in this column may be considered suitable values modified, as appropriate, by the expressions “Better,” “Worse,” etc. Additional discussion can be found below the table.

K.13.8 SURFACE FACILITIES WITHIN ONE MOORING RADIUS OF ANY ANCHOR

K.13.8.1 General

The danger of having a surface facility within one mooring radius of any anchor is that it is possible for the MODU to break most of its mooring lines and swing into the facility. This can be particularly severe if the mooring line length at any anchor is comparable to the distance from that anchor to the permanent facility. Under these circumstances swinging on the anchor will facilitate a direct hull-on-hull collision. Many of the interaction discussions given in K.13.7 apply in this case as well, as do the damage and consequence discussions. If computing numerical values, the Likelihood Factor value range has been reduced to account for the increased distance from the MODU to the facility.

This scenario should also be used to cover the case in which the moorings of the MODU are crossed with those of a spar, permanent semi-submersible or other spread moored facility, even if the platform is not actually within one anchor radius of the MODU (see definition for surface facility). The potential for mooring line interaction is significant, particularly if any of the MODU anchors drag. “Crossed moorings” occur when the smooth curve drawn through the MODU anchors intersect a similar curve for an adjacent permanent facility.

K.13.8.2 Likelihood Factor

If calculating numerical values, a base value of 0.2 to 0.3 may be used. The likelihood factor is higher for spread moored surface facilities since there is a higher likelihood of adverse interaction leading to loss of station, damage to the facility, and damage to the wells.

K.13.8.3 Computation of Numerical Values

If computing numerical values, the consequence values for Surface Facility within one radius of any anchor (Surface-out$_v$) should be reported as:

$$\text{Surface-out}_v = \text{Both}_f \times \Sigma(\text{Number} \times \text{Likelihood Factor} \times \text{Synthetic Multiplier} \times \text{Facility Value})$$

where "Both$_f$" is defined below and the "Synthetic Multiplier" is either unity, or adjusted to account for the presence of synthetic moorings.

See Table K.12 for for guidance on the numerical values for Likelihood Factors and Values for TLPs, spars, semi-submersibles, compliant towers and jackets.

Table K.12—Surface Facility within Anchor Radius

SURFACE FACILITIES WITHIN ONE ANCHOR RADIUS Directionality does not matter	Number of Items	Likelihood Factor	Synthetic Multiplier	Possible Value[a]	Total Value
Is there a permanent installation(s) outside the mooring pattern, but within one anchor radius of any anchor? If yes, indicate which of the following types.					
Full-size TLP		Base		Base: 400 to 700	
Mini TLP		Base		Better	
Spar		Worse		Similar	
Synthetic moored?			1.5 to 2.5	Similar	
Semi-submersible		Worse		Slightly Better	
Synthetic moored?			1.5 to 2.5	Slightly Better	
Compliant Tower		Base		Better	
Hub Jacket		Base		Better	
Other Jacket		Base		Much Better	
Total Sum of Surface Facility within One Radius Consequences (see note below)					

[a]If computing a numerical value, then the numbers given in this column may be considered suitable values modified, as appropriate, by the expressions "Better," "Worse," etc. Additional discussion can be found below the table.

K.13.9 BOTH CROSSED MOORINGS WITH A TEMPORARY FACILITY AND AN ADJACENT PERMANENT FACILITY

If the MODU has crossed moorings with another temporary facility AND there is an adjacent permanent facility, then there is an increase in risk to the permanent facility due to the increased likelihood of interaction between the MODU and other temporary facility.

This scenario could be considered as "double dipping" since it is possible the other temporary facility will also have been assessed through some form of risk assessment. However, the probability that any one of the two facilities suffers a significant failure is higher than the sum of the two individual probabilities of a failure (there are scenarios in which mooring line interaction could result in failure, a dragged anchor could increase the likelihood of mooring line interaction, a single line damage case may result in interaction, etc.). In addition, the consequences of a failure of one of the temporary facilities, leading to failure of the other, would have a far greater impact on an adjacent permanent facility with a much increased consequence of failure.

It is not known what the design return period of the mooring system of the adjacent temporary moored facility will be, but it may be comparable to that of the MODU in question. If two units are close together and one fails, there is an increased likelihood that the other will fail due to unfavorable interaction. The increased failure probability on the nearby surface infrastructure needs to be taken into account as a result of this scenario. If computing numerical values, consideration should be given to increasing the consequence values for permanent facilities within either mooring pattern or a radius of an anchor if the MODU has crossed moorings with another temporary facility. Such a multiplier may have a value of between 1.3 and 1.8.

If computing numerical values, the factor for both crossed moorings and a surface facility anywhere within one radius of any anchor ($Both_f$) should be reported as:

$$Both_f = \text{Additional multiplier from Table K.13.}$$

Table K.13—Both Crossed Mooring Lines and Adjacent to Permanent Facility

MOORING LINES CROSSED WITH OTHER TEMPORARY FACILITY AND ADJACENT PERMANENT FACILITY	Factor	Additional Multiplier for Surface-in$_v$ and Surface-out$_v$[a]
Does the MODU have crossed moorings (as defined in K.13.6) AND have an adjacent permanent facility within one mooring radius of any anchor?	Yes = 1 No = 0	1.3 to 1.8

[a]If computing numerical values, this additional multiplier may be appropriate.

K.13.10 FACILITIES BETWEEN ONE MOORING RADIUS AND 15 NAUTICAL MILES WITHIN EACH OCTANT

Having accounted for close proximity infrastructure in the previous sections, it is now necessary to establish what infrastructure there is within the likely striking distance of a drifting MODU that has broken its moorings. This section addresses infrastructure between one mooring radius of the well center, and 15 nautical miles. The use of a 15 nautical mile limit can be considered somewhat arbitrary, however, it does have some foundation in experience and calculations. (Herein, 15 miles should be read as “15 nautical miles” or 91,200 feet)

Mooring failures in the 2004 and 2005 hurricane seasons resulted in MODUs drifting up to 120 miles, but in only two cases were anchors dragged in excess of 5 miles. While there were a number of MODUs that could have hit surface facilities, there were only two that were in a position to cause significant subsea infrastructure damage at a distance. The importance of this information is that pipelines offer large targets to be hit by a dragged anchor, but surface facilities are relatively small targets. At 15 nautical miles, there is less than 0.15% likelihood of a drifting MODU directly hitting a surface facility, and this conditional probability still needs to be reduced to include the probability that the MODU suffers a complete mooring system failure, the initial event. This event was considered to be suitably low to not necessitate specific additional inclusion. In addition, the item addressing the general block area of operations should inherently account for some increase in risk in certain areas, and reductions in others, thereby implicitly accounting for additional (or lack of) distant infrastructure.

In order to better account for the number and sizes of pipelines and umbilicals, the circle of 15 mile radius, centered on the MODU location, needs to be split into subsections. When undertaking a detailed formal risk assessment, each individual piece of infrastructure within the 15 mile radius would be addressed. Due consideration would be given to the likelihood of drifting towards, say, a pipeline based on its length, distance from the MODU, and possibly its direction from the MODU. Such detail is beyond the capability of a simplified consequence assessment checklist approach. In order to make the problem tractable, the 15 mile circle has been split into 8 equal octants, each representing a 45° arc. A separate reporting table should be completed for each octant.

The octants for which these tables need to be completed are N (337.5° to 022.5°), NE (022.5° to 067.5°), E (067.5° to 112.5°), SE (112.5° to 157.5°), S (157.5° to 202.5°), SW (202.5° to 247.5°), W (247.5° to 292.5°), and NW (292.5° to 337.5°), as shown in Figure K.9.

Any pipeline or umbilical that was addressed as within a mooring pattern, or within one mooring radius of an anchor, does not need to be included in the responses to this series of octant questions, unless there is either a significant change in potential consequence of damage, or the size of a pipeline increases (e.g.; after picking up production from a subsea well).

Pipelines and umbilicals need to be counted in all octants they pass through where they are less than 15 nautical miles from the MODU. This way there is due consideration given to the real likelihood of impacting the pipeline or umbilical.

K.13.10.1 Pipelines and Umbilicals by Octant

The possible values have been discussed in Table K.14. There is some reduction in value for distance, but the greatest effect of distance is that a distant pipeline will be in fewer octants than a near pipeline (reduced subtended angle). This will inherently lead to a reduced factor in the calculations when the drift direction is considered. The total sum pipeline and umbilical consequence for the octant ($Pipe\text{-}dist_v$) can be calculated as:

$$Pipe\text{-}dist_v = \Sigma(\text{Number} \times \text{Flow Ratio} \times \text{Value})$$

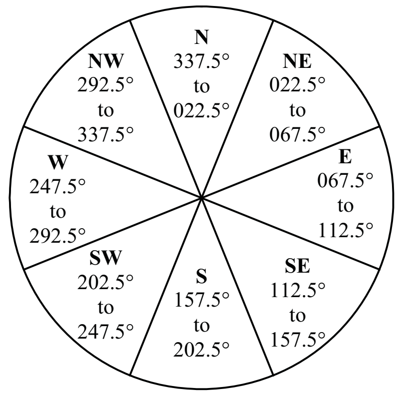


Figure K.9—Octant Definition

Table K.14—Pipelines and Umbilicals in Octant

Octant				
	Number of Items[1]	Flow as Ratio of Capacity[2]	Possible Values[3]	Subsea Total Value
ACTIVE PIPELINES				
How many active pipelines are there in this octant that are less than 91,200 ft (15 nautical miles) from the well center, but outside the mooring pattern, and are:				
< 10 in. diameter?			Better	
10 in. ≤ D < 15 in.?			Base: 15 to 35	
15 in. ≤ D < 20 in.?			Worse	
20 in. ≤ D?			Much Worse	
UMBILICALS				
How many umbilicals are in the octant that are less than 60,800 ft (10 nautical miles)1 from the well center, but outside the mooring pattern?			Base: 1 to 15	
Total Sum of Pipeline and Umbilicals Consequences for Octant (see note below)				

[1]It is acceptable to ignore smaller pipelines of less than 12-in. diameter in the range between 10 and 15 miles, and all umbilicals may be ignored in the 10 to 15 mile range.

[2]The BOE flow in a pipeline affects the cost of downtime due to the magnitude of the lost or delayed "production". It is therefore reasonable to account for the actual BOE flow rate in the pipeline when assessing the potential damage due to dragged mooring components. If computing numerical values, the base values given in the "Possible Values" column are for the pipeline transporting oil at 100% capacity. Generally gas lines will transport a lower BOE than oil lines. This reduction in BOE flow may be accounted for unless loss of such flow would disrupt the flow in another undamaged pipeline (e.g., by requiring production be shut-in).

[3]If computing a numerical value, then the numbers given in this column may be considered suitable values modified, as appropriate, by the expressions "Better," "Worse," etc.

K.13.10.2 Subsea Wells by Octant

If computing a numerical value, Subsea wells, as discussed in Table K.15, may have a value of 1 to 15, however, this needs to be reduced to account for the distance from the MODU, and hence the reduced likelihood of interaction, even if the MODU is dragging a mooring component along the seabed. The simplest way to do this is to calculate the likelihood of drifting within the angle subtended by the wells from the MODU, and use this as a simple multiplier. The angle subtended can be conservatively taken as 5° at one mile. So the likelihood of drifting towards the subsea wells, given that the MODU is drifting within this specific octant, can be calculated as (L-well$_f$):

$$\text{L-well}_f(\text{Drifting towards wells} \mid \text{drifting in this octant}) = [5°/(\text{distance in feet}/6{,}800)]/45°$$

The total subsea well consequence value for the octant (Wells-dist$_v$) can therefore be calculated as:

$$\text{Wells-dist}_v = \Sigma(\text{Number} \times \text{Value} \times \text{L-well}_f)$$

The total subsea consequence value for the octant (Subsea-dist$_v$) can be calculated as:

$$\text{Subsea-dist}_v = \text{Pipe-dist}_v + \text{Wells-dist}_v$$

Table K.15—Subsea Wells in Octant

Octant			
SUBSEA WELLS (Not P&A)	Number of Items	Possible Values*	Subsea Total Value
Are there any subsea wells or completions in the octant that are less than 60,800 ft (10 nautical miles)[1] from the well center, but outside the mooring pattern?		Base: 1 to 15	
If "Yes," calculate L-well$_f$ as described below			
Total Sum of Subsea Well Consequences for Octant (see note below)			
[1]It is acceptable to ignore any individual subsea wells in the range between 10 and 15 miles if their individual production rates are lower than 50,000 BOE per day. However, any wellhead cluster that has a production rate of over 50,000 BOE per day should be included. A wellhead cluster is taken to be any close group of wells that could be effectively shut-in by dragging an anchor through their midst.			

K.13.10.3 Surface Facilities by Octant

K.13.10.3.1 Spread Mooring Factor

As discussed in K.13.10.3.2, the distance of the surface facility from the MODU will affect the likelihood that there is an interaction between the two structures. However, a spread moored facility offers a much larger "target" to a MODU that is dragging mooring components below the keel. If calculating a numerical value, this factor may be considered to lie in the range of 1 to 5. Clearly, if the MODU is not dragging any components below the keel, then there is no increase in likelihood. Conversely, if it is dragging anchors, then the increased likelihood of an interaction is vastly increased due to the spread on the facility mooring system.

K.13.10.3.2 Calculation of Sum

If computing a numerical value, Surface Facilities, as discussed in Table K.16, may have a value of 400 to 700 with a potential additional multipliers to account for spread mooring and synthetic moorings. This needs to be reduced, however, to account for the distance of the facility from the MODU, and hence the reduced likelihood of interaction. The simplest way to do this is to calculate the likelihood of drifting within the angle subtended by the facility from the MODU, and use this as a simple multiplier.

Table K.16—Surface Facility in Octant

Octant				
SURFACE FACILITIES UP TO 15 NAUTICAL MILES AWAY	Number of Items[1]	Synthetic & Spread Multiplier	Possible Value[2]	Surface Total Value
Are there any permanent installations in the octant that are less than 91,200 ft (15 nautical miles)[1] from the well center, but outside the mooring pattern? If yes, calculate L-surface$_f$ as described below.				
Full-size TLP			Base: 400 to 700	
Distance (ft)				
Mini TLP			Better	
Distance (ft)				
Spar			Similar	
Distance (ft)				
Spread Mooring Factor		1 to 5		
Synthetic moored?		1.5 to 2.5		
Semi-submersible		Slightly Better		
Distance (ft)				
Spread Mooring Factor		1 to 5		
Synthetic moored?		1.5 to 2.5		
Compliant Tower			Better	
Distance (ft)				
Hub Jacket			Similar	
Distance (ft)				
Other Jacket			Better	
Distance (ft)				
Other structures, or additional of above				
Total Sum of Surface Facility Consequences for Octant (see note below)				

[1]It is acceptable to ignore any facilities with design production capacity of below 50,000 BOE per day in the range between 10 and 15 miles.

[2]If computing a numerical value, then the numbers given in this column may be considered suitable multipliers modified, as appropriate, by the expressions "Better," "Worse," etc. Discussion of the values and influences, including possible reductions based on the design production capacity, can be found beneath Table K.5.

The angle subtended can be conservatively taken as 7° at one mile. So the likelihood of drifting towards the surface facility, *given that the MODU is drifting within this specific octant*, can be calculated as (L-surface$_f$):

$$\text{L-surface}_f\,(\text{Drifting towards facility} \mid \text{drifting in this octant}) = [7°/(\text{distance in feet}/6{,}800)]/45°$$

The total distant surface facility consequence value for the octant (Surface-dist$_v$) can therefore be calculated as:

$$\text{Surface-dist}_v = \Sigma(\text{Number} \times \text{Spread Moor} \times \text{Synthetic} \times \text{Value} \times \text{L-surface}_f)$$

The "Spread Moor" and "Synthetic Multiplier" are either unity, or adjusted to account for the presence of spread moorings or synthetic moorings.

K.13.10.4 Summation over Octants

If computing numerical values, it becomes necessary to sum the results for the various octants, adjusting for the likelihood that the unit drifts within the specific octant. The results for each octant should be summarized in Table K.17, and then the total value, over all octants, can be calculated.

Table K.17—Summation Over Octants

Octant	Direction Likelihood		Subsea-dist$_v$	Surface-dist$_v$
	Base L.[a]	Modified L.[a]		
N	0.125	0.12		
NE	0.125	0.06		
E	0.125	0.06		
SE	0.125	0.10		
S	0.125	0.12		
SW	0.125	0.18		
W	0.125	0.18		
NW	0.125	0.18		
Individual Sum Totals Over all Octants (see K.13.10.4.5)				

[a]The "Base Likelihood" is the conditional probability that the MODU will drift towards the relevant direction, given that the moorings have failed, if it is assumed that the drift direction is completely random. The sum over all directions is equal to 1.0, as it must be. "Modified Likelihood" has divided the drift direction conditional probabilities based, in part, on the direction of the worst winds in the series of storms used to create the database of metocean extremes over the four zones within the Gulf of Mexico. The data have been smoothed and also sum to 1.0. It should also be noted that even if the extreme winds are in the relevant direction, the direction at the MODU location will change over time, hence the drift direction will change.

Experience from the 2004 and 2005 hurricane seasons tends to confirm that in general drift is towards the northwest, but that is based on a very limited number of events. An alternative way of viewing this is that the highest winds within a hurricane are normally in the northeast quadrant, blowing towards the northwest. It is likely that a MODU will first be affected by the northern side of a hurricane before the southern side. Hence, the most likely direction of MODU drift can be estimated.

It can be seen that there are a number of arguments for either a relatively even distribution of drift directions, or a weighted distribution based on a combination of experience (albeit limited), logic concerning the likely MODU location with respect to the storm, and the data on metocean extremes.

When deciding which set of values to use, it may be helpful to consider the MODU location, and the adjacent infrastructure. If infrastructure is randomly distributed around the MODU, then it makes little difference which series of numbers is used, however, there may be merit is using both approaches, and reporting results from the more conservative. This exercise would be particularly important if there was a strong directionality to the infrastructure.

If computing numerical values, the sums over all octants can be calculated as:

$$\text{Subsea.all-dist}_v = \Sigma(\text{Subsea-dist}_v \times \text{Direction Likelihood})$$

$$\text{Surface.all-dist}_v = \Sigma(\text{Surface-dist}_v \times \text{Direction Likelihood})$$

K.13.11 COMBINED LOCATION CONSEQUENCE FACTORS

If computing numerical values, the intermediate consequence factors can be taken from the parameters described in K.13.3 through K.13.10, and included in Table K.18.

Table K.18—Combined Location Consequence Factor

Parameter	Factors	Surface Value	Subsea Value	Description
Block_v				Block area value (same value for both surface and subsea)
WD_f				Water depth factor (on subsea values only)
Subsea-in_v				Subsea within the mooring pattern
Subsea-out_v				Subsea outside mooring pattern but within one radius
Cross_v				Crossed moorings with a temporary facility
Surface-in_v				Surface facility within the mooring pattern
Surface-out_v				Surface facility outside mooring pattern but within one radius
Subsea.all-dist_v				Subsea facilities within 15 miles
$\text{Surface.all-dist}_v$				Surface facilities within 15 miles
Surface.total_v				Total site Surface Consequence Factor (see note below)
Subsea.total_v				Total site Subsea Consequence Factor (see note below)

The total consequence factors are summed from Table K.18, although the subsea factor needs to be modified by the water depth to account for the increased difficulty of repairs. They are each given by:

$$\text{Surface.total}_v = 0.5 \times \text{Block}_v + \text{Cross}_v + \text{Surface-in}_v + \text{Surface-out}_v + \text{Surface.all-dist}_v$$

and

$$\text{Subsea.total}_v = 0.5 \times \text{Block}_v + \text{WD}_f \times (\text{Subsea-in}_v + \text{Subsea-out}_v + \text{Subsea.all-dist}_v)$$

K.13.12 LIKELIHOOD ADJUSTMENT FACTORS

K.13.12.1 General

The previous sections address the consequences of a MODU suffering a mooring failure. There are, however, some factors associated with the mooring system design that influence the likelihood of suffering the consequences and can have a direct influence on the consequences. These are discussed below.

If computing numerical values, in most cases the base case factor will have a value of 1 with alternates reducing that value.

K.13.12.2 Anchor Type and Pullout

To mitigate subsea infrastructure damage, the best anchors are those that will not pull out of the seabed and will not drag components across the seafloor in the event of any mooring failure. Drag anchors have a higher modified consequence value than other anchor types. The reason is that there is a relatively high likelihood that the leeward anchors will pull out in the event of windward mooring line failure. Hence, even if the anchor has a higher holding capacity than the strength of the mooring line, if the windward lines fail, the leeward anchors likely will be dragged as the MODU drifts over them and pulls them in the “wrong” direction. Notwithstanding this, drag anchors performed remarkably well during the MODU failures in Katrina and Rita. There were only four units that dragged anchors for over 1 mile.

It is important that if piles, Normally Loaded Plate Anchors, or Near Normally Loaded Plate Anchors are used to mitigate the likelihood of damaging subsurface equipment, then their holding capacity should be greater than the maximum breaking strength of the mooring line in any possible loading direction, and in all reasonably possible soils conditions, even considering all possible mooring line failure combinations. In addition, the installation procedure should be developed to ensure that this holding capacity can be achieved. This is particularly important for the Normally Loaded Plate Anchors which will tend to pull out if overloaded rather than drag at depth, or continue to embed. It is of note that during Hurricane Rita one unit fitted with normally loaded plate anchors suffered a mooring failure and dragged some of the anchors for over 100 miles. The likely reason is that the anchors were installed with insufficient horizontal load. However, even though the plate anchors were dragged for over 100 miles, crossing many pipelines, the extent of damage caused was reported to be limited. The manufacturer asserts that this is an advantage of the anchor not being designed to self-embed, and hence not as likely to grab subsea equipment. While the results of the historical experience are compelling, it may be difficult to justify a low numerical value for a dragged a plate anchor, particularly if used to offset the increased likelihood due to low holding capacity. Hence, unless pull out can be absolutely guarded against through design and installation, normally loaded and near normally loaded plate anchors should be rated at a comparable level to “high holding capacity anchors [less capacity than mooring minimum break load (MBL)]” with some possible reduction for their reduced propensity o grab subsea equipment.

K.13.12.3 Anchor Pullout

The historical database of MODU mooring failures during 2004 and 2005 hurricane season contains 17 documented cases of MODUs drifting for over one mile, and in only four cases were anchors dragged for a significant percentage of that drift distance. Of those four cases, in only two were anchors dragged for over 5 miles. While the database is not large, it is reasonable to say that the likelihood of dragging an anchor over the subsea infrastructure itemized above is in the range of 12% to 25%. If computing numerical values, then it is reasonable to include an Anchor Drag Factor as follows:

Anchor Drag Factor: in the range 0.12 to 0.25

If computing numerical values, the subsea factor for anchors (Anchor_f) should be reported as:

$$\text{Anchor}_f = \text{Subsea Multiplier from Table K.19} \times \text{Anchor Drag Factor}$$

Table K.19—Anchor Type

Anchor Type	Subsea Multiplier[a]
Suction Pile (designed for significant out-of-plane loading)	Best Option
Suction Pile (NOT designed for significant out-of-plane loading)	Significantly Better
High Holding Capacity Drag Anchor (HHCDA) (capacity greater than capacity of mooring line)	Much Better
High Holding Capacity Drag Anchor (HHCDA) (less capacity than capacity of mooring line)	Better
Conventional Drag Anchor	Base: 1.0
Normally Loaded Plate Anchor	Much Better
Near Normally Loaded Plate Anchor	Much Better

[a]The anchor subsea multiplier should be chosen based on two criteria: (i) what is the likelihood that an anchor will pull out of the seabed before all the mooring lines have parted, and (ii) the potential consequences of dragging such an anchor over the subsea infrastructure.

K.13.12.4 Mooring Component at the Seafloor

The mooring component that is at the seafloor will have a major effect on the amount of subsea infrastructure damage in the event of a mooring line failure at, or close to, the anchor. Due consideration should be given to the potential extent of damage and its significance to operations. A pipeline that is damaged, but can continue in service until it can be scheduled for repair at a time of no flow is a far less serious loss than a pipeline of comparable flow that has to be immediately taken out of service. Conversely, even minor damage to a pipeline’s insulation or cathodic protection may lead to long term problems that can be expensive to repair, particularly if left and forgotten about. As a general rule, damage that can be repaired later is far less critical than damage necessitating immediate action. This needs to be borne in mind when deciding on the damage factor for dragged mooring components.

The intent of the question is to ascertain what types of component can be dragged along the seabed, regardless of where the mooring line failure occurs, not just the component at the anchor. For example, if a mooring line is comprised of rig wire, intermediate chain, and anchor wire, and the rig wire is sufficiently long such that both it and the intermediate chain can be dragged along the seabed, then the least favorable chain would be assumed to be at the seabed for the purpose of determining the subsea factor for the component at the seabed

It is of note that in the 2005 hurricane season approximately 5% of mooring lines failed at the anchor, and an additional nearly 15% failed in intermediate mooring component between the fairlead wire or chain and the anchor, so there is a relatively high likelihood that a MODU suffering a mooring line failure will have components that have broken at both the fairlead and away from the fairlead.

If computing numerical values , then the base factor, to be used for chain, has to be chosen depending on the expected quantity of damage due to a dragged chain by comparison to other components (note, drag anchor factor = 1.0). The suggested method of combining consequences given below is to use the factor for the worst dragged mooring component or anchor as the factor to be applied to all subsea equipment. The base number if one is following this approach, therefore, is the amount of damage that a dragged chain would cause by comparison to a dragged anchor with a value of 1.0. While chain may cause significant damage, it is unlikely to cause as much as a dragged anchor. A suggested range of 0.1 to 0.3 has been included for consideration. Based on this discussion, and that above, the subsea factor for the component at the seabed (Component_f) should be reported as:

$$\text{Component}_f = \text{Multiplier from Table K.20}$$

Table K.20—Mooring Component at Seafloor

Component at Seafloor (Worst case should be chosen)	Subsea Multiplier
Chain at seafloor	Base: 0.1 to 0.3
Wire at Seafloor	Much Better
Synthetic at seafloor	Significantly Better

K.13.12.5 Subsea Buoyancy Used to Mitigate Local Subsea Damage

In certain mooring arrangements, it may be advantageous to include either additional buoys or lengths of synthetic mooring line in order to give additional protection to subsea components (see Table K.21). It is possible that these buoys were used to aid in mooring line installation or mitigate the risk of dropped mooring lines during installation. The primary area of interest in this particular question concerns mooring equipment falling onto the subsea infrastructure, not being dragged over it. This item is addressed in K.13.12.6.

Table K.21—Mitigation of Close Subsea Infrastructure

BUOYANCY OR SYNTHETIC USED TO MITIGATE DAMAGE TO CLOSE SUBSEA INFRASTRUCTURE	Factor	Possible Reduction Factor
Are buoys or length of synthetic mooring line included within the mooring arrangement that will mitigate the risk to subsea infrastructure due to falling mooring components?	Yes = 1 No = 0	See discussion in this section.

A buoy will be very effective at mitigating damage to local subsea infrastructure under certain limited circumstances, as follows.

- The mooring line fails between the buoy and the fairlead and the buoy prevents anchor chain or wire from falling on subsea components.
- The buoy is positioned such that if the mooring line fails between it and the anchor, it will prevent the upper mooring components from falling onto the seabed. In addition, the length of line between the buoy and the anchor should be insufficient to drop on any subsea infrastructure, or should be synthetic.

The buoy will not be effective if:

- the mooring line fails at the fairlead (in most cases the rig wire plus intermediate component would be long enough to allow the rig wire to fall onto the seabed);
- the buoy has insufficient buoyancy to carry the additional load of the failed components;
- the buoy collapses due to increased hydrostatic head when dragged down by mooring components.

Similar scenarios exist for the use of synthetic components to mitigate damage to subsea infrastructure.

Some additional information from the 2005 hurricane season may help illuminate the issues. Approximately 80% of all the mooring failures were in the rig component at, or close to, the fairlead. This means that there is a very high likelihood that out of, say, four lines that may be extended over a piece of subsea infrastructure, there will be at least one that fails at the fairlead. If the buoy or synthetic line does not mitigate damage to the subsea infrastructure under this circumstance, then it will have almost no effect on the likelihood of damage.

It is clear from the preceding discussion that there will be a limited number of cases in which buoyancy or synthetics can be effectively used to mitigate the risk of mooring components falling onto local subsea infrastructure. However, if it can be conclusively shown that there is real mitigation offered through the use, then advantage may be taken. It is suggested that only a relatively small reduction should be taken if numerical values are being calculated (i.e., use a factor close to unity), and only for subsea infrastructure within the mooring pattern, or within one mooring radius of any anchor.

If computing numerical values, the reduction factor for use of buoyancy or synthetics to mitigate damage to subsea infrastructure (Buoy-in$_f$) should be based on the discussion above, and reported as:

Buoy-in$_f$ = Factor representing mitigation from Table K.21

K.13.12.6 Subsea Buoyancy Used to Mitigate Remote Subsea Damage

It is possible to envisage scenarios in which subsea buoys could be used to help prevent mooring components being dragged across the seabed in the event of a MODU mooring failure. However, for similar arguments to those given when discussing the use of buoyancy to mitigate damage due to falling components on close in subsea infrastructure, there are too many ways in which the system can fail to work effectively unless carefully designed. As an example, approximately 5% of the 2005 hurricane season line failures occurred at the anchor, so if there is any anchor chain at the anchor, there is a relatively high likelihood that it will be dragged over the seabed due to insufficient buoyancy. In addition, approximately 20% of MODUs that suffered a mooring failure dragged their anchors for over 1 mile, so no amount of buoyancy would have prevented the potential for damage.

For these reasons, it is suggested that this factor not normally be considered unless it can be conclusively shown that there is real mitigation offered through the use of the buoys under all credible scenarios. Buoyancy can only be considered if there is no anchor dragging, so is limited to mitigating the effects of dragged wire, chain, or synthetic and can only be realistically used with anchor piles.

If computing numerical values, the reduction factor for use of buoyancy to mitigate damage to subsea infrastructure outside one mooring radius of any anchor (Buoy-out$_f$) should be based on the principles presented in this section, and reported as:

Buoy-out$_f$ = Factor representing mitigation from Table K.22

Table K.22—Mitigate Damage Due to Dragged Mooring Components

BUOYANCY USED TO MITIGATE DAMAGE TO SUBSEA INFRASTRUCTURE FROM DRAGGED COMPONENTS	Factor	Possible Reduction Factor
Are buoys or length of synthetic mooring line included within the mooring arrangement to mitigate the risk to subsea infrastructure?	Yes = 1 No = 0	See discussion in this section.

K.13.13 COMBINED CONSEQUENCE VALUES AND ADJUSTMENT OR MITIGATION FACTORS

Having determined the main consequence values and likelihood adjustment factors, it is necessary to consider the effects of combining them. In principle, the various components can be combined in a number of different ways, depending on how and what was developed. However, if computing numerical values, the following discussion may help give some guidance on one possible approach.

The total surface infrastructure consequence value (Surface.total$_v$) is basically as it is, without any modifiers included. It has been assumed that the reliability of the mooring system is the driver for preventing damage to surface infrastructure, and the suitability of that should be determined, in part, based on the results of this consequence assessment. This is, in reality, a simplification that will tend to produce conservative results. It may be possible to more precisely determine the potential interactions between a drifting MODU and the surface facility of interest and therefore refine the numerical values used. An example could be the interaction between a drifting MODU and the mooring lines of a spar. Simple probabilistic analysis can give the likelihood that different MODU mooring components will interact with the spar's moorings, and therefore affect the likelihood of damage. Detailed methodology is beyond the scope of this simplified checklist approach, but the basic information can be used in many ways to refine the analysis results.

The total subsea infrastructure consequence value (Subsea.total$_v$) will also be affected by the mooring system reliability, but will be modified by the anchors used, and components at the seabed. These components have a direct effect on the extent of damage that can be caused and the likelihood of sustaining that damage. It may also be modified by factors designed to prevent mooring components dropping or dragging, if these have been defined. The simplified method of determining total consequences based on the subsea adjustment factor given below will tend to produce a conservative result. It is possible, and reasonable, to assess different mooring component drag factors for the different subsea infrastructure. As an example, an umbilical will likely be severely damaged by a dragged wire rope whereas a pipeline may suffer very minimal damage. As discussed in K.13.12.4, immediate failure tends to be far more serious than damage that can be scheduled for later repair without affecting production. Hence, by subdividing the subsea infrastructure into constituent parts and using different component damage factors for each subsea item, it is possible to determine a refined subsea consequence factor. This will tend to be important when there is a large amount of subsea infrastructure within the 15 mile radius of the well location.

A simple summation methodology is to assume that the worst of the factors for either the mooring component at the seabed or the anchor should be used and then applied to the subsea infrastructure consequence factor. Hence, the subsea adjustment factor (Drag$_f$) is given by:

$$\text{Drag}_f = \text{Greater of Anchor}_f \text{ or Component}_f$$

The total adjusted consequence value (Total-Consequence$_v$) is then given by:

$$\text{Total-Consequence}_v = \text{Surface.total}_v + \text{Drag}_f \times \text{Subsea.total}_v$$

K.14 Risk Assessments for MODU Operations

K.14.1 OVERVIEW AND INDUSTRY EXPERIENCE

The purpose of this appendix is to describe the basic elements of a risk assessment and to identify the primary drivers of MODU operational risks as they relate to mooring failure. This appendix does not provide detailed guidance on risk assessment methods, only a general overview related to this specific subject.

The offshore industry has been extremely successful in evacuating platforms in advance of hurricanes without loss of life. Given the number of people that have had to be evacuated, and the limited time available, this has been a remarkable achievement.

Also, in the 2004 and 2005 hurricane seasons there was very little pollution due to the failures that did occur in hurricanes. There were some small spills from damaged pipelines, but these were minor by comparison to the potential losses that could have occurred.

It was in the areas of asset loss and industry reputation that the greatest damage occurred. There was a strong perception that industry had not done a good job because of the number of fixed platforms destroyed, pipelines damaged, jackups lost or damaged, and MODUs that drifted. The overall result was that the majority of the Gulf of Mexico production was shut-in for months. The following discussion is aimed specifically at the issues affecting moored MODUs.

There were approximately 20 semi-submersible MODUs that lost station in the 2004 and 2005 hurricane seasons. Some of these units drifted for well over 100 miles while others remained in the same vicinity, with a reduced number of mooring lines holding. Notwithstanding the number of units that went adrift, the actual damage to Gulf of Mexico infrastructure caused by drifting semi-submersible MODUs was small. The greatest damage was to the Mars export pipelines. This damage could have resulted in the field and tieback production being shut-in for three months, but the actual consequences were more than an order of magnitude less because the facility had wind induced damage that resulted in an eight month shut-in. [Ref. 1, 2, 3 and 4]

Despite the lack of significant damage to Gulf of Mexico infrastructure from these mooring failures, there is an expectation that industry should improve the reliability of MODU moorings. There is also an expectation that the potential consequences of a mooring failure be fully understood, and where necessary, suitable mitigation measures implemented to reduce the potential infrastructure damage should a MODU break adrift. One of the outcomes of the work undertaken to achieve these ends has been the increased use of risk analysis techniques to assess proposed drilling locations.

The question may be raised as to why mooring failure risk assessment techniques are not required for floating permanent facilities by this document while they are now recommended for mobile platforms? A key difference is MODUs are designed as mobile facilities, and are intended to deploy and retrieve their mooring systems repeatedly and in a limited time frame with readily available equipment. Permanent floating facilities utilize specialized installation vessels due to the size of their mooring components and installation takes more time requiring a longer mild weather window. In addition, the consequence of a mooring failure for a MODU can be very different compared to a permanent floating facility. The list of these differences is numerous, but in general, the financial consequence of a permanent mooring line or system failure will be far greater than that of a MODU. Therefore, it is not appropriate to use the same criteria as used for permanent facilities. However, to offset the increased probability of suffering a mooring failure due to a lower design return period, the consequences of such a failure need to be suitably assessed.

K.14.2 TERMS AND DEFINITIONS

For the purposes of this section, the following terms and definitions apply.

K.14.2.1 consequence: The effects of a mooring failure.

K.14.2.2 hazard: An event with potential adverse consequences.

K.14.2.3 initiating event: Hardware failure, control system failure, human error, extreme weather or geophysical event, which could lead to hazards being realized.

K.14.2.4 likelihood: The conditional probability of an event (consequence) occurring. That is, at a minimum the likelihood of an event occurring is conditional on partial or complete mooring system failure.

K.14.2.5 mooring failure: The definition of mooring failure will vary depending on the circumstances, but for the purpose of a risk assessment, a mooring failure is a failure of any parts of the mooring system that could lead to adverse consequences. For some mooring systems, for example deployed over pipelines, a mooring failure could be as simple as an anchor slipping a short distance. For a MODU operating far from any infrastructure, a mooring failure may necessitate breaking a number of mooring lines and dragging anchors for a considerable distance: lesser failures, such as loss of some mooring lines and limited anchor slippage, may be considered acceptable if the MODU remains in the vicinity of its drilling location.

K.14.2.6 probability: The relative frequency that an event will occur, as expressed by the ratio of the number of occurrences of the event to the total number of possible occurrences.

K.14.2.7 reliability: A measure of the probability of an item or system to adequately perform a required function under stated conditions of use and maintenance for a stated period of time.

K.14.2.8 risk: The product of the probability of occurrence of a hazardous event and its consequence(s).

K.14.2.9 tolerable risk: risk which is accepted in a given context based on the current values of society. Also referred to as acceptable risk.

K.14.3 RISK ASSESSMENT GENERAL

Risk is defined as:

$$\textit{Risk} = [\textit{Probability of an adverse event occurring}] \times [\textit{The consequences associated with that event}]$$

Risk assessment is the study of the probability of an adverse event occurring, the potential consequences of that event, and the measures taken to reduce the probability and consequences of such an event. A fundamental part of reducing the risk is to ensure that all parties have a clear understanding of their “Risk Exposure.” The risk can be reduced either by reducing the probability of experiencing an incident, prevention, or by reducing the consequences of that incident should it occur, mitigation.

Accidental and extreme environmental events may result in a number of adverse consequences, including:

- injury or fatality;
- environmental damage;
- property damage, potentially leading to a disruption of production due to damage to Gulf of Mexico infrastructure;

- damage to corporate image;
- deterioration in public perception and industry reputation.

Risk management can be used to assess and maintain risks within acceptable levels. Risk assessment techniques can be used to evaluate frequencies and potential consequences of accidents. Risk assessment methods can also be used to help evaluate and sort the risks. Further analysis can then be used to help determine and implement mitigation measures, where applicable. Risk management is a process that can be effectively integrated into future operations to provide continuous improvement: past experiences can be reviewed with the aim of improving both system reliability and reducing adverse consequences.

A major advantage of undertaking a risk assessment is that it requires the stakeholders to be involved in the process and give consideration to the issues that make up the potential risk. This does not require massive attendance at, for example, the HAZID workshops, but there is a danger in making any risk assessment process too automated. Risk analysis is an efficient way of helping to comprehend and evaluate issues that cannot be quantified by conventional means or design codes. It is through *the process* that the participants understand the risks which, in turn, help them to decide on the appropriate acceptance criteria and correct mitigation measures.

K.14.4 MODU-SPECIFIC RISK ASSESSMENT OVERVIEW

K.14.4.1 General

The probability and consequences of a MODU losing station when operating at any location within the US Gulf of Mexico should be assessed. The intent of the assessment process is to determine the characteristics of the area of operation and identify options related to mooring component selection, mooring system design, scheduling of operations, and mitigation opportunities prior to finalizing the mooring design and installing the mooring system. For the planned MODU operation, the mooring system should be associated with an acceptable risk, either by minimizing potential consequences of mooring component or system failure or by reducing the probability of mooring component or system failure.

The general risk definition is composed of the following elements:

1. Probability of a hurricane producing extreme environmental conditions at site:
   - hurricane occurring;
   - distribution of hurricane intensity;
   - distance of hurricane track from MODU location.
2. Probability of MODU mooring failure:
   - strength of mooring line:
   - holding capacity of anchor;
   - mooring component resistance (anchor or line) is less than demand.
3. Likelihood and consequence:
   - likelihood of MODU drifting toward surface infrastructure;
   - likelihood of MODU dragging or slipping anchors toward subsurface infrastructure;
   - likelihood of damage to infrastructure of differing values (damaged or lost asset or lost production).

The metocean criteria for a specific location reflects the combination in item 1. The probability of suffering a mooring failure reflects the combination in item 2. The likelihood of causing damage, having suffered a mooring failure, is given in item 3. The risk is determined by the product of the probability and suitably summed consequences.

The financial consequences of a MODU mooring failure can be divided into three types:

1. consequences of damage to the surrounding subsea and surface infrastructure;
2. consequences of damage to the MODU and its mooring system;
3. consequences to Operator’s drilling program.

The risk assessment described in this appendix addresses the consequences of damage to surrounding infrastructure. For MODU operations in the hurricane season, where the MODU is evacuated, it is the responsibility of the Drilling Contractor and Operator to manage the risk associated with damage to the MODU and its mooring system.

The probability of mooring failure can be assessed through analysis of the mooring design, and the consequences of failure assessed by giving due consideration to the infrastructure local to the proposed drilling location. Figure K.10 shows the general

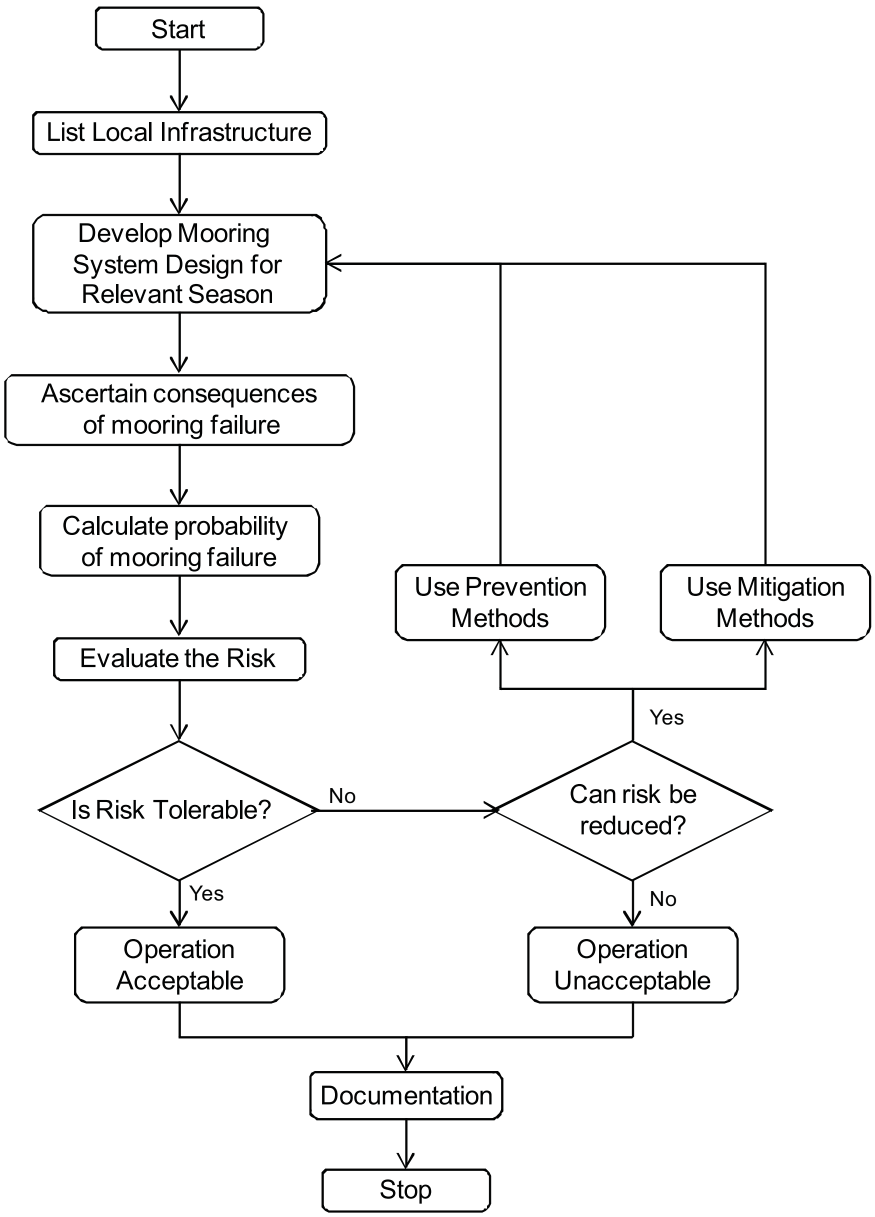


Figure K.10—Mooring System Failure Risk Assessment Overall Process

methodology for carrying out a risk assessment of MODU mooring failure when considering the potential for damage to the surrounding infrastructure.

Each element of this overall process is discussed as follows.

a. **List Local Infrastructure:** This covers all surface and subsurface infrastructure that can suffer consequences from a MODU mooring failure. The list may be divided up according to infrastructure that is within the mooring pattern, within one mooring diameter, within 15 nautical miles and infrastructure beyond 15 nautical miles that may require special consideration due to size and importance.

b. **Develop Mooring System Design for Relevant Season:** This requires performing a mooring analysis of the proposed mooring system to API 2SK using appropriate metocean design criteria. See K.11 for additional information.

c. **Ascertain Consequences of Mooring Failure:** Using an appropriate process, such as hazard identification (HAZID), all the potential consequences of a MODU mooring failure are identified. Further information can be found in K.14.8. Information on logic to perform a consequence assessment is found in K.13.

d. **Calculate Probability of Mooring Failure:** The probability of MODU mooring system failure decreases with increasing design return period for which the mooring system satisfies all of the requirements of API 2SK. Further information can be found in K.14.7.

e. **Evaluate the Risk:** This involves taking information from probability of mooring failure and consequence of mooring failure and assessing the risk of the proposed MODU mooring operation. See K.14.9.

f. **Is Risk Tolerable?** Once the risk is evaluated, the Operator's standards shall be used to determine if the risk is tolerable. Further information can be found in K.14.10.

g. **Can Risk Be Reduced?** Practical mitigation or prevention measures should be evaluated and implemented as appropriate to reduce the risk. See K.14.11.

h. **Operation Acceptable or Unacceptable:** Using all the information from the risk assessment process, the Operator can determine if the location for a given season and MODU mooring system is acceptable or not. If no further mitigation or prevention measures are possible and the risk is deemed high, then the operation should be rejected. Usually changing the season of operation, in particular if it is planned for peak of hurricane season, and rescheduling to off-peak or non-hurricane season will make the operation acceptable. See K.14.10 for additional information.

i. **Documentation:** The risk assessment process must be formally documented. The documentation should include all information required to support the risk assessment results. Further information can be found in K.14.11.

Without participation by personnel experienced in MODU moorings, their failure modes, and infrastructure sensitivity, the risk assessment process will not advance to the stage where it can become meaningful.

K.14.5 TYPES OF CONSEQUENCES

Most corporate risk assessments include five types of consequence. These five have been supplemented by an additional consequence type, national interest, that is specific to offshore operations in the Gulf of Mexico. The six consequence types are:

1. health and safety;
2. environmental;
3. financial;
4. corporate reputation and image;
5. industry reputation and image;
6. national interest.

National interest has been added since Gulf of Mexico oil and gas production has a direct influence on the cost and availability of hydrocarbons to the public and the requirements for imports.

For MODU operations in the hurricane season where the MODU is evacuated and wells and pipelines are shut-in, health, safety, and environmental consequences associated with MODU mooring system failure are relatively low. Assessments of consequence types 4 through 6 will be subject to considerable corporate interpretation, and there will be large variations in risk tolerance. In the case of industry reputation (5) and national interest (6), the consequences depend on the performance of all MODUs operating in the Gulf of Mexico at any one time. The consequences of failure will include public and regulatory perception, which will be influenced by the number of MODUs that fail and the result of those failures on other industry infrastructure in a single hurricane, hurricane season, or few years.

In addition to the risk analysis of specific MODUs, there are also considerations for the performance of the entire MODU fleet. There is an expectation that a large hurricane in the Gulf of Mexico may cause multiple MODUs to break adrift, however, there are limits on the acceptable number of drifting MODUs. Fleet performance is difficult to address through individual MODU risk assessments: it is more driven by overall minimum design return period requirements and fleet distribution throughout the Gulf of Mexico.

K.14.6 RISK ANALYSIS

K.14.6.1 General

Risk assessments can be either qualitative or quantitative. The first step for either of these risk assessments is a Hazard Identification (HAZID), resulting in event trees that can be evaluated either qualitatively or quantitatively.

The normal expectation is that the HAZID would be used to assess the broad risks that may be associated with a location, including issues such as:

- recovery of a drifting rig;
- personnel evacuation;
- sudden hurricane survival capability;
- mooring installation and recovery risks;
- additional effects of mitigations that may be required by the main mooring failure risk assessment (e.g., consequences of necessitating additional or stronger mooring equipment).

Direct consequence mooring risk assessment is the main issue discussed in this appendix. This type of assessment may be used to assess the specific probability and consequences of suffering a mooring failure at a particular location (e.g., probability of mooring failure, and the consequences and likelihood of the MODU or its mooring system interacting with both near and far infrastructure). In this assessment, frequency of occurrence of hazardous events, the likelihood of escalation into further accidents, and the magnitude of potential consequences are evaluated. The methods used could be qualitative or quantitative depending on the system definition and the objectives of the risk assessment. The initiating event frequencies and the likelihood (conditional probabilities) of the chains of events leading to accident scenarios are established using a combination of historical databases, fault tree, event tree, and reliability analysis techniques. Historical data [1, 2, 4] are available for some failure probabilities, but there is limited experience within the Gulf of Mexico. Experience from other areas may not be appropriate due to differences in environmental conditions, water depth, and mooring line components.

Fault tree analysis can be used to estimate the probability of suffering a mooring failure, but in most cases it will be more accurate and easier to use a combination of historical data and structural reliability calculations. Event trees are often used to estimate the likelihood of event escalation and the associated consequences.

Consequence analysis involves analyzing the range of possible outcomes of an accident or initiating event. Consequence analysis can be carried out in either a qualitative or quantitative manner. When undertaking quantitative analysis it is important to have sufficient data available to make realistic estimates.

Qualitative consequence analysis, typical of a HAZID, involves verbal development of an accident scenario and then subjectively evaluating the consequence intensities. It often uses a Risk Matrix to assess the results.

In most mooring failure risk analyses it is anticipated that there will be a combination of qualitative and quantitative risk assessment, both using a risk matrix approach, or similar, to assess acceptability.

K.14.6.2 Levels of Detail

The detail within the risk analysis process should be designed to complement the level of work required to understand the site-specific situation and demonstrate compliance, or lack thereof. There is little point in performing extremely detailed risk analyses if the proposed location is far from any significant infrastructure. Equally, one can expect to perform a detailed analysis if the intent is to prove acceptability of a location that is in a highly congested area either because of production infrastructure or multiple MODUs.

A basic risk assessment may entail following a process similar to that contained in K.6.3. A detailed/supplemental risk assessment may include a quantification of the risks, including quantification of both the probability of mooring failure and the consequences and likelihood of interacting with surrounding infrastructure.

K.14.6.3 Data Requirements

The data required for a risk assessment will depend on the level of analysis being undertaken, as discussed below. The following information is required in order to determine the consequences of a mooring failure. In addition, it will be necessary to determine some measure of the probability of suffering a mooring failure.

K.14.6.3.1 Data Requirements for All Level of Analysis

As a minimum, the following data will be needed to undertake a MODU mooring failure risk assessment.

- The global mooring system description and mooring analysis report, including anchoring system assessment.
- Details on the mooring line components including jewelry and interconnecting hardware (to help ascertain potential for damaging subsea infrastructure).
- Anchor details including type, weight, capacity, fluke angle (if relevant) and any specific geotechnical limitations.
- List of all surface and subsurface infrastructure within 15 nautical miles of the wellsite, including:
    - infrastructure within the mooring pattern;

- infrastructure within one mooring radius of any anchor;
- infrastructure within 15 nautical miles of the wellsite.

One source of infrastructure information is the Gulf of Mexico infrastructure map maintained by the Minerals Management Service.

The mooring system inspection should be current and in compliance with API RP 2I. While this will not, by itself, assure that the mooring components will not fail at loads significantly below their catalogue values, it should help minimize the probability of such failures.

Infrastructure details should include size and type of any pipeline. If information on flow rate is unavailable conservative estimates should be used.

Information will be required on the physical size of surface facilities. Such information should include both the size of the structure above the waterline and the size of its seabed footprint as well as rated hydrocarbon processing capacity. The likelihood of interacting with surface infrastructure, in the event of a mooring failure, will depend on the size and distance of the surface infrastructure from the wellsite. For a TLP, jacket, etc. the surface and subsurface-footprint size will be similar, although export risers may be considered to have the same effect on subsurface-footprint size as mooring lines (discussed below).

Spread moored infrastructure needs to be considered differently from other structures. With spread moored infrastructure there is a possibility that broken MODU mooring components will be dragged and damage the moorings of the moored permanent facility. The likelihood and consequences of this interaction will depend on:

- size of the facility's mooring pattern (footprint size);
- mooring components used on the facility (chain, wire, polyester, etc.);
- likely mooring components being dragged by the MODU.

As an example, if the facility's moorings include polyester mooring lines and the MODU mooring lines are steel, then it is more likely that facility's moorings will be damaged by dragged MODU components, assuming there is some interaction. Conversely, if the MODU moorings are largely synthetic, and the facility's moorings are steel, the interaction is less likely to cause substantial damage.

K.14.6.3.2 Data Requirement for Detailed/Supplemental Risk Assessment

In some cases it may not be necessary to gather additional information for the detailed risk assessment. However, if close operations between the MODU and a permanent surface facility are considered, then it will be necessary to fully understand the potential interactions between the MODU's mooring system and the surface facility's above and under water structure. This type of situation may be addressed within a detailed risk assessment and would likely be classified as an "Atypical Operation" in K.6.4.

As an example, consideration needs to be given to the following list which is not all inclusive.

a. The possibility of damaging a mooring line, TLP tendon or their foundations by dragging a MODU mooring line over it.

b. Mooring line interaction with SCR(s), subsea flowlines, manifolds or trees.

c. Mooring line interaction with the hull of a floating structure or the structural elements of a jacket and any of their critical appurtenances.

d. Potential to damage fuel or crude oil tanks leading to pollution (e.g., if such tanks exist in exposed pontoons on a permanently moored semi-submersible).

e. Damage survivability of the surface facility including:

   - damaged stability;
   - tendon failure;
   - structural reserve;
   - damaged mooring capability;
   - effect on risers.

The intent is to document the realistic scenarios so that their criticality and likelihood can be determined. For example, in most cases any collision between a MODU and a surface facility will occur during the passage of the storm, so survivability of the surface facility should be viewed in light of the likely storm condition at the time of damage. It may be that, for example, a TLP has a single tendon damage survival case that includes a severe storm, so it may then be reasonably assumed that the TLP will survive a "loss of tendon" scenario. Conversely, should the TLP have limited storm survival capability with tendon damage, then it would not be unreasonable to assume that loss of the tendon is equivalent to loss of hull system, based on the high likelihood of the entire tethering system failing.

What is imperative is that sufficient data is gathered so that all possible interaction scenarios can be adequately considered and, where necessary, quantified.

K.14.7 PROBABILITY OF MOORING SYSTEM FAILURE

K.14.7.1 General

An integral part of any risk analysis is the determination of the probability of the initiating event. In the case of a mooring risk assessment, the initiating event is mooring failure. The definition of failure will vary depending on the circumstances, but for the purpose of a risk assessment, a failure is any event that could lead to adverse consequences. For some mooring systems deployed over pipelines, that could be as simple as dragging an anchor a short distance (see definitions for more details).

A simple estimate of the probability of MODU mooring system failure can be taken as the inverse of the return period corresponding to the load where failure is expected. In doing this, consideration should be given to actual anchor capacity and mooring line strength. Mooring line strength may be reduced due to component degradation, bending over the fairlead, etc., in comparison to catalog values. (See K.3.2.)

One way to determine the probability of suffering a mooring failure is through the use of reliability analysis, thereby incorporating to some degree the uncertainty in the environmental loads and the component strengths. Due to uncertainty in the definition of basic variables, methods of structural reliability analysis are best suited to the calculations of comparative system probabilities of failure. Caution should be exercised when using structural reliability methods to calculate absolute probabilities of failure.

The sophistication of the reliability analysis can vary depending on the level of detail required, but in all cases the following factors should be considered.

a. The slope and shape of the metocean extreme curves (parameter vs. return period). This will vary depending on location and season within the Gulf of Mexico.

b. The distribution of mooring component strength. The mean value will vary with age, use, maintenance, etc. A mooring system reliability analysis should not be based on the full CBS of the mooring components but should reflect the component age, inspection history results, and fairlead bending considerations.

c. Variability in reliability depending on storm approach direction with respect to MODU heading.

d. Different reliability of mooring systems with different redundancy.

K.14.7.2 Mooring Component Failure Locations

The location of the failure along the length of the mooring line affects the possible consequence of mooring failure. The effects of having multiple mooring lines needs to be carefully considered when determining the likely mooring line failure locations. As an example it is reasonable to assume that 80% of mooring lines fail close to the fairlead, but on an eight line unit there is approximately an 85% chance that at least one line will fail away from the fairlead. Similarly, only approximately 5% of lines failed at the anchor in the 2005 hurricane season, but that equates to over 33% probability that on an eight line unit there will be at least one mooring line failure at the anchor. These factors become extremely important when determining the likelihood of various components being dragged over the seabed [1].

K.14.8 CONSEQUENCES OF MOORING FAILURE

The greatest concerns for potential asset damage are described in the following.

a. **Surface Facilities—**Relatively low likelihood for direct vessel to vessel collision unless the MODU is very close, but the cost for a major installation can be well in excess of $1 billion for a major deepwater facility, not accounting for shut-in loss. Contact likelihoods depends on the “target” size, including any mooring and riser spread. While contact with the surface facility does not necessarily equate to total loss, due consideration needs to be given to the environment in which the collision will occur (i.e. during a storm). Similar, consideration should be given to potential damage to the mooring or risers. This kind of event has a higher likelihood than the direct vessel to vessel collision but would not be a complete facility loss but may still result in significant repair costs and lost or deferred production.

b. **Pipeline/Flowlines—**Relatively large “target” if the drifting MODU is dragging an anchor. Cost of damage needs to include the impact on production upstream of the pipeline, and if those facilities feeding the pipeline can produce through any alternative route. Repair costs in deepwater can be high, with long duration. Recent experience is that only approximately one in five MODUs that broke adrift dragged anchors for any significant distance. While dragging an anchor can cause significant damage, it is less clear how much damage can be caused by a dragging a failed wire or chain. The loads imposed by a dragged wire or chain will not be very large, however, damage to the coating or insulation of a pipeline may be sufficient to necessitate costly repairs in the future. There were cases reported in the 2004 and 2005 hurricane seasons where a dragged wire or chain that apparently did not damage steel pipelines that they crossed. However, if a groove gets started, then a wire or chain will tend to cut into the steel. For flowlines, there is lower likelihood of damage than a pipeline as they tend to be shorter, but conversely may be closer to the MODU operations site. Likelihood of interaction depends on the angle subtended. Flowlines being infield or intra-field versus pipelines which are for export to shore, tend to be smaller and thus lower throughput does lesser consequence if damaged.

c. **Wellheads**—Low likelihood of damage by dragged anchor or broken mooring line(s) due to small size, however likely to be damaged by a dragged wire or chain. Normally the consequences would be limited because safety features would prevent flow even if the wellhead were pulled off the well. However, there have been wells where the sub-surface safety valve has been taken out for repair prior to hurricane arrival. Damage to the wellhead in these cases could lead to a significant hydrocarbon spill.

d. **Umbilicals—**Similar likelihood of damage to flowlines, although often less robust, so more prone to damage from dragged mooring components. Normally would not lead to large shut-in production, although there are some umbilicals used for flow assurance for a number of wells. Loss of one of these umbilicals would result in significant shut-in.

There is a high concern for extended shut-in of production. In most cases, the production of a facility can be reasonably estimated, but there are some facilities, often older ones, that are producing relatively little, but significant quantities of hydrocarbon transit across the facility. These hub facilities represent a special risk, as do the main pipelines that feed them.

Determining the cost of shut-in production is not simple. The production is not normally lost, unless the damage is so great that the economics of replacing the facility are unacceptable. However, the delay in production leads to significant loss of cash flow and may impact the ability to finance the development of other fields.

Due consideration should be given to some of the massive pipelines that carry crude from hub facilities and the LOOP. Damage to these could have an impact on oil supplies to the U.S. and therefore should be subject to special assessment.

While drifting of a MODU into a major surface facility may be a low likelihood event, it is one of the cases in which the consequences could significantly outweigh the direct financial damage. The perception of such a collision could be quite detrimental to the industry.

K.14.9 RISK EVALUATION—THE RISK MATRIX

Although risk is defined as the product of the frequency of occurrence of a hazardous event and its consequences, this definition is sometimes inadequate. In the case of a financial assessment, the result is the "expected loss," in real currency, if the venture is undertaken. A high probability event of low consequence can have the same risk as a low probability event with high consequences. This is a common definition, but for some extremely high consequence events with low probability of occurrence, this definition can lead to misleading conclusions; society will accept frequent low consequence events more readily than less frequent high consequence events.

The usual method of presenting results makes use of a risk matrix, whether the mooring failure risk assessment is undertaken at a simplified or detailed level. It is difficult for people, even those trained in risk analysis, to get a good understanding of what an event with a probability of 10^{-4} means when that event is associated with consequence of $1 billion. In order to put these numbers into perspective it is best to use a risk matrix such as shown in Figure K.11. This is a table of cells, each cell representing a single combination of probability range with consequence range. Figure K.11 is a four-by-four matrix, but many companies use different shapes and sizes. Each cell is assigned either a low, moderate or high risk rating.

In many cases, particularly when considering mooring failures, the detail of the quantification, the magnitude of the numbers, and level of accuracy is such that the best way to interpret and present the results is through the use of a risk matrix. The selection of levels probability and consequence depends on the Operator, and these must be defined at the start of the risk analysis. Different matrices may be used at different stages of the analysis.

The risk matrix can be used to assess various type of consequence as discussed in K.14.5. As discussed previously, financial consequence may not be the critical consequence type for some stakeholders, but it is the most easily quantified. Based on the position in the matrix, a risk classification such as low, moderate, and high may be used to decide the risk potential from an individual hazard. Figure K.11 has not been drawn with specific risk categories, but they should be revised to suit the requirements of the stakeholder. An example of three "Risk Levels" follows.

a. *Low risk (L)*: The bottom left corner of Figure K.11. Severity is low and likelihood is also low. Minimal risk that may be tolerated because it represents low probability of relatively small loss and may be addressed as part of the normal on-going continual improvement processes.

b. *Moderate risk (M)*: The middle area of Figure K.11, from the upper left corner to the lower right corner. There is either a low probability of suffering a large loss (upper left), or a relatively high probability of suffering a small loss (lower right). Generally, the risk may be within tolerable limits. However, the expected loss is sufficiently high to require best attempts to mitigate the risk. In a more general sense, this risk level requires implementation of reasonable and practicable risk reducing measures, or more detailed analyses to better define probability and consequences.

c. *High risk (H)*: The top right corner of Figure K.11. A high probability of suffering a large financial loss that is not tolerable without implementation of effective risk reduction measures. Risk reduction measures may include reducing the probability of mooring failure or reducing the consequences should one occur. One way to reduce the probability of failure may be to change the season of operation. Possible consequence reduction measures are discussed in the following section.

Consequences		Probability			
		A	B	C	D
		Less Likely			More Likely
IV	High				High Risk
III			Moderate Risk		
II					
I	Low	Low Risk			

Figure K.11—Typical Risk Matrix used for MODU Mooring Risk Assessment

K.14.10 RISK ACCEPTANCE, ALARP AND RISK REDUCTION

K.14.10.1 Risk Acceptance

Risk acceptance involves deciding whether a risk is tolerable and whether risk reduction measures are needed. Tolerable risk levels should provide a balance between absolute safety requirements and cost and benefits of proposed risk reduction measures. Acceptability is generally determined by comparing mooring failure risk against the acceptable risks established for similar or other offshore systems with acceptable operating experience or with those established by other industries.

Operators and other stakeholders may have different risk acceptance criteria that may be driven by different consequence types. The situation becomes increasingly complex when considering either extremely high financial losses or the other consequence types. It may be possible to develop a relatively simple set of criteria for financial loss, however the other consequences of a MODU mooring failure may be difficult to objectively assess.

Other consequences besides financial, such as corporate image, may be involved at this stage. Considering only financial risk may mislead the overall assessment conclusions. In addition, when dealing with extremely low probability but high consequence events, the normal approach of cost-benefit analysis can break down.

Example 1: Consider an event with a 0.1 annual probability of occurrence with an associated $100,000 financial consequence produces the same financial risk as an event with a 0.0001 annual probability of occurrence with an associated $100 million financial consequence that is a $10,000 annual risk. However, an event that produced a $100 million loss is likely going to have far greater impact on corporate image than a $100,000 event.

Example 2: Consider the case where there is a 0.001 probability of doing $2 billion damage. The financial risk can be calculated as $2 billion × 0.001 or $2 million. By implication, it would not be financially advisable to spend more than $2 million (the total financial risk) to reduce the probability to a lower level. However, because the $2 billion loss may be more than the company could tolerate, it would likely be advantageous to attempt to reduce the probability to a lower level, even at an expense of over $2 million.

Financial risk may be useful to determine what mitigation or prevention measures are worth investing in to reduce the risk. The ALARP (As Low As Reasonably Practicable) process can also be used to determine if the risk is tolerable or that the Operator has done everything reasonable to reduce the risk.

K.14.10.2 ALARP

When evaluating the risk of a mooring failure an operator should make an effort to satisfy themselves that the risk is ALARP. The ALARP concept is part of the risk decision analysis. ALARP goes beyond determining the risk level based on the adequacy of existing mitigation measures by asking *"What else can be done to further reduce the risk and what is the argument for not doing it?"* The key to the ALARP concept is that the burden of proof is to demonstrate why you wouldn't do more, as opposed to explaining what has or will be done to reduce the risk.

Philosophically, all risks should be reduced to a level that is ALARP. The ALARP concept hinges on what is reasonably practicable in terms of effort and benefit, recognizing that it is not reasonable to expect every possible risk reduction measure to be implemented. To demonstrate that a risk is ALARP it is necessary to show that there is a gross disproportion between the benefit (risk reduction) gained and the resources of implementing further risk reduction measures. Gross disproportion implies there is a bias towards risk reduction. What constitutes gross disproportion will depend to a great extent on the potential consequences associated with the risk—the greater the consequences the greater should be the bias towards risk reduction. The ALARP concept is consistent with a philosophy of continuing risk reduction while recognizing the principle of diminishing returns.

Consider the ALARP concept as it relates to an example of three possible risk levels—higher, medium and lower. The suggested response to a higher risk is to reduce it to at least the medium level which in most cases would generally not be considered to be as low as reasonably practicable. Lower risks would be addressed as part of the normal on-going improvement processes. Thus, at this lower end of the risk spectrum, where there is little scope for further risk reduction, the ALARP test is typically intuitive. So it is at the medium level where there may be less obvious decisions to be made about further risk reduction, and therefore may warrant a more rigorous demonstration of ALARP.

As it applies to evaluating the risk of a MODU mooring failure, the ALARP process requires an operator evaluate the efforts and benefits associated with alternative mooring system designs (e.g., catenary vs. semi-taut configurations, steel vs. fiber rope, various anchor designs, etc.) and alternative drilling locations and schedules (e.g., can the location be drilled outside of the peak of hurricane season, is there a lower risk location in another region of the GOM, is it feasible to trade MODU slots or share the MODU with another operator, etc.) to demonstrate that the risk of mooring at the location is ALARP.

K.14.10.3 Risk Reduction

If a tolerable risk level is not achieved in the risk assessment process, the next step is to identify risk reducing measures and evaluate their potential to reduce the risks to a tolerable level. Risk assessment is an iterative process, i.e., it needs to be repeated considering the changes in the system until a tolerable risk level is achieved.

Some of the methods that can be used to reduce the risks include:

- drilling the well during a more environmentally benign time of the year to reduce probability of mooring failure (prevention);
- strengthening the mooring system to reduce the probability of mooring failure (prevention);
- using different mooring components to reduce the consequences of mooring failure (mitigation).

The consequential effects of risk reduction measures should always be considered: there is little point in reducing the risks of one operation only to find that the comparable risks of another have been increased.

K.14.11 DOCUMENTATION

It is important to document the basis, and any assumptions inherent within the analysis regardless of the level of risk analysis that is being undertaken. Normally for a simple "spreadsheet" type assessment this will be easy to document since the simple sets of answers should always be available. The important point is that anyone auditing the process at a later date can determine the fundamental information for the analysis. One important piece of information is a document register that gives the number, date and revision number of all documents used in the assessment. There should also be clear documentation of personnel involved.

K.14.12 OUTLINE METHODOLOGY FOR QUASI-QUANTIFIED MOORING FAILURE FINANCIAL RISK ASSESSMENT

The following approach assumes that the probability of mooring failure has been determined. This methodology is provided for guidance only and is not intended to be all-inclusive. When calculating the probability of a mooring failure it is important to ensure that a suitable factor has been used on the mooring line strength.

1. Obtain a map of area showing all the surface and subsurface infrastructure.
2. Divide it up into homogenous sectors. A homogenous sector is one in which there are no changes in infrastructure: the damage caused by a drifting MODU will be independent of the direction it drifts off location within the sector. It may be reasonable to exclude point sources (e.g., subsea wells or distant surface facilities) if angle they subtend is small. These would then be handled separately.
3. Determine the likelihood that the MODU drifts in that direction (based on either mooring analysis or metocean extremes, or both).
4. Determine likelihood of dragging each of the components in the mooring system (based on line break statistics). This will necessitate building a table of components, failure likelihood, and potential for dragging across the seabed.
5. Determine the likelihood and extent of damage to subsea facilities (based on water depth at subsea infrastructure and dragged components, etc.).
6. Determine the consequences of that damage, including direct costs to repair, and delayed or lost production.
7. Develop a weighted sum of the product of consequence and likelihood for each type of subsea infrastructure that it is desired to keep separate (so they can be plotted on a risk matrix). Alternatively, determine a weighted average for expected loss for all subsea equipment lumped together.
8. Determine the likelihood that dragged mooring components damage subsurface structures.
   - All: consider potential for dragged mooring line interaction with SCRs, well risers, subsea tieback flowlines, etc.;
   - For TLPs: consider pile, tendon, porch, and hull;
   - For jackets: consider jacket structural members;
   - For spread moored floaters: consider interaction with mooring system components based on what is dragged, layout of permanent facility mooring, and type of moorings (synthetic or steel). A grouped synthetic mooring system is expected to have the highest likelihood of suffering catastrophic damage due to the potential of damaging an entire group of lines.
9. Determine consequences of drifting into, or otherwise interacting with, surface facility, including direct repair cost and delayed or lost production.
10. Sum the various types of surface facility consequences so that, with the related probabilities, so they can be plotted onto a risk matrix.
11. Present the results in both tabular form, and plotted on a suitable risk matrix.

K.14.13 REFERENCES

1. MODU Mooring Strength and Reliability JIP, "Post Mortem Failure Assessment of Semi-Submersible MODUs during Hurricanes Katrina & Rita." Report No. ABSC/1514096/LB-08, 2007
2. Sharples, Malcom "Post Mortem Failure Assessment of MODUs During Hurricane Ivan," U.S. Minerals Management Service Report No. 0105PO39221, 2006
3. Coyne, Mike "2005 Hurricane Season Impact," API Offshore Hurricane Readiness and Recovery Conference Proceedings, Nov 2006.
4. Det Norske Veritas, "Pipeline Damage Assessment from Hurricanes Katrina and Rita in the Gulf of Mexico," U.S. Mineral Management Service Report No. 44814183, 2007.
5. Floating Production Mooring Integrity JIP, (UK HSE Report 444), 2006.

K.15 Storm Reporting Sheet for Semi-submersible Rig Status Report

This reporting sheet can be used as required for documenting information on the MODU mooring after an event. This form may also be useful documenting the as-installed mooring system information as per K.10.2. Every effort has been taken to make the form cover all situations. However, there will be cases where it does not exactly ask the right questions, thus flexibility is requested of the person completing it. The intent is to capture the impact of a storm on the MODU and its mooring.

The reporting sheet is divided into four sections:

1. General Description of the MODU and the Mooring Location;
2. As-installed MODU Mooring Information;
3. As-abandoned MODU Mooring Information;
4. Post-storm MODU Condition.

Please use consistent units throughout (either feet and kips or tonnes and meters, line diameters in in. or mm).

Section 1—General Description of the MODU and the Mooring Location

Date Form Completed:		
Contact Information:		
Drilling contractor:		
Contact name:	Telephone:	E-Mail:
General MODU Characteristics:		
MODU name:		
Designer:	Designer class description:	
Classification society and notation:		
MODU modified since delivery?	Yes	No
Brief description of modifications:		
Location Description:		
Operator of well:		
Block name and no.	Latitude:	Longitude:
Water depth:	MODU heading:	
Soils data available?	Yes	No
If soils data is available, please supply brief description and strength profile.		

Section 2—As-installed MODU Mooring Information

General Information:				
Was mooring MODU's own system or preset?	Own	Preset	Both own and preset	
If preset, whose equipment was used?				
Number of mooring lines (details requested in table below):				
What is mooring line 1 (e.g. Starboard; Bow):				
What is numbering sequence? (Add drawing if required.)	clockwise from above		anti-clockwise from above	
Anchor Information:				
Type of anchors	Drag	Plate anchor	Pile	Other
Anchor description (e.g. weight, size, manufacturer, model, etc.):				
For drag embedment anchors:				
Manufacturer	Type		Weight and fluke angle	
Anchor test load and duration				
Were any anchor legs run short?	Yes		No	
If any were run short, why?				
Tension and Length Information:				
Method of payout measurement during installation:				
Method of measuring pretension and operating tension:				
Are anchor scopes known or estimated?	known		estimated	

Please Complete for AS-INSTALLED Condition

	Mooring Line Number											
	1	2	3	4	5	6	7	8	9	10	11	12
Line azimuth (True North)												
Fairlead-anchor horizontal distance												
Fairlead component type, size, outboard length												
Component type, size, length												
Component type, size, length												
Anchor component type, size, length												
Buoy/clump size and location												
Type of anchor size, etc.												
Fluke angle or shear pin size (force to break)												
Test load at fairlead or AHV stern roller or AHV bollard pull												
Line arrangement during test load												
Test load at anchor shackle												
Anchor test load duration (min)												
Anchor drag distance during installation												
Location of MODU during test load												
Nominal operating pretension												

Mooring Line Component Information			Lines ______ to ______			
	Type	Construction	Diameter	Break Strength	Manufacturer	Age
At Fairlead						
Intermediate Line 1						
Intermediate Line 2						
At Anchor						
Mooring Line Component Information			Lines ______ to ______			
	Type	Construction	Diameter	Break Strength	Manufacturer	Age
At Fairlead						
Intermediate Line 1						
Intermediate Line 2						
At Anchor						
Note: The table above has been developed to ease information flow. If mooring system cannot easily be described through use of this table, please attach a separate and full description.						

Section 3—As-Evacuated MODU Mooring Information

Mooring System Details:		
Was rig position modified for evacuation?	Yes	No
How modified? (distance and direction)		
Were line tensions modified prior to evacuation?	Yes	No
Was line slackening complicated by high currents, high winds, etc. that made it difficult to accurately establish the line tensions on evacuation?		
	Yes	No
Prevailing weather conditions at time of mooring adjustment		
Seas	Height	Direction
Wind (1 minute average)	Speed	Direction
Current	Speed	Direction

Please Complete for AS-EVACUATED Condition

	Mooring Line Number											
	1	2	3	4	5	6	7	8	9	10	11	12
Line azimuth (True North)												
Fairlead-anchor horizontal distance												
Fairlead component outboard length at evacuation												
Nominal survival pretension (at zero environment)												
Evacuation tension (measured)												
Note: The table above has been developed to ease information flow. If mooring system cannot easily be described through use of this table, please attach a separate and full description.												

Section 4—Post-storm MODU Condition

Storm Name and Date:		
Hull and Structural Condition Summary		
Did the unit suffer any damage during the hurricane?	Yes	No
Can repairs be effected on site?	Yes	No
Major: Description of hull or structural damage requiring third party or shipyard repair?		
Significant: Description of hull or structural damage that must be completed prior to restarting drilling operations:		
Minor: Description of hull or structural damage that can be repaired during normal operations. Please include whether there was green water damage.		
What surprised you when you got back on the MODU? (either damage or indications of things)		
Mooring System Condition Summary		
Did the unit suffer any mooring related failures?	Yes	No
Did any anchors drag, and if so, how far?	Yes	No
	How far?	

	Mooring Line Number											
	1	2	3	4	5	6	7	8	9	10	11	12
Failed at fairlead												
Failed at intermediate												
Failed at anchor												
Dragged anchor												
Other (anchor broke, brake failure, etc.)												
Component(s) recovered for inspection?												
Inspection results and availability?												
Length of any “dangling” mooring component below the keel												

MODU Recovery and Reboarding Operations Summary		
How far did unit drift?		
Where was the unit after the storm when found?		
Was the unit grounded?	Yes	No
Were tugs dispatched to recover the unit?	Yes	No
Did the tugs prevent additional drift?	Yes	No
Any comments on effectiveness of tugs?		
Is course of unit drift known (e.g., through transponder)?	Yes	No
Did the transponder operate properly during the storm, and if not, why (e.g., batteries failed, etc.)?		
Is the plot of location against time (to help with hindcasting and drift prediction) available?		
Other comments on MODU recovery and reboarding operations		