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Planning and Execution of a Marine Methane Hydrate Pressure Coring Program for the Walker Ridge and Green Canyon Areas of the Gulf of Mexico

Final Report

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ABSTRACT

The objective of this project (and report) is to produce a guide to developing scientific, operational, and logistical plans for a future methane hydrate-focused offshore pressure coring program. This report focuses primarily on a potential coring program in the Walker Ridge 313 and Green Canyon 955 blocks where previous investigations were undertaken as part of the 2009 Department of Energy JIP Leg II expedition, however, the approach to designing a pressure coring program that was utilized for this project may also serve as a useful model for planning pressure coring programs for hydrates in other areas.

The initial portion of the report provides a brief overview of prior investigations related to gas hydrates in general and at the Walker Ridge 313 and Green Canyon 955 blocks in particular.

The main content of the report provides guidance for various criteria that will come into play when designing a pressure coring program. The key topics covered are:

- Defining the scientific objectives
- Developing a coring plan based on understanding of potential hydrate intervals
- Selection of pressure coring tools and core analysis tools
- Planning of onshore and offshore core analysis program
- Selection of Vessel for offshore coring operations
- Permitting for offshore operations
- Logistical considerations for offshore operations
- HSE considerations for field operations
- Project Management requirements

At the conclusion of the report, specific recommendations for a pressure coring program at the Walker Ridge 313 and Green Canyon 955 blocks are provided.

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LIST OF ACRONYMS AND ABBREVIATIONS

APC	Advanced Piston Corer
APCM	Advanced Piston Corer Methane
APCT	Advanced Piston Corer Temperature
BGHS	Base of Gas Hydrate Stability
BHA	Bottom Hole Assembly
BIO	Bio-Studies
BOEM	Bureau of Ocean Energy Management
BP	British Petroleum
BSF	Below Seafloor
BML	Below Mud Line
BSEE	Bureau of Safety and Environmental Enforcement
BSR	Bottom Simulating Reflector
CBHA	Fugro's medium Common Bottom Hole Assembly
DAPC	Dynamic Autoclave Piston Corer
DOE	Department of Energy
DP	Dynamic Positioning
DSC	Direct Shear Chamber
DSV	Deep-Submergence Vehicle
EIA	Environmental Impact Assessment
EOR	End of Operations Report
EP	Exploration Plan
ESC	Effective Stress Chamber
FC	Fugro Corer
FHPC	Fugro Hydraulic Piston Corer
FMCB	Fugro Marine Core Barrel
FPC	Fugro Pressure Corer
Ft	Foot/Feet
FXMCB	Fugro Extended Marine Core Barrel
GC955	Green Canyon Block 955
G&G	Geological and Geophysical
GOM	Gulf of Mexico
GH	Gas Hydrate
GHSZ	Gas Hydrate Stability Zone
HPTC	High Pressure Temperature Coring System
HYACE	Hydrate Autoclave Coring Equipment
HYACINTH	HYACE In New Tools on Hydrates
Hybrid PCS	Hybrid Pressure Coring System
IODP	Integrated Ocean Drilling Program
IPF	Impact Producing Factors
IPTC	Instrumented Pressure Testing Chamber

JAMSTEC	Japan Agency for Marine-Earth Science and Technology
JAPEX	Japan Petroleum Exploration Co Ltd
JIP	Joint Industry Project
JNOC	Japan National Oil Corporation
LWD	Logging While Drilling
M	Meter/Meters
MAC	Multiple Autoclave Corer
MMS	Minerals Management Service
MTD	Mass Transport Deposit
NETL	National Energy Technical Laboratory
NDT	Non-Destructive Testing
NTL	Notice to Lessees
OCS	Outer Continental Shelf
ODP	Ocean Drilling Program
PCB	Pressure Core Barrel
PCS	Pressure Core Sampler
PCTB	Pressure Corer Tool with Ball-valve
PCATS	Pressure Core Analysis and Transfer System
PCCT	Pressure Core Characterization Tool
PEP	Project Execution Plan
PMP	Project Management Plan
PTCS	Pressure Temperature Corer System
QMS	Quality Management System
RCB	Rotary Core Barrel
SUCO	Sugar Corer
SWF	Shallow Water Flow
TRW	Topographic Rossby Waves
USGS	United States Geological Survey
WOB	Weight on Bit
WR313	Walker Ridge Block 313
XCB	Extended Core Barrel

1. EXECUTIVE SUMMARY

The objective of this project study (and report) has been to conduct activities necessary to support and produce a guide to developing scientific, operational, and logistical plans for a future methane hydrate-focused offshore pressure coring program.

This has been accomplished through the establishment of a highly qualified, cross disciplinary project team who has pulled together years of direct experience and critical lessons learned from field work related to the planning and conduct of marine research expeditions with a focus on the needs of an expedition whose objective is the collection of pressurized hydrate cores (P-cores). The team utilized outside subject matter experts in developing the framework of the guide through direct input, workshop activities and peer review of technical content. Those activities have resulted in the technical content contained in this final technical project report.

The technical content of this report is focused specifically on defining, describing and discussing the areas of effort. The effort includes a scope of work, technical specifications, and schedule needed to implement a pressure core–focused marine gas hydrate investigation. Much of what is presented could be applied to gas hydrate exploration and coring programs anywhere, but the framework and specific examples included here were developed specifically for planning and conducting a methane hydrate pressure coring program in Walker Ridge 313 (WR313) and Green Canyon 955 (GC955) areas in the deepwater Gulf of Mexico (Sites of documented hydrate occurrence established by the 2009 Department of Energy (DOE) JIP Leg II Logging-While-Drilling expedition conducted under prior DOE project DE-FC26-01NT41330). In 2009, the JIP Leg II field program indicated the presence of gas hydrate reservoirs at boreholes in both WR313 and GC955 based on Logging While Drilling (LWD) results. Conclusions drawn from the 2009 JIP Leg II program included recommendations to perform additional research drilling programs to further delineate the potential hydrate resource through the use of pressure coring and pressure core analysis systems.

The overall focus of this project is to help enable—through detailed scientific and operational planning—the future collection of methane hydrate pressure cores, which would add to the body of scientific knowledge of the characteristics of in situ methane hydrate occurrences and contribute to scientific and engineering efforts to assess potential exploitation of methane hydrates as an energy resource.

The project would help guide and enable future field-based collection of hydrate data through the completion of detailed logistical, scientific, technical, and operational plans. These plans would facilitate the conduct of future marine hydrate research expeditions, which represent a critical path to collecting the data required to characterize the occurrence and behavior of oceanic hydrates and, ultimately, assess their feasibility as a potential future energy resource.

A field program is an expensive and complex undertaking for which the prospecting, target location, preliminary planning and evaluation research performed before initiating a field program could often take several years. This effort is intended to build off prior work at these sites where much of that preliminary planning work was already completed as part of the previous campaigns. The encouraging aspect of planning a coring field program in WR313 and GC955 is that good coring targets have already been identified, thereby optimizing the chances for a successful campaign that could significantly advance gas hydrate science and delineate prospective reservoirs for future production scenarios.

This report is organized around the components needed in the planning and conduct of a marine gas-hydrate pressure coring expedition targeting specific locations in WR313 and GC955 areas of the Gulf of Mexico (GOM) and provides discussion on and recommendations regarding each of those components. Below is included a brief summary of the areas of technical content housed in this report.

To-date, there have been approximately 20 major gas hydrate field programs. The field programs in the GOM and elsewhere (Japan, India, Korea, and China) have shown that the distributions of methane hydrate are more complicated than original expectations. The application of a "petroleum systems approach" to gas hydrate prospecting has emerged in recent years. The JIP Leg II field program discovered (via LWD drilling) high saturation gas hydrates in sands that matched pre-drill predictions. A pressure coring field program at those JIP Leg II sites in WR313 and GC955 could further validate the method and calibrate the LWD data.

Pressure coring tools were developed to capture in situ gas hydrate samples that would allow investigation of their fundamental characteristics. The pressure coring tools have evolved and are continually being modified and updated to improve gas hydrate pressure coring operations. The first pressure corers were rotary designs. Mud-driven pressure coring was developed next with the advantage that they could use a seabed frame and the vessel heave compensator to advance the corer decoupled from the ship's movement. It has always been a challenge to core unconsolidated sands. A new pressure coring system with a ball valve has been designed, in part, to enable recovery of pressure cores in sands and to take longer cores. This planning study recommends the use of this new ball valve-equipped pressure coring system design given the targeting of hydrated sands in WR313 and GC955.

2. INTRODUCTION

2.1 Objective

The objective of this research effort (and report) is to produce a guide to developing scientific, operational, and logistical plans for a methane hydrate-focused offshore pressure coring program in the US Gulf of Mexico. This goal is to be accomplished by using prior experience of the research team on similar studies to develop and describe, a scope of work, technical specifications, schedule and timing estimates needed to plan and implement a coring-focused marine gas hydrate research expedition. The principal elements addressed in the report include: (1) planning a gas hydrate field program, (2) a summary of prior JIP Leg II site selection process, LWD logging expedition, and results, (3) potential for carrying out a coring program at the JIP Leg II gas hydrate deposits, (4) pressure coring devices and pressure core analysis, (5) field program options, (6) vessel selection, (7) permitting, (8) premobilization, mobilization, and demobilization, (9) health, safety and environment (HSE), (10) operations, and (11) recommendations for a specific program.

The planning approach outlined in this report is applied specifically to a potential program in the Walker Ridge and Green Canyon Areas of the Gulf of Mexico, but is generally applicable to planning similar programs in other areas as well.

2.2 Purpose and Scope of Work

The overall project, and specifically the content provided within this project final report, is intended to serve as a resource for the planning and conduct of a future coring–focused gas hydrate research expedition specifically targeting the WR313 and GC955 areas of the GOM previously identified as viable, high saturation hydrate targets by the DOE – Chevron JIP project. This is to be achieved through development and documentation of notional scientific and operational plans for such a research expedition that would add to the body of scientific knowledge of the characteristics of in situ methane hydrate occurrences and contribute to scientific and engineering efforts to assess potential exploitation of methane hydrates as an energy resource.

The scope of this project was focused on defining, describing, and discussing the areas of research effort needed to implement a pressure core-focused marine gas hydrate investigation. Much of what is presented could be applied to gas hydrate exploration and coring programs anywhere, but the framework and examples included here were developed specifically for planning and conducting a methane hydrate pressure coring program in Walker Ridge 313 (WR313) and Green Canyon 955 (GC955) areas in the deepwater Gulf of Mexico (sites of documented hydrate occurrence established by the 2009 DOE JIP Leg II, Logging-While-Drilling expedition conducted under prior DOE project DE-FC26-01NT41330).

The technical content contained in this final technical project report includes, but is not limited to the following:

(1) An overview of the process of planning a gas hydrate field program, e.g., where to take cores, for what purpose, at what cost, and how to do it all safely and efficiently; range of typical targets and host sediments, the evolution of gas hydrate field programs, etc.;

(2) A brief summary of prior Gulf of Mexico (GOM) gas hydrate Joint Industry Project (JIP), an international cooperative research program led by Chevron and funded by DOE and JIP members by contributions or in-kind contributions, specifically, JIP Leg II site selection process, LWD logging expedition, and results (e.g., drilling target, permitting process, drilling hazards analysis, operational platform, operational issues and performance, etc.);

(3) A discussion of a potential coring program at the JIP Leg II gas hydrate deposits with a sample coring plan;

(4) A description of the suite of five (5) pressure coring devices and pressure core analysis recommended for carrying out a coring program at the WR313 and GC955 sites;

(5) A discussion of field program options including gas hydrate detection and analysis plans for both conventional cores (C-cores) and pressurized cores (P-cores);

(6) A review of available Dynamic Positioning (DP) vessel selection process that require the use of a suitable deepwater drilling vessel fitted with draw-works and a heave compensated, top-drive drilling rig. The selection range of these DP vessels should have capability to operate in water depths as deep as 2,000m and drilling depths as deep as possible beyond 2,000m;

(7) A review of the various permitting requirements to perform a deep stratigraphic test, such as permit to conduct Geological or Geophysical Exploration (G&G Permit), exploration plan, and permit to drill;

(8) A description of the premobilization, mobilization, and demobilization which are critical aspect of the process to ensure that appropriate procedures are followed to allow for a smooth and safely run operation, such as vessel charter, insurance, equipment, subcontractors, supply vessels, drilling mud, schedule, weather, selection of ports, permits, customs, logistic supports, etc.;

(9) Guidance on Health, Safety and Environment (HSE). HSE should be held paramount to the entire coring operation. Working in a marine environment has inherent dangers in itself. Established practices and procedures are available through efforts of DSDP, ODP and IODP;

(10) A recommendation on the operations detailing how the GOM coring expedition should be conducted or operated;

(11) A recommendation for a specific program at WR313 (G and H) and GC955 H based on the results of prior JIP Leg II LWD expedition.

3. PLANNING A GAS HYDRATE FIELD PROGRAM

3.1 Overview of the Process

A field program to find and characterize buried gas hydrates is an expensive and complex undertaking and is usually the culmination of dedicated efforts over years by many contributors. There are several principal considerations that are a part of such a process: where to take cores, for what purpose, at what cost, and how to do it all safely and efficiently?

The research done prior to a decision to plan and undertake a large scale field research could take several years. In many cases, especially in areas of the world without the benefit of the data from active conventional oil and gas exploration such as Japan, Korea, and Taiwan, gas hydrate research programs have had to invest in large scale data acquisition over many years including, geochemistry, heat flow, seafloor mapping, 2D seismic programs, electromagnetics, and 3D seismic programs as precursors to decisions on whether to undertake gas hydrate drilling, logging and coring programs.

With so much time and effort invested, a gas hydrate field program needs to be well planned and well prepared. The selection of suitable coring locations is of course an essential element of the planning phase. The available gas hydrate targets and the types of research questions to be answered would guide the scientific objectives and design of the field program.

This project (and report) however, focuses specifically on a coring program in WR313 and GC955 where scientists already have a set of previously identified coring targets around which to design and execute a field program that could significantly advance gas hydrate science.

After the core targets and scientific objectives are determined, a research budget needs to be developed. The vessel/platform choice could constrain the onboard science program. The choice of vessel would determine how fast the work is done and how much work could be done in a given timeframe / budget. Vessel availability and cost are important considerations, but layout, berths for scientists and workflow are also key considerations. Decisions on coring tools and the types of analyses are also critical.

Vessels that have previously been involved with gas hydrate research programs have in some cases included standard geophysical research vessels, such as those operated by universities and industry. While these vessels could perform some relevant work, such as obtaining shallow cores of a few meters' penetration, imaging the seabed and water column, simple seismic acquisition, etc., these vessels are not suitable for obtaining samples of buried gas hydrate. Sampling buried gas hydrate requires a drilling vessel. Vessels capable of obtaining samples include a subset of vessels used for geotechnical drilling applied to the design of offshore foundations, or a limited set of scientific drillships such as the JOIDES Resolution and the Chikyu. Vessels that specialize in workover and tophole completions, such as Helix Q4000 and the Fugro Synergy have also been used on gas hydrate programs (See Section 8 for further details). Deepwater drilling vessels used for deepwater oil and gas exploration could also be considered, but may be cost prohibitive.

The costs for chartering any of these vessels are high and may be prohibitive for research programs. The most economical are vessels used for geotechnical drilling, followed by workover and tophole completion vessels and those whose costs are partially underwritten by the international science community.

Operations need to be conducted in a safe manner; safety is a paramount concern for all offshore operations. Drilling operations add complexity and safety concerns for offshore personnel. The trend for offshore drilling is to reduce the number of people required for drill floor operations. For instance, some drill floors are completely unmanned during normal drilling and tripping operations.

The following sections discuss in more detail the parts of the planning process that should be included in the planning of a gas hydrates field program. Additionally, lessons learned from previous field programs are discussed and should be considered in the planning of future field work to improve upon the past performances.

3.1.1 Prior Gas Hydrate Investigations

The paradox of gas hydrate distribution, as mentioned, is that gas hydrates seem to be both ubiquitous and elusive. It is commonly understood that gas hydrates are widespread on the continental margins and that the volume of methane stored in these formations greatly exceeds conventional gas reserves. But, gas hydrate exploration scientists should not confuse the enormity of resource with any corresponding ideas of uniform distribution. Several major field expeditions did not successfully recover methane hydrate in the areas selected for the expensive expeditions (Claypool et al., 2006). The resources required for a field program are too precious to return to port with little to show for the effort. Any field program needs to assure specific and well developed gas hydrate targets with depths, thicknesses, and host sediments and a well-conceived coring program for those targets.

Beginning in 1995 with Ocean Drilling Program (ODP) Leg 164, there have been approximately 20 major marine hydrate-focused field expeditions. Each of these field programs have contributed to the knowledge base. Each has had its own specific scientific objectives and each has discovered something new. A good review of these programs, through 2012, and their objectives and results is Consortium for Ocean Leadership (2013). We have also summarized these programs in Section 3.2.1. A common thread through many programs was the objective to confirm the presence of gas hydrate and to understand geologic controls on gas hydrate formation and distribution in the study areas. Early gas hydrate field programs, using the state of knowledge at the time were guided by overly simplistic interpretations of BSRs (bottom simulating reflectors) and their relationship to gas hydrate distribution and saturation. The field programs in the GOM and elsewhere, (e.g. Japan, India, Korea, China) have shown that factors controlling the distribution of hydrates are more complicated. A concept of a gas hydrate petroleum system began to emerge with the establishment of a set of criteria analogous to those used in conventional petroleum exploration. Testing the petroleum systems approach to gas hydrate prospecting was one of the principal objectives of the JIP Leg II field program. The success of the LWD performed during this program and good coincidence between pre-drill predictions and the interpretation of the LWD data offers the opportunity to further validate the method and calibrate the LWD data by means of a coring field program in WR313 and GC955.

A field pressure coring program for gas hydrate sampling in WR313 and GC955 would have several advantages; in particular the benefit from years of gas hydrate target development by the Chevron DOE JIP and a LWD program that identified a wide range of excellent coring targets. Because the same explorations concepts were utilized to identify a number of targets in other areas, a field program in WR313 and GC955 could also make strong contributions to a fuller understanding of the gas hydrate distribution in these areas through either a combined LWD and coring expedition or through a coring and core analysis program alone.

3.1.2 Range of Typical targets and host sediments

Gas hydrates that have been inferred from geophysical logs and/or confirmed from normal and P-cores occur at, and within, a wide range of depths and host sediments. The thickness of the GHSZ is controlled by hydrostatic pressure which is a function of the water depth and temperatures of the local geothermal gradient. Gas hydrate targets, whether shallow, middle or deep are all relative to the thickness of the GHSZ. The shallowest gas hydrates in the system are those on the seafloor and associated with near seafloor vents (Brooks et al., 1985). These are typically associated with carbonate hardgrounds and chemosynthetic communities, and are commonly recovered in marine geochemical programs that target natural hydrocarbon seepage but have also been sampled to support gas hydrate programs (Kojima, 2002).

Gas chimneys within the gas hydrate stability zone (GHSZ) are also targets for coring. Shallow and mid depth hydrates in clays or, in sands intersected by the gas chimney are targets of interest in some gas hydrate systems. The two Korean field programs (UBGH 1 and UBGH 2) and JIP Leg I targeted these types of deposits (Park et al., 2008). Strata-bound gas hydrates in clays (JIP Leg II), high amplitudes in strata along faults or on structures offer targets (ODP Leg 204), and areas exhibiting amplitude blanking (ODP Leg 164), also present potential coring targets within the middle of the GHSZ. The deepest targets for gas hydrate would be associated with gas charged sands at, or near, the Base of Gas Hydrate Stability (BGHS) (JIP Leg II) and continuous BSRs (ODP Leg 164 & Nankai Trough). It should also be noted that a common finding of all of the field programs is that relatively few sediments within the GHSZ host gas hydrate.

A summary of these findings for gas hydrate occurrence is tabulated according to energy resource potential in Figure 3.1 (modified from Boswell et al., 2015). Representative gas hydrate saturations are superimposed on five stylized wells. The GC955 and WR313 locations are shown on this figure as type sections. The GC955 gas hydrate deposits are represented on the far left of the figure as the most prospective targets and, next to them and also prospective, are the primary targets at the WR313 sites. The strata-bound fracture-fill gas hydrates found at the WR313 locations are stylized on the right side of the diagram, as the least prospective targets.

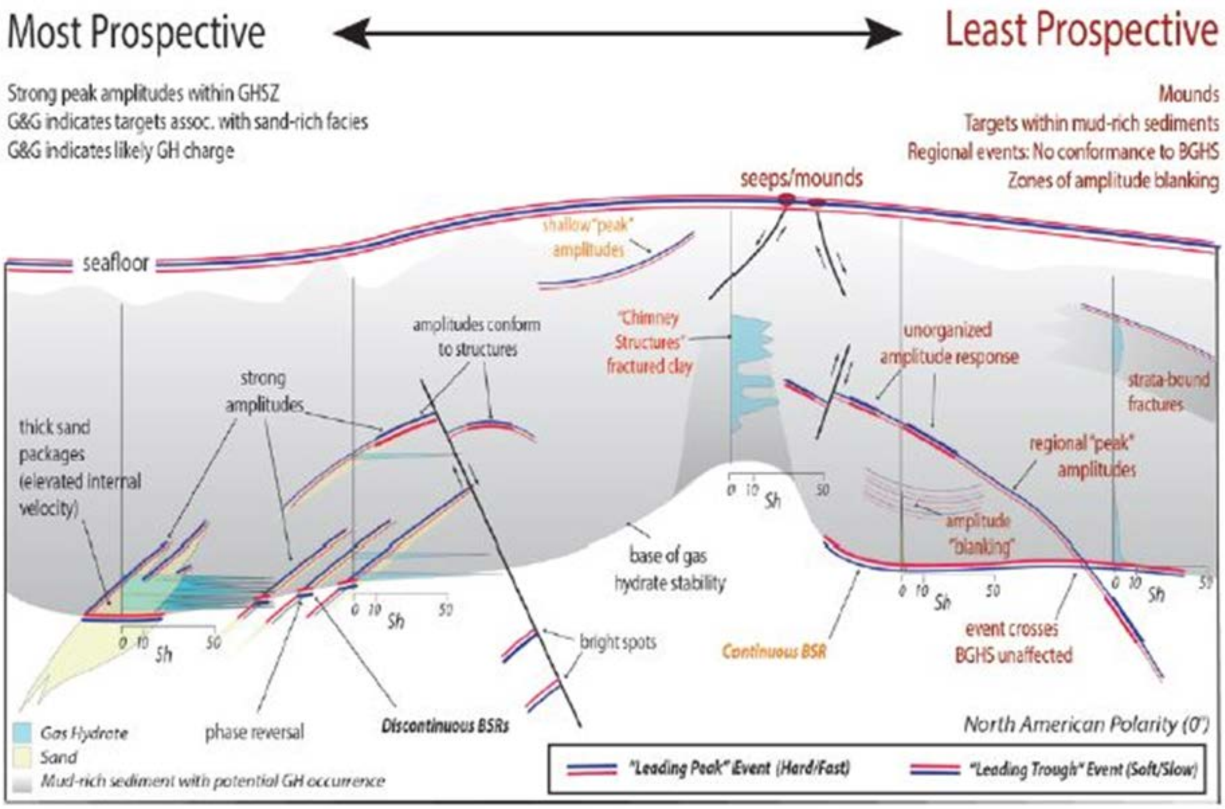

Figure 3.1 Gas hydrate occurrence according to energy resource potential (from Boswell, R., et al, 2015)

3.1.3 Scientific Objective

The design of an offshore gas hydrate field program would vary widely depending on the scientific objective. For instance, a program that is investigating the effect of gas hydrate dissociation on engineered structures would be different from a program that is gathering data to analyze energy resources and potential gas hydrate production, which, in turn, would be different from a program gathering data about the greenhouse gases and flux from the deep ocean environment into the atmosphere. The depth of cores, the types of onboard testing, the number and distribution of cores would depend on the assembled data and the hypotheses to be tested.

Scientific objectives for field programs to date have included (COL, 2013):

- Fundamental distribution and relationship to seismic indicators
- Assessment of resource potential of gas hydrate deposits
- Understanding models of gas hydrate formation and flux
- Collection of gas hydrate samples for laboratory studies
- Understanding hazards to drilling
- Pore water chemistry to constrain models of formation
- Hydrate formation in different geologic settings e.g. accretionary margins

- Hazards to placement and performance of engineered structures
- Testing of prediction models for gas hydrate occurrence
- Evaluating production methods
- Environmental impact of gas hydrate production
- Field testing of gas hydrate exchange kinetics
- Engineering data for production system design.

The scientific objective would determine, to a large degree, the coring tools, types of hydrate targets, analyses to be performed, number of scientists, layout of the laboratories, and the vessel to be chartered.

3.2 Evolution of Methane Hydrate Field Programs

3.2.1 Offshore

Historically, there have been a number of offshore gas hydrate field expeditions as listed below. Some of these were for geohazards, but the majority were for resource detection or evaluation. There have been a variety of vessels employed for this work over the years. A list of previous offshore gas hydrate investigations and the vessels employed follows:

- ODP Leg 164 (1995), R/V JOIDES Resolution
- Japan Nankai Trough Project (1999---2000), MODU MG Hulme
- ODP Leg 204 (2002), R/V JOIDES Resolution
- Chinguetti Woodside, Offshore Mauritania (2003), SRV Bavenit
- Japan Tokai-oki to Kumano-nada Project (2004) , R/V JOIDES Resolution
- Gulf of Mexico JIP Leg I (2005), MSV Uncle John
- IODP Expedition 311 (2005), R/V JOIDES Resolution
- Shell Malaysia Gumusut---Kakap Project (2006), SRV Bavenit
- India NGHP Expedition 01 (2006), R/V JOIDES Resolution
- China GMGS Expedition 01 (2007), SRV Bavenit
- Republic of Korea UBGH Expedition 01 (2007), M/V REM Etive
- Gulf of Mexico JIP Leg II (2009), Helix Q4000
- Republic of Korea UBGH Expedition 02 (2010), D/V Fugro Synergy
- MH-21 Nankai Trough Pre-Production Expedition (2012---2013), RV Chikyu
- China GMGS Expedition 02 (2013), M/V REM Etive
- Meiji University Sea of Japan Expedition 01 (2014), RV Hakarei
- India NGHP Expedition 02 (2015), RV Chikyu
- China GMGS Expedition 03 (2015), D/V Fugro Voyager.
- Meiji University Sea of Japan Expedition 02 (2015), RV Hakarei
- China GMGS Expedition 04 (2016), D/V Fugro Voyager, ongoing.

There have been great learnings and experience gained from these programs, and it seems as if every expedition is unique and has its own set of challenges. The learnings from those experiences serve to inform considerations for future hydrate marine field expeditions.

3.2.2 Onshore

Investigations into gas hydrate systems and production technology have also been conducted at several onshore locations including:

- Mallik Gas Hydrate Testing Projects (1998/2002/2007-2008)
- Anadarko Hot Ice – South of Kuparuk field (2003/2004)
- Alaska Mount Elbert Stratigraphic Test Well (2007)
- Alaska Iġnik Sikumi Gas Hydrate Production Test Well (2011-2012)

4. OVERVIEW OF PRIOR JIP EXPEDITIONS

The Gulf of Mexico gas hydrate Joint Industry Project, an international cooperative research program led by Chevron, began research on marine gas hydrates and collection of data in the Gulf of Mexico in 2001. The project was funded by DOE and the JIP members by contributions or in-kind contributions. The US Department of Energy provided research funding through the National Energy Technology Laboratories. Beyond this, several academic and industry groups with interest and expertise in gas hydrates provided contributions to the project's success.

The JIP made significant contributions to the understanding of marine gas hydrates, testing several exploration concepts and exploration workflows. There were two field expeditions, Leg I and Leg II, conducted under the JIP. A third field program, Leg III, was on the project timeline but never executed. Interrupted by the Deepwater Horizon accident and the moratorium on drilling in the GOM in 2010, the JIP decided to not launch a Leg III field program to sample any gas hydrates found during the Leg II LWD reconnaissance field program, and concluded its operations.

The first field expedition, JIP Leg I, focused on testing the ability to operate in regimes typical of gas hydrate occurrences in deep water areas of the Gulf of Mexico. Sites were selected in Atwater Valley 13 and 14 and in Keathley Canyon 151 (Claypool, 2006). The locations were also chosen, in part, to test flux models for gas hydrate systems. The results of the JIP Leg I are important because they indicate that there is a high chance of not finding gas hydrate even in hydrocarbon rich basins; thus, target selection is of paramount importance. Exploration concepts, especially for gas hydrates, are still being understood. Another lesson from studying JIP Leg I is that pressure coring is a complex operation. Largely because of the failure to bring back good cores on a combined LWD and coring mobilization, the next field program was divided into an LWD leg (JIP Leg II) to be followed by a dedicated coring program (or coring and LWD depending on the confidence in the exploration concepts and pre-drill predictions).

JIP Leg II took a different exploration approach from JIP Leg I and other field programs. The principal objectives of the JIP Leg II program were to extend the knowledge-base for gas hydrate to coarse-grained systems, high grade subsequent sites for conventional and pressure coring, calibrate seismic techniques for gas hydrate detection, provide data to test exploration and production models, and inform the BOEM in-place assessment.

The JIP Leg II formed four principal functional teams over the course of the project and was managed by Chevron: site selection, operational and site hazard assessment, operations, and the science party. The JIP Leg II field program was highly successful in all areas both technically and operationally. It was completely on-time and under budget with no injuries. All scientific objectives were met. Experiences gained from this successful expedition could be used to assist future research teams to develop and describe, including scope of work, technical specifications, schedule and timing estimates needed to plan and implement the next DOE/NETL sponsored coring-focused expedition. A summary of prior JIP Leg II site selection process, LWD logging expedition, and results is presented in Appendix D.

There are many articles and technical reports about the Gulf of Mexico Gas Hydrate JIP over the project's timeline. Good summaries of JIP Leg I and transition to JIP Leg II could be found in Claypool (2006), Ruppel et al., (2008) and Jones et al., (2008).

The initial scientific reports for the WR313 and GC955 JIP Leg II sites including references to the site selection reports and the corresponding initial scientific reports for the Alaminos Canyon sites could be found in Boswell et al., (2009), Collett et al., (2009), McConnell et al., (2009a), McConnell et al., (2009b), Cook et al., (2009) and Guerin et al., (2009).

5. POTENTIAL CORING PROGRAM AT THE JIP LEG II GAS HYDRATE DEPOSITS

Given the rich data set provided by JIP Leg II, a coring program that follows on this work could make significant contributions to gas hydrate science. The LWD sites provide critical information for core planning which should translate to improved chance of a successful program. Another option to consider is a combined LWD and coring program that would investigate some of the gas hydrate targets that were not drilled. Considering the accuracy of the pre-drill predictions against as-drilled results in JIP Leg II, a follow-on LWD and coring program could also broaden the understanding of the distribution of gas hydrate at these two sites. The following section provides a brief description of additional JIP Leg II targets that were not explored at WR313-G, WR313-H, and GC955-H. Each target was ranked. These rankings, although not provided here, could likely be made available and would be useful to those considering additional targets for a follow-on field program.

Gas hydrate saturation estimates are interpreted primarily from the analysis of resistivity and velocity logs. Gas hydrates like other hydrocarbons are electrically resistive, but unlike other hydrocarbons have shorter interval transit times (higher velocity) because the pore matrix of the sediment has been filled to some degree by solid gas hydrates, or in the case of clays, actual displacement of sediment by resistive gas hydrate can sometimes occur. There are other key factors to consider in the interpretation of gas hydrate from resistivity measurements and also key uncertainties that a pressure coring expedition could help resolve. For example, electrical log analysis of conventional hydrocarbons assumes homogeneity of pore filling fluids since gas and oil are buoyant and displace brine waters, however, this assumption does not hold true for the heterogeneous mode in which gas hydrate is often emplaced in sediments. Archie’s equation which equates resistivity values to hydrocarbon saturations, using a range of empirical values, therefore needs to be modified if used to estimate gas hydrate saturation.

Acquiring data to help understand the relationship between resistivity and acoustic logs and gas hydrate saturations could be one of the principal contributions of a pressure coring expedition at the WR313 and GC955.

5.1 Potential Coring Intervals at WR313

The following section provides a detailed description of key hydrate bearing intervals at WR313-G and WR313-H based on the LWD work in JIPII. Additionally, we have suggested coring intervals for the sites previously drilled in JIPII.

5.1.1 WR313-G

5.1.1.1 <u>Fracture-filled hydrate in clays.</u>

LWD data acquired at the Well G location are interpreted to show gas hydrates ranging from low to high saturations across varied lithologies and thicknesses (Collet et al., 2012). In most parts of the hole, analysis of LWD logs and core samples indicate low gas hydrate saturations of less than 20%The two gas hydrate bearing zones of interest are in a clay-rich zone with elevated resistivity between 815 and 1,300 ft. below seafloor, where gas hydrates are thought to fill vertical fractures. The LWD logs show separations in the propagation resistivity measurements resulting from the electrical anisotropy of the fracture filling gas hydrate. JIPII scientists used Archie's equation to determine gas hydrate saturation from the measured resistivity (Cook et al., 2009). In the fracture filling gas hydrate section, the gas hydrate saturation is estimated to be 20-30%, however, it is noted that the gas hydrate saturation may be significantly overestimated for fracture filling gas hydrate by using the Archie's equation.

5.1.1.2 Gas hydrate in Sands.

The targeted pore filling, high saturation gas hydrate sands are characterized by high resistivities, high P-wave velocity, and low gamma ray. These targets are identified between 2,796 and 2,866 ft. BML at the "blue" reflector. Other gas hydrate filled sands at Well G are: a 10 ft. sand at 1,973 ft. BML and 10 ft. net of sand between 2,727 ft. and 2,753 ft. BML. High resistivity peaks of up to 200 Ohm-m indicate high saturation gas hydrates in these sands. Archie's equation indicates gas hydrate saturation range from to 40 to 90%.

5.1.1.3 Sample Coring Plan

The location for a coring and sampling borehole, could be set close to the borehole of WR313-G,. Based on the LWD logs of WR313-G, shallow sediments could be drilled without coring until reaching just above the interval of fracture filling gas hydrate at 815 ft. BML. Use of DOE's PC Tool (or Fugro's PCTB or Aumann/Geotek equivalent) is recommended to obtain P-core samples between 815 and 1,300 ft. BML. The coring operation for hydrate-bearing sands could run at two intervals (2,725-2,745 ft. BML and 2,805-2,860 ft. BML).. A proposed sampling plan for the WR313-G coring target is provided in Table 5.1.

Table 5.1 WR313-G Sampling Proposal

Sampling Proposal: Borehole WR313-G							
Pilot Hole Information: Hole name: WR313-G Water depth: 6,614 ft. (2,016 m) below the rig floor Total depth: 3,584 ft. (1,092 m) BML							
Target zones: 1. A hydrate bearing fracture zone is interpreted between 815 and 1,300 ft. (248 and 396 m), BML. 2. A hydrate bearing sand zone is interpreted between 2,725 and 2,745 ft. (831 and 837 m), BML. 3. A hydrate bearing sandy zone is interpreted between 2,805 and 2,860 ft. (855 and 872 m), BML.							
Event	Depth, [m, BML]		LWD Interpretation		Corer	Estimated Time* (hrs.)	Remarks
No	From	To	Lithology	S_h			
					RIH	8.1	250m/hr.
1	0	248	Clay		Drill	9.9	25m/hr.

2	248	251	Clay	0.01	PCTB	4.5	Hydrate bearing fracture
3	262	265	Clay	0.12	PCTB	4.5	Hydrate bearing fracture
4	273	276	Clay	0.26	PCTB	4.5	Hydrate bearing fracture
5	284	287	Clay	0.19	PCTB	4.5	Hydrate bearing fracture
6	296	299	Clay	0.23	PCTB	4.5	Hydrate bearing fracture
7	307	310	Clay	0.22	PCTB	4.5	Hydrate bearing fracture
8	319	322	Clay	0.25	PCTB	4.5	Hydrate bearing fracture
9	332	335	Clay	0.32	PCTB	4.5	Hydrate bearing fracture
10	342	345	Clay	0.24	PCTB	4.5	Hydrate bearing fracture
11	356	359	Clay	0.12	PCTB	4.5	Hydrate bearing fracture
12	368	371	Clay	0.12	PCTB	4.5	Hydrate bearing fracture
13	379	382	Clay	0.06	PCTB	4.5	Hydrate bearing fracture
14	390	393	Clay	0.06	PCTB	4.5	Hydrate bearing fracture
15	393	831			Drill	43.8	10m/hr.
16	831	834	Sand	0.45	PCTB	4.5	Hydrate bearing sand
17	834	837	Sand	0.24	PCTB	4.5	Hydrate bearing sand
18	837	855			Drill	0.72	25m/hr.
19	855	858	Sand	0.43	PCTB	4.5	Hydrate bearing sand
20	858	861	Sand	0.50	PCTB	4.5	Hydrate bearing sand
21	861	864	Sand	0.67	PCTB	4.5	Hydrate bearing sand
22	864	867	Sand	0.45	PCTB	4.5	Hydrate bearing sand
23	867	870	Sand	0.38	PCTB	4.5	Hydrate bearing sand
23	870	873	Sand	0.31	PCTB	4.5	Hydrate bearing sand
	EOH	EOH			POOH	11.6	250m/hr.
				Total est. coring length			66 m
				Total est. coring time			167.9 hrs. (7.0 days)

Notes:
1. S_h - Hydrate Saturation Estimate (% of pore space)
2. * Time estimate assumes lower bound estimate for pipe tripping (i.e., pulling double joints)
3. A total of approximately one (1) day could be gained on the 3-BH Program outlined using a vessel with faster trip times (e.g. running and pulling triple joints instead of double joints)

5.1.2 WR313-H

The LWD data acquired at Well H, which was drilled approximately 2 km updip from Well G, generally encountered similar gas hydrate distributions and saturations. The H well had two objectives: i) to test the updip extent of the inferred gas hydrates at the "blue" reflector that was the primary target at Well G, and ii) to test gas hydrate at the similar but deeper "orange" reflector and to test for the presence of sand at the "green" reflector. Shallow, fracture-filling gas hydrate in clays was present in the same seismic unit penetrated at Well G. At Well H, fracture fill gas hydrate occurrence was found between 590 ft. and 1,000 ft. BML. Sediments at the "blue" horizon were less porous than at Well G, but thin gas hydrates were present based on the LWD interpretation. At the primary target for Well H, the "orange" reflector revealed two very clean sands, a 16 ft. thick sand and a 21 ft. thick sand, both highly saturated (> 85%) with gas hydrate. Logs showed that the "green" reflector was a reservoir quality sand, which was an important finding for other undrilled primary gas hydrate targets at the green reflector at other locations in WR313.

5.1.2.1 Fracture filled hydrate in clays.

In hole WR313 H, fracture filling gas hydrate is interpreted to occur from 590 to 1,030 ft., BML on the borehole resistivity images. The intervals of fracture filling gas hydrate in WR313 G and WR313 H occur in the same seismic unit (McConnell et al., 2009a). The same techniques were applied in WR313 H to determine gas hydrate saturation from the measured resistivity by using Archie's equation. The equation suggests gas hydrate saturations near 20-30% in the fracture interval of WR313 H (Cook et al., 2009).

5.1.2.2 Gas hydrate in Sands

Comparing to WR313 G, the apparent highly-concentrated, hydrate-bearing sands are thicker in WR313-H. They occur in two intervals from 2,644 to 2,656 ft. and from 2,663 to 2,685 ft. BML. The shallower sand layer was inferred to have 75-90 % gas hydrate saturation while Archie's equation suggests slightly lower saturation of ~40-70% for the deeper layer. The top of the hydrate bearing sand interval in WR313-G is interpreted as the Blue Horizon based on 3D seismic data, and is intersected at 2,305 ft. BML in the WR313-H borehole. The equivalent horizon in WR313-H is inferred to be within a mud-rich sandy interval containing only limited occurrence of gas hydrate. The highly concentrated hydrate-bearing sands in WR313-H appear to be in the sands below the Blue Horizon.

5.1.2.3 Sample Coring Plan

The location for a coring and sampling borehole could be set close to the borehole of WR313-H,. Based on the LWD logs of WR313-H, shallow sediments could be drilled without coring until reaching just above the interval of fracture filling gas hydrate at 590 ft. BML. Use of the PCTB is recommended to obtain P-core samples between 590 and 1030 ft. BML. The coring operation for hydrate-bearing sands could run at two intervals (2,644 ft. - 2,656 ft. BML and 2,663 ft. - 2,685 ft. BML). A proposed sampling plan for the WR313-H coring target is provided in Table 5.2.

Table 5.2 WR313-H Sampling Proposal

Sampling Proposal: Hole WR313-H							
Pilot Hole Information: Hole name: WR313-H Water depth: 6,501 ft. (1,982 m), below the rig floor Total depth: 2,685 ft. (819 m), BML							
Target zones: 1. A hydrate bearing fracture zone is interpreted between 590 and 1,030 ft. (180 and 314 m), BML. 2. A hydrate bearing sand zone is interpreted between 2,644 and 2,656 ft. (806 and 810 m), BML. 3. A hydrate bearing sandy zone is interpreted between 2,663 and 2,685 ft. (812 and 819 m), BML.							
Event	Depth, [m, BML]		LWD Interpretation		Corer	Estimated Time* (hrs.)	Remarks
No	From	To	Lithology	S_h			
					RIH	7.9	250m/hr.
1	0	180	Clay		Drill	6.0	30m/hr.
1	180	183	Clay	0.04	PCTB	4.5	Hydrate bearing fracture
3	191	194	Clay	0.05	PCTB	4.5	Hydrate bearing fracture
4	202	205	Clay	0.11	PCTB	4.5	Hydrate bearing fracture
5	213	216	Clay	0.12	PCTB	4.5	Hydrate bearing fracture
6	224	227	Clay	0.11	PCTB	4.5	Hydrate bearing fracture
7	235	238	Clay	0.22	PCTB	4.5	Hydrate bearing fracture
8	246	249	Clay	0.28	PCTB	4.5	Hydrate bearing fracture
9	257	260	Clay	0.31	PCTB	4.5	Hydrate bearing fracture
10	268	271	Clay	0.24	PCTB	4.5	Hydrate bearing fracture
11	279	282	Clay	0.05	PCTB	4.5	Hydrate bearing fracture
12	290	293	Clay	0.01	PCTB	4.5	Hydrate bearing fracture
13	301	304	Clay	0.08	PCTB	4.5	Hydrate bearing fracture
14	312	315	Clay	0.10	PCTB	4.5	Hydrate bearing fracture
15	314	806			Drill	49.1	10m/hr.
16	806	809	Sand	0.13	PCTB	4.5	Hydrate bearing sand
17	809	812	Sand	0.74	PCTB	4.5	Hydrate bearing sand
18	812	815	Sand	0.45	PCTB	4.5	Hydrate bearing sand
19	815	818	Sand	0.42	PCTB	4.5	Hydrate bearing sand
19	818	821	Sand	0.71	PCTB	4.5	Hydrate bearing sand
19	821	824	Sand	0.30	PCTB	4.5	Hydrate bearing sand
	EOH	EOH			POOH	11.2	250m/hr.

				Total est. coring length	57 m 162.75
				Total est. coring time	159.7 hrs. (6.7 days)

Notes:
1. S_h - Hydrate Saturation Estimate (% of pore space)
2. * Time estimate assumes lower bound estimate for pipe tripping (i.e., pulling double joints)
3. A total of approximately one (1) day could be gained on the 3-BH Program outlined using a vessel with faster trip times (e.g. running and pulling triple joints instead of doubles).

5.1.3 Potential Issues

The main considerations when coring the WR313 sites is the depth (up to 2,700 ft. BML) of the main gas hydrate targets which led to very difficult drilling conditions during the JIP Leg II expedition prompting a change in the drilling plan for the WR313-G well. Sufficient drilling fluids need to be included in the well plan to address this concern.

The other consideration is core recovery. Pressure coring in clays has been more successful than pressure coring in sands. The geometries of many of the Walker Ridge targets allow for gas hydrate coring without free gas hazard risk, but data and good interpretations are needed.

5.2 Potential Coring Intervals at GC955

The Green Canyon (GC) Block 955 is located in over 6,500 ft. of water depth on the Gulf of Mexico abyssal plain. A prominent Pleistocene channel/levee system traverses the center of Block 955 from northwest to southeast at a depth of ~1,000 ft. BML. The most prospective areas for gas hydrate occur in a faulted, four-way structural closure in the southwestern corner of the block. The GC955 dome hosts a complex array of strong but patchy seismic amplitudes that are roughly equal to or greater than the inferred BGHS. The dome is cut by a complex network of normal faults and contains numerous indications of active fluid flux.

Three wells were drilled in GC955 in JIP II. All were identified with gas hydrate from LWD logs. In GC955-I, the only gas hydrates are interpreted to occur only in low saturation around 1,400 ft. BML in an interval with a thickness of only a few feet This hole does not appear to be a good site for a coring and sampling program.

In Hole GC955-Q, only the top of the gas-hydrate-bearing sand was penetrated. Although the hole is interpreted to contain high concentrations of gas hydrate (Guerin et al., 2009), we do not recommend it for a coring program due to the potential for encountering shallow gas.

Hole GC955-H is considered to be the best location in GC955 for hydrate coring and sampling; gas hydrate is inferred to fill more than 50% of the pore space in almost 100 ft. of sands and also occurs within high-angle fractures over a ~300 ft. interval (Guerin et al., 2009).

5.2.1 GC955-H Borehole

In GC955-H hole, fracture filling gas hydrate is interpreted to occur in two intervals (630 to 960 ft., and 1,115 to 1,142 ft., BML) from LWD logs, which show separations in the propagation resistivity measurements resulted from the electrical anisotropy of the fracture filling gas hydrate. On the resistivity images, the gas hydrates appear as resistive sinusoids. JIP II scientists used Archie’s equation to determine gas hydrate saturation from the measured resistivity (Guerin et al., 2009). In the fracture filling gas hydrate section, the gas hydrate saturation is estimated to range from 10 to 60%, however, gas hydrate saturation may be significantly overestimated for fracture filling gas hydrate by using the Archie's equation.

In GC955-H, pore filling hydrate bearing sands, suggested by high resistivity, high P-wave velocity, and low gamma ray values, are interpreted to occur in two sections: one thick interval from 1,348 ft. to 1,445 ft. BML followed by a thinner interval from 1,460 ft. to 1,468 ft. BML. Archie's equation indicates some thin layers could contain >70 % gas hydrate saturation while other interbedded thin layers could have gas hydrate saturation as high as 50-60%.

The location for a coring and sampling borehole could be set close to the borehole of GC955-H,. Based on the LWD logs for GC955-H, shallow sediments could be drilled without coring until reaching just above the interval of fracture filling gas hydrate at 630 ft. BML. Use of PCTB is recommended to obtain P-core samples in the intervals of fracture filling gas hydrate, from 630 to 960 ft. and from 1,115 ft. to 1,142 ft. BML. The coring operation for hydrate-bearing sands could run at one interval from 1,348 ft. to 1,468 ft. BML. Table 5.3 summarizes a proposed plan for coring of GC955- H.

Table 5.3 GC955-H Sampling Proposal

Sampling Proposal: Borehole GC955-H							
Pilot Hole Information: Hole name: GC955-H Water depth: 6,721 ft. (2,049 m) below the rig floor Total depth: 1,936 ft. (590 m) BML							
Target zones: 1. A hydrate bearing fracture zone is interpreted between 630 and 960 ft. (192 and 293 m), BML. 2. A hydrate bearing fracture zone is interpreted between 1,115 and 1,142 ft. (340 and 348 m), BML. 3. A hydrate bearing sand zone is interpreted between 1,348 and 1,445 ft. (411 and 441 m), BML. 4. A hydrate bearing sandy zone is interpreted between 1,460 and 1,468 ft. (445 and 448 m), BML.							
Event	Depth, [m, BML]		LWD Interpretation		Corer	Estimated Time* (hrs.)	Remarks
No	From	To	Lithology	S_h			
					RIH	8.1	250m/hr.
	0	192	Clay		Drill	6.4	30m/hr.
1	192	195	Clay	0.37	PCTB	4.5	Hydrate bearing fracture
2	205	208	Clay	0.45	PCTB	4.5	Hydrate bearing fracture
3	218	221	Clay	0.22	PCTB	4.5	Hydrate bearing fracture
4	231	234	Clay	0.2	PCTB	4.5	Hydrate bearing fracture
5	244	247	Clay	0.49	PCTB	4.5	Hydrate bearing fracture
6	257	260	Clay	0.27	PCTB	4.5	Hydrate bearing fracture

7	268	271	Clay	0.41	PCTB	4.5	Hydrate bearing fracture
8	281	284	Clay	0.36	PCTB	4.5	Hydrate bearing fracture
9	290	293	Clay	0.14	PCTB	4.5	Hydrate bearing fracture
		340	Clay		Drill	1.9	25m/hr.
10	340	343	Clay	0.36	PCTB	4.5	Hydrate bearing fracture
11	343	346	Clay	0.28	PCTB	4.5	Hydrate bearing fracture
12	346	349	Clay	0.21	PCTB	4.5	Hydrate bearing fracture
		411	Clay		Drill	3.1	20m/hr.
13	411	414	Sand	0.7	PCTB	4.5	Hydrate bearing sand
14	414	417	Sand	0.68	PCTB	4.5	Hydrate bearing sand
15	417	420	Sand	0.64	PCTB	4.5	Hydrate bearing sand
16	420	423	Sand	0.66	PCTB	4.5	Hydrate bearing sand
17	423	426	Sand	0.73	PCTB	4.5	Hydrate bearing sand
18	426	429	Sand	0.71	PCTB	4.5	Hydrate bearing sand
19	429	432	Sand	0.69	PCTB	4.5	Hydrate bearing sand
20	432	435	Sand	0.75	PCTB	4.5	Hydrate bearing sand
21	435	438	Sand	0.11	PCTB	4.5	Hydrate bearing sand
22	441	444	Sand	0.46	PCTB	4.5	Hydrate bearing sand
23	444	447	Sand	0.08	PCTB	4.5	Hydrate bearing sand
	EOH	EOH			POOH	11.6	250m/hr.
				Total est. coring length			69 m
				Total est. coring time			134.6 hrs. (5.6 days)

Notes:

1. Sh - Hydrate Saturation Estimate (% of pore space)
2. * Time estimate assumes lower bound estimate for pipe tripping (i.e., pulling double joints)
3. A total of approximately one (1) day could be gained on the 3-BH Program outlined using a vessel with faster trip times (e.g. running and pulling triple joints instead of doubles).

5.2.2 Potential Issues

The risk of penetrating free gas at the GC955 coring targets has to be considered. The interaction of varying gas hydrate saturations, reservoir thicknesses, and free gas occurrence generates a complex expression in seismic profiles across GC955. The amplitude response is complicated in a mixed gas and gas hydrate system. It is difficult to determine the relationship between hydrate over water vs hydrate over gas based on seismic amplitudes. Compounding this difficulty is that bed thickness also affects seismic amplitude. Zhang et al. 2012 discusses these issues and presents possible methods for discrimination of free gas hazards. If the coring program has access to 3D seismic data in GC955, then a closer look at the GC955 gas hydrate reservoirs is warranted. If no further work with 3D seismic can be done, then it would be best to twin the GC955-H location that was gas free.

6. PRESSURE CORING DEVICES AND PRESSURE CORE ANALYSIS

6.1 Pressure Coring Tools

During the last few years, pressure coring has become an indispensable part of offshore gas hydrate expeditions, e.g. in the United States, Canada, India, China, South Korea, and Japan. Some of the tools used have been developed within the European research projects HYACE and HYACINTH; continued improvements on the prototypes have led to great successes and make the tools more and more reliable (Schultheiss, 2006; Pettigrew, 1992; and Stahl, 1995).

Past observations have shown that significant sample disturbance can occur (sometimes the cores were completely destroyed) when gas hydrate-bearing sediments are retrieved to the surface using conventional coring tools (non-pressurized coring). This is due to the phase transition of the solid gas hydrate into gas and water in response to a change of pressure and temperature. Therefore, pressure coring is the only direct method from which a core can be retrieved to the surface under close to in situ conditions in order to determine the in situ concentration of the natural gas present in the gas hydrate.

Based on the results of the JIP Leg II LWD logging expedition, a suite of five pressure coring systems could be considered for carrying out a coring program at the WR313 and GC955 sites. Obviously, since the DOE has funded a PCTB tool themselves, the assumption is that this tool would be used, but it might be prudent to have one or more of the other tool(s) as a backup or complementary system. The five pressure coring systems currently available are:

- Pressure Core Sampler (PCS - IODP);
- Fugro Pressure Corer (FPC);
- Hybrid Pressure Coring System (Hybrid PCS – Japanese System);
- Pressure Corer Tool with Ball valve (PCTB –Fugro and DOE); and
- Pressure Temperature Corer System (PTCS), newest version called PTCSIII.

PCS was developed by the Ocean Drilling Project (ODP) as the first pressure core system used to study methane hydrates. The PCS was a free-fall, deployable, hydraulically-actuated, wireline tool designed to retrieve a 1-m long sediment core at near in situ pressures. Although the PCS is very effective at obtaining samples that are suitable for overall gas concentration analysis, it was not designed to be used for other types of analyses that might reveal the physical structure of sediments or gas hydrate in the core. It is also not possible to transfer or sample the PCS core without releasing the pressure.

The Fugro Pressure Corer (FPC) was developed within the European Research Projects HYACE and HYACINTH by Fugro Engineers BV. FPC is suitable for use in unlithified sediments. The design and operation of the FPC tools differs in two significant respects from that of the PCS. First, the FPC tool penetrates the seabed using a down hole driving mechanism powered by fluid circulation (water/mud hammer) rather than by top-driven rotation with the drill string. This allows the drill string to be clamped stationary in the hole while core is being cut, which improves core quality and recovery. Second, the FPC tool recovers lined cores, which enables them to be transferred under pressure into a family of chambers, allowing cores to be preserved and studied under pressure. The FPC is used with a seabed clamp (SBF) to control movement of the drill pipe. A passive heave compensator system is required for the drill string compensation.

The Hybrid PCS delivers longer cores and features robust ball-valve sealing system. It was developed for the Japan Agency for Marine-Earth Science and Technology (JAMSTEC) by Aumann and Associates Inc. (AAI) for the purpose of recovering gas hydrate-bearing sediments, offshore Japan. This system achieved good recovery rates during its first commercial deployment in 2012 from the Chikyu.

The Fugro version of the Pressure Coring Tool with Ball valve (PCTB) measures 3.5-m long and was also developed by AAI to be compatible with Fugro's medium Common Bottom Hole Assembly (CBHA). The PCTB is a rotary coring system and has inner barrel assemblies that are retrieved using the wireline. Note that the Hybrid-PCS and the PCTB are essentially the same tool with only minor length differences. The same holds true for the DOE version of the PCTB.

The Hybrid-PCS/PCTB was modified from the design of the successful Pressure Temperature Coring System (PTCS). The PTCS is a rotary coring tool designed by Jim Aumann that was first used onshore at Mallik in the Canadian Arctic. Additionally, it was used in the Japanese Nankai Trough hydrate program (MH-21) in 2002 from the JOIDES Resolution. It requires a special drill string with larger (at least 5.65-in) ID. It also takes a 3.5m core and uses a ball-valve for sealing. The disadvantage to this system is that it isn't compatible with the pressure core analysis equipment (PCATS) developed by Geotek.

6.2 Pressure Core Analysis Tools

Pressure cores can be subjected to non-destructive testing to reveal the distribution and morphology of the gas hydrate relative to the surrounding sediment and also to determine properties of the gas hydrate/sediment matrix. Moreover, eventual controlled depressurization of the core provides the best quantitative analysis of gas hydrate concentration; critically, it is the only technique that could identify the absence of the gas hydrate.

Initial pressure coring analysis tools included the Multi-Sensor Core Logger – Pressure (MSCL-P) that was used with Fugro's FPC and Fugro Rotary Pressure Corer (FRPC, formally known as HRC) and the Multi-Sensor Core Logger-Vertical (MSCL-V) that was primarily used for the PCS cores. FPC and FRPC use plastic (Cellulous Butyrate) liners and enabled more NDT measurements compared to the MSCL-V with PCS which uses steel liners. The FRPC is no longer in service and was originally called the HYACE Rotary Corer (HRC). The University of Clausthal originally developed this tool as part of the HYACE Program in Europe (Schultheiss et al., 2006). Geotek's Pressure Core Analysis and Transfer System (PCATS) was developed to enable the hydrate-bearing cores retrieved under pressure to be transferred and measured/analyzed under pressure or without depressurization. The PCATS allows acoustic P-wave velocity, gamma ray attenuation (density), and X-ray imaging of recovered pressure cores. PCATS has been adapted over the years from what was first used to transfer and analyze the pressure cores. PCATS also enables samples to cut into whole core subsamples at full pressure environment for further measurements. Subsamples are taken for controlled depressurization to accurately determine gas hydrate concentrations, testing in PCATS Triaxial, and for rapid depressurization and immersion into liquid nitrogen.

PCATS has the ability to take full X-ray CT scans on recovered pressure cores. It also allows one to section the core for storing sub-samples or preparing sections of core for triaxial and resonant column testing in PCATS Triaxial or for use in other PC analysis systems such as the IPTC or other pending tools designed for analysis of P-cores or subsamples from those cores.

The latest addition to the analysis system is the Pressure Core Characterization Tools (PCCTs), which were designed and built by Georgia Tech and the U.S. Geological Survey (USGS) with long-term support from DOE and JIP. The system includes core manipulation tools and the Instrumented Pressure Testing Chamber (IPTC), which was the first device capable of measuring certain properties of pressure cores (e.g., seismic, electromagnetic, and strength properties, etc.) without first depressurizing the cores. The modular design allows any two tools / chambers to be coupled through an identical flange-clamp system. The manipulator (MAN) is a longitudinal positioning system that is used to transfer the core along the interconnected chambers and valves under the required P-T conditions. The system is designed to handle 1.2-m-long cores which can be sub-sampled or cut into short specimens using a cutting tool (CUT) that houses either a linear or a ring-shaped saw blade within a clamp-type chamber. The CUT is mounted in series between the MAN and any other tests or storage chamber. The PCCTs deployment may include the following measurement chambers:

1. **Instrumented Pressure Testing Chamber (IPTC).** The IPTC is developed to sample fluids and to measure P- and S-wave velocities, undrained shear strength, electrical conductivity, and internal core temperature. This cylindrical chamber has two sets of four diametrically opposite port pairs. The first pair drills holes (ID=8 mm) in the plastic liner so that contact probes in successive ports could be pushed into the specimen. In characterization mode, the IPTC is coupled to the MAN on one side and an extension chamber on the other, and measurements can be conducted at any position along the length of the core. The eight access ports make the IPTC a versatile chamber for conducting well-monitored production studies in view of reservoir calibration models.

2. **Effective Stress Chamber (ESC).** The ESC maintains P-T stability conditions and restores the effective stress that the sediment sustained in situ. Pressure cores are recovered and stored in the ESC at fluid P-T conditions needed to preserve hydrate. The original design was based on a zero lateral strain boundary condition. This chamber was updated to accommodate a stress-controlled boundary condition using a jacket. The resulting triaxial stress configuration consists of σ_3' applied with the jacket and σ_1' applied by a piston that is advanced through the ball valve and acts directly on the pressure core. The piston and the base pedestal house the sensors needed for the measurements of physical properties, including stiffness (wave velocities), thermal conductivity, and electrical resistivity.

3. **Direct Shear Chamber (DSC).** The DSC consists of a thick wall stainless steel ring that is pushed to shear the central third of the specimen. The DSC includes the piston to restore effective stress (similar to the ESC), a liner trap to capture the plastic liner before the specimen enters the shear chamber, and a small, lateral built-in frame to push the side piston that displaces the ring. The

maximum shear displacement (δ_{max}) is 15 mm, allowing both peak and residual shear strengths to be determined.

4. **Sub-sampling Tool for Bio-Studies (BIO).** The BIO chamber is loaded with a core segment using the MAN; afterwards, it is detached from the MAN for all successive procedures. Its operation involves (i) nitrogen-liquid replacement, (ii) core face cleaning and chamber sterilization, (iii) sub-sampling using a rotary sampling head, and (iv) sample deposition into the bio-reactor that is pre-filled with nurturing solutions (volume=10 mL). All operations can be observed through a sapphire window. Bio-reactors are readily replaced by closing a system of two ball valves and decoupling a quick connect fitting. This device allows the collection of a large number of specimens from a single core segment under in situ hydrostatic pressure.

5. **Controlled Depressurization Chamber (CDC).** The CDC is designed to help preserve the core lithology and to gain valuable information during depressurization, with minimal demand on personnel resources. This stand-alone device has a built-in drilling station to perforate the liner at selected locations in order to reduce the longitudinal expansion of the specimen. A pressure transducer and a thermocouple monitor the gas P-T conditions inside the chamber. In addition, three self-drilling thermocouples are deployed along the CDC; these are driven into the core to monitor the internal sediment temperature during depressurization. Finally, a 2-L water trap and a 55-L gas trap are attached in series to the needle valve that controls the rate of depressurization. These traps allow measurement of the water and gas produced.

6. **The Instrumented Pressure Testing Chamber (IPTC)** was developed by Carlos Santamarina while at Georgia Tech University with sponsorship from DOE/NETL. It was utilized onboard the Uncle John during JIP 1 in 2005, as well as on the work for NGHP1 in Singapore, post cruise in 2006. It was also used in Japan from the PC acquisition program performed from the Chikyu in 2012; again post cruise. The system has the ability to test sediments while still in pressure/storage chambers. It measures P & S wave velocities, shear strength (by means of a miniature cone penetrometer) and electrical conductivity (Yun et al., 2008).

Data sheets or brochures for the tools described here can be obtained by contacting the tool developers that are cited.

7. FIELD PROGRAM OPTIONS

7.1 Selection of Coring Tools

The main goal of the proposed Gulf of Mexico (GOM) expedition would be to obtain pressurized and non-pressurized coring (mostly pressure coring), perform in-situ measurements and formation testing of the hydrate-bearing sand reservoirs discovered during JIP Leg II at the Green Canyon Block 955 (GC955) and Walker Ridge Block 313 (WR313) sites. A key method in meeting this objective is to acquire the highest quality core and test the hydrate-bearing sediments or hydrates in their natural state, which is essential for characterization of naturally occurring gas hydrate deposits or to investigate the nature of hydrate occurrences in sand-dominated systems in the GOM.

Natural gas in deep marine sediments may be present in three phases. If the concentration (molality) of gas in pore water is less than the solubility, the gas is dissolved. If the concentration of gas is greater than its solubility, gas is present as a free phase (bubbles) below the Gas Hydrate Stability Zone (GHSZ) and as solid hydrate within the GHSZ. As such, knowledge of the gas concentration in deep marine sediment is critical for understanding the dynamics of hydrate formation and the effect hydrates have on the physical properties of the sediment. Because gas solubility decreases as pressure decreases and temperature increases, cores recovered from great depth often release a large volume of gas during recovery (Wallace et al., 2000; Paull and Ussler, 2001). The only way to quantify the presence of hydrates in the GHSZ (i.e., in situ concentrations of natural gas hydrate) and to have a better knowledge of the properties of the naturally occurring gas hydrate deposits in the sub-seafloor, is to use a suite of downhole tools that can be employed to measure in situ pore pressure and temperature, to retrieve pressure cores and non-pressure cores, to determine strength and index properties of hydrate-bearing sediments, and to estimate in situ concentration of methane and other gas compositions, etc.

Planning an offshore gas hydrate expedition in the Walker Ridge and Green Canyon Area of the Gulf of Mexico with only a pressure coring program may not be the best approach. A more cost effective approach for a site characterization program for naturally occurring gas hydrate deposits might also include non-pressurized coring. One could take much longer C-cores in the upper sections using non-pressurized systems like IODP's APC or Fugro's FHPC which take 9.8m and 7.8m long cores, respectively.

Both PCS and FPC tools are designed for obtaining core sample length of up to about 1-m. Continuous pressure core sampling in 1-m sections in the unlithified sediments within the GHSZ could extend over hundreds of meters or more. This means the tools would be deployed hundreds of times. Since, a large percentage of the cost of coring is the vessel time associated with tripping of the core barrels, this potentially leads to significant costs added to the expedition due to additional vessel time. This impact would be exacerbated in deep water environments. We would therefore recommend a combination of non-pressurized and P-cores be taken. For the pressure cores in particular, we would recommend a combination of FPC and PCTB so that the pressure cores are compatible with the PCATS and full NDT analysis could be conducted on board.

To quantify the presence of hydrates in hydrate-bearing sand reservoirs that were discovered during the JIP Leg II at the Green Canyon Block 955 (GC955) and Walker Ridge Block 313 (WR313) sites, a suite of non-pressurized and pressurized corers (as described below) could be used.

7.1.1 Non-Pressure Coring Systems

The non-pressure coring tools may include Fugro Hydraulic Piston Corer (FHPC), Fugro Corer (FC), Fugro Marine Core Barrel (FMCB), Fugro Extended Marine Core Barrel (FXMCB), or ODP's Advance Piston Corer (APC), Extended Core Barrel (XCB), Rotary Core Barrel (RCB), and Advance Diamond Core Barrel (ADCB) . Some selected subset of intervals within the top 100 to 300m below seafloor could be cored with the FHPC (or APC) "shoot" corer for targeting soft, non-lithified sediments, depending on the actual soil conditions. The FHPC and APC are designed to recover 7.8- and 9.8-m long cores, respectively. Cores have been recovered to a depth of 313m BML with the FHPC, but typically, a maximum depth of about 200m BML is more realistic.

The FC percussion corer is more suitable for hard clays and cemented sands and would take over when the sediments are too stiff to be recovered with the FPHC. Alternatively, IODP's XCB performs well in the more indurated sediments and would take over when APC either has high pull-out forces to recover from the sediments or drill-over options are required to free it from the bottom of the borehole. The FMCB, FXMCB or RCB downhole corers could be used for recovering more lithified sediments or weak rock to crystalline rock. The FMCB, FXMCB, and FC are designed to recover 2 to 3-m long cores. The XCB takes a 9.8-m long core. The RCB takes a 1-m long core and requires a separate BHA (pipe trip). The ADCB may be used to attempt to recover continuous core samples from firm to well lithified sedimentary or igneous formations when the APC, SCB, and RCB coring techniques are ineffective. The ACDB provides a crucial alternative tool using diamond coring technology that may improve core recovery in formations that are difficult to core with conventional rotary coring tools. The ACDB is designed to recover 4.75 m to 9.5 m long cores.

7.1.2 Pressure Core Systems

As mentioned previously, based on a number of previous expeditions that Fugro has conducted for industry and for National Hydrate Programs, a suite of seven (7) pressure coring systems could be considered for carrying out a coring program at the JIP Leg II gas hydrate deposits.

The Ocean Drilling Program's (ODP) and Integrated Ocean Drilling Program (IODP) has extensively used their Pressure Coring System (PCS), It is an upgraded and modified version based on the original design by Jim Aumann from the early days of ODP. The Fugro Pressure Corer (FPC) developed through European Union research projects, is one other system currently available. The HRC (later named FRPC) was also developed by the EU HYACE program but no longer in service. The Pressure Temperature Coring System (PTCS) was developed by Jim Aumann with a Japanese consortium of JAPEX, JNOC, etc. The PCTB is a rotary coring system measuring 3.5-m long also developed by Aumann & Associates, Inc. (AAI) for Fugro to be compatible with Fugro's medium Common Bottom Hole Assembly (CBHA). The PCTB takes the same size core as the FPC (64-mm OD & 58-mm ID). In addition to Fugro's PCTB, the DOE has sponsored the design and manufacture of a nearly identical PC system. This system is referred to as the Hybrid PCS or PCTB. CDEX/JAMSTEC also owns a Hybrid PCS developed by AAI as does JOGMEC. Geotek/Aumann recently built another PCTB for the upcoming Sea of Japan hydrate program for Meiji University. There are only minor differences between the Hybrid PCS and the PCTB.

One of the major differences between the FPC and other PC systems is that it doesn't require that the drill pipe be rotated in order to collect a core. This enables one to activate a passive heave compensation system and keep the pipe clamped at the seabed, therefore eliminating pipe movement and potential for core "biscuiting". The same is true for the Fugro Corer (FC). All the other coring systems including the PCS, PCTB, PTCS, FMCB FXMCB, XCB and RCB all require pipe rotation. This could cause core disturbance due to ship heave when operating in rough seas.

One new system is being developed to help control the weight variations on the bit / core barrel and the rate of penetration (ROP). The system is named the Fugro Sea Devil. In theory, Sea Devil would allow the control of weight on bit (WOB) and ROP at the seafloor instead of up on the drill floor of the vessel/drill rig. A brochure for the Sea Devil is included in appendices.

7.2 Gas Hydrate Detection and Analysis Plans including Method Statements for C-cores

7.2.1 Detecting Gas Hydrate in C-cores

Gas hydrates (normally methane hydrates) can dissociate rapidly when recovered in conventional (non-pressurized) cores as a result of decreasing pressure and increasing temperatures (taking the gas hydrate outside of stability conditions) while the cores are raised through the water column. Detection of methane hydrate in C-core relies on visual observation and measurements of characteristics created by dissociating hydrate. Methane hydrate dissociates into; i) methane gas, which expands to create gas voids and cracks within sediment cores, and ii) fresh water, which can be detected as a freshening of pore fluids relative to background or visually as moussy sediment textures in some sediment lithologies. The dissociation of hydrate requires significant heat energy that creates transient negative thermal anomalies which could be detected and imaged using a suitable imaging infrared (IR) camera. All of these characteristics are measured to assess the occurrence of gas hydrate in sediments recovered with conventional coring techniques.

Hydrate detection in C-cores is complicated by a number of factors. Recovery of hydrate to the rig floor could be extremely difficult in warm water conditions due to dissociation of the hydrate during recovery. Even if core recovery is rapid, the expansion of gas associated with hydrate-bearing sediment may cause the core to be lost in transit. Once the core is recovered, methane hydrate that has dissociated in transit may or may not be detectable. The techniques mentioned above could provide a lower bound on in situ hydrate abundance, but accurate quantification of in situ hydrate abundance is generally not possible using C-cores. At medium to low hydrate concentrations, the existence of gas hydrate might even escape detection.

7.2.2 IR Track and Camera

C-cores (e.g. FHPC, APC, XCB, FC, FMCB) can be imaged immediately after recovery using an infrared camera mounted on a computer-controlled, motorized track. The composite thermal image created of the core would show any large-scale hydrate features--or remnant hydrate features--as negative thermal anomalies (cold spots).

To detect lower levels of gas hydrate, the cores may be split immediately after they are cut into sections (after any whole-core geotechnical samples have been removed). These split cores can be subjected to a series of automated infrared scans to follow the evolution with time of thermal anomalies that correspond to gas hydrate occurrence and dissociation. The sequence of scans could enable some semi-quantitative estimation of hydrate concentration and may provide a lower bound on hydrate abundance.

The shape of the thermal anomalies seen on the face of the split cores could provide information about the presence of the hydrate within sediments: whether as veins, lenses, nodules, or general dissemination throughout the pore space. The locations and shapes of the anomalies can be correlated with sedimentological descriptions and/or automated nondestructive measurements (e.g., MSCL data) of the split core to determine if hydrate occurrence is controlled by lithology.

7.2.3 Gas Chromatography

Gas voids in plastic-lined C-cores can be sampled to detect methane, ethane, and propane (C1-C3). For this purpose, the core liners would be punctured, gas samples collected, and gas analyzed for hydrocarbons by gas chromatography. C-cores containing sediment that seals well against the liner would have total methane volume to sediment volume measured (taking into account pressure in gas voids) to provide a lower bound on in situ methane concentration.

7.2.4 Porewater Salinity

Samples of C-cores can be taken for porewater analysis, guided by the infrared imaging. For this purpose, the samples would be taken inside negative thermal anomalies as well as in adjacent sediments with no thermal anomalies in order to establish background salinity levels. Sediments would be trimmed and squeezed on board. The salinity would be measured on board by refractometry and conductivity, and porewater aliquots would be frozen for further onshore analyses if necessary.

7.2.5 Visual Observation of Hydrate or Hydrate Dissociation Textures

The fresh water and methane gas released upon hydrate dissociation can create a frothy or mousy texture in sediments, which collapses (like a delicate soufflé) into soupy textures when stored. Trained observers would examine the whole and split C-cores for hydrate or hydrate dissociation textures, and digital images of split cores would be recorded.

7.2.6 Field Logging of Samples of Hydrated Sediment

Cores that are suspected to contain gas hydrates can be described and logged in accordance with the expedition specifications. The onboard expedition leader, in consultation with the scientific personnel, would determine the logging program for each core in the field. The primary objectives of the field testing and logging of hydrated sediment is to provide sufficient information for:

1) Detection of gas hydrate inclusions.
This would be achieved through IR imaging and visual observation.

2) Description of sediment-hydrate structure.
This objective would be achieved by IR imaging on C-cores.

3) Geochemical sampling of pore water to determine salinity.
This would be determined from pore water squeezing and subsequent refractometry and conductivity tests.

4) Quantification of in situ hydrate saturation.
This would be determined from pressure core degassing experiments and salinity anomalies.

5) Determination of hydrate number and chemical constituents.
This would be determined from gas chromatography analysis of the gas samples.

6) Preservation of intact core segments with gas hydrate inclusions for onshore testing.
They would be cut from cores and preserved in liquid nitrogen.

7) Geochemical sampling of gas voids to determine gas constituents.
This would be determined from gas chromatography analysis of the gas samples.

In general, C-cores would be scanned with track-mounted infrared (IR) cameras. If anomalous cold zones are detected by the IR scan, then the core can also be scanned by X-ray linear and/or Computerized Tomography and sections of core preserved in liquid nitrogen dewars. Gas voids shall be sampled and analyzed in a gas chromatograph. Porewater shall be sampled and salinity measured by refractometry and conductivity.

7.3 Gas Hydrate Detection and Analysis Plans including Method Statements for P-cores

7.3.1 Detecting Gas Hydrate in P-cores

Gas hydrates remain stable in cores recovered by pressure coring techniques (e.g., FPC and PCTB pressure coring systems) as long as the combined pressure/temperature (P/T) profile is kept within gas hydrate stability conditions during recovery. To ensure this, there is a need for tracking the P/T conditions in each pressure core. Note that it is therefore still important to recover the cores to the surface as quickly as is practically possible and to immediately chill the P-cores upon recovery to deck. Detection of methane hydrate in P-core relies on a combination of nondestructive testing and dissociation tests. Nondestructive tests on static P-core, including measurements of density, acoustic velocity, multi-sensor core logs, and X-ray images, provide important data on the fine-scale nature and distribution of gas hydrate within the sediments. To maximize the information extracted from cores, all the contact tests including P- and S-wave velocity, electrical resistivity, and shear strength (via a cone penetrometer) can be performed in direct contact with the sediments under pressure by drilling holes through the core liner inside an effective stress chamber (ESC). In some cases, nondestructive measurements could also be performed during active depressurization/dissociation experiments, allowing dissociating gas hydrate to be imaged while the gas released from dissociation is measured and collected for gas chromatographic analysis. Measuring the total volume and composition of gas released enables the in situ concentration of gas hydrate to be calculated and the type of gas hydrate to be inferred.

7.3.2 Gas Chromatography

Gas samples taken from P-cores would be analyzed to determine both the total amount and type of gas present. This would lead to the determination of hydrate content in situ.

7.3.3 Pressure Core Analysis and Transfer System (PCATS)

This nondestructive measurement system enables cores to be logged in detail while still at in situ hydrostatic pressures. The PCATS measures sediment density (via gamma attenuation) and P-wave velocity on a centimeter scale, and obtains X-ray images with a resolution typically 100 µm. Using this equipment, the physical properties of sediments containing gas hydrate can be determined under both static and dynamic conditions of depressurization/dissociation. This information could be used to constrain the nature and distribution of gas hydrate within the sediment. Most importantly subsamples of pressure cores could be cut and transferred to storage chambers under pressurized condition where they can be accurately assessed or analyzed for gas hydrate concentration and other measurements.

7.3.4 X-ray Computed Tomography (CT) Scanner in PCATS

The X-ray CT equipment, which is a component of PCATS, can provide a detailed (100 micron) 3-dimensional analysis of the density structure of sediment and hydrate within a P-core.

7.3.5 PCATS Triaxial

PCATS Triaxial is an apparatus that enables physical and geotechnical property testing, such as Resonant Column test, stress-strain tests, etc., to be performed using core samples that have been cut from the pressure core inside PCATS. In this way crucial data can be obtained from samples that have been minimally disturbed and that have never been depressurized. Samples are extruded from the plastic liner and are sleeved in a thin rubber sleeve enabling in situ effective stress conditions to be applied. Typically, nondestructive measurements are performed first, and follow-up Resonant Column tests provide damping and elastic properties (e.g. shear modulus/shear velocity) while direct flow measurements provide permeability measurements (at any stage during the test process). Testing is concluded by stress strain tests to determine shear strength at in situ stress conditions followed by controlled degassing to measure the concentration of gas hydrate in the sample.

7.3.6 Pressure Core Characterization Tools (PCCTs)

The key tool is the instrumented pressure testing chamber which enables measurement of certain properties of pressure cores (e.g., seismic, electromagnetic, and strength properties, etc.) without first depressurizing the cores. The modular design allows any two tools / chambers to be coupled through an identical flange-clamp system. The PCCTs deployment may include the IPTC, ESC, DSC, BIO, and CDC measurement chambers. These various devices with multiple sensing systems support the comprehensive characterization of natural hydrate-bearing sediments under in situ pressure, temperature, and or stress conditions, and permit detailed monitoring of gas production tests. All PCCT chambers allow core-scale gas production tests by depressurization, heating, or chemical injection (e.g., inhibitors or carbon dioxide). More detailed descriptions of the PCCTs including the IPTC, ESC, DSC, BIO, and CDC are provided in Section 6.2.

7.3.7 Depressurization/Degassing Equipment and Experimental Procedures

The depressurization equipment consists of a series of valves and chambers allowing the pressure in a storage chamber or other pressure vessel to be lowered in incremental stages, with sampling of gas collected at each stage. The total volume of gas is measured and the samples are analyzed for gas content in the Gas Chromatograph (GC). A complete analysis of the evolved gas, together with a knowledge of in situ temperature, pressure and salinity, enables the concentration of gas hydrate occurring in situ to be estimated.

7.3.8 Field Logging of Samples of Hydrated Sediment

Cores that are suspected to contain gas hydrates would be described and logged in accordance with the expedition specifications. The onboard expedition leader in consultation with the scientific personnel, shall determine the logging program for each core in the field. The primary objectives of the field testing and logging of hydrated sediment are to provide sufficient information for:

1) Detection of gas hydrate inclusions.
   This would be achieved through IR imaging and visual observation.

2) Description of sediment-hydrate structure.
   This objective would be achieved by IR imaging on C-cores and by logging and degassing on P-cores.

3) Geochemical sampling of porewater to determine salinity.
   This would be determined from porewater squeezing and subsequent refractometry and conductivity tests.

4) Quantification of in situ hydrate saturation.
   This would be determined from P-cores degassing experiments and salinity anomalies.

5) Determination of hydrate number and chemical constituents.
   This would be determined from gas chromatography analysis of the gas samples.

6) Preservation of intact core segments with gas hydrate inclusions for onshore testing.
   They would be cut from cores and preserved in liquid nitrogen and or stored in pressurized storage chambers.

7) Geochemical sampling of gas voids to determine gas constituents.
   This would be determined from gas chromatography analysis of the gas samples.

8) Measurement of sediment strength and permeability.
This would be determined on sections of pressure core using PCATS Triaxial and or PCCTs.

In general, P-cores would be scanned in PCATS or IPTC (PCCT) to measure gamma ray attenuation density and P-wave velocity. P-cores may also be scanned using X-ray linear and/or Computerized Tomography. If hydrates are detected then the core would either be depressurized for additional logging and geochemical analysis, or part or all of the sample would be transferred to a pressurized storage chamber for further onshore analysis. Cores which are selected for depressurization, should be scanned in the PCATS / PCCTs at intervals during depressurization. Exsolved gases from solution or released by dissociation of gas hydrates should be collected and analyzed in a gas chromatograph. PCATS Triaxial or PCCTs would be used to determine strength and permeability properties of hydrate-bearing sediments under in situ conditions.

7.3.9 Onboard Analysis

In general, it is best to do all that can possibly be done while onboard and in the field. This provides the level of information needed to make informed decisions on the next step in the expedition, but also to ensure that no information gaps remain prior to leaving the site and risking the cost of remobilization. However, ship limitations (in the form of deck space and/or bunk space availability) frequently preclude the optimum scenario of performing all work and analysis offshore.

In particular, for a next Pressure Coring Expedition in the GOM at GC955 and WR313 (as well as alternate sites), the recommendation is that key onboard analysis be performed with PCATS after the pressure cores have been recovered to deck. PCATS access would also be considered key to having the ability to obtain mechanical property testing of the pressure cores onboard using PCATS Triaxial. Ample storage chambers should be available to store pressure core sections for subsequent testing onshore if space limitations do not allow for the PCATS Triaxial system onboard and to provide samples for onshore analysis using other available tools / systems (such as IPTC, PCCT or other pending pressure core analysis tools).

One would also like to have basic geochemical testing onboard. This would include Salinity, Chlorinity and Alkalinity analysis as a minimum. Additionally, Sulfate and Bromide testing by ion chromatography, and Ammonium, Phosphate and Silica by spectrophotometry should ideally be performed onboard. Major seawater cations can be measured by ICP-OES.

If C-cores are to be acquired during the expedition, it will be essential to have IR scanning capability onboard. This would identify the pore water extraction locations. Additionally, the onboard team should sample any gas voids for gas analysis, therefore requiring gas sample storage facilities, or more likely, onboard gas chromatograph capability.

Also, for non-pressurized (NP) coring, it would also be desirable to have whole core and split core analysis capabilities including MSCL-S, MSCL-XCT, MSCL-CIS, and MSCL-XR. If deck and personnel space is critical, the MSCL-CIS and MSCL-XR analysis could be performed onshore.

If laboratory space is available, it would be desirable to have mechanical property testing capability for C-cores onboard. This would include Pycnometer (unit weight), Shear Strength with Miniature Vane or conventional Triaxial UU Testing, and shear strength testing for clays.

For index properties, we would recommend moisture content and grain size analysis onboard if space allows.

7.3.10 Shore Based Analysis

As previously mentioned, sometimes compromises must be made to balance what can be done onboard in the field compared to what might be performed post-expedition in a shore based laboratory. If C-cores are obtained, these could be packaged and stored in a refrigerated container for onshore analysis. One key disadvantage from postponing onboard analysis is losing the ability to utilize the data/information to help direct additional work planned in the field. therefore, it is recommended that, as much as practically possible, analyses be performed onboard in the field. As mentioned above, storage chambers should be made available to store pressure core sections for subsequent testing onshore using other available core analysis tools or systems (such as IPTC, PCCT or other pending pressure core analysis tools).

Included in the appendices are two information sheets on the PCATS, IPTC and PCCT systems as well as a list of typical science capabilities onboard and a brochure on the PCATS Triaxial System.

7.4 Core analysis

All cores (C-cores and P-cores) recovered should be processed with the objective of determining the nature, distribution and concentration of gas hydrates, as well as investigating the seals or bounding units, and understanding the variation of lithology for the occurrence of gas hydrates at a larger scale along the continental margin in the Gulf of Mexico, A comprehensive suite of core curation, core processing and core analysis equipment will be necessary for this purpose. This equipment will enable a wide range of geophysical and geochemical measurements to be performed on all the cores recovered.

All C-cores should be geophysically logged using a variety of core logging equipment (Multi Sensor Core Loggers – MSCL's), including infrared scanning to look for early signs of gas hydrate dissociation. Other core logging to be performed on whole cores includes a full suite of geophysical parameters as well as X-ray imaging. Apart from whole core samples that are removed, all core sections should be longitudinally split before being cleaned and imaged using a high-resolution line scan imaging system. The final split core logging system includes X-ray Fluorescence (XRF) measurements, which enable elemental logs to be obtained (particularly useful for sedimentological studies). All split cores should be wrapped and placed in "D" tubes before being boxed and stored in an onboard refrigerated container.

P-cores should be processed using the Pressure Core Characterization Tools (PCCT) or the Pressure Core Analysis and Transfer System (PCATS).

The PCCT system includes core manipulation tools and the Instrumented pressure testing chamber. The key tool is the instrumented pressure testing chamber which allows for determining certain properties of pressure cores (e.g., physical, mechanical, and hydraulic characteristics of gas hydrate-bearing sediments) without first depressurizing the cores.

The PCATS apparatus enables the P-cores to be transferred from the pressure core autoclaves into a core logging chamber where geophysical measurements could be made (density and P-wave velocity) as well as full 3D CT X-ray imaging. PCATS also enables samples to cut into whole core subsamples at full pressure environment for further measurements. Subsamples are taken for controlled depressurization to accurately determine gas hydrate concentrations, testing in PCATS Triaxial, and for rapid depressurization and immersion into liquid nitrogen. The PCATS Triaxial equipment is used to determine mechanical properties of relatively undisturbed gas-hydrate-bearing sediments. These properties included elastic shear modulus, permeability, and shear strength.

Both C-cores and P-cores should be subjected to a suite of geochemical tests. This consists of collecting gas and sediment porewater samples for compositional analysis and performing onboard analyses. Gases should be analyzed for air components and light hydrocarbons while porewater samples should be analyzed for major and minor cations, major anions, and alkalinity. The gas compositions and porewater analyses enable near-real-time calculation of gas hydrate concentration from depressurized core samples.

Note that not all pressure coring systems are compatible with the PCATS. Fugro's PCTB and FPC, DOE/NETL's PCTB, as well as the Japanese Hybrid PCS are compatible. The IODP PC system (PCS) is not compatible with PCATS nor is PTCS.

7.4.1 Core Analysis and Sample Handling Procedures Overview

An accurate assessment of gas hydrate throughout the sediment column can be achieved by robust core analysis. Gas hydrate morphology is determined through non-destructive analysis of pressure cores while gas hydrate distribution is determined through infrared analysis of C-cores and grain size analysis of hydrate-bearing and non-hydrate-bearing sediments. Gas hydrate concentration is determined by methane mass balance from pressure core depressurization and porewater freshening analysis from P-cores and C-cores. Gas composition is determined by gas chromatographic analysis of gas samples from P-cores, C-cores, and gas hydrate samples. Integrating all these measurements, including downhole geophysical data if possible, provides the most accurate and comprehensive estimate of gas hydrate nature, concentration and distribution.

7.4.1.1 Pressure Core Manipulation and Analysis

When P-cores are brought onboard, they are immediately transferred into a storage chamber using the PCCT manipulator (MAN) or the Pressure Core Analysis and Transfer System (PCATS) (Figure 7.1). The MAN captures the core and transfers it to the temporary storage chamber. The ball valves are then closed, and the depressurized storage chamber is separated. The selected characterization tool (e.g., IPTC, ESC, DSC, CDC and BIO tools) is coupled to the MAN and is pressurized to initial or in situ pressure. The ball valves are then opened, and the core is pushed into the characterization tool. The stand-alone characterization tool may be detached after retrieving the rest of the core and closing the valves.

After the P-cores are transferred into the PCATS, a PCATS-compatible pressure corer autoclave is connected to the end of the PCATS. The core inside the autoclave is latched onto by the PCATS manipulator and withdrawn into the main body of the PCATS. As the core is withdrawn, live X-ray images of the core are displayed and the core quality can immediately be determined. If a good quality core has been acquired, the core is isolated in the PCATS and the corer autoclave is removed and returned to the rig floor. The core is rotated and translated while viewing the X-ray images to determine the orientation, or orientations, in which to collect data using the MSCL-P.

Figure 7.1 MSCL-P prior to PCATS development.

Inside the IPTC and PCATS, which maintains pressure and temperature within the hydrate stability zone, non-destructive measurements of physical properties are made and X-ray images are taken using the integral Pressure Multi-Sensor Core Logger (MSCL-P). Once all non-destructive data have been collected, the core can be cut into sections for storage or further analyses onshore. Selected subsections of core can be depressurized quantitatively for estimation of hydrate content.

7.4.1.2 <u>Pressure Core (P-core) Measurements</u>

Automated, non-destructive measurement of gamma density and P-wave velocity with simultaneous high-resolution X-ray imaging are made in the MSCL-P. Data is typically collected at a spacing of 0.5 cm, and all scans are carried out automatically along the length of each core, at each specified orientation. Rotational movies could also be automatically created from a set of X-ray images taken of a specific location on the core while the core is rotated in single-degree increments.

Gamma density is determined from the measured attenuation of gamma rays through the core with a typical precision of ±2%. P-wave velocity is measured using a pulse transmission technique at 230 kHz, with a typical precision of ±1.5 m/sec, providing calculated velocities with an accuracy of ±1%. X-ray images are collected with a microfocal source and image intensifier providing digital images with a pixel resolution of approximately 120 microns. The voltage and current on the polychromatic X-ray source are tuned to provide the best image quality through the aluminum pressure housing. Calibrations are performed with custom calibration pieces, made from the core liner of the core to be logged. Gamma density is calibrated with standards of aluminum and water while P-wave velocity is calibrated with distilled water.

7.4.1.3 Core Pressure and Temperature Maintenance

Pressure is maintained inside all PCCT chambers and the PCATS using a high-pressure pump and manifold system, with surface seawater as the pressurizing fluid while temperature is maintained by a circulating refrigerated water system. Temperature and pressure are maintained as close to in situ conditions as is possible for each core, or at least at temperatures and pressures that are well inside the gas hydrate stability field; the maximum operating pressure for the PCCT chambers is 350 bar and for the PCATS is 250 bar.

7.4.1.4 Interpretation of Non-Destructive Measurements for Hydrate Investigations

The details of the non-destructive physical data are used to determine the nature and distribution of gas hydrate in relation to the sediment structure. Grain-displacing gas hydrate structures, such as veins and lenses, are normally visible in density and X-ray data as low-density structures and, if they are large enough, visible in the P-wave velocity data as high velocities. Pore-filling disseminated gas hydrate is often not evident in density and X-ray data, as gas hydrate has a similar density to pore fluid, but often produces an anomalously high P-wave velocity if the sediment is cemented with gas hydrate. The non-destructive data set is also necessary to provide parameters for the mass balance calculations of hydrate from P-cores.

7.4.1.5 Sub-Sampling Under Pressure

Cores can be sectioned under pressure within the PCCT and the PCATS for further analysis and storage. Cutting within the PCCT is performed with a cutter tool (CUT) that houses either a linear or a ring-shaped saw blade within a clamp-type chamber. The saw-based cutting ensures clean surfaces and minimizes specimen disturbance. The CUT is mounted in series between the MAN and any other test or storage chamber as needed. A custom parting tool and stainless steel guillotine is used for separating the sediment within the PCATS.

7.4.1.6 C-core Infrared Imaging

Gas hydrate can be quickly identified in C-cores recovered to the surface without any temperature or pressure control by examining cores for cold spots, which indicate gas hydrate dissociation in progress. Geotek infrared thermography provides a thermal image of a lined core surface in real time to aid sampling of gas hydrate-bearing cores.

7.4.1.7 Core Handling

All procedures must be performed in a consistent fashion to provide a uniform thermal background on which anomalies can be identified. The cores should be recovered to deck as soon as practically possible after pausing to cool the cores at the seabed where the water temperatures are coldest before raising the cores through the water column that warms with height above the seabed. Cores must be handled with insulating gloves before performing infrared imaging in order to avoid overprinting of thermal anomalies.

Figure 7.2 IR scanning an APC liner on the "Catwalk" of the JR.

7.4.1.8 Core Temperature Measurement

For core temperature measurements, the core is placed on a rack with the top of the core clear of obstructions and not exposed to weather or sunlight. The core liner is wiped clean of mud and water. Calibrated thermal images of the liner are collected using a FLIR infrared (IR) A40 camera on an automated track. The camera is fixed to a skate that rides along the surface of the lined core, ensuring that the core is centered in the infrared camera and facilitating image concatenation. A reference infrared image is collected prior to each core to provide quality control. A visual image is collected at the same time so that voids in the core can clearly be seen and correlated with the IR image.

Both visual and infrared images are automatically concatenated into full-length core images and displayed in real-time. A matrix of core temperatures is also automatically extracted from the images.

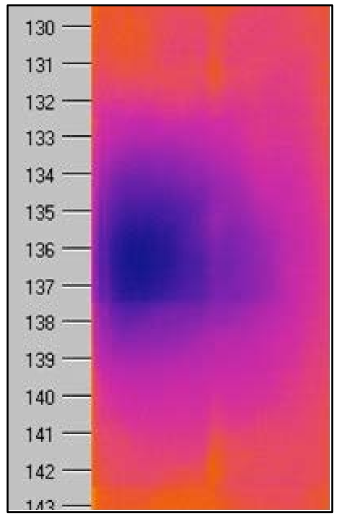

Figure 7.3 IR image depicting cold spot where hydrates were once present.

7.4.1.9 Geochemical Analysis for Hydrate Quantification

This suite of methods is designed to quantify gas hydrate and determine its distribution in the sediment column. The different analyses are designed to complement each other, each contributing information to create the most accurate picture of hydrate distribution through depressurization and complete gas collection. Porewater freshening analysis, both from P-cores and C-cores, provides a quantitative measure of hydrate that can be verified by methane mass balance analysis. Gas composition analysis validates the thermodynamic models used in methane mass balance analysis. Grain size analysis allows a common controlling factor of hydrate distribution to be tested.

7.4.1.10 Depressurization Experiments & Quantification of Gas Hydrate

Sections of P-cores stored in depressurization chambers are depressurized in a controlled fashion to quantify the total amount of hydrocarbon gas in all phases, including gas hydrate, within the cores.

The pressure in each chamber is slowly and incrementally reduced through a manifold and expelled gas and fluid are collected. Gas is sub-sampled during depressurization and analyzed using a gas chromatograph to determine the composition of the gas released. The total released volume of methane and other hydrate-forming gases is determined by measuring the volume of gas expelled from the system and adding the volume of fluid expelled from the system.

Total gas volumes are used to calculate in situ gas concentrations within sediment. The calculated concentration of methane is compared to methane saturation for in-situ conditions; for this calculation, in situ temperature measurements, in the same or a nearby borehole, are required. Any methane present above dissolved methane saturation (excess methane) is assumed to be in a methane hydrate phase or a free methane gas phase, depending on the calculated thermodynamic phase boundaries. This is the only method that can confirm the absence of gas hydrate in a sample.

Figure 7.4 Degassing experiment.

7.4.1.11 Porewater Sampling, Analyses, & Quantification of Gas Hydrate

Samples of cores are taken for porewater analysis, in the case of C-cores guided by the core liner temperatures from infrared imaging, and in the case of P-cores guided by the non-destructive geophysical data. Samples should be taken in sediments that might contain gas hydrate (negative thermal anomalies or high P-wave velocities) as well as in adjacent sediments with no evidence of gas hydrate. Plug samples of sediment (~40 cm^3) are taken from the centers of C-cores and squeezed in a hydraulic press to separate the porewater for chemical analyses. For the P-cores, a water sampler is be used to withdraw pore fluids from several of the PCCT chambers. Porewater salinity is measured onboard by refractometry; the error on salinity measurements is ±0.5 ppt (precision of refractometer). Porewater chloride concentration is measured onboard by titration with silver nitrate using a chromate indicator; repeatability of chloride concentration measurements is ±0.5%. Chloride standards should be run with every batch of samples.

Sulfate levels are measured using barium sulfate nephelometry (detection limit 0.5 mM sulfate) to detect any dilution of porewater from drilling fluid. In sedimentary porewater sulfate levels eventually drop to zero at depths varying from less than 5 m to more than 50 m below seafloor due to microbial sulfate reduction, as seen throughout the world's ocean basins. If the decrease of sulfate is monitored, , the sulfate levels can be used as a tracer for drilling fluid once below the depth of zero sulfate. The drilling fluid signature can be removed through a two-component mixing model. . Sulfate standards are run with every batch of samples. Samples of drill water are processed in the same manner as porewater samples.

Porewater freshening is calculated from the difference between measured chlorinity and the estimated in situ baseline chlorinity. Baseline chlorinity profiles are constructed using the maximum measured chlorinities from the C-cores as well as data from pressure cores. Gas hydrate saturation, as a percentage of pore volume, is calculated from porewater freshening and the density and water content of gas hydrate. The porewater freshening mixing model used assumes that the pore space can be occupied by porewater or gas hydrate but not both. The calculated gas hydrate saturation has an estimated error of ±2% of pore volume (this error value is an empirical estimate based on prior expeditions).

Figure 7.5 Geochemical analysis with auto-titration.

7.4.1.12 <u>Gas Sampling and Analyses</u>

Gas voids in C-cores are sampled to detect light hydrocarbon gases. Core liners are punctured with a sampling probe, gas samples collected in a plastic syringe, and the gas analyzed for methane, ethane, propane, isobutane, and butane by gas chromatography. Gas samples taken from P-cores are also analyzed to determine both the total amount and type of gas present. The PCCT's Controlled Depressurized Chamber (CDC) can be deployed with collection chambers or flow meter to quantify gas and water expulsion during a controlled dissociation process of a selected section of P-core. These gas compositions reflect the composition of the gas exsolved from pore fluids, free gas, and dissociating gas hydrate.

Headspace sediment samples are taken from near-surface cores to determine the depth of the sulfate-methane interface. A 5 ml plug of sediment is sealed in a 26 ml glass vial using a Teflon-coated septum and an aluminum crimp seal. After addition of 2 ml of saturated NaCl solution to the vial, the sediment is slurried and the vial placed in a 60°C oven for two hours. The vials are allowed to cool to room temperature, the headspace of the vial analyzed, and the concentration of hydrocarbon gases in the porewaters calculated.

Figure 7.6 Collecting a porewater analysis specimen.

Gas composition is measured using an Agilent MicroGC 3000A gas chromatograph with molecular sieve and PLOTU columns and thermal conductivity detectors. The instrument is calibrated for oxygen, nitrogen, carbon dioxide, methane, ethane, propane, isobutane, and butane, and calibrations are checked before every batch of samples. Air contamination during sampling is removed from gas totals.

7.4.1.13 Grain Size Analysis

Samples of each sediment plug taken for porewater analysis are slurried with a 5% solution of sodium hexametaphosphate. Samples are analyzed using a Malvern Mastersizer 2000 with a HydroMU dispersion unit, using water as the dispersant. Clay refractive indices are used unless samples are obviously composed of another material (e.g., quartz sand). The instrument self-calibrates before each measurement during alignment, and instrument background is measured before each sample.

7.4.1.14 Integration of Hydrate Data Sets

All collected data sets, from infrared imaging to pressure core non-destructive testing to geochemical analyses, are combined to create an overall description of quantitative gas hydrate distribution throughout the section. If other data sets are available that vary with hydrate concentration, especially downhole log data, they can be added to this amalgamated data set. Downhole electrical resistivity, if the gas hydrate is in the correct geometry, can be used as a quantitative measure of hydrate concentration when properly ground-truthed; sonic velocity can occasionally be used in a similar fashion. Correlations are developed between other available data sets and quantitative hydrate determinations if possible to create quantitative hydrate estimates for the entire sediment column.

Electronic data are presented both in the raw form collected by the MSCL systems, and an operator-processed spreadsheet and graph or image including MSCL-P data files, X-ray image files, Thermal image files, Depressurization experiments, Porewater chemistry, Gas analysis, Grain size analysis, Hydrate summary, and Geotek MSCL software.

7.4.2 Core Analysis Method Overview

Once C-core sections are brought into the laboratory, vane shear measurements are made and sections are prepared for whole-core X-ray and Standard Multi Sensor Core Logger (MSCL-XR and MSCL-S) analysis. After the MSCL non-destructive measurements are complete, sections are split, cleaned as required and immediately imaged. After imaging, split cores are covered with plastic wrap for further non-destructive testing in the MSCL-XZ as required before being sub-sampled and finally stored. These general procedures could be modified and adapted to suit the particular expedition and technical requirements.

7.4.2.1 Vane Shear Measurements

The miniature vane test is used to measure the undrained shear strength of cohesive soils if required. A small, 4-bladed vane is inserted into the top of a section to be tested. Torque is applied to the vane through a calibrated spring until soil shear failure occurs (ASTM D 4648–94, Standard Test Method for Laboratory Miniature Vane Shear Test for Saturated Fine-Grained Clayey Soil). Alternatively, strength testing with a hand-held "Torvane" device or pocket penetrometer could be performed at a later stage on the split cores.

Figure 7.7 Physical property measurement with motorized miniature vane on recovered core specimen.

7.4.2.2 X-ray imaging of whole cores

Linear digital X-ray images can be collected on conventional whole core, split core, or slabbed core sections. The MSCL-XR is a closed cabinet device that is operated in a shipboard laboratory space. Automated rotation of whole core sections allows users to visualize and record three-dimensional structures within the cores. X-ray imaging provides valuable intrinsic data as well as information about core quality for sub-sampling or further analyses.

Figure 7.8 MSCL – XCT.

7.4.2.3 MSCL-S whole core measurements

Gamma density, P-wave velocity, magnetic susceptibility, and electrical resistivity of C-cores are measured simultaneously using a multi-sensor core logger (MSCL). The measurement interval can be varied, but is typically set at 1 or 2 cm to obtain a high down-core spatial resolution. Gamma density is measured using the attenuation of a narrow gamma beam with a typical precision of ±2%. P-wave velocity is measured using a pulse transmission technique at 230 kHz, with a typical precision of ±1.5 m/sec. Magnetic susceptibility is measured with a Bartington MS2C loop sensor; the accuracy of the magnetic susceptibility measurement is typically ±5%. Electrical resistivity is measured using a custom non-contact inductive resistivity sensor also with a typical accuracy of ±5%. The magnetic susceptibility and electrical resistivity measurements are made with similar techniques, and their repeatability (precision) is normally better than ±1%.

Figure 7.9 Calibrations on the MSCL-S.

Calibrations are performed prior to core logging using custom calibration pieces, made from the same type of core liner as the core to be logged, and checked at the beginning of every core. Gamma density is calibrated with standards of aluminum and water. P-wave velocity is calibrated with distilled water, and electrical resistivity is calibrated with salt solutions. Magnetic susceptibility is checked with a custom check piece from the manufacturer. All sensors are compatible with plastic-lined core; electrical resistivity and magnetic susceptibility are not compatible with aluminum-lined core while P-wave velocity measurements can sometimes be made on large-diameter cores in aluminum liner.

Prior to logging, core sections are allowed to equilibrate to the laboratory temperature (maintained at 20˚C) to minimize any temperature effects in the data. Sections are logged through the MSCL with orientation arrows or manufacturer's marks aligned, if present. A set of check pieces are analyzed before each core to provide quality assurance and confirm the calibration for each core. Raw MSCL data are processed in real time using the calibration parameters and any invalid data, such as that collected near the endcaps, can be edited/hidden in the final, processed data set. Summary processed data plots are printed immediately to aid in the post-splitting sedimentological description and to help determine appropriate sub-sampling locations.

7.4.2.4 Core splitting

C-cores are split using the Geotek core splitter, with vibratory cutters and hooked blades to split the liner and a thin stainless steel wire to split the sediment. Cores are mounted in the splitter with the orientation arrows or manufacturer's marks up and are split from bottom to top. The cutting position is normally set to be exactly in the middle of the core to create equal size "working" and "archive" halves. However, if unequal halves are required then the cutting height could be easily adjusted for this purpose. When the liner cutting depths are adjusted correctly, the combination of cutting techniques provides a clean cut which minimizes the possibility of plastic swarf disturbing the cleanly-cut sediment surface.

Figure 7.10 Core splitter.

7.4.2.5 Core imaging

As soon as possible after splitting, the split surface of each core section is carefully prepared by horizontal scraping (where required) to ensure that all the visible sedimentary features are clearly revealed. Core is imaged using a 3-CCD line- scan camera system on the MSCL-CIS. The resolution is normally set at 200 pixels per centimeter (50 microns) although higher or lower resolutions are possible. The color balance of the camera and the brightness of the image is routinely calibrated with a standard photographic 18% grey card. Once the camera has been set up for the appropriate core size and calibrated, the imaging process itself is quick and easy. The operator simply places the section on the track, ensures the top is butted against an end stop and that the surface is level. Once started, the imaging itself typically only takes 3 minutes per meter of core. Raw section images are 48-bit TIFF files, which are concatenated into full-core JPEGs.

Figure 7.11 MSCL- CIS.

Electronic rulers are automatically appended and numeric RGB data sets are automatically generated. It is normal practice to print core section images, singly or as a core composite, on a color laser printer immediately after imaging to aid the core description, split-core measurements, and sub-sampling that may follow.

7.4.2.6 <u>MSCL-XZ measurements</u>

Once the cores are split and imaged, additional non-destructive analyses can be performed on the split core surface. These measurements include elemental composition via X-ray fluorescence, color reflectance spectra, and high resolution magnetic susceptibility. The split cores are covered in plastic wrap and placed on the MSCL-XZ (Split-Core Benchtop Multi- Sensor Core Logger). The measurement interval can be varied, but typically is set at 2 cm. X-ray fluorescence (XRF) measurements are made with an Innov-X Alpha X-ray fluorescence spectrometer, color reflectance spectra are collected using a Minolta color spectrophotometer, and high-resolution magnetic susceptibility is measured with a Bartington MS2E "point" sensor. The Innov-X XRF spectrometer and Minolta color spectrophotometer are calibrated with reference standards before each core. The Bartington point magnetic susceptibility sensor is zeroed between each measurement.

Figure 7.12 X-ray fluorescence (XRF) spectrometer.

7.4.2.7 Electronic data

Electronic data are presented both in the raw form collected by the MSCL systems, and an operator-processed spreadsheet and graph or image. Typical electronic data sets include MSCL-S data files, visual and X-ray image files, MSCL-XZ data files, MSCL software, and image viewer software.

7.5 In situ testing

As previously discussed, apart from recovering pressure cores and non-pressure cores for laboratory analyses, the only way to quantify in situ concentrations of natural gas hydrate and to have a better knowledge of the properties of the naturally occurring gas hydrate deposits in the sub-seafloor, is the use of a suite of downhole tools that can be employed to measure in situ pore pressure and temperature in order to determine strength and index properties of hydrate-bearing sediments, and to estimate in situ concentration of methane and other gas compositions, etc.

The in situ pore pressure and temperature data can be utilized to address possible hazards posed by hydrate. For example, hydrate dissociation during drilling or production reduces the volume of a solid phase in the formation and converts it into a mixed fluid phase that is several times larger in volume, with immediate implications for fluid pressure, effective stress strength, and volumetric deformation. Potential implications include the collapse of the production borehole [Birchwood et al., 2008] and seafloor slope instability. Strength loss due to hydrate dissociation must also be considered while producing conventional hydrocarbons underlying hydrate-bearing strata as relatively warm hydrocarbons pumped through hydrate-bearing layers could destabilize hydrate surrounding the production well [Long et al, 2014].

7.5.1 Temperature

Temperature equilibrium test data are recorded using the temperature probe. A temperature sensor incorporated in the probe allows for data collection to measure downhole temperature stabilization and temperature gradient. In-situ temperature equilibrium tests can be performed using WISON EP system or a Temperature Cone Penetration Test (TCPT). The tool (temperature probe) is lowered on a sandline to the bottom of the drill string. Upon reaching the bottom-hole assembly (BHA), the system is latched in place and the temperature probe is either hydraulically advanced into the soil formation or is pushed into bottom sediment using the drill string.

A detailed description of the tools together with schematic diagram of the tool are provided in the appendices.

7.5.2 Pore Pressure

A small diameter Piezoprobe (WISON EP Piezoprobe) can be utilized to measure excess pore pressure and to determine the dissipation characteristics of the sub-soils. In addition, results from the tests can be used to estimate the in-situ permeability and consolidation characteristics of the soil, and also to provide insight into pile-soil set-up. The tool should be compatible with the BHA and suite of tools being used in order to facilitate deployment.

A typical system consists of a push-in probe equipped with a pore pressure sensor that allows the in-situ measurement of pore water pressure dissipation during a penetration interruption. The variation of pore water pressure with time can give an indication of the consolidation and permeability characteristics of the soil. Measurement of equilibrium in situ pore water pressure is also possible if a sufficiently long dissipation period is maintained. The required period depends on factors such as geometry and size of the probe and soil coefficient of consolidation.

Common push-in probes for dissipation testing are as follows:

1. Piezo-cone penetrometer.
2. Piezoprobe.

The feasibility of test interpretation for consolidation or permeability depends primarily on the drainage

characteristics of the soil and the location of the pore pressure filter in the probe. In low-permeability soil, the probe generates:

- excess (positive) pore pressures as a result of normal stresses due to plastic soil failure
- positive or negative pore pressures as a result of shear-induced stresses.

A detailed description together with a schematic diagram of the tool is provided in the appendices.

7.5.3 Modular Formation Dynamics Tester (MDT)

MDT has been used on onshore hydrate projects including Mallik (McKenzie Delta in Canada) for JOGMEC and Canadian National Resources. It was also used in the Mt Elbert stratigraphic test in the Milne Point Unit of the Alaska North Slope as well as Conoco Phillips site within the Prudhoe Bay Unit on the North Slope of Alaska. At this time, we are not aware of it being used on a marine investigation for hydrates.

One key note about this system is that if used, a pipe trip would be required as a different diameter drill pipe and BHA would be needed.

For example, the Schlumberger (SLB) MDT* Modular Formation Dynamics Tester tool provides fast and accurate pressure measurements and high-quality fluid sampling. It can also measure permeability anisotropy. In a single trip, the MDT tool is able to acquire most of the data requirements needed for accurate and timely decision making.

The key to this tool is an innovative, modular design that lets you customize the tool for the required applications. MDT modules combine to meet the exact needs and goals of the data acquisition program. This designed flexibility makes the tool compatible with almost all Schlumberger measurement technologies and allows the MDT tool to evolve as new measurement techniques, technologies and options evolve.

Reservoir pressure measurements using a wireline tester require inserting the probe into the reservoir and withdrawing a small amount of fluid. Since the pressure gauge is exposed to many temperature and pressure changes, these measurements require accurate gauges with high resolution that can dependably react to the dynamic conditions. The MDT tool uses highly accurate gauges with best-in-class resolution, repeatability and dynamic response for pressure measurements. with no compromise in accuracy or resolution. Precise flowline control during testing and sampling ensures monophasic flow. These innovative features provide the most efficient and accurate permeability determination available. A detailed description and schematic diagram of the tool are provided in the appendices.

Additional in situ testing could also include seabed PCPT and vane shear tests (see Appendix G for details).

7.6 Selection of scientific program

7.6.1 Geochemistry

A well-considered geochemistry program can be invaluable to a fundamental coring gas hydrate characterization field program. Understanding fluid migration and the geochemical processes are fundamental questions for any field sampling program. What is the source fluid? Is it biogenic, thermogenic, or reworked thermogenic gas that appears biogenic? What do carbon isotope analysis reveal about gas hydrate source gas and migration? A geochemistry program can explain why gas hydrate is forming in layers and not in others. What is the chemistry of pore water at the base of a gas hydrate deposit and the top of a deposit? What is the relationship between lithology and gas hydrate concentration? Does the gas hydrate fractionate across the deposits and do the pore waters reflect this? Within a hydrate deposit, what is the variation of salinity? Pore fluid analysis can help explain these relationships.

For example, at WR 313, what controls updip migration of hydrate in the main hydrate filled sands? What is the geochemistry of the pore waters in the bounding strata with no hydrate deposits?

Also at WR 313, why does hydrate form in the shallow stratabound clays, but not in the bounding strata above and below? While these are gas hydrate systems questions, the pore water chemistry will help answer these questions.

Likewise, at GC955 H, high saturation gas hydrate filled the thick sands, but was not present in the cleaner sands that that were filled with gas hydrate immediately above and below. Why is that? A geochemical program can help understand these key questions.

A program should seek input from scientists in the pore water chemistry sector who have worked on gas hydrate research, who are familiar with the results to date and can help formulate hypothesis and a geochemical program that can add data to answer these questions.

Likewise input from the laboratory modelling community that are working on production fundamentals should be sought

7.6.2 Physical Properties

Properties such as bulk density, framework grain density or specific gravity, and meso-scale mechanical parameters such as sediment strength and elastic moduli may be evaluated as part of the scientific program, particularly with regard to their bearing on methane hydrate occurrence.

Bulk density is directly influenced by sediment porosity, as a result of the large density contrast between the solid grains and the hydrate or water phases occupying the pores of the sediment. Elastic moduli along with porosity can be utilized in inverse modeling to derive hydrate concentration.

Strength is a critical parameter in evaluations of seafloor stability for drilling and development planning in areas of sediments containing gas hydrates. Published experimental studies indicate that the shear strength of hydrate-bearing sediments is larger than the shear strength of hydrate-free sediments and that the shear strength of hydrate-bearing sediment increases with increasing degree of hydrate saturation (Ebinuma et al., 2005; Hyodo et al., 2008; Ohmura et al., 2002; Yun et al., 2007). The increase in strength of hydrate-bearing sediments is largely due to hydrate acting as a bonding agent within the sediment structure (Waite et al., 2009). Both hydrate saturation and hydrate growth habits in the pore spaces (e.g., cementing or pore filling) control the amount of increase in shear strength of the host sediment. The elevated shear strength of hydrate-bearing sediment translates into an enhanced stability of the seafloor in areas where hydrate-bearing sediments are present compared to areas characterized by hydrate-free sediments.

Strength loss due to gas hydrate dissociation is an important aspect that requires a rigorous investigation in relation to drilling operations and seafloor development. Hydrate-bearing sediments exposed to changes in pressure and/or temperature may experience dissociation of the gas hydrate component of the system if the thermodynamic equilibrium is disturbed. Gas hydrate dissociation involves release of significant amounts of water and gas (Carstens, 2004). This process may result in an increase of the pore fluid pressure of the host sediment if the rate of pore pressure increase due to dissociation is higher than the rate of pore pressure dissipation from the host sediment. The generated excess pore pressure along with loss of bonding originally created by the hydrate culminate in a reduction of the shear strength of the sediment, eventually leading to sediment failure (Paull et al., 2000). Seafloor failure triggered by gas hydrate dissociation may occur even for very gentle slope conditions (e.g., 1-3 degrees) since the amount of excess pore pressure generated by hydrate dissociation may be large enough to bring the available shear strength below the relatively small static shear stress acting on such slopes. Case histories of past submarine slope failures on very gentle slopes associated with gas hydrate dissociation have been documented on the northeastern Sakhalin continental slope in Sea of Okhotsk (Wong et al., 2003) and in the Amazon Fan (Maslin et al., 1998).

7.6.3 Sedimentology

Sedimentological and stratigraphic aspects of the scientific program should include consideration of depositional processes and delineation of sedimentological facies, development of regional and site-specific stratigraphic frameworks, mineralogy/geochemistry, and other aspects particularly with regard to their bearing on methane hydrate occurrence.

Geological sediment cores are a critical tool in the broader scheme of geological site assessment with the purpose of understanding present and past geological processes, providing risk analysis for these processes, and forecasting future geological events that may pose a significant threat to drilling or seafloor development. In seafloor development planning, these analyses are of equal importance to geophysical and geotechnical analyses and should be integrated with these other data sets to provide a robust site assessment.

Geological core logging provides a very high resolution ground truth to geophysical observations allowing for the refinement of interpretations of the geophysical data. Geotechnical data can be supplemented by geohazard core data where specific layers of interest, potentially missed by traditional geotechnical sampling methods, can be further subsampled. Geohazard core logging data may also be input into numerical models of geohazards and their impact on facilities. These data may also be used as a test on such models.

Sedimentological evidence recorded in multiple cores allows for interpretation of a depositional setting and classification of sediments into sedimentological facies. Facies classifications are the basis on which a site assessment is established. Shallow gas or gas hydrate present in the shallow sediments are easily identified and lead to a better understanding of the post-depositional history of the region. In order to determine potential impacts on a development, understanding the spatial and temporal distribution is essential. As such, cores at multiple locations across a development are required. Age dates must be determined in multiple locations and at multiple depths. This provides the information on timing and frequency that allow for a complete assessment.

8. VESSEL SELECTION

One of the important elements to the successful execution of the GOM data acquisition campaign is to acquire the highest quality core and test the hydrate-bearing sediments or hydrates in their natural state This would require the use of a suitable deepwater drilling vessel fitted with drawworks and a heave compensated, top-drive drilling rig.

Drilling operations in the Gulf of Mexico JIP Leg II were marked by the constant challenge of optimizing data quality by maintaining borehole stability, which was difficult to achieve, in particular within the shallow unlithified sediments. In addition, several of the targets were exceptionally deep. The two WR313 wells were drilled in water depths of approximately 2000 m and penetrated more than 1000 m below the seafloor (~3100 m below rig floor) and exceeded by more than 300 m the previous record for the deepest gas hydrate research wells (NGHP Expedition 01, Site 17, Andaman Islands). The process of drilling the Gulf of Mexico JIP Leg II wells provided new insights into the optimal drilling strategies for marine “open-hole” drilling programs without surface conductors or drilling fluid returns. Most notably, original plans to drill these deep holes with minimal drilling fluid use were revised due to difficulties with borehole stability observed in the first well drilled (WR313-G). For a pressure coring campaign in similar circumstances, the dynamic positioning (DP) vessel selected for the expedition should have the capability to operate in water depths as deep as 2,000 m and achieve drilling depths of 2,000 m or more, with the following characteristics:

1. Riserless drilling: The single most distinguishing characteristic of the vessel is that it would drill without a riser. The Chikyu is the exception to this, however use of a riser for pressure coring operations is not required or expected.

2. Continuous sampling: The main objectives dictate that continuous or near-continuous high-quality samples would be required from the seafloor to the target depths. This is in stark contrast to typical exploration or production drilling, where the primary objective is to “make hole,” especially in the upper portions of the section. High quality sampling would require improved heave compensation, drill string stabilization, or a new combined compensation and stabilization system.

3. Mud and drill pipe capacity and storage: For riserless drilling operations, with no mud returns to the vessel (the mud is expelled at the seafloor), the capacity for bulk mud storage will be important. Sufficient storage and handling facilities for 4,000 m of drill string will also be required.

4. Combined drill string length: The maximum combined drill string length (water depth plus drilling depth and air gap) that has been identified is approximately 4,000 m.

5. Drill string: The drill string should be composed of industry-standard drill pipe, and should have a minimum ID of 4.125 inches (105 mm) in order to have the required clearance for sampling, coring, and wireline logging tools.

6. Station keeping: The vessel must be dynamically positioned. The vessel should be able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse. The system should have redundancy, such as DP II or DP III.

7. Endurance: The vessel must be able to remain on location for periods up to 30 days without resupply or port call.

8. Laboratory and sample storage: four elements of laboratory and sample storage space have been identified:

- Up to 175 m^2 of interior heated/air conditioned lab space.
- Deck space for up to two (2) 20-foot (refrigerated) containers for the storage of cores.
- Deck space for six (6) 20-foot containers for special-purpose labs and consumables.
- Deck space for two (2) 40-ft containers for core processing (IR) and core analysis tools (e.g., PCCTs, PCATS, etc.)

9. Accommodations: There should be accommodations and services for 10 to 20 scientific staff (over and above marine, drilling, and catering crew), in 2-person cabins, with no more than 4 persons per head/shower. Suitable recreational facilities would also be needed.

10. Safety, Lifesaving, and Communications: The vessel should be equipped with safety, lifesaving, and communications equipment to allow it to operate in the GOM and any jurisdiction in the world.

Many drillships do not comply with one or more of the requirements outlined above and are therefore considered to be unfeasible or not suitable to meet the range of objectives for the coring expedition. Some examples with unsuitable characteristics are listed below:

- Geotechnical drillship: Limited drilling depth
  Limited accommodations
- Submersible: Limited water depth
- Semisubmersible: Port option limited
  Slow in transit
  May require dedicated support vessel
  Limited deck / variable load
  High day rate

However, many geotechnical vessels have successfully been used for various gas hydrate research programs. The R/V Bavenit was used for GMGS1, South China Sea in 2007. The M/V REM Etive was used on (UBGH1) for KNOC in the Ulleung Basin, offshore Korea in 2007. The M/V Fugro Synergy was used on UBGH2 for KNOC during the period July to September, 2010. In 2013, the REM Etive returned to the South China Sea for GMGS2 with a R-100 ram rig mobilized onboard. The U.S. Geological Survey (USGS) was one of the participating organizations in many of these research efforts. Geotek Ltd. was involved extensively in all these expeditions.

8.1 Range of Vessels

Based on lessons learned from the various gas hydrate research programs, as well as from the perspective of defining the operational and scientific characteristics of the drilling vessel to undertake the proposed pressure coring campaign in the GOM, we consider that six (6) scientific research drilling vessels (D/V Chikyu, R/V JOIDES Resolution, M/V Fugro Synergy, Helix Semi-submersibles Q4000 and Q5000, and Helix 534) would be suitable to undertake the proposed pressure coring campaign. These vessels were conceived and designed to provide drilling, logging and coring services in water depths exceeding 3,000 m. On-board laboratory facilities permit storage, testing and analysis of cores and samples during field operations. A more detailed layout of the vessels is provided in the report Appendices.

8.1.1 D/V Chikyu

The D/V Chikyu, a DP Class 2 scientific drilling vessel, is equipped with industry-standard riser capabilities (Figure 8.1). Riser drilling technology enables remarkable drilling and downhole logging capabilities and provides unprecedented hole stability, enabling the shipboard team to retrieve high-quality wire-line logging data as well as well-preserved core samples. CHIKYU is designed to perform drilling operations in a maximum of 4,000m of water.

Figure 8.1 D/V Chikyu

CHIKYU is equipped with a 1,250-ton maximum rated static hook load derrick compensated by a Hydralift, CMC1000-25, compensator capacity 518 ton, stroke 7.6 m, with active heave compensator. The Top drive is a Hydralift, HPS 1000 2E AC, hoisting capacity 907 ton, continuous torque 90,800 ft.-lbs., driven by two 858KW AC motors, with pipe handler, retractable dolly and rotating parking system. Mud pumps consist of 3 x National Oilwell, 14-P-220, 7,500 psi WP each driven by two 820KW DC motors. Two sets of fully automatic pipe racking system consisting of Hydralift, Hydra Racker IV, hydraulic trolley column with three arms. A remotely operated, Hydraulic roughneck and automatic slips at the rotary table support the drilling system.

She has drilled several deepwater hydrocarbon wells in addition to scientific drilling operations. The vessel is 210 m long and 38 m wide, and its derrick rises about 70 m above the water line. The drilling system can handle 10,000 m of drill pipe, long enough for drilling in any of the world's oceans.

The vessel's principal characteristics are as follow:

1. Capable of both riserless and riser drilling;
2. Retrieve continuous or semi-continuous high quality core samples;
3. Storage capacity for bulk mud is 697 cu.m and sack storage capacity of 200 pallets (~288 cu.m), and has handling facilities for more than 4,000 m of drill string;
4. Maximum combined drill string length (water depth plus drilling depth and air gap) is about 10,000 m;
5. Industry-standard drill pipe, with a minimum ID of 4.125 inches (105 mm) would be used in order to have the required clearance for sampling, coring, and wireline logging tools;
6. A DP II (Class B DPS of Dynamic Positioning System) vessel. She is able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse;
7. Able to remain at sea for periods exceeding 30 days without resupply or port call;
8. Onboard laboratory space over 2,300 m^2 (the Lab Stack) is spread out over four decks: the Lab Roof Deck, the Core Processing Deck, the Lab Street Deck and the Lab Management Deck. Each deck has specialized areas for specific research purposes. The Lab Roof Deck has two sections: the indoor Downhole Measurement Lab, and the semi-enclosed Core Cutting Area. The deck outside the core cutting area has space for cold-storage core containers, a downhole logging unit, and special lab containers;
9. Air conditioned cabins for 150 persons. Four stories of laboratories and living quarters with an array of tools and equipment provide space for fifty scientists and technical support staff;

8.1.2 R/V JOIDES Resolution

JOIDES Resolution is outfitted with the most modern laboratory, drilling, and navigation equipment (Figure 8.2). The ship is 143 meters long and 21 meters wide, and its derrick rises 61.5 meters above the water line. The drilling system can handle 9,150 m of drill pipe, long enough for drilling in 99.9% of the world's oceans. A computer-controlled system regulates 12 powerful thrusters in addition to the main propulsion system.

Figure 8.2 R/V JOIDES Resolution.

The drill pipe is lowered from the steel derrick through the “moon pool,” a seven-meter-wide hole in the bottom of the ship. A heave compensator in the derrick acts as a giant shock absorber, so that the up and down movements of the ship are not transferred to the drill pipe, allowing cores could be cut and lifted smoothly. To drill through soft sediment or mud, a hydraulic piston corer is used. This device uses compressed seawater to drive a steel barrel through the sediment. To penetrate into harder sediment and rock below the seafloor, drill bits with cutting heads are used. As the drill bit or hydraulic piston corer cuts through layers of sediment and rock, cores of sub-seafloor material as long as 9.5 m are collected in plastic tubes and returned to the ship on a wire cable inside the drill pipe. Using an acoustic beacon set near the drill site on the seafloor, this system keeps the ship stabilized over the borehole despite wind and waves, allowing drilling in water as deep as 8,235 meters. The vessel’s principal characteristics are as follows:

1. Capable of riserless drilling;
2. Retrieve continuous or semi-continuous high quality core samples;
3. Storage capacity for bulk mud is 377 cu.m and sack storage capacity of 200 pallets (~288 cu.m), and has handling facilities for two times 4,000 m of drill string;
4. Maximum combined drill string length (water depth plus drilling depth and air gap) is about 9,150 m;
5. Industry-standard drill pipe including ~14,172 m (drill pipe, 5 and 51/2 in), ~700 m (drill collars (81/4 and 61/2 in.) and 2,240 m (casing, 20/16/13 3/8/11 3/4/ 10 ¾ in.) is available in order to have the required clearance for sampling, coring, and wireline logging tools;
6. A DP II vessel, and able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse;
7. Able to remain at sea for periods for up to 75 days without resupply or port call;
8. Onboard laboratory or scientific space is ~1,672 m^2 and refrigerated core storage space of about 743 cu. m;
9. Air conditioned cabins for 50 scientists and technicians, and 65 crew members; and

10. Worldwide telecommunication capability including the VSAT and Immarsat systems and a range of equipment capable of performing the radio communication functions of the Global Maritime Distress and Safety System (GMDSS – A4). Lifesaving equipment include four motor propelled, self-contained, totally enclosed lifeboats for 280 persons. Eight (8) inflatable life rafts, each with a capacity of 35 or 25 persons. A total of 246 life jackets.

8.1.3 M/V Fugro Synergy

Fugro Synergy is a state-of-the-art DP2 miniaturized drillship (Figure 8.3). She is equipped with a 190 metric ton working load derrick compensated by a Rexroth/HMC hydraulic system with 7-m effective stroke. The Top drive is a hydraulic Varco TDS 250 with 28Kn/m output. Mud pumps consist of 3 x Wirth TPK triplex pumps with a maximum discharge pressure of 345 bar.

Figure 8.3 M/V Fugro Synergy.

A fully automatic MH pipe handling system consisting of a knuckle boom handling crane and remote operated pipe chute for efficient lay-down. A remotely operated, Varco iron roughneck and automatic slips at the rotary table support the drilling system. ROV support is provided with a Fugro ROVTech 3,000m capable 150-hp work-class vehicle. This system is an integral part of the ship. The Drill String used for the Republic of Korea UBGH Expedition 02 (2010) project consisted of standard geotechnical drill collars 5m in length, with 7" OD and 4" ID. The drill pipe used throughout was 5 ½" OD, 21.9 lb./ft. with TT550 low torque connections. The minimum ID at the tool joints was 4.25-in. The M/V Fugro Synergy was used on UBGH2 for KNOC during the period July to September, 2010.

The vessel's principal characteristics are as follows:

1. Riserless drilling;
2. Retrieve continuous or semi-continuous high quality core samples;
3. Storage capacity for bulk mud is 426 cu.m and sack storage capacity of 800 x 25 kg sacks, and has handling facilities for 4,000 m of drill string;

4. Industry-standard drill pipe, with a minimum ID of 4.125 inches (105 mm) would be used in order to have the required clearance for sampling, coring, and wireline logging tools;
5. Maximum combined drill string length (water depth plus drilling depth and air gap) is about 4,800 m;
6. A DP II vessel, and able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse;
7. She has sufficient storage capacities for fuel oil, drill water, and potable water be able to remain at sea for periods for up to 45 days without resupply or port call;
8. Onboard laboratory or scientific space is ~259 m2 and refrigerated core storage space of about 7 m2;
9. Air conditioned cabins for 50 scientists and technicians, and 65 crew members; and
10. Telecommunication capability including the VSAT and Data access (multiple bands). Lifesaving equipment include two (2) motor propelled, self-contained, totally enclosed lifeboats for 180 persons; two (2) inflatable life rafts, each with a capacity of 35 persons each; a total of 114 life jackets and 113 survival suits; and one (1) Mare Safety GRP700 230 hp fast rescue boat.

8.1.4 Semi-submersible Helix Q4000

The Q4000 entered service in the Gulf of Mexico in 2002 and has since built one of the most extensive well intervention track records of any vessel in the world (Figure 8.4). The semi-submersible drilling vessel Helix Q4000 was successfully used for the Gulf of Mexico Gas Hydrate Joint Industry Project Leg II (JIP Leg II) expedition that began in April 2009.

Figure 8.4 Semi-submersible Helix Q4000.

Named for its 4,000-ton capacity deck, the Q4000 is a DP3 semisubmersible vessel purpose-built for well intervention and construction in water depths to about 3,000 m. Because of its stable design and unique open deck, the Q4000 is an optimal platform for a wide variety of tasks, including subsea completion, decommissioning and coiled tubing deployment. Among the vessel's notable features is its 600-ton multipurpose tower capable of fulfilling all traditional derrick roles, plus one crane and one traction winch with lifting capacities of 160 and 360 tons, respectively.

Q4000 also features an 11.9 m x 6.4 m moonpool, a 7-3/8" intervention riser system and two 150hp, work class ROV's with 3,000 m ratings. The LARS are heavy-weather capable (one cursor launched and the other deck launched). Another unique feature of the Q4000 is its skid deck plan which allows for quick and efficient mobilization of project supplies and equipment on or off the vessel in a single lift. In 2008, the Q4000 was upgraded with a slimbore drilling system, further expanding well intervention and field development capabilities. The vessel provides a stable platform for a wide variety of tasks, including subsea completion, decommissioning and coiled tubing deployment, and is specifically designed for oil well intervention and construction in depths of up to 3,048 meters of water

The vessel's principal characteristics are as follows:

1. Riserless drilling;
2. Retrieve continuous or semi-continuous high quality core samples;
3. Storage capacity for liquid mud is 1,190 bbls of liquid mud on the surface and 1,800 bbls in the columns and sack storage capacity of 1000 sacks of various mud.
4. Storage capacities for drill string length including ~14,172 m (drill pipe, 5 and 51/2 in), ~700 m (drill collars (81/4 and 61/2 in.) and 2,240 m (casing, 20/16/13 3/8/11 3/4/ 10 ¾ in.).
5. Maximum combined drill string length (water depth plus drilling depth and air gap) is about 9,150 m.
6. A DP II vessel, and able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse.
7. She has sufficient storage capacities for fuel oil, drill water, and potable water be able to remain at sea for periods for up to 75 days without resupply or port call;
8. Onboard laboratory or scientific space is ~1,672 m^2 and refrigerated core storage space of about 743 cu. m;
9. Air conditioned cabins for 59 scientists and technicians, and 76 crew members.
10. Worldwide telecommunication capability including the VSAT and Immarsat systems and a range of equipment capable of performing the radio communication functions of the Global Maritime Distress and Safety System (GMDSS – A4). Lifesaving equipment include four motor propelled, self-contained, totally enclosed lifeboats for 280 persons. Eight (8) inflatable life rafts, each with a capacity of 35 or 25 persons. A total of 246 life jackets.

8.1.5 Semi-submersible Helix Q5000

The Q5000 is scheduled to enter service in the Gulf of Mexico in 2015 (Figure 8.5). It was built on the experience gained from the Q4000 and has additional deck capacity (5000 tons instead of 4000 tons).

Figure 8.5 Semi-submersible Helix Q5000.

Named for its 5,000-ton capacity deck, the Q5000 is a DP3 semisubmersible vessel purpose-built for well intervention and construction in water depths to about 3,000 m. Because of its stable design and unique open deck, the Q5000 is an optimal platform for a wide variety of tasks, including subsea completion, decommissioning and coiled tubing deployment. Among the vessel's notable features is its 750-ton multipurpose tower capable of fulfilling all traditional derrick roles, plus two cranes with lifting capacities to 440 tons. Q5000 also features a 24.7 m x 7.9 m moonpool, a 7-3/8" intervention riser system and two 3000 m heavy weather ROV systems.

Another unique advantage the Q5000 is its skid deck plan which allows for quick and efficient mobilization of project supplies and equipment on or off the vessel in a single lift. The Q5000's Multipurpose Tower has a lifting height of 44m and both active and passive heave compensation systems. The passive compensator has a maximum stroke of 20ft (6.4m). The MODU is capable of running triple joints. It has an automated horizontal pipe racking system made by Hydralift combined with a 13.6 ton knuckle boom crane. It uses a built in NOV Iron Roughneck system.

The 1,150 hp top-drive system has a maximum capacity of 750 ton, drill speed of 0 to 280 rpm, and drilling torque of 78,181 ft./lbs. Mud capacities include: 5,250 bbls of liquid mud; bulk cement tanks of 3,200cu ft.; 4,000 sacks of various muds and 5,185 bbls of drill water. Q5000 is fitted with a slimbore drilling system, further expanding well intervention and field development capabilities. The Q5000 also has a unique column-stabilized semi-submersible design that combines dynamically positioned station-keeping with a large deck space, significant deck load capacity and a high transit speed of 12 knots. The vessel provides a stable platform for a wide variety of tasks, including subsea completion, decommissioning and coiled tubing deployment, and she is specifically designed for oil well intervention and construction in depths of up to 3,048 m of water.

The vessel’s principal characteristics are as follows:

1. Riserless drilling;
2. Retrieve continuous or semi-continuous high quality core samples;
3. Storage capacity for liquid mud is 1,190 bbls of liquid mud on the surface and 1,800 bbls in the columns and sack storage capacity of 1000 sacks of various mud.
4. Storage capacities for drill string length including ~14,172 m (drill pipe, 5 and 51/2 in), ~700 m (drill collars (81/4 and 61/2 in.) and 2,240 m (casing, 20/16/13 3/8/11 3/4/ 10 ¾ in.).
5. Maximum combined drill string length (water depth plus drilling depth and air gap) is about 9,150 m.
6. A DP III vessel, and able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse.
7. She has sufficient storage capacities for fuel oil, drill water, and potable water be able to remain at sea for periods for up to 75 days without resupply or port call;
8. Onboard laboratory or scientific space is ~1,672 m2 and refrigerated core storage space of about 743 cu. m;
9. Air conditioned cabins for 64 scientists and technicians, and 76 crew members.
10. Worldwide telecommunication capability including the VSAT and Immarsat systems and a range of equipment capable of performing the radio communication functions of the Global Maritime Distress and Safety System (GMDSS – A4). Lifesaving equipment include four motor propelled, self-contained, totally enclosed lifeboats for 280 persons. Eight (8) inflatable life rafts, each with a capacity of 35 or 25 persons. A total of 246 life jackets.

8.1.6 Drillship Helix 534

The HELIX 534 has entered service in the Gulf of Mexico in 2015 (Figure 8.6). It was modified by Helix based on the well intervention experience gained from the Q4000 and have additional deck capacity (8900-tons). The HELIX 534 is a DP2 semisubmersible vessel purpose-built for well intervention and construction in water depths to about 3,000 m. Because of its stable design the HELIX 534 is an optimal platform for a wide variety of tasks, including well intervention, subsea completion, decommissioning and coiled tubing deployment. Among the vessel’s notable features is its 594 ton derrick capable of fulfilling all traditional derrick roles, plus four cranes with lifting capacities ranging from 62 to 75 tons. HELIX 534 also features an 8.1 m x 5.5 m moonpool, a 7-3/8" intervention riser system and two 3,000 m heavy weather ROV systems. Helix 534 has accommodations for 150 persons and has a standard marine crew of 76 persons.

Figure 8.6 Drillship Helix 534.

The HELIX 534 is a second generation drillship that Helix recently acquired. It is a monohull and supplements their Well Intervention fleet. HELIX 534 also has a ship-shaped design that combines dynamically positioned station-keeping with a large deck space, and significant deck load. The vessel provides a stable platform for a wide variety of tasks, including subsea completion, decommissioning and coiled tubing deployment, and she is specifically designed for oil well intervention and construction in depths of up to 3,048 meters of water

The vessel's principal characteristics are as follows:

1. Riserless drilling;
2. Retrieve continuous or semi-continuous high quality core samples;
3. Storage capacity for liquid mud is 6,994 bbls and sack storage capacity of 2,200 sacks of various mud;
4. Storage capacities for drill string length including ~14,172 m (drill pipe, 5 and 51/2 in), ~700 m (drill collars (81/4 and 61/2 in.) and 2,240 m (casing, 20/16/13 3/8/11 3/4/ 10 ¾ in.).
5. Maximum combined drill string length (water depth plus drilling depth and air gap) is about 9,150 m.
6. A DP III vessel, and able to continue dynamic positioning (DP) operations in Beaufort 8 conditions or worse.
7. She has sufficient storage capacities for fuel oil, drill water, and potable water be able to remain at sea for periods for up to 75 days without resupply or port call;
8. Onboard laboratory or scientific space is ~1,672 m2 and refrigerated core storage space of about 743 cu. m;
9. Air conditioned cabins for 150 persons; and
10. Worldwide telecommunication capability including the VSAT and Immarsat systems and a range of equipment capable of performing the radio communication functions of the Global Maritime Distress

and Safety System (GMDSS – A4). Lifesaving equipment include four motor propelled, self-contained, totally enclosed lifeboats for 280 persons. Eight (8) inflatable life rafts, each with a capacity of 35 or 25 persons. A total of 246 life jackets.

8.1.7 Vessel Selection Criteria

Vessel selection is very important for a successful pressure coring expedition. Many vessels have been used for various expeditions over the last 30 years. These include the JOIDES Resolution for ODP Leg 164, Blake Ridge, Japan's MH-21 program (in Nankai Trough – 2002), and ODP 204, IODP 311 and NGHP1 (DGH India). The Chikyu has also been used for expeditions in Japan for MH-21 and most recently for the NGHP2 program in India. The Q4000 was used for the Gulf of Mexico JIP II, LWD drilling in 2009. Fugro's vessels have been used on several hydrate expeditions including the REM Etive with a portable drill rig mobilized onboard for KNOC/KIGAM in 2007 and for GMGS2 in 2013. The Bavenit was used for GMGS1 in 2007 and for the Shell Gumusut work in Malaysia in 2005. Fugro Synergy was used for KNOC/KIGAM in 2010. The Fugro Voyager has been used for GMGS3 and GMGS4 in the South China Sea.

The water and drilling depths below mudline requirements for GC955 and, more importantly, WR313, restrict the vessel selection process to all but a few of the vessels that have experience on hydrate programs. Additionally, there are a few new vessels that could also meet the depth requirements for the Pressure Coring expedition including Helix's Q5000 and 534.

We have determined that the six (6) vessels described in sections (8.1.1 through 8.1.6) are the most viable for this work. Obviously, the final decision would be determined based on availability, capability and costs.. Since vessel availability will depend on timing of the expedition and cannot be confirmed at this time, we shall concentrate on capability and estimated duration of the program as the selection criteria examined in this report.

Certainly, the most capable vessel out of the six evaluated here is the Chikyu. Chikyu has the highest hook load capability and the ability to house the greatest number of scientists. Chikyu also has the capability to run quadruple stands of drill pipe which creates efficiency in deepwater areas like those planned for this expedition. The JR and the Helix vessels could run triple stands of drill pipe, but in the case of the Q4000, they must be laid out horizontally on deck and broken into single joints. Both Helix 534 and Q5000 have the ability to stand pipe back in 3 x 30-ft lengths as could the JR that has a horizontal racking system that handles 90-ft sections of pipe.

The Fugro Synergy could run/pull 60-ft sections of drill pipe. The automated pipe handling system could horizontally stack 60-ft drill pipe sections, but as with the other vessels/rigs, the initial make-up of drill pipe would be from single joints, as this is how they are transported.

ROV's – The program would require visual observation of the borehole annulus during drilling operations. Permitting requirements would also require visual observation of the drilling site prior, during and after drilling.

On many expeditions, a camera has been mounted on the Seabed Frame (see the Appendices for examples) to observe the borehole annulus during drilling operations. However, based on the permitting rules post-Macondo, it would be necessary to visually survey the drill sites and therefore, stationary mounted cameras on the Seabed Frame, or ones like those used for the JOIDES Resolution which are lowered around the drill pipe to the seabed, would not be sufficient. Consequently, the vessel would need to have an ROV installed onboard. All vessels considered in this report have permanently installed ROV(s) onboard with the exception of the JOIDES Resolution.

Station Keeping/ DP – It is anticipated that Dynamic Positioning (DP) would be required at the subject drill sites due to the water depths and to avoid the cost of anchoring. All of the vessels considered have ratings for DP2 or DP3 with the exception of the JOIDES Resolution (DP1). However, the JR has drilled hundreds of boreholes for the scientific community over the years and as far as we are aware, it has never had a problem with station keeping. We anticipate that the DP1 status would be considered and proper risk management procedures would be developed as part of the Project Execution Plan (PEP) to identify and mitigate the risks of a drive off situation.

Heave Compensation Systems – all of the selected vessels referenced here have heave compensation systems. Some only have passive systems and others have both active and passive systems.

Mud Systems – All of the selected vessels are believed to have mud systems adequate for the proposed work. Details should be confirmed with the vessel operators.

Costs/Day Rates –Costs and day rates are constantly changing in the current energy industry downturn. Vessel owners should be contacted directly to obtain current costs and rates when the timing for the expedition has been better refined.

Brochures and specifications for drilling platforms described here can be obtained by contacting directly the owners or operators for each platform. A summary of all vessels is included below as Table 8.1.

Table 8.1 Summary of Vessel Information

Table 4.1 Summary of Vessel Information

VESSEL NAME	Year Constructed	Quarters Capacity (persons)	Marine Crew Complement	Length (m)	Width (m)	Transit Draft (m)	Max height at transit draft (m) (Panamax – 62.48 m)	Moonpool Dimensions (m)	Total Vessel H.P.	D.P. Rating, manufacturer	Top drive load rating (tonnes)	Drilling wave/wind (m/kt)	Maximum Water Depth Non-riser (m)	Minimum Water Depth Non-riser (m)	Maximum Drilling Depth (m)	Derrick Rating (static) (tonnes)	Derrick Height (m)	Drawworks hook load (tonnes)	Compensator type	Compensator lift capacity (active/locked) (tonnes)	Total Stroke (m)	Mud Pit Active Volume (m^3)	Bulk Storage Capacity (m^3)	Sack storage (sacks) m^3	Remotely Operated Vehicle	Riser Capability
JOIDES Resolution	1978/2009	135		143.2	21.3	5.5	61.5	6.7 x 6.7	19,450	Dual redundant / Nautronix – DP 1		4.6 / 45	8,230	91.4	9,143	536	58.5	494	Active & Passive Active de-commissioned	357/536	6.1	340	377	161	No	No
Chikyu	2005	200		210	38	9.2	121	12 x 22	34,260	DP 3	823		10,000		10,000	1,134	70.0	1,250	Active	470	7.6	511	1,275	500	?	Yes
M/V Synergy	2009	84	50	103.7	19.7	6.5	55	7.2 x 7.2	14,000	DP 2	150	4.0 / 45	3,000	25	4,000	190	49 (incl. mast)	190	Passive	150	7.0	306.4	300	Adjust-able	2 x 150 HP	No
Helix Q4000	2002	135	76	95.1	64	8.0		11.6 x 6.1	51,630	DP 3	590		3,048			600	40.2	600	Active & Passive	600	6.0	2495	272.4	1000	2 x 150 HP	Yes
Helix Q5000	2015	140	76	109.1	70.1			24.7 x 7.9	71,880	DP3	750		3,048			679	41.5	679	Active & passive	440	7.6	626		4000	2 x 150 HP	Yes
Helix 534	1975/2013	150	76	169.2	27	7.8	83.1	7.9 x 3.0 x 5.5	36,640	DP2	650		3,048			594		679	Passive	680.4	7.6	834	339.8	2200	2 x 150 HP	Yes

Note 1: n/a - heave compensated drawworks

[grey box] Data not provided directly by vessel owner /manager

9. PERMITTING

9.1 Requirements

In order to perform a deep stratigraphic test, permits must be obtained from the agencies who oversee the Federal waters: the Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental Enforcement (BSEE). The application for the permit must be filed with the BOEM Regional Supervisor for Resource Evaluation for the OCS in the Gulf of Mexico at least 180 days prior to the planned start date of operations. The approval of the permit usually takes about 60 days from the date of submittal. This includes preparing and submitting the following items:

1. Application for Permit to Conduct Geological or Geophysical Exploration (G&G Permit)
2. Exploration Plan
3. Application for Permit to Drill

Due to the explosion and sinking of the Deepwater Horizon, as a consequence of the blowout of the BP Macondo well, the BOEM requires additional information concerning new planned activities in the Outer Continental Shelf in the Gulf of Mexico. Currently, the regulations are superseded by Notice to Lessees and Operators (NTL) No. 2015-N01, which has changed some requirements when submitting the Drilling Plan, as mentioned in 30 CFR 551.7(b)(1). This drilling plan is now referred to as an Exploration Plan (EP). The EP encompasses all of the required information in 551.7(b)(1), but now must be accompanied by a blowout scenario description, information regarding oil spills, and calculations of the worst case discharge scenario. Also, as mentioned in 551.7(b)(2), the Environmental Report is now referred to as an Environmental Impact Assessment (EIA). The EIA is now included in the contents of the Exploration Plan as stated in 30 CFR 550.227.

Each of these parts are discussed below in more detail:

9.1.1 G&G Permit

Two originals, one digital copy, and one public copy of the Application for Permit to Conduct Geological or Geophysical Exploration (Form BOEM-0327) must be submitted to the BOEM Regional Supervisor for Resource Evaluation for the OCS in the Gulf of Mexico. A nonrefundable service fee of $2,012 must be paid electronically through Pay.gov at: https://www.pay.gov/paygov/, and you must include a copy of the Pay.gov confirmation receipt page with your application. Within BOEM-0327, there are separate sections to be completed for both, geological or geophysical activities. Two separate form BOEM-0327 must be submitted to apply for a geological or geophysical operations.

Attachments required:

- A public-information, page-size plat(s) showing:
  - The location(s) of the proposed area of activity or each test;
  - BOEM protraction areas; coastline; point of reference;
  - Distance and direction from a point of reference to area of activity; and

  - Must be labeled as "Public Information"
- The appropriate geological or geophysical form pages, within BOEM-0327;
- Maps, plats, and charts as specified on each form, pertaining to either the geological or geophysical operations that would be performed.

Deep stratigraphic tests are deemed geological operations and would require the submittal of a Permit for Geological Exploration for Mineral Resources or Scientific Research on the Outer Continental Shelf. The Geological Permit includes Form BOEM-0329 in addition to Form BOEM-0327. Approval of the G&G permit usually takes about 60 days from the date of submittal.

9.1.1.1 Notifications of Commencement

When conducting G&G scientific research, approval must be obtained for all of the above mentioned permits, as well as filing a Notice of Commencement. A notice of Commencement must be filed with the BOEM Regional Director at least 30 days prior to the planned start date of operations. Also, BOEM must be informed, in writing, when work concludes.

In order for BOEM to manage G&G activities and minimize duplicative drilling, group participation opportunities must be provided for stratigraphic testing. The procedures for group participations in drilling activities are as follows:

- Publish a summary statement in Houston, New Orleans, and Lafayette newspapers, that describes the approved activity in a relevant trade publication;
- Forward a copy of the published statement to the Regional Director;
- Allow at least 30 days from the summary statement publication date for other persons to join as original participants;
- Compute the estimated cost by dividing the estimated total cost of the program by the number of original participants; and
- Furnish the Regional Director with a complete list of all participants before starting operations, or at the end of the advertising period if you begin operations before the advertising period is over. The names of any subsequent or late participants must also be furnished to the Regional Director.

9.1.1.2 Extensions

Extensions of the time period specified must be requested in writing every 60 days. A permit plus extensions for activities other than a deep stratigraphic test are limited to a period of not more than 1 year from the original specified issuance date of the permit. The duration of a permit for a deep stratigraphic test must be controlled in accordance with 30 CFR 551.7.

9.1.1.3 Status Reports

Status reports are to be submitted every two months to the Regional Supervisor, Resource Evaluation. The report must include a map of appropriate scale showing sampling locations, protraction areas, blocks, and block numbers. The map should be a cumulative update for each status report and clearly distinguish between planned sampling locations and locations in which samples have already been collected.

9.1.1.4 Final Report

A Final Report must be submitted to the Regional Supervisor within 30 days after the completion of operations. The Final Report must contain the following:

- A brief description of the work performed including number of samples acquired as well as coring, drilling, and sampling methods including depth of penetration;
- A brief daily log of operations describing the operations for each day and indicating pertinent activities. The logs should begin on the date that the vessel begins to transit to the permitted area and end on the date in which the vessel either transits away from the permitted area or when operations pertinent to the permitted activity ceases.
- A PDF or, preferably a GeoPDF or shape file depicting the areas and blocks in which any exploration or scientific research activities were conducted. These graphics must clearly indicate the location of the activities so that the data produced from the activities can be accurately located and identified;
- The start and finish dates on which the actual geological exploration or scientific research activities were performed;
- A narrative summary of any:
    - Hydrocarbon slick or environmental hazards observed;
    - Adverse effects of the geological exploration or scientific research activities on the environment, aquatic life, archaeological resources, or other uses of the area in which the activities were conducted;
- The estimated date on which the processed or analyzed data or information would be available for inspection by BOEM;
- A CD or DVD containing all of the data or sample locations in latitude/longitude degrees (and/or X, Y coordinates). The data should also be submitted as an ESRI shapefile(s) illustrating the location of all Geological data collection;
- Identification of geocentric ellipsoid (NAD 27 or NAD 83) used as a reference for the data or sample locations; and
- Such other descriptions of the activities conducted as may be specified by the Supervisor.

9.1.2 Exploration Plan

The Exploration Plan (EP), replaces the Drilling Plan as referenced in 30 CFR 551 & 30 CFR 251. The EP must be developed in conjunction with the drilling engineer and must include the following criteria as stated in 30 CFR 550 Subpart B and in NTL No. 2015-N01:

- The proposed type, sequence, and timetable of drilling activities;
- You must include the service fee of $3,442, for each surface location, as required by 550.125;
- A description of the drilling rig, indicating the important features with special attention to safety, pollution prevention, oil-spill containment and cleanup plans, and onshore disposal procedures;
- Pursuant to 30 CFR 550.213(g) a blowout scenario description must be included along with information regarding potential oil spills and calculations of worst case discharge scenario, in accordance with 30 CFR 550.219 and 550.250. Due to the nature of the Deep Stratigraphic Tests, should no BOP’s be used

in the drilling and depths should not encounter hydrocarbons, these sections would still need to be included, but would describe they are not going to be present;

- The location of each deep stratigraphic test that would be conducted, including the location of the surface and projected bottomhole of the borehole;
- EIA description as referenced in 30 CFR 551.7 (see description below)
- The types of geological and geophysical survey instruments being use before and during drilling;
- Seismic, bathymetric, sidescan sonar, magnetometer, or other geophysical data and information sufficient to evaluate seafloor characteristics, shallow geologic hazards, and structural detail across and in the vicinity of the proposed test to the total depth of the proposed test well; and
- Any other relevant data and information that the BOEM Regional Director may require after reviewing the application.

The Regional Supervisor would review the submission within 15 working days. Additional information may be requested by BOEM if there are any problem or deficiencies with the submitted plan. Within the 15 working days, the Regional Director would notify you of any information needed. Once all requirements, or deficiencies, with the plan have been fulfilled, the EP is then deemed “submitted”. Approval should be granted in 60 - 90 days from the date that the plan is “submitted”. Any changes to an approved drilling plan must be submitted to BOEM and the revised drilling plan must be approved by the BOEM Regional Director.

9.1.2.1 Environmental Impact Assessment

The Environmental Impact Analysis (EIA), referenced as an Environmental Report in 30 CFR 551.7, must meet the requirements of Federal Regulation 30 Chapter V Subchapter B Part 550.227 for an Environmental Impact Analysis (EIA) and should be prepared by someone with an environmental, biological or marine biological background. The report should assess damages and be site specific. Data from past surveys could be utilized.

Generally, the following environmental resources should be considered for a given site, but this list is not exclusive: Designated topographic features, pinnacle trend live bottoms, eastern Gulf live bottoms, chemosynthetic communities, water quality, fisheries, air quality, marine and pelagic birds and public health and safety and essential fish habitat. Additionally, any species defined as Threatened and Endangered, therefore currently marine mammals and sea turtles should be considered. However, if the applicant identifies other environmental resource add them to the consideration.

In addition to the above, cultural review is covered within the EIA so shipwreck sites and prehistoric archaeological sites need to also be considered when considering impacts. The Archaeological Assessment report for the block should be used and referenced.

Associated impacts are also required to be considered; therefore, coastal resources such as beaches, wetlands, shore birds and coastal nesting birds, coastal wildlife refuges and management areas, and lastly wilderness areas should all also be considered, even though they may not be near the project site.

There are several Impact Producing Factors (IPFs) associated with the activities to consider when evaluating the impacts to the environment, such as emissions, effluents, physical disturbance, waste and accidents (including oil spills), however other IPFs could be identified based on specific operations or equipment.

Each one of the IPFs should be considered for each resource. Avoidance, minimization, and mitigation steps that have been implemented should be outlined in the environmental report.

Ocean current models have been used to develop probability charts in the event of oil spills. This should be used to anticipate direction of impact for spills to determine which resources are susceptible for the given location.

A reasonable attempt to consider accidents and large scale impacts are needed since the Macondo event has broaden the possible scenarios to consider.

Include in the report and consultation that may have been done to collect data and reference all sources of data.

The results of the environmental report would be reviewed along with the other portions of the application.

9.1.3 Application for Permit to Drill

The application for a permit to drill (APD) must be submitted, via https://ewell.bsee.gov/ewell/ according to NTL No. 2014-N03, in accordance with 30 CRF 250.410 – 250.418, and approved prior to commencing drilling. The form for an APD is BSEE-0123. In addition to submitting an APD, a Supplemental APD Information Sheet (Form BSEE-0123S) must also be submitted and approved by BSEE.

- Drilling prognosis and summary of drilling design, cementing, and mud processes
- Payment of the service fee of $2,113, as required in 30 CFR 250.125;
- Directional Program, proposed wellbore schematic and well location plat, & casing a cement programs
- Diverter and BOP systems descriptions, if BOP's would be used, and;
- Such other information that the District Manager may require

9.1.3.1 Rig Movement Reports

The movement of all drilling units, including both MODU and platform rigs, must be reported at least 24 hours before the arrival or departure of a rig on to or off of a location, in accordance with 30 CFR 250.403. The Rig Movement Notification Report (Form BSEE-0144) must be submitted on eWell according to NTL No. 2014-N03, indicating the rig name, lease number, and expected time of arrival or departure.

9.1.3.2 Weekly Activity Reports

For drilling operations in the GOM OCS Region, a Weekly Activity Report (WAR) must be submitted to the District Manager via eWell (Figure 9.1) according to NTL No. 2014-N03, on Form BSEE-0133. A brief description of daily activities is to be submitted on a weekly basis, along with BOP test dates and significant events that occur during the reporting week period until the date that the rig is moved off of location. This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next WAR. The reporting period for the WAR is never longer than seven days, but it could be less than seven days for the first reporting period and the last reporting period for a particular well operation.

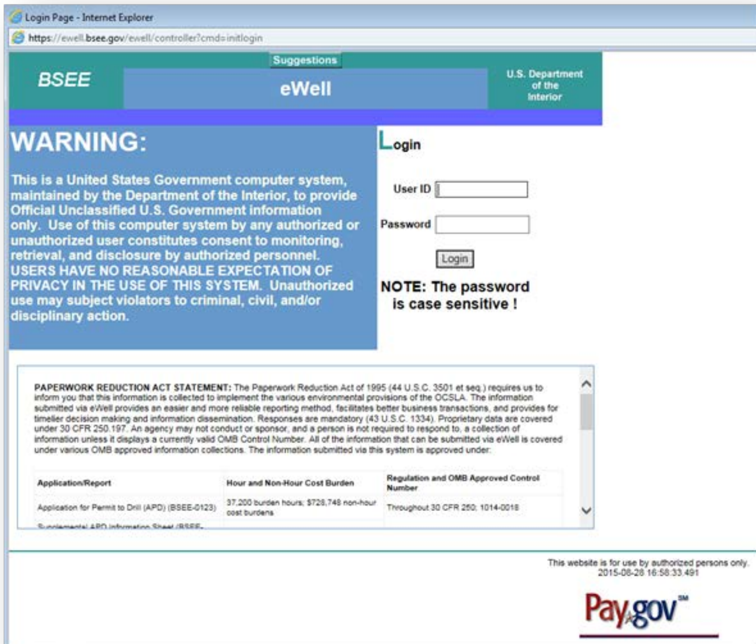

Figure 9.1 eWell login page.

9.1.3.3 <u>End of Operations Report</u>

The End of Operations Report (EOR) must be submitted via https://ewell.bsee.gov/ewell/ according to NTL No. 2014-N03, in accordance with 30 CFR 250.420 and 250.465. The EOR (Form BSEE-0124) must be submitted within 30 days of completing operations permitted under the APD, and must include the status of the well and date operations were completed, along with information on work performed.

After drilling a borehole must be permanently plugged and abandoned and meet the requirements in 30 CFR part 250.

9.2 Responsibilities

Obtaining the permit authorization would be the responsibility of either the operator's in-house or consulting regulatory agent. Personnel in the industry with experience preparing specifically stratigraphic test applications is limited, however other personnel experienced with the oil and gas development permitting would be able to performing these tasks. The parallels between the two permit proceeds are close enough for those personnel to work on both.

The permit must be acquired in the operator's name. The operator would be required to provide the bond assurance.

It is the drilling engineer's responsibility to provide the details of the drilling plan to the permit application preparer. The location map should be prepared by a licensed surveyor that has experience with offshore project drawings before.

Useful web-based references include:

https://ewell.bsee.gov/ewell/
http://www.ecfr.gov/
http://www.bsee.gov/Regulations-and-Guidance/Notices-to-Lessees-and-Operators/
http://www.boem.gov/notices-to-lessees-and-operators/

10. PREMOBILIZATION\MOBILIZATION\DEMOBILIZATION

Premobilization, mobilization and demobilization are critical aspects of the process. Experienced personnel and/or operators should be consulted to ensure that appropriate procedures are followed in order to ensure a smooth and safely run operation.

Many factors are of great importance when planning a complicated operation that involves drilling and pressure coring gas hydrate formations. These expeditions are planned and executed based on operational procedures established to address specialized tool requirements and the complexity of the work.

As mentioned in Section 3.2 (History) many different platforms have been used over the years to accomplish the various programs. Here there are several factors that come into play and most are driven by availability and cost.

Projects are often rushed to commence field operations, typically because funding is late in materializing, yet the project team desires to keep the original schedule. Many times, the mobilization schedule that would ideally have a minimum duration of six months will get shortened to three months or less. This could have (and has had) detrimental effects on the fieldwork. The key lesson here is to allow ample time after funding has been secured to plan and conduct a proper mobilization.

Commercial projects are operated much differently than scientific drilling projects. For research vessels like the JOIDES Resolution or the Chikyu, schedules and availability are known sometimes a year or more in advance and definitive plans can be made and counted on for exact mob dates and exact completion dates.

Commercial fleets operate much differently. Vessels such as the Fugro Synergy or the three Helix vessels mentioned in Section 8, are generally moving from one project to the next, often without firm knowledge of the scope of work, duration, etc. This fact leaves availability and mobilization dates uncertain, which in turn makes premobilization and mobilization schedules difficult to predict. Listed below are some key items for consideration in the pre-mob and mobilization stage:

10.1 Vessel Charter

The biggest cost item on an offshore operation of this nature would be the vessel/platform. Negotiations must start early on to secure the charter and confirm a schedule for field operations. The duration of charter and potential penalty clauses for early withdrawal need to be carefully negotiated. Mutual indemnification and liability clauses would be key points of interest.

10.2 Insurance

The vessel and equipment would require marine insurance. This can be complicated, particularly when working with government sponsored vessels and equipment like on the JOIDES Resolution and Chikyu. Insurance requirements need to be established early on in the process. Risk, or perceived risk, generally correlates strongly with pricing/costs. One should strive not to overburden one party with all the operational risks. Personnel insurance would be covered by workman’s compensation for those working in the USA.

Insurance requirements for personnel working on projects outside the USA would be determined on a case-by-case basis.

10.3 Equipment

A large amount of equipment would need to be mobilized for this program. A short list includes: PC systems, PCATS, MSCL-N, various workshops and containers, fishing winches (if not already onboard the various vessels being considered), survey gear, drill pipe and BHA(s), hydraulic power packs, perhaps deck generation units, etc. The mobilization manager would need to ensure that this is coordinated with the chosen port facility and the vessel Captain.

10.4 Subcontractors

Many subcontractors would be required to bring the various equipment and science components together to meet project needs. One party should take on direct responsibility. That one responsible party would need to subcontract others like Geotek, Jim Aumann & Associates, various academic institutions and scientists, survey personnel, etc. These would require the issue of Blanket Subcontractor Agreements and full disclosure to all involved parties. Additionally, it would be expected that separate subcontractor agreements would be established with the following:

10.4.1 Supply Vessels

Depending upon the actual duration and number of boreholes to be drilled, together with the vessel selection and its particular mud storage capabilities, it may be necessary to contract supply vessels to bring additional consumables to the drilling vessel operating in the field. Alternatively, a port call for the drilling vessel may be required, but should be avoided if possible.

10.4.2 Other Transportation Services

Depending upon the duration of the fieldwork, there may be a need to contract transportation services such as helicopters for crew changes and certainly there would be a provision in the Emergency Response Plan (ERP) contained in the PEP to allow for Medivac in the unfortunate event of somebody getting hurt or ill during operations offshore.

10.4.3 Drilling Mud

A pressure coring program would benefit from understanding the drilling conditions and problems encountered during JIP Leg II LWD drilling. The JIP II plan called for drilling with seawater and occasional sweeps to clear cuttings as needed. At the first hole at WR313-G, the drilling plan required modification because of borehole pack-off and high torque requirements. Weighted muds were employed along with other modifications to finish drilling at WR313-G. The same protocol was employed at the other boreholes with success. At the GC955 location, thick sands with high gas hydrate saturation were drilled. There was no gas beneath the thick gas hydrate at the GC955-H location. At the GC955 Q location a gas bubble was observed by the ROV at the primary gas hydrate target. The gas bubble could have been either from the dissociation of gas hydrate cuttings or from subjacent free gas.

Lessons learned from the JIP II LWD work should be considered and applied for the pressure coring program. For drilling at a typical location with a nominal diameter of about 10-in. and the maximum combined drill string length (water depth plus drilling depth and air gap) of about 2,800 m below rig floor, the estimated total mud consumption would be ~2 ton of Guar Gum, 16 ton of Bentonite, 41 ton of Barite, 250 kg of Caustic Soda, 120 kg of Soda Ash, 32 kg of Biocide, 177 cu. m of drill water, and 678 cu m of brine. However, somewhat different drilling considerations exist between LWD drilling and a detailed pressure coring program. Drilling rates would be slower for the coring expedition and there would be substantial “wait” periods during the coring operations where the drill string would be at a near stationary depth depending upon the type of PC system employed.

Mud supplies in the form of Bentonite and Salt Gel (Attapulgite clay) would be required for these relatively deep boreholes. Whatever vessel is chosen, both liquid and dry drilling mud would be taken on board based on the expected usage for the full program. Should additional drilling fluids be required, these would be sourced and brought to the vessel via a supply vessel.

10.4.4 Schedule

Schedule would likely be dictated by vessel availability as previously mentioned. The other main factors for consideration include: 1) weather (addressed below); 2) time of year; it is likely that some professors would be joining the expedition and it may be necessary to work around their availability schedules; and 3) funding schedule.

10.5 Weather

The best time for offshore work in the Gulf of Mexico is during the summer months. However, the variance on that is the hurricane season that runs from 01 June through 30 November each year. Additionally, the summers are generally plagued with Loop Current events that could shut down drilling operations and were particularly bad in the summer of 2015. Careful consideration needs to be made to balance the risk of hurricane season, loop currents and spring and winter storms. Services for predictive weather models are available.

10.6 Selection of Port/ Agents

Careful consideration for available ports and agents is another key point to the premobilization and mobilization process. Two major ports along the Gulf Coast include Galveston and Port Fourchon. Port Fourchon is actually closer to the work areas than Galveston, but Galveston’s close proximity to Houston makes it convenient. Close coordination with ship’s agents and the main contractor would be critical. It is recommended that one agent is selected to handle all the various party’s needs.

10.7 Permits

Drilling permits are covered in Section 9. However, considering that small gamma ray sources are required for PCATS and some MSCL equipment, advance planning is required to secure the proper permits for the radioactive sources.

10.8 Customs

Depending upon the vessel selection, it would be necessary to address customs issues. In any event, temporary work permits for foreign nationals would be required and importation of foreign equipment such as PCATS and others would also be necessary.

10.9 Transportation

Trucking services would be required to get the various equipment and containers from their local stations to the port of mobilization, likely Galveston or Port Fourchon. For the Gulf Coast Region, this is routine and no difficulties should be expected. One should check early on for “permit loads” if applicable. This could restrict the days or hours of the day in which certain items could be trucked.

10.10 Safety Training/Medical

All offshore personnel would be required to undergo Survival Training and Helicopter Evacuation Training as a minimum. Additionally, UKOOA medical exams would be required for all vessel personnel including client representatives.

10.11 Preparing a Project Execution Plan (PEP)

A PEP is essential for complex offshore hydrate expeditions and for all offshore operations involving complicated equipment, drilling operations and vessels. We have provided an example PEP for a gas hydrate expedition in Appendix B.

10.12 Organizational Chart

An example Org Chart is included in the PEP. This would need to be updated with the appropriate job categories and with names for the various positions.

10.13 Communication Protocol

Communication protocols need to be established to ensure that 1) nobody is left out of the communications loop that should be informed; and 2) sensitive information is only sent to the appropriate team member in need of such information. Communications should be sent directly to the person(s) who need to respond or take action. Copied team members are informed, but are not expected to respond or take action.

10.14 Layout of equipment

Another key component to the efficient mobilization and workability of the work floor is achieved by optimizing the deck layout of equipment. There is always a compromise on optimum sites for various tool laydown areas, laboratories and other required deck gear.

10.14.1 Laboratories & Tool Containers

Various laboratories and tool containers would be mobilized for this type of operation. Typically, a 40-ft core processing container (or equivalent like the “Cat Walk” on the JR) would be required for processing C-cores. In this laboratory, the NP core is first subjected to an IR Camera scan to determine where hydrates may be, or have been, once the core is recovered to the deck. It is essential that NP cores are efficiently handled and brought to the core processing center as quickly and safely as possible. Additional deck laboratories may be required depending upon the vessel selected for the work. PCATS is comprised of two x 20-ft containers laid end to end on the deck with room for at least a 15-ft extension on one end. The cooling system for PCATS also comprises another 20-ft container. If PCATS Triaxial is used, another 20-ft container is required and is also utilized for PC storage. PCTB requires a 40-ft container plus additional room for an ice-trough in front of it. If other NP coring tools are determined to be useful, at least one more 40-ft container would be required to house BHA, FHPC/APC, FMCB/XCB and perhaps another one if a back-up PC system like FPC is required.

A geochemistry laboratory would be required and this would typically require a 20-ft container for the pore water squeezers/presses and the various other processing equipment. If NP coring is planned and it is determined that cores would be split onboard and placed in D-tubes, another container for sedimentology may be required to house the MSCL-CIS equipment, microscopes and work table for the process.

On the Chikyu and the JOIDES Resolution, these laboratories and most of the tool containers are “built in”. The exception is PCATS and PCTB containers. For the Synergy, Fugro has utilized a two-story 30 ft. x 30-ft custom built laboratory to house the physical properties lab, sedimentology lab, geochemistry and microbiology labs, vent hoods, etc. Ample workspace was available for scientists working on the data and for onboard science meetings. Something similar could be arranged on either of the three Helix vessels.

NP coring would also require the mobilization of containers to house the MSCL-S, MSCL-XCT and MSCL-XR if desired. One could quickly see that good planning would pay back dividends in the mobilization process considering the number of laboratories and special equipment required. These requirements would change significantly depending upon the decision for NP coring or only PC’s and PC Analyses.

10.14.2 Deck Workflow

In order to gain efficiency in the deck operations and the overall marine work, we found it beneficial to spend a good deal of time during the premobilization phase to determine an optimum deck workflow. This is difficult many times because all the various operators and technicians want to occupy the same, critical spaces. The key is to determine what activity on deck would be utilized the most and therefore get the prime deck space. Some other determinations could be made simply by visualizing how everything would fit. Solid Model software is very useful to make paper mock-ups of the equipment mated to the deck of a particular vessel. The deck could get very crowded on these operations and with the expense of the vessel being the highest cost, a good deck workflow could save money and allow for more work to be performed in a given amount of time.

10.15 Testing of tools and winches & Safety Audit

All lifting gear would require current certification. It is highly recommended that a full function test of all the required tools be undertaken prior to mobilization. One should also consider both dry and wet testing of critical tools like the pressure coring system(s) themselves.

10.16 Project Execution Plan (PEP)

The following sections are covered in detail on our Example Project Execution Plan (PEP) in Appendix B:

- Premobilization Meeting
- Kick off Meeting
- Vessel Orientation Meeting
- Daily meetings
- Safety meetings

10.17 Core Transportation and Monitoring

Handling and transportation of cores to an onshore laboratory or storage facility should be carefully planned. In particular, transportation of the P-cores in pressurized storage chambers must be performed with utmost caution. The chambers should be constructed using ASTM protocols and OSHA standards (i.e., pressure tested at conditions to 1.5 times the maximum working pressure of the chambers, and rated to DOT standards. Air transportation is suitable for dry ice or liquid nitrogen shipping containers, or when non-flammable gas is used for pressurization. The ground transportation for custom chambers need the current DOT certification.

10.17.1 Shipping to Onshore Core Laboratory

Shipment of cores to an onshore base laboratory could take many forms. The options are to transport the cores by helicopter or workboat. In many cases the workboat option may be too slow, and shipping the cores by helicopter is the only viable option, where the weight and space limits of the helicopter must be met. Care should be taken to give the rig superintendent as much lead-time as possible for helicopter planning.

A sample inventory log should be made detailing the contents of each box or crate. Each box/crate lid should be labelled with the well/borehole name, core number, core depth and destination address.

Once the core reaches the helibase/shorebase, the shipment must be met and trucked (preferably using refrigerated truck) to either a local laboratory, an airport for further transport, or placed on a truck for overland shipping. Air schedules must be determined well in advance in order to minimize delays. Adequate freight space on the plane must be reserved as far in advance as possible. Careful investigation must be done to determine the type of documentation needed for sending the cores by airfreight. The core must be met on the destination end and transferred to the laboratory. Care must be taken to avoid any temperature extremes.

10.18 Demobilization

Demobilization is almost always completed much quicker than mobilization. There is something about returning from an offshore expedition that motivates personnel who are anxious to go home. This is particularly true after long-duration fieldwork programs.

The important things to mention here include restoring the vessel to its original condition. Charter agreements stipulate this within "normal wear and tear" confines. It is always important to conduct Tool Box Talks and Safety Briefings during this period to avoid accidents. Typically, there is a lot of deck "hot work" being conducted to cut welds and tie-downs that were required to sea-fasten the equipment. It is recommended to always conduct this process in accordance with a shipboard "Permit to Work" system.

11. HSE

11.1 Introduction

Health, Safety and Environment (HSE) should be considered as a paramount focus for the entire coring operation. Working in a marine environment has inherent dangers in itself. Established practices and procedures are available through efforts of DSDP, ODP and IODP. Fugro has also established practices and procedures that have been applied to a total of 17 expeditions related to Gas Hydrates Site Characterization without an incident thus far. Some of these have been in conjunction with ODP and IODP; others have been conducted independently by Fugro.

Present below is a compilation of safe drilling practices. This is patterned after a White Paper on Current Safe Practice for the Drilling and Coring of Gas Hydrates, dated December 2003 (Pollard, G. and Storms, M. (2003) “White Paper on Current Safe Practice for the Drilling and Coring of Gas Hydrates”, dated December 2003), as well as lessons learnt from operations during the Gulf of Mexico JIP leg I (2005), IODP Expedition 311 (2005), Malaysian Gumusut-Kakap Project (2006), India NGHP Expedition 01 (2006), China GMGS Expedition 01 (2007), Republic of Korea UBGH Expedition 01 (2007), Gulf of Mexico JIP leg II (2009), Republic of Korea UBGH Expedition 02 (2011), China GMGS Expeditions 02 (2013) and 03 (2015).

Additionally, Fugro’s Shallow Gas Procedures is included in the appendices. More detailed information on Health, Safety and Environment are contained in the example Project Execution Plan (PEP) also contained in the appendices.

11.2 Safe Drilling Practices

The intent of this section is to provide a general overview of Safe Drilling Practices and not to be considered as a complete, stand-alone document. Safety while performing offshore site investigations is the first priority of all involved in the investigation and should be of the utmost importance.

11.2.1 Responsibilities and Authority

Vessel Master: The Vessel Master has the ultimate and overall authority onboard the vessel for the safety and wellbeing of all personnel. The Vessel Master works with the onboard supervisors (Chief Engineer, Offshore Manager, Drilling Supervisor, etc.), the onboard Client Representative and onshore personnel to monitor the ongoing operations.

Offshore Manager: The Offshore Manager is the onboard Project Management representative and works with the Vessel Master and Drilling Supervisor to monitor the onboard safety and implement changes, as needed.

Drilling Supervisor: The Drilling Supervisor is the most senior drilling crew member and is in charge of the operations on the Drill Floor and associated tasks. The Drill Crew report to the Drilling Supervisor. The Drilling Supervisor works with the Vessel Master, Lead Scientist, Lead Engineer, senior laboratory technicians and the Chief Engineer to monitor, plan and change operations as needed.

Onboard Client Representative: The Onboard Client Representative is the highest authority for the Client while onboard the vessel. The Client Representative is the Client's onboard HSE representative, unless otherwise designated. The Client Representative would work with the Vessel Master, Offshore Manager and Drilling Supervisor on matters that pertain to safe drilling.

All crewmembers have the authority to Stop the Job if they feel a hazard exists that should be addressed.

11.2.2 Safe and Efficient Operations

The Client, Contractor and subcontractors need to work together closely to maintain safe drilling practices. Safety is always of the highest importance, however, extra attention is needed during hydrate drilling and coring activities due to the possibility of rapid hydrate decomposition. The Gulf of Mexico has relatively warm waters, which increases the possibility of quick dissociation of hydrate materials in the cored soils. If gas hydrates change state while in the corer, high-pressure may build up due to gas expansion as it changes phases from solid to gas, leading to an increased potential for the corer and liners to explode and generate flying projectiles. The crewmembers need to have a plan in place and work closely to maximize the operational efficiency and reduce lost time due to repairs or maintenance.

11.2.3 Known Hazards/Issues

The known hazards identified in this section do not constitute a comprehensive; additional hazards may exist, depending on the operations and conditions encountered.

- High pressure build up from gas hydrate changing from solid to gas state (i.e., Influx of gas generated by drilling-induced dissociation) may cause loss of well control.
- Dissociation of gas hydrate near seafloor could lead to seafloor heave or subsidence and loss or damaged to infrastructures.
- Hydrate formations could be "sticky" to drill through, may swell or be unstable, possibly causing casing to get stuck in the hole.
- Loss of formation competency accompanying dissociation may cause hole enlargement, wellbore collapse, casing collapse, and/or seafloor instability.
- Encountering free gas and / or water flows into boreholes may cause costly delays or perhaps loss of well control.
- Overpressured gas accumulations trapped below gas-hydrate-bearing sediments are considered potential hazards when penetrated during drilling operations.
- Moving heavy items or equipment, especially on the moving deck of a vessel.
- Short cuts that are tempting to take, but increase risk, etc.

11.2.4 Planning

The Client, Contractor and subcontractors should work together to make a comprehensive project plan prior to the start of the fieldwork. The project plan should be documented in the Project Execution Plan (PEP) and be distributed to all project members, as well as be available onboard the vessel. Additionally, all parties involved should work together on the project details, such as feasibility, cost, timing, environmental and safety factors, internal and external requirements, etc.

11.2.4.1 Data Review

Site-specific and nearby soil data, such as geophysical and geotechnical data, should be reviewed in a desktop study by experienced professionals (Geophysicists, Geotechnical Engineers, Scientists, Drillers, Vessel Master, Marine personnel and HSE) to identify potential hazards or issues. The review should also identify the expected drilling conditions at the proposed locations. The results of the review should be distributed to the project team.

11.2.4.2 HAZID

A Hazard Identification (HAZID) meeting should be conducted well in advance of the field work. This meeting should include both onshore and offshore personnel from the Client, Contractor and subcontractors. The goal of the meeting is to review all of the planned and potential operations from mobilization to demobilization and identify any potential hazards. For the identified hazards the group would work to identify mitigations and processes to reduce the risk of the hazard.

11.2.4.3 Permitting

The Client would need to secure the required permits in advance of the fieldwork. The permitting authority may specify certain items, procedures or actions as a requirement for performing the permitted work. The Client and Contractor should review all permits and associated requirements to ensure compliance.

11.2.4.4 Campaign Planning Meetings

Campaign planning meetings should be held between the Client, Contractor and subcontracts as needed during the time leading up to the offshore campaign. During these meetings any contractual, safety or operational concerns should be raised and addressed as early as possible in the process. Logistics, crewing and supplying should be covered as well.

11.2.4.5 Mobilization Planning Meetings

The Contractor, subcontractor and vessel personnel should plan the pre-project mobilization and receive input from all groups involved. A comprehensive mobilization plan should be generated and distributed to the group. This plan includes all actions to be performed during the mobilization, proposed deck and equipment layout, modifications, personnel travel plans, etc.

11.2.4.6 Campaign Kick-off Meetings

A campaign kick-off meeting should be conducted at the mobilization port with the project management and crewmembers. Additional kick-off meetings may be held as needed, e.g. with shore based personnel who are not located at the mobilization port.

A meeting should be held onboard the vessel with the onboard client representative, drill, survey and marine personnel to confirm the operational details, such as survey geodetic information, limitations/restrictions, expected soil conditions, anticipated hazards, etc. The boring/coring prognosis should be confirmed between the different parties and then distributed to the group. Additionally, the planned process should be discussed, as well as backup options.

11.2.4.7 Project Meetings

Project Meetings should be held onboard the vessel daily with the onboard supervisors and client representative.

11.2.5 Standing Orders/Instructions

The Supervisors of each department should issue a Standing Order regarding the operations for the department. The Vessel Master, Chief Engineer, Offshore Manager and Laboratories should have Standing Orders/Instructions. These instructions should be given both verbally and in written form.

11.2.6 Safety Meetings

Pre-shift Safety Meetings – Pre-shift safety meetings should be held before each shift, as described in the PEP. Topics that should be covered include, but are not limited to: operational update from the previous shift, expected operations during the upcoming shifts, changes to plans or processes, safety issues, weather, and equipment issues.

Toolbox Meetings – Toolbox meetings should be held by the groups who would be performing the operations. If the crew needs to deviate from the planned operation during the shift (e.g. equipment breakdown requires maintenance) a toolbox meeting should be held with those involved in the new task.

Weekly Safety Meetings – Weekly safety meetings should be held with all of the onboard crew members. The meeting should cover any safety issues raised in the previous week, safety alerts, and a review of hazard observations.

11.2.7 Drilling/Coring Recommendations

Each project should have specific guidelines developed for the expected conditions at the locations and the operation setup onboard the vessel. The established project guidelines/recommendations should be reviewed and revised as needed.

Procedures and processes should be developed ahead of time and agreed upon by the parties who would be involved with the operations. During the course of the project the procedures or processes should be revised, if needed. Any changes should be made following a Management of Change plan and communicated to the involved parties.

When an issue or potential issue is identified the supervisor of the area should be notified. Area supervisors are on-call when off-shift and should be advised of problems as they occur or potential problems when observed. Other supervisors may need to be notified, depending on the situation. Some examples are:

- Gas, such as hydrogen sulfide, high pressure gas, hydrate, hydrocarbons, or other potential hazardous substances are detected.
- Hydraulic oil leak.
- Issues with drilling equipment that would delay or significantly impact operations.

- Borehole conditions including
    - Increased borehole instability, flow or amount of borehole cleaning
    - Increased circulating pressure from borehole packing-off
    - Cuttings recovered in sampler from borehole cleaning issue, sampler issue, flow back.
    - Increased drag or sticking from soil swelling, borehole deviation or a dirty borehole.
    - Heavy flowback at connections due to dirty borehole or flow
    - Loss of circulation when making connections
- Gradual pressure loss, which may indicate possible washout of borehole walls or possible pipe failure.
- Abrupt change in the drilling rate or how the borehole is drilling, which may indicate a quick change in drilling conditions or flow.
- Deterioration of weather/sea conditions No or minimal recovery of core sample for multiple cores.
- Vessel unable to hold position due to equipment failure.

Some other recommendations for drilling operations include:

- A minimum of 5 in-situ soil temperature measurements should be performed for methane/ethane (C_1/C_2) ratio hydrocarbon maturity analysis. The measurements should be started approximately 130 ft. below seafloor and be performed every third core until at least 5 good data points have been taken. A formation temperature gradient should be calculated and used to determine what temperature range the hydrocarbon targets are within (normal, anomalous, or hazardous).
- The Driller should be authorized to use drilling mud when seawater is not sufficient for the drilling conditions. The mud make-up will be determined by suitably qualified drillers or mud engineers.
- If the borehole is drilled to more than 500-ft below the seafloor the US Government permitting authority may require that the borehole be filled with cement when the operations are completed at the location.
- A kill pit of heavy weight mud should be mixed and readily available in case there is a gas encounter during the borehole operations.
- A final “fix” or “tie” recording the coordinates of the borehole should be taken as soon as possible once the drill pipe has spudded into the soil. The Surveyors should provide the final position report to the Offshore Manager once it has gone through the appropriate quality checks/controls.
- Borehole angle and deviation should be measured every 100 ft. to avoid borehole deviation issues, if possible.

11.2.8 Hydrocarbon Safety

Project personnel need to be aware of the risk of an uncontrolled hydrocarbon spill and the consequences, including environmental damage or fire. At hydrate sites there may be flowing or leaking hydrocarbon fluids from the seafloor and into the water through naturally occurring faults or chimneys. Proper planning of site selection and operational processes are used to reduce the chance of a hydrocarbon spill.

If the field personnel believe that there is a possibility of a hydrocarbon release they may choose to take shorter cores or re-evaluate whether or not to proceed with the borehole after each core. Both onshore and offshore personnel with knowledge in hydrates drilling and safety should be available at all times for consultation, if needed. Personnel on the vessel should have the contact information for the onshore experts.

Prior to the start of the campaign the project personnel (Client, Contractor and subcontractors) should perform a desktop study to assess the potential for hydrocarbon encounters. The desktop study should review all available site and nearby information, including seismic records, previous boring records, regional experience, etc. The information generated in this study should be used by the project team to plan how the team would perform the operations in these zones. The plans should include ways to mitigate the risk of drilling into the hydrocarbon zones.

The Client and Contractor would need to agree on what approach is the safest way to perform the fieldwork. This should include reviewing their shallow gas encounter procedures and procedures specific to drilling in hydrate zones. All onboard personnel should be made familiar with the plans and procedures for when hydrocarbons are encountered and what their job duties and roles are during an encounter. Personnel should be made familiar with the plans and the onboard personnel should raise any questions or concerns as soon as possible so they may be addressed promptly.

A gas monitor system should be installed on the vessel and monitored at all times. The plan/procedure for gas encounters should be followed and the required PPE should be readily available at the designated stations. In the event of an encounter the procedure should be followed immediately and personnel should respond appropriately. Additionally, safety equipment like a Coring Blowout Preventer (BOP) should be well maintained and in good operational conditions prior to starting operations. Another piece of equipment that may be used is a non-return valve/float valve. A non-return valve does not allow fluid to enter into the drill pipe from the seabed.

During riserless drilling if a gas encounter occurs the gas flows through the easiest path, which is generally up the borehole annulus around the drill pipe and then the gas is discharged at the seafloor into the water column. Generally, in deep water, the gas would be dissipated through the water and would be moved with the water current. Because of this indications of gas, such as bubbles alongside the vessel, may not be observed at deep water locations. Any indications of a gas encounter should be promptly reported by the observer to the appropriate supervisor. The project HSE plan addresses shallow gas encounters and should be followed.

Backflow, i.e. fluids coming out of the drilling pipe when a connection is made, is a normal occurrence during drilling operations. Backflow can be induced by the difference in the density of the warmer water in the drilling fluids from the vessel mixing with the denser cold seawater, air trapped in the drill pipe when connections are made, or from cuttings or drilling fluid in the borehole annulus flowing back in the drill pipe. Sometimes hydrocarbons, cuttings, or other items/debris from the borehole may flow back into the drill pipe and plug the drill pipe, bit nozzles, or the non-return valve. Backflow could also occur when retrieving tools from downhole. Backflow should gradually decrease as the pressure differential equalizes.

At deep water locations an uncontrolled hydrocarbon “kick” or flow may not be visible from the ship due to the gas mixing with the sea water and the currents moving it from the vessel and dispersing the gas. Some indications that the vessel is experiencing a gas kick are listed below. Additionally, some subsea systems, like underwater cameras or sonar could be used to check for gas flow at the sea floor.

- drop in standpipe pressure
- fluctuation of pump pressures
- packing off of the annulus
- sudden increase in the rate of penetration
- change in bit torque
- reduction in bit weight/string weight
- appearance of gas on the surface of the sea or through drill pipe
- other borehole issues

Some general precautions that could be taken are:

- Keep the mud valve shut whenever possible.
- Keep the drill string full of mud when lowering and retrieving wireline tools.
- Pull wireline tools and drill pipe slowly.
- Maintain the maximum hydrostatic head at all times.
- Ensure that "shut in" mud pressure is at zero before exposing pipe bore to atmosphere.
- Ensure that the drill string bore maintains a pressure on the formation which is slightly higher than that exerted by natural in situ forces which create formation pressure
- Have a tank of kill weight mud mixed and available at all times in case a gas encounter occurs.
- If needed advance the borehole core-by-core and reassess whether to continue the borehole after each core has been recovered.
- Consider drilling a pilot hole near the proposed location before beginning the borehole for gas hydrate sampling.

When drilling within a suspected gas horizon:

- Pump a slug of heavy mud into the borehole equal to the fluid volume of the borehole prior to venting pipe bore to atmosphere.
- No burning or welding should be undertaken while drilling is in progress.
- In an emergency, should burning or welding be necessary within this zone, the drilling must be stopped and a careful gas check carried out prior to and during the operation.

If a gas kick occurs, the shallow gas procedure and plan must be invoked. A copy of the plan should be included in the project execution plan or the contractor’s safety management system. Kill weight mud should be used to control the gas flow. Cement will not set when gas is flowing, so if it is decided that the borehole needs to be abandoned and there is time, the first step is to control the flow with heavy drilling mud and then slug the borehole with cement to seal it. If it is a major flow and it is decided that the crew or vessel is at risk the Vessel Master should move the vessel up wind off of DP before the drill crew attempts to recover the drill string.

11.2.9 Drilling, Sampling and Sample Handling

The drilling, sampling and sample handling process is unique to hydrate boreholes and samples so special tools and processes should be used. Good communication is needed between all involved in the program.

Sample expansion is a risk associated with taking samples for hydrate investigations. Methane hydrates, for example, could expand up to 160 times their in-situ volume when the solid hydrate changes to a gaseous state. The gas hydrate, in a gaseous state, expands as the pressure applied to the sample decreases or the sample temperature increases. The sample expansion usually occurs with non-pressurize sampling systems. The core may expand and cause either core extrusion or expulsion on the drill floor or during the handling and testing process.

Care needs to be taken to avoid backlash and explosive core expulsion from the top of the piston coring system when the quick release connection between the upper and lower core barrels is released. At times the piston head may form a seal with the core liner and prevent the pressure inside the core liner from dissipating. Previous experience working with hydrate coring samples have led to the following suggestions:

1. Secure the core barrel assembly vertically to a piece of equipment or item on deck that is permanently or securely attached to the vessel and won't move or allow the core barrel assembly to move.

2. Use a large barrel to cover the top of the core barrel. The large barrel would keep any soil/debris from being explosively ejected into the working area.

3. Use a rope to perform the last rotation or release of the breach-lock quick release assembly. The use of rope would allow the drill floor personnel to maintain a safe distance until the pressure inside the core barrel has safety vented.

Once the pressure has been vented from inside the core barrel, a risk still exists of the core liners splitting or bursting with certain sampling systems. Proper PPE, especially eye wear, should be worn at all times when handling hydrate soil samples. Also, when transporting samples do not carry them at neck or shoulder height, instead carry the samples at hip-height. The sample handling area should be monitored for gas concentration and the crew handling the samples should have training in handling samples with H_2S and should use the appropriate PPE.

The crew working on the drill floor and handling the samples should always monitor the samples for indications of gas pressure increasing in the liners.

- The core sample may extrude itself out of the core liner. Pressure relief holes may be drilled into the core liner, approximately 1/8-inch in diameter while extracting the core liner to assist in relieving the built up pressure.

- Water or gas may blow out of the shoe threads or the inner core barrel spacer sub when they are being removed from the inner core barrel. The inner core barrel can be secured to a rig floor support post or similar item to allow the gas to vent while the shoe is removed. A barrier, such as wood, should be placed in front of the shoe and all non-essential personnel should be moved from the area. There have been some instances of the core shoe being released suddenly and the shoes have become projectiles.
- One of the drill floor tuggers may need to be used to remove the core liner from the inner core barrel if there has been expansion due to gas, accumulation of sand or other granular material on the outside of the core liner, liner damage or over-compaction of the sample with lateral expansion occurring. The crew may also try turning the liner to free it.
- Imperfections may be noticed in some core liners. Before beginning the campaign, the liners should be checked to insure they have not become brittle with age or otherwise damaged.
- Personnel may observe soil, fluid or gas moving in the liner. The soils containing gas may have a frothy or spongy look. Additionally, gas voids may be observed through the liner. If observations such as these are made caution should be used when handling and processing the sample.
- Special precautions should be taken with "gassy cores". These should be documented in the sampling handling procedures.

It is important that all crewmember follow the established safety procedures for the campaign. If an improvement to the existing process is found, the crew should follow the established procedure for updating the TRA, policy, procedure, etc. The laboratory and drill crew should work together to make sure the timing of drilling, sampling and sample processing works for all. Avoid having samples on deck while waiting for the laboratory crew to finish processing the previous sample. The sample handling personnel should work as efficiently as possible and minimize the amount of time between retrieval and processing, while adhering to the safety procedures. All required safety signs should be posted in easily visible locations and loudspeaker announcements made, as needed. Personnel not involved in the drilling or sample handling operations should not congregate near the drill floor or processing area. Only those involved with the operations should be in the immediate area. The drill crew and bridge crew should work together to try to keep the wind blowing across the drill floor, allowing for better ventilation of the working area.

11.2.10 Safety Equipment

All personnel should use the required PPE at all times and follow the established procedures. If any of the PPE is damaged it should be promptly reported to the supervisor and replaced. Damaged safety equipment should be destroyed and discarded so it won't be re-used. Additional safety equipment is needed for those involved in the core handling. Examples include: hard hats with face shields, Kevlar penetration resistant gloves, towels, blankets, arm protection and aprons.

11.2.11 Hydrogen Sulfide (H_2S)

Hydrogen sulfide (H_2S) precautions should be taken during the gas hydrates campaign. These precautions should be documented in the project execution plan and the contractor's H_2S and shallow gas policy. This includes proper training, well ventilated work areas, proper PPE available for the crew, as well as procedures to: quickly degas cores on the open deck, monitor the gas concentrations at multiple locations, such as the drill floor and sample handling areas, halt work and muster the crew as needed.

11.2.12 Weather Conditions

The weather and sea state conditions should be constantly monitored by the crew. Weather reports should be received from a weather forecasting agency and reviewed by the area supervisors. If bad weather is expected the supervisors should meet and evaluate halting work and set criteria for when work would be halted. If weather conditions make it dangerous to continue working, the operations should be stopped until the conditions improve.

11.2.13 Shipboard Emergency

Drilling operations may need to be suspended in the event of a shipboard emergency, such as fire, man-overboard, etc. In the event that drilling activities need to be suspended the driller should stop as soon as it is safe to do so and wait for further instructions from the Vessel Master. Some situations may require that the crew muster. The Vessel Master would issue all instructions regarding shipboard emergencies and would determine when it is safe for the crew to resume their prior activities.

11.2.14 Closing

A document from ODP, “Safety and Operating Guidelines for Hydrate Drilling and Coring Operations is included in the appendices. The document has some good reference information, however most hydrate expeditions outside of ODP/IODP have not adhered to the strict guidelines for C_1/C_2 ratio cut offs. Although, the document referenced above is mainly based on operations from the JOIDES Resolution, the principles apply to any vessel performing this type of work.

12. OPERATIONS

The intent of the defined future GOM coring expedition would be to create a better understanding of the nature of hydrate occurrences in a sand-dominated system in the GOM as well as the impact of methane hydrates on safety, seafloor stability, and to provide data that could be used by scientists and engineers in their study of climate change and assessment of the feasibility of marine hydrate as a potential future energy resource.

The primary objective of the expedition is to obtain pressurized and non-pressurized cores (mostly pressure coring) and to perform in-situ measurements and formation testing of the hydrate-bearing sand reservoirs discovered during JIP Leg II at the Green Canyon Block 955 (GC955) and Walker Ridge Block 313 (WR313) sites.

To meet these objectives it is proposed to acquire well-preserved cores and test the hydrate-bearing sediments or hydrates in something closer to their natural state, which is essential for characterization of naturally occurring gas hydrate deposits or for investigation of the nature of hydrate occurrences in a sand-dominated system in the GOM.

Based on prior experience and lessons learned from the various gas hydrate research programs, comprehensive, detailed project planning is considered to be a critical element to effectively execute a drilling, coring, logging and testing program. The planning will comprise all documents such as: the Deepwater Operations Plan (DWOP); Hazard Identification (HAZID) assessment; drilling permits; hazard site reviews; and special engineering studies needed to execute the drilling and coring plan. Therefore, a well-planned and detailed project execution plan (PEP) should be created to guide both project execution and project control. The primary uses of the PEP are to document planning assumptions and decisions, facilitate communication among scientists and engineers in the field, and document approved scope, cost, and schedule baselines. Some elements for consideration in a PEP for the proposed pressure coring expedition are summarized below. An example of a full Project Execution Plan (PEP) is provided in the appendices.

The operations plan for this expedition should be based on formations and depths inferred from seismic and geological interpretations combined with data from previous Gulf of Mexico JIP Leg I and Leg II drilling operations at the WR313 and GC955 sites. The primary objective is to conduct operations in close proximity to the previously conducted borehole WR313-G, WR313-H, and GC955 locations from the GOM JIP Leg II Expedition.

In riserless drilling, maintaining borehole stability is a constant challenge. As mentioned in Section 8 above, the process of drilling the Gulf of Mexico JIP Leg II wells provided new insights into the optimal drilling strategies for marine “open-hole” drilling (riserless drilling) programs without surface conductors or drilling fluid returns. Drilling operations during GOM JIP Leg II were marked by the constant challenge of optimizing data quality while maintaining borehole stability, which was difficult to achieve within the shallow unconsolidated sediments. Seawater was exclusively used with periodic gel sweeps as needed. This plan was altered in the field to include the use of regular drilling mud, upon the observation that inefficient cuttings removal during the drilling of the first well (WR313-G) resulted in necessary back-reaming that eroded the hole, thereby compromising the quality of some of the LWD data. Throughout the remainder JIP Leg II, mud circulation was utilized prior to the onset of hole-packing or pipe-sticking issues, commonly at about 600 mbsf, resulting in substantially improved data quality. This mud circulation plan should be adopted for the proposed expedition together with careful control of drilling-fluid temperatures to mitigate the risks related to methane-hydrate dissociation during drilling (reviewed in Ruppel et al., 2008).

12.1 Drill Plan

Considerable effort should be committed to the development of a drill plan that would deliver a safe and efficient coring program. This drill plan should be part of the PEP. Before mobilization, a sea trial should be conducted to test drilling and coring equipment and to measure the vessel's performance. A kick-off meeting should be conducted with all science parties in the project team to review the drill plan, proposed drilling sites, drilling, coring and analysis tools.

12.2 Operations Communication

Operational reporting should be regular and constant; there should be direct lines of communication from field operations to onshore operational support staff, as well as communication to suppliers and in some cases to project stakeholders. The formal operational communication could follow the sample communication plan described in Table 12.1 and the protocols described in the preceding section.

Table 12.1 Communication Protocol

* E = Email, L = Letter (hardcopy), R = Report (can be electronic and/or hardcopy), F= Form, M = Meeting or Workshop ** D = Daily, W = Weekly, M = Monthly, Ps = Defined on Project Schedule, A = Ad-hoc						
ID	**Communication**	**Objective**	**Originator**	**Distribution**	**Medium***	**Frequency****
1	Daily Progress Report (DPR)	To provide the Project Team with a daily progress update for each of the field Work Elements. DPR to include a breakdown of the survey activities, production summary, weather conditions experienced and forecast, HSE summary and details of additional chargeable items.	Offshore Manager	CLIENT: Project Director, Project Manager DRILLING CONTRACTORS: Project Director, Project Managers HSE: OTHERS:	R	D
2	Contract Modification (Variation Order)	To provide the client with details of any requested contractual variation, the schedule for undertaking the variation and its cost.	Project Manager	CLIENT: OTHERS:	F	A

3	Management of Change	To provide the Project Team with details of any required changes to the project plan, the description and justification for the change, any HSE implications (positive or negative) and changes to the project risk profile (positive or negative). If the change has a contractual implication a Variation Order shall also be raised.	Project Manager	CLIENT: OTHERS:	R	A

12.2.1 Management of Change (MOC)

The PEP will describe the scope of work at time of publishing; however, through the project life cycle, the work scope may change based on circumstances.

Should a change of work scope or methodology be required, either generated upon Client request or as a result of other factors, the Project Manager as a minimum will revise and re-issue the project documentation if applicable and record the agreed changes using the Management of Change (MOC) form and/or a Variation Order (VO) which is attached to this PEP within the appendices.

Table 12.2 Management of Change

Stage		Activities
1	Identify	All project personnel to review project documentation (PEP, contract, scope of work and technical specifications) prior to commencement of field operations. Project documentation to be reviewed during the course of the project for non-conformities/omissions.
2	Define	Any change deemed to be required will be communicated to the Project Manager by completing a Management of Change form.
3	Discuss	MOC Form to be reviewed by Project Manager against project documentation (contract etc.) to ensure its validity. MOC Form to be issued to client group for review.
4	Agree Response	Client to approve MOC / VO Form following discussions with Project Manager.
5	Confirm Modification	Project Manager to communicate the change via the appropriate channels.

A daily meeting should be held onboard at which the coring program for the day would be discussed with relevant project personnel; the Client Representatives together with the OM, Master, Coring Lead Scientist, Drilling Supervisor and Toolpusher and Safety Officer. Any new HSE issues that would have been raised during the previous 24 hours would also be reviewed.

All personnel onboard the vessel, have a mandated responsibility to suspend operations if they are perceived to be unsafe,. With regard to safety of personnel, data quality and equipment safety or performance, the Offshore Manager, in consultation with the Vessel Master and Client Representative, will be ultimately responsible for decisions relating to the suspension of geotechnical operations and when to recommence. The Vessel Master will have ultimate authority on any activities that may affect the safety or operation of the vessel and related aspects.

12.3 Core Sampling

The main objective of the proposed expedition is to establish a Pressure Coring and Pressure Core Analysis program to "ground truth" the findings from JIP II work. The coring strategy is developed to best meet the objective and be consistent with that objective of the project team at DOE/NETL. The boreholes at WR313-G, WR313-H and GC955-H would be drilled to retrieve P-cores using a PTCB tool. Based on the proposed coring programs, the first P-core sample would be retrieved just above the interval of fracture filling gas hydrate at ~248 mbsf in borehole WR313-G, ~180 mbsf in borehole WR313-H, and ~192 mbsf in borehole GC955-H. The proposed P-core sampling intervals are developed based on the LWD logs at each borehole location. These proposed pressure coring programs are described in more details in Sections 6 and 13.

However, use of the non-pressure coring tools including Fugro Hydraulic Piston Corer (FHPC), Fugro Corer (FC), Fugro Marine Core Barrel (FMCB), Fugro Extended Marine Core Barrel (FXMCB) is recommended to obtain non-pressurized cores (C-cores) periodically in the drilling intervals that are not cored (0- to 248 mbsf, 0- to 180 mbsf, and 0- 192 mbsf), respectively, in boreholes WR313-G, WR313-H, and GC955-H. Samples of C-cores would be taken for pore water analysis. Pore water salinity and chlorinity would be measured to gauge the extend of pore water freshening due to hydrate dissociation. These measurements would be used to establish the salinity and chlorinity baselines at the core depth in quantification of gas hydrate in the C-core. Thus, the hydrate quantification could be extended to cover for the entire cored intervals.

Sampling of cores will include whole-round and discrete sampling following traditional IODP sample policies. Basic shipboard sampling, community samples, and individual sample requests will be coordinated by the Sample Allocation Committee (SAC) and exact numbers and location of samples will be based on core recovery.

12.3.1 Core & Sample Nomenclature & Curation

Cores should be named in International Ocean Drilling Program (IODP) style: Expedition-Site/Hole-Core/Type. Example: JIP3-WR313B-3A, where the Expedition is JIP3, the Site is WR313, the Hole is B, the Core is 3, and the Core Type is A. The boreholes are lettered using the English alphabet, starting over from A at each site. Cores & tests are numbered sequentially from the top of each hole, regardless of core type. Types of cores & tests are designated as FHPC (H), FMCB (M), FXMCB (X), FPC (P), PCTB (A), Temperature Probe/Cone Penetrometer (T), and Cone Penetrometer/Piezoprobe (Z).

Cores would be cut into sections where no single piece was longer than 1.00 m. Sections are named 1, 2, 3, etc. starting from the top. If a section is cut into multiple pieces, each piece should be named a, b, c, etc. from the top of the section (e.g., pieces 2a, 2b, 2c, 3a, 3b). A white adhesive label with the full name of the core section/piece, the interval, and the depth of the top of core should be placed at the top of each core section or piece. A blue end cap should be placed at the top of the core section/piece and a clear endcap at the bottom of the section/piece. A missing piece from a section should be indicated by a large yellow dot on the endcap of the adjacent piece or pieces within the section.

12.3.2 Preservation of Gas Hydrate Samples

In warm water near the sea surface and on board, methane hydrates could start dissociating. To prevent this, all operations have to be fast, and recovered cores should immediately be submerged in ice water to cool them. On the drill floor, a mouse hole could be filled with ice water and used as a vertical ice bath. After the cool down in ice water, the core inner barrel can be disassembled.

Samples of gas-hydrate-bearing sediment could be stored in pressurized storage chambers (e.g., the Effective Stress Chamber (ESC) or preserved in liquid nitrogen for onshore analysis. The ESC maintains P-T stability conditions and restores the effective stress that the sediment sustains in situ. Pressure cores can be recovered and stored in the ESC at fluid P-T conditions needed to preserve hydrate.

Samples from the C-cores (FHPC, FMCB, or FC) should be rapidly cut, following the infrared thermal scan. These samples would be wrapped in aluminum foil, placed in Tyvek sample bags, and submerged in liquid nitrogen to rapidly freeze the samples.

12.4 Core Processing Procedures

For the P-core process, cores should be cut into shorter subsamples under pressure and then moved into 1.5 m or 0.3 m core storage chambers without depressurizing them. Subsampling options should be determined based on CT images. Some samples in the short storage chamber could be quickly depressurized in ice water and place into liquid nitrogen to minimize hydrate dissociation. Although liquid-nitrogen treatment may disturb microstructure of sediments, these cryofrozen samples in which gas hydrates are stable under atmospheric pressure are valuable for precise laboratory works that need well-shaped specimens such as permeability or mechanical strength measurement, because the samples could be trimmed and shaped minutely. Moreover, some short samples could be sent to PCCT and PCATS-triaxial test chamber (Holland et al., 2011 and Priest et al., 2015) to obtain elasticity and strength properties under in situ hydrostatic pressure conditions. The samples collected and stored on board should be kept in a refrigerated container under pressure, and transferred to an onshore laboratory for more detailed analyses.

All P-cores (pressure cores) would be quantitatively degassed using the Controlled Depressurization Chamber (CDC). This would allow the measurement of total gas per core, and a calculation of gas hydrate within each core and help preserve the core lithology and to gain valuable in-formation during depressurization, with minimal demand on personnel resources. After depressurization, these cores would be treated as C-cores: X-rays and geophysical logs were collected on each.

Prior to any whole-round or discrete sampling of cores, all C-cores (conventional cores) should be geophysically logged using a variety of core logging equipment (Multi Sensor Core Loggers - MSCLs) which included infrared scanning to look for early signs of gas hydrate dissociation. Other core logging on whole cores include a full suite of geophysical parameters as well as X-ray imaging. After nondestructive logging, non-time-sensitive whole-round samples would be taken as approved by the Co-Chief Scientists. Cores would then be split into a "working half" and "archive half" with the working half being available for sampling by shipboard and shore-based scientists. The archive half would preserve retrieved material while providing flexibility and broader access to important material post expedition.

Both C-cores and P-cores would be subjected to a suite of geochemical tests. This would consist of collecting gas and sediment porewater samples for compositional analysis and performing onboard analyses. Gases would be analyzed for air components and light hydrocarbons. Porewater samples would be analyzed for major and minor cations and major anions. The gas compositions and porewater analyses would allow calculation of gas hydrate concentration from depressurized core samples.

12.5 In Situ Testing

The in situ temperature profile would be determined from temperature measurements using the Wison EP temperature/cone penetrometer probe, which also provided sediment strength measurements. The in situ temperature data would provide valuable information about the base of gas hydrate stability and active hydrocarbon seepage. The Wison EP piezoprobe could be utilized to measure excess pore pressure and to determine the dissipation characteristics of the sub-soils. In addition, results from the tests could be used to estimate the in-situ permeability and consolidation characteristics of the soil.

In addition to the pressure coring and non-pressure coring programs, a suite of downhole in situ testing tools and advanced laboratory measurements could be employed to measure in situ pore pressure and temperature, to determine strength and index properties of hydrate-bearing sediments, and to estimate in situ concentration of methane and other gas compositions, etc. They could also be used to investigate physical properties of hydrate-bearing sediment. A detailed description of these in situ testing tool and advanced laboratory measurements are provided in the appendix.

13. RECOMMENDATIONS FOR A SPECIFIC PROGRAM

13.1 Science Objectives

We understand from the project team at DOE/NETL that many of the science objectives for prediction of hydrate occurrence based on a "Petroleum Systems Approach" have been met during the successful JIP II Program in 2009. If fact, based on the title of this Funding Opportunity for which this report has been prepared, the main objective here is to establish a Pressure Coring and Pressure Core Analysis program to "ground truth" the findings from JIP II work. Consistent with that objective, the outlined plan is meant to collect an adequate amount of PC's to provide a scientific correlation between the gas hydrate saturations and occurrence intervals based on LWD data versus pressure coring. Pressure coring has become the "Gold Standard" for determination of gas hydrate presence, saturation and habitat.

13.2 Coring Program

In preparation of this report, we have evaluated the results from available seismic data and the LWD program conducted from the Q4000 for the JIP II expedition. Based on the results of that expedition and the logs collected, we have designed a pressure coring program that is recommended for the next DOE/NETL sponsored expedition. Tables are contained in Section 5 for specific P-cores programs at WR313-G and H, as well as GC955-H. These tables are included here again for reference:

Sampling Proposal: Borehole WR313-G

Pilot Hole Information:

Hole name: WR313-G

Water depth: 6,614 ft. below the rig floor

Total depth: 3,584 ft. BML

Target zones:

1. A hydrate bearing fracture zone is interpreted between 815 and 1,300 ft. (248 and 396 m), BML.
2. A hydrate bearing sand zone is interpreted between 2,725 and 2,745 ft. (831 and 837 m), BML.
3. A hydrate bearing sandy zone is interpreted between 2,805 and 2,860 ft. (855 and 872 m), BML.

Event	Depth, [m, BML]		LWD Interpretation		Corer	Estimated Time(hrs.)	Remarks*
No	From	To	Lithology	S_h			
					RIH	8.1	250m/hr.
1	0	248	Clay		Drill	9.9	25m/hr.
1	248	251	Clay	0.01	PCTB	4.5	Hydrate
3	262	265	Clay	0.12	PCTB	4.5	Hydrate
4	273	276	Clay	0.26	PCTB	4.5	Hydrate
5	284	287	Clay	0.19	PCTB	4.5	Hydrate
6	296	299	Clay	0.23	PCTB	4.5	Hydrate
7	307	310	Clay	0.22	PCTB	4.5	Hydrate
8	319	322	Clay	0.25	PCTB	4.5	Hydrate

9	332	335	Clay	0.32	PCTB	4.5	Hydrate
10	342	345	Clay	0.24	PCTB	4.5	Hydrate
11	356	359	Clay	0.12	PCTB	4.5	Hydrate
12	368	371	Clay	0.12	PCTB	4.5	Hydrate
13	379	382	Clay	0.06	PCTB	4.5	Hydrate
14	390	393	Clay	0.06	PCTB	4.5	Hydrate
15	393	831			Drill	43.8	10m/hr.
16	831	834	Sand	0.45	PCTB	4.5	Hydrate
17	834	837	Sand	0.24	PCTB	4.5	Hydrate
18	837	855			Drill	0.72	25m/hr.
19	855	858	Sand	0.43	PCTB	4.5	Hydrate
20	858	861	Sand	0.50	PCTB	4.5	Hydrate
21	861	864	Sand	0.67	PCTB	4.5	Hydrate
22	864	867	Sand	0.45	PCTB	4.5	Hydrate
23	867	870	Sand	0.38	PCTB	4.5	Hydrate
23	870	873	Sand	0.31	PCTB	4.5	Hydrate
	EOH	EOH			POOH	11.6	250m/hr.
				Total est. coring length			63 m
				Total est. coring time			168.6 hrs. (7.0

Sampling Proposal: Borehole WR313-H

Pilot Hole Information:

Hole name: WR313-H

Water depth: 6,501 ft. (1982 m), below the rig floor

Total depth: 2,685 ft. (819 m), BML

Target zones:
1. A hydrate bearing fracture zone is interpreted between 590 and 1,030 ft. (180 and 314 m), BML.
2. A hydrate bearing sand zone is interpreted between 2,644 and 2,656 ft. (806 and 810 m), BML.
3. A hydrate bearing sandy zone is interpreted between 2,663 and 2,685 ft. (812 and 819 m), BML.

Event	Depth, [m, BML]		LWD Interpretation		Corer	Estimated Time (hrs.)	Remarks*
No	From	To	Lithology	S_h			
					RIH	7.9	250m/hr.
1	0	180	Clay		Drill	6.0	30m/hr.
1	180	183	Clay	0.04	PCTB	4.5	Hydrate bearing fracture
3	191	194	Clay	0.05	PCTB	4.5	Hydrate bearing fracture
4	202	205	Clay	0.11	PCTB	4.5	Hydrate bearing fracture
5	213	216	Clay	0.12	PCTB	4.5	Hydrate bearing fracture
6	224	227	Clay	0.11	PCTB	4.5	Hydrate bearing fracture

7	235	238	Clay	0.22	PCTB	4.5	Hydrate bearing fracture
8	246	249	Clay	0.28	PCTB	4.5	Hydrate bearing fracture
9	257	260	Clay	0.31	PCTB	4.5	Hydrate bearing fracture
10	268	271	Clay	0.24	PCTB	4.5	Hydrate bearing fracture
11	279	282	Clay	0.05	PCTB	4.5	Hydrate bearing fracture
12	290	293	Clay	0.01	PCTB	4.5	Hydrate bearing fracture
13	301	304	Clay	0.08	PCTB	4.5	Hydrate bearing fracture
14	312	315	Clay	0.10	PCTB	4.5	Hydrate bearing fracture
15	314	806			Drill	49.1	10m/hr.
16	806	809	Sand	0.13	PCTB	4.5	Hydrate bearing sand
17	809	812	Sand	0.74	PCTB	4.5	Hydrate bearing sand
18	812	815	Sand	0.45	PCTB	4.5	Hydrate bearing sand
19	815	818	Sand	0.42	PCTB	4.5	Hydrate bearing sand
20	818	821	Sand	0.71	PCTB	4.5	Hydrate bearing sand
21	821	824	Sand	0.30	PCTB	4.5	Hydrate bearing sand
	EOH	EOH			POOH	11.2	250m/hr.
				Total est. coring length			57 m
				Total est. coring time			159.7 hrs. (6.7 days)

Sampling Proposal: Borehole GC955-H

Pilot Hole Information:

Hole name: GC955-H

Water depth: 6,721 ft. below the rig floor

Total depth: 1,936 ft. BML

Target zones:

1. A hydrate bearing fracture zone is interpreted between 630 and 960 ft. (192 and 293 m), BML.
2. A hydrate bearing fracture zone is interpreted between 1,115 and 1,142 ft. (340 and 348 m), BML.
3. A hydrate bearing sand zone is interpreted between 1,348 and 1,445 ft. (411 and 441 m), BML.
4. A hydrate bearing sandy zone is interpreted between 1,460 and 1,468 ft. (445 and 448 m), BML.

Event	Depth, [m, BML]		LWD Interpretation		Corer	Estimated Time(hrs.)	Remarks*
No	From	To	Lithology	S_h			
					RIH	8.1	250m/hr.
	0	192	Clay		Drill	6.4	30m/hr.
1	192	195	Clay	0.37	PCTB	4.5	Hydrate bearing fracture
2	205	208	Clay	0.45	PCTB	4.5	Hydrate bearing fracture
3	218	221	Clay	0.22	PCTB	4.5	Hydrate bearing fracture
4	231	234	Clay	0.2	PCTB	4.5	Hydrate bearing fracture

5	244	247	Clay	0.49	PCTB	4.5	Hydrate bearing fracture
6	257	260	Clay	0.27	PCTB	4.5	Hydrate bearing fracture
7	268	271	Clay	0.41	PCTB	4.5	Hydrate bearing fracture
8	281	284	Clay	0.36	PCTB	4.5	Hydrate bearing fracture
9	290	293	Clay	0.14	PCTB	4.5	Hydrate bearing fracture
		340	Clay		Drill	1.9	25m/hr.
10	340	343	Clay	0.36	PCTB	4.5	Hydrate bearing fracture
11	343	346	Clay	0.28	PCTB	4.5	Hydrate bearing fracture
12	346	349	Clay	0.21	PCTB	4.5	Hydrate bearing fracture
		411	Clay		Drill	3.1	20m/hr.
13	411	414	Sand	0.7	PCTB	4.5	Hydrate bearing sand
14	414	417	Sand	0.68	PCTB	4.5	Hydrate bearing sand
15	417	420	Sand	0.64	PCTB	4.5	Hydrate bearing sand
16	420	423	Sand	0.66	PCTB	4.5	Hydrate bearing sand
17	423	426	Sand	0.73	PCTB	4.5	Hydrate bearing sand
18	426	429	Sand	0.71	PCTB	4.5	Hydrate bearing sand
19	429	432	Sand	0.69	PCTB	4.5	Hydrate bearing sand
20	432	435	Sand	0.75	PCTB	4.5	Hydrate bearing sand
21	435	438	Sand	0.11	PCTB	4.5	Hydrate bearing sand
22	441	444	Sand	0.46	PCTB	4.5	Hydrate bearing sand
23	444	447	Sand	0.08	PCTB	4.5	Hydrate bearing sand
	EOH	EOH			POOH	11.6	250m/hr.
				Total est. coring length			69 m
				Total est. coring time			134.6 hrs. (5.6 days)

Notes:

1. S_h - Hydrate Saturation Estimate (% of pore space)
2. * Time estimate assumes lower bound estimate for pipe tripping (i.e., pulling double joints)
3. A total of approximately one (1) day could be gained on the 3-BH Program outlined using a vessel with faster trip times (e.g. running and pulling triple joints instead of double joints)

This program of three boreholes is for Pressure Coring ONLY. However, it is recommended to consider the addition of periodic in situ temperature (T) measurements at least every 15 m or so in the various boreholes. It would not be necessary to perform T measurements (to the full depth) in both the WR313 BH's provided consistent results are obtained between the first BH with T measurements and after a quick check for similar results in the second BH. Temperature measurements should be made approximately every 15 to 30 m for the GC955-H site. These temperature measurements should be checked against calculations for GHSZ based on Type I hydrate. We know that based on the study of the seismic data and the results of the well logs, it is likely that the base of GHSZ would be driven deeper due to the probable presence of thermogenic gas. In any event, good in situ measurements of T would be important for future production test planning and design and should be included as part of the program.

Additionally, it is recommended to intersperse some C-cores (non-pressurized) coring as a substitute for some PC's. By substituting C-cores, this would speed up the overall operation and potentially reduce costs. NP cores would also help to establish background salinity and chlorinity levels in areas lacking hydrates (as interpreted from the well logs). Back-to-back PC's using PCTB as suggested in the tables would require a large number of autoclaves to be made available onboard. It would also mean that some of the PC logging would likely need to occur post-cruise in the interest of vessel time and cost in which case, more storage chambers would be needed so that the PC's could be stored after an initial view in PCCTs. Ample time would need to be allocated for the manufacture of additional autoclave sections and storage chambers.

13.3 Core Analyses Recommendations

Pressure Core Characterization Tool (PCCT) and the Pressure Core Analysis and Transfer System (PCATS) would be the system of choice for the PC's collected. The PCCT deployment may include IPTC, ESC, DSC, CDC and BIO tools. This would allow the cores to be subsampled and stored in pressurized storage chambers for later shore base analyses. The subsamples could be subjected to various analyses and measurements without first depressurizing the cores. This would provide valuable data including density, P-wave velocities and precision x-rays on collected cores, measurements of physical properties, including stiffness (wave velocities), thermal conductivity, and electrical resistivity. Additionally, depressurization/degassing experiments could be performed utilizing the Controlled Depressurization Chamber (CDC). For example, the CDC is designed to help preserve the core lithology and to gain valuable information during depressurization, with minimal demand on personnel resources. The IPTC is developed to sample fluids and to measure P- and S-wave velocities, undrained shear strength, electrical conductivity, and internal core temperature, the ESC is developed for consolidation parameters, the DSC is allowing both peak and residual shear strengths to be determined, etc. As a minimum, PCATS would be required in the field and if deck and bunk space is sufficient, then PCATS Triaxial and PCCTs should also be incorporated onboard for the expedition.

IPTC has been used successfully on three hydrate expeditions, JIP I (2005), NGHP1 (2006) and KNOC2 (2010). For JIP I it was used onboard the Uncle John, however in the other two expeditions, the work with IPTC was performed post expedition. We recommend that the IPTC be used post cruise in this expedition.

The benefits of doing core analyses onboard should be weighed against the option of performing them onshore. The objective of this exercise is to balance the benefits of obtaining information offshore that could be used to make informed decisions about the remaining coring program versus the availability of the required lab and bunk space. There are certain tests and analyses that must be performed onboard to avoid jeopardizing the results of the work. We recommend that basic geochemistry including salinity, chlorinity and alkalinity analysis be performed onboard as a minimum, the pros and cons of offshore versus onshore analyses is covered in greater detail in Sections 7.3.9 and 7.3.10.

We recommend that when the schedule for the fieldwork becomes more defined, availability of the various vessels outlined in this report should be evaluated. Additionally, the costs of the various options could be made. At this time, particularly with the downturn in the vessel market, we are unable to project potential costs for the various platforms presented.

13.4 Reporting

It would be important to document the fieldwork and post cruise activities. Typical field reporting, directly from the ship upon completion of the drilling and coring work includes: Driller's Logs; details of the bits, BHA's and mud program utilized; Core Technician Sheets with various observations such as firing pressures required, core recovery lists, pressure and temperature measurements; Ship's logs; ROV logs and videos; Chief Scientist(s) observations, etc. Final BH plans with indications of the type of coring tools utilized, recoveries and comments are extremely important. Finally, all shore-based analyses should be compiled together with the field report with recommendations for future work. We would expect that many technical papers would be generated from this planned expedition and welcome the opportunity to participate.

13.5 Post-project Review

A post-project review of successful and unsuccessful aspects, along with recommendation for future projects, should be included in any methane hydrate coring program.

14. SUMMARY

14.1 Conclusions

This document describes the basic strategy, procedures, and equipment necessary to conduct a methane hydrate pressure coring program, specifically with regard to the Walker Ridge and Green Canyon Areas of the Gulf of Mexico.

14.2 Recommendations

Methane hydrate pressure coring is a technologically challenging, and potentially dangerous, procedure that should be undertaken with a full understanding of the risks and complexities involved. This document outlines a basic procedure and describes the kinds of tests and evaluations that could be undertaken; however, it is not exhaustive and appropriate operational and technical expertise must be included in any program.

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APPENDICES

A. PERMITTING DOCUMENTS FROM BOEM

A.1 BOEM FORM 0327

A.2 BOEM FORM 0329

B. PROJECT EXECUTION PLAN

B.1 PROJECT EXECUTION PLAN Part A - OPERATIONAL PLAN

B.2 PROJECT EXECUTION PLAN Part B - QUALITY PLAN

B.3 PROJECT EXECUTION PLAN Part C – HEALTH, SAFETY, ENVIRONMENTAL PLAN

B.4 PROJECT EXECUTION PLAN Part D – EMERGENCY RESPONSE (ERP) PLAN

B.5 SAFETY AND OPERATING GUIDELINES

B.6 SHALLOW GAS PROCEDURES

C. SUMMARY OF PRIOR JIP LEG II SITE SELECTION, LWD LOGGING EXPEDITION AND RESULTS

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C.5 PERMITTING PROCESS

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D.2 EXPLORATORY SOIL BORINGS (DRILLING TECHNIQUES)

D.3 GEOTECHNICAL, GEOPHYSICAL AND GEOCHEMICAL LABORATORY TESTING

D.4 CONVENTIONAL LABORATORY TESTING

D.5 ADVANCED LABORATORY TESTING

A. PERMITTING DOCUMENTS FROM BOEM

A.1 BOEM FORM 0327

A.2 BOEM FORM 0329

OMB Control Number: 1010-0048
OMB Approval Expires: 0 2 / 2 8 / 1 8

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

(select one)

(Insert Appropriate Regional Office)

Requirements for Geological and Geophysical Explorations or Scientific Research on the Outer Continental Shelf

Application for Permit to Conduct Geological or Geophysical Exploration for Mineral Resources or Scientific Research on the Outer Continental Shelf

(Attachment 1)

Nonexclusive Use Agreement for Scientific Research on the Outer Continental Shelf

(Attachment 2)

SUBMIT: Two originals, one digital copy, and one public copy (all with original signatures).

Paperwork Reduction Act of 1995 (PRA) Statement: The PRA (44 U.S.C. 3501 *et seq*.) requires us to inform you that the Bureau of Ocean Energy Management (BOEM) collects this information to evaluate applications for permits to conduct pre-lease exploration offshore and to monitor activities of scientific research conducted under notices. BOEM uses the information to ensure there is no environmental degradation, personnel harm, damage to historical or cultural sites, or interference with other uses. Responses are mandatory or to obtain or retain a benefit. Proprietary information is protected in accordance with standards established by the Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1733), the Freedom of Information Act (5 U.S.C. 552(1), (4)), and Department regulations (43 CFR 2). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid Office of Management and Budget control number. The reporting burden for this form is estimated to average 300 hours per response in the Gulf of Mexico Region and 1,000 hours per response for applications in the Pacific, Alaska, and Atlantic OCS due to NEPA requirements. Much of the work to comply with NEPA requirements has already been done in the Gulf; however, for areas outside the Gulf, BOEM is accounting for the total time expended to compile and submit the necessary information to obtain the required authorizations to acquire a BOEM permit. This includes the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to the Information Collection Clearance Officer, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

REQUIREMENTS FOR GEOLOGICAL AND GEOPHYSICAL EXPLORATIONS OR SCIENTIFIC RESEARCH ON THE OUTER CONTINENTAL SHELF

Authority

You must perform all geological and geophysical explorations or scientific research activities authorized and conducted in the Outer Continental Shelf (OCS) according to the OCS Lands Act, 30 CFR Parts 551, 251, and other applicable Federal statutes and regulations, and amendments thereto.

General Requirements of Permits and Notices

You must conduct geological and geophysical activities for mineral exploration or scientific research activities authorized under 30 CFR Parts 551, 251, and in compliance with all applicable mitigation measures so that those activities do not:

A. Interfere with or endanger operations under any lease or right-of-way or permit issued or maintained pursuant to the OCS Lands Act;
B. Cause harm or damage to aquatic life or to the marine, coastal, or human environment;
C. Cause pollution;
D. Create hazardous or unsafe conditions;
E. Unreasonably interfere with or harm other uses of the area (including submarine cables); or
F. Disturb archaeological resources.

Any person conducting geological or geophysical activities for mineral exploration or scientific research under 30 CFR Parts 551 and 251 must immediately report to the Regional Director, BOEM:

A. Detection of hydrocarbon occurrences;
B. Encounters of environmental hazards that constitute an imminent threat to human activity; or
C. Activities that adversely affect the environment, aquatic life, archaeological resources, or other uses of the area in which the exploration or scientific research activities are conducted.

Any person conducting shallow or deep stratigraphic test drilling activities under a permit for mineral exploration or scientific research under 30 CFR Parts 551 and 251 must utilize the best available and safest technologies.

The authorization that BOEM grants you under 30 CFR Parts 551 and 251 to conduct geological and geophysical explorations for minerals or for scientific research does not confer a right to any discovered oil, gas, or other minerals, or to a lease under the OCS Lands Act.

Time Restriction for Permits and Notices

Permitted activities approved for a specified period, including requests for extensions, and activities under a notice may not exceed 1 year.

Geological and Geophysical Activities Requiring Permits and Notices

Geological and Geophysical Explorations for Mineral Resources

You may not conduct geological and geophysical explorations for mineral resources in the OCS without an approved permit unless you conduct such activities pursuant to a lease issued or maintained under the OCS Lands Act. You must obtain separate permits for either geological or geophysical explorations for mineral resources. If BOEM disapproves an application, the statement of rejection will state the reasons for the denial and will advise the applicant of those changes needed to obtain approval.

Geological and Geophysical Scientific Research

You may not conduct geological and geophysical scientific research related to oil, gas, and sulphur in the OCS without an approved application for permit or filing of a notice. You must obtain separate permits for geological and geophysical scientific research that involves the use of solid or liquid explosives or the drilling of a deep stratigraphic test. If BOEM disapproves an application for permit, the statement of rejection will state the reasons for the denial and will advise the applicant of the changes needed to obtain approval.

You must file a notice with the BOEM at least 30 days before you begin scientific research not requiring a permit. We may inform you of all environmental laws and regulations pertaining to the OCS. BOEM recommends that you submit your notice 90-120 days prior to beginning your work to ensure timely review of your notice by BOEM.

Information Required for Permits

Each applicant for a permit must complete the applicable sections of the Application for Permit (Attachment 1) and must include a public-information, page-size plat(s) showing the location of the proposed area of activity (Section B.2 or C.2 of Attachment 1). In addition, each applicant for a geological or geophysical permit must submit the appropriate attachment to section D of the Application. This includes a detailed map of the proposed activity for Section D.8 (Geological Application) or Section D.12 (Geophysical Application). Only applicants for a notice of scientific research must complete a Nonexclusive Use Agreement (Attachment 2).

The information provided on the Application for Permit (excluding section D) and on the Nonexclusive Use Agreement, including continuation sheets and the page-size plat(s), is considered NON-PROPRIETARY INFORMATION. These non-proprietary portions of the application constitute the “public information” copy of Form BOEM-0327 and with the executed permit will be available to the public upon request.

The information listed in Section D is considered PROPRIETARY INFORMATION and you should NOT attach it to the public information copy. BOEM will not make this information available to the public without the consent of the potential permittee or for a period mandated by law or regulation. However, BOEM may determine that earlier release is necessary for the proper development of the area permitted.

Modifications to Approved Permits

The BOEM Regional Supervisor must approve any modification to the permitted operations.

Filing Locations for Permits to Conduct Explorations for Mineral Resources and for Permits or Notices to Conduct Scientific Research

File two originals, one digital copy, and one public copy (all with original signatures) at the following locations at least 30 days before you begin operations. BOEM recommends that you submit your notice or application 90-120 days prior to beginning your work to ensure timely review of your notice by BOEM.

A. For the OCS off the State of Alaska:

Regional Supervisor for Resource Evaluation
Bureau of Ocean Energy Management
Alaska OCS Region
3801 Centerpoint Drive
Suite #500
Anchorage, Alaska 99503-5823

B. For the OCS in the Gulf of Mexico and off the Atlantic Coast:

Regional Supervisor for Resource Evaluation
Bureau of Ocean Energy Management
Gulf of Mexico OCS Region
1201 Elmwood Park Boulevard
New Orleans, Louisiana 70123-2394

C. For the OCS off the States of California, Oregon, Washington, or Hawaii:

Regional Supervisor, Office of Strategic Resources
Bureau of Ocean Energy Management
Pacific OCS Region
760 Paseo Camarillo
Suite #102
Camarillo, California 93010-6092

Attachment 1

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

(select one)
____
(Insert Appropriate Regional Office)

APPLICATION FOR PERMIT TO CONDUCT GEOLOGICAL OR GEOPHYSICAL EXPLORATION FOR MINERAL RESOURCES OR SCIENTIFIC RESEARCH ON THE OUTER CONTINENTAL SHELF

(Section 11, Outer Continental Shelf Lands Act of August 7, 1953, as amended on September 18, 1978, by Public Law 95-372, 92 Statute 629, 43 U.S.C. 1340; and 30 CFR Parts 551 and 251)

____
Name of Applicant

____
Number and Street

____
City, State, and Zip Code

Application is made for the following activity: (check one)

_______Geological exploration for mineral resources

_______Geological scientific research

_______Geophysical exploration for mineral resources

_______Geophysical scientific research

Submit: Original plus three copies, totaling four copies, which include one digital copy, and one public information copy.

===

To be completed by BOEM

Permit Number: ____________________ **Date:** ____________________

A. General Information

1. The activity will be conducted by:

______________________	For ______________________
Service Company Name	Purchaser(s) of the Data
______________________	______________________
Address	Address
______________________	______________________
City, State, Zip	City, State, Zip
______________________	______________________
Telephone/FAX Numbers	Telephone/FAX Numbers
______________________	______________________
E-Mail Address	E-Mail Address

2. The purpose of the activity is: __________ Mineral exploration

   __________ Scientific research

3. Describe your proposed survey activities (i.e., vessel use, benthic impacts, acoustic sources, etc.) and describe the environmental effects of the proposed activity, including potential adverse effects on marine life. Describe what steps are planned to minimize these adverse effects (mitigation measures). For example: 1) Potential Effect: Excessive sound level Mitigation; Soft Start, Protected Species Observers (PSO's), mammal exclusion zone or 2) Potential Effect: Bottom disturbance; Mitigation: ROV deployment/retrieval of bottom nodes) (use continuation sheets as necessary or provide a separate attachment):

   ____

   ____

4. The expected commencement date is: ______________________________

   The expected completion date is: ______________________________

5. The name of the individual(s) in charge of the field operation is:

   ____

   May be contacted at:

   ____

   Telephone (Local) ______________________ (Marine) ______________________

   Email Address: ______________________

6. The vessel(s) to be used in the operation is (are):

Vessel Name (s)	Registry Number(s)	Radio Call Sign(s)	Registered Owner(s)
____________________	_________________	_________________	_________________
____________________	_________________	_________________	_________________
____________________	_________________	_________________	_________________

7. The port from which the vessel(s) will operate is: ____

8. Briefly describe the navigation system (vessel navigation only):

____

____

B. Complete for Geological Exploration for Mineral Resources or Geological Scientific Research

1. The type of operation(s) to be employed is: (check one)

   a. ___________ Deep stratigraphic test, or

   b. ___________ Shallow stratigraphic test with proposed total depth of ____________, or

   c. ___________ Other ____

2. Attach a page-size plat showing: 1) The generalized proposed location for each test, where appropriate, a polygon enclosing the test sites may be used, 2) BOEM protraction areas; coastline; point of reference; 3) Distance and direction from a point of reference to area of Activity; 4) Label as "**Public Information**."

____

C. Complete for Geophysical Exploration for Mineral Resources or Geophysical Scientific Research

1. The proposed operation: ____
   a. Acquisition method (OBN, OBC, Streamer): ____________________________________
   b. Type of acquisition: (High Resolution Seismic, 2D Seismic, 3D Seismic, gravity, magnetic, CSEM, etc.)

   ____
   ____

2. Attach a page-size plat showing:
   a. The generalized proposed location of the activity with a representative polygon,
   b. BOEM protraction areas; coastline; point of reference,
   c. Distance and direction from a point of reference to area of activity, and
   d. Label as "**Public Information**."

3. List all energy source types to be used in the operation(s): (Air gun, air gun array(s), sub-bottom profiler, sparker, towed dipole, side scan sonar, etc.).

____

____

4. Explosive charges will ___ will not ____ be used. If applicable, indicate the type of Explosive and maximum charge size (in pounds) to be used:__________

Type ____________________ Pounds ____________ Equivalent Pounds of TNT ___________

D. Proprietary Information Attachments

Use the appropriate form on page 9 for a "geological" permit application or the form on page 11 for a "geophysical" permit application. You must submit a separate Form BOEM-0327 to apply for each geological or geophysical permit.

E. Certification

I hereby certify that foregoing and attached information are true and correct.

Print Name:_______________________________________

SIGNED _______________________________________ **DATE** ____________________

TITLE ____

COMPANY NAME: ____

===

TO BE COMPLETED BY BOEM

Permit No.__________________ **Assigned by** _____________________________ **Date** ________

of BOEM

This application is hereby:

a. _____ Accepted

b. _____ Returned for reasons in the attached

SIGNED __________________________ **TITLE** Regional Supervisor **DATE** _____________

Section D Proprietary Information Attachment
Required for an Application for Geological Permit

1. Description of proposed coring, drilling or sampling method. Include heat flow measurements and depth of penetration.
____
____

2. Description of coring, drilling or sampling equipment to be used:
____
____
____

3. List proposed coring, drilling or sample location(s) with their latitude and longitude coordinates and the total number of samples to be acquired. These locations may be sent digitally on a CD. (Attach separate page if necessary): ____
____

4. Navigation system or method to be used to position sample locations: ______________________
____
____

5. Method of sample storage, and handling: ____
____

6. List each test to be conducted on the samples with a brief description of its objective:
____
____
____

7. Estimated date on which samples, logs, and analyzed and/or processed data will be ready for inspection: ____

8. Attach map(s), plat(s), and chart(s) (preferably at a scale of 1:250,000) and/or an electronic version of same showing latitude and longitude, scale, protraction areas, specific block numbers, and specific sample location(s) in latitude(s) and longitude(s) for each of the proposed sample site(s). The map, plat or chart should be submitted at a sufficient size and scale to make out all details of the activities shown. Label the hardcopy map "**Proprietary**." Along with the hardcopy map, submit on CD, the ArcGIS shape files needed to reproduce the map of the proposed sample site(s) including individual site names in the attribute table.

Section D Proprietary Information Attachment
Required for an Application for Geophysical Permit

1. Attach detailed narrative, modeling of sound propagation, and description of the energy source(s) and streamer(s) (receiving array): ______________________

2. Attach a map view diagram that illustrates vessel(s) source and receiver(s) configuration. Label each vessel indicating its function and include the dimensions of streamer(s), tow fish, etc. Indicate the number of chase and alternate vessels to be used.

   ____

   ____

3. List each energy source to be used (e.g., airgun, airgun array(s), sparker, towed dipole, side scan sonar, sub bottom profiler, etc.). Indicate the source's manufacturer, model, Source Level (SL) in dB re 1µPa @1m in water (RMS) and if applicable, Source Level (SL) in dB re 1µPa @1m in water (Peak to Peak). If the manufacturer does not provide a peak to peak level (many side scan sonars, etc.), please enter N/A. Additionally, provide the operational frequency ranges.

Energy Source	**Manufacturer**	**Model**	**Array or Airgun Size (cu. in.)**	**Source Level (SL) in dB re 1µPa @1m in water (RMS)**	**Source Level (SL) in dB re 1µPa @1m in water (Peak to Peak)**	**Frequency (Hz, kHz range)**

For air guns/air gun arrays, provide the maximum distance from the sound source to the following SPL in RMS db levels: (Required for Alaska Region; GOM Region only requires this information for surveys in the GOM that will use simsource during acquisition; Not required for Atlantic permits).

dB level	**Maximum Distance from Source**
190 db	
180 db	
160 db	

4. Shot (energy pulse) frequency per linear mile (statute):

____

5. Towing depth (ft/m) of the energy source:

____

6. Towing depth (ft/m) of the receiver(s):

____

7. CSEM, OBN, Magnetotelluric, and OBC surveys: Describe the node deployment and retrieval procedures. Indicate the location (latitude and longitude coordinates), number and spacing of any ocean bottom receivers, cables, and anchors. If anchors will not be retrieved, provide their physical composition and rate of decomposition. Location data may be submitted digitally on a CD (attach separate page if necessary).

____

8. Navigation/positioning system or method used to position shotpoint locations and or ocean bottom receivers:

____

____

9. Proposed areal extent (blocks) for 3D surveys or total number of line miles proposed for 2D or high resolution survey: ____

10. Provide the company identification name of the proposed survey (e.g., Deep Six Survey). List all proposed initial and final processed data sets that will result from acquisition under this activity (e.g., 3D Time Migration processed as Kirchhoff Depth Migration, Wave Equation Migration, etc.).

____

____

11. Estimated date (month and year) on which initial and final processing will be available for all proposed processed data sets:

____

12. Attach map(s), plat(s), and chart(s) (preferably at a scale of 1:250,000) and an electronic version of same showing latitude and longitude, scale, specific protraction areas, block numbers. The map, plat or chart should be submitted at a sufficient size and scale to make out all details of the activities shown. The map should be labeled "**Proprietary**." For 2D data acquisition provide specific track lines with line identifications with the total number of line miles proposed or a representative polygon and total number of blocks for 3D surveys. Along with the hardcopy map, submit on CD, the necessary ArcGIS shape files to reproduce the map for 2D track lines including individual line names in the attribute table. For 3D surveys provide a representative polygon as an ArcGIS shape file.

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

(select one)

____
(Insert Appropriate Regional Office)

NONEXCLUSIVE USE AGREEMENT FOR SCIENTIFIC RESEARCH ON THE OUTER CONTINENTAL SHELF

A. State the time and manner in which data and information resulting from the proposed activity will be made available to the public for inspection and reproduction, such time being the earliest practicable time.

____

____

____

____

____

B. ______________________________ (applicant) agrees that the data and information resulting from the proposed activity will not be sold or withheld for exclusive use.

____
(Signature of Applicant)

____
(Type or Print Name of Applicant)

____
(Title)

____
(Date)

Submit: Two originals, one digital copy, and one public copy (all with original signatures).

UNITED STATES DEPARTMENT

OF THE INTERIOR

BUREAU OF OCEAN ENERGY MANAGEMENT

(select one)

____

(Insert Appropriate Regional Office)

PERMIT FOR GEOLOGICAL EXPLORATION FOR MINERAL RESOURCES OR SCIENTIFIC RESEARCH ON THE OUTER CONTINENTAL SHELF

In consideration of the terms and conditions contained herein and the authorization granted hereby, this permit is entered into by and between the United States of America (the Government), acting through the Bureau of Ocean Energy Management (BOEM) of the Department of the Interior, and

____

(Name of Permittee)

____

(Number and Street)

____

(City, State, and Zip Code)

PERMIT NUMBER: __________________ **DATE:** ________________________

This permit is issued pursuant to the authority of the Outer Continental Shelf Lands Act, as amended, (43 U.S.C. 1331 *et seq*.), hereinafter called the "Act," and Title 30 Code of Federal Regulations Part 551 (Geological and Geophysical (G&G) Explorations of the Outer Continental Shelf).

Paperwork Reduction Act of 1995 (PRA) Statement: This permit refers to information collection requirements contained in 30 CFR Parts 551 and 251 regulations. The Office of Management and Budget (OMB) has approved those reporting requirements under OMB Control Number 1010-0048.

Section I. Authorization

The Government authorizes the permittee to conduct:

☐ ____ Geological exploration for mineral resources by means other than a deep stratigraphic test, as defined in 30 CFR 551.1. This activity utilizes geological and geochemical techniques, including, but not limited to, gas sniffing, various bottom sampling methods, and shallow test drilling.

☐ ____ Geological scientific research by means other than a deep stratigraphic test, as defined in 30 CFR 551.1. This activity involves drilling and gathering of geological data and information for scientific research purposes, including, but not limited to, shallow test drilling.

☐ ____ Geological exploration for mineral resources or scientific research by means of a deep stratigraphic test, as defined in 30 CFR 551.1, or developing data and information for proprietary use or sale.

This permit authorizes the permittee to conduct the above geological activity during the period from __________________________ to __________________________ in the following area(s):
____.

The permittee shall not conduct any geological operation outside of the permitted area specified here in. Extensions of the time period specified above must be requested in writing. A permit plus extensions for activities other than a deep stratigraphic test will be limited to a period of not more than **1 year** from the original specified issuance date of the permit. The duration of a permit for a deep stratigraphic test must be controlled in accordance with 30 CFR 551.7. Group participation in test drilling activities, bonds, inspection and reporting of geological exploration activities, suspension and cancellation of authority to conduct exploration or scientific research activities under permit and penalties, and appeals must be carried out in accordance with 30 CFR 551.7, 551.8, 551.9, and 551.10.

The authority of the Regional Director may be delegated to the appropriate Regional Supervisor for the purposes of this permit.

Section II. Type(s) of Operations and Technique(s)

A. The permittee will employ the following type(s) of operations:

____
____;

and will utilize the following instruments and/or technique(s) in such operations:

____
____.

B. The permittee will conduct all activities in compliance with the terms and conditions of this permit, including the " Stipulations," "Environmental Protective Provisions," and the approved "Application for Permit, which are attached to and incorporated into this permit. Any additional mitigations will be included in the permit cover letter.

C. The permittee will conduct all geological exploration or scientific research activities in compliance with the Act, the regulations in 30 CFR Parts 551 and 251, and other applicable statutes and regulations whether such statutes and regulations are enacted, promulgated, issued, or amended before or after this permit is issued. Some of the provisions of 30 CFR Parts 551 and 251 are restated in this permit for emphasis. However, all of the provisions of 30 CFR Parts 551 and 251 apply to this permit.

Section III. Reports on Operations

A. Status Reports

1. In the Gulf of Mexico and Atlantic OCS Regions:

The permittee must submit status reports every **two months** in a manner approved or prescribed by the Regional Supervisor, Resource Evaluation (here after, except in Section V wherein Supervisor refers to the Regional Supervisor for Operations, referred to as Supervisor). The report must include a map of appropriate scale showing sampling locations, protraction areas, blocks, and block numbers (if map scale permits). The map should be a cumulative update for each status report and clearly distinguish between planned sampling locations (one color) and those locations in which samples have already been collected (a second color). The map should be submitted in digital format, preferably as a GeoPDF.

2. In the Alaska and Pacific OCS Regions:

The permittee must submit status reports on a **weekly basis,** beginning when the permittee enters the permit area in a manner approved or prescribed by the Regional Supervisor, Resource Evaluation (here after, except in Section V wherein Supervisor refers to the Regional Supervisor, Leasing and Plans, referred to as Supervisor). The report must include a map of appropriate scale showing sampling locations, OCS blocks with OCS block numbers (if map scale permits), and the OCS boundary or other important boundaries as specified. The map should be a cumulative update for each status report and clearly distinguish between planned sampling locations (one color) and those locations in which samples have already been collected (a second color). The map should be submitted in digital format, preferably as a PDF and an ESRI file – gdb-feature class(s) or shape files of the weekly data collection. All maps must be submitted in NAD 83.

B. The permittee must submit to the Supervisor a Final Report within **30 days** after the completion of operations. The Final Report must contain the following:

1. In the Gulf of Mexico and Atlantic OCS Regions:

i. A *brief* description of the work performed including number of samples acquired as well as coring, drilling, and sampling methods including depth of penetration;

ii. A *brief* daily log of operations. A suggested format for the daily log of operations would include, but is not limited to, a table that provides a date column and an operations column. Preferably, the date column would commence on the date in which the vessel begins to transit to the permitted area and end on the date in which the vessel either transits away from the permitted area or when operations pertinent to the permitted activity ceases. The corresponding operations column would contain a brief description of the operations for each day listed in the date column noting activities such major work stoppages, and other pertinent activities. This may be submitted as a digital Word document or as an Excel spreadsheet;

iii. A PDF or, preferably a GeoPDF or shape file depicting the areas and blocks in which any exploration or scientific research activities were conducted. These graphics must clearly indicate the location of the activities so that the data produced from the activities can be accurately located and identified;

iv. The start and finish dates on which the actual geological exploration or scientific research activities were performed;

v. A narrative summary of any: (a) hydrocarbon slick or environmental hazards observed and (b) adverse effects of the geological exploration or scientific research activities on the environment, aquatic life, archaeological resources, or other uses of the area in which the activities were conducted;

vi. The estimated date on which the processed or analyzed data or information will be available for inspection by BOEM;

vii. A CD or DVD containing all of the data or sample locations in latitude/longitude degrees (and/or x,y coordinates). The data should also be submitted as an ESRI shapefile(s) illustrating the location of all Geological data collection;

viii. Identification of geocentric ellipsoid (NAD 27 or NAD 83) used as a reference for the data or sample locations; and

ix. Such other descriptions of the activities conducted as may be specified by the Supervisor.

2. **In the Alaska and Pacific OCS Regions:**

i. A *brief* description of the work performed including number of samples acquired as well as coring, drilling, and sampling methods including depth of penetration;

ii. A *brief* summary of operations that provides, but is not limited to, the name of the survey, the date, the number of samples collected each day, and a discussion of any operational or environmental issues that occurred (e.g., major work stoppages, no data acquired, safety incidents, protected species mitigation actions, and other pertinent activities). Provide the date for the start of operations and the end date when operations pertinent to the permitted activity are completed.

iii. A PDF map(s) and a geodatabase file(s) or shape file(s) depicting the areas and OCS blocks in which any exploration or scientific research activities were conducted. These graphics must clearly indicate the location of the activities so that the data produced from the activities can be accurately located and identified;

iv. The start and finish dates on which the actual geological exploration or scientific research activities were performed;

v. A narrative summary of any: (a) hydrocarbon slicks or environmental hazards observed, and (b) adverse effects of the geological exploration or scientific research activities on the environment, aquatic life, archaeological resources, or other uses of the area in which the activities were conducted;

vi. The estimated date on which the processed or analyzed data or information will be available for inspection by BOEM;

vii. A CD or DVD of a *single*, final edited navigational data file, coded in ASCII, containing all of the data or sample locations in latitude/longitude degrees (and/or x, y coordinates). The data should also be submitted as an ESRI file – gdb-feature class(s) or shape file(s) illustrating the location of all Geological data collection.

viii. Identification of geocentric ellipsoid, which in the Alaska and Pacific Regions must be NAD 83, used as a reference for the data or sample locations; and

ix. Such other descriptions of the activities conducted as may be specified by the Supervisor.

Section IV. Permit or Notice Requirements for Shallow Test Drilling

Before any shallow test drilling begins for exploration for mineral resources or for scientific research, the Supervisor may require for permits, or recommend for notices, the gathering and submission of geophysical data and information sufficient to determine shallow structural detail across and in the vicinity of the proposed test. Data and information may include, but are not limited to, seismic, bathymetric, side-scan sonar, and magnetometer systems, across and in the vicinity of the proposed test. When required, 30 CFR 551.7(a) will apply to permits issued for shallow test drilling. All Outer Continental Shelf (OCS) regulations relating to drilling operations in 30 CFR Part 550 and 250 apply, as appropriate, to drilling activities authorized under this section.

Section V. Permit Requirements for a Deep Stratigraphic Test

A. No deep stratigraphic test drilling activities may be initiated or conducted until a Drilling Plan is submitted to the Regional Supervisor, Leasing and Plans; in the Pacific, submit to the BOEM Regional Director; and an Application for Permit to Drill is submitted by the applicant and approved by the BSEE Regional Director (BSEE-RD); in Alaska, submit to the BSEE Alaska Regional Director; in the Pacific, submit to the BSEE Pacific Regional Director. The Drilling Plan must include:

1. The proposed type of sequence of drilling activities to be undertaken together with a timetable for their performance from commencement to completion;

2. A description of the drilling rig proposed for use, unless a description has been previously submitted to the Supervisor, indicating the important features thereof, with special attention to safety features and pollution prevention and control features, including oil spill containment and cleanup plans and onshore disposal procedures;

3. The location of deep stratigraphic test to be conducted, including the surface and projected bottomhole location of the borehole;

4. The types of geological and geophysical instrumentation to be used for site surveys;

5. Geophysical data and information sufficient to evaluate seafloor characteristics, shallow geologic and man-made hazards, and structural detail across and in the vicinity of the proposed test to the total depth of the proposed test well. Data and information from side-

scan sonar and magnetometer surveys must be submitted as required, at the option of the Supervisor; and

6. Such other relevant data and information as the Supervisor may require.

B. At the same time the applicant submits a Drilling Plan to the Supervisor, an Environmental Report must be submitted. The report must be in summary form and should include information available at the time the related Drilling Plan is submitted. Data and information that are site-specific, or that are developed subsequent to the most recent Environmental Impact Statement or other environmental analyses in the immediate area, must be specifically considered. The applicant must summarize and provide references for data, information, and issues specific to the site of drilling activity in the related plan, and in other environmental reports, analyses, and impact statements prepared for the geographic area. Any material based on proprietary data, which is not itself available for inspection, should not be referenced. The Environmental Report must include the following:

1. (a) A list and description of new or unusual technologies that are to be used, (b) the location of travel routes for supplies and personnel and a description of all vessels to be used, (c) the kinds and approximate levels of energy sources to be used, (d) the environmental monitoring systems that are to be used, and (e) suitable maps and diagrams showing details of the proposed project layout;

2. A narrative description of the existing environment. This section must include the following information on the area: (a) geology, (b) physical oceanography, (c) other uses of the area, (d) flora and fauna, (e) existing environmental monitoring systems, and (f) other unusual or unique characteristics that may affect or be affected by the drilling activities;

3. A narrative description of the probable impacts of the proposed action on the environment and the measures proposed for mitigating these impacts;

4. A narrative description of any unavoidable or irreversible adverse effects on the environment that could be expected to occur as a result of the proposed action; and

5. Such other relevant data and information as the Supervisor may require.

C. Any revisions to an approved Drilling Plan must be approved by the Supervisor.

D. All OCS regulations relating to drilling operations in 30 CFR Parts 550 and 250 apply, as appropriate, to drilling activities authorized under this Permit.

E. At the completion of the test activities, the borehole of all deep stratigraphic tests must be permanently plugged and abandoned by the permittee before moving the rig off location in accordance with the requirements of the regulations in 30 CFR Parts 550 and 250.

Section VI. Submission, Inspection, and Selection of Geological Data and Information

A. The permittee must notify the Supervisor, in writing, when the permittee has completed the initial analysis, processing, or interpretation of any geological data and information collected under an exploration permit or a scientific research permit that involves developing data and information for proprietary use or sale. If the Supervisor asks if the permittee has further analyzed, processed, or interpreted any geological data and information collected under a permit, the permittee must respond within 30 days. If the data or information are further analyzed or reprocessed, it is the responsibility of the permittee to keep the most current resulting products available in the event the Supervisor requests the current status of data analysis or processing. At any time within 10 years after receiving notification of the completion of the acquisition activities conducted under the permit, the Supervisor may request that the permittee submit for inspection and possible retention all or part of the geological data, analyzed geological information, processed geological information, and interpreted geological information.

B. In the event that a third party obtains geological data, analyzed geological information, processed geological information, or interpreted geological information from a permittee or from another third party by sale, trade, license agreement, or other means:

1. The third party recipient of the data and information assumes the obligations under this section, except for notification of initial analysis, processing, and interpretation of the data and information, and is subject to the penalty provisions of 30 CFR Part 550, Subpart N;

2. A permittee or third party that sells, trades, licenses, or otherwise provides the data and information must advise the recipient, in writing, that accepting these obligations is a condition precedent of the sale, trade, license, or other agreement; and

3. Except for license agreements, a permittee or third party that sells, trades, or otherwise provides data and information to a third party, must advise the Supervisor in writing within 30 days of the sale, trade, or other agreement, including the identity of the recipient of the data and information; or

4. With regard to license agreements, a permittee or third party that licenses data and information to a third party, within 30 days of a request by the Supervisor, must advise the Supervisor, in writing, of the license agreement, including the identity of the recipient of the data and information.

C. Each submission of geological data, analyzed geological information, processed geological information, and interpreted geological information must contain, unless otherwise specified by the Supervisor, the following:

1. An accurate and complete record of geological (including geochemical) data, analyzed geological information, processed geological information, and interpreted geological information resulting from each operation;

2. Paleontological reports identifying microscopic fossils by depth, and/or washed samples of drill cuttings normally maintained by the permittee for paleontological determination and are made available upon request by the Supervisor. In addition, any other samples or cores requested by the Supervisor are made available on request;

3. Copies of well logs and charts: one paper copy, one copy on a reproducible stable base, and copies of composite digital well logs on magnetic tape or other suitable medium in a format approved by the Supervisor;

4. Data and results obtained from formation fluid test;

5. Analyses of core or bottom samples or a representative cut or split of the core or bottom sample;

6. Detailed descriptions of any hydrocarbons or hazardous conditions encountered during operations, including near losses of well-control, abnormal geopressure, and losses of circulation; and

7. Such other geological data, analyzed geological information, processed geological information, and interpreted geological information as may be specified by the Supervisor.

Section VII. Reimbursement to Permittees

A. After the delivery of geological data, analyzed geological information, processed geological information, and interpreted geological information requested by the Supervisor in accordance with subsection VI of this permit, and upon receipt of a request for reimbursement and a determination by BOEM that the requested reimbursement is proper, BOEM will reimburse the permittee or third party for the reasonable costs of reproducing the submitted data and information at the permittee's or third party's lowest rate or at the lowest commercial rate established in the area, whichever is less.

B. The permittee or third party will not be reimbursed for the costs of acquiring, analyzing, or interpreting geological information.

Section VIII. Disclosure of Data and Information to the Public

A. BOEM will make data and information submitted by a permittee available in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2), the requirements of the Act, and the regulations contained in 30 CFR Parts 550 and 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), 30 CFR Part 551, and 30 CFR Part 552 (Outer Continental Shelf (OCS) Oil and Gas Information Program).

B. Except as specified in this section, or Section X of this form, or in 30 CFR Parts 550, 551 552, and 250, no data or information determined by BOEM to be exempt from public disclosure under subsection A of this section will be provided to any affected State or be made available to the executive of any affected local government or to the public unless the permittee or third party and all persons to whom such permittee has sold, traded, or licensed the data or information under promise of confidentiality agree to such an action.

C. Geological data, analyzed geological information, processed geological information, and interpreted geological information submitted under a permit, and retained by BOEM will be disclosed as follows:

1. The Director, BOEM, will immediately issue a public announcement when any significant hydrocarbon occurrences are detected or environmental hazards are encountered on unleased lands during drilling operations. In the case of significant hydrocarbon occurrences, the Director will announce such occurrences in a form and manner that will further the national interest without unduly damaging the competitive position of those conducting the drilling. Other data and information pertaining to the permit will be released according to the schedule provided in subsection D and paragraphs 2 and 3 of this subsection.
2. BOEM will make available to the public all processed geological data, analyzed geological information, processed geological information, and interpreted geological

information (except geological data, analyzed geological information, processed geological information, and interpreted geological information obtained from drilling a deep stratigraphic test) 10 years after the date of issuance of the permit under which the data and information were obtained; and

3. BOEM will make available to the public all geological data and information related to a deep stratigraphic test at the earlier of the following times: (a) 25 years after the completion of the test, or (b) for a lease sale held after the test well is completed, 60 calendar days after the Department of the Interior executes the first lease for a block, any part of which is within 50 geographic miles (92.6 kilometers) of the site of the completed test.

D. All other information submitted as a requirement of 30 CFR 551.8 and determined by BOEM to be exempt from public disclosure will be considered as "PROPRIETARY." Such data and information will not be made available to the public without the consent of the permittee for a period of 10 years from the date of issuance of the permit; unless the Director, BOEM, determines that earlier release is necessary for the proper development of the area permitted. The executed permit will be considered as "NONPROPRIETARY" and will be available to the public upon request and also on BOEM's website.

E. The identities of third party recipients of data and information collected under a permit will be kept confidential. The identities will not be released unless the permittee and the third parties agree to the disclosure.

Section IX. Disclosure to Independent Contractors

BOEM reserves the right to disclose any data or information acquired from a permittee to an independent contractor or agent for the purpose of reproducing, analyzing, processing, or interpreting such data or information. When practicable, BOEM will advise the permittee who provided the data or information of intent to disclose the data or information to an independent contractor or agent. BOEM notice of intent will afford the permittee a period of not less than 5 working days within which to comment on the intended action. When BOEM so advises a permittee of the intent to disclose data or information to an independent contractor or agent, all other owners of such data or information will be deemed to have been notified of BOEM's intent. Prior to any such disclosure, the contractor or agent will be required to execute a written commitment not to sell, trade, license, or disclose any data or information to anyone without the express consent of BOEM.

Section X. Sharing of Information with Affected States

A. At the time of soliciting nominations for the leasing of lands within 3 geographic miles of the seaward boundary of any coastal State, BOEM, pursuant to the provisions of 30 CFR 552.7 and subsections 8(g) and 26(e) of the Act (43 U.S.C. 1337(g) and 1352(e)), will provide the Governor of the State (or the Governor's designated representative) the following information that has been acquired by the Supervisor on such lands proposed to be offered for leasing:

1. All information on the geographical, geological, and ecological characteristics of the areas and regions proposed to be offered for leasing;

2. An estimate of the oil and gas reserves in the area proposed for leasing; and

3. An identification of any field, geological structure, or trap located within 3 miles of the seaward boundary of the State.

B. After the time of receipt of nominations for any area of the OCS within 3 geographic miles of the seaward boundary of any coastal State and Area Identification in accordance with the provisions of Subparts D and E of 30 CFR Part 556, BOEM, in consultation with the Governor of the State (or the Governor's designated representative), will determine whether any tracts being given further consideration for leasing may contain one or more oil or gas reservoirs underlying both the OCS and lands subject to the jurisdiction of the State.

C. At any time prior to a sale, information acquired by BOEM that pertains to the identification of potential and/or proven common hydrocarbon-bearing areas within 3 geographic miles of the seaward boundary of any such State will be shared, upon request by the Governor and pursuant to the provisions of 30 CFR 552.7 and subsections 8(g) and 26(e) of the Act, with the Governor of such State (or the Governor's designated representative).

D. Knowledge obtained by a State official who receives information under subsections A, B, and C of this section will be subject to the requirements and limitations of the Act, the regulations contained in 30 CFR Parts 550, 551, 552, and 250.

Section XI. Fishermen's Contingency Fund

For deep stratigraphic test drilling activities as described under Section V of this permit, the permittee must meet the requirements of establishing an account with the Fishermen's Contingency Fund for the drilling activities area pursuant to Title IV [Subsection 402(b)] of the Act and pay assessment as required in 50 CFR 296.3 (Chapter 11 - National Marine Fisheries Service; Subchapter J - Continental Shelf). The amount of the assessment is specified by the Secretary of Commerce, collected by the Director, BOEM, and deposited in the fund to be appropriate account.

Section XII. Permit Modifications

The Department will have the right at any time to modify or amend any provisions of this permit, except that the Department will not have such right with respect to the provisions of Sections VIII, IX, and X hereof, unless required by an Act of Congress.

IN WITNESS WHEREOF the parties have executed this permit and it will be effective as of the date of signature by the Supervisor.

PERMITTEE:	**THE UNITED STATES OF AMERICA:**
______________________________	______________________________
(Signature of Permittee)	**(Signature of Regional Supervisor)**
______________________________	______________________________
(Type or Print Name of Permittee)	**(Type or Print Name of Regional Supervisor)**
______________________________	______________________________
(Title)	**(Date)**
______________________________	
(Date)	

B. PROJECT EXECUTION PLAN

B.1 PROJECT EXECUTION PLAN PART A - OPERATIONAL PLAN

B.2 PROJECT EXECUTION PLAN PART B - QUALITY PLAN

B.3 PROJECT EXECUTION PLAN PART C – HEALTH, SAFETY, ENVIRONMENTAL PLAN

B.4 PROJECT EXECUTION PLAN PART D – EMERGENCY RESPONSE (ERP) PLAN

B.5 SAFETY AND OPERATING GUIDELINES

B.6 SHALLOW GAS PROCEDURES

WR 313 and GC 955
GAS HYDRATE GEOTECHNICAL DRILLING
GULF OF MEXICO

U.S. DEPARTMENT OF ENERGY

PROJECT EXECUTION PLAN
OPERATIONAL PLAN
LEVEL 2 DOCUMENT
PROJECT NO. 27.2012-2580
PART A

03 September 2015

1				G. Humphrey	August 30, 2015
0	Draft	A. Wingate	J. Rojas		August 25, 2015
Revision	**Description**	**Prepared By**	**Checked By**	**Approved By**	**Date**

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ABBREVIATIONS

ADCB	Advanced Diamond Core Barrel
ADS	Autoclave Degassing System
APC	Advanced Piston Corer
APCT	Advanced Piston Corer Temperature
APCM	Advanced Piston Corer Methane
BHA	Bottom Hole Assembly
BML	Below MudLine
CASOW	Core Analysis Scope of Work
CBHA	Common Bottom Hole Assembly
COMPANY	U.S. Department of Energy
CTD	Conductivity Temperature Depth
DOE	U.S. Department of Energy
DGNSS	Differential Global Navigation Satellite System
DGPS	Differential Global Positioning System
FC	Fugro Corer®
FGCI	Fugro GeoConsulting, Inc.
FHPC	Fugro Hydraulic Piston Corer
FIHK	Fugro International (Hong Kong) Ltd
FMCB	Fugro Marine Core Barrel
FXMCB	Fugro Extended Marine Core Barrel
FPC	Fugro Pressure Corer
GH	Gas Hydrates
HOC	Hazard Observation Card
HSE	Health, Safety & Environment
ISSMGE	International Society of Soil Mechanics and Geotechnical Engineering
MSL	Mean Sea Level
MOC	Management of Change
MOPO	Matrix of Permitted Operations
OPCO	Operating Company
PCTB	Pressure Corer Tool with Ballvalve
RCB	Rotary Core Barrel
SBF	SeaBed Frame
Starfix.Seis	Fugro's Windows-based navigation and data logging computer System
SWL	Safe Working Load TRA Task Risk Assessment USBL Ultra Short Baseline
UTM	Universal Transverse Mercator
WGS84	World Geodetic System 1984
WISON® EP	WIreline SOuNding Extra Penetration
XCB	Extended Core Barrel

1. OBJECTIVES AND INTRODUCTION

Contractor (Initials) was contracted the U.S. Department of Energy (DOE) to perform a scientific soil investigation drilling campaign into the potential presence of gas hydrate (GH) accumulations in offshore continental slope sediments (and Abyssal Plane) in Block 313 of the Walker Ridge Area and Block 955 of the Green Canyon Area, in the Gulf of Mexico, located approximately 250 to 300 km from Cocodrie, LA.

The objective of the project is to acquire petro-physical, geophysical, geotechnical and geochemical data of gas hydrate bearing soils through coring and offshore laboratory analysis. A previous campaign collected Logging While Drilling (LWD) information that was used to select the two locations for further investigation.

Prior to the fieldwork a drilling hazard assessment and site selection will be performed in close co-operation with the DOE. The purpose is to provide a preliminary, "first-pass" characterization of seafloor and subsurface sediments, and to identify the areas at which gas hydrate is most likely to be encountered in boreholes while also minimizing potential drilling and other operational hazards. We will also reference the drilling hazard assessments performed by AOA from 2009.

The fieldwork will be performed in a single (Coring) phase. Water depths at the locations are expected to be up to 2,050 meters below sea level. The drilled boreholes shall be performed up to depths of up to approximately 880 meters below mudline (BML).

One Coring Leg is planned for and will be executed using a DP Geotechnical Drilling Vessel. The port of mobilization will be Galveston, TX, where the coring and GH lab testing equipment will be loaded. The local mobilization and operational port (logistics and port calls) will be Galveston, TX. A fieldwork kick-off meeting for the project will be planned prior to the beginning of the campaign.

2. PROJECT ORGANISATION AND MANAGEMENT

The project team headed by the Project Manager are responsible for the execution of the project throughout the life cycle and according to the scope of work described; this includes execution of the agreed changes to the work scope.

2.1 Organization Diagram

The following Figure 2-1 illustrates the project organization chart:

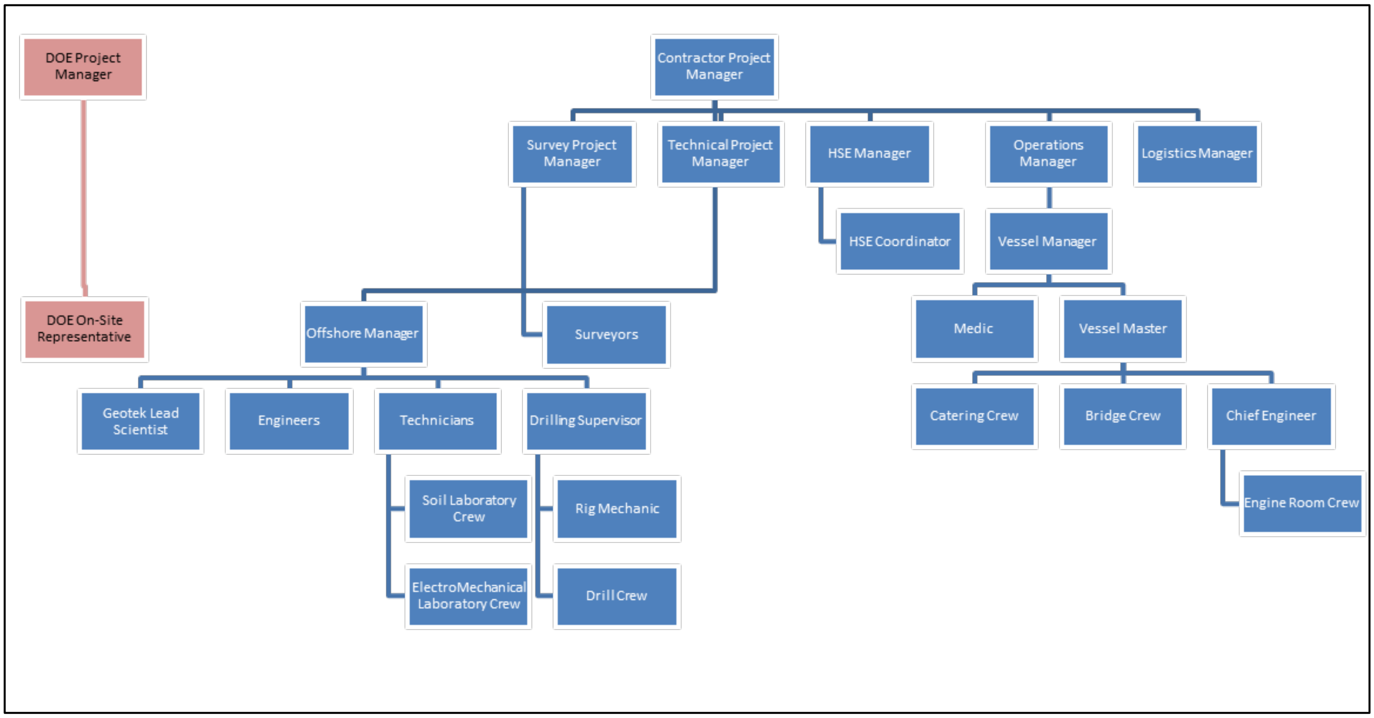

Figure 2.1 Project Organization Chart

The following Table 2.1 provides general detail on the typical roles and responsibilities of the personnel mentioned in the project organization chart, additional detail is available within the management systems where the individuals are employed.

Table 2.1 Personnel Roles and Responsibilities

Project Role	Name	Company Abbreviation	Direct Tel No. Cell	Email	Responsibilities
Project Manager					Contract Holder and acts as point of focus for the Client. Project Management. Assigned to this project covering all other aspects of the project
Operations Manager					Drilling and back deck operations
Technical Project Manager					Ensure that contract technical requirements are met.
Logistics Manager					Local logistics and liaison with agent.
Vessel Manager					Provides the necessary resources and trained marine crew and provide the authority for those persons to carry out the plan in a safe and proper manner in compliance with all relevant legislation
QHSE Advisor					Ensure that all HSE and Quality Assurance procedures are in place and objectives are achieve
Vessel Master					Total authority on safe navigation and all associated vessel operations
Offshore Manager					Supervising/Coordinating offshore activities and direct point of contact with Offshore Client Representative
Lead Geophysicist					Advisor for reviewing logging while drilling (LWD) and geophysical data
Geotek Lead Scientist					Scientific coring and gas hydrates analysis
Technical Project Manager					Drilling Hazard Assessment and Reporting

2.2 Contractor Details

The follow Table 2.2 provides details of the Contractor Operating Companies (OPCO) details and the principle contact related to this specific project.

Table 2.2 Contractor OpCo's Details

OPCO	Service	Contact	Location	Telephone	Email
Company	Contract Holder and Contract Mgt. Client Liaison and local logistics				
	Provision of Vessel , Marine, Positioning and Drilling Services				
	Provision of coring and in-situ testing tools (FPC, FMCB, FC, EP)				
	Provision of coring tools (FHCP, PCTB)				
	Technical Advisor, Drilling Hazard Assessment and Reporting				

2.3 Company Details

The following Table 2.3 provides contact details of the COMPANY who have engaged the services of the Contractor for the project described within this PEP.

Table 2.3 Company Details

COMPANY	Contact	Role	Location	Telephone	Email
U.S. Department of Energy		Company Representative			

2.4 Operational Communication

Operational reporting shall be regular and constant; there are direct lines of communication from field operations to onshore operational support staff, in addition there is communication to supplier's and in some cases to project stakeholders.

Formal operational communication shall follow the communication plan described in the following Table 2.4 and follow the protocol described in the preceding section of this document.

Table 2.4 Communications

* E = Email, L = Letter (hardcopy), R = Report (can be electronic and/or hardcopy), F= Form, M = Meeting or Workshop
** D = Daily, W = Weekly, M = Monthly, Ps = Defined on Project Schedule, A = Ad-hoc

ID	Communication	Objective	Originator	Distribution	Medium*	Frequency**
2	Contract Modification (Variation Order)	To provide the client with details of any requested contractual variation, the schedule for undertaking the variation and its cost.	Project Manager	CLIENT: CONTRACTOR:	F	A
1	Daily Progress Report (DPR)	To provide the Project Team with a daily progress update for each of the field Work Elements. DPR to include a breakdown of the survey activities, production summary, weather conditions experienced and forecast, HSE summary and details of additional chargeable items.	Offshore Manager	CLIENT: CONTRACTOR:	R	D
3	Management of Change	To provide the Project Team with details of any required changes to the project plan, the description and justification for the change, any HSE implications (positive or negative) and changes to the project risk profile (positive or negative). If the change has a contractual implication a Variation Order shall also be raised.	Project Manager	CLIENT: CONTRACTOR:	R	A

2.5 Management of Change

This PEP is intended to describe the scope of work at time of publishing; however through the project life cycle, the work scope may change based on circumstances.

Should a work scope of methodology change be required, either generated upon Client request or as a result of other factors, the Project Manager as a minimum will revise and re-issue the project documentation if applicable and record the agreed changes using the Management of Change (MOC) form and/or a Variation Order (VO) which is attached to this PEP within the appendices.

Table 2.5 Management of Change

Stage		Activities
1	Identify	All project personnel to review project documentation (PEP, contract, scope of work and technical specifications) prior to commencement of field operations. Project documentation to be reviewed during the course of the project for non-conformities/omissions.
2	Define	Any change deemed to be required will be communicated to the Project Manager by completing a Management of Change form.
3	Discuss	MOC Form to be reviewed by Project Manager against project documentation (contract etc.) to ensure its validity. MOC Form to be issued to client group for review.
4	Agree Response	Client to approve MOC / VO Form following discussions with Project Manager.
5	Confirm Modification	Project Manager to communicate the change via the appropriate channels.

3. WORK SCOPE

The scope of work is defined in Appendix A (Reference Documentation) and the main contract.

The planned work consists of at least three (3) coring boreholes to be performed. The coring/testing program of the coring boreholes will be planned based on the data analyses from the LWD boreholes previously performed. The target depth for each coring borehole will in the order of 450–890 m BML. Water depths will range from 2,000 to 2,050 m.

The ODE shall inform the final borehole coordinates planned for each coring location prior to commencement of the project mobilization.

Table 3.1 Scope of Work Documentation

Company	Document Number
Contractor	XXXXX-PEP Contract Section VI – Contractor Proposal XXXX - dated
Client	Not available.
Joint	Contract Section IV Contract Section VI – Contractor Proposal - date

The Project Schedule in Gantt chart format based on above scope can be found in Appendix A.

3.1 Work Breakdown Structure (WBS)

The following Table 3.1 Work Breakdown Structure (WBS) provides a representation of the way the different activities and work packages contribute to the final completion of the project:

Table 3.2 Work Breakdown Structure

	Activity	Start	End	Duration (days)	Responsible Manager
1.0	**Mobilization**				
1.1	Mobilization in Galveston				
1.2	Transit to Site/USBL Calibrations				
2.0	**Coring Phase**				
2.1	Coring Phase				
3.0	**Demobilization**				
3.1	Transit to Port, Demobilization in Galveston				
4.0	**Drilling Hazard Assessment and Reporting**				
4.1	Drilling Hazard Assessment				
5.0	**Onshore Analytical & Scientific Work Reporting**	To Be Confirmed			

3.2 Work (Elements) Packages

The schedule and high level details related to work packages have generally been described in sections 3.0 and 3.1. The work elements or packages are described below in a higher level of detail as per below:

Table 3.3 Work (Elements) Packages

	Activity	Document Reference
1.0	**Mobilization**	
1.1	Mobilization in Galveston	Port Call Plan Gate List for entrance into port Contractor related documents Company related documents
1.2	Mobilization in Port	Port Call Plan Gate List for entrance into port Contractor related documents Company related documents
1.3	Transit to Site / USBL Calibration and Position Vessel at Site	DP Operations Manual
2.0	**Coring Phases**	
2.1	Downhole Operations and Gas Hydrate Core Analysis	Geotek Gas Analysis Geotek Handling of Liquid Nitrogen Geotek Porewater Analysis Geotek Pressure Core Analysis.doc Geotek Unpressurized Core Analysis MSCL-S Core Logging
3.0	**Demobilization**	
3.1	Transit to Port, Demobilization in Galveston	Port Call Plan Contractor related documents Company related documents
4.0	**Drilling Hazard Assessment and Reporting**	
4.1	Drilling Hazard Assessment	Pre Field Work Desktop Study
4.1	Reporting	Post Field Work onshore reporting

The Work Instructions Register include the documentation references mentioned in Table 3.3 can be found in Appendix C.

3.3 Mobilization Phase

3.3.1 Mobilization in Galveston, TX

The Project Manager will be in liaison with the Vessel Manager, Offshore Manager, operations staff, and Vessel Master to ensure appropriate preparations / installations are done during the mobilization of the DP Geotechnical Drilling vessel in Galveston, TX. The key elements of the preparation, modifications and actual mobilization include:

- Pre-Engineering.
- Workshop between operations staff, Drilling Supervisor and coring specialist to define back operations, and finalize deck layout.
- Removal of equipment (if needed) to create back deck space.
- Pre-Engineering for deck layout & power/water supply for containers to be installed.
- Bunkering and loading provisions.
- Re-alignment of existing equipment, if needed
- Installation of equipment as needed
- Revise layout for drill pipe racks to optimize tool handling area, if needed.
- Installation of Ice Baths.
- Loading eight (8) containers with coring and gas hydrate lab testing equipment including hook-up:

  #1 1 x 40’ Geotek Core Processing Laboratory
  #2 1 x 20’ Geotek Geochemistry Laboratory
  #3 1 x 20’ Geotek ADS Reefer
  #4 1 x 20’ FHPC Container
  #5 1 x 20’ PCTB Container
  #6 1 x 20’ FPC Container
  #7 1 x 20’ Reefer
  #8 1 x 20’ Consumables Container

- Assembling and dry / fit testing PCTB, FPC and FHPC corers
- DGPS Verification and Gyro Calibration

These survey measurements will be done when the vessel is alongside in Galveston prior to departure and includes:

• Calibration of the vessel Gyro heading, referenced to an established baseline.
• Verification of the Starpack GPS Positioning System onboard the vessel with reference to established survey control points and terrestrial baseline.

- Perform Trial Borehole in shallow water in the Gulf of Mexico waters in approximately 35 m water depth in order to test and demonstrate:

• Safe and efficient handling of PCTB and FPC,

- Suitability and acceptability of tool handling area and rigging arrangements,
- Downhole tool performance of above corers.

The trial borehole will be conducted with specialist coring staff. The outcome will be evaluated and remedial measures will be taken, if so required. These could include deck and/or rigging re-arrangements and tool modifications.

Upon completion of above activities, vessel clearance formalities and demob project/installation crew, the vessel will sail to Galveston, TX.

3.3.2 Mobilization and Port Calls in Galveston

The local mobilization and operational port for local logistics, crew changes, and intermediate port calls will be Galveston, TX.

Following local immigration and security formalities all personnel joining and all crew already onboard the vessel will attend a Project Induction and Orientation onboard the vessel or in a hotel (TBC).

Prior to commencement of mobilization operations onboard the vessel, the project team, marine crew and subcontractors will hold meetings to plan the mobilization tasks. All crew will review and update the mobilization TRA as required.

After setting up the SLB equipment and interfacing the vessel drill rig, the compatibility of SLB bottom hole assembly with the contractor's drill string will be tested and verified.

Upon completion of kick-off meetings and vessel clearance formalities (at first arrival), the vessel will sail directly to the USBL calibration site and then onto the work site.

The mobilization phase will be over when the vessel arrived at the first site and ready to commence drilling operations. Where applicable, a mobilization completion certificate shall be signed off by the Offshore Manager and Lead Client Representative.

Prior to commencing operations, a copy of the geodetic parameters from the navigation computer system shall be presented to the Client Offshore Representative for review and confirmation. The project coordinates as supplied by the Client and entered in the navigation software shall be cross-checked and signed off by both the Offshore Manager and the Lead Client Representative

3.3.3 Transit to Location and USBL Calibrations

Nominal transit speed is 10-12 knots. During the transit, preparations for the Coring program will continue and toolbox meetings will be held to ensure all personnel are familiar with the operations.

While in route to the site and at a location that is approved by the COMPANY, USBL calibrations if required will be undertaken. Prior to commencement, a CTD/SVP cast will be performed.

The USBL calibration can be carried out using the contractor's USBL software module or alternatively the internal Simrad software. The principles of either method are the same and the dynamic manoeuvers required by the vessel are the same whatever method is selected.

A transponder will be deployed to the seabed in suitable water depth for the work program. An appropriate water depth for the accurate calibration of the USBL system is expected to be approximately 2,000 m. A CTD cast will then be performed and the results entered in the USBL unit.

The calibration involves positioning the vessel at four cardinal points around the seabed beacon, at a horizontal distance of half the water depth while maintaining a constant heading. The logged data is then used to derive corrections for orientation, scale, pitch and roll values. These corrections will be set in the contractor's survey module, or in the Simrad unit, such that the output is corrected beacon position.

3.4 Data Acquisition

The work instruction register plus the relevant work instructions for the Coring operations can be found in Appendix C.

3.4.1 Sequence of Work

The order of operations will be decided onsite and on a daily basis by the Offshore Manager (OM) and Client Offshore Representative with prevailing weather and sea conditions being the primary factors determining the order in which the survey progresses.

The testing program of the coring in will be determined from the previously collected LWD data.

A daily meeting will be held in where the coring program for the day will be discussed with relevant project personnel; the Client Representative together with the OM, Master, Coring Lead Scientist, Drilling Supervisor, and Safety Officer. Any new HSE issues that have been raised during the previous 24 hours will also be reviewed.

All personnel onboard the vessel, have a mandated responsibility to suspend operations if they are perceived to be unsafe, as per Company safety policy. With regard to safety of personnel, data quality and equipment safety or performance, the Offshore Manager, in consultation with the Vessel Master and Client Representative, will be ultimately responsible for decisions relating to the suspension of geotechnical operations and when to recommence. The Vessel Master will have ultimate authority on any activities that may affect the safety or operation of the vessel and related aspects.

All equipment used will be operated in accordance with the relevant contractor work practices, an electronic copy of which will be available on the survey vessel.

3.4.2 Project Program

The project program the Coring Phase is summarized in Table 3.4.

Table 3.4 Project Program

ACTIVITY	DESCRIPTION	QUANTITY- DEPTH [No.] - [m]	REMARKS
SCOPE OF WORK			
Fieldwork will be performed in 1 Leg Leg Geotechnical Coring with Coring and in-situ testing			
Leg 1: Coring Boreholes	Boreholes with pressure coring, coring and in-situ testing Focus on pressure coring in Gas Hydrate bearing zones	3 Coring BH's to 450 m – 880 m BML	• Lowering Seabed Frame to seabed, monitor Seabed with camera survey • Lower Drill String to seabed • Monitor gas venting during drilling and downhole operations • Seabed Frame with Seaclam will be used for immobilizing the drilling string for coring / in-situ testing
Water Depth		Water depth Approx. 2,000 m (Max 2,050 m)	
FIELDWORK PERSONNEL AND SYSTEMS			
Working hours	24 hours/day	2 shifts	
Personnel General	Marine Crew Offshore Manager Senior Rig Mech Offshore Medic Offshore HSE Coach Drilling Crew Positioning team	26x 1x 1x 1x 1x 7x 2x	**General Personnel: 39**
Specific Personnel Coring Leg 1	DOE Representatives Lead Scientist Tool Pusher Tools Operators Scientist Staff	7x 1x 1x 9x 8x	**Specific Personnel Leg 1: 26** **Total POB Coring Phase 1** **65 Persons**
Survey Apparatus	Satellite Positioning System	2 sets	DGPS (primary)

Vessel	Geotechnical Investigation Vessel		Dynamic Positioning DP Class 2 or 3
Location	X and Y data		Location as directed by Client tolerance ± 5 m
Water Depth Survey	Echosounder or HPR system Drill string at seabed		accuracy 0.5 m to 1.0 m
Drilling	Drilling System		Open hole rotary drilling: self-weight of drill pipe including drill collars. Passive heave compensation See Appendix B, Project Equipment
Non-Pressurized Coring Tools	(FHPC) FC) (FMCB)		Mud Actuated Piston Corer Mud Driven Hammer Sampler Reaction from self-weight of drill pipes, drill collars and SEACLAM Rotary Coring System driven by rotating drill pipe.
Pressurized Coring Tools	(FPC)		Mud Driven Sampler using F C as Hammer Device Reaction from self-weight of drill pipes, drill collars and SEACLAM
	Pressure Core Tool Ball valve (PCTB) With pressure vessel: Autoclave with bottom ball valve		Rotary Coring System driven by rotating drill pipe.
In-Situ Testing downhole tool	WISON® EP with temperature probe / cone.		Mud driven CPT rod insertion tool with real-time logging capability.
Coring / In-Situ Termination for all downhole tools	Whichever occurs first: – Reaching maximum permissible core/ sample tube penetration – Reaching maximum capacity of sample insertion equipment, coring tube or CPT rod – Reaching maximum capacity of reaction equipment – Circumstances at discretion of operator, such as risk of loss of equipment		
CORE ANALYSES SCOPE OF WORK (CASOW) Ref. Section 3.4.3 to 3.4.5 Detailed in Appendix B – Geotek CASOW with ADS document.			

3.4.3 Non Pressurized Core Processing

Whole core processing and logging first takes place on the back deck of the vessel in the Geotek Processing Laboratory and then is completed onshore in the Geotek mobile laboratories.

The following will be performed in the Geotek Core Processing Laboratory:

- Whole Core Curation and Sample Preservation
- Infrared Thermal Imaging
- Whole Core Physical Properties using MSCL-S
- Whole Core X-ray Imaging

All cores and samples will be recorded and labelled. Gas hydrate samples encountered will be wrapped, labelled and preserved in liquid nitrogen for further onshore studies.

3.4.4 Geochemical Analyses

Geochemical analysis takes place on the back deck of the vessel in the Geochemistry Laboratory, where general chemical laboratory infrastructure will include drying ovens, filtration hood, deionized water supply and general chemical laboratory supplies.

The following processes will be carried out in the Geochemistry Laboratory

- Gas Hydrate Saturation from Pore water Analysis (Salinity and Chlorinity)
- Alkalinity Measurement
- Major and Minor Cation Analysis
- Major Anion Analysis
- Preservation of Pore water Samples for Shore-based Analysis
- Light Hydrocarbon Analysis

3.4.5 Pressurized Core Processing

An Autoclave Degassing System (ADS) coupled to the autoclave, enables pressure cores to be safely depressurized in stages to accurately determine the volume and composition of the gases inside the core.

The following processes will be carried out in the ADS Reefer

- Preservation of Microbiological Samples
- Determination of Methane Content of Pressure Core

3.5 Sample Logistics

When the vessel returns to Galveston, TX after completion of the field work, the samples will be offloaded and transported to the appointed laboratory in the U.S. Stored Pressure Cores will need to have Department of Transportation (DOT) permits in place prior to arrival or will otherwise need to stay at the dock or the ship until such permits are acquired.

3.6 Demobilization

Upon completion of the survey program, the vessel will return to Galveston, TX for client and project crew demob for outward clearance and demobilization. The demobilization activities comprise:

- Demob Client- and Project Crew
- Bunkering and provisions, if required.
- Prepare for Transit to Port of Origin

The Offshore Manager shall provide to the Lead Client Representative information of the fieldwork upon demobilization.

Where applicable, on completion of demobilization, a demobilization completion certificate shall be signed off by the Offshore Manager and Lead Client Representative.

3.7 Reporting

The following reports will be issued from the vessel during fieldwork and from the office after demobilization in accordance to the agreed schedule.

3.7.1 Daily Progress Reports

Daily Progress Reports will be submitted once the mobilization commences through to completion of demobilization and will as a minimum comprise of the following:

- Date and Location
- Number of Contractor Personnel onboard
- Weather and Sea State Conditions
- Progress of Work (including test footage for the day, number of tests carried out and number of samples recovered)
- Summary of all HSE Issues (meetings, milestones, hazards, incidents etc.)
- Project Specific KPIs (HOC's, TRA's etc.)
- 24 hour look ahead of planned activities

3.7.2 Field Data

The field data including all GH core processing results, and drill logs/operation records will be submitted before completion of the field work.

3.7.3 Onshore Analytical and Scientific Work Reporting

The final scope of onshore analytical and scientific work reporting for project is subject to be agreed with DOE.

In addition to operation and geotechnical reports, pre-drill and post-drill analyses of the GOM gas hydrate prospect would be applied. A gas hydrate petroleum system is considered in the pre-drill analysis, which includes seismic interpretation, migration pathway interpretation, and reservoir stratigraphic interpretation. The focus of the post-drill analysis is to evaluate the procedures used for the pre-drill interpretation on the basis of in-situ measurements of LWD logs and core samples. Seismic, logging and core data would be integrated and analyzed. For those well sites where hydrate is not found, recommendations to improve the pre-drill procedures would be presented. For those well sites that hydrate-bearing sands are verified, the post-drill analysis also includes 1) determine accurate gas hydrate saturation and reservoir thickness from well logs, and 2) update the pre-drill gas hydrate system.

We estimated that onshore analytical and scientific work reporting will be completed in approximately two (2) to three (3) months upon completion of the fieldwork. Depending upon the reservoir characterization work options, this could be longer.

4. PROJECT ASSETS

4.1 Survey Vessel

The details of the survey vessel offered as part of this proposal are summarized below.

Description
Offshore Survey Vessel –

General information:
Owners :
Operators :
Built :
Class :

Dynamic positioning: DP2 –
Number of berth :

Main Dimensions:
Length OA :
Breadth :
Draft :

Capacities and Speed:
Fuel :
Cruising speed :

4.2 In Situ Testing and Coring Equipment

The following geotechnical sampling and testing equipment will be mobilized for the project:

Downole/Drilling System:

- Drilling Derrick:
  - Type:
  - Capacity:
  - Drill Rig Heave compensated Rig

- Drill Rig:

- Heave Compensator:
  - Stroke length
  - Max Heave length

- Topdrive
  - Type:

- Automated Pipe handling:
- Pipe Handling Crane
- Tubular Feeding Machine
- Iron Roughneck
- Rotary Slips

In-situ Testing equipment

- Seabed SEACLAM system
- WISON® EP MK IV downhole in situ testing system;
- Temperature Probe

Gas Hydrate Sampling Equipment - Non Pressurized Cores

- (FHPC)
- (FC)
- (FMCB) or XCB

Gas Hydrate Sampling Equipment - Pressurized Cores

- (FPC)
- (PCTB)

Gas Hydrate/Sediment Laboratory Equipment (Geotek Ltd)

- Core Processing Laboratory
- Liner/End-Caps, Brady label printer, Camera, Aluminum Foil and Bags
- Infrared Imaging System (MSCL-IR)
- Whole Core Sensors (MSCL-S)
- Whole Core X-Ray Imaging (MSCL-XCT)
- Geochemistry Laboratory
- Pore water squeeze cells & presses
- Temperature-compensated Refractometer for salinity
- Digital Titrator for chlorinity
- Spectrophotometer for sulfate
- Temperature Controlled Digital Titrator for alkalinity and pH
- Ion chromatograph for sulfate and bromide
- Inductively-coupled plasma optical emission spectrometer for major & minor cations
- Gas chromatograph for C1-C4 and air components
- Autoclave Degassing System (ADS) Reefer
- Autoclave Degassing System
- Chest Freezer (-20°C, ~300L)

4.2.1 SEACLAM

The SEACLAM is a clamping device on the Seabed Frame that is used to immobilize the drill string during in situ testing and sampling. During drilling the Seabed Frame will provide lateral stability to the drill string at mudline. It will also facilitate the re-entry of the drill string into the borehole with the underwater guide frame (bit guide).

4.2.2 Drilling Equipment

Drilling will be performed using standard straight flush rotary methods without a riser. Seawater or Bentonite will be used as a drilling fluid. An open face wing bit (9" OD, 3-1/2" ID) or four cone roller bit (9" OD, 3-1/2" ID) will be used which is connected to the standard bottom hole assembly (BHA) (7-1/4" OD, 3-1/2" ID), 7" OD drill collars and 5-1/2" API drill pipe – Grade E.

Drilling is performed through a center moonpool using a top drive power swivel. The drilling rig will be capable of drilling to approximately 2,000 m below deck with 5-1/2" standard drill pipe. The pipe handling should be automated; including a pipe handling crane, a tubular feeding machine, an iron roughneck and rotary slips.

Other equipment includes a fixed derrick rig, mud mixing and pumping unit below deck, as well as other tools and accessories required to carry out the survey. A compensator system is connected to the working platform to ensure the drill bit maintains a uniform pressure during drilling operations. Sufficient spare parts and other supplies will be on board.

4.2.3 WISON® EP Downhole Spread

The WISON® EP system is a downhole spread that comprise of a temperature probe. The EP operates with a logging cable and can be used in depths to around 2000 m below the vessel. Tests can be performed consecutively or intermittently throughout the borehole providing a continuous or semi-continuous profile of measured parameters.

4.2.4 Downhole Coring Spread

The contractor's downhole coring spread comprise a suite of tools fully compatible with one type bottom hole assembly (BHA), the so-called common BHA. Also the WISON® EP system fits in this BHA.

The FHPC, FC, FMCB and FXMCB will be the non-pressure coring tools, and starting with the FHPC corer will be targeted for soft, non-lithified sediments usually to top 200 m BML, depending on the actual soil conditions. The FC percussion corer is more suitable for hard clays and cemented sands and will be used when the sediments are too stiff to be recovered with the FPHC. The FMCB downhole corer can be used for bridging more lithified sediments or weak rock.

For collection of pressurized cores the FPC and PCTB corers will be deployed. The FPC obtains quality gas hydrate 1 m cores within a range of soil formations, including soft to hard clays, dense (cemented) sands and weak rock. The PCTB provides an alternative to the mud driven FPC and is able to acquire 3.5 m cores in more lithified sediments, but is modified to extend the range also to unconsolidated and clay type formations.

5. SIMOPS

There are no Simultaneous Operations (SIMOPS) expected.

The Matrix of Permitted Operations can be found in Work Instruction #####.

6. PROJECT SITE INFORMATION

6.1 Location

The site is located approximately 250 to 300 kilometres from Cocodrie, LA, with expected water depths of 2,000 m.

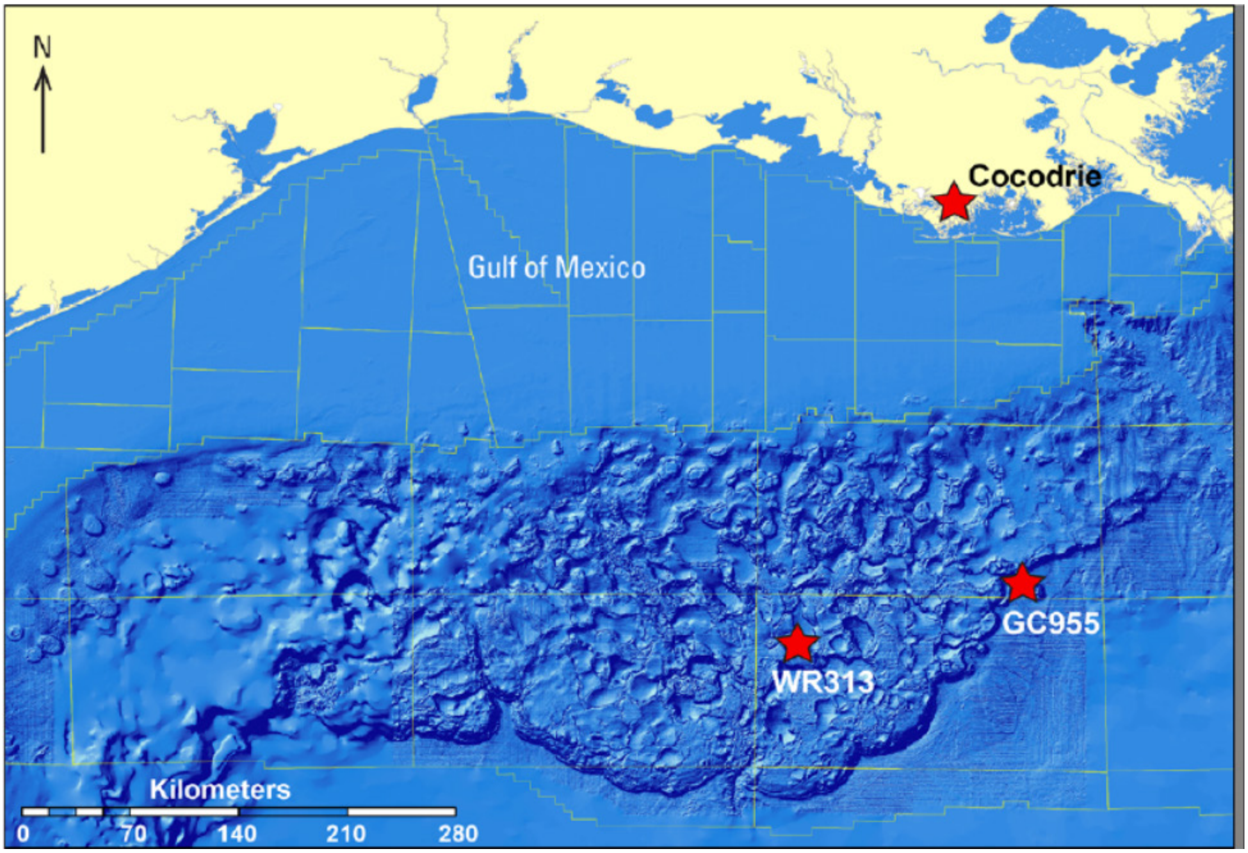

Figure 6.1 General Vicinity Plan

Figure from USGS Report on Deepwater Gulf of Mexico Seismic Survey (2014)

6.2 Geospatial information

6.2.1 Project Geodetic Parameters

The following parameters were provided by the DOE. The parameters to be used in this project will be confirmed by the Client prior to mobilization.

Table 6.1 Geodetic Parameters

Global Positioning System Geodetic Parameters	
Datum:	
Spheroid:	

Grid Units:	
Projection:	
UTM Zone:	
Central Meridian:	
False Easting:	
False Northing:	
Notes:	

6.3 Starfix DGNSS Reference Stations

The Reference Stations to be used for this project are defined in Table 6.2. Actual choice of Reference Stations may be amended at the discretion of the online surveyor and with the agreement of the Client Offshore Representative.

Table 6.2 DGPS Reference Stations

Station	ID	Uplinks

6.4 Vertical Control

Tidal corrections to MSL are to be performed for observed water depth measurements throughout the course of drilling / testing operations at each location. Corrections from nearby tidal stations will be applied to the observations to reduce the observed water depths to Mean Sea Level (MSL).

The specific tidal stations and harmonic constants will be provided by the DOE to generate predicted tides at the survey area over the campaign period. If no tide information is provided by the DOE, Company will use a model based on the standard ports closest to the survey area.

6.5 Horizontal Control and Positioning

6.5.1 Positioning

Primary Positioning System

STARFIX is a multiple reference station Differential GPS (DGPS) system uses Spot beam satellites to broadcast differential correction data from each reference station. To provide coverage for the Gulf of Mexico region permanent STARFIX reference stations have been established at various locations.

Data from each reference station is transmitted to the NCC either directly by digital data line or up-linked to the satellite and then down linked to Houston where it is then transmitted over a digital data line to the NCC.

All stations have a backup, dial-in telephone line which can be used to remotely configure the reference station or if necessary, to modem the data from the station to the NCC. At the NCC, which is manned 24 hours per day, Quality Control of the data is carried out prior to it being encoded into a proprietary format and up-linked to the Spot beam satellites for onward relay to the end user. Average latency of the differential corrections received by the user is typically 5 seconds or less.

The primary positioning system used for this project shall be the STARFIX HP (High Performance) system with differential signals obtained from the satellite, positioned to cover the Gulf of Mexico region. Use of this satellite obviates the requirement for bulky Inmarsat antennae and makes the mobile equipment highly portable.

The STARFIX HP is an augmented wide-area service providing sub-meter accuracy up to 1000 km from HP reference stations. The system is an advance on the STARFIX Plus system introduced as a solution for ionosphere induced errors during periods of high sunspot activity, particular in equatorial areas. The HP uses dual frequency for ionospheric correction combined with observed signal carrier phase to achieve the high accuracy of the system.

Secondary Positioning System

SKYFIX XP has been designed to give the same quality of service expected from HP positioning system on a truly global scale. This state-of-the-art system draws on a completely new technique to provide highly reliable corrections for any location, regardless of distance to a reference station. This unique system is therefore ideal for all offshore operations and activities.

Traditional Differential GPS services use the fixed location of a single reference station to measure the ranges to all GPS satellites in view. These measurements are then compared to the computed ranges at that location and the resulting differences in the observations are transmitted as pseudo range corrections. This technique introduces some inaccuracies as the distance from the reference station grows. SKYFIX XP removes this range limitation by using a completely new technique known as Satellite Differential GPS (SDGPS). Orbit and clock corrections are determined for each GPS satellite continuously utilizing Fugro's global network of reference stations. These corrections are then broadcast to the user and can be used at any location, regardless of distance to any reference station, making the system truly global.

Local troposphere and ionospheric errors are corrected at the user end by using a dual GPS frequencies receiver. Multipath and receiver noise are addressed by using carrier-phase observations within the XP calculation.

DGNSS Positioning

The Starpack system will be used for surface positioning. The StarPack unit consists of a survey grade GNSS combined L-band receiver and powerful processor, running Linux multitasking operating system.

The receiver is capable of tracking all current satellites (GPS, GLONASS) and is Galileo ready. StarPack can be extended with a second GNSS card (in the same unit), to provide accurate, GNSS derived heading. In addition to GNSS observations, the second card provides also L-band functionality, creating an independent source of corrections for backup.

The combination of receiver and processor provides robust multiple simultaneous precise position calculations and extensive QC. For maximum system reliability, the internal software is embedded on a flash memory. System can be controlled and configured via the front panel, web interface or a serial port. Raw GNSS data and corrections are continuously logged internally and can be exported to RINEX to enable high quality support and back-up. User can download this data and send it to Fugro's development center for re-processing.

The embedded processing software of the StarPack GNSS receiver provides multiple configurable simultaneous precise positioning solutions, including G2.

Four independent correction sources:

- HP Network
- XP Network
- G2 Network GPS
- G2 Network GLONASS

Choice of two independent calculation engines (Starfix or SkyFix) that can be configured to use combinations of the above mentioned available correction sources.

There are nine solutions available: Starfix HP, Starfix XHP, Starfix GHP, Starfix XP, Starfix G2, SkyFix XP, SkyFix G2, Starfix L1 and Starfix EPlus.

The new "Best Position" solution is combining all available solutions in to one, using proper weighting. "Best Position" provides increased availability and better accuracy.

The StarPack contains an NTP (Network Time Protocol) server, providing a time accuracy of 500 μs or better with a convergence time after power-on within several minutes.

The StarPack contains also NTRIP (Networked Transport of RTCM via Internet Protocol) client. When internet connection is available StarPack can be connected to Fugro's (or third-party) corrections servers providing additional, independent from L-Band, corrections backup.

Extensive quality control is provided through StarPackQC, a standalone PC based application, or on web interface, Quality control parameters indicating precision, reliability and availability can be visualized for estimated positions as well as for corrections and individual satellites.

At a distance of 1,000 km from the nearest Reference Station, the accuracies are typically 10 cm and 15 cm (95%) in the horizontal and vertical planes respectively. See below in Table 6.3 for more details.

Table 6.3 Positioning Accuracy

Service/ Solution	Accuracy (hor. 95%)	System	Correction Data	Coverage
Starfix L1	1.5m	GPS	L1 pseudo range corrections from multiple reference stations	Regional <500km
Starfix Eplus	1m	GPS GLONASS	Clock and orbit corrections	Global
Starfix HP	0.1m	GPS	Ionosphere-free carrier phase corrections from multiple reference stations	Regional <1000 km
Starfix HP	0.1m	GPS	Ionosphere-free carrier phase corrections from multiple reference stations + clock and orbit	Regional <1000 km
Starfix GHP	0.1m	GPS GLONASS	Ionosphere-free carrier phase corrections from multiple reference stations + clock and orbit	Regional <1000 km
Starfix XP SkyFix XP	0.1m	GPS	Clock and orbit corrections	Global
Starfix G2 SkyFix G2	0.1m	GPS GLONASS	Clock and orbit corrections	Global
Best Position	0.1m	GPS GLONASS	All available correction data	Global
Heading	Better than 0.1° for	GPS GLONASS	-	Global

Acoustic Positioning System

The Sonardyne Ranger 2 USBL system will be used for precise positioning (within the required tolerances) of the SBF at all geotechnical sampling and in situ testing locations.

The transceiver head is permanently mounted on the vessel through a hull pole. Two mini beacons, the CTD and Sonardyne Compatt will be placed on the SBF. All underwater positioning will be recorded by logging the position from the USBL system in Starfix. All positions logged are referenced to the surface navigation.

Upon arrival in the field the Seabird SBE 19Plus V2 probe will be lowered to the seabed to determine the Sound Speed Profile. The full Sound Speed profile will be entered into the USBL system. The sampling rate of the SBE 19Plus V2 is 1 Hz, battery life is in excess of 40 hours. These measurements will be performed upon arrival in the field and repeated as deemed necessary. The water column profile shall then be input into the UBSL console so the appropriate ray tracing compensations can be done. This will compensate for the refraction of the USBL sound waves through the water column.

Once on location and in operation the final position will be recorded. Logging positioning data for the SBF will continue the entire time it is in the water. The SBF will be located on the seabed within a 5 m radius of the target coordinates. A total of 100 position updates from the seabed frame USBL mini beacon shall be recorded and averaged. The result shall be considered a final location report of the final drill string position.

The following data is available to the drillers and operators in the Drilling Cabin:

- Water depth with echosounder
- Heading of the vessel
- Range + bearing to target
- Vessel speed
- Date and time
- BH ID
- Co-ordinates
- Tide
- SBF depth (from USBL mini beacon)

6.5.2 Navigation and Data Logging - Starfix Navigation Computer System

Fugro's STARFIX.SEIS software is an advanced vessel positioning software system and it shall be utilized as the navigation and logging system. The STARFIX.SEIS application enables the navigation system to be configured and modified in real time. It makes use of high accuracy external time sources, such as GPS timer cards or timer-boards connected to GPS (1PPS), to provide microsecond precision and synchronization of all data.

Interfacing to the various systems is achieved either directly via the PC's serial ports and add on multi-port serial cards or through a Qubit Q2780 series interface box. Data from gyros or other survey systems can also be input via the interface box.

The main components of the STARFIX Navigation Suite are:

STARFIX.ANCHORS	-Anchor handling application.
STARFIX.CONTROL	-Toolbar which launches and closes all the applications.
STARFIX.DISPLAY	-Graphical and text display system. STARFIX.IOWIN- Device input and output interfacing application.

STARFIX.LOGGING	-Control raw logging, playback and filters to UKOOA and other formats.
STARFIX.MM	-Message Manager; Central Data distribution system.
STARFIX.MRDGPS	-Multi Reference Differential GPS.
STARFIX.PRINT	-Printing module providing real-time printing sync for all navigation applications; allowing selection of printed information, such as navigation information, anchor activity, for one or more printers and from one or more sources.
STARFIX.QCPLOT	-QC display system for time series plots, statistics, and histograms.
STARFIX.SEIS	-Real-time hydrographic navigation and data logging software module.
STARFIX.WOMBAT	-Control of Tugs and Remote Vessels

Upon completion of installation and interfacing of the systems and sensors, a record shall be generated and outputs to other equipment tested to confirm operational status. A configuration summary shall be printed out and filed in the survey file.

6.5.3 Gyrocompass

The vessels' gyrocompasses will be used to provide continuous digital heading input into the Starfix.Seis navigation computer via a serial interface. This will enable accurate, continuous computation of the vessel offsets from the datum position.

6.5.4 Conductivity / Temperature / Depth Probe

A SBE 19plus V2 (SeaCAT Profiler combined Conductivity / Temperature / Depth (CTD) probe (or equivalent) will be used to obtain speed-of-sound profiles in the water column; this probe will be attached to the seabed frame and the frame will be lowered to the seabed and hoisted back into the moonpool to obtain this speed-of-sound profile. Typically dips are acquired across a spatial distribution that provides a firm representation of the expected sound velocity profile of the survey area. Profiles are geographically referenced and can be spatially or temporally weighted by software.

Conductivity
Range: 0 to 9 S/m
Resolution: 0.005 S/m
Accuracy: ±0.005ºC
Temperature
Range: -5°C to +35°C Resolution : 0.0001°C Accuracy : +/- 0.005°C Pressure
Range: 0 to 20 / 60 / 130 / 200 / 270 / 680 / 1400 / 2000 / 4200 / 7000 / 10500 meters
Resolution: 0.0025% of full range scale
Accuracy : +/- 0.02% of full range scale
Depth
Depth rating: <7000 m

6.5.5 DP Positioning

The ships' DP system will use the corrected DGNSS and the beacon on the seabed frame (or on the seabed) as the second independent position reference.

6.6 Drilling Hazard Assessment and Site Selection

Prior to the fieldwork a drilling hazard assessment and site selection will be performed by Company in close co-operation with the DOE. The purpose is to provide a preliminary, "first-pass" characterization of seafloor and subsurface sediments, and to identify the areas at which gas hydrate is most likely to be encountered in boreholes while also minimizing potential drilling and other operational hazards. Selection of the specific locations for the coring sites will be determined by the results of the assessment.

APPENDICES

A. PROJECT SCHEDULE AND SCOPE OF WORK

B. PROJECT EQUIPMENT

C. PROJECT REFERENCE DOCUMENTATION

A. PROJECT SCHEDULE AND SCOPE OF WORK

B. PROJECT EQUIPMENT

C. PROJECT REFERENCE DOCUMENTATION

WR 313 and GC 955
GAS HYDRATE GEOTECHNICAL DRILLING
GULF OF MEXICO

U.S. DEPARTMENT OF ENERGY

PROJECT EXECUTION PLAN
QUALITY PLAN
LEVEL 2 DOCUMENT
PROJECT NO. 27.2012-2580
PART B

03 September 2015

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0	Draft	A. Wingate	J. Rojas		August 25, 2015
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Figure 1.1 Project Work Breakdown Structure

1. QUALITY MANAGEMENT SYSTEM

1.1 The need for a Quality plan

This project specific Quality Plan has been written to fulfil the following requirements:

i. To show how the Contractor will apply its quality management systems to this project;
ii. To demonstrate, both internally and externally how the quality requirements of the contract will be met;
iii. To show how the project activities have been organized and planned so that the quality requirements and the quality objectives of the contract will be met;
iv. To minimize the risk of not meeting the quality objectives of the contract.

1.2 Scope of the Quality plan

It is essential that this plan does not create unnecessary duplication; the scope of this plan is the following:

i. To identify the processes and quality characteristics that are particular to this specific project and include them for reference;
ii. To provide sufficient detail that the Client and other project stakeholders can have confidence that the quality requirements contained within the contract for this project will be achieved;
iii. To describe the extent to which this project specific quality plan is supported by a documented quality management system;
iv. To define the project management structure, responsibilities of the functions defined and, wherever possible, the individuals assigned to these functions;
v. To detail the document and project control that will be established for the running of the project;
vi. Specific details of the methods of working for each aspect of the work with time schedules and, where required predefined ‘hold’, ‘witness’ or inspection points;
vii. To detail the quality control and quality assurance processes applicable to this project

1.3 Quality Policy

It is the objective of the contractor to provide a continually improving high level of service to the Client which meet the requirements specified and agreed in the contract documents in the most efficient and professional manner available. The delivery of a high quality service is integral to the contractor’s strategic business goal of being the market leader in the field of seabed risk assessment, mitigation and management.

The contractor has developed and implemented a comprehensive management system to control operations which is based around ISO 9001:2008 as a minimum standard and wherever appropriate

the contractor will exceed these requirements to achieve the project’s defined quality objectives. The Quality Policy and Accreditation Certificates applicable to the project are included within Appendix A.

1.4 Scope of Work

The scope of work and how the Contractor will undertake to complete it, has been described in detail Part A – Operational Plan of this Project Execution Plan. However, in order that this Quality Plan can be read as a stand-alone document a short summary of the work to be performed on this project is summarized below in the project Work Breakdown Structure (WBS). This diagram provides a graphical representation of the way the different activity's and work packages fit together and contribute to the final completion of the project:

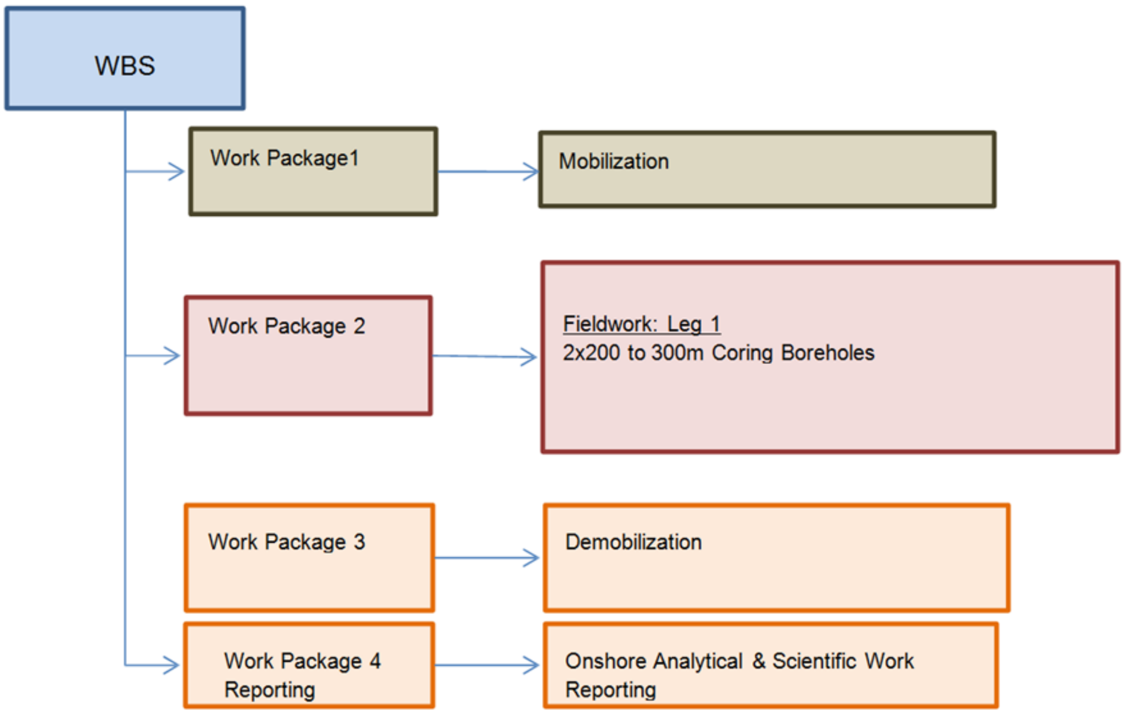

Figure 1.1 Project Work Breakdown Structure

The Operational Plan will contain and describe the relevant standards and criteria required for the successful completion of the project. These have not been repeated here.

2. MANAGEMENT RESPONSIBILITY

2.1 Management Commitment

The Contractor's Senior Management is committed to the successful and professional completion of this project. Indeed, as previously mentioned in Section 1.3 – Quality Policy, the delivery of a high quality service is integral to the Contractor's strategic business goals. The Senior Management responsible for this project are detailed below in Table 2-1 and are the points of contact with the Client in the order listed. Day to day responsibility for the project rests with the Project Manager:

Table 2.1 Senior Project Management Team

Name	Project Role	Direct Tel No Cell No	Email

2.2 Project Resources and Responsibilities

The implementation of the project quality plan is the responsibility of the entire project team under the leadership of the Project Manager. However, the Senior Management team listed in section 2.1 has responsibility for the following:

i. Maintaining a focus on the Client's explicit requirements and/or those requirements that may arise in the course of the project;

ii. Providing leadership in the area of quality management by ensuring that the projects quality management system is established, implemented, maintained and appropriately resourced;

iii. Ensuring that appropriately competent and trained personnel are included within the project teams so that the project objectives can be met;

iv. Ensuring the people in the project organization are fully engaged in achieving the quality objectives and have well defined responsibilities and appropriate authority corresponding to these assigned responsibilities;

v. Identifying and documenting references, processes, procedures and standards that applies to this project. This may include identifying and establishing unique processes that may need to be created, and includes the interactions of these project specific processes with other existing processes;

vi. Identifying and managing the interrelated processes as a system to support efficient and effective project delivery. This requires establishing and documenting clear divisions of responsibility between the different elements of the project's organization;

vii. Making certain that the lessons from previous projects has been applied and that the learnings from this specific project are recorded and available within the management system for analysis and use in the Contractor's continual improvement process;

viii. Ensuring a factual approach to decision making based on analysis of data and information is taking place. This involves analysis of performance and progress evaluations and subsequent revisions of the schedule and/or the PEP;

ix. Maintaining an environment on the project that is mutually beneficial for the Contractor and the project suppliers / sub-contractors. This involves working with the suppliers to reduce risks and in some cases sharing risks when this leads to an increased likelihood of achieving the projects quality objectives.

2.3 Implementation of the Quality Plan

Each Work Package of the project as detailed within the Operational Plan WBS has its own quality measures and persons responsible for carrying out specific quality controls.

2.4 Quality Planning Review

Project quality reviews take place throughout the lifecycle of the project. The project manager maintains the records of these review sessions. It is important that these meetings are held regularly or at key points during the project so that an assessment of quality performance can be made and communicated.

The initial project kick-off meeting is an important milestone where all involved will have the final opportunity to review project planning just prior to entering the execution phase of the project. It is important that all parts of the project team are represented. Minutes of kick-off meetings and regular project review meetings held by the Project Manager will be distributed as required. Details of the planned project review meetings are as follows.

Table 2.2 Planned Project Review Meetings

Meeting	Occurrence Point	Follow on action
Teleconference Planning & Service order	Project preparation / Pre mobilization	agree minutes
Internal kick-off meeting	Pre mobilization	Issue presentation
Vessel kick-off meeting	Vessel mobilization	Issue/agree minutes
Lab test schedule agreement (if applicable)	After borehole and fieldwork completion	Issue/agree schedule
Lesson Learnt / project debrief	After fieldwork completion	Issue/agree minutes
Project Closeout	Project completion	Issue feedback release form to Client

3. PROJECT QUALITY CONTGROLS

3.1 Inspection and Test Plan

The Inspection and Test Plan (ITP) identifies the inspection and test requirements for each phase of work and indicates the witness, review and hold points. It describes who is responsible for the activity and includes supplier and subcontractor requirements. Relevant documentation which needs to be completed is also identified.

The ITP is split into sections to cover the various different types of activity to be performed. The ITP is reviewed and finalized once the methodology for each stage of the installation has been agreed.

The ITP is prepared by the Project Manager with the assistance of participating Opco's and maintained by designated members of the project team.

Table 3.1 Inspection Test Plan

Item	Description	Specification / Criteria	When	Record	Inspection and Acceptance			
					CONTRACTOR		COMPANY	
1	Approval of PEP	Ensure compliance with COMPANY Specifications & Requirements.	BS	Issued as FINAL	H	R	A	
2	Vessel Inspection Audit	Ensure compliance with COMPANY standard requirement.	BS	Vessel Audit Report	H		H	
3	Offshore Laboratory Inspection	Ensure compliance with COMPANY Specifications & Requirements.	BS	Laboratory Inspection Report	H		W/R	

BS: Before Project Execution Phase
DS: During Project Execution Phase
AS: After Project Execution Phase
A : Approval
R : Review
W : Witness Inspection
H : Hold for Inspection REFERENCES

3.2 Instrumentation Calibration and Accreditation

Where equipment is required to be calibrated to reference standards, under relevant procedures, the calibration certificates will be available with the equipment concerned or with the supplying department of the Contractor for inspection and review. In the case of onshore laboratories, accreditation certificates are included in Appendix A.

4. MEASUREMENT ANALYSIS AND IMPROVEMENT

4.1 General

The Contractor and the Contractor's contracted principle suppliers of products and suppliers to this project have planned the implementation of monitoring, measurement, analysis and improvement of the processes needed to demonstrate:

i. Conformity of service to the contractual requirement;
ii. Conformity with the quality management systems;
iii. Continually improve the effectiveness of the quality management system.

4.2 Client Satisfaction

Client feedback is always welcomed and is monitored at key points during the project. Achieving the project objectives is the most important way of gaining Client satisfaction. However, in addition to achieving the project's objectives, ease of communication and the attitude of staff are important elements that are also measured using the Client Feedback Form that is included in Appendix B.

4.3 Internal and External Audits

Internal and external audits are considered as tool for maintaining focus on certain critical areas that can impact the quality of the project.

4.4 Analysis of Data

Feedback generated as a result of the project quality reviews and the ITP, and from other relevant sources, shall be analyzed by the project manager and the project team to demonstrate the effectiveness of the Quality Plan for the project and, if needed, used to stimulate additional actions.

The analysis of feedback should provide information relating to the following:

i. Client Satisfaction
ii. Conformity to specifications
iii. Characteristics and trends related to process and including opportunities for preventative action

4.5 Lessons Learned

The organization shall continually improve the effectiveness of the project management processes and the quality management systems that support projects and operations.

Lessons learned from this project will be captured, via non-conformance reports, meeting minutes, customer feedback forms, and participant interviews and meetings, and used to implement the continued improvement of subsequent projects.

APPENDICES

A. CONTRACTOR'S ISO9001 CERTIFICATE

B. CLIENT FEEDBACK FORM

A. CONTRACTOR'S ISO9001 CERTIFICATE

B. CLIENT FEEDBACK FORM

Customer Importance Rating (**CIR**)	1	2	3	4	5	6	7	8	9	10
	Low								*High*	
Performance Score (**PS**)	1	2	3	4	5	6	7	8	9	10
	Poor								*Excellent*	

PROPOSAL	**CIR** Score *(1-10)*	**PS** Score *(1-10)*
1. Response to your enquiry		
2. Understanding of your requirements and objectives		
3. Standard of proposals		
4. Presentation of project specific QHSE documentation		
PROJECT EXECUTION & COMMUNICATION		
5. Ease of communication		
6. Adherence to project time and cost schedules		
7. Reporting of project progress		
8. Response to queries / concerns		
9. Attitude of our staff		
10. Technical ability of our staff		
11. Performance and suitability of Company equipment spread		
12. Performance and suitability of Company software packages		
13. Ability to manage on site HSE issues		
14. Site Management performance		
15. Project Management performance		
16. Standard of our reports		
17. Quality of reporting and supporting documentation		
18. Adherence to the project QHSE plan		
OVERALL PERFORMANCE		
19. Overall performance on this project		
STRENGTHS –What were our strengths on this project?		
IMPROVEMENT – How could we improve our performance on future projects?		
ADDITIONAL COMMENTS		

WR 313 and GC 955
GAS HYDRATE GEOTECHNICAL DRILLING
GULF OF MEXICO

U.S. DEPARTMENT OF ENERGY

PROJECT EXECUTION PLAN
HEALTH, SAFETY, ENVIRONMENTAL PLAN
LEVEL 2 DOCUMENT
PROJECT NO. 27.2012-2580
PART C

03 September 2015

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Figure 3.1 Project Organogram

ABBREVIATIONS

ADI	Alternate Duties Injury
ALARP	As Low As Reasonably Practicable. To satisfy the ALARP principle, measures necessary to reduce risk must be undertaken until or unless the cost of those measures, whether in money, time or trouble, is disproportionate to the reduction in risk.
BAC	Blood Alcohol Content
BDV	Blowdown Valve
BOSIET	Basic Offshore Survival Induction and Escape Training
CHESM	Contractor Health, Environmental & Safety Management
EEBD	Emergency Escape Breathing Device
ERT	Emergency Response Team
ESD	Emergency Shutdown
FAI	First Aid Injury
FMC	First Medical Certificate
HAZID	Hazard Identification process
HES	Health, Environment and Safety
HOC	Hazard Observation Card
HSSE	Health, Safety, Security and Environment
HSR	Health and Safety Representative
IMCA	International Marine Contractors Association
IMO	International Maritime Organization
ISPS	International Ship and Port Facility Security Code
JHA	Job Hazard Analysis
LMRA	Last Minute Risk Assessment
LTI	Lost Time Injury
LOTO	Lock Out Tag Out
MOC	Management of Change
MSIC	Maritime Security Identification Card
MSDS	Material Safety Data Sheet
MSW	Manage Safe Work
MSZ	Maritime Security Zone
Nm	Nautical miles
NM	Near Miss
OpCo	Operating Company
OVID	Offshore Vessel Inspection Database
PFD	Personal Flotation Devices
PPE	Personal Protective Equipment
Ppm	Parts per million
PSHH	Pressure Safety High High
PSLL	Pressure Safety Low Low
PSV	Pressure Safety Valve

PTW	Permit to Work
RIS	Rig Inspection Services
SIMOPS	Simultaneous Operations
SOP	Safe Operation Procedures
SOLAS	Safety of Life at Sea
SOPEP	Shipboard Oil Pollution Emergency Plan
STF	Slips Trips and Falls
SWA	Stop Work Authority
SWP	Sate Work Procedures
TRA	Task Risk Assessment
VMS	Vessel Management System

DEFINITIONS

Accident	*Any event which results in injury, and / or damage, and / or loss.*
Alternate Duties Injury (ADI)	*Any work-related injury or illness (other than an LTI) which results in a person being unfit for full performance of their regular job on any day after the occupational injury or illness as determined by the current medical certificate. The alternate work placement may involve:* ▪ Assignment to a temporary job, whether full time or part time (>4hrs per day) ▪ Part time work (>4hrs per day) at the normal job ▪ Full time work at the normal job, but not performing all of the normal duties of the normal job.
Competence	*The ability to perform a particular job in compliance with performance standards*
Contingency Plan	*A pre-established plan to mitigate an unusual situation which has the potential for harm, which incorporates the best use of local GMGS remote facilities and resources.*
Danger	*The risk of injury.*
Dangerous occurrence	*Readily identifiable event with potential to cause an accident or disease to persons at work and the public or of significant actual or potential material damage.*
Environmental Incident	*An event that has the potential to adversely affect the environment.*
Fatality	*Death due to work related injury or illness.*
First Aid	*The skilled application of accepted principles of treatment on the occurrence of an accident or in the case of sudden illness, using facilities and materials available at the time:* ▪ *To sustain life.* ▪ *To prevent deterioration in an existing condition.* ▪ *To promote recovery.* ▪ *The most important areas of first aid treatment are:* ▪ *Restoration of breathing (resuscitation).* ▪ *Control of bleeding.* ▪ *Prevention of collapse.*
First Aid Injury (FAI)	*A work related minor injury or illness which can be treated by a first aider or equivalent and does not require a professional physician or paramedic.*
Generic Hazard	*A hazard which may be generally present throughout an operation or industry but which may have widely different levels of risk, depending on the specific site characteristics.*

Hazard	*An object, physical effect, or condition with potential to harm people, property or the environment. The potential to cause harm, including ill health or injury, damage to property, plant, products or the environment; production losses or increased liabilities. A source of danger which, if not adequately controlled or if suitable precautions are not taken could create an unsafe condition. The potential for adverse consequences to arise from the occurrence of an identified event affecting the safety of people, the environment or economic resources.*
Hours worked	*The hours that an employee is present at the work location. The actual hours worked for onshore operations. For offshore workers a 12 hour day.*
Housekeeping	*Maintaining the working environment in a tidy manner so that, in particular, access and movement is not hindered.*
HSE Management System	*The company structure, responsibilities, practices, procedures, processes and resources for implementing health, safety, environmental and security management.*
HSE Plan	*A description of the means of achieving health, safety and environmental objectives.*
HSE policy	*Those documents which record the HSE policy of the organization.*
Incident	*An unplanned release / event or chain or events which have caused or could cause injury, illness and/or damage (loss) to assets, the environment or third parties.*
Injury	*Physical harm or damage to a person resulting from traumatic contact between the body of the person and an outside agency, or from exposure to environmental factors.*
Lock out/Tag out	*A documented system of barriers and notices that prevents the accidental or inadvertent operation of equipment whilst it is being maintained or inspected.*
Lost Time Injury (LTI)	*Any work related injury or illness which prevents that person from doing any work the day after the accident.*
Lost Time Injury Frequency (LTIF)	*The number of LTI's recorded for a group of workers, per million hours worked by that group.*
Material Safety Data Sheet (MSDS)	*A sheet issued by a manufacturer of chemical substances that sets out the hazards likely to be encountered by those who come into contact with the substance. The sheet may also identify recovery procedures following adverse exposure.*
Medivac	*The evacuation for medical reasons from the work location to a hospital.*
Medical Treatment Injury (MTI)	*The injured or sick person requires treatment (more than First Aid) from a professional physician or qualified paramedic.*
Near miss/near accident (NM)	*Any event which had the potential to cause injury, and/or damage and/or loss, but which was avoided by circumstances.*
Occupational Illness	*An abnormal health condition or disorder (physical or mental) that is caused or aggravated by exposure to environmental factors associated with employment, including chemical, physical, biological and ergonomic factors.*
Occupational Injury	*Work related physical injury or disease (illness) which results in death; being unfit to work the day following the event; restriction of work or motion including temporary or permanent transfer to another job.*
Permit to Work system (PTW)	*A formal written system used to control certain types of work which are identified as hazardous. It is also a means of communication between site/installation management, plant supervisors and operators and those who carry out the work Essential features of a Permit To Work are: Clear identification of who may authorize particular jobs (and any limits to their authority) and who is responsible for specifying the necessary precautions Training and instruction in the issue and use of permits Monitoring and auditing to ensure that the system works as intended.*
Personal Protective Equipment (PPE)	*All equipment and clothing which is intended to be worn or held by a person at work and which affords protection against one or more risks to health and safety. This includes clothing designed to protect against adverse weather conditions.*

Policy	*The expression of the general intentions, approach and objectives of an organization and the criteria and principles on which actions and responses are based.* *A public statement of the intentions and principles of action of a company regarding its health, safety and environmental effects, giving rise to its strategic objectives and targets.*
Preventative Maintenance	*Maintenance carried out before the unit or system fails to ensure its continued reliability and safe operation.*
Procedure	*A document that describes how an activity is to be performed and by whom.*
	A document that specifies the way to perform an activity.
Putrescible waste	*Solid waste that contains organic matter capable of being decomposed by microorganisms and of such a character and proportion as to cause obnoxious odors and to be capable of attracting or providing food for birds or animals.*
Quality	*The totality of features and characteristics of a product or service that bear on its ability to satisfy stated or implied needs.*
Quality Management	*The aspect of the overall management function that determines and implements the quality policy.*
Reasonably Practicable	*A risk reduced to levels such that further risk reduction measures would be so disproportionate to the probability and consequences of occurrence that it would be objectively unreasonable to implement them.*
Recordable Injury	*Includes any work related incident where a person is fatally injured or becomes fatally ill or requires treatment from a professional physician or paramedic on more than one occasion for the same incident.*
Recordable Environmental Incident	*An incident arising from an incident that:* *Breaches a performance objective or standard in the EP that applies to the activity; and* *Is not a reportable environmental incident.*
Reportable Environmental Incident	*An incident relating to the activity that has caused, or has the potential to cause, moderate to significant environmental damage (as categorized by the EP risk assessment process).*
Reportable Incident	*Those incidents which are considered significant enough to warrant being recorded as a statistic.*
Responsibility	*Those actions, activities or assets for which a person is held liable and for which they alone must account.*
Risk	*The product of the chance that a specified undesired event will occur and the severity of the consequences of the event.* *The measure of the likelihood of occurrence of an undesirably event and of the potentially adverse consequences which this event may have upon people, the environment or economic resources.*
Risk Assessment	*A careful consideration by competent people of the hazards associated with a task. The potential effect of each hazard, how severe it might be and the likelihood of it occurring should be considered to determine the effort required to make the work site as safe as reasonably practicable.* *The whole process of risk analysis and the evaluation of the results of the risk analysis against technological and/or economic, social and political criteria.*
Risk Management	*A management system which eliminates or mitigates the threat from hazards.*
Risk Sensitive Job	*Activities, personnel or measures that have been identified as vital to ensure asset integrity, prevent incidents, and/or to mitigate adverse HSE effects.*
Significant Incident	*Incidents with a consequence Rating of 'A or B' are classified as significant / serious according to the Risk matrix*
Standard	*A document established by consensus and approved by a recognized body that provides, for common and repeated use, rules, guidelines or characteristics for activities or their results.*
Stress	*Any interference that disturbs a person's healthy mental and physical well-being.*
Substance (Abuse)	*Any substance which chemically modifies the body's function resulting in psychological or behavioral change. In this context substance includes but is not limited to alcohol, intoxicating products or medicine. Substance Abuse is the use of these substances in a harmful or improper way.*

Training	*The process of imparting specific skills and understanding to undertake defined tasks.*
Toxic	*The characteristics of a chemical substance to produce injury once it reaches a susceptible site in or on the body.*
Unsafe Act	*Any act that deviates from a generally recognized safe way or specified method of doing a job and increases the potential for an accident.*
Verification	*Verification is an examination performed to confirm that an activity, product or service is in accordance with specified requirements.*
Waste	*Any material, (solid, liquid or gas), which is introduced into the work location as a product of the work but which fulfils no further useful purpose, at that location.*
Waste Management	*A system to achieve reduction, re-use, reclamation, recycling and responsible disposal of materials.*

1. INTRODUCTION

1.1 Purpose

To perform a scientific soil investigation drilling campaign into the potential presence of gas hydrate (GH) accumulations in Block 313 of the Walker Ridge Area and Block 955 of the Green Canyon Areas in the Gulf of Mexico.

This Project Health, Safety, Security and Environmental (HSSE) document is prepared for the services under this contract.

This HSSE Plan is to define the systems that is expected to be used in the management and administration of Health, Safety, Security and Environment associated with the specific geotechnical survey services.

The following is covered in this HSSE Plan:

- Provide assurance of the effective working of the interface between the HSSE Management
- Systems of the Contractor and the project specific level and to document this interface.
- Demonstrate that the contractor have the necessary procedures and controls in place to achieve the work program without compromising HSSE performance in accordance with Company requirements under the Contract.
- Document any Project specific hazards which may not (or not adequately) be covered in other documents.
- Complement the Vessel's Management System Safety Manual, in order to provide concise documentation that avoids duplication.
- This HSSE Plan is to be read in conjunction with the following project documentation.

- Project Execution Plan - Operation Plan

1.2 Scope of Work

The Geotechnical Scope of Work consists of:

- Coring Boreholes
- In-situ Temperature Measurements

The Project Execution Plan (PEP) explains how the scope of work will be carried out.

1.2.1 Load Out / Mobilization

The Vessel will be mobilized to Galveston, Texas and the contractor shall be responsible for mobilization of crew for the project.

1.2.2 Crew Change

Crew changes for will take place approximately every 35 days. This project is planned for a single phase, with coring to take place. Crew changes will be performed as needed during the investigation.

1.2.3 Demobilization

- Transit from site to Galveston, Texas
- Demobilization of crew and client representatives.
- Demobilization of equipment

1.2.4 Expected Duration

The duration of the fieldwork is expected to be approximately 90 days.

1.2.5 Project Objectives

The objective of the investigation is to collect sufficient data for reach into gas hydrate bearing sediments in the Walker Ridge and Green Canyon Areas of the Gulf of Mexico.

A DP2 or DP3 geotechnical research vessel will be used for this project.

1.3 Project HSSE Goals

The project goals are:

- Zero incidents
- Zero injuries
- Zero environmental incidents
- Reports provided in accordance with milestones

1.4 Compliance Requirements

To ensure Compliance Assurance with the references, regulations and standards identified, the contractor has in place a HSSE management system (HSSE-MS) comprising policies, procedures and practices that meet regulatory, corporate, Contractor Health Environmental & Safety Management (CHESM) and industry requirements.

All personnel including employees and subcontractors shall understand and comply with the identified requirements and they must follow the HSSE Management System (HSSE-MS) and referenced documentation therein.

Project specific HSSE requirements are covered by this HSSE Plan which shall be available to all personnel on the project.

The Project Induction shall include HSSE components, and shall cover both Client and Contractor’s HSSE expectations and requirements.

This Project HSSE Plan and other associated HSSE documents states the controls necessary to achieve and maintain compliance with these HES related acts, regulations, compliance requirements and policies and these controls must be implemented.

The on-board management team, supervisors and safety professionals shall ensure the self-audit process in place to assess and verify compliance with Contractor related policies and standards, and with the spirit and letter of all applicable acts and regulations, regardless of the degree of enforcement, be conducted as per the requirements of this HSSE Plan. Refer also to Section 12.2.

Any identified instances of potential non-compliance will be addressed under Consequence Management (refer Section 4.5) and the instances tracked to resolution.

The Project HSE Coach on board shall evaluate overall compliance status and liaise with onshore HSE Manager and make appropriate process improvements as required.

Oversight and governance shall be conducted in accordance with the vessel ISM system and through management systems certification audits.

2. LEADERSHIP, COMMITMENT AND ACCOUNTABILITY

Contractor has a core value of maintaining and improving the health, safety and security of all personnel and contractors under its control.

Visible and genuine leadership and commitment are key elements towards achieving the HSSE best practice performance and ensuring the effective implementation of this Project HSSE Plan and through compliance with Contractor's HSSE Management & Leadership booklet.

This commitment will be expressed and demonstrated via positive leadership actions and resource allocation. Contractor is committed to providing a safe and efficient place of work for its employees, sub-contractors and Clients. This aim will be achieved by adhering to a defined set of standards and controls that continually strive to improve the performance of its operations and management systems.

2.1 HSSE Management

The Contractor operates a Business Management System (BMS), certified compliant to ISO 9001 and ISO 14001 requirements by DNV Certification and OHSAS 18001:2007 by Lloyd's Register.

All onshore and offshore locations are to ensure effective and efficient access to the project HSSE Plan both electronically and in hard copy where required.

Document and records management will be effectively maintained for all operations in accordance with specified information management details specified later in this Plan. These will be made available for audit, investigation and archive purposes as required.

2.2 Policies and Objectives

The Management of the Contractor is committed to providing a safe and efficient place of work for its employees, sub-contractors and Clients. This is achieved by adhering to a rigid set of standards and controls that continually strive to improve the performance of its operations and management systems.

The Contractor manages the provision of equipment and services in a marine environment and therefore prevention of pollution is of prime importance. The Contractor is committed to minimizing the impact of its operations and processes on the environment and people by a process of continual improvement as defined by the BMS system.

The Health, Safety and Security Policy, and the Environmental Policy are attached in Appendix A. These policies will be followed during the running of the Project. The Contractor's policies and procedures are available for review by the Client to ensure compliance with their Contractual requirements.

During operations onboard the vessel the Company and Client Substance Abuse Policy shall be adhered to. This policy shall be posted at various locations on the vessel and explained during both the project briefing given by the Project Manager at the vessel safety induction performed by the vessel Offshore HSE Officer.

2.3 Visible Management HSSE Commitment

- Communicating expectations for line managers and supervisors to regularly review local HSSE
- Performance and incident root cause data with their teams and seek areas for improvement.
- Safety walk-arounds, safety inspections, audits, observations, incident investigation, risk assessments, training, and other management input as required to maintain required HSSE standards.
- Conducting routine HSSE Meetings. Meetings are held on each vessel, chaired by the Offshore Manager.
- Discussing the progress of leading indicators relative to the project. Enquiring and discussing outcomes from their reviews etc.
- Supporting and implementing the Policy objectives.
- Providing adequate resources to achieve the HSSE policy objectives.
- Reinforcing positive behavior and recognition of excellence in HSSE performance.
- Communicating expectations for individual to actively recognize personnel for their positive commitment to HSSE by the submission of positive Hazard Observation Cards (HOCs) and having awards for any participating in the initiative.
- Being accountable for the HSSE performance of the operations of the project.

2.4 Communication of HSSE Objectives and Goals

Contractor management is responsible for supporting and communication of HSSE objectives and ensuring effective implementation of HSSE objectives and goals.

This communication will be demonstrated through leadership and management meetings, management reviews and HSSE meetings.

2.5 Project Improvement Plan and Key Focus Areas

The processes and systems outlined in the HSSE management documentation provide the tools to enable the application of Contractor's HSSE Aspirations and Expectations. It is however, the commitment and diligence of all personnel and subcontractors that determines the effectiveness of those processes and systems.

To measure the effectiveness of the onboard safety culture, a hazard observation system (HOC) is in place on the vessel.

Some of the key focus areas on this campaign include the following:

Element	Detail	Action	Responsibility
Slips, Trips and Falls (STF)	*Statistics show that STFs have been a major contributing factor in the injury of personnel at site*	*STF to be an item on daily and weekly meetings.*	*Vessel Master/ Offshore Manager*
		Increased awareness of the potential for STFs communicated to all personnel	*Supervisors / HSE Coach*
		Report any potential STF on HOC's.	*All personnel*
DROPS campaign	*DROPS is an ongoing campaign to raise awareness of dropped object incidents*	*Hazard hunt weekly to inspect all locations for any uncontrolled or unnecessary objects that have the potential to fall.*	*Vessel Master Offshore Manager, HSE Coach*
		Increased awareness of the potential for Dropped Objects communicated to all personnel	*Supervisors / HSE Coach*
		Report any potential Drops on HOC's.	*All personnel*

3. PEOPLE MANAGEMENT

3.1 Project Organization

The following table lists the entities, and the services they provide, involved in the project.

Designation	
Company	*Client*
Contractor	*Prime Contract Holder*
Subcontractors	*Provision of Vessel , Marine, Positioning and Drilling Services*
	Provision of coring tools (FHCP, PCTB)
	Provision of coring and in-situ testing tools (FPC, FMCB, FC, EP)
	Survey, positioning and navigation services
	Technical Advisor, *Drilling Hazard Assessment and Reporting*
	Medical and Emergency Evacuation Support

3.1.1 Project Organogram

The project organogram shown in Figure 3.1 summarizes the reporting relationships between the various project personnel.

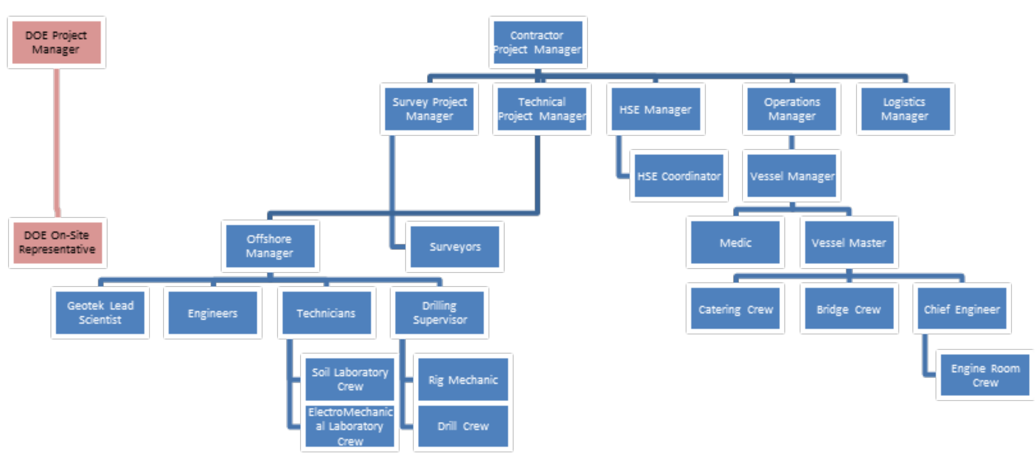

Figure 3.1 Project Organogram

3.2 Client / Contractor Communications

The Project Manager is the prime point of contact with the client. All communications with the Client Representative offshore will be through the Offshore Manager.

Facilities are available onboard the vessel for conferences and meetings. The Project Induction is to be presented prior to personnel joining the vessel. Suitable projection and presentation material will be utilized.

3.3 Project Responsibilities

3.3.1 Responsibilities and Accountabilities Onshore

Contractor's management team is responsible for setting clear leadership examples by their own actions and by promoting a high degree of HSSE awareness. Specific responsibility statements are included below.

Contractor's Management Team	
Managing Director	Responsible for the management of operations.
Project Manager	Will be involved with day to day communications with the Operations Manager and Project Manager.
Operations Manager	Responsible for the geotechnical operations and equipment.
Vessel Manager (VM)	First point of contact in daily operational vessel issues. Responsible MD for operating and maintaining the ships in a safe, economic and efficient manner in accordance with Flag and Class requirements.
QHSE Officer	Responsible for the development, implementation and maintenance of QHSE systems on board vessel. Responsible for monitoring QHSE conditions, ensuring adequate resources to support the systems are in place, and supporting the lead OpCo in any HSSE assessment and reporting requirements.

3.3.2 Responsibilities and Accountabilities Offshore

It is the responsibility of Contractor to ensure the vessel provides a safe place of work as well as provision of safe systems of work for all operations onboard.

OFFSHORE SURVEY & GEOTECHNICAL DIVISIONS		
Offshore Manager	Vessel Based	The Offshore Manager is responsible for the onboard project management including HSSE management of all project related activities including but not limited to all deck and sub-sea activities and associated works and the planning and co-ordination of the work programs and vessel movements. He operates in close consultation with the Master and reports everything related to HSSE to the Master. He will report to the Project Manager and Operations Manager.
Master	Vessel Based	The Master is responsible for the safety of the vessel, the safe execution of all elements of the scope of work carried out by marine personnel and the safety, health and welfare of all persons on board. The Master has the authority to veto the start of project operations or to order their termination if he considers the safety of the personnel, the vessel and/or the environment to be at risk. He is also responsible for the observation of all maritime laws, rules and regulations issued by the vessel flag authority, IMO and port authorities. A major part of this responsibility lies in the implementation of international conventions, codes of practice and national legislation in regard to environmental protection. To this end the vessel Master must motivate the people on board the vessel in the execution of those policies, issue appropriate orders in a clear simple manner and review the safety and pollution procedures onboard the vessel. In matters of safety the Master has the overriding authority and discretion to implement whatever actions he considers to be in the best interests of the persons on board, the vessel and the marine environment.
Lead Geotechnical Engineer	Vessel Based	The Lead Geotechnical Engineer reports to the Offshore Manager and is responsible for obtaining the geotechnical field data. This includes the supervision of geotechnical aspects of the project including laboratory work, soil data collection and QA / QC of geotechnical data. He will report to the Offshore Site Manager and Project Manager onshore.
Drilling Supervisor	Vessel Based	Responsible for the safe and effective operation of all drilling related equipment. Onboard reports to the Offshore Manager for project related matters and the Master for the drilling equipment. Reports to the Operations Manager ashore.
Lead EM and Soil Technicians	Vessel Based	Responsible for the safe and effective operation of all geotechnical tools and systems. Reports to the Offshore Manager onboard and the Operations Manager ashore.
Safety Officer	Vessel Based	The Safety Officer is responsible for the provision of HSS&E advice and support to the operations personnel and reports to the Offshore Manager and Master, functionally reports to the HSEQ Manager. The Safety Officer is not responsible for safety for all on the vessel but rather to advise and mentor everyone on the vessel in all aspects of the Contractor's HSSE Management System.

3.4 Workforce Involvement

3.4.1 Encouragement of Workforce Involvement

The contractor is committed to actively encourage the involvement of personnel in all aspects of HSSE performance. Workforce involvement shall include routine day-to-day contact and discussion, including a structured system of HSSE meetings. These include safety briefings, Tool Box Talks, risk assessments, TRAs, audits, team meetings, daily management meetings, vessel safety meetings, and onshore HSSE project meetings.

Personnel shall be encouraged to contribute innovative ideas, and voice safety and environmental concerns to HSE representatives. Emphasis shall be placed on the role of each individual in the workforce, working together to achieve stated objectives during project HSSE briefings.

All project personnel are authorized to STOP WORK for any activity they believe to be unsafe in accordance with HSE guidelines.

3.4.2 Offshore Safety Representation

The Contractor is committed to actively encourage Safety Representatives in carrying out their role, recognizing the valuable contribution they can make.

Personnel engaged on the project have the option, should they wish, to elect and appoint a Health and Safety Representative (HSR). The elected HSR has the authority to form an H&S committee and make representation to management with regard to any H&S issues that may arise. In the event that an HSR is to be elected, the Contractor will provide facilitation of the election process.

Arrangements for consulting, involving and communicating with Safety Representatives and the workforce on health and safety shall be established prior to project commencement. The Contractor shall provide facilitation for the election of Safety Representatives where requested.

Elected Safety representatives shall be invited to participate in safety-related activities, such as work place risk assessments and worksite safety inspections.

3.5 Safety Stand Downs

Safety Stand Downs may occur from a Stop Work Authority or an incident investigation. Safety Stand Downs shall be used to investigate the situation to ensure it is safe to resume operations. The contract allows for Safety Stand Down’s to be assessed until operations re-commence.

3.6 HSE Meetings

All Contractor and subcontractor personnel shall take an active role in weekly HSSE meetings, daily toolbox talks, vessel safety meetings and any other HSE related meetings required by the Client.

The following are items to be raised and discussed:

- Review of any HSSE issues that have arisen since the last meeting
- Reports on any accidents / incidents or near misses
- Review of Hazard Observation Cards and safety suggestions
- Reports on any Incident investigations

- Review status of close-out of action items
- Any HSSE alerts received from onshore
- Review of the proposed Scope of Work and the need for any review of TRAs

The Client Representatives shall be invited to attend and communicate Client expectations at these meetings.

3.7 Daily Progress Meetings and Reports

A progress meeting will be held daily. Attendees shall include all key stakeholders; Offshore Manager, Lead Geotechnical Engineer, Safety Officer, Client Offshore Representative, functional department heads, key contractor representatives and Vessel Master.

The aim of the meeting is to communicate progress towards project objectives, any HSSE concerns /issues and key targets for the next 24hrs. Items will include:

- Any HSSE alerts received from ashore
- Review of HOC reports
- Review of any HSSE issues and non-conformances
- Communications of activities to be undertaken in the next 24 hours
- Progress against the offshore schedule
- Deviations from agreed and approved operations, procedures or specifications (change management)
- Weather updates

Those attending the meeting are required to pass on relevant information to their subsequent reports to ensure all personnel are informed of current progress, any HSSE issues for attention and planned activities for the day.

The Daily Operations Report shall be sent by the Offshore Manager to all concerned stakeholders and shall include the following information:

- A record of any accidents or incidents
- Work progress
- Personnel coverage hours
- Details of any HSSE related drills and meetings
- Hazard Observation Card (HOC) summary
- Any HSSE issues
- All discharges to the atmosphere, spills from fuels and chemicals used on the project are to be reported.

3.8 Toolbox Talks

Toolbox talks shall be held at every shift change to communicate relevant safety information including status of activities, plant and equipment, hazards, HSSE themes, incidents and any other relevant information.

The discussion could include:

- Any incomplete work to the oncoming shift. Particular attention should be given if the work requires a permit
- New hazards that have been introduced during the previous shift
- Any HSSE issues or points of concern
- Any relevant information of the daily planning meetings

3.9 Communication Language

The common language for communication onboard will be English. Everyone onboard must be sufficiently proficient in the English language.

3.10 Stop Work Authority

Stop Work Authority (SWA) establishes the responsibility and authority of any individual to stop a task when an unsafe condition or act could result in an undesirable event. In general terms, the SWA process involves a stop, notify, correct, and resume approach for the resolution.

Upon ceasing the task, the worker shall notify their supervisor, identify and implement changes to safely complete the task and record the SWA and learning's (a HOC may be used).

If further controls are required to safely mitigate the risk, the Supervisor shall immediately notify the Offshore Manager and HSE Coach and further risk identification may take place to resolve the issue.

4. PROJECT INDUCTION AND COMPETENCY

Project Induction		
Detail	**Venue**	**Responsibility**
Pre Project Briefing	*Onshore*	*Project Manager*
Project HSSE Induction	*Offshore*	*Vessel Master*

4.1 New Employee Induction

New employees undergo an induction process prior to arrival at their workplace. Prior to commencement of employment, new employees are provided with information on:

- Introduction to Company
- Training / inductions
- Company's policies including quality, HSE, alcohol and drugs, working hours / fatigue, bullying etc.
- Company benefits
- Insurance
- Employee responsibilities

On arrival in the workplace, new employees also received an induction which covers subjects such as alarm types, muster points, nearest exits, nearest fire extinguisher, nearest alarm etc.

Personal contact details of the new employee and contact details for next of kin are provided to the HR Manager.

4.2 Training and Competence

Prior to each phase of the work and before commencing offshore operations, the Contractor will ensure that all employees and Subcontractors under project control, including Subcontractors' and vendors' employees, are trained and inducted (to project requirements), in accordance with Contractor's and Client's HSSEQ requirements as defined in the Contract.

The Project Manager will provide CVs for the Master, Offshore Manager, Drilling Supervisor, Lead Geotechnical Engineer and other key personnel to the client.

Other project personnel will have the necessary experience, training and knowledge for the position they are fulfilling on the project.

All personnel involved shall have received relevant HSE training relating to the roles they fulfil, and project specific briefings shall further supplement this.

The Project Training & Competency Program comprises of the HSE Training Needs Analysis and HSE Training Matrix for all roles on-board. The Project Manager shall track compliance for the project team and the Safety Officer for the marine staff.

The Supervisors of the work area will ensure that on-board personnel can demonstrate competence in their vocation, the vessel rules, hazard identification skills and the HSEMS requirements of this Project HSSE Plan.

Employees are to be made aware of the their roles and responsibilities in achieving conformity with the requirements of the HES management system and the potential consequence of departing from the specific procedures

Persons with roles in the MSW process must be trained and authorized to carry out their respective roles and responsibilities

The Contractor shall ensure that a training needs analysis for their Scope of Work is developed, implemented and maintained for all employees requiring specific skills or competencies involved in MSW.

4.3 New Personnel

Personnel who are new to the vessel may require assistance from the vessel experienced personnel. Supervisors and experienced personnel are expected to mentor the SSEs in the correct and safe way to work on-board.

4.4 Project Inductions

All personnel shall undertake a Project Induction onshore prior to joining the vessel. The Project Induction includes HSSE components, including (but not restricted to):

Company policies

- Health and safety policy
- Environmental policy
- Drugs and Alcohol Policy
- Employee relations policy
- Travel policy

- Project HSE Objectives
- Safety Focus Areas
- Slip Trips and Falls
- DROPS Campaign
- Project Organization Chart
- Onboard HSE and Security Systems
- Ship security (ISPS Compliance)
- PPE standards
- Jewelry Policy
- Fitness for Work
- Drugs and Alcohol
- Working in extreme conditions

- Hazard Observation Cards (HOC)
- Incident Management
- Hazard/Risk Assessment
- Toolbox Talks
- Lifting and Rigging
- Environmental Awareness – MARPOL – SOPEP/SMPEP, Waste Management, Marine Wildlife
- Management and environmental commitments.

4.5 Consequence Management

Breaches to HSSE rules, regulations and procedures referenced in this Plan shall be dealt with on site by the Offshore Manager and Master in conformance with the Contractor's HR Manual.

Employees and subcontractors will be removed from duty and from the project if they are in willful violation of the safety rules or exhibit gross negligence in the control of risks to themselves or their work mates. This includes breaches to the Substance Abuse Policy.

Employers of employees and subcontractors who have been subjected to this project consequence management process will follow up with their company disciplinary process.

4.6 Incident Free Operations

A workplace culture program applies to the all personnel onboard.

5. RISK MANAGEMENT

Detail	Date	Venue	Responsibility
Job Hazard Analysis/Task Risk Assessments	*Prior to the start of all non-routine tasks and as a pre-requisite for all Permits to Work*	*Vessel*	*Offshore Manager / Operations Supervisor / Drilling Supervisors / Master*
Toolbox Talks	*To be completed prior to the application for a PTW and at each shift handover*	*Vessel*	*Supervisor*
Project Debrief (offshore, prior to demob)	*Offshore, prior to demob*	*Vessel*	*Offshore Manager*
Lessons Learned	*After demobilization*	*Office*	*Project Manager*

5.1 Hazard Identification and Risk Assessment

Identifying and managing hazards and adverse effects of hazards is a vital part of HSSE management. Contractor hazard management process is designed to do this, and this process has been divided into the four basic steps of Identify, Assess, Control, and Recover, with the aim of reducing risk to a level that is tolerable and as low as reasonably practicable (ALARP).

The main purpose of the hazard evaluation and analysis is to ensure that the risks associated are addressed and preventative and mitigation actions are taken by all parties involved with our operations.

The Risk Matrix shall be used for all risk assessments.

5.2 Task Risk Assessment

The purpose of the risk assessment process is to ensure that hazards identified in the workplace Task Risk Assessment (TRA), also known as Job Hazard Analysis (JHA), identifies and assesses the hazards for each step of a specific task, and defines the appropriate controls and recovery measures.

TRA sheets will be completed by Contractor and subcontractors for all tasks where there is a potential for personal injury (serious or minor), damage to property and equipment or loss. Where specific jobs have a potential for introducing new and unidentified hazards, this will be discussed as part of the daily planning meeting and incorporated into the TRA and Toolbox Meeting.

Generic TRA's identified for this project have been written with reference to previous works performed. These TRAs will be further discussed, modified and signed off by the actual team performing the task prior to the commencement of work and throughout the life of the project.

Changes to equipment, personnel or the vessel will require a review of existing generic TRAs to capture all associated hazards.

- The Offshore HSE Officer will maintain the vessel's TRA Register which will document all TRAs in use on-board.
- Personnel performing TRAs shall have received training and are competent to perform their role.
- Appropriate subject matter experts are to be included in the development of the TRA.

- TRAs shall be reviewed and updated as appropriate (including change in hazards or work conditions) for each shift change.
- When Stop Work Authority (SWA) is initiated an onsite review of the TRA by the affected work crew is required prior to resuming work
- Upon completion of task/job a review of the TRA is conducted to be capture lessons learned and amended prior to recording in TRA library/archive.

5.3 Last Minute Risk Assessment

Personal must carry out a Last Minute Risk Assessment (LMRA) prior to commencing their task to ensure the job is safe to proceed. This LMRA may use STOP or Step-back 5x5 techniques.

5.4 Management of Change

The Contractor's MOC Process will apply to event driven, planned or interface organizational changes, both permanent and temporary. Organizational change and key change drivers covered by the process include:

- Reorganization or redesign
- Upscaling or downsizing

This includes all proposed temporary and permanent changes to processes, procedures, instructions and standards as well as changes to plant, equipment, approved rigging design, safety critical equipment, major conversions, client equipment and maintenance processes

Proposed changes must ensure:

- Sound technical and commercial justification
- The impact of changes are reflected in documentation, including operating procedures and drawings
- The Offshore HSE Officer will log facility change requests in the Vessel MOC database, the Change Originator shall ensure any project changes are logged in project change the Project MOC Register. Every change that will affect the project must be signed off by the Project Manager and Contractor's Responsible Authority together with the Client project representative.

5.5 SIMOPS / Permitted Operations

The matrix of permitted operations summarizes the various operations that may be permitted to be carried out and also the environmental parameters that limit the operation. These parameters have been devised by the Vessel Masters and Drillers based on their operational experience. These parameters are intended for guidance to all stakeholders onboard and should not be used to overrule local decisions made by the Master or Offshore Manager to suspend operations based on safety reasons. The Matrix states that certain operations are not allowed to be carried out concurrently; such prohibitions have the status of firm Contractor rules and may only be overruled by the Management of Change process.

6. HSE PLANNING PERFORMANCE AND MANAGEMENT

6.1 Regulatory Requirements

The Contractor is committed to ensuring compliance with all relevant standards, best practice, regulatory and statutory requirements.

6.2 Performance Reporting

The following are the offshore reporting requirements for the project.

Detail	Target	Responsibility	Where Reported
Daily Report including POB, man hours, HSE Data	*Daily*	*Offshore Manager*	*Daily Report*
Audit / Inspection			
Supervisor safety walk	*1 per day*	*Department Supervisor*	*Informal walk around worksite under their supervision*
Formal Safety Inspection	*1 per week*	*Department Supervisor / Offshore HSE Officer*	*Safety inspection checklist* *Sent weekly to HSE Coordinator and HSE Manager*
Hygiene Inspections	*1 per week*	*Medic*	*Hygiene Inspection*
HSE Communication			
HSEQ Meetings	*1 per week*	*Vessel Master / Offshore Manager*	*Safety meeting minutes* *Sent weekly to HSE coordinator and Project Manager*
Risk Assessment			
Permit to Work	*A TRA accompanies every PTW*	*Permit Authority* *Offshore Manager* *Lead Geotechnical Engineer*	*Permit records* *DPRs*
Non-routine tasks	*A TRA completed prior to all non-routine tasks*	*Supervisor* *Offshore Manager* *Master*	*TRA forms* *DPRs*
Permit to Work Audits	*At least 50% of PTW's audited*	*Offshore HSE Officer*	*Sent weekly to HSE Coordinator*
Induction			
Project Induction	*100% Company and Contractor staff, Third Party Contractors and Project Crew and Client receive induction*	*Project Manager* *Offshore Manager* *Offshore HSE Officer*	*Project induction records (sent to HSE Coordinator)* *DPRs*
Vessel induction	*100% of project crew receive induction*	*Vessel Master* *Offshore Manager* *HSE Officer*	*Vessel induction records* *DPRs* *Sent to HSE Coordinator*

Incident Reporting			
Incident Notification	*Verbal notification within 1 hour.* *2 hours for Environmental incidents*	*Offshore Manager* *Offshore HSE Officer* *Project Manager*	*Verbal notification to Offshore Client Representative* *Incident Notification Form to Incident Report Email Group* *Completed form to Client*
Incident Report	*Within 24 hours of incident event*	*Offshore Manager* *Offshore HSE Officer* *Project Manager*	*Incident Notification Form to Incident Report Email Group* *Completed form to Client*
Draft Incident Investigation, ***all parts completed***	*Within 48 hours of incident event*	*Offshore Manager* *Offshore HSE Officer* *Project Manager*	*Incident Notification Form to Incident Report Email Group* *Completed form to Client*
Final Incident Investigation	*Within 14 days of incident event or as agreed with Client and/or Regulator*	*HSEQ Manager*	*Final incident investigation report*
Presentation of incident report to Client for incident classification ADI or above	*Within 14 days of incident event or as agreed with Client*	*HSEQ Manager*	*Final incident investigation report*
Behavior Safety And Hazard Observation			
Hazard Observation Card reporting	*An average minimum of 1 x card per person per week*	*Vessel Master* *Offshore Manager*	*HOC database to be sent to HSE coordinator weekly*
Safety Critical Plant and Equipment			
Safety Critical Plant and Equipment maintenance, inspection and testing requirements	*All maintenance, inspection and testing activities to be executed in accordance with predetermined schedules*	*Vessel Master*	*TM Master maintenance and certification records*
Actions arising from maintenance, inspection and testing activities	*Actions tracked and close out within agreed timeframes*	*Vessel Master*	*TM Master maintenance and certification records and action tracking*

The HSE Coach shall prepare a weekly report on each of the above items and report the results at each Safety Meeting. The Vessel Master or Project Site Supervisor shall address shortfalls where applicable.

6.3 Incident Reporting

All employees shall be trained to recognize incidents and understand reporting guidelines for all incidents including near misses during inductions.

Detail	Method	Where Reported
Initial Notification onboard the vessel	*Verbal Notification within 1 hour*	*Offshore Site Manager or Master to inform Client Representative immediately*
Incident Report	*Notification of Incident within 2 hours of event*	*Email distribution list:*
Hazardous condition observations	*Hazard Observation card*	*To HSE Officer on vessel*
Unsafe act observations	*Hazard Observation card*	*To HSE Officer on vessel*

The Offshore Client will be notified of an incident or near miss immediately by the Offshore Manager. An incident report shall be sent to all stakeholders within 24 hours.

The Client shall be invited to participate as part of an investigation team.

The Client has then the opportunity to review the initial draft incident investigation report and comment as appropriate.

Contractor's management shall present incident investigation outcomes to Company when requested. Depending on the severity of the incident, a thorough incident investigation with onshore assistance may be required.

A final incident investigation report shall be issued to the Client within 14 days from the time of the incident (dependent on the severity of the incident) or as agreed with the Client. All Near Miss events are to be investigated at the realistic potential consequence level.

The Client Site Representative will complete the reporting process in accordance with Client requirements for incident reporting and the Offshore HSE Officer provide all necessary information and assistance to ensure timely completion.

The QHSE Manager shall ensure that all work related injuries and illnesses are reported via the

IMPACT reporting process.

Incident reports shall be completed for any of the following:

- Fatality
- Lost Time Incident
- Alternate Duties Incidents
- Medical Treatment Injury
- First Aid
- Occupational Illness
- Environmental Incidents

- Near Misses (including High Potential Incidents)
- Road Traffic Accidents
- Non-work related illnesses
- Incidents resulting in damage to equipment, fire or property

Contractor's investigation and causal analysis system shall be used to investigate incidents, the Contractor shall assist Company to align with the Company investigation report form requirements which include but are not limited to Company root cause categories and Tenets of Operation in order for the findings to be re- recorded in the Company safety management system.

6.4 Level of Incident Investigation Reporting

While all incidents should be investigated, the extent of such investigation shall reflect the severity of the incident. There are three levels of reporting and they are defined based on the incident risk analysis and with reference to the Risk Assessment Matrix.

Level 1: Low Risk	**Level 2: Medium Risk**	**Level 3 : High Risk**
Area supervisor (analysis leader) *Employees involved in and witnesses to the incident* *Master / Offshore Manager / Offshore HSE Officer* *Other as deemed necessary*	*Area supervisor* *Employees involved in and witnesses to the incident* *Master / Offshore Manager / Offshore HSE Officer* *HSE Representative* *Affected Line Manager* *Other as deemed necessary*	*Area supervisor* *Employees involved in and witnesses to the incident* *Master / Offshore Manager / Offshore HSE Officer HSE Representative Affected Line Manager Managing Director or their representative* *Others as deemed necessary*

Incident investigation shall be led by a trained and competent Incident Investigation Leader.

6.4.1 Environmental Incidents

All environmental incidents are to be reported by the Project Director to the Company Environmental Specialist for determination of recordability in the Company Safety management record system, Spill and Leak Database.

Environmental incidents may include:

- A spill of any liquids or substances to deck
- A spill of any hydrocarbon or hazardous chemical to the sea
- Death or injury to individuals from a Listed Species under the Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act) during an activity
- Unplanned impact caused to a matter of national environmental significance during an activity
- Introduction of an invasive marine species
- Accidental discharge of domestic or hazardous waste to the marine environment

- Unplanned discharge of ballast or bilge water
- Loss of equipment to seabed
- Impact to heritage values e.g. damage to shipwreck
- Significant disturbance to fishing / shipping and / or vessel collision.

6.4.2 Hazard Observations

Hazard Observations will be reported using the Hazard Observation Cards (HOC).

All HOCs will be compiled into the Vessel Action Tracking Register and reviewed daily by the vessel management team. The Register will be reviewed at the weekly vessel HSE meeting and a copy placed on the notice board so that all parties can view the status of the hazard observations. A copy of the register shall be sent weekly to the HSE Coordinator.

6.4.3 HSE Reporting Database

All incidents will be reported into the Contractor’s database. All subcontracted OpCos shall notify the Project HSE Coordinator of who their Responsible Person will be.

Notes:

1. Incident Report issues within 24 hours.
2. Offshore Manager will issue Incident Report to all stakeholders
3. Vessel will compile draft report Revision A and send to Investigation Reviewers.
4. QHSE Manager will collate response and send back to vessel as Rev B for review and clarifications (and cc Investigation Reviewers).
5. Subsequent drafts will C, D and etc.
6. QHSE Manager will approve Final Report – Revision 0 and authorize PM to issue to all stakeholders.
7. Incident Report will be entered into database by Responsible Person
8. Incident Investigation Report (Rev 0) will be entered into IMPACT.
9. Project Manager and QHSE Manager should be named as Reviewers as they have to demonstrate to external stakeholders that all actions have been closed out

6.5 Safe Work Procedures

Requirements for operations, including standards, codes of practice, general procedures, work instructions and various policies are found within the Vessel MS and project specific procedures. The requirements detailed have been developed to ensure Contractor complies with all applicable health, safety and environmental legislation.

Contractor standards and procedures shall meet or exceed the Company standards and procedures.

Contractor shall ensure that all affected personnel are competent in the SWP's that apply to their work and level of responsibility prior to performing the work or be under the direct (and constant) supervision of a competent supervisor. Refer to section 5.2 - Training and Competence.

Procedures and guidelines shall be followed and be consulted prior to commencing any given activity. Where a change to any of these procedures or guidelines is considered, the following guidelines should be used.

- Processed in accordance with Management of Change (MOC) refer to Section 5.4
- Fully discussed with all interested parties
- Appropriately risk assessed
- Approved by the appropriate authority prior to undertaking the activity

Where no formal procedure or guideline is available the following steps shall be undertaken prior to commencing an activity:

- Implement relevant MOC procedure. Written method statement appropriate to the criticality and scope of the work
- The method statement discussed with all interested parties
- Appropriate risk assessments undertaken
- Approval gained from the appropriate authority.

Contractor may use Standard Operating Procedures (SOP) to perform repeatable or routine work activities. Where a SOP is used in place of conducting a formal Hazard Analysis it shall, at a minimum, meet the following requirements:

- Be specific to the work being done with the full scope of work described
- Break the work down into clearly defined tasks
- Identify potential safety, environmental, health hazards associated with each task and define appropriate mitigation
- Define any requirements for additional permits for Safe Work Practices such as isolations of hazardous energies etc
- Identify activities, roles, responsibilities and authorities assigned to individuals included in the scope
- Be written in a language understandable to the workers doing the job and in a manner that is useful as a reference in the field for onsite review of the hazards and as the job progresses
- Be developed by competent personnel and knowledgeable in the work
- Describe normal operating conditions and what to do in the event of changes in conditions, including emergency response and safe shutdown procedures
- Define any PPE, emergency, special protective clothing, testing/monitoring and other equipment required as mitigations
- Describe any relevant standards (Client, Contractor or Industry) which may be applicable to the job
- Approved by a PTW approver or an appropriate nominated person qualified to approve a SOP
- Performed by trained, competent and qualified personnel knowledgeable of the hazards and capable of implementing the mitigation measures described

- Notwithstanding a formal and documented analysis of hazards must be completed onsite and signed by all members of the field team prior to commencing work.

6.5.1 Lifting Operations and Lifting Equipment

Each lifting operation onboard the vessel shall be undertaken in accordance with lifting, inspection & certification. This does not preclude any legislative duties placed on the individual suppliers of equipment.

All lifting equipment and associated lifting devices supplied shall meet the provisions of the following standards:

- EN12079 Offshore containers and associated lifting sets - Part 3: Periodic inspection, examination and testing
- ABS - Guide for Certification of Lifting Appliances
- MCA M187 - Guidelines for Lifting Operations
- DNV 2.7-1 – Standard for Certification – Offshore Containers
- DNV 2.7-2 – Certification Notes – Offshore service Containers
- DNV 2.7-3 – Standard for Certification – Portable Offshore Units

The additional client specified requirements for lifting are as follows:

- Natural fiber slings shall not be permitted.
- Pallets alone shall not be used to transport equipment offshore; they must be placed within a cargo carrying container or half height container or a designated pallet carrier.
- Tag lines must be of sufficient length to allow personnel handling cargo to work in a safe position well clear of the suspended load, they should be made up from a single length of manila.
- Copies of lifting permits and associated documentation (including records of lifting equipment inspection, maintenance, hazard analysis and competencies) shall be maintained in accordance with the Company Permit to Work SWP Standard.

All lifting equipment and lifting accessories sent offshore shall be accompanied with a current Test Certificate (Record of Examination) stating the date of the inspection / test.

6.5.2 Permit to Work (PTW)

The PTW system will be explained at the project induction and the Vessel Master will ensure the PTW system is used effectively throughout the campaign. If anyone feels that insufficient control or protection is given, the job should be stopped, and the matter should be addressed with their Supervisor, Vessel Master, Offshore Manager or HSE Coach.

The Permit to Work requirements are stringent and the following requirements apply:

- A PTW to be raised when there is a transfer of work and responsibilities from one group to another; or
- Communication across more than one area, group, or technical type is required to accomplish the task; or

- If the Area Controller determines permit is required; or
- Work involving the use of dangerous substances, including radioactive materials and explosives.
- Danger of dropped objects
- Working at height where a rescue plan is required
- Work that requires simultaneous or concurrent activities
- Maintenance activities which compromise critical safety systems or which remove them from service e.g. fire and gas detection systems, public address systems, lifesaving equipment and firefighting equipment

In general, the person issuing the permit to the person in charge of the work should ensure that:

- The work site has been examined, and all precautions specified, including isolations, to be taken before work commences have in fact been taken and will remain effective while the permit remains in force
- The person in charge of the work being done under the permit is aware of the precautions taken, any additional precautions, which are to be taken, PPE to be used or worn, and the procedures to be followed, during the period of the permit
- The work site is examined at any time when work is suspended, and before it is restarted, and finally when the work is completed to ensure that it is in a safe condition
- A TRA is included with permit to work (PTW) for approval
- The TRA is approved by PTW signatory.
- The TRA is kept with the PTW at all times.

Operations within the restricted zone of a Host Facility shall be conducted in accordance with the PTW system onboard the Host Facility.

Permit to Work records shall be retained for at least 12 months except those involving Confined Space Entry which shall be retained for a period of at least 5 years.

6.5.3 Confined Space Entry

Confine space entry to be avoided where possible. If a confined space entry is to occur, a TRA and permit to work shall be raised. The conditions of the permit have been communicated with everyone involved, or affected by the work and a rescue plan is in place. A standby person(s) is in place at all times to raise the alarm – they shall not attempt a rescue.

The Qualified Entry Watch (Standby Person) must maintain the Confined Space Entry Log which includes the name of the entrants and the time(s) they entered or exited the confined space.

Unauthorized entry shall not be permitted. All sources of energy affecting the confined space are isolated. Testing of atmospheres is conducted, verified and repeated as often as defined by the permit conditions.

A separate Confined Space Certificate must be issued for the Qualified Gas Tester prior to entering the space for initial testing.

The persons involved are competent to do the work associated with the confined space. Refresher training shall be provided as follows:

- When significant changes are made to the procedure
- When an individual's training certification expires (generally 3 years).
- Personnel regularly performing a role must also satisfy their supervisor (or other suitable qualified assessor) of their competency, prior to formal appointment by the Person in Charge or Permit Approver, and be able to demonstrate continuous competency throughout their appointment.
- s needed when identified by verification, inspections, incidents or audits

The following are conditions for exercising a Stop Work Authority.

- Work must be stopped and the Permit to Work returned to the Permit Approver for re-evaluation to assess whether the permit can be revalidated under the following conditions:
- The Qualified Gas Tester did not conduct gas testing
- Gas test results exceed established parameters
- The mechanical ventilation system in the confined space fails or is shut down
- Changes occur in the condition of the job site after the permit is issued
- The Entry Watch leaves their post without obtaining a qualified replacement
- The scope of work has changed, such as work not originally anticipated being added
- Unsafe conditions are found that were not previously known
- Portable or continuous gas-testing equipment fails (for example, the battery is depleted)
- Serious safety concerns raised by a worker or company representative
- Facility emergency alarms were activated
- Events from adjacent processes occurred, such as a gas release, fire or spill
- A minor incident or near loss occurred onsite
- The workers reached the time limit designated on the Confined Space Entry Certificate or Permit to Work
- All personnel exited the confined space due to a lunch break or work stoppage lasting more than
- 30 minutes and no one remained at the site to monitor the conditions in the confined space
- The Permit to Work for the confined space is no longer valid.

6.5.4 Working at Height

Refer to

- Contractor Working at Heights policy (part of Contractor Safety Manual)

Where portable ladders are used for access and egress the following applies:

- The person shall maintain three points of contact with the ladder at all times (i.e. hand and two feet or two hands and one foot)
- The ladder must extend at least 900mm above the stepping –off point
- The ladder must be on level firm ground and secured to the structure at all times or footed by another person.
- The base of the ladder shall be placed so that the horizontal distance from the support structure is ¼ of the vertical height of the ladder.
- The ladder must be properly maintained and inspected annually by a competent person.

Refresher training must be provided as follows:

- When significant changes are made to the procedure
- When an individual has not been performing the required role for a period of 12 months.
- Personnel regularly performing a role must also satisfy their supervisor (or other suitable qualified assessor) of their competency, prior to formal appointment by the Person in Charge or Permit Approver, and be able to demonstrate continuous competency throughout their appointment.
- As required by applicable regulations.
- As needed when identified by verification, inspections, incidents or audits.

Scaffolding must be designed, erected, inspected, labelled and dismantled by competent, trained persons.

Prior to working with differences at heights, a consideration to other options such as using a fixed or portable platform.

Fall arrest systems shall be full body harnesses. They will have double locking snap hooks and the lanyards and lines are free of knots and not hooked into themselves. Every fall arrest system is to be inspected regularly and shall hold the proper certificates.

When performing work at height a permit to work has to be issued when the TRA / checklist identifies this but at all times when the height is more than 2 m. The work should always be properly planned and organized. Those involved in working at heights have to be trained and competent. As part of the risk assessment procedure a rescue plan has to be identified and documented.

Workers wearing harness systems shall never work alone; someone must be available to begin the rescue process quickly if a fall should occur. A Safety Standby must be present to notify Rescue Personnel (who must be immediately available) to assist a fallen worker.

6.5.5 Electrical Safety Management

All repair work on electrical equipment with a fixed power supply shall be covered under a Permit to Work. Any repair work on electrical equipment is to be completed by persons that are authorized and competent to carry out the work.

Circuits should be shown to be dead by using the appropriate testing equipment. The testing equipment should be demonstrated to be in working order, both before and after carrying out the tests, and intermediately, if necessary, when testing is prolonged or testing operations are interrupted.

Care shall be taken to ensure that all electrical power supplies, associated with the particular electrical apparatus, plant or equipment, are isolated and that this is done in such a manner to preclude any likelihood of any supply being accidentally or inadvertently made live.

Particular attention shall be paid to the isolation of ancillary supplies for control and indication purposes, etc., and that capacitors are discharged in a safe manner. Work is not allowed on or near exposed live parts of equipment unless it is absolutely unavoidable and suitable precautions have been taken to prevent injury, both to the workers and to anyone else who may be in the area.

When fitted, integral earthing equipment should be used for connecting all main conductors of an isolated unit to earth; alternatively, temporary earthen should be fitted in an approved manner. A danger notice shall be posted.

6.5.6 Process / Mechanical Isolations

All machinery, electrical equipment and or systems being modified or repaired are required to be Locked and Tagged out of service. LOTO shall be used only for servicing, repair, or maintenance, never as a permanent device.

LOTO is firstly done via an actual Lockout followed by a Tag Out. If a lockout is not possible only a Tag Out can be sufficient. To determine if safety standards are not compromised a TRA needs to be held. The TRA should then demonstrate that the level of safety achieved by only applying a Tagout device is equivalent to the level of safety obtained by using a Lock Out and Tag Out combination.

Additional means to be considered are the implementation of additional safety measures such as the removal of an isolating circuit element, blocking of a controlling switch, opening of an extra disconnecting device, or the removal of a valve handle to reduce the likelihood of inadvertent energization.

A PTW must be issued before a LOTO is place.

6.6 Plant and Equipment

Sufficient technical information shall accompany all equipment to ensure that health, safety and environmental concerns are satisfied, specifically with regard to:

- Lifting
- Commissioning
- Operating
- Maintenance
- De-commissioning and demobilization.

The Contractor is responsible for the provision of competent personnel for the installation, operation, maintenance and inspection of their equipment in order to maintain its fitness for purpose. As soon as practicable, any hazard or risk related deficiencies should be reported to Lead Geotechnical Engineer.

All equipment supplied, maintained and used on the project shall be fit for purpose and certified in accordance with the requirements of the following standards as follows.

6.6.1 Bypassing Critical Protections

Definition of Critical Protections - Devices or systems designed to protect personnel, the environment, process, equipment and properties from an undesirable event. Functional critical protections are a vital component of safety systems. They are designed and installed to ensure safe, reliable and environmentally sound operations. Critical protections consist of hardware and software which include, but are not limited to, the following:

- Shutdown devices or systems such as Pressure Safety Low Low (PSLL), Pressure Safety High High (PSHH), Emergency Shutdown (ESD) valves, etc.

- Fire and gas detection and fire suppression devices such as fire pumps, deluge systems, fusible loops, CO_2 fire extinguishing systems, etc.
- Pressure Safety Valve (PSV), Blowdown Valve (BDV) and associated valves
- Safety critical manual valves that are (normally) locked open or closed
- Equipment safeguards, over speed trip, fired equipment flame detectors and similar safety systems.

The requirements include:

- Personnel involved in the authorization, approval, and implementation of bypassing critical protections shall be trained and competent in the roles for which they are responsible.
- Hazards involved with bypassing critical protections for maintenance or testing, planned or unplanned, must be assessed, and alternative protections must be identified.
- Bypassing, inhibiting, isolating, or removing critical protection devices shall be carried out under

Permit to Work controls unless approved to be carried out using a Qualified SOP.

- Bypassing, isolating, or removing critical protections during upset/abnormal operating conditions in order to maintain production is strictly forbidden.

- Only a minimum number of critical protective devices shall be bypassed at a time. There shall be at least one other layer of protection whenever a critical protection is on bypass.
- The Master shall conduct periodic audits and verifications to ensure compliance to this standard.

When considering work that involves bypassing critical protection devices, always consider viable alternatives such as whether the work can be carried out when the equipment, operations or process is shut down.

Bypassing Steps - The following steps should be followed when placing a critical protection device in bypass:

1. Identify critical protection devices to be temporarily bypassed
2. Carry out a TRA hazard analysis and obtain approval to bypass devices
3. Flag devices to be bypassed
4. Perform bypass and record in the Vessel's Critical Protection Bypass Register
5. Monitor the bypassed or blocked-out functions
6. Complete startup, shutdown, operation, maintenance, or testing activities
7. Return critical protective device or system to normal service, and verify functionality
8. heck/verify work completion and notify affected personnel before removing the bypasses and flags

6.6.2 Personal Protective Equipment (PPE)

All project personnel shall be provided with appropriate PPE. Sub-contractors shall ensure that adequate PPE is provided to their personnel.

Personal protective equipment shall be provided and worn when hazards from harmful substances or processes cannot otherwise be prevented or suitably controlled e.g. by elimination, substitution, isolation or administrative controls.

All visitors to the vessel are expected to bring safety glasses, long sleeved shirts, trousers and lace up safety boots, and/or other approved relevant foot protection identified for the task.

Personal Flotation Devices (PFD) shall meet or exceed the requirements of International Standards, or equivalent. The PFD shall be either inherently buoyant or self-inflating on water contact, easily secured to the body, be readily visible and not prone to snagging under water. Retro-reflective strips and clip-on self-igniting lights shall be fitted when undertaking night operations.

Fall Arrest Protection, Inertia Reels and Self-retracting lanyards shall incorporate a personal energy absorber and comply with or International Standards, or equivalent.

LADSafe fall restraint system is implemented onboard the Vessel.

Information on use, maintenance and requirements for PPE are given in safety practices.

6.6.3 Hazardous Substances

Control of Substances Hazardous to Health outline the requirements relating to hazardous substances and dangerous goods. Contractor shall ensure that an MSDS accompanies any hazardous substance supplied, and that activities related to the control of substances hazardous to health are assessed in accordance with the recommendations stipulated on the relevant MSDS.

Contractor shall ensure that all substances are approved in accordance with contract requirements prior to shipping offshore.

All hazardous materials involved with this project will only be used, handled or stored on the Vessel.

All chemicals (i.e. Hazardous Substances and Dangerous Goods) shall be managed in accordance with the hierarchy of control, with the least hazardous material selected where practicable.

Significant risks and potential impacts to human health and the environment (including natural resources) shall be identified, assessed, mitigated and communicated for those health hazards associated with operations, emissions, releases and wastes.

All activities using radioactive sources comply with the Ionizing Radiations Regulations 1999 (IRR99).

6.7 Human Factors Engineering

6.7.1 Manual Task Risk Management Program

Contractor shall have a Manual Tasks Risk Management Program in place for all personnel involved in manual handling and manual tasks. At a minimum this process will:

- Implement a system for the identification, risk assessment and control of manual tasks, at a minimum through TRA, JHA or equivalent;
- Ensure manual handling training is provided to all personnel who complete manual tasks. This training should be provided at the commencement of the scope of work and refreshed as relevant to meet the requirements of their scope of work. This requirement is stated in the Project Training Program – Training Needs Analysis and in the Training Matrix.

6.8 Human Factors Engineering

6.8.1 Chemical Hazards

Refer to section 6.6.3 for Hazardous Substances.

6.8.2 Noise

The Vessel is built to comfort class 3 where considerations to noise and vibration have been included during the design phase of the vessel. The DNV Comfort Class system defines a set of requirements and limits based on International Standards and the vessel conforms to the Comfort Class 3 of acceptable. DNV have certified the vessel as such in the Classification Certificate.

If a potential noise issue presents as an actionable risk, noise surveys can be conducted as required. Where noise is identified as an issue through Task Risk Assessments, actions shall be implemented to reduce the exposure to the noise. These mitigation controls could include limiting the exposure time the task, or through job rotation and use of ear protection.

6.8.3 Temperature Extremes

Temperature extremes are to be identified in advance as part of on-going risk assessments and risks reduced to ALARP standard. Controls and management of temperature extremes must be managed similar to other HSS risks.

Heat stress may be a consideration where a hazard such as heat exposure is present (weather or other sources).

Heat stress shall be reported to the Medic and raise an incident report. Offshore HSE Officer facilitates the investigation as required.

The Offshore team should be encouraged to:

- Organize the work so that jobs with a heat strain risk are done during the coolest time of day
- Use work methods that minimize physical exertion and exposure to heat stress risks, e.g. choose tools and equipment accordingly
- Ensure adequate rest breaks in cool areas are taken
- Keep fluid intake up
- Look out for each other, as heat illness can be hard to self-diagnose due to associated confusion

The following action should be taken if someone has symptoms of heat stress:

- Remove person from heat and rest them in the shade
- Cool person down with a fine spray of water and fan them
- Loosen clothing if possible
- If conscious, give cool, but not cold, water to drink.
- Remove personnel to air-conditioned accommodation.

6.8.4 Vibration

Any vibration issues shall be identified and addressed during the project HSE Meeting.

6.8.5 Hygiene

The Chief Steward or Chief Cook is responsible to ensure that the highest standards of hygiene and cleanliness are maintained throughout the public accommodation areas such as public sanitary rooms, galley and mess rooms.

All personnel onboard are responsible for ensuring that their immediate work area is kept clean and tidy and for informing their supervisor of any spill or debris that may occur as a result of carrying out their work.

Ships may be randomly inspected by surveyors in accordance with the relevant flag state legislation for food safety and hygiene standards.

A hygiene inspection is to be carried out onboard every week by the Medic together with the head of the catering department. The results of each inspection shall be recorded on a hygiene inspection checklist covering the relevant areas onboard (Contractor Hygiene Inspection policy). The time and place of the inspection is to be noted in the official bridge logbook. Findings noted shall be recorded via the HOC system. The results of the inspection shall be discussed in the next safety meeting.

6.9 Fitness for Work

All project personnel working offshore will hold a current OGUK medical certificate with a validity of two years. All marine personnel will hold current IMO standard medical certificates.

Medical and Physical/Functional Assessment shall address:

- The identification of candidates who may potentially aggravate a pre-existing injury or illness (e.g.; undiagnosed chest pain, a history of dizzy spells, or a musculoskeletal problem that may limit performance during test)
- Remote Work (due to the physical nature of the work in remote environments there is no ‘light work’ in the conventional interpretation)
- Work Environment (e.g. adverse weather conditions, exposures in physical exertion to heat)
- Work Factors (shift work with extended hours, changes to routine – working at nights, disrupted work patterns due to crew changes, absence from home for prolonged periods, helicopter and boat travel, open and confined spaces, response to external stimuli – visual and sound, limited privacy)

Medical and Physical Fitness Assessments for all remote area work – offshore personnel shall:

- Ascertain a comprehensive medical history
- Include the following examinations:
  - Audiometry and spirometry
  - A resting EKG to be performed at the examining physician’s discretion

- A sub maximal cardiovascular exercise test (Bruce Protocol or equivalent)
- Include a physical fitness evaluation:

- Pre-existing injuries
- The minimum level of fitness required to safely fulfil job criteria (cardiovascular fitness)
- Muscular-skeletal deficiencies which increase the risk of injury (injury prevention)
- Cardiovascular endurance
- Muscle endurance
- Strength
- Flexibility
- Nutritional habits

■ Include Vaccinations:

- Vaccinations according to World Health recommendations for international travel and work;
- Hepatitis B and Tetanus vaccination should be current for members of ERT and sewerage and waste handlers, with the additional requirements for Hepatitis A vaccination in the latter group.

■ A pre-employment drug and alcohol test is required on the initial assessment (refer to Drug and Alcohol Policy)

■ Roles with specific medical and physical requirements include but are not limited to, scaffolding, working at heights, climbing ladders/walkways, stairs confined areas, use of self-contained breathing apparatus, exposure to extremes of physical exertion, exposure to heights, manual tasks, and significant travel (more than 6 work related trips per year).

6.9.1 Drugs and Alcohol

Personnel shall ensure that any prescription or non-prescription medication is notified and risk of impairment assessed. Individuals will be required to:

■ Discuss with their medical practitioner the nature of their duties to identify any possible side effects from the prescribed medication, which may affect their fitness for work.

■ Notify their supervisor and Facility Medic of the medication they are taking and quantities they have in their possession. This includes anti-smoking aids.

■ Personnel shall ensure that they have sufficient supplies of their medication with them on their offshore trip bearing in mind that delays and extended periods offshore may be unavoidable so additional supplies of their medication are to be carried as required.

■ All personnel who work offshore must have blood alcohol content (BAC) of 0.00 g / 100 ml. Personnel may be subject to testing and failure of any tests will result in disciplinary action.

Contractor shall have for all personnel, a drug and alcohol testing program that meets the Company requirements.

A positive result for alcohol and/or Controlled Substances conducted are to be confirmed sample results at the following nominated levels:

■ Alcohol - greater than 0.00% BAC.

■ Controlled Substances, as per the table below:

Controlled Substances	Cut Off Level (μg/L)
Opiates	300
Amphetamine type substances	300
Cannabis metabolites	50
Cocaine metabolites	300
Benzodiazepines	200

Prior written consent shall be obtained from any individual who is to be tested. A positive test, or a failure to give written consent for a test, or a substituted or adulterated test, or a failure to take a requested test is cause for removal from the vessel, and may result in the individual being restricted or disqualified from performing offshore services.

6.9.2 Fatigue

When allocating shift patterns and rosters, supervisors shall take into account the additional fatigue that may be imposed on persons arriving at the Facility and suitable arrangement shall be implemented to minimize exposure to fatigue and related fatigue risks (such as driving or operating machinery or equipment).

Once a person has been assigned a shift pattern, the person should remain in that shift pattern for as long as the shift arrangement is in place. Supervisors must avoid changing a person's shift pattern where possible and obtain required authorizations for shift change to the Offshore Manager (Project Personnel) or Master (Marine Personnel)

The project work carried out by Contractor varies considerably both in complexity and duration and the length of offshore trips vary accordingly.

Normal offshore working is a twelve-hour shift pattern. Those that have been working for over 14 hours are required to seek authorization for each event greater than 14 hours. If a person is called out during an off shift period, the person shall be provided with an eight hour break between completion of call out and the recommencement of work.

For all personnel operating mobile and fixed plant, equipment and those with designated safety critical positions, work hours shall not exceed 16 hours.

While personnel are on shift, adequate rest and meal breaks are to be provided.

6.10 Medical Facility

The Vessel is equipped with medical facilities and staffed by an ISOS Medic in compliance with standard vessel requirements.

This will enable the provision of medical facilities and personnel qualified to deal with the majority of injuries likely to be sustained during project work and the escalation of these injuries to minimize the requirement for medical evacuations as much as possible.

Medical evacuation options are considered in Project Emergency Response Plan.

6.10.1 First Aid

Any workplace event requiring a first aid treatment and subsequent observation of minor scratches, cuts, burns, splinters, etc., which do not require professional medical care, can be treated by the site / facility.

First aid assessment and administration may be conducted by a First Aider, Medic, Medical practitioner or registered professional may also administer First Aid.

7. ENVIRONMENTAL CONTROLS

7.1 General

The vessel has an approved management systems that are certified to the International Convention for the Prevention of Pollution from Ships, 1973.

7.2 Performance Objectives, Standards and Criteria

Preventative and management measures will be applied throughout the offshore phases, to ensure that significant environmental impacts and risks associated with the activities are minimized, mitigated or avoided.

7.3 Waste Management

The applicable marine environmental protection includes:

International

- International Convention for the Prevention of Pollution from Ships (MARPOL):
- ANNEX I – Oil Pollution
- ANNEX II – Noxious Liquids Bulk
- ANNEX III – Harmful Packaged Substances
- ANNEX IV – Sewage
- ANNEX V – Garbage
- ANNEX VI – Air Pollution

The following are environmental commitments which must be adhered to:

- All personnel working on the vessel shall comply with the vessel waste disposal procedures, including those for routine discharges, and are responsible for assisting in minimizing waste generation and effective segregation of waste, to optimize reuse, recovery and recycling.
- Sewage / putrescible wastes macerated prior to disposal.
- Treated sewage to be discharged >3 nm from land; untreated sewage to be discharged >12 nm from land. Sewage discharge requirements apply also for marine protected area boundaries
- If survey vessel unable to treat/store grey water, where possible biodegradable soaps and detergents will be used.
- Discharges of sewage and putrescible wastes recorded in survey vessel engine room log.
- Bilge water contaminated with hydrocarbons to be contained and disposed of onshore, except if oil content of effluent is <15 ppm. Bilge water discharges recorded in engine room log.
- Bilge water discharge will only occur at distance of >12 nm from nearest boundary of any marine protected areas
- If survey vessel unable to treat/store grey water, where possible biodegradable soaps and detergents will be used
- Discharges of sewage and putrescible wastes recorded in survey vessel engine room log

- Bilge water contaminated with hydrocarbons to be contained and disposed of onshore, except if oil content of effluent is <15 ppm. Bilge water discharges recorded in engine room log
- Bilge water discharge will only occur at distance of >12 nm from nearest boundary of any marine protected areas
- Bilge water contaminated with chemicals must be contained and disposed of onshore, except for low toxicity chemicals
- All chemical and hazardous wastes segregated into clearly marked containers prior to onshore disposal. All storage facilities and handling equipment in good working order and designed in such a way as to prevent / contain any spillage
- No discharge of plastics or plastic products of any kind from vessels. No discharge of domestic or maintenance wastes overboard
- All solid, liquid and hazardous wastes (other than sewage, grey water and putrescible wastes) to be incinerated or compacted; stored in designated areas and sent ashore for recycling, disposal or treatment
- Incinerator compliant with MARPOL and IMO requirements and operated by trained personnel in accordance with established operating procedures. Records maintained of incinerator usage (engine room log).
- Incineration of any oil sludge aboard, or disposal of any oil sludge/slops in port, must be recorded in Oil Record Book
- Garbage Record Book maintained to record quantities of non-burnable wastes transported to shore, and detailed records of waste accidentally discharged

Waste management procedures onboard require garbage to be segregated into the following categories for collection and recycling in port by our waste management service provider:

- Scrap metal
- Batteries
- Glass
- Aerosol cans
- Medical waste and sharps (e.g. syringes and blades)
- Hazardous waste (e.g. chemical, fibrous)
- Aluminum cans
- Plastics
- All paper.

The vessel has an incinerator and shall be operated by a trained person and used in accordance to specification.

Incineration of the following is prohibited:

- Cargo residues from oil and noxious bulk tanks and related packaging materials
- Cooking oils and greases

- Garbage containing more than traces of heavy metals
- PCBs (polychlorinated-biphenyls), PVC (unless certified)
- Refined petroleum products containing halogens
- Aluminum cans
- Aerosol cans
- Plastics

All waste which has been incinerated must be recorded in accordance with MARPOL requirements.

All garbage that is disposed to sea must be recorded in accordance with MARPOL. The location of the recycling bins shall be explained at the time of induction.

All bins are clearly labelled and have lids to prevent cross contamination and to prevent rubbish from being blown away, refer to Garbage Management System 4239-109-003.

7.4 SOPEP

Refer to:

- Contractor SOPEP Manual
- Contractor Waste Stream Management Plan.

Environmental commitments to be adhered to include:

- SOPEP's are available around the vessel in high risk areas and managed by the bosun.
- All used SOPEP kits are to be placed into skip bins with lids, and disposed by contracted waste management service providers.
- Liquid wastes are to be bundled to ensure no spills.
- Hazardous wastes are to be stored and segregated from other general waste.
- The SOPEP is subject to at least two scheduled oil pollution drills during the course of survey, the first of which will occur within seven days of start of survey. The first drill includes verification of List of Coastal State contacts and Port Interest Contact.

8. SUBCONTRACTOR MANAGEMENT

All subcontractors on this project, other than the provision of some marine crew are all OpCos.

All the subcontractors, shown in Section 3.1, have previously worked together on various other projects with the Contractor. They all have their management systems certified to OHSAS 18001. The safety of the facility is considerable enhanced by each Contractor's operating company providing highly competent and trained specialists who are used to working together to the common Contractor HSE standards.

All subcontractor and OpCo personnel are included in the application of this HSSE Plan on the vessel and all personnel are included in the delivery of the project HSE Induction prior to the start of work.

All project personnel engaged at the worksite operate in accordance with the Contractor HSSE Policies, Standards, Plans, procedures and processes as indicated in this plan:

- Each subcontractor will identify a single point individual accountable for each contract.
- The Contractor's Project Director will ensure active engagement of all subcontracted parties in implementing safety management processes including:
- Ensure that they are working toward the same HSSE, reliability and efficiency goals as Company for incident- and injury-free operations
- Ensure that their management takes ownership in communicating and implementing applicable
- HSSE procedures
- Ensure that they have a process of dialogue and communication throughout the Sub Contractor organization thereby creating an environment for two-way communications.

9. INFORMATION MANAGEMENT

9.1 Protocols

All protocols in relation to contractual correspondence, document and records control for the project will be in accordance with the Project Survey Plan.

The Project Manager is the focal point for project / contract related correspondence with Company. All outgoing formal documentation to Company must be reviewed and signed by the Project Manager or nominated delegate.

10. SECURITY

Security process for key service providers including freight forwarding, aviation, shipping, road transport, supply bases, port facilities and EPCMs (in addition to the above) shall:

Have developed and implemented risk based security management plans for the specific operation including:

- Preventative measures and procedures that minimize the probability of a security incident occurring including:
- Identity Control
- Access control
- Freight and Mail Security
- Security Guard Force Operations
- Key Management and lock up procedures
- Information Protection
- Response measures and procedures that minimize the loss or damage if a security incident does occur including:
- Police notification and response
- Bomb threat
- Workplace violence
- Fraud and theft
- Crime scene management
- Discovery of contraband
- Business continuity arrangements that enable essential business functions to recover from a security related incident as quickly as possible.
- Communication and consultative arrangements in place that ensures all staff are vigilant to the security environment including:
- Security Awareness and Vigilance
- Where applicable education, training, drills and exercise are undertaken to test and enhance any security arrangements
- Security incident reporting and action process is in place
- Include an auditing and review process to continually enhance the plan

10.1 ISPS Compliance

In order to comply with the requirements of the International Ship and Port Facility Security Code (ISPS) implemented on 1 July 2004, measures have been implemented to reduce the threat to the vessel from terrorist attack.

To ensure compliance with the vessel security policy, and in accordance with the Ship Security Plan, the Contractor shall notify in advance the Ship Security Officer of the name date and identification details (generally passport) of all personal joining the vessel. Personnel shall note that if the vessel has not been notified, there will be delays and potential embarrassment caused by people being treated suspiciously.

In addition to the passport required for identification, if the person is participating in the offshore element of the project, a valid medical certificate and Safety of Life at Sea training certificate (BOSIET), should be presented when arriving onboard all vessels.

10.2 Security Alert Levels

Level 1: Normal operational level. Minimum appropriate protective security measures shall be maintained at all times.

Level 2: Heightened risk of a security incident. Appropriate additional protective security measures shall be maintained for a period of time where there is an increased risk of a security incident.

Level 3: Security incident probable or imminent (even with non-specific target). Specific protective security measurements are maintained as required.

10.3 Port Security

A Security Officer shall be placed at the gangway to ensure all personnel and assets going on-board are verified.

10.4 Maritime Labor Convention Requirements

In conformance with International Labor Organization (ILO) Maritime Labor Convention (MLC) 2006, which entered force in August 2013, all personnel who sail on the vessel must be able to produce to the Master the requisite documentation required under the MLC Boarding Requirements.

11. EMERGENCY RESPONSE

Refer to: Project Emergency Response Plan

The response procedure for emergencies onboard the Facility is detailed in the project Emergency Response Plan.

In the event of an incident or emergency medical need, the Facility Medic, in consultation with International SOS Medical support team shall convey recommendations on a case by case basis.

11.1 Oil Spill

The Shipboard Marine Pollution Emergency Plan (SMPEP) 4239-109-001 contains the process for spill management in accordance with the requirements of the International Convention for the Prevention of Pollution from Ships as adopted by the International Maritime Organization (IMO) known as MARPOL 73/78. The SOPEP is a vessel-based response to an oil spill. In the event of a spill determined to be beyond the capability of the vessel SOPEP, the Client oil spill contingency plan shall be activated by the Client Site Representative.

11.2 Project Emergency Contacts

For full information on emergency notifications for the project refer to the project Emergency Response Plan.

Emergency Contacts			
Detail		**Phone**	**Email**

11.3 Drills

Drills and exercises are carried out in accordance with the requirements of "SOLAS" and flag states as a minimum. The events during such exercises are recorded in the official deck log book and engine room log book when appropriate. The Drill Matrix is followed when planning drills as far as appropriate.

A desktop Medivac emergency response exercise will be conducted prior to transit to site with the purpose of testing the ER arrangements. In addition to the desktop exercise, Contractor and Company will conduct weekly ER communication checks and report this accordingly in the DPR. If any of the contacts or contact number changes throughout the life of this document, the document will be revised accordingly and reissued.

12. AUDIT AND REVIEW

12.1 Client Audit

The Client or their authorized representatives shall have unrestricted access at all reasonable times to the facilities, equipment, materials, personnel, and records to audit any or all of the Health, Safety and Environmental Systems of Contractor.

12.2 Audit and Inspection

The following audits and inspections are conducted on a regular basis:

Audit Type	Frequency
HSE Inspections	Weekly
Hygiene Inspections	Weekly
PTW Audits	Daily
Vessel HSE Audit	Weekly
Working at Heights	At least once per project
Review of standards	In accordance with Audit Schedule
IMCA/OVID Vessel Audit	Annual

12.2.1 Field Safety reviews

Onboard Management and Line Supervisors will conduct regular planned Field Safety Reviews (Engagements) to confirm that the requirements of this project HSE plan are being applied effectively to their areas of responsibility onboard. They shall discuss and review the nature of the field work identified in the Hazard Analysis and submit a Positive HOC to record their discussion.

12.3 Performance Feedback

As part of the Contractor’s quality assurance system, ongoing Client feedback is requested regarding HSSE systems during the offshore campaign and at the close of every campaign. A CFSF (Customer Fieldwork Services Feedback) form shall be sent to the QA Manager once completed.

12.4 Improvements

If a review of the findings from performance feedback or audit highlights areas where health, safety and environmental performance do not meet agreed standards, Contractor shall co-operate with the Client to produce and implement an appropriate improvement plan. All actions arising from the HSE continual improvement process will be entered into database and assigned to a responsible person, the Project Manager will monitor the actions and ensure they are closed out.

12.5 Lessons Learned

The lessons learned process shall be carried out in two stages:

- Lessons Learned review – held onboard as a project debrief at the end of the project before the demobilization when personnel will be leaving the vessel. Aim to capture valuable information gained from project personnel.
- Lessons Learned session – held at the Contractor offices when all project work is completed.

Participants could include senior personnel from subcontractors and the Client. Information gained at the project debrief shall be included in the lessons learned session.

Actions emanating from the Lessons Learned session shall be captured in the Contractor's database and assigned for action and should include estimated dates for completion. Revisions to HAZID worksheets, project plan templates and procedures shall include the approved recommendations from the lessons learned sessions.

12.6 Project Close Out

A review of project performance shall be held by the Contractor on completion of the project. This shall allow the identification of areas where improvements may be made in the future.

13. DISTRIBUTION

Copies of this procedure have been distributed as follows:

DOE - 1 x electronic copy

APPENDICES

A. POLICY STATEMENT

B. TASK RISK ASSESSMENT REGISTER

C. MATRIX OF PERMITTED OPERATION

D. PPE MATRIX

A. POLICY STATEMENT

B. TASK RISK ASSESSMENT REGISTER

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:							Last Revised:	
Department:	GE = General		DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical		GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		
ID#	**Rev. Date**	**Revision**	**Title**			**Prepared by**	**Initial risk**	**Residual Risk**
GENERAL								
			General Manual Handling					
			General Work At Height					
			General Hot Work					
			General Crane Operations					
			General Working On Electric Or Electric Equipment					
			General Working In Confined Spaces					
			General Use Of Hand Power Tools					
			General Working In Hot Environment (Heat, Sunlight)					
			Removal Of Isolation Material					
			General Mobilization And Demobilization					
			Diving Operations					
			Shortening of Sheeve Frame Bit Guide Locating Dowels					
			Use of bench grinder					
			1000M Zone of DSV					
			Welding in ER 2nd deck AC unit					
DECK								
			Anchor Operation					
			Mooring Operation					
			Chipping And Cleaning With High Pressure Wash Gun					
			Launch And Recovery MOB					

MATRIX OF PERMITTED OPERATIONS (MOPO)

	Activity												Environmental Condition						
Activity	Small boat ops (except emergency)	Crane Ops Inboard	Crane Ops Outboard - within port limits only	3rd party (external) crane at sea re-supply with barge or other vessel	Moonpool Ops - Drilling and Downhole Operations	A-Frame Ops - Deploy/ Retrieve Equipment	Conversion from drilling to seabed mode and vice versa	At sea bunkering	Hotwork outside accommodation	Working at height	Close Approach to Offshore Facility (500m) *	Boat-Boat transfer	Wave Height < 0.5m	Wave Height > 0.5m and < 2.5m	Wave Height > 2.5m	Vessel's Heave > 2.0 m	Vessel's Heave > 3.0 m	Hours of Darkness	Wind Strength >30 kts, h = 10m
Small boat ops (except emergency)		Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	Y	N	N	N	N	N	N
Crane Ops Inboard			Y	Y	Y	Y	Y	Y	Y	Y	Y	N	Y	1	1	1	N	1	N
Crane Ops Outboard - within port limits only				N	N	N	N	N	Y	Y	Y	N	Y	N	N	N	N	N	N
3rd party (external) crane at sea re-supply with barge or other vessel					N	N	N	N	Y	Y	Y	N	Y	N	N	N	N	N	N
Moonpool Ops - Drilling and Downhole Operations						N	N	N	Y	Y	Y	N	Y	Y	Y	Y	N	Y	2
A-Frame Ops - Deploy/ Retrieve Equipment							N	N	Y	Y	Y	N	Y	Y	Y	N	N	Y	Y
Conversion from drilling to seabed mode and vice versa								N	Y	Y	N	N	Y	N	N	N	N	Y	N
At sea bunkering									N	Y	N	N	Y	N	N	N	N	Y	Y
Hot work outside accommodation										Y	N	Y	Y	Y	Y	Y	N	Y	N
Working at height											Y	Y	Y	Y	N	N	N	Y	N
Close Approach to Offshore Facility (500m) *												Y	Y	Y	Y	Y	Y	Y	Y
Boat-to-Boat transfer													Y	N	N	N	N	N	N

Notes:

- This document is a guideline only.
- Only the Master has over-riding authority

Legend:

Y	Operation permitted
N	Operation NOT Permitted
1	Operation permitted only with roll and pitch angles < 3 degrees
2	Operation permitted only when vessel is within the DP Operational Limits.

Vessel Management System

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical	GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		

ID#	Rev. Date	Revision	Title	Prepared by	Initial risk	Residual Risk
			Gangway Maintenance And Operation			
			Entering Dry Dock			
			General Maintenance On Crane			
			Working Over The Side			
			Personnel Transfer From/To Crew Boat By Pilot Ladder			
			Vessel Back Deck and A Deck Ports and Starboard			
			Vessel Back Deck (1^{st} deck) under the A frame			
			High Pressure Wash			
			High Pressure Wash Pot Water Tanks			
			Energizing Drives For Thrusters At Port			
			Deployment And Recovery Beacon With Forecastle Winch			
			Loading Of Dry Bulk			
			Operation Of Compactors			
			Deployment And Recovery Of Taut Wire			
			Deployment And Recovery Beacon With E-Line Winch			
			Helicopter Medivac By Winching			
			10ft Container Vessel To Vessel Transfer			
			Painting			
			Spooling wire of beacon winch			

Vessel Management System

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical	GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		

ID#	Rev. Date	Revision	Title	Prepared by	Initial risk	Residual Risk
CATERING AND GALLEY						
			Galley And Mess Room Activities			
ENGINE ROOM						
			General Maintenance On 4 Point Mooring Winches			
			Emergency Generator Maintenance			
			Purifier Maintenance Work			
			Thruster Filter Inspection/Replacement			
			Thruster Maintenance			
			Aft S.W. Pump#1 Maintenance/Repair Work			
			Thruster No1 Drive Test			
			Bilge Holding Tank Pumping			
			FO Booster Pump Maintenance/Repair Work			
			MDO Bunkering			
			Air Compressor Maintenance Work			
			FW Aft Stb. Pump#2 Maintenance/Repair Work			
			SW Pump No1 Maintenance/Repair			
			Operation Of Incinerator			
			Main Generator Maintenance			
			Inspection dry bulk tanks			

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical	GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		

ID#	**Rev. Date**	**Revision**	**Title**	**Prepared by**	**Initial risk**	**Residual Risk**
			Inspection FO tanks			
Rig Maintenance						
			Hydraulic Maintenance work			
			HP Air System Work			
			Pipe hustler Maintenance			
			Iron Roughneck Maintenance			
			Maintenance of Winches			
			Triplex Mud pump maintenance			
ELECTRICAL OPERATIONS						
			Thruster No1 Drive Test			
			Main Switchboard Maintenance			
			Main Generator Maintenance			
GEOTECHNICAL OPERATIONS						
			Function Testing The HP Air System			
			Conversion SBF From Downhole Mode To Seabed Mode			
			Removing Or Installing Traction Winch Drums			
			Reeving wire over Traction Winches And Through Sheaves			
			General Moonpool Operations			

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical	GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		

ID#	**Rev. Date**	**Revision**	**Title**	**Prepared by**	**Initial risk**	**Residual Risk**
			Seabed Ops With SEACALF - Stringing And Unstringing CPT Rods			
			Handling, Extrusion & Storage Of WIP And Piston Samples			
			Stringing And Unstringing Drill Pipes			
			WISON EP Operations			
			Working In Roosterbox With Downhole Tools			
			WISON MK IV Operations			
			Conversion SBF From Seabed Mode To Downhole Mode			
			Loading And Unloading Of Drill Pipe			
			Transiting With SBF Down			
			Fishing of Downhole Tools with EP Winch			
			Handling Logging / UPC Cable To Seabed Frame			
			Boxcore Operations through A-frame			

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						Last Revised:	08-03-2015
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical	GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		

ID#	Rev. Date	Revision	Title	Prepared by	Initial risk	Residual Risk
			Winch Spooling On Drill Floor (Guiding Cable Manually)			
			Deckscout Operations			
			A-frame Winch Function Test And Load Test			
			Large Gravity Piston Core (LGPC) Operations			
			Traction Winch Function Test			
			Pressure Testing Of Umbilical Cable			
			Pressure Testing Of WVA On Stand Pipe			
			Spooling A Frame Winch Wire Rope			
			Spooling E Line Wirerope For Pull Test			
			Lowering SBF From Drill Floor Door To Moonpool Flippers			
			Reeving UCE Cable Over UCE Sheaves			
			Rig Simulation Test With Water Bags			
			Un-Reeving UCE Cable Over UCE Sheaves			
			HPU Start Up And Pressure Test			
			Elevator Pull Back Test			
			Cutting TW & UPC Wire			
			Spooling/Unspooling Traction & Storage Winches			
			Spooling UPC Wire Onto UPC Winch			

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
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ID#	**Rev. Date**	**Revision**	**Title**	**Prepared by**	**Initial risk**	**Residual Risk**
			Spooling Headline Winch Wire Rope			
			Headline Winch & Tool Handler Function & Load Test			
			Mud Mixing			
			Deployment And Recovery Of SBF			
			Moving SBF From Hatch To Moonpool			
			Seasoning Traction Winch Wires & UPC Wire			
			Assembling And Disassembling SBF At Sea			
			Operating The Iron Roughneck			
			FMCB Operations			
			WISON EP Operations – With Personnel In Roosterbox			
			Pipe Handler Operations			
			Deploying And Recovery Of SBF After Seasoning Wire Rope			
			Working On SBF In Moonpool On Chains			
			Use Of Manual Tongs with Headline for Pup Joint			

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
	EL = Electrical	GO = Geotech.Ops	LA=Laboratory	SU=Survey	SE = Security		

ID#	**Rev. Date**	**Revision**	**Title**	**Prepared by**	**Initial risk**	**Residual Risk**
			Assess E-Line Wire In Crown Beam And Retrieve Tool			
			Testing of E-Line Winch Tension Settings			
			Assembling and Disassembling SBF			
			Transiting with Moonpool Doors Open with Levelling Frame			
			Seabed Ops with SEACALF – Unstringing CPT Rods using Deck Clamp			
			Removal of LGPC Rails			
			Seabed Ops With SEACALF - Stringing And Unstringing CPT Rods with Buoy			
			Operating in close proximity to subsea assets			
			Assembling And Disassembling Levelling frame			
			Transiting with the Moonpool Doors Open.			
			UPC Winch Constant Tension and Load Test			
			Tripping Pipes Using Manual Tongs			

TASK RISK ASSESSMENT REGISTER

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ID#	Rev. Date	Revision	Title	Prepared by	Initial risk	Residual Risk
			Seabed Ops With SEACALF – DP Vessel Move with CPT Rod String located in the Derrick			
			Seabed Ops With SEACALF - Stringing And Unstringing CPT Rods with Orange Buoy			
			Exchange of UPU on SBF on short chains			
			LGPC Operations – Trigger wire caught around trigger arm (emergency recovery)			
			Reeving Headline Wire Rope over top sheaves			
			Triaxial Unconsolidated Undrained Test			
			Sample Preparation			
			Ovens For Drying Of Soil Samples			
			Carbonate Content			
			Hot Wax			
			Manual Lifting Of Heavy Loads			
			Miniature Vane Test			
			Sample Transport Onboard the Voyager			

TASK RISK ASSESSMENT REGISTER

Vessel/Office name:						**Last Revised:**	**08-03-2015**
Department:	GE = General	DE = Deck	CA = Catering & Galley	ER = Engine Room			
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ID#	**Rev. Date**	**Revision**	**Title**	**Prepared by**	**Initial risk**	**Residual Risk**
			Vessel to Vessel Transfer Of Sample Boxes			
SURVEY						
			Compatt Deployment And Recovery - USBL Calibration			
			Gyro Compatt Deployment And Recovery			
			CTD Probe Deployment And Recovery Using E Line			
			CTD Deployment And Recovery Using A Frame			
SECURITY						
			Security Passage Plan India To Singapore			

C. MATRIX OF PERMITTED OPERATION

D. PPE MATRIX

WR 313 and GC 955
GAS HYDRATE GEOTECHNICAL DRILLING
GULF OF MEXICO

U.S. DEPARTMENT OF ENERGY

PROJECT EXECUTION PLAN
EMERGENCY RESPONSE PLAN
LEVEL 2 DOCUMENT
PROJECT NO. 27.2012-2580
PART D

03 September 2015

1	Final			Gary Humphrey	August 30, 2015
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1. INTRODUCTION

The purpose of this plan is to set out how the Contractor shall respond to a notification of an emergency situation and who shall be responsible for the process.

This plan shall apply to any notification of an emergency situation, which effects company personnel, and shall include those working on the various vessels to be utilized on the project.

Emergency response is a key element of the HSE Management System. It is the final means of demonstrating that all reasonable care has been taken to minimize risk to personnel, plant and the environment. The objective of emergency response is to be prepared in order to respond to emergencies in a timely and effective manner.

1.1 Responsibilities

It shall be the responsibility of the Project Manager to ensure that this plan is implemented. It shall be the responsibility of the Offshore Manager and Vessel Master that this plan is adhered to by the project team.

1.2 Emergency Definition

An emergency by its very definition is an unpredictable unforeseen event. For the purpose of this plan an emergency shall be a situation which cannot be dealt with locally, at a work site, and which requires some immediate external support and assistance to be mobilized. This shall include medical cases requiring evacuation.

‘Major’ emergencies are those involving serious injury or fatality to personnel, severe damage to a vessel/equipment and/or a significant environmental contamination.

1.3 Emergency Awareness

Personnel induction is conducted in Contractor’s office. All project personnel intending to sail or work on any project vessel shall attend a Vessel Induction given by the Vessel Master or his nominee. This induction will be conducted within 24 hours of anyone joining the vessel for the first time.

Emergency situations are assessed on a project basis and a specific Emergency Response Plan for medical evacuation (MEDEVAC) of personnel is prepared at time of the contract.

2. EMERGENCY RESPONSE PROCEDURE

A dedicated emergency contact telephone number shall be promulgated in all contract correspondence.

2.1 Emergency Response Initiation

When an emergency occurs, the initial alert will usually be made from the emergency location itself.

The Vessel Master (where appropriate) and / or Offshore Manager has the authority to initiate an emergency response or medical evacuation of a seriously injured person. This is to be carried out by working directly with any of the established emergency services or MEDEVAC resources operating in the area (e.g. the client representative, OIM of nearby platform or a helicopter operator).

Where applicable this project specific Emergency Response Plan should be read in conjunction with the Emergency Response Plan of the work site or vessel operators (held onboard the vessel).

2.1.1 Primary Communication

Upon identification of an emergency, initiation of an emergency response should be commenced by communicating with the following primary contacts. These primary contacts will allow an appropriate response to be coordinated.

- Onboard / on site Client's Representative;
- Onboard Offshore Manager (if emergency is raised by the Vessel's Master);
- Emergency services/coastguard agencies;
- Vessel owners / operators (where appropriate);

2.1.2 Secondary Communication

Once the emergency response has been initiated, through the primary communication channels, the following secondary contacts should be informed of the emergency (when safe to do so and at a time which will not interfere with the immediate emergency response).

- The Emergency Response Duty Officer should be contacted by the Vessel Master or Offshore Manager;
- The Project Manager should be contacted by the Emergency Response Duty Officer;
- The Client should be contacted by the onboard / on site Client Representative, and then by the Project Manager once he has been made aware of the emergency.

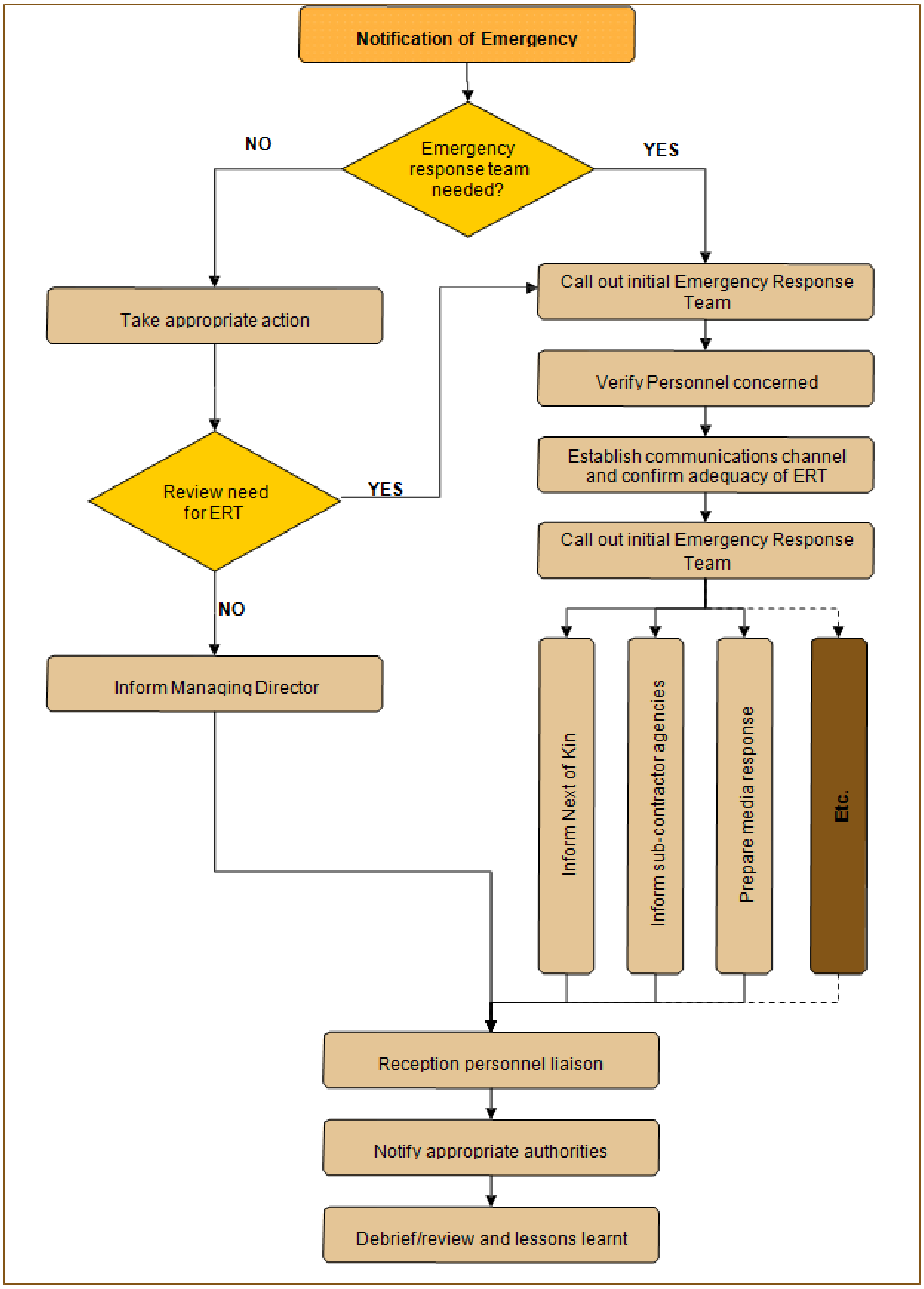

Figure 2.1 Management Emergency Response Flowchart

2.2 Emergency Response Team (ERT) Requirement

Upon receiving notification of an emergency the Emergency Response Duty Officer shall log the following:

- Contact person, date & time of notification;
- Communication details, telephone & fax numbers, e-mail address and any reporting schedule;
- Work site affected by emergency;
- Nature of emergency and current status;
- Number of personnel thought to be involved. They shall then undertake the following:
- Liaise with Companies involved;
- Liaise with vessel owners/operators;
- Inform Engineers, Directors/Managing Director;
- Liaise with stakeholders (i.e. client, next of kin).

The Emergency Response Duty Officer shall review current knowledge of the emergency and then decide whether an initial Emergency Response Team (ERT) is required. In general, all notifications of a ‘major’ emergency will require an ERT to be convened.

2.3 ERT Not Required

Where the decision is taken that an ERT is not required, the following actions will be taken by the

Emergency Response Duty Officer:

- Monitor the situation and log details (see Section 2.6);
- Keep stakeholders and Project Manager appraised of the situation;
- Once the emergency is declared under control inform all parties and record final details and close the log;
- Debrief and review (see Section 2.5).

2.4 ERT Required

Where the decision is to convene an ERT the selection of team members will be in accordance with the following guidelines. The ERT Leader will use their experience to decide which team members are required for a particular emergency.

Table 2.1 Emergency Response Team Guidelines

ERT Member	1st Choice	Possible Deputies
Team Leader	Emergency Response Duty Officer	Director/Managing Director
Project Specialist	Project Manager	Package Manager
Operations	Package Manager	Package QHSE Advisor
NOK/Relative Support 1	Personnel to be selected as dictated by the Emergency	
NOK/Relative Support 2		
Media Response	Managing Director	Director
Switchboard	Suitably briefed member of staff	

2.4.1 Verification of Personnel Involved in the Emergency

The first task of the ERT once it has gathered in the emergency room is to confirm the names and number of personnel on or at the emergency site. This information is contained in the Emergency Response Manual (see Section 2.6).

2.4.2 Emergency Response Team Responsibilities

The ERT Leader shall allocate responsibilities to include, but not limited to

- Communications with worksite ERT;
- Record keeping;
- Next of Kin/Relative Support;
- Media response;
- Communications with Main Office.

2.4.3 Record Keeping

It is essential that an accurate written and timed Event Log of all events and actions taken throughout the duration of the emergency is maintained. This shall include all communication to and from the ERT with details of caller or person being called together with brief description of content of the call.

2.4.4 Establish Communications

The ERT Leader shall establish communications with the initial reporting person, issue the direct telephone & fax numbers for the Emergency Response Room, establish the status of the emergency, and set up a contact schedule.

Two dedicated landlines plus mobile phone communication will be maintained.

Where required by contract, communications will be established with the relevant client personnel.

2.4.5 Communications/Contact Numbers

Contact details for Client and Contractor's key personnel, both onshore and offshore, are presented in Appendix B.

2.4.6 Emergency Response Team Adequacy

The ERT Leader shall continually review the adequacy of their resources to tackle the current emergency. If required, additional resources shall be called out.

2.4.7 Access to Premises

During the period of an emergency access to the premises shall be restricted and controlled. Clear identification shall be required for all those seeking access. If during normal office hours then additional security personnel should be considered.

2.4.8 Notification of Next of Kin

In the event of fatalities, most countries have fixed guidelines and rules about who shall inform Next of Kin (NOK).

The NOK Support members of the ERT shall, wherever practical, be the sole contact for Next of Kin or relatives of any member of staff.

NOK/relatives shall be appraised of the situation as soon as possible and be provided with direct telephone numbers to keep in touch with the ERT.

2.4.9 Media Response

The media response members of the ERT shall prepare a response to any likely questions relating to the emergency raised by the media.

It is essential that any information given to the press is well coordinated and consistent with that issued by other parties involved.

A company director must approve press statements, following liaison with the Managing Director. Personnel disembarking a vessel following a major incident or disaster offshore, who are faced by the press, should refrain from making any comment.

Release of information regarding an incident must be approved by the Client before dispatch.

In the event of any hydrocarbon or chemical escape into the sea, the Shipboard Oil Pollution Emergency Plan (SOPEP) shall be used. The Client shall be informed as soon as possible and the vessel shall respond to their requirements.

In the event of an incident of a Non-Government Organization (NGO) nature, reference will be made to the Contractor Emergency Procedures. The Client shall be informed as soon as possible.

Table 2.2 Release of Information

Incident	Response Role	Description
Incident involving NGO activists	DOE	Press releases to be agreed between DOE / Contractor before release
Incident involving oil spill	DOE	Press releases to be agreed between DOE / Contractor before release
Any other incident *	DOE	Press releases to be agreed between DOE / Contractor before release

2.4.10 Notifying Authorities

Depending upon the nature of the emergency certain authorities have to be notified within prescribed periods e.g. RIDDOR. The Project HSE Advisor shall be responsible for ensuring all relevant organizations are informed in a timely manner.

2.5 Debrief and Review

A debrief meeting and review of the actions taken in response to the emergency situation shall be undertaken by the Management Team, lessons learnt from this shall be recorded for future reference.

2.6 Emergency Response Manual

An Emergency Response Manual will be produced and maintained. There will be two copies, one held in the vessels Emergency Response Room and one by the Project Manager.

The manual will contain as a minimum;

- Project Execution Plan;
- Project persons onboard (POB); and
- Staff contacts details.

3. CLIENT REPRESENTATIVES DUTIES

3.1 Emergency

In an emergency, the Client Representative onboard will carry out the actions covered in the vessel emergency procedures. If possible, he will contact the onshore Client.

• On fire or gas detection or other life threatening emergency, the Client Representative will follow instructions given by the Vessel Master or Offshore Manager and go to the muster station/muster point as per the vessel emergency procedures. If not a false alarm, the Representative will contact the Client, if possible; and

• The Client Representative will log developments, attend the debrief meeting, review the official report and report to the Client relevant manager / supervisor.

3.2 Other Incidents

In the case of a fatality, injury, man-overboard, kidnap or ransom, malpractice and misdemeanors, the Vessel Master will be the on-scene commander to take charge of situation and carry out the necessary actions as per the relevant vessel/site procedures. As soon as possible the, Client Representative will inform the onshore Client.

The Client Representative will log developments, attend the incident review meetings, review the official report. A copy of the report will be send by the Offshore Manager to the Client.

4. INITIAL MEDICAL RESPONSE

4.1 Minor Cases

The paramedic and/or certified First Aiders on-board the vessel will deal with all minor cases.

4.2 First Aid Medical Treatment Cases

The paramedic and / or First Aider on-board the vessel will assess all medical treatment cases. If the injury/condition is not life threatening, then the paramedic will provide the appropriate treatment and seek further medical advice. Contact details for local emergency services are presented in Appendix B

4.3 Emergency Medical Treatment Cases

If the situation arises where a serious medical incident occurs and the casualty requires emergency medical treatment that is not available on-board the vessel, the MEDEVAC procedure outlined in Section 5 should be followed.

It recognized that a considerable period of time can be consumed between the moment an emergency rescue is called for and the practical moment when the patient is physically transported from the vessel/work site.

The paramedic or Offshore Manager shall (he can assign these duties to competent crewmembers):

- Monitor the patient's status;
- Advise shore representatives on sea state/weather conditions;
- Decide on a safe method of evacuation based on the needs of the patient, safety of the crew and vessel;
- Communicate with the onshore doctor regarding the needs of the patient.

The Vessel Master has the responsibility to assess the suitability of the patient for a transfer.

The Master of the vessel from which the patient will be transferred has the responsibility for the safety of the transfer operation after consulting with the respective master(s) of the other vessel(s).

The Vessel Master is to give due consideration to the potential hours of time saving compared with the increased risk of transferring the patient to another vessel for evacuation.

When a patient is evacuated, the following information is to accompany the patient:

- Patients name;
- Time and location;
- Description of incident, injury or illness;
- State of patient;
- Pick-up location.

5. MEDICAL EVACUATION (MEDEVAC) PROCEDURE

5.1 MEDEVAC Procedure

The nature of the MEDEVAC will largely depend on the location of the incident (offshore / near shore) and the severity of the casualty (life is in danger/life is not in danger).

If the situation arises where a serious medical incident occurs and the casualty requires emergency medical treatment, the following action should be taken:

- The Paramedic / First Aider on board the vessel should immediately administer first aid and prepare the casualty for medical evacuation;

- The Vessel Master and / or Offshore Manager will immediately cease operations. During marine operations the Vessel Master shall prepare the vessel for maneuvering and/or steaming to the nearest port or transfer point;

- Depending upon the availability of services in the area and the local weather conditions several transfer scenarios are possible. A general diagram of MEDEVAC possibilities is given in Figure 5.1. Contact with the emergency services should be conducted in the following manner:

Marine Operations: Vessel Master has primacy for on-vessel emergency response. Decision to medevac to be made by vessel Master with input from Medic and consulting with the DOE Offshore Representative;

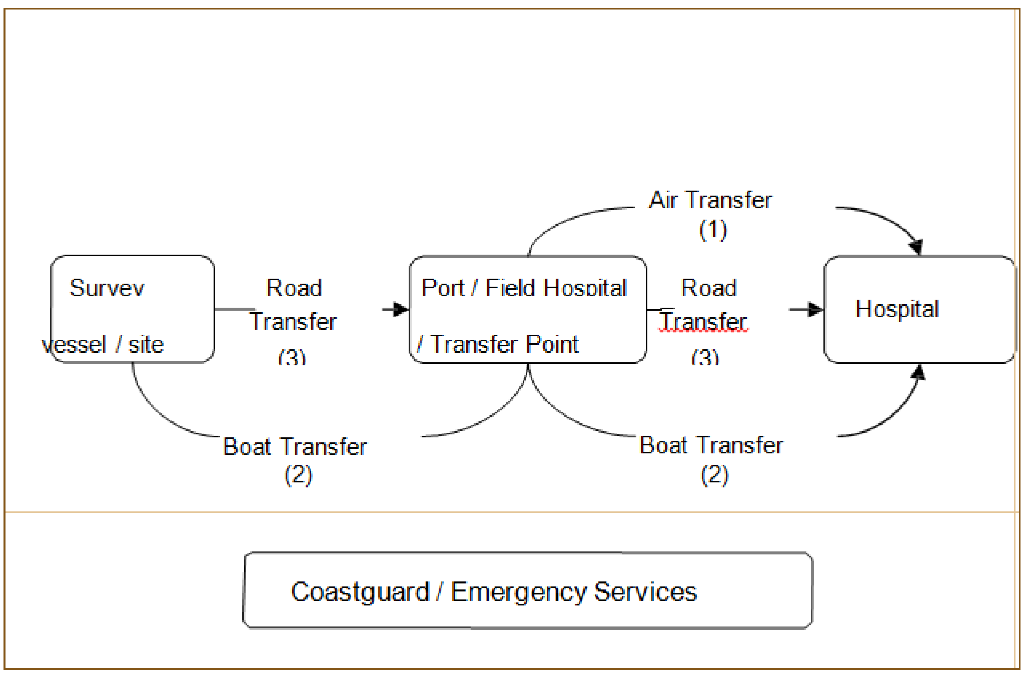

Figure 5.1 All Transfer Scenarios

APPENDICES

A. EMERGENCY AND OPERATIONAL CONTACTS

A.1 PRIMARY EMERGENCY RESPONSE

A.2 SECONDARY EMERGENCY RESPONSE

A.3 CLIENT EMERGENCY AND OPERATIONAL CONTACTS

A.4 THIRD PARTY ORGANIZATIONS AND CONTACTS

A. EMERGENCY AND OPERATIONAL CONTACTS

A.1 PRIMARY EMERGENCY RESPONSE

Vessel Owner / Operator	
Main Switchboard	
Vessel Manager	
Operations Manager	

A.2 SECONDARY EMERGENCY RESPONSE

Main Switchboard	
Managing Director	
Senior Project Manager	
Project Manager	

A.3 CLIENT EMERGENCY AND OPERATIONAL CONTACTS

A.4 THIRD PARTY ORGANIZATIONS AND CONTACTS

SAFETY AND OPERATING GUIDELINES
for
HYDRATE DRILLING AND CORING OPERATIONS

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I. GENERAL SAFETY & OPERATIONAL CONSIDERATIONS

The purpose of these "guidelines" is to provide a practical and flexible framework on which hydrate drilling and coring operations and site-specific "operations procedures" can be based by mutual agreement of the Drilling Contractor's and Operator's management, engineers, shipboard supervisors, and scientific community. It is not possible in one document or procedure to foresee and clearly cover all the contingencies, combinations of reactions, or ultimate effects that may occur in a given situation; therefore, a team effort is crucial to determine the best course of action and coordinate operations.

I.A. Responsibility and Authority

Maritime law states that the ultimate and overall responsibility for safety on board the ship resides with the master of the vessel (i.e., the Captain). The Drilling Contractor's senior representative onboard (i.e., the "Drilling Superintendent" or equivalent) is typically in charge of drilling related operations when the ship is in dynamic positioning mode (except where the safety of the ship is involved). The Operator's representative has a parallel responsibility to monitor operations and stop any potentially unsafe operations. The vessel's viability as everyone's life-support system has first priority. The safety of individuals has priority over the safety of the drill string and other equipment.

I.B. The Contract

The Contract must specify which is authorized to issue operating instructions (preferably written) to the Contractor. The Operator's representative is responsible for working with the Contractor's supervisory personnel to ensure compliance with the contract and insure the safe and most effective use of time and materials in compliance with the Operations Plan. All parties should ensure that operations are conducted with professionalism and mutual dedication to getting the job done efficiently and safely. The responsibility for interpreting and administering the Contract should reside with the Operator's and Contractor's administrative office onshore.

I.C. Optimizing Operations & Safety

The Operator's and Contractor's supervisors should work closely together to encourage safe operating practices. Aside from humane considerations, safety is even more critical to hydrate operations because of the potential for hydrate decomposition with the rapid expansion of high-pressure methane gas and the potential for bursting liners or launching core and projectiles. Also, moving heavy equipment on a heaving, rolling ship is a potentially hazardous business; however, prudent and professional personnel can perform many tasks with minimal risk and exposure through planning and the use of proper equipment, tools, and personnel.

<u>The taking of unnecessary risks for expediency SHOULD NOT BE ENCOURAGED OR PERMITTED.</u>

The Operator's and Contractor's supervisors should work closely together to maximize operating time and minimize unproductive or lost time by "scheduling" downtime events (elective repairs and maintenance) when possible for more efficient operations and to reduce risk during downtime in hydrate formations, which typically are sticky, swell and are unstable.

II. PLANNING & SAFETY MEETINGS

II.A. Operational Planning

The Operator's seismic and geological information and operations plan for each drill site should be reviewed by an external safety panel. The safety panel should provide advice to the Operator and Contractor regarding potential safety and pollution hazards that may exist due to general or specific geology of the seafloor or as a consequence of drilling activities.

The Operator's operations plan should be reviewed with the Contractor and other responsible parties to reach agreement on feasibility, time, cost, location, environmental factors, safety, and pollution prevention. A pre-operations meeting should be held with operations personnel about 6 months prior to operations to ensure that the necessary tools, equipment, and supplies will be available.

II.B. Initial Introduction & Safety Meeting

The Operator's and Contractor's supervisors are responsible for ensuring that all personnel aboard the vessel are informed of the vessel's safety policies and regulations and that they cooperate in the attendance of fire, lifeboat, H_2S, and other drills which may be held on board the ship. Before departing port, a meeting should be held for all personnel to introduce the Contractor's and Operator's supervisors and explain safety policies. The Operator's Supervisor should ensure that policies regarding safety equipment (hard hats, safety shoes and glasses), visits to the rig floor and derrick, consumption of alcohol and other prohibited drugs, etc are fully explained and rigidly enforced for visiting technical personnel. The Operator's Supervisor is also responsible for controlling the rate of core recovery to ensure that core handling lab personnel have adequate time to prepare and store hydrate cores and cleanup before new core comes on deck.

II.C. Pre-Spud Meetings

A "Site Operations Plan" for each new site should be prepared by the Operator's Supervisor in consultation with the Contractor's personnel and technical / scientific personnel at least one day before departing for a new site. The Plan should have the latest approved details such as GPS coordinates, estimated water depths, proposed coring program, safety limitations imposed by the safety panel, any known hazards, lithological information, proposed temperature and fluid sampling plans, bit and BHA plan, and a time estimate. Suggested changes should be resolved before the Pre-Spud Meeting.

The Pre-Spud Meeting should be held before departing for the next site. The Pre-Spud Meeting should be attended by the Operator’s Supervisor, Contractor’s Supervisor(s), Vessel Captain, Drillers, Coring Technicians, technical / scientific personnel, logging representative, and others as appropriate. The seismic and offset hole information, lithology, and geological objectives should be discussed with emphasis on potential hazards. Ship routes, pre-site surveys, potential seafloor hazards, dynamic positioning, etc. should be reviewed with the Vessel Captain. The Operator’s and Contactor’s Supervisors and Drillers should discuss the coring program, review safety issues, and agree on responses to potential problems and authority to act. The logging program should be reviewed with the logging representative.

Riserless operations require quick and precise action on the part of the Driller to limit potentially hazardous situations. All operations personnel should agree on “Standing Instructions to the Driller” to authorize immediate action by the Driller in the event of a potential safety problem (i.e., gas / water flow, lost circulation, heavy backflow, stuck pipe, loss of dynamic positioning, etc.).

The exploratory nature of hydrate coring operations dictates that the “Site Operations Plan” may be modified or changed at any time in response to changing technical / scientific objectives and opportunities, poor recovery and hole problems, equipment problems, time constraints, potential hazards, etc. A revised plan should be issued when there are major changes in the scope of operations. There is a potential for confusion in having outdated copies of orders in circulation; therefore, a date and time should be printed on all plans and “Standing Instructions to Driller” for clear identification.

II.D. <u>Rig Safety Meetings & Program</u>

The Contractor should hold weekly supervisors' safety meetings when practical and the Operator’s Supervisor should attend because a safe operation is in the best interest of both parties to the Contract.

III. <u>CORING GUIDELINES</u>

III.A. <u>Coring Guidelines</u>

The **"**Coring Guidelines**"** are intended to establish boundary-operating guidelines within which operations will be conducted under normal conditions and to inform operating personnel of situations in which the Contractor’s Supervisor should be consulted. The guidelines are open to discussion at any time. If it is necessary to deviate from the guidelines for safety reasons or to protect personnel, the hole or equipment in an emergency, the Contractor's Supervisor should be advised as soon as it is practical.

1) General operational procedures will be agreed to by the all operations personnel prior to the initiation of coring.

2) The Operator's Supervisor should be notified any time that symptoms of potential problems or hole threatening occurrences are detected, such as:
   a) H_2S, high-pressure gas, hydrate, hydrocarbons, or a potentially hazardous change in conditions are detected.
   b) Contractor's or Operator's equipment problems may significantly affect or delay operations by more than 30 minutes.
   c) Hole conditions change appreciably such as:
      - increased fill on connections (hole cleaning, instability, flow),
      - increased torque (hole swelling shut, deviation, hole cleaning)
      - increased circulating pressure (hole packing-off, hole cleaning, flow)
      - cuttings recovered with the core (hole cleaning, bit / inner barrel problem, flow back),
      - increased drag or sticking (hole swelling shut, deviation, hole cleaning),
      - heavy flow-back on connections (hole cleaning, flow),
      - significant drop in fluid on connections (lost circulation).
   d) A gradual pressure loss is noted, which might indicate a washout or impending pipe failure, or
   e) A radical change in drilling rate or behavior is noted that might signal an abrupt formation change or flow.
   f) weather or sea state conditions deteriorate appreciably.
   g) core recovery is negligible for 3 cores.
   h) ship positioning becomes unstable because of equipment problems or beacon failure

2) At least four good Heat Flow measurements must be obtained for C1/C2 ratio hydrocarbon maturity analysis. Measurements normally start at about 40 meters penetration and are run every other core until four good readings are obtained.

3) Seawater will be used for normal hole cleaning to reduce core contamination from drilling mud and chemicals; however, the Driller is authorized to pump viscous mud sweeps <u>as required by hole conditions</u> when sea water alone is no longer adequate to clean the hole or keep the drill string free and open.
   a) Sepiolite (8.9 ppg) mixed to 27 ppb with seawater and sheared through nozzles to MFV=90-120 sec is preferred.
   b) Bentonite (gel) mud sweeps (9.0 ppg) may be used in formations that do not contain hydrophilic swelling clays. The bentonite is pre-hydrated in fresh water with 1/4 ppb soda ash and 1/2 ppb caustic soda and is mixed 50/50 with seawater when pumped.

c) Holes that are conditioned for logging may be loaded with 9.0 ppg Sepiolite mud as directed by the Operator's Supervisor.
d) Holes deeper than 400 m on continental shelf and slope areas should be plugged with 10.5 ppg gel mud (subject to governmental agency approval).

4) A kill mud pit of 1.5 X hole volume of 10.5 ppg gel mud weighted with barite will be kept ready for pumping at all times. (Example: 11-1/2 in. hole = 0.1285 bbl/ft X 1.3 washout factor X 1200 ft depth X 1.5 volume = 300 bbls). The kill mud pit may be weighted up to 12.5 ppg if casing is set into hard (indurated) or well-compacted sediments (i.e., higher fracture gradients), the hole depth approaches 1500 m, or higher pore pressures are indicated.

5) The precise GPS coordinates of the site should be obtained as soon as possible and the hole angle and direction should be read every ~100 ft if possible to avoid deviated hole problems and provide a hole trajectory if required.

III. B. <u>Standing Instructions To Drillers</u>

Standing Instructions to Drillers are prepared by the Operation's Supervisor based on a short informal review of the next days proposed operations with the Operator's Supervisor and both Drillers. The Instructions specify boundaries for operating parameter and help the Driller prepare equipment and rig floor personnel for more efficient operations for the next 24 hr. Instructions may be modified several times a day to reflect changes in operating conditions and goals; therefore, all written orders should have the date and time of issue clearly noted to avoid confusion over which one is the latest version.

1) The standing orders to the Driller will be:
   a) At any time that a potential flow is detected in the hole, the Driller is authorized to pump the hole full of kill weight mud. In formations with higher fracture gradients, the kill weight mud may be pumped at high rate (i.e., 500 to 1000 gpm) to take advantage of dynamic kill effects.
   b) Operations should be suspended for a flow check (and further evaluation) if potential pressure seals and/or abnormally pressured formations are encountered.
   c) If kill weight mud is not able to stop a hydrocarbon flow, the hole will be filled with 15.6 ppg cement.
   d) When retrieving inner core barrels or when an inner core barrel is in place (holding the float valve open), circulation should be maintained at low pump rates (50 gpm) to prevent swabbing and/or prevent fluid from U-tubing up into the drill string

2) In the event of high overpull or stuck pipe, do not pull over 70K lb or increase pump pressure above 1000 psi without first calling the Contractor's and Operator's Supervisors. The preferred procedure is to try to establish circulation

and rotation and initiate hole cleaning steps before compacting a problem area with additional overpull or high pump pressure.

IV. <u>HYDROCARBON SAFETY</u>

The Operator's and Contractor's position must be very conservative with regard to the hazards and environmental consequences of an uncontrolled hydrocarbon spill using riserless drilling techniques. Hydrate sites may be actively flowing or leaking fluids into the ocean through natural faults or chimneys; nevertheless, the obligation is obvious for a prudent self-regulating hydrate coring program to be environmentally responsible in its actions and investigations. Danger to the ship and personnel from an uncontrolled hydrocarbon flow and/or fire is very unlikely because of the strict site selection, safety precautions, deep water depths, and the types of geological settings of most hydrate sites. Unintentional environmental pollution is considered to be the greatest risk in the event of a hydrocarbon flow in deep water.

If there is any doubt about the prudence of advancing a hole, the Operator's Supervisor may wish to take a short core or stop advancing the bit until the latest data is evaluated and a convincing case is made that it is safe to continue. A member of the safety panel should be available for consultation related to safety questions. The Operator's Supervisor should take careful notes of all phone conversations, repeat back any authorization that is given verbally, request written verification for verbal authorizations, and keep the Contractor's Supervisor informed of all conversations and authorizations.

The Operator and Contractor should have a clear notification list with alternates so company management can be fully and promptly informed of any contingency situation during operations that might require a substantial change of plans (i.e., major mechanical problem, uncontrolled flow, etc.). Any need to inform governmental agencies should be determined before operations commence. Any drilling records, photos, video, or other pertinent information should be saved for future reference.

IV. A. <u>Pollution Hazard Reduction</u>

The best pollution-hazard reduction policy is to emphasize prevention. The general recommendations and site-specific pollution and hazard-reduction recommendations of the Safety Panel should be strictly followed.

1. Proposed sites should be scrutinized carefully by the Safety Panel(s) to avoid potential hydrocarbon accumulations. Seismic records, offset drilling data, and other regional and site-specific information are required and should be reviewed critically for potential hydrocarbon source beds, trapping formations, and accumulations. Therefore, the probability of drilling into a large accumulation of oil or gas at a site approved by the Safety Panel(s) is very small.

2. Marine drilling operations without a riser in deep water mean that any flow of hydrocarbon gases or fluids that exits the hole at the sea floor probably would be mixed in the sea water column and/or carried away by current; therefore, a minor sub-sea flow (similar to a natural seep) might not be evident on the ship (even after cores are recovered). The Vessel Captain and marine crew should rigorously monitor for oil slicks or gas bubbles indicating a flow.

3. Marine drilling operations employing a drill rod inside a drill string using a gravity base or seafloor baseplate potentially could allow hydrocarbon gases or fluids to flow up the drill string. A flapper-type float valve should be run above the bit to prevent the entry of any fluid into the drill string (except when an inner core barrel is in place). The inner core barrel opens the flapper for coring. When an inner barrel is in place, the drill string is nearly always connected to the rig's mud-circulating system through the top drive. For open-ended logging or tripping situations, a Texas Iron Works (TIW) drill string safety-valve should be available on the rig-floor at all times to be made up to the top of the pipe. The drill pipe can be connected to the standpipe also with a high pressure circulating hose. Routine drills should be held so rig-floor crews can practice quick-response stabbing and makeup of the drill string safety valve. A Baker wireline retrieved drill string float-valve should also available on the rig floor for installation in the drill string (if required to control flow back when running in the hole).

IV. B. <u>Monitoring & Evaluating Hydrocarbons</u>

The Operator's Supervisor has the responsibility and independent authority to terminate drilling or coring operations for reasons of hydrocarbon safety. Hydrocarbon conditions can change on a core-by-core basis, and the Operator's Supervisor may be the only supervisor providing critical near-real-time monitoring of hydrocarbon status because of shift schedules and other duties faced by the other shipboard personnel. Therefore, the Operator's Supervisor should work closely with any hydrocarbon scientist / chemist monitoring samples onsite in the lab and set alarm conditions. A positive indication of the presence of migrated and thermally mature liquid hydrocarbons is cause for termination of the hole. Suggested operating procedures are as follows:

1) The Safety Panel should review drill site survey material and may grant conditional approval of a site. The Operator's Supervisor should study and become very familiar with the concerns expressed by the Safety Panel about each site and any depth, operational, and area limitations imposed.

2) A meeting should be held with the any shipboard hydrocarbon monitoring personnel to establish punctual monitoring, recording and reporting of hydrocarbon data on a continuous basis while coring. Alarm conditions should be specified that would result in immediate notification of the Operator's Supervisor even if he were asleep.

3) At least three (3) temperature measurements should be taken as quickly as possible in each new area, and an accurate temperature gradient should be established to assist in monitoring hydrocarbon maturity. The data from previous nearby holes may

be used to plot new hydrocarbon data until a reasonable area temperature gradient is established.

4) Gases present in each core are monitored through the sampling of "vacutainer" gas (extracted by syringe from gas expansion voids in each core liner tube) and "headspace" gas (extracted from small sediment samples in the lab using heat and vacuum). The gas samples are analyzed by chromatograph on a current basis and the data is used to determine whether coring can continue safely. The object is to distinguish "biogenic" gas (which has been generated in-place) from "thermogenic" gas, which may have migrated upward from a deeper source of accumulated hydrocarbons. The Operator's Supervisor needs to insure that hydrocarbon gas analysis data is entered on a punctual (near real time) basis into the "shipboard" data system so it can be accessed on a continuing basis and evaluated quickly.

The C_1/C_2 ratio should be plotted (log scale) vs. the Temperature °C (linear scale) using the Claypool "Thermal Maturity Graph". Both vaccutainer and head space gas sources should be plotted together vs. formation temperature gradients (determined from heat flow (APCT, IWS, or DVTP) temperature measurements. Data points that fall in the "anomalous" section may indicate hydrocarbons from more thermally mature sources, which have moved up faults or dipping beds into shallower formations.

In general, shallow sediments showing high biogenic methane concentrations are also characterized by higher organic carbon contents, high sedimentation rates, and fine silts (that can act as plugs to seal gas in the core liner). The "normal" biogenic and thermogenic gas field proposed by George Claypool has been extended by experience to lower C_1/C_2 ratios in the low-temperature part of the record using headspace gas (Proceedings of the ODP, Vol. 151, Hole 909, Fig. B, pg. 390, APPENDIX 8). Experience has shown that a relatively "normal" C_1/C_2 ratio trend for both headspace and vacutainer gas can be plotted against static borehole temperatures (as extrapolated from Adara and WSTP temperature data).

A normal decrease in C_1/C_2 (methane/ethane) ratio occurs with increasing temperature (and depth) as more carbon is converted by thermogenic processes to heavier hydrocarbons. The sediments at greater depths are compressed more by the increasing overburden, with a corresponding decrease in porosity and permeability; therefore, the larger C_3 to C_8 (butane to octane) hydrocarbons are not able to degas as easily as the smaller C_1 before the core gas is sampled. There is usually a substantially larger amount of C_1 in the trapped headspace gas than in the more depleted vacutainer samples; however, the C_1/C_2 ratio slope "signature" should be the same. A change in the slope of the C_1/C_2 ratio is normally evident when the soft sediments start to become more compacted and stiff (around 200 to 300 mbsf) and again when the formation becomes hard (around 400 to 600 mbsf). The XCB and RCB rotary drilling systems also partially flush the core with seawater and allow more gas to escape than the APC system. When APC cores become too gassy, it is advisable to switch to XCB coring.

Chromatograph analyses take time (i.e., lag behind coring), analyses could be in error, and a crucial interval could be missed; however, an increase in heavy hydrocarbons (C_{3-8}) is often associated with an increase in petroleum odor or stain. Such situations could indicate the presence of liquid hydrocarbons; therefore, a suspect sample should be checked for hydrocarbon fluorescence. A one cc sample is put in a lab dish in a non-fluorescing solvent bath (acetone and methyl alcohol work well) and is allowed to soak and partially evaporate. The sample is checked under black light for fluorescence. Fluorescence can indicate either minerals or liquid hydrocarbons; however, only hydrocarbons will leave an evaporation ring on the side of the dish. Blue-white, yellow, and orange fluorescence are indicative of light liquid-hydrocarbons. A stream of fluorescent oil flowing from a rock sample in solvent can indicate mobile hydrocarbons. Coring lubricants should also be checked for fluorescence to avoid confusion or false alerts.

Gas quantities and C_1/C_2 ratios from vaccutainer and headspace gas sources should be plotted together on a hydrocarbon gas (ppm-log scale) vs. depth (meters below seafloor-linear scale) graph to evaluate both the general quantity and gas ratio trends.

Note: A sudden decrease in the C_1/C_2 ratio, and/or a sudden increase in "heavy" C_{2-8} hydrocarbons, and/or a large increase in gas volumes could indicate proximity to a more thermally mature hydrocarbon source and potentially active flow up fractures; however, the same effects could merely indicate a reduction in formation porosity or permeability (less core flushing), and/or sampling anomalies. Coring should be terminated (pending further evaluation) if hydrocarbon staining, strong odor, and/or streaming cut / oil fluorescence is detected.

Notification:
The Operator's Supervisor, Drillers, and Captain should be notified immediately when the following events are noted:
a) an unexplained increase in the amount of gas,
b) a sudden decrease in C_1/C_2 ratio,
c) a sudden increase in heavier hydrocarbons (C_{3-8}),
d) C_{iso}/C_{normal} ratios for C_{3-8} drop below 1:1, or
e) occurrence of a strong petroleum odor or stain or fluorescence.

The Operator's Supervisor should notify the Driller and Contractor's Supervisor on duty whenever hydrocarbons are increasing and potential hydrological or pressure seals may be drilled. The Driller should be instructed to stop drilling after penetrating no more than a few meters into a drilling break below a hard seal, and the situation should be reevaluated. A short core may be taken to get a hydrocarbon reading if in doubt.

There is no hard diagnostic-cutoff-limit for evaluating hydrocarbon shows given the tremendous range of operating conditions. Each case must be evaluated separately, and the weight of each decision rests squarely on the Operator's Supervisor shoulders, which compels them to err on the side of caution.

IV. C. Backflow

Backflow from the drill pipe is a normal occurrence when a connection is broken at the rig floor. Backflow can result from the "density differential" of warm (low density) surface water pumped down the pipe against cold (denser) water in the ocean, from air that has been trapped on connections and pumped down the pipe, from dense cuttings or mud in the annulus flowing back (“U-tubing”) to equalize hydrostatic pressure, etc. Backflow into the pipe is usually reduced by the closure of the down-hole float valve, but some backflow occurs while retrieving core barrels and through the bit nozzles. Hydrocarbons, hot acidic fluids, H_2S, and/or cuttings and debris from the hole may backflow into the pipe and plug the pipe or bit nozzles or jam the down hole float valve in the open position. Backflow will usually gradually decrease within a short time as the pressure differential is equalized.

IV. D. Detecting A Kick

In deep water, an uncontrolled flow (or “kick”) of hydrocarbon gases or fluids exiting from a drilled hole at the sea floor probably would be diluted by mixing with the sea water column and dispersed by currents so that the flow might not be visibly evident on the ship. Fluctuating pump pressures, packing off in the annulus, decreasing string weight, and hole problems may indicate that a kick is in progress. The ROV-TV and sonar could be used to look for suspicious “plumes” in the water column if a gas flow is suspected or used to check the hole at the sea floor for flow (i.e., an unusual debris cloud or turbidity or sonar “hot spot” returns). If a hydrocarbon kick is suspected, a kill procedure should be started immediately.

A kick up the pipe is most likely to occur when the annulus is packed-off, the pipe is open-ended (i.e., no float valve), or when the float is held open by a core barrel, debris, or malfunction. A kick inside the drill pipe might be differentiated from normal flow-back events because the flow-back rate from the pipe becomes progressively stronger with time. Note: as the pressure is reduced when gas rises, gas expands in inverse proportion (Boyles Law: $P_1V_1=P_2V_2$). In the event of heavy and increasing flow from the drill string, circulation should be reestablished as quickly as possible to pump intruding fluid out of the pipe. If the top drive is in use, it should be made back up to the drill string immediately. If the top drive has been racked, it will be faster to install the rig-floor TIW safety valve and close the valve to stop backflow. The top drive or a circulating head can then be used to circulate down the drill string.

IV. E. Running Back To Bottom

It is more difficult to kill a flow if the bottom of the pipe is not below the flow. If the pipe is off-bottom and the Operator’s and Contractor’s Supervisors agree that an attempt to kill the flow does not pose a risk to the ship and personnel, an attempt may be made to run pipe back in to bottom. If a drill string safety-valve has been installed, it may be necessary to install a sub with a Baker model G (5f-6R) float-valve above the safety-valve so the safety-valve can be opened at the rig-floor. A rig-floor safety sub with a Baker float-valve should be on the rig floor at all times to act as a check valve, permitting fluid to be pumped down the pipe but preventing back-flow on connections. The Baker float valve can be used in instances (such as when using a logging bit or after dropping a bit) when the top drive is set back and/or a float-valve is not in the string.

The pipe can be run back down into the good open-hole section, using the top drive to fill the pipe frequently (to insure gas is not moving up the pipe). The drill string should not be forced down into bad hole conditions because stuck-pipe severing operations would not be possible through a drill string float-valve. Bad hole conditions probably indicate that the hole is collapsing and the flow will kill itself. Attempt to pump kill mud as deep as possible under good hole conditions.

IV. F. Controlling A Kick

Despite careful screening and operating procedures, the possibility remains that an uncontrolled flow of gas or petroleum (known as a “kick”) could occur despite all the safety precautions. In case a kick should occur, the Operator’s and Contractor’s Supervisors must be prepared to take immediate and appropriate action in concert to kill the flow if possible.

In riserless drilling, there is no re-circulating mud system, BOP, or choke and kill lines to control hydrocarbon or water kicks in the normal oil field manner (i.e., circulating heavy mud through a choke with back pressure). Penetrating a significant hydrocarbon reservoir is unlikely because potential traps for significant hydrocarbon accumulations are strictly avoided. Also, open (uncased) holes typically are cored to relatively shallow penetration depths in hydrates (~2000 ft = 600 m) in soft to semi-indurated sediments in deep water; therefore, the formations could not withstand the pressure of a heavy-mud hydrostatic-column.

The objective in killing a flow is to quickly fill the hole with a mud column that has enough hydrostatic pressure to slightly exceed the formation pore pressure. However, the kill mud “weight” (density) must not exceed the formation fracture pressure, which would cause the mud to flow laterally, reducing the effective height and hydrostatic pressure of the kill mud column.

It may be prudent to advance the bit on a core-by-core basis if there is an increasing indication of “dead” migrated (but not “live” liquid) hydrocarbons. In most circumstances, the detection of migrated and more-thermally-mature or liquid hydrocarbons requires suspension of drilling operations. Some areas with known gas seeps or dead hydrocarbon stains have been cored safely and successfully using data from offset holes and a series of pilot “test” holes that are down-dip from the primary site.

Any flow or “kick” is likely to be from flow along a fault or of the low pressure and low volume "shallow gas pocket" or “salt water” variety. Without casing for hydrostatic pressure containment; circulating dense (“heavy”) mud weights exceeding 10.5 ppg (1.26 gm/cc) might fracture soft sediments.

The fracture gradient at the weakest point in the hole (usually the casing shoe) is the effective limit on the imposition of additional hydrostatic kill pressure. See APPENDIX - standard Gulf of Mexico Pore Pressure / Fracture Gradient / Mud Weight graph for riserless drilling in 3000 ft (915 m) water depth. For example, in 915 m (3000 ft) water depth and 915 mbsf (3000 ft) of penetration, the predicted formation pore pressure is 10.1 ppg (2925 psi). If the hole were loaded with 10.1 ppg kill mud, the formation fracture gradient would be exceeded at about 150 m (500 ft) with normal trip (surge) and circulation pressures. Therefore, 10.1 ppg mud would probably fracture (i.e., break down) the formation, and the mud would flow out into the formation at that point (i.e., more or heavier mud would not increase hydrostatic pressure control).

At 1500 mbsf penetration, the pore pressure approaches 10.5 ppg and the fracture gradient would be exceeded above 450 m (1500 ft). Therefore, overall considerations indicate that a 10.5 ppg kill mud is probably the heaviest practical kill mud for holes less than 1500 mbsf penetration under normal circumstances. A volume of heavier kill mud (perhaps 100 bbls of 12.5 ppg) could be placed on bottom (i.e., below 10.5 ppg mud) in deeper holes if fracture gradient conditions permit.

Note that cement does not set in the presence of a gas flow; therefore, mud must be used to kill a gas flow before the hole is plugged with cement.

If a kick occurs, an attempt should be made if practical (and safe) to run pipe to total depth and fill the hole with pre-mixed kill mud and/or cement slurry. As in all well-control situations, judgment and rapid response are critical. It is probable that regardless of any attempt at human intervention, the turbulence from flowing fluids during the kick would destabilize the soft sediments in the borehole wall and the hole would load up with debris and/or collapse and reseal itself (which is what happens in natural flow events). It is possible in some instances to destabilize holes by pumping fresh water to swell hydrophilic clays and/or pumping SAPP (Sodium Acid PyroPhosphate) to disperse and destabilize the formation.

IV. G. Minor Flows

A relatively minor or weak flow of gas or liquid hydrocarbons could seep into the hole from a formation that has been penetrated and could go completely undetected for the duration of drilling operations in deep water. A minor flow could manifest itself in unstable hole conditions and "packing off" around the drill string. If a flow is suspected, the TV-sonar system could be used to look for suspicious “hot spot plumes” in the water column, and look for gas bubbles or liquids escaping from the hole. An attempt should be made to kill such a suspected flow if it appears to be a safe operation.

If the pipe is open-ended or the down-hole float valve is malfunctioning, the drill string safety valve and drill string float valve should be put into the drill string below the top drive before the pipe is run to total depth to displace the kill mud (in case the annulus packs off during pumping operations and flow is diverted up the pipe). While the kill mud is being displaced, preparations should be made to follow it with heavier mud or cement if required. If the flow can be stopped, the hole should be plugged with cement in accordance with governmental agency guidelines.

IV. H. Major Flows

In the event that a hydrocarbon flow is detected, coring or drilling operations should be terminated immediately. The Operator’s and Contractor’s Supervisors and Captain should review the situation and agree on a plan of action. However, if anyone feels that a kill attempt is too risky to the ship or personnel, the bit should be pulled above the sea floor and the ship should be moved off location up-wind in DP mode before the remainder of the drill string is recovered. On the positive side, environmental damage from shallow gas blowouts is usually limited because the soft sediments in shallow holes tend to collapse and kill the flow after a relatively short time.

The kill mud should be followed by heavier kill mud (if required to control the flow) and cement to permanently plug the hole. A flowing open-hole is often unstable, and the chances of getting the pipe stuck are significant. If the drill string becomes stuck, the normal through-the-drill-string severing procedures might be impossible or too hazardous. The danger to the ship and personnel from a hydrocarbon flow in deep water (with riserless operations) would be small under normal conditions. Hasty actions such as offsetting the ship before the pipe is clear of the sea floor or dropping the drill string might aggravate the situation, endanger personnel, or lead to the unnecessary loss of expensive hardware if not done properly. If an emergency situation required that the ship be moved immediately away from hydrocarbons, the only other option would be to drive-off and attempt to drag the drill string out of the hole.

IV. I. Hydrates & Gassy Cores

Methane hydrates can be stable on the deck at 6-12° C and can expand to 160 times their volume when they decompose suddenly. Free gas in cores expands as the pressure decreases ($P_1V_1=P_2V_2$) when the core is retrieved upward through the water column. A minor amount of gas expansion can occur if the temperature increases from a cool bore hole to warmer surface temperatures ($P_1/T_{1°R}=P_2/T_{2°R}$). Most of the gas expansion occurs near or on the surface and ship. Some gas and core blows out of the top and bottom of the liner on the wireline trip up the pipe (evident from “dirty” flow-back water) and on the rig floor and core deck. Plastic core liners are pliable enough to allow some swelling from gas expansion and mechanical compaction and lateral extrusion of sediments, and gassy liners sometimes have to be forcefully pulled out of the inner barrel. The core shoes may have be restrained against a rig-floor support-post with ropes to permit degassing when the shoe is removed. Pressure relief holes (1/8 in. diameter) may be drilled in the liner to relieve gas while it is still in the inner barrel.

Liners have split or burst in the inner core barrel on rare occasions when coring into harder formations apparently because the core is extruded laterally by piston over-compaction and/or the liner suffers physical impact damage. The incidences of liner failure have no clear correlation to the amount or composition of gas or hydrates (probably because gas pressure is usually relieved through permeable core sections or core expansion); however, moderately dry and fine clayey-silts in the core can sometimes form an impermeable pressure seal that bridges against the liner wall and traps pressure. A few liners have failed on the core receiving platform when the liners were structurally weakened by coring impact, stretched during forced removal from the inner barrel, or structurally weakened by drilling closely spaced gas-pressure relief holes. Therefore, eye protection should always be worn when working near cores, and Kevlar body protection and protective blankets should be used when gas pressure is noted.

Most gas hydrates contain about 98.5% C_1 and 1.5% CO_2. Hydrates are usually found below the normal sulfate reduction zone, which is fed by the sulfates in down-flowing sea water; however, unusual concentrations of H_2S gas are possible (i.e., in cases of active hydrological down flow for example). H_2S precautions should be in effect and monitors should be in operation. Crews should be trained in handling H_2S cores and breathing safety equipment should be available.

Monitoring

Drill crews and Supervisors should monitor all cores for indications that gas pressure is building up in the liners:

1. Core may be observed blowing or being extruded out of the inner core barrel shoe and/or top after removal from the pipe to the floor shuck, or while laying the inner core barrel down prior to removing the shoe.

2. Water and/or gas may blow out of the threads on the shoe and spacer sub when they are being screwed off of the inner core barrel. The bit spacer sub may be unusually difficult to unscrew.

3. The core liner may be difficult to pull out of the inner core barrel (from gas expansion, coring over-compaction with lateral extrusion, sand in the liner-to-inner-core-barrel annulus, or impact damage), which may require the use of a tugger or extra effort to extract it from the inner core barrel

4. The plastic core liner may exhibit ripple-like distortions along its length. These distortions, ripples, and/or liner thinning are usually intermittent and spaced out along a portion of the core. Some burst core liners (i.e., Leg 160) showed unusually numerous and closely spaced ripples along nearly its entire length.

5. The core may contain gas voids of considerable size if the sediment permits gas migration and core movement. Certain gas-charged sediment types will appear frothy or mousse-like. Core segments, gas, and/or liquids may be observed to be moving inside the liner.

Levels of Protection

Level 1

1. The first level of protection (and a mandatory safety policy) is for everyone working in the core handling area to wear safety glasses or shields.

Level 2

2. The second level of safety procedures will be instituted when any of the indicators of highly pressurized core liners have been observed. The Drill Crew, and Driller should be the first personnel to observe the pressurized core liners, and they in turn should alert the core handling crew and Supervisors. Time is of the essence in handling, drilling and sectioning the liner to keep the core cold and reduce the amount of expanding gas. Hydrate core should be retrieved as fast as possible and either removed from the inner core barrel and processed immediately or the core barrel can be placed in ice water until it can be handled.

3) Routine application of these safety procedures will slow down the handling time for gassy cores. In shallow water depths, the next core could be on deck before the previous core has been handled. It may be prudent to slow down core retrieval to permit proper and orderly handling of the gassy core liners.

4) Warning signs should be posted at the entrances to the core handling area, safety-breathing equipment should be staged in position, and fixed and portable H_2S detectors should be available. Fixed H_2S detectors should be installed on the core handling deck, in the cutting room, in the core description room, and in the core reefer. A suction fan system should be available in the core splitting room and a fan should be blowing on the core handling deck.

5) Access to the drill floor and the core-receiving platform should be limited. All supervisory personnel are responsible for ensuring that proper safety equipment is used.

6) The Captain is responsible for keeping the ship turned into the wind (preferably about 30 degrees off the starboard side) to assure a steady flow of air over the core handling area to dilute the gas and H_2S and flush it away from the quarters and ventilation system intake.

Safety Equipment

7. Those individuals moving the core from the drill floor to the core handling deck will use the safety equipment stored on the core handling deck to protect the face and body should the liner fail catastrophically. The safety equipment

includes: a) hard hats with polycarbonate face shields to protect the face, b) shatter and penetration resistant Kevlar fabric gloves, c) Kevlar fabric towels to wrap around the core liner, d) Kevlar fabric blankets to drape over the core liner while drilling gas relief holes, e) Kevlar fabric arm protection, and f) Kevlar fabric aprons to protect the chest and waist area.

“Gassy Core” Precautionary Procedures

1. When a “Gassy Core Alert” is sounded, personnel receiving the core will use hard-hats with the face shields down, wear Kevlar gloves, and use the Kevlar towels. As the core liner is extracted from the core barrel, a Kevlar towel will be wrapped around the liner where it is picked up. The core will be carried at waist level (i.e., not at neck and face level) to the core handling rack.

2. After the core is on the handling rack, only personnel wearing suitable protection equipment (i.e., a helmet with face shield, Kevlar apron, Kevlar sleeves, and Kevlar gloves) will approach the core. All others will retreat to a safe distance.

3. Two core handlers will drill 1/8" holes in the liner at gas voids to release gas pressure. After the major gas voids are degassed, additional drilling between voids may be required. The core may be allowed to continue to degas on the rack or on the catwalk floor.

4. The liner will be cut into 1.5 m lengths immediately in areas of rippled or distorted plastic or unusual gas activity. At the discretion of the senior technician on duty, the liner can be processed normally after it has been depressurized. Note any unusual liner distortion, gas pressure, or reconsolidation of the core (to eliminate gas voids).

V. H_2S HAZARDS

If the potential for H_2S is known or suspected in an operating area, H_2S precautions should be reviewed before the leg, a training program should be conducted for all personnel, an H_2S evacuation drill should be conducted, general H_2S precautions should be in effect, safety equipment should be serviced and staged, lab personnel should receive safety equipment training, and monitors should be calibrated and in operation. H_2S concentrations are normally less than 50 ppm in the normal near sea floor sulfate reduction zone, which is fed by sea water (to about 40 mbsf). Cores are quickly degassed outside on the core handling deck by drilling holes in the liner and sectioning the liners, and the H_2S is diluted by normal air flow mixing aided by the core-handling-deck fan. The suction fan in the core cutting room should be used to further degas the cores. MLS personnel may need to wear air packs when handling and cutting the cores. It may be prudent to allow some core sections to degas on the outside core storage rack.

Unusual isolated concentrations of H_2S gas are possible (i.e., especially in cases of active hydrological down-flow or sulfate-rich up-flow in faults for example). H_2S concentrations to 50,000 ppm have been noted in short core sections and handled safely. However, coring operations should be suspended while H_2S concentrations in the ambient air on the core-handling-deck exceed 10 ppm and air packs should be used. Operations should be terminated if H_2S concentrations in ambient air on the core-handling-deck exceed 20 ppm or interfere with safe operations or if high concentrations of H_2S are noted throughout several consecutive cores.

H_2S concentrations have been noted in the presence of hydrates; therefore, the potential for H_2S in hydrates should be treated with extreme caution because of the potential for sudden high-volume releases of H_2S. If H_2S is noted in the presence of hydrates, a full H_2S alert should be declared and coring should be halted pending an evaluation of the situation.

VI. <u>COMBINED HAZARDS</u>

Procedures are in place to manage most operational hazards and situations that occur by themselves. Situations that might escalate to produce a substantial problem would probably occur as a result of a combination of hazardous factors; therefore, leg and operational planning and analysis should include consideration of reasonable combinations of hazards.

The Operator's Supervisor should review potential hazards and responses with the Captain and Contractor's Supervisor at the Pre-Cruise Meeting and attempt to arrange operations to have the flexibility to drill pilot (evaluation) holes and transects, wait for good weather windows, and have alternative sites available. Personnel should be aware of:

- a) the critical alert conditions to suspend operations and pull up to as near the sea floor as practical, or
- b) pull the drill string to the ship and evaluate the situation or terminate operations, and
- c) the lead time necessary to take each corrective action.

Special contingency operations plans should be summarized in a written document, reviewed with the Driller and crew, posted on the bulletin board, reviewed at the pre-spud meeting, and discussed with any scientists / technical personnel.

VI. A. <u>Environmental & Operations</u>

Changing environmental conditions that should be considered in operations plans include: sea state, wind direction and force, high velocity and erratic currents, swirling eddy currents, tidal flows, moving ice, fog, and approaching storms and weather systems. Operational areas that may require special operating constraints include areas with proximity to: shallow water and restricted passages (fjords, atolls, channels), ice floes or bergs, shipping lanes and ports, military exercise or munitions dumping areas, and commercial operations (ferry routes, fishing fleets, etc.). Prolonged operations that are sensitive to changing environmental conditions include tripping long and heavy drill strings, fighting hole problems, stuck pipe, running guide bases and casing, reentries, deep uncased penetrations, and diamond coring. Elective operations should be scheduled to allow flexibility to perform other operations (preferably nearby) while waiting on good weather windows.

VI. B. BSRs, Hydrates, Gas & H_2S

The known or potential presence of Bottom Simulating Reflectors (BSRs), hydrates (clathrates), gassy sediments, and H_2S should be considered at the Pre-Spud Meeting, and special precautions should be reviewed with the Contractor and noted in the Operations Plan. Operations may be slowed down to permit adequate evaluation and handling of the cores. Operations may be terminated if liner failures or unsafe levels of gas or H_2S are detected in the core handling area, lab cutting room, or enclosed ship areas.

There are several hazards that could occur from a combination of these effects:

1) Hydrates and authigenic (biological methanogenic) carbonates can form an effective pressure seal and free gas can accumulate under the seal. PCS data indicated that the biogenic-gas pressure can be 350 psi above sea water hydrostatic pressure (i.e., it is over-pressured) at 450 mbsf; however, no gas flow has been noted in BSR penetrations. Poor permeability in silty clays under the hydrates may have restricted flow thus far; however, this may not always be the case.

2) Hydrates were analyzed as 98.5% methane and 1.5% carbon dioxide; however, hydrocarbon stains have been noted in association with hydrates in the GOM; therefore, BSRs and hydrate sections should be penetrated carefully.

3) Detecting a sea floor flow could be rather difficult given in riserless operations; however, the following procedure is recommended:

- a) Coring should be halted if an appreciable 2-3 m drilling break is encountered under a potential hard seal (i.e., a sudden increase in rate of penetration that might indicate a permeable sand). Note any change in pump pressure and rate or string weight.
- b) The core barrel should be pulled to check the core and close the drill string flapper valve.
- c) Circulation should be maintained down the pipe to circulate any gas out of the pipe.
- d) The only way to confirm whether the hole is flowing may be to look for a rising gas column on the PDR or run the VIT-TV and sonar. The TV may

show visible flow and the color sonar may show (white) gas bubbles in the water column.

4) The hazard of a gas flow to the ship is negligible in deep water depths; however, a high-volume gas flow in shallow water with no current could create a potentially explosive atmosphere and require the ship to move off a hole quickly and sacrifice the pipe to avoid the explosive gas. The partial loss of the ship's buoyancy from gas in the water is more likely to cause stability problems; therefore, it would be a good idea to close hatches on the main deck level as a precaution.

VI. C. Fire

A fire in any area of the ship could get out of control and threaten power availability (i.e., to thrusters, drawworks, compressors, or pumps), threaten positioning control, or force a change in ship orientation (i.e., sacrifice stability to position the wind as required); therefore, in the event of a shipboard fire:

1) Suspend coring or drilling, pick up off bottom two stands, and set the 500 ton elevators or drill-string safety landing sub in case of an emergency loss of positioning. If time permits, the compensator will be locked and the 500-ton elevators will be landed on the rotary. All personnel will be restricted from the rig floor.

2) If the fire is not immediately controlled or occurs in combination with other potential problems (i.e., bad weather, constricted passage, near floating ice, etc.), consult with the Supervisors and Captain to determine if it is feasible to pull the bit up to 50 mbsf, set the 500 ton elevators or drill-string landing-sub, and suspend rig floor operations.

3) Terminate operations and pull out of the hole to the ship (if practical) if the fire is in a sensitive location which might cause loss of power or ship positioning (i.e., the rig room, power controls, dynamic positioning, etc.) or if the ship's ability to circulate or pull the pipe may be jeopardized.

SHALLOW GAS PROCEDURES

1. PURPOSE

The vessel is to develop their specific shallow gas procedure to manage the shallow gas risk. The guidelines outlined within this document should be used to develop vessel specific shallow gas procedures.

2. DEFINITIONS

Attapulgite Clay: A smectite clay (aka; Palygorskite) that is generally used as a viscosifier (gel) in salty and brackish drilling fluid systems

Barite: A mineral consisting of barium sulfate, typically as colorless prismatic crystals or thing white flakes

Bentonite Clay: An impure montmorillonite clay that is commonly used as a viscosifier (gel) in freshwater drilling fluid systems

BOP: Blow Out Preventer

EEBD: Emergency Escape Breathing Device

ERP: Emergency Response Plan

ETO: Electrical Technical Officer

IDLH: Immediately Dangerous to Life and Health (level that interferes with the ability to escape) (NIOSH)

LEL: Lower Explosive Limit; Lowest concentration of gas capable of producing a flash of fire in presence of an ignition source (normally expressed as a % @ 25C)

NIOSH: National Institute for Occupational Safety and Health www.cdc.gov/niosh

OSHA: Occupational Safety and Health Administration https://www.osha.gov/

OSPAR: Commission – Ensures the interactions and collective effects of human activities has a limited effect on the environment

PEL: Permissible Exposure Limit (enforceable – OSHA)

PLONOR List: List of substances determined by OSPAR that are used and discharged during mining activities at sea and are deemed to cause no or little harm to the environment

PPE: Personal Protection Equipment

PPM: Parts Per Million

PSSGRR: Project Specific Shallow Gas Risk Register

REL: Recommended Exposure Limit (NIOSH)

ROP: Rate of Penetation

RPE: Respiratory Protection Equipment

Spudding: Making the initial start to drilling a hole

TIW: Texas Ironworks Valve

UEL: Upper Explosive Limit; Highest concentration of gas capable of producing a flash of fire in presence of an ignition source (normally expressed as a % @ 25C)

VSSGP: Vessel Specific Shallow Gas Procedure

Xanthum Gum: A thickening agent using in drilling mud serve to carry solids cut by drilling back to the surface

3. PROCEDURE

Encountering Shallow Gas during geotechnical drilling and sampling operations is an inherent risk that must be managed to ensure safe operations. To manage this risk the Contractor is committed to completing various checks and processes during each stage of the project lifecycle.

3.1 What is Shallow Gas?

Shallow gas is defined as any hydrocarbon-bearing zone which may be encountered at a depth close to the surface or seabed.

3.2 Why is Shallow Gas Dangerous?

Exposure to shallow gas during offshore geotechnical operations poses a risk to personnel and assets. With shallow gas kicks, there is the a chance that gas is released and rises up the water column to the vessel, it is important to remember that gas is heavier than air and will concentrate at the deck or low barrier levels if not dispersed. Gases that migrate to the drill floor can cause explosion, fire, poisoning or asphyxiation, all posing as a threat to the safety of personnel on board a vessel. Shallow gas kicks can also result in seabed expulsion craters that could lead to the loss of or damage to seabed equipment, these craters can also require site remediation before development activities can take place.

3.3 How Does Shallow Gas Form?

Shallow gas can form from either phytogenic sources, derived from decaying plant material within the shallow sediments or petrogenic sources, gas that has migrated from a petroleum source formation through faults, fissures, formation traps or petroleum production infrastructure.

3.4 Drilling into Gas Charged Formations

Drilling into a zone where gas is stored under pressure can cause a sudden release of liquid or free flowing gas into the borehole. This fluid influx can quickly dilute or displace the drilling fluid and underbalance the well bore. A full shallow gas release situation can quickly follow. To mitigate this, barriers must be put in place to prevent the displacement of drilling fluid and ultimately gas reaching the drilling platform.

4. SHALLOW GAS MANAGEMENT PROCESS

Consideration should be given to carrying out shallow seismic surveys in areas of shallow gas risk. In the absence of such surveys, assessment should be based on the exploration seismic data, historical well data and the geological probability of a shallow gas trap.

4.1 Tender Stage

Complete a shallow gas hazard assessment for each site location considering the following:

The client's anticipated shallow gas risk at the location

Consulting any previous drilling experience Contractor or the client may have in that location

Interrogate relevant site specific geophysical and seismic data

If dictated by the anticipated site conditions a complete in house shallow gas risk assessment desk study should be completed to more fully quantify the site specific risks

The output of the shallow gas hazard assessment will determine the potential for Low Risk, Medium Risk or High Risk to the drilling locations. This information will allow operations personnel to apply specific shallow gas procedure as required by the risk rating.

4.2 Preparation or Mobilization Phase

Allocate suitable personnel and equipment to ensure that the identified shallow gas risk can be managed in accordance with the specific shallow gas procedures

Mobilize equipment and personnel as required

Provide employees, subcontractors and clients sufficient information, training and supervision to maintain the necessary levels of competency and awareness

4.3 Implementation Phase

Implement and maintain shallow gas control measures as per the vessel shallow gas procedures

Conduct an ongoing review of the project specific shallow gas procedures based on the conditions encountered

Maintain shallow gas engineering measures in line with the vessel specific shallow gas procedures and vessels planned maintenance system

Periodic inspection of safety equipment and PPE in line with the vessel's planned maintenance system

4.4 Demobilization and Project Completion Phase

Demobilize and maintain project specific shallow gas control measures

Identify and record all lessons learned

5. SHALLOW GAS CONTROL MEASURES

The following measures will be implemented when managing Shallow Gas:

Engineering Controls
Detection and Monitoring
RPE and PPE
Personnel Competency and Awareness Training
Emergency Drills
Procedural Controls

The number of control measures implement on board a specific vessel will be dependent upon the vessel and the specific shallow gas procedures.

5.1 Engineering Control Measures

For all geotechnical drilling operations in a medium or high risk shallow gas area at least **TWO** control measures (barriers) must be in use or installed and ready for immediate use.

5.1.1 Primary Barrier

The primary barrier for all drilling operations in MEDIUM or HIGH shallow gas risk areas is the use of water based drilling fluid. When drilling open hole (i.e. drilling fluids being returned to seafloor) all components of the drilling fluid must appear on the OSPAR Commission PLONOR list http://www.ospar.org showing that they have tested as posing little or no risk to the environment.

The viscosifier (gel) used must suspend an adequate amount of barite or other drilling fluid weighting agent so that fluid density may be varied from slightly more than seawater up to 10 pounds per gallon. The most common gels for this purpose are bentonite clay, attapulgite clay and xanthum gum. Other gels may be used so long as they adequately suspend barite or other weighting material.

When drilling in HIGH risk areas the vessel will maintain a kill pit of weighted mud for immediate use should the vessel experience a gas kick.

5.1.2 Secondary Barriers

The second barrier shall be one (or a combination) of:

Wireline BOP
Oil Saver Valve
Non-Return or Full Bore Float Valve in the drill string

Texas Iron Works Valve (TIW) ready on drill floor in the case that the drill string is disconnected at the time of a kick

5.1.3 Temporary Barriers

When drilling in HIGH risk areas weighted mud must be employed at all times since it provides the best protection against gas incursion both through the pipe bore and up the annulus. However, additional temporary barriers must be employed when adding or breaking pipe in HIGH risk areas. Examples of acceptable Temporary Barriers for HIGH risk areas are as follows:

5.1.3.1 Flow Checks

Stop drilling and lift the bit off bottom and take the drill string out of compensation.

Shut down the mud pump and verify that no mud pressure is present.

Open the mud valve.

Monitor for mud flowing out of the mud valve (flowback).

If a steady stream of mud is being released from the mud valve this could indicate that formation fluid is entering the borehole. If flowback is observed, close the mud valve and pump mud to circulate influx fluid out of the annulus and then repeat the Flow Check sequence.

If no fluid is seen flowing from the mud valve, proceed with breaking the connection and adding drill pipe.

Note: it can be difficult to determine if flowback is caused by fluid incursion due to formation pressure (shallow gas) or because of sediment settling in the annulus (a "dirty hole"). If there are any questions, **ASK THE DRILLING SUPERVISOR**.

5.1.3.2 Non-Return Valve

This is a valve that closes by fluid pressure to prevent a return flow. This permits liquids or gases to flow in one direction only.

5.1.3.3 Full Bore Float Valve

This is a device that controls the direction in which fluid flows, opening and closing in response to changes in the fluid direction. The full bore portion of the name refers to the closure mechanism whose bore dimension is the same or larger than the valve body.

5.2 Detection and Monitoring

5.2.1 Visual or Seabed Monitoring

Visual monitoring for shallow gas is mandatory in Medium and High risk areas. One of the following seabed systems should also be in place:

Seabed Sonar
ROV
Seabed Camera
Acoustic Underwater Positioning – signal interruption is an indication of gas in the water column

5.2.2 Surface Monitoring

When seabed monitoring cannot be implemented or is ineffective, surface monitoring would be implemented. Surface monitoring should be carried out from the bridge or another position on the vessel with a wide field of view.

Personnel assigned to surface monitoring must be well briefed in the warning signs of shallow gas. These warning signs include:

Bubble masses in the moon-pool or around the vessel (even far from the vessel)
Unusual current movement or disturbances in the moon-pool or around the vessel, can be tested via Bubble Test
Vibration or oscillation of cables in the water (seabed frame wires, umbilicals, taught wires, anchor cables, etc.).

5.2.3 Gas Detection System

A fixed gas detection system installed onboard the Vessel can be used to detect gas that has migrated from the borehole to the Vessel. Gas migration can be either through the drill string or the water column.

A fixed gas detection system consists of the following components:

Sensors and sensor housings
Control and readout cabinet
Wiring
Gas detectors should be installed in the following areas:

Moonpool
Drill Floor
Rooster Box

For short duration mobilizations or on smaller vessels with little space for permanent installations, portable gas detection systems may be more useful and cost effective. This should be defined in the vessel specific shallow gas procedures.

5.3 Personnel Competency and Awareness Training

To ensure emergency response in line with the vessel specific shallow gas procedures, personnel need to be adequately trained and aware of the associated risks and how to respond accordingly. Personnel competency and awareness training will include a combination of instruction and awareness briefings, familiarization with the VSSGP, formal training, on the job awareness training and emergency drills. The required training and awareness requirements are role specific and outlined below.

5.4 Emergency Drills

Emergency drills will be completed onboard as per the vessel specific shallow gas procedures.

5.5 Designated Personnel – Key Responsibilities

5.5.1 Vessel Master

Overall responsibility for the safety of all personnel on board the Vessel
Ensures that personnel have the required training for their given role
Carries out all required emergency drills

5.5.2 Site Manager

Ensures all necessary project and shallow gas briefings are completed prior to departure for site
Ensures that the ERP is distributed and appropriate for the anticipated risk

5.5.3 Drilling Supervisor

Overall responsibility of drilling operations
Ensures all required shallow gas equipment is mobilized, correctly installed and that preventative maintenance is up to date
Inspects and function tests the fixed gas detection system daily
Ensures all handheld gas detection devices remain charged and are available for use

5.5.4 Shift Driller

Carries out drilling operations in accordance with the applicable procedures
Responsible for immediately reporting any shallow gas events to the Drilling Supervisor and the Officer of the Watch
Responsible for inspecting and testing all shallow gas barriers prior to each shift

5.6 Procedural Controls

5.6.1 Indications of Shallow Gas

Sudden Increase in the rate of penetration (ROP)

Abnormal Bit Weight Reduction

Abnormal Torque Fluctuation

Excessive flow back of drilling fluid when breaking pipe

Fluctuation in mud pump pressure

Smell of gas or signs of gas bubbles in samples

Unusual pore pressure readings during PCPT testing

Bubbles around the vessel or in the moon-pool

Unexplained loss of Echo Sounder signal

Gas sensor alarm

5.6.2 General Gas Kick Remedial Process

1. Shift Driller recognizes an influx of gas.
2. Shift Driller will instruct all drill floor personnel to make up all top drive or Kelly connection and pipe connections.

   Note: Verbal Communications may be difficult due to the noise of an uncontrolled gas kick.
3. Start mud pumps and begin pumping with whatever drilling fluid is currently lined up on the system.
4. Shift Driller should instruct another member of the drill crew to contact the Drilling Supervisor and inform the Officer on Watch.
5. Driller should instruct the drill crew to mix an appropriate volume of mud that is approximately 0.5ppg heavier than the fluid that was in the hole at the time of the kick.
6. Driller should switch over to the heavier fluid and fully displace the annulus of the boring.
7. Driller should then standby for 15 minutes while monitoring the mud pressure and looking for gas bubbles around the vessel. Any noticeable gain or drop in mud pressure should be noted on the drilling log.
8. If the flow check shows no flow back the boring may proceed with the Drilling Supervisors approval.
9. If the flow check shows continued flow back the drill crew should repeat Steps 5-7 above. This process should continue until the boring is cleared of gas influx or the Drilling Supervisor instructs the crew to abandon the boring.
10. Once approval is given to abandon the boring, and it is safe to do so, a toolbox meeting should be held to ensure that the appropriate primary, secondary and temporary barriers are in place to mitigate the gas risk while pipe is recovered to deck. If no toolbox meeting is possible because of an uncontrolled gas kick, the Drilling Supervisor should be directly involved in the recovery operation.

6. VESSEL SPECIFIC SHALLOW GAS PROCEDURE

6.1 Purpose

The purpose of the vessel shallow gas procedures is to ensure that drilling vessels follow a uniform approach to managing shallow gas risks. Each vessel is to develop their own procedures to manage the shallow gas risk. The vessel will have different shallow gas response requirements based on their design, operability and existing procedures.

C. SUMMARY OF PRIOR JIP LEG II SITE SELECTION, LWD LOGGING EXPEDITION AND RESULTS

C.1 PROSPECT DEVELOPMENT

The gas hydrate exploration philosophy employed by the JIP Leg II site selection team was to develop targets based on a petroleum systems approach used in conventional oil and gas exploration but modified for methane hydrates- a methane hydrate petroleum system. The basic components of a methane hydrate petroleum system are: a) methane hydrate pressure temperature conditions b) gas supply c) gas migration d) water supply and e) host reservoir. This exploration philosophy results in the development of highly localized and specific gas hydrate prospects.

Site selection for gas hydrate bearing sands for the JIP Leg II field program started in 2006 through a review of industry drilling logs within the gas hydrate stability zone. Also, at that time, it was thought that the exploration well at Chevron's Tiger Shark prospect in AC818 (AC 818 #1) penetrated gas hydrates in the Frio sandstone. Boswell et al. (2008) tied the well log and drilling summaries from AC 818 #1 and shallow logs from industry oil and gas wells, and proposed that the GOM was prospective for gas hydrates in sands, the type of emplacement of most interest for resource evaluation. This prompted the site selection committee to search for gas hydrate deposits in this area. Eighteen gas hydrate targets were identified for possible drilling in the AC 818 area. The site selection committee opened a process for other prospects in the GOM with potential for gas hydrates in sands. A dozen sites were considered from which GC955 and WR313 were selected for JIP Leg II. After further analysis AC818 was dropped from the drilling program for geohazard considerations, namely the risk of wellbore instability and flowing sands (shallow water flow). Additional targets were developed in GC 781, GC 825, EB 990, EB 992, AC 21 and AC 25 for the field program. The final sites for JIP Leg II were set during the two months ahead of mobilization to include 28 locations in WR313, GC955, EB 990, EB 992, AC 21, and AC25 for which specific targets had been developed, hazard analysis completed, and permits applied (Figure C.1).

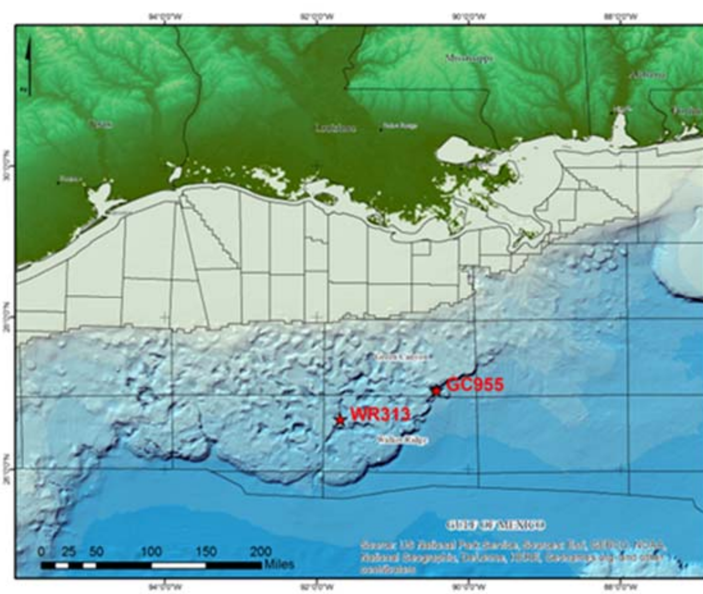


Figure C.1 Location map

The prospects were identified from the interpretation of conventional seismic amplitude data. Rock physics modeling by Nur and Dvorkin (2008) indicated that gas hydrate saturation in sand would increase P-wave impedance. These phenomena were also observed as fast anomalies in deepwater sands, where the sands in the lower part of the GHSZ are characteristically low impedance reflectors relative to bounding clays. Finding prospects to test these hypotheses was one of the exploration concepts employed by the site selection team.

Gas hydrate saturations predicted for the AC818, WR313, and GC955 locations were derived from the same 3D conventional seismic data used for prospecting. The method to predict gas hydrate combined pre-stack seismic inversion, rock physics modelling and stratigraphic interpretation. P-impedance and S-impedance volumes were generated and compared to estimate gas hydrate saturations. The predictive models worked well where moderate to high gas hydrate saturations occur but were less accurate at low saturations (Shelander et al. 2012).

C.2 WR313

Gas Hydrates in the Walker Ridge area were first hypothesized by McConnell and Kendall in 2002 using 3D exploration seismic data in which, in dipping sedimentary sequences, the depths to the topmost gassy sediments in the sands are consistent with pressure and temperature control and therefore, likely indicated the BGHS. Later work by McConnell and Zhang (2005), using acoustic inversion imaged the potential updip extents of gas hydrate deposits and described phase reversals at the BGHS in the basic seismic amplitude sections (Hutchinson et al., 2009a). Drilling locations developed for JIP Leg II are shown on Figure C.2.

A traverse through seismic amplitude and gas hydrate saturation prediction volume through the two wells drilled by JIP Leg II and the industry well are shown on Figures C.3 and C.4 respectively.

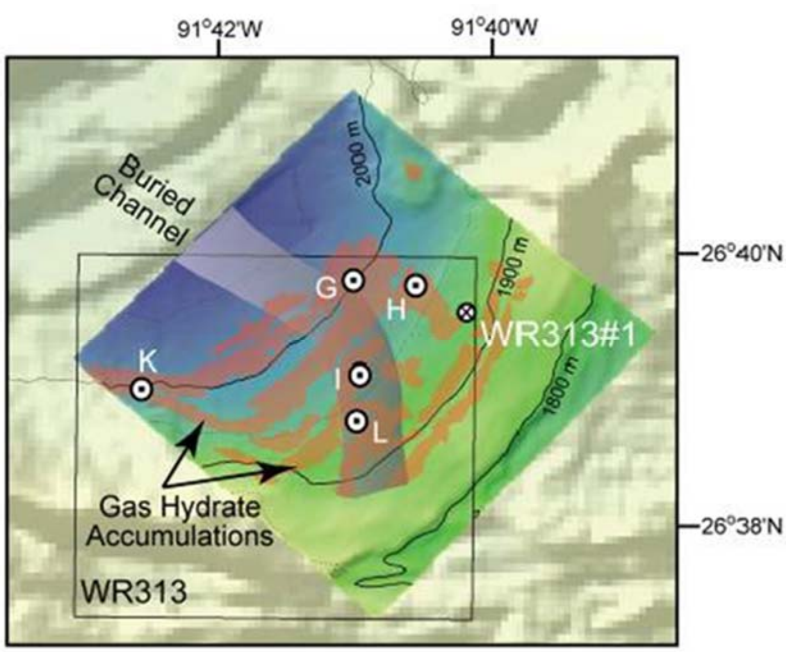


Figure C.2 Drilling Locations WR313

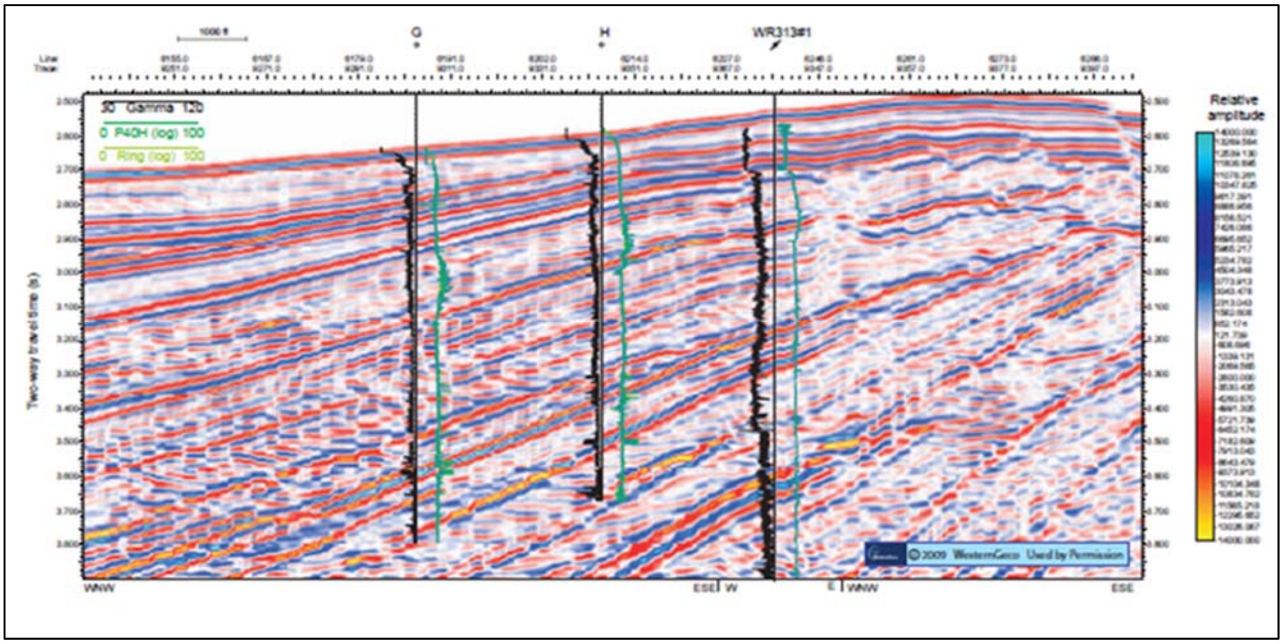


Figure C.3 Traverse through amplitude showing JIP and industry well with gamma and resistivity logs. Seismic data courtesy of WesternGeco.

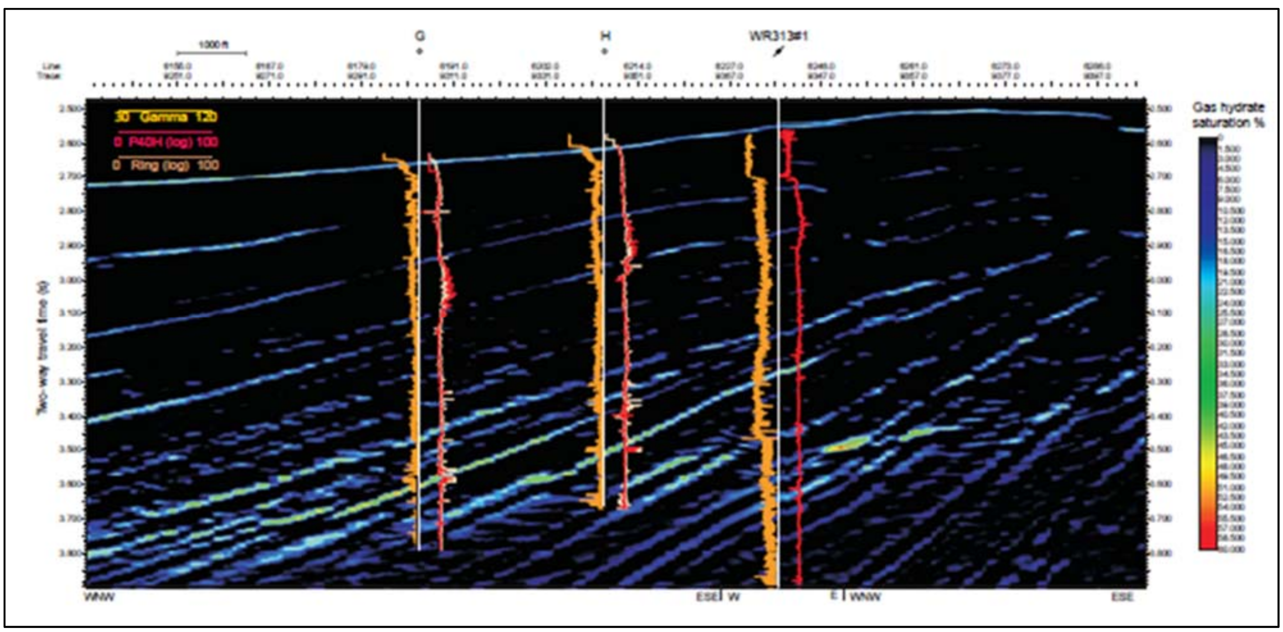


Figure C.4 Traverse through gas hydrate saturation prediction volume showing JIP and industry well with gamma and resistivity logs. Image provided by Schlumberger.

WR313-G (drilled) – The primary target at the WR313-G was predicted high saturation sand at what was termed the blue horizon at 2,835 ft. BML. Secondary targets were tests of other sands that were high saturation gas hydrate targets at other wells but not at WR313-G. The secondary target for sand was the orange unit at 3,383 ft. BML and the green sand at 3,529 ft. BML. WR313-G was drilled in the Leg II field program. High saturation gas hydrate sands were confirmed at the blue horizon primary target. A hydrate bearing sand zone was logged about 100 ft. above the primary target between 2,725 ft. and 2,745 ft. BML. Another hydrate bearing sand zone that included the predrill primary target was logged between 2,805 ft. and 2,860 ft. BML.

Other gas hydrate bearing zones at WR313-G were in fracture fill clays- the base of which was much shallower within the GHSZ approximately 1680 ft. above the primary gas hydrate target. The gas hydrate bearing clays were strata-bound between 815 ft. and 1,300 ft. BML.

WR313-H (drilled) – The primary target at the WR313-H location was predicted high saturation sands in the orange unit at 2,632 ft. BML. Secondary targets included an up dip test of gas hydrates at the blue horizon at 2,272 ft. BML for possible low saturation gas hydrates and a sand test at the green horizon at 3,426 ft. BML. High saturation gas hydrate was confirmed in sands at the primary target between 2,644 ft. and 2,656 ft. BML. Another gas hydrate bearing sand zone was found between 2,663 ft. and 2,685 ft. BML.

The same fracture-filled clayey zone, stratigraphically equivalent to the fractured-filled clays at WR313-G was found at WR313-H between 590 ft. and 1,030 ft. BML.

Three other locations in WR313 were prepared for possible drilling during the Leg II field program. If WR313-G had not found gas hydrates, then the next hole would have been one of the following three locations and probably would have been the WR313 L location that tested gas hydrate associated with an interpreted sandy channel. The discovery of gas hydrate at WR313-G, instead prompted the selection of WR313-H that could test lateral extents of the hydrate bearing sands.

C.2.1 WR313 I and WR313 I (Alt) (not drilled)

The main target at WR313 I is gas hydrate filled channel sands where the channel crosses the BGHS. An optimized location WR313 I (Alt) would also target the same gas hydrate filled channel sands but with a surface location less than 100 ft. SW of WR313 I. The alternate location was selected to increase distance from gassy sediments down dip of the gas hydrate target at WR313 I. Coring to test gas hydrate at WR313 I should positioned at the WR313 I (Alt) location. The coordinates for WR313 I (Alt) are X: 2,070,538.82 and Y: 9,673,156.76 (UTM Zone 15 NAD 27).

The WR313 I Alt location could also test the blue unit sand that had gas hydrate fill at WR313-G. The predictive model suggests no to low gas hydrate saturation.

The WR313 I (Alt) location could also test whether the strata-bound fracture fill gas hydrate in clays extend to the WR313 I (Alt) location. If so, they would be encountered between approximately 605 ft. BML and 1,060 ft. BML.

WR313 K (not drilled) - One of the targets that developed from the predictive gas hydrate saturation models produced by Schlumberger for the JIP is WR313 K. WR313 K is the furthest west of the WR313 targets. It targets extensive moderate to high gas hydrate saturations between the blue horizon sand and the BGHS between 2,858 ft. BML and 3,183 ft. BML.

WR313 L and WR313 L (Alt) (not drilled) - Similar to the WR313 I and I (Alt), the L locations primary target is gas hydrate in channel sands at the orange horizon where the channel crosses the BGHS. However, drilling at the L location should be done at the alternate location. WR313 L (Alt), 126 ft. to the south of the L location, is optimized to avoid gassy sediments. The coordinates for WR313 L (Alt) are X: 2,070,352.86 and Y: 9,670,885.36.

Secondary targets at WR313 L (Alt) are the blue sand where little to no gas hydrate is predicted.

C.3 GC955

The GC955 locations were a good test of the petroleum systems approach to gas hydrate exploration. In this case, the test was to determine whether focused gassy fluid flow to sands spanning the BGHS would deposit gas hydrates. The prospectivity of the GC955 site was presented to the JIP site selection workshop based on interpretations by McConnell (2000) and Heggland (2004). Although neither author mentions the potential for gas hydrate deposits, both described geophysical indications of ample gas sourcing and gas migration pathways through faults into a large Pleistocene channel levee complex. The JIP sanctioned prospect development in GC955 with seismic data provided by Chevron.

The most prospective areas for gas hydrate occur in a faulted, four-way structural closure in the southwestern corner of the block. The GC955 structure hosts a complex array of strong but patchy seismic amplitude near and below the BGHS within channel levee sands the dome is cut by a complex network of normal faults and contains numerous indications of active fluid flux.

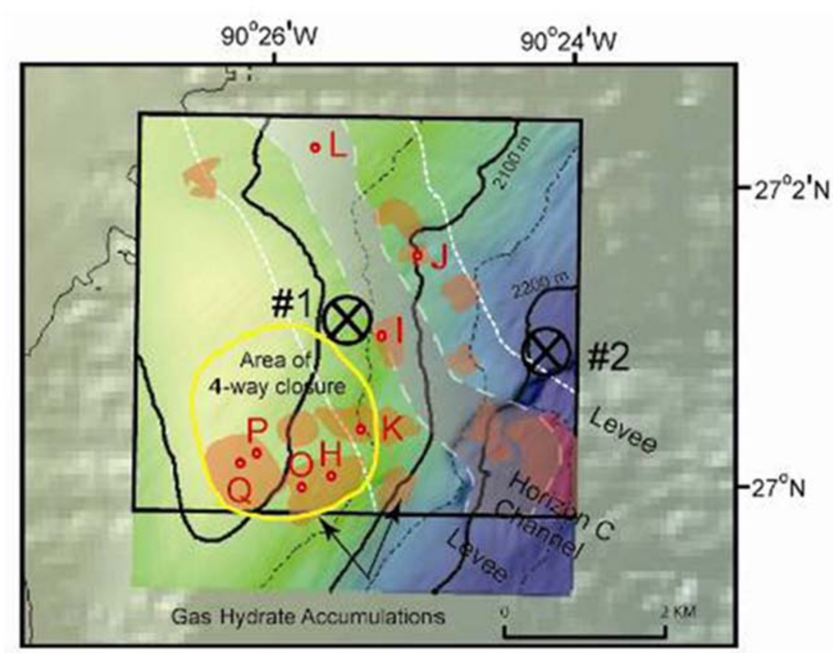


Figure C.5 Drilling locations GC955

Eight locations target gas hydrate saturations in channel sands near the BGHS within the four-way closure or proximal to the prominent buried channel axis at Horizon C (Figures C.5 and C.6; Table C.1).

A traverse through the JIP Leg II drilling locations and the two industry wells is shown on Figure C.7. A map view of the gas hydrate saturation prediction volume at GC955 is shown as Figure C.8.

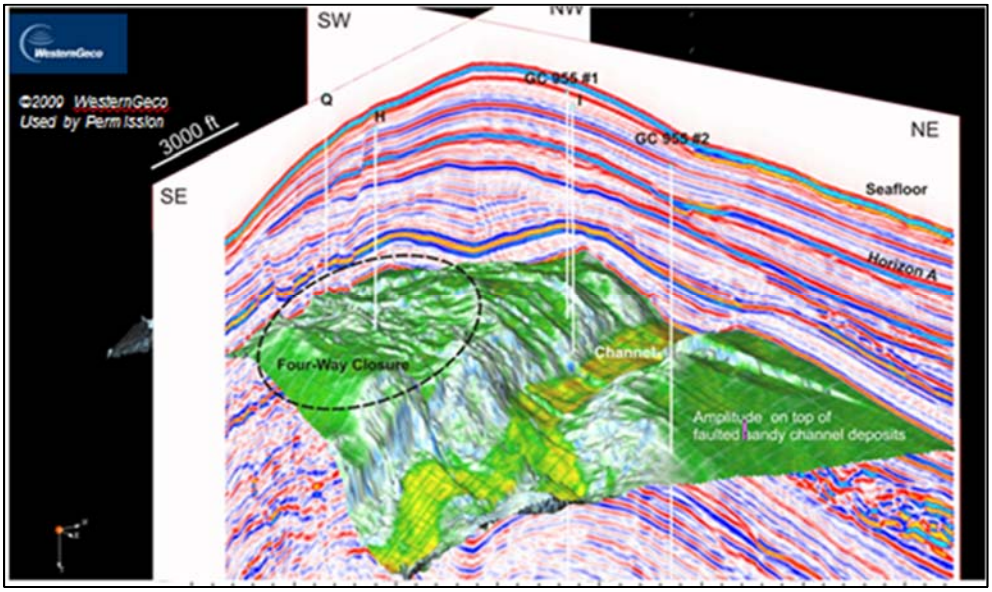


Figure C.6 Targeting gas hydrate saturations in channel sands near the BGHS within the four-way closure or proximal to the prominent buried channel axis at Horizon C.

Table C.1 GC955 Targets

Target Name	Target Setting	Target Description	Depth
GC955-H (drilled)	Proximal sand levee on the west side of Horizon C channel	Patchy high gas hydrate saturation in channel levee sands in four-way closure. West of channel axis.	Principal target 1,490 ft. to 1,670 ft. BSS
GC955-I (drilled)	Proximal sand levee on the west side of Horizon C channel	Moderate gas hydrate saturation in thickest part of channel levee west of the channel axis. On the eastern side of the four-way closure.	Principal target 1,483 ft. to 1,583 ft. BSS
GC955-J	Proximal sand levee on the east side of Horizon C channel	Moderate gas hydrate saturation in the levee east of the channel axis. Outside of the four-way closure.	Principal target 1,609 ft. to 1,681 ft. BSS
GC955-K	Proximal sand levee on the west side of Horizon C channel	High gas hydrate saturation at the BGHS, down dip of the four-way closure	Principal target 1,554 ft. to 1,590 ft. BSS

GC955-L	Near where Horizon C channel axis crosses the BGHS	High gas hydrate saturation along channel axis outside of four-way closure	Principal target 1,997 ft. to 2,164 ft. BSS
GC955-O	Distal levee within four-way closure	High gas hydrate saturation above BGHS within the four-way closure. Wellbore closer a seafloor mound	Principal target 1,152 ft. to 1,600 ft. BSS
GC955-P	Distal levee within four-way closure	High saturation targets near the BGHS at near crest of four-way closure	Principal target 1,329 ft. to 1,684 ft. BSS
GC955-Q (Alt Q drilled)	Distal levee within four-way closure	High saturation targets near the BGHS at the crest of the four-way closure on the up thrown side of fault but down dip of potential gas.	Principal target 1,296 ft. to 1,664 ft. BSS

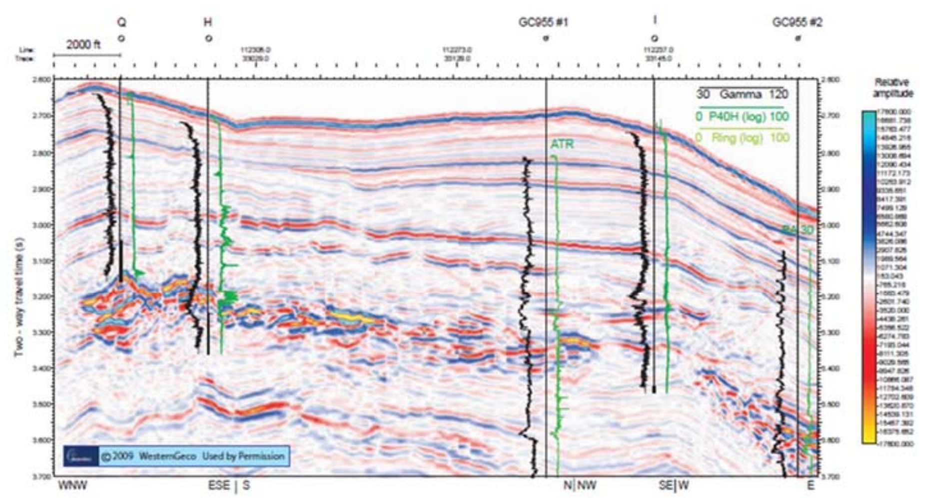


Figure F12: *Arbitrary line through amplitude volume showing JIP and industry wells with gamma and resistivity logs. Seismic data courtesy of WesternGeco.*

Figure C.7 Arbitrary line through amplitude volume showing JIP and Industry wells with gamma and resistivity logs. Seismic data courtesy of WesternGeco

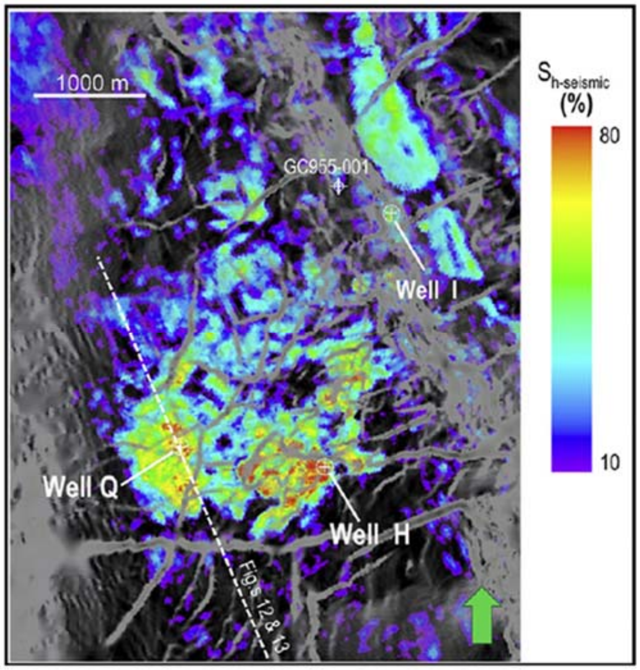


Figure C.8 A map view of the gas hydrate saturation prediction volume at GC955 (from Shelander, et. al 2012)

C.4 DATA

JIP Leg II used existing conventional 3D seismic data for prospect generation. WesternGeco/ Schlumberger reprocessed the 3D exploration seismic amplitude cubes in addition to producing gas hydrate saturation volumes. The methodology for gas hydrate saturations was developed during JIP Leg I and explained in Dai et al 2008a and 2008b and Shelander et al., 2010.

As mentioned, P-impedance and S-impedance volumes were generated and compared to estimate gas hydrate saturations. Gas hydrate saturation volumes were produced from p-impedance and for hybrid p-impedance and s-impedance methods (Shelander et al., 2012).

C.4.1 WR313

The data used by McConnell and Kendall (2002) and for prospect generation at the Mineral Management Service (MMS, now Bureau of Ocean Energy Management, or BOEM) were conventional exploration time migration data collected and processed by Veritas, now CGG. The data supplied to JIP Leg II was wide azimuth “Q” data from WesternGeco processed for subsalt imaging. Thus, the data were not optimal for gas hydrate imaging. Near offsets were missing, but the main detrimental attribute was that sub salt imaging caused a jagged, discontinuous imaging in the supra-salt section (WR313 inline). Nevertheless, the data were useful and gas hydrate saturation volumes were generated that matched the LWD results at the main targets.

C.4.2 GC955

Two sets of conventional 3D seismic were used to develop prospects and refine targets at GC955. The first set were data acquired by WesternGeco, under license to Chevron who subcontracted AOA Geophysics in order to develop potential gas hydrate targets. The second set of data were provided by JIP in-kind contributor Schlumberger. These data were also reprocessed for the JIP by Schlumberger and gas hydrate saturation estimates were produced.

Descriptions of all 3D seismic datasets and processed derivations used in JIP Leg II are listed in Table C.2.

Table C.2 JIP Leg 3D Seismic Data Inventory

Inventory 3-D Seismic Data	Seismic Data Associated with Drilled JIP Leg II Locations								
Area	Data Owner/Licensee	Data Contractor	License or Ownership Terms (licensed, purchased)	Name 1	Name 2	Type	Description	Inline range	Crossline range
Green Canyon 955 and Vicinity	JIP	Western Geco	licensed? Gifted?	GC955_NRM2_Final_WLS_PRT_STK_AVA_VOL.sgy	GC955 NAD27 TM15 FT, GC955 Conditioned Stack Vol	Amplitude	4ms samples, Bin size 82.02ft by 41.01ft, 6s record	111993-112537	32846-33430
Green Canyon 955 and Vicinity	JIP	Schlumberger	purchased?	GC955_Inversion P	same	P impedance	4ms samples, Bin size 82.02ft by 41.01ft, 4.2s record	111993-112537	32846-33430
Green Canyon 955 and Vicinity	JIP	Schlumberger	purchased?	GC955_Inversion S	same	S impedance	4ms samples, Bin size 82.02ft by 41.01ft, 4.2s record	111993-112537	32846-33430
Green Canyon 955 and Vicinity	JIP	Schlumberger	purchased?	GC955_SgHIP01	same	Gas Hydrate Saturation from IP	4ms samples, Bin size 82.02ft by 41.01ft, 4.2s record	111993-112537	32846-33430
Green Canyon 955 and Vicinity	JIP	Schlumberger	purchased?	GC955_SgHIPIS01_hybrid	same	Gas Hydrate Saturation from IP and IS hybrid	4ms samples, Bin size 82.02ft by 41.01ft, 4.2s record	111993-112537	32846-33430
Green Canyon 955 and Vicinity	Chevron	??	licensed	GC955_for_hazard_segy_EBCDIC	1.Migrated Time Data Load from Contractor SEGY Data Phases, WR-W1-24-5Ultra, GC-W10Ultra, GC-W12Ultra, 2 Extracted 9 OCS blocks center GC955, 3. Merged 3 data phases, 4. Geometry assignment-Crossline numbers based on GC-W12Ultra, 5. Padded traces, truncated to 8.0 s 6. SEGY data written	Amplitude	4 ms samples, Bin size 65.617 ft by 41.0099 ft, 8s record	6546-2404	7508-3945
Walker Ridge 313 and vicinity									
Walker Ridge 313 and vicinity	JIP	Western Geco	licensed? Gifted?	WR313 CONDITIONED STACK VOL	WR313_NRM_RAAC_FINAL_WLS_PRT_STK_VOL.seg2	Amplitude	4ms samples, Bin size 82.02 ft by 41.01 ft, 5 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313)IP_02_10_NRM_PRT_RAAC_Seg2	same	P impedance	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) IS_02_10_NRM_PRT_RAAC_Seg2	same	S impedance	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) VpVs_02_10_NRM_PRT_RAAC_Seg2	same	Vp/Vs	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) PR_02_10_NRM_PRT_RAAC_Seg2	same	Poisson Ratio	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) RHO_02_10_NRM_PRT_RAAC_Seg2	same	Density (Rho)	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) SghIP02_10RAAC_sand_shale_model_Seg2	same	Gas Hydrate Saturation from IP	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) SghIS02_10RAAC_sand_shale_model_Seg2	same	Gas Hydrate Saturation from IS	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) mig_intvel_ft_s_WR313.seg	same	Velocity	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
Walker Ridge 313 and vicinity	JIP	Schlumberger	purchased?	(WR313) sova_intvel_ft_s_WR313.seg	same	Velocity	4ms samples, Bin size 82.02 ft by 41.01 ft, 4 s record	6114-6324	9050-9474
AC21 and Vicinity	JIP	Western Geco	Licensed? Gifted?	AC21 NAD27 UTM15 FT AC21 STACK VOL	AC21_QDIANA_STK_VOL	Amplitude	2 ms samples, 41.0105 ft by 20.5052 ft, 3.96 s record	1605-1190	8156-7400
East Breaks 990 and Vicintly	JIP	Western Geco	Licensed? Gifted?	EB990 NAD27 UTM15 FT AC21 STACK VOL	EB990_QDIANA_STK_VOL	Amplitude	2 ms samples, 41.0105 ft by 20.5052 ft, 3.96 s record	1865-2033	7285-8220
East Breaks 992 and Vicinity	JIP	Western Geco	Licensed? Gifted?	EB992 NAD27 UTM15 FT AC21 STACK VOL	EB992_QDIANA_STK_VOL	Amplitude	2 ms samples, 41.0105 ft by 20.5052 ft, 3.96 s record	2211-2689	5986-6721
Green Canyon 781/825 and vicinity	Chevron	Western Geco	Licensed	gow11_12	emig_merge_for_phil_von_dullen.sgy	Amplitude	4ms samples, Bin size 65.62 ft by 41.01 ft, 4 s record	5704-6769	3137-5029
	Chevron	Western Geco	Purchased	inversion_jip-gh2	AOA inversion	P impedance	4ms samples, Bin size 65.62 ft by 41.01 ft, 4 s record	6027-6452	3137-5029

C.5 PERMITTING PROCESS

Permits from the federal government are required for any drilling related to oil and gas in federal waters. Most wells are drilled by lessees. Lease holders exploring and developing oil and gas need to comply with many requirements governing their preparation, activities, and reporting - there is a subset of these regulations pertaining to drilling permits. There is another type of permit that could be issued to non-lessees- a permits for scientific research activities. The Code of Federal Regulations allows for geologic and geophysical research in the Outer Continental Shelf. One of the activities that requires a permit is drilling more than 500 ft. below seafloor. This type of drilling, for research purposes, is called a deep stratigraphic test. A key requirement for scientific research related to oil and gas is that deep stratigraphic tests are open to participation by other interested parties as long as they share of the cost. Another key aspect is that the data are publicly available within 60 days once a lease has been issued within 50 miles of the stratigraphic test. The process of obtaining a permit for a deep stratigraphic test in the federal OCS has been updated since the Deepwater Horizon accident. The current process for obtaining permits for deep stratigraphic tests are described in Section 8 of this report.

The eventuality that the locations chosen through the site selection process would need to be permitted and through what process was discussed by the site selection team and the operational planning and site hazards team. Some of the locations were in OCS blocks under active lease. Only WR313 was an “open block”, the lease previously issued having expired. The possibility that the JIP drilling would need to follow the regulations required of lessees for the blocks under lease was discussed.

Because the LWD holes would be drilled riserless and in a hydrocarbon prone basin, the operations planning and site hazards assessment team recommended that site hazards assessments be completed for all locations even though hazards assessments were only required for permits for lessees.

C.6 HAZARDS ANALYSIS

Geoscientists with geohazard experience were on the site selection team. Geohazard considerations guided target selection in addition to gas hydrate prospectivity and locations were revised to meet both objectives. After the locations were selected for possible drilling, wellsite hazards were analyzed at each location and a MMS (now BOEM) compliant shallow hazards report for drilling by lessees was generated. Two principal hazards to riserless drilling are the risk of penetrating free gas and flowing sands. The wells are drilled with seawater with returns to the seafloor. Cuttings, however need to be cleared from the hole and a mud program designed to keep the hole static without influx from sediments along the well bore and to clear cuttings need to be employed. Wellbore stability analyses with emphasis on gas hydrate dissociation were done at the locations so that temperatures that could cause gas hydrate dissociation were not reached (Collett et al., 2009).

WR313 - In general, the well paths at the locations in WR313 were assessed with low risks for drilling hazards. The geometry of the dipping beds allowed the gas hydrate deposits targeted for drilling to be penetrated with clear paths to the target with little to no risk for penetrating gas at the BGHS (Figure C.3,

Figure C.9, Figure C.10, and Figure C.11). A descriptive traffic light tophole hazard assessment system: negligible (green), low (yellow), moderate (orange), and high (red) scale was used to describe potential hazards along the wellbore (Figure C.9).

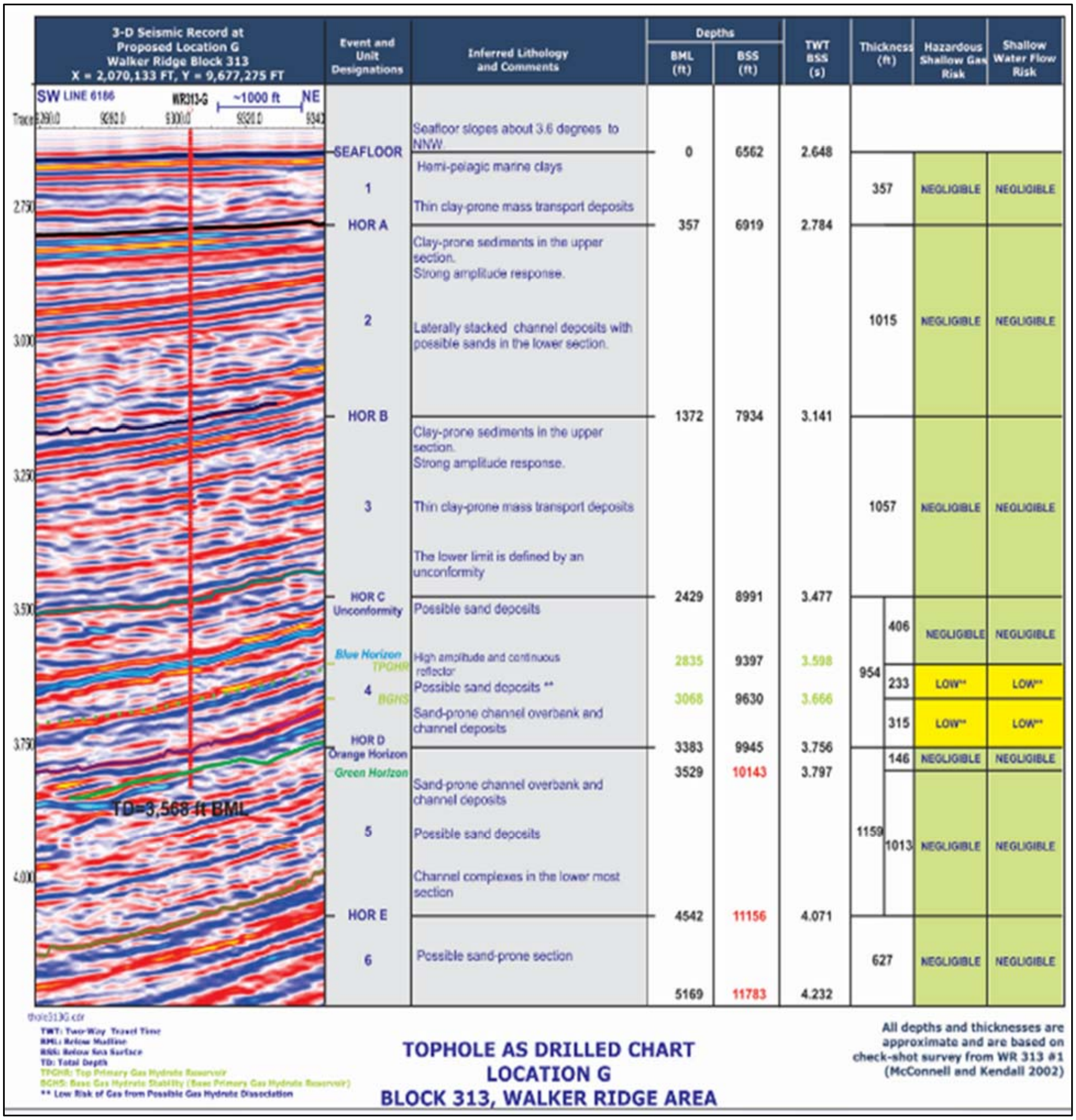
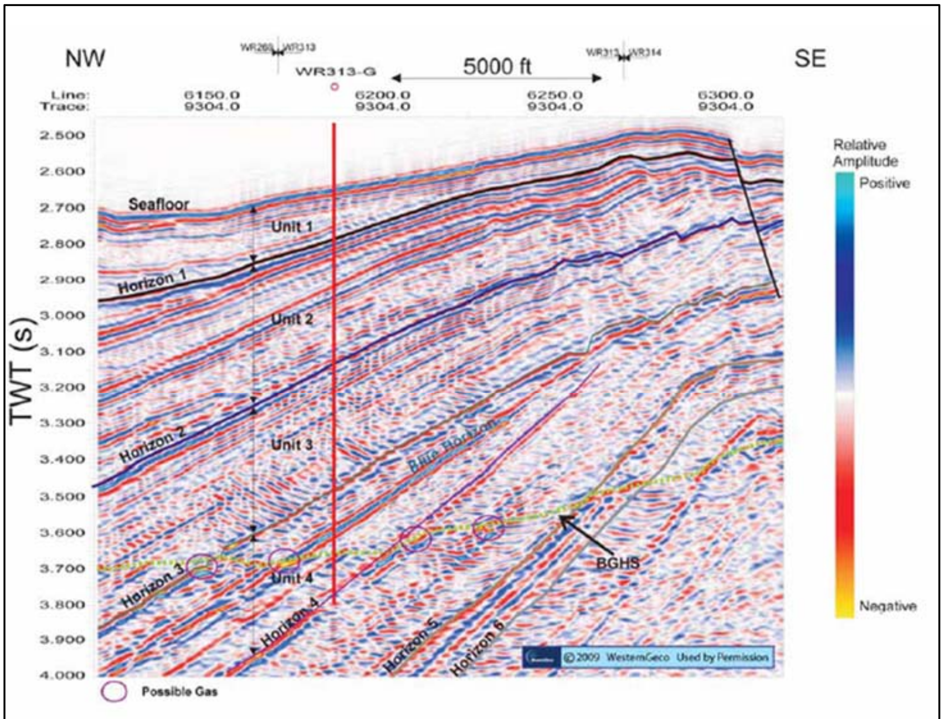
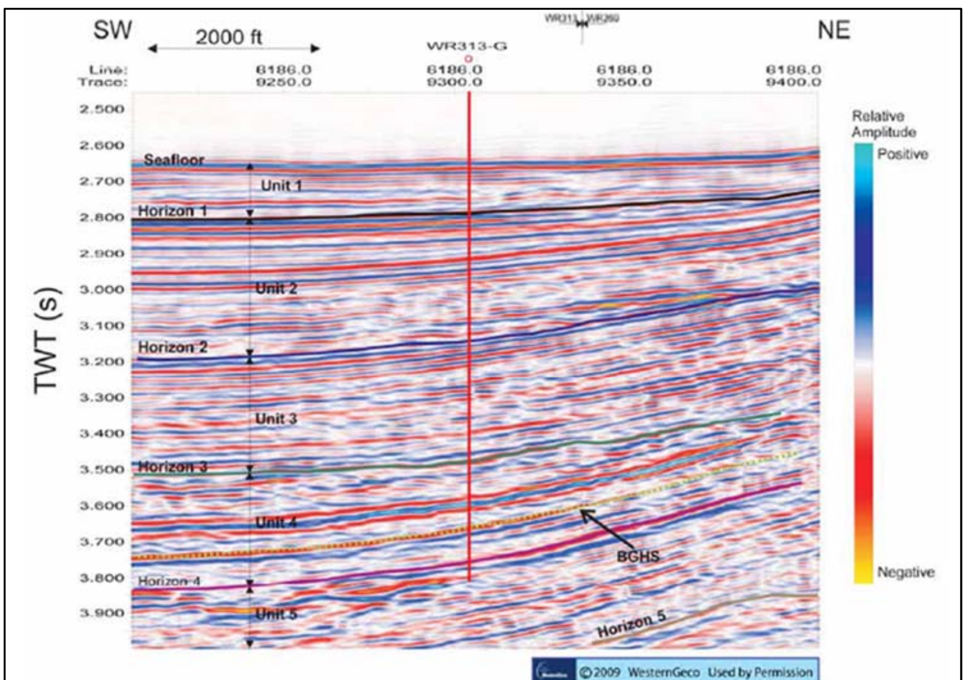


Figure C.9 Tophole hazard assessment WR313-G (modified from Hutchinson et al., 2009a).



3D Seismic Record, Crossline 9304, Location G Block 313, Walker Ridge Area

Figure C.10 3D seismic record crossline 9304, location WR313-G (from Hutchinson et al., 2009a).



3D Seismic Record, Inline 6186, Location G Block 313, Walker Ridge Area

Figure C.11 3D seismic record inline 6186, location WR313-G (from Hutchinson et al, 2009a).

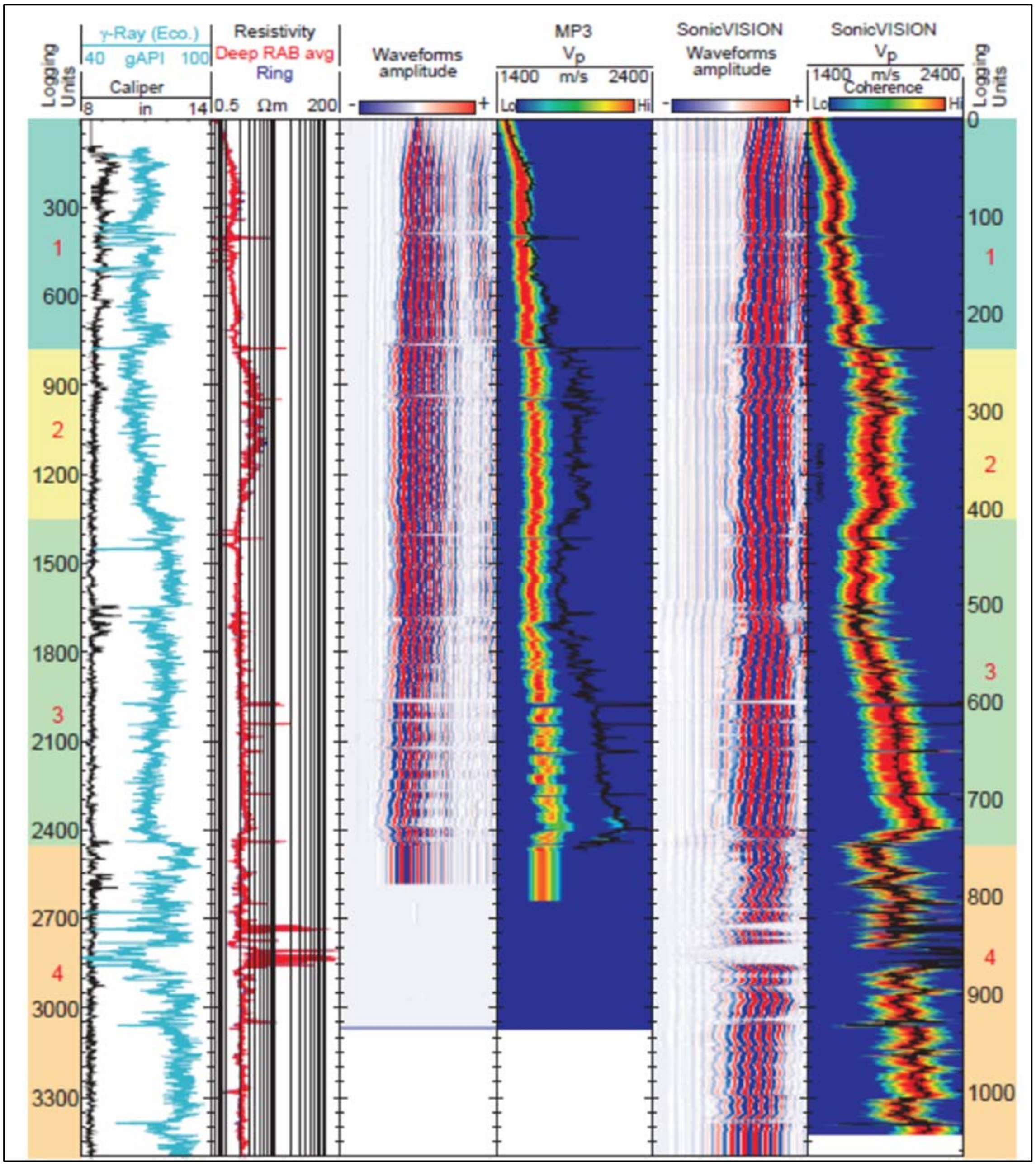


Figure C.12 Caliper, gamma, resistivity, density, and hydrate saturation logs at Well WR313-G (Cook et al., 2009).

Most of the locations in WR313 were assessed with negligible risk for gas and shallow water flow except for the interval with the primary target gas hydrate deposits. These intervals were assessed with low risk for shallow gas and shallow water flow- both as consequence of potential dissociation that could supply gas and weaken sands along the wellbore. An example of the well prognosis is shown as Figure C.9. The exception is WR313 L where, because of proximity to down dip gas in the channel sands, a moderate risk of gas was assessed.

GC955 - In contrast to the locations in WR313, many of the locations at the GC955 site have a high risk of free gas. A sandy channel levee system extends across the GC955 including the sediments within the GHSZ (Figure C.6). These channel levee sediments have been uplifted by a large salt diaper that has faulted the overlying sediments, with some faults reaching or nearly reaching the seafloor. The salt movement that faulted the overlying sediments also created pathways for fluid and gassy fluid migration from the surrounding draw to migrate to thick sandy deposits at the BHGS. An example of a well prognosis is shown as Figure C.13.

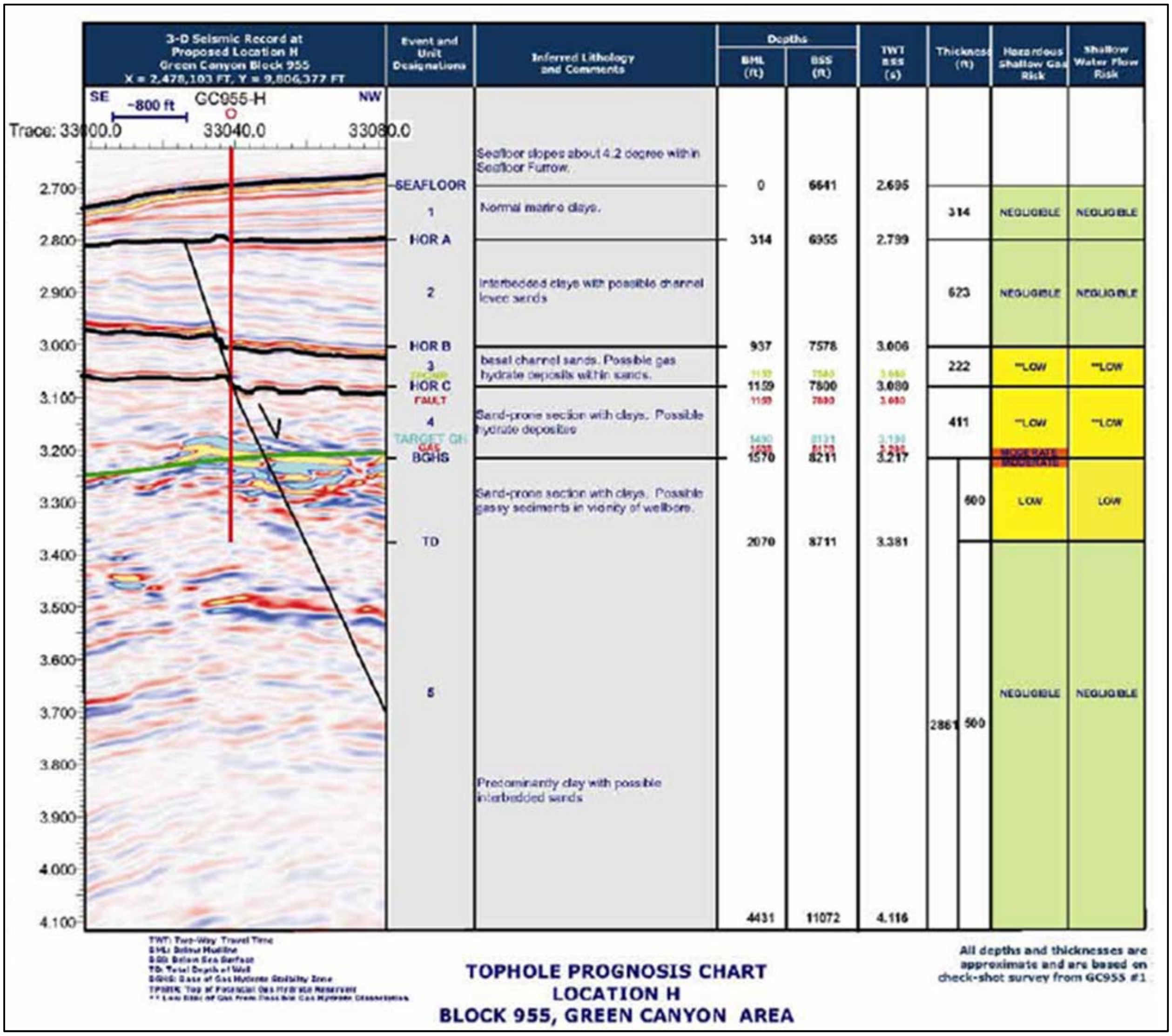
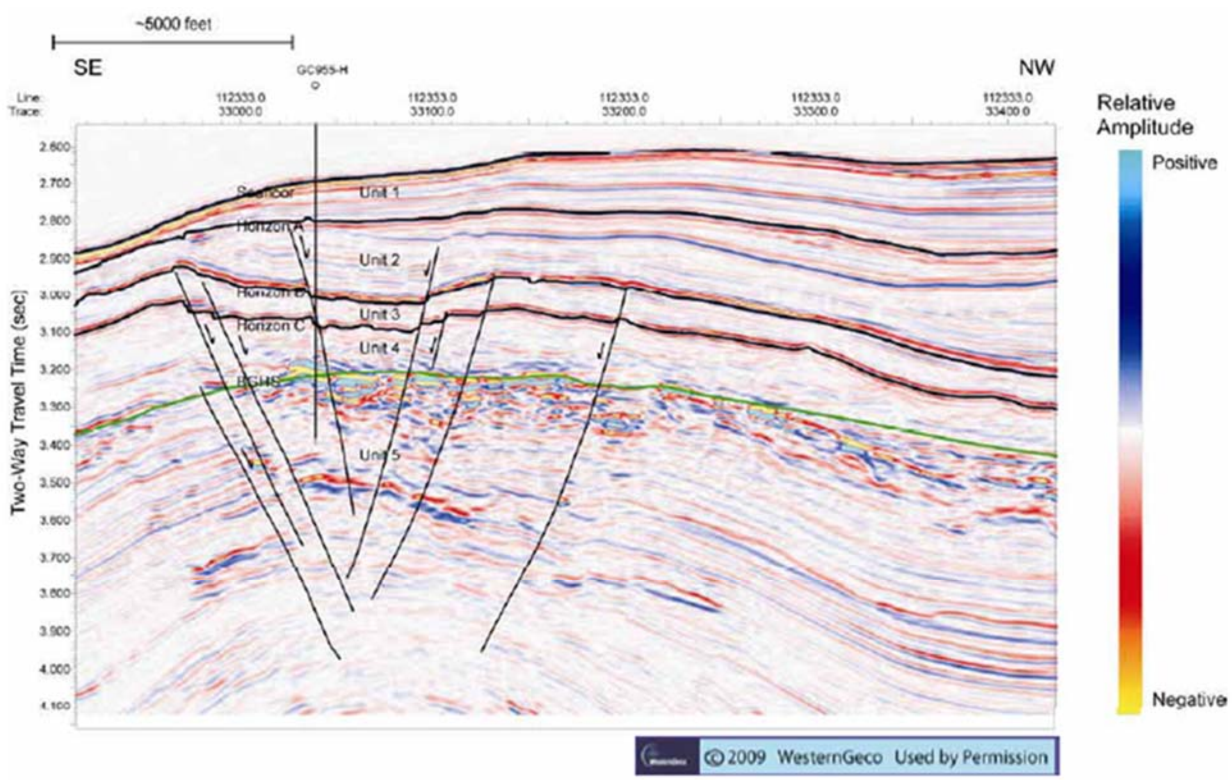


Figure C.13 Tophole hazard assessment GC955-H (from Hutchinson et al., 2009b).

The seismic response of thick gas hydrate over gas in a sand is difficult to distinguish from thick gas hydrate over little or no gas in seismic amplitude sections (Nur and Dvorkin, 2008). Because of this ambiguity, GC955 was considered to carry the high risk for penetrating subjacent free gas at the gas hydrate deposits.

GC955 I is the first of the three locations drilled during JIP Leg II, was considered the least risky. The hole did penetrate thick sands containing hydrate but the main target predicted to have moderate saturation of gas hydrate did not (Figure C.7).

GC955-H was the highest ranked of the GC955 locations. It penetrated thick, high saturation gas hydrate at the primary target and importantly, no gassy sediments beneath the gas hydrate deposit (Figure C.7, Figure C.14 and Figure C.15).



3D Seismic Record, Line 112333, Location H Block 955, Green Canyon Area

Figure C.14 3D seismic record, line 112333, location GC955-H (from Hutchinson et al., 2009b).

Because of the absence of gas at GC955-H, GC955 Q, the science party moved the location from a distal down dip portion of the predicted gas hydrate accumulation to the center of the target with the highest predicted saturations. As discussed in the following section, the gas hydrate was tagged at GC955 Q (Figure C.7) before a gas vented up the wellbore requiring mitigation and abandonment (Collett et al., 2009).

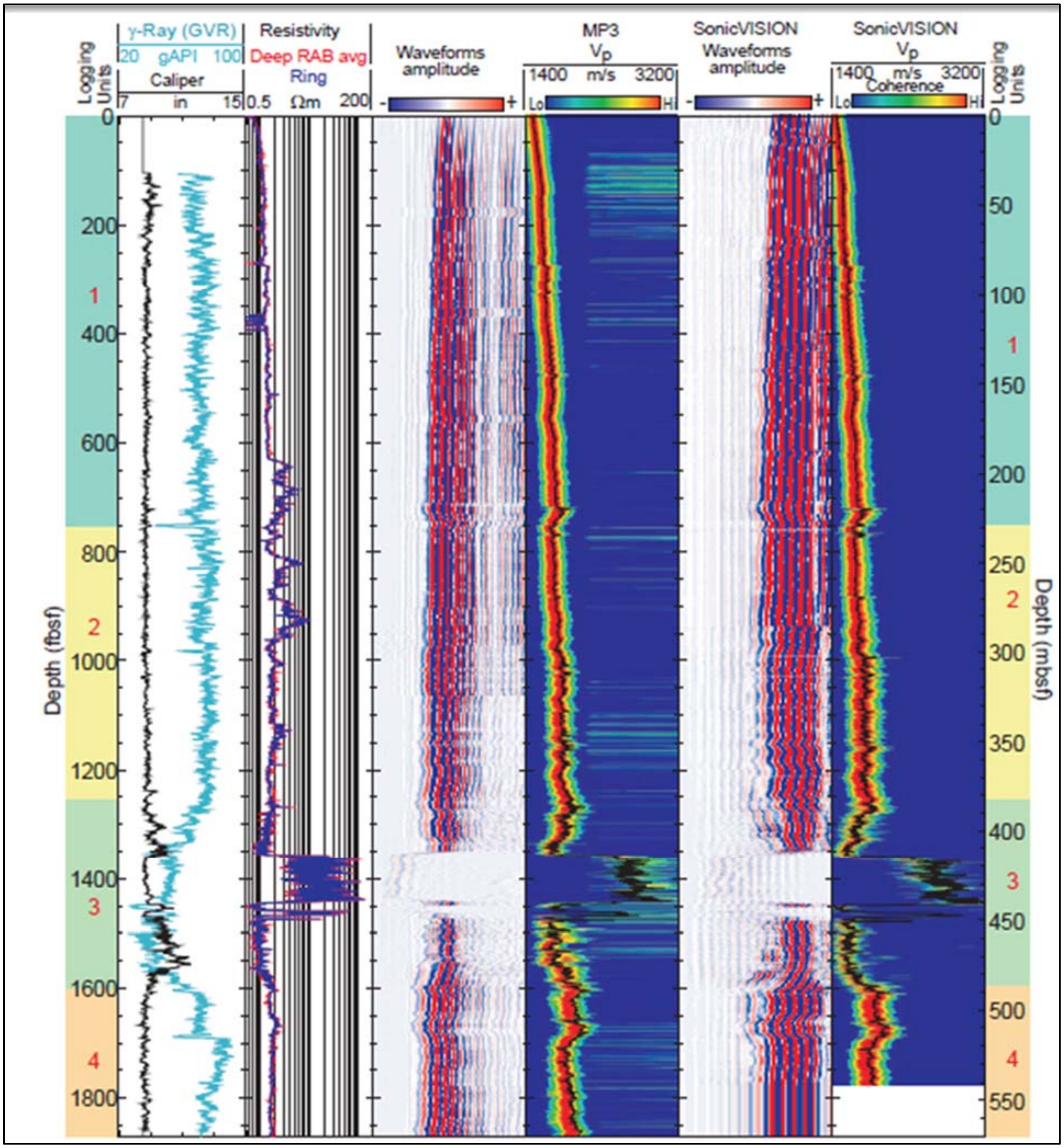


Figure C.15 Caliper, gamma, resistivity, density, and hydrate saturation logs at Well GC955-H (Guerin et al., 2009).

It is important to note, and the users of this report that want to plan a field program at these sites for further study are cautioned, that every location was deliberately and carefully chosen for both prospectivity and hazards mitigation. Conditions described at one location do not necessarily extend to other locations. A careful and professional analysis of hazards should be performed by qualified specialists for any locations not analyzed by the JIP.

C.7 OPERATIONAL PLATFORM

Field operations for JIP Leg II were conducted on the Helix Q4000 semisubmersible drilling vessel (Figure C.16). The Q4000 is typically used for deepwater well intervention. The Q4000 is self- propelled with transit speeds between 4 and 7 knots. Characteristics include a large deck space which was only partly used for the LWD only program, and good pipe handling capability, including horizontal pipe racking, the ability to run triple sections in the water column and doubles below mud line, and a work-class ROV. The Bottom Hole Assembly (BHA) consisted of six logging while drilling and measurement while drilling tools including two multipole acoustic, electrical imaging, propagation resistivity, density, neutron, measurement telemetry, and directional propagation resistivity. The BHA is shown on Figure C.17

Figure C.16 Helix Q4000 semisubmersible drilling vessel.

	Collar OD (in)	Max OD (in)	Cumulative Length (ft)	Cumulative Length (m)
sonicVISION 675 w/ 8-3/8" stabilizer	6.750	8.375	172.60	52.61
PeriScope 675	6.906	7.500	144.70	44.10
TeleScope 675	6.890	6.890	123.58	37.67
EcoScope 675 w/ 8-1/4" stabilizer	6.890	8.250	93.51	28.50
geoVISION 675 w/ 8-1/4" stabilizer	6.750	8.250	66.85	20.37
6-3/4" x 8-1/2" hole opener	6.500	8.500	56.81	17.32
SonicScope 475 (MP3) w/ 2 x 6-1/2" stabilizers	4.750	6.500	51.03	15.55
Pony drill collar	4.750	4.750	18.37	5.60
Near-bit stabilizer	4.750	6.500	6.34	1.93
6-3/4" PDC bit	6.000	6.750	0.86	0.26

Figure C.17 Bottom Hole Assembly (BHA) consisted of six logging while drilling and measurement while drilling tools (from Collett et al., 2009).

C.8 OPERATIONAL ISSUES AND PERFORMANCE

Drilling operations aimed to optimize data and maintain wellbore stability in shallow unconsolidated sediments was challenging. Several of the targets were exceptionally deep. The two locations drilled in WR313 are more than 3000 ft. below the seafloor are the deepest gas hydrate research wells drilled to date. The original plan that called for drilling the open holes with seawater and minimal drilling fluids- without surface conductors or drilling fluid returns had to be revised because of difficulties encountered at the WR313-G location. What follows are extracts from the operations review written by Collett, et al., 2009.

The WR313-G location spudded with a 6 ¾ inch drill bit followed by an 8 ½ inch hole opener to accommodate the dual diameter BHA. Drilling operations proceeded smoothly – pumping seawater between 380 and 410 gallons per minute with sweeps of 10.5 lb. drilling fluid as needed. The rate of penetration was reduced to approximately 100 ft./hr. in order to capture higher-resolution log images in a thick zone of elevated resistivity. This interval was interpreted as fracture-filling gas hydrate in clays. Approximately 400 ft. below this zone, drilling became very difficult despite increasing the number of fluid sweeps. Rotary speed was increased to 120 rpm in response to torque. The drill string would occasionally pack off despite multiple backreams per stand required to protect the BHA and advance the well. A major pack off stalling the rotary and required 140,000 lb. of overpull at about 9,200 ft. below sea surface required a change to continuous drilling with 10 lb./gal drilling fluid. The primary target was drilled at an expected depth of 9,360 ft. bss where logs revealed a net 30 ft. of high saturation gas hydrate within a 70 ft. interval. The hole was weighted up to 10.5 lbs./gal and drilled to the planned total depth without incident. The hole was displaced with 12 lb./gal drilling fluid.

The plan called for drilling another intra site location in WR313 but it was decided to pull the BHA to assess its condition and to investigate data issues with some of the sensors. To take advantage of the time to pull the BHA, and because gas hydrates were discovered at the WR313, the Q4000 transited to the GC955 site with a plan to return to WR313 on the transit to the Alaminos Canyon site.

Three wells were drilled at the GC955 site using the new protocol of automatically switching to 10.5 lb./gal drilling fluid after slowing rpm to log zones of interest. The hole was drilled to total depth of 8975 ft. BSS. The well was not displaced with heavy drilling fluid since weighted mud was used in drilling the lower part of the well. After pull-out the ROV observed fluid flow from the well but no gas bubbles were observed. The BHA was retrieved, exchanged with a simple BHA to place a cement plug.

Following the same protocol running more frequent gel sweeps and switching to 10.5 lb./gal drilling fluid after slowing to log zones of interest, the GC955-H well was drilled without incident, other than increasing rpm in response to torque. After reaching at total depth of 8605 ft. bss the hole was displaced with 13 lb./gal in order to suppress water flow. The logs recorded hydrate fracture fill gas hydrate, numerous thin high saturation gas hydrate sands, and a 100 ft. thick gas hydrate bearing sand at the principal target.

Based on the technical and operational success of the GC955-H well, the science team elected to drill GC955 Q which was in a structurally higher position with seismic indications of a much thicker gas hydrate bearing zone. Gas risk, which had been assessed as “high” at the well, was decreased based on no evidence of gas below the thick gas hydrate deposits at GC955-H. Using the protocols established at the previous three wells, drilling the well proceeded normally. After switching to 10.5 lb./gal fluid after slowing to log a zone of interest the well encountered a gas hydrate saturated sand at the expected depth of the primary target. The ROV observed gas release from the well at 7962 ft. bss that lasted less than a minute. Because the LWD pressure sensor did not record any gas entering the well, it in plausible that the gas observed was from hydrate cuttings in the hole. The gas hydrate at the target depth was penetrated at a combined stand-run and shift change. It is possible that the gas release may have been caused by dissociation of gas hydrate in the cuttings during the drilling hiatus.

The hole was initially displaced with a 13 lb./gal drilling fluid and no flows were observed for over an hour. In preparation for placing a cement plug, a small sustained flow was observed from the well. The well was bridged and displaced with two borehole volumes of 16 lb./gal kill mud. Two more borehole volumes were displaced into the well before cementing. It is possible that the use of heavy kill muds may have fractured the gas hydrate bearing sediments allow free gas or lateral subjacent gas to enter the well.

After completing operations in GC955 Q, the vessel transited to WR313-H. Following the protocols established at the previous wells- running gel sweeps every stand and a switch to 10.6 lb./gal drilling fluids after loggings shallow zones of interest or at approximately 1,600 ft. BML, GC955-H was drilled without incident. The fracture fill interval was seen at WR313-G was also present at WR313-H. Gas hydrate deposits were found in nearly all sands at WR313-H as well as at the target interval where two 15 ft. thick and one 21 ft. thick hydrate bearing sands were indicated in the logs.

C.9 SUMMARY OF RESULTS

The JIP Leg II field program was highly successful in all areas both technically and operationally. It was completed on-time and under budget with no injuries. All scientific objectives were met. The robust site selection process broke new ground in gas hydrate prospecting and prediction. The LWD tools performed exceptionally well with no down-time. The science team adapted drilling protocols after very difficult drilling at the first location. Drilling at the other locations proceeded normally, using standard drilling procedures to maintain wellbore stability and hole advancement.

JIP Leg II produced a very rich data set that could be used for further work and study with pressurized cores (P-cores) and non-pressurized cores (conventional cores (C-cores)).

D. GEOTECHNICAL SITE INVESTIGATION

Discussions during the Methane Hydrate Community Workshop identified three integrated science challenges: (1) Methane Hydrate Resource Assessment and Global Carbon Cycle, (2) The Challenge of Producing Methane Hydrate, and (3) Methane Hydrate Related Geohazards. To address these challenges requires accurate laboratory and field data and the development of advanced laboratory and field measurement tools to make critical measurements before, during, and after drilling activities. These data and tools are critical to the development of accurate and reliable pore-scale and transport models, physical property and geochemical field and laboratory measurements, and reservoir prediction on models. Therefore, in addition to the pressure coring and non-pressure coring programs, a suite of downhole in situ testing tools and advanced laboratory measurements could be employed to measure in situ pore pressure and temperature, to determine strength and index properties of hydrate-bearing sediments, and to estimate in situ concentration of methane and other gas compositions, etc. They could also be used to investigate physical properties of hydrate-bearing sediment requires to addressing these challenges.

Based on the above discussions, a comprehensive geotechnical and geomechanical site survey program should be planned and executed in support of methane hydrate drilling plans during, or prior to, the production test to receive hazard insurance for the scheduled offshore test. The field investigation should obtain good quality samples and employ in situ testing methods, in multiple borings, and with extensive laboratory testing programs, to provide site-specific information on the geologic and geotechnical conditions for understanding the geohazard and the stability assessment of subsea facilities and wellbore.

The scope of work for vertical and horizontal extent of a geotechnical site investigation in areas selected for methane hydrate drilling and production test plans includes soil sampling and coring, in-situ testing, number, depth, and location of exploratory soil borings, and geotechnical laboratory testing.

Two approaches that are typical for deepwater sampling and testing are the seabed mode (non-drilling techniques) and down-hole mode (drilling techniques). Seabed-mode methods provide soil data to adequately characterize the shallower strata, but do not require the use of drill pipe or rotary drilling techniques. However, the penetration capability varies with soil type and consistency, and is usually limited to penetrations of less than 165 ft. The down-hole mode involves advancing a borehole into the seabed using rotary-boring techniques. Coring and in situ tools are deployed and retrieved through the drill pipe to sample sediment below the bit in advance of the borehole.

Soil conditions in areas selected for methane hydrate drilling and production test plans should be investigated by performing seabed mode in-situ testing including seabed piezocone penetration tests (PCPTs) and seabed vane shear tests, seabed mode sampling (seabed box cores and piston cores), downhole mode sampling (non-pressurized and pressurized sampling) and in situ testing (downhole remote vanes, downhole piezoprobe dissipation tests, downhole formation temperature tests, and downhole PCPTs in exploratory soil borings.

The in-situ vane shear testing, including seabed and downhole vane shear testing, is the most versatile and widely used technique for investigating undrained shear strength and sensitivity of cohesive soils in their natural or in situ state. The in situ vane shear test could also reveal anomalies in soil properties that may not be reliably detected in conventional sampling. These anomalies could provide significant information about the geologic history of the site. These test tools, however, are too weak to penetrate and perform tests in sand layers. The seabed vane shear tests should be performed in combination with the down-hole in-situ tests to obtain continuous soil stratigraphy. Figure D.1 showing a typical geotechnical and geomechanical site surveys.

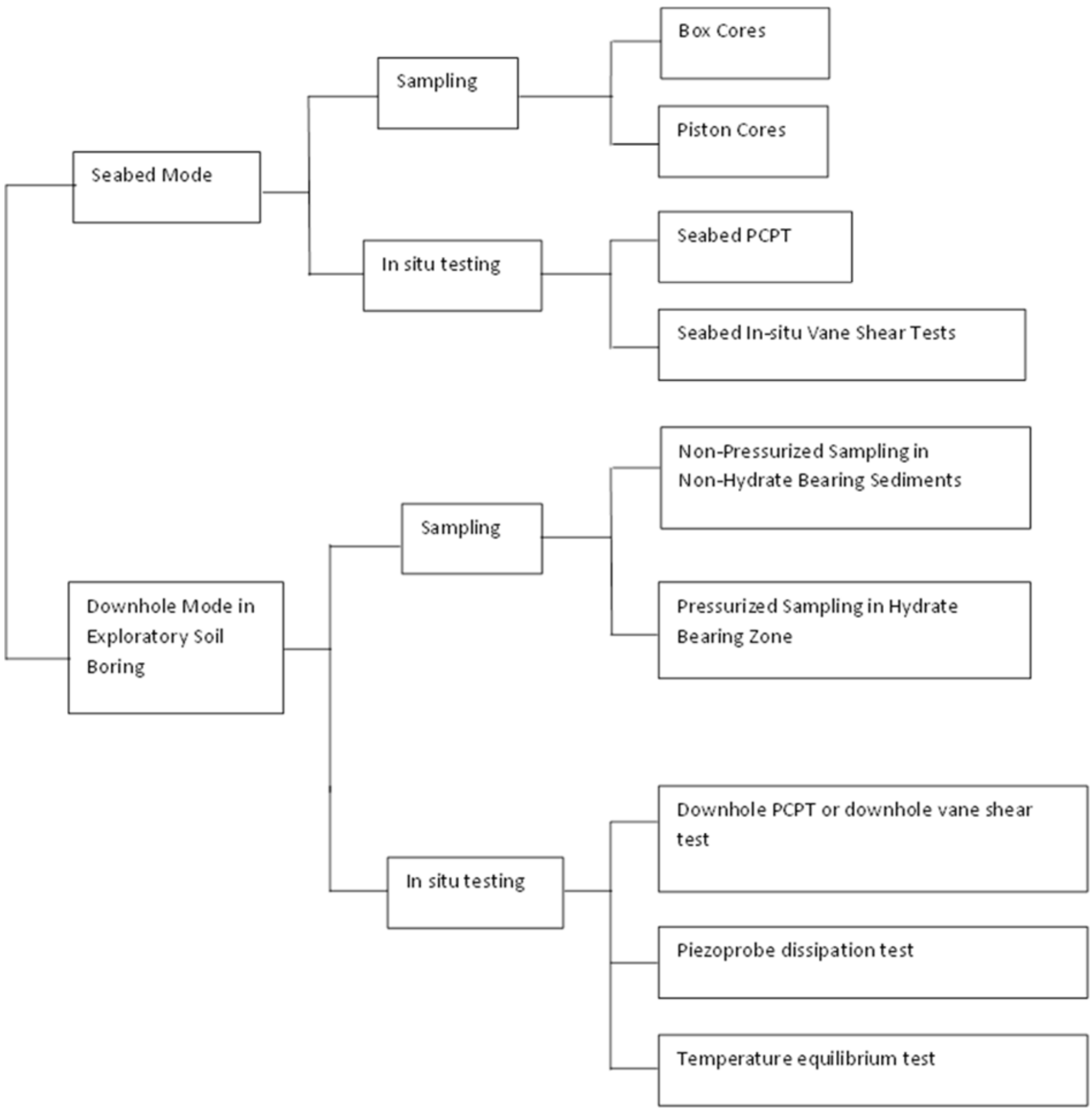


Figure D.1 Demonstration of Typical Geotechnical and Geomechanical Site Surveys.

D.1 SEABED MODE (NON-DRILLING TECHNIQUES)

The seabed mode in-situ testing including seabed piezocone penetration tests (PCPTs) and seabed vane shear tests, seabed mode sampling (seabed box cores and piston cores),

D.1.1 Seabed Wheel-Drive Piezocone Penetration Tests (PCPTs)

Seabed PCPTs could be performed continuously from mudline to penetration of up to 40 m using a seabed Wheel-Drive system subject to ground conditions and configuration adopted. Results of the seabed PCPTs consist of measured and calculated values. The measured values are cone resistance (q_c), sleeve friction (f_s), and pore pressure (u_2). The calculated values are net cone resistance (q_{net}), pore pressure ratio (B_q), and friction ratio (R_f). These values are typically presented in graphical format versus test penetration. The seabed PCPT results aid in soil classification, stratigraphy delineation, soil strength and relative density determination, sensitivity analysis, etc.

Fugro's Deepwater SEACALF® system (Figure D.2) is a deepwater seabed rig for performing continuous static cone penetration tests (CPT's) and in situ vane shear tests from the seabed in water depths up to 3,000 m (9,843 ft.). The penetration force for the Deepwater SEACALF® is provided by a seabed Wheel-Drive system in which two or four wheels grip the test rod and, when rotated, move it up or down. The newest development of the wheeldrive system uses contoured blocks instead of wheels to reduce wear on CPT rods and increases available force (Figure D.3). The system is generally designed to use 10 cm^2 or 15 cm^2 (cones of 33 cm^2 projected area could be used) Piezocones. The probe is pushed into the seabed using a single wheel-drive module capable of exerting a maximum thrust of 49 kN (11,016 lbs.) or higher. The wheels are hydraulically driven from a power pack mounted on the seabed frame (reaction mass). Tests are generally performed using 36 mm-OD x 1.00 m (1.4 in-OD x 3.28 ft.) long rods. However, the system could also use 55 mm-OD (2.1 in-OD) rods. Pore-water pressure measurements are made by a transducer via a porous stone (filter) mounted behind the cone shoulder.

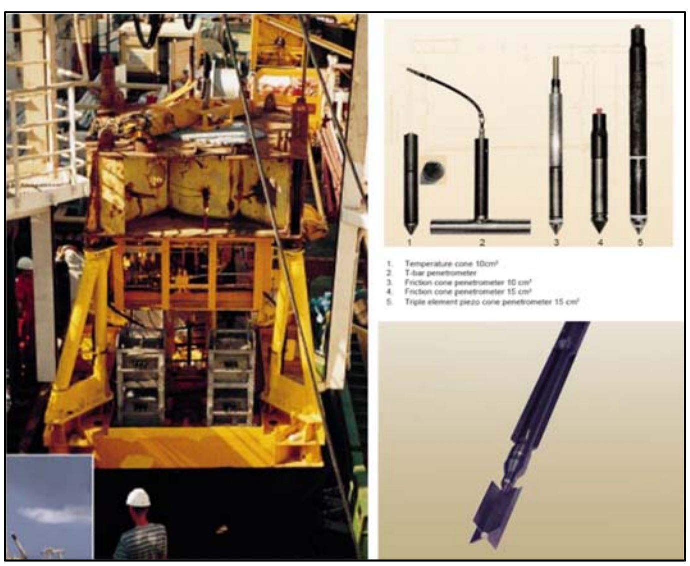


Figure D.2 Deepwater SEACALF®.

After lowering the system to the seabed, the operator, who controls all operations via a computer in the control cabin, starts the test. Signals from the cone are transmitted in digital form from the seabed unit and stored for subsequent computer processing. In addition, the data are displayed on the operator's computer, enabling monitoring of the test to be carried out as the test progresses. The penetration of the cone is approximately 2 cm per second (0.8 inches per second). Tests are terminated based on the total thrust being applied to the rods, the tip resistance, deviation of the cone from vertical, and soil conditions through which the cone had already passed. The test equipment and procedures meet ASTM specifications D-3441.

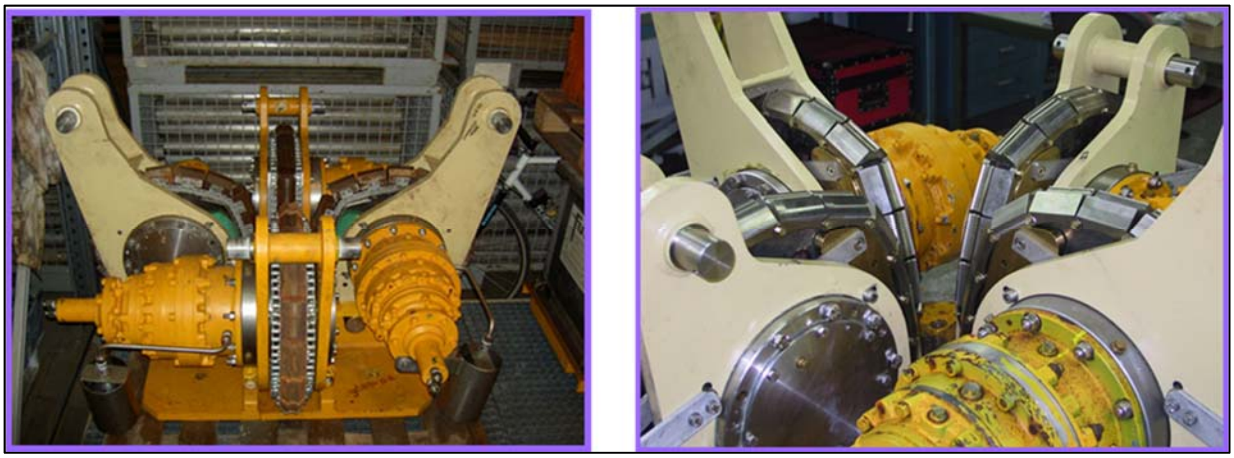


Figure D.3 Block Drive SEACALF®.

D.1.1.1 Deepwater SEADEVIL® System

The SEADEVIL (Figure D.4) was developed by Fugro. Its main advantage is that it provides an independent, controlled feed system at seabed level, in both downhole- and seabed mode. The SEADEVIL fits within Fugro's existing seabed frame configuration and the system is rated for 3000 m (9,843 ft.) water depth.

The SEADEVIL pulls the drill string down in a controlled manner without being influenced by vessel movement. This provides better control of the weight (WOB) on bit and rate of penetration (ROP), resulting in a better quality borehole which is important when drilling in soft or highly variable soils. Also, the top section of the borehole is better maintained. Unlike previous systems, the changeover between drilling and seabed mode could be done without taking the seabed frame apart thus saving many heavy lifts meaning that the operation does not have to take place in port or sheltered waters.

During seabed PCPT testing the SEADEVIL is used much in the same way as with downhole operations. The chuck and feed system are used to push the PCPT rod into the soil at a constant speed. Due to the single chuck set up currently the push is intermittent, but a future double chuck configuration would provide a continuous PCPT push.

EQUIPMENT SHEET OFFSHORE GEOTECHNICAL

FUGRO

FUGRO SEADEVIL

The SEADEVIL is Fugro's latest innovative development. Its main advantage is that it provides an independent, controlled feed system at seabed level, in both downhole- and seabed mode. The SEADEVIL fits within Fugro's existing seabed frame configuration.

APPLICATION

The SEADEVIL pulls the drillstring down in a controlled manner without being influenced by vessel movement. This provides better control of the weight on bit and rate of penetration, resulting in a better quality borehole which is important when drilling in soft or highly variable soils. Also, the top section of the borehole is better maintained.

Unlike previous systems, the changeover between drilling and seabed mode can be done without taking the seabed frame apart thus saving many heavy lifts meaning that the operation doesn't have to take place in port or sheltered waters.

EQUIPMENT DETAILS

The SEADEVIL is built inside the existing seabed template, much in the same way as the SEACLAM set-up. The chuck inside the feed system is used to lower or lift raise the drillpipe or PCPT rod in a controlled manner. The pipe clamp secures the drill string during testing and, by the use of. When inserts are used in the chuck,, the clamping range can be reduced to smaller sizes for clamping PCPT rods.

SEADEVIL

www.fugro.com 1

Figure D.4 Fugro SEADEVIL®.

D.1.1.2 <u>CPT Stinger System</u>

CPT Stinger System (Figure D.5) consists of a seabed CPT Stinger, a CPT Stinger, and a gravity CPT Stinger, and is capable of operating in water depths up to 3,000 m (9,843 ft.).

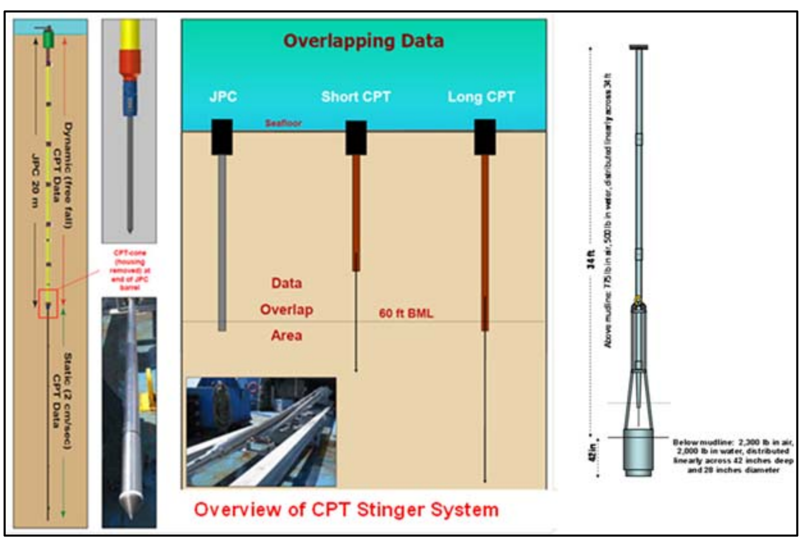


Figure D.5 CPT Stinger Systems.

The seabed CPT Stinger system is to gather static PCPT cone data from the mud line to 7.62 m or 10.67 m (25 or 35 ft.) BML. In addition to its lead-filled weight stand (weighted base), skirt, and tower assembly, the coring system comprises an 8.5-m or 11.6-m long barrel, a cone push rod inside the barrel, a cone pushing module, and a PCPT cone penetrometer that measures tip resistance, sleeve friction and pore pressure using standard ASTM protocols. Upon approach to seabed, its 71 cm OD x 58 cm ID (28 in OD x 23 in ID) tubular weighted base is inserted into the soil to about 1.1 m (42 inches) BML. Once the weighted base is fully embedded in the seafloor and a reaction force of 13.3 kN (3,000+lbs) is available, the Seabed CPT is programmed to extend its internal rod with the PCPT cone from the mudline into the formation per ASTM D5778-07 and ISSMGE specifications. The cone advances at 2 cm/sec penetration rate, but could be also programmed to advance at other rates. Data from the probe are logged every 0.1 mm of penetration as the push progresses. Parameters so-logged include tip resistance (tsf), sleeve friction (tsf), pore pressure (psi), cone acceleration (m/sec^2) and cone tilt (°) from vertical.

The CPT Stinger system is installed in a Jumbo Piston Core (JPC) corehead, deployed and triggered with a JPC process, and allowed to free-fall ballistically to insert itself into the sediment like a JPC. Once fully embedded into the seafloor with the resulting reaction force of 53.4 to 71.2 kN (12,000 to 16,000+lbs) now available, the CPT Stinger is programmed to extend an internal rod deeper into the formation (like a 'stinger') at the standard CPT cone push rate.

The gravity CPT Stinger system is to gather dynamic PCPT cone data from the mud line to 3 to 6 m (10 to 20 ft.) BML. In addition to its 907 kg (2,000 lbs.) driving head with lifting bale and coupling, the rig comprises a self-contained PCPT cone penetrometer that measures tip resistance, sleeve friction and pore pressure using standard ASTM protocols. The gravity CPT Stinger system is deployed using the same winch, A-frame, and process as for gravity coring. Upon approach to seabed, the tool is inserted into the soil to about 3 m (10 ft.) BML (4.6 or 6 m (15 or 20 ft.) BML with extensions) at winch speed, using the downward momentum of the driving head.

D.1.2 Seabed Vane Shear Tests (VSTs)

The seabed remote vane (also known as the Halibut) operates from mudline (0.6-m or 2-ft penetration) to about 9-m (30-ft) penetration BML.

D.1.2.1 SEACALF Vane Shear Tests

The SEACALF® vane shear test is deployed similar to that used for the Deepwater SEACALF® seabed CPT. The vane apparatus is mounted on the lower end of the push rods. The vane includes a motor, vane blade and an internal sensing device for measuring torque and rotation. At each test location a deck test was performed (360° rotation at 0.4°/s) to confirm equipment functionality. If results were satisfactory the seabed system was lowered to seafloor and a system-offset test was performed (90° rotation at 0.2°/s) before testing commenced. The test sequence is generally for 90° rotation at 0.2°/s for undisturbed test phase, 720° rotation at 0.4°/s for remolding phase, and 45° rotation at 0.2°/s for remolded test phase.

D.1.2.2 Halibut Vane Tests

The Halibut Vane system (Figure D.6) consists of a ballasted seafloor support frame that houses either one or two remote vane tools. The equipment is self-contained, remotely operated and suitable to operate in water depths up to 2,000 m (6,562 ft.). The maximum shear strength that could be measured is around 300 kPa (6.3 ksf).

The Halibut system is generally deployed using the A-frame of the vessel, a winch, and steel cable. The system consists of a lightweight square basket (1.5 x 1.5 m (5 x 5 ft.)), the remove vane system, weights and some rod extensions to achieve the required penetration test depth. The vane equipment is housed in the basket and once deployed would rest on the seafloor. The vane rods extend below the basket to the required testing depth. Weights are sometimes added, as necessary, to insure penetration of the rods to the prescribed depth. All power and data acquisition systems are attached to the unit.

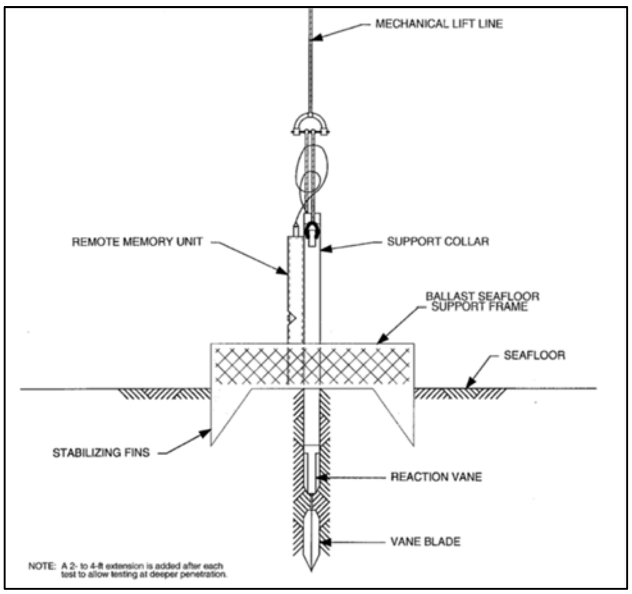


Figure D.6 Halibut Vane System.

The Halibut system could perform tests at one (using the one remote vane configuration) or two (using the two remote vane configuration) depths in a single deployment. To set the equipment up for the next depth(s), the Halibut must be brought back to deck, and vane rods (0.6-m (2-ft) length) must be added or removed.

D.1.3 Large Diameter or Jumbo Piston Coring (JPC)

A Jumbo Piston Corer (JPC) is typically configured with a core-head weight of 4,100 kg (9,039 lbs.) and a maximum barrel length of 21 m (70 ft.) (Figure D.7). Shorter barrel lengths are used in order to avoid buckling during penetration (as presence of hard near-seafloor soils are interpreted at locations called out from companion CPT records). A free-fall height of 1.5 m (5 ft.) is generally set for the cores. JPC samples are retrieved in a 101.6-mm-ID (4-in-ID) plastic PVC liner housed inside a 146.0-mm-OD (5.75-in-OD) steel barrel. The leading edge of the JPC barrel is equipped with a cutting shoe and a flexible spring steel core catcher. The JPC normally could provide high quality samples. The JPC is deployed and recovered over the stern of the vessel using a specially designed stinger mounted to a trolley system.

Figure D.7 Deployment of JPC over the stern.

While the JPC is on deck in the horizontal position, the piston and deployment cables are assembled, the plastic liner is inserted and the cutting shoe and trigger arm are attached. The stinger frame and bucket, which cradles the JPC, are then pulled to the stern and lowered to the vertical position, and the triggering weight is attached. The JPC is then lifted free from the stinger bucket and lowered to the seabed.

D.1.4 Large Diameter Stationary-Piston Core Sampling (STACOR®)

STACOR® (Figure D.8) is a large-diameter free fall gravity corer (STACOR®) equipped with a truly stationary piston. The STACOR® was deployed and recovered using a specially designed stinger mounted to the side of the vessel. The STACOR® was fixed with a 25-m (82-ft) long barrel for each deployment. The steel barrel has an outside diameter of 17 cm (6.7 in.) and an inside diameter of 13 cm (5.1 in). The sample is retrieved in a plastic inner liner, 12.6-cm (5.0-in) outside and 10.5-cm (4.1-in) inside diameter. The driving weight of assembly is typically set at 4,600 kg (10,141 lbs.). In general, a free-fall height of 1.4 m (4.6 ft.) is set for the cores. The operational sequence of the STACOR® is similar to that of the JPC.

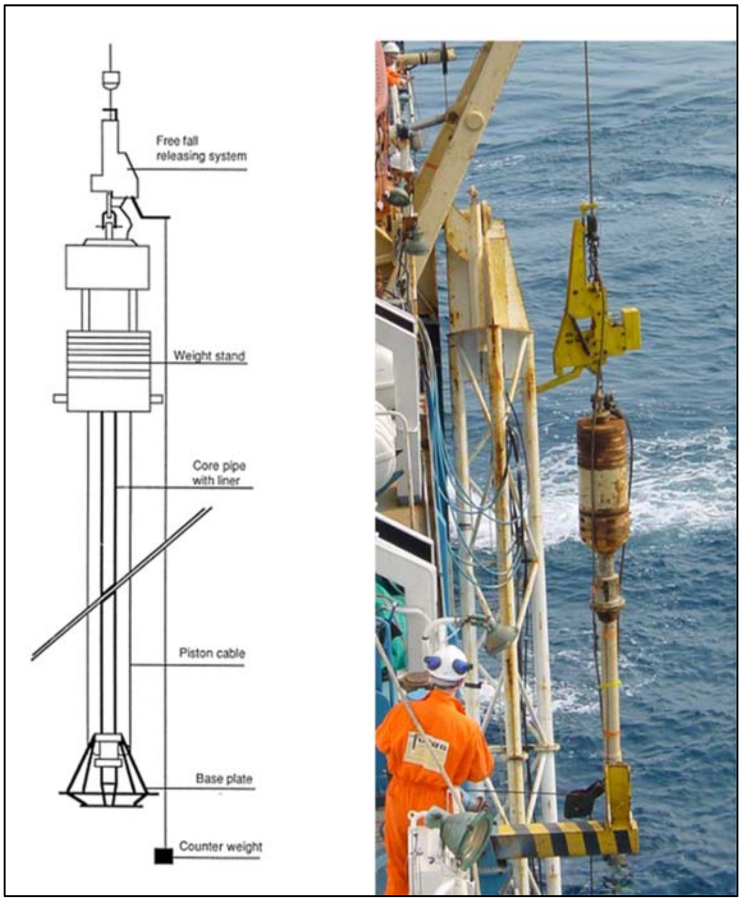


Figure D.8 Large Diameter Stationary-Piston Core Sampling (STACOR®).

D.2 EXPLORATORY SOIL BORINGS (DRILLING TECHNIQUES)

Exploratory soil borings are primarily intended for down-hole mode in-situ testing and non-pressurized and pressurized soil sampling. The exploratory soil borings traditionally are performed from a surface mounted geotechnical drilling systems on a drilling vessel or be performed from a remotely operated seabed drilling system (SFD).

For the surface mounted drilling systems, soil borings are drilled using conventional open-hole wet rotary techniques, with drilling returns expelled at the seafloor. The drill string is a combination of a drag bit, followed by 178-mm-OD (7.0-in.-OD), 102-mm-ID (4.0-in.-ID) drill collars, with the remaining joints being either 139.70-mm-OD (5.5-in-OD), 104.78-mm-ID (4.1-in.-ID) steel or aluminum drill pipes. The drag bit is used for coring and aids in advancing the borehole during drilling operations. The drill collars add weight to the drill string to maintain the drill pipes from deviating while being lowered into the water (effects of currents) and in maintaining a vertical borehole during drilling. The aluminum pipes would make up the drill string in the water column. Steel pipes would be used for the sections that would enter into the seabed and at the deck level during drilling operations.

On the SFD, the drill pipe 114.3-mm-OD and 101.6-mm-ID (4.5-in.-OD and 4.0-in.-ID smooth joint drill pipe) is advanced with the appropriate cutting shoe. The shoe cut a slight kerf, 15.9-mm (5/8-in.), which reduced pressure on the up-hole drill pipe. A latching system is connected behind the first joint of drill pipe and contains the landing ring for soil sampling or in situ test tool to latch into. The sampling or in situ test tool is then lowered and raised via wireline using a patented Marshall Pardy "toggle latch". The borings are also advanced by conventional open-hole wet rotary drilling techniques, with returns expelled at the seafloor. Primarily, seawater is used to suspend and remove drill cuttings; if necessary, mud is also used to stabilize the boreholes and help remove drill cuttings.

D.2.1 Soil Sampling and Coring

The coring system could be categorized in two primary groups, Non-pressurized and Pressurized Coring Systems. Both systems are used to obtain soil samples through the drill string.

D.2.1.1 Non-Pressure Coring Systems

The non-pressurized sampling system is intended to obtain standard soil samples using either the Shelby tubes for cohesive samples or using the thin/thick-walled tubes for granular materials. The sampling tubes are deployed downhole and could contain up to 60-cm (24-in.) of soil when retrieved to deck. The technique used for each type of sampler is described as follows:

D.2.1.1.1 Push Sampler

The downhole push sampler is capable of obtaining 64-mm-OD (2.5-inch) or 76-mm-OD (3.0-inch) diameter samples up to 1 m (3 feet) in length. A range of sample tubes is available for different soil conditions. A 76.0-mm-OD (3.0-in-OD), 72.0-mm-ID (2.83-in-ID) thin-walled Shelby tube sampler is used for soft to hard cohesive soils (with undrained shear strengths > 20 kPa (0.40 ksf)) (Figure D.9). These sampler tubes are pushed into the formation using the weight of the drill string and the technique is called push sampling. In the push sampling technique, the drill bit is raised from the bottom of the borehole after the boring is drilled and cleaned out to the desired sampling interval. The push sampler is then lowered through the drill pipe until it rests on a catch ring in the drill bit, with the mechanical pawls, sample tube, and tube adapter protruding beyond the drill bit. The drill string is then lowered to engage the mechanical pawls, and the weight of the drill string pushes the sample tube into the soil formation. The drill string is then raised to pull the sample tube out of the soil. The Shelby tube is retrieved to the drill floor using a sandline.

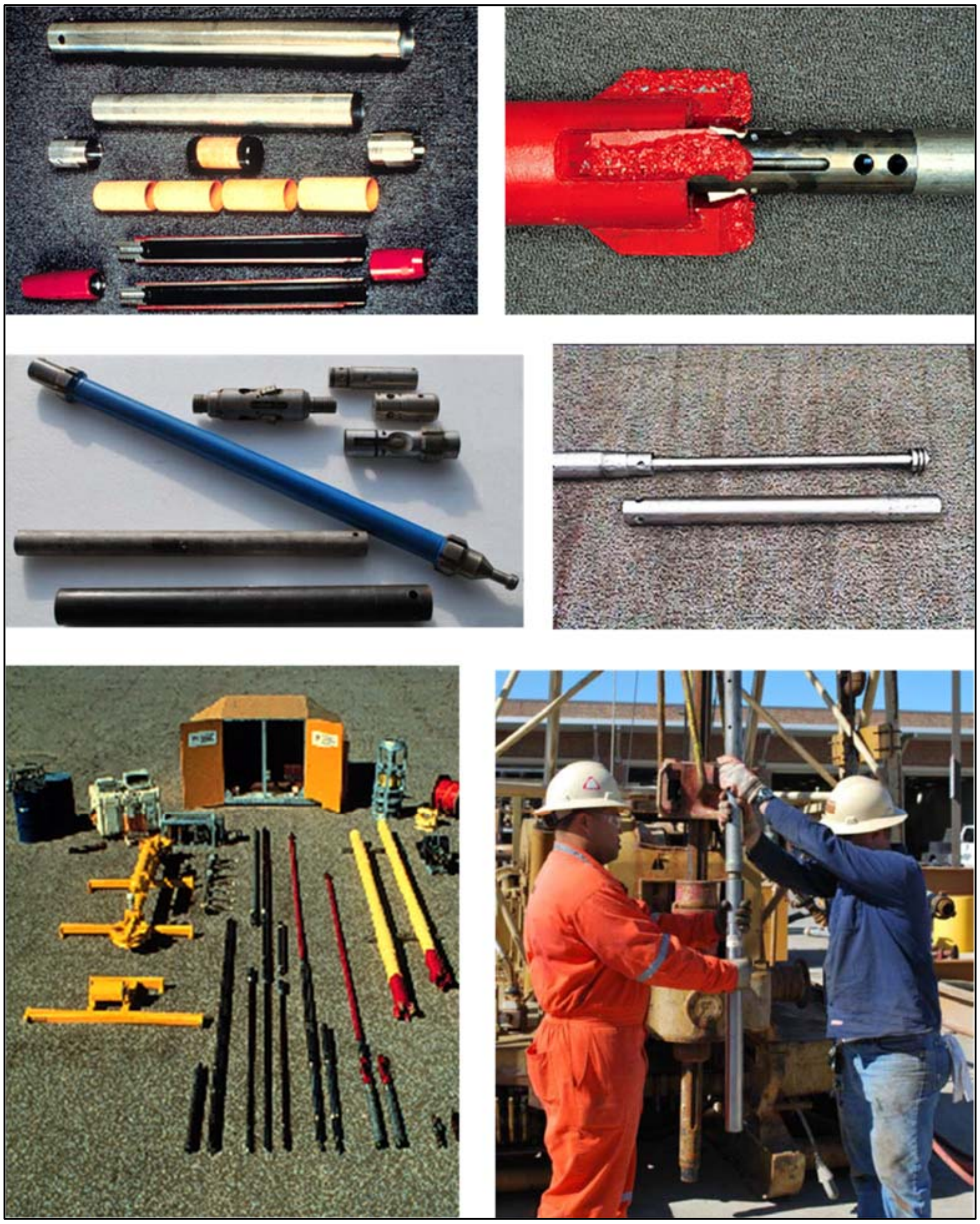


Figure D.9 Downhole Sampling Equipment.

D.2.1.1.2 Liner Sampler

Liner Sampler is a type of push sampler with liners as inserts for very soft soils to soft near seafloor cohesive soil samples (with undrained shear strengths ~20 kPa (0.4 ksf)) (Figure D.9. The sample diameter is 50.80-mm-OD, 47.63-mm-ID (2.0-in-OD, 1.88-in-ID) or 63.50-mm-OD, 53.98-mm-ID (2.5-in-OD, 2.1-in-ID). In each liner barrel are four individual liners, each 12.7-cm (5.0-in.) long, placed end to end in the liner barrel. The liner barrel, attached to a 774-Newton (175 lb.) slide and hammer assembly, is lowered through the drill pipe until it rests on a catch ring in the drill bit. The liner barrel is allowed to penetrate the formation using the weight of the hammer and slide assembly alone. The drill string is then raised to pull the liner barrel out of the formation. The liner barrel together with the slide and hammer assembly is retrieved to the drill floor using a sandline.

D.2.1.1.3 <u>Percussion Sampler Note: This method is used in shallow water, and is not possible in deep water.</u>

The technique, called wireline percussion sampling (commonly termed driven samples) is limited to shallow water and cannot be used in deep water (Figure D.9), involves lowering a hammer and slide assembly with the thin-/thick-walled tube attached to its end, through the drill pipe to the desired sampling interval. The 774-Newton (175 lb.) hammer is a sliding weight that is raised and dropped (one blow) using a wireline approximately 1.5 m (5 ft.), to achieve a maximum penetration of 0.6 m (2 ft.), or for a maximum of 30 blows. The reference mark on the wireline, indicating the top of the sampling interval would be checked at the end of either a maximum penetration of 0.6 m (2 ft.) or a maximum of 30 blows, to determine the penetration of the sample tube. In granular soils, samples are obtained with 57-mm-OD, 53-mm-ID (2.25-in-OD, 2.1-in-ID) thin-walled steel tubes. In very dense granular or cemented soils, percussion samples are obtained either with a 63.5-mm-OD, 53.0-mm-ID (2.5-in-OD, 2.1-in-ID) tapered, thick-walled tube sampler, a 76-mm-OD, 63.5-mm-ID (3.0-in-OD, 2.5-in-ID) split spoon sampler, or a 50.8-mm-OD, 38.1-mm-ID (2.0-in-OD, 1.5-in-ID) split-spoon sampler.

D.2.1.1.4 <u>Piston Sampler</u>

A type of push sampler which incorporates a fixed piston to improve sample quantity and recovery in clay soils. This system uses the same Shelby tube as the push sampler, but has a piston flush with the end of the sample tube. The Piston sampler is lowered into the bottom hole assembly and seats into the sealed system. Mud pumps then increase the pressure inside the drill pipe, advancing the sample tube into the soil. The piston stays at the same point in reference to the drill pipe, with the tube advancing around it.

D.2.1.1.5 <u>Advanced Piston Corer (APC)</u>

The Advanced Piston Corer (APC) is commonly used to obtain soil samples for high-resolution climate and paleoceanographic studies (IODP, 2006). The APC (Figure D.10) is a hydraulically actuated piston corer designed to recover relatively undisturbed continuous 9.5 m (30 ft.) long oriented core samples from very soft to firm sediments that cannot be recovered well by rotary coring.

The APC inner core barrel is deployed (and recovered) using the coring wireline to avoid premature release of the shear pins, which determine penetration force of the barrel into the sediment. The APC inner core barrel is run to bottom on the coring wireline. Pump pressure is then applied to the drill pipe, which severs the shear pins and strokes the inner core barrel 9.5 m (30 ft.) into the sediment. The inner core barrel containing the core is then retrieved by wireline. A wireline packoff at the top of the drill string permits rotation of the drill string and continued circulation while the core is retrieved. This allows rapid recovery of core with minimal non-productive time. After core retrieval, the bit and bottom-hole assembly (BHA) are again advanced 9.5 m (30 ft.), repeating the process.

The APC core could be oriented with respect to the Earth's magnetic field by running a downhole orientation tool above the core barrel. This allows recovery of oriented core for paleomagnetic studies. Additionally, special APC shoes have a pocket in which a thermistor unit could be run to record the in situ formation temperature after taking a core. This provides in situ heat flow measurements for science and hydrocarbon safety.

Variations of the APC tool include a temperature measurement in the core cutter portion of the tool (APCT) as well as the inclusion of sensors to measure methane gas (APCM).

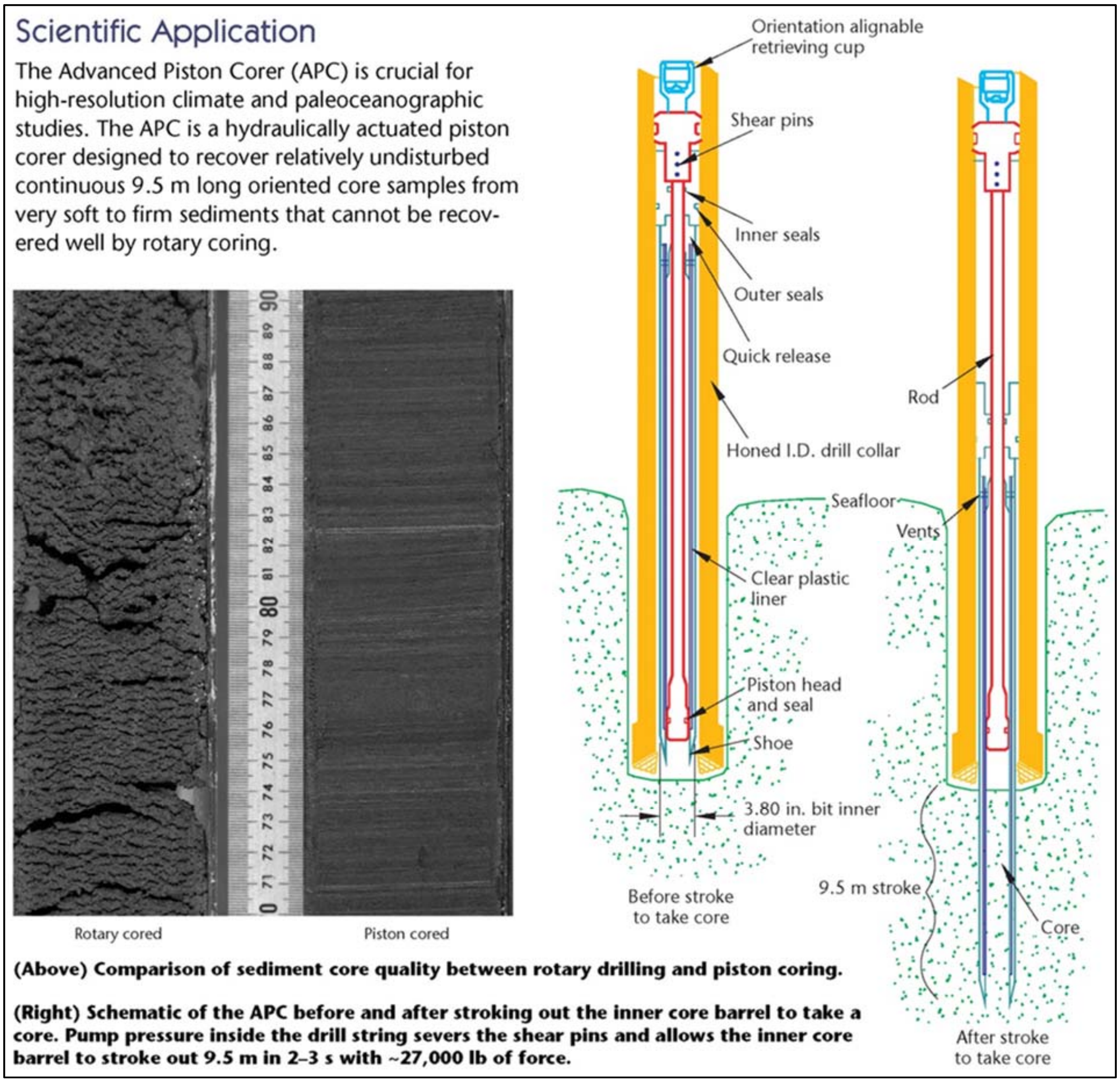


Figure D.10 Advanced Piston Corer.

APC Specifications:
Maximum Piston Stroke
(Core) Length

Typical Operating Range:
Formation
Very soft to firm sediments

9.5 m (31.16 ft.)	Depth Range
APC Shoe Inside Diameter	Seafloor to +300 m BML
(Core Outer Diameter)	APC piston shoe extending through $11\frac{7}{16}$ in.
6.2 cm (2.44 in)	APC/XCB bit
Piston Force	23,000 to 28,000 lbf at 2300 to 2800 psi pump pressure

The downside of the APC tool is it does not penetrate or recover granular formations (such as sand) or hard ground. The core barrel may stick in firm sediments and require drill-over.

D.2.1.1.6 Advanced Piston Corer Methane (APCM)

The Advance Piston Corer Methane (APCM) (Figure D.11) tool continuously monitors temperature, pressure, and conductivity changes in the core liner during coring, wireline retrieval, and handling to quantify changes that occur in gas-rich cores (IODP, 2006). By comparing data plots from successive cores, stratigraphic variations and relative amounts of gas stored in sediments could be determined at individual sites and variations between sites could be assessed. Models indicate that the data also provide information on the presence of gas hydrate in the sediment that may disassociate before core retrieval.

Temperature, pressure, and conductivity sensors are embedded within the piston head on the standard APC. During the APC coring stroke, the piston head acts as a plunger to evacuate water from the inner core barrel, which allows the core to enter. The APCM is deployed at the beginning of APC coring and removed when coring is suspended. A 100-hr long-life battery allows continuous 1-Hz recording of data for the duration of the APC coring sequence. This allows scientists to calculate the amounts of gas stored in sediments.

Scientific Application

The Advance Piston Corer Methane (APCM) tool continuously monitors temperature, pressure, and conductivity changes in the core liner during coring, wireline retrieval, and handling to quantify changes that occur in gas-rich cores. By comparing data plots from successive cores, stratigraphic variations and relative amounts of gas stored in sediments can be determined at individual sites and variations between sites can be assessed. Models indicate that the data also provide information on the presence of gas hydrate in the sediment that may disassociate before core retrieval.

Tool Operations

Temperature, pressure, and conductivity sensors are embedded within the piston head on the standard ODP Advanced Piston Corer (APC) (Fig. 1, Fig. 2). During the APC coring stroke, the piston head acts as a plunger to evacuate water from the inner core barrel, which allows the core to enter.

Design Features

Wireline Deployment

The APCM is deployed at the beginning of APC coring and removed when coring is suspended. A 100-hr long-life battery allows continuous 1-Hz recording of data for the duration of the APC coring sequence.

Benefit: Allows scientists to calculate the amounts of gas stored in sediments.

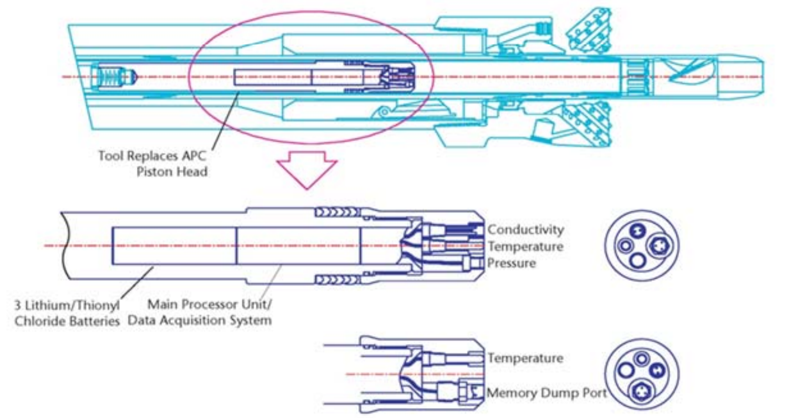


Figure D.11 Advanced Piston Corer Methane (APCM).

Top schematic shows the APCM inside the APC bottom-hole assembly. The bottom two drawings show the APCM head in more detail along with a schematic of the top of the sensor head.

D.2.1.1.7 <u>Extended Core Barrel (XCB) coring system</u>

The Extended Core Barrel (XCB) coring system (Figure D.12) is used to obtain soil samples for sedimentological, climate, and paleoceanographic studies. The XCB is used to recover 9.5 m (30 ft.) long core samples from soft to moderately hard formations. The XCB is typically deployed when the formation becomes too stiff to piston core (i.e., upon piston coring "refusal") or when it is not hard enough to permit efficient recovery with the Rotary Core Barrel (RCB). The XCB cutting shoe extends ahead of the main bit in soft sediments but retracts into the main bit as the weight on bit increases when firm lithologies are encountered. The XCB uses the same bottom-hole assembly (BHA) as the Advanced Piston Corer (APC). The XCB relies on rotation of the drill string to advance the hole, and an integral cutting shoe trims the core sample at the same time.

(i.e., core damage caused by water jets from the main drill bit nozzles).

Benefit: Improves core recovery and reduces core disturbance in soft to moderately hard formations.

2) Retractable Cutting Shoe

A unique retraction device allows the XCB, which is normally extended ahead of the core bit, to retract inside the BHA until the cutting shoe is flush with the core bit.

Benefit: Cutting shoe is retracted to reduce failures when hard formations are encountered.

3) Nonrotating Core Liner

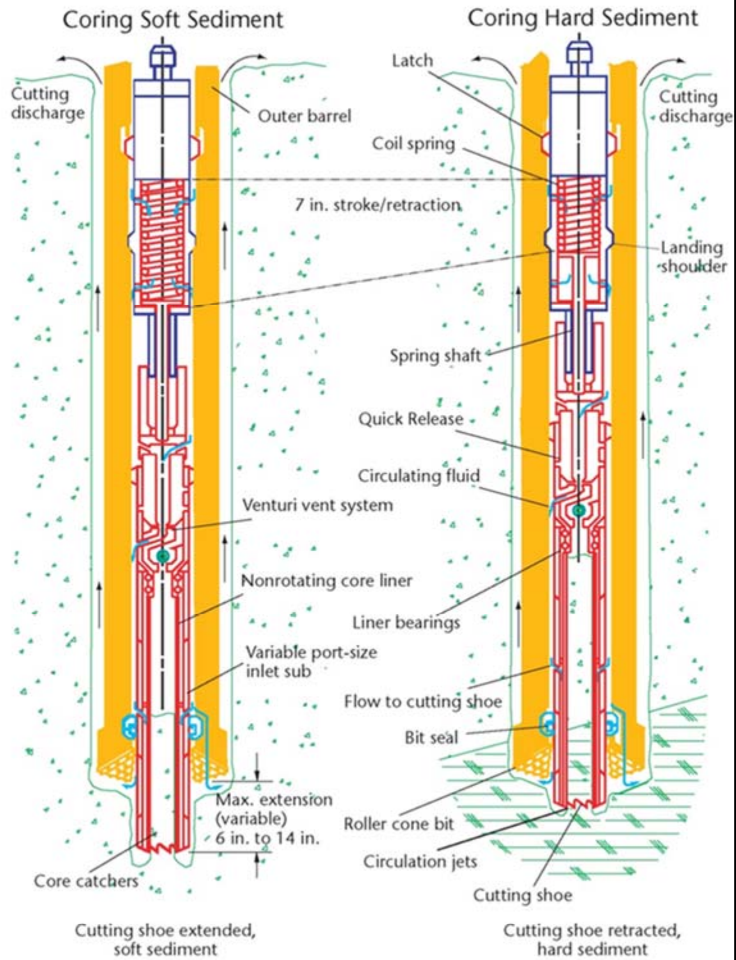
An inner core barrel swivel allows the core to remain stationary relative to the formation as the bit rotates, thereby reducing the transfer of rotary torque to weakly laminated formations.

Benefit: Reduces "biscuiting" (artificial layering), which is a type of core disturbance caused by transferring rotary torque to the core.

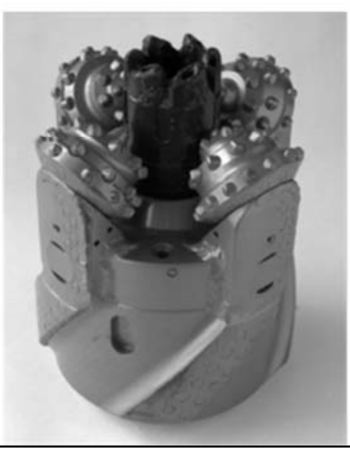
4) Compatibility

Utilizes the same BHA as the APC coring system.

Benefit: The APC and XCB core assemblies can be run in the same assembly, avoiding non-coring time for pipe trips.



Schematic of the XCB retractable cutting shoe in standard coring mode. The XCB shoe extends 6 to 14 in. ahead of the bit in very soft formations and retracts ~7 in. (inside the main bit) as weight on bit exceeds about 12,000 lb (collapses a coil spring).



XCB Specifications

Core Diameter
2.312 in. (60 mm)

Maximum Core Length
9.5 m

Cutting Shoe Extension
7 in. beyond bit (maxium)

Typical Operating Range

Formation
Soft to medium firm sediments

Depth Range
Typically from APC refusal to ~400 to 700 m below seafloor (mbsf) in sediments and can core top of igneous basement (destroys shoe).

Rate of Penetration
Typically 30 to 12 m/hr.

Quantity of Core on Deck
1 to 2 cores/hr depending on water depth and formation

Limitations

Does not recover ooze or very soft sediments, granular formations (such as sand), fractured rock or rubble, or hard igneous formations.

Figure D.12 Extended Core Barrel.

The XCB uses an integral cutting shoe to trim the core. The shoe is positioned ahead of the main core bit, which reduces core "washing" (i.e., core damage caused by water jets from the main drill bit nozzles), and improves core recovery and reduces core disturbance in soft to moderately hard formations.

A unique retraction device allows the XCB, which is normally extended ahead of the core bit, to retract inside the BHA until the cutting shoe is flush with the core bit. The cutting shoe is retracted to reduce failures when hard formations are encountered. An inner core barrel swivel allows the core to remain stationary relative to the formation as the bit rotates, thereby reducing the transfer of rotary torque to weakly laminated formations. This would reduce "biscuiting" (artificial layering), which is a type of core disturbance caused by transferring rotary torque to the core.

The limitation of the XCB is that it does not recover ooze or very soft sediments, granular formations (such as sand), fractured rock or rubble, or hard igneous formations.

D.2.1.1.8 Rotary Core Barrel (RCB) coring system

The Rotary Core Barrel (RCB) is a rotary coring system designed to recover core samples from firm to hard sediments and igneous basement. The RCB (Figure D.13) is crucial for oceanic crustal hard rock studies.

The RCB inner core barrel free falls (and is pumped) through the drill string and latches into the RCB bottom-hole assembly (BHA). The main RCB bit trims the 58.7 mm (2.312 in.) core. The BHA, including the bit and outer core barrel, is rotated with the drill string while bearings allow the inner core barrel to remain stationary. The inner core barrel could hold a 9.5 m (30 ft.) core and is retrieved by wireline. A wireline packoff at the top of the drill string permits rotation and circulation of the drill string to continue while using the wireline to retrieve the core.

The RCB BHA, bit, and inner core barrel assembly have a rugged design for use in abrasive and fractured hard sediments and igneous basement. The rugged design increases operating time of the bit and improves penetration of hard formations.

A center bit could be used to drill a hole without attempting to recover core. The center bit is used to drill ahead in hard rock and is run on a special inner barrel sub to lock it into the outer barrel for rotation. The center-bit assembly is configured to allow circulation through the center bit. The center bit could be interchanged with a standard RCB core barrel for "spot" coring. A Mechanical Bit Release (MBR) could be operated by wireline to drop a bit in the hole or on the seafloor to provide a fully open BHA for logging. Wireline logs could be run after coring with the RCB system without making a pipe trip to install a logging bit.

The limitation of the RCB is that it cannot be used to recover soft sediments or granular formations (such as sand, fractured rock, or rubble).

2) Drilling with Center Bit

A center bit can be used to drill a hole without attempting to recover core. The center bit is used to drill ahead in hard rock and is run on a special inner barrel sub to lock it into the outer barrel for rotation. The center-bit assembly is configured to allow circulation through the center bit.

Benefit: The center bit can be interchanged with a standard RCB core barrel for "spot" coring.

3) Wireline Logging with Bit Release

A Mechanical Bit Release (MBR) can be operated by wireline to drop a bit in the hole or on the seafloor to provide a fully open BHA for logging.

Benefit: Wireline logs can be run after coring with the RCB system without making a pipe trip to install a logging bit.

RCB Specifications

Inner Core Barrel Length
9.5 m (31.16 ft)

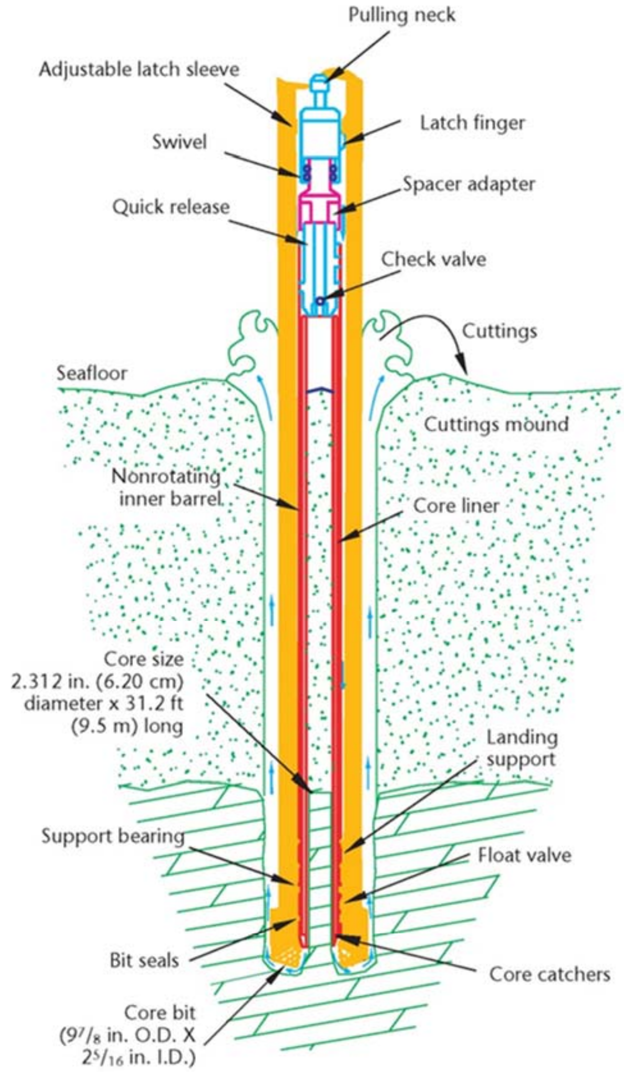
RCB Bit Throat (Core Diameter)
5.87 cm (2.312 in.)

Typical Operating Range

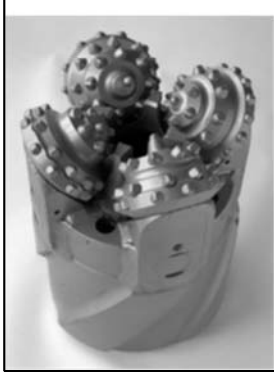
Formation
Firm to very hard sediments and igneous basement

Depth Range
Seafloor through igneous basement

Mean Recovery
20% to 55%



Schematic of the RCB coring system in coring mode with a bare seafloor spud-in. A center bit can be run on the inner core barrel to drill ahead without core recovery.



Quantity of Cores on Deck
0.3 to 2 cores/hr depending on water depth and formation hardness

Rate of Penetration
Depends on rock properties, but averages 4.0 to 9.8 m/hr

Limitation

Does not recover soft sediments or granular formations (such as sand, fractured rock, or rubble)

Figure D.13 Rotary Core Barrel.

D.2.1.1.9 Advanced Diamond Core Barrel (ADCB) coring system

The Advanced Diamond Core Barrel (ADCB) (Figure D.14) coring system may be used to attempt to recover continuous core samples from firm to well lithified sedimentary or igneous formations when Advanced Piston Coring, Extended Core Barrel, and Rotary Core Barrel (APC/XCB/RCB) coring techniques are ineffective. The ADCB provides a crucial alternative technique using diamond coring technology to attempt to improve recovery of formations that are difficult to core with conventional rotary coring tools.

Equipment

The inner core barrel has a positive indicator latch to confirm inner core barrel latch-in.

Diamond stabilizers on the outer core barrel reduce core barrel vibration.

Bit types include diamond impregnated for hard rock, polycrystalline diamond compact (PDC) for friable rock, and surface-set diamond bits for sedimentary formations.

ADCB bit showing circulation test.

Typical Operating Range

Formation

Designed for hard or well-cemented sediments and igneous formations.

Recovery

May be higher (relative to XCB and RCB) in formations that are difficult to core, such as fractured hard rock or rubble and interbedded hard and soft formations.

Limitations

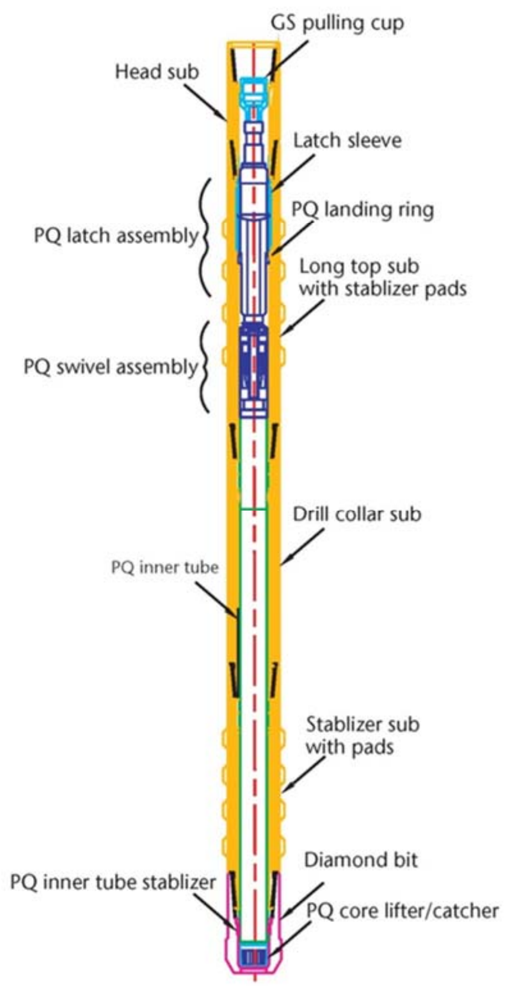
Does not recover soft sediments and granular formations (such as sand, gravel, or coral debris).

Cannot be used for bare rock spud.

The ADCB requires good weight-on-bit control and use of the active heave compensator.

The inner core barrel and core may be pulled before coring the full 4.75 m length if the core jams.

Depth range is limited by the number of 6¾ in. drill collars (presently ~350 m) available. The 8¼ in. drill collars above the 6¾ in. drill collars will not fit in the hole made by the ADCB. Thus, the pipe must be tripped to change to a rotary bit and BHA to enlarge the hole, then a second pipe trip is made to return to ADCB coring. ADCB cores are of larger diameter than APC or rotary cores. This presents problems in shipboard core processing and curation.



Schematic of the ADCB showing the bit, outer core barrel, and inner core barrel. The ADCB is an adaptation of a mining style "PQ" coring assembly.

Figure D.14 Advanced Diamond Core Barrel (ADCB).

The ADCB uses a 171.5 mm (6 in.) bottom-hole assembly (BHA) and requires some (~20 m, 66 ft.) lateral support (i.e., deployment in an existing hole) to commence coring. The ADCB relies on rotation of the drill string to advance the hole while the 184.2 mm (7 in.) drill bit trims the core sample.

The ADCB uses a diamond mining-style bit to trim the core and incorporates a pressure indicator to monitor core jams which may improve core recovery in hard formations, interbedded firm and hard formations, and poorly consolidated formations that are difficult to recover with the RCB and XCB.

The ADCB's 184.2 mm (7 in.) mining-style thin-kerf diamond bit produces a smaller and smoother borehole wall than rotary drilling, and the 171.5 mm (6 in.) BHA provides a "packed hole" with a narrow annulus. Hole stability is improved in hard formations, which requires less time for reaming and hole cleaning and reduces stuck pipe problems. The ADCB diamond bit creates a fine rock powder (i.e., not rock chips or cuttings); therefore, hole cleaning requires less fluid velocity, circulating rates are lower, and the core is not directly exposed to high-pressure fluid from the bit jets. The ADCB reduces fluid invasion (i.e., "core flushing") and improves core quality in porous and water sensitive formations.

The ADCB diamond bit produces a smooth 184.2 mm (7 in.) hole rather than the larger and more rugose borehole walls typical of rotary coring. Electric log quality is improved by better pad contact and smaller hole diameter, 184.2 mm vs. 250.8 mm (7 in. vs. 9 in.). The PQ3 mining-style bit produces cores with an 83 mm (3.27 in.) diameter when optional split steel or Lexan liners are used. The PQ bit, which does not use liners, has a core diameter of 85 mm (3.345 in.). Typically, the corer is 4.75 m (15 ft.) long to reduce core weight and problems with core jamming in the core barrel. A 9.5 m (30 ft.) version is also available.

D.2.1.2 Pressure Core Systems

The pressurized coring systems offer the possibility of recovering complete specimens of hydrate and sediment, preserved at the downhole, ambient pressure. They could bring soil samples to the surface with close to in situ pressure. In general, Pressure coring systems are difficult tools to operate and to consistently get quality cores at ambient pressure or near to ambient pressure. Pressure and temperature sensors are deployed with these coring systems so that the core could be monitored to determine if it has been kept within the gas hydrate stability zone. These systems are used in conjunction with Pressure Core Analysis Systems to perform Non-Destructive (NDT) and destructive testing upon recovery to deck.

D.2.1.2.1 Fugro Pressure Corer (FPC)

The Fugro Pressure Corer (FPC) (Figure D.15) and the Fugro Rotary Pressure Corer (FRPC) (Figure D.16) are the typical pressurized coring systems. They are the wireline-conveyed (lowered and retrieved through the drill pipe on wires) devices that are designed to collect approximately 1 m (3.28 ft.) of sediment sample and preserve it in pressurized autoclaves. The cores are brought to the surface as quickly as possible, and placed in an ice bath where the sample chamber is extracted from the device and transferred to shipboard labs for analysis. The FPC uses a water hammer driven by well fluid circulation to drive the core barrel into the sediment ahead of the well bit. As such, it is suitable primarily for sampling in unlithified sediments (muds, sands, and gravels). The FPC acquires a core 57 mm (2.2 in.) in diameter. The FRPC is rotary corer developed at the Technical University Clausthal and Berlin in Germany. It uses a downhole motor driven by fluid circulation to cut a core by rotating the barrel. As a result, it is capable of taking core both in soft sediments and in harder rocks. The FRPC obtains a core 51 mm (2.0 in.) in diameter. Both the FPC and FRPC are rated to retain up to 2.5 kN per square centimeter (5,120 psf) of pressure.

MAIN DIMENSIONS

Length: ~10 m
Diameter: ~100 mm
Weight: ~450 kg
Core length: ~1 m
Core diameter: ~58 mm
Max. autoclave pressure: ~25 MPa

MAIN FEATURES

- Deployed using a wireline through the drill pipe.
- Core liner/barrel forced into the soil formation by a built-in hammer activated by drilling fluid (seawater).
- An autoclave section holds core under in situ pressure.

EQUIPMENT

- The downhole (driving) coring tool.
- A barrel/liner/cutting shoe assembly
- Autoclave capable of retaining pressures of up to 25 MPa.
- Internal liners.
- Bottom Hole Assembly (BHA).
- Stands to remove the core from the FPC.

Gas Hydrate core in ice-chuck

GENERAL DRILL RIG REQUIREMENTS

- The FPC is retrieved using a sandline with capacity of ~1,000 to 3,000 kg
- Crossovers are available from the BHA to standard API threads
- During operations the reaction forces of the tool create an upward force on the drill pipe. Therefore a seabed structure such as a template with pipe clamp (SEACLAM) is recommended for better quality cores
- An open deck area of about 3 by 12 m is required for assembling, maintenance, and servicing the FPC. In addition, the tool is self-contained within a 20-ft (7 m) shipping/work-shop container.
- Pumping capabilities of ~160 to 250 liters per minute and ~20 to 50 bars of mud pressure
- Mud types, such as polymer or bentonite mud or similar to ensure smooth drilling process for open hole geotechnical or geological drilling.

FPC can be deployed/recovered with existing equipment available in most drill ships

Assembly of the FPC takes places on deck of the drill ship in a horizontal position

After assembly the tool is lifted up into the derrick

Assembly of FPC requires an open deck area of only 3 m by 12 m

Figure D.15 Fugro Pressure Corer (FPC).

The driving mechanism of the FPC is identical and interchangeable with that of the FC. The system was developed as part of the European HYACE (Hydrate Autoclave Coring Equipment) project and incorporates an autoclave system into the Fugro Corer with the objective of sealing the core tube at ambient in-situ pressure conditions. The FPC, just like the FC, penetrates the formation like a hydraulically driven push-sampler until soil resistance reaches a threshold during penetration. Once the formation resistance exceeds the threshold level (~2.75 MPa (58 ksf) mud pressure), the pressure driven percussion hammer activates and drives the coring system. Core samples are recovered in 64-mm-OD, 58-mm-ID (2.5-in-OD, 2.3-in-ID) liners. A pressure sensor incorporated in the tool remotely monitored the pressure development during coring and recovery of the system, and gave a first indication of the retained pressure inside the autoclave upon recovery of the system.

SAMPLING PROCEDURES

After drilling the borehole to the required sampling depth, procedures for operation of the tool are generally as follows:

Phase 1. The tool is lowered down the drill pipe by wireline and landed in a sealing ring so that the bottom end of the cutting head extends through the opening of the main drill bit.

Phase 2. Drilling fluid being pumped through the tool operates the built-in water-driven rotary motor starting the coring process. The core enters a plastic liner through the pilot section of the cutting head and a specially designed core catcher.

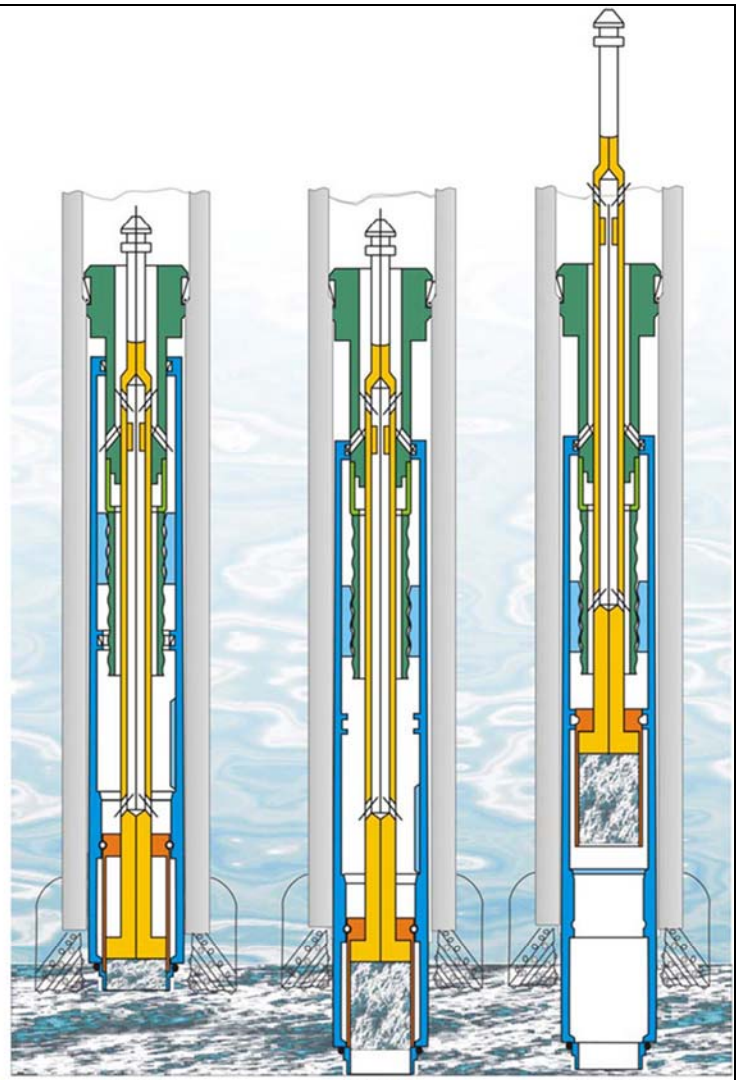
Phase 3. The FRPC tool is then recovered to the surface using the wireline, thereby pulling the core into the high-pressure autoclave section. A special shaped flapper valve closes automatically, sealing and preserving the in-situ pressure.

The tool is raised to mudline level for temperature stabilization during a period of ~30 min.

When brought back on deck, the autoclave section is immediately disconnected from the tool. Core Cooling in ice-bath helps maintain the necessary temperature for keeping methane hydrate stable, preventing any additional dissociation.

Finally, the autoclave section brought inside the on-site the processing lab.

Successful pressure core **recovered by FRPC being transferred to on-site processing laboratory**



Phase 1 ***Phase 2*** ***Phase 3***

The autoclave section containing the core liner undergoes further processing in an on-site cooled laboratory, where the autoclave is connected to a *"Transfer System"* that allows retrieval of the core without loss of pressure. The core can then be logged by means of X-ray, P-wave velocity and Gamma Ray, which allow deep insight core analysis under in situ pressure. The core can then be degassed or cut using the *"Shear Transfer Chamber"* and stored in high-pressure storage chambers for further testing.

Figure D.16 Fugro Rotary Pressure Corer (FRPC).

D.2.1.2.2 Pressure Core Tool with Ballvalve (PCTB)

The PCTB is a rotary coring system and have inner barrel assemblies that are retrieved using the wireline. The PCTB (Figure D.17) Coring System has an inner barrel that passes through the core bit and a cutting shoe on the inner barrel cuts and trims the core. The inner barrel and cutting shoe act as a pilot bit. The main core bit only enlarges (reams) the hole to allow the drill collars and the rest of the drilling assembly to advance. The PCTB inner barrel assembly operates interchangeably in the same BHA as the Fugro's Hydraulic Piston Coring System (FHPC). Any of the coring systems could be deployed at any point in the operation to optimize core recovery in varying formations. The PCTB inner barrel assembly must be locked in place rotationally to cut the core with the cutting shoe. So, to avoid damaging the core, the inner tube and plastic core liner are suspended on a bearing so that the core liner and core catcher stay stationary minimizing disturbance to the core. As with all the coring systems, core catchers allow the core to enter easily but prevent the core from falling out during the trip out of the hole. The PCTB is not dropped and pumped down the drill pipe but is lowered in the drill pipe using a wireline. The PCTB is a top landing system. The landing shoulder is near the top of the inner barrel assembly. The inner barrel assembly is suspended and held down by the latch while cutting the core.

The PCTB measures 3.5-m (11.5-ft) long and has been developed by Aumann & Associates, Inc. (AAI) for Fugro to be compatible with Fugro's medium Bottom Hole Assembly (BHA). The PCTB takes the same size core as the FPC, 64-mm OD, 58-mm ID (2.5-in-OD, 2.3-in-ID). It takes core by rotating the drill string unlike the pressure corers designed by Fugro. The Fugro Pressure Corer (FPC), as well as the retired Fugro Rotary Pressure Corer (FRPC), both use mud pressure to advance the corer. This allows for the drill string to be clamped at the SBF and the string is compensated from movement. The PCTB is a merging of elements of the NC-PTCS, IODP PCS and Fugro FPC. The PCTB is designed so that the core liner and core could be transferred to the Geotek Pressure Core Analysis and Transfer System (PCATS) that allows the core liner and core to be transferred and analyzed while being maintained at in-situ pressure. See on the next page.

FUGRO

PRESSURE CORER TOOL with BALLVALVE

The Pressure Corer Tool Ballvalve (PCTB) is a conventional wireline-deployed, rotary coring system driven by rotating drill pipe. However, the PCTB has an autoclave system that allows the cores to be maintained at in situ pressures during wireline retrieval to deck.

The PCTB is the newest pressure coring tool from Fugro. It provides an alternative to our mud-driven pressure coring tools and acquires a much longer core.

Developed for lithified sediments and hard rock formations, the tool has now been modified to drill in soft, unconsolidated and clayey formations as well. This extends the range of applications to all types of sediments where gas hydrates might occur.

The PCTB incorporates an autoclave to seal the core at ambient in situ pressure (up to 25 MPa) and thermal conditions. The PCTB recovers 50 mm diameter and up to 3.5 m long pressurized cores.

Gas hydrates with many different types of morphologies have been recovered using the PCTB system, as determined by subsequent detailed core analysis at full pressure and maintained temperature conditions.

Integrity of sample; the cutting shoe of the PCTB uses a small kerf design with PCD cutting elements that allows the core to enter into the inner barrel before any flushing fluid could contaminate the material.

PCTB on deck stands with core liners.

Technical Specifications

Description	Length		Estimated Weight		Maximum Diameter	
	m	ft	kg	Lb	mm	in
Inner Barrel Assembly	10.92	35.83	294	650	99.50	3.92
Upper Inner Barrel Assembly	5.73	18.79	181	300	99.57	3.92
Lower Inner Barrel Assembly (deployed)	5.26	17.26	113	250	95.25	3.75
Outer Barrel Assembly (not including bit)	10.51	34.48	1,364	3,000	177.80	7.00
Top Sub	0.49	1.6	114	250	177.80	7.00
Drive Sub	0.43	1.42	57	125	177.80	7.00
Core (approximate)	3.46	11.4	28	62	50.80	2.00
Bit	0.43	0.85	-	-	209.55	8.25

PDC core bit with cutting shoe

PDC cutting shoe

PCTB basket core catcher

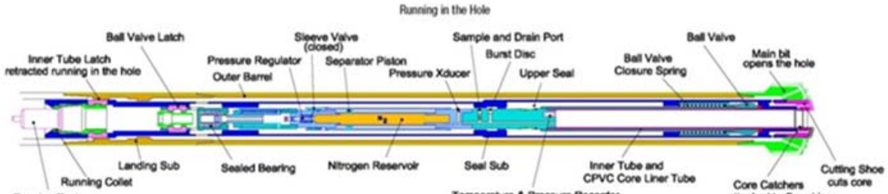


Figure D.17 PCTB Coring System.

D.2.2 Downhole Piezocone Penetrometer Testing

Downhole piezocone penetration tests (Figure D.18) generally are performed in the soil boring, concurrently with the drilling, sampling and coring operations to aid in stratigraphy identification and delineation, and to estimate the in-situ soil strength.

The downhole piezocone penetration tests could be performed using Fugro's Dolphin piezocone penetrometer. The first step in operating the Dolphin piezocone penetrometer is to lower a reaction mass or seabed frame to the seafloor prior to the start of the PCPT operation. The drill bit is lifted about 3 m (10 ft.) from the bottom of the boring and the PCPT tool is allowed to free-fall through the drill pipe until it rests on a catch ring in the bottom hole assembly (BHA) or lowered on the sand line. Following, the pipe is lowered to the bottom of the boring and the seabed frame clamps are closed to fix the drill string to the stationary seafloor, and the rig's motion compensation system is activated. Then, the drill string is pressurized to initiate the test.

The piezocone is forced into the soil formation at a controlled rate of penetration of about 2 cm per second with reaction being provided by the weight of the drill string and the reaction mass. The cone tip resistance (q_c), sleeve friction (f_s), and pore pressure (u_2) are recorded at a rate of two records per second. The test is terminated after achieving a 3 m (10 ft) stroke or refusal.

Cone Penetrometer Testing

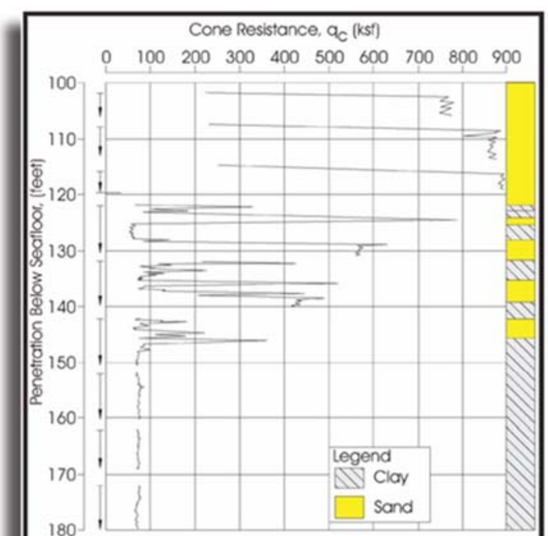
Cone Penetrometer Testing (CPT) and Piezocone Penetrometer Testing (PCPT) are excellent methods for obtaining soil property information for most soil types. In addition, these techniques allow extremely detailed profiling to be accomplished. The cone penetrometer probe contains load cells which measure the compressive force on the tip of the probe and the frictional force over a known cylindrical area along the side of the probe. The Piezocone also allows the measurement of pore water pressure during probe penetration.

Fugro's CPT/PCPT is a component of its Dolphin In Situ Sampling and Testing System. To conduct a test, the unit is lowered into the drill pipe until it reaches the Bottomhole Assembly (BHA). Mud pressure is then applied to the drillstring and the flow-rate controlled shear pin system pushes the cone penetrometer into the soil at the ASTM standard rate of 2 cm/sec. The stroke length is 3.0m or until refusal is met. During the push, the Dolphin Remote Memory collects and stores pertinent data from the test. Upon test completion, the CPT unit is recovered using an overshot and wireline. Once on deck, data is transferred from the Remote Memory Unit (RMU to a PC for processing and display.

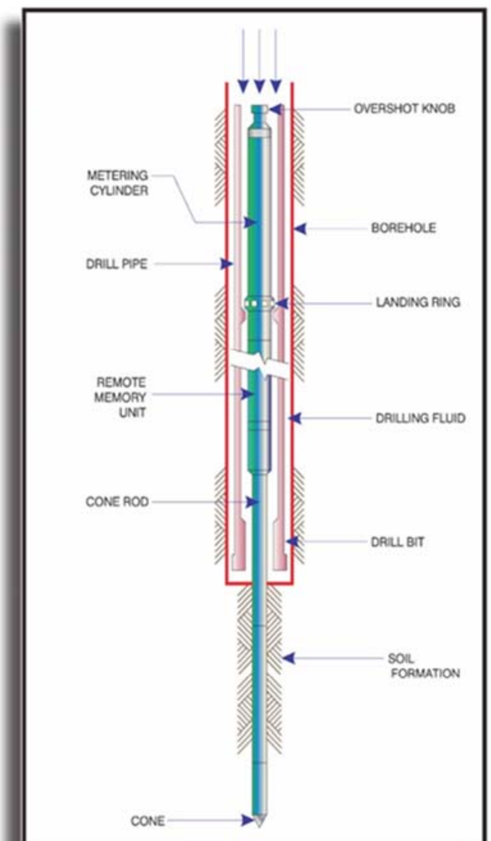
Information which can be obtained from CPT/PCPT tests

include:

- detailed stratigraphy
- soil type
- undrained shear strength (in clays)
- relative density (in sands and silts)



Cone Resistance Data

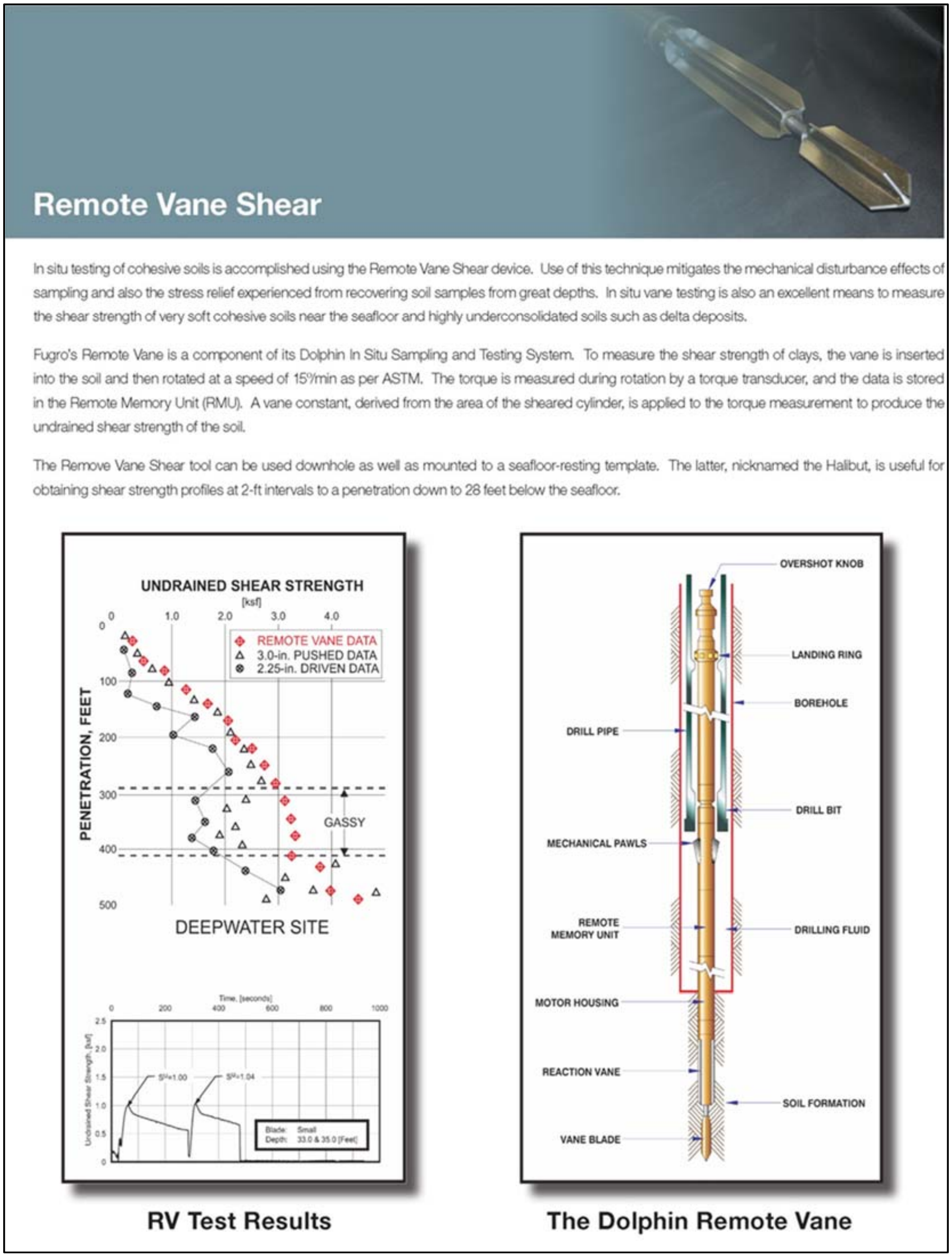


The Dolphin Cone Pentrometer

Figure D.18 Downhole Piezocone Penetrometer Testing.

D.2.3 Downhole Remote Vane Testing

The downhole remote vane tests (Figure D.19) are performed in companion with sampling operations and downhole PCPTs to investigate the undrained shear strength and sensitivity of cohesive soils in their natural or in situ state.


Remote Vane Shear

In situ testing of cohesive soils is accomplished using the Remote Vane Shear device. Use of this technique mitigates the mechanical disturbance effects of sampling and also the stress relief experienced from recovering soil samples from great depths. In situ vane testing is also an excellent means to measure the shear strength of very soft cohesive soils near the seafloor and highly underconsolidated soils such as delta deposits.

Fugro's Remote Vane is a component of its Dolphin In Situ Sampling and Testing System. To measure the shear strength of clays, the vane is inserted into the soil and then rotated at a speed of 15°/min as per ASTM. The torque is measured during rotation by a torque transducer, and the data is stored in the Remote Memory Unit (RMU). A vane constant, derived from the area of the sheared cylinder, is applied to the torque measurement to produce the undrained shear strength of the soil.

The Remove Vane Shear tool can be used downhole as well as mounted to a seafloor-resting template. The latter, nicknamed the Halibut, is useful for obtaining shear strength profiles at 2-ft intervals to a penetration down to 28 feet below the seafloor.

RV Test Results **The Dolphin Remote Vane**

Figure D.19 Downhole Remote Vane Testing.

The downhole remote vane tests could be performed using Fugro's Dolphin system. Vane tests are usually performed below 10 m (30 ft) penetration in normally consolidated or slightly over-consolidated clays of up to ~145 kPa (3.0 ksf). Data recording begins after the torque on the vane blade, driven by an electric motor, exceeds a pre-programmed torque threshold. The data are sampled twice every second and stored temporarily in the RMU of the vane tool, which is later connected to the computer for data retrieval. Data collection is automatically terminated if the torque exceeds 33.9 N-m (25 ft-lb). The test is usually allowed to run for about 3 minutes. At the end of the test, the drill string is lowered to push the tool an additional 0.6 m (2 ft.) to perform a second test. This procedure allows twice the chance of getting a successful test on a single deployment.

D.2.4 Piezoprobe Dissipation Testing

Note: Dissipation Tests could also be run with normal 10 cm^2 CPT systems, particularly in coarse grain sediments. Piezoprobe dissipation tests (Figure D.20) are used for measuring pore-water dissipation. The downhole piezoprobe tests are performed using a wireline-operated, small-diameter piezoprobe equipped with two pressure sensors, one of which is located on the face of the tapered section (u1) and the other located just behind the shoulder of the tapered section (u2). For each test, the piezoprobe would be pushed into virgin soil beyond the bottom of the borehole and pore pressure with time is recorded.

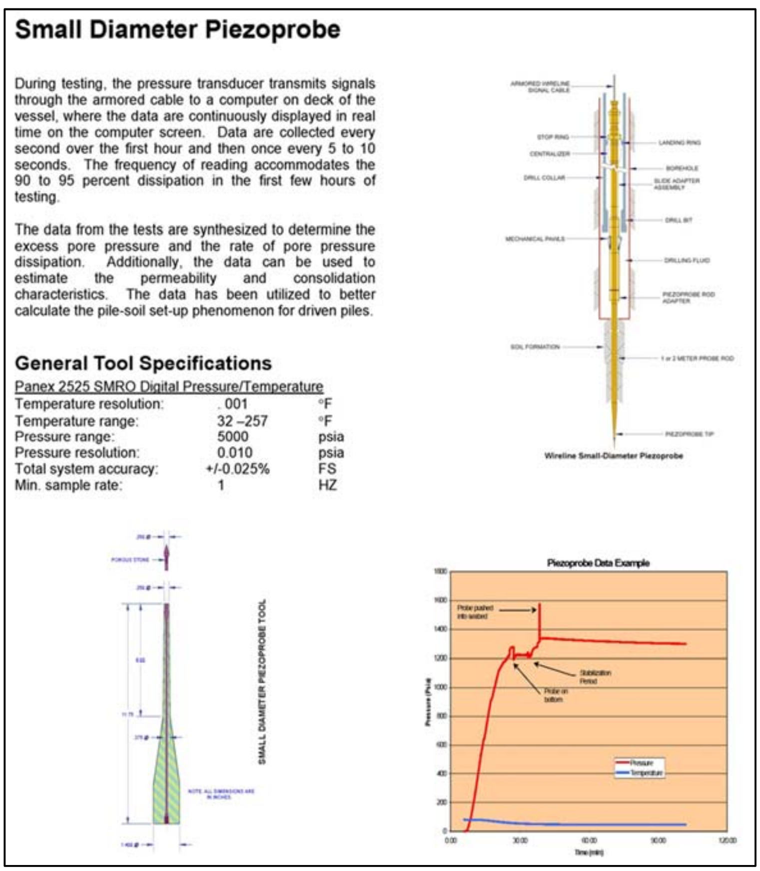


Figure D.20 Piezoprobe Dissipation Testing.

D.2.5 Temperature Equilibrium Tests

Temperature equilibrium test data are recorded using the temperature probe. A temperature sensor incorporated in the probe allows for data collection to measure downhole temperature stabilization and temperature gradient.

D.2.5.1 Advanced Piston Corer Temperature (APCT)

The Advanced Piston Corer Temperature (APCT) (Figure D.21) tool is an instrumented version of the coring shoe that is run on the Advanced Piston Corer (APC) (IODP, 2006). It is deployed in soft sediments to obtain formation temperatures to determine the heat flow gradient and is essential in determining hydrocarbon maturity for pollution prevention purposes.

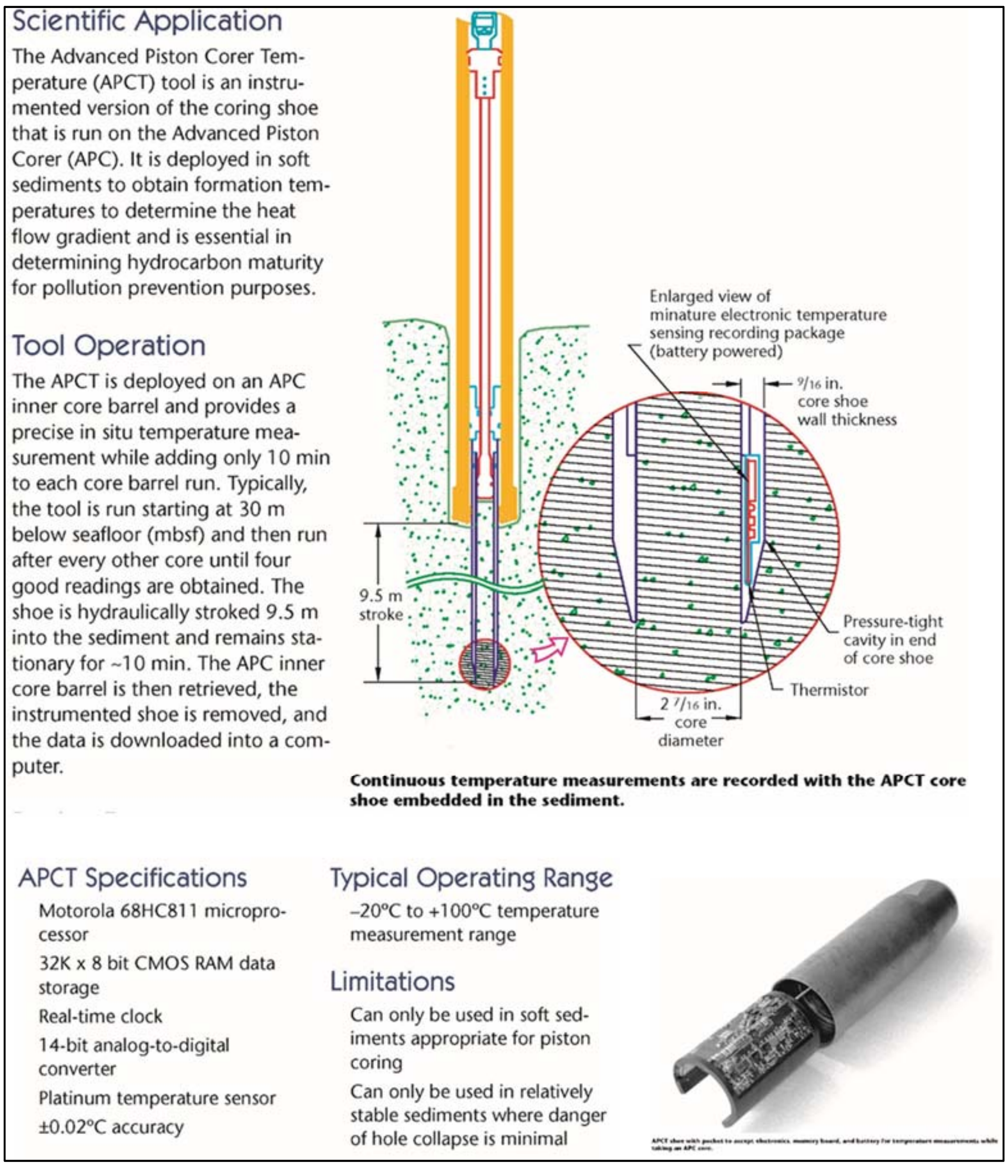


Figure D.21 Advanced Piston Corer Temperature (APCT)

The APCT is deployed on an APC inner core barrel and provides a precise in situ temperature measurement while adding only 10 min to each core barrel run. Typically, the tool is run starting at 30 m (100 ft.) BML and then run after every other core until four good readings are obtained. The shoe is hydraulically stroked 9.5 m (30 ft.) into the sediment and remains stationary for ~10 min. The APC inner core barrel is then retrieved, the instrumented shoe is removed, and the data are downloaded into a computer. The APCT sensor, electronics, and memory are contained in an annular cavity inside the APC coring shoe. The APCT provides a precise in situ temperature while adding only 10 min to each core barrel run. The instrumented shoe is removed as soon as the APC inner core barrel is retrieved, and the data are downloaded into a computer program for immediate processing. This would allow for hydrocarbon maturity evaluations to proceed during coring to avoid delays for data handling.

D.2.5.2 Davis-Villinger Temperature Probe (DVTP)

The Davis-Villinger Temperature Probe (DVTP) (Figure D.22) is designed to take heat-flow measurements in semi-consolidated sediments that are too stiff for the Advanced Piston Corer Temperature (APCT) tool. Coring must be interrupted to take a temperature measurement. The DVTP could also be run on wireline and hung below the bit (when the bit is off bottom) as a temperature logging tool for borehole fluids.

The DVTP is run through the drill string on a dedicated coring wireline round trip. The DVTP is typically run with the colleted delivery system, which latches into the BHA. The DVTP probe extends 1.4 m (4.6 ft.) below the bit and is pushed into bottom sediment by the driller with 22.2 to 66.7 kN (5000 to15,000 lbs.) and held there for 10 min. The tool latches into either the Advanced Piston Corer/Extended Core Barrel (APC/XCB) or Rotary Core Barrel (RCB) BHA and the probe extends below the bit. This allows the probe penetrates into relatively undisturbed sediments ahead of the bit.

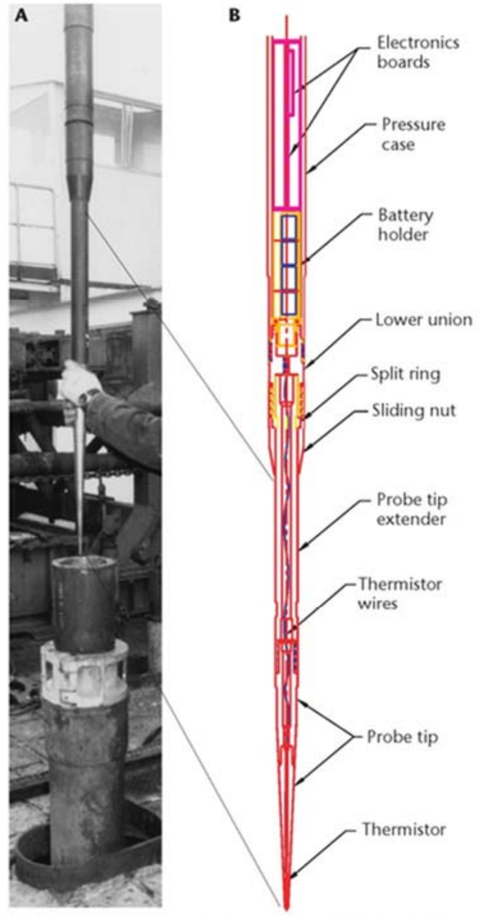
The DVTP is deployed on the colleted delivery system, which allows the probe to be disengaged from the BHA after it is pushed into the sediments. This prevents drill string movement (from ship heave) from disturbing the probe while recording formation temperature. An onboard accelerometer monitors tool disturbance while a thermistor records formation temperature and measures potential tool movement during data recording to assist in interpreting temperature data. The tool is capable of storing eight channels of data for 24 hours when sampling at 3-s intervals. After the tool is recovered, the data are downloaded and calibrated on a computer running ODP LabView software. However, the DVTP tool is no longer in service due to the availability of other tools (e.g., Wison EP temperature/cone penetrometer probe) for a more precise in situ temperature measurements.

Scientific Application

The Davis-Villinger Temperature Probe (DVTP) is designed to take heat-flow measurements in semi-consolidated sediments that are too stiff for the Advanced Piston Corer Temperature (APCT) tool. Coring must be interrupted to take a temperature measurement. The DVTP can also be run on wireline and hung below the bit (when the bit is off bottom) as a temperature logging tool for borehole fluids.

Tool Operation

The DVTP is run through the drill string on a dedicated coring wireline round trip. The DVTP is typically run with the colleted delivery system, which latches into the bottom-hole assembly (BHA). The DVTP probe extends 1.4 m below the bit and is pushed into bottom sediment by the driller with 5000–15,000 lbs and held there for 10 min.



A. Inserting the DVTP tool in the top of the drill pipe to take a temperature measurement. B. Schematic of the DVTP tool showing the robust probe tip with thermistor and electronics package. The tool is run on wireline using the colleted delivery system, which is above the quick release.

DVTP Specifications

16-bit analog-to-digital converter

496 Kb of RAM memory

Programmable sample interval from 3 to 10 s

51,000 ohm thermistor temperature sensor

Temperature accuracy ±0.02°C

Acceleration accuracy ±2 G

Conical probe tip continuously tapered at 2.5° from 55.5 to 8 mm in diameter

Typical Operating Range

–5°C to 105°C temperature measurement range

Soft to semiconsolidated sediments (e.g., chalks or firm clays)

Limitation

Not used in hard rocks (e.g., chert, dolomite, limestone, or basalts)

Figure D.22 Davis-Villinger Temperature Probe (DVTP)

D.2.5.3 Schlumberger Modular Formation Dynamics Tester (MDT)

Real-time measurements

Schlumberger's MDT has been used on other hydrate projects including Mallik (McKenzie Delta in Canada) for JOGMEC and Canadian National Resources. It was also used in the DOE / BP Mt. Elbert Stratigraphic test well (Milne Point Unit Alaska North Slope as well as the Conoco Phillips Ignik Sikumi well in the Prudhoe Bay Unit on the North Slope of Alaska. The project team is not aware of it being used on a marine investigation for hydrates, but this is still under investigation.

The Schlumberger (SLB) MDT* Modular Formation Dynamics Tester tool provides fast and accurate pressure measurements and high-quality fluid sampling. It could also measure permeability anisotropy. In a single trip, the

MDT tool is able to acquire most of the data requirements needed for accurate and timely decision making.

Flexibility

The key to this remarkable tool is an innovative, modular design that lets you customize the tool for the required applications. MDT modules combine to meet the exact needs and goals of the data acquisition program. This designed flexibility makes the tool compatible with almost all Schlumberger measurement technologies and allows the MDT tool to evolve as new measurement techniques, technologies and options evolve.

Quick, accurate pressure and permeability measurements

Reservoir pressure measurements using a wireline tester require inserting the probe into the reservoir and withdrawing a small amount of fluid. Since the pressure gauge is exposed to many temperature and pressure changes, these measurements require accurate gauges with high resolution that could dependably react to the dynamic conditions. The MDT tool uses highly accurate gauges with best-in-class resolution, repeatability and dynamic response for pressure measurements. These pressure gauges exhibit excellent response with no compromise in accuracy or resolution. Precise flowline control during testing and sampling ensures monophasic flow. These innovative features provide the most efficient and accurate permeability determination available.

A brochure for this system is included in the Appendices.

D.3 GEOTECHNICAL, GEOPHYSICAL AND GEOCHEMICAL LABORATORY TESTING

The geotechnical laboratory testing program comprises both conventional and advanced geotechnical soil tests of selected core samples. Conventional laboratory tests could be conducted both offshore and onshore. Advanced laboratory testing is conducted exclusively onshore. The laboratory testing program is designed to evaluate pertinent index and static and dynamic engineering properties of the soils recovered in the sampling program.

All cores are logged in the field using the Multi-Sensor Core Logger (MSCL), prior to any processing the cores in the on-board laboratory for index and strength property tests.

D.4 CONVENTIONAL LABORATORY TESTING

The conventional laboratory testing program could be conducted in two phases: (1) offshore – in a laboratory onboard as the field activities progress; and (2) onshore – in a laboratory facility on land.

D.4.1 Offshore Testing

The offshore testing comprised of the onboard laboratory testing for index and strength properties on extruded samples and a wide range of geophysical and geochemical measurements with the specific aim of determining the nature and distribution of gas hydrate within the sedimentary sequence, as well as to quantify gas hydrate concentrations where it is found.

D.4.1.1 Index and Strength Properties Testing

With the exception of specially designated "SAVE" tube samples, samples obtained from the sampler would be extruded from their sample liners or tubes and be visually classified by the onboard geotechnical personnel.

The following classification and strength tests be performed offshore on extruded samples:

1. Visual classification;
2. Moisture content (MC) and wet density measurement;
3. Motorized miniature vane (MV) tests on undisturbed and remolded specimens (MVr);
4. Motorized miniature vane residual (MVres) tests; and
5. Unconsolidated-undrained (UU) triaxial compression tests on undisturbed and remolded specimens (UUr).

The offshore testing for "SAVE" tube samples should be limited to visual classification, moisture content, and miniature vane (MV) tests conducted on the lower end portion of each tube. After testing, all samples should be sealed and stored in refrigerated containers for shipment and testing onshore.

D.4.1.2 Geophysical and Geochemical Testing

A comprehensive suite of core curation, core processing and core analysis equipment is utilized. This equipment enabled a wide range of geophysical and geochemical measurements to be made on all non-pressure and pressure cores recovered as follow:

D.4.1.3 Whole Non-Pressure Cores

- Infrared core scanning
- Direct temp measurements
- Thermal Conductivity
- Multi Sensor Whole core measurements
- P Wave velocity

- Gamma Density
- Magnetic Susceptibility
- Electrical Resistivity
- X-Ray imaging
- 2D scanning
- 2D rotational visualization
- 3D CT imaging
- Mini-Vane Shear strength

D.4.1.4 Whole Pressure Cores

- Multi Sensor Whole core measurements
- P Wave velocity
- Gamma Density
- X-Ray imaging
- 2D scanning
- 2D rotational visualization
- 3D CT imaging
- Degassing/methane analysis for accurate hydrate concentration

D.4.1.5 Split Cores (pressure and non-pressure)

- High resolution digital imaging
- Color spectroscopy
- Magnetic Susceptibility
- X Ray Fluorescence (XRF)

D.4.1.6 Sediment samples

- Laser grain size analysis
- Moisture Content/Density

D.4.1.7 Pore Water samples

- Salinity Alkalinity
- Chlorinity
- Sulfate and Bromide by ion chromatography
- Ammonium, Phosphate, Silica by spectrophotometry
- Major seawater cations by ICP-OES

D.4.1.8 Gas samples

- C_1-C_4, CO_2, N_2, O_2 by gas chromatography

D.4.1.9 Microbiology

- ATP analysis
- Biomarker analysis
- Functional gene analysis hydrogen sulfide analysis
- Microbial culture

D.4.2 Onshore Testing

The following onshore conventional laboratory testing program including:

1. Liquid and plastic limits;
2. Moisture content;
3. Specific gravity;
4. Carbonate content;
5. Organic content;
6. Grain size analyses (percent material finer than No. 200 sieve and hydrometer analyses);
7. Miniature vane shear tests on undisturbed and remolded specimens; and
8. Unconsolidated –undrained triaxial tests, undisturbed and remolded.

D.5 ADVANCED LABORATORY TESTING

The following advanced laboratory testing program is recommended to allow evaluation of the stress history of the soils at the production test sites, to obtain static and dynamic soil strength properties, to determine the hydraulic conductivity characteristics of the soil, and to investigate the thermal conductivity of the soils:

1. X-Ray Radiography;
2. Constant-rate-of-strain (CRS) one-dimensional consolidation tests;
3. K_0-consolidated, undrained triaxial compression tests with pore pressure measurement (CK_0U);
4. Thermal conductivity tests;
5. Static and rapid direct simple shear tests;
6. Resonant column tests;
7. Strain-controlled cyclic direct simple shear tests for cohesive samples; and
8. Stress-controlled cyclic direct simple shear tests for granular soil specimens.

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