HYBRID WELL RISER RISK OF FAILURE AND PREVENTION

Study Report

Prepared for

MMS TAR&P

Reference No. 4-1-4-319/SR01

Rev. 1

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EXECUTIVE SUMMARY

The MMS contracted MCS to perform an investigation into the causes and probabilities of top-tensioned riser (TTR) failures from workover and drilling operations through existing single and dual casing production risers with a surface Blow-Out Preventer (BOP). Specific attention was paid to potential wear issues due to rotating drill pipe within riser systems that have already been in service for a substantial period of time, and that may have been subject to corrosion and VIV fatigue.

Performing drilling operations through any production TTR poses a critical hazard which must be addressed prior to the start of the operation. If the riser has not been designed to handle the additional fatigue and wear associated with drilling, then an engineering assessment should be completed to determine the riser's suitability. For risers not designed to be drilled through, mitigation measures such as wear sleeves and non-rotating protectors may be implemented to achieve an acceptable level of risk. Additionally, inspection and monitoring measures can help to detect warning signs of potential failure modes which allows operators to take action to prevent them.

Technical questionnaires were sent to each of the nine operators responsible for the 22 facilities online in the Gulf of Mexico with dry tree top-tensioned production risers. Five of the operators have had experience performing drilling operations through top-tensioned production risers, encompassing 10 of the 22 facilities in the Gulf of Mexico. The ten facilities in the Gulf of Mexico that have drilled through their production TTRs have typically done so infrequently. The approach used for determining appropriate operational criteria is generally the same for drilling through production TTRs as for traditional drilling risers.

Potential failure modes for production TTRs during workover operations have been compiled as a part of this study. For sidetrack and redrilling, the most critical riser failure modes outside of typical production hazards included drilling-induced vibration fatigue, and riser wear from direct contact with the drill string. Due to the lack of historical data regarding GOM production TTR drilling applications, some of the possible failure modes will reflect the best guesses from operators' experience in other regions around the world.

A risk assessment methodology is outlined for determining potential risks. This methodology has been adapted from the methodology MCS developed during the SCRIM

JIP in 2004-2008 and the Flexible Pipe Integrity JIP in 1995-97. Following the methodology developed in the JIPs, an indexing analysis is recommended, with risk defined as the product of one score representing the probability of failure (Probability Index) and another representing the consequence of failure (Consequence Index). The relative risk is used to guide the user towards recommending available integrity management (IM) strategies.

Following a risk assessment of the top-tension riser system, each failure mode is assessed to determine the required level of integrity management. Four *Strategic Inspection Levels* (SILs) are identified to denote these integrity management levels. Combinations of IM measures are selected according to SIL. An IM strategy details how these measures are implemented for each failure mode, and form the basis of the IM Plan.

Potential mitigation measures are included to address specific failure modes. Drilling induced vibration may be mitigated by monitoring for warning signs of resonant motion. If DIV begins to occur, the weight on bit (WOB) or RPMs can be adjusted to bring the riser out of its resonant frequency or the drilling fluid density can be changed in order to redefine the natural frequency of the riser. Non-rotating protectors are designed to maintain a stand-off between the drill pipe and the riser, consisting of a mud-lubricated inner liner connected rigidly to the drill pipe and a tough outer polymer sleeve that is free to rotate about the liner. By preventing the rotating drill string from directly contacting the riser, the risk of wear is minimized.

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1 INTRODUCTION

1.1 BACKGROUND

In an attempt to mitigate the cost and time restraints associated with deepwater workover, redrill, and sidetrack drilling operations, some operators have either considered or performed these operations through existing single or dual bore production top tensioned risers.

Floating production facilities with surface completion systems are typically more economical than traditional subsea completion systems, which require an additional vessel to be engaged in order to deploy and recover the riser casings.

Dual and single casing Top Tensioned Riser (TTR) systems are, to date, widely used by operators in conjunction with deepwater floating production facilities. These riser types provide direct vertical access for completions and workovers, and use the effective tension distributions between casing and risers to mitigate collapse or buckling. There are a number of potential issues related to riser operations in these conditions that may result in a lower reliability for single and dual bore systems in terms of well control.

In this context, MMS has requested an investigation into the causes and probabilities of riser failures from workover and drilling operations through existing single and dual casing production risers with a surface Blow-Out Preventer (BOP). Specific attention is paid to potential wear issues due to rotating drill pipe within riser systems that have already been in service for a substantial period of time, and that may have been subject to corrosion and VIV fatigue.

1.2 OBJECTIVES

The objective of this study is to examine the causes and probabilities of riser failures from well intervention operations performed through existing single and dual casing production risers with a surface BOP.

1.3 SCOPE

The overall project workscope is defined by following five subtasks, based on MCS experience of TTRs and integrity management (SCRIM JIP):

Task 1 - Industry Survey (CTR 1.1)

Task 2 - Riser Failure Modes SBOP (CTR 1.2)

Task 3 - Risk Assessment Methodology (CTR 1.3)

Task 4 - Integrity Management Strategy (CTR 1.4)

Task 5 - Reporting and Admin (CTRs 1.5 & 1.6)

For Task 1, a literature and industry survey was completed to assess the frequency of use of surface BOPs for workover operations from floating production facilities through existing single and dual bore production top tensioned riser systems. The study also assessed equipment and conditions in which the equipment would generally be deployed, for operations in the Gulf of Mexico.

For Task 2 potential failure modes of production TTRs were compiled with emphasis on workover operations involving drilling operations with a surface BOP. For convenience in identifying and presenting potential failure modes, each mode has been categorized into one of several identified *Failure Drivers*. These are convenient categories (such as fatigue or accidental damage) which identify the primary cause of pipe failure and into which several such modes may be grouped. The failure modes are presented in terms of the *Failure Initiator* (the event or condition which begins the failure process) and associated *Failure Mechanism* (the sequence of stages through to full failure) associated with each mode. Attention has also been given to the identification of any mitigation or preventative measures that, if implemented, might potentially lower the risk associated with particular failure modes.

Analysis of frequency of occurrence of loss of integrity with a critical review of cause and effect was also to be included in this task. However, the industry survey completed for Task 1 indicated that operators in the Gulf of Mexico had not experienced a loss of production TTR integrity due to these workover operations. In lieu of instances of loss of integrity, the operators were queried as to any unanticipated, adverse results (such as wear rate beyond predictions). Instances of these results are also limited. Drilling induced vibration (DIV) fatigue was raised as a concern in recent years from experience in other parts of the world. Subsequent investigations have indicated that DIV is only a concern within specific, manageable criteria [6]. Operators reported no unanticipated instances of wear or damage from drilling, which are the other major riser integrity concerns identified for the operations. As such, analysis of frequency of occurrence of loss of integrity was not conducted within this task.

For Task 3 a risk assessment methodology is defined for assessing the risks associated with the failure modes identified. A modified indexing method will be implemented, adapted from the methodology MCS developed from the SCRIM JIP in 2004-2008 and the Flexible

Pipe Integrity JIP in 1995-97. A qualitative index for risk (*Integrity Management Index*, IMI) is defined as the product of one score representing the probability of failure (*Probability Index*, P) and another representing the consequence of failure (*Consequence Index*, C).

For Task 4 an integrity management strategy is outlined with particular attention paid to mitigators/remedial action that can be applied to reducing risk for production TTRs subjected to workover operations involving drilling with a surface BOP. Suggested mitigation measures/remedial actions are presented to address the potential failure modes discussed in previous reports.

1.4 CHARACTERISTICS OF TOP TENSIONED RISERS

Top Tensioned Risers are rigid, vertically pretensioned risers, and are typically used as production, drilling, workover and completion risers. TTR systems are considered a mature technology, having been used for drilling since the 1950s and for production since 1975. They can be highly complex systems, particularly for deepwater applications.

TTRs are normally tensioned either at the deck of the host vessel by a mechanical tensioning system or a self-supporting buoyant tensioning system. A variety of pipe configurations have been used to date. TTR systems are mainly used with Tension Leg Platform (TLP), Spar/Deep Draft Caisson Vessel (DDCV), and deepwater moored semi-submersible (DTS) facilities, as these floating structures typically have relatively low heave and rotational motions.

The conventional production TTR consists of the following components:

- Surface tree & surface wellhead
- Tensioning system
- Vertical riser joints
- Tieback connector & subsea wellhead
- Specialty joints & components are usually located at the vessel and seabed interfaces to provide stiffness transition and protect the riser from excessive bending stresses (e.g. tapered stress joints and keel joints)

In order to reduce hang-off loads and therefore tension requirements, materials such as titanium, aluminium, and composites may be applicable.

1.4.1 Surface Tree and Wellhead

The surface tree (or dry tree) is an assembly of control valves, gauges and chokes that directs and controls the flow of production fluid at the topsides, preventing the release of oil or gas from a producing well into the environment. A surface tree is supported by a surface wellhead, and therefore moves, along with the riser, with respect to the vessel hull.

1.4.2 Tensioning Systems

Since, by definition, TTRs are supported from the top, tension requirements, and the ability of any tensioning system and/or vessel for maintaining tension to support the risers, is a critical aspect of any TTR design. Typically, TTRs are tensioned by either a mechanical (e.g. hydro-pneumatic tensioners) or buoyant (i.e. air cans) system. Air can tensioned TTRs are primarily used in conjunction with Spar vessels, while mechanical tensioners are typically used for Tension Leg Platforms (TLPs) or Deep Draft Caisson (DDCV) facilities. Both types of TTR tensioning arrangements are shown in Figure 1.1, with some of the typical riser components also labeled for illustration.

1.4.3 Riser Cross-Section: Single vs. Dual Casing

TTRs for dry tree applications are typically either single or dual barrier systems, depending upon the functional requirements of the system. The single barrier system comprises a single casing (riser) and internal production tubing. This arrangement tends to have the smallest diameter and offers the lightest solution with lowest capital cost. This also offers the simplest system in terms of tension distribution calculation and analysis. The disadvantage of this system is that the casing provides only a single structural barrier to produced fluids under workover conditions with the tubing removed. In certain cases mud contained in the riser can be considered a second independent barrier depending upon whether there is sufficient mud below the mudline to maintain control of the well in the event of casing leakage or failure.

In order to mitigate the risk of loss of well control resulting in environmental contamination, many operators select a dual casing system, in which two concentric structural casing strings are deployed and tension in the riser is shared between them. For the dual casing system, a loss of integrity of the inner casing under workover conditions would still leave the outer casing as an additional independent barrier. It is also possible to detect leaks from the inner casing through pressure increase in the annulus between the two casing strings.

Other cross-section variations exist, such as multiple non-concentric production tubulars within a single casing. However, the single and dual casing configurations described above are the most common configurations, with existing dry tree units using each configuration in approximately equal numbers.

1.4.4 Tieback Connector and Subsea Wellhead

The tieback connector provides a leak-tight connection between the subsea wellhead and the bottom-most joint of the riser. The host vessel horizontal excursions are translated to the upper end of the riser, which can result in an applied bending moment at the wellhead. The wellhead will also experience axial loading from the tension applied in the riser system. If insufficient tension is applied to support the riser string, this can result in compressive load at the wellhead. Thus, the tieback connector must be able to withstand the various loading conditions it will experience during both installation and operation and ensure a continuous pressure tight seal.

Typically, tieback connectors installed on the external casing of top tensioned risers can be hydraulically locked and unlocked by an ROV. In the case of a dual casing riser, the inner casing is connected to the wellhead casing via an internal mechanical connector welded on the riser string; this connector latches on the complementary connector on the wellhead casing.

1.4.5 Specialty Joints

Specialty joints are designed to reduce riser bending stresses at the vessel and the subsea wellhead interfaces. They are typically forged, in order to avoid the presence of a seam on the joint. Therefore, these joints are unlikely to fail unless they contain a fabrication defect. The most common specialty joints include:

- Keel joints;
- Tapered stress joints;
- Flexible joints.

A keel joint is used to reduce bending loads at the vessel interface; either a tapered stress joint or a flexible joint would be used subsea, immediately above the tieback connector to reduce to bending loads at the wellhead.

1.4.5.1 Keel Joint

The keel joint is a riser joint with increased wall thickness used to increase bending stiffness at the location where the riser first enters the keel of the spar hull. It is also a pivot point of the riser and provides relative motion compensation between riser and hull. By doing so, it protects the riser against large bending stresses. In order to prevent wear on the next section, it is possible to add wear material to the keel joint. A keel joint is usually unnecessary for TLPs, but is always used for top tensioned risers installed on a SPAR. For a SPAR, the keel joint is typically located at the lower end of the stem pipe 20 to 30ft below the keel of the spar. Upper and lower transition keel joints make the connection between standard riser joints and the keel joint. They are typically tapered stress joints used to control bending moments in this critical area. The keel guide is used to guide the riser in the hull at the keel joint, and may incorporate a keel centralizer.

1.4.5.2 Tapered Stress Joint (TSJ)

TSJs are transition members between a rigid or stiffer section of the riser and a less stiff section of the riser. The bending stiffness at one of its ends is close to the stiffness characteristics of the stiffer section whereas the other end has a lower stiffness than the less stiff section of the riser. This transitional capability of the TSJ is achieved by varying its wall thickness. TSJs are typically made of steel or titanium. In a top tensioned riser, the tapered stress joint is located at the bottom of the riser vertical section and is linked to the well casing through the tieback connector. The top end of the TSJ may be connected either to a crossover joint which is itself coupled to the lowest standard riser joint or directly to the lowest standard riser joint, depending on the structural performance at the base of the riser.

1.4.5.3 Flexible Joint

Flexible joints act as a flexible coupling between the riser and tieback connector. The most common configuration consists of a molded elastomeric element housed in a forged steel body with a steel retainer ring.

1.5 OVERVIEW OF WELL INTERVENTION OPERATIONS

Over the life of the well, changing reservoir conditions or deteriorating condition of the completion may require some well intervention operation to maintain or improve the production of the well. The three distinct categories of well intervention operations have been considered during this project:

- **Redrilling -** Subsequent drilling of the wellbore, typically to deepen or otherwise expand the borehole in order to improve the flow of hydrocarbons.
- **Sidetrack Drilling -** Drilling a new section of wellbore, either to circumnavigate an unusable section of borehole or to penetrate a different formation.
- **Workover Operations -** Any non-drilling, remedial operation performed on a producing well in order to improve or restore the flow of hydrocarbons. These may include:
  - Sand wash-out
  - Acidizing the well
  - Hydraulic fracturing
  - Plug back
  - Squeeze cementing
  - Rig Workovers

Specific attention is paid to potential wear issues due to rotating drill pipe within riser systems that have already been in service for a substantial period of time, and that may have been subject to corrosion, erosion and fatigue.

Redrilling and sidetrack drilling well intervention activities require the well to be killed, and the surface tree and production tubing removed prior to intervention. If retrievable, the production packer is released and pulled out with the completion string; if the packer is permanent, the tubing is cut just above the packer. A BOP will then be attached to the wellhead, and the drill pipe would be run.

Workover operations may be implemented through the production tubing, typically by means of coiled tubing or wireline.

1.5.1 Redrilling

The process of performing a redrilling operation through an existing top tensioned production riser involves several preliminary steps. The surface tree is first replaced by a surface BOP in order to protect against any potential blowouts during drilling. A drilling package is then installed. The drill pipe and associated bottomhole assembly is then lowered through the riser and into the wellbore to begin the drilling process.

Before undertaking a new drilling project, the operator must make sure that the vessel can handle the increased deck load imposed by the additional weight associated with the drilling equipment [1], [13].

1.5.2 Sidetrack Drilling

Sidetrack drilling is defined within this study as any drilling operations deviating from the original planned path of the well. There are several potential reasons to perform a sidetrack operation. Unsuccessful fishing operations or a collapsed section of the well may prevent any further production. If milling the stuck tool is ineffective or it is not feasible to redrill, a sidetrack may restore access to the reservoir. If production rate significantly diminishes, an additional wellbore may be drilled to another section of the reservoir. Sidetracking may also be performed to explore a new formation outside of the path of the original wellbore.

Sidetrack drilling requires much of the same equipment as redrilling, and follows similar procedures. In addition to the general drilling equipment, specialized tools may be needed to change the well path. A whipstock may be used in order to create the initial deviation from the wellbore. This device usually consists of a hard steel wedge placed on top of a cement plug or the bottom of the hole that is used to guide the drill bit onto a new path. Coiled tubing is utilized in certain situations to perform sidetrack drilling operations using a mud motor to rotate the drill bit as opposed to rotating the entire drill string. Coiled tubing will thus cause negligible wear to the riser compared to the more traditional rotating drill pipe. A knuckle joint may also be required to complete a sidetrack drilling operation if not using coiled tubing. The knuckle joint attaches just above the bottomhole assembly and allows the drill bit to bend independently of the rest of the drill string. A spudding drill bit is designed specifically to initiate the new path for deviated wells before being replaced by a more traditional bit. Figure 1.2 illustrates a sidetrack drilling operation using coiled tubing [1], [13].

1.5.3 Workover Operations

It is not uncommon for workover operations to be performed through production TTRs instead of dedicated workover risers. When these operations are preformed through production TTRs, the surface tree and production tubing typically remain in-place. Coiled tubing or wireline may be run through the production tubing. Some common workover operations are given a cursory treatment in this scope. These operations may have an impact upon subsequent drilling operations.

1.5.3.1 Sand Cleanout

Sand cleanouts are performed in order to remove sand from the wellbore that may be clogging the formation and constricting the flow of hydrocarbons. Coiled tubing units are used for these operations, often with a jetting tool connected to the downhole end of the coiled tubing. The coiled tubing is lowered through the riser into the wellbore. Cleanout fluid is then pumped through the tubing and out of the jetting tool, effectively removing sand and other fill from the hole [13].

1.5.3.2 Plug Back

When plugging back a well, cement is used to seal off and abandon a certain portion of the wellbore. This can be performed to avoid water in the bottom of a well, or as a preliminary measure taken prior to carrying out a sidetrack operation [1].

1.5.3.3 Acidizing

To acidize a well, an acid or mixture of acids (e.g. hydrochloric, formic, or acetic acids) is injected into the well, typically to increase the size of the pores in the formation, allowing increased flow of hydrocarbons from the formation. Additionally, acidizing can help to dissolve any substances that could inhibit production [1], [13].

1.5.3.4 Hydraulic Fracturing

During hydraulic fracturing, special fracturing fluids are pumped into a well under high pressure in order to expand cracks and increase the permeability of the rock formations. Proppants (small pieces of sand or other material of a specific grain size) are mixed with the fracturing fluid. When the hydraulic fracturing procedure opens up the formation cracks, the proppant particles enter the newly expanded fractures and hold them in place after the fracturing treatment has concluded [13].

1.5.3.5 Squeeze Cementing

For squeeze cementing, a cement slurry is forced under pressure through holes in the casing or liner and into the formation. Once the operation is properly completed, the cement cures inside of the holes and other voids, sealing off the wellbore from the surrounding formations [13].

1.5.3.6 Rig Workovers

Rig workovers include replacing or repairing leaks within the production tubing, replacing a failed gravel pack, or recompleting the well with a new gravel pack.

1.6 REVISION HISTORY

This is Rev. 1, issued for MMS review and comments.

Figure 1.1 Top Tensioned Riser Tensioning Systems

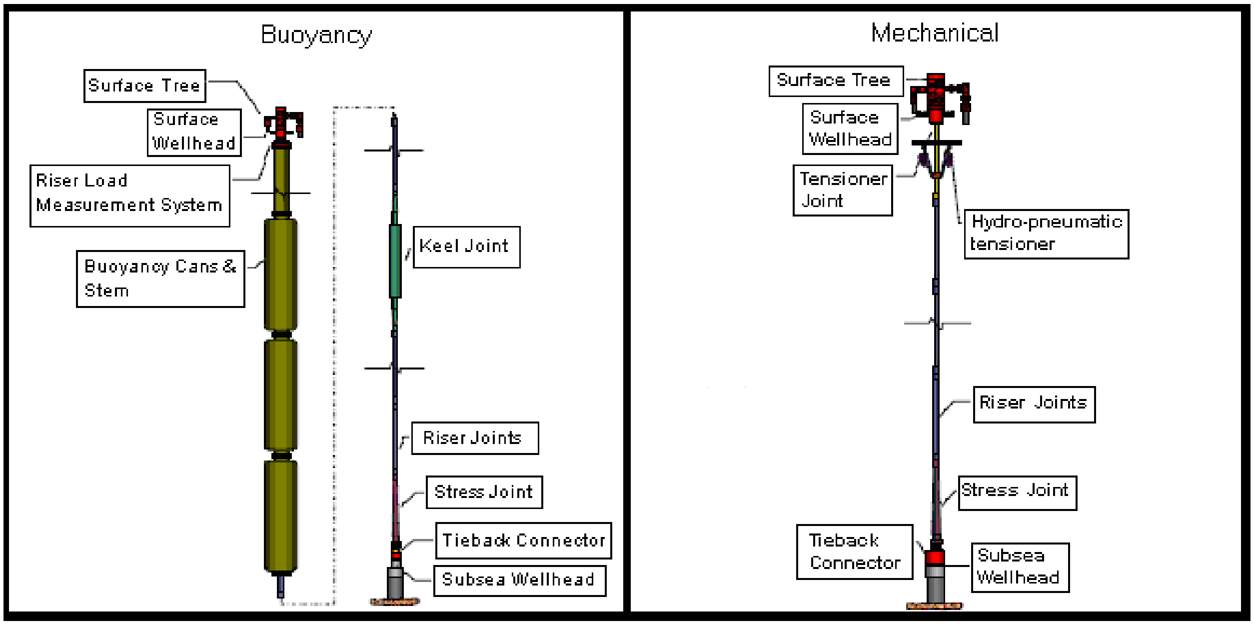
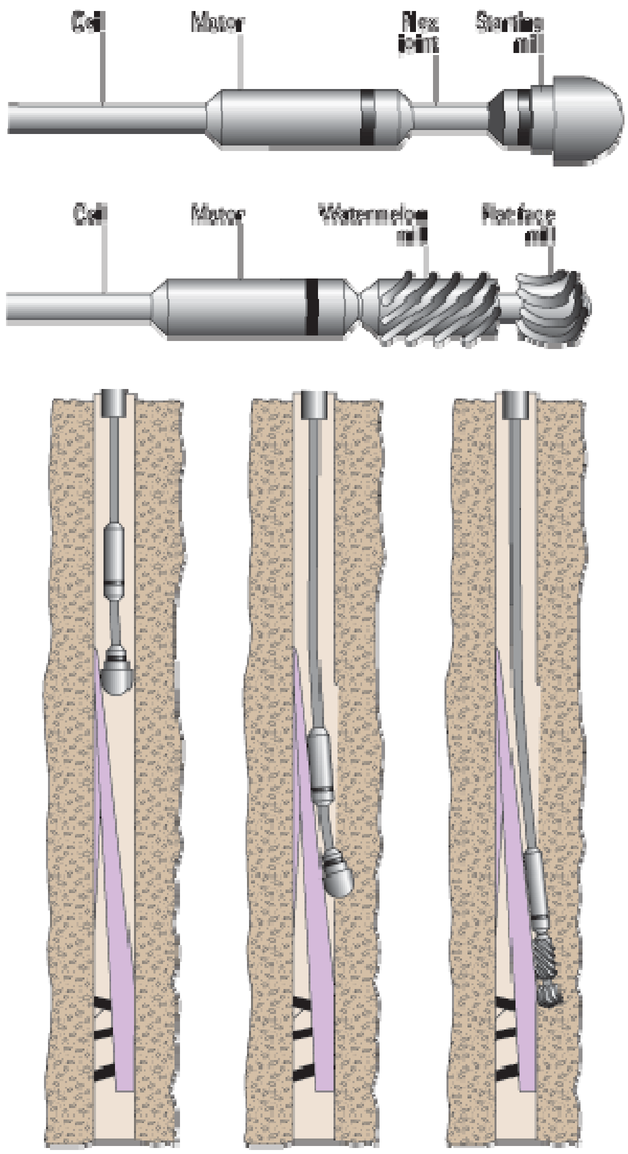


Figure 1.2 Sidetrack Drilling [13]



2 INDUSTRY SURVEY

2.1 GULF OF MEXICO DRY TREE PRODUCTION FACILITIES

2.1.1 General

The first task carried out for the study was to compile a comprehensive list of all platforms in the Gulf of Mexico that utilize top tensioned production risers and the corresponding operators. Technical questionnaires were then sent out to contacts at each of the operators. The survey included questions regarding the frequency of occurrence as well as the operational conditions in which production TTRs were drilled through. This report is based on responses from 21 of the 22 Gulf of Mexico facilities with dry tree production TTRs.

Emphasis was placed on operations in which a surface BOP was deployed and drilling operations were carried out through a production TTR. Since many non-drilling workover operations are routinely carried out through the production risers, it was not deemed necessary to question operators on the frequency of occurrence of these operations.

As of this report, only one survey is still outstanding, representing a single facility out of 22 with dry tree production TTRs in the GOM. If this survey is returned prior to the end of the project, the results will be included in the final report.

2.1.2 Systems In-Place and Planned

There are currently 30 floating production units (FPUs) with production TTRs in service worldwide, with an additional 13 planned or under study. Of those facilities in service, 22 are in North America, specifically the Gulf of Mexico. All counted, there are 223 production TTRs currently flowing in the GOM, with an additional 41 planned or under study.

Of the floating facilities reviewed, it is noted that all currently in operation have a minimum light workover capacity.[10] As of February 2008, 12 Spars and 9 Tension Leg Platforms (TLPs) have dry tree production TTRs flowing in the GOM.

2.1.3 State-Of-The-Art Operations

The surveys revealed that approximately half of the operators with facilities flowing in the GOM have performed drilling operations through production TTRs. Those who have drilled through production TTRs have typically done so infrequently. Out of all of the survey responses, only ten individual platforms in the Gulf of Mexico have had their production TTRs drilled through. Three of these platforms have only been drilled for well completion operations as opposed to well intervention after initial production.

The relatively infrequent implementation of these operations can be attributed to a combination of potential factors:

- Facility already has dedicated drilling and/or workover riser;
- Inability to implement operations due to deck space or riser size;
- Experienced complications while drilling through production TTRs in other regions.

Nearly half of the 22 facilities operating in the GOM have dedicated drilling and/or workover risers. Although this does not preclude operators from drilling through their production TTR, it is less likely that they will choose to do so.

Some facilities simply do not have the deck capacity to support full-on drilling equipment and may only be capable of handling a small work-over rig package. Another concern is the inner diameter of the riser casing, which may be too small for efficient drilling operations. The typical marine drilling riser inner diameter is 19.5", and inner diameters as small as 12" have been used. Smaller inner diameters restrict the outer diameter of drill pipe and tools used in drilling operations and may prohibit thru-riser operations due to strength and geometry limitations.

Some operators have encountered problems with wear and drilling-induced vibration in other regions around the world. These operators have decided to investigate these problems before conducting these operations in the GOM.

Due to the lack of historical data regarding GOM production TTR drilling applications, some of the possible failure modes reflect the best guesses from operators' experience in other regions around the world.

Table 2.1 All Production TTRs in GOM

Facility Type	Status (No. of Facilities)					Total No. Facilities Drilled
	Conceptual	Discovery	Flowing	Pending / Construction	Total	
Compliant Tower	0	0	1	0	1	0
DDCV /Spars	0	0	12	1	13	5
FPSO, FPSO Roundship	0	1	0	0	1	0
MinDoc	0	0	0	1	1	0
Semi-FPS	1	0	0	0	1	0
TLPs	1	0	9	0	10	5
Total	2	1	22	2	27	10

Notes: 1. All production TTRs off of North America are in the GOM
2. Includes Production, Production & Drilling, Production & Injection, and Production & Test TTRs

2.2 TYPICAL METOCEAN OPERATIONAL CRITERIA

2.2.1 General

Meteorological and oceanographic (i.e. metocean) conditions drive offshore operational limitations. A site-specific metocean study is preferable for any analysis, but some generalizations can be made. A stand-alone API recommended practice on metocean conditions (API RP 2MET) is in development for August 2008, with increased focus on metocean requirements for deepwater and floating facilities. [4]

2.2.2 Typical Metocean Conditions for the Gulf of Mexico

A metocean specification includes current, wave, and wind conditions based on statistical analysis of site-specific measurements. Wind, wave, and current speed and direction in the GOM have been measured since the 1970s by the National Data Buoy Center and facility operators. Simple combination of current, wave, and wind extremes at the same return period is typically overly conservative. Consideration is given to define seastates by location, time of year, and predominant condition (e.g. the 10yr extreme current seastate is composed of the 10yr extreme current and the wind and wave associated with it). Seasonal sets of data are typically classified in three metocean events: the Loop current, winter storms, and hurricane events.

2.2.2.1 Loop Current

The loop current refers to the large clockwise circulation of warm water through the eastern region of the Gulf of Mexico, with water flowing in from the Caribbean Sea through the Yucatan Channel and exiting through the Florida Straits. The loop current sometimes pinches off, spawning a clockwise eddy current that can move westward into the waters in which platforms are most concentrated [12].

The waters associated with the loop currents are considerably warmer than those typically found within the Gulf of Mexico. This can allow a hurricane passing over the loop current to strengthen significantly more than it ordinarily would. In 2005, the rapid strengthening of hurricanes Katrina and Rita was attributed to this phenomenon.

2.2.2.2 Hurricane Events

If possible, operators avoid well intervention operations during hurricane season which stretches from the beginning of June through the end of November. The harsh wind, wave and current conditions brought on by hurricanes create too many complications and safety concerns to justify the operation in most cases. Thus for most projects it is not necessary to analyze the hurricane sea states for these operations [5].

Several efforts are under way to update existing metocean conditions following Hurricanes Rita and Katrina. In May 2007, API issued Interim Guidance on Hurricane Conditions in the Gulf of Mexico (API Bulletin 2INT-MET) to immediately supersede the hurricane conditions specified in API RP 2A-WSD.

2.2.2.3 Winter Storms

Winter storm conditions compile the weather statistics from the months considered in the winter storm season (December to March). The current and wave conditions are thus considerably lower than the comparable hurricane condition allowing for a more realistic assessment of risk [11].

2.2.3 Where to Find Metocean Data

Site-specific information is required for any detailed assessment. However, some guidance can be found in various API codes with regards to typical metocean conditions for preliminary assessments. However, not only are these recommendations scattered across multiple documents, most have not been revised since 1993. Efforts are currently underway to consolidate these criteria into one document (API RP 2MET) and update these criteria based on additional data and better statistical tools [18].

2.2.4 Typical Metocean Criteria

Each operator had unique site-specific metocean criteria put in place for drilling through their production TTRs. Each of the three operators implement a maximum allowable offset while to help determine if conditions are appropriate for drilling operations. While other metocean conditions may affect the drilling conditions, offset is a good indicator of the overall environmental suitability as it is affected by wind, wave and current conditions.

Generally speaking, the dominant current seastates will determine riser operational limits subsea. The sea state which drives the maximum vessel offset will typically limit the topsides design. For any design or operation, a range of sea states should be looked at to provide a more complete picture of the metocean conditions likely to be experienced.

2.3 TYPICAL OPERATIONAL CRITERIA

2.3.1 General

The operational criteria operators use when drilling through a production TTR depends on several factors (such as location, time of year and length of operation) and is unique to each situation. There is no discernable difference in the approach to determine the appropriate criteria between drilling through production TTRs compared to traditional drilling risers.

2.3.2 Mud Weights

The mud weight in a well controls the hydrostatic pressure exerted onto the bottom of the hole and helps to prevent formation collapse and unwanted flow into the well. Mud weights are based on drilling requirements, such as the type of soil being drilled through and vary according to estimated formation pressures.

2.3.3 Reservoir Characteristics

2.3.3.1 Temperature/Pressure

Temperature and pressure characteristics are unique and vary from one well to the next. Drilling through a production TTR versus a dedicated drilling or workover riser has no effect on the temperature or pressure exerted by the well.

2.3.3.2 Vessel Offset

Vessel operating envelopes are based on the inclination in the riser. If the vessel offset is too large, the inclination in the risers will be too great, causing increased contact loads between the drill string and the riser walls. This scenario is undesirable as it leads to increased wear in the riser system.

3 FAILURE MODES

3.1 GENERAL

The second task carried out for the study was to compile a comprehensive list of all possible failure modes for production TTRs during workover operations.

Emphasis was placed on operations in which a surface BOP was deployed and drilling operations were carried out through a production TTR. Since many non-drilling workover operations are routinely carried out through the production risers, it was not deemed necessary to question operators on the frequency of occurrence of these operations.

The specification of failure modes has concentrated on the most susceptible modes to which the pipe and components may be subjected. Theoretically possible modes which are considered extremely unlikely have not been considered. The failure modes presented in this report are intended for use by operators of TTRs as an initial list to be refined by project-specific hazards as part of the process of developing an integrity management (IM) plan. Only failure modes that end in significant loss of fluid containment have been included. It is assumed that a small riser leak will deteriorate into complete riser separation or similar loss of fluid containment if left unmitigated.

3.2 FAILURE MODES FORMAT

To facilitate risk assessment and the identification of mitigation and integrity management measures, failure modes have been defined as the combination of each the following elements:

- **Failure Initiator**, the event or process that initiates a failure mode;
- **Failure Mechanism**, the sequence of stages after initiation which lead to ultimate structural failure (i.e. either rupture or leakage);
- **Potential Mitigation Measures**, typical options available to the operator to mitigate and reduce high risk;
- **Potential Design Uncertainties**, key 'unknowns' or uncertainties involved in the design of the riser and/or its components that may impact this failure mode.

Detailed knowledge of the initiator and each of the possible stages towards failure provides the operator with the option to specify corrective action at one or more stages prior to failure. A consistent approach to integrity assessment implies that potential failure modes which carry an unacceptable risk should be addressed by taking mitigation measures. The remaining failure modes are those typically addressed as part of an integrity management plan. IM Measures can be implemented with the purpose of detecting these critical stages.

Potential Design Uncertainties identify key design inputs that may affect the perceived risk. These uncertainties may be validated during the initial phase of a project, thereby reducing the perceived risk and eliminating future IM Measures.

3.3 CRITICAL FAILURE MODES

For sidetrack and redrilling, the most critical riser failure modes outside of typical production hazards included drilling-induced vibration fatigue, and riser wear from direct contact with the drill string. The risk associated with some typical production TTR hazards may also be affected by these operations. In particular, the potential for a kick causing excessive internal pressure to occur is greater during drilling operations than during production.

The failure modes list, though not exhaustive, is intended to include the most likely sources of a production TTR or component failure. Additional failure modes may, on occasion, be identified based on specific project conditions to which a TTR is likely to be exposed. For the purpose of risk assessment, such modes should be added to the list presented in this document prior to performing a project-specific risk assessment.

3.3.1 Drilling Induced Vibration

Drilling induced vibration (DIV) fatigue has only recently been brought to the attention of operators through observations made in the field. DIV occurs when the rotational speed of the drill string causes contact to occur with the riser in a pattern matching its natural frequency. As drilling continues, the entire riser begins oscillating, accelerating fatigue damage [**6**].

DIV is most likely to occur when drilling hard formations through a narrow annulus. A narrow annulus leaves less room for the drill string to vibrate before contact with the riser is initiated. Drilling through hard formations slows the rate of penetration and can help to trigger periodic oscillations of the drill string. As most production risers are significantly smaller in diameter than typical drilling risers, this phenomenon is of particular concern to operators considering drilling through their production risers. If gone unnoticed, drilling induced vibration fatigue damage can accrue rapidly resulting in a significant reduction in riser life or even complete failure of the riser [**6**].

3.3.2 Riser Wear

Riser wear was considered the most critical potential hazard by the majority of the GOM operators. For drilling risers, potential wear is mitigated by limiting allowable vessel offsets during drilling operations [3]. However, the acceptance criteria are contingent on the relatively short duration of service and the ability to perform thorough visual or UT inspection before and after operations. While there is a possibility of retrieving the inner casing string of a dual casing production TTR for UT inspection, detection of minor drilling wear while the TTR is in-place may be challenging, especially for risers with larger (>13in) inner diameter. Uncertainty in the contour of the worn surface and the ability to detect wear makes it critical to fully assess the risk associated with this hazard.

Wear of the riser casing could potentially be caused by a number of factors:

- Dents and gouging to riser casing while running the drill string, liner casing or any tool;
- Direct, abrasive contact between the drill string and riser casing during operations;
- Abrasion of the riser casing during rotary drilling through sandstone.

As most production riser annuli are narrower than the sizes typically used for drilling risers, the potential for contact between the drill string or conductor casing and the riser is higher, especially if weather conditions cause extreme facility offsets. Side loads within the riser or insufficient riser top tension can cause dog legs that rapidly increase wear in a localized section of the casing.

Wear may result in a localized reduction of wall thickness due to:

- Direct abrasive loss of riser material;
- Localized corrosion of gouges.

If left unmitigated, any reduction in wall thickness may lower the pressure rating of the riser or reduce its fatigue resistance [**15**].

3.4 FAILURE DRIVERS

Each failure mode has been categorized into one of several identified Failure Drivers to aid in identifying and presenting the various failure modes. These categories (such as fatigue or wear) identify the primary causes of pipe failure and organize them into groups. This document presents a list of failure modes, presented in terms of the *Failure Initiator* (the event or condition which begins the failure process) and the *Failure Mechanism* (the sequence of stages through to full failure) associated with each mode. Each potential failure mode is related to well intervention with emphasis on drilling operations. The following failure drivers are those into which failure modes have been categorized:

- Pressure
- Fatigue
- Corrosion
- Accidental damage

Failure modes are presented in Table 3.1 to Table 3.4 according to these Failure Drivers. Considerable overlap may exist between Failure Drivers. The Failure Drivers are simply the categories chosen for organizational purposes. Ultimately, organization of the failure modes is at the discretion of the user.

Table 3.1 Pressure Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	**Mode**	**Initiator**	**Mechanism**		
P001	Overpressure of riser casing during well interventions	Excessive internal pressure	1. Plastic straining 2. Pipe rupture	• Well pressure profile	• Allow for overpressure in design

Table 3.2 Fatigue Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	**Mode**	**Initiator**	**Mechanism**		
F001	Drilling-induced vibration fatigue of riser	Drill pipe rotational speed matches riser natural frequency	1. Resonance response of riser 2. Increased accumulated riser fatigue cycles 3. Reduced fatigue life 4. Fatigue failure	• Riser natural frequency • Drill pipe interaction with drilling fluid • Metocean conditions	• Adjust drill string weight on bit (WOB) • Adjust drill string rate of penetration (ROP) • Adjust drill string rotational speed • Allow drill string to unwind • Change drill bits • Use smaller drill pipe
F002	Drill pipe stress cycling fatigue of riser	Non-resonant response of riser due to drill pipe motion	1. Increased accumulated riser fatigue cycles 2. Fatigue failure	• Drill pipe interaction with drilling fluid • Metocean conditions	• Adjust drill string weight on bit (WOB) • Adjust drill string rate of penetration (ROP) • Adjust drill string rotational speed • Allow drill string to unwind • Change drill bits

Table 3.3 Corrosion Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	**Mode**	**Initiator**	**Mechanism**		
C001	Localized corrosion initiated by abrasion of riser walls from rotary drilling through sandstone (burst)	Rotational drilling through abrasive sandstone	1. Deep scratches or pits develop on riser 2. Severe localized corrosion 3. Reduction in localized wall thickness 4. Riser casing burst		• Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling
C002	Localized corrosion initiated by abrasion of riser walls from rotary drilling through sandstone (collapse)	Rotational drilling through abrasive sandstone	1. Deep scratches or pits develop on riser 2. Severe localized corrosion 3. Reduction in localized wall thickness 4. Riser casing collapse		• Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling
C003	Localized corrosion initiated by drill string abrasion of riser walls during drilling operations (burst)	Abrasive contact between riser and drill string during drilling operations	1. Localized corrosion 2. Reduction in localized wall thickness 3. Riser casing burst		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling
C004	Localized corrosion initiated by drill string abrasion of riser walls while running drill string (burst)	Abrasion of riser walls during running of drill string	1. Localized corrosion 2. Reduction in localized wall thickness 3. Riser casing burst		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling
C005	Localized corrosion initiated by drill string abrasion of riser walls during drilling operations (collapse)	Abrasive contact between riser and drill string during drilling operations	1. Localized corrosion 2. Reduction in localized wall thickness 3. Riser casing collapse		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling
C006	Localized corrosion initiated by drill string abrasion of riser walls while running drill string (collapse)	Abrasion of riser walls during running of drill string	1. Localized corrosion 2. Reduction in localized wall thickness 3. Riser casing collapse		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling

Table 3.4 Accidental Damage Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	**Mode**	**Initiator**	**Mechanism**		
AD001	Drill string abrasion of riser walls during drilling operations (burst)	Direct contact between riser and drill string during drilling operations	1. Reduction in localized wall thickness 2. Reduced structural capacity 3. Riser casing burst		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling
AD002	Drill string abrasion of riser walls during running (burst)	Abrasion of riser walls during running of drill string	1. Reduction in localized wall thickness 2. Reduced structural capacity 3. Riser casing burst		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling
AD003	Drill string abrasion of riser walls during drilling operations (collapse)	Direct contact between riser and drill string during drilling operations	1. Reduction in localized wall thickness 2. Reduced structural capacity 3. Riser casing collapse		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling
AD004	Drill string abrasion of riser walls during running (collapse)	Abrasion of riser walls during running of drill string	1. Reduction in localized wall thickness 2. Reduced structural capacity 3. Riser casing collapse		• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling
AD005	Riser clashing during drilling operations (burst)	Unexpected motion resulting in clashing	1. Impact with other riser or subsea component 2. Reduction in localized wall thickness 3. Reduced structural capacity 4. Riser casing burst		• Strict vessel offset envelopes • Strict metocean condition requirements

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	Mode	Initiator	Mechanism		
AD006	Riser clashing during drilling operations (collapse)	Unexpected motion resulting in clashing	1. Impact with other riser or subsea component 2. Reduction in localized wall thickness 3. Reduced structural capacity 4. Riser casing collapse		• Strict vessel offset envelopes • Strict metocean condition requirements

3.5 HAZARD IDENTIFICATION

The Failure Modes lists, though not exhaustive, are intended to include the most likely sources for riser failure. Additional Failure Modes may be identified through a hazard-identification (HAZID) process. These Failure Modes should be based on the application-specific project conditions an integrity group is likely to be exposed to. Such modes should be added to the list presented in this document prior to performing a project-specific risk assessment.

4 RISK ASSESSMENT METHODOLOGY

4.1 GENERAL

As part of the third task of this study, a risk assessment methodology is outlined for assessing the risks associated with well intervention operations performed through existing single or dual bore production TTRs. This methodology has been adapted from the methodology MCS developed from the SCRIM JIP in 2004-2008 and the Flexible Pipe Integrity JIP in 1995-97.

Following the methodology developed in the JIPs, an indexing analysis is recommended, with risk defined as the product of one score representing the probability of failure (Probability Index) and another representing the consequence of failure (Consequence Index). This relative risk is referred to as an Integrity Management Index (IMI). The IMI is used to guide the user towards recommending available integrity management (IM) strategies.

4.2 PROBABILITY INDEX (P)

The Probability Index, P, is defined as:

$$P = (P_0 + U)$$

Where

P_0 = Basic Probability Index

U = Uncertainty Index

The Basic Probability Index is defined to indicate the proximity of the system design to the allowable design code limit for the relevant Failure Mode. The Uncertainty Index captures all experience-based modifiers to the Basic Probability Index. In this way, risks associated with the how the system is designed are separated from risks inherent to uncertainties in design theory or application.

4.2.1 Basic Probability Index, P_0

The *Basic Probability Index*, P_0, is used to define the proximity of the system design to the allowable design code limit for the relevant *Failure Mode*. A progressive scale should be used to govern the selection of P_0, between the limits:

- Component is designed to operate below code allowable;
- Component is designed to operate at or near the code allowable.

The typical scale used for P_0 is shown in Table 4.1. This scale is not inclusive for all flexible pipe failure modes, such as those for temperature degradation. MCS follows detailed internal guidelines based on previous Joint Industry Projects (JIPs) and additional, corporate-specific guidelines we have authored. The criteria used to assess individual failure drivers will be included in the MCS risk assessment reports.

Table 4.1 Basic Probability Index Score

Rating	Description
1	Component operates below 95% code allowable
2	Component operates at or above 95% code allowable

Failure Modes where the design is far below the code allowable (i.e. $P_0 = 0$) are typically not analyzed, save where significant uncertainties exist. Any instance where the component operates above code allowable is assessed as an anomaly, and is accounted for under the *Uncertainty Index*.

Typically these operations are taken into account during the design phase of the riser system. If drilling operations have not been considered in the design phase, an engineering assessment may be required. Circumstances where drilling interventions are required more frequently than anticipated are taken into account in the *Uncertainty Index*.

4.2.2 Uncertainty Index, U

The *Uncertainty Index*, U, captures expert, experience-based modifiers to the *Basic Probability Index*. In order to maintain transparency in the risk assessment process, the *Uncertainty Index* has been further classified by indices:

- Technology Step-Out (TSO);
- Design Uncertainty (DU);

- Anomalies (A).

After assessing the level of uncertainty for each of these categories associated with a particular *Failure Mode*, the total probability modifier is calculated by a simple summation:

$$U = TSO + DU + A$$

Accordingly, the value of U is taken as zero if:

- The design represents a well-established technology with no new applications;
- All design uncertainties have been validated;
- No anomalies (in either system response or conditions) exist that may effect predicted behaviour.

The *Uncertainty Index* allows user expertise to quantify the uncertainty in design input or prediction of response. The index is an important asset to risk assessment accountability and transparency.

However, the effectiveness of the *Uncertainty Index* relies on the knowledge possessed by the developer of *IM Strategy*. In particular, since many of the responses to design inputs are highly nonlinear, DU and A can not be simply proportional to the ratio of the design input variability to corresponding response variability.

Thorough and well chosen Input Sensitivity Studies can provide useful assistance in understanding the effect of a critical design input's variability on response (e.g. wall thickness tolerances' effect on stress or fatigue life). For this reason, strong benefit is attributed to carefully choosing the Design Input Sensitivity Studies which should be performed during the design process.

4.2.2.1 Technology Step-Out, TSO

Technology Step-Outs account for the uncertainty associated with new applications of existing technology or new technology implemented. Some examples of these applications may include record-breaking water depths, extreme well pressures or temperatures, or new tensioning system designs.

The *Technology Step-Out Index* is intended to capture confidence in ability to identify the applicable hazards associated with an application, primarily based on previous experience.

Some key questions an engineer should ask when assessing whether the TTR system design, operations, environmental or site conditions warrant a TSO rating are:

- How often has this application been used or performed? (e.g. Company X has drilled through production TTRs for 4 other facilities at similar water depths and riser IDs.)
- Have similar applications been implemented that directly correlate to this application? (e.g. While the minimum production TTR ID that has been drilled through is 9.625", drilling rigs have used smaller casing diameters.)

4.2.2.2 Design Uncertainties, DU

Design Uncertainties reflect uncertainties concerning design basis input and/or analytical technique. Some typical design basis concerns include:

- Metocean criteria
- Current profiles
- Well fluid characteristics
- Soil stiffness
- Operational temperature / pressure
- Drag coefficients

Analytical uncertainties portray the limits of applicable theories or modelling techniques. One of the most prominent examples is vortex-induced vibration response. Other examples include flexible joint elastomer degradation and drilling induced vibration (DIV). Many common design uncertainties are list with associated Failure Modes

4.2.2.3 Anomalies, A

Anomalies reflect uncertainty concerning predicted behaviour due to some significant level of defect. Anomalies can occur at any stage of the system life. Significance is usually assessed based how the uncertainty may potentially effect the confidence in the prediction of future TTR response. In general, this may be determined by:

- Size of anomaly;
- Effect on code compliance.

Anomalies always require an Ad Hoc Engineering Assessment to determine their significance. Examples of anomalies include:

- Larger than anticipated riser wall thicknesses that were approved by the operator;
- Greater than anticipated fatigue damage accumulation due to riser hanging on tensioners during storm conditions;
- Damage to strakes during installation;
- Global as-installed configuration different from design configuration;
- Occurrence of extreme metocean conditions.

Anomaly limits define when an anomaly has occurred.

4.3 CONSEQUENCE INDEX (C)

The *Consequence Index*, C, is defined by a scale of increasing severity, which accounts for all safety, environmental and operational consequences of failure. Failure is always defined as the termination of the integrity group's ability to perform its required function. Whether a TTR is ruptured due to clashing with other risers or collapsed due to tensioner failure, the consequence scale used to assess the severity of failure remains the same.

There are several ways to account for the consequence associated with failure. It is common practice for companies to develop individual indices for each category; the Consequence Index is then determined either by selecting the most severe category index or by the summation of the category indices, depending on company philosophy. Other companies may develop a single consequence scale that includes all three categories. Any of the above methods can be tailored to emphasize corporate priorities (i.e. safety has a lower threshold for a high consequence rating).

MCS preference is to develop one consequence scale that includes all three categories. For most subsea systems, the safety consequence will typically be negligible, except in the case of a blowout. The environmental and operational consequences that drive the *Consequence Index* are potentially closely entwined.

4.3.1 Safety Consequence, C_S

Safety consequences consider potential impact on any population near the integrity group, typically in terms of injury and death. For subsea failure modes, these consequences may be broadly defined by proximity to a population. For example, if a riser leaks at the tieback connector, it will not likely cause a direct threat of injury or death to the personnel topside.

A typical scale is included in **Table 4.2.**

Table 4.2 Typical Safety Consequence Index Score

Rating	Description
0	No injury or illness
1	Personal injury requiring first aid and/or medical attention
2	Personal injury resulting in restricted work activities
3	Lost Time Injury / Illness (LTI)
4	Single fatality or serious personal injury/illness resulting in permanent disability
5	Multiple fatalities

4.3.2 Environmental Consequence, C_E

Environmental consequences only consider damage to the environment. These consequences refer to the ecological concerns, such as the possible impacts of failure on marine mammals, birds, fish and shellfish, and the natural habitats that support these resources. An Environmental Impact Assessment is a good resource for determining the environmental consequence. The environmental consequences are typically specified in terms of the type of resources required to isolate and/or remove the pollutant and volume of product released in the environment.

A typical scale is included in Table 4.3**.**

Table 4.3 Typical Environmental Consequence Index Score

Rating	Description
0	No environmental impact
1	Non-reportable spill or release contained within facility.
2	Reportable spill or release contained within facility, or small release not requiring activation of any remedial measures.
3	Reportable spill or release not contained within facility and requiring activation of facility's remedial actions or measures.
4	Reportable spill or release into water requiring activation of external measures. Regulatory restriction or enforcement action.
5	Reportable spill or release into water causing severe ecological impact. Direct impact on public. Prosecution.

4.3.3 Operational Consequence, C_O

Operational consequences consider the significant monetary costs associated with failure, specifically loss of operating capability. Typically, these are assessed in terms of shutdown time or reduction in overall productivity. Some factors to consider are:

- Value of lost production time
- Direct damage to facility and/or adjacent structures
- Repair costs to facility & riser
- Clean-up costs
- Penalties for project delay
- Fines or other punitive measures

A typical scale is included in Table 4.4.

Table 4.4 Typical Operational Consequence Index Score

Rating	Description		
0	No cost impact	**and**	No downtime
1	< $100,000 loss	**or**	< 1 hour downtime
2	$100,000 to $1,000,000 loss	**or**	≥ 1 hour but ≤ 1 shift downtime
3	$1,000,000 to $10,000,000 loss	**or**	> 1 shift but ≤ 5 days downtime
4	$10,000,000 to $75,000,000 loss	**or**	> 5 days but ≤ 30 days downtime
5	> $75,000,000 loss	**or**	> 30 days downtime

4.4 RISK MODIFIERS

Mitigation Measures are any action that will reduce risk, and help form the preliminary basis for any IM strategy. Mitigations always reduce the IMI, typically by modifying the Probability Index. These measures can be classified as either fabrication or strategical measures.

Fabrication measures require some sort of fabrication to implement, such as applying strakes to a TTR to mitigate VIV. While some of these measures can be implemented retroactively, many can only be added during the design phase. These typically modify the Basic Probability Index, Po.

Strategical measures emphasize IM measures that must be included in the IM strategy, such as requiring the use of fresh water during a hydrotest. Some of these broad measures might mitigate the Consequence Index. Most of these measures modify the Uncertainty Index, U.

Failure Modes which carry an unacceptable risk should be addressed by applying mitigation measures. However, a good integrity management strategy may sufficiently address Failure Modes with acceptable but high IMIs, or even manage risk for less critical Failure Modes so effectively that no mitigation is required. In this case, the most cost effective method (i.e. mitigation or integrity management strategy) should be applied. Any Failure Modes with high IMIs after mitigation should be specifically focused on as part of the detailed integrity management strategy.

4.5 INTEGRITY MANAGEMENT INDEX (IMI)

The integrity management index is defined as:

$$IMI = P \times C$$

Where

P = Probability index

C = Consequence index

This allows implementation across the industry and flexibility for different operators with different risk assessment approaches.

The value obtained from this calculation can now be used to choose from a variety of integrity techniques to ensure the continued and safe operation of the system.

5 INTEGRITY MANAGEMENT PLAN

5.1 INTEGRITY MANAGEMENT PLAN DEVELOPEMENT

5.1.1 General

Following a risk assessment of the top-tension riser system, each failure mode is assessed to determine the required level of integrity management. Four *Strategic Inspection Levels* (SILs) are identified to denote these integrity management levels. Combinations of IM measures are selected according to SIL. An IM strategy details how these measures are implemented for each failure mode, and form the basis of the IM Plan.

Performing drilling operations through any production TTR poses a critical hazard which must be addressed prior to the start of the operation. If the riser has not been designed to handle the additional fatigue and wear associated with drilling, then an engineering assessment should be completed to determine the riser's suitability. For risers not designed to be drilled through, mitigation measures such as wear sleeves and non-rotating protectors may be implemented to achieve an acceptable level of risk. Additionally, inspection and monitoring measures can help to detect warning signs of potential failure modes and allow operators to take action to prevent them.

5.1.2 Strategic Inspection Levels

Four *Strategic Inspection Levels* are used to relate the degree of required integrity management to the degree of risk identified for a particular failure mode. These levels are generically defined as:

1. **None:** Integrity management is not required for a particular failure mode;
2. **Basic:** Basic integrity management is required, typically based in part on regulatory requirements;
3. **Detective:** Detection of failure initiation or a critical stage in the failure mechanism is required;
4. **Predictive:** Integrity management measure must be capable of predicting the remaining life.

Realistically, all systems require some IM strategy. Each failure mode of an integrity group will have an individual SIL. As such, no system will have an SIL of *None* for all failure modes. It is also unlikely that a system will not require at least an SIL of *Basic* for all failure drivers.

Basic IM measures are typically put into place by operators by default. These measures are typically the baseline on which operators build upon if necessary.

Detective IM measures are put in place to detect when a failure mode is occurring. These are typically not included by default and are not able to predict ahead of time whether a critical failure mode will be initiated.

Predictive IM measures require either the direct monitoring of the progress towards failure or the assignment of a degradation model to failure. A failure degradation model analytically calculates the progress and the associated remaining time to failure, based on the input of measured data.

The typical IM Measures presented in Section 3 include each method's applicability to the different SILs. However, it is up to the judgment of the user to:

- Define the risk levels associated with each SIL;
- Categorize the SILs for each procurable measure;
- Assess where, when and how to implement the measures.

5.1.3 Integrity Management Measures

Several measures are available to maintain the integrity of a TTR. Based on the required *Strategic Inspection Level* for a particular failure mode, an integrity management strategy is selected from any combination of measures. For simplicity, these measures are identified under the following categories:

- Inspection Measures
- Monitoring Measures
- Analysis & Testing
- Operational Procedures

- Preventative Maintenance Measures
- Remedial Maintenance Measures

Broadly, inspection and monitoring measures refer to obtaining information about the system. Analysis & Testing (A&T) measures refer to how the information is assessed. Operational procedures, preventative maintenance measures and remedial maintenance measures refer to actions designed to prevent failure.

Inspection measures serve as periodic critical appraisals. Increasing frequency usually denotes increasing severity of risk. For subsea systems, inspection options may require innovation. In particular, subsea inspections are typically restricted to visual ROV / AUV limits.

Monitoring measures provide approximately continuous measurements of either environmental or structural conditions. Current sensor technology is capable of measuring and monitoring response extremely precisely and accurately, using a variety of different sensors and methods.

Analysis & Testing measures are designed to verify design assumptions and assess the impact of any variations. These measures include evaluation of monitoring and inspection equipment. Reanalysis of fatigue under monitored metocean conditions to determine the actual remaining life is a typical A&T measure.

Operational procedures establish specific guidelines to avoid the most common risk-critical situations during any planned operation. Some examples include abandonment & recovery procedures, lifting & handling procedures, and vessel exclusion zones. Common ad-hoc events are also addressed in these procedures, such as dropped object protocols.

Preventative maintenance measures are modifications to system components prior to an expected failure initiation or critical stage of failure mechanism. They are scheduled to prevent premature failure by servicing or replacing equipment to reduce wear and maintain optimal performance. Scouring marine growth, replacement of anodes, and recalibration of instrumentation are some examples. Manufacturer recommendations are a primary source for these measures.

Remedial maintenance measures are modifications to system components to address an unlikely failure initiation or critical stage of failure mechanism. For example, flexjoint degradation due to anomalously high temperature may require the flexjoint to be replaced. These measures are always initiated by an Ad-Hoc Engineering Assessment after some anomaly limit has been exceeded.

The IM measures feed into each other. Dropped object protocols should be included in Operational procedures. Following implementation of this procedure, additional monitoring or remedial maintenance measures may be required.

5.1.4 Integrity Management Plan

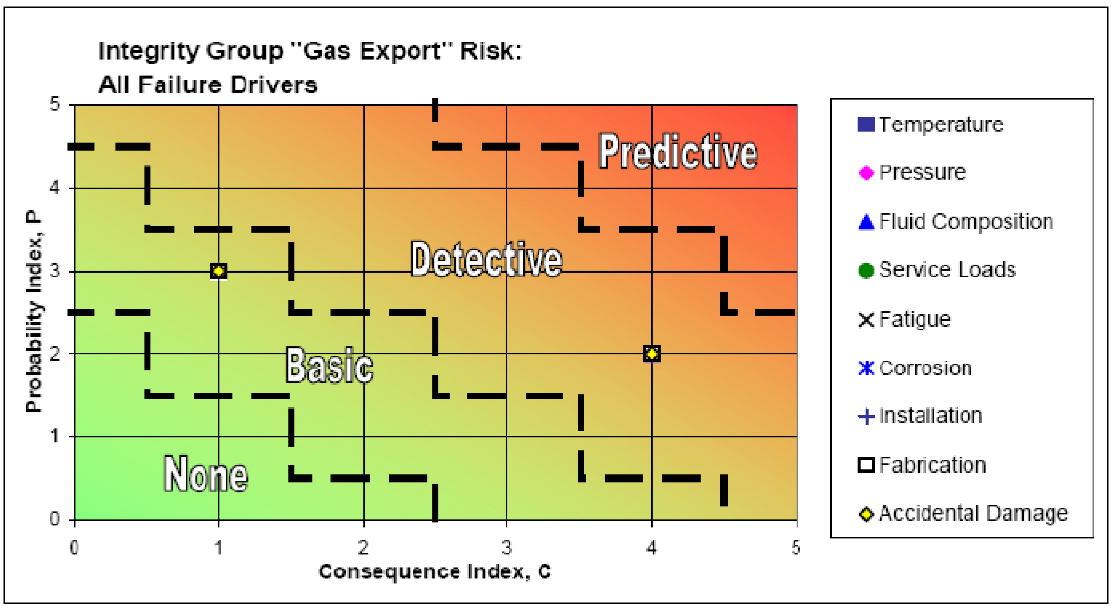
An IM plan is developed from the IM strategies, expressly detailing all IM measures with frequency of implementation and anomaly limits. A detailed description and schedule for at least one future integrity review should be included, although a schedule for several such reviews is not precluded.

A first-pass IM plan typically is developed during the design phase of a project, so that any IM measures requiring hardware can be incorporated into the design. Any significant alteration to the system or its operational conditions may require a reassessment of the risk assessment and IM plan.

A preliminary schedule and detailed procedure for at least the first integrity review are critical components of the IM plan.

Figure 5.1 below illustrates the *Strategic Inspection Levels* as they relate to probability of occurrence and consequence.

Figure 5.1 Example SILs as a Function of Probability and Consequence



5.2 MITIGATION MEASURES

5.2.1 General

Mitigation measures are any action that will reduce risk, and help form the preliminary basis for any IM strategy. Mitigations always reduce the risk rating, typically by modifying the probability index. These measures can be classified as either fabrication or strategic measures.

Fabrication measures require some sort of fabrication to implement, such as applying strakes to a TTR to mitigate VIV. While some of these measures can be implemented retroactively, many can only be added during the design phase. These typically modify the Basic Probability Index, Po.

Strategic measures emphasize IM measures that must be included in the IM strategy, such as requiring the use of fresh water during a hydrotest. Some of these broad measures might mitigate the Consequence Index. Most of these measures modify the Uncertainty Index.

Failure modes which carry an unacceptable risk should be addressed by applying mitigation measures. However, a good integrity management strategy may sufficiently address failure modes with acceptable but high risk, or even manage risk for less critical failure modes so effectively that no mitigation is required. In this case, the most cost effective method (i.e. mitigation or integrity management strategy) should be applied. Any failure modes with a high risk rating after mitigation should be specifically focused on as part of the detailed integrity management strategy.

5.2.2 Potential Mitigation Measures

Preventing drilling-induced vibration from occurring begins with monitoring the inclination, stress, acceleration, weight on bit (WOB), rate of penetration (ROP), rotary speed and any other variables for warning signs of harmonic motion. If DIV begins to occur, the WOB or RPMs can be adjusted to bring the riser out of its resonant frequency. Additionally, the drilling fluid density can be changed in order to redefine the natural frequency of the riser.

Non-rotating protectors are designed to maintain a stand-off between the drill pipe and the riser, consisting of a mud-lubricated inner liner connected rigidly to the drill pipe and a tough outer polymer sleeve that is free to rotate about the liner. By preventing the rotating drill string from directly contacting the riser, the risk of wear is minimized [20].

5.3 INTEGRITY MANAGEMENT MEASURES

5.3.1 General

As part of the fourth task of this study, an integrity management strategy is outlined for addressing the risks associated with well intervention operations performed through existing single or dual bore production TTRs. This strategy has been adapted from the methodology MCS developed from the SCRIM JIP in 2004-2008 and the Flexible Pipe Integrity JIP in 1995-1997.

This section will focus primarily on the potential mitigation measures and remedial actions that can be taken in order to reduce the risks identified in the risk assessment portion of this study. Vendors of equipment and services that assist in risk reduction relating to the scope of this project were consulted in order to evaluate the various techniques currently available in the industry.

5.3.2 Inspections

5.3.2.1 Inspection Methods Available

Inspection techniques and methods can be simplified into some basic groups:

1. Metal loss due to erosion or corrosion

2. Crack detection

3. Optical/visual inspections

Within these groups there are several different inspection methods available. There is a significant amount of overlap between these inspection techniques. Visual inspections may be carried out by an ROV surveying the length of the riser. Caliper logs may be taken before and after drilling in order to monitor the wall thickness of the riser. If necessary, the riser can be pulled and tested more accurately using ultrasonic or other non-destructive testing methods. Pulling the riser however, is very costly, and operators tend to avoid this route if at all possible.

5.3.3 Monitoring systems

5.3.3.1 Monitoring Systems Available

Current techniques and instrumentation are capable of accurately measuring and monitoring the following quantities:

- Acceleration
- Inclination
- Stress / Strain
- Corrosion
- Crack Growth
- Current profile
- Temperature
- Pressure

Monitoring systems will consist of all or most of the following components;

1. Sensor: Detects the measurand of interest
2. Transducer: Converts the measurand into a usable signal
3. Signal Conditioner: Makes signal suitable for transmission or interfacing
4. Transmission: Transmits this signal to the Data AcQuisition system (DAQ)
5. DAQ: Converts the signal into a digital signal for analysis and storage
6. PC: Data storage
7. Power Supply: Power requirements for sensors

Typical commercially available monitoring systems may be described as:

- Vortex Induced Vibration monitoring systems

- Stress monitoring systems
- Metal loss – corrosion and erosion
- Pressure and temperature

A description of these systems and how they can be adapted for use in monitoring for specific risks associated with well intervention operations performed through existing production TTRs is presented in the following sections.

5.3.3.2 Real-Time versus Post-Processed Data

In certain situations real-time data is necessary and useful to an operator, particularly when monitoring a riser during drilling operations. Examples of this data include vessel position and offset and riser top tension. In other situations the availability of real-time data, is of little use to an operator. An example of this may be Vortex Induced Vibration (VIV) measurements. The fact that the riser may be vibrating is of little concern to an operator, however, the more useful application of this data is in post processing to reveal accumulated fatigue damage or riser response.

This distinction can be drawn for most of the monitoring technologies, and can be considered an influential factor in the design and specifications of any monitoring system. The requirement for real-time data will influence other factors in the design of a monitoring system, by determining the requirements for data transmission and analysis. Real-time data is considered to be more pertinent for drilling applications as it is a short term operation when compared to the overall design life of the riser.

5.3.3.3 Stress Monitoring

Drilling through a production TTR may introduce additional stresses into the riser. To this end, it is important to know the load being applied to the riser during these operations, in particular in the regions that are the most susceptible to fatigue damage (i.e. at the keel and subsea equipment interface locations).

At the topsides, the top tension, inclination, and the bending moments are relatively easily monitored due to the accessibility and location of this region. From this data alone, it may be possible to ensure that the riser is within the design limitations by extrapolating along the length of the riser.

The technology involved in stress monitoring packages is well defined and relatively simple. The application of this technology to the offshore environment is far more complex. Monitoring packages to date have had limited application and have been of limited use (i.e. continuous monitoring to ensure riser integrity or conformation of design assumptions).

At topsides, top tension can be measured by conventional metallic strain gauges, fibre optic strain gauges, LVDTs or even a load cell. Using the correct configuration strain gauges could also be used to measure bending stresses and hence bending moments. An inclinometer can be used to measure the inclination of the riser. This technology is available and the way to provide accurate and long term data is well established.

5.3.3.4 VIV/DIV Monitoring

The VIV phenomenon is one of the main design considerations for deep water riser design. Drilling Induced Vibration (DIV) is emerging as a major concern particularly when drilling through small diameter production TTRs. DIV occurs when the rotational speed of the drill string causes contact to occur with the riser in a pattern matching its natural frequency. As drilling continues, the entire riser begins oscillating, accelerating fatigue damage [**6**].

VIV monitoring systems typically concentrate on measuring acceleration (accelerometer), inclination (inclinometer), and stress/strain. The inclinometer is a good measure of the low frequency motions caused by the vessel motion and the accelerometer is ideal for picking up the higher frequency motions caused by VIV. It is possible to determine the displacement/curvature of the riser from analysis of these measurements. This can then be compared with the modal analysis performed during design.

Direct measurements of acceleration have been the most common technique employed to measure vibrations. Another more direct method is to monitor strain over time and directly determine the curvature of the structure. The advantage in using accelerometers is that they do not require intimate contact with the pipe surface.

The same types of monitoring systems used to detect VIV can potentially be implemented in order to detect whether or not DIV is occurring during drilling operations as well. In addition, operators should monitor drilling conditions such as the weight on bit (WOB), rate of penetration (ROP), and rotary speed for warning signs of DIV throughout drilling operations.

5.3.3.5 Corrosion and Erosion

During drilling operations, wear of the riser casing due to contact with the drill string is considered by most operators to be the biggest threat to riser failure. After drilling operations have ceased, the likelihood of corrosion leading to riser failure could be increased from scratches and wear.

Throughout the drilling process, ditch magnets can be utilized to check for metal shavings returned to the surface with the drilling fluid. To minimize potential wear to the riser, non-rotating protectors can be attached along the drill string. After drilling has ceased the use of a combination of corrosion assessment techniques is advisable in order to minimise the disadvantages/limitations of individual techniques (when used in isolation). The following is a list of possible metal loss monitoring or inspection techniques:

- General Visual Inspection
- Close Visual Inspection
- Internal monitoring of fluid composition (erosion/corrosion of a sample)
- Ultrasonic, radiographic inspection

5.3.3.6 Other Monitoring Techniques

Several other well defined monitoring techniques of interest as part of an integrity management strategy are:

- Vessel motions:
    - Vessel location (GPS)
    - Vessel motion (combination of accelerometers and gyroscopes)
- Environmental Data:
    - Wave monitoring (instrumented bouys)
    - Full water column current measurements (ADCP or other water velocity measurement devices)
    - Wind speed

- Temperature and Pressure
  - Well established technology
  - Combined with various other sensors (e.g. Corrosion/erosion probe)
  - Use of fibre optic sensors to monitor internal pressure and temperature
- Annulus monitoring to detect leaks
- Monitoring of drilling returns for metal shavings

Most of these techniques are already well defined and understood and have been developed for other engineering and scientific fields. These techniques aid in an integrity management strategy but are outside of the scope of riser monitoring and inspection.

5.3.4 Integrity Management Techniques

Table 5-1 below lists the most probable failure modes along with mitigation techniques that can be implemented.

Table 5-1 Typical Integrity Management Techniques

ID	Failure Mode	Techniques	Strategic Inspection Level		
			Basic	Detective	Predictive
P001	Overpressure of riser casing during well interventions	Pressure monitoring	X	X	
F001	Drilling-induced vibration fatigue of riser	Inclination monitoring		X	X
		Acceleration monitoring		X	X
		Stress monitoring		X	X
		WOB, ROP, and RPM monitoring/adjusting	X	X	X
F002	Drill pipe stress cycling fatigue of riser	Inclination monitoring		X	X
		Acceleration monitoring		X	X
		Stress/strain monitoring		X	X
		WOB, ROP, and RPM monitoring/adjusting	X	X	X
C001	Localized corrosion initiated by abrasion of riser walls from rotary drilling through sandstone (burst)	Corrosion monitoring	X	X	X
		Pressure monitoring	X	X	X
		Stress monitoring		X	X
		Temperature monitoring	X	X	X
C002	Localized corrosion initiated by abrasion of riser walls from rotary drilling through sandstone (collapse)	Corrosion monitoring	X	X	X
		Pressure monitoring	X	X	X
		Stress monitoring		X	X
		Temperature monitoring	X	X	X
C003	Localized corrosion initiated by drill string abrasion of riser walls during drilling operations (burst)	GVI / Close Visual Inspection	X	X	X
		Corrosion monitoring	X	X	X
		Pressure monitoring	X	X	X
		Stress monitoring		X	X
		Temperature monitoring	X	X	X
C004	Localized corrosion initiated by drill string	General / Close Visual Inspection	X	X	X

ID	Failure Mode	Techniques	Strategic Inspection Level		
			Basic	Detective	Predictive
	abrasion of riser walls while running drill string (burst)	Corrosion monitoring	X	X	X
		Pressure monitoring	X	X	X
		Stress monitoring		X	X
		Temperature monitoring	X	X	X
C005	Localized corrosion initiated by drill string abrasion of riser walls during drilling operations (collapse)	General / Close Visual Inspection	X	X	X
		Corrosion monitoring	X	X	X
		Pressure monitoring	X	X	X
		Stress monitoring		X	X
		Temperature monitoring	X	X	X
C006	Localized corrosion initiated by drill string abrasion of riser walls while running drill string (collapse)	General / Close Visual Inspection	X	X	X
		Corrosion monitoring	X	X	X
		Pressure monitoring	X	X	X
		Stress monitoring		X	X
		Temperature monitoring	X	X	X
AD001	Drill string abrasion of riser walls during drilling operations (burst)	General / Close Visual Inspection	X	X	X
AD002	Drill string abrasion of riser walls during running (burst)	General / Close Visual Inspection	X	X	X
AD003	Drill string abrasion of riser walls during drilling operations (collapse)	General / Close Visual Inspection	X	X	X
AD004	Drill string abrasion of riser walls during running (collapse)	General / Close Visual Inspection	X	X	X

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APPENDIX A

Sample Survey

QUESTIONNAIRE Workover Operations			
Client:	MMS	**Date:**	28th Feb 2008
Project:	MMS TAR & P	**Job No.**	4-1-4-319
Completed by:		**Received:**	
Representing:			
Distribution:	File	**Doc. No.**	QST-XX Rev.01

Background

On behalf of the MMS, MCS is investigating the cause and probability of potential riser failures when workover operations are performed through existing single or dual bore production risers. As part of this investigation, MCS is performing an industry and literature survey of current practices in the Gulf of Mexico regarding these workover operations. Any information provided may be incorporated into a public domain report for the MMS.

Questions

1 DRILLING CAPABILITIES

Which of your facilities has a dedicated drilling riser?

Facility	Yes	No
	☐	☐
	☐	☐
	☐	☐
	☐	☐
	☐	☐
	☐	☐

Which of your facilities have the capability to drill through your production TTR?

Facility	Yes	No
	☐	☐
	☐	☐
	☐	☐
	☐	☐
	☐	☐
	☐	☐

	Questions			
2	**HISTORY & CRITERIA**			
	Which facilities have you drilled through your production TTR? How often?			
	Facility	Yes	No	#
		☐	☐	
		☐	☐	
		☐	☐	
		☐	☐	
		☐	☐	
		☐	☐	
	What operational criteria do you require to drill through your production TTR?			
3	**ISSUES**			
	What have been your primary concerns about drilling through your production TTR?			
	How did you address these concerns, or what measures have you taken to ensure the integrity of your riser?			

APPENDIX B

Case Study

B.1 OVERVIEW

This study addresses the risk assessment of a hypothetical established production top-tensioned riser located on a TLP facility in the Gulf of Mexico with regards to the hazards posed by redrill activities.

B.2 SYSTEM DESCRIPTION

In this hypothetical case study, an operator is seeking to drill into a hard formation through a single casing top-tensioned production riser with a small diameter. The riser has been in service for 15 years of its 20 year design life; it has been previously drilled through in year 5 with some wear noted by examining the drilling fluid returns for metal shavings. The riser terminates at a TLP platform in 3,000 ft of water and has a corrosion allowance of 3/16". Corrosion coupons were not installed onto the riser and no drilling-induced vibration analysis has been done to date.

B.3 APPLICABLE FAILURE MODES

Pressure related failure modes are deemed significant for this system, as there is only a single barrier between the production fluids and the environment. The possibility for wear has substantial potential impact on these modes; further reduction in wall thickness beyond the wear already noted and anticipated corrosion loss may result in significant loss in pipe structural capacity.

Drilling-induced vibration is another potential failure mode that should not be overlooked. Due to the riser's small diameter, there will be a narrow drilling annulus, which leaves less room for the drill string to vibrate before contact with the riser is initiated. Since the operator will be drilling through a hard formation, the rate of penetration will be slow which can lead to periodic oscillations within the riser.

Table B.1 lists all of the failure modes applicable to this case study.

B.4 INTEGRITY MANAGEMENT INDEX RATING

B.4.1 Safety Consequence, C_S

During drilling operations, the likelihood of a blowout is increased when compared to non-drilling activities. A blowout could easily cause loss of life to multiple people if it was to occur and thus a consequence index value of 5 is assigned during drilling operations. Subsequently, after drilling operations have ceased and production resumes, the most likely failure modes involve riser burst below the waterline. Thus, there would not be a direct threat of injury or death as a result of the failure and a consequence index value of 2 is assigned. For the purposes of this study the safety consequence rating will be based upon failure occurring after drilling activities have completed.

B.4.2 Environmental Consequence, C_E

During drilling operations, if the riser were to fail to maintain its structural integrity, there would be no way to quickly shut in the well due to the lack of a subsea BOP or seabed isolation device. During a blowout event, the surface BOP would be activated but nothing could be done quickly to prevent the uncontrolled flow of hydrocarbons from the well into the environment. Therefore, an environmental consequence index rating of 5 is assigned for any failure modes that potentially fail during drilling operations. During production operations, a failure of the riser could still release a large quantity of hydrocarbons into the environment. However, the flow of hydrocarbons could be cut off as soon as the riser failure was detected. The environmental impact should therefore be kept to a minimum with a corresponding Consequence Index value of 3.

B.4.3 Operational Consequence, C_O

The implications involved in a production riser failing can be substantial. For this case, the riser would need to be replaced at a large cost to the operator. Then, there is the additional cost of lost production during the time leading up to and including installation of the replacement riser. The cleanup costs and fines should be minimal assuming there were not multiple system failures. The operating consequence index value for is thus a 3 for this case.

B.4.4 Probability Index (P)

Since the original riser design did not consider drilling conditions during fatigue calculations, a basic probability index of 2 is assigned.

This particular riser has been drilled through before, so the operator does have experience with this operation and thus there is no technology step-out. The wear that occurred during the first drilling operation is considered to be an anomaly which adds a value of 1 to the uncertainty index. Since corrosion coupons are not present along the riser, the corrosion damage along the riser is left as an uncertainty. Additionally, the riser's inclination towards drilling induced vibration is not fully understood. These uncertainties add an additional value of 1 to the uncertainty index. The uncertainty index values combined with the basic probability index value bring the overall probability index value to 4.

B.4.5 Integrity Management Index (IMI)

The integrity management index is defined as:

IMI = P x C = 3 x 4 = 12

Where

P = Probability index

C = Maximum Consequence index

The maximum consequence value of 3 with a corresponding probability index value of 4 produces an integrity management index value of 12 for this case. This value requires mitigating measures to reduce the probability of occurrence when economically feasible.

B.5 POTENTIAL MITIGATION MEASURES

For this example a full riser inspection is recommended after completion of drilling operations. Additionally, a detailed wear log should be taken throughout the drilling process. Non-rotating protectors should be installed along the length of the drill pipe in order to minimize any additional wear.

The inclination and vibrations of the riser should be closely monitored throughout drilling to check for signs of harmonic motion. If drilling-induced vibration does begin to occur, then the weight-on-bit, rate of penetration, and rpm's should be adjusted appropriately until the vibration subsides. Additionally, if the problem persists, adjusting the drilling fluid density will change the natural frequency of the riser and thus prevent harmonic motion.

Table B.1 Case Study: Applicable Failure Modes

Failure				Mitigation Implemented	Probability Index, P						Consequence Index, C				IMI
					P_o	Uncertainty Index, U				P	C_S	C_E	C_O	C	
ID	Mode	Initiator	Mechanism			TSO	DU	A	U						
P001	Overpressure of riser casing during well interventions	Excessive internal pressure	3. Plastic straining 4. Pipe rupture	• Allow for overpressure in design	2		1	1	1	4	2	5	3	5	20
F001	Drilling-induced vibration fatigue of riser	Drill pipe rotational speed matches riser natural frequency	5. Resonance response of riser 6. Increased accumulated riser fatigue cycles 7. Reduced fatigue life 8. Fatigue failure	• Adjust drill string weight on bit (WOB) • Adjust drill string rate of penetration (ROP) • Adjust drill string rotational speed • Allow drill string to unwind • Change drill bits • Use smaller drill pipe	2		1	1	2	4	2	3	3	3	12

Failure				Mitigation Implemented	Probability Index, P						Consequence Index, C				IMI
					P_o	Uncertainty Index, U				P	C_S	C_E	C_O	C	
ID	Mode	Initiator	Mechanism			TSO	DU	A	U						
F002	Drill pipe stress cycling fatigue of riser	Non-resonant response of riser due to drill pipe motion	3. Increased accumulated riser fatigue cycles 4. Fatigue failure	• Adjust drill string weight on bit (WOB) • Adjust drill string rate of penetration (ROP) • Adjust drill string rotational speed • Allow drill string to unwind • Change drill bits	2		1	1	2	4	2	3	3	3	12
C003	Localized corrosion initiated by drill string abrasion of riser walls during drilling operations (burst)	Abrasive contact between riser and drill string during drilling operations	4. Localized corrosion 5. Reduction in localized wall thickness 6. Riser casing burst	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling	2		1	1	2	4	2	3	3	3	12

Failure				Mitigation Implemented	Probability Index, P						Consequence Index, C				IMI
					P_o	Uncertainty Index, U				P	C_S	C_E	C_O	C	
ID	Mode	Initiator	Mechanism			TSO	DU	A	U						
C004	Localized corrosion initiated by drill string abrasion of riser walls while running drill string (burst)	Abrasion of riser walls during running of drill string	4. Localized corrosion 5. Reduction in localized wall thickness 6. Riser casing burst	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling	2		1	1	2	4	2	3	3	3	12
C005	Localized corrosion initiated by drill string abrasion of riser walls during drilling operations (collapse)	Abrasive contact between riser and drill string during drilling operations	4. Localized corrosion 5. Reduction in localized wall thickness 6. Riser casing collapse	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling	2		1	1	2	4	2	3	3	3	12
C006	Localized corrosion initiated by drill string abrasion of riser walls while running drill string (collapse)	Abrasion of riser walls during running of drill string	4. Localized corrosion 5. Reduction in localized wall thickness 6. Riser casing collapse	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling	2		1	1	2	4	2	3	3	3	12

Failure				Mitigation Implemented	Probability Index, P						Consequence Index, C				IMI
					P_o	Uncertainty Index, U				P	C_S	C_E	C_O	C	
ID	Mode	Initiator	Mechanism			TSO	DU	A	U						
AD001	Drill string abrasion of riser walls during drilling operations (burst)	Direct contact between riser and drill string during drilling operations	4. Reduction in localized wall thickness 5. Reduced structural capacity 6. Riser casing burst	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling	1		1	1	2	3	2	3	3	3	9
AD002	Drill string abrasion of riser walls during running (burst)	Abrasion of riser walls during running of drill string	4. Reduction in localized wall thickness 5. Reduced structural capacity 6. Riser casing burst	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling	1		1	1	2	3	2	3	3	3	9

Failure				Mitigation Implemented	Probability Index, P						Consequence Index, C				IMI
					P_o	Uncertainty Index, U				P	C_S	C_E	C_O	C	
ID	Mode	Initiator	Mechanism			TSO	DU	A	U						
AD003	Drill string abrasion of riser walls during drilling operations (collapse)	Direct contact between riser and drill string during drilling operations	4. Reduction in localized wall thickness 5. Reduced structural capacity 6. Riser casing collapse	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Monitoring of drilling mud return for metal shavings • Multifinger caliper tool inspection of riser casing post-drilling	1		1	1	2	3	2	3	3	3	9
AD004	Drill string abrasion of riser walls during running (collapse)	Abrasion of riser walls during running of drill string	4. Reduction in localized wall thickness 5. Reduced structural capacity 6. Riser casing collapse	• Strict vessel offset envelopes • Use of non-rotating protectors/ centralizers • Multifinger caliper tool inspection of riser casing post-drilling	1		1	1	2	3	2	3	3	3	9