Transocean

Title:

PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES MANUAL

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Transocean

SMART REVIEW

NONCONTROLLED

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GENERAL

INTRODUCTION

The purpose of the company's management system (CMS) is to define and communicate company leadership's values, beliefs and expectations. This provides direction so that people can align their efforts and determine the best methods to achieve the desired result.

The CMS establishes consistent performance standards across the company's worldwide operation. It describes processes for monitoring results, improving performance, and capturing and sharing lessons learned. This provides people with the opportunity to align their understanding of expectations, make personal commitments, and to apply their efforts to meet performance standards.

The CMS includes performance standards established at all three levels: Level 1 – Corporate, Level 2 – Division, and Level 3 – Installation.

This manual represents a Level 1A document within the CMS. The purpose is to communicate the Performance and Operations group performance standards. The Vice President Performance and Operations is the designated owner of this document and is responsible for its content and implementation.

Recommended changes to the procedures in this manual are submitted to Quality Services through the SMART process, (see HQS-CMS-GOV, in Section 5.1). The SMART (System Management and Review Team) process enables people at different levels in the Company (Corporate, Division and Installation) to propose and implement changes to the Company Management System through the individual Core Management Functions.

The relationship between this manual and the other Management System documents is found in the Company Management System Manual, HQS-CMS-GOV, in Section 5.2.

This document contains acronyms that describe the action to be applied for each responsibility requirement. The definition of these action acronyms is in the following key:

IM	Implement and Monitor: Put into effect an operational requirement and keep under observation to regulate or control
PM	Perform and Monitor: Carry out individually or with a crew, an operational requirement and keep under observation to regulate or control
V	Verify: Check to make sure that an operational requirement is accurately carried out by independent confirmation

GENERAL

THE PERFORMANCE AND OPERATIONS GROUP FUNCTION

The HQS Performance and Operations Group are comprised of three support functions, Performance and Operations, Well Operations, and Technology. The combined group, which forms part of the Company's management organizations, is responsible for providing a world-wide approach to rig and well operations which promotes a safe performance culture, and contributes to supporting field operations to deliver both premier and preferred service to our Customers. This level 1A manual details specifically, the Policies and Procedures relative to Performance and Operations which supports day to day field operations.

The key roles of Performance and Operations are:

- Provide installation performance and operations management support to field operations to ensure effective Customer service delivery and safe rig and well operations.
- Ensure performance planning and measurements define key performance drivers to enable both the asset and performance organizations to optimize rig and well operation processes and performance results.
- Proactively benchmark performance to search and identify new ideas, methods, best practices and processes, which are either adopted or the best features adapted and then implemented to improve safe performance, and achieve operational excellence.
- Ensure appropriate operation risk management methods and requirements are proactively applied with Customers to prevent and mitigate potential risk of personal and organizational errors, to achieve effective rig and well operation integrity management.
- In conjunction with the Asset organization, collaboratively support operational oversight for critical rig operation and maintenance activities to ensure operations are effectively risk assessed and managed, and that reliability (Asset – Engineering), maintainability (Asset – Maintenance) and operability (Performance and Operations) performance aspects are considered and aligned to achieve effective rig and well operation integrity management.
- Translate field experience into key competencies and operational training content to ensure effective training supports rig and well operation integrity management and strategic performance objectives.
- Coordinate the development, review, and approval of relevant rig operation policies, procedures, standards, with Divisions, Installations and other Corporate Departments.

- Participate in global operations staffing decisions to ensure consistency with company expectations, activity levels, and objectives.
- Participate in the review and optimization of the field operating organization and other departments to ensure key Customer interfaces and organizational efficiencies are prioritized.

The key roles of Well Operations are:

- Provide well operations planning and well construction management support to field operations to ensure effective Customer service delivery and safe rig and well operations.
- Identify the necessary well operation competencies, training content and resources for operation personnel which support the strategic performance objectives.
- Coordinate the development, review, and approval of relevant well operation policies, procedures, standards, and recommended practices with unit, divisions and other corporate departments.
- Establish operation risk management requirements to be applied to prevent personnel and organizational errors to reduce well operation risks and ensure effective rig and well operation integrity management.
- Review well design, well construction, and well control performance to ensure safe and efficient well operations.
- Provide support to in-house and Customer well technology initiatives.
- Optimize well planning by ensuring company policy and procedures related to well operations safely and effectively supports the execution of Customer well programs.
- Promote well operation efficiency by making assessments of well operations and verification of compliance with Corporate Operations policies and procedures.

The key roles of Technology are:

- Provide the Performance and Operations Group a technology watch focal point.
- Foster collaboration to identify and implement innovative and new technology.
- Evaluate new drilling and rig technology to enhance the company's existing fleet and influence future rig design.
- Provide Company representation in industry forums and conferences.

GENERAL

PERFORMANCE AND OPERATIONS GROUP ORGANIZATION, ROLES AND RESPONSIBILITIES

1 DEPARTMENT ORGANIZATION

The Executive Vice President, Chief Operating Officer (COO), is responsible for the performance of the Performance and Operations Group. The Vice President Performance and Operations is authorized to establish the policies and procedures and to ensure they are communicated and implemented effectively. They have the responsibility to monitor performance and identify corrective and improvement opportunities and to ensure actions are followed up and completed.

2 ROLES AND RESPONSIBILITIES

The responsibilities for Performance and Operations Group are summarized below:

2.1 PRESIDENT AND CHIEF EXECUTIVE OFFICER (CEO)

The President and Chief Executive Officer (CEO) is responsible for safe and efficient operations and the financial performance of the Company and the following operational considerations:

- Assure that the value placed on safety in operations is never compromised at the highest level of the Company.
- Final approval of the necessary resources to maintain and improve the Company's operations.

The President and Chief Executive Officer (CEO) reports directly to the Board of Directors.

2.2 EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER (COO)

The Executive Vice President and Chief Operating Officer (COO) is responsible for safe, efficient operations and financial performance for operations and the following operational considerations:

- Ensure implementation of operating policies and procedures of the Company.
- Assist the Marketing Department with contracts that support Company operating policies, procedures and philosophies.

- Assist in the establishment of annual worldwide operating objectives and goals.
- Actively support and recognize the efforts of personnel.

The Executive Vice President and Chief Operating Officer (COO) reports directly to the President and Chief Executive Officer (CEO).

2.3 VICE PRESIDENT PERFORMANCE AND OPERATIONS

The Vice President Performance and Operations is responsible for the safe, efficient operations and financial performance of activities worldwide and for the following operational considerations:

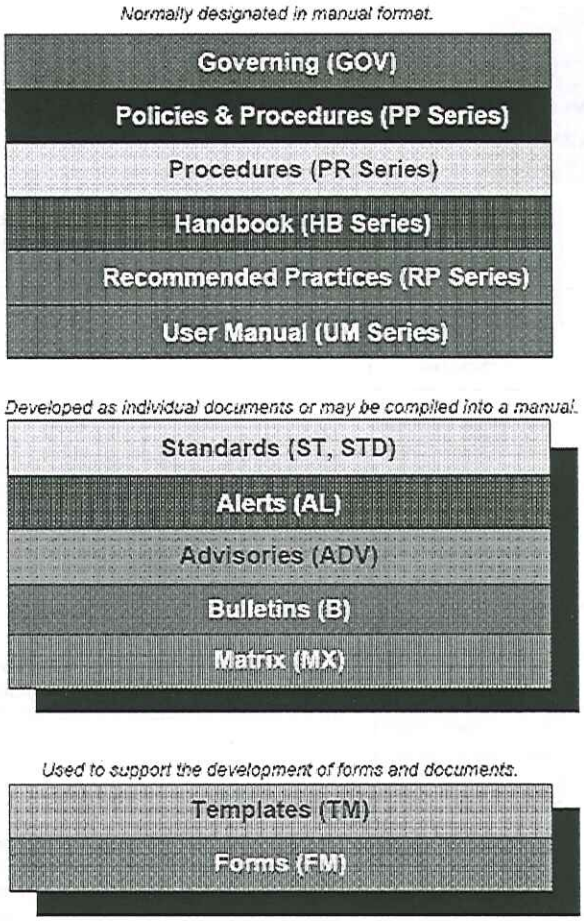
- Review and preliminary approval of relevant Company level 1A operating policies, procedures and related documentation applicable to world wide operations.
- Review and approval of relevant Company level 1B operating policies, procedures and related documentation applicable to world wide operations.
- Ensure a consistent approach to performance measurement, monitoring, and improvement across all operations.
- Oversee the identification and review of new technology for potential application on Company installations.
- Oversee global project management and integrated service activities offering innovative technical and commercial solutions.
- Monitor and assess the performance of key projects and operations to ensure achievement of objectives.
- Monitor and implement operating policies and procedures worldwide.

The Vice President Performance and Operations reports directly to the Executive Vice President and COO.

1 DOCUMENT ORGANIZATION

The manual and document type identifiers that are used by Performance and Operations are displayed below in Figure 1.4.1.

Figure 1.4.1, Manual and Document Type and Identifiers



2 DOCUMENT DESCRIPTION

Each manual and document shown in Figure 1.4.2 is accompanied by a brief description. The description includes a summary of the content and, in the case of supporting manuals, a reference to the policy(s) supported.

Figure 1.4.2, Performance and Operations Document Organization Chart

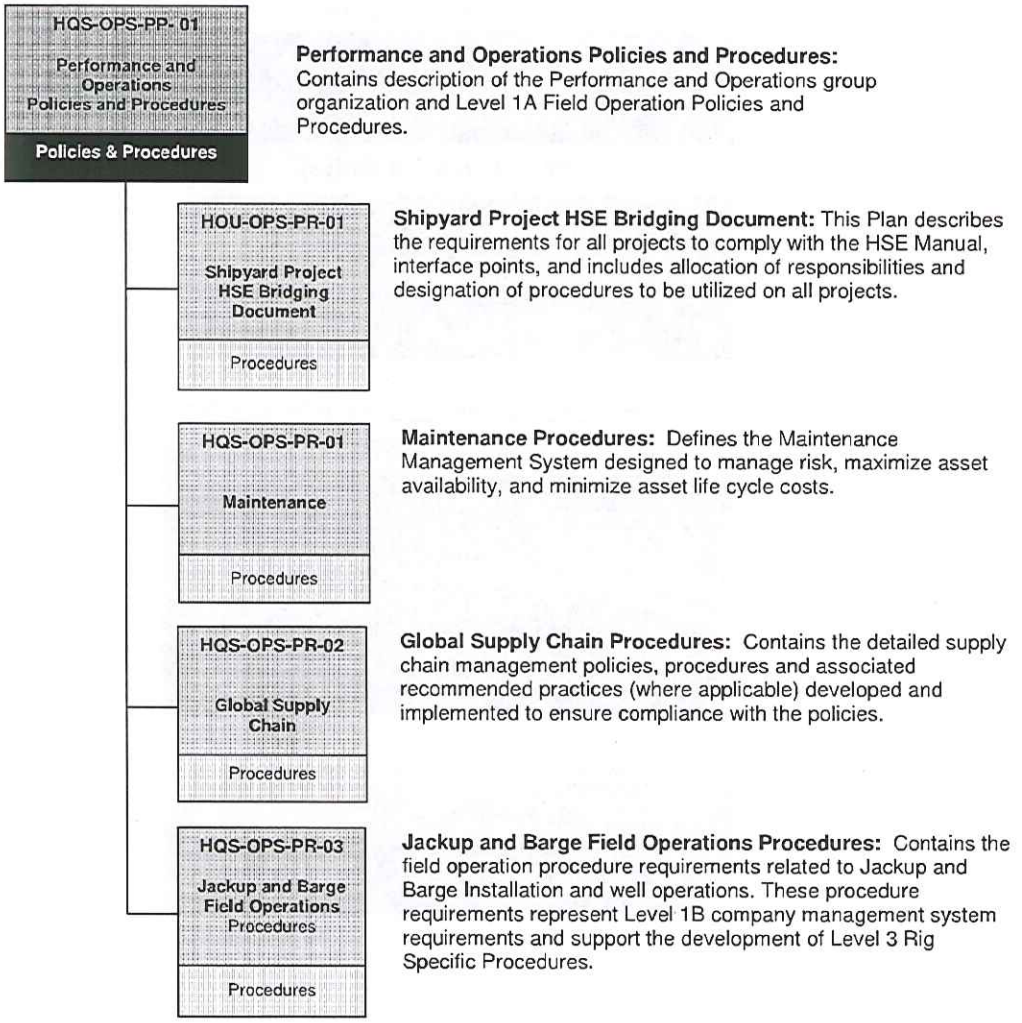
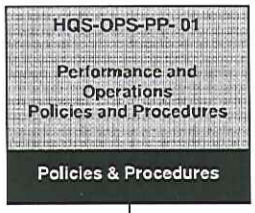
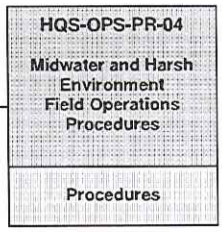


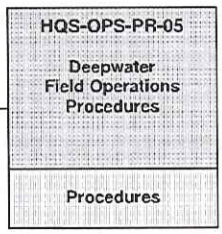
Figure 1.4.2, Performance and Operations Document Organization Chart (continued)



Performance and Operations Policies and Procedures: Contains description of the Performance and Operations group organization and Level 1A Field Operation Policies and Procedures.

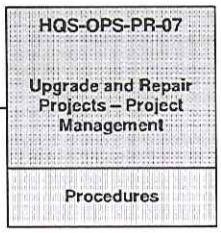


Midwater and Harsh Field Operations Procedures: Contains the field operation procedure requirements related to Midwater and Harsh Environment Installation and Well Operations. These procedure requirements represent Level 1B company management system requirements and support the development of Level 3 Rig Specific Procedures.



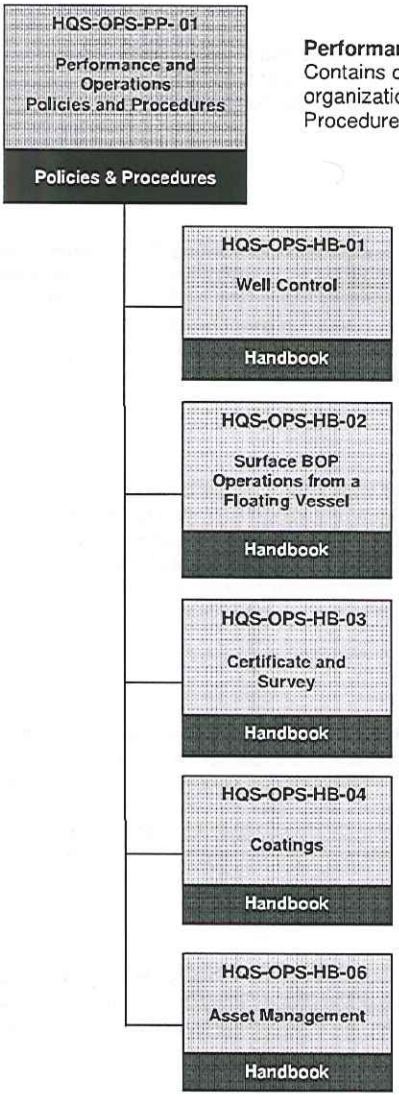
Deepwater Field Operations Procedures: Contains the field operation procedure requirements related to Deepwater Installation and Well Operations. These procedure requirements represent Level 1B company management system requirements and support the development of Level 3 Rig Specific Procedures.

Marine Compliance Procedures: Contains the Marine Compliance procedures for Installations to meet and maintain in accordance with internationally recognized rules, standards. marine requirements and legislation which contributes to marine integrity management. These procedure requirements represent Level 1B company management system requirements.



Upgrade and Repair Projects – Project Management: Contains the key elements of the Stage Gate Process approach to be used for carrying out all major projects on Company rigs/assets.

Figure 1.4.2, Performance and Operations Document Organization Chart (continued)



Performance and Operations Policies and Procedures: Contains description of the Performance and Operations group organization and Level 1A Field Operation Policies and Procedures.

Well Control: Contains well control procedures, recommended practices, and reference information applicable to all rig types. The procedure requirements represent Level 1B company management system requirements and support the development of Level 3 Rig Specific Procedures.

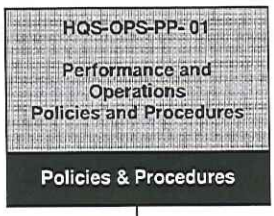
Surface BOP Operations from a Floating Vessel: Contains the field operation procedures related to Surface BOP Operations. These procedure requirements represent Level 1B company management system requirements and support the development of Level 3 Rig Specific Procedures.

Certificate and Survey: Contains the field operation procedure requirements related to Deepwater Installation and Well Operations. These procedure requirements represent Level 1B company management system requirements support the development of Level 3 Rig Specific Procedures.

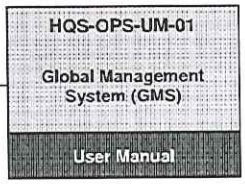
Coatings: Contains the field operation procedure requirements related to Deepwater Installation and Well Operations. These procedure requirements represent Level 1B company management system requirements support the development of Level 3 Rig Specific Procedures.

Asset Management: Contains recommended practices and supporting information to develop an Asset Management Plan for each rig with the dual focus to manage physical assets and performance.

Figure 1.4.2, Performance and Operations Document Organization Chart (continued)



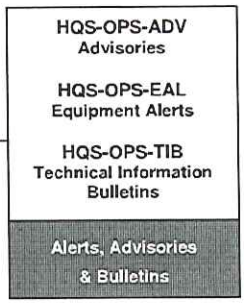
Performance and Operations Policies and Procedures: Contains description of the Performance and Operations group organization and Level 1A Field Operation Policies and Procedures.



Global Management System: Contains the Global Management System (GMS) procedure requirements and instructions for onshore and offshore personnel related to the GMS Operation Module. These User Manual instructions and requirements represent Level 1B company management system requirements.

Corporate Card: Provides information regarding the Corporate VISA Card program ("Corporate Card", "Card") that is designed to simplify the process of making business-related purchases.

Equipment Standards: Various standards have been developed and published to support maintenance activities and communicate Lessons Learned that are specific to equipment.



Alerts, Advisories, and Bulletins: Various types of alerts, advisories and bulletins have been issued to communicate Lessons Learned and are for action or information only.

3 HQS PERFORMANCE AND OPERATIONS INTRANET SITE

Other documentation and information related to Performance and Operations is found on the intranet site at http://www.rigcentral.com/hqs/pt/. This includes the following:

- Performance Operations
- Technology
- Well Operations

4 REFERENCES

4.1 FIGURE 1.4.2, PERFORMANCE AND OPERATIONS DOCUMENT ORGANIZATION CHART

4.2 INTRANET SITE: http://www.rigcentral.com/hqs/pt/

OPS – PLANNING AND REPORTING

WELL CONSTRUCTION PLANNING

1 POLICY

Well Construction Planning must be performed for each well by the Installation Supervisors and Managers in collaboration with the Customer. The Installation Supervisors and Managers must take into account all information from the Customer's well program, the installation capabilities and the required maintenance to ensure that all requirements are known, communicated and executed in a safe and efficient manner.

2 PURPOSE

The purpose of this policy is to provide a consistent approach for each installation team to develop effective Well Construction Planning to:

- Provide an installation and well operation plan for a specific installation and Customer's Well Program, within a specific operation environment.
- Optimize simultaneous operation activities at online and offline work paths.
- Optimize installation reliability, maintainability and operability of equipment and systems.
- Reduce the occurrence of unplanned operation events by identifying risk reducing controls through the review and evaluation of specific installation and well operation scenarios.
- To ensure adequate communication between the Customer and the Company and eliminate "assumptions" that may have a negative impact towards safety of personnel, environment, equipment or operational performance.
- To communicate Transocean's methods of operation, understand the Customer's expectations, identify risks / opportunities for operational improvement, required resources and well-site information required for safe and efficient operations.
- Apply a multidisciplinary team approach in planning installation and well operation activities in order to ensure proven and successful operation best practices, lessons learned from previous wells, or other installation locations are included.

3 SCOPE

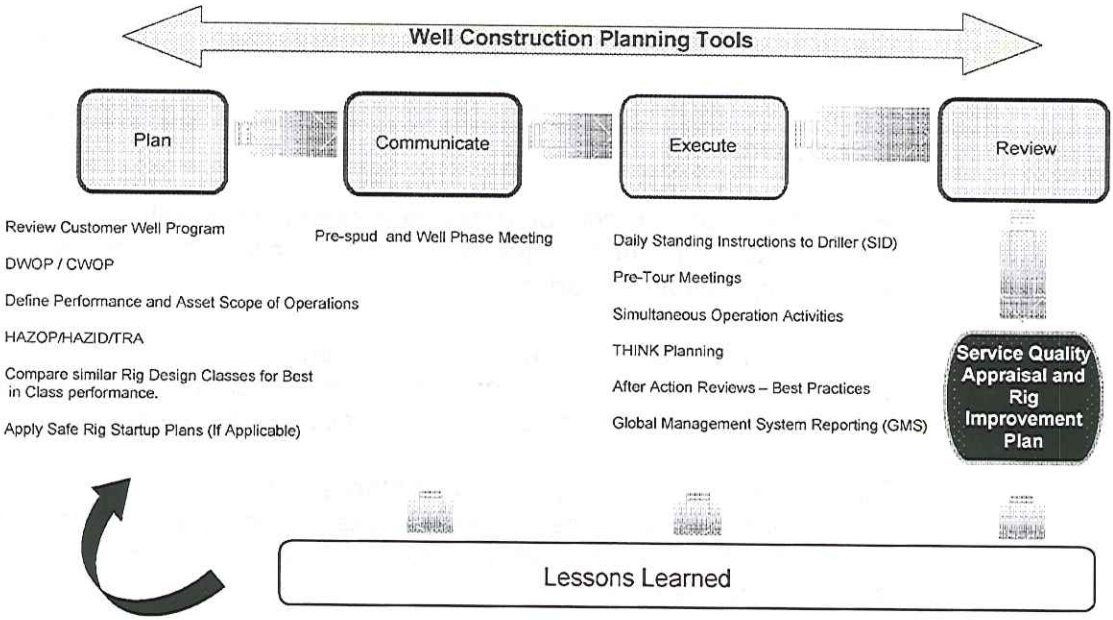
This Policy is applicable to all Installations.

4 PROCEDURE

4.1 WELL DELIVERY PROCESS

The well delivery process is the process by which the Customer's well program is planned, communicated, executed and reviewed between Transocean and the Customer.

Figure 2.1.1, Well Delivery Process



4.2 DEFINING WELL CONSTRUCTION PLANNING

Well Construction Planning enables the identification of the critical path time, maintenance of well integrity, reduction of installation and well non-productive time, and the ability to maintain the installation and equipment during the Customer contract.

Well Construction Planning is comprised of:

- Customer's Well Program and Installation Contract
- Installations Scope of Operations

4.2.1 Customer's Well Program

The plan for executing the required activities to complete each section of the well. This is normally comprised of:

- Overview of the operations goals and objectives
- Potential hazards and their prevention and mitigation
- Time and cost targets
- Detailed engineering information by well section

Transocean's role is to review and feedback to the Customer for the following:

- Identify operation activities which will be performed on the Critical and Offline operation work paths to maximize the efficiency of the installation.
- Review Lessons Learned and actions from the last well.
- Agree to target times for operation activities that are represented in the time depth curve, for the well.
- Ensure all operation and maintenance activities do not conflict with the Company Management System Policies and Procedures.

4.2.2 Installations Scope of Operations

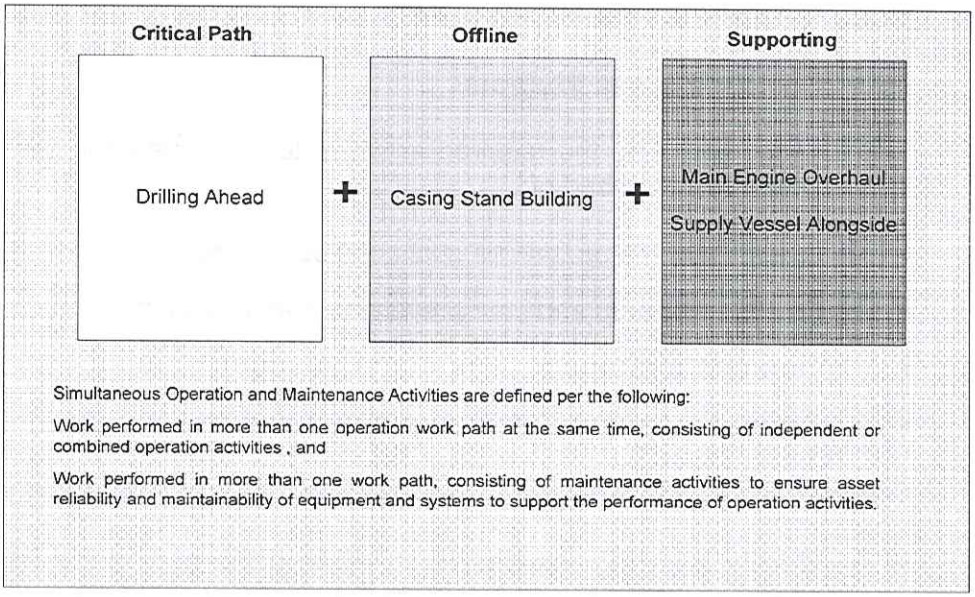
This is the combined operations and maintenance activities that are required as a part of the Well Program or a consequence of the Well Program.

See Global Management System Performance and Operation, User Manual HQS-OPS-UM-08.

A. Planning of Performance Operation Activities

Planning Operation Activities is the work to be carried out in either one or all of the critical path, offline, or supporting operation work paths as defined in the Installation's Scope of Operations.

Figure 2.1.2, Example of Simultaneous Operation and Maintenance Activities



B. Planning of Maintenance Activities

Planning of Maintenance Activities supports asset reliability and maintainability of equipment and systems to perform operation activities.

Maintenance Activities should be planned to minimize non-productive time and the consequence of equipment failure. Planning needs to account for the increased complexity of simultaneous operations.

4.3 WELL CONSTRUCTION PLANNING AND EXECUTION PROCESS

Well Construction planning and execution process consists of defining the plan prior to beginning operations and the day to day executing of the well drilling program on board the installation.

It is important to understand the scope of the Customer's requirement and communicate the necessary planning activities that are dependent to be completed prior to continuing the execution of the planned work.

Review the site specific information for Items that increase the risk or complexity of the operation, such as the presence of Shallow Gas. These are to be subsequently planned according to Transocean's policy and procedure requirements. The impact of the requirements on the operations and scheduling are to be communicated to the Customer.

4.3.1 Non-standard Operations

Any non-standard operations will require further evaluation using a detailed risk analysis process – such as a HAZOP/HAZID. Non-standard operations include but are not limited to:

- Surface BOP (SBOP)
- Managed Pressure Drilling (MPD)
- Well Testing

4.3.2 Service Partner Operations

Service Partner operations require planning and communication with the Customer to ensure operations are carried out in accordance with Transocean policies and procedure. Service Partner equipment that is required to be used will need to be reviewed for the installation and operation requirements.

4.3.3 Operation of Transocean Equipment

Only Transocean personnel are authorized and permitted to operate installation equipment and systems. Customer and Customer Service Partner personnel related to the following services (but not limited to), may provide guidance and advice but are not authorized or permitted to operate Transocean equipment:

- Fishing Tool Representatives
- Directional Drillers
- Wellhead Service Engineers
- Offshore Customer Representatives

See within this manual, PR - Well Related Equipment Installation and Operation, Section 2, Subsection 1, Appendix 1.2 for more information.

See in the Health and Safety Policies and Procedures Manual, HQS-HSE-PP-01, Section 4, Subsection 2.3, Customer and Subcontractor Personnel and Equipment.

Elements of the Well Construction Planning process should include but not limited to the following:

- Drill Well or Complete Well on Paper exercises (DWOP / CWOP)
- Crew engagement meetings and potential hazard identification
- Review of maintenance requirement
- Review of Lessons Learned from Previous wells (Transocean and Customer)
- Additional support / review as required (QHSE, Engineering, Marine, Well Operations, etc)

Tools that should be used to communicate and execute the plan include but are not limited to:

- Pre-Spud Meeting
- Daily Operations Meetings
- Standing Instructions to Driller (SID)
- Management of Change
- After Action Reviews (AARs)
- Well Section and Well Phase Reviews

4.3.4 Pre-Spud Meetings

Pre-spud meetings should be held onshore and/or on the Installation with the Customer, to discuss the drilling program of the well ahead of spudding the well and

communicate the expectations of the well to the rig crew. Appropriate service partners should be encouraged to attend and participate in the pre-spud meetings.

Well planning checklists can be used while reviewing the drilling program to assist in determining meeting agenda issues to be covered. An example is provided in the Appendix to this section – RP Well Construction Planning Checklists. This checklist can be modified to address installation specific requirements.

Location site specific information must be received from the Customer including bathymetry, metocean data, field layout, soil conditions, shallow hazards and seafloor hazards. Wellhead torque and bending limits must be obtained for DP Installation operations.

If adverse weather conditions are anticipated, personnel must be made aware of the hazards and determine the controls to be put in place.

Well Pre-planning Recommended Practice:

- Operations Policies and Procedures, HQS-OPS-PP-01, Section 2.1, Appendix 1, Recommended Practice - Well Construction Planning Checklists

4.3.5 Daily Operation Meetings

The daily operation meeting should be held with the customer on a daily basis to review the status of the well and ensure the daily operations adequately achieve the overall objective of the well program.

4.3.6 Standing Instructions to Driller (SID)

The Standing Instructions to Driller (SID) is utilized to support day to day communications related to the well delivery process and is a key component of Well Construction Planning. Use the form HQS-HSE-PP-01 FM441C.

Customer Representative issued work instructions require a signed and authorized SID by the OIM, Customer Representative and Senior Toolpusher / Toolpusher.

The Standing Instructions to Driller (SID) includes but not limited to the following:

Drilling Parameters
Mud Properties
Detailed Instructions

Safety Requirements / Considerations

A. Approval of Standing Instructions to Driller (SID)

Standing Instructions to Driller (SID) are required to be completed a minimum of once per 12 hour tour. The Driller is required to utilize the SID during the duration of his tour.

4.3.7 Management of Change

The Management of Change is to be used to safely implement and monitor any changes in the drilling program to ensure that an adequate risk assessment has being carried out and the appropriate control put in place to prevent or mitigate potential hazards that could occur due to the change. Reference the Company Management System Manual (HQS-CMS-GOV) and the Health and Safety Policies and Procedures Manual (HQS-HSE-PP-01).

4.3.8 After Action Reviews

After action reviews should be conducted during the course of executing the well operations. The After Action Review meeting should be a facilitated discussion between people who participated directly in the operation or maintenance activity carried out during the execution of the well drilling program.

The After Action Review meeting should provide the means to:

- Verify the operation or maintenance activity was achieved and the Customer is satisfied with the performance.
- Review the effectiveness and execution of Level 3 Rig Specific Operation and Maintenance Activities Procedures and the application of the **THINK** Planning Process.
- Identify which risk reducing control described in the rig specific operations and maintenance procedure were effective and which ones require improvement.
- Identify what needs to be done differently on the Installation the next time the operation or maintenance activity is to be performed.
- Submit and classify proposed lessons learned on the Installation in real time.

Refer to Section 2, Subsection 5 - Performance Improvement - Lateral Learning of this manual for more information on the process for conducting after actions reviews.

4.3.9 Well Phase and Well Sections Reviews

The well phase and well sections reviews should be held with the customer at predefined stages of the well. These reviews should include a consolidated analysis of the performance results for the completed phase or section of the well against the well plan to identify performance gaps and identify improvement opportunities. The lessons learned from these reviews should be documented for consideration during the development of subsequent Customer drilling programs for similar well types.

4.4 LEVEL 1 WELL EXECUTION PROCEDURE REQUIREMENTS

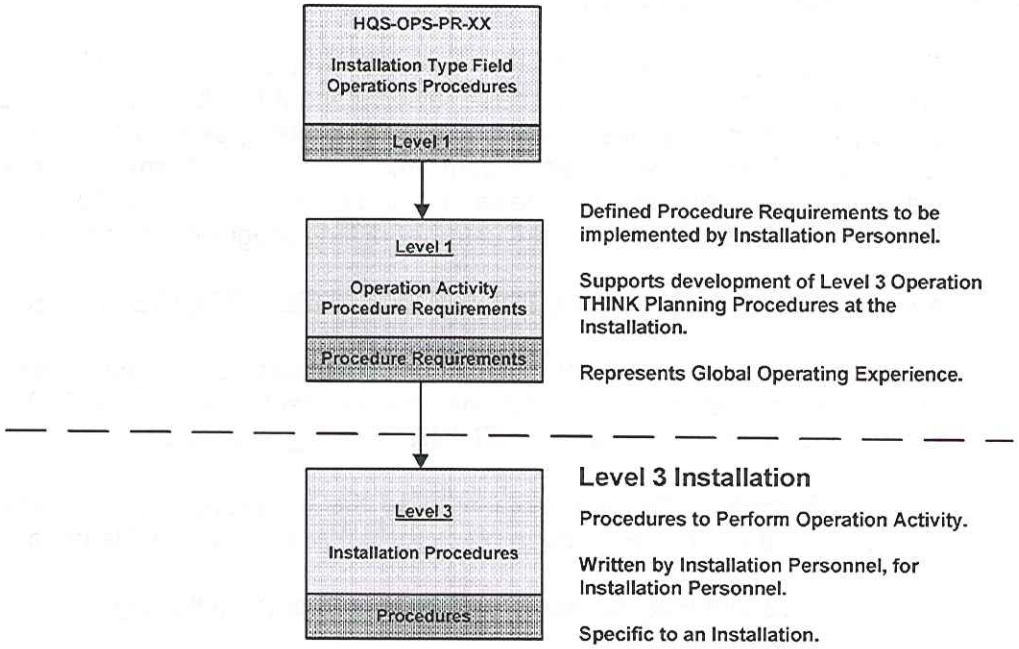
Detailed communication on individual activities and tasks will be clearly communicated using the installations management system (TSTP, MHRA, Marine Operations Manuals, etc) and the **THINK** Planning Process.

Level 1 Procedure Requirements provide the installations management team the controls that are required to be in place for Well Construction Planning.

Level 1 Procedure Requirements are composed of the following:

- The essential requirements to execute operation activities safely and effectively (HQS-CMS-GOV, Section 3, Subsection 2, 3.2)
- Requirements necessary to be explicitly defined in people's responsibilities (HQS-CMS-GOV, Section 3, Subsection 1, 2.2)
- Key preventive and mitigating risk reducing controls to be used during the THINK planning process (HQS-HSE-PP-01, Section 4, Subsection 2.1)

Figure 2.1.3, Procedure Requirements versus Procedures



4.4.1 Field Operations Procedures Manuals

The Field Operations Procedures Manuals provide Field operation procedure requirements specifically related to each of the Installation Type Categories. The Field Operations Procedures Manuals support the policies within Transocean Management System.

The Field Operations Procedures Manuals are organized by the following:

- Jackup and Barge Field Operations Procedures Manual (HQS-OPS-PR-03)
- Midwater and Harsh Environment Field Operations Procedures Manual (HQS-OPS-PR-04)
- Deepwater Field Operations Procedures Manual (HQS-OPS-PR-05)

Inside each manual, the operation activities are organized within the following categories:

- Marine
- Drilling
- BOP

4.5 ONBOARD WELL CONSTRUCTION PLANNING

Onboard Well Construction Planning should be performed:

- Prior to and during drilling or completing a well.
- To enable implementation of any specific action items determined.
- When the proposed drilling/completion program is complete and ready for issue.
- For a sequence of wells, defined within a development project. This includes a review of performance on previous Customer wells and use of the Global Management System (GMS) to set specific targets.
- To identify and address any potential risks or concerns in performing the drilling or completion of a Customer's Well Program.

To be used as a part of the education and familiarization of the well construction team for a new process or the use of new technology.

4.6 READY TO DRILL PLANNING

The Ready to Drill Planning is the Installation and well plan requirements specifically developed to support the commencement of safe operations under the following circumstances:

- New Customer
- Change of Division
- Change of Countries within a Division
- After completion of New build or Shipyard period (Upgrade and Repair Project, HOU-OPS-PR-01)

OPS – PLANNING AND REPORTING

WELL CONSTRUCTION PLANNING

There is a wide potential of complexity that can be present when bringing an Installation to be Commissioned and Ready to Drill. The following should be considered in Ready to Drill Planning including but are not limited to:

- Customer Communication Plan
- Installation Contract Review
- Customer / Transocean Bridging Document
- Installation Reactivation / Stacking Documentation Review (if applicable)
- Logistic / Local Support
- Installation Scope of Operations
- Customer Well Program
- Planned Major Equipment Maintenance and Commissioning
- Installation and Customer Inspections
- Personnel Training Matrix (e.g. License to Drill, License to Lift)
- Short Service Employees (SSE)
- Contractor Service Partner Assessment
- Administration & Documentation
- Handover of Installation from Project Management to Performance and Asset
- Corporate Risk Management Requirements
- Installation Mobilization

5 RESPONSIBILITY

	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher	HQS Marine Support Group
Maintain uniformity of Installation well planning operations.	IM	IM	PM	PM	PM		PM
Hold daily operations meeting with Customer Representative and rig department heads.					PM		
Attempt to receive site specific information from the Customer at least one month in advance of the planned spud date in order that HQS Engineering has time to analyze and approve the location. Refer to the HQS-OPS-PR-06, Marine Compliance Procedures Manual.			PM				
The Performance Responsibilities is the installation well planning and work applied to achieve defined Well Phases: • Location Approval • Planned Operation Activities • Planned Simultaneous Operation Activities			PM				
The Asset Responsibilities include planned major equipment maintenance and other planned maintenance activities: • Event Based Maintenance • Calendar and Condition Monitoring Based Maintenance • Usage Based Maintenance		PM					

OPS – PLANNING AND REPORTING

WELL CONSTRUCTION PLANNING

	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher	HQS Marine Support Group
Coordinate and collaborate between the Performance and Asset departments to achieve the purpose of the Well Construction Planning Policy.	IM	IM	PM	PM			
Attend DWOP and CWOP reviews and provide recommendations to Customer to optimize rig and well operations to achieve safe performance efficiencies.	IM		PM		PM		
Communicate to the Customer the critical planned maintenance and out of service time which affects Well Construction Planning.	IM		PM	V	PM		
Meet with Customer on a daily basis to support the delivery of professional rig and well operations, resulting in effective drilling and completion performance.			PM				
Prior to the well being spudded, review the drilling program for compliance with Company policies and procedures, and the ability of the Installation to perform drilling operations. For Well Control procedures see HQS-OPS-HB-01, Section 1, Subsection 2, 1.1. Submit exemption as required for review.	IM		PM		PM		
Review performance on previous Customer wells using Global Management System (GMS) to set specific targets.			PM		PM		

OPS – PLANNING AND REPORTING

WELL CONSTRUCTION PLANNING

	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher	HQS Marine Support Group
Coordinate and maintain Regulatory Class and Flag State surveys.	IM	V	V	PM	PM		
Complete as applicable, mooring system analysis, riser analysis and jackup site assessment approvals for each location.	IM		IM		V		PM
Visit the installation to support effective management visibility, monitor rig performance results and to ensure consistent and effective communication with the OIM and Department Supervisors.	PM	V	PM	PM			
Act as primary Customer contact regarding all service provision related matters.	IM		PM				
Key Installation personnel are to be trained, competent in all safety critical areas including but not limited to Marine Licensing, DPO, Management of Major Emergency, Well Control, License to Drill, License to Lift, Stability and Ballast Control.	IM	IM	IM	PM	PM		PM
Provide the Customer with Technical information on equipment and installation specifications.				PM			
Maintain an up to date contractual rig equipment list.	IM	IM	PM				
Ensure rig equipment and systems are operated within technical and design capabilities (Scope of Operations).	IM	IM	IM	IM	V		

OPS – PLANNING AND REPORTING

WELL CONSTRUCTION PLANNING

	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher	HQS Marine Support Group
Investigate OERs, close out corrective actions and communicate the Lessons Learned.	IM	IM	PM	PM	V		
Participate in HSE incident analysis, close out corrective actions and communicate the Lessons Learned.	PM	PM	PM	PM	PM		PM
Identify and define innovative technical solutions to meet Customer needs.	PM			PM			
Monitor the Well Construction Planning process to assure proposed well design is being executed properly and provide technical solutions as required.	PM	PM	PM	PM	PM		PM
Maintain an adequate level of inventory and consumables on the installation to meet the Well Construction Planning requirements and the emergency repair of safety and operations critical equipment.			V	PM	PM		
Use the Computerized Maintenance Management System to support asset reliability and maintainability of equipment and systems to perform operation activities.		IM		IM	V		
Develop the Standing Instructions to Driller (SID) taking into account any Customer Representative issued work instructions with the Customer Representative.					PM	PM	

	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher	HQS Marine Support Group
Review and approve the Standing Instructions to Driller (SID) each Tour with the Customer Representative.					PM	PM	
Communicate the Standing Instructions to Driller (SID) to the Driller(s) prior to commencing their tour.						PM	

6 REFERENCES

6.1 FIGURE 2.1.1, WELL DELIVERY PROCESS

6.2 GLOBAL MANAGEMENT SYSTEM PERFORMANCE AND OPERATIONS, USER MANUAL, HQS-OPS-UM-08

6.3 FIGURE 2.1.2, EXAMPLE OF SIMULTANEOUS OPERATION AND MAINTENANCE ACTIVITIES

6.4 PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES, HQS-OPS-PP-01, SECTION 2.1, WELL CONSTRUCTION PLANNING, APPENDIX 1.2

6.5 COMPANY MANAGEMENT SYSTEM, HQS-CMS-GOV, SECTION 3.2, POLICIES AND PROCEDURES

6.6 COMPANY MANAGEMENT SYSTEM, HQS-CMS-GOV, SECTION 3.1, LEADERSHIP IN MANAGEMENT

6.7 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.2.1, RISK MANAGEMENT

6.8 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.2.3, CUSTOMER AND SUBCONTRACTOR PERSONNEL AND EQUIPMENT

6.9 FIGURE 2.1.3, PROCEDURE REQUIREMENTS VERSUS PROCEDURES

6.10 JACKUP AND BARGE FIELD OPERATIONS PROCEDURES, HQS-OPS-PR-03

6.11 MIDWATER AND HARSH ENVIRONMENT FIELD OPERATIONS PROCEDURES, HQS-OPS-PR-04

6.12 DEEPWATER FIELD OPERATIONS PROCEDURES, HQS-OPS-PR-05

6.13 UPGRADE AND REPAIR PROJECT, HOU-OPS-PR-01

6.14 MARINE COMPLIANCE PROCEDURES MANUAL, HQS-OPS-PR-06

6.15 WELL CONTROL HANDBOOK, HQS-OPS-HB-01, SECTION 1.2, WELL CONTROL PROCEDURES

1 CHECKLISTS

The purpose of a Well Construction Planning checklist is to provide the Rig Manager – Performance and Rig Manager - Asset and other relevant persons (onshore as well as offshore) with a well planning management tool. It is recommended that a checklist be used from the time of contract review through to the pre-spud meeting to identify Transocean, Customer and Service Partner issues and responsibilities.

The checklist provided in this subsection is an example and may not be all-inclusive. Rig Managers should use the provided checklist as a "starting point" and make necessary modifications as required.

2 RECORDING, FILING AND RETENTION

A checklist should be completed by the Rig Manager - Performance or his designate prior to every commencement of a drilling program. Problems that may arise should be brought to the attention of the Rig Manager - Performance for resolution prior to commencement of operations. The checklist should be completed and made part of every pre-spud meeting.

Completed checklists should be retained as part of the well files.

Figure 2.1.1.1, Sample Well Construction Planning Checklist

	ADMINISTRATION	Yes	No	N/A
1a	Navigation restrictions – Restrictions are listed on the Insurance – Risk Management website			
1b	War risk – Purchase additional coverage if warranted			
1c	Reactivation survey – Installation has been stacked over 180 days			
1d	Approved contractor – A data base of all Company approved contractors can be found on the Insurance Risk Management website			
1e	Special insurance requirements required by contractor or local legislation			
1f	Certificate of Financial Responsibility if Installation is in USA waters			
1g	Emergency contact numbers in the event of an injury or incident			
1h	Importation permit – Installation equipment list / Support documentation			
1i	Working visas for all personnel going overseas			
1j	Installation classification documentation			
1k	Ensure The Company is in compliance with all local and country environmental regulations			
1l	Ensure the operator has the APD (Application for permit to drill)			
1m	Drilling Contract issues, Review the Company Marketing Manual			
1n	Ensure all MSDS (Material Safety Data Sheet) are available on the Installation			
	GEOLOGY	Yes	No	N/A
2a	Surface location (Co-ordinates) of the well			
2b	Bottom hole location (Co-ordinates) & TVD			
2c	Location map within the block / field			
2d	Seismic map showing surface and bottom hole locations			
2e	Seismic sections with the main reflectors to show the structure of the trap			
2f	Offset wells and hazards (faulting) delineated			
2g	Lithology and Stratigraphy column with depth uncertainty			
2h	Pore pressure profile			
2i	Formation fracture profile			
2j	Temperature profile			

Figure 2.1.1.1, Sample Well Construction Planning Checklist (continued)

	SITE CONDITIONS	Yes	No	N/A
3a	Metocean data: Winds, currents, waves			
3b	Soil conditions			
3c	Site survey & hazards e.g. scouring			
3d	Proximity of any nearby pipelines			
3e	Shallow gas assessment			
3f	Nearby subsea facilities / suspended wells			
3g	Proximity to shipping lanes and / or MOD range			
3h	Mooring analysis			
3i	Operating envelope for the Installation			
3j	Environmental impact assessment			
3k	Impact on fishing activity			
3l	Water depth and rotary elevation			
3m	Riser analysis and conductor tension for the location			
3n	Potential diving operations at the location			
	POTENTIAL HAZARDS	Yes	No	N/A
4a	Faults			
4b	Sand lenses			
4c	Sea floor hazards: Unconsolidated sediment, Geological features, Gas seepage, Chemo-synthetic Communities, man made features			
4d	Below mud line hazards: Shallow gas reservoirs, Shallow water flows, Gas hydrates, Buried faults or channels, Chaotic zones			
4e	Low fracture pressures			
4f	Overpressure zones			
4g	H_2S			
4h	CO_2			
4i	Lost circulation			
4j	Salt domes			
4k	Formation: Differential sticking, Well bore ballooning, Well bore instability			

Figure 2.1.1.1, Sample Well Construction Planning Checklist (continued)

	DIRECTIONAL DRILLING PROGRAM	Yes	No	N/A
5a	Well trajectory profile and plan view			
5b	Target criteria			
5c	Collision risk / clearance: Spider plot Anti-collision scan listing Summary of close approach wells detailing F1 & F2 distances Possible requirements for plugging adjacent wells			
5d	Surveying requirements Tools planned for the well Radius of error achieved at target and TD			
	MUD PROGRAM	Yes	No	N/A
6a	Mud type: riserless drilling operations , riser attached drilling operations			
6b	COSHH requirements			
6c	Environmental requirements, seabed sampling, oil on cuttings, etc			
6d	Rheological & fluid loss properties for each hole section			
6e	Need for lab/field testing of mud system (HPHT well)			
6f	Mud weight for each hole section			
6g	Hydrates, Cold ocean temperature mud formulations			
	CASING DESIGN	Yes	No	N/A
7a	Wellhead design – Low pressure wellhead housing, High pressure wellhead housing, wellhead torque considerations, liners, wear bushings, tools, annular shut off, rigid lock down, ROV intervention. Wellhead configuration			
7b	Riser tension / Conductor tension, Riser tensioner support ring - Slip ring / KT ring			
7c	Comprehensive basis of casing design			
7d	Casing design similar to offset wells?			
7e	Design safety factors			
7f	Pressure testing requirements for casing string			
7g	Kick tolerance for casing strings			
7h	Leak off / formation integrity test for each section			
7i	Maximum wellhead pressures expected for each section			
7j	Effects of casing wear			
7k	Contingency liner or other contingency plan			

Figure 2.1.1.1, Sample Well Construction Planning Checklist (continued)

	CEMENTING PROGRAM	Yes	No	N/A
8a	Foam cement: Placement techniques, annular control, foam cement safety, tools and accessories.			
8b	Top of cement for every casing string, and the S.G. of the cement slurries			
8c	Thickening time vs. planned mixing and displacement time			
8d	ECD vs. leak off test and fractures gradient			
8e	Cement placement method – inner string, one plug or two, subsea or surface launch			
8f	Additional considerations – gas migration, salt formations, temperature, etc			
8g	Conductor cement jobs Maximum angle for PGB after cementing Contingency plan for top up job			
	WELL CONTROL PROGRAM	Yes	No	N/A
9a	Well control equipment pressure rating for each hole section			
9b	Well control equipment pressure testing requirements			
9c	Well control equipment temperature limitations			
9d	Ram configuration for each hole section			
9e	Kill and choke line configurations			
9f	Shallow gas plan			
9g	Diverter system equipment			
9h	Wellhead pressure testing			
9i	Wellhead pressure and temperature rating			
9j	Additional training requirements			
9k	Mud gas separator capacity / instrumentation			
9l	Controlled blowout study			
	WELL TESTING / DST	Yes	No	N/A
10a	Programs			
10b	Likely reservoir fluids			
10c	Maximum formation pressure / temperature			
10d	Maximum wellhead shut in pressure			
10e	Maximum wellhead flowing temperature			
10f	Maximum anticipated flow rate for the well test / production			
10g	H_2S, CO_2, H_2O, Cl content, GOR, density of fluid			

Figure 2.1.1.1, Sample Well Construction Planning Checklist (continued)

	WELL CONTROL	Yes	No	N/A
11a	BOP ram size and configuration			
11b	BOP pressure and temperature rating			
11c	BOP pressure testing requirements			
11d	Completion fluid (type, S.G., inhibition)			
11e	Packer fluid (type, S.G., inhibition)			
	XMAS TREE	Yes	No	N/A
12a	Tree metallurgy			
12b	Tree, tubing bonnet and tubing spool pressure and temperature rating			
12c	Tree, tubing bonnet and tubing spool pressure testing requirements			
12d	Tree and tubing spool valve configuration			
12e	Fire safe envelope			
	TUBING DESIGN	Yes	No	N/A
13a	Design safety factors			
13b	Pressure testing requirements (tubing, annulus, safety system)			
13c	Pressure, temperature and mechanical rating of tubing, tubing hanger and downhole components			
13d	Tubing and tubing hanger downhole component metallurgies			

3 REFERENCE

3.1 FIGURE 2.1.1.1, SAMPLE WELL CONSTRUCTION PLANNING CHECKLIST

1 PROCEDURE

Well related equipment installation and operation includes, but is not limited to the following:

- Temporary Installation of Customer / Service Partner Well Related Equipment and Systems.
- Transocean Contracted Diving Services

1.1 TEMPORARY INSTALLATION OF CUSTOMER / SERVICE PARTNER WELL RELATED EQUIPMENT AND SYSTEMS

1.1.1 Initial Well Related Equipment Installation Information

Equipment and systems to be installed on the installation require detailed equipment installation information to be provided. This includes but is not limited to the following:

- Certification for all Customer / Service Partner equipment.
- Size, weight (both full and empty), and foot print dimensions of each piece of equipment proposed to be installed on the Installation.
- Specifications of the hoses, piping, unions or chicksans intended to be used.
- Specifications for the system intended to be used to control the flow of hazardous material.
- Specifications for the instrumentation to be used to monitor pressure, temperature, and flow of hazardous material.
- Specifications for installation, commissioning and operational testing of well related equipment.
- Written operating procedures for all Customer / Service Partner equipment and systems are required including Safety System features. These include but are not limited to, pressure relieving devices, alarms and/or fail-safe shut-downs activated due to exceeding pre-set maximum temperatures or pressures, etc.

- Specifications for any physical interface with Installation systems or equipment, including any required electrical power supplies, compressed air, fuel, water, etc.

1.1.2 Temporary Well Related Equipment and System Installation Assessment

Assess the impact and requirements for temporary installation of equipment and systems including but not limited to the following:

- Fire Fighting and Safety Equipment Plan Layout.
- Hazardous Area Ratings.
- Installation's Safety Case (if applicable).
- Access or egress routes for personnel required to respond to an emergency or abandonment of the Installation.
- Availability of water outlets in the immediate area for responding to unplanned spillages of hazardous material (e.g. liquid N2).
- Deck loading and structural interfaces inclusive of securing arrangements for operation and emergency scenarios (e.g. adverse weather, stability event etc).
- Supplies of rig electrical power, compressed air, fuel, and water, along with the specifications of such interface, such as volts, amps, flow rates, etc.
- Dropped Object potential.

1.1.3 Installation of Temporary Well Related Equipment and Systems

Enforce Transocean's requirements during the Installation of Temporary Well Related Equipment and Systems. This includes but is not limited to the following:

- The length of the hoses, chicksans, and piping is required to be kept to a minimum.
- The area selected for installation is required to be as remote as possible to avoid routine crane lifts and encroachment by normal personnel traffic.
- Areas around tanks, hoses, chicksans, and piping used to store or convey acids, liquid N2, or other hazardous material require:
  - To be restricted to only personnel authorized to be in the work area.

  - To have an adequate water supply to provide pressurized water hoses for immediate use.

- The area beneath all tanks, hoses, chicksans, and piping that convey acids, liquid N2, and other hazardous material are required to be prepared to contain any spillage of such material as follows:

  - Cover the steel deck with timber (scaffold boards).
  - Build up an outer perimeter of at least 4 inches in height with scaffold boards.
  - Drape heavy duty, water-tight tarpaulin material or sheeting, such as Visqueen™ (or equivalent) over the entire area to create a watertight barrier. Scaffold boards may be placed inside the perimeter to secure the water-tight tarp or sheeting material in position and to prevent chafing or damage of the tarp or sheeting material that could come into contact with equipment skids or other structure or equipment with sharp edges.
  - Fill the containment area with water to a depth of 2 to 3 inches to provide a means of diluting acids or other hazardous material, and to provide a heat sink for spilled liquid N2.
  - A charged water hose or fire hose shall be provided for immediate use by personnel in case of spillage of acids, liquid N2, or other hazardous material.
  - All personnel, including third party service partners, who are assigned the responsibility for using such water hoses in the event of a spill, are required to receive prior instructions on what Personnel Protective Equipment (PPE) to wear, and how to use such water hoses in such a manner as to avoid spreading spilled hazardous material to other areas.

- Barriers with appropriate signs will be erected and maintained around equipment and systems that contain hazardous material to prevent casual entry of non-essential personnel.
- A Complex Lift Plan is to be used for each crane lift that is performed above pressurized tanks, piping, hoses, or chicksans containing hazardous material. REF: Lifting Operations Handbook (HQS-HSE-HB-01).

- Chicksans hoses or piping used for conveying acids, liquid N2, or other hazardous material are required to be pressure tested after installation to the maximum anticipated pressure of the equipment or system prior to use.
- Tie-downs and equipment securing arrangements required to withstand Installation survival mode conditions must be continuously monitored and checked throughout the operation activity for capability of the application.
- Rotary hoses made to meet API Specification 7K shall not be used during well stimulation, under-balance drilling, or any other type of operation that would expose this hose to pressurized gases of any kind. If rotary hoses are necessary to be exposed to any pressurized gases during these operation activities, they require to be manufactured in accordance with API Specification 17B.

A. Suspending Service Partner Equipment in the Derrick

Service Partner equipment required to be temporarily installed and suspended inside the derrick requires to be suspended by either:

- An existing Rig Floor hoist (K5 or greater), or
- A dedicated padeye and hang off line which is available and already installed in the derrick.

Do not utilize two or more Rig Floor hoists to suspend equipment in the derrick.

B. Equipment Suspension Procedure Requirements

The following procedure requirements are to be implemented and performed when suspending third party service partner equipment in the derrick:

- Complete the applicable form(s) related to the equipment to be suspended:
  - HQS-HSE-PP-01 "Approval to Install and Operate Customer and Subcontractor Equipment Form", Form FM423A.
- Pad-eye design, its attachment to the derrick, all sheaves and loose gear such as shackles, safety slings, and other hardware installed in the primary load path shall have a load rating that meets or exceeds the Resultant Load as defined in the HQS Engineering Standard HQS-OPS-EST-674-01.

- All pins, bolts and fasteners used in components such as shackles, sheaves, and other loose gear shall have a visible means of retention, such as a split pin, R-clip, or lock wire.
- All shackles used to suspend third party service partner equipment in the derrick shall be Crosby G-2130 or G-2150 bolt-type shackles.
- All equipment utilized in the load path must have a load rating twice that of the hoist.
- The breaking strength of the wire rope selected for use with the hoist shall be greater than 2.5 times the load rating of the hoist.
- The dedicated padeye and hang off line must be maintained according to the requirements in the Computerized Maintenance Management System (CMMS).

1.2 INSTALLATION SYSTEM CONNECTIONS AND SERVICES TO SERVICE PARTNER EQUIPMENT

Transocean will not provide the following Installation system connections or services:

- Compressed air to well testing equipment, burner booms, or other equipment or systems that connect to or contain well bore fluids.
- Primary compressed air, water, and electric power for human performed diving operations.
- Live oil storage in mud pits.

Equipment or systems provided by the Customer or other service partners to supply compressed air to well testing equipment, burner booms, and other equipment and systems that connect to or contain well bore fluids, are subject to review and approval per the following:

- Approval To Install and Operate Customer and Subcontractor Equipment.

2 RESPONSIBILITY

	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM
Review for approval the plans for any equipment or systems to be installed to support an operation activity.			IM	IM	PM
Review for approval HQS-HSE-PP-01 "Approval to Install and Operate Customer and Subcontractor Equipment Form", Form FM423A.					PM
Interface with the Onshore Customer Representative and their third party service partners who will provide the equipment and systems for detailed equipment installation information.			PM		
Interface with the Customer Representative and their third party service partners to assess the impact and requirements for temporary installation of equipment and systems.					PM
Interface with the Offshore Customer Representative and their third party service partners during the installation of the Temporary Well Related Equipment and Systems to enforce Transocean's requirements.					PM
Coordinate and maintain Regulatory Class and Flag State surveys.	IM	V	V	PM	PM

3 REFERENCES

3.1 LIFTING OPERATIONS HANDBOOK, HQS-HSE-HB-01

3.2 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, CUSTOMER AND SUBCONTRACTOR PERSONNEL AND EQUIPMENT, SECTION 4.2.3

3.3 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, "APPROVAL TO INSTALL AND OPERATE CUSTOMER AND SUBCONTRACTOR EQUIPMENT FORM", FORM FM423A

3.4 LIFTING OPERATIONS HANDBOOK, HQS-HSE-HB-01

3.5 HQS ENGINEERING STANDARD, HQS-OPS-EST-674-01

1 PURPOSE

The purpose of these procedures is to establish a standard for the control of Diving Operations on all worksites both onshore and offshore and to act as guidance for Diving Operations.

2 SCOPE

The procedure applies to the following types of Diving Operations conducted on or near to an installation or pipeline owned or operated by Transocean:

- Surface Orientated Air Diving
- Surface Orientated Mixed Gas Diving
- Mixed Gas Bell Diving
- Saturation Diving

3 PROCEDURE

3.1 ACCEPTANCE CRITERIA FOR THE PROVISION OF DIVING SERVICES

Transocean does not have employee divers as Transocean personnel, and does not have the knowledge in-house to control divers directly. The term "specialist" in this procedure refers to a non-Transocean employee.

Therefore, the company requires all diving operations to be carried out by a specialist Diving Contractor. The local Division or Project QHSE department is available to assist and advise on all types of diving operations.

Where diving operations are extensive and/or complex, an Independent Diving specialist acting on behalf of Transocean must be utilized to oversee the diving operations performed by the Diving Contractor.

In some circumstances, the country where operations are taking place (coastal state) may have specific regulations governing diving operations. Examples are Health, Safety and Environment (HSE) documents in the United Kingdom (UK), United States Coast Guard (USCG) documents in the United States (US) and Norwegian Petroleum Directorate (NPD) documents in Norway. All diving activity conducted on an installation or within the vicinity where Transocean has

responsibility, shall be conducted in accordance with any current local legislation and regulations.

Prior to the commencement of any diving activity, (and usually before mobilization of diving equipment) the diving contractor should be subject to a number of audits to ensure Commercial, Quality, Technical and Safety capabilities are within Transocean's acceptance criteria.

Transocean's Acceptance Criteria for the provision of diving services are as follows:

- The Diving Contractor must have diving rules. These rules must comply with or exceed the minimum requirements of current local legislation and Transocean. The Diving contractor must have Operating Manuals or procedures to effectively control:
  - Safety, Environmental and Quality Management
  - Diving Operations
  - Diving Emergencies
- The diving plant and equipment proposed by the contractor for this contract must be demonstrated to be:
  - Fit for purpose
  - Certified by the relevant authority
  - Accompanied by the relevant operating and maintenance manuals
  - Accompanied by a complete and in date certification package
  - Complete with a planned maintenance program in place
- The Diving Contractor must have an appropriate emergency response procedure including emergency medical support.
- The Diving Contractor must provide medical advisory support for Diving and Topside Emergencies as well as non-emergency situations.
- The Diving Contractors proposed personnel for this contract shall be:
  - Qualified (and in possession of appropriate documents/certificates)
  - Competent
  - Medically fit

- In possession of letters of appointment (where appropriate)
- In possession of offshore firefighting & survival certificates of training

- Failure Mode & Effect Analysis (FMEA) studies (where appropriate) shall be performed on the equipment and procedures proposed for a project and any recommendations of such studies implemented.

- HAZOP & HAZID studies (where appropriate) shall be performed for the proposed diving system installation and operation and any recommendations of such studies implemented.

- An equipment Mobilization / Installation procedure shall be produced by the Diving contractor for the proposed project.

3.2 EMERGENCY RESCUE PROCEDURES

There are a number of emergencies which may present a problem for divers. Some of these are as follows:

- Installation in danger of capsize or sinking.
- Severe fire or explosion or leakage of toxic gas.
- Fire within the diving system or mechanical failure of an integral part of the chamber complex.
- A lost diving bell situation.
- Medical problems with individual divers who may require evacuation to a special treatment center without the inconvenience of decompressing the whole complex.

3.3 CUSTOMER EMPLOYED DIVING CONTRACTORS

Where the Diving Contractor is employed by the Customer to work on a Transocean installation they shall still meet Transocean Acceptance Criteria. The Rig Manager performance is responsible for communicating this with the Customer. The Rig Manager Asset is still responsibly for developing and approving a Diving Project Plan.

Figure 2.1.1.3.1, Permit to Work Checklist for Diving Operations

Transocean	PERMIT TO WORK CHECKLIST FOR DIVING OPERATIONS	Tracking No.

To be completed with a positive response prior to the issue of Permit to Work.		
	√	OIM SIGNATURE
Has any associated activity that may have an impact on the Diving Operation been suspended or controlled by permit?	☐	
Has any combined operations which may have an impact on the Diving Operation been informed and issued their 'Permit'	☐	
Has the Diving Supervisor completed a Workscope?	☐	
Has the Diving Supervisor been warned of all other activity which is in progress?	☐	
Has the Diving Supervisor been informed of all subsea activity and obstructions?	☐	
Has the Standby Vessel, if available, been informed?	☐	
Are the appropriate Flags, Lights, Signs and other warning devices in place?	☐	
Has all over the side work been suspended?	☐	
Has all crane lifts over the diving system been suspended?	☐	
Has all underwater Discharges, Inflows and Outflows in the vicinity of the diving operations been isolated?	☐	
Has all scaffolding work and movement of tubulars been suspended?	☐	
Has all other work which may affect the diving operation been informed of its commencement?	☐	
Has an announcement, warning all personnel that "*Diving is About to Commence*", been made?	☐	

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4 RESPONSIBILITY

	Operations Manager - Performance	Rig Manager - Performance	Rig Manager - Asset	OIM
All Diving Operations are to meet the requirements set out in this procedure and are to be carried out in accordance with Transocean and the Diving Contractors Policies and Procedures. Any Service Partner Policy or Procedure that does not meet Transocean requirements must be addressed with the OIM prior to beginning the work.	IM	IM	IM	IM
Conduct the Transocean Acceptance Criteria for the provision of Diving Services.	IM	IM	PM	
A Diving Project plan must be developed and approved.		V	PM	V
The Permit to Work Checklist for Diving Instructions Form HQS-OPS-PP-01_FM2116 is to be completed and signed with a positive response prior to the issue of Permit to Work.				PM
Review for approval the Diving Operations 'Permit to Work' prior to beginning any diving operations.				PM
Diving Operations shall only be conducted having taken account of the present and forecasted environmental conditions.				IM
PA announcements will be made and barriers erected to warn personnel of operations which could create hazards for the Divers.				PM
Underwater discharges and inflows/outflows will be isolated or clearly identified to the diving team.			PM	PM

OPS – PLANNING AND REPORTING

WELL CONSTRUCTION PLANNING

Diving Operations

	Operations Manager - Performance	Rig Manager - Performance	Rig Manager - Asset	OIM
No overside work will be performed in the vicinity of the diving operation.				IM
No scaffolding work or the lifting of any tubular during diving operations.				IM
No lifting operations will be conducted over the diving equipment.				IM
When applicable, collaborate with an Independent Diving Specialist on contracts which will require diver intervention.			PM	
Liaise with Regulatory bodies, Customer and Contractors.			PM	
When applicable, collaborate with an Independent Diving Specialist on all aspects of the diving program, from the selection and auditing of the diving contractor through planning, execution and monitoring of the diving program, to the final report writing.			PM	PM
When applicable, collaborate with an Independent Diving Specialist for professional assistance and to provide advice to the diving contractor (whilst offshore).				PM
When necessary, veto the start or order the termination of diving operations.				PM

	Operations Manager - Performance	Rig Manager - Performance	Rig Manager - Asset	OIM
When applicable, collaborate with an Independent Diving Specialist to be aware of all changes to current legislation, Diving Safety Memorandum, AODC guidance notes and all industry related information and documentation. This information will be held by the Independent Diving Specialist and only relevant up-dates and revisions will be transmitted to the diving worksite for the attention of the OIM. Any changes in regulation/guidance which will have an impact on the conduct of the diving contract will be communicated immediately.			PM	V
The Diving Contractor shall appoint (in writing) the Diving Supervisors who are to be in immediate control of the diving operation.			IM	V
The diving operation is to be kept under immediate control and supervision.				PM
All diving contractor plant and equipment being used is to be verified fit for purpose and to meet regulatory requirements. Transocean will not provide installation system connections or services used for primary compressed air, water, and electric power for human performed diving operations. REF: HQS-OPS-PP-01, Sec. 2, Sub 1, Appendix 1.3			IM	IM
Diving Supervisors are to provide access to the diving contractor's procedures for each member of the diving team.				V
Diving Supervisors are to maintain an accurate diving operations log book that is signed upon completion of the diving shift.				V

5 REFERENCES

5.1 FIGURE 2.1.1.3.1, PERMIT TO WORK CHECKLIST FOR DIVING INSTRUCTIONS FORM, HQS-OPS-PP-01_FM2116

5.2 PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES MANUAL, HQS-OPS-PP-01, SECTION 2.1, WELL CONSTRUCTION PLANNING

OPS – PLANNING AND REPORTING

FIELD OPERATIONAL REPORTING

1 POLICY

All Installations and Facilities must report operational performance, financial results, and other information as required.

2 PURPOSE

To ensure required information regarding field performance and events is communicated within the Company.

3 SCOPE

This procedure covers Company personnel, Installations and facilities.

4 PROCEDURE

4.1 GENERAL

1. English is the official language of the Company. Internal written Correspondence and Company related documentation must be in the English language. To the extent practical and necessary, Company policies, procedures and work instructions must be published in the local language.

2. Reports must never be falsified. Corrected report(s) must be accompanied by an explanation of why the change is being made.

3. Reporting requirements from corporate departments are contained in the respective manual e.g., accounting reports in the Finance Manual, HQS-FIN-PP-01, personnel reports in the Human Resources Manual, HQS-HRM-PP-01, incident and injury reports in the HSE Manual, HQS-HSE-PP-01.

4. Copies of reports must be retained in accordance with the Company's, Corporate or Division filing and document retention policy as applicable.

4.1.1 Field Operation Reporting Requirements

- IADC Report
- Rig Products Report
- Well Planning

- Riser Running and Pulling Report
- Tubular Report
- Morning Report
- Rig Rate Report
- Operations Event Report
- Personnel Onboard Report
- Dynamic Positioning Report
- Rig Move Report
- HSE Reports
- Service Quality Appraisal
- Rig Improvement Plans

4.1.2 Emergency Reporting

- Reports of emergencies must be made on an immediate basis to the COO, Executive Vice President of Operations and the Vice President Performance and Operations via the Chain of Command. Examples of emergency situations include:
  - Any significant medical situation such as a serious disease.
  - Civil unrest or detention of personnel.
  - Any other situation that seriously jeopardizes employees, equipment or the environment.
  - Any event which triggers a Division Emergency Response System action.
- The exception to reporting via the Chain of Command is when there is a fatality. If this occurs, the CEO and COO must be notified as per the Health and Safety manual, HQS-HSE-PP-01, Sec. 4, Sub. 6.3.

4.1.3 Operational Abnormality Notification

Each Division or Business Unit will ensure that all Operational Abnormalities that meet any of the following criteria are promptly reported to the distribution list below.

- Operations downtime or equipment failure that has lasted, or has the potential to last, more than 24 hours.
- An environmental pollution problem greater than 50bbls or potential problem of equal significance.
- Property damage in excess of $250,000.
- Significant problems or potential problems with Customers.
- Injuries or illnesses that require emergency evacuation from the place of work.
- Any incident that clearly had the potential to result in a fatality.
- Potential insurance claims as a result of property damage.
- Rig evacuation for any reason, tropical storm, security concerns, etc.
- Any other significant issues that could be considered to have a material impact on the Company's well being.

The Operational Abnormality Notification should be e-mailed to the following positions:

Executive Vice President – Performance
Executive Vice President – Assets
Vice President – QHSE Services
Vice President – Engineering and Technical Services
Vice President – Asset Management – Floaters
Vice President – Asset Management – Jackups
Vice-President – Performance
Director - QHSE
Director – Performance Operations
Manager – Well Operations
Global Marketing Account Manager – Customer specific as required

The Operation Abnormality Notification should include the following information however priority must be given to circulating the report quickly rather than ensuring

all the information is complete. **The report should be in e-mail form to enable easy reading from a Blackberry.**

- Rig name and location
- Date and time incident happened
- Customer
- Brief description of the incident
- Potential P&L impact or downtime
- Recovery plan and any external resources required
- Any additional relevant information

The Subject line of the e-mail should be in the format: "Abnormality Report – RIG – DIV – YYMMDD – short description".

In the case that the rig is down (or anticipated to be down) for more than 24 hours a daily update should be sent to the same distribution list. This update should include the current status and forward plan, highlighting any resources or assistance required from outside the Unit.

At the end of the incident, an email should be sent to confirm the installation is back to work and to provide the total amount of downtime.

5 RESPONSIBILITY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Rig Manager - Performance	OIM
Establish procedures dealing with the submission of reports within the Division.	IM			PM	PM
Ensure that reports under their area of expertise and specified to be supplied are correct and submitted according to the established schedule.	PM	PM	PM	PM	PM
Document the procedures to be followed for emergency response per the HSE Manual, HQS-HSE-PP-01.		PM		PM	PM
Reports of emergencies must be made on an immediate basis to the Corporate Operating Officer, Executive Vice President of Operations and the Vice President Performance and Operations.	PM	PM	PM	PM	PM
All Operational Abnormalities that meet the notification criteria are to be promptly reported to the distribution list.	PM	PM			

6 REFERENCES

6.1 FINANCE MANUAL, HQS-FIN-PP-01

6.2 HUMAN RESOURCES MANUAL, HQS-HRM-PP-01

6.3 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.6.3, EVALUATING AND IMPROVING

OPS – PLANNING AND REPORTING

OPERATIONAL EVENT REPORTING

1 POLICY

All Operational Downtime, Equipment Failure Events and other significant events involving Transocean's full or partial responsibility must be recorded, investigated and appropriate action taken to avoid reoccurrence.

2 PURPOSE

To ensure that:

- Downtime and other significant operational events are properly and consistently recorded.
- These events are fully investigated, including the failure analysis of parts when prudent, and that the lessons are learned and shared across the Company.
- Action is taken to prevent reoccurrence.
- The data collected in these reports is also used for equipment performance studies.

3 SCOPE

This procedure is applicable to all Transocean operated installations. The reporting procedure below applies to all installations using GRS for operations reporting.

4 PROCEDURE

Equipment failure events and other significant events that represent incidents are indicators where performance can be improved. Incident analysis uses critical information to establish what happened and how important it is to the company to act on it. Incidents analysis identifies corrective and improvement opportunities that represent lessons learned. The following three steps are required to be completed for incident analysis:

- Fact finding
- Management review of facts
- Communication of corrective and improvement opportunities

4.1 DEFINITIONS

4.1.1 Non Productive Time (NPT)

Non Productive Time (NPT) is defined as any event caused by people, equipment, procedure or environmental conditions that interrupts the normal course and progress of the operations.

As illustrated in Figure 2.3.1 below, NPT is divided between Transocean NPT, Waiting on Weather (WOW) and non-Transocean NPT. Transocean NPT is further sub-divided between planned NPT (preventive maintenance, other planned work stoppages) and unplanned NPT. For the purpose of this policy, only unplanned Transocean NPT is called Downtime (DT).

Non-Transocean NPT is sub-divided into three categories: non-productive time associated with hole problems with the well, non-productive time for which the Customer, or Third Party are responsible, and Well Control Events.

NOTE: WOW that is incurred during or because of a DT event must be accounted for as DT.

The following events are NOT considered to be downtime, whatever the contractual rate:

- Planned delay of operations required to carry out scheduled preventive maintenance.
- Planned shut down of operations to carry out planned modifications to the Installation or planned inspections such as Special Periodic Surveys (SPS) surveys.
- Delays while preparing for a new contract except due to equipment downtime during Customer acceptance testing.
- Delays due to damages to the Installation because of operational incidents beyond Transocean's control, such as work-boat damage to the installation or punch-through on a jack-up Installation.
- Any other delays to operations due to operational difficulties beyond our control.
- Waiting on weather (WOW) except where such WOW occurs during an on-going Transocean responsible DT event.

- Waiting on Customer orders, equipment, materials or third parties.
- Interruptions due to events beyond our control such as those caused by Force Majeure, National strikes, security disruption or governmental orders.
- Time spent performing drills or other preventive actions.
- Time spent recovering from and investigating personal injuries or incidents.

4.1.2 Equipment Failures (EFR)

- Equipment Failures (EFR) designate short and relatively ordinary Transocean equipment related events incurring less than 3 hours of downtime, damage or repairs worth less than $25,000.

4.1.3 Major Equipment Failures (MEF)

- Major Equipment Failures (MEF) designate equipment failures that resulted in 3 or more hours of downtime, damage or repairs worth $25,000 or more, or in the opinion of the originator, are significant and worthy of follow-up and/or sharing with others.

4.1.4 Procedural Error or Failures (PEF)

- Procedural Error or Failures/Transocean responsible (PEF) designate operational events or well problems caused by human procedural error(s) under Transocean's responsibility. Examples of this are: fishing objects dropped in the well, pulling back a string due to an error in the assembly or recovering a stand dropped in the derrick due to an operator error. For the purpose of clarification, fishing or string recovery operations following wash-out or failure of Transocean owned or supplied tubular must be reported as equipment downtime in the category drill string.

4.1.5 Other Events Transocean (OET)

- Other Events/Transocean responsible (OET) if they are under our control. For example, waiting on equipment to be supplied by Transocean or a strike of Transocean staff only, etc.

4.1.6 Other Events Customer (OEC)

- Other Events or Well Events / Customer & Third Party responsible (OEC) beyond Transocean's control. For example waiting on Customer equipment,

orders or materials, Force Majeure event, national or general strike, security events etc.

4.1.7 Hole Problems (HPR)

- Hole Problems (HPR) non-productive time associated with problems in the hole beyond Transocean's control. Examples of HPR are stuck pipe events not attributed to Transocean.

4.1.8 Well Control Event Report (WCE)

- A Well Control Event Report (WCE) represents non-productive time to remedy an unplanned well control event.

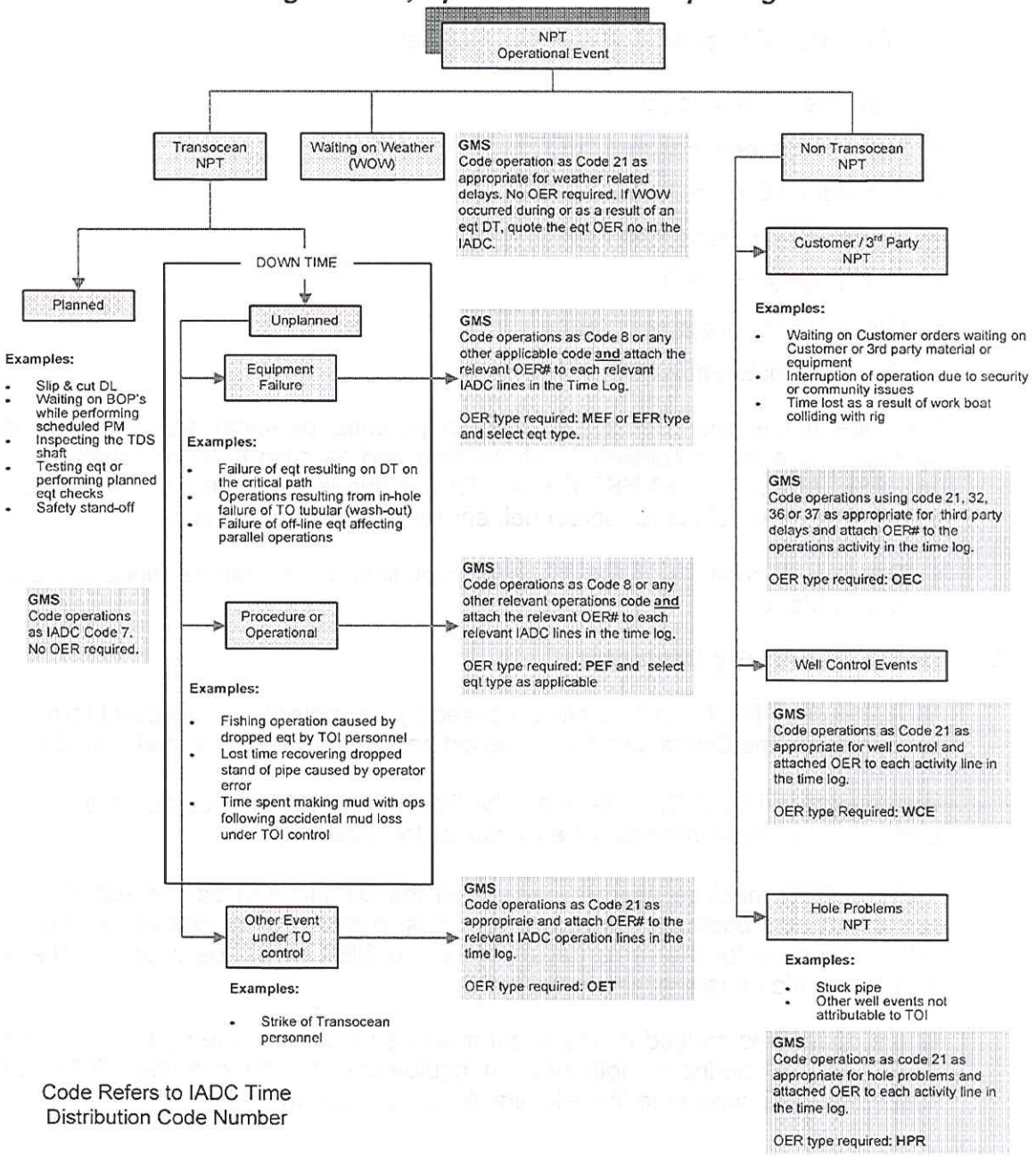
NOTE: The reported DT hours must include all the process hours lost as a result of the event independently of the contractual rate structure. Equipment DT must include all the hours lost and not just the time spent repairing the equipment. Non equipment DT must include all the hours spent returning to the previously achieved point or until final abandonment of the well.

Examples are provided for illustration at the end of this policy. In case of doubt, the Installations and Performance Rig Managers must seek clarification from the Performance Operations Manager.

OPS – PLANNING AND REPORTING

OPERATIONAL EVENT REPORTING

Figure 2.3.1, Operational Event Reporting



Code Refers to IADC Time Distribution Code Number

4.2 REPORTING PROCEDURE

The Operational Events to be reported include:

- Equipment Failures (EFR)
- Major Equipment Failures (MEF)
- Procedural Error or Failures (PEF)
- Other Events Transocean (OET)
- Hole Problems (HPR)
- Other Events Customer (OEC)
- Well Control Event (WCE)

If an operational event results in actual or potential personal injury, environmental damage, the event is considered an incident and as such must be reported as per the HSE Manual, HQS-HSE-PP-01. This includes determining the actual and potential severity values for personnel, environment and property.

- Detailed instructions on the procedures outlined below can be found in the GMS User's Manual.

4.2.1 TRANSOCEAN Rig Downtime

All Transocean Rig Downtime either caused by equipment or procedural failure must be reported in the Operations Event Report and associated to the daily IADC report.

Most events will be IADC code 8 but the Downtime must be recorded even if code 8 is not used (in agreement with the Customer for example).

A single OER must be used to capture all the DT incurred as a result of a single equipment or procedural failure. If the DT is interrupted by productive operations before resuming for the same cause, the same OER should be used and the same number should be referenced in the IADC.

All the operations caused by the event must be included in the rig DT. In particular, WOW incurred during or following an equipment DT (for example, BOP repair). Attach the OER number to the relevant WOW report in the IADC.

4.2.2 WOW

WOW does not require an OER. However filling in an OER is strongly encouraged whenever, in the opinion of the reporter, the event is significant and worth sharing with others in Transocean.

4.2.3 OEC / HPR

Other non productive time for which Transocean bears no responsibility **must** be reported in the IADC as either wait on Customer/third parties or, as applicable and agreed with the Customer (for example, fishing). It is also mandatory that an OER is filled for these events.

4.2.4 WCE

All well control events **must** be reported in the IADC. It is also mandatory that an OER (WCE) is filled for these events.

4.2.5 Planned Interruptions (SPM or SPS)

Planned interruptions must not be reported as DT but instead be described using the appropriate code. They do not require filling an OER. Planned maintenance in particular must be reported using IADC code 7. However, if the contract requires such interruption to be coded IADC code 8 and/or zero rate this must not affect the Company internal DT record.

4.3 DUAL OR PARALLEL ACTIVITY OPERATIONS

- The failure of equipment used for off-line activity is accounted for as DT when it affects the global and not just the main line activity.

NOTE: On the Dual-Activity Installations, any DT that interrupts on going activities on the secondary rotary is considered to be DT (except if the main operations are already interrupted).

NOTE: On the Multi-Activity Installations, any DT at an auxiliary station that stops or slows down the main operation must be reported as DT.

4.4 OER REVIEW PROCESS

As soon as an OER report is validated and approved by the rig manager, it will become available in GMS for review and comments by shore based personnel.

The aim of the OER review process is to allow company individuals at various management levels to provide feedback and insight into the Event in a structured manner. Through Subscription and Notification system, the OER will follow a data flow based on the company organizational structure and will be accessible via 5 possible levels of subscription. Anyone having access to a rig can subscribe for events (or reports) issued by the rig at any level. However, the "normal" process and level of subscription would be:

- Level 0 for Rig managers (or anyone who wants to be notified immediately when the report is released).
- Level 1 for Division level personnel (Division Mgr or Division Ops mgr)
- Level 2 for Unit/Division level Field Support
- Level 3 for Corporate personnel interested to view and comment on the report after appropriate review and investigation

4.5 CLOSING OF OERs

The completion of the review process is not the closing of the OER. This must be done by the Rig Manager

The purpose of the OER is not only to report and account for the event but also to analyze the root causes of the event, to identify what can be done to prevent reoccurrence and to document the follow-up and corrective action. The OER must be completed by or with the input of the on-board person(s) competent to analyze the event. The failure and the remedial work carried out must also be reported in Maintenance Management System (MMS) and/or FOCUS.

No such report must be considered complete and closed until all the causes of the failure and the recommended remedial actions have been identified and listed in the OER. If the analysis work has not been done at the time the daily report is being filled and more time is needed to complete the report, the OER should be left open until such time it can be completed as required. It is always possible to come back on and amend an OER if facts or conclusions that should be included in the report are uncovered after a report has been submitted.

- The Rig Manager Performance or Rig Manager Asset can close out an OER when all of the following is met:
  - When the causes of the event have been identified

- All required corrective actions have been carried out or are tracked in FOCUS

4.6 INCIDENT INVESTIGATIONS

At the discretion of the Division General Manager a Kelvin TOP-SET investigation may be required for certain incidents.

5 EXAMPLES

5.1 EXAMPLE: EVENTS HAVING INCURRED NO DOWNTIME

- Premature failure of a bearing in a thruster unit due to oil contamination. No DT but the unit is unserviceable and will need to be pulled. Failure could have been avoided if oil analysis and oil filtering equipment had been used. Open an OER, select PEF as report, fill report in and submit. The reason for being an OER is because this is a potential Lesson Learned to be shared company wide.

5.2 EXAMPLE: EQUIPMENT RELATED DOWNTIME

- The Installation experiences 2.0 hrs of downtime due to the requirement to change out 2 pump liners while circulating at reduced rate as drilling cannot continue during the repairs Open an OER and select EFR.
- In the case where the Customer Representative and the OIM agree that it must not be recorded as code 8 on the IADC report but as circulating time, the activity report may be amended to show circulation, IADC code 5, but the OER should still be filled in and recorded as DT in the OER.
- The bit must unexpectedly be pulled to the shoe while a mud pump module is being replaced. 3 hours are spent POOH, 4 hours waiting for the repair to be completed and 3 hours to return to bottom. A total of 10 hours of DT must be recorded as follows in the IADC report:
  - 3 hrs POOH for repair, IADC code 8 not code 6, (Quote OER number)
  - 4 hrs Repair Rig, IADC code 8 (Quote OER number)
  - 3 hrs RIH to bottom, IADC code 8 not code 6, (Quote OER number)
- If while the pump was being repaired, productive operations (picking up drill pipe stands for example) are carried out as requested by the company man,

then the productive activity must be reported in the IADC and the repair time must be reduced accordingly.

- The Installation experiences a problem with the H4 Connector on a subsea BOP and it requires securing the well and pulling it to surface in 16 hours. After correcting the problem in 12 hours the weather deteriorates and it is not possible to run the BOP for 24 hours. The weather improves and the BOP is run and tested in 32 hours. This incident should be reported on an OER as MEF (equipment type BOP) for a total of 84 hrs. The time waiting on weather (WOW) should be included with the overall DT in this instance as it resulted from the failure and need to trip the BOP.
- A workboat hits and damages an Installation column; the operations are stopped for the time necessary to inspect the column and do emergency repairs. Because this collision is considered to be beyond our control, the time spent doing so must NOT be considered DT and be reported in the IADC as Waiting on Customer; Open an OER and select OEC.

5.3 EXAMPLE: NON EQUIPMENT RELATED DOWNTIME

- The Derrickhand is transferring mud between the mud pits, opens the wrong valve and dumps 450 bbls of water-based mud overboard. Operations are stopped, mud volume is rebuilt in 6 hrs, and drilling proceeds. This incident should be reported in the IADC as code 8, Waiting on Transocean. Open an OER and select PEF (An LOC report must also be completed).
- The pipe handler operator makes an operating mistake and drops a stand of drill pipe. The time spent resolving this problem must be reported in the IADC as code 8, Waiting on Transocean and not as equipment DT. Open an OER and select PEF.

5.4 EXAMPLE: HOLE PROBLEM, CUSTOMER & OTHER THIRD PARTY RESPONSIBLE NON PRODUCTIVE TIME

- 2 hours are spent waiting on a logging tool to continue the operations. Open an OER and select OEC.
- 3 days are spent in fishing operations as the result of the introduction of a new tool that failed. Open an OER and select HPR.

  This is a potential Lesson Learned to be shared company wide.

  The operations reported are the actual fishing operations and are recorded as NPT (not DT) in the GMS statistics.

5.5 EXAMPLE: PLANNED INTERRUPTIONS

- The BOP inspection and PM planned between wells cannot be completed in time as a result of a very short field move. 5 hours are spent waiting for the stack to be ready. Assuming no other productive operations could be performed during this time, 5 hours of Preventive Maintenance must be reported in the IADC under code 7. IADC code 8 must not be used as it would result in the recording of non-equipment related DT.

6 RESPONSIBILITY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Maintenance Supervisor
Review and approve all OERs from the installation. Departmental Supervisors are responsible to provide the OIM the information required to review and approve.					PM	PM	PM	
Report the work done in the Computerized Maintenance Management System (CMMS) referencing the OER number.							IM	PM
Close out all OERs.					PM	PM		
Define the follow up process and verify that this process is working effectively.		PM	PM	PM				
Determine if a TOP-SET investigation is to be performed for the incident.	IM	PM						
Investigate OERs, close out corrective actions and communicate the Lessons Learned.			IM	IM	PM	PM	V	

7 REFERENCE

7.1 FIGURE 2.3.1, OPERATIONAL EVENT REPORTING

OPS – PLANNING AND REPORTING

PERFORMANCE MEASUREMENT

1 POLICY

Performance measurements must be established to compare operational performance against agreed benchmarks and plans, to identify best practices and provide recommendations for improvement.

2 PURPOSE

The purpose of this policy is to provide a simple and consistent approach to performance measures and metrics that enables people to continuously improve performance by:

- Understanding performance in terms of Customer: expectations, service, feedback, satisfaction and value.
- Recognizing Divisions, Installations and Individual contributions to Company performance results.
- Identifying lessons learned through effective benchmarking of performance.
- Utilizing performance measurements to determine efforts that contribute to operational excellence and continuous improvement.

3 SCOPE

This Policy covers all Installations owned, operated or managed by the Company.

4 PROCEDURE

4.1 GLOBAL MANAGEMENT SYSTEM – PERFORMANCE MEASUREMENT AND REPORTING

The Global Management System provides the ability to report and measure performance at the Installation level through use of the following examples:

- End of Well Report
- Downtime Results
- Safety Performance Results
- Key Step Measures (KSM) Report
- Service Quality Appraisal Reports
- Rig Manning levels

For further information see the Global Management System Performance and Operations User Manual (HQS-OPS-UM-08) which represents the Operations Module in GMS.

4.2 END OF WELL REPORT

The End of Well Report available in the Global Management System (GMS) contained the following well performance summary information:

- Well Construction Plan Summary
- Summary of well time by Well Phase / Well Section
- Summary of well time by IADC codes
- Summary of Simultaneous Operation Activity Time by Well Phase:
- Well drilling performance Scorecard
- Key Step Measure (KSM) – Performance
  - Tripping
  - Casing Running
  - Running and Pulling BOP
  - Rig Move and Positioning
- Rig and Well Non-Productive Time
- Health, Safety and Environment (HSE) Performance
- After Action Reviews (AAR) - Best Practices / Lessons Learned
- Service Quality Appraisal (SQA)
- Rig Improvement Plan (RIP)

4.2.1 Key Step Measures (KSM)

Is defined as measure used to track and benchmark set of operations activities carried out during the well construction process that are determined to be within the control and responsibility of the rig in way of resources and occurrence. The KSM operations activities contribute to the overall well construction time and are represented by the flat spot section of time-depth curve for the well.

The Key Step Measures (KSM) which are tracked and reported in GMS:

- Tripping
- Casing Running
- Running and Pulling BOP
- Rig Move
- BHA Handling
- Slip and Cut Drill Line
- Rig Up and Rig Down

4.3 PERFORMANCE BENCHMARKS

Performance benchmarks will be set to establish the target. Performance Benchmarking is the process of assessing and comparing the Installations performance result against a predetermined target in order to search for new ideas, methods and continuous improvement techniques to achieve a desired result. Performance benchmarking can be carried out within the following comparison groups.

- Rig Types
- Rig Categories
- Rig Design Class
- Rig Performance Group

For further information see the Global Management System Performance and Operations User Manual (HQS-OPS-UM-08) which represents the Operations Module in GMS.

4.3.1 Rig Types

Rig Types are defined per the following:

The shape, function and arrangement of marine, drilling and BOP equipment which differentiates and distinguishes one rig type from another.

Rig Types include the following:

- Barge
- Jackup
- Semi-Submersible
- Drill Ship

4.3.2 Rig Type Category

Rig Type Category is defined per the following:

Consolidated grouping of rig types based on the water depth capacity, environmental capability, and functional arrangement of marine and BOP equipment which differentiates and distinguishes one grouping from another.

Rig Category includes the following:

- Jackup and Barge Rigs
  - High Specification Jackup
  - Standard Jackup
  - Swamp Barge
- Midwater and Harsh Environment Floating Rigs
  - Midwater Floater
- Deepwater Floating Rigs
  - Ultra – Deepwater (> 7,500 ft)
  - Deepwater (< 4,500 ft) Confirm

4.3.3 Rig Design Class

Rig Design Class is defined per the following:

Engineering and technical capabilities that define rig operation boundary and limits, within a specified marine operating environment.

- Examples of Rig Design Class are the following:

- Aker H-3.2 Self-Propelled Semi-submersible
- Baker Marine Services BMC-300-IC
- Earl & Wright / Sedco 700 Series
- Friede & Goldman L-780 MOD II
- Earl & Wright / Sedco 711 Series
- Global Marine Glomar 456 Class
- Marathon Letourneau Class 116-C
- Mitsui Modec 300-C-38
- Reading & Bates RBS-8M
- Samsung / Reading & Bates Discoverer Class
- Sedco Forex Express 2000
- Rauma Repola Arctic DP
- Enhanced Enterprise Class
- Enterprise Class

4.3.4 Rig Performance Group – Technical Drilling Capability

Rig Performance Group(s) is defined per the following:

Consolidated grouping(s) of rigs based on Rig Types and Rig Design Classes to provide the capability to effectively benchmark performance across a wide base number of rigs.

Rig Performance Groups include the following:

- Dual Activity Drill Ship
- Multi-Activity Drill Ship
- Dual-Activity Semi-submersible
- Multi-Activity Moored Semi-submersible
- Moored Semi-submersible

- Standard Jackup
- Multi-Activity Jackup
- High Specification Jackup
- Barge

5 RESPONSIBILITY

	Executive Vice President Performance	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM
Review and provide input analysis on Division Performance results to ensure that adequate resources are in place to achieve Company performance expectations.	IM	PM						
Review and provide input analysis of GMS monthly and quarterly scorecard performance measurements to identify improvements for continuous improvement.		IM	PM					
Identify opportunities for improving operability and maintainability of the installation equipment.		IM	IM		PM			
Review and provide input analysis of GMS quarterly rig performance measurements to identify improvements for continuous performance improvement.		IM	IM	PM		PM		
Compare the installation over time against similar performance benchmarks outside of his management scope.				IM		PM		PM
Identify and communicate operational requirements which may potentially impact proposed rig modifications, design and installation of new equipment.				IM		PM	V	

	Executive Vice President Performance	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM
Present performance results to the Installations crew to demonstrate the potential performance improvement opportunities, identify gaps and to communicate expectations.				IM		PM		PM
Ensure all operational information is accurately entered into GMS.						IM		PM

6 REFERENCE

6.1 GLOBAL MANAGEMENT SYSTEM PERFORMANCE AND OPERATIONS USER MANUAL, HQS-OPS-UM-08

OPS – PLANNING AND REPORTING

PERFORMANCE IMPROVEMENT – LATERAL LEARNING

1 POLICY

Rig supervisors and managers are expected to achieve Continuous Performance Improvement and Innovation through lateral learning:

- **to make effective decisions.**
- **to contribute to experiences and operation knowledge within a shared company culture across all boundaries.**
- **to achieve operational excellence through continuous performance improvement and innovation that sustains a safe performance advantage.**

2 PURPOSE

The purpose of this policy is to:

- Achieve Continuous Performance Improvement and Innovation through lateral learning by sharing operation knowledge.
- Communicate expectations to personnel that identifying, sharing and embedding lessons learned to improve performance is a responsibility of all persons.
- Connect and recognize people who are willing and able to share their experience and knowledge with each other and the organization.
- Leverage the size advantage of the organization to access best practices in a wide range of functions, disciplines and operations to improve performance and support innovation.
- Ensure work practices and people's experience are not only transferred and shared, but are transferred and implemented effectively to make a difference in performance.
- Provide our Customers access to a wide base of experience and operational capability to support effective delivery of well construction services which meet, or exceed, agreed Customer requirements.
- Capture and embed lessons learned in performance standards to establish effective operational boundaries and limits criteria.

3 SCOPE

The policy is applicable to the following rig categories performing rig and well operations:

- Jackup and Barge Rigs
- Midwater and Harsh Environment Floating Rigs
- Deepwater Rigs

4 PROCEDURE

4.1 PERFORMANCE IMPROVEMENT – LATERAL LEARNING

By capturing and embedding the lessons learned through our daily operations, managers and supervisors are able to make informed decisions which contribute to achieving operational excellence.

Informed people are able to make better decisions, which leads to developing a safe performance culture that values and drives Continuous Performance Improvement. Performance Improvement – Lateral Learning is achieved through the following:

- Identifying the sources of lessons learned
- Submitting and classifying proposed lessons learned within Transocean
- Approval and implementation of lessons learned to achieve Lateral Learning

4.1.1 Identifying the Sources of Lessons Learned

The sources of Lateral Learning opportunities can be found throughout Transocean operations. Each and everyone of Transocean employees have the responsibility and authority to identify lessons learned that can be utilized at the local installation level, a rig class level, rig type or even throughout the entire fleet.

Examples of where Lateral Learning opportunities can be identified:

- Daily Job Meetings
- Pre-Tour Meetings
- Pre-Task Meetings
- Tour Change Handovers
- End of Well Phase Reviews
- Performance Reporting
- Development of Well Construction Plans
- After Action Reviews
- Weekly Operation Event Reviews

- Quarterly Performance Reviews
- Operation Forums
- Service Quality Appraisals
- THINK Planning
- START Observation and Monitoring
- Performance Monitoring Audit and Assessment (PMAA)
- System Management and Review Teams (SMART)
- FOCUS Planning and Tracking

Lessons learned are identified during the review of operational, maintenance and management activities.

If a lesson is not effectively captured, shared and embedded, performance will not be sustained or improved.

Not all lessons learned are possible or practical to be documented or written down, nor do all have an application across all Rig Types, Rig Design Classes and operating locations.

The following rules are for determining if a lesson learned has been identified:

- Is the Lesson Learned recognized by people at the Installation or Facility as a technique or methodology that, through experience, has been Proven to reliably lead to an improved result?
- Is the Lesson Learned recognized by people at the Installation or Facility as an idea that is Practical and can be applied with reasonable efforts so an improved result can be delivered and realized with fewer unforeseen problems?
- Is the Lesson Learned recognized by people at the Installation or Facility as a Safe and Effective way to perform a task or activity with the least amount of effort, based on repeatable procedures that have proven themselves over time?

4.2 SUBMITTING AND CLASSIFYING PROPOSED LESSONS LEARNED WITHIN TRANSOCEAN

Transocean has a number of processes in place that allow for the contribution of lessons learned. It is important to recognize the tools that are at your disposal for capturing the proposed learning.

If a Lesson Learned is verified as Proven, Practical, Safe, and Effective and requires documentation, then the learning can be submitted through the following:

- Rig Specific Document Approval Process
- GMS – SMART
- Computerized Maintenance Management System (CMMS) – Change Request
- REA
- Lesson Learned databases (future addition to the management system)

4.2.1 Rig Specific Document Approval Process

The process for submitting lessons learned for a Rig Specific Procedure requires the OIM to developed and reviewed by the OIM and approved by the Rig Manager. Exceptions to this approval authority are regulatory-approved documents, which do not require Rig Manager approval. Maintenance tasks provided by corporate, Unit, Division and/or rig management require OIM approval only. REF: HQS-CMS-GOV Sec. 5, Sub. 2. 5.1.4.

A Task Specific Think Procedure (TSTP) is a Rig Specific Procedure document. The TSTP uses the THINK application to facilitate the approval process.

4.2.2 GMS – SMART

The SMART process enables people at different levels in the Company (corporate, unit, division and installation) to propose and implement change to the Company Management System categorized by core management functions. REF: HQS-CMS-GOV, Sec. 5, Sub 1.

The SMART Request form can be found in the Global Management System (GMS).

4.2.3 Computerized Maintenance Management System (CMMS) – Change Request Process

The process for submitting lessons learned must be submitted for review and potential implementation through the Change Request Process within the Computerized Maintenance Management System tool known as the Computerized Maintenance Management System (CMMS).

All Change Requests will be reviewed by installation supervisors, Rig Manager - Asset, and key shore-based support personnel to determine the applicability to fleet wide operations. REF: HQS-OPS-PP-01, Sec. 5.

4.2.4 REA

A lesson learned that requires an REA will be submitted to HQS Engineering Department using the Request for Engineering Action process. REF: HQS-OPS-PP-01, Sec. 2, Sub 8.

4.3 APPROVAL AND IMPLEMENTATION OF LESSONS LEARNED TO ACHIEVE LATERAL LEARNING

When a proposed Lesson learned has been reviewed and validated it will need to be approved and implemented.

4.3.1 Approval of Lessons Learned

The approval of a lesson learned requires that it be documented in one or more of the following as operation content:

- Level 3 Rig Specific Procedures
- Company Management System
- Computerized Maintenance Management System (CMMS)
- REA Database

Once entered through the appropriate system the lesson learned can be reviewed validated, and disseminated appropriately within the company management system.

4.3.2 Implementation of Lessons Learned

Updates occur within Transocean's management system at a frequent interval. To successfully implement the new update and to leverage the size advantage of Transocean's global operations, operation content must be shared through the interaction of people.

4.4 AFTER ACTION REVIEW (AAR) MEETING

An After Action Review meeting is a facilitated discussion between people who participated directly in an operation or maintenance activity to improve work process performance and results.

Performance of After Action Review Meeting requirements provides the means to:

- Verify the operation or maintenance activity was achieved and the Customer is satisfied with the performance.
- Review the effectiveness and execution of Level 3 Rig Specific Operation and Maintenance Activities Procedures and the application of the **THINK** Planning Process.
- Identify what needs to be done differently on the Installation the next time the operation or maintenance activity is to be performed.
- Submit and classify proposed lessons learned on the Installation in real time.

4.4.1 After Action Review Participation

The following is required to be performed by all participants during an effective After Action Review (AAR) Meeting:

- Verify if the activity achieved its goals in the most safe and efficient manner.
- Do not judge success or failure.
- Discover why things happened, good or poor.
- Focus directly on the Level 3 Rig Specific Operation and Maintenance Activities and task steps that were required to be performed and achieved.
- Identify which risk reducing controls described in the Level 3 Rig Specific Operation and Maintenance Activities were effective and which ones require improvement.
- Encourage people who participated in the activity to share important personal lessons learned through effective conversations.
- Involve a wide base group of participation so more of the operation and / or maintenance activity and specific task steps can be recalled, and more Best Practices can be learned and shared. The more people learn from one another the more effectively they will perform; and the more likely people will succeed.

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PERFORMANCE IMPROVEMENT – LATERAL LEARNING

The following are the five steps to be applied for performing an After Action Review (AAR):

Step 1	What was supposed to happen? What were we trying to accomplish? • What was the purpose of the activity in delivering service to our Customer? • How were the Level 3 Rig Specific Operation and Maintenance Activities expected to be applied to achieve the activity?
Step 2	What exactly happened? Why? Why not? What were the results? • What happened while performing the Level 3 Rig Specific Operation and Maintenance Activities? • How was the Level 3 Rig Specific Operation and Maintenance Activities monitored and was it achieved effectively or ineffectively? • Who performed Level 3 Rig Specific Operation and Maintenance Activity task steps? • What was learned from performing the Level 3 Rig Specific Operation and Maintenance Activity task steps? • What did happen which was better than what was expected, as well as what did not meet requirements? • Why did the activity achieve, or not achieve the expected results?
Step 3	What was learned? • Based on what was agreed to do and what actually happened, what did people learn? • What do people know now that people did not know before the activity commenced? • What are the key lessons learned people have learned which represent specific performance improvements? • If another team, group or individual(s) were responsible to perform the same or similar activity, what lessons learned or performance improvements would be proposed?
Step 4	Determine how the task should be done differently • Based on what people have learned, what further additional actions are required to sustain or improve performance?
Step 5	Apply Actions to Share and Embed Lessons Learned • For any lessons learned that require documentation, who are the people responsible to follow-up on the proposed lesson learned(s)?

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PERFORMANCE IMPROVEMENT – LATERAL LEARNING

5 RESPONSIBILITY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Submit Rig Specific lessons learned for a Rig Specific Procedure.							PM	
Approve Rig Specific lessons learned for a Rig Specific Procedure.					PM			
Review for approval the change request within the Computerized Maintenance Management System tool known as the Computerized Maintenance Management System (CMMS).						PM	PM	

6 REFERENCES

6.1 COMPANY MANAGEMENT SYSTEM, HQS-CMS-GOV, SECTION 5.2, MANAGEMENT SYSTEM DOCUMENT STRUCTURE

6.2 COMPANY MANAGEMENT SYSTEM, HQS-CMS-GOV, SECTION 5.1, SYSTEM MANAGEMENT AND REVIEW TEAM (SMART)

6.3 PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES, HQS-OPS-PP-01, SECTION 5, ASSET (MAINTENANCE, PROCUREMENT AND INVENTORY)

6.4 PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES, HQS-OPS-PP-01, SECTION 2.8, REQUEST FOR ENGINEERING ACTION (REA)

OPS – PLANNING AND REPORTING

CUSTOMER SERVICE DELIVERY

1 POLICY

Rig Supervisors and Managers are to initiate, develop and sustain effective communications and relationships with Customers to ensure well construction services are safely delivered meeting agreed requirements.

2 PURPOSE

The purpose of this policy is to:

- Establish a service setting which supports effective Customer relationships.
- Deliver well construction services which meet, or exceed, agreed Customer requirements.
- Provide Customers a service experience which supports sustained service partnerships.

3 SCOPE

This policy applies to all Installations and facilities owned, operated or managed by the Company and to all employees of the Company involved in delivering Customer service.

4 PROCEDURE

4.1 CUSTOMER COMMUNICATION PLANNING

Customer feedback is a key element of knowing how well the Company is meeting its commitments and how well it understands its Customers.

Customer Communication Planning is intended to provide the opportunities for the people who actually perform the work and deliver service to Customers to build the right relationship which supports open and honest dialogue.

Customer Communication Planning is comprised of the following:

- Pre-Spud Meeting
- Daily Meeting
- Standard Instructions to Driller (SID)
- End of Well Review

- Service Quality Appraisal

It is the responsibility of the Rig Manager – Performance to implement Customer Communication Planning onboard the Installation.

4.2 CUSTOMER SERVICE PARTNERSHIP

The Core Values, Company Management System processes and responsibilities are how Customer services are delivered and develops a customer service partnership.

Customer service delivery directly affects the Customer service partnership.

4.3 SERVICE QUALITY APPRAISAL

The Company's Service Quality Appraisal (SQA) is intended to align Transocean's focus and efforts to:

- Understand our customers' needs.
- Communicate with our customers on the performance they can expect the Company to deliver.
- Work collaboratively with our customers to identify improvement and corrective opportunities, and then apply the necessary actions to achieve positive change.

The SQA is a communication tool designed to facilitate communication between:

- Customer Representative onboard the Installation and the OIM.
- Customer Representative onshore and the Rig Manager – Performance and Asset.

Communicating with our customers on the quality of the service we provide is critical to our business.

Although the Service Quality Appraisal process is a communication tool designed to obtain feedback from our customers, it is only effective when a mutual relationship of trust and open communication exists.

It is the responsibility of managers and supervisors to know our customers and understand their needs. Establishing a relationship that fosters honest feedback ensures we can communicate and work together with our customers to identify and

define actions in SQA Rig Improvement Plans that represent solutions to deliver optimal performance.

REF: Global Management System (GMS) User Manual (HQS-OPS-UM-08) - for further information related to submitting the SQA and Rig Improvement Plans (RIP) via GMS.

4.3.1 Service Quality Appraisal Performance Categories

The SQA performance categories represent a summary of the scope of well construction services the Company is committed to provide and deliver to our Customers.

The SQA Performance Categories include the following:

A. Health and Safety

- Housekeeping Practices
- Compliance with Transocean Key Safety Processes
- Participation in START Observation and Monitoring Process
- Effectiveness of **THINK** Planning Process
- Utilization of Time Out For Safety (TOFS) and Permit to Work (PTW)
- Quality of Safety Drills and Emergency Response Preparedness

B. Operations Management

- Performance Planning
- Between Wells
- Interface with Service Partners (Third Parties)

C. Drilling Operations

- Drilling
- Tripping
- Running Casing
- BOP / Riser Handling / Testing

- BHA Change Out, Planning and Execution

D. Marine Operations

- Station Keeping / Rig Move Operations
- Deck Management
- Emergency Drills
- Management of Service Vessels

E. Equipment

- Operations of Equipment
- Performance of Equipment
- Reliability of Equipment
- Maintenance of Equipment
- Execution of Planned Maintenance During Well Operations
- Care of Customer Equipment

F. Environmental Affairs

- Waste Management and Segregation
- Pollution Prevention and Response
- Awareness of Crew (EMS, Basic Requirements)
- Onboard Communication (Spill Plans, Waste plans, Green Team Notice boards, Awareness Material)

G. Accommodation Services

- Living Quarters and Facilities
- Catering

H. Personnel

- Attitude
- Teamwork

- Leadership
- Management and Organization
- Training and Crew Competence

I. Communications

- Responsiveness to Customers' Needs
- Conduct of Daily Meetings
- Coordination of Logistics
- Frequency of Rig Visits by Transocean Management

5 RESPONSIBILITY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Participate in identifying and defining innovative business solutions to meet Customer needs.	PM	PM	PM		PM			
Customer contact for all service provision related matters.	IM	PM	PM		PM			
Ensure rig equipment and systems are operated within technical and design capabilities.	IM			IM		PM	IM	
Effectively monitors and evaluates Customers concerns and responds quickly to meet Customer needs and resolve problems.		IM			PM		PM	
Ensure rig equipment and systems capabilities are aligned within Rig Contract requirements.		IM	IM	IM	PM	V		
Develop the annual rig Maintenance, Repair and Operating Costs (MRO) and CAPEX Budget in response to customer's needs. Market existing equipment, new equipment and services to current and potential Customers.			PM	V		V		

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CUSTOMER SERVICE DELIVERY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Identify and communicate with the Customer operational requirements which may potentially impact proposed rig modifications, design and installation of new equipment required by Customer Service Partner Equipment.			IM	V	PM	V		
Communicate to the Customer the critical planned maintenance and out of service time which affects Well Construction Planning.			IM		PM	V	PM	
Provide technical information and proposed solutions for equipment.				IM		PM		
Meet with Customer on a daily basis to support the delivery of professional rig and well operations, resulting in effective drilling and completion performance.					PM			
Visit the installation to support effective management visibility, monitor rig performance results and to ensure consistent and effective communication with the OIM and Department Supervisors.			PM	V	PM	PM		
Coordinate and maintain Regulatory Class and Flag State surveys.			IM	V	V	PM	PM	

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Work closely with the Offshore Customer Representative to optimize performance to meet agreed targets and minimize potential well-related Non-Productive Time (NPT) due to the consequential impact of procedural errors and equipment faults.					IM	V	PM	
Verify specific Procedure Requirements and interfaces to be done on the Installation between Company, Customer, and Third Party Service Partners and achieve agreement with all involved parties, particularly with respect to defining responsibilities and limits of authority.					IM		PM	
Interface with Offshore Customer Representative to ensure contractual obligations offshore are met.					IM		PM	

6 REFERENCE

6.1 GLOBAL MANAGEMENT SYSTEM USER MANUAL, HQS-OPS-UM-08

OPS – PLANNING AND REPORTING

RIG MODIFICATION REQUEST (RMR)

1 POLICY

Modifications and upgrades to Installations must be reviewed, approved and carried out in a safe, planned, controlled and cost-effective manner. All applicable drawings and documentation must be amended to reflect the changes.

2 PURPOSE

The purpose of this policy is to:

- Ensure Installations, Divisions and Field Support organizations are aware of the correct procedures and documentation required for review and approval of any modifications or upgrades.
- Ensure all modifications, changes and upgrades are executed in an effective, safe and professional manner, with fit-for-purpose solutions.
- Ensure all Installation documentation is updated and current.

3 SCOPE

This Procedure applies to all facilities and employees of the Company as well as employees of any operator, contractor, or outside agency that work on any offshore Installation owned, operated, and/or managed by the Company.

4 PROCEDURE

1. 1 GENERAL

A modification may be any alteration or addition to the installation's hull, superstructure, mechanical equipment, electrical system, electronic equipment, instrumentation and control or software systems. A modification may also be any amendment of installation-specific technical documentation, operating procedures or manuals.

A modification will fall into one of the following three categories, corresponding to choices on the Rig Modification Request (RMR) form. Refer to part 6 of this subsection for definitions.

A repair which reinstates equipment or systems to original condition (i.e. like-for-like replacements) is NOT considered a modification and will be documented in accordance with the policies and procedures outlined in the Maintenance Management System EXCEPT in the case of primary structure where repair

planning and procedures require special attention to ensure continued safety of the installation and personnel onboard.

A repair which leads to a change, improvement or enhancement of the equipment or system is not a like-for-like replacement and is considered a modification subject to review and approval under the RMR/REA system.

Modifications may be requested by Offshore or Onshore Installation Management or Operator Representatives. Where applicable (subject to regional or installation-specific requirements), due reference must be made to the Safety Case /Operations Integrity Case (OIC)/Major Accident Hazard Risk Assessment (MAHRA) and all risks identified and assessed prior to any modification being proposed. Task Risk Assessments should be attached to the RMR submittal.

All modifications, regardless of category, will be adequately risk assessed in accordance with HSE Manual.

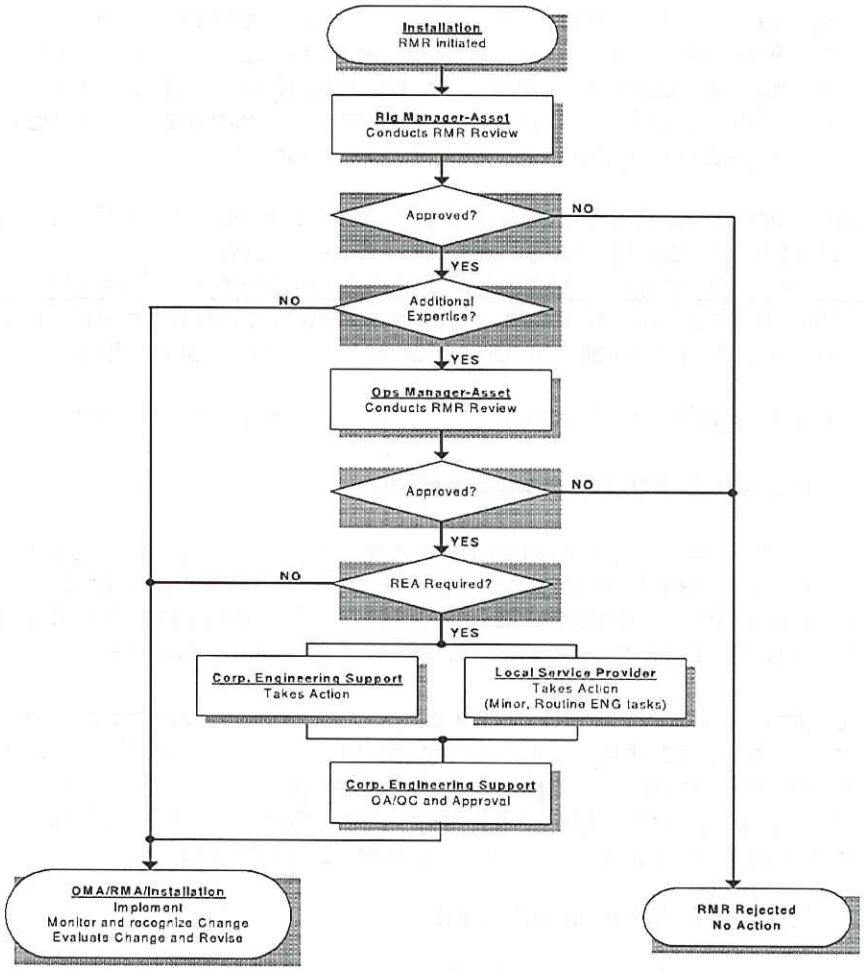
All proposed modifications to an Installation will be evaluated by competent personnel other than those involved in carrying out the modification. Due consideration will be paid to the future operation of the Installation as well as the safety, environment and maintenance standards aspects.

Each modification will be assessed to determine whether proposed changes require engineering support, and whether the scope should be managed as a stand-alone project. Assessment criteria will include, but not be limited to:

- Risk
- Cost
- Complexity
- Compliance with applicable certification requirements from the Class Society, original equipment manufacturer, API, CE and other regulatory requirements.
- Compliance with company equipment and engineering standards and recommended practices.
- Impact on ongoing operations, e.g., timing, system availability, etc.
- Operational constraints, e.g., bed space, hot work, helicopters.

Modification proposals will be submitted on the Rig Modification Request (RMR) form to the Rig Manager – Asset (RMA) for review. The following work flow describes the RMR process.

Figure 2.7.1, RMR Process



1.2.8 Section H, Agency Review

This section must be completed when review of Classification Society, Flag Administration, Coastal State or other external agency is required. Major and Moderate modifications typically require review by the relevant agencies.

NOTE: Review by multiple regulatory agencies is often required and must be evaluated with appropriate action taken.

1.2.9 Section I, Approvals

The Rig Manager, or their nominee, shall be responsible for obtaining the relevant approvals.

When all of the mandatory fields on the electronic RMR form have been filled out, the form may be submitted by the requester to the Rig Manager, Asset (RMA) for review and approvals.

Supporting documents should still be attached to the RMR and can be deposited in the supporting documents folder corresponding to the RMR number (links are provided at the bottom of the RMR form only after submittal and on the right-hand side of the screen). Please note that since the supporting documents folder is not created until an RMR number is assigned, you cannot attach documents until AFTER you have submitted an RMR. There is a maximum 50MB per file limitation. Various file types (e.g., pdf, jpg, etc.) can be uploaded to the Supporting Documents file that corresponds to the RMR. There are several upload options displayed for the supporting documents. Setting the "View" to "Explorer View" on the upper right side of the display allows for drag-and-drop functions similar to Windows Explorer.

The Rig Manager - Asset determines the need for additional expertise and where required passes the RMR to the Operations Manager, Asset for review and approval.

The Operations Manager, on review of the proposal provides the approval to proceed and determines the need for Engineering Approval, based on the tables included in the Field Operations Manual and Section 2, Subsection 4 of this document. Basic, routine engineering tasks can be performed by approved, local engineering service providers with deliverables reviewed and approved by the Engineering Support prior to implementation. If there is confusion as to whether an REA is required, for example a modification that does not cleanly fit the criteria in the tables, contact the engineering support team, for assistance.

1.2.10 Close Out

On completion of the work, receipt of appropriate agency approvals, receipt of revised drawings, receipt of documentation packages and their appropriate approval/ and acceptance, the Rig Manager-Asset shall sign to confirm that the modification is completed and closed out, including necessary regulatory approvals, manuals, RMS updates, as-built drawings, arrangement updates, light-ship modification log, submission of documentation to Houston Engineering Support for file and reference. The RMR will then be closed in the Technical Services website and remain visible and searchable for future reference. The onboard modification log and rig records will be updated in accordance with company policy and procedures

Table 2.7.1, Modifications, Upgrades and Tasks Which Require HQS Engineering Support, Review and/or Approval

STRUCTURAL	
Item	**Application**
Alteration or modification of the basic Installation structure, excluding like replacement of structural members and plating, which constitutes a repair to as-built conditions. Special care must be exercised when cropping out basic Installation structure to avoid permanent deformation of surrounding structure.	• Any structural modification which alters the hydrostatic characteristics, motions, or stationkeeping capabilities of the Installation, including hull blisters and sponsons. • Addition of hull braces, struts, or brackets as remediation of cracking or other chronic defects. • Alterations requiring welding to a derrick or highly loaded structure (OEM approval also required). • Addition of marine riser tension, hook load, setback, or pipe/riser rack capacity. • Welding of high tensile steel requiring special attention for the welding procedure and NDT control which is not addressed in the approved construction portfolio for the unit.
Variable load (as defined in the approved Installation operating manual) reduced by 5% or more as a result of proposed modifications or when an inclining test or deadweight survey is required by the classification society.	• Weight additions to the Installation which exceed the load capacity of the deck/location chosen for Installation. • Deadweight surveys. • Inclining tests.
Alterations that consist of or include attachment points for suspension of equipment, materials, or personnel in excess of six metric tons safe working load (SWL).	• Any padeye with SWL in excess of 6 te. • Hangoff padeyes (derrick, substructure, moonpool). • Suspended walkways, work platforms • Lifting equipment foundations. • Any modifications to manriding/personnel lifts/elevators regardless of safe working load.
Computational tasks	• Site-specific structural assessment for self-elevating offshore Installations. • Structural and fatigue analyses.

ELECTRICAL / CONTROLS	
Item	**Application**
When specifying modifications, upgrades, new systems, or when establishing and evaluating commissioning and acceptance testing procedures.	• Power generation (main, emergency or UPS). • Any alteration to protective devices (relay settings, fuse sizes, overload devices) • Any alteration that affects main power or control system one-line diagrams. • Dynamic positioning systems including position reference and other subsystems including dock trials, sea trials, customer acceptance and Failure Mode and Effect Analysis (FMEA) studies and testing, DP Operations manuals. • Control systems (DP, VMS, PMS, ballast, drilling, BOP, deadman, autoshear, ROV intervention, riser tensioner, etc.). • Monitoring systems (fire, gas, ESD, tank gauging, CCTV, etc.). • Communication systems (PBX, LAN, GMDSS, VSAT, PA/GA, etc.)
Alterations to any Installation critical system software that require changes or additions to the system software.	• Any software change affecting Installation critical systems (DP, PMS, VMS, BOP Multiplex Controls, Integrated Drilling Controls, Ballast, ESD, EDS, Riser Tensioner Control, Deadman, Autoshear, Zone Management, etc.)
Alterations to Main Power One Lines	• Main Power One Line Diagram. • All Power Distribution One Line Diagrams. • Emergency Power One Line Diagrams. • All MCCs. • Control and Instrumentation schematics and diagrams.
Analysis or Studies to support power plant operation	• All, including short circuit, coordination and harmonic studies Transient and Steady State response testing procedures.
Variable Speed Drives	• Selection of drive technology (type) and sizing.
Power Quality	• Selection of harmonic and surge suppression equipment.

MECHANICAL	
Item	**Application**
Alteration of fluid systems in such a way that the system pressure or temperature **rating** is changed, the fluid system one line diagrams require modifications or modifications to regulatory-approved drawings becomes necessary.	**Bilge and Ballast System** • Any modification that alters the fluid system one-line diagram (regulatory approval required). • Change in system working pressure and test pressure. • Replacement of ballast/salt water/bilge pumps with equipment differing from system OEM specification. • Alterations requiring pressure-drop and volume flow rate calculations, including pump replacement with equipment other than system OEM specification. **Fire/Salt Water System** • Addition of new fire fighting stations or monitors (pressure drop calculations required). • Change in system working pressure and test pressure. • Replacement of fire pumps with equipment differing from system OEM specification. • Changes that effect the efficiency of any cooling system. • Changes in the fixed fire fighting systems (Halon to CO2and/or extension of system coverage). • Well Control Systems. • Any modification that alters the fluid system one-line diagram. • Change in system working pressure and test pressure. **Low Pressure Mud System (including processing)** • Any modification that alters the fluid system one-line diagram.

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RIG MODIFICATION REQUEST (RMR)

MECHANICAL	
Item	**Application**
Alteration of fluid system in such a way that the system pressure **rating** is changed, the fluid system one line diagrams require modification or modifications to regulatory-approved drawings becomes necessary. Rig Equipment and Systems	**High Pressure Mud System** • Any modification that alters the fluid system one-line diagram. • Alterations which increase the **rated** system pressure. • Alterations which require modification of routing for pressure relief piping from systems of 5000 psi working pressure and above. • Alterations which require modification of controlled, fluid system one-line diagrams. • Alterations which require Installation of materials not addressed by the approved construction portfolio. • Alterations that require welding HP piping. **Hydraulics/Pneumatics (Sub-Sea Systems, Tensioner Systems, Starting Air, Installation Air, Instrument Air, etc.)** • Any modification that alters the fluid system one-line diagram (regulatory approval required). • Addition of accumulators, reservoirs, receivers or vessels which alter the capabilities or **rated** pressure of an affected system. • Alterations which result in changes to **any controlled** system one-line diagrams and/or power requirement. • Discharge piping systems, a change that might result in an uncontrolled discharge of waste fluid to the environment. • Any modifications or changes which affect the capability and/or capacity of diesel engines, thrusters and other propulsion machinery.

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RIG MODIFICATION REQUEST (RMR)

MECHANICAL	
Item	**Application**
Rig Equipment and Systems	**Any changes or modifications which change the capabilities and/or capacity of hoisting, pumping and rotating equipment or systems, including:** • Any alterations to the flow rate, temperature, operating pressure (or back-pressure) in steam or HVAC systems onboard the installation. Any modifications or changes which affect the capability and/or capacity of diesel engines, thrusters and other propulsion machinery.

GENERAL	
Item	**Application**
Alterations to structure, systems or equipment which are subject to review, and/or approval by classification or regulatory bodies relevant to the Installation.	• Hazardous Area Designations. • Firefighting and Lifesaving Equipment Plans. • Escape Routes. • Installation Operating Manual and any drawing in the Installation Operating Manual. • Structure fire protection. • Any vessel-critical plans. • Increase POB. • Change to Lifeboats and capacity of Lifeboats.

5 RESPONSIBILITY

	Director HQS Engineering Support	HQS Engineering Department Heads and Administrators	HQS Engineering Support Staff	Operations Manager - Asset	Rig Manager - Asset	OIM
Ensure the RMR is completed correctly, approved onboard and submitted to the Rig Manager, Asset (RMA) with sufficient back-up information for review and approval.						IM
Reviews and approves RMR submittal and ensures submittal is correctly prepared and reviewed at rig level.					PM	
Ensure that local Management of Change (MOC) procedures are followed by reviewing and approving rig modification requests and determining the need for technical support and/or engineering assistance where required using the REA process.				PM		
Ensure that this policy is followed in accordance with the REA procedures.		PM	PM			
Decide whether work requests comprise requests for engineering action (REAs) or routine, non-REA support based on their assessment of time and resources required to fulfill the expectations of the originator.		PM				
Assign engineering resource to respond to REAs originated from the RMR process.		PM				
Ensure that employees are familiar with and understand these policies.		PM				
Ensure that the policy is enforced and procedures fully implemented within the HQS Engineering Support Department.	IM					

6 DOCUMENTATION

6.1 COMPANY MANAGEMENT SYSTEM MANUAL, HQS-CMS-GOV, SECTION 5.5, MANAGEMENT OF CHANGE

6.2 FIGURE 2.7.1, RMR PROCESS

6.3 RIG MODIFICATION REQUEST FORM, TECHNICAL SERVICES RMR/REA WEBSITE IN SHAREPOINT, http://moss01.deepwater.com/sites/MTS/default.aspx

6.4 REQUEST FOR NEW RIG MODIFICATION REQUEST, URL: http://moss01.deepwater.com/sites/MTS/RMR%20Forms/Forms/AllItems.aspx

6.5 TABLE 2.7.1, MODIFICATIONS, UPGRADES AND TASKS WHICH REQUIRE HQS ENGINEERING SUPPORT, REVIEW AND/OR APPROVAL

7 DEFINITIONS

MAJOR Modifications involve alterations to the primary structure, or for other categories are extensive in nature. A modification requiring expenditure greater than USD 250,000 is considered major.

MODERATE Modifications involve alterations to structure, equipment, systems, operating procedures or manuals. A modification requiring an expenditure greater than USD 100,000 but less than USD 250,000 is considered moderate. A modification as described in 7.2 which must be completed under supervision of the classification society, flag administration, coastal state regulator or other external agency will be considered MAJOR if the coast exceeds USD250,000 (refer to 7.1) and MODERATE in all other cases regardless of cost.

MINOR Modifications are those changes which cannot be categorized above and have no effect on material or operational safety of equipment or systems.

OPS – PLANNING AND REPORTING

REQUEST FOR ENGINEERING ACTION (REA)

1 POLICY

Engineering tasks related to certain modifications and upgrades to Installations must be performed, reviewed and/or approved by HQS Engineering Support. All requests for action to be taken by HQS Engineering Support Department must be documented using the Request for Engineering Action (REA) process.

2 PURPOSE

The purpose of this policy is to ensure:

- That Installations, Divisions and Business Units are aware of the correct procedures and documentation required for review and approval of any modifications or upgrades,
- That modifications, changes and upgrades are executed in a safe, cost-effective and professional manner.
- That all Installation drawings and documentation are accurate at all times, reflecting the latest arrangement and details of the installation.
- That Engineering support is controlled so that work is properly prioritized, adequate resources provided, progress monitored and quality assured.

3 SCOPE

This policy covers facilities and employees of the Company as well as employees of any contractor, or outside agency that perform work on behalf of HQS Support for any offshore Installation owned, operated, and/or managed by the Company.

4 PROCEDURE

4.1 GENERAL

The Request for Engineering Action (REA) system is the internal process for requesting assistance from the HQS Engineering Department. The REA should be used to track and capture:

- Any engineering support task which is deemed of sufficient value to be readily accessible for future reference, and/or application to other company installations.
- Any work expected to take more than one day of HQS Engineering Department time.

Major or critical system changes or upgrades require consultation and HQS Engineering approval prior to AFE approval and commencement. A non-exhaustive list of issues that require, as a minimum, HQS Engineering review and approval is provided in HQS-OPS-PP-01, Rig Modification Request (RMR),Table 2.7.1.

In addition, HQS Engineering will be notified directly, or via Technical Field Support whenever:

- Modifications, repairs, changes or upgrades to the Installation are controlled by Class (ABS, DNV, Lloyds) or IMO.

- Changes are required to documentation which has formerly been submitted to Class or Regulatory Bodies (i.e. Vessels Operating Manual, Fire & Safety Plan, Hazardous Area Drawings, Dynamic Positioning System Failure Mode and Effect Analysis FMEA, etc).

- Modifications, changes or upgrades to high pressure piping and other mechanical systems which store or contain a significant amount of energy.

If engineering support is required, a request will be forwarded to, or opened by HQS-Engineering Support in the form of a Request for Engineering Action with applicable drawings and any required documentation.

Engineering calculations, drawings and tasks will be carried out with careful consideration of company Equipment Standards, Engineering Standards and Recommended Practices. Consideration will be given to the impact any modifications have on the future operation of the Installation with regard to the Company's safety, environmental, operational and maintenance standards.

4.2 BASIC STEPS

1. A need for assistance from HQS Engineering Support Department is identified at the installation level or above. A Request for Engineering Action may be generated at the installation level, within the unit/division technical field support organization, within marketing and business development departments or within HQS Engineering Support to capture development and other types of work. REAs are generated electronically within a web-based SharePoint™ application used to log, track and capture the supporting documents and deliverables from REAs.

   a. Access to the Technical Services REA system is not enterprise-wide and is limited to those submitting and completing engineering (or marine) REAs. The Technical Services web site can be accessed at

http://moss01.deepwater.com/sites/mts/default.aspx and provides real-time REA status. A link is also available on the RigCentral Engineering Support webpage (under request for engineering action) at the following URL: http://www.rigcentral.com/hqs/eng/tech_support/

2. An electronic REA form must be completed that adequately defines the problem or engineering assistance required. A contact person must be assigned to interface with HQS Engineering support. It is important that this contact person is available to clarify any questions; this person may or may not be the original requester. Prior to generating the engineering request, the REA should be reviewed at the asset manager level to ensure management of change process has been followed, the work is relevant, necessary and budgeted (where appropriate). The REA request can be generated by pointing your browser (inside the company firewall only) to http://moss01.deepwater.com/sites/MTS/REA%20Forms/Forms/AllItems.aspx and clicking "Engineering Action" on the "new" pull-down menu. Fields with a red asterisk must be completed in order for an REA to be submitted.

NOTE: Please be advised that the REA database is primarily an issue tracking tool. While most user groups have rights and access sufficient to submit REAs directly to HQS Engineering Support, doing so bypasses the Management of Change process. It is important that MOC is managed locally and REAs reviewed/approved by the RM-Asset or appropriate PIC prior to sending on to Houston.

3. When all of the mandatory fields on the electronic REA form have been filled out, the form may be submitted by the requester. On submittal, the REA will be delivered to the selected engineering manager, who will receive an e-mail notification with a link to the submitted REA for review and further action.

4. Supporting documents should still be attached to the REA and can be deposited in the supporting documents folder corresponding to the REA number (links are provided at the bottom of the REA form after submittal and on the left-hand side of the screen). Please note that since the supporting documents folder is not created until an REA number is assigned, you cannot attach documents until AFTER you have submitted an REA. There is a maximum 50MB per file limitation. Various file types (e.g. pdf, jpg, etc.) can be uploaded to the Supporting Documents file that corresponds to the REA. There are several upload options displayed for the supporting documents.

Setting the "View" to "Explorer View" on the upper right side of the display allows for drag-and-drop functions similar to Windows Explorer.

5. On assignment to an engineering person in charge (PIC) by the engineering manager, the requester and alternate contact receive email notification confirming acceptance, the Engineering PIC and any additional comments required.

6. REA status is always available on the Technical Services web site.

7. Upon completion of the task, the necessary information is forwarded to the contact person with copies to the Rig (Asset/Performance), Business Unit and Division Manager, Business Unit Operations Manager or Marketing as appropriate, and the REA is then closed by Engineering.

The REA tracking system is equipped with an online user manual, including pdf and flash video demonstrations of the various tasks associated with the REA database.

5 RESPONSIBILITY

	Director, HQS Engineering Support	HQS Engineering Department Heads and Administrators	HQS Engineering Support Staff	Operations Manager - Asset	Rig Manager - Asset
Ensure that local management of change (MOC) procedures are followed by reviewing requests and obtaining approval from Operations Manager, Asset prior to submittal of formal REA to HQS engineering support.					PM
Ensure that local management of change (MOC) procedures are followed by reviewing and approving rig modification requests and determining the need for technical support and/or engineering assistance where required using the REA process.				PM	
Ensures that REAs are submitted for all work (excluding technical projects) of more than one day going through the headquarters engineering department.	PM				
Ensure that this policy is followed in accordance with the REA procedures. Engineering department heads are empowered to decide whether work requests comprise requests for engineering action (REAs) or routine, non-REA support based on their assessment of time and resources required to fulfill the expectations of the originator.	IM	PM			
Ensure that this policy is followed in accordance with the REA procedures.			PM		

6 DOCUMENTATION

6.1 PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES, HQS-OPS-PP-01, SECTION 2.7, RIG MODIFICATION REQUEST (RMR), TABLE 2.7.1

6.2 TECHNICAL SERVICES WEBSITE, http://moss01.deepwater.com/sites/mts/default.aspx

6.3 RIG CENTRAL ENGINEERING SUPPORT WEBPAGE, URL: http://www.rigcentral.com/hqs/eng/tech_support/

6.4 REQUEST FOR ENGINEERING ACTION WEBSITE, http://moss01.deepwater.com/sites/MTS/REA%20Forms/Forms/AllItems.aspx

6.5 COMPANY MANAGEMENT SYSTEM MANUAL, HQS-CMS-GOV, SECTION 5.5, MANAGEMENT OF CHANGE

6.6 PERFORMANCE AND OPERATIONS POLICIES AND PROCEDURES MANUAL, HQS-OPS-PP-01, SECTION 2.7, RIG MODIFICATION REQUEST (RMR)

OPS – DRILLING RELATED

WELL CONTROL – INCIDENT PREVENTION AND MANAGEMENT

1 POLICY

Prevention and management of well control incidents must conform to the requirements detailed in the Well Control Handbook and be carried out by competent, well control certified personnel.

2 PURPOSE

To ensure that well control incidents are prevented, or where prevention is unsuccessful, incidents are managed by competent, well control certified personnel to reduce the risk of injury to personnel on the Installation and minimize damage to the environment and equipment.

3 SCOPE

This policy applies to all Installations and employees of the company, as well as employees of any operator, contractor or outside agency that work on any Installation owned, operated or managed by the Company.

4 PROCEDURE

4.1 GENERAL

The key elements of Well Control – Incident Prevention and Management, covered in detail in the Well Control Handbook:

- Preparation
- Prevention
- Detection
- Remedy

5 RESPONSIBILITY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Comply with the Well Control – Incident Prevention and Management Policy.	IM	IM		IM	IM		IM	PM
Conduct independent assessments (PMAA), as they deem necessary.	PM	PM	PM		PM			
Conduct hardware audits, as they deem necessary.	PM	PM		PM		PM		

6 REFERENCE

WELL CONTROL HANDBOOK, HQS-OPS-HB-01

OPS – DRILLING RELATED

WELL CONTROL – EQUIPMENT

1 POLICY

All well control equipment must conform to the specification and testing requirements detailed in the Well Control Manual.

2 PURPOSE

To ensure that the well control equipment is designed and tested to safely handle well control incidents on the Installation.

3 SCOPE

This policy applies to all Installations owned, operated or managed by the Company.

4 PROCEDURE

The key elements of Well Control – Equipment detailed in the Well Control Manual, HQS-OPS-HB-01 include:

- Well Control Equipment Standards
- Pressure Tests
- Function Testing
- Casing, Wellheads and Pressure Control Equipment

5 RESPONSIBILITY

	Division Managing Director	Division General Manager	Operations Manager - Performance	Operations Manager - Asset	Rig Manager - Performance	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Comply with the Well Control – Incident Prevention and Management Policy.	IM	IM		IM	IM		IM	PM
Conduct independent assessments (PMAA), as they deem necessary.	PM	PM	PM		PM			
Conduct hardware audits, as they deem necessary.	PM	PM		PM		PM		

6 REFERENCE

6.1 WELL CONTROL HANDBOOK, HQS-OPS-HB-01, SECTION 9, WELL CONTROL EQUIPMENT

OPS – DRILLING RELATED

DRILLER'S KEY RESPONSIBILITIES

1 POLICY

Drillers must conduct drilling operations in compliance with the Driller's Key Responsibilities.

2 PURPOSE

Critical responsibilities that are required to be clearly communicated, understood, and followed by the Driller in order to ensure that drilling operations are conducted in a safe and efficient manner.

3 SCOPE

This Procedure covers all Installations owned, operated or managed by the Company. All Drillers and all personnel authorized to relieve the Driller are required to understand and follow Driller's Key Responsibilities as described.

4 PROCEDURE

Driller's Key Responsibilities are to be posted at a visible location in proximity to the Driller's Work Station.

4.1 DRILLER'S KEY RESPONSIBILITIES

1. Verify all well control equipment is lined up according to the Installation operating procedures at the beginning of each tour.

2. Shut-in the well as quickly as possible if a kick is indicated or suspected. Early recognition of the warning signals and rapid shut-in are the key to effective well control. Shutting in the well quickly will minimize the amount of formation fluid entering the well bore.

3. Flow check all drilling breaks as soon as they are detected and any time there are doubts about the stability of the well.

4. Verify the fixed hands free communication system is operational.

5. When tripping pipe, flow checks must be performed at the following times:

   - At the bottom of the well, before any trip out of the hole.

- At the lowest casing shoe.
- Anytime the hole displacement is incorrect during a trip.
- Anytime the Driller (or the person performing the Driller's functions) has any concerns regarding the well status.
- If continuous volume monitoring of the hole volume is not possible, then a flow check must be made, prior to pulling the HWDP or Drill Collars through the BOPs.
- Prior to boosting the annulus while tripping.
- On completion of boosting prior to tripping continuing.

Boosting of the riser annulus during tripping operations is not a routine operation due to the potential for this practice to reduce early kick detection and thereby increase the volume of any influx taken during the operation.

If boosting of the riser while tripping is considered necessary an exemption must be granted by the Rig Manager Performance.

The Rig Manager Performance must consider the following if an exemption is to be granted for boosting while tripping.

- Where there is no open hole the integrity of the barriers involved such as mechanical or cement plugs or cemented liners and casing strings must have been suitable tested.
- Where there is exposed open hole then a Task Risk Assessment must be performed addressing the following fully.
- There must not have been any well control or hole problems in the exposed open hole.
- Where potential hydrocarbon-bearing zones are present, the reservoir characteristics and formation behavior must be known and understood.
- The current overbalance or trip margin must be known and considered adequate.
- In the case of an exploration well, sufficient data must have been collected to meet all of the above requirements. Even then, extreme caution should be exercised.

- Pit and flow line instrumentation settings must be sensitive enough to detect an influx while lined up to an active pit instead of the trip tank.
- Fluid transfers involving the active pit must not be made while tripping in this manner.
- If it is proposed to close blind/shear rams in order to isolate the open hole and boost while tripping through the riser then the specific hazards related to this practice must be included in the risk assessment.

6. Keep the hole full at all times:

   - The trip tank should be used while tripping.
   - Observe the flow path after each trip tank line up.
   - Accurate trip fill-up records must be maintained.
   - Should the trip tank pump fail, an alternative must be to use a mud pump while pulling pipe.
   - If the trip tank is not available:

     – The annulus must be filled with mud before the change in mud level decreases the hydrostatic pressure by 75 psi (500 kPa, 5 bar) or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure.

     – When pulling HWDP or drill collars the hole must be filled every stand. The pit from which the hole is being filled must be isolated from all other pits and the volume closely monitored and recorded on a trip sheet.

7. Do not leave the drill floor during tour unless properly relieved.

8. Know the distance from the rotary table to the pipe rams and annulars in the BOP stack at all times and post a space-out diagram in the vicinity of the Driller's BOP panel. Drillers on floating units must be provided with tide charts.

9. Know true vertical depth (TVD) and measured depth (MD).

10. Keep a complete record of all tools and tubulars run in the hole showing made-up lengths, tool joints, ODs and IDs, serial numbers and fishing necks.

Driller must also make sure that the Installation has the fishing tools required to retrieve the down hole tools supplied as per contract.

11. A hole cover must be installed at any time there is no drill string, casing or Wireline, etc. in the hole.

12. If the Installation utilizes a manual derrick, obtain verbal confirmation from the Derrickhand that his safety harness is properly secured before tripping operations begin.

13. Take and record slow circulating rates:

- If practical, at the beginning of each tour
- Anytime the mud properties change
- Anytime the bit or BHA has been changed
- As soon as possible after bottoms up following any trip
- At least every 1000 ft (305m) drilled. (Well Control Manual, HQS-OPS-HB-01)
- Following major mud pump or surface equipment changes/repairs

14. Check, calibrate and reset the critical safety systems such as COMs, KEMs, floor savers and zone management:

- At the beginning of each tour
- After slipping and/or cutting drilling line
- After handling long BHA components
- After any other events when the settings have been changed

Full function testing to be done based on the regular maintenance schedule.

15. Have drilling mud properties checked and recorded on a regular basis, at least every 30 minutes, or immediately upon any noted change.

16. Constantly monitor speed, pump strokes, pressure, pit volume, trip tank, penetration, mud weight and rotary torque to detect anything unusual or out of the ordinary.

17. Avoid operating at or near critical rotary speeds as indicated by string vibrations.

18. Secure the Driller's mechanical brake in such a way to prevent the draw-works drum from turning whenever the Driller's position is left unattended, e.g., chain for manual brakes. Brake should be locked during maintenance on hoisting equipment.

19. An inspection of the derrick/mast for potential falling objects to be carried out after jarring, sudden shock loads etc. e.g. dropped blocks and extreme heavy weather or other similar incidents where the derrick/mast may have been subjected to stress and strain.

20. At no time during any operation, should any type of weight hang on the control handle for the Electro Magnetic Brake Controller.

21. The Driller must ensure that proper maintenance is carried out on all drilling equipment according to the prescribed lubrication and maintenance schedule.

22. Tripping operations must be carried out in a planned and controlled manner according to the requirements detailed in Tripping 4.7.4 of this section.

23. The maximum allowable makeup torque and maximum pull in the case of a stuck drill string in the hole must be governed by size, type and grade of pipe. Maximum pull must be that given in the API specification RP7G and RP7G1. Further reference is made to API bulletin 5A2, 5C2 and 5C3.

    - For each trip the maximum allowable pull at zero torque value for the string must be calculated and clearly posted at the Driller's position i.e. at 80% of the API RP7G premium used tubular maximum allowable pull tables. Also the reduced allowable pull must be calculated and posted for an appropriate applied torque value e.g. for 5" DP if 25K ft-lbs was applied; the maximum allowable pull must be reduced to +/- 500,000 lbs which will result in a maximum pull of 400,000 lbs with an 80% factor.

    - Care must be taken with mixed strings that the maximum allowable pull is not exceeded in any part of the string.

    - For critical landing or drilling strings, tubular inspections can be made to qualify remaining body wall (RBW), in which case 80% of the tensile at the qualified RBW can be utilized as the maximum allowable pull. In these

instances an exemption form must be completed including the inspection results and the maximum allowable values which must be approved by the Rig Manager - Performance on a well by well basis. The approved values must be clearly posted at the Driller's position.

24. The Driller must only pull the drill string over the 80% posted maximum allowable values under the direct supervision of the Senior Toolpusher /Toolpusher up to a maximum of 90% of the API RP7G used tubular maximum allowable pull tables.

25. Transocean equipment shall be operated up to a maximum of 90% of its rated capacity on a continuous basis unless exceptional circumstances require it to be operated at 100% capacity as dictated by emergency situations that threaten the integrity of the rig or its equipment or the safety of personnel.

26. At no time will Transocean equipment be operated above its maximum rated capacity.

27. Tubulars must be used within their design limits and maintained to maximize useful life.

28. Post operation event management inspections and checks are required to be performed as defined in Computerized Maintenance Management System (CMMS) Event Based Maintenance when the following occurs:

    a. Fishing and Jarring

    b. Drill String Over Pull

    c. Derrick Collision

    d. Dropped Objects from the Derrick

29. The Driller's Collision Checklist must be reviewed before starting a task for possible obstructions that may result in a dynamic dropped object if there were a collision. (Ref: HQS-HSE-PP-01, Sec. 4, Sub. 2.5). The position of the link tilt must be checked to ensure that there is no interference with any derrick equipment.

30. Distractions must be managed to maintain safe operation of rotating / hoisting / lifting equipment. REF: HQS-HSE-PP-01 Sec 4, Sub 2.5 – Risk Management, Para. 4.1.2.

a. Use of a hand held phone, during the operation of rotating / hoisting / lifting equipment that requires or may require both hands, is prohibited. All rotating / hoisting equipment must be in the parked or locked position, prior to using a hand held phone. A hands-free system can be used for essential communications.

31. The derrick racking board and the rotary table must be visible to the Driller either by direct line of sight or by remote camera. Tripping operations must stop and the Senior Toolpusher / Toolpusher is to be informed if the visibility of the traveling equipment and its possible interference with any equipment in the derrick is impaired.

5 RESPONSIBILITY

	Operations Manager - Performance	Rig Manager - Performance	OIM	Senior Toolpusher / Toolpusher	Driller	Assistant Driller
Understands the Driller's Key Responsibilities.	IM	IM	IM	PM	PM	PM
Monitor the Drillers performance daily to verify compliance.			IM	PM		
Communicate to the Customer the Drillers Key Responsibilities.		PM	PM	V		
During relief or handover, communicate and reinforce the relevant Driller's Key Responsibilities in relation to the ongoing operation.			IM	PM	PM	PM
Provide training on the Driller's Key Responsibilities to all Drillers and all personnel authorized to relieve the Driller.	IM	PM	PM	PM	PM	PM
Act as the primary Customer contact and respond quickly to resolve problems arising from non-compliance of the Drillers Key Responsibilities.		PM				

6 REFERENCES

There is a Company requirement for information regarding certain drilling operations to be recorded on an approved form and made readily available and regularly communicated to relevant persons. The Standing Instructions to Drillers (SID) and shift handover forms can be obtained from the HSE Manual, HQS-HSE-PP-01, Section 4, Subsection 4.1, Communication, HSE Information.

6.1 WELL CONTROL HANDBOOK, HQS-OPS-HB-01

6.2 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.2.5, DROPPED OBJECTS

OPS – DRILLING RELATED

SIMULTANEOUS DRILLING AND PRODUCTION OPERATIONS

1 POLICY

Operations in close proximity to producing wells must only be carried out after a risk assessment is completed, appropriate risk prevention and mitigation measures are implemented, and all relevant personnel are informed of the risks and preventive and mitigating measures prior to beginning operations.

2 PURPOSE

The purpose of this policy is to ensure:

- simultaneous drilling and production operations are carried out safely
- all risks are identified, assessed, mitigated and managed at an acceptable level
- all relevant personnel are informed of the risks and mitigating measures

3 SCOPE

This Policy covers all Installations owned, operated or managed by the Company.

4 PROCEDURE

4.1 GENERAL

A Task Specific THINK Procedure (TSTP) inclusive of a Task Risk Assessment (TRA) is required for simultaneous drilling and production operations. The operations covered under this policy include:

- Moving Onto / Off a Platform or Subsea Installation where wells are producing
- Drilling operations adjacent to producing wells

4.1.1 Moving On or Off a Platform or Subsea Installation where Wells are Producing

The Task Specific THINK Procedures (TSTP) must include but not limited to the following:

- Down-hole safety valves

- Manned emergency shut-down (ESD) stations and communications
- Online gas monitoring
- Weather limitation criteria for Installation moves
- Towboat available horse power
- Back up anchors
- Development of detailed procedures including responsibilities,
- Emergency response plans developed
- A review of the critical procedures in the Installation and Well Operations Manual
- Sea bed surveys used must be current and up to date
- All sea bed survey and weather information provided by the Customer
- Object / Structures e.g. wellhead, wreck, mooring line hazards
- Excessive current hazards
- Excessive Installation velocity hazards
- Potential power blackout of Installation or tow vessels

4.1.2 Drilling Operations Adjacent to Producing Wells

The Task Specific THINK Procedures (TSTP) must include but not limited the following:

- Online gas monitoring
- Manned emergency shut-down (ESD) stations and communications
- Down-hole safety valves
- Live wellhead protection from load impact damage
- Dropped object avoidance procedures
- Clearance from existing wells

- Development of detailed simultaneous drilling and production procedures including responsibilities
- Emergency response plans developed

5 RESPONSIBILITY

	Managing Director	General Manager	Operations Manager - Performance	Rig Manager - Performance	OIM	Toolpusher / Senior Toolpusher	Driller
Approve simultaneous drilling and production operations prior to their commencement.		PM	PM	PM			
Task Specific THINK Procedure (TSTP) inclusive of a Task Risk Assessment (TRA) must be created.				PM	PM	PM	PM

6 DOCUMENTATION

6.1 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.2.1, RISK MANAGEMENT

OPS – DRILLING RELATED

WELL TESTING / DST

1 POLICY

Well Testing and DST operations must be pre-planned and risk assessed.

2 PURPOSE

To ensure safe and effective Well Test and DST operations onboard all Installations. Floating operations require additional planning to include the performance of moorings, DP systems and subsea test trees.

Preplanning must include, but are not limited to:

- Installation-specific interfaces
- Well-test equipment to be used
- Well-specific issues
- Customer requirements
- Service Partner requirements
- Environmental conditions

3 SCOPE

This policy is applicable to all Installations conducting well test and DST operations.

4 PROCEDURE

4.1 WELL TEST AND DST PROCEDURE REQUIREMENTS

The following procedure requirements are to be applied in the planning and performing of Well Test and DST operation activities.

- Each Installation must have Task Specific THINK Procedures (TSTP) for well test and DST operations.
- The TSTP and the Task Risk Assessments (TRA) required must be approved by the Managing Director or General Manager.
- For each Well Test or DST the TSTP and TRA must be reviewed by the Rig Manager Performance to ensure they remain relevant. Any changes made to the TSTP or the TRA must be approved by the Managing Director or General Manager.
- If the Customer or Service Partner provider conducts a hazard identification risk assessment (HAZID) the TSTP and TRAs must be reviewed during the HAZID for relevance to the proposed operation.

4.1.1 Well Test and DST Operational Steps

The Well Test and DST Operational steps are composed but not limited to:

1. Wellbore Displacement and Clean-up
2. Running Test String
3. Perforating
4. Flow Testing
5. Well Kill / Temporary Abandonment

4.1.2 Procedure Requirements for Wellbore Displacement and Clean-up

- The OIM and Customer must approve the Mud Engineer's Installation completion fluid handling plan.
- The Mud Engineer must prepare a pit clean out procedure ahead of schedule and review with Installation personnel. Extra crew and equipment may be required.

- If Brine is to be used the appropriate PPE must be available and used by all personnel who will come in contact with the Brine.
- If the well is to be pickled with either Acid or Xylene dedicated pumping equipment, storage and disposal tote tanks must be used.

4.1.3 Procedure Requirements for Running Test String

- Transocean drill pipe or collars must not be used as a test string during well testing operations.
- Drill pipe must not be used as a test string or completion string in a gas well or in a well where H_2S is present.
- All down hole testing and completion equipment, except tubulars, must be pressure tested to the maximum anticipated operating pressure prior to running in the well bore.
- Equipment testing and preparatory measures must be recorded. Original test records must remain on the Installation.
- All testing and or completion operations must conform to the principle of double valve isolation inside the test or completion string and in the annulus.
- Develop a separate THINK plan to address any drifting of tubulars.
- All tools in the test string must be measured, recorded and a drawing developed.
- Physically measure with calipers, the ID of all elevators and the OD of the tubulars to be used to confirm compatibility. Confirm the elevator bore is compatible with the profile of the tubular.

4.1.4 Procedure Requirements for Perforating

- A pre-test meeting must be held on site with all relevant Installation, Customer and service company personnel present.
- Perforating activities must be carried out in accordance with Company HS&E and Well Control procedures and controlled by the Permit to Work system.
- The complete gas detection system and safety equipment including installation ESDs, fire-fighting systems, alarms and communication systems, must be verified as fully operational prior to perforating and the commencement of testing operations.

- All surface well testing and completion equipment must be pressure tested with water to 1000 psi above the maximum anticipated surface pressure but not exceeding the safe working pressure, prior to perforating. A full function test of all valves and automatic systems must be conducted and the Well Test/DST ESD system operation verified.
- Adequate volumes of kill mud/brine plus loss circulation material must be onboard the Installation prior to perforating the well.
- All support vessels in the vicinity and the helicopter operator must be informed of the time of perforating.
- The Well Test Tree Control Station must be manned at all times.

4.1.5 Procedure Requirements for Well Testing

- A pre-test meeting must be held on site with all relevant Installation, Customer and Service Partner personnel present.
- For the initial test, well test tools must not be opened at night without approval of the Division Managing Director or the General Manager.
- The complete gas detection system and safety equipment including ESDs, fire-fighting systems, alarms and communication systems, must be verified as fully operational prior to the commencement of testing operations.
- The Service Partner provider must develop a diagram of all the lines in the well test system including all flow paths from the drill stem through the well test equipment, bleed off points and ESD system. The diagram must show all connections verifying there are no mismatching unions.
- All connections on pressurized lines must be snubbed with adequate means to prevent them from swinging or kicking in case of sudden release of pressure or rupture of the line and must be suitable for the pressure intended.
- Adequate volumes of kill mud/brine plus loss circulation material must be onboard the Installation prior to flowing the well.
- All surface Well Testing and completion equipment must be pressure tested with water to 1000 psi above the maximum anticipated surface pressure but not exceeding the safe working pressure, prior to flowing the well. A full function test of all valves and automatic systems must be conducted and the ESD system operation verified.
- Airlines to burners must have non-return valves fitted. The air supply must be independent of the Installation air supply systems.

- All support vessels in the vicinity and helicopter operator must be informed of the time of commencement of testing.
- The maximum anticipated temperature during the well test must not exceed the continuous temperature rating of the BOP elastomers.
- The Well Test Tree Control Station must be manned at all times.
- The line up of valves for cooling water from the mud pumps to the burner boom must be controlled under a Permit to Work.

A. ON FLOATING INSTALLATIONS

- A review of the BOP test string space out must be carried out to ensure that if the BOP is disconnected the follow actions can be performed:
  - the shear rams can be closed above the SSTT
  - two sets of pipe rams are able to close on the slick joint
  - the shear sub is located across the shear rams
- Well Test operations must be shut in down-hole when Installation heave exceeds 5-foot total (double amplitude) measured at the drill floor, the test string depressurized and the sub-sea tree shut in preparation for disconnecting
- Where a passive motion compensator system is not installed, a passive compensated lift frame must be used during well testing.

The potential of a primary motion compensator failure has been identified. Primary motion compensation is defined as Active Heave Drawworks, Crown Mounted and Drill String Compensating Systems.

A failure of the primary motion compensator could impose undue stress upon the Well Test/DST tubing. The maximum compression and tension on the tubing should the motion compensator fail as compared to the projected heave operating envelope of the installation must be identified.

When an Active Heave Drawworks Compensating system (AHC) fails where the drawworks either stops compensating or fails "safe" by setting the brakes, a mitigating system must be in place. To address this issue, the Company initiated engineering and construction of a passive compensated coil tubing lift frame to be used in conjunction with the primary motion compensator during DST/Completion operations.

The passive compensated coil tubing lift frame can operate as a stand alone passive compensator or an additional in-line safety device in the event of a drawworks failure. The passive compensated coil tubing lift frame is designed to stroke out, minimizing the added tension on the DST tubing, and allowing sufficient time to secure the test and disconnect the test string.

The CCTLF must be used on an installation with an AHC drawworks during well testing. If a CCTLF is not to be used, an exemption must be raised and reviewed to determine the working envelope of the environmental conditions in which the tubing will not fail in the event of a drawworks failure.

B. ON INSTALLATIONS WITH DYNAMIC POSITIONING (DP)

- Well Testing/DST-Well Specific Operations Criteria (WSOC) must be developed that address the interactions between the Driller, Well Test Service Partner and the DPO. The WSOC for Well Testing/DST must be agreed to and signed by the Customer. In the event the Customer does not sign-off on the WSOC, the Management of Change process must be raised.

4.1.6 Procedure Requirements for Well Kill / Temporary Abandonment

- There must be a means to circulate the contents of the test string, prior to pulling out of the hole with the test string.
- Adequate volumes of kill mud/brine plus loss circulation material must be onboard the Installation prior to well kill/temporary abandonment of the well.
- A flow check must be performed before any trip out of the hole.
- A minimum of one safety valve and one inside BOP with crossovers, to fit all connection sizes of tubulars in the drill string, must be available on the drill floor at all times.
- The hole must be kept full at all times using a trip tank or calibrated pit. Accurate hole fill records must be kept during trips.
- Tripping out the hole without full returns is potentially hazardous and will only be permitted under known conditions and with the approval of the Operations Manager Performance.
- A minimum of two independent and tested barriers must be in place at all times. Upon failure of a barrier, normal operations must cease and not resume until a two barrier position has been restored. A barrier is defined as:

- Any remote operated valve or set of valves that can be regularly pressure tested.
- A known and monitored fluid column that exerts sufficient hydrostatic pressure to overbalance the pore pressure.
- Any cement plug in the well bore that has been suitable tested.
- Any mechanical device installed in the wellhead, Christmas tree, tubing, annulus or wellbore that has been suitable tested – either inflow tested or pressure tested to the maximum anticipated surface pressure.
- Any other pressure sealing mechanism installed for preventing flow of fluids from a well.

- The well must be monitored for flow at all times.

4.1.7 Example Documentation

The following are examples of documentation that can be used to assist in the Well Testing / DST process.

Figure 3.6.1, Example of a Schlumberger DST Landing String

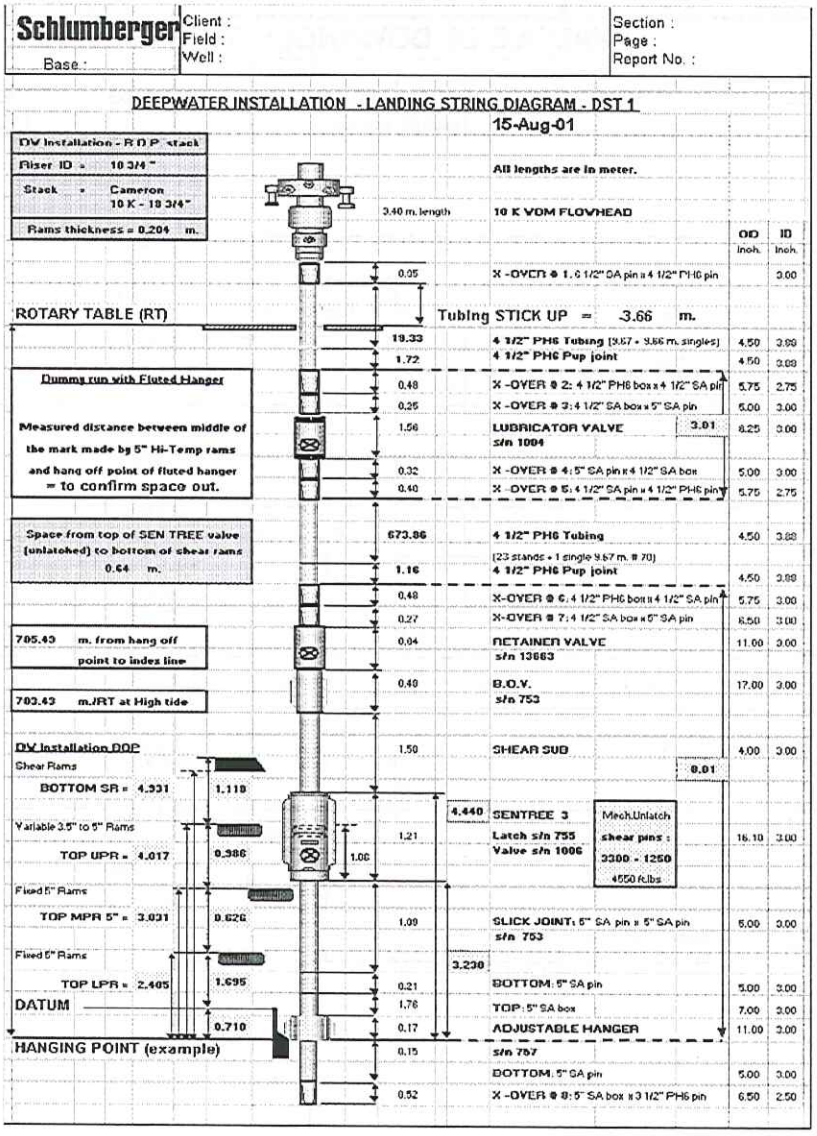

Figure 3.6.2, Example of a Schlumberger Downhole Test String

Schlumberger

Client : Various
Field :
Well :

Rig:

Date: 11-Dec-01

EXAMPLE OF DOWNHOLE TEST STRING

TOOL	DESCRIPTION	O.D. Inches	I.D. Inches	Tensile Str.	THREADS	LENGTH FEET	DEPTH TO BOTTOM FEET
							5000.00
	4 1/2" 533 Tubing (from x-over below fluted hanger)	4.50	3.83		4 1/2" 533 Box 4 1/2" 533 Pin	30.00	
	Gauge Carrier	7.00	3.50	255,000	4 1/2" 533 Box 4 1/2" 533 Pin	22.00	
	4 1/2" 533 Tubing	3.50	3.83		4 1/2" 533 Box 4 1/2" 533 Pin	7000.00	
	X-Over	5.00	2.25			1.50	
	3 1/2" PH6 Tubing	3.50	2.75		3 1/2" PH6 Box 3 1/2" PH6 Pin	30.00	
	Single Shot Reversing Valve (SHORT)	5.00	2.25	360,000	3 1/2" PH6 Box 3 1/2" PH6 Pin	4.49	
	Multi Cycle Circulating Valve (MCCV)	5.00	2.25	350,000	3 1/2" IF Box 3 1/2" IF Pin	6.17	
	Pump Through Safety Valve (PTSV)	5.00	2.25	350,000	3 1/2" PH6 Box 3 1/2" PH6 Pin	6.55	
	3 1/2" PH6 Tubing	3.50	2.75		3 1/2" PH6 Box 3 1/2" PH6 Pin	30.00	
	Data Latch (DGA + LDCA)	5.00	2.25	350,000	3 1/2" PH6 Box 4 1/4" Taperd ACME	23.48	
	Intellegent Remote Dual Valve (IRDV)	5.00	2.25	300,000	4 1/4" Taperd ACME 3 1/2" IF Pin	20.41	
	SCAR sample carrier	5.25	2.25		3 1/2" PH6 Box 3 1/2" PH6 Pin	18.80	
	Gauge Carrier	5.00	2.25	250,000	3 1/2" PH6 Box 3 1/2" PH6 Pin	15.63	
	Tubing Fill Tester Valve (TFTV)	5.00	2.25	350,000	3 1/2" PH6 Box 3 1/2" PH6 Pin	5.60	
	Seal Assembly (in Permanent Packer)	5.96	2.44		3 1/2" PH6 Box	20.00	

Table 3.6.1, Basic Precautions for DST Checklist

TASK	REMARKS
1. Prior to conducting any DST the BOPs and the gas detection system should be tested.	
2. Transocean's drill pipe should not be used for DST.	
3. Prior to testing a zone when high pressure is expected, the OIM and the operator must meet to discuss the operation. Any disagreement must be referred to the Rig Manager. During the test the annulus pressure should be monitored to ensure a leak does not develop in the drill stem.	
4. All DST work must use a surface tree (flow head) that enables the drill stem to be closed in. A minimum of two primary surface pressure barriers must be used in the flow path. The valves must be rated (W.P.) to at least 1.25 times the maximum expected shut-in pressure. The primary shut-in valves are located in the SSTT.	
5. Special attention should be emphasized for H_2S detection.	
6. DSTs on floating units must always be conducted with the drill stem hung-off in the BOPs, a subsea master valve installed (E-Z tree or subsea test tree), a Pressure Controlled Tester Valve installed that can be opened or closed by annulus overpressure.	
7. Should the Customer select not to run one of the above, an Exemption must be filed with final approval by the Division General Manager prior to opening the first DST.	
8. The BOP pipe rams are closed around the slick joint situated immediately below the master valve thus sealing off the well annulus. Following emergency closure of the master valve and disconnection of the hydraulic operator, the blind/shear rams must be closed above the master valve during temporary abandonment.	
9. Ensure the shear rams can shear the flat pack, shear point.	

Table 3.6.1, Basic Precautions for DST Checklist (continued)

TASK	REMARKS
10. Lock out rams that should not be allowed to close on the tree.	
11. Master valve strong enough to cut coil tubing and wireline.	
12. When it becomes necessary to pull off location due to rough seas or other emergencies, the well is closed in subsea, pressure is bled off, the retainer valves closed and the hydraulic latch assembly is disconnected, leaving the well shut-in and safely under control.	
13. Discuss the function of annular pressure. Annular Pressure activates the down hole ball valve in either the open or closed position. Further annular pressure is monitored to insure a down hole packer is holding and not leaking and if necessary annular pressure can operate the SSTT unlatch function.	
14. Disconnection of the subsea test tree during a well test may allow for small amounts of gas to be released into the riser. Calculations considering mud weight in riser and water depth must be made to insure any gas trapped between retainer valve and master valve in SSTT will "U-tube" out the bottom of the riser following a quick or emergency disconnect.	
15. Ensure enough high-pressure flexible lines are used to allow compensation for the maximum Installation heave in which the test string must remain connected.	
16. Ensure the EDS is set to the correct mode for each phase of the operation.	
17. Surface SSTT control station is to be manned at all times.	
18. Airlines to burners must have non-return valves fitted. Air supply must be independent of Installation air supply.	

Revised December 31, 2001

Table 3.6.2, Precautions While Testing Checklist

TASK	REMARKS
1. When testing wells containing H_2S, **no gas**, no matter how small the amount should be released into the atmosphere unless it is burned immediately. Testing of wells with H_2S is not permitted unless the Installation is equipped and personnel trained for H_2S. A separate detailed HAZOP is required.	
2. When sampling, the separator must be properly grounded.	
3. Always open up a well slowly, using the upper master valve.	

Revised December 31, 2001

Table 3.6.3, Special Well Control Situations Checklist

TASK	REMARKS
1. All Installations must develop a DST-Well Specific Operations Guidelines that addresses DP-DST interactions between the Driller, Well Test subcontractor and DPO. The DP-WSOG must be agreed by the Operator/OIM and implemented onboard the Installation.	
2. A surface shutdown system is required in any well test hook-up.	
3. Steel hammers or sledgehammers should be banned; brass is a must.	
4. Never allow a flame or naked light inside the safety perimeters. All hot work must be suspended.	
5. Always pressure test the installation prior to well opening.	
6. When designing a well testing set-up, make sure the equipment planned can safely withstand and handle the maximum wellhead pressure for the portion that may be exposed to such pressure.	
7. Thermal expansion of test string below BOP should be taken into consideration. Check design of test string slip joints and test string weight in view of expansion of test string due to temperature increase. Expansion may lead to unseating of fluted hangar in wellhead and test string moving up in BOP with potential damage to BOP components or re-positioning of shear sub away from shear rams.	

Table 3.6.3, Special Well Control Situations Checklist (continued)

TASK	REMARKS
8. The pressure in the BOP needs to be evaluated before a well test. BOPs are not designed to resist hydrostatic pressure from outside. External pressure can lead to collapse of components inside the BOP. Potential for severe down time and operational risks (loss of BOP integrity and control of well bore pressures) exists if BOP internal pressure is less than external hydrostatic pressure.	
9. The spacing between the various units comprising a well test hook-up should be reviewed considering BOP arrangement, Installation heave at drill floor, motion compensator space out. Spacing should also consider location of lubricators and bails with relation to Installation floor and hook so as to allow access to the lubricator with wireline tools.	
10. When reversing out do not allow the fluid to u-tube and create negative internal pressure which might damage the bonnet seals.	
11. Extended bails for test provided by Operator if coil tubing frame is not used. Use of slings not allowed as emergency disconnect requires turning to the right.	
12. Wind direction should be considered when blowing gas into the atmosphere. Total lack of wind currents may create hazardous conditions as gas mixes 1:10 with air potentially creating hazards in non-hazardous rated areas. Combustible gases can migrate towards lower pressure areas that are not suitable rated. "No wind, no test" is a recommended practice.	
13. DST tools must not be opened at night the first time without permission of the Division General Manager.	
14. All units must be properly grounded to prevent risks of ignition by static electricity.	

Revised July, 2002

Table 3.6.4, Pre-DST Checklist

TASK	REMARKS
1. Those items noted in the DST section of the Well Control Manual (HQS-OPS-HB-01) must be checked.	
2. Each operation must list the Installation specific equipment required on location for DST. Items such as oil dispersant, absorbents for spills, pup joints for correct space outs, brass sledgehammers and fishing tools for testing equipment must be included. Workboat with foam fire fighting capabilities plus spill chemicals must be on location.	
3. The DST landing string and tubing should be checked internally and verified free of contaminants.	
4. The subsea test tree configuration should be reviewed with testing personnel to verify the shear rams can close above the valve part of the subsea tree.	
5. A landing string diagram (Refer to Example) showing space out and configuration must be prepared and reviewed by the Testing Company, Operator and OIM. TEST STRING CALCULATIONS MUST BE REVIEWED FOR STRETCH IN THE EVENT OF COMPENSATOR LOSS.	
6. The entire Installation (down hole and surface) should be function and pressure tested at least 25% above the maximum anticipated pressure, and not to exceed the WP of the equipment. Pressure tests must be personally witnessed by the OIM or his designee.	
7. Have a heightened state of alert when non-shearable tubulars go thru the BOP.	
8. Wind direction and speed should be sufficient to carry burned products away from the Installation. Safe briefing areas must be designed and known by all personnel. Crews must know the location of the windsock and how to determine wind direction. All crews must be briefed on escape routes to safe briefing areas. Total lack of wind currents may create hazardous conditions. Burner boom must face downwind.	
9. Water curtains and fire-fighting equipment must be checked and verified operational before opening the well.	
10. All well testing units and gauge tanks must be electrically grounded. All well testing equipment inclusive of air compressors must be spark arrested and/or explosion proof. If they are not, the equipment must be located outside the hazardous area.	

Table 3.6.4, Pre-DST Checklist (continued)

TASK	REMARKS
11. All breathing apparatus must be checked and verified operational and sufficient for 30 minutes of use. The donning and use of emergency breathing apparatus must be reviewed until all personnel are proficient in its use.	
12. The conditions for allowing helicopter landings while flaring must be reviewed with the Customer and Helicopter Company, and an agreed plan must be established.	
13. Yokohama fenders must be removed from the water during well testing. Past experience has resulted in a Yokohama fender becoming oil soaked then burned and impossible to extinguish resulting in Installation damage.	

Revised Dec, 2003

Figure 3.6.3, Example HAZID / Task Risk Assessment Criterion

Hazard/Cause	Consequences	Safeguards	Recommendation
Communication • PRIOR FLOW PERIOD • During flow period	Health/Safety	Develop communication Examples during flow testing period with SSTT across BOPs. Ensure this is posted through the Installation and communicated to all parties.	
Disconnect Sequence: • Prior to perforating • After perforating – prior to SSTT • SSTT across BOP • Shear Scenario	Health/Safety Financial Impact	Develop "Emergency Disconnect Procedure", ensure this is posted through the Installation and communicated to all parties. Develop evacuation plan. Contingency - Ensure fishing equipment is on location if shearing is required.	
RU on motion compensator • Perforating Phase • Gravel Packing Phase • SL Operations • CT lift frame/Flow Testing	Health/Safety Financial Impact	Develop Operating Procedure with and with out compensator (determine setting criteria acceptable heave to handle task). Ensure this is posted through the Installation and communicated to all parties.	
Heave on Installation floor (Weather)	Health/Safety Damage to Coflex. Hose & Surface Tree	Prepare stackup drawing above Installation floor. Operating envelope for heave. Spaced surface tree - > 10 ft above Installation floor Accommodate space for CT lift frame, bails, elevator & etc.	

Wellbore Displacement / Cleanup Phase

Step 1

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Scheduling of supply boat for displacement of SOBM and completion brine	Financial Impact Delay	Extra supply boat for this period.	Work out detail schedule.
Time required to clean the pits	Financial Impact Delay	Extra crew and equipment may be needed to clean pits. Prepare a procedure ahead of schedule and review with Installation personnel to ensure an efficient / safe cleaning process is executed.	
Brine contamination during displacement	Financial Impact Healthy/Safety Delay	Review and test the valves in the pits (leak resistant), or remove all the mud is from the Installation. Develop a detail plan on how the brine must be stored and managed on the Installation. Proper PPE equipment to be ordered and worn by personnel who will come in contact with the brine. Review the First-Aid brine treatment with brine in the eyes and on the skin.	The mud engineer must prepare an Installation completion fluid handling plan. This plan must be approved by the Customer and the OIM

Step 2

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Casing Leak (13 5/8" x 9 5/8" x 7 5/8")	Financial Impact Repair	Pressure Test casing. If leak - Isolate with packers, tieback casing.	Existing safeguards satisfactory.

Wellbore Displacement / Cleanup Phase (Continued)

Step 3

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Poor/bad cement job across tests zone	Financial Impact Repair – block squeeze.	Centralization, spacer, mud & cement compatibility check.	Existing safeguards satisfactory.

Step 4

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Pickle: Xylene & Acid (10% HCL) disposal	Health/Safety Environmental Impact	Use dedicated pumping equipment. Gel spacer ahead/behind product. Disposal tote tanks same as storage/mixing tank. Service Company must provide communication radios for this operation and line to reverse fluids to tanks.	Existing safeguards satisfactory and may want to consider evaluating alternative products instead of Xylene for pickle. Develop a procedure of collecting the Xylene/Acid after pumping on the Installation.

Step 5

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Unable to shear tubulars during test	Health/Safety Financial Impact	All tubing string (3 ½", 4 ½" & 5 ½") except packers is shearable. Minimize time with non-shearable items across BOPs.	

Wellbore Displacement / Cleanup Phase (Continued)

Step 6

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Plugs filter equipment & contamination of completion fluid	Financial Impact	Pit capacity on the Installation is not an issue to hold both mud & completion brine. Procedure (scrapers & brushes) BHA and high pump rate and contingency Diatomaceous Earth (DE) and filters on location. Ensure sufficient quantities of DE are on the Installation.	

Perforating Phase

Step 1

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Unable to set Sump Packer	Financial Impact (tag top of liners, stuck in casing, GR-CCL locators fails)	Make a bit/scraper/brush run across casing/ TOLS. Clear filter (brine) – Solids Free. USIT/CBT log run across casing/TOLS. Straight hole.	Existing safeguards satisfactory.

Step 2

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Damage while picking up perforating string and TIH	Health/Safety (handling "Live: gun, damage to tools while, obstruction in test string)	(Optional) Radio/phone silent while PU guns and making up firing head. Safety joint above between firing head and gun. Only essential people on Installation floor while making up firing head. Procedure – Hold safety meeting on Installation floor. Rabbit all tubulars while tripping in hole.	

Step 3

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Leak in perforating string (work string, packer or test tools)	Financial Impact (Unable to hold a pressure test against the TFTV on the perforating string)	Pressure tests tubing against TFTV after the 3 ½" test tools are picked up. Repeat the testing 3 ½" x 4 ½" tubing 2 more times.	Existing safeguards satisfactory.

Perforating Phase (Continued)

Step 4

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Downhole circulating valve mal-function (achieve under balance).	Health/Safety Financial Impact (Unable to open circulating valve, failure to close circulating)	Inspection/certification of equipment. The circulating tool is very reliable. Previous experience with tool.	Consider perforate over balance followed by surge trip on the perforations.

Step 5

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
No pressure buildup after firing guns	Financial Impact (Guns fail to fire - drop bar not reaching firing head – obstruction in test string)	Contingency firing system – Pressure delay. Clear filtered brine – Solid free. Rabbit all tubulars while TIH with perforating string. If necessary – confirm by injection test.	Confirm firing procedure Existing safeguards satisfactory.
Problems with SL Operations (Retrieve Bar)	Financial Impact (Guns fire with SL in hole, pull out of SL, pull out of lubricator)	SL lubricator rated for 10K psi. Subsea Lubricator included in Perforating string. SL can be cut by valves if rapid disconnect is required.	Define tool string & define sufficient lubricator length for tool string. Existing safeguards for pressure rating satisfactory.

Perforating Phase (Continued)

Step 6

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Downhole circulating valve mal-function, achieve under balance, kill well, reverse circulate	Health/Safety Financial Impact (Unable to open circulating valve, failure to close circulating)	Kill well by bullheading down test string.	Existing safeguards satisfactory.

Step 7

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Pull perforating string	Health/Safety (handling "Live: gun, damage to tools while pulling out of hole, stuck guns)	If pull live gun: (Optional) radio/phone silent while PU guns and making up firing head. Ensure bar is retrieved. Safety joint above between firing head and gun. Only essential people on Installation floor while removing the firing head. If guns are stuck - Release perforating string at CTR – tension release sub (85 Ksi). Wash over guns and then latch guns.	

Gravel Packing (Frac-Pack: Sand Control) Phase

Step 1

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Damage to gravel pack assembly and TIH	Health/Safety (Handling "Screen/Blank" Damage to tools while TIH, Obstruction in test string)	Procedure – Hold safety meeting on Installation floor. Screen table, tongs & etc. Rabbit all tubulars while tripping in hole.	Existing safeguards satisfactory.

Step 2

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Leak in GP/FP string (work string, packer or cross-over test tool)	Health/Safety Financial Impact (Unable to set packer, pressure test against cross-over tool).	Procedure – trip speed in hole & ball drop. Tested during perforating stage (same string).	Existing safeguards satisfactory.

Gravel Packing (Frac-Pack: Sand Control) Phase (Continued)

Step 3

HAZARD/CAUSE	Consequences		Recommendation
Problems during Gravel Pack (Frac-pack Treatment) operations	Health/Safety Financial Impact (Pre-mature screen-out, failed to PU & reverse out, reverse out ceramic, proppant, cut surface choke out. Weather – Stimulation Boat moored next to the Installation	Procedure – Experienced Supervisor (hold safety meeting on the Installation floor). Surface head – rated form 10K psi. Pop-off valves – Shut down pumping. Communication between operator and tool man. Backup choke - Dual choke for reversing out. Calm/good weather: 4'-6' perform treatment off stimulation boat next to Installation. (NO DP required). Pumped only during good conditions, pickle performed from skid equipment.	

Step 4

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Problems retrieving tool out of hole and losing completion fluid	Health/Safety Financial Impact (Fluid loss, wash pipe inside GP screen).	Install fluid loss device in GP assembly (Shur-Shot) 2 3/8" WP (0.794" clearance between screen and wash pipe) Skid pump/blender must assist in mixing the LCM pill to ensure the correct volume is pumped (Contingency Only). Procedure moving cross-over tool – Minimize surging the formation with screen in hole. 125 Micron Poroplus - screen.	

Running Test String Phase

Step 1

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Damage and injury to personnel while picking up DST tools and TIH	Health/Safety (Handling downhole tools, damage to tools while TIH, obstruction in test string)	Procedure – Hold safety meeting on Installation floor. Rabbits all tubulars while tripping in hole.	

Step 2

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Leak in Tubing (3 ½" & 4 ½")	Financial Impact (Unable to pressure test tbg against the TFTV on the perforating string).	Pressure tests tubing against TFTV after the 3 ½" test tools are picked up. Repeat the testing 3 ½" x 4 ½" tubing 2 more times.	
Packer leak	Financial Impact (Unable to test tbg/pkr on the backside).	10 ft of seals. Clear filtered (brine) completion fluid. Straight hole.	

Running Test String Phase (Continued)

Step 3

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
	Health/Safety (Handling downhole tools, damage to tool/umbilical while TIH, obstruction in test string)	Procedure – Hold safety meeting on Installation floor. Pre-stackup drawing confirmed by Installation personnel prior to equipment RU. Rabbit all tubulars while tripping in hole. Use Weatherford – Flush Mounted Rotary Table (or equivalent) with slot to accommodate control lines & umbilical without squeezing them when hanging off string. Clamps (protect) umbilical.	

Running Test String Phase (Continued)

Step 4

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Damage injury to personnel while picking up surface tree and CT lifting frame	Health/Safety (Handling equipment, clearance on Installation, damage to tool/umbilical while PU).	Procedure - Hold safety meeting on the Installation floor. Pre-Stackup drawing - Verify required elevations, work area. Inspection/certification on all hoisting equipment (elevators, bails & etc) equal or exceed expected loads.	
Leak of tree/surface lines	Financial Impact Health/Safety (Unable to hold pressure test system)	Pressure tests lines upstream/downstream to choke manifold. Pressure from SSTT to choke (through surface tree).	

Step 5

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Unable to land seals into packer/fluted hanger on wear bushing	Financial Impact	Stackup drawing with actual strapped BOP dimension. Make a space out trip with adjustable fluted hanger and painted slick joint. Have the joint painted at least two days before task. This will provide strapped length from wear bushing to middle and check against the initial drawing.	

Flow Testing Phase

Step 1

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Downhole circulating valve mal-function (achieve under balance).	Financial Impact (Unable to open circulating valve, failure to close circulating)	Inspection/certification of tool. The circulating tool is very reliable. Previous experience with tool.	Consider achieving an under balance with chemical injection system. Rock well with diesel/SW – last option. After shearing fluid loss device.

Step 2

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
No flow or stops (low pressure) during initial unloading phase.	Health/Safety (Hydrate, debris blockage, SSTT closed line rupture, increase in annulus pressure or EDS).	During startup- Spot methanol across SSTT. (Prevent hydrate - continuously inject methanol until starts to flow). All lines are pressure tested prior to unloading well. Continuously monitor annulus pressure, do not let it build up over "SHORT" shear valve.	

Flow Testing Phase (Continued)

Step 3

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Flow Test Well: • Installation Floor – Visual Indication of problem w/ wellhead or tubing • Installation Floor – Leak in co-flex line or connection • Surface leak/problem other than on Installation floor • Well flowing on annulus (trip tank)	Health/Safety Potential fire/explosion	Procedure – Hold safety meeting on Installation floor prior to opening up well. All equipment must be pressure tested. ESD installed on the Installation. Sampling for CO2 & H_2S. Equipment design for maximum rate and pressure.	Shut-in SSTT, as soon as possible, notify Co. Man & Tool pusher. Shut-in 1st surface tree from panel if accessible. If not accessible, shut in lubricator or SSTT. Shut-in, ESD system from affected area.
		Riser Sealer Mandrel (RSM) – seals on around diverter, run below rotary, no damage to umbilical for SSTT and lubricator.	Shut-in at the same time: Lubricator valve & SSTT

Flow Testing Phase

Step 3 (Continued)

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
FLOW TEST WELL: • Annular pressure increase (rapid, not tie to changes in well flow) • Annular pressure decrease (rapid, not due to changes in well flow)	Health/Safety Potential fire/explosion	ALL EQUIPMENT MUST BE PRESSURE TESTED. ESD installed on the Installation. Sampling for CO2 & H_2S. Equipment design for maximum rate and pressure. Riser Sealer Mandrel (RSM) – seals on around diverter, run below rotary, no damage to umbilical for SSTT and lubricator.	If pressure increase cannot be bled off immediately & stabilized, then Shut-in: ESD system. Prepare to kill well by bullheading down the tubing. Attempt to increase pressure with Installation pump. If continued decrease in annular pressure, isolate Installation pump from BOP stack by closing standpipe valve. Monitor annulus pressure from choke manifold gauge. If pressure cannot be stabilized immediately, then Shut-in.

Flow Testing Phase

Step 3 (Continued)

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
FLOW TEST WELL: • High pressure (between choke manifold and steam exchanger) • Low pressure (between choke manifold and steam exchanger) • Heat radiation Gas in riser (due to leak in landing string)	Health/Safety HEALTH/SAFETY Financial Impact Health/Safety Financial Impact	ALL EQUIPMENT MUST BE PRESSURE TESTED. ESD installed on the Installation. Sampling for CO2 & H_2S. Equipment design for maximum rate and pressure. Riser Sealer Mandrel (RSM) – seals on around diverter, run below rotary, no damage to umbilical for SSTT and lubricator. Water spray (curtain) on Installation / HITEC flare boom - Protects Installation and personnel. The calculations are acceptable (depends on wind direction) at 30,000 BOPD rate (more water is desirable). Plans are to test at lower rates.	High pilot would trip shut down valve on choke manifold and master panel (Well shut-in). Low pilot would trip shut down valve on choke manifold and master panel (Well shut-in). Additional (portable spray) must be installed to protect life boat/ etc. The flare boom installed on the Installation already includes water spray.

Flow Testing Phase

Step 3 (Continued)

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
FLOW TEST WELL: • Methanol leak (chemical injection system)	HEALTH/SAFETY Financial Impact *Potential Fire/ Explosion*	ALL EQUIPMENT MUST BE PRESSURE TESTED. ESD installed on the Installation. Sampling for CO2 & H_2S. Equipment design for maximum rate and pressure. Riser Sealer Mandrel (RSM) – seals on around diverter, run below rotary, no damage to umbilical for SSTT and lubricator.	Install a deluge spray system over the methanol tanks. Additional chemical /foam (hand held fire fighting equipment) for both methanol and hydrocarbon fires. Drape the tanks with caution barricade tape and applied salt around the manhole covers where opening of tanks may occur. Add dye to methanol, help in locating leaks. Stainless steel tubing (eliminated) major problems of hoses burning if a fire occurs. ESD was also tied into the injection pumps to shut them down in case of emergency. Someone present in the area and every 30 minutes check areas with gas detector for leaks.

Flow Testing Phase

Step 3 (Continued)

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
FLOW TEST WELL: • High pressure (between steam exchanger and separator) • Low pressure (Between steam exchanger and separator) • High Shell pressure (steam exchanger) • High Pressure, Low Pressure, High Level, Low Level (on Separator) • High Pressure, High level (on p-tank)	Health/Safety Health/Safety Health/Safety Health/Safety Health/Safety	ALL EQUIPMENT MUST BE PRESSURE TESTED. ESD installed on the Installation. Sampling for CO2 & H_2S. Equipment design for maximum rate and pressure. Riser Sealer Mandrel (RSM) – seals on around diverter, run below rotary, no damage to umbilical for SSTT and lubricator.	High pilot would trip shut down valve on choke manifold and master panel (Well shut-in). Low pilot would trip shut down valve on choke manifold and master panel (Well shut-in). Trip master panel (Well shut-in). Trip master panel (Well shut-in). Trip master panel (Well shut-in).

OPS – DRILLING RELATED

WELL TESTING / DST

Flow Testing Phase

Step 3 (Continued)

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
FLOW TEST WELL: • High Level Controller • Low Level Controller • Level-Safety Low • ESD Panels • Gas Leak in riser • High flow	Health/Safety Health/Safety Health/Safety Health/Safety Health/Safety (Cut choke out surface choke w/ sand).	ALL EQUIPMENT MUST BE PRESSURE TESTED. ESD installed on the Installation. Sampling for CO2 & H_2S. Equipment design for maximum rate and pressure. Riser Sealer Mandrel (RSM) – seals on around diverter, run below rotary, no damage to umbilical for SSTT and lubricator. Well is gravel pack (sand control) ESD installed on Installation. Onsite supervision - Personnel monitoring well at all times.	Open dump valve (Start flow from p-tank). Close dump valve (Stop flow from p-tank). Close S.D.V. (Stop flow from p-tank). Trip master panel (Well shut-in). Low L.E.L. sound horn. High L.E.L. trip master panel (Well shut-in). Trip master panel (Well shut-in).

OPS – DRILLING RELATED

WELL TESTING / DST

Well Kill / Temporary Abandonment Phase

Step 1

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Downhole circulating valve mal-function, achieve under balance, kill well, reverse circulate	Financial Impact (Unable to open circulating valve, failure to close circulating)	Kill well by bullheading down test string.	

Step 2

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
DAMAGE AND INJURY TO PERSONNEL WHILE RD CT LIFT FRAME & SURFACE TREE/LINES	Health/Safety (Handling equipment, clearance on Installation, damage to tool/umbilical while RD).	Procedure (Safety Meeting) Experience from RU equipment.	

Step 3

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Damage while POOH with test string	Health/Safety (Handling equipment).	Hole starts taking fluid - Spot fluid loss pill. Experience from running/handling DST tools during installation.	Experience from RU equipment.

Well Kill / Temporary Abandonment Phase *(Continued)*

Step 4

HAZARD/CAUSE	Consequences	Safeguards	Recommendation
Unable set packer plug and dump 50' – 75' sand on top	Financial Impact (Debris inside packer prevents sting into packer, sand plugs work string)	Procedure spotting pill. Skid pump/blender will assist in mixing the pill to ensure the correct volume is pumped. Clear filter (brine) – Solids Free. Large amounts of sand – pump using a slurry using the skid pump/blender.	

5 RESPONSIBILITY

	Division Managing Director	HQS Well Operations Manager	Division General Manager	Operations Manager - Performance	Rig Manager - Performance	Operations Manager - Asset	Rig Manager - Asset	OIM	Senior Toolpusher / Toolpusher
Develop the TSTP and TRA.								IM	PM
Review and approve TSTP and TRA and forward to Rig Manager – Performance.					IM			PM	
Review and approve TSTP and TRA and forward to Division Managing Director or General Manager.					PM				
Review and provide final approval of TSTP and TRA.	PM		PM						
Request approval to open well test tools for the initial well test if to be done at night.				PM	PM			PM	
Provide approval to open well test tools for the initial well test if to be done at night.	PM		PM						
Review the request for exemption for submittal to HQS Performance and Operations.			IM	IM	PM	V	V		
Review for approval, the CCTLF exemption request.		PM							

6 REFERENCES

RECOMMENDED PRACTICES WITHIN THE FILED OPERATIONS MANUAL PROVIDE EXAMPLE DOCUMENTS ILLUSTRATING WELL TEST OPERATING CRITERIA, RECOMMENDED PERFORMANCE STANDARDS AND HAZARD IDENTIFICATIONS (HAZID) RELATED TO WELL TEST OPERATIONS.

6.1 MARINE COMPLIANCE PROCEDURES MANUAL, HQS-OPS-PR-06, SECTION 6.7, MARINE CONSIDERATIONS DURING DRILL STRING TESTING (DST)

6.2 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.2.1, RISK MANAGEMENT

6.3 HEALTH AND SAFETY POLICIES AND PROCEDURES, HQS-HSE-PP-01, SECTION 4.5.7, IMPLEMENTING AND MONITORING

6.4 FIGURE 3.6.1, EXAMPLE OF A SCHLUMBERGER DST LANDING STRING

6.5 FIGURE 3.6.2, EXAMPLE OF A SCHLUMBERGER DOWNHOLE TEST STRING

6.6 TABLE 3.6.1, BASIC PRECAUTIONS FOR DST CHECKLIST

6.7 TABLE 3.6.2, PRECAUTIONS WHILE TESTING CHECKLIST

6.8 TABLE 3.6.3, SPECIAL WELL CONTROL SITUATIONS CHECKLIST

6.9 TABLE 3.6.4, PRE-DST CHECKLIST

6.10 FIGURE 3.6.3, EXAMPLE HAZID / TASK RISK ASSESSMENT CRITERION

MARINE COMPLIANCE

MARINE OPERATIONS

1 POLICY

All installations must be operated in accordance with Company established Marine Compliance Procedures, Class approved Installation-specific Operating Manual limits, contingency plans provided in the Installation's Emergency Response Manual, and any other applicable Company-specified operating limits.

2 PURPOSE

To communicate the standard of Marine Operations the Company expects for protection of personnel, the environment, and the Installation.

3 SCOPE

This policy is applicable to all Installations owned or operated by Transocean or its subsidiaries.

4 PROCEDURE

The key elements of Marine Operations are covered in the Marine Compliance Procedures Manual, HQS-OPS-PR-06 and include:

- Marine Administration
- Management of Marine Personnel
- Rig Move Operations
- On-Location Marine Operations
- Special Marine Operations
- Stability

5 RESPONSIBILITY

	Managing Director	General Manager or Designee by Managing Director	Division Marine Manager / Marine Superintendent	Operations Manager - Performance	Rig Manager - Performance	OIM
Ensure consistent application of Marine Compliance Procedures.	IM					
Ensure implementation of the Marine Compliance Procedures.		IM	V			
Ensure Installation operations are conducted in accordance with the Marine Compliance Procedures.				V	PM	
Ensure that all applicable requirements contained within the Marine Compliance Procedures are implemented on the Installation.						PM

6 REFERENCE

6.1 MARINE COMPLIANCE PROCEDURES MANUAL, HQS-OPS-PR-06

MARINE COMPLIANCE

WELL SPECIFIC OPERATING CRITERIA (WSOC)

1 POLICY

Well Specific Operating Criteria (WSOC) must be developed for each Dynamically Positioned Installation at each location prior to the commencement of drilling operations.

2 PURPOSE

The WSOC is intended to identify the specific conditions that must result in change of operational status of a DP MODU from normal to an Advisory or Alert condition.

3 SCOPE

This policy is applicable to all Dynamically Positioned Installations owned or operated by Transocean or its subsidiaries.

4 PROCEDURE

The key elements of the Well Specific Operational Criteria (WSOC), covered in the ET&S Standard HQS-ETS-STD-01 (Guidelines for Creating Well Specific Operating Criteria) and the Marine Compliance Procedures Manual, HQS-OPS-PR-06, Section 5, Subsection 3, Well Specific Operating Criteria (WSOC), include:

- WSOC Template
- Site Specific Criteria
- Limiting Criteria
- Critical Issue Identification
- Equipment and Capabilities
- WSOC review and approval
- Riser Analysis Limitations
- Responsibilities

5 RESPONSIBILITY

	Operations Manager - Performance	Rig Manager - Performance	OIM
Ensure a WSOC is developed for each drilling location, review and approve the WSOC prior to commencement of drilling operations and ensure the limitations identified within the WSOC are closely followed.	IM	PM	
Ensuring that a WSOC is developed for each drilling location and approved by the Rig Manager Performance prior to commencement of drilling operations.			PM

6 REFERENCES

6.1 ET&S STANDARD, HQS-ETS-STD-01, GUIDELINES FOR CREATING WELL SPECIFIC OPERATING CRITERIA

6.2 MARINE COMPLIANCE PROCEDURES MANUAL, HQS-OPS-PR-06, SECTION 5.3, WELL SPECIFIC OPERATING CRITERIA (WSOC)

MARINE COMPLIANCE

PERSON IN CHARGE (PIC)

1 POLICY

The Person in Charge (PIC) for emergency situations must be specified on the Installation Station Bill.

2 PURPOSE

The MODU Code requires the Company designate by title, the person to whom all personnel on board the Installation are responsible to in an emergency. This policy ensures communication of the chain of command during an emergency and clarifies the Master's Authority aboard self-propelled Installations as required by Element 5 of the International Safety Management Code.

3 SCOPE

This policy is applicable to all Installations owned or operated by Transocean or its subsidiaries.

4 PROCEDURE

The key elements of Person in Charge (PIC), covered in the Marine Compliance Procedures Manual, HQS-OPS-PR-06, Section 3, Subsection 1, Designation of OIM and PIC, include:

- Company identification of the OIM and PIC by Installation type
- Roles, Responsibilities and Authority of the Master and OIM
- Responsibilities and actions required of the PIC

5 RESPONSIBILITY

	General Manager or Designee by Managing Director	Operations Manager - Performance	Rig Manager - Performance	OIM	Installation Department Head
Ensure all OIM and PIC are identified according to this Policy and the associated Procedure.	IM	PM			
Ensure the PIC is specified on the Installation Station Bill and the OIM is clearly identified in writing according to this Policy and the associated Procedure.			PM		
The OIM is responsible for ensuring that the provisions of this Policy and associated Procedure are implemented on the Installation.				IM	PM

6 REFERENCE

6.1 MARINE COMPLIANCE PROCEDURES MANUAL, HQS-OPS-PR-06, SECTION 3.1, DESIGNATION OF OIM AND PIC