DEEPWATER DRILLING

WELL PLANNING, DESIGN, ENGINEERING, OPERATIONS, AND TECHNOLOGY APPLICATION

PETER AIRD

DEEPWATER DRILLING

DEEPWATER DRILLING

Well Planning, Design, Engineering, Operations, and Technology Application

Peter Aird

ELSEVIER

Gulf Professional Publishing
An imprint of Elsevier

Gulf Professional Publishing is an imprint of Elsevier
50 Hampshire Street, 5th Floor, Cambridge, MA 02139, United States
The Boulevard, Langford Lane, Kidlington, Oxford, OX5 1GB, United Kingdom

Library of Congress Cataloging-in-Publication Data
A catalog record for this book is available from the Library of Congress

British Library Cataloguing-in-Publication Data
A catalogue record for this book is available from the British Library

ISBN: 978-0-08-102282-5

For information on all Gulf Professional publications
visit our website at https://www.elsevier.com/books-and-journals

Publisher: Brian Romer
Senior Acquisition Editor: Katie Hammon
Editorial Project Manager: Ana Claudia A. Garcia
Production Project Manager: Anitha Sivaraj
Cover Designer: Greg Harris

Typeset by SPi Global, India

Foreword

I am honored to write the foreword to this Deepwater Drilling Guide as it brings together a vast body of knowledge and experience that is not found elsewhere. This business is like no other on the globe, where harsh conditions challenge the operator, contractor, and service providers to extend their limits. As marine drilling operations seek to operate in higher-pressure environments, deeper waters, and harsher conditions and in remote areas of the globe, the limits of technology must evolve and change to meet these needs. Technology often advances in the oil and gas industry faster than it can be documented. This text is Peter Aird's contribution to bringing current methods and thinking to the reader.

The processes required to penetrate deepwater objectives have undergone dramatic revision and change in only a few short years. What was once thought to be "deeper" has become routine and common, and ultra depths thought to be unobtainable have been reached in recent history. Therefore, this comprehensive text on the subject brings together recent technologies and innovations made in deepwater drilling operations. This text does that and more.

I have known the author, Peter Aird, for more than 15 years and have worked with him professionally on politically visible, HTHP high-risk and deepwater projects in very harsh environments. These projects were completed successfully in part by the skill and dedication of the drilling team of which Aird was the team lead. From this work experience, I have grown to respect and hold Peter in high regard for his engineering abilities and strong work ethic. Peter is a professional engineer, trainer, lecturer, and a world-class drilling man. However, he did not start his working career with this goal in mind.

After a basic education in Scotland, he chose to utilize his mechanical skills in the engine room on a blue water merchant ship. After a short time, he realized his advancement and more importantly his life experience would be limited and the challenges of the engine room would never satisfy his curiosity to expand his knowledge and the physical workings of science surrounding him. To advance himself, he took a training position on a major oil operator's contracted drilling rigs and quickly moved through the ranks, where this working environment embraced all the disciplines outside the mechanical workings of the rig into drilling engineering. At this point, Peter realized he should not only learn as much as the company program offered but return to school and pursue a distance learning university engineering degree so that he could understand why things worked the way they do. In my knowledge, it is a rare person who after starting down one career path in the trades can reroute that path toward higher learning in the school of engineering. Peter did this while starting a family, earning a living, and self-financing this higher learning, sacrificing much of his "free" time to advance himself and his knowledge. I have found that the person who takes this path in industry has a well-rounded and practical knowledge that is rare in the business.

In these deepwater work collaborations, Peter and I have discussed that deepwater industry publications concerning drilling operations generally lag far behind the advances in practice and technology and moreover lack the benefit of knowledge, experience, and innovations made by the industry. Peter has a curiosity in all things related to his profession of drilling wells and delivering the best project possible and is constantly searching for new and better solutions and results to the task of drilling wells in deepwater.

Peter took this to heart and has produced a deepwater drilling guide that describes the present technology. I do hope that the beholder of this text benefits and has use for the knowledge that is presented.

L. William Abel
Abel Engineering Inc., Houston, TX, United States

Author's Preface

My drilling work began in 1980 when, as a former Merchant Navy marine engineering officer, I became a trainee for Shell International, working through a drilling supervisors development program that I then served for both Shell and BP Internationally from 1986 to 1993. Thereafter, as a consultant, I was employed in the same role globally for various recognized companies, drilling frontier leading edge wells, many of which were in deepwater. In 1998, I was approached and reluctantly agreed to develop industry first training materials for deepwater drilling and well engineering, confessing a lack of training skills, knowledge, and experience, but convinced a need for this training was and is today sorely needed. Through the decades, I have since shared knowledge and experience gained by facilitating and delivering deepwater and other complex well design, drilling engineering, and operations training courses.

I felt similarly unprepared to write this book, even with the deepwater opportunities and experiences gained within drilling, well engineering, and operations specialist positions held, conducting leadership and consultancy support roles in multiple deepwater projects in recent years. Despite having produced numerous technical and operational documents, I had absolutely no writing skills. But again I saw the great need for a guide since, as the deepwater industry, technology, principles, and practices grow and change, so does the need for more discussion, sharing and distribution of knowledge from lessons learned and from things that go wrong.

The reason for this book is twofold.

Foremost was this opportunity to continue one's self-education and development journey in all deepwater subject matters. That, through this process, has uncovered and raised multiple aspects to what we as an industry know, don't know, and require more focus on, to assure deepwater programs, projects, technologies and best practices succeed, remain competitive, learn from the past, and deliver the *SEE* (*Safe, Effective, and Efficient*) outcomes and benefits desired.

Secondly, this is a first edition (and a time-constrained mission) to serve as a training, learning, and development vehicle for myself and others to collaborate, share, discuss, develop, and educate the next technological and digitized deepwater generation with the far wider skill set, knowledge, and experience demanded for field and project use.

To the many people through the decades who have evidently contributed to this deepwater drilling guide, we thank you deeply. In particular more sincere thanks go to the sterling work of my editor, Carolyn Barta (without whom this book would never have resulted), illustrator Dianne Cook (of One Giant Leap), my well control guru and friend Bill Abel (Abel Engineering), Alexander Edwards (Ikon Geoscience), and Deiter Wijning (Huisman), and to my publisher, Elsevier, whose flexibility and extended deadlines have made this publication possible.

Finally, thanks to my dearest beloved wife Joyce, and our two grandsons who can all shout "hurrah" that this mammoth task is done (for now) and that they shall now be afforded the attention and availability they have so patiently been waiting for.

Enjoy,

Peter Aird (The "Kingdom of Fife," Scotland, Driller.)

CHAPTER

1

Mission, Mission Statement

MISSION

The mission of this book is to provide a usable comprehensive, practical, and understandable "Guide to Deepwater Drilling" for people at all levels who already understand basic drilling principles, standards, and practices. Readers can use and apply the guide in their respective workplaces, to further self-educate, enhance, and develop the skill sets to meet specific deepwater project requirements.

Due to the relative infancy and untapped nature of deepwater, this book serves as a guide. When regional or local knowledge, experience, understanding, and physical, people and paper evidence exists, these factors shall take precedence to assure safe, effective, and efficient deepwater project delivery. With time, this guide shall be developed further.

A GUIDE TO DEEPWATER DRILLING

General Introduction

The world's accessible offshore hydrocarbon has been produced in abundance from the 1960s. Easy offshore hydrocarbons today are more difficult to find, yet deepwater exploration remains where potential "big oil" exists. Deepwater is a continuance of accumulated best-practiced drilling knowledge and experience to manage, control, and change in more challenging operating environments. If big oil discoveries continue to result in deepwater, more wells will need to be drilled and business will continue to grow. Operating companies are therefore not only searching and exploring into more distant seas and oceans but also in more remote, harsh, and inhospitable locations and environments for big oil in a rapidly changing and uncertain world of energy needs, supply, and demand.

Economic Factors of Deepwater Exploration

The commonly accepted economic objectives to explore successfully in deepwater environments are viewed as:

1. thick, continuous reservoirs that exhibit high flow rates with large drainage radius;
2. recoverable reserves of at least five to several hundred million barrels or more;

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00001-6

3. geologically and seismically well defined and relatively simple reservoirs in nature, down to and including the producing horizons, so that highly accurate petroleum, reservoir, and production modeling can result to reduce risks and uncertainties.

The Purpose of Drilling in Deepwater

The purpose of deepwater drilling projects is essentially no different from other drilling, i.e., to discover commercial hydrocarbons safely, effectively, and efficiently at the lowest cost. When discovery results, the key decision trigger is how much capital investment is needed to sanction appraisal drilling, to assure, and acquire must- have vs. nice-to-have data, then process and interpret the data to meet the complexity of multidiscipline issues to be resolved.

The challenge then is to manage the project development according to controls that assure doing the right things and getting things done right the first time, at the lowest capital and operating costs, avoiding damage, loss or harm to the people, businesses and environment as low as practicable, as illustrated in Fig. 1.1.

As offshore deepwater basins remain relatively unexplored when compared to onshore or shallow offshore, the greater the water depths should present a greater likelihood of discovering big oil, especially in the 2000–3500 m (6562–11,583 ft) water depths.

The promise of discoveries can offset the significantly higher costs, risks and uncertainties that come with increased water depth, and offer the economic viability to explore in these environments.

Deepwater Drilling Goals and Objectives

Objectives and goals to be met in deepwater drilling-related projects, i.e., *through Exploration, Appraisal, Development and Production* phases, summarized, are to:

1. lower finding, capital, intervention, workover and abandonment costs;
2. accelerate and maximize production;
3. create greater value returns on investment, e.g., increase ultimate recovery.

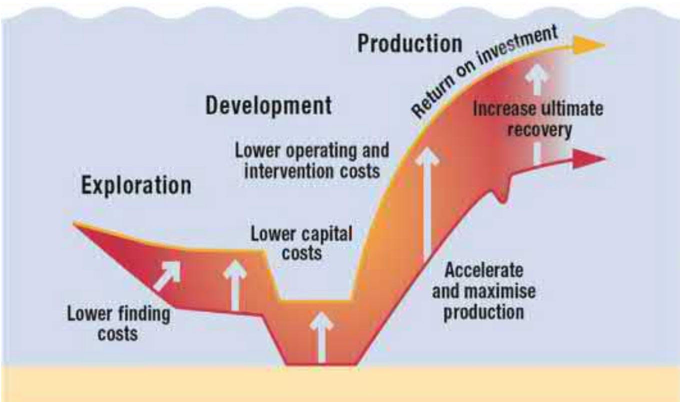


FIG. 1.1 Deepwater well-life-cycle project goals and objectives. *Source: Kingdom Drilling, 2018.*

To counter these challenges, multiple offshore technological and adaptive advancements would have to be met during the project life period. Example: the building and construction of a more fit-for-purpose, multi-functional, next-generation deep and ultradeepwater operating fleet is perhaps demanded to step change the advancements and technological solutions required. Where this investment is going to come from is a key factor. A new fleet would however offer far more optimism that deepwater can survive in such turbulent, challenging, and changing times.

A Guide to Deepwater Drilling Projects

As the continuous search for deepwater discovery precipitates drilling projects into untapped and progressively more remote, harsh, deep, and ultradeep environments—where more complex geology, geoscience, petroleum, reservoir, drilling, subsea, technical, and technology operational challenges arise—this guide can identify and evaluate how and why deepwater drilling can evolve from more singular frontier activities into a far safer, more intrinsic, and strategic element of an operator's offshore portfolio.

This guide also focuses primarily on deepwater exploration and appraisal drilling that may lead into development, intervention, and abandonment activities required. All such specialist areas require separate guides. Content is targeted at an intermediate-to-advanced drilling level, for those with a good working understanding and knowledge of offshore drilling; well safety and management systems; and well delivery using a multidisciplinary, project-managed approach and a belief that ordinary people can make a difference.

According to the Plan-Do-Check-Act (PDCA) (Deming cycle) as shown in Fig. 1.2, continuous quality improvement is achieved by iterating through a well's life cycle by consolidating progress as discussed later in this guide. Emphasis is placed on the importance to utilize three fundamental SEE principles to realize deepwater delivery outcomes and benefits desired, i.e.:

1. ***S*** Being Safe; the control of loss,
2. ***E*** Being Effective; by doing the right things,
3. ***E*** Being Efficient; by getting things right first.

This guide is for deepwater participants, who require further engagement, knowledge, and understanding about the fundamental differences of what drives the drilling of deepwater wells. It should appeal to the multidisciplinary range of seasoned professionals involved in programs and projects requiring more specifics in terms of deepwater well design, engineering standards, principles, current advancements, new and adaptive technologies, specific techniques, systems, equipment, and operational best practice used and applied.

The introductory deepwater guide chapters include:

1. Introductions, what defines deepwater. An outline of the basic concepts and precepts of operating wells
2. Geology and geoscience aspects from a driller's perspective
3. Pressure management of wells
4. Metocean operating conditions and environments that exist
5. Essential differences and drivers compared to a standard drilling norm
6. Program, project management, safety and loss control aspects

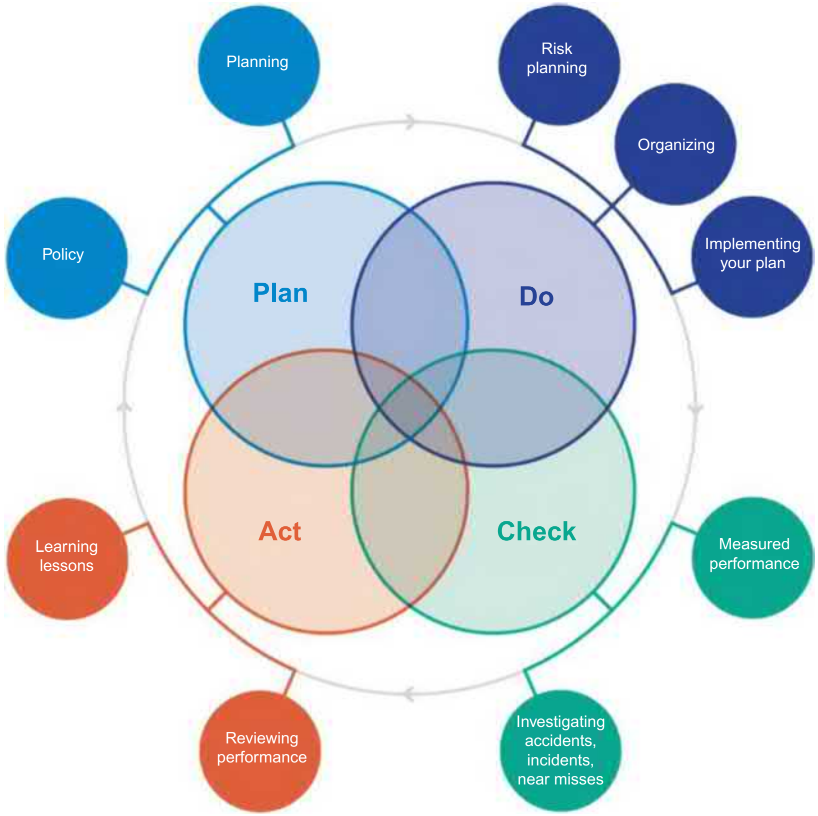


FIG. 1.2 Plan-Do-Check-Act. *Source: http://www.hse.gov.uk/pubns/indg275.pdf*

The middle section includes deepwater design, management, engineering, and planning.

7. Well planning and design
8. Structural design
9. Main well design and operations engineering
10. Operations, regulations, programs, and emergency response

The concluding chapters focus on deepwater well's drilling operations, engineering application, and project execution, i.e.:

11. Project implementation "readiness to drill"
12. Riserless drilling
13. Riserless best practices
14. Subsea BOP and marine drilling risers
15. Intermediate wellbores drilling and pressure detection
16. Production wellbore drilling and well control assurance

Deepwater Drilling Defined

Deepwater drilling environments and definitions have changed through the decades as oil and gas capabilities and technology have transformed. In the 1970s, 100–200 m (328–656 ft) was considered as deepwater. In the 1980s 450–600 m (1476–1969 ft), in the 1990s deep progressed to 1000–1500 m (3281–4921 ft), and with seismic technology advancements this opened up other deeper basins to greater than 3000 m (9843 ft) water depths as drilled today. The technical limit is +/-4267 m (14,000 ft) water depth. Definitions, it should be noted, vary from operating regions and settings and according to environments/conditions that exist. So first and foremost, there are no hard or fixed rules. Deepwater and ultradeepwater can be whatever you want it to be.

In this guide, water depths are defined and adhered to as illustrated in Fig. 1.3.

1. *Deepwater* classed as water depths exceeding 450–600 m (1476–1969 ft)
2. *Ultradeepwater* classed as water depths exceeding 1000–1500 m (3281–4921 ft)
3. *Deepwater exploration drilling capabilities*, 3658–4267 m (12,000–14,000 ft) water depths.

Deepwater Definition

Evident reasons and rationale:

1. Regional consensus on deepwater definitions typically states this range of water depths.
2. Conventional subsea systems operate capably up to 450–600 m (1476–1969 ft) water depth.
3. Greater than 500 m (1640 ft) water depths, a more specific type of floating vessel systems and equipment requirements is required to operate on wells.

Ultradeepwater Definition

1. Regional consensus on ultradeepwater definitions typically states this range of water depths.
2. Once water depth deepens notably beyond 1000–1500 m (3280–4920 ft) drilling conditions and operating environments change quite significantly.

FIG. 1.3 Deepwater and ultradeepwater drilling classification and definition. *Source: Compiled via Kingdom Drilling Training, 2006.*

3. Below 1000–1500 m (3280–4920 ft), a more specific class of floating vessel, systems, tools, and equipment is often required to more safely, effectively, and efficiently operate these wells.

DEEPWATER DRILLING AND OPERATING ENVIRONMENTS

General Introduction

We can draw further conclusions from Fig. 1.3 about deep and ultradeepwater projects conducted worldwide today in our seas and oceans, including operating conditions and environments as illustrated in Figs. 1.4 and 1.5.

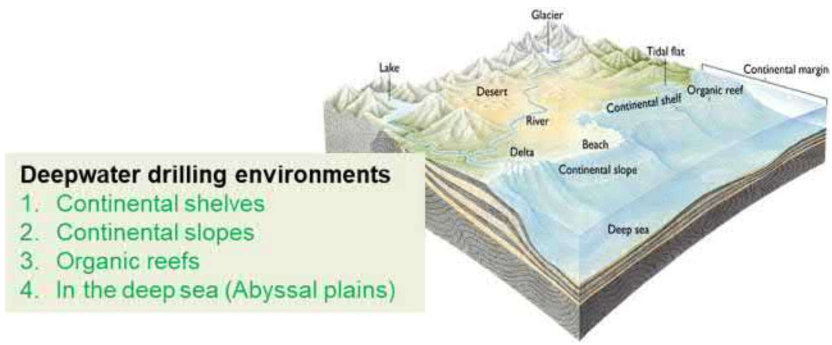


FIG. 1.4 Continental margins, deepwater settings and environments. *From Kingdom Drilling training construct.*

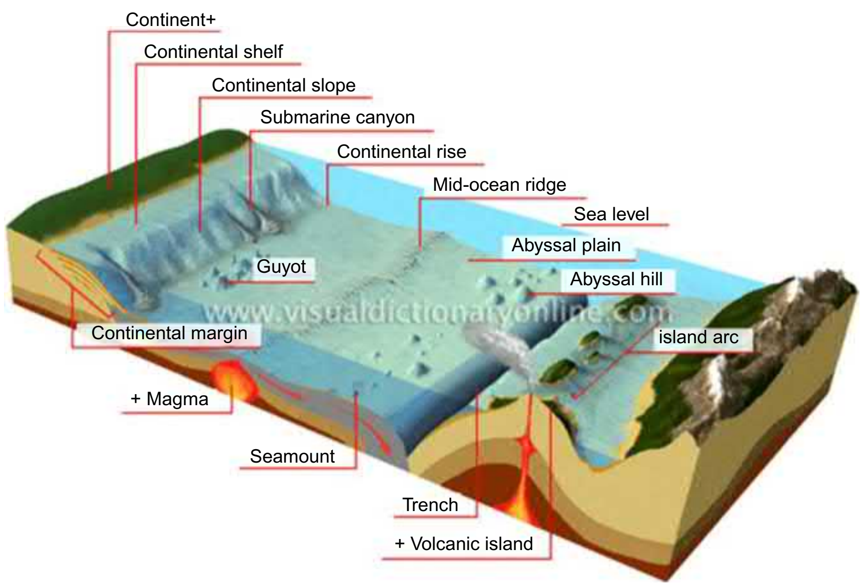


FIG. 1.5 Further deepwater specific operating conditions and environments. *Source: http://www.visualdictionaryonline.com/images/earth/geology/ocean-floor.jpg*

What immediately sets deep and ultradeepwater apart from conventional offshore programs and projects is that operations have to be conducted at far greater supply, logistic, and operating distances from shore. This makes the supply chain and conducting of operations far more challenging.

Additionally below the deep and ultra-deepwater depths, the continental margins that exist have variant conditions, settings, and environment as illustrated through a regional example of deepwater exploration and appraisal wells in Fig. 1.6. Here, it can be viewed how variant well designs differ across this region.

It is further evident in Fig. 1.6 that the deepwater sedimentary stratigraphy that exists on each well is far from the same. Wells are exposed to different sets of operating conditions that can be more or less problematical from a drilling operational standpoint.

At this early stage, it is important to begin to comprehend why geological risks and uncertainties essentially can drive the deepwater well design, construction, and the drilling challenges that arise, and why these issues reside high on the project hazard and risk register until wells are safely drilled, data gathered, and more can be learned and translated into added project value.

One can conclude again the variant geological and drilling conditions and environments must be safely managed through a deepwater well's life cycle within such fields. With lower oil prices that may exist well into the future, more competitive means, effective and efficient methods shall have to result to assure that developing and producing these prospective regions remains commercially sustainable delivering even greater outcomes and benefits.

Brazil Presalt Petroleum Systems

The presalt system occurs beneath a layer of evaporate sediments, i.e., salt anhydrite and other minerals formed by an ancient, massive evaporation of basin waters. Salt evidently results more or less continuously across much of the Atlantic margin of both Brazil and West Africa sides, but is not present on the northern *equatorial margin of Brazil or Africa.*

The organic-rich sediments that exist and the thermally mature physics of the source rocks, and the primary and secondary migration into the reservoir rocks and seals within the rift basin, resulted as the tectonic forces pulled Africa and South America apart to create the South Atlantic Ocean during Cretaceous and younger times—beginning 145 million years ago. The subsalt reservoirs that capture the petroleum then divided into two groups:

1. **Clastic sediments**, formed of both sandstone and conglomerates that were eroded from the mountains that flank the rift basin, and,
2. **Carbonate sediments** (rock consisting mostly of calcium carbonate). This porous limestone and some dolostone reservoirs were deposited in shallow marine water along the edges and crest of the mountains as they were eventually flooded and then buried by older sandstone and associated sediments.

Above the reservoirs, the salt formed the top seal that trapped the petroleum accumulations.

Brazilian Postsalt Petroleum System

The postsalt petroleum system in the Atlantic margins lies above the regional salt layer and was deposited on the western margins of the growing South Atlantic Ocean under conditions of normal marine shelves and deepwater slopes. The postsalt system is divided also into two main units:

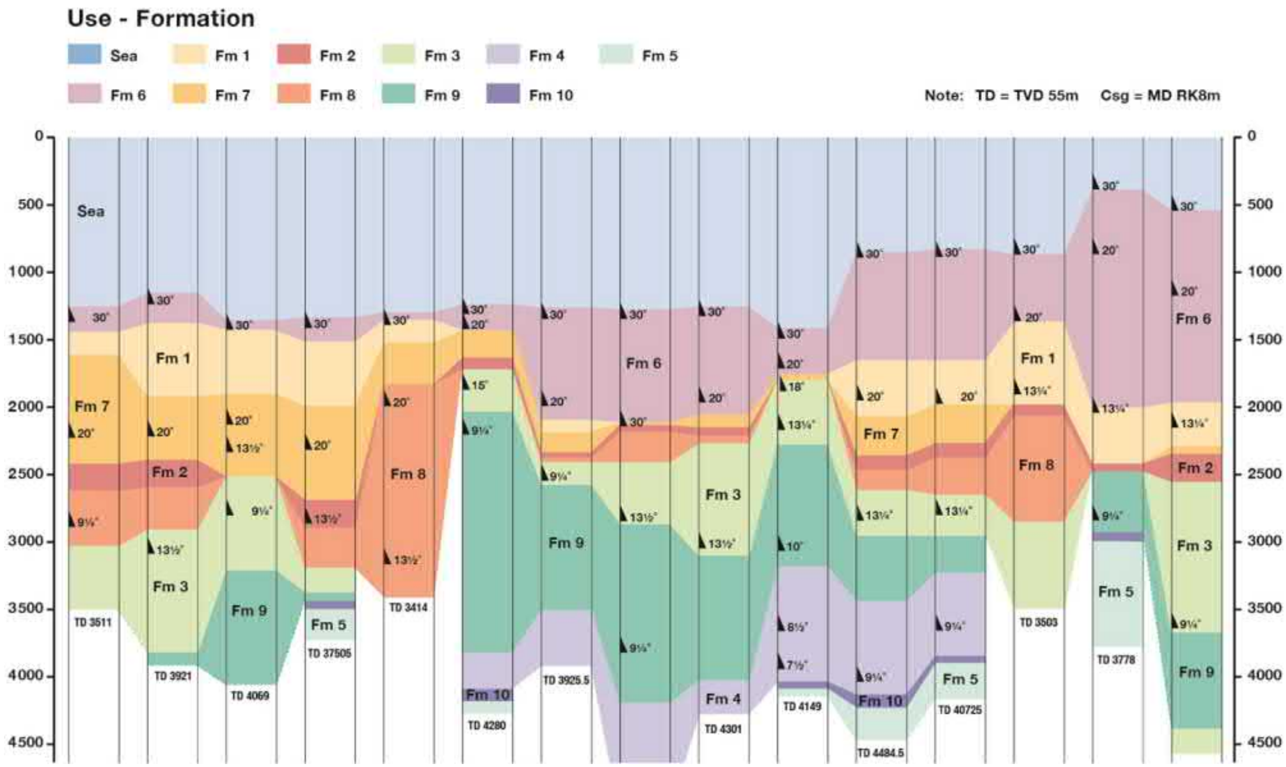


FIG. 1.6 Deepwater wells stratigraphy and casing depths variations. *Source: Kingdom Drilling Training, 2018.*

1. Shallow water carbonates, largely grainstones resting on top of the salt layer, and
2. A younger clastic system section, with local sandstone reservoir in a variety of oil and gas traps.

Grainstones = A kind of limestone comprised of grains with cement called spar.

Salt intrusion in the subsurface creates the diapirs and windows from a deeper stratigraphic horizon to provide migration routes within the post-salt sections, with younger sediments providing the classic source rock reservoir and traps demanded for a commercial prospect to exist.

Structural traps are associated with the salt diapirs and roll over structures created by faulting. In addition, further stratigraphic traps are formed coinciding with the edges and pinch outs of these fields typically within sandstone either along the flanks or the up dip edges of the reservoir body.

Limestone in the postsalt system was deposited under normal marine conditions resulting from the opening of the South Atlantic Ocean during the cretaceous period. These deposits can be clean and well sorted to provide ideal reservoir rocks. Note: Deposits of similar age and environments are also found in deepwater on the West African side of the South Atlantic Ocean, for example, the Cabinda limestones, offshore Angola.

Above the Brazilian postsalt carbonates lie the younger units comprised of alternating layers of sandstone reservoirs and claystone by seaward and landward migrations of deltaic, debrite, and turbidite deposits that will be discussed in more detail in this chapter. Major seaward migrations (regressions) of the shore line delivered considerable sand to the basin in the form of a series of deltas at the shelf edges.

Sand is transported into the deepwater slope and basin areas as a variety of channelized and sheet-like turbidite sequences. At other times, rapid landward migration of the shoreline (transgressions) results in more widespread deposition of fine grained mudstone and clay over broad areas of the shelf and deepwater as water depths rapidly increase. The clay sequence of deposits formed multiple seal layers for the sand sequences. Some of Brazil's largest fields are found in sealed turbidites accounting for a large majority of oil and gas being produced since the Namorado field was discovered in 1975, followed by Albacora (1984), Marlim (1985), Albacora Leste (1986), Marlim Sul, Leste (1987), and Roncador in 1986.

Deepwater West Africa

Africa commenced exploring in water depths greater than 300 m (984 ft), to discover deepwater success in comparison to Brazil. Deepwater successes in West Africa followed those in Brazil and the Gulf of Mexico, benefitting from technology advancements/adaptations and the building of fourth, fifth and ultimately sixth generation drilling vessels.

The discoveries in West Africa defined the significance of two major deepwater petroleum systems of the Niger Delta and the Congo basin, both areas of prolific hydrocarbon generation from Tertiary marine source rocks.

WEST AFRICAN GEOLOGY

As the continents separated and extended the African Plate form South America, this stretched and thinned the continental crust remaining to the point of rupture and the beginning of the South Atlantic Ocean. The first marine waters laden with salt entered this depression from the South, across a shallow shelf called the Walvis Ridge. The climate this period up to 125 million years ago ultimately resulted in the rapid deposition of the thick salt deposit now present below some of the oil-producing regions in Brazil and West Africa. With time and because these thick salts sequences behaved like plastic when loaded by overlying sediments, the movement of the salt deformed the sedimentary layers into the structural features that contain the oil and gas that exists today.

The sea floor separated the continents further apart dividing the salt basin in two areas characterized by narrow shelves beyond which water depth rapidly increased across broad slopes to water depths of 3300 m (10,827 ft) since the end of the early Cretaceous period. The great Niger and Congo rivers of Africa then dumped layers of clay, sand, and organic-rich mudstones into these deep marine waters to form the source, structure, seals, and reservoir rocks to generate and trap oil and gas in typically sands and sandstone deposited in the Oligocene and Miocene periods of the Tertiary era, i.e., 35 to 5 million years ago.

Unlike classic models used to describe deepwater reservoirs such as Gulf of Mexico, submarine fan systems typically depict concentric sediments being deposited in belts radiating away from the mouth of a submarine fan canyon.

However, early West Africa models suggested gradual down fan decreases in reservoir and sand thicknesses. Thankfully, modern 3D seismic now being used and many cores that have been taken from West African reservoirs have characterized and provided us with the big takeaway that these systems have very different mode of deposition with far more complex reservoirs and sealing architectures as was first predicted.

Many African deepwater reservoirs for example exhibit geometries like filled-in rivers or streams formed by turbidity currents, i.e., *deep currents laden with sediments pulled essentially by gravity*. These currents therefore cut channels, build levees, create meandering channel patterns like rivers.

In summary, because of the complex distribution of reservoir sands and muds associated with channelized deepwater reservoirs systems common in West Africa, successful development is highly dependent on high-quality seismic data, so geoscientists can develop more accurate models and locate wells to assure maximum oil recovery, thereby reducing the number of wells required and increasing production per well to deliver greater returns on investment—all critical factors in deepwater.

Deepwater Salt Challenges

Salt challenges and difficulties in deepwater are not exclusive to Gulf of Mexico, Brazil, and West Africa as illustrated in Fig. 1.7. Common elements of salt are:

1. All salts are not the same.
   a. Simple salts, e.g., halite, remain relatively stable during drilling.
   b. Complex salts, e.g., carnallite, tachyhydrite, can creep more rapidly.
2. Wellbore conditions impact creep.
   a. Temperature. The higher the temperature, the more salt can move.
   b. Pressure differential. The higher the differential between mud weight and formation pressure, the more salt can move.

Challenges presented in salt are often before entry and at the exit of the systems as highlighted in Figs. 1.8 and 1.9.

FIG. 1.7 Worldwide deepwater salt regions. *Source: Perez, M.A., Clyde, R., D'Ambrosio, P., Israel, R., Leavitt, T., Nutt, L., Johnson, C., Williamson, D., 2008. Meeting the subsalt challenge. Oilfield Rev. 20 (3), 32–45.*

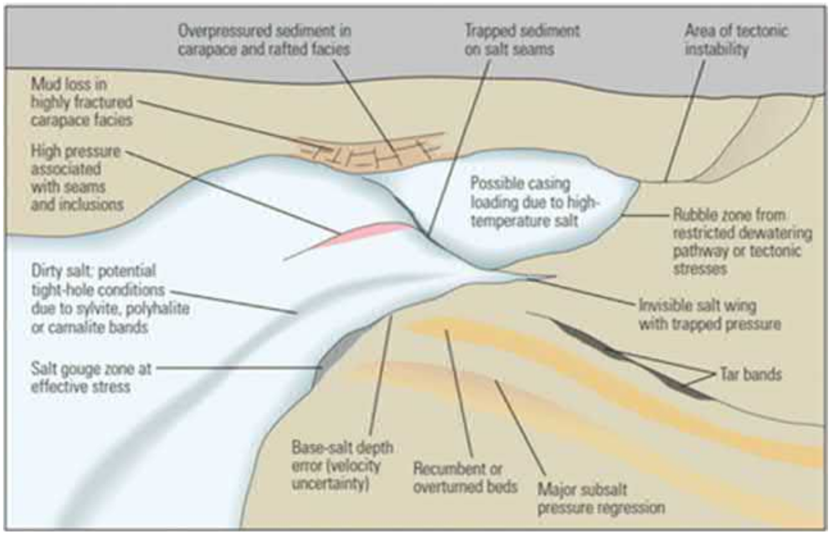


FIG. 1.8 Deepwater potential hazards in and around salt. *Source: Perez, M.A., Clyde, R., D'Ambrosio, P., Israel, R., Leavitt, T., Nutt, L., Johnson, C., Williamson, D., 2008. Meeting the subsalt challenge. Oilfield Rev. 20 (3), 32–45.*

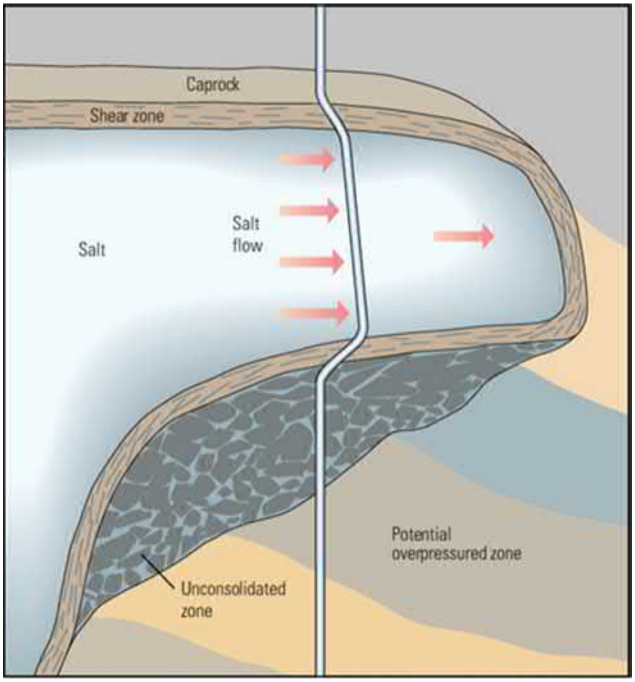


FIG. 1.9 Cementing across mobile salt. *Source: Perez, M.A., Clyde, R., D'Ambrosio, P., Israel, R., Leavitt, T., Nutt, L., Johnson, C., Williamson, D., 2008. Meeting the subsalt challenge. Oilfield Rev. 20 (3), 32–45.*

The opportunities to experience operational problems to, through and out of salt are many and are derived from salt tendency to move. Industry limited ability to image salt can lead to mistaking base of salt depths and unexpected encounters with abnormal or subnormal pressure zones beneath the salt.

Combating the effects of nonuniform loading caused by salt creep requires full cement returns to top of salt. In Fig. 1.9 (left), a liner is set inside a cemented casing in to reduce radial pipe deformation. Salt movement (right) continues to load casing/liner strings that may result in failure over time.

In the case of mobile "plastic" salt operating loss that can ultimately result are:

1. wellbore drilling difficulties, loss of quality, and operational delays
2. stuck pipe
3. casing deformation
4. wellbore instability
5. drilling troublesome rubble and/or fractured zones vs. avoidance.

Mitigating measures include:

1. higher mud weight
2. design cement to minimize point loading (high tensile strength, flexible)

3. thicker walled (higher strength) casing
4. more casing
5. specialized tool procedures and guidelines
6. people developed with a wider skill set to fully understand these problems.

In much deeper and older stratigraphy in deepwater, a further issue below the salt in certain specific operating conditions and environments is where tar exists, e.g., the Gulf of Mexico. Key points are:

1. Mobile tar *(bitumen)* appears in pockets below salt, along faults.
2. Mobility can range from none to very active.
3. Presence is impossible to predict, does not appear in seismic data.

This is a common problem that is well reported and documented in journal papers highlighting specific Gulf of Mexico well challenges/problems that can result, such as:

1. packoffs behind BHA (lost returns)
2. swabbing
3. BHA damage from shock and vibration
4. stuck logging tools
5. stuck casing
6. excessive trips to clean tar in casing and riser
7. surface handling problems

Unfortunately mitigation choices are limited.

Either avoid it or fight it.

References

Joyes, R., 2001. South Atlantic Geology: deciphering turbidites on seismic key to understanding basins off Africa, Brazil. Oil Gas J. 99, 38–43.

Leffler, W.L., Pattarozzi, R., Sterling, G., 2011. Deepwater Petroleum Exploration and Production: A Non-Technical Guide, second ed. PennWell, Tulsa, OK.

Perez, M.A., Clyde, R., D'Ambrosio, P., Israel, R., Leavitt, T., Nutt, L., Johnson, C., Williamson, D., 2008. Meeting the subsalt challenge. Oilfield Rev. 20 (3), 32–45.

Press, F., Siever, R., 1998. Understanding Earth, second ed. W.H. Freeman and Co, New York, Basingstoke.

CHAPTER

2

Deepwater Geology & Geoscience

DEEPWATER GEOLOGY & GEOSCIENCE

General Introduction

Seventy percent of the earth's surface is covered by sea, of which a large part is defined as deepwater. The constraints of deepwater petroleum systems as shown in Fig. 2.1 dictate that only relatively restricted sedimentary surface areas and depths underlain by the continental plates are considered as commercially prospective for hydrocarbons.

Although analogous fields have been discovered in deepwater, the evident influences within these environments provide perhaps less reason to expect better quality or larger volume reservoir accumulations than in shallow water. However, considerable unexplored areas of deepwater have the potential to contain entrapped hydrocarbons and through the application of more modern exploration tools (seismic, logging while drilling, seismic while drilling) make deepwater a better place today than in earlier offshore years.

A deepwater petroleum system must contain the Geology and Geoscience (G&G) ingredients required for commercial hydrocarbon success. That system, among other factors, must contain the static and dynamic elements such as reservoir, trap, source rock, cap rock, primary and secondary migration, and all required interconnections. All elements must be present and correctly linked in time and space. Most of the elements are affected by the context in which they find themselves and certain features in deepwater environments also affect the eventual nature and volumes of the hydrocarbons trapped.

An introductory examination of deep water geology and geoscience is presented in this chapter covering seismic, shallow hazards, deepwater geology and geoscience, characteristics, reservoir sedimentology, trapping, geometry, source rock maturation, and migration essentials.

Deepwater Seismic Interpretation

At the beginning of deepwater projects, seismic data are generally all that is present. Advances in 3D and 4D seismic techniques today provide geologists and geophysicists with greater analysis and interpretation potential to manage and predict deepwater shallow hazards, predict and detect pressure regimes, hydrocarbon petroleum, and reservoir aspects. Continuous improvement in these fields explains why the industry is capable of exploring in deeper offshore frontier such as subsalt, etc. that was certainly not previously possible.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00002-8

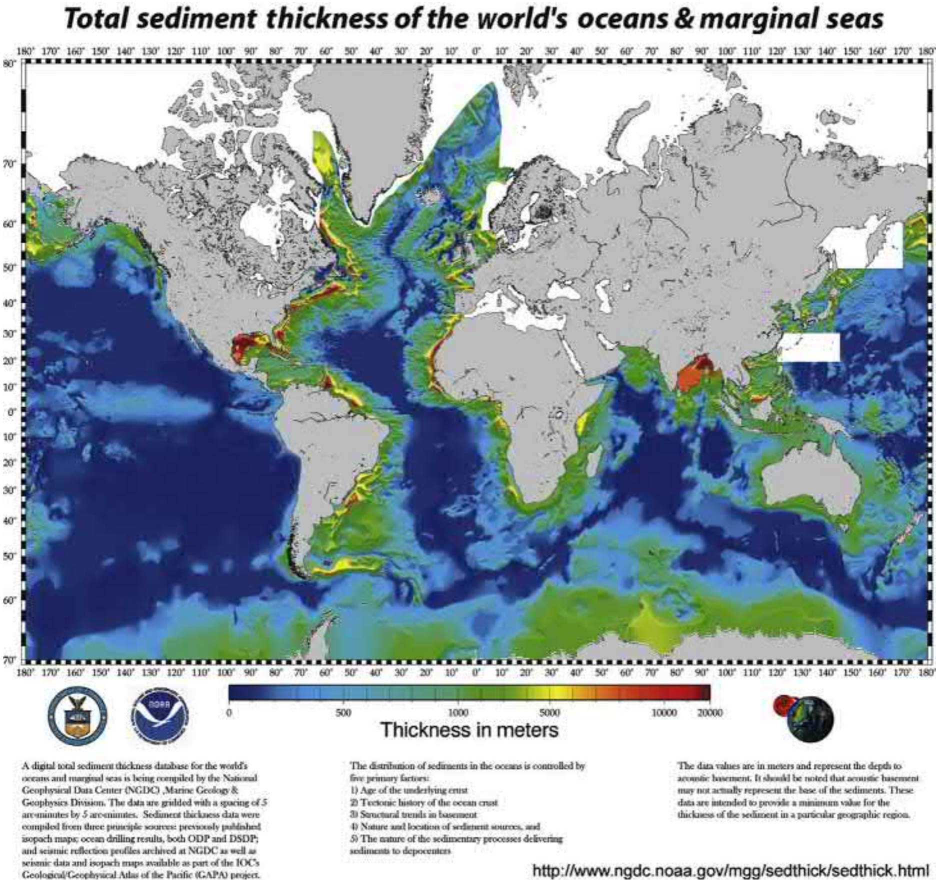


FIG. 2.1 Ocean sediment and oil reserves, total sediment thickness. *Source: Divins, NGDC.*

Initially, governments acquire seismic in prospective deepwater basins with modern equipment to obtain the data, that they may process and to a limited degree interpret. Most of the detailed scope of interpretation remains within the oil company domain. In the initial exploration phase, 2D lower cost seismic sections are acquired and interpreted to initially highlight potential oil "plays." The exploration companies then work to identify the potential traps, source rock, seal and presence of hydrocarbons to select the best prospects to bid for that, if successful, may require further well location, site survey, and environmental studies to consider.

No matter how worthy seismic may have progressed, wells must be drilled below the seabed to discover what physically exists below the deepwater subsurface strata. From a project's perspective, seismic technology has transformed to greatly increase the probability of success before a well is drilled and to reduce several of the technical, operational risks and geological uncertainties.

Offshore Marine Seismic surveys (Fig. 2.2) are used to improve an understanding of the environment of deposition and sedimentological units. High-resolution 3D is used to depict more intense images of the sea bottom and subsurface features and attributes to assure safe well operations result.

Seismic data are used to identify geohazard occurrences, using both conventional and reprocessed 3D seismic, 2D and 3D high-resolution seismic, seismic velocity data, analogue site surveys, and core samples. In exploration plays with limited well data, seismic velocity data are used and viewed as important to evaluate deepwater subsurface structures where:

1. Hazards and uncertainties may exist,
2. Pressure regimes are predicted,
3. Hydrocarbons may be trapped.

Seafloor debris hazards are recognized and analyzed using side-scan sonar, while slumps and faults are identified and presented as breaks in seismic reflections using 2D and 3D seismic sections and time slices.

Overpressurized (water flow/gas) pockets can be predicted through seismic data and attribute analysis that may produce anomalous high amplitudes and reflection time sags. Indications of hydrates are also predicted via similar seismic data attributes and velocity analysis. Mud volcanoes and pockmarks, on the other hand, are represented through 3D seafloor visualizations and seismic sections.

Marine Seismic Surveys

Fig. 2.2 outlines the seismic essentials to know in that all cases, marine seismic vessels involve a source (S) and some kind of array of receiver sensors (individual receiver packages are indicated by the black dots).

Fig. 2.2 illustrates:

1. Towed streamer geometry,
2. On bottom geometry,
3. A buried seafloor array (note that multiple parallel receiver cables are subtly deployed),
4. VSP (vertical seismic profile), where the receivers are positioned in a well.

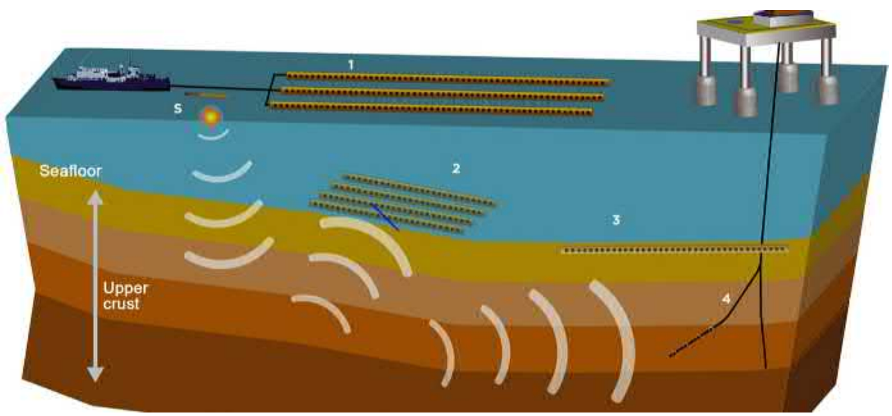


FIG. 2.2 Offshore marine seismic survey. *Source: IOGP shallow hazard guidelines.*

Oil companies generally outsource the seismic acquisition, initial processing and display, with the final processing then conducted by service companies or specialist individuals. Some companies will do their own processing and display for most of their own prospects.

The seismic process serves three main data gathering functions: Acquisition, Processing and Display, and Interpretation, as illustrated in Figs. 2.3 and 2.4. The geophysical interpretation that results then works to define with a certain degree of certainty the subsurface geology, geoscience, and structures in terms of:

1. Project delivery hazards and uncertainties that may exist in the subsurface,
2. Predict pressure regimes,
3. Determine where hydrocarbons or further hazards/risk might be trapped or may be pinpointed or exist or not.

Why 3D–4D?

When several operators entered deepwater in the 1990s, they created "prospect quality teams" that reviewed each exploration prospect by the company's assets and, through applying a consensus approach, established, ranked, and risked the relative size of each prospect. What this did was change their risk portfolio management to greater prospective successes by focusing more on acreage capture and aggressive use of 3D higher resolution seismic.

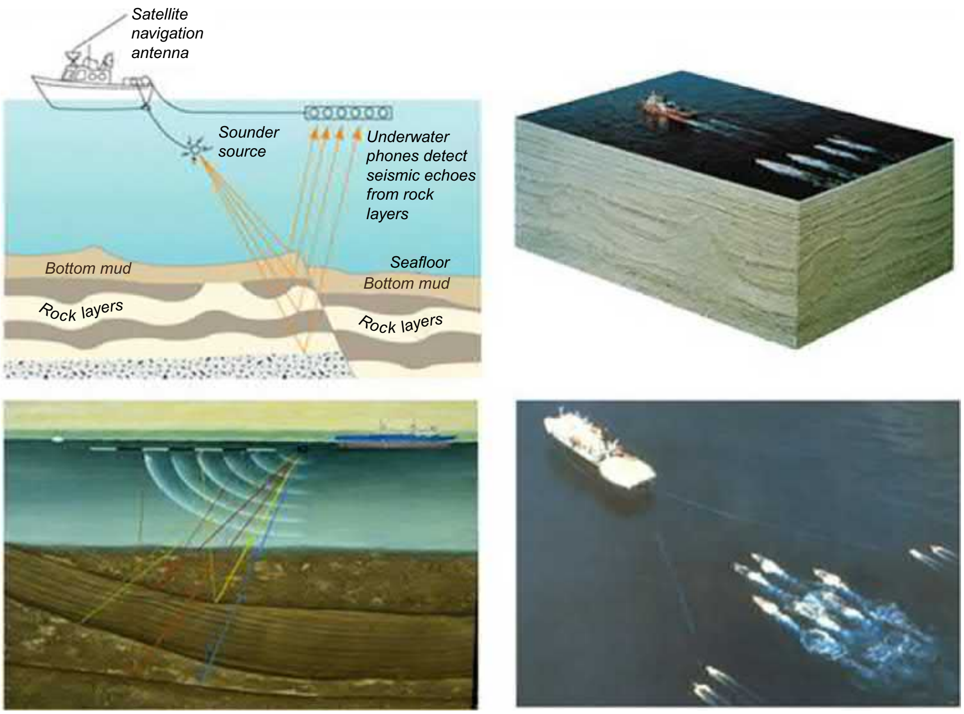


FIG. 2.3 Deepwater seismic process. *Source: Kingdom Drilling.*

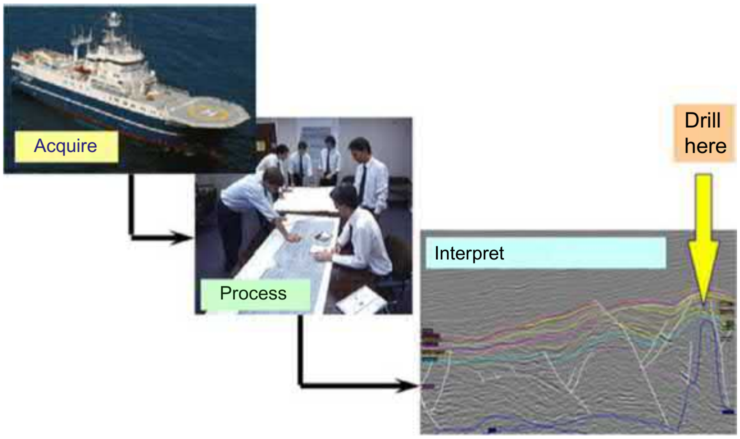


FIG. 2.4 Offshore seismic processes. *Source Kingdom Drilling.*

They worked to "Create Value through Exploration" by defining a new strategic approach to show it was possible to quickly and effectively capture attractive new areas for exploration licensing. Companies also created "Networks of Excellence" charged with discovering and disseminating external and internal best practices throughout the company or selective benchmarking. These initiatives delivered significant value to these companies and are the prime reasons that turned fortunes in terms of deepwater plays using advancing seismic upfront-loading techniques and methods as used today.

Fig. 2.5 presents illustrative seismic interpreted examples of shallow and deep marine stratigraphy that, without seismic, optimal hazard predictive identification and risk-based safer operating solutions could not have resulted.

Site-Specific Surveys

When wells sites are selected, a further more specific and detailed shallow site survey—to obtain higher-quality resolution, 2D or 3D specific data—may be deemed necessary and would follow in a suitable time frame, before a well's project commencement as illustrated in Fig. 2.6. The higher-quality survey data are used to further predict, reduce, and mitigate potential project hazards, risks, and uncertainties through utilizing the multidiscipline of people now involved to deliver work scope required. It is recommended that a site survey program start 6 months prior to, and no less than 3 months ahead of, the proposed well's spud date.

SEISMIC SURVEY DATA MODELING

The conceptual framework diagram of the Seabed Survey Data Model SSDM is illustrated in Fig. 2.7.

This seismic standard is proposed by the IOGP (International Association of Oil and Gas Producers) to standardize modeling and survey project details (extents, equipment coverage, track lines, etc.), hydrographic, shallow geophysical and geotechnical geographical entities and attributes, including surface and subsurface geologic hazards that are interpreted from seabed surveys. This standard and related site survey technical guide documents can be downloaded from http://www.iogp.org/.

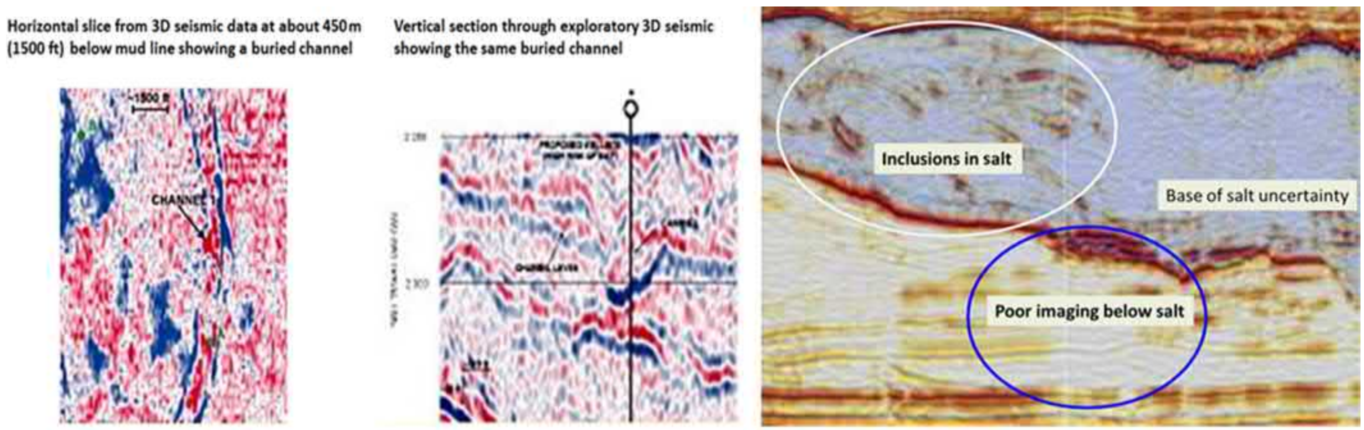


FIG. 2.5 Use of 3D seismic to identify a potential shallow flow zone and evaluate salt entry, inclusion and exist challenges. *Source: Compiled by Kingdom Drilling training 2009.*

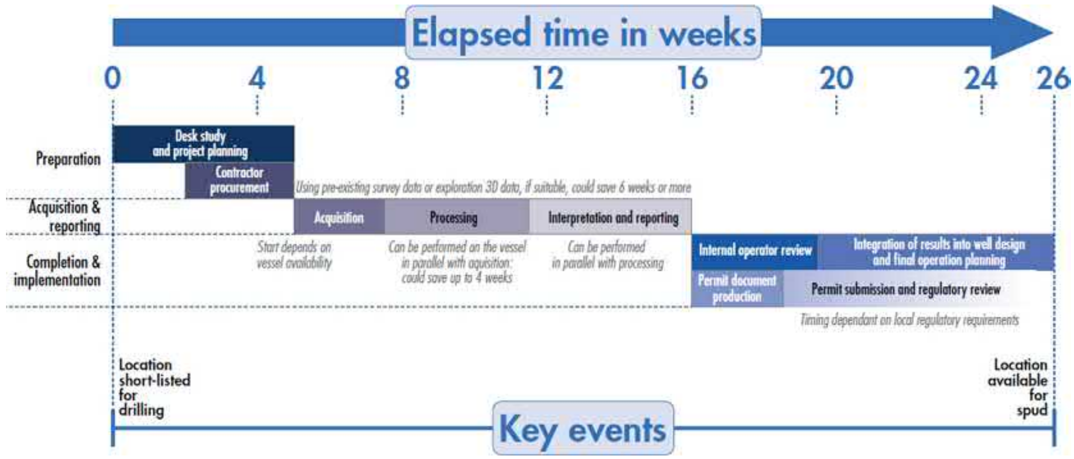


FIG. 2.6 Typical time line for site specific site survey. Ref IOGP shallow hazard guidelines.

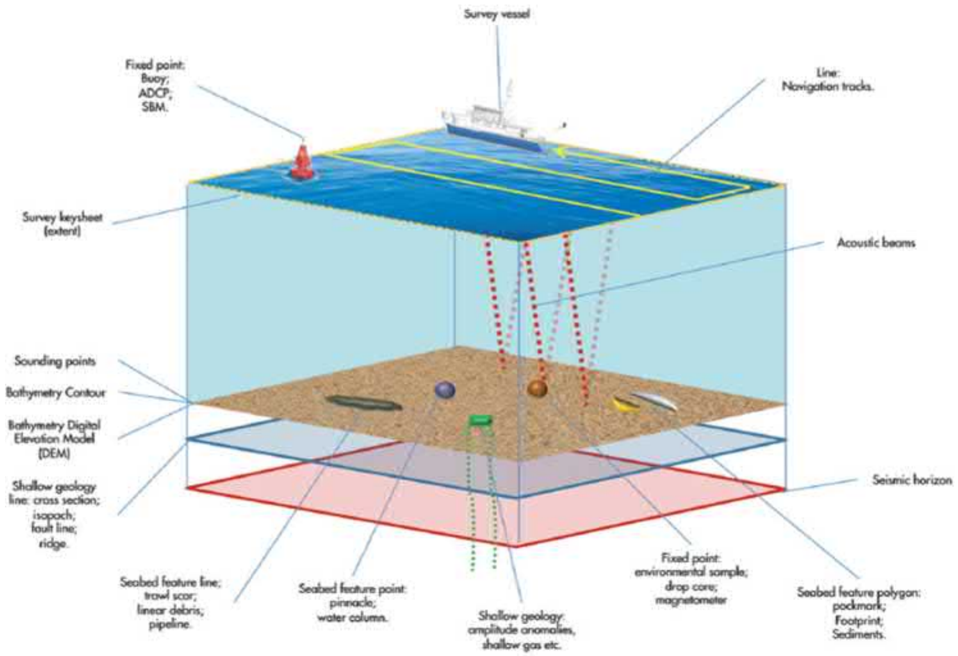


FIG. 2.7 Ref. IOGP Geomatics 462 series Data models note 1, version 1, April 2011.

Shallow Seismic Systems and Methods for Deepwater

Seismic survey data used to identify deepwater geohazard occurrences are shown in Tables 2.1 and 2.2. This includes conventional 2D and later higher resolution, to reprocessed 2D, 3D, 4D seismic, seismic velocity data, analogue site surveys, and core sampling.

Traditional Site Survey

This is a survey with both analogue systems and 2D high-resolution seismic. Most commonly used equipment can be operated simultaneously with a minimum of interference between the systems.

2D High-Resolution Seismic Survey

This is multichannel seismic with high-resolution sources. The target depth is approximately 300–1200 m (1000–3940 ft) below seabed. These surveys use short group lengths, short streamers 600–1200 m (2000–3940 ft), and short shot distances.

Analogue Survey

Analogue Surveys use boomer/sparker/parametric source, mini-seismic source, towed sonar and hull-mounted single/multibeam echo sounder and are often referred to as analogue surveys. All analogue data can be digitally recorded and enhanced by processing the high-frequency data acquired from echo sounding, side-scan sonars, and sub-bottom profiling, to provide accurate bathymetry maps, seafloor mosaics, indications of seafloor gas, and shallow fault detection.

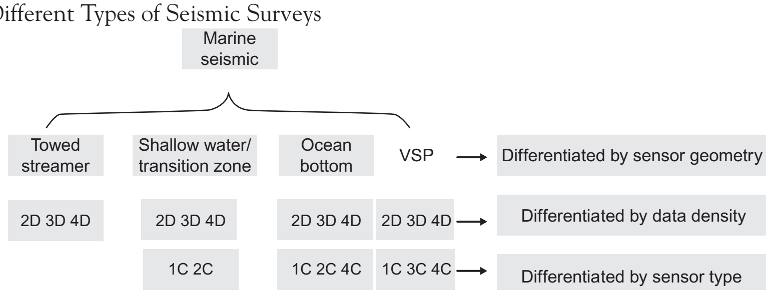
Digital Site Survey

Digital survey data can result in improved imaging of the subsurface near the seafloor, leading to improved fault and thin-bed mapping. Unfortunately, although data consist of higher frequencies than 3D seismic, there is a disadvantage of being unable to resolve the 3D nature of the hazards. When used in conjunction with 3D data, they may aid in the interpretation.

ROV Survey

It is possible to get excellent side scan sonar and echo sounder data using ROV (remotely operated vehicle), but the ROV cannot transport seismic systems to be used for detection of shallow gas/hydrates. Note: ROV survey costs are often several times that of analogue surveys.

TABLE 2.1 Different Types of Seismic Surveys



This table summarizes the majority of the different types of marine seismic surveys.
Source: IOGP shallow hazard guidelines (Jack Caldwell and Chris Walker).

TABLE 2.2 Shallow and Deep-Site Survey General Capabilities

Equipment		**Comments**
Surface positioning	Diff. GPS/radio nav.	*Very good*
Hydroacoustic positioning	Ultrashort baseline	poor, not acceptable
	Long baseline	*very good*
Hull-mounted echo sounders	Single beam	good (max beam angle 2 degrees)
	Multibeam	good
ROV-mounted	Single beam	*very good*
Echo Sounders	Multibeam	*very good* (better than above)
Magnetometer, Towed, or ROV-mounted		good for big objects
Side-Scan Sonar	ROV-mounted	*very good*
	Towed	good
	Hull-mounted	not acceptable
***Seismic systems, target depth 0–50 meters*:**		
Pinger		variable
Parametric source		good
Deep towed boomer/sparker		good
Chirp		good/*very good*
***Seismic systems, target depth 50–500 meters*:**		
Mini seismic source		*very good*
3D high resolution		*very good*
Seismic systems, target depth below 200 meters:		
2D high resolution		good
3D seismic		can be good
3D seismic, reprocessed		can be good

Source: Kingdom Drilling 2002.

3D Deep Seismic

The 3D data can also be used for interpretation of shallow gas/hydrates.

3D High-Resolution Seismic

3D high-resolution surveys are shot with a high-frequency source and with fewer offsets than deep-seismic 3D. The sampling frequency is higher and the distance between shots is also less than for other 3D. The result should be very high vertical and horizontal resolution in the upper 1000 m (3281 ft) of sediment. Due to high cost compared to 2D high-resolution seismic (about 2–3 times more expensive), this method has to yet be fully tested and proved.

Rules of thumb and a derived deepwater site survey interpretation check list can be developed as illustrated in Table 2.3, to predict and analyze survey evidence to better qualify, quantify and assign appropriate risk to each seismic hazard, feature, attribute, or anomaly observed.

Shallow Hazard Assessment Rules of Thumb & Checklist

1. Various methods and techniques exist for mapping of all shallow hazards. The optimum method for mapping of seabed hazards is to use ROV-mounted sonar and multibeam echo sounder.

TABLE 2.3 Example, Shallow Seismic Hazard Interpretation Checklist

Shallow Hazard Interpretation Guide Points	Yes	No
1. Is the reflection from the suspected gas pocket anomalous or bright in amplitude?		
2. Do seismic data allow the anomaly to be ties to an offset well where gas was present in the same interval?		
3. Is the amplitude anomaly structurally consistent?		
4. Is the amplitude of the anomaly equivalent to five times, or more than, the background (nonbright value) for the same reflector?		
5. If bright, is there one reflection from the top of the reservoir and once from the base?		
6. Do the amplitudes of the top and base reflections vary in unison, dimming at the same point at the limit of the reservoir?		
7. Is a flat spot visible?		
8. Is the flat spot dipping or consistent with gas velocity sag?		
9. Is there a pull down effect of underlying reflectors indicative of gas velocity sag?		
10. If present, is the flat spot uncomfortable with the structure but consistent with it?		
11. Does the flat spot have the correct zero-phase character?		
12. Is the flat spot located at the down dip limit of brightness (or dimness)?		
13. Is a phase change visible at the edge of the anomaly?		
14. Is the phase change structurally consistent and at the same level as the flat spot?		
15. Have the seismic data being used been converted to zero phase?		
16. Do the bright/dim spots or phase changes show the appropriate zero phase character?		
17. Is there an anomaly in velocity derived stacking velocity across the interval?		
18. Is there a low-frequency shadow below the suspected reservoir?		
19. Did a study of amplitude versus offset on the unstacked data support the presence of gas?		
20. Does a near-offset range stack show a lower amplitude response than a far-offset range stack for the same event?		
21. Is there comparative P & S wave section's available to aid in clarification of gas presence?		

Source: Kingdom Drilling.

2. The upper tens of metres can best be mapped with a hull-mounted parametric source or a Chirp system. If ROV is used for mapping of the seabed hazards, the seismic system should be mounted on the ROV.
3. Shallow water flow and gas reservoirs from 50–1000 m (164–3281 ft) below seabed are best mapped with high-resolution 3D seismic. The second best choice is a combination of seismic data from mini air gun or mini water gun and either high-resolution 2D or possible conventional 3D seismic, if this shows good resolution in the interval not covered by the mini-seismic system.
4. Typical line spacing for the 3D seismic surveys is 25 m (82 ft). For 2D surveys, it is 250 m (820 ft) in one direction and 500 m (1640 ft) in the other. For 2D surveys, it is common to make a denser pattern around the well location applying 100 m (328 ft) spacing in both directions. Typically, a time frame of 4 weeks should be expected from when the field work is finished to presentation of final results.
5. It is recommended to avoid drilling at identified shallow hazards. The location of exploration wells should be moved away from:
   - Areas where faulting to shallow depths may be expected
   - Shallow depth structural closures, or a closure of the BSR (base of hydrates)
   - Shallow gas accumulation
   - Shallow reservoirs.
6. If it is impossible to move away from shallow hazards, the well should be designed to minimize the risks.
   - If practically possible, a weighted mud system should be used rather than sea water when a possible shallow gas zone has to be penetrated.
   - The well should be placed as far down flank on a mapped structure as possible.
   - Procedures and methods for risk reduction as described under the chapter covering Shallow Gas should be implemented.
7. Soft seabed may cause anchoring problems. Possible solutions to the problem would be to use specially designed mud or vertical lift-assisted (VLA) anchors or suction anchors. Use of piggyback anchors or increased number of anchor lines from 8 to 12 or more can also be considered.
8. The soft formation's support to the wellhead may not be sufficient for use of standard equipment. Depending on the results of the seabed strength analysis, larger than standard OD conductor may be required (36 in (914 mm)), higher grade (X52 or X56), or thicker wall (1.5 in or 1.75 in (38.1–44.5 mm)). The use of a conductor anchor node as used in more recent deepwater applications 'CAN' also be evaluated.
9. Small operating margins between pore pressure and fracture pressure shall exist when drilling the shallower riserless wellbore sections.

Soil Sampling

Shallow soil sampling may be acquired to obtain and measure geotechnical properties below the seabed. A common method is to use gravity-based coring devices that can produce a continuous core of the upper 0–6 m (0–20 ft) below the seabed. The unit is simple and reliable and can operate well in water depths >1000 m (3281 ft). The gravity corer cannot however function when the seabed consists of sand, gravel, or other hard soils. Under such circumstances, more comprehensive geotechnical equipment must be used; where more autonomous and expensive solutions are available to meet required deep water depth capabilities and all subsurface soil conditions, i.e., >3500 m (11,400 ft).

Possible solutions for extraction of shallow sediments are push samplers or CPTs. Both are mounted on a weight platform, e.g., 7 tons, size 5×5 m (16×16 ft). Surface supplied hydraulics is one method used to force a test pipe into the shallow seabed soils.

Shallow Hazard and Risk Assessment Guidelines

Project site survey shallow hazard assessment can be split into two categories, ***Seabed Hazards*** and ***Subseabed hazards***.

1. **Seabed Hazards** consist of:
   - **a.** Topography, slump, and scours feature
   - **b.** Slumps or faults extending up to the seabed
   - **c.** Manmade objects
   - **d.** Wrecks, mines, etc.
   - **e.** Poor anchoring conditions
   - **f.** Very soft clay, mud slides, cemented sand.
2. **Subseabed Hazards** Figs. 2.8 and 2.9 consist of:
   - **a.** Shallow gas, shallow water flow
   - **b.** Gas hydrates and molds
   - **c.** Faulting and glide planes to shallow depths
   - **d.** Mud volcanoes
   - **e.** Incompetent sediments
   - **f.** Abnormally pressures zones
   - **g.** Layers of boulders
   - **h.** Low fracture pressures
   - **i.** Shallow prospects.

Notes: The term "shallow" is not definitive and as a general guide refers to depths <1000–1250 m (3280–4100 ft) below the seabed. Shallow hazards in the context of deepwater seismic risk assessment are defined in this guide as:

a. ***High***: An anomaly showing ***ALL*** seismic characteristics of a shallow hazard that ties to an offset well, or is located at a known regional shallow hazard horizon.

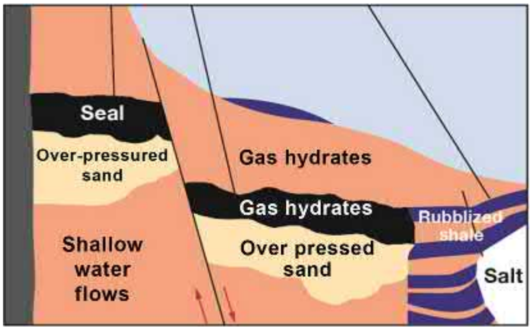


FIG. 2.8 Key shallow hazards to predict and assess prior to project implementation. *Source: Kingdom Drilling 2018.*

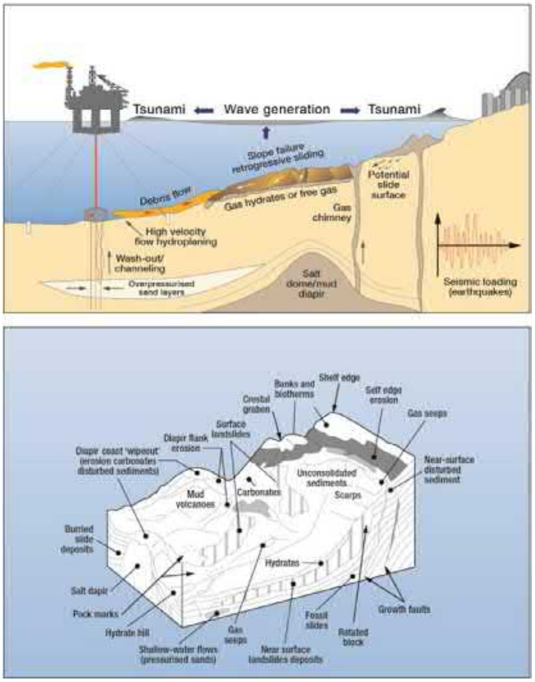


FIG. 2.9 Reconstructed in 2018 by Kingdom Drilling, from a widely used summary of deepwater geohazards.

b. ***Moderate***: An anomaly showing ***MOST*** of the seismic characteristics of a shallow hazard, but which could be interpreted not to be a hazard or reasonable doubt exist for the presence of such hazards.

c. ***Low***: An anomaly showing ***SOME*** of the seismic characteristics of a shallow hazard interpreted as a low risk although some doubt exists.

d. ***Negligible***: Either there is ***NO ANOMALY PRESENT*** at the location or anomaly is clearly due to nonhazardous, causes.

Note: *Any one* indication can be spurious. Shallow hazard interpretation on seismic data involves accumulation of evidence, competent, highly skilled judgment, and a well to be drilled.

Shallow hazards are mapped with combinations of data from echo sounder, side scan sonar, very high-resolution seismic, and further assessed via geotechnical and environmental samples from the upper few m of the seabed to as deep as is practicable.

Shallow hazards data are acquired, processed, interpreted, and mapped with various seismic equipment systems, techniques, and methods.

The more interpretive points answered yes or no as illustrated in Table 2.3, the more or less likely shallow hazard risks are present. A typical risk analysis flowchart framework is illustrated in Chart 2.1.

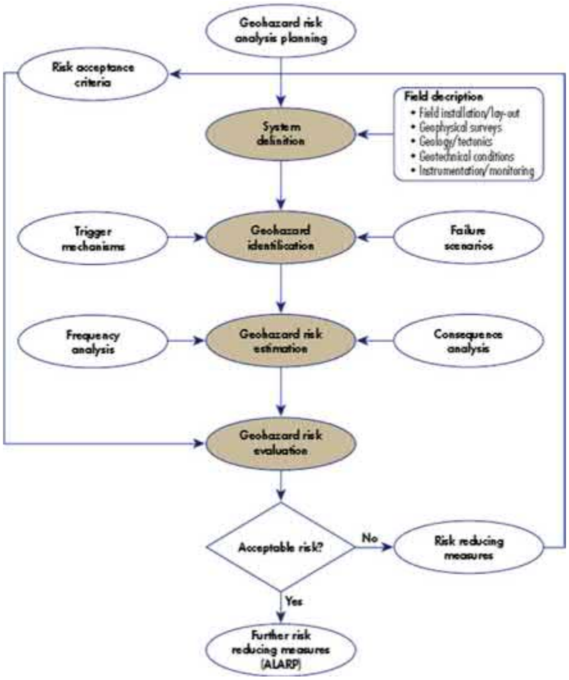


CHART 2.1 Geo-hazard risk analysis framework. *Source: OGP JIP report.*

Addressing Deepwater Geohazards

The main concerns offshore teams have to deal with and address are:

1. Site-specific selection, for lowest geo-risk,
2. Surface and subsurface geohazard avoidance,
3. Geohazard mitigation.

Multidisciplinary teams shall work to provide the offshore delivery team with more open networks of information, allowing for better location selection and improved decision making through the well design, construction, planning, and execution processes to prevent the occurrence of shallow hazard loss time events.

Shallow Flow

Shallow water (SWF) and shallow gas are higher risk hazards in narrow margin deepwater drilling environments, arising from a combination of overpressure and trapping mechanisms.

Important points regarding shallow flow indicators (Figs. 2.10 and 2.11), risks, and problem-solving strategies to be met during riserless drilling operations are:

1. Shallow fluid flows present a potentially serious drilling hazard and risk in deepwater.
2. Shallow water flows are encountered in geopressured aquifers.

FIG. 2.10 ROV snapshot of "Strong" deepwater shallow fluid flow. *Source: Kingdom Drilling training.*

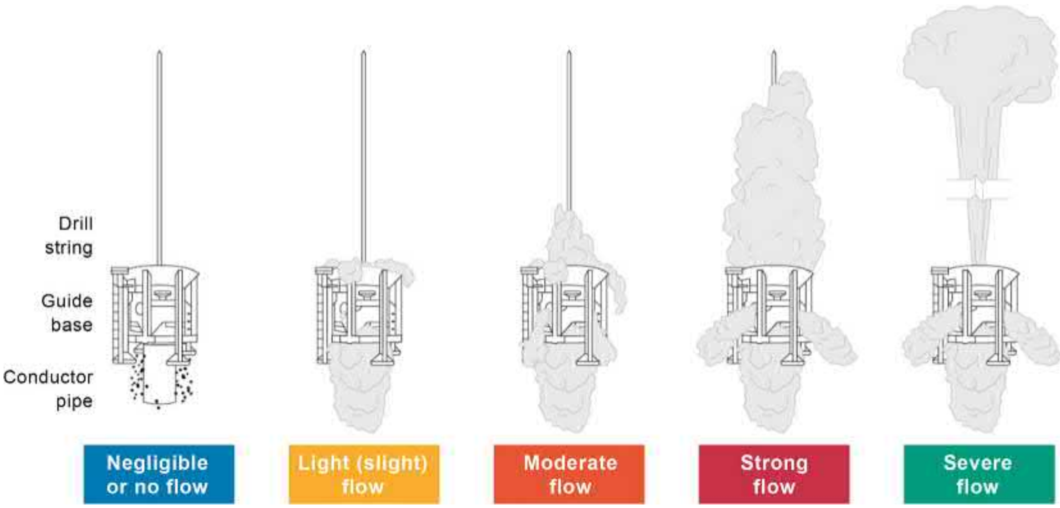


FIG. 2.11 Illustration to classify shallow fluid flows. *Source: Reconstructed for Kingdom Drilling training 2006.*

3. Shallow flows are correlated with water depth, burial depth, and stratigraphy.
4. Shallow flow events appear controlled by sedimentation rate and seal effectiveness.

Classifying Shallow Flow

Drilling shallow, weak, and trapped over pressured formations, being able to control the operating densities in more restrictive operating margins, i.e., 0.2–0.5 ppg (24–60 kg/m^3), is no simple task. Should primary well control assurance not be maintained shallow formations can flow, leading to costly loss time-operating events. Classifying shallow fluid flows are proposed in Fig. 2.11 and Table 2.4 as follows.

TABLE 2.4 Classification of Shallow Flow

Type of Flow Observed	Description	Comments
Negligible or NO flow	Mud and cuttings may drop from the lower parts of the wellhead but not over the top	
Low (Slight) flow	Mud and cuttings spilling over the wellhead and dropping out of the side ports	
Moderate flow	Cloud streaming upward <3–5 m (10–15 ft) and outward form the top of the guide base	Fluid flowing over the wellhead may obscure fluid flow out of the side ports.
Strong flow	Billowing upward with high energy 10–50 m (30–150 ft) from the top of the wellhead	
Severe flow	Strong vertical expulsion up to 100–150 m (300–500 ft) or more above the wellhead	

Source: Kingdom Drilling May 2018.

Hydrate Detection Using Seismic Data

A process for gas hydrate detection, analysis, and quantification as used within the Gulf of Mexico deepwater is outlined in Fig. 2.12.

The process involved (1) reprocessing of seismic data for higher resolution, (2) detailed stratigraphic evaluation and interpretation to locate possible hydrate-bearing zones, (3) seismic attribute analysis to further delineate these zones, (4) seismic inversion to obtain appropriate elastic param of these zones in 3D, and (5) quantitative estimation of gas hydrate saturation from seismic data using inversion and rock physics principles.

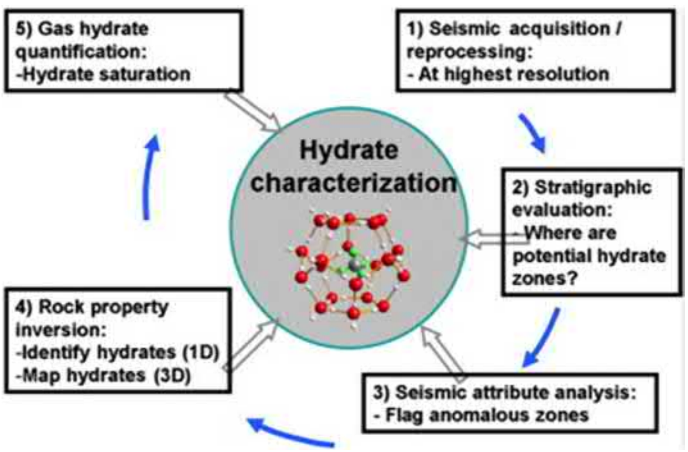


FIG. 2.12 Hydrate detection process using seismic data. *Source: Elsevier.*

BASE OF GAS HYDRATE STABILITY

The outcomes, and benefits of the process are the ***base of gas hydrate stability*** (BGHS) can be confidently inferred from the seismic data processed, displayed, and interpreted from a hydrate perspective.

Bottom-simulating reflectors (BSRs) are interpreted from within the seismic geophysical indicators of the base of gas hydrate stability. Note: BSRs occur when gas hydrate-saturated sediments overlie gas-saturated sediments. Three types of BSRs exist: *continuous* BSRs, *discontinuous* BSRs, and *pluming* BSRs.

Superimposed in Fig. 2.13 are outlines of 145 areas in which features inferred to mark the BGHS are observed in seismic data. The color indicates the dominant morphology (many areas show elements of more than one form) of BSRs, for example: as continuous (yellow), discontinuous (red), and pluming (green). The dashed blue line indicates the area of uninterrupted 3D seismic data coverage available for the study.

Key features resulting from this study were:

1. Most BSRs are found on the flanks and over the crests of salt diapirs.
2. The majority of hydrate features were not associated with BSRs in the classic sense, i.e., continuous coherent events that crosscut primary stratigraphy.

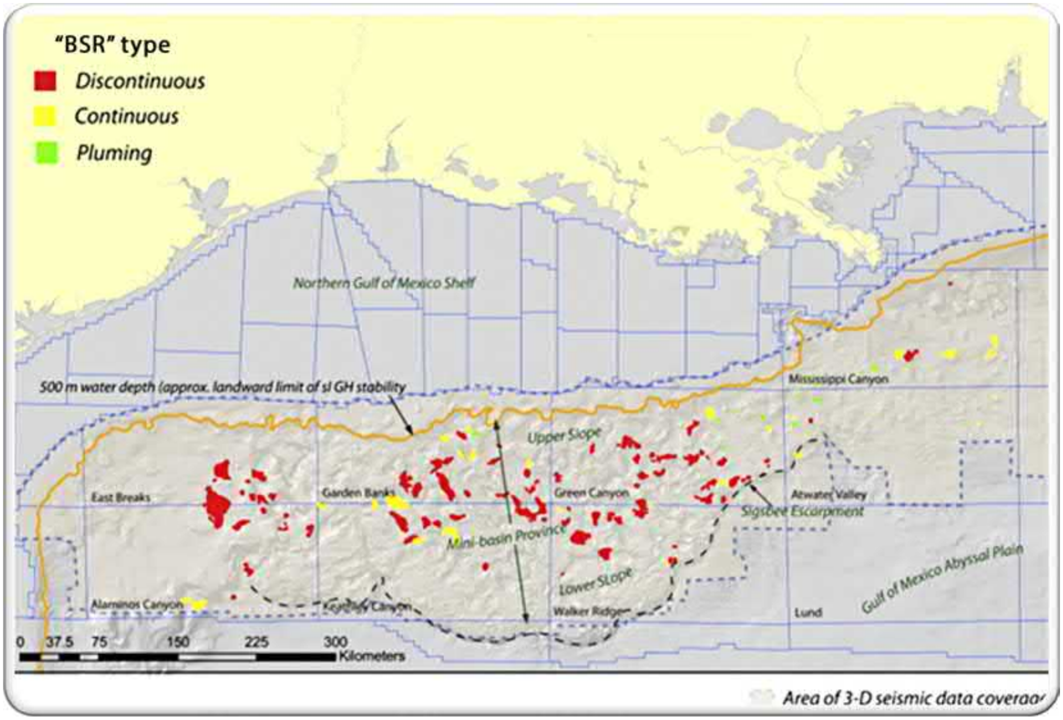


FIG. 2.13 Seafloor morphology of the northern Gulf of Mexico. *Source: Elsevier.*

DEEPWATER GEOLOGY PRINCIPLES

Essential Principles

The essential principles of Geology and Geoscience (G&G) as shown in Fig. 2.14 apply to any well including all deepwater operating environment and conditions. The difference to these principles in terms of deepwater are discussed in this chapter.

How Deepwater Sediments Are Formed

The sedimentary rock cycle is illustrated in Figs. 2.15 and 2.16.

Clastic sediment is sediment consisting of fragments of rock, transported from elsewhere and redeposited to form another rock. ***Clasts*** are individual grains that make up the sediments. The sediment particles are then further exposed to rain, wind, and gravity, which batters and break them apart through further weathering and erosion processes.

The products of weathering will finally include particles ranging from clay to silt, to pebbles and boulders, that are then suspended and transported downstream by wind, streams, rivers, and ocean tides and currents to the earth's ocean and sea basins below, where they are buried, lithified, subjected to heat and pressure at various depths to solidify into the many different sedimentary rock types that exist.

As the earth consists 70% of water, a great majority of sediments will form into the estuaries, deltas, seas, lakes, and oceans to form sedimentary sequences that will often result in kilometers of sedimentary rock sequences below the subsurface, i.e., seabed, where, when

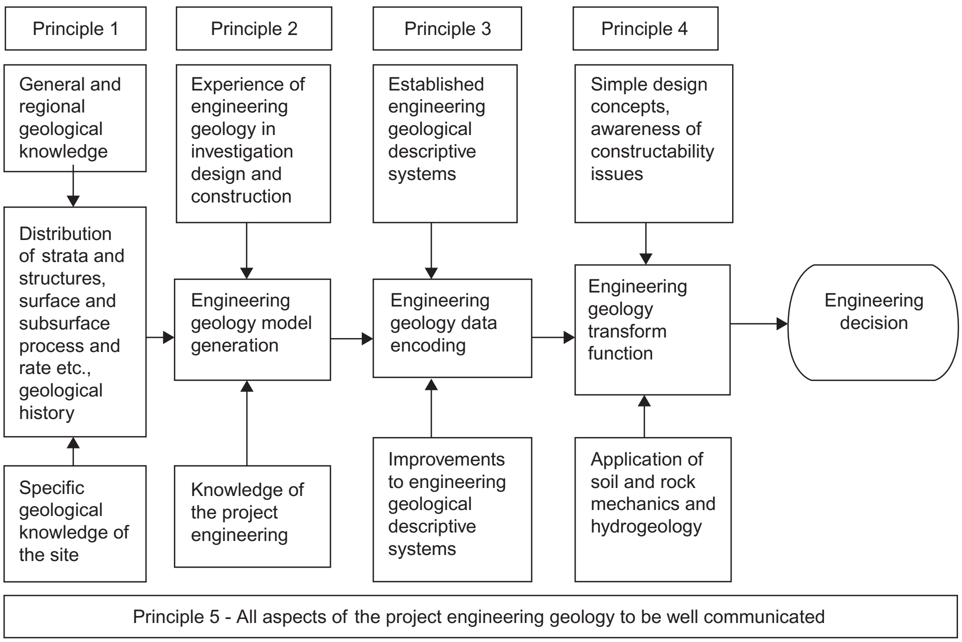


FIG. 2.14 Essential Geology and Geoscience principles. *Source: Kingdom Drilling training 2002.*

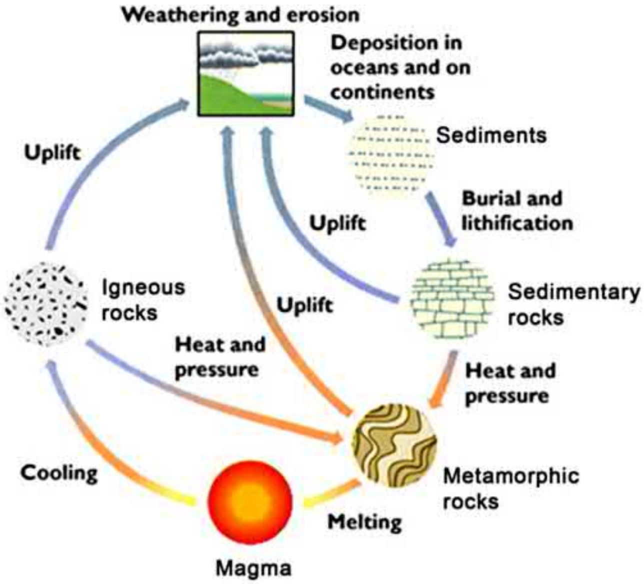


FIG. 2.15 The sedimentary rock cycle. *Source: Understanding Earth.*

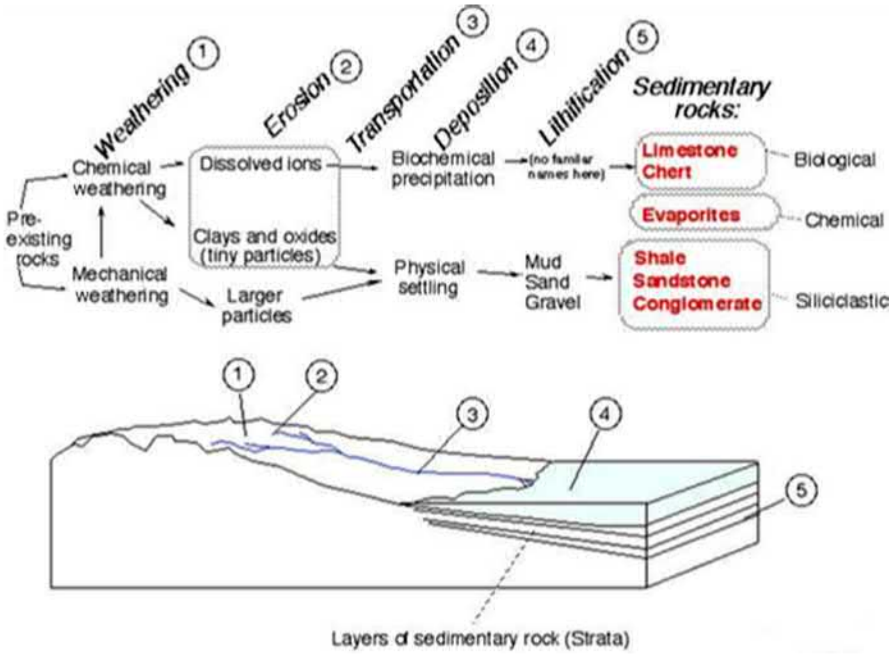


FIG. 2.16 How sedimentary rocks are formed. *Source: Kingdom Drilling training 2015.*

deep enough, further pressure, heat, and temperature changes further cook and change the sedimentary rock.

Above the metamorphic bedrocks within the earth basins, sediment thicknesses overlying the majority of the world's oceans, seas, and margins have been mapped, interpreted, and can be readily obtained to conclude deepwater sedimentary basin sequences and rock thickness where hydrocarbons exist are not all the same.

Ocean sediments are products of weathering, erosion, and transportation through layered streams of sand, silt, mud (clay), and other materials (carbonates) further precipitate from solution. These materials then are deposited on the continental ocean and sea floors as tectonic plates converge, diverge, rise, or subside to form ocean ridges or other unique seabed features to form the world's deepwater sedimentary ocean floors and drilling basins that exist today.

Deepwater Sedimentary Environments

General

Two deepwater sedimentary environment categories (**shallow** and **deep marine**) are shown in Fig. 2.17.

Shallow marine extends from the shore to the edges of the continental shelf. *Lime, clay-bound mud silts and sands are the principal sediments deposited.*

Deep marine characterizes the deep oceans beyond the continental slopes and include deep sea fans and abyssal plains. *Sands, silts, and clay bound mud are the principal sediments deposited.*

The environments by which sediments are transported in deepwater, e.g., within Fig. 2.18, Tables 2.5 and 2.6 are unlikely to have the same subsea topography and can vary quite significantly: for example, West of Shetland, Gulf of Mexico, West Africa, Brazil, Southeast Asia, India, Caspian, and Red Sea. Each deepwater environment likely to have a unique identity set of sedimentary geological and individual formation characteristics.

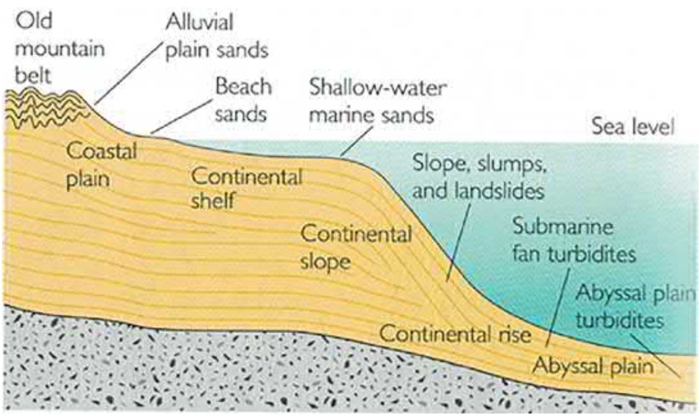


FIG. 2.17 Atlantic passive continental margin off southern New England (After Emery, K.O., Uchupi, E., 1972. Atlantic Continental Margin of North America, AAPG). *Source: Understanding Earth.*

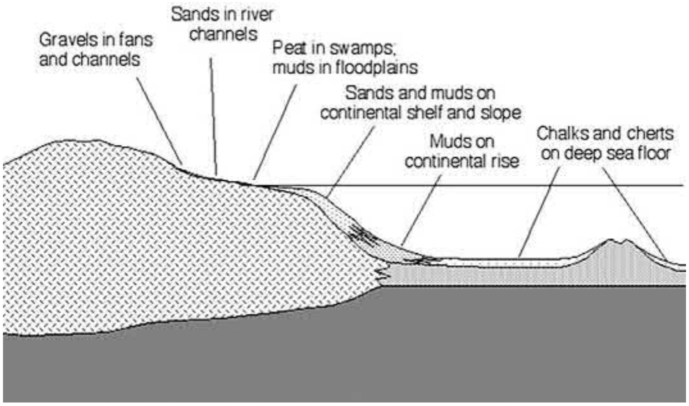


FIG. 2.18 Further examples of how deepwater sedimentary environments are formed. *Source: Kingdom Drilling training 2006.*

TABLE 2.5 Major Chemical and Biochemical Sedimentary Environments

Environment	Precipitation Agent	Sediments
Shoreline and Marine		
Carbonate includes reef, bank, deep sea, etc.	Shelled organisms, some algae, inorganic precipitation from seawater	Carbonate sands & muds, reefs.
Evaporite	Evaporation of seawater	Gypsum, halite, other salts
Siliceous deep sea	Shelled organisms	Silica
Continental		
Evaporite	Evaporation of lake water	Halite, borates, nitrates, salts

Tectonic Content

Excluding the effects of salt, the majority of deepwater sedimentary drilling environments, particularly the first three to as much as several thousand feet of sediments deposited below the seabed, will display little and limited tectonic change, content of effect, albeit effects of storms, earthquakes, volcanoes, uplift, slumping, mass-shifting of sediments shall play their part to the sedimentary depositional environments and stratigraphy end results.

Climate

Climate, notably water temperature and the overburden pressure effect of the water, has a significant role in how sediments are deposited and in regards to the diagenetic effects and operational issues that then take place, as presented in Figs. 2.16–2.21 and Tables 2.5 and 2.6. In deepwater, these processes result in sediments of very differing formation sequences and characteristics in relation to offshore and shallower water drilling environments.

TABLE 2.6 Clastic Sedimentary Environments

Environment	Transportation/Deposition Agent	Sediments
Continental		
Alluvial	Rivers	Sand, gravel, mud
Desert	Wind	Sand, dust
Lake	Lake, current, waves	Sand, mud
Glacial	Ice	Sand gravel, mud
Shoreline		
Delta	Rivers + waves, tides	Sand, mud
Beach	Waves, tides	Sand, gravel
Tidal flats	Currents	Sand, mud
Marine		
Continental shelf	Waves, tides	Sand, mud
Continental margins	Ocean currents	Mud, sand
Deep sea	Ocean currents, settling	Mud

Depositional Processes

Deepwater offshore sedimentary environments exist through the mechanisms of:

1. *Weathering and Erosion* cause sediments to form, that are then
2. *Transported and Deposited* within the onshore systems and into the offshore drilling environments over tens of millions of years.
3. Offshore varying sediments are further transported and deposited, over long periods of time to become *buried*, that with *depth, pressure, and temperature*, experience diagenesis as shown in Figs. 2.15 and 2.19.

Regarding deepwater sedimentary transportation, it is important to appreciate the evident physics and science that sediment grains are modified the further the distance they are transported. For example, Fig. 2.20 shows progressive sorting and different grain sizes that can result as a function of distance from shore to deepwater offshore. This is important because well-rounded, well-sorted sand particles can result in prolific source and reservoir rocks.

Deepwater Sedimentary Transportation Agents

GENERAL

The main agent for transportation of both shallow and deep marine sediments results through a sequence of repeating: sedimentary gravity flows, sliding, and slumping, turbidity currents (Fig. 2.21), debris flows, and, of less importance, grain flows, liquidized and fluidized sediment flows.

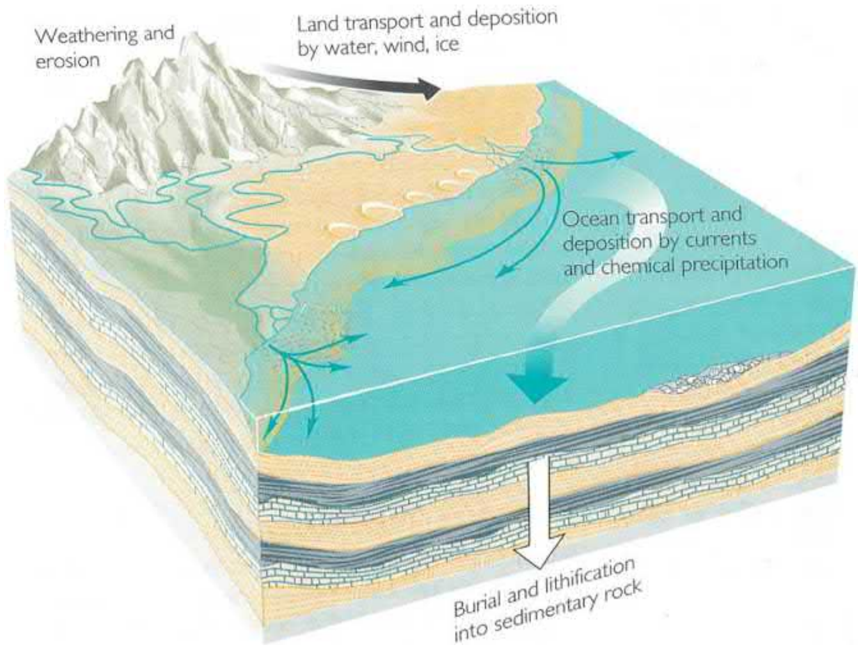


FIG. 2.19 Deepwater sedimentary formation processes. *Source: Understanding Earth.*

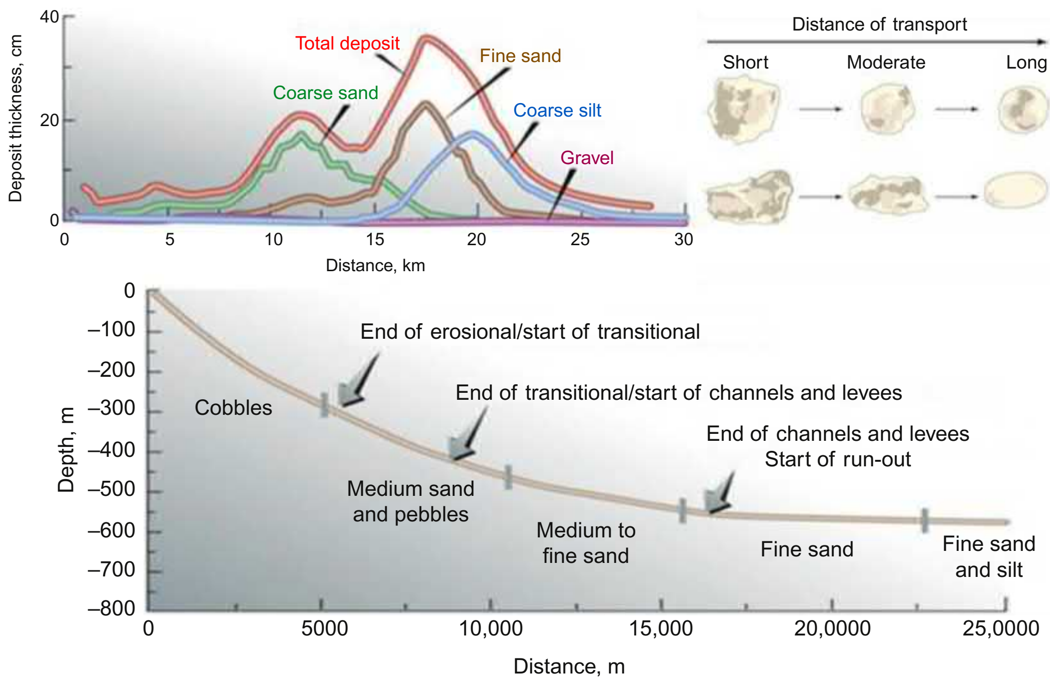


FIG. 2.20 General trends of progressive sorting in downstream direction. *Source: Kingdom Drilling training 2002.*

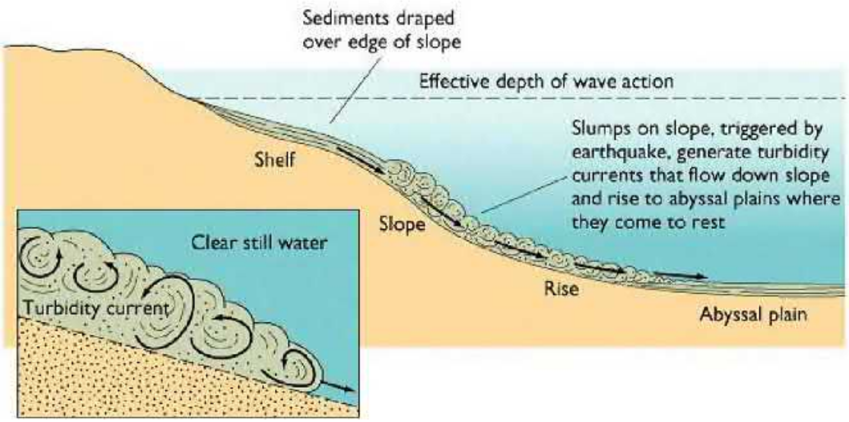


FIG. 2.21 How a turbidity current forms in the ocean. These currents can erode and transport large quantities of sand down continental slopes. *Source: Understanding Earth.*

SEDIMENTARY GRAVITY FLOW, SLIDES AND SLUMPING, AND SLOPE FAILURE

Sediment gravity flow is one type of sediment transport mechanisms, most recognized. ***Slides and slumps*** as illustrated in Fig. 2.21 involve small to large masses of sediment, with more internal deformation, occurring in slumps.

Slumps may develop into sediment-gravity flows. Slides and slumps are typical for slope environments and give rise to scars and discontinuities in generally evenly bedded fine-grained sediments.

Slope failure, generating slumps and sediment gravity flows can be induced by earthquake shocks, but also by storm wave loading. Oversteepening of slopes by rapid sedimentation is also important. These are summarized and discussed in further detail.

SUMMARY OF DEEPWATER SEDIMENTARY TRANSPORTATION AGENTS

Types of sedimentary gravity flows are recognized based on their rheology (liquid vs. plastic behavior) and particle support mechanism (Table 2.7).

TABLE 2.7 Laminar Sediment Gravity Flow Classification Based on Flow Rheology and Particle Support Mechanisms

Flow Behavior	Flow Type	Sediment Support Mechanism
Fluid	Turbidity current	Fluid turbulence
	Fluidized flow	Escaping pore fluid
	Liquefied flow	Escaping pore fluid
Plastic	Grain flow	Dispersive pressure
		Matrix density and strength

Source: Table created from findings by Lowe.

1. *In turbidity currents*, sediments are supported by the fluid turbulence and low-high density flows can be distinguished.
2. In *a fluidized flow*, sediment is supported by upward-moving pore fluid.
3. In a *liquefied flow*, sediment is not fully supported; the grains settle through the fluid, which is displaced upwards.
4. *Grain flow sediments* are supported by the dispersive pressure arising from grain collisions.
5. *Debrite*, mud or cohesive flows, is where the sediment is supported by a cohesive matrix.

Notes: Sediment is deposited from decelerating gravity flows by two different mechanisms. In fluid flows grains are deposited individually, either from the bed load (traction sedimentation) or from suspension, so that deposition takes place from the base of the bed upwards. With debrite flow, the flow freezes as the shear stress falls below the yield strength of the moving material, so that deposition takes place on-mass or from the outside inwards.

The mass-gravity flows that result in offshore marine environments are modeled and divided into two main categories and different flow models for each set of the principal mechanisms developed, i.e.:

1. Debrite flow and
2. Turbidity currents.

DEBRITE FLOW

Debrite flow, including mud flows, are mass movements in which the source sediment travels down slope, coming to rest after the initially stored potential energy is dissipated by friction (Fig. 2.22). During the flows, the source sediment is remolded and reconstituted; the degree to which this occurs determines the rheological properties and flow type. Generally, the soil mass travels as a viscoplastic material, with distinct stress-strain rate characteristics.

Debrite flow deposits are characterized by a bimodal distribution of grain sizes, in which larger grains and/or clasts float within a matrix of fine-grained clay. Because the muddy matrix has cohesive strength, unusually large clasts may be able to float on top of the muddy material making up the flow matrix and thereby end up preserved on the upper bed boundary of the resulting deposits.

Grains are supported by the strength and buoyancy of the matrix. Mudflows and debris flows have cohesive strength, which makes their behavior difficult to predict using the laws of physics. As such, these flows exhibit non-Newtonian behavior. Because mudflows and debris flows have cohesive strength, unusually large clasts may be able to literally float on top of the mud matrix within the flow.

Of the sediment gravity-flow deposits, in deepwater, debrite flow deposits are believed to be the more significant. The strength of the muddy matrix in some debrite flows is understood to be abundant enough to transport mass blocks of sediments significant distances. Debrite flow is also typically mud-dominated with scattered clasts, in a matrix-support fabric.

Due to the relative geological time involved and depositional age of the sediments, *they are deposited in nearly horizontal layers*. Typical debrite sequences as illustrated in Fig. 2.22 and typical of the shallower sedimentary formation sequences that can be encountered within the deepwater drilling processes and operations required.

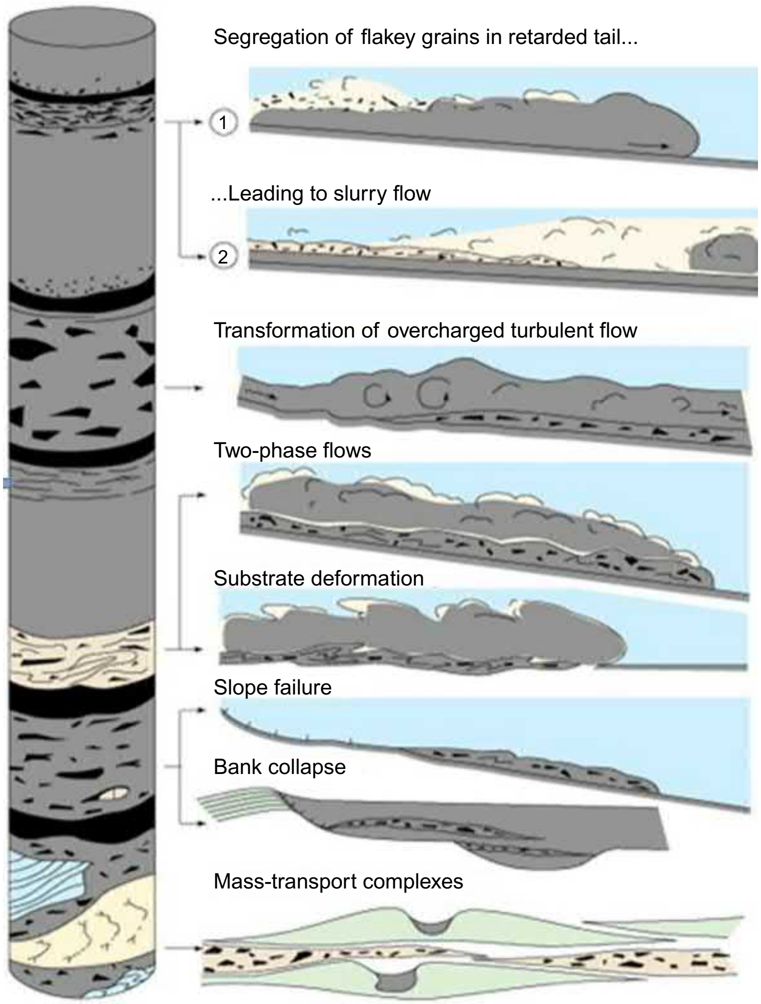


FIG. 2.22 Debrite flow sequences and key deepwater heterogeneities. *Source: Kingdom Drilling training 2002.*

TURBIDITY CURRENTS

TURBIDITY FLOW A turbidite is the geologic deposit of a turbidity current flow, which is a type of sediment gravity flow responsible for distributing vast amounts of clastic sediment into the deep ocean. Turbidites are deposited in the deep ocean troughs below the continental shelf, or similar structures in deep lakes, by underwater avalanches, which slide down the steep slopes of the continental shelf edge (Figs. 2.23 and 2.24).

When the material comes to rest in the ocean trough, it is the sand and other coarse material, which settles first followed by mud and eventually the very fine particulate matter. Grains are suspended by fluid turbulence within the flow.

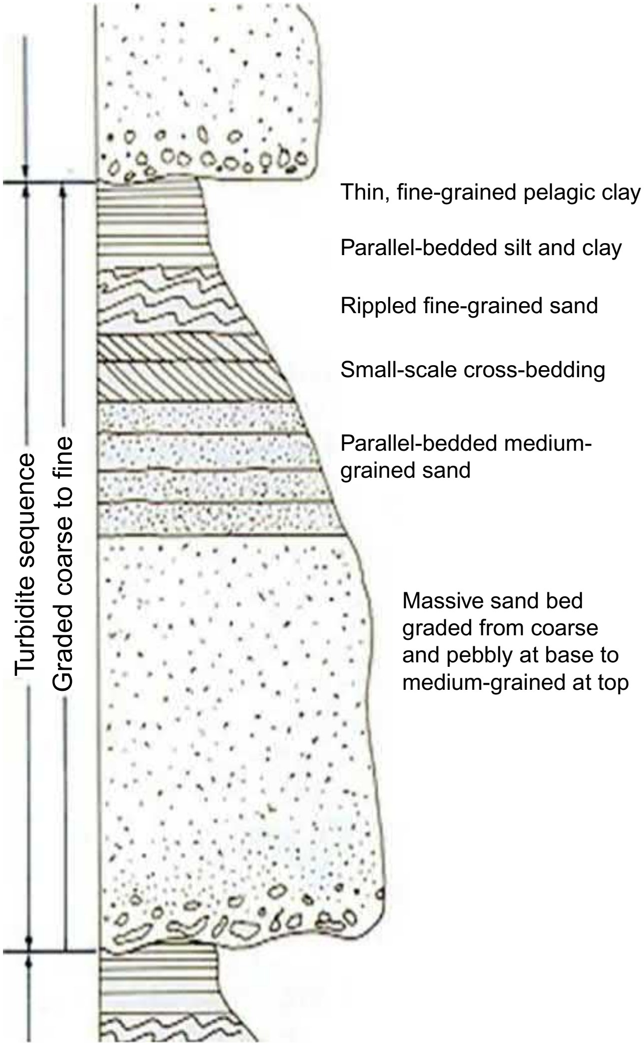


FIG. 2.23 Turbidity current sequence. *Source: Understanding Earth.*

Because the behavior of turbidity currents is largely predictable, they exhibit Newtonian behavior, in contrast to flows with cohesive strength, i.e., mud flows and debris flows. The behavior of turbidity currents in subaqueous settings is strongly influenced by the concentration of the flow, as closely packed grains in high-concentration flows are more likely to undergo grain-to-grain collisions and generate dispersive pressures as a contributing sediment support mechanism, thereby keeping additional grains in suspension.

The results of turbidity currents, as illustrated in Figs. 2.23 and 2.24, represent a significantly different form of mass-gravity flow. Suspended sediment provides the density contrast

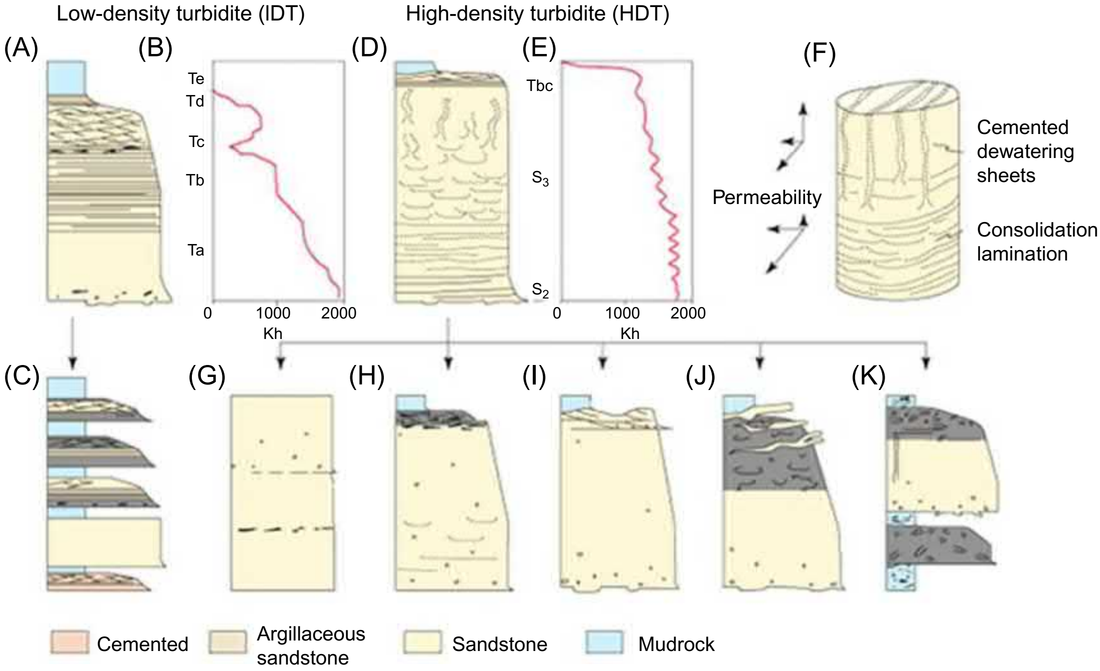


FIG. 2.24 Features and examples of deepwater low-density and high-density turbidites. *Source: Kingdom Drilling training 2002.*

with the ambient water in these turbulent currents and gives rise to the gravitational energy that drives the flows. These flows erode on the steep upper slopes and form deposits further downslope.

The density of turbidity currents is in the order of 2%–4% percent greater than that of the surrounding ambient water. These flows could travel as fast as 22 m/s (79 km/h, 49 mph) but more recent measurements indicate speeds ranging between 10 m/s (36 km/h, 22 mph) to a fraction of 1 m/s (<3.6 km/h, <2.2mph).

In addition, ocean bottom currents produced through thermocline density difference can transport and rework sediments. Apart from these resedimentation processes, deeper water environments are sites of pelagic and hemipelagic deposition.

Turbidity currents are an important feature of the deepwater sedimentary gravity flows as they deposit sediments with a characteristic internal structure that typically will change along the transportation path.

HIGH-DENSITY TURBIDITY High-density turbidity current deposits are characterized by much coarser grain size than in low-density turbidites, with the basal portions of the deposits often characterized by features that result from the close proximity of the grains to each other. Thus, indications of grain-to-grain interactions, i.e., grain flow processes and interaction of grains with the substratum, are generally present in the lower portions of these deposits.

High-density turbidity currents are capable to carry gravel and coarse sands, mostly in the form of a traction carpet at the base of the flow and in suspension just above. Fluid turbulence, dispersive pressure from grain collisions, and finer sediment exerting a matrix buoyancy life, keep the gravel and sand moving until the flow decelerates through increasing slope or dilution.

LOW-DENSITY TURBIDITY Low-density turbidity current deposits (turbidites) are characterized by a succession of sedimentary structures, which result from decreasing energy within the flow, i.e., waning flow, as the turbidity current moves downslope. Low-density turbidity currents transport sediment up to medium sands, kept in suspension by the fluid turbulence.

As the flow decelerates, sediment is moved as bed load in a traction carpet. The deposits of these currents are commonly classic turbidites.

Significance of Turbidity Current and Systems in Oil and Gas

The oil and gas industry is further interested in turbidity currents because it is often these currents that have deposited organic matter that over geologic time gets buried, compressed, and transformed into hydrocarbons. The use of numerical modeling and flumes is therefore commonly used to help understand these questions. Much of the modeling used then to reproduce the physical processes, which govern turbidity current behavior and deposits.

In summary, sediment gravity flows, i.e., *primarily turbidity currents, but to a lesser extent debris flows and mud flows,* are understood to be the primary processes responsible for depositing sand, silt, and mud (clay) onto the deep ocean floors. This is due to the understanding that anoxic conditions at depth in the deep oceans are conducive to the preservation of organic matter, which, with deep burial and subsequent maturation through the absorption of heat, can then generate oil and gas. The deposition of sand in particular deep ocean settings ultimately juxtaposes petroleum reservoirs and source rocks. In fact, a significant portion of the oil and gas produced in the world today is found in deposits (reservoirs) originating from sediment gravity flow.

Resulting Deepwater Sedimentary Environment

On a gross scale, the overriding factors of deepwater sediment and environment formation are built on several unique sets of operating environments and conditions that exist over variant periods of geological time, i.e.:

1. The depositional processes and changes that resulted through the earth's geological history.
2. The depositional environments that existed during these geologic times.
3. Tectonic content or lack of this in each period.
4. Climate that existed with each period of geological time.
5. Other conditions as presented.

In terms of deepwater geological- and regional-specific factors, all these features cumulatively combine to form unique deepwater well's depositional environments that in turn contribute significantly to the formation characterizations that result and exist. That are then foremost predicted via seismic interpretive techniques, from where best prospects, safe and suitable deepwater locations are selected to be drilled.

Fig. 2.25 illustrates a generic ultradeepwater well example located in 2430 m (7972 ft) water depth with a required target depth of 7125 m (23,380 ft) to present 4695 m (15,400 ft) of variant deposited sediments required to be drilled.

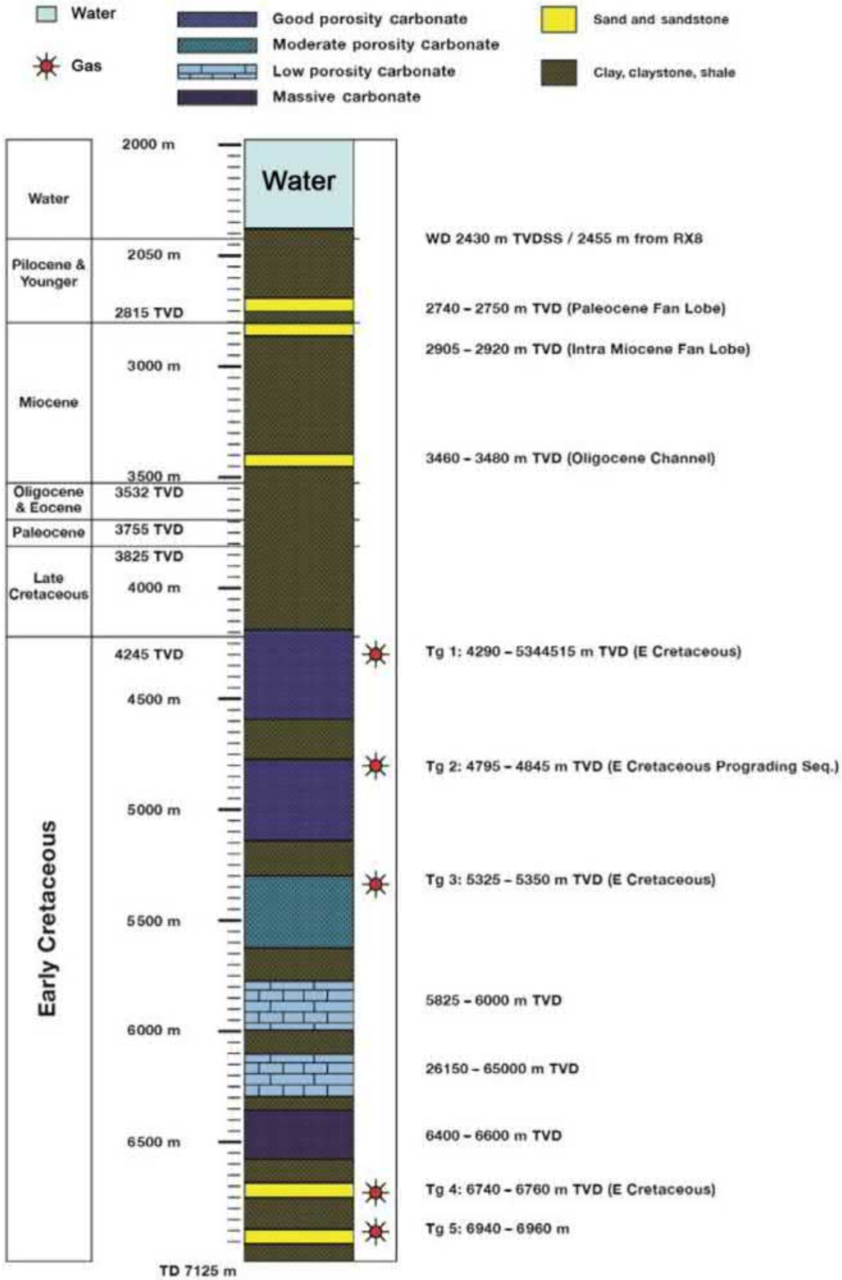


FIG. 2.25 Ultra deepwater well in 2430-m water depth that illustrated typical geological stratigraphic setting, sedimentary features, and depositional environments. *Source: Kingdom Drilling 2009.*

This deepwater example was to determine hydrocarbon potential in a fault closed, continental shelf system that exhibited prograding features in the early cretaceous marine environments where high-amplitude seismic predicted both stratigraphic fan and channel featured complexes within the tertiary and deeper early cretaceous (sand) interval sections as illustrated in Fig. 2.25.

DEEPWATER GEOLOGICAL CHARACTERISTICS/ ENVIRONMENTS

General Sedimentary Formation Characteristics

Building on the principles of how deepwater sediments are formed in both shallow and deep marine environments, this section develops concepts to understand key sedimentary formation characteristics to comprehend in regards to operating deepwater wells.

This first primer is related to the compaction features of sedimentary sequences and rocks, that are composed entirely of *four fixed simple compositional minerals and a fifth element* that combined constitute >90% of all buried rocks sequences.

1. *Quartz* (sand),
2. *Calcite* (carbonates, calcium carbonate $CaCo_3$),
3. *Anhydrite* (anhydrous calcium sulfate, $CaSO_4$),
4. *Halite* (rock salt)
5. *Clay* mineral (this is by far the most common deposited).

Mineralogy presents further composition controls over the sedimentary grain-matrix-compaction of these five minerals throughout their burial history. After accounting for force balance, only two mineralogic coefficients are generally used to relate effective stress to grain framework strain within rocks. These are *intrinsic sediment grain* and *rock properties*.

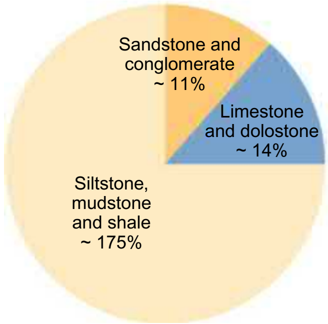
Rock's final compaction resistance is primarily controlled by the rock's average mineralogic hardness. The effective stress compaction component is then related to mineral hardness and clay mineral interparticle repulsive force.

Average effective stress is borne by mineral ionic bonds and interparticle repulsion between the *clay mineral particles*. In opposition, *quartz, calcite, anhydrite, and halite* have negligible cation exchange capacities. These minerals resist compaction only with their internal crystalline bonds that can range from very high to very low.

When these minerals are mixed with sedimentary clay, the compaction resistance of the composite is the volume weighted average of its mineralogic constituents.

Composition of Offshore Marine Sediments

Typical composition of offshore marine sediments illustrated in Fig. 2.26 cannot be considered to be always the case and shall vary greatly for the region and subsurface conditions to be drilled. As a general rule of thumb expect to be drilling more clay/shale than anything else, supported by variant intervals of sands/conglomerates, carbonates, and dolostone.



Rock	Abv	Code	Grain size	Description
Claystone & Shale	Clst Sh		Less than 4 μm	Rocks formed from an accumulation of clay and silt particles
Marl	Mrl		Less than 4 μm	Rocks formed from an accumulation of clay minerals and calcite
Siltstone	Slst		4 to 60 μm	Rocks formed from an accumulation of mineral grains (quartz)
Sandstone	Sst		60 μm to 2 mm	Sandstone compressive strength, +/– 9000 psi

FIG. 2.26 Typical composition of offshore marine sediments. *Source: Kingdom Drilling 2018.*

Grain size descriptions of the most common sedimentary rocks are listed in Figs. 2.26 and 2.27.

From the seabed to subsurface below, in simple terms, the stratigraphic sedimentary sequences to be drilled are composed of *Sands, Silts, Clay, and Mudstones as illustrated in* Fig. 2.27. These sediments are deposited through suspension via *Turbidity currents and Debrite flow*s as previously described to form massive, laminated, and often very complex,

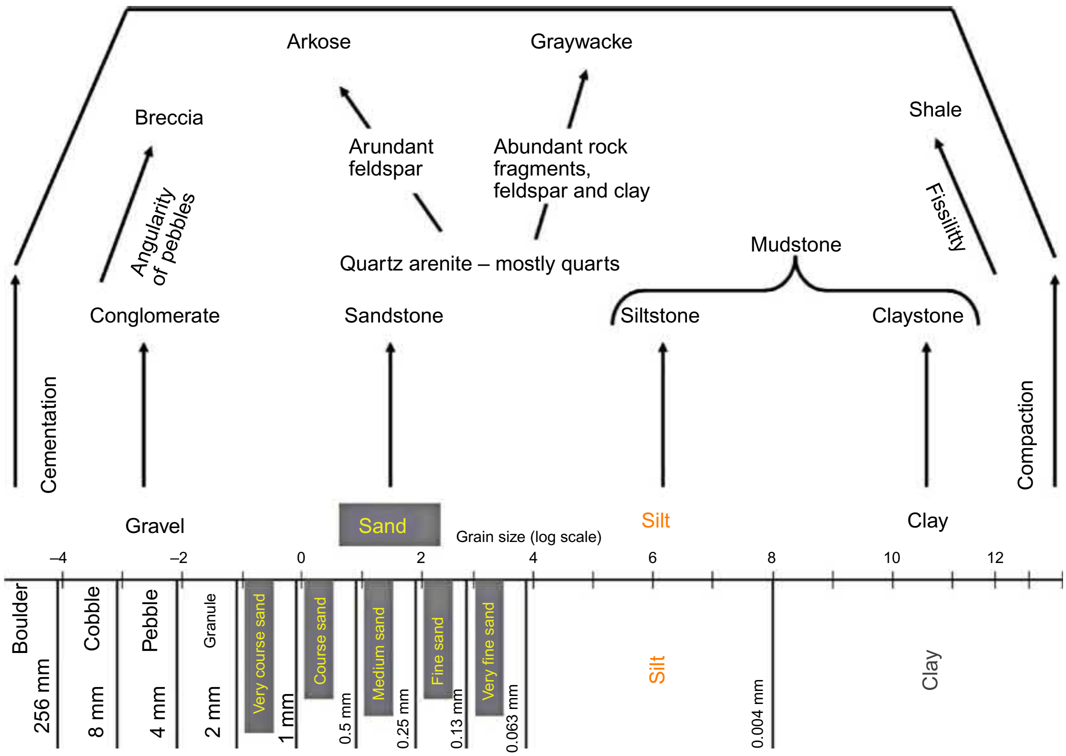


FIG. 2.27 Sedimentary grain size compaction and cementation chart. *Source: Kingdom Drilling training 2006.*

changing, and variant graded interbedded sequences. Complex sequences that exist can make optimal deepwater drilling bit BHA and drilling systems selection in such circumstances somewhat of a challenge.

With burial and compaction, below the seafloor shallow eventually becomes deep in depth terms with further lithification, pressure and temperature transform the minerals through diagenesis to result in sandstone, siltstone, mudstone, conglomerates, and breccia, arkose, graywacke, and shale, as shown in Fig. 2.27 and Table 2.8.

Deepwater Mineral Descriptions of Importance

CONGLOMERATES

Conglomerates are clastic sedimentary rock that contains mostly pebble-size rounded clasts. The spaces between the clasts are generally filled with smaller particles and/or chemical cement that then binds and formed the rock matrices together.

CLAYSTONE

A claystone is lithified and nonfissile mudrock. In order to be considered a claystone, it must consist of up to 50% clay, which measures <1/256 of a millimeter in particle size. Clay minerals are integral to mudrocks, and represent the first or second most abundant constituent by volume, as there are 35 recognized clay mineral species on earth. Clay by far is the smallest of particles recognized. Most materials in nature are clay minerals, but quartz, feldspar, iron oxides, and carbonates can weather to sizes of a typical clay mineral. On size

TABLE 2.8 Claystone and Shale Classification

Shale Type	Typical Wellbore Problems	MBT[a]	Water Content (wt%)	Clay Types	Wt%	Density (g/cc)
Soft	Tight hole due to swelling. Hole enlargement due to wash out (dispersion). Ledges if interbedded with sandstone. Bit balling, mud rings.	20–40	25%–70%	Smectite Illite	20%–30%	1.2–1.5
Firm	Tight hole due to swelling. Possible wash out (poor mud inhibition). Particularly prone to bit balling. Occasional cavings.	10–20	15%–25%	Illite mixed layer	20%–30%	1.5–2.2
Hard	Cavings. Cuttings beds leading to pack off. Drag and tight hole in stressed formations.	3–10	5%–15%	Illite possibly Smectite	20%–30%	2.0–2.3
Brittle	Cavings leading to hole collapse. Time delayed failure	0–3	2%–5%	Illite kaolinite Chlorite	5%–30%	2.1–2.5

[a]**MPT** = *methylene blue test; a measure of cation exchange capacity; high MBT equates to smectite-rich scale (meg/100 g).*
Source: Kingdom Drilling training 2004.

comparison, a clay-sized particle is 1/1000 the size of a sand grain. This means a clay particle will travel 1000 times further at constant water velocity, thus requiring quieter conditions for settlement. The formation of clay is well understood, and can come from soil, volcanic ash, and glaciation. Ancient mudrocks are another source, because they weather and disintegrate easily.

MUDSTONE

Mudstone is a siliciclastic sedimentary rock containing a mixture of silt and clay-sized particles (at least one-third of each).

SILTSTONE

A siltstone is a lithified, nonfissile mudrock. In order for a rock to be named a siltstone, it must contain over 50% silt-sized material. Silt is any particle smaller than sand, 1/16 of a millimeter, and larger than clay, 1/256 of millimeter. Silt is believed to be the product of physical weathering, which can involve freezing and thawing, thermal expansion, and release of pressure. Physical weathering does not involve any chemical changes in the rock, and it may be best summarized as the physical breaking apart of a rock. Silt tends to be noncohesive, nonplastic, but can liquefy easily. A simple test to determine whether a rock is a siltstone is to put the rock to one's teeth. If the rock feels "gritty" against one's teeth, then it is a siltstone.

SANDSTONE

Sandstone is a clastic sedimentary rock composed mainly of sand-sized (0.0625–2 mm) mineral particles or rock fragments. Most sandstone is composed of quartz or feldspar because they are the most resistant minerals to weathering processes at the earth's surface. Sandstone may be any color due to impurities within the minerals, with the most common colors being tan, brown, yellow, red, grey, pink, white, and black. Rock formations that are primarily composed of sandstone are commonly porous and permeable to allow them to be the vehicle to store large quantities of fluid volumes, making them valuable petroleum or storage reservoirs.

Sandstones are clastic in origin as opposed to being either organic or chemical. They formed from cemented grains that may either be fragments of a pre-existing rock or be mono-nomineral crystals. The cements binding these grains together are typically calcite, clays, and silica. Grain sizes in sands are defined (in geology) within the range of 0.0625 mm to 2 mm (0.002–0.079 in.).

The formation of sandstone involves two principal stages:

1. A layer or layers of sand accumulates as the result of sedimentation, either from water (as in a stream, lake, or sea) or from air (as in a desert). Typically, sedimentation occurs by the sand settling out from suspension, i.e., ceasing to be rolled or bounced along the bottom of a body of water or ground surface.
2. Once accumulated, sand becomes sandstone through compaction of the overlying deposits and/or cemented through precipitation of minerals within the pore spaces between the sand grains. The most common cementing materials are silica and calcium carbonate, which are often derived either from dissolution or from alteration of the sand after it was buried.

SHALE

Shale as classified in Table 2.8 is a fine-grained, hard, laminated low-permeable mudrock, consisting of clay minerals, and quartz and feldspar silt. Shale is lithified and fissile. It must have at least 50% of its particles measure <0.062 mm. This term is confined to argillaceous, or clay-bearing, rock. There are many varieties of shale, including calcareous (chalky) and organic rich; however, black shale, or organic-rich shale, that deserve further evaluation. In order for shale to be classed as black shale, it must contain >1% organic carbon. A good source rock for hydrocarbons can contain up to 20% organic carbon. Generally, black shale receives its influx of carbon from algae, which decays and forms ooze. When this ooze is cooked at desired pressure, 1.8–3.7 miles (2.9–6.0 km) depth, and temperature, 90–120°C (194–248°F), it will form kerogen. Kerogen then will yield up to 10–150 US gallons (0.038–0.568 m^3) of product per ton of rock and is one of the processes of how oil and gas is formed.

CARBONATES

Sedimentary rocks consisting mostly of calcium carbonate, limestone, and dolomite. Limestone, dolostone, and chalk are all carbonate rocks. Carbonates can be clastic but are more frequently formed by precipitation and/or chemical cementation that binds the rocks constituents together.

LIMESTONE

The final sedimentary mineral of importance is limestone, which presents a very specific place in deepwater drilling, geology, and geoscience.

In summary, about 10% of all sediments are limestones. Limestone is a sedimentary rock, composed mainly of skeletal fragments of marine organisms such as coral, forams, and mollusks. Its major materials are the minerals calcite and aragonite, which are different crystal forms of calcium carbonate ($CaCO_3$). The solubility of limestone in water and weak acid solutions leads to karst landscapes, in which water erodes the limestone over thousands to millions of years.

Most cave and vugular systems experienced while drilling in certain regions and environments are through limestone bedrock.

SUMMARY: DEEPWATER SEDIMENTS AND DRILLING ENVIRONMENTS

Table 2.9 summarizes typical deepwater sediments, rocks, and how these have likely accumulated within deepwater environments to be drilled.

All other factors being equal,

1. sandstone is classed as medium strength,
2. shale high and
3. limestone very high.

Note: Sandstone exhibits the lowest compressive and tensile rock strength.

These key aspects within deepwater drilling environments need to be fully understood in order to comprehend, determine, and evaluate further in situ stresses, pressure management, rock and wellbore stability, geomechanics and geotechnical aspects of the formations.

TABLE 2.9 Sediment, Rocks, and Accumulating Environments

Sediments	Sedimentary Rocks	Where/How Marine Sediments Accumulate
Gravel, Pebbles Boulders	Conglomerates	Alluvial fans, river channels, wave swept, glaciated coastlines
Sand	Sandstone	River channels, beach, shore lines, deltas, shallow seas, storms, turbidites (*submarine channels and fans*)
Mud	Mud rock, Shale	Lakes, river flood plains, tidal flats, distal deltas, debrite flow, deep sea
Shells/lime mud	Limestone	Warm Shallow seas
Ca Co_3 produced by marine plankton	Chalk	Deep sea
SiO_2 produced by marine plankton	Chert	Deep sea
Salt	Rock Salt	

Source: Kingdom Drilling 2006.

Influencing Characteristic of Drilling Deepwater Sediments

Formations in deepwater open water environments shall as a function of shallow to deeper wellbore depths, exhibit higher porosity, lower compressive strengths, and higher permeability values as shown in Fig. 2.28. *Each of such physical changes can thus impact drilling practices*, e.g., *lower rock strength impacts the rate of higher penetration and dilation properties of sands, slits, and clay. This, in turn, can impacts torque and drag in nonvertical wells. Also because clay contains higher water content, problems can result*, e.g., *increased balling up of bottom-hole assemblies*, etc. Just as important, dealing with hydrostatic and formation pressure relationships is a key subject area.

Influencing characteristics in regards to the drilling of deepwater sedimentary environments covered in the remainder of this section are:

1. Porosity and permeability (Figs. 2.28 and 2.29),
2. Rock mechanics in situ stresses of the formation(s) and what can externally affect this (Figs. 2.30 and 2.31),
3. Pressure management (covered in more specific detail throughout this guide)

The primary process after the depositional sequence is burial and compaction. This is of particular importance in regards to deepwater mud (clay) sequences, as compaction will expel the fluid content (water) from the rock clasts, thereby quickly reducing the thickness of the sediment clasts as a function of depth by a factor up to ten.

When initially deposited, mud (clay) bound sequences rocks can contain up to 70%–80% water by volume at the seabed, overburden normal trend compaction reducing porosity to approximately 13% at a burial depth of 1000 m (3280 ft) below the seabed.

Quartz sand however is different as revealed in Fig. 2.28 due to inherent larger particle size and stronger rock features. Sand porosity reduces far less, i.e., from 40% on the seabed to 31% 6000 ft. (1829 m) below the seabed.

Note: Water contained within the voids of all deepwater sedimentary clasts deposited is not free pore water but is contained within the lattice of the clay minerals and absorbed by

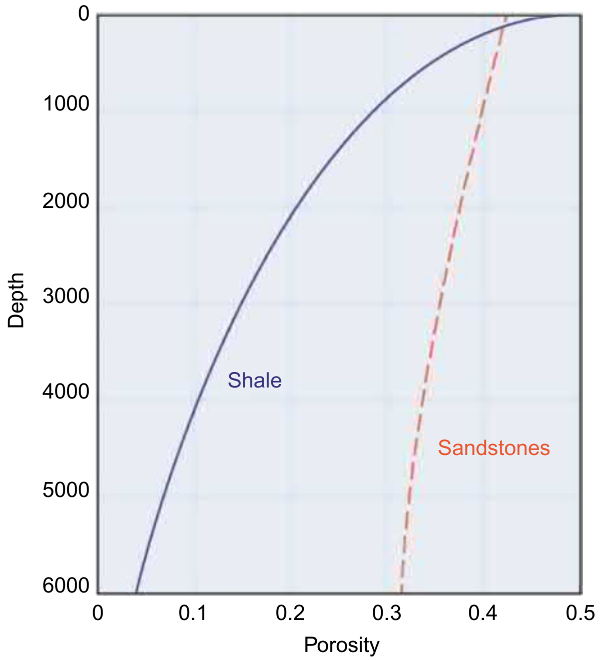


FIG. 2.28 Normal compaction curve. *Source: Kingdom Drilling 2018.*

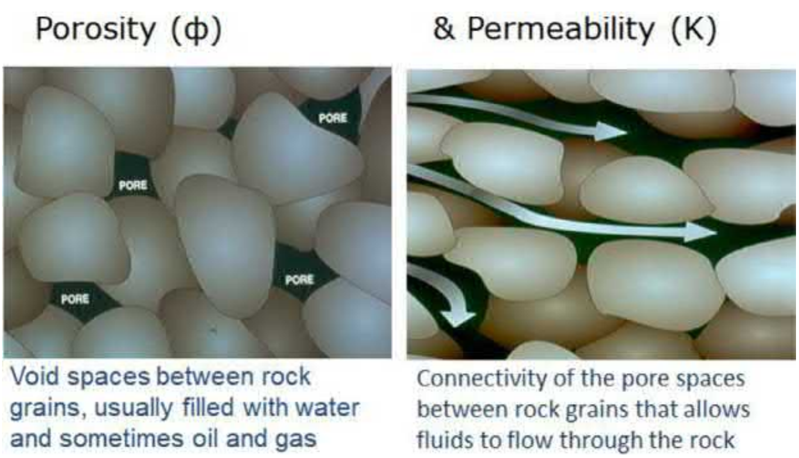


FIG. 2.29 Definitions of porosity and permeability. *Source: Kingdom Drilling training 2006.*

the clays or within the sand voids. As water depth increases the overburden of the water results in more water retained in the lattice of the clay minerals or absorbed by the clays than at the shallow depths. For example, a 50-m (164 ft) clay mineral interval in deeper water will typically have far greater porosity and permeability than if deposited in shallower waters, as would most other minerals deposited. The key takeaway in deepwater drilling terms is

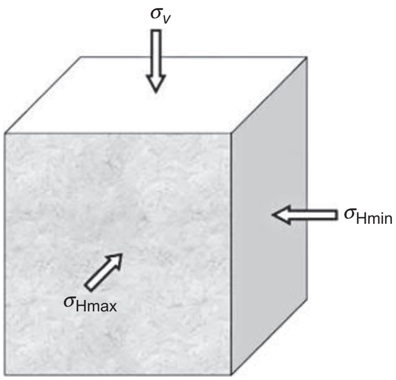


FIG. 2.30 Principle stress components. *Source: Kingdom Drilling*.

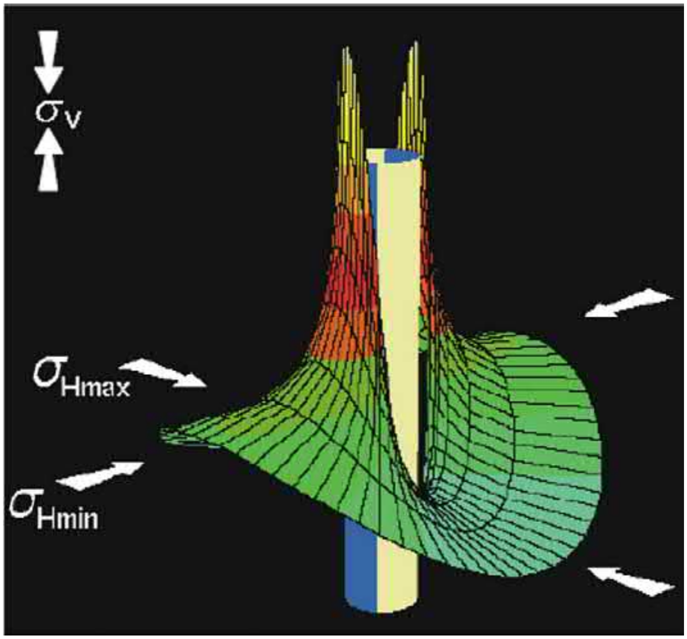


FIG. 2.31 Hoop stress distribution around a vertical wellbore. *Source: Geoscience UK, 2017.*

that these same shallow sedimentary sequences are inherently weak until sufficient depth, burial, and compaction results. As a general rule of thumb, the following applies to normal compaction:

1. *Overburden* depends upon porosity, and porosity depends on overburden stress.
2. Generally:
   a. *Claystone* is more compactible than sandstones.
   b. *Young claystone* is more compactible than older claystone or shales.
   c. *Limestones and dolomites* are slightly compactible.

POROSITY AND PERMEABILITY

To supplement and support the previous section, average porosity in offshore sediments decreases with compaction and increased overburden load as a function of depth (Fig. 2.28). Further depth results are increased bulk density and greater rock strengths.

Key points to note:

- Fluids can only be present and exist within the pore space that represents the porosity of the sedimentary and reservoir rocks.
- Movement of fluids from pore space, to the next pore space, is described by and addressed by the *Permeability* of the sediments.
- Sand with 150 psi (10 bar) overpressure and 500 m (1500 ft) burial depth below the seabed in a normal depositional compaction trend should have ±38 PU porosity units.
- Permeability can be modeled. In the case above for the same, permeability sand, using grain sizes varying from 100 to 250 μm with poor to moderate sorting:
  - The model would show that the permeability would range between 1 (with poor sorting) and 20 darcies (moderate sorting).

Rock Mechanics, Formation "In Situ Stress"

Rock Mechanics, General

Rock mechanics is the study of the mechanical behavior of subsurface sedimentary strata and rocks that are formed. The basic principle is that rock simply responds to ***stress*** by changing in volume or form. *The change in the rock volume or form due to the applied stress is called* ***strain.*** Rocks subjected to **compressive** *stress (+) or* **tensile** *stress (−)* can go through three stages of strain deformation.

1. In ***elastic deformation***, the rock deforms as stress is applied and returns to its original shape as stress is relieved. In elastic deformation, the strain is proportional to the stress (Hooke's Law).
2. When applied stress in a rock reaches the elastic limit, the rock begins to exhibit ***plastic deformation***. In plastic deformation, the rock partially returns to its original shape as stress is relieved.
3. If continued stress is applied, fractures develop and the rock fails (*ultimate failure stress*).
   a. Rocks can fail in a *brittle* manner, usually under *low confining* stress, or
   b. In a *ductile* manner under *higher confining* stress.

Under compression, rocks fail in shear, as it is easier to slide rock grains past each other than to crush them. High confining pressure resists sliding on the shear plane and the rock appears stronger. Furthermore, if the confining pressure and axial load were equal, there would be no shear stress on the rock and no shear failure. Some further key aspects of rock mechanics in relation to drilling are:

- *Equal stresses* promote wellbore *stability*.
- *Unequal stresses* promote *shear* stress and possible shear *failure*, i.e., wellbore *instability*.

In actual borehole conditions, pore pressure exerts a force that tends to push the rock grains apart. This is why effective stress is used in rock mechanics when applied to wellbore stability studies. Rock mechanics simply uses failure models to predict wellbore stability.

In Situ (Far-Field) Stress Overview Before Drilling

Before drilling, all subsurface rocks are exposed to a balanced or near balanced stressed environment. The naturally occurring stress in place is called the ***in situ*** *stress*, which is normally compressive due to the weight of the overburden. The in situ stress field is described by three orthogonal principal stresses, which are typically a *vertical stress* (σv) and a *maximum* (σ_{Hmax}) and *minimum* (σ_{Hmin}) *horizontal stress* (Fig. 2.30). It is customary to represent stress with the Greek lower case letter sigma (σ). The formation pressure or pore pressure within the rock pore spaces acts on the rock grains (rock matrix) to reduce the stress experienced by the rock as outlined in Equation 2.1:

EFFECTIVE STRESS EQUATION

$$\text{Effective stress} = \text{Total stress} - \text{Pore pressure} \tag{2.1}$$

The three principal stress magnitudes are rarely the same, differences in the magnitudes of these principal stresses give rise to an anisotropic stress field, which requires three-dimensional analysis to account for the wellbore and stress field orientations.

There are a number of combinations of these principal stresses that give rise to a number of stress regimes, the three main stress regimes encountered are:

1. *Normal*: $\sigma_{\mathrm{Hmin}} \leq \sigma_{\mathrm{Hmax}} < \sigma_{\mathrm{v}}$
2. *Strike Slip*: $\sigma_{\mathrm{Hmin}} < \sigma_{\mathrm{v}} \leq \sigma_{\mathrm{Hmax}}$
3. *Reverse*: $\sigma_v < \sigma_{\mathrm{Hmin}} \leq \sigma_{\mathrm{Hmax}}$

Particular stress regimes tend to be determined by regional tectonics; however, local variations can occur for example around salt diapirs. Each stress regime can give rise to a specific set of well operating problems, which are highlighted as appropriate during an assessment.

OVERBURDEN STRESS

Overburden stress (σ_v) is the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth.

- Density logs can be used to determine the overburden stress.
- If a density log is not available, overburden stress may also be estimated from alternatives methods that use variable density curves, time average equation, sonic travel time, bulk density and porosity.
- As the overburden squeezes the rock vertically, it pushes horizontally, but is constrained by the surrounding rock to create horizontal stresses.

MINIMUM AND MAXIMUM HORIZONTAL STRESS

In most drilling areas, and particularly in deepwater where no structural, deformation, or tectonic changes have resulted, the horizontal stresses are equal. When drilling near massive structures where structural deformation has resulted, such as salt domes or in tectonic areas, this will likely result in both minimum (σ_{Hmin}) and maximum horizontal stress (σ_{Hmax}).

- Minimum horizontal stresses can be determined and evaluated through conducting well integrity tests, e.g., *limit, leak off, or extended leak off tests.*
- Maximum horizontal stress can be estimated using rock mechanics equations because it is difficult to determine from field measurements.

EFFECTIVE STRESS

The rock matrix does not support the full overburden load, as part of the load is being supported by the fluid in the pore space, i.e., *pore pressure*. The overburden stress that effectively stresses the rock matrix is termed the *effective overburden stress* and is equal to the difference in total overburden stress and pore pressure. Effective stress is used in rock mechanics to determine the stability of the well bore.

EFFECTIVE HORIZONTAL STRESS

Effective horizontal stresses can be determined. Usually the horizontal stresses are equal, and the effective horizontal stress is equal to the effective overburden stress times a lithology factor, *k*.

- The lithology factor (*k*) is equal to one (= 1) for fluids but
- Less than one (<1) for more rigid material such as rock.

In Situ Stresses After Drilling

Once a deepwater wellbore section interval has been physically drilled, the support provided by the sedimentary strata for the first few to several thousand feet, and then the deeper buried rocks, is now removed and replaced by hydrostatic drilling fluid, geological, and operating applied pressures. These are pressures that change to alter the in situ stresses present. Stress at any point in or near the wellbore can be described in terms of:

1. *Radial stress* that acts along the radius of the wellbore,
2. *Hoop stress* that acts around the circumference of the wellbore (tangential), and
3. *Axial stress* that acts parallel to the well path.

These three stresses act perpendicular to each other and for mathematical convenience are used as a borehole coordinate system.

HOOP STRESS

Hoop stress as illustrated in Fig. 2.31 depends on:

1. Wellbore pressure,
2. In situ stress magnitude and orientation,
3. Pore pressure, and
4. Wellbore inclination and direction.

Note: Wellbore pressure is directly related to equivalent mud weights (EMW) that exist at any period of time that will change as operating activities and conditions change.

KEY POINTS TO HOOP STRESS

- For a vertical wellbore with equal horizontal stresses, hoop stress depends on the mud weight and the magnitude of the horizontal stresses and is equally distributed around the wellbore.
- A deviated well creates unequal distribution of hoop stress around the wellbore due to the redistribution of the horizontal and vertical stresses.
- Hoop stress acting on a cross-section of the wellbore is a maximum at the sides of the wellbore perpendicular to the maximum stress.
- The same is true when drilling a vertical well in an in situ environment of unequal horizontal stress.
- Hoop stress is a maximum at the side of the well bore perpendicular to the maximum horizontal stress.

AXIAL STRESS

Axial stress is oriented along the wellbore path and can be unequally distributed around the wellbore. Key points:

- Axial stress is dependent upon in situ stress magnitude and orientation, pore pressure, wellbore inclination and direction.
- Axial stress is not directly affected by mud weight.
- For a vertical well with equal horizontal stress, axial and vertical stresses are the same.
- Axial stress in a deviated well is the resolution of the overburden and horizontal stresses.

RADIAL STRESS

Radial stress is the difference in wellbore pressure and pore pressure and acts along the radius of the wellbore. Wellbore pressure and pore pressure both stem from fluid pressure acting equally in all directions. Therefore, in radial stress, pressure difference is acting perpendicular to the wellbore wall, along the wellbore radius.

Rock Mechanics and In Situ Stress Key Points

1. *Hoop stress*, *radial stress*, and *axial stress* describe the near wellbore stress state of the rock.
2. To maintain the mechanical stability of the wellbore, these stresses must be managed to prevent shear or tensile rock failure.
3. Generally, the stresses are *compressive*, and they create *shear* stress within the rock. The more equal these stresses, the more stable will be the rock.
4. Whenever hoop or radial stresses become *tensile* (negative):
   a. The rock is prone to fail in tension.
   b. Tensile failure of the hoop stress region should not result in a change in the far-field rock strength and therefore cannot lead to loss of circulation.
5. These types of failures result in excessive cuttings and associated problems. Mechanical stability is achieved by controlling the parameters that affect hoop stress, axial stress, and radial stress. These include:
   a. Equivalent mud weight (EMW) is condensed of three components, i.e., mud weight, ECD (equivalent circulating density), and +/− all other pressure operational effects.

  b. Pressure volume and temperature effects in very deep deepwater wells can become very important factors to additionally contend with.
  c. Mud filter cake
  d. Well path (inclination and azimuth)
  e. Practices applied, as these will change pressure and wellbore stress effects.

6. Uncontrollable parameters include:
  a. unfavorable in situ conditions,
  b. adverse formations,
  c. constrained wellbore trajectory,
  d. thermal effects as a well heats up or cools down before or after a period of drilling, circulating etc.

7. Mechanical stability of the well is also impacted by drilling fluid/formation interaction. Chemical instability eventually results in mechanical failure of the rock in shear or tension.

8. Equivalents mud weight, ECD, and all other pressure effects, e.g., pipe movement, cuttings loading, drillstring heave, pressure swab/surges on the wellbore resulting from drilling will directly affect hoop stress and radial stress. For example:
  a. An increase in mud weight decreases hoop stress and increases radial stress.
  b. Similarly, a decrease in mud weight increases hoop stress and decreases radial stress.
  c. The result on wellbore stability depends on the magnitude of the mud weight increase/decrease.

WELLBORE INCLINATION AND DIRECTION

9. The inclination and direction of the wellbore greatly impacts the stability of the well. Unequal distribution of hoop stress and axial stress around the circumference of the well tends to make the wellbore less stable.

HIGH BOTTOM-HOLE TEMPERATURE WELLS

High bottom-hole-temperature deepwater wells can further experience stability problems as hoop stress changes because of temperature differences between the mud and formation. If the mud is cooler than the formation, it reduces the hoop stress as the formation is cooled. This reduction in hoop stress can prevent shear failure and stabilize the hole, if the hoop stress were high due to low mud weight. On the other hand, if the mud weight is too high and near the fracture gradient, excessive cooling can lower the hoop stress and make it tensile. This could cause tensile failure or fracturing as it effectively lowers the fracture gradient. If the mud is hotter than the formation, exactly the opposite occurs as hoop stress is increased. This can promote instability and/or shear failure.

One needs to consider what happens during a typical round trip on a deepwater, deep high-temperature well. During the trip, formation temperature returns to its ambient value, which causes the hoop stress to increase. When back on bottom and circulation resumes, the cooler mud traveling down the drillstring reduces the temperature of the nearby formation, which causes hoop stress to decrease. As the hot bottoms up mud circulates past formations at shallower depths, hoop stress increases as the mud heats up the formations. These variations in hoop stress have the same effect as pressure surges associated with swabbing and surging and can cause both tensile and shear failure downhole.

Rock Mechanics Summary

The key takeaway is that, as narrow and constrained *operating margins are more common in deepwater wells*, far more operational safety and control has to be exercised by the project teams involved. The key factors presented can result in far more difficult and challenging operating conditions in specific deepwater wells.

WELLBORE STABILITY FAILURES

Wellbore stability failures and/or operationally related wellbore stability problems directly (Fig. 2.32) account for many unscheduled lost time rig events in deepwater that can be prevented through greater skills sets, knowledge, experience, teamwork, planning, organization, and controls.

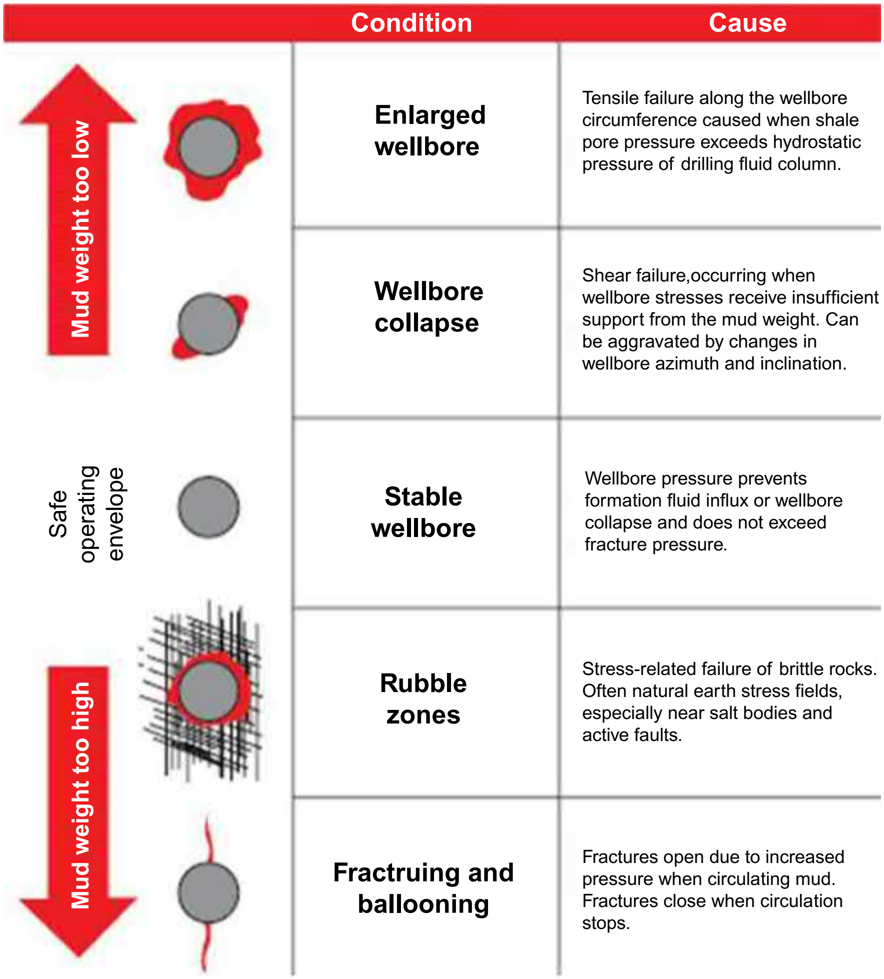


FIG. 2.32 Diagnosing wellbore failures chart. *Source: Kingdom Drilling training 2006.*

Wellbore stability problems can affect deepwater operating efficiency as when wellbore quality deteriorates significant loss time events can then result.

Note: Severe wellbore deformation in deepwater wells can often result when extreme in situ stress environments, such as geopressured, mobile, reactive formations are penetrated, manifested, or created.

Wellbore failures *do not just simple happen but are caused*, and can be measured, diagnosed, predicted, monitored, controlled, and prevented.

Features of Drilling Deepwater "Shallow" Sediments

General

Features of drilling deepwater shallow sediments are discussed in this section. Once the subsea BOP is installed and mud is introduced into the drilling process, formation, fluid, and drilling operational characteristics interactions and features shall evidently change.

FORMATION AND FILTRATE INVASION

In terms of drilling deepwater shallow sediments under ideal conditions, the pressure exerted by the column of drilling fluids used results in fluids (solids and fluid) and as drilled sedimentary particles invading into the porous, permeable formations, as illustrated in Figs. 2.33–2.35.

Note: 32 ft (10 m) of a 36″-inch wellbore of 40% porosity, equates to +/− 15,000 lbf (6804 kg) of drilled sediments to be removed from the as drilled wellbore annulus.

Through the drilling process what in fact results is that the formation *pores act as a filter, separating the drilling fluids from their liquid and solid constituents*. The heavier drilling fluid flows into the formation, while the solids (mud products and solids as drilled) form a deposit around the borehole after it is drilled, accumulating to create a *mud cake* on the wellbore wall

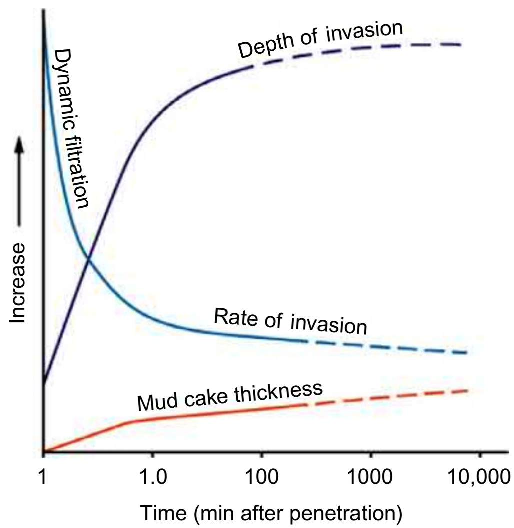


FIG. 2.33 Filtration/solids invasion. *Source: Kingdom Drilling 1998.*

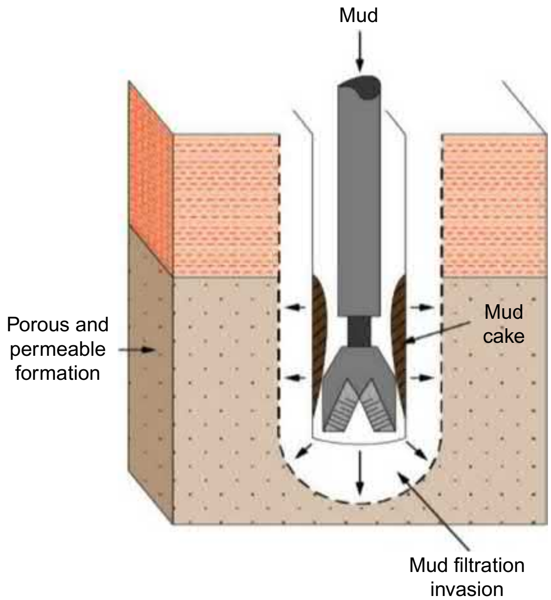


FIG. 2.34 Fluid invasion effects. *Source: Kingdom Drilling 1998.*

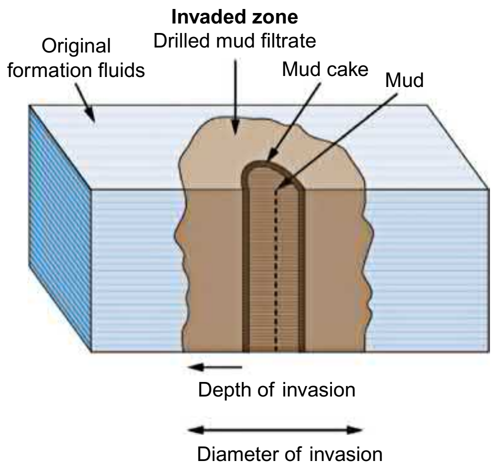


FIG. 2.35 Depth of invasion. *Source: Kingdom Drilling.*

to a point where a (*filter cake*) skin is formed over the interval drilled. Note: A fundamental and very important wellbore quality aspect for all to take note of and fully appreciate.

As the bit enters new formation, complete disequilibrium results and this dynamic filtration process will repeat itself (Figs. 2.34 and 2.35 illustrates fluid invasion effects). Below and around the bit, a continuous flow of filtrate into the formation results, depending on pressures and the nature of formation characteristics present.

As porosity and permeability exists, in clay, silts, and sands until much deeper in these wells, and as the mud cake builds up and forms, an impermeable (filter-cake) barrier is created and filtration ceases.

This represents a vital agent in regards to wellbore stability preservation, a subject frequently discussed in this guide.

Invasion

The replacement of the original formation fluids by the drilling fluid filtrate is called invasion. Invasion is vital to understand as it affects all porous and permeable formations in the immediate vicinity of deepwater wellbores, notably, all formations drilled in the shallow sections as they exhibit these features. Invasion is described by the depth or diameter of invasion, i.e., *the distance reached by the invading filtrate with respect to the borehole*, reference Fig. 2.35.

The Importance of Filter Cake

Filter cake plays an important and essential role in stabilizing porous permeable formations. The ideal (thin, tough, impermeable and flexible) filter cake can isolate the wellbore fluids from the pore fluids at the wellbore wall. This is important in terms of wellbore stability and to prevent differential sticking. If there is poor or no filter cake, the pore pressure near the wellbore increases to the hydrostatic pressure and the effective radial stress is zero. The simultaneous decrease in effective hoop stress reduces the stability of the formation and causes the stress state to move left in the stability envelope. In simple terms, the ideal filter cake provides a more stable wellbore. The chemical composition of the mud and the formation permeability control the filter cake quality and the time taken to form.

Elastic Limit and Formation Strength

The elastic limit and strength of sedimentary formation(s) sequences affect the rate of penetration (ROP) and drilling performance/loss that ultimately results. Each deepwater formation therefore has a threshold force that requires an initial bit weight to be applied to initiate drilling. The fact that deepwater shallow formations can be normally pressurized for a long depth interval permits drilling fluid filtrate *(clay)* to readily penetrate into the rock ahead of the bit equalizing pressure. This makes the sedimentary formation in the initial stage of a deepwater easier to drill. *High drillability is thus possible under normal conditions in deepwater*. Some formation characteristics on the other hand inhibit performance (sand, interbedded variability, thin stringers), where controls must be initiated during drilling to prevent wellbore failure, difficulties, or operational loss from resulting. Following are examples.

SOFT STICKY CLAYS

Soft sticky clay can exist within specific clay mineralogy and can directly cause the bit, stabilizers, and BHA components to *become plugged form mud rings, and "ball-up" with clay particles.* This can result in reduced drilling efficiency leading to drilling, connection, tripping, and more significant operating problems, such as pack-off, wellbore collapse, and stuck pipe. The importance of maintaining the bit cutters and BHA components free and clean through applying properly afforded bit/bottom hole cleaning hydraulics in the presence of specific clay formations is a fundamental aspect to be appreciated.

BOULDERS/COBBLE BEDS

If in the shallower sedimentary formation and environments, glacial drift or debris, i.e., rocks ranging from boulder size to cobble bed intervals, exist. An example of this often exists at the bottom of a sand in a turbidite sequence. Deepwater shallow section intervals have been shown to range from meters to tens of meters thick in top or surface-hole sections, resulting in drilling difficulties, instantaneous shallow microdoglegs, wellhead setting angle difficulties, ledges, difficulty running tubulars, well instability, and on occasion stuck pipe situations. *Note: if such an interval becomes unstable and/or wellbore is enlarged, softer over and underlying formations can also then become unstable, collapse, and cause well to even crater to result in a redrill.*

UNCONSOLIDATED FORMATIONS (SANDS)

Porous permeable sands are commonly encountered in top and surface wellbores to present further unique hazards, such as shallow gas, nonconsolidation, and shallow water flows, in certain deepwater regimes and environments Once unstable, these sequences can mechanically "flow" into the wellbore. Once breakdown is initiated, sands may continue to flow and collapse into the wellbore. Stabilization of the wellbore can then become time consuming, where often the original in situ stress cannot be regained, which can then result in a stuck drillstring or at worst a requirement to respud the well.

STRINGERS

Thin harder stringers can create more consistent and repetitive problems and difficulties during drilling and tripping if best practices are not applied. In one exploration deepwater campaign, this was perhaps the most common vertical wellbore drilling hazard to result in terms of consequential operating risk and lost times that resulted. E.g., *Drilling vibrational problems, wellbore deterioration, connections, tripping, inability to run logs (hanging up on doglegs created) difficulties,* all resulting from direct cause and effect form stringers not being drilling using best practice. Resulting in costly delays and wiper trips often required. Best practices rule simply to do whatever is needed to drill the stringers to assure no compromise to the prefect cylinder and wellbore quality results. One occasion where taking time will ultimately save overall operating time and reduce loss and costs considerably.

Deepwater Reservoir & Source Rocks

More Deepwater Oil

Studies conducted on producing continental shelves extending into deepwater environments confirm an evident tendency toward heavier hydrocarbons in deepwater fields with the potential for significant differences in hydrocarbon generation/expulsion or in the modification of entrapped hydrocarbons after expulsion in petroleum systems in the two environments. These studies represent petroconsultant data gathered from shelf and deepwater drilling since 1945, exclusive of North America.

The statistics produced suggested that if the deepwater and shelves are compared, the following tendencies apply in deepwater: Exploration is more risky, the largest fields are smaller and hydrocarbons are heavier. Based on certain aspects of the petroleum system, such as reservoir sedimentology and constraints on hydrocarbon generation, expulsion, and migration, possible explanations for differences can be proposed.

Reservoir Sedimentology

It was further stated from the data gathered that many reservoirs in present-day deepwater were deposited in environments other than that in which they are now found, e.g., cases of shallow water carbonates or deltaic deposits. In contrast, some reservoirs deposited in deepwater still find themselves there today. For example, deepwater sands form some of the very best, and many of the worst, hydrocarbon reservoirs on earth, demonstrating their variability. This section touches on the sedimentation processes in deepwater and favored situations where good reservoirs can be expected and governed through what are viewed as three main processes:

1. *Resedimentation* by mass flows (turbidity currents) along the continental margins.
2. *Settling* of fine particles.
3. *Reworking* by permanent currents.

First, sedimentation by mass flows (turbidity currents) exists along continental margins, to deposit sand into deep basins. The second process considered as background sedimentation only deposits very fine-grained clastic material, i.e., clay particles or shells from living organisms (mostly calcareous plankton). Permanent ocean currents that traverse the oceans then redistribute sand, but are not able to bring new sediments into the system. Reservoirs in deepwater can therefore only likely to be generated by turbidity currents as discussed in these sections.

RESERVOIR-MAKING PROCESSES

Turbidite reservoirs are often deposited from mixed sand-mud flows, and comprise a bottom sand-rich part and a mud layer at the top. Turbidites are more likely to result in mud-based layer cakes rather that perfect reservoirs. However, some of the very best reservoirs have been deposited from turbidity currents in deepwater. The conditions to produce the "perfect" reservoir are therefore built by turbidity currents.

Three mechanisms to developing reservoirs from turbidites are *amalgamation, sieving, and selective sand sourcing*.

Amalgamation: This is where the energy of an incoming turbidity current is sufficient to erode the mudstone top of the previously deposited turbidite, likely in proximal settings, i.e., within channels where the turbulence is very high, or at the outlet of the channels, not in the distal pans of the system.

Sieving: Sieving or selective trapping of the sand fraction occurs in specific settings where sand has been deposited, while the mudstone upper part of the current can overflow to the deep basin. A somewhat similar process is obtained where turbidites are deposited in deep areas swept by bottom currents. Bottom currents typically flow along the base of slope or perpendicular to the incoming turbidity currents, which flow down slope. The permanent current can then winnow the shale out of the incoming flow, thus producing good reservoirs. In addition to that, bottom currents can locally prevent deposition, ensuring that the reservoir is not connected with sand upslope.

Selective sourcing: The most likely process results in massive redepositing of sand only bodies in deepwater basins. This is favorable wherever there is a sorting agent between the primary delivery of sand to the basin (river) and the feeder (canyon/channel) of the system. Specific climatic conditions and localized geology can also result in an exclusive supply of sand to the river, which gives the same type of sand bodies.

RESERVOIR TRAPPING

One problem with turbidite reservoirs is their ineffectiveness, e.g., the sandy part of turbidites deposited by mixed flows dies out progressively, leaving a high clay content. The distal part of the turbidite system can then be a waste zone rather than a reservoir or seal. By contrast, lateral on-lap onto a margin of a basin can provide a good stratigraphic trap with a weakness, i.e., the entry point to the system (the feeder channel). These regions then often are infilled in the later stages of the system by turbidites, which can make a drain toward the shelf.

RESERVOIR GEOMETRY

A characteristic feature of all outcropping turbidites is their flat geometry, such as outcropping turbidites deposited either as sheet-like sands, continuous over tens of kilometers, or infill pre-existing topographies. In both cases, the tops of the sand bodies lie flat and paleohorizontal. Most turbidites at the outcrop represent the infill of former foredeep basins by mixed sand and shale flows. On the other hand, the mounded sand-rich turbidites are usually observed in subsurface in cratonic basins and are made of a stacking of sand flows rather than mixed flows.

Mudstone mounds are also common, in particular on continental slopes where huge collapses of mud material result in thick-mounded sedimentary bodies, which do not contain any sand. At present, there is no unequivocal way to distinguish between sandy and mudstone features from their geometry only.

RESERVOIR CONCLUSIONS

For a good reservoir to be deposited, three elements are necessary:

1. *An identified source* (a river channel with a silica-clastic hinterland).
2. *A conduit* to lead the reservoir constituents from the shelf to the prospect (a canyon system).
3. A *trap* (low in a slope, or at least a decrease in slope).

Most fan deposits do not fulfil these criteria and are unlikely to be originators of reservoirs. Fan systems are essentially dispersive and transport distances of sand-rich turbidity currents are limited. Thus, the quality and thickness of reservoirs will degrade rapidly from the end of the conduit.

Origins of Source Rocks

Two possible ranges of origins of source rocks currently exist in deepwater environments, although there are likely to be more. These origins of source rocks are:

1. Those deposited in a deepwater environment, possibly with a deepwater reservoir in the same context as the source rock, and
2. Those deposited in a less deep environment (lacustrine, deltaic, or shallow marine).

It is not uncommon to find such a source in close juxtaposition with (overlain by) sandstones and shales, which themselves were deposited in deeper water associated with deposits in the deep water.

The three principal factors controlling the formation of a marine source rock are:

1. the organic productivity at the surface of the water body,
2. the presence of a reducing environment in the sediments on the sea floor,
3. low rate of inorganic sedimentation.

Furthermore, studies of deepwater sediments have shown that deposits at greater water depth are poor in organic matter, suggesting that during transport, through the large water column volume, the organic matter is destroyed—probably eaten or dissolved.

Cold Arctic and Antarctic currents that traverse oceans floors also establish oxygenic conditions at the sediment water interface, further diminishing the possibility of establishing favorable conditions for source rock deposition and why it is unlikely a good thick source rock is likely to be deposited and preserved in deepwater.

Upwelling currents develop on continental slopes caused by the movement of cold currents across the slope in conjunction with opposing offshore dominant wind directions. These upwelling currents are rich in organic matter. Examples: Current upwelling offshore Namibia generates deposits rich in organic matter at water depths between 200 m (656 ft) and 1000 m (3281 ft). Thick intervals of shale with dispersed organic matter of terrestrial detritic origin (plant matter) are found associated with deltas such as the Niger Delta and Offshore Angola that are probably effective source rocks. These events likely extend into deepwater and are associated with sands derived from the delta complex.

The case of deepwater source rocks that were deposited initially in shallow water is well known in major deepwater petroleum, e.g., Brazil or Angola with lacustrine source rocks deposited in the grabens or of marine origin deposited in a post rift sequence. Thermal subsidence at the end of the basin rift initiated deeper water depth that then continued during the period of drift and ocean formation.

A problem in this circumstance is to judge whether the most distal rifts contain a lacustrine facies or whether the source in the post rift marine sequence retained qualities required in deep offshore.

Source Rock Maturity

Although the nature of the source rock maturity, chemical process is the same in the deep and shallow offshore, there are additional difficulties in attaining a sufficient level of maturity to generate hydrocarbons in deep water. Since when one goes from the continent to the offshore, the thickness of sediment increases, passes through a maximum, and then diminishes again. As a result, for a source rock of a given age, it will be less buried and therefore cooler than the equivalent source rock on the shelf. This can mean that in deepwater the same source rock may not be mature enough for the generation/expulsion of hydrocarbons. Furthermore, in deep water, compared to onshore, the temperature of the sea water just above the sediment-water interface at water depths >1000 m (3281 ft) is never >4–5°C (41°F) vs. up to 30°C (86°F) onshore. This effect lowers the temperature attained in a given depth of sediment in deepwater.

Primary Migration

The "background" source sediment in deepwater is generally claystone/shale. Significant thicknesses of claystone/shale sequences therefore should be predicted and, for any potential reservoirs predicted as high quality, can often be isolated from the potential source rock by the same shale. Furthermore, structural presence or laterally continuous feeder beds to assist migration paths of generated hydrocarbons is unlikely.

For a petroleum system to work in deepwater, the connection between the source and the reservoir needs to be efficient. In a petroleum system where source rocks formed in association with rifting are coupled with later turbidite reservoirs, migration problems could exist.

In fact, for turbidite units developed in association with a quite thick argillaceous unit, if claystone/shales are too thick, migration can be inefficient, requiring the presence of faults to assure primary migration. A favorable situation would be where source rocks are in closer proximity to the reservoirs within an efficient trap for hydrocarbons, especially for heavy oil products generated and expelled early. In the absence of later lighter products due to the cool thermal regime, the resulting reservoirs are likely to contain heavier rather than normal oils.

REFERENCE STANDARDS

OGP (International Association of Oil and Gas Producers). December 2009. Geohazards from seafloor instability and mass flow. Report 425.

OGP. March 2010. Regulators use of Standards. Report 426.

IOGP (International Association of Oil and Gas Producers). April 2011. Geomatics 462 series Data models note 1, Version 1.

OGP & IAGC (International Association of Geophysical Contractors). April 2011. Overview of Marine Seismic Operations. Report 448.

OGP. April 2013. Guidelines for the conduct of offshore drilling hazard site surveys, 373-18-1, Version 1.2.

IOGP. May 2015. Standards and guidelines for well construction and well operations. Report 485. Ref. Appendix 1.

IOGP. October 2015. Conduct of offshore drilling hazard site surveys – Technical notes. Report 373-18-2.

ISO (International Organization of for Standardization) standards.

References

Alberty, M., 1998–2002. BP Exploration, Various Technical Articles, on Shallow Hazards and Water Flows, Generated by Mark Alberty.

Aylor, W.K., December 1998. The role of 3D seismic in a world class turnaround. Lead. Edge 17 (12), 1678.

Beglinger, S.E., Doust, H., Cloetingh, S., 2011. Relating petroleum system and play development to basin evolution: West African South Atlantic basins. Mar. Petrol. Geol. 30, 1–25.

Dai, J., Snyder, F., Gillerspie, D., Koesoemadinata, A., Dutta, N., 2008. Exploration for gas hydrates in the deepwater, northern Gulf of Mexico: Part I. A seismic approach based on geologic model, inversion, and rock physics principles. Mar. Petrol. Geol. 25 (9), 830–844.

Holbrook, P., 2004. Pore Pressure through Earth Mechanical Systems. Force Balanced Publications.

Imbert, P., Pitton, J.L., Yeats, A.K., 1996. Total exploration. In: Deepwater Geology: Heavier Hydrocarbons, Cooler Environment Found in Deepwater. Offshore Magazine. April 1.

Joyes, R., 2001. South Atlantic Geology 1 & 2: Geologic insights listed into Africa, Brazil deepwater exploration. Oil Gas J. March 26.

Press, F., Siever, R., 1998. Understanding Earth, 2nd ed. W.H. Freeman & Co., New York, Basingstoke.

CHAPTER

3

Deepwater Pressure Management

Pressure Management

The Pressure Management of deepwater wells may not appear to be that much different from any other offshore well, but making such an assumption contributes to a multitude of drilling and well operational problems. Certain classes of deepwater wells as presented throughout this guide have pressure regime complexities and difficulties in a class of their own. That demands far greater well planning, construction, drilling, and delivery requirements utilizing a multidisciplinary approach.

Deepwater's most disastrous, consequential, loss control drilling event, illustrated in Fig. 3.1, resulted from several pressure management loss control event failures. The consequential impact resulted in a rig explosion and loss of the vessel to the seabed, 11 fatalities, 17 further injuries, uncontrolled loss of well control with >5 million barrels of crude oil released into the Gulf of Mexico in the months that followed. The disaster devastated the region's economy and continues to threaten the health of residents and the environment.

This one event alone serves to remind persons using this guide to the Pressure Management assurance demanded in deepwater projects as is ably demonstrated through the evident tens of hundreds of complex, challenging, and difficult deepwater wells as illustrated in Fig. 3.3 that have been safely effectively and efficiently drilled.

Pressure Management Studies and Objectives

REVIEW OF PRESSURE DRILLING AND GEOLOGICAL ANALOGUES

Chapter 2 highlighted how seismic-based exploration advancements contribute to the identification of new potential deepwater hydrocarbon basins and provide strong evidence for active petroleum systems. 2D and 3D seismic interpretation and attribute understanding indicates the presence of trapping geometry and fluid type, driving a greater need to understand deepwater pressure regimes. Interdisciplinary teams learn how to assess these data and use existing experiences from similar analogue wells to further derisk basin interpretation where no well data or pressure control exists. Such a well may, in some cases, be located many hundreds of kms away.

Many basin studies for selection of analogues evolve around basin-scale tectonostratigraphic studies often to derisk the basin. In terms of geological pressure for these basins, further work is required to derisk the operating pressure limits. For example, sand-shale geometries, reservoir plumbing, top of cement within shales, thermal evolution, and sedimentation rate).

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00003-X

FIG. 3.1 Deepwater horizon on fire before sinking to the bottom of the Gulf of Mexico basin. *From https://en.wikipedia.org/wiki/Deepwater_Horizon_explosion#/media/File:Deepwater_Horizon_offshore_drilling_unit_on_fire_2010.jpg.*

For deepwater environments, globally these basins share characteristics that can help derisk the pressure environment; such characteristics include more claystone/shale/ isolated sand facies, thinner overburden, missing or eroded sequences, more or less fracturing/faulting. Examples of pore and fracture pressures are then predicted to assist in the understanding of the likely pressure regimes, and guide the drilling operating limits, environments and conditions expected.

DEEPWATER STUDIES

Once a project is approved, a pressure and wellbore stability study work would be considered and scoped, particularly for new areas. The work scope identified then resourced, tasked, and scheduled to provide a comprehensive regional pressure analysis of all representative well data, with the resultant output used to *predict* pressure to assure safe well location, design and later *detect* pressure to assure that drilling meets desired goals, objectives and well value-added realization. Studies can further provide a definitive analysis of the pressures in the region to enable an understanding of pressure distribution, operating hazards, and risks.

STUDY OBJECTIVES Representative study objectives would be to:

1. Identify relevant offset or analogue wells.
2. Gather relevant pressure data including measured formation pressures, kick pressures leak-off data, mud weight, measured annular pressures, drilling pressure indicators, velocity, and resistivity logs.

3. Understand the pressure regime and causes of overpressure generation.
4. Derisk trap mechanisms, seal failure, and identify positive reservoir characteristics.
5. Determine and evaluate key components required for safe well planning: reservoir pressure, clay/shale pressure, overburden, fracture, and collapse pressure models.
6. Provide a robust deterministic pressure and overpressure profile well-tie in (based on seismic lines provided) for the purposes of seismic velocity calibration.
7. Understand the overall pressure magnitudes and distributions considered to represent the deep-water environments to be drilled.
8. Use offset well data to calibrate lithology used in the porosity-permeability-effective stress relationships, to build or run 1D-3D basin models. Compare basin model with the pressure measurements and geologically driven basin model to produce a most likely pressure profile.
9. Capture reasonable uncertainties in geological understanding and pressure profiles, and communicate the relevant risks.

DATABASE, ANALOGUE REVIEWS Study interpretations would be weighted, ranked, and risked based on their quality and relevance helping analyst to capture the uncertainties in the data and derived models. These data can be grouped into two main areas: *direct* and *indirect* measurements.

Direct Measurement Pore pressure from wellbore formation tests is viewed as the most reliable method to acquire pressure measurements from analogue wells, providing data that are assessed and interpreted effectively, particularly if permeable formation intervals were tested.

Lost circulation and *kick* loss events provide reliable and accurate direct pressure management measurement well control data within analogue data sets reviewed.

Indirect Measurement Indirect pore pressure measurements are obtained from a variety of sources, including:

1. Mud weight history
2. Gas monitoring at the well
3. Drilling parameter analysis (e.g., dc exponent)
4. Interpretation of porosity trends from wireline or LWD/MWD data

Primary and secondary pressure *prediction* and *detection* indicators, before, during, and after drilling operations are summarized in Fig. 3.2, Tables 3.1 and 3.2.

In conclusion, many methods are used to detect abnormally pressured zones while drilling. It is important to note these can vary in effectiveness and should be classified on the basis of reliability as shown in Table 3.1. Lithology viewed as the key determinant to correct interpretation than must be linked to each parameter independently.

Pressure management in deepwater is not easy or straight forward, because of all petro physical, engineering, scientific, and reservoir interpretations demanded. Deposition, conditions, and environments are also often very complex in nature/characteristics and therefore fraught with hazards, risks and uncertainties. Bringing all specialist skills, knowledge, and experience together throughout a project should not be underestimated to deliver the essential pressure management outcomes required.

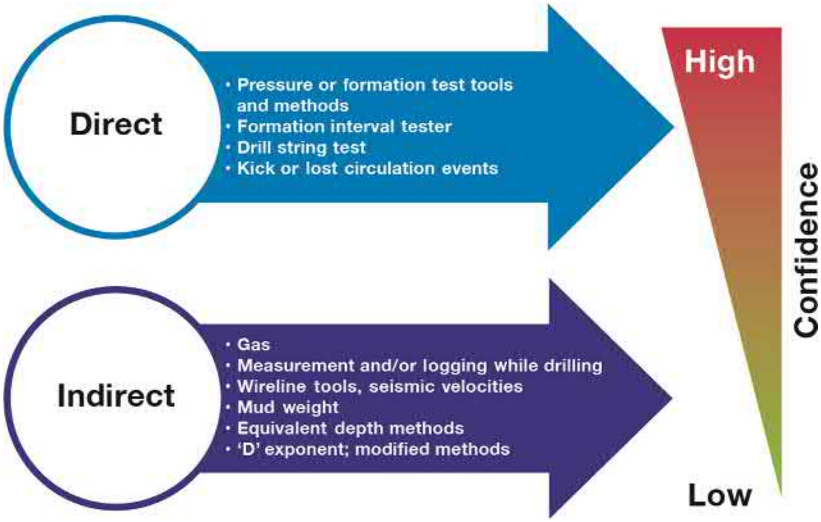


FIG. 3.2 Hierarchy of pressure data via confidence ranking. *Note*: ranking would vary and is highly dependent on data quality. "Equivalent depth" in this case refers to relative comparison of data. *Source: Kingdom Drilling 2018.*

TABLE 3.1 While Drilling Primary Pressure Indicators

Detection Parameter	Real Time Methods	Delayed (Lag Time) Methods
Reliable	Drilling rate e.g., drilling break. Flow measure (increase/decrease) Losses and/or gains Measurement while drilling "MWD" (Neutron density)	*Gas Measurement* Drilled (background gas) Connection gas Reservoir gas
Moderately reliable	MWD (Gamma ray/Resistivity)	Gas: composition Trip Gas Shale density, shale factor. Abundance, size shape of cuttings
Not reliable	Pump pressure	Mud temperature

Source: Kingdom Drilling.

Pressure Regime Essentials

Pressure regimes to be managed and controlled in deepwater are *Pore*, *Fracture*, and *Overburden collapse* pressure profiles. Regimes are often very different to offshore shallow water wells, which drives greater demands in well planning, design, and operating standards. Example: Fig. 3.3 provides a generalized review as to the variance of deepwater pressure regimes and drilling operating windows that exist. Some regimes are difficult to pressure-manage with greater complexities in terms of well design, engineering, and operational requirements: *more casing strings, contingencies, revised casing setting depths, different string size*

TABLE 3.2 Summary of Pressure Management Detection Methods

Source of Data	Parameters	Time of Recording
Geological	Regional geology Offset data studies and analysis Pore pressure and wellbore stability studies	Prior to spudding well
Geophysical	Formation velocity (Seismic, 3D, high-resolution, etc.), Gravity, Magnetics, & Electrical prospecting methods	
Drilling parameters	Drilling rate, lithology, WOB/RPM, torque, drag, pressure effects (swab/surge, EMW, ECD), d exponent, sigma log, normalized data, MWD, APWD, People & equipment.	During drilling (real time) Delayed by time required for sample returns.
Drilling Mud	Gas Content, Mud weights in/out, "losses & kicks," Temperature, Chlorine variation, Drillpipe & annular pressures, Pit volumes, Flow rate, Hole Fill up	
Drilling Cuttings	Lithology, Shale cuttings, volume, shape size, density, shale factor. Cuttings gas. Electrical resistivity. Novel geochemical, and other geomechanical techniques	
Well logging	Electrical survey, Resistivity, Conductivity Shale formation factor, Salinity variations Interval transit time, Bulk density Hydrogen index, Thermal neutron Nuclear magnetic, Resonance Downhole gravity data	After drilling
Direct pressure measuring devices	Drill stem test Wireline formation test Check shots, VSP	When well formations are tested or completed

Source: Kingdom Drilling.

and selection, enhanced pressure scrutiny, more well control, and greater knowledge understanding and skill sets to assure safe and loss free drilling of wells.

The deepwater pressure regimes illustrated in Fig. 3.3 can be divided into two categories:

1. ***Conventional***: *Deep Transitional*, *Normal*, and *Constant pressure* gradient to plan, design, construct, engineer, drill, manage, and control ranging up to
2. ***Complex***: *Pressure Regression*, *Continuous Narrow Margin*, and *Ricochet* pressures that can be more hazard prone, extreme, challenging, time consuming, and costly.

Note: The pressure profiles in Fig. 3.3 provide a composite range of deepwater wells that exist today to illustrate and represent the scope of well design, engineering, and operational aspects to be evaluated in the context of deepwater within this guide.

Normal Pore Pressure

Normal pore pressure varies from 8.33 ppg pounds per gallon (998 kg/m^3) in fresh water, to 8.66 ppg (1038 kg/m^3) in seawater, and up to 10.0 ppg (1198 kg/m^3) in highly salt saturated water environments.

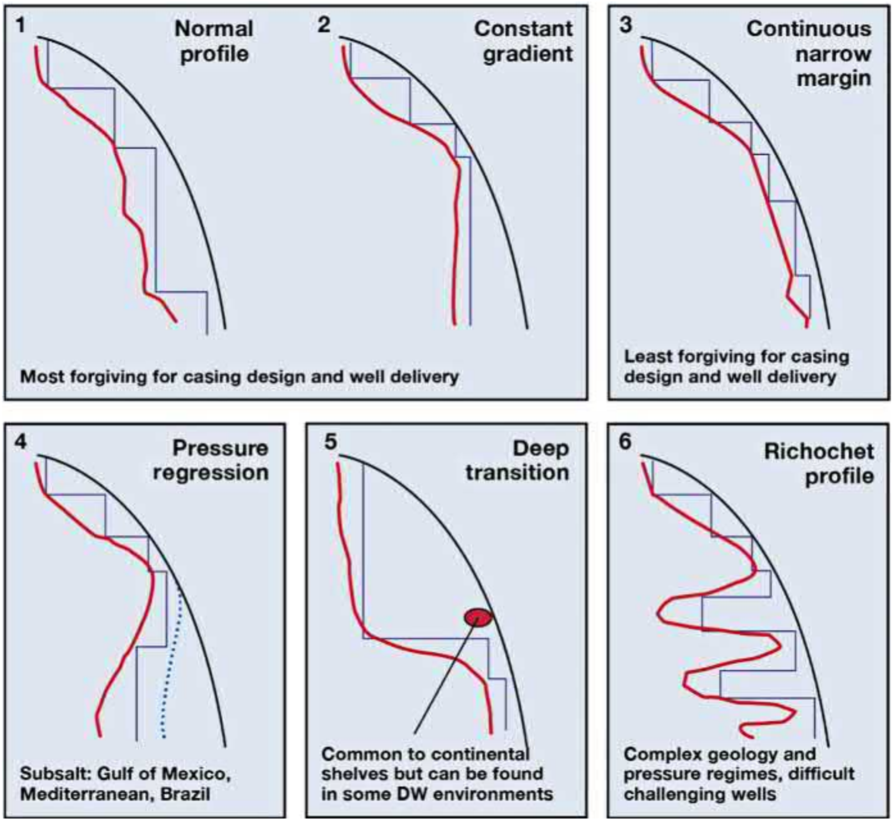


FIG. 3.3 Deepwater pressure regimes. *Source: Kingdom Drilling reconstruct 2018.*

PRIMARY CAUSE OF NORMAL PRESSURE

Normal hydrostatic pressures predominantly result when *fluid escapes at a rate* relative to loading, such that:

1. Porosity will decrease in equilibrium with the increasing load
2. The entire load is supported by framework grains
3. None of the load is supported by the pore fluid so that the pore fluid pressure remains normal (hydrostatic pressure).

Abnormal and Subnormal Pore Pressure

Deepwater pressure profiles are normally pressured from the seabed to a vertical depth where an abnormal or subnormal pressure mechanism would exist as illustrated in Fig. 3.4. Pressure change results and varies due to depositional setting, environment, mechanical, and chemical processes that exist.

"*Abnormal*" and "*subnormal*" are greater or less than the normal pressure environment and condition that exist.

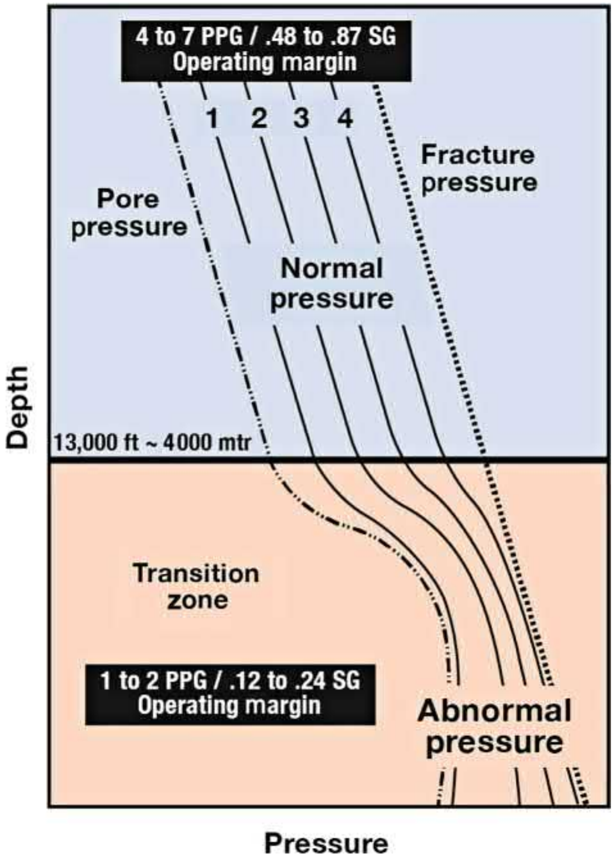


FIG. 3.4 Normal and abnormal pressure. *Source: Kingdom Drilling 2018.*

In these situations, pressure-related drilling operating margins are reduced as illustrated in Fig. 3.4.

$$\begin{bmatrix} 8.33 \\ 8.66 \\ 9.0 \\ 9.5 \\ 10 \end{bmatrix} .\text{ppg} = \begin{bmatrix} 998 \\ 1038 \\ 1078 \\ 1138 \\ 1198 \end{bmatrix} \frac{\text{kg}}{\text{m}^3}$$

WHAT IS "ABNORMAL" PRESSURE?

Abnormal pressure is derived when water is present as the pore fluid in a formation or reservoir interval. When the pressure gradient is greater than the hydrostatic gradient, the pressure difference at this specified depth between the fluid pressure along this gradient (Pp) and the hydrostatic pressure (P_{hydro}) is the amount of overpressure (ΔP) present. As represented in Eq. (3.1).

DEFINITION OF OVERPRESSURE

$$P = Pp - P_{\text{hydro}} \tag{3.1}$$

Maximum fluid pressure is characteristically controlled by the *fracture strength of the weakest exposed formation* to which the wellbore fluids are exposed.

Fracture Pressures and Gradients

Fracture gradients result due to the effective change in overburden and pore-pressure profiles and in situ stresses driven by sedimentation, tectonic history, lithology, operating environments, and subsurface development conditions within each basin. A fracture in drilling terms is noted by first instance of fluid being taken into wellbore formation that has been or is being drilled. The *fracture pressure* is the pressure that fractures formations, when the minimum compressive stress and tensile strength are exceeded by the pore fluid pressure.

In practical terms, the fracture pressure is the upper limit of pressure that the wellbore formation can withstand from the exerted mud column and associated cumulative wellbore operating pressure effects.

Well Integrity Tests

Once each intermediate or production wellbore section is drilled, cased, and cemented with steel tubular pipe to provide the required well and barrier integrity demanded to safely protect the well from failing during its intended life cycle. The planning, design, and engineering of each wellbore section is decided through determining and evaluating an optimal safe setting depth range (how shallow or how deep can this be set) to meet all well objectives and to further enable safe, loss-free drilling of the next wellbore section.

Drilling engineers shall have a preference to set casing in fine-grained (low permeability) lithology, such as claystone/shales and certain types of chalks, and/or above or across (to isolate) trouble zones with potential abnormal or subnormal pressure, instability, or associated pressure problems. When drilling through known abnormal intervals or transition zones, both the engineered and operational plans and factors experienced during operations set the drilling limits as far as is practical before setting casing.

The key advantage if able to set casing deeper in abnormally or high-pressure transition regime provides the most probable set off conditions to achieve a higher fracture gradient to enable drilling the next section to its required depth or potentially deeper, which can reduce operating risks and requirements to run additional casing strings, etc. somewhat.

At each casing setting depth, well integrity of the cement/formation around the base (shoe) can be confirmed by drilling 3–5 m (10–16 ft) of new formation and then conducting a well (or formation) integrity test prior to drilling ahead.

Well, Limited, Intake, Formation, Leak-Off, or Extended Leak-Off integrity tests (FIT, LOT, X-LOT). *Note*: An extended leak-off test as illustrated in Fig. 3.5 serves to provide well integrity methods of choice to consider conducting. Example: A leak-off test provides the

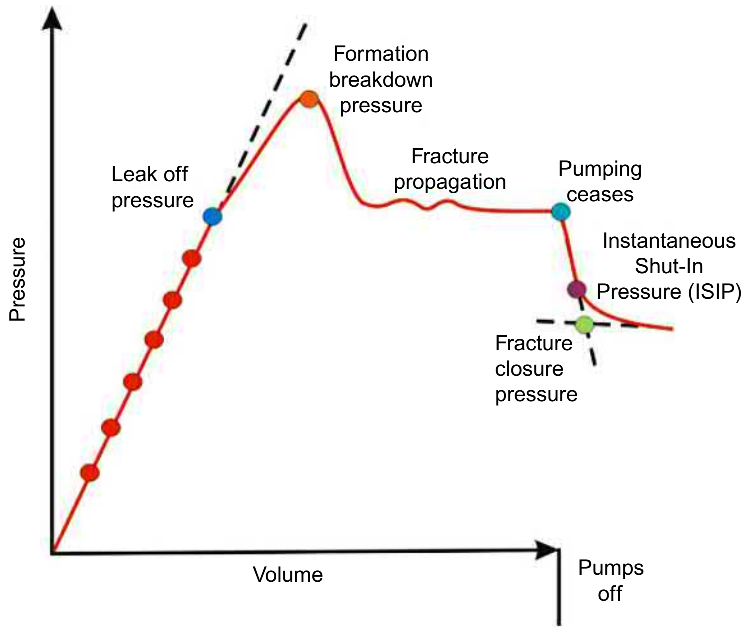


FIG. 3.5 Extended leak-off test schematic highlighting all the potential stages of this test. *Source: Ikon Science, Pressures and overpressure in the subsurface course 2015.*

maximum static mud weight that can be used before mud loss results due to hydraulic fracturing of the weakest formation exposed in the wellbore at the time of the test.

For exploration and appraisal wells a trend of LOTs can be valid and representative; hence, use of Daines, Mathews and Kelly, Eaton models is suitable for deepwater.

Basic Fracture Gradient Theory

Evaluating fracture pressures requires information of the in situ stresses in the formations. Three principal compressive stresses act on the rock matrix mass at a specified depth, each orthogonal to one another: in sedimentary basins one of the principal compressive stresses is assumed to be vertical (S_v), making the other two horizontal (S_h and S_H), where (S_h) is the smaller and (S_H) the larger component of the horizontal compressive stresses. Knowledge of (S_v) comes from the estimate of the lithostatic pressures, (S_h) from well integrity tests data where ($S_h < S_v$), but where (S_H) is generally poorly known (Ref. Fig. 3.7).

Tensile fracture is when the pore pressure forces the sedimentary grains of the formations apart. The direction and orientation in which the tensile fracture opens presents the least path of resistance and is termed the *minimum compressive stress direction*.

When failure results in open homogeneous mediums, fracture typically extends parallel to the direction of the intermediate and maximum principal stress.

Experience of this fracture development often results in deepwater layered sediments where the dominant direction of propagation is the direction of the intermediate principal stress. When fractures are layer bounded.

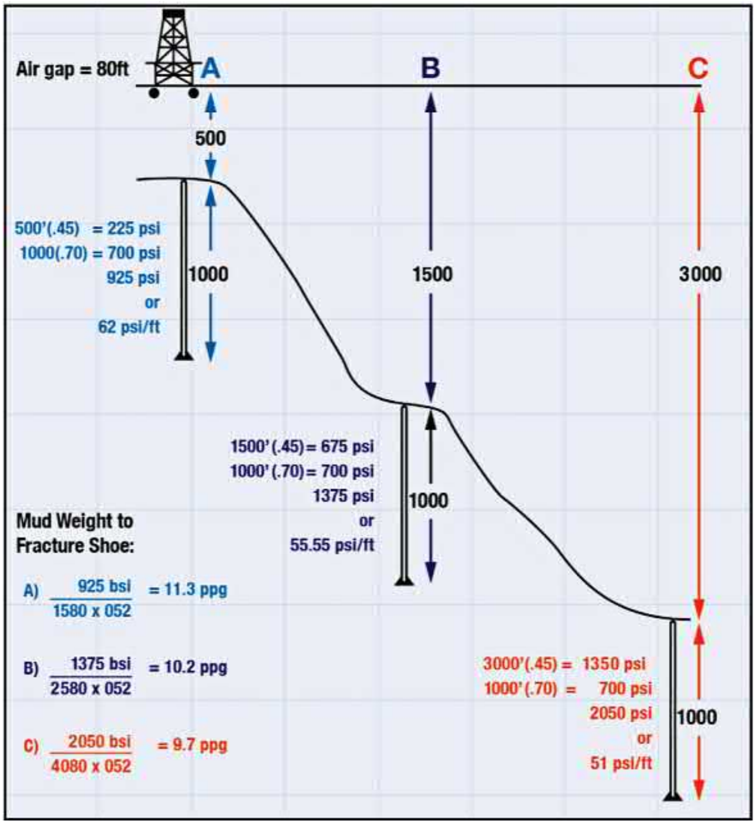


FIG. 3.6 Fracture gradient as a function of water depth. *Source: Kingdom Drilling reconstruct 2017.*

What is important in deepwater is that if the same formation sequence was drilled below the seabed as opposed to shallower water, the resulting fracture gradient at the casing *reduces as a function of water depth increase* as shown in Fig. 3.6.

Determining Fracture Pressures

Fracture pressures are determined from available well integrity test data to evaluate the most suited method to accurately predict fracture pressure. If a small differentiation exists between the test data, it is often not possible to discern precisely what type of test was conducted. In such cases, it is preferred to assume a leak-off test (LOT) unless well reports state otherwise. Limit or formation intake tests should be removed from the well's data set.

Fracture Pressure Algorithms

MAIN ALGORITHM IN POPULAR USE

To estimate fracture gradients and pressures are *Matthews and Kelly 1967, Eaton 1969, Daines 1982, and an approach by Breckels and van Eekelen 1982* that is based on a more global database.

Other methods exist to determine fracture gradient, most involving empirical formulations relating to formation rock matrix properties such as Poisson's ratio and the magnitude of the overburden pressure.

Note: In subsequent well planning, design, and engineering sections in this guide, the most appropriate fracture pressure methods shall be used, applied, and further discussed.

Pore Pressure-Stress Coupling

Theory: Theory considers the relationships of fracture to lithostatic and hydrostatic to overpressure.

A generalized representation of pressure relationships versus depth is presented in Fig. 3.7 to demonstrate that when the fluid pressure is hydrostatic, fracture pressure is frequently a consistent fraction of the lithostatic pressure.

However, when the fluid pressure is greater than hydrostatic, the fracture pressure is greater than would be expected for a hydrostatic condition.

IMPLICATIONS FOR DRILLING

Fig. 3.7 illustrates a typical deepwater pressure depth trend relationship. However, trends observed in over pressured deepwater wells vary globally. The pressure trends commonly presented by the operations geologist and drilling engineer will predict a low, expected, and high-pressure case. Design and operating aspects then adopt a low fracture and high-case pressure design and an engineered operational approach until real physical pressure evidence is detected to reduce risks and uncertainties.

From a different perspective if a noncoupled fracture pressure model, e.g., 85% of vertical stress or a far too simple depth-dependent fracture pressure equation is used, fracture pressure can be underestimated in an overpressured regime. Underestimation could result in

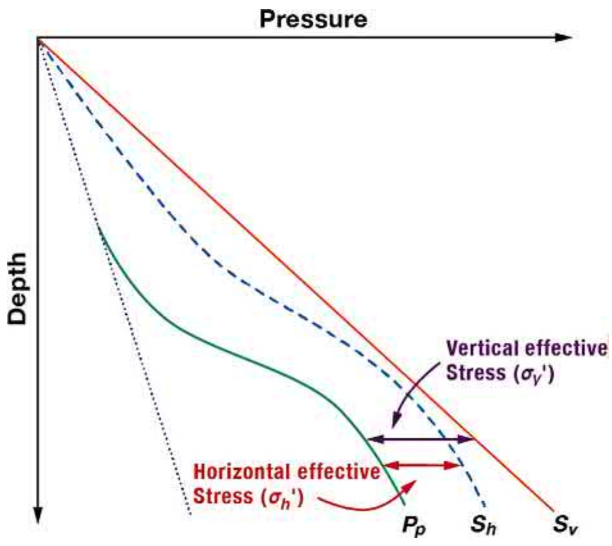


FIG. 3.7 Lithostatic, hydrostatic, fracture, and overpressure relationships.

purchasing casing strings that are not in fact required or, in a worst case, decisions are taken not to drill the well due to excessive casing strings time, costs, and risks evaluated from such misrepresentation.

Another far more poignant repercussion is wells are not drilled to their required license depth. This can lead to governmental problems, where regulators have banned companies for not meeting total well depths where failure has implied HSE problems had resulted during the implementation of the well's program.

The links of fluid pressure and fracture pressure to more complex wells in deepwater further enforce and assure a need for *accurate and precise estimation of all pressures prior to planning, designing, and engineering the drilling/casing program* and the communication of risk and what underlines these models.

Project execution must assure best practice exist to safely drill the wellbore sections as deep as the operating window safely permits for optimal fracture strengths to result. Failing or falling short of desired casing depths by setting casing or liner strings too shallow can seriously compromise project well plans and drilling objectives. For example, casings are not set at optimal design and operating depths.

Optimizing wellbore depths and delivering safe operating windows is therefore tantamount in specific wells, particularly when entering and drilling abnormally pressured transition zone or specific intervals where pore and fracture pressure increase can result. The value of added fracture pressure must also be duly balanced with operating risk and primary well control assurance concerns regarding kick and lost circulation tolerances, which must always be safely managed within the wellbore that are again driven directly by the limits of pore, fracture pressure, operating window, and best practices used.

Drilling Operating Window

General

Understanding the implications of mud weight, pore pressure, and fracture pressure is necessary in pressure management and later when discussing well control assurance. These data are best illustrated via graphs by pressure on the x-axis versus true vertical depth (*referenced from the drilling rig floor*) on the y-axis (Fig. 3.8). Within these figures, the region of the graph bounded by the fracture pressure curve on the upper side and by the pore pressure curve (*in ppg equivalent*) on the lower side, i.e., *between the solid and dotted lines* is often referred to and defined as the Drilling Operating Window.

The key part is that as water depths increase and when abnormal or subnormal pressures exist the pressure management and drilling operating window limits are critical and often quite complex factor in deepwater.

The two parameters required to define the drilling operating window are *pore pressure* and *fracture collapse pressure*. Values once determined then used extensively in well planning, design, and engineering, before, during, and after all well-drilling and related operating activities.

Operating Safety Margins

Deepwater operating standards that exist concerning upper and lower sides of the drilling operating window is determined for the class of well complexity and operating pressures

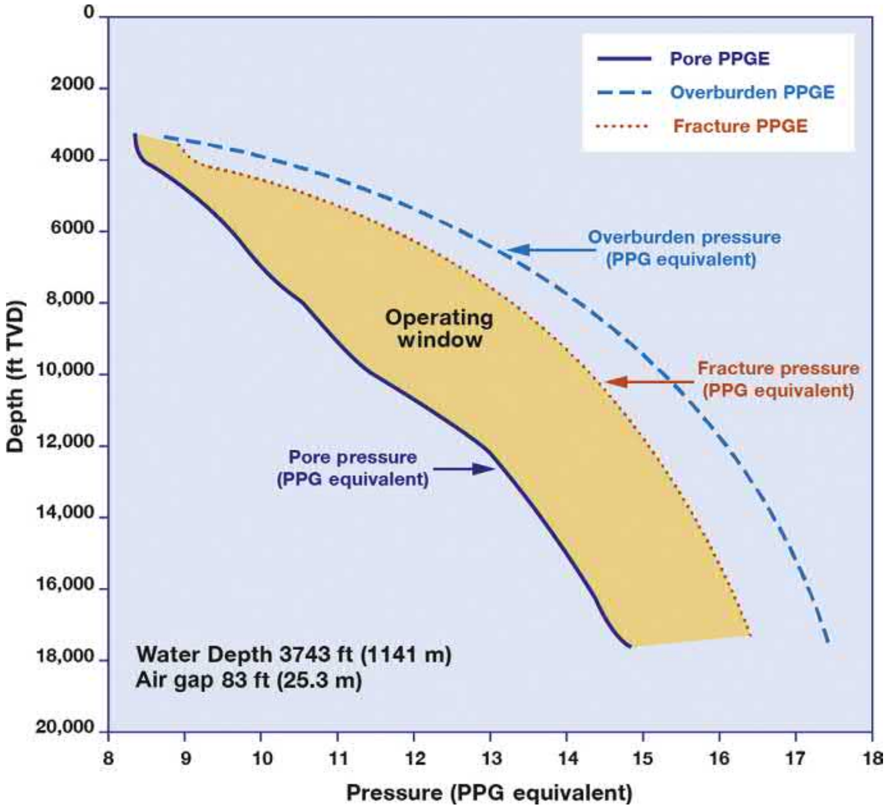


FIG. 3.8 Deepwater operating window, pressure vs. depth graph. *Source: Kingdom Drilling 2018.*

evaluated to exist at an early project stage. Specific standards and other evident operating aspects evaluated shall assure that a combined static, dynamic, and transient pressure approach are applied, and not a more prescribed method, such as an arbitrary one-suit-to-fit-all approach, for example applying a regulatory or company standard.

Note: *Prescription without diligent pressure diagnosis viewed as malpractice in any business.*

UPPER LIMIT

"Upper limit" is driven by the weakest exposed formation (Fig. 3.7). The limit exists to assure each section is safely operated without fracturing the weakest wellbore exposure or prevent instability or associated problems resulting. *All operating pressure must be accounted* to effectively control the individual and/or combined downhole and pressure components that exist during all, operating drilling, circulating, pump start-up, shutdown, and noncirculating conditions (Ref. Fig. 3.9).

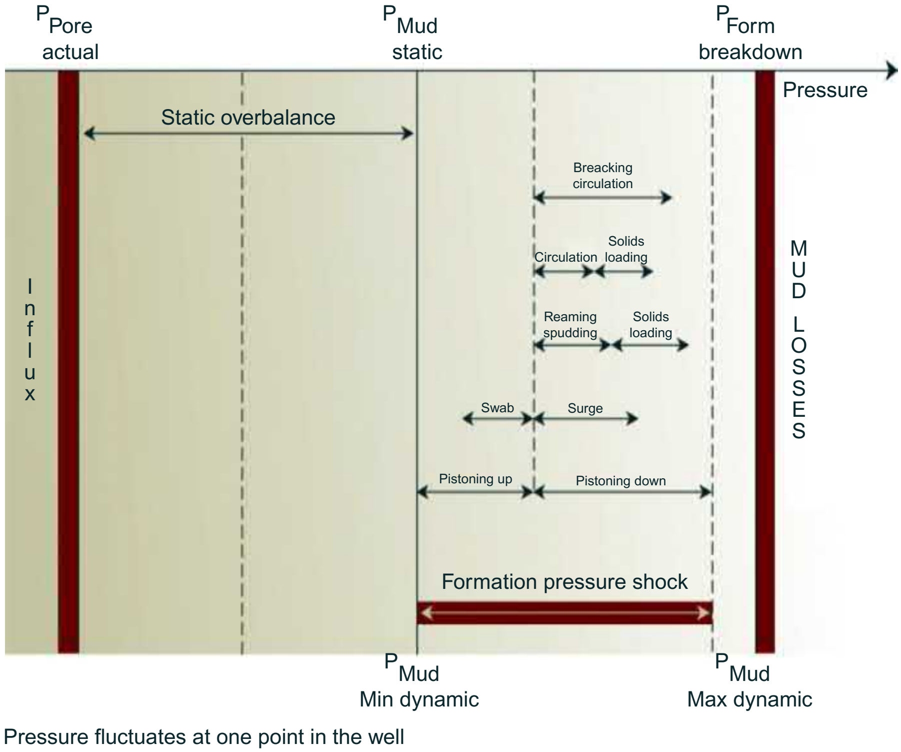


FIG. 3.9 Drilling operating window "pressure cause and effect" components that exist singularly or in combination at any specific depth in the well. *Source: Kingdom Drilling 2001.*

Factors determining upper well design and drilling operating limits are:

- *Operating Standards*: 1 ppg (0.052 psi/ft) (120 kg/m^3) is a common applied standard for exploration wells, 0.5 ppg, 0.026 psi/ft. (60 kg/m^3)for development wells.
  a. Normal standards often cannot be worked into a deepwater well's program due to the extent of operating pressure margins that exist. Management of change then required to be approved at an early project stage.
  b. Lower Margins ranging from 0.2–0.5 ppg (24–60 kg/m^3) are sanctioned and approved in more complex deepwater pressure regimes in conjuntion with sensitivity analysis to be performed. The increased operating risks determined to be mitigated and assured through appropriate well control assurance standards to be taken and greater emphasis in well program, risk assessment, and operating orders.
- ***Equivalent mud weight (EMW)*** (Eq. 3.2) is defined and outlined as follows:
  a. *MW* = Static mud weight anticipated for each wellbore section. In complex wells this is affected and changed through Pressure, Volume, and Temp (PVT) effects.
  b. *ECD* = Annular, Equivalent Circulating Density friction pressures result when circulating.
  c. *AOPE* = All Other, formation, wellbore, and operating Pressure Effects, e.g.

i. Cuttings loadings effect, that depends on drilling rate, hole size, etc.
ii. equivalent static density, i.e., that is influenced by several AOPE
iii. Swab surge pressures, pipe movement, rotation, heave effects, etc.
iv. Pump start-up after noncirculating periods (*pressure inertia, gelation effects due to the static mud, particularly in the marine riser*).

- Pressure, temperature, and volume (PVT) effects on deepwater drilling muds (*a separate component of EMW, MW, ECD, and AOPE*) should be engineered, modeled, then monitored at the well site in greater and more finite detail.
- Kick tolerances (static and dynamic) and further sensitivity analysis, assessed not only to safely shut in the well but also alleviate concerns that well can be operationally killed is a further critical requirement when pressure complexities exist.

EQUIVALENT MUD WEIGHT EMW, PRESSURE MANAGEMENT EQUATION FOR COMPLEX WELL DRILLING

$$\mathrm{EMW} = \mathrm{MW} + \mathrm{ECD} + \mathrm{AOPE} \tag{3.2}$$

LOWER LIMIT

"Low limit" is defined by the maximum pore pressure present in each wellbore section drilled, and is reduced by standards and safe operating requirements, such as trip or wellbore overbalance margins, or stability required to meet company standards.

OPERATING MARGINS

Operating margins exist so that primarily well control wellbore pressures are maintained to prevent kicks, lost circulation events, and enable stable wellbore operating conditions during all well operating activities at minimal loss.

To conclude, pressure management and well control assurance must be managed within clearly defined standard limits that reflect both realistic and practical worst-case static, dynamic, and transient wellbore pressure effects that physically and evidently result.

Best practice always viewed to plan, plan, plan, design, and engineer, to prevent pressure related problems vs. having to affect what are often time consuming and costly cures.

Mud Weight (MW) Essentials

Mud weight forms an integral and vital component part in controlling the drilling operating window and wellbore pressure management requirements. It contributes to both direct and indirect indicators and is a key metric of the magnitude and extent of pressure and operating conditions that exist. Mud primarily provides the hydrostatic density and pressure as a function of vertical depth to support the range of wellbore formation pressures that exist in each section to be drilled. It serves to assure that no kicks, lost circulation, or wellbore instability events result in both static and dynamic operating conditions during all drilling operating activities conducted.

If mud weight objectives and rheology properties are not met in full, notably in porous and high permeability formation intervals that commonly exist in deepwater, the resultant changes can cause and effect pressure management issues to arise, resulting in lost time events as fluids and pressures are either gained or lost to/from the wellbore. Lost time events then must be dealt with through suitable well control assurance, equipment, and best practices applied. Another probable scenario in deepwater is a low permeability formation interval. *Example: shales where drilling "underbalanced" can perpetually result.* This is because despite people best efforts and endeavors, operating conditions shall exist where mud weight and operating pressures exerted are less than the formation pressure (particularly when a connection is made, or circulation is stopped). In this case, low permeability prevents detectable measurable warning signs or indicators to result, e.g., fluid gains detected by the drillers, mud loggers. Problems often result once the first permeable formation is drilled and encountered. In such cases, higher kick level alertness practices shall be utilized. A "Higher alertness" mud weight strategy will vary considerably in response to pressures that exist even in similar stratigraphy, where wellbore, drilling conditions, and operating environments can rapidly change. In these instances, safe assurance, the drilling operating window, and mud weight pressures must be continually monitored and controlled. Example: In critical pressure regimes, deepwater wells can require a separate mud weight for drilling and tripping a particular wellbore sections.

Mud weights and pressure management in complex wells, as illustrated in Fig. 3.10, also command a greater understanding of the finer pressure measurement margins issues that exist in low and high mud weight limits where lost time events can result if mud weight pressure aspects are not safely monitored and controlled.

In summary, to safely pressure manage narrower operating windows, greater emphasis shall be placed regarding operating plans, designs, engineering, standards and practices to apply in deepwater.

CLAYSTONE/SHALE, OTHER PRESSURE PREDICTION METHODS

General

Claystone and shales are the principal sediment responsible for overpressure generation, and the rock type in which it can be possible to interrogate the overpressure magnitude using rock properties. Based on these conclusions, this section characterizes why and how disequilibrium compaction is the main source of deepwater overpressures and is logical to investigate in details of the magnitude within claystone/shales using wireline data.

Pore pressure prediction in claystone/shales is based on the premise that the response of sonic velocity, resistivity, and density tools are a proxy for porosity. A further assumption is that high porosity in the formations at depth is due to the inability to dewater (compact with depth). The retention of water a) preserves porosity and b) requires that the retained water must support a proportion of the vertical load, i.e., generating overpressure. This component that the vertical load in the rock framework supports is termed the vertical effective stress, with vertical stress linked to both pore pressure and vertical effective stress, as defined by Eq. (3.3) (Terzaghi and Peck's principle).

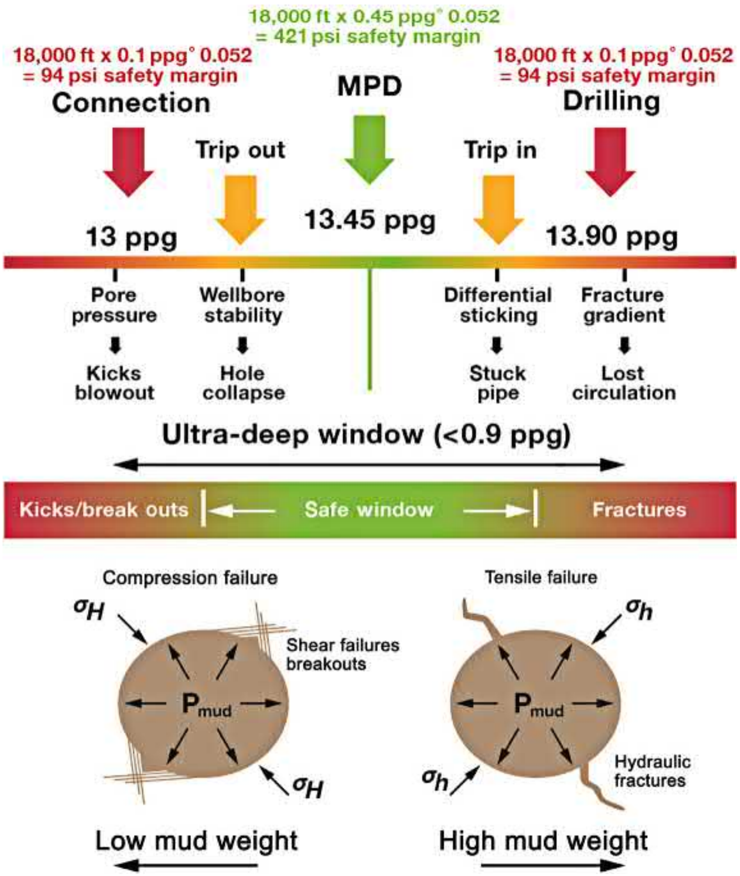


FIG. 3.10 Importance of mud weight management in narrow margin wells. *Source: Kingdom Drilling training reconstruct 2018.*

TERZAGHI PRINCIPLE LINKING THE VERTICAL STRESS (S_V) TO THE PORE PRESSURE (P_P) AND THE VERTICAL EFFECTIVE STRESS (σ'_V)

$$S_\vartheta = P_p + \sigma'_V \tag{3.3}$$

Rearrangement of Eq. (3.3) principle allows pore pressure to be defined in terms of vertical and vertical effective stress.

As can be observed in Eq. (3.4), for a given value of the vertical stress (S_v), a large value of vertical effective stress corresponds to a low pore pressure; similarly, a low vertical effective stress corresponds to high pore pressure (Fig. 3.11).

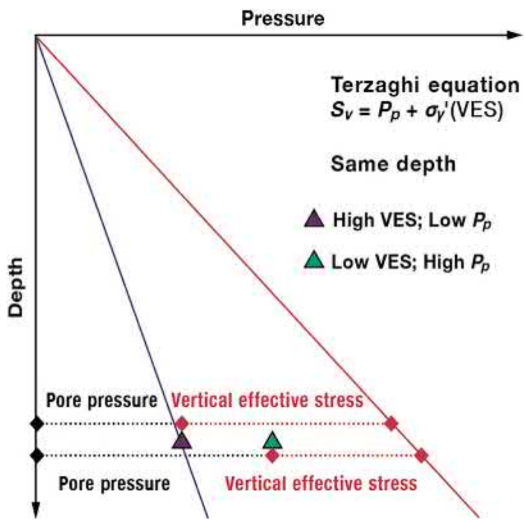


FIG. 3.11 Pressure-depth schematic plot to illustrate the principles of the Terzaghi equation. The *purple* triangle is normally pressured, hence corresponding to a high vertical effective stress for its depth. The *green* triangle has higher pressure and the vertical effective stress is smaller than for the *purple* triangle.

TERZAGHI PRINCIPLE REARRANGED TO FIND PORE PRESSURE IN TERMS OF THE VERTICAL STRESS AND VERTICAL EFFECTIVE STRESS

$$P_P = S_v - \sigma'_V \tag{3.4}$$

The vertical stress is commonly known as the overburden or lithostatic pressure and is found through modeling the bulk density data with depth.

By accurately modeling the overburden, one of the three terms of the Terzaghi Principle can be determined to an acceptably low uncertainty. With knowledge of the vertical stress, estimation of the pore pressure requires an accurate interpretation of the vertical effective stress. The vertical effective stress is determined through comparison of the wireline data with a normal compaction trend for the same data and lithology type, i.e., claystone/shale sonic velocity, resistivity and/or density. Once a normal compaction trend is established, traditional formula for estimating pore pressure via the vertical effective stress can be applied. Examples are *Eaton Ratio*, *Equivalent Depth* or suitably chosen *Modified Methods.*

Quantification of the reservoir pressure can be achieved through logging while drilling or wireline formation test tools or through a well test. However, several processes may cause reservoir pressures to not be in equilibrium within the claystone/shales above and below.

An example is through lateral drainage, where the reservoir pressures can be much less than the shales pressures above and below leading to fluid flow and hydrodynamics (e.g., Wilcox formation in Gulf of Mexico, Paleocene sand fans in Central North Sea). By contrast, there are instances when the reservoir pressures can be higher than the shales due to lateral transfer of pressures from deeper; this is associated with large structures (e.g., Nile Delta, Gulf of Mexico).

Normal Compaction Behavior

In normal compacted conditions, the vertical load increases due to sedimentation as the rock matrix naturally tries to compact. For compaction to occur, the water in the pore spaces must escape (Fig. 3.12). The compaction and dewatering process leads to a trend of decreasing porosity with increasing depth (Fig. 3.13, middle image). If the porosity is decreasing, then the rock matrix phase must support an increasing amount of the vertical load, i.e., the vertical effective stress increases (Fig. 3.13, right image). If the vertical effective stress increases with increasing depth and the rock matrix is fully compacted for the depth of burial, then the pore pressure will equal the hydrostatic gradient (Fig. 3.13, left image).

A normal compaction trend is a curve that represents the porosity or proxy of porosity (e.g., sonic velocity, resistivity, density) for a claystone/shale when it is normally pressured, and only if at its maximum depth of burial.

If a rock matrix is unable to dewater effectively under increasing vertical load, then the matrix can no longer compact (Fig. 3.14).

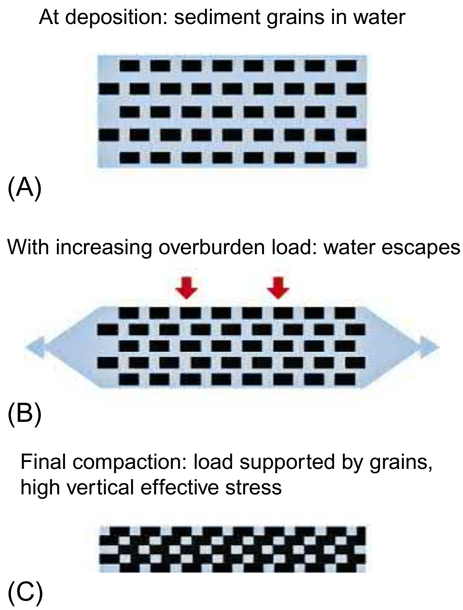


FIG. 3.12 The evolution of the compaction of sediments lain down in water that can dewater effectively: (A) Initial slurry of clay grains in water, (B) Under increasing load the water can escape and the rock compacts, and (C) Under full compaction the porosity is low therefore the vertical effective stress is high. *Source: Ikon Science, Pressures and overpressure in the subsurface course 2015.*

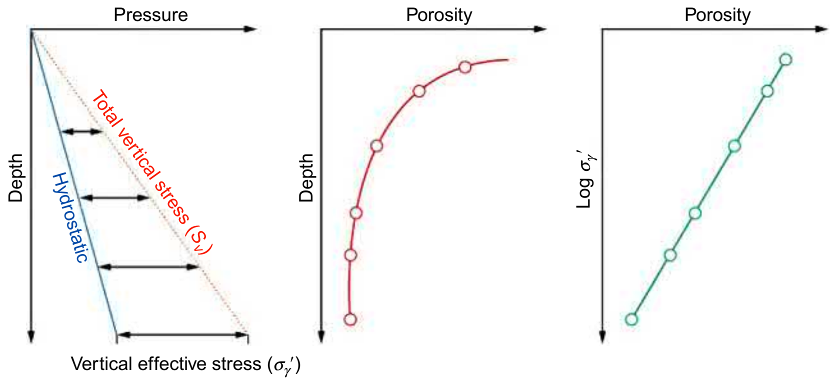


FIG. 3.13 A series of plots outlining the relationship between porosity, vertical effective stress, and pressure with increasing depth. If the rock matrices are fully compacted at all depths, then the porosity decreases with depth *(middle image)*. Therefore, the vertical effective stress increases with decreasing porosity *(right image)* and the pore pressure builds along the hydrostatic gradient with increasing vertical effective stress with increasing depth. *Source: Ikon Geoscience.*

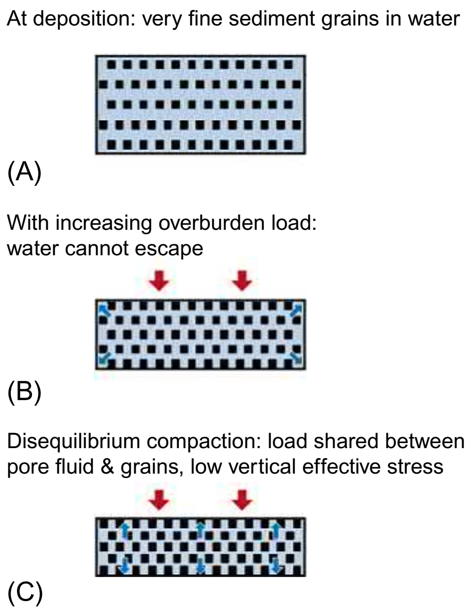


FIG. 3.14 The evolution of the compaction of sediments that cannot dewater effectively; (A) Initial slurry of clay grains in water, (B) Under increasing load the water cannot escape due to a lack of permeable pathways and the rock no longer compacts, and (C) Under full vertical load the porosity is abnormally high, the water phase is overpressured and the vertical effective stress is lower. *Source: Ikon Science, Pressures and overpressure in the subsurface course 2015.*

The inability of the rock matrix to dewater is controlled by the permeability of the sediments; a fine-grained clay-rich material will rapidly lose permeability under compaction, reducing the dewatering pathways within the rock matrix.

Once the matrix can no longer dewater it means that the porosity of the rock matrix cannot decrease (Fig. 3.14, middle image) assuming cool (<80°C) temperature conditions. In reality, the rock matrix will continue to dewater with time; however, the loss of fluid (dewatering) becomes so slow relative to the rate of burial that the porosity is effectively constant with depth.

From the Terzaghi equation, we see that the vertical stress is comprised of the pore pressure (porosity controlled) and the vertical effective stress. If the shale porosity does not change, then the vertical effective stress cannot change (Fig. 3.15, right image). A constant vertical effective stress results in a pore pressure profile (in claystone/shale) that is parallel to the vertical stress pressure (Fig. 3.15, left image).

Note: The depth at which the constant vertical effective stress profile intersects the hydrostatic gradient (*as a mathematic construct and deeper than the "top of overpressure" in these sediments*) is termed the *Fluid Retention Depth* (FRD).

Normal Compaction Trend Constraints

The first stage in building a normal compaction trend (NCT) is to apply a V-shale filter to the data. The technique for estimating pore pressure from wireline data is only valid, however, in claystone/shale dominant intervals as other lithology does not often conform to simple compaction trends. A V-shale cut-off is applied to filter out the nonclaystone/shale data from the interpretation before defining a normal compaction trend. As a final note, normal compaction trend is typically picked and constrained by:

1. Thick (>10 m), shallow, normally compacted shales
2. Sensible geological values for sea-floor log values and fully compacted matrix log responses,
3. Empirical fit to the shallowest (presumed hydrostatic) log data, and

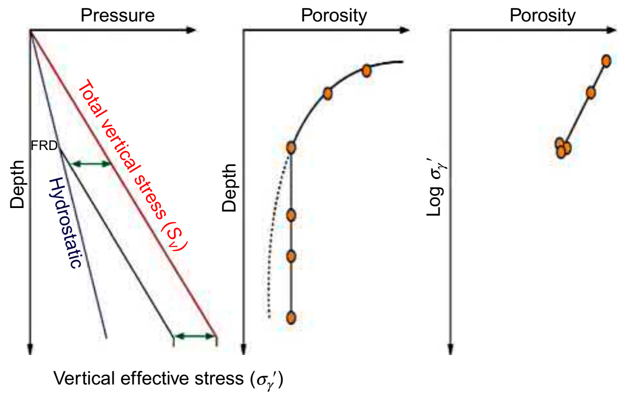


FIG. 3.15 Plots outlining relationships between porosity, vertical effective stress, and pressure with increasing depth. If the rock cannot compact (dewatering ceases) at some depth, then the porosity stops decreasing (stays constant) at the depth the rock can no longer dewater *(middle image)*. Therefore, the vertical effective stress remains constant with constant porosity *(right image)* and the pore pressure builds along a vertical stress parallel profile due to constant vertical effective stress with increasing depth. *Source: Ikon Science, Pressures and overpressure in the subsurface course 2015.*

4. Calibration to pressure and drilling history data but only to those data considered to be in equilibrium with the claystone/shales. Often the calibration phase is only applied to refine the model after an initial trend has been built using 1) and 2) above.

Petrophysics Key Analysis Elements

Shale-based pore pressure prediction relies on log data (both wireline and LWD), the quality of which can be highly variable. Therefore, to standardize these logs, a best practice workflow relies on robust petrophysics analysis to be performed on the log data during the pressure prediction workflow. From a pressure perspective, key reviews undertaken are:

1. Log conditioning (including log merging), despiking, and removal of borehole washout effects,
2. Poor wellbore quality and environmental corrections,
3. Forward modeling of missing logs, e.g., sonic and density,
4. V-Shale modeling for shale identification,
5. Density log correction for construction of an overburden model.

Note: The assessment and approach to be applied to the wireline data in the context of pore pressure prediction is typically derived from the gamma ray, sonic\Vp, resistivity, and density logs that exist and are relevant in regard to the specifics of the well to be drilled.

Log Conditioning

The wireline data gathered will likely have no petrophysical conditioning preapplied. The use of original data is preferred to avoid any bias of pore pressure prediction and interpretation process that results. Specialists or third-party company persons assigned will decide on when and how to condition the data to produce the best pore pressure predictive results. Example: identification and characterization of clean claystone/shale/sand packages.

1. The log conditioning process is generally limited to the wireline data used in pore pressure prediction, i.e., the gamma ray, calliper, sonic, resistivity, density logs.
2. Numerous logs require a variety of operations to modify the logs into the appropriate condition to conduct desired processes required, i.e.:
   a. ***Splitting, shifting, and remerging*** of data above and below a casing shoe in wells where the data were not coherent across the shoe. *Care needs to be applied not to shift data that differed across a shoe for geological reasons.*
   b. ***Despiking (clipping)*** of data to remove nongeological artifacts in the data, e.g., cycle skipping in sonic tools data.
   c. ***Smoothing of data***where numerous spikes/noise in the data exists to inhibit the ability to discern a reliable depth trend.
   d. ***Removal of borehole enlargement effects*** by removing data from the wireline log. *Careful comparison with the calliper and wellbore size logs is needed to identify the intervals affected by enlargement.*

V-Shale Modeling

A shale volume (V-shale) curve is critical to understand the ratio of sand to claystone/shale. When making a claystone/shale-based pressure prediction, porosity data from sand-rich intervals must be removed from the pressure interpretation process. Log data from sand-rich intervals also removed as sandy sediments normally do not have the same wireline data-effective stress response as the claystone/shale intervals. The V-shale curve is computed from various wireline logs such as thorium (from the spectral gamma ray log) or gamma ray GR, Density-Neutron, & Density-Sonic methods. Once computed these provide a robust workflow to compare results, adjust parameters if required. Poor wellbore quality logic is typically used to switch between methods where required and additional more simplistic methods of minimum or average VSH methods may also be employed.

Factors that affect the magnitude of the log response include wellbore diameter and different logging tools. To minimize the effect of different wellbore diameter/tools, well log data can be split into multiple working intervals based on casing points.

Different minimum and maximum values are then chosen for each casing run. In some wells data, the same minimum and maximum values are applied to multiple casing runs, but only after visual inspection of the data.

The ultimate goal is to produce a representative lithology volume for a log run over the whole borehole. Once this process is complete, a cut-off to separate sands from shales can be applied for use in the fluid pressure prediction calculation.

Pore Pressure Prediction Methods

Pore pressure prediction methods used attempt to quantify the vertical effective stress, which is then subtracted from the overburden to generate a pore pressure value for a given depth (Eq. 3.5).

Within each study, chosen prediction strategies, techniques, and methods are used to estimate the pore pressure within claystone, sands, and shales etc.; techniques are both independent and used to corroborate with each other and/or to provide an understanding of lateral variation in formation pressures that may exist.

It should be noted that all common pore pressure methods for example, (Eaton, Equivalent Depth, Bowers Loading methods) assume that the main mechanism of overpressure generation is that of disequilibrium compaction generated through burial, and that there is a velocity-effective stress relationship.

In areas that this does not occur, these example methods will be undermined and pore pressures will be underestimated (e.g., compressional systems; offshore Sabah, mixed lithology packages particularly in carbonates and salt; Offshore Morocco and Angola, high TOC shales; offshore West Africa; fault transfer of pressures; Carnarvon basin Australia, gas generation; South China Sea). In these circumstances, other methods or more integrated processes to derive and understand the pore pressures based on the geology must be constructed.

Eaton Ratio Method

The Eaton Ratio Method is an empirically derived formula to estimate the pore pressures in shales from reservoir pressure tests and wireline logs. The purpose is to develop a correlation of effective stress to the resistivity ratio (defined later) and the sonic interval transit time ratio (defined later).

The Eaton Ratio Method uses the ratio of the recorded wireline value relative to the value on the normal compaction curve raised to an exponent in conjunction with the overburden

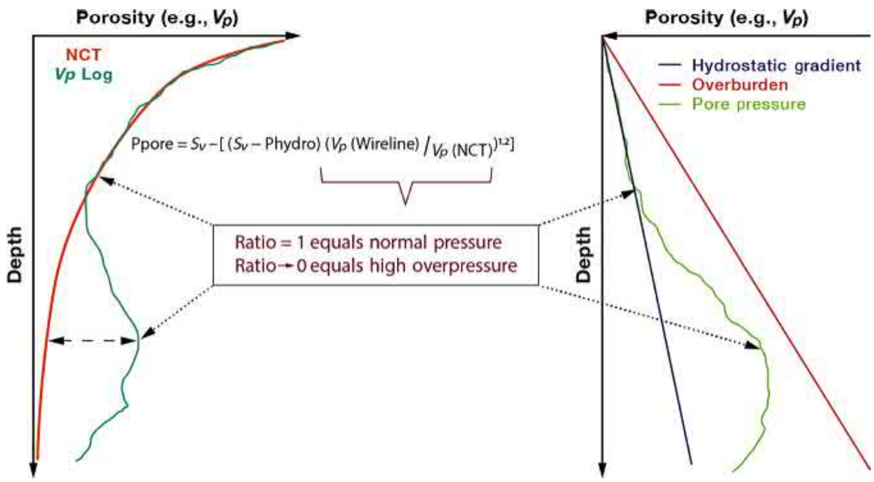


FIG. 3.16 Wireline data (e.g., V_p) and the NCT relationship and a pressure-depth plot to illustrate: Eaton Ratio Method. *Source: Ikon Science, Pressures and overpressure in the subsurface course 2015.*

and hydrostatic pressures. The value of the exponent is based on matching empirical data with outputs from the formulae; the value of the exponent is not a fixed value and can be varied, if required, to calibrate to local data. Typically, a value of 3.0 for the exponent for sonic data and 1.2 for the resistivity exponent suffice in most areas. A local calibration would be a more accurate approach given sufficient calibration data. The ratio, raised to the exponent, is then multiplied by the term "$S_v - P_{\text{hydro}}$," e.g., Eq. (3.5) to generate the Vertical Effective Stress; $S_v - P_{\text{hydro}}$ is the maximum vertical effective stress at any depth.

A ratio value close to 1.0 results in near-normal pore pressure and a value close to 0.0 results in very high overpressure (pore pressure near to the overburden pressure, see Fig. 3.16.)

One advantage of the Eaton Ratio Method is that any units for pressure or mud weight can be input for the overburden and hydrostatic pressure, e.g., kPa, kPa/m, kg/m3, and if they are consistent to all the input terms in the equation then output is in the same units.

RESISTIVITY-BASED FORMULA

EATON RATIO FORMULA TO PREDICT PORE PRESSURE FROM RESISTIVITY

$$P_{\text{pore}} = S_v - \left[\left(S_v - P_{\text{hydro}}\right) \left(\text{Resis}(\text{Wireline}) \big/ \text{Resis}(\text{NCT}) \right)^{1.2} \right] \tag{3.5}$$

P_{pore} = pore pressure; S_v = overburden pressure; P_{hydro} = hydrostatic pressure; Resis (wireline) = observed (measured) resistivity at the depth of interest (ohm m); Resis (NCT) = resistivity at the same depth on the NCT (ohm m).

VELOCITY-BASED FORMULA

EATON RATIO FORMULA TO PREDICT PORE PRESSURE FROM VELOCITY

$$P_{\text{pore}} = S_{\upsilon} - \left[\left(S_{\upsilon} - P_{\text{hydro}} \right) \left(V_p\,(\text{Wireline}) \big/ V_p\,(\text{NCT}) \right)^3 \right] \quad (3.6)$$

P_{pore} = pore pressure; S_{υ} = overburden pressure; P_{hydro} = hydrostatic pressure; V_p (Wireline) = observed (measured) velocity at the depth of interest (m/s); V_p (NCT) = velocity at the same depth on the NCT (m/s).

Equivalent Depth Method (EDM)

The Equivalent Depth Method (Fig. 3.17) is a deterministic method assumes that porosity relates to vertical effective stress; therefore, pore fluid pressure can be derived using Terzaghi's equation (Eq. 3.6). The technique is most valid for sonic/density logs and is not applied to resistivity logs as the response is sensitive to temperature. If the shallow data are of poor log quality or limited vertical extent, then application of the equivalent depth method is often problematic. An implicit assumption of the method is that the lithofacies at the depth of interest and the equivalent depth are the same, i.e., no unconformities, diagenetic alteration of claystone/shale or facies change.

Bowers Loading Method

Bowers developed a new method for estimating pore pressure from sonic velocity data. Unlike previous techniques, this method accounts for excess pressure generated by both under

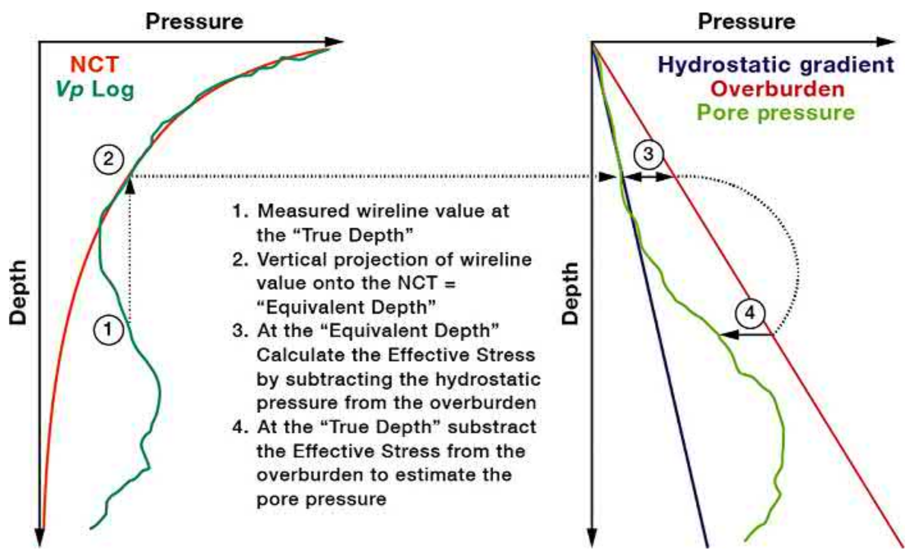


FIG. 3.17 Equivalent Depth Method Relationship between wireline data, e.g., *Vp* and NCT alongside a pressure-depth plot. *Source: Ikon Pressures and overpressure in the subsurface course 2015).*

compaction and fluid expansion mechanism such as aquathermal pressuring, hydrocarbon maturation, clay diagenesis, and charging from other zones. The method is an effective stress approach. To be able to include multiple sources of overpressure, a pair of velocity versus effective stress relationships are introduced. One relation accounts for normal and overpressure cause by compaction. The second is applied inside velocity reversal zones caused by fluid expansion mechanisms. Bowers demonstrated examples from the US Gulf Coast, the Gulf of Mexico, and the Central North Sea in a 1995 journal paper. Other pore pressure estimation approaches were examined to demonstrate how techniques unknowingly accounted for overpressure mechanism other than compaction. The paper explains how velocity versus effective stress data can be used to identify the general cause of overpressure in an operating area. Example: Empirical correlations of Hoffman and Johnson indicate that overpressure along the US Gulf Coast cannot be due to only undercompaction.

Bowers concluded that there appears to be misconceptions about fluid expansion as a source of overpressure that occurs more frequently than is generally assumed. It was surmised that velocity versus effective stress is an important factor to evaluate. Another misconception is that fluid expansion overpressure cannot be estimated from geophysical data, yet a number of pore pressure estimation methods are doing so without realizing it. It was finally stated that failing to account for the absence of fluid expansion overpressure can lead to large errors in pore pressure estimation. It is therefore important to have a systematic approach for both undercompaction and fluid expansion.

Fluid Retention Depth Analysis

The top of overpressure is the point at which the pore pressure starts to deviate from the hydrostatic line. In terms of process, as fluids are inhibited from escaping during sediment loading, porosity loss is slowed, and overpressure builds. There is a departure from the normal compaction curve at this depth. The depth of top of overpressure is controlled by permeability, rock compressibility, and sedimentation rate (Fig. 3.18).

The Fluid Retention Depth or FRD defines the "Clay/Shale Pressure Gradient" expected for continuous clay/shales. Many well profiles where clay/shale is the dominant lithology

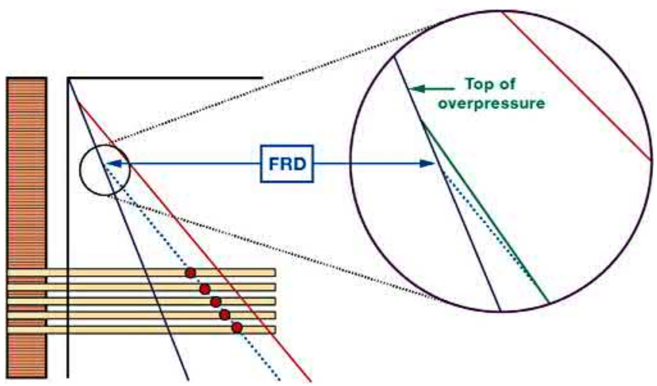


FIG. 3.18 Image to illustrate difference between the top of overpressure and the fluid retention depth. *Source: Ikon Science, Pressure and overpressures in the subsurface course, 2015.*

can be shown to have such gradients (linked to thin isolated reservoirs which have been pressure tested), typically from approximately 1.0 km below the FRD. The true "top of overpressure" is generally shallower than the FRD as it takes an interval of partial dewatering before an approximate overburden-parallel clay/shale gradient is fully developed. Below the FRD, effective stress is constant therefore porosity reduction ceases and remains constant during burial.

FLUID RETENTION DEPTH ESTIMATION

Swarbrick et al. demonstrated a broad relationship between the log of sedimentation rate and the FRD. The original sedimentation rate—FRD relationship from Swarbrick et al. was updated by Swarbrick with subsets of lithology added for clay-rich shales, silty shales, and siltstones from an increased global data set (Fig. 3.19).

Fig. 3.19 further highlights the control of both sedimentation rate and lithology on the fluid retention depth. Example: Assuming a sedimentation rate of 800 m (2625 ft) /Ma, e.g., Nile Delta, the fluid retention depth for a clay-rich shale could be as shallow as 200 m (656 ft); the FRD for a silty shale could be 800 m (2625 ft) and the FRD for a siltstone could be 1500 m (4921 ft). Typically, the more clay-rich a lithology is, then the shallower the FRD will result, as permeability is lower; hence, the rock matrix ceases to be able to dewater effectively at the shallower depth.

COMPARISON OF FRD ANALYSIS WITH NCT-DERIVED CLAY/SHALE PRESSURES

Fluid retention depth modeling is not designed to replace traditional pore pressure prediction serving to provide an independent corroboration as to the overall scope and trend of pore pressure with depth established using traditional clay/shale-based prediction particularly when only seismic velocities are available and in data-limited areas such as frontier

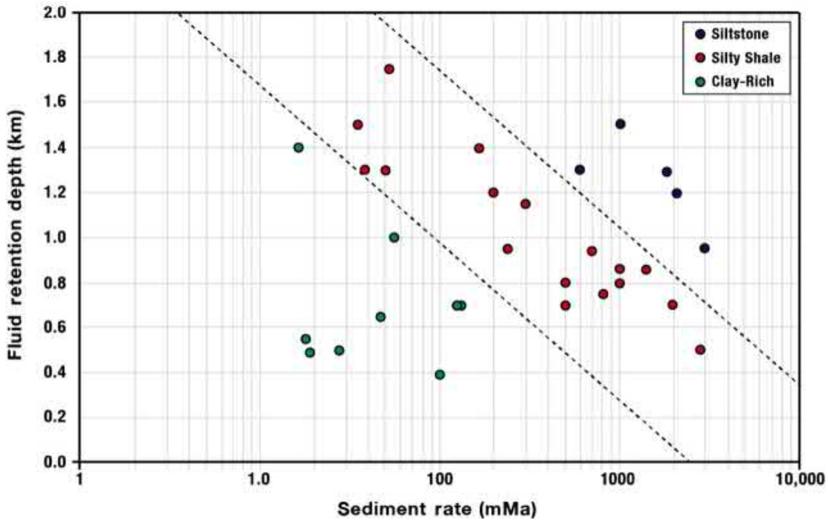


FIG. 3.19 Plot of log sedimentation rate vs. FRD for a global dataset of various lithologies. The *dashed lines* are empirically drawn to separate different lithologies.

basins. If the technique can be shown to be reliable in areas with good pore pressure control, i.e., those wells with deep high overpressure, then the effectiveness of applying the technique in frontier areas, such as the deep-water basins, is reinforced.

Fluid retention depth techniques offer an independent method to predict the range of overpressure in deep tertiary targets with potential application to deeper intervals as well. Furthermore, the technique is only applicable to young, thick clay/shale sequence practically relevant only to tertiary deltas.

Primary Reasons for Abnormal Pressure in Deepwater

Disequilibrium Compaction

Disequilibrium compaction (Fig. 3.20) is interpreted as the primary mechanism of overpressure generation in sedimentary basins, notably in rapid fine-grained depositional marine systems and environments. Rapid deposition generates overpressure, notably during high sedimentation of low permeability rock such as claystone, mud rocks, and shales, when incomplete dewatering results. Rapid increase in vertical stress by burial causes sediments to compact and expel fluids. If fluids cannot escape sufficiently rapidly, some of the compressive load is borne by the pore fluids, and overpressure develops.

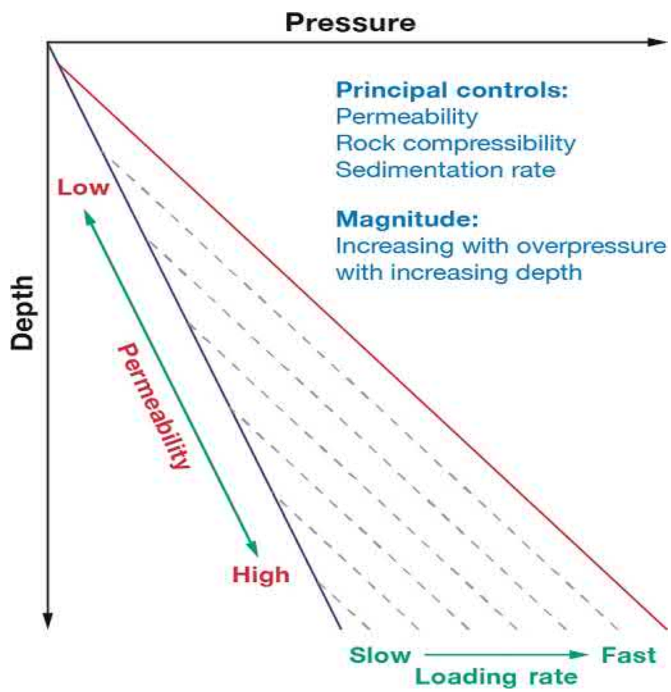


FIG. 3.20 Illustrative pressure profiles due to variable loading rates and variable permeability's. *Source: Ikon Science, Pore pressures and overpressures in the subsurface course 2015.*

If the sediment matrix is not sufficiently permeable to allow complete dewatering within the period that stress is imposed (for example during and after addition of load during sedimentation), the increment of additional stress is distributed only partially on the grains and the remainder on the fluids. *Incomplete dewatering leads to the overpressure mechanism termed "compaction disequilibrium."*

The magnitude of overpressure from compaction disequilibrium is controlled by:

1. The weight of the added load (vertical stress), and any coupled responses in the horizontal stresses, or a tectonic push.
2. Rock properties such as compressibility.
3. Rapid burial.

The principal control on dewatering is permeability, and sedimentary matrices most prone to ineffective dewatering are fine-grained matrices, such as claystone, shales, and chalk dominant ones. Interbedded coarser-grained units, within the fine-grained sediments, such as sandstones, compact at much slower rates for the same applied stress. They are influenced by the surrounding fluid pressures in the adjacent sedimentary formation matrices and will often share similar overpressures. More permeable sediments will redistribute the fluid and pressure laterally along continuous units.

Where fluid pressure redistribution occurs, the formations, and reservoirs and the adjacent fine-grained sediments, may not be in exact pressure equilibrium, especially when permeable units conduct excess fluid pressures by lateral drainage (for example direct communication to the sea bed, either directly or via faults).

During progressive burial (such as Late Cretaceous and Tertiary history in certain deepwater regions), what results is a continuous addition of vertical load, at varying rates. Continuous burial that does not generally favor pressure dissipation from fine-grained sediments would then remain over pressured (often increasing in overpressure with time).

OTHER PRESSURE MECHANISMS AND CONSIDERATIONS

Other mechanisms contributing to overpressure in basins are outlined in this section. With the exception of gas reactions, the contribution of all fluid volume change mechanisms is considered as relatively small, i.e., measured in <1000 kPa (<145 psi) under normal basin conditions; nevertheless, a brief outline of each is written for completeness. The magnitude of overpressure associated with gas generation, on the other hand, either during secondary reactions in kerogen or by in situ oil to gas cracking, can be an order of magnitude higher, i.e., 10,000 kPa; (1450 psi).

Identifying Overpressure Mechanisms

Clay/hale velocity vs. density crossplots are used to distinguish between overpressure generated through disequilibrium compaction and that generated by fluid expansion and secondary mechanisms in absence of XRD and/or cuttings analysis type data. Fig. 3.21 summarizes trends commonly identified when clay/shale velocity and density data are crossplotted. Fig. 3.21 presents that when changes in matrix grain size reflect more silt/sand or more

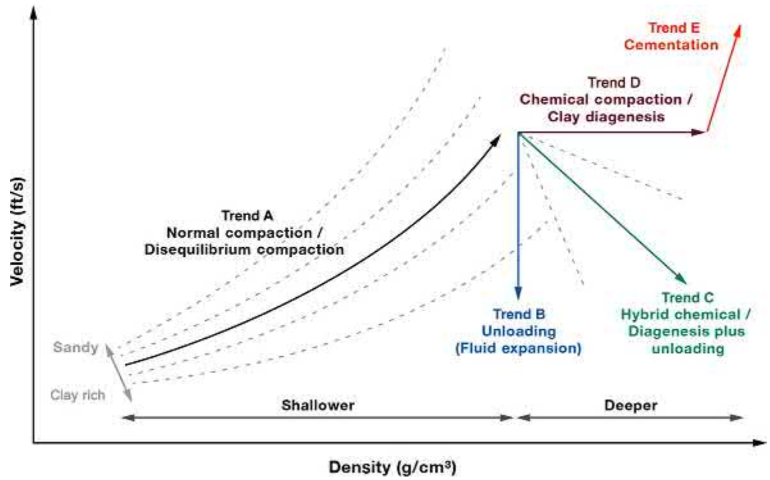


FIG. 3.21 Schematic diagram of a velocity-density crossplot showing the normal compaction trend and the possible diversions from this trend for different components of secondary overpressure generation.

clay-rich sediments moves from the data from the primary trend to a parallel trend, i.e., clay-rich lithology move slightly toward higher density and slower velocity whereas sand-rich lithology move slightly toward lower density and faster velocity, the following can be surmised:

- ***Trend A***: normal compaction trend (also applicable when compaction is reduced or ceases due to disequilibrium compaction, i.e., overpressure due to disequilibrium compaction).
- ***Trend B*****:** fluid expansion trend (significant velocity decrease and negligible increase in density), normally termed "unloading" (Bowers, 1995),
- ***Trend C***: hybrid trend, (density increase and velocity decrease), due to a combination of chemical diagenesis and consequential unloading as the overburden stress is transferred onto the fluid, due to incomplete drainage.
- ***Trend D*****:**early chemical diagenesis trend (significant density increase and negligible increase in velocity).
- ***Trend E*****:** later diagenetic change at very low porosity (high density) when velocity increases very rapidly.

In order to identify which overpressure mechanism trend(s) is active for a given sedimentary sequence or region,

- Clay/shale velocity (wireline sonic velocity) and density data are crossplotted.
- Clay/shale-rich horizons are identified by producing a V-shale log based on gamma ray cut-offs.
- All nonshale lithology is removed prior to plotting of the data, which can be usefully colored by depth or temperature.

In this process, an important distinction should be made between the secondary mechanism capable of generating pressure, such as fluid expansion and the secondary process capable of modifying the rock framework but not capable of generating addition pressure, or cementation.

Uplift

The importance of recognizing uplift has two main important factors in the pressure prediction space. First, normal compaction trends and all pore pressure methods assume that the wells are currently at their maximum burial depth; however, with uplift this may not be true. For example, Ware and Turner (2002) used measured sonic velocities in the shales to estimate the amount of uplift and erosion in the EISB. A regional compaction trend was established using wells with the longest log coverage. The compaction trend was plotted below mudline and all sonic data were moved onto the trend. The amount of vertical movement required to make the data fit the trend was the amount of uplift and erosion recorded in the publication.

The second is that in gas saturated systems can lead to a large volume increase generating overpressure (Ikon Science/HIS, 2010). Uplift of basins leads to gas expansion adding more overpressure to the system and therefore has implications for seal integrity and remigration of hydrocarbons.

In the deepwater setting, toe thrust faults at the delta front can also have the impact give rise to vertical movement and hence needs to be taken into account.

Centroid or Lateral Transfer Effect

When reservoirs are tilted and the surrounding fine-grained rocks governing the reservoir pressures are at different pressures, there is a transfer of fluids from down-dip to the crest, a process known as lateral transfer. Lateral transfer is not a mechanism as such, but rather a redistribution process. If the reservoir is surrounded in the crest position by rocks, which do not permit dissipation of the excess pressures, reservoir pressures are enhanced relative to the surrounding rocks, and are out of equilibrium with expected pressures relative to depth of burial. In the down-dip position, the reservoir overpressure will be lower than the overpressure in the associated fine-grained rocks (see Fig. 3.22).

A more rigorous sand pore pressure estimation methodology in this respect assumes that sands are only equal to the pore pressure of the encasing clay/shales at a single depth, i.e., the sand Centroid depth. This depth is equivalent to the sand body's center of pore volume much like the concept of a body's center of mass. This effect, which has been both empirically observed and calculated, using basin hydraulic flow models, is also taken as a Centroid Effect.

The Centroid depth will be some distance down dip from the crest of the sand body. That distance is a fraction of the total sand body elevation difference between the upper most crest of the sand body and its lowest most extent. The Centroid depth has been solved for some simple 2-D and 3-D sand body geometries that can be used to estimate the Centroid depths of most sands you will encounter.

The point of pressure equilibrium between the aquifer and confining beds is known as the centroid (Traugott, 1997). If the reservoir can communicate and dewater to the surface,

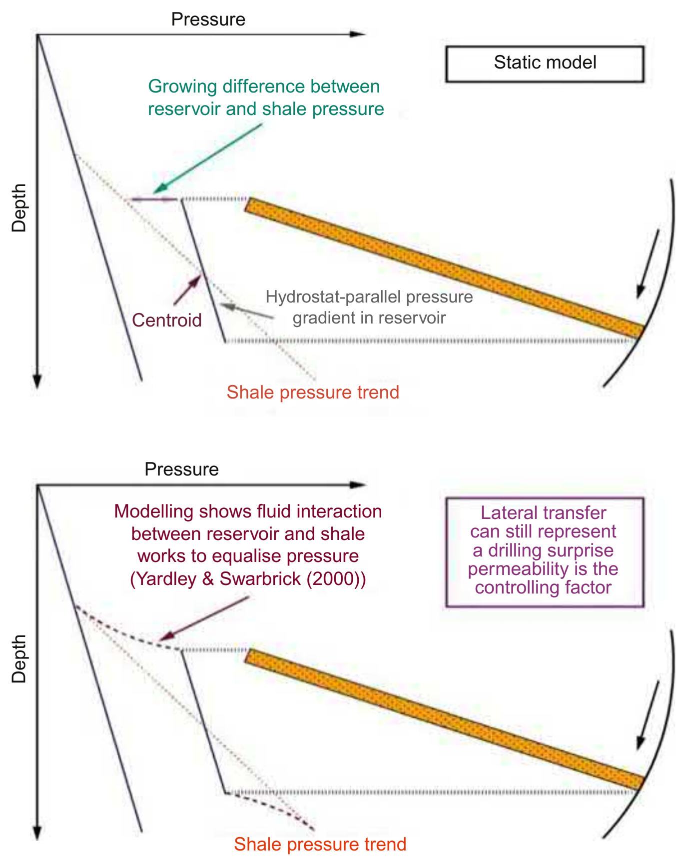


FIG. 3.22 Principles of lateral transfer (or centroid effect). *Source: Ikon Science, Pressure and overpressure in the subsurface course 2015.*

however, the entire reservoir will have lower pressures than expected for the depth of burial and referred to as a “laterally draining” reservoir.

Fig. 3.23 further illustrates a planar sand of constant thickness with its Centroid elevation located at the center of the sand elevation. Notice that the sand is only in equilibrium with the encasing shale at the Centroid depth. The sand pore pressure is greater than the shale pore pressure everywhere above the Centroid while the sand pore pressure is less than the shale pore pressure everywhere below the Centroid.

Depending on the 2D or 3D sand body geometry, that fractional distance will generally be between 1/3 and 2/3 of the total sand body elevation change.

Dipping flat, planar sands of constant thickness have 1/2 of their pore volume up dip of the center of the sand and 1/2 down dip, and therefore the Centroid will be 1/2 the distance as illustrated above in Fig. 3.23.

In deepwater, it is not uncommon for drilling targets to have very large structural elevation changes of up to 3000 ft. (914 m) or more. This can result in sands having pore pressures several pounds per gallon in excess of the encasing claystone/shale, particularly if drilled at

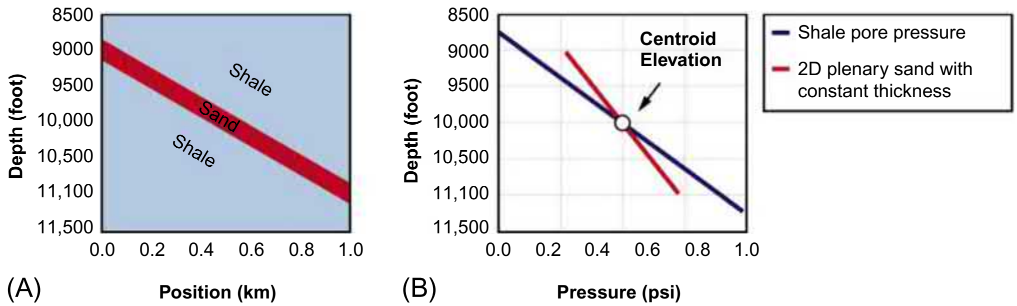


FIG. 3.23 Centroid effect 2D—Planer Geometry. (A) Cross-section. (B) Pressure-depth plot. *Source: BP/Chevron Deepwater Drilling Training Alliance slide extract.*

the crest of the sand. In many cases, this Centroid effect can result in the sand pore pressures at the crest of the structure being virtually equal to the claystone/shale fracture gradient, making drilling at the crest impossible. Some wells can only be drilled by moving the location some distance off-structure in order to penetrate the sand down flank to penetrate the sand with sufficient margin between the pore pressure and fracture gradient.

Hydrocarbon Buoyancy Effect

Overpressure can further result in the hydrocarbon phase of a petroleum accumulation, where the magnitude is assessed from knowledge of the fluid densities, and the length of the hydrocarbon column (Fig. 3.24). This effect is similar to the Centroid effect and results when the sand is filled with buoyant hydrocarbons instead of water.

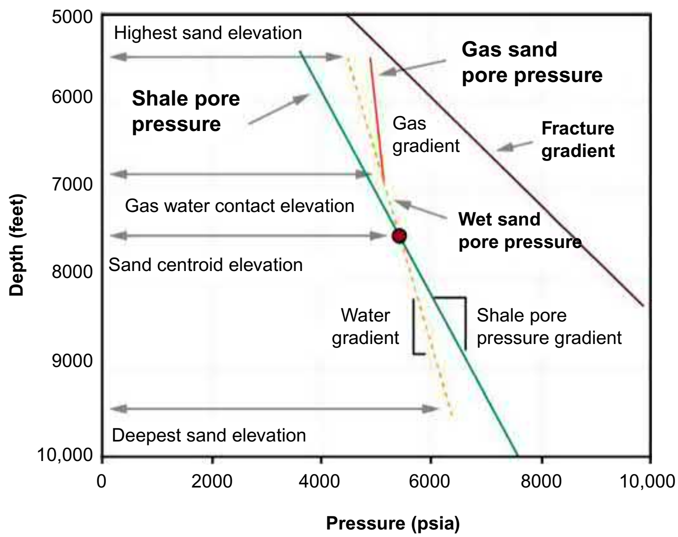


FIG. 3.24 Hydrocarbon buoyancy effect.

The buoyancy of the hydrocarbon column increases the sand pore pressure encountered. This effect increases with increasing column length and is greatest for gas columns. Fig. 3.24 illustrates this additional effect.

Key Note: Centroid and buoyancy effects *reduce drilling operating windows*, *the effect can be significant*.

Lateral Drainage

Claystone/shale and deepwater sandstone or carbonate reservoir pressures may not necessarily be in equilibrium with each other, if reservoir is isolated in three dimensions. Example: With thinly bedded strata or thicker deposits isolated by sedimentology or structure, the fluid pressure in the reservoir will be in approximate equilibrium with the surrounding claystone/shale.

Structural isolation can be due to complex rifting leaving isolated overpressured fault compartments, preventing sand-on-sand juxtaposition across faults, or by causing faults to be flow barriers due to clay smear or shale gouge building up. Stratigraphy can also lead to isolation of reservoir units. For example, isolated deepwater turbidite sandstones tend to be entirely encased in claystone/shale, whereas more parallel sandstones tend to be thicker and more extensive and therefore more able to laterally drain.

In some instances, reservoir pressure magnitude is controlled by fluids moving freely through the reservoirs, which then may not be in equilibrium with the claystone/shales in contact with the reservoir. If a deeply buried reservoir is connected to an extensive system of reservoirs and the fluid can escape, i.e., drain, the fluid pressure will be lower than the claystone/ shales and possibly at hydrostatic pressure. The necessary configuration for lateral drainage to occur is when permeable intervals underlie overpressured formations and the water from these units then flow to lower pressured intervals via basin margin faults or by connection to normally pressured outcrops or subcrops.

The *reduction of fluid overpressure in permeable units is termed "lateral drainage"*.

Drilling Risks Associated With Lateral Drainage

Lateral drainage raises risk during drilling. Example: If a laterally drained permeable unit is penetrated and the mud weight is too high, the mud may be lost to the formation, and mud weight reduced to counteract any losses. If drilling continues with a lower mud weight, it is possible that one could drill through further overpressured claystone/shale in an underbalanced condition state with no primary drilling wellbore indicator, e.g., no increase in background or connection gas. If an isolated permeable unit is then subsequently penetrated, the internal fluid pressure will be approximately equal to the overpressured zone, resulting in kick influx of fluid into the wellbore. Identifying potential laterally drained and undrained permeable units during the well planning stage is therefore very important to prevent kicks from occurring.

GENERALIZED BASIS OF DEEPWATER PRESSURE SYSTEMS

Fundamentals of Deepwater pressure Systems

The reality is that deepwater pressure regimes result from very variant sets of pressures, factors, and spatial scales, the descriptions that follow are presented to understand the fundamental basis of representative deepwater pressure systems and operating environments (Table 3.3).

TABLE 3.3 Principle Elements of a Typical Continental Margin

Continental Shelf	Continental Slope	Continental Riser	Abyssal Plain
Avg. width 75 km (47 miles)	Avg. width 10–100 km (32–320 miles)	Avg. width (0–600 km) (0–373 miles)	n/a
Average slope/gradient 1.7 m/km (0.1 degrees)	Avg. slope/gradient 70 m/km (4 degrees)	Avg. slope/gradient 1–10 m/km (0.05–0.6 degrees)	Avg. slope/gradient 1 m/km (0.05 degrees)
Avg. Water depth "WD" 130 m (426 ft)	Avg. WD 150–1500 m (492–4920 ft)	Avg. WD 1500–4000 m (4920–13,123 ft)	Avg. WD >4000 m (>13,123 ft)

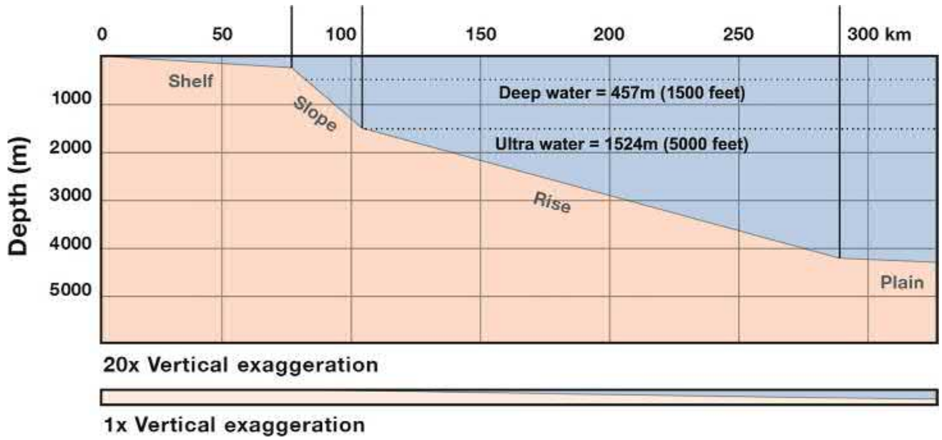


FIG. 3.25 Principle elements of a typical continental margin.

Fig. 3.25 presents the average range of parameters of width, seabed, slope, and water depth for the four principle elements of a generalized deepwater continental margin.

1. The continental shelf presented has a width of ±75 km (47 miles) and 0.1 degrees gradient.
2. Shelf water depth ranges out to about 130 m (427 ft). At the edge of the shelf, a section is characterized by a break in the seabed known as the continental slope.
3. The slope region is generally 10 m (33 ft) to 100 m (328 ft) wide with a seabed gradient of about 4 degrees. Water depths across the slope region range from 150 m (492 ft) to 1500 m (4921 ft), placing most of this region in the "deep" water realm.
4. The slope is then followed by a more modest seabed gradient section known as the continental rise. This rises up from the abyssal plain to meet the slope.
5. The width of the continental rise in this example ranges up to 600 km (373 miles). The average seabed gradient can range from 0.05 to 0.6 degrees.
6. Water depths in this particular "ultradeep" range of 1500 m (4921 ft) to 4000 m (13,123 ft).
7. Finally, the rise gives way to the abyssal plain. This region is generally flat with an average seabed gradient of 0.05 degrees and water depths >4000 m (13,123 ft.)

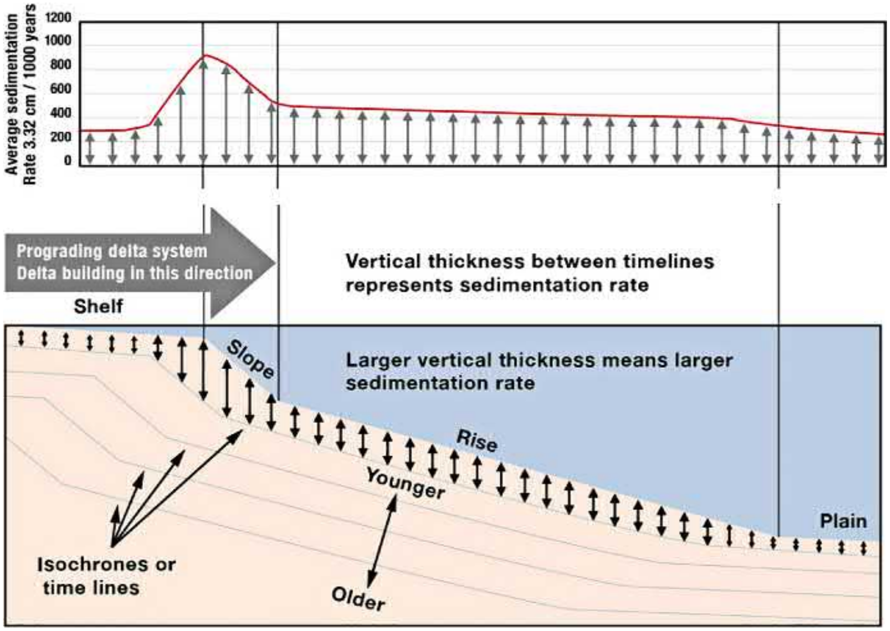


FIG. 3.26 Sedimentation rate versus water depth, generalized example *(top)*. Regional example offshore Brazil (*bottom* illustration). *Source: Marcus Assayag, Petrobras, Pre-Sub Salt Challenges presentation, London March 2010.*

TABLE 3.4 Sedimentation Rate Versus Water Depth

Continental Shelf	Continental Slope	Continental Riser	Abyssal Plain
Typical average sedimentation rate 100 to >1000 cm per 1000 years	Typical average sedimentation rate 500 to >1000 cm per 1000 years	Typical average sedimentation rate 100 to 500 cm per 1000 years	Typical average sedimentation rate 10 to 200 cm per 1000 years

Note: Deepwater marginal systems are more likely than not, far more geologically complex, vast, spatial, and variable than shallower offshore counterparts.

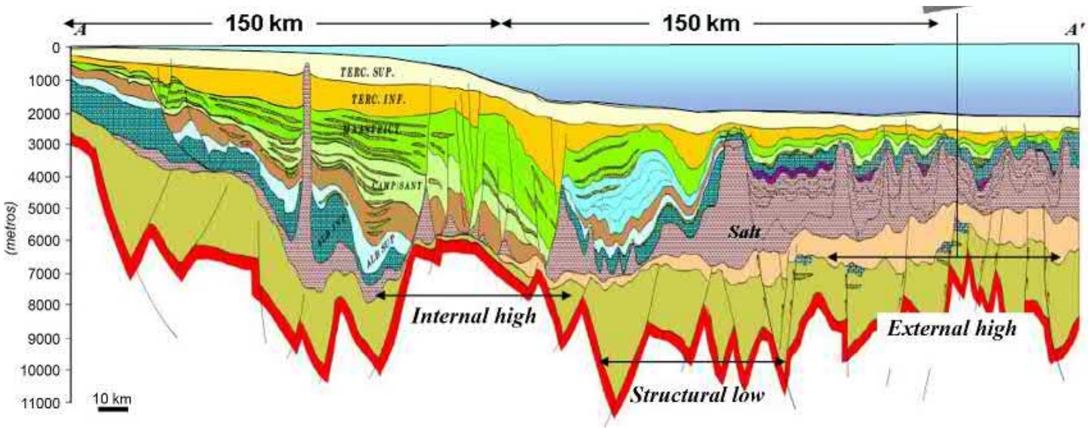
Sedimentation Rate Changes With Water Depth

Sedimentation rate defines how fast the overburden load is applied to the compacting sedimentary formations deposited. Fig. 3.26 and Table 3.4 illustrate sedimentary depositional rate variations across a continental margin in a prograding deltaic system. The vertical thickness between isochrones or equal time (age) lines indicates the relative amount of deposition for a given unit of time. Thicker units represent greater depositional rates.

As illustrated in the top portion of Fig. 3.26, the distance between the first and second isochrones can be plotted as the average sedimentation rate. Everything else being equal, *abnormal pore pressure is generated in regions of high sedimentation rate*, such as near the slope break, and the top of abnormal pressure will generally be seen much higher in the sediment section. Bear in mind these are generalizations of sedimentation rates.

Note: Very high sedimentation rates often exist in deepwater continental margins. Examples include Gulf of Mexico, Norway, Africa, India, SE Asia, in the Caspian, Caribbean, Mediterranean Seas, and other operating regions. Should high sedimentation rates exist, increased hazard and associated risks of shallow water flow, gas, hydrocarbons, over pressured and pressurized zones can result in such depositional environments.

$$\begin{bmatrix} 10 \\ 100 \\ 200 \\ 500 \\ 1000 \end{bmatrix} \cdot \text{cm} = \begin{bmatrix} 0.328 \\ 3.281 \\ 6.562 \\ 16.404 \\ 32.808 \end{bmatrix} \text{ft}$$



BRAZILIAN PRESALT SANTOS AND CAMPOS BASINS

Hydraulic Conductivity

Hydraulic conductivity defines how easily pore fluid escapes from the compacted pore space. For a given deepwater loading history, increasing sediment hydraulic conductivity increases the amount of pore fluid that will escape per unit time. On a macroscale, the gross sediment hydraulic conductivity is a function of both the amount of sand in the section and the lateral extent of the sands. Fig. 3.27 and Table 3.5 illustrate general hydraulic conductivity characteristics of the deepwater continental margin used.

1. The shelf is generally characterized by massive amounts of laterally extensive sands causing very high conductivity.
2. Deepwater slope deposition beyond the shelf break usually consists of more moderate amounts of sand and sand bodies of very limited extent. This results in low hydraulic conductivity.

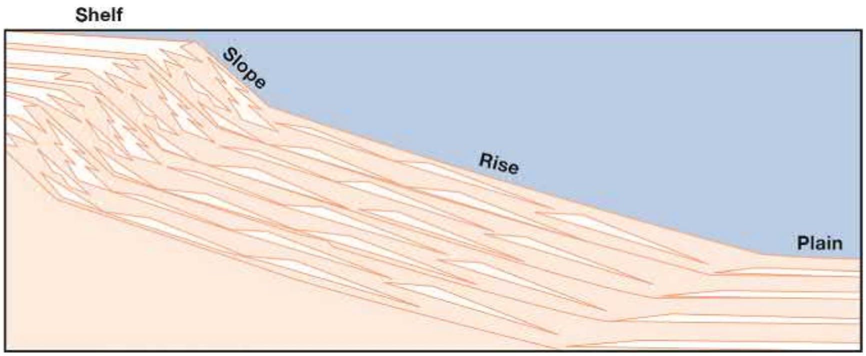


FIG. 3.27 Deepwater hydraulic conductivity.

TABLE 3.5 Deepwater Hydraulic Conductivity

Continental Shelf	Continental Slope	Continental Riser	Abyssal Plain
Massive extended Sands	*Limited extent* Sand bodies	*More Aerially* Extensive Sand	Very Extensive Sands
45%–85% Sand	20–40% Sand	20–40% Sand	15%–25% Sand
Very High Hydraulic conductivity	*Low* Hydraulic conductivity	*Moderate* Hydraulic conductivity	*Moderate to Low* Hydraulic conductivity

3. The deepwater continental rise has similar amounts of sand, but they are generally a little more extensive resulting in moderate hydraulic conductivity compared to the slope.
4. The abyssal plain generally has slightly less amounts of sand, but they may be more extensive resulting in moderate to low hydraulic conductivity.

Deepwater Pore Pressure With Water Depth

The combination of overburden, sedimentation rate, and hydraulic conductivity shall change with water depth, to result in pore-pressure variances that shall exist. Ref. Figs. 3.28, 3.29 and Table 3.6.

The deepwater shelf, features illustrated have very high hydraulic conductivity covering a long normally pressured section interval. The top of abnormal pressure generally results from 7000 m (2134 m) to 10,000 ft. (3048 m) below sea floor. The transition to abnormal pressures is extremely sharp and quickly increases at a rate of 2–5 ppg (240–599 kg/m^3) per 1000 ft. (305 m) or greater. Abnormal pressure can be up to 16–18 ppg (1917–2157 kg/m^3). The overburden is usually at its greatest on the shelf as water depth effect is less. The deepwater drilling operating window between pore pressure and fracture gradient is large in the normal pressured section. Below the first few thousand feet, drilling operating window range between pore and fracture pressure can be up to 5–8 ppg (599–959 kg/m^3).

Due to a rapid transition zone, over short vertical depths, abnormally pressured intervals will generally see this operating window decrease rapidly to as low as a 2–3 ppg (240–360 kg/m^3). The top of abnormal pressure usually rises when moving toward the shelf break and generally

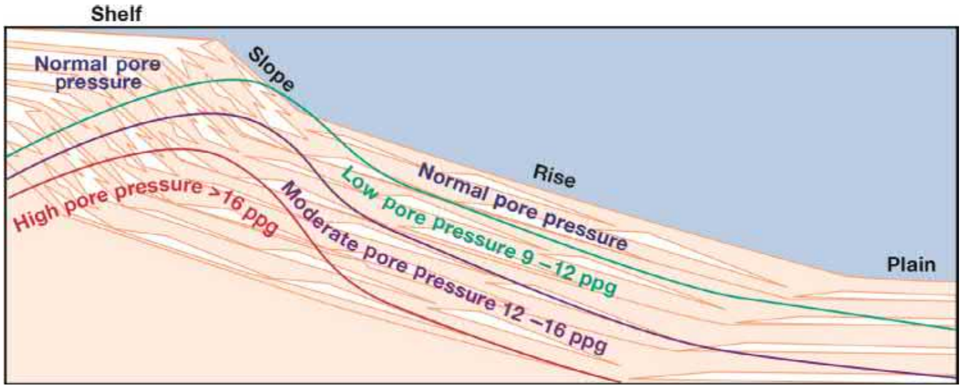


FIG. 3.28 Pore pressure change versus water depth.

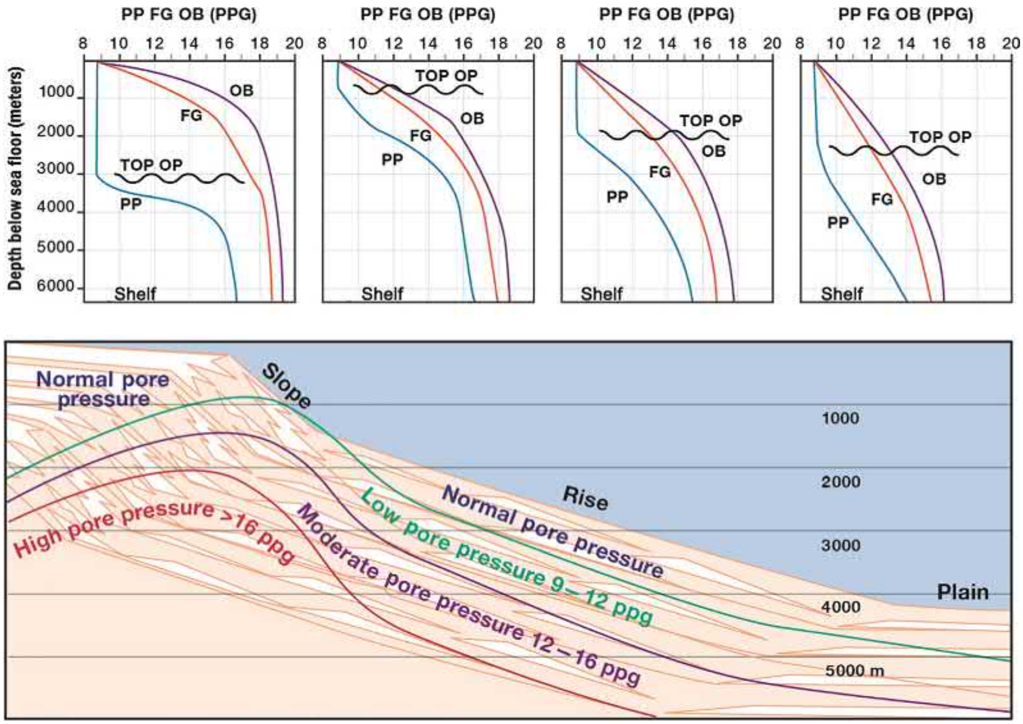


FIG. 3.29 Deepwater drilling operating window versus water depth.

occurs at its shallowest point in this slope environment due to the rapid sedimentation rate and low hydraulic conductivity. The top of abnormal pressure can be found as shallow as 1000 ft. (305 m) or less. The transition to abnormal pressure is more modest than the shelf occurring at a rate of 1–2 ppg (120–240 kg/m^3) per 1000 ft. (305 m). Deep sections can have pore pressures approaching 16–18 ppg (1917–2157 kg/m^3).

TABLE 3.6 Pore Pressure Change Versus Water Depth

Continental Shelf	Continental Slope	Continental Riser	Abyssal Plain
Top of over pressure arises at 7000–10000 ft. DBSF (2134 to 3038 m) or more	Top of over pressure generally arises at 1000–3000 ft. DBSF (305–914 m) *but can be very shallow*	Top over pressure generally arises at 2000–10000 ft. DBSF (610–3048 m)	Top over pressure generally arises at 5000–10000 ft. DBSF (1524–3048 m)
Sharp quick transition to high over pressure	Moderate transition to high over pressure	Slow transition to high over pressure	Slow transition to high over pressure
2–5 ppg per 1000 ft. in transition zone	1–2 ppg per 1000 ft. in transition zone	0.5–1 ppg per 1000 ft. in transition zone	0.5–1 ppg per 1000 ft. in transition zone

Water depths in the range of 500 (152.4 m) to 5000 ft. (1524 m) begin to have a more pronounced effect to reduce the overburden, which when coupled with the very shallow top of abnormal pressure results in a very narrow drilling operating window. The window generally ranges from 1 to 4 ppg (120–480 kg/m^3) over most of the section and thus often requires diligent management of all other pressure causes and effects.

In the ***continental rise***, which is farther out, lower sedimentation rates and somewhat higher hydraulic conductivities contribute to a deeper top of abnormal pressure than seen on the slope. The top will generally be found from 2000 to 10,000 ft. (610–3048 m) below the sea floor. The transition to abnormal pressure is slower at 0.5–1 ppg (60–120 kg/m^3). Pressures can range up to 14–18 ppg (1678–2157 kg/m^3) at depth. Very deepwater depths of 5000–10,000 ft. (1524–3048 m) or more have severely reduced the overburden.

Operating windows gradually increase with depth to a maximum at the top of overpressure where range values of 3–5 ppg (360–599 kg/m^3) exist that decrease at a slower rate to result in a 1–3 ppg (120–360 kg/m^3) depth range due to lower overburden and slow pressure transition values.

Abyssal plains finally will generally have long-normal or near-normal pressured sections due the very low sedimentation rates and moderate hydraulic conductivity. The transition to abnormal pressures is very slow at 0.5–1 ppg (60–120 kg/m^3) *I* 1000 ft. (305 m). Pressures reach to 12–14 ppg (1438–1678 kg/m^3) at depth.

Extreme water depths can result in the lowest overburdens. Operating margins remain closer throughout the entire section, e.g., within a 1–3 ppg (120–360 kg/m^3) range. Continuous management of all other wellbore pressure effect remains as essential for successful well construction and safe loss-free drilling delivery to result.

The descriptions of pore pressure profiles and deepwater drilling operating windows in this section illustrate a generalization of the four major deepwater continental margin regimes that can exist. Specifics, such as sedimentation rate, will result in very different and variant pressure profiles as shown in Figs. 3.28 and 3.29; Table 3.6. and as further outlined in this guide. However, through a better understanding of the concepts presented in this chapter, people should be better equipped to identify types and variance of deepwater pressure profiles, situational locations, depths and environment conditions presented.

REFERENCE STANDARDS

OGP Regulators use of Standards, Report 426, March 2010.

International Association of Oil and Gas Producers: Standards and guidelines for well construction and well operations. Report 485, May 2015. Ref. Appendix 1.

ISO standards. Ref. Appendix 1.

References

Bowers, G., 1995. Pore pressure estimation from velocity data. Accounting for overpressure mechanism besides compaction. vol. 10. Society of Petroleum Engineers. SPE Drilling & Completion, pp. 89–95. June.

Ikon Science/HIS, 2010. West of Shetlands Regional Pressure Study. Unpublished proprietary study . Ikon Science/HIS.

Traugott, M., 1997. Pore Pressure and Fracture Pressure Determinations in Deepwater. Deepwater Technology Supplement to World Oil. Amoco E & P Technology, Houston. August.

Further Reading

Aird, P., 2009a. Deepwater drilling, well design and construction, introduction to pore pressure and fracture gradients. Kingdom Drilling Services Ltd. July.

Aird, P., 2009b. DW Pressure Detection Methods. Kingdom Drilling Services Ltd. July.

Albertin, M., Bacon, R., Heppard, P., Onyia, E., Thomsen, L., Traugott, M., 1995. Pore Pressure Estimation in Non-Shales By The Pore Pressure Team. Applied Mechanics Technologies, Houston. December 19, Project Agreement D-95-2533. Glenn Bowers, consultant.

Baker Hughes INTEQ, 1996. Formation Pressure Evaluation, Reference Guide 80824 Rev. B. January.

Bowers, G., 1996. A Procedure for Choosing an Appropriate Pore Pressure Estimation Strategy. September 30, The Wellbore Stability Team, the Seals and Formation Pore Pressure Team, AMT Houston.

Chevron/BP, 2007. Drilling Training Alliance. Floating Drilling Manual and Deepwater Drilling Manual.

Green, S., Goodman, W., Heinemann, N., Edwards, A., 2013. Regional Pore Pressure Analysis of Offshore Newfoundland and Labrador: Unlocking the Shelf-To-Deepwater-Transition. Ikon Science.

Heppard, P.D., M.O. Traugott. n.d. Deepwater Pore Pressure Documents in the Late 1990s Amoco Exploration and Production Technology Group, Houston, TX.

Heppard, P.D., M.L. Albertin, B.E.Wagner, and D.J. Bettencourt. Success and Failure in Pressure Prediction Using Seismic Velocities in Deep Water Environments. BP-Amoco Production Company. n.d.

Knowledge Systems, Inc., 1998. Develop an Improved Methodology for Pre-Drill Geopressure Prediction for Deep Water Wells, a joint DEA Europe industry project proposed by Knowledge Systems, Inc. . December 11. (Jim Bridges, Project Manager; Don Beaumont PhD, Senior Geologic Consultant; Eamonn Doyle, Geopressure Systems; Steve Hobart, Manager Engineering Applications; Robert Dwiggins ll, Senior Engineering Consultant; Glenn Bowers Ph.D., Consultant; other industry consultants.).

Moschovidis, Z.A., Pattillo, P.D., 1995. Preliminary Guidelines for Extended Leak-off Tests By Wellbore Stability Team. December 1.

Shaker, S.S., 2008. Loss of Circulation: Causes and Consequences in Geopressured Systems. American Association of Drilling Engineers. Geopressure Analysis Services (G.A.S.). AADE-08-DF-HO-22.

The BP Amoco Pore Pressure Network, 1999. Pore Pressure Prediction and Detection Methods. A Summary of Methods and Limitations for Operational Applications. November.

CHAPTER

4

Deepwater Metocean Environments

DEEPWATER METOCEAN ENVIRONMENTS

Metocean Introduction

Recent offshore operational disasters have generated a greater awareness to offshore metocean, environmental, safety, and marine preservation within the "Blue Planet" of Earth. With such responsibility unavoidable duties must be assured by governments, regulators, agencies, operators, and/or any vested bodies involved in offshore oil and gas exploitation. Concerns raised from recent events should further demand that any industry engaged in our seas or oceans takes a far more responsible and accounted role regarding the environmental and associated standards, metrics, and controls needed to police and mitigate potential maritime or environmental damage that can result. Furthermore, it is essential to measure and monitor any impact operations may have regarding local communities, sea life, seabed colonies, shipping, fishing, military/naval operations, or any other maritime or offshore activity where the environment can potentially be harmed.

Evaluating Metocean Conditions

Meteorological conditions in this chapter pertain to combined effects of all subject matters regarding deepwater regional or well operations that result within specific operating periods. The planned acquisition of metocean information is required to assess and address the issues so that the evidence provided can potentially realize project cost savings, reduce associated operational risk, and provide safety management benefits through the planned life cycle of offshore well activities. A metocean understanding is needed to be applied through project planning, design, construction, engineering, and then safely managed and controlled. All component parts are reliant on accurate, precise, and longstanding metocean data criteria. Overestimating can result in significant project cost overruns. Underestimating outcomes could accelerate wear induce premature failure, damage or increase productive plant, equipment, or operating systems loss. Offshore operations require that all vessels, installations, systems, procedures, and processes involved both above and below the sea level are designed and applied to withstand the extremities of metocean conditions.

Metocean forecasts of wind, waves, current, ice movement, and combined effects are viewed as the crucial elements to fully comprehend in offshore design and engineering. This assures that high-risk operating activities are identified that when exposed to more extreme metocean condition limits outside of "well's specific operating conditions guidelines," are

https://doi.org/10.1016/B978-0-08-102282-5.00004-1

acted upon safely and responsibly. Deepwater operations driven primarily by metocean extremity that defines the operating conditions of continuous, restricted, or suspended work that result. A safety-first operational approach must be adopted to assure that in exceptional situational circumstance minimal lost time results.

Force majeure (unavoidable accident or catastrophe) is an evident offshore operational risk to accept. Waiting is often by far the safest best practice judgment to exercise when extreme conditions prevail.

One of the first items at a project start is therefore to consult with internal or external specialists to establish regional metocean and environmental plans and strategies, then to discuss identify and assess right from the start the major hazards/risks. It is important early in a project to decide what metocean, site survey, safe well location, environmental base line studies, assessment reports are needed to assure the delivery of optimal operational safety, value, and risk reduction, in regards to metocean terms. The end result is to produce a metocean regional strategy, establish safe operating standards, and deliver well-specific guidelines to share, distribute, and enable all operations teams, in the office, externally and at the well site. Failing to exercise these necessary metocean processes, not to obtain the necessary data, not conduct the required studies, not being able to utilize or react to real information in the correct manner is likely to result in costly endangerment to personnel, well operating loss, and environmental disruption.

In summary, metocean management is primarily based on data integrity management and quality control assessment to decide if metocean elements and data sets are well presented, measured and real or not. The physical metocean metrics used (1-year, 10-, or 50-year return period data) shall have a considerable impact on the design, engineering, and operational implication. Informed decisions must rely upon other evolved standard methods, systems, and a detailed understanding of the data source, the metocean processes, work flow and end results involved for the region or well specifics in question.

In deepwater, a project often begins with a distinct lack of information to make informed, data-driven decisions. A sound understanding of the end user's application is required to make pragmatic, informed knowledge- and experience-based choices. Assumptions and uncertainties must be well reasoned and clearly communicated to ensure data are used appropriately. Metocean and ocean work is also typically conducted via software models that use a rigorous digital workflow of system and process. This assures that critical data manipulation is fully traceable and can be efficiently reproduced following small changes at any stage in the analysis process. Proprietary software toolkits repeatedly undergo continuous development to improve functionality, including operational statistics and generation of extreme metocean values. Understanding the essential processes that impact offshore deepwater operations is fundamental. This a prerequisite for selection of appropriate data sources and assessment of data quality and integrity required inclusive of the characterization of all said processes by the operator's personnel. Who must evaluate the use of specialists to provide a clear and pragmatic interpretation of metocean data to highlight the key features of design and engineering risk significance that exists.

To summarize, in remote deepwater metocean operating environments, conditions at their extremes must be fully understood and accounted for. This chapter outlines the basic guiding principles of metocean aspects.

Metocean Operating Cause and Effect

During deepwater operations, the primary situational requirement is to maintain the vessel and all associated equipment attached to the well from moving around too much or frequently, with assured measures and plans in place to do what is needed to prevent, reduce, or mitigate operating problems, delays, damage, failure, and loss should extreme conditions arise. When drilling from floating vessels, a primary objective is to maintain all tubular or riser strings as near as vertical over the well and able to compensate against metocean cause and effects that will change vessel movement with time. Current velocity, wind, and combined conditions that will horizontally displace, pitch, roll, and heave vessels and associated suspended tubulars, in limiting circumstances and situations, can severely impact well operations. Below sea level regional effects shall vary as shown in Fig. 4.1 that can further impose major stresses on all subsea wells' components to consider in riser design. At surface, fog, snow, ice, temperature, and heavy rain can all play their part. When combined forces or horizontal offsets a vessel or systems component result to be significant, it can interrupt and increase operating safety risks to more severe exposure.

Metocean and environmental resultant forces also affect rig selection, operating practices, and often define the optimal season to minimize "waiting" lost time. The diversity of metocean and environmental conditions from selected deepwater regions as illustrated in Fig. 4.1 and Table 4.1 can be classified for low to high risk, driven and dependent upon the metocean elements, conditions, and environments that result through each season.

A diverse range of metocean hazards and risks can ultimately affect and impact; *operations, vessels, associated equipment, systems, well design, and all safety aspects*, due to all static and dynamic forms of metocean conditions and situations that prevail.

Environmental Forces

Based on metocean environmental conditions, operating modes of vessel and equipment movement placed upon all components and systems required for station keeping and all activities, the resultant forces fall into two groups: ***Aerodynamic*** and ***Hydrodynamic***. *Aerodynamic forces* result from wind forces, snow, rain, etc. and *Hydrodynamic forces* are all the forces acting on the operating vessels, including current, waves, or tidal effects.

The characteristics and reality of combined environmental forces vary significantly within deepwater regions and well specific areas as illustrated in Fig. 4.1 and Table 4.1.

When performing deepwater station keeping or well operating risk analysis and assessing capability plots for dynamic position, mooring systems, riser management analysis, etc. Deepwater operating and evident failures testify to what can go wrong if not being able to recognize, analyze, identify, risk manage, and act to control the extent of metocean forces at their probable extremes. *Example:* The greatest historical maritime loss by far is due to vessels capsizing during tropical storms, etc.

Furthermore as deepwater migrates into the seas and oceans, with a preference to remain on station for as little as 1–6 months up to 30–40 years in a production scenario. Operators must demonstrate design, engineer, and match the operating capability to exceed anticipated life cycle metocean conditions, and assure safe operating measures are managed throughout to ALARP levels, i.e., as low as is reasonable practicable.

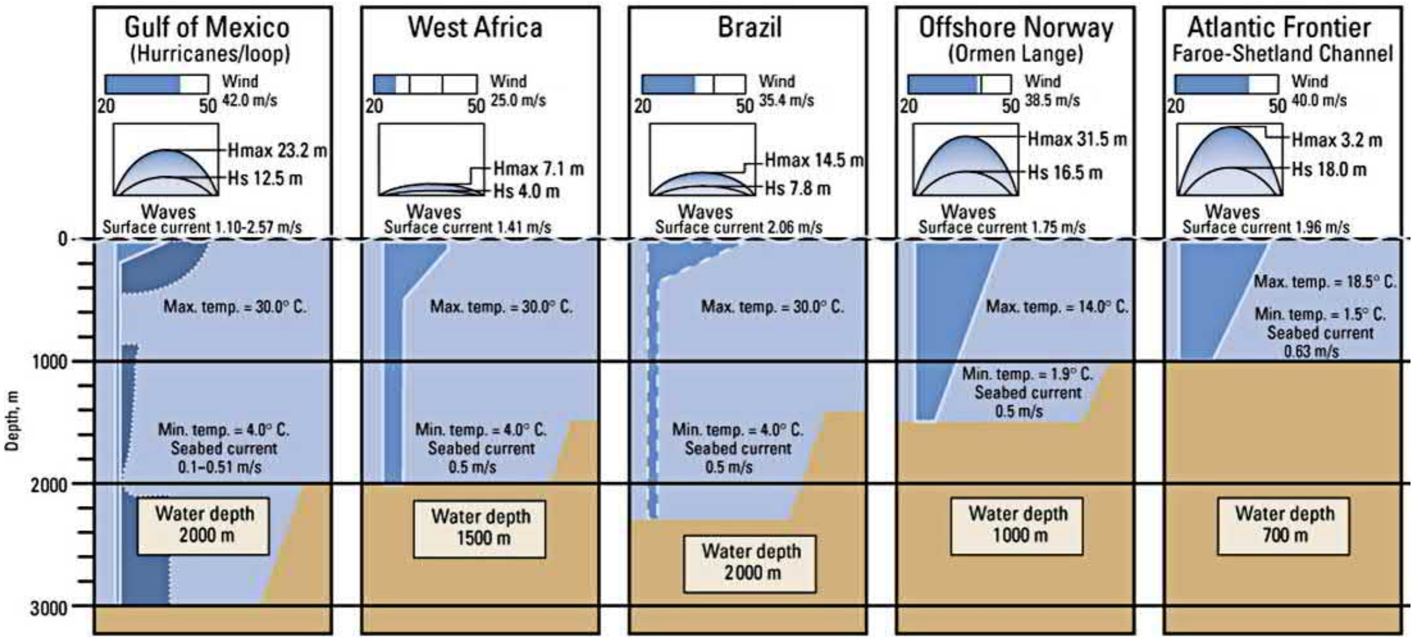


FIG. 4.1 Deepwater Environmental Metocean and oceanographic conditions. *From Kingdom Drilling.*

TABLE 4.1 Deepwater Extreme Metocean Conditions

Location	Wave Height (m)	Wave Period (s)	Wind Speed (m/s)	Current (m/s)
East Kalimantan	2	6-7	17	1.5
Campos Basin	8–10	12–15	25	1
Gulf of Mexico	11	14	44–48	1
South China Sea	12–14	13–14	45–56	1.0–2.0
Northern North Sea	15–16	15–17	38–39	0.9–1.2
West of Shetland	15–17	16–19	39–41	1.0–3.0
Atlantic Ireland	16–18	16–20	39–41	1.0–1.5
Voring Basin Norway	14–15	16–17	37–39	1.0–1.5
West Africa	4–6	10–16	20	0.3–0.6

$$\begin{bmatrix}4\\6\\8\\10\\11\\14\\15\\16\\17\\18\end{bmatrix} m = \begin{bmatrix}13\\20\\26\\33\\36\\46\\49\\52\\56\\59\end{bmatrix} ft \quad \begin{bmatrix}20\\25\\30\\35\\40\\45\\50\\55\end{bmatrix} \frac{m}{s} = \begin{bmatrix}44.7\\55.9\\67.1\\78.3\\89.5\\100.7\\111.8\\123\end{bmatrix} \frac{mile}{h} \quad \begin{bmatrix}0.25\\0.5\\0.75\\1.0\\1.25\\1.5\\2.0\\2.5\\3.0\end{bmatrix} \frac{m}{s} = \begin{bmatrix}0.8\\1.6\\2.5\\3.3\\4.1\\4.9\\6.6\\8.2\\9.8\end{bmatrix} \frac{ft}{s} \quad \begin{bmatrix}0.25\\0.5\\0.75\\1\\1.25\\1.5\\2\\2.5\\3.0\end{bmatrix} \frac{m}{s} = \begin{bmatrix}0.5\\1\\1.5\\1.9\\2.4\\2.9\\3.9\\4.9\\5.8\end{bmatrix} knot$$

Source: Kingdom Drilling, December 2017.

Technology Note: Maximum storm conditions are generally defined from theoretical and empirical determinations. However, new wave measurements from advancing technologies such as laser and radar recordings have shown inordinate discrepancies in such estimates.

EXAMPLE

The 100-year wave in extreme Atlantic margins is now understood to be perhaps 2–3 m higher than existing structures are often designed for, based on new technology data presented. In addition, because the wave crest measurement used determines the deck height of fixed or floating structures (if at operating drafts), the industry cannot address these differences without executing further investigation. Analysis of existing data and an evaluation of other measuring techniques and measurements are all examples of tasks to be performed particularly in deepwater where higher risks and uncertainties exist.

Metocean Hazards

Metocean hazards impacting deepwater well operations and limits are driven by:

1. Poor visibility
2. High waves and currents, loop and eddy currents
3. Extreme winds; hurricanes, typhoons, tornadoes, and cyclones
4. Combined forces of wind waves and currents
5. Heavy rain, snow, ice loading.

Factors that result in hazardous/risk-based operating conditions and situational events are managed and controlled through an understanding, determination, and evaluation of:

1. Extreme return periods, i.e., probability that the 1-, 10-, 50-, or 100-year storm will result
   - **(a)** At operating locations,
   - **(b)** During the operating period.
2. When "Well-Specific Operating Limits" are exceeded.
   - **(a)** Pitch, roll, heave, and offset, displacement, safe working limits exceeded.
   - **(b)** Operations are restricted or suspended.
   - **(c)** Planned and/or unplanned (emergency) contingent actions enforced.
3. Capability to maintaining vessel, ROV, or supply vessels on station.
   - **(a)** Operations are restricted or suspended.
   - **(b)** Planned and/or unplanned (emergency) disconnect from wells result.
   - **(c)** Unable to load offload tools, equipment etc. Supply chain halted.
4. Safe riser management and/or associated operating difficulties capability.
5. Pipe and tubular handling capabilities in excessive rig motion or displacement.
6. Inability to fly helicopters, crew change by boat, etc. Personnel cannot be evacuated from fixed installations or rigs.
7. Equipment fitness for purpose or resulting ineffectiveness, inefficiencies, or failure.
8. Emergency and contingent capabilities: For loss of power, rig drive or drift off, major or sudden equipment or operational failure.

Managing Deepwater Metocean Environments

If probability predicts that extreme metocean and environmental forces result during active operating periods as shown in Fig. 4.2. Far more careful and detailed planning, design, engineering, and more timely and accurate forecasting, with closer local monitoring must be afforded due to the greater risk and uncertainty of events that can result.

In the planning phase, gathering and assessing regional and site-specific data, studies are advisable particularly when more extreme metocean risks exist. The resulting cause and effect of *water-column, currents, waves winds, seafloor, shallow top-hole soil and geologic conditions* all can adversely combine to severely impact operating conditions and why all key aspects must be duly risked, managed, and controlled. Pre well operational studies must be conducted to better understand, assess, and address how to control regional metocean hazards at each specific location.

Metocean information and evident data can then put to valuable use so that personnel involved in the planning or supervision of well operations have access to all necessary data required: *wind, wave, current, tidal forecasts, and combined effects, and indirect data such as*

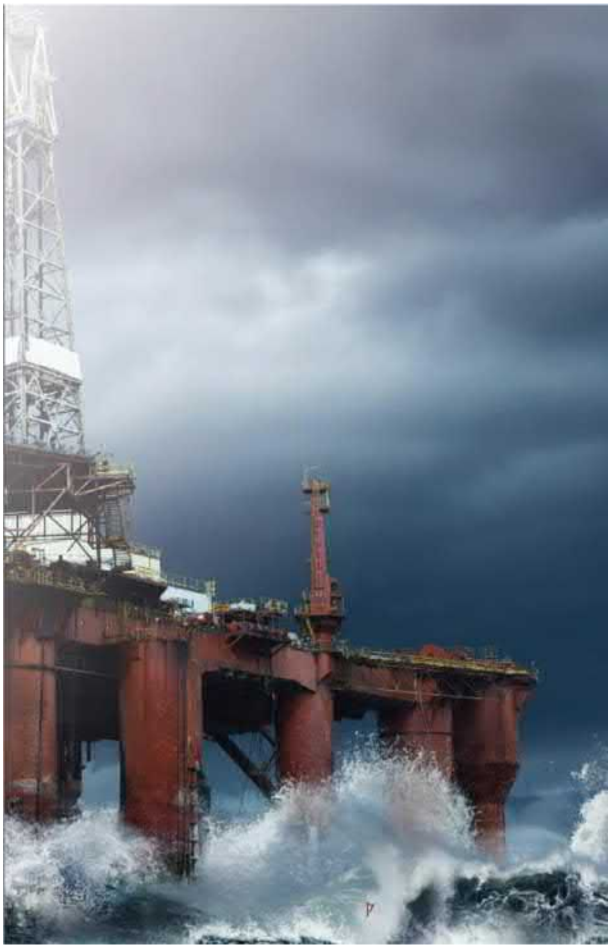


FIG. 4.2 Deepwater rig operating on the Norwegian Continental shelf. *Source: Norwegian Deepwater Program 1996–2016.*

information on migrating sediments, surface and near surface faults, shallow hazards, irregular seafloor topography, seafloor soil characteristics, manmade objects, environmental assessment, sampling requirements, shipping, and fishing operations.

Program and project aspects to consider for planning, administrating, and implementation include the following:

(a) Independent specialist review of all metocean data is fully assessed and addressed.
(b) Regulatory, standards, control, and compliance assurance all in place and met in full.
(c) Metocean hazards, risk, and potential impact of all well design and drilling operations aspects measured and assured.
(d) Well specific reviews to clearly define "Limits" to assure all contingency plans can be met in full.

Specific metocean project related metocean aspects to consider during planning are:

1. Remote operating conditions
2. Water depths
3. Seabed site and shallow surveys
4. Winds, waves, tides
5. Currents
6. Solitons
7. Environment and ecosystems
8. Ice management (if/as applicable)
9. Metocean and riser management
10. Metocean lost time events analysis.

Other associated matters to review are:

I. Operator, government, and regulatory requirements
II. Socio economic climates, cultures, working conditions etc.
III. Time of year and project duration.
IV. Rigs, specific equipment, systems
V. Skill and competency training.

Remote Operating Conditions

Due to the remoteness and nature of maritime operations, people cannot physically change the time, velocity, path, and duration of a typhoon or an internal solitary wave heading toward an operating location. What can be afforded is predictive forecasting, monitoring and detection exists to be timely acted upon. When warning signs are evident, necessary mitigations, action plans can be safely implemented for example to disconnect from the well or safely evacuate personnel from the operating installation in a more managed, coordinated manner, based on the severity of hazards/risks considered. Operators when facing real events must decide and conclude at an early stage how metocean studies, data gathering and systems management will work best for each regional organization to safely resolve the metocean risks that exist.

Remote offshore metocean predictions for well operations in principle first shall assume that future conditions match regional statistical history as illustrated in Figs. 4.5–4.8, 4.10, and 4.11 examples provided. Remote regions may lack evident data to make well-reasoned judgment calls to satisfy all safe operational concerns. Forecasting must be predicted using all information available. In this, forecaster's needs would be the provision of precise well locations, water depths, and anticipated operating periods. The common sources of information are:

1. Vessel metocean observations, reports and records from operating regions.
2. Hind cast studies of wind and/or wave parameters from analogue historical surface weather charts. *Note*: Key measurements used and defined in these processes are:
   (a) **Return Period** or Recurrence Interval, which is the average time interval between occurrences of an event, e.g., exceeding a certain wave height where the height corresponds to a 100-year return period (the 100-year wave.)
   (b) **80 Percentile**: Value that a parameter, e.g., wind speed, is <80% of the time in a given season, or the 80 Percentile value is exceeded 20% of the time.

(c) Hind Cast Calculation: In some areas, metocean and weather may not be severe; however, seasonal hurricanes, tropical storms, monsoon periods, ice management, and current events could elevate risks. All facts to be understood before operations begin.

Operating Environments: Probability and Return Period

Metocean, spectra-time data-based history values as illustrated in Fig. 4.3 is the most used method to conduct probability-based modeling on return periods. Examples, from Fig. 4.3:

- A probability of 18% is determined for a well with an estimated design life of $L=20$ years that will experience an $N=100$ year storm during its design life.
- Similarly, a short exploration with <1 year design life results in a 15% probability that it will experience the $N=10$ year storm.

Relevant qualitative and quantitative metocean data are required to assure a degree of accuracy for software-based programs to deliver precise results regarding deepwater, foundation, mooring, station keeping, riser and operational analysis by assessing combined loads and using return periods as presented in Fig. 4.3. *Note*: The value selected is driven by the expected design lifetime cycle specifics of the operative item or component assessed.

From this design principle, other extenuating metocean and environmental loads, conditions, and operating aspects are further evaluated in more detail regarding design, construction, and operating limits constraints to evolve project well-life-cycle work flow processes needed. As these issues are often not of direct concern to the assigned engineers, a genuine risk is that specific and critical metocean issues are overlooked, such that during an operating phase or situational a lost time event can result to severely impact project delivery. The importance to assure specialists is resourced and assigned to deliver the desired results and recommend corrective operative actions to be taken cannot be overstated.

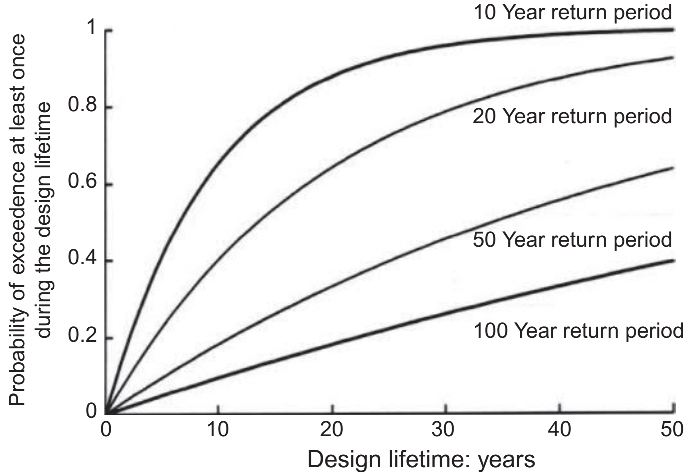


FIG. 4.3 Probability and return period. *From Kingdom Drilling training construct.*

Water Depth

A key component in deepwater is water depths as illustrated in Fig. 4.4. As water depths progress beyond 1000 m (3,281 ft) to >1500 m (4,921 ft), metocean, environments, and conditions change to reflect the following:

1. Lower ambient temperatures from sea level to the seabed. Different current profiles, strengths, and temperatures often result at variant depths.
2. Higher hydrostatic pressures at the seabed.
3. Reduced pressure margins between pore and fracture regimes.
4. Reduced operating margins that drive more casing and contingent string requirements than a conventional well design norm.

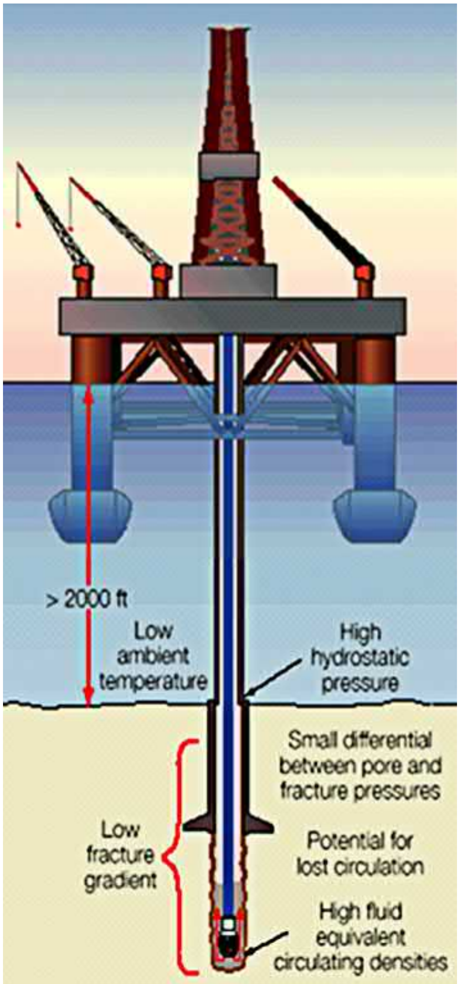


FIG. 4.4 Water depth effects on cementing. *Source: Kingdom Drilling training 2002.*

5. Item 4 leads to extended operating time and added well risks and costs.
6. Greater potential for shallow geological hazards and risks to result.
7. Drilling tools, equipment, systems, and technologies may not be suited for deepwater.
8. New and adaptive technology required. *Examples*: *Mooring, dynamic positioning, subsea wellheads,* etc. *are often water depth and seabed conditions dependent.*

Seabed, Site Surveys

Metocean seabed and site surveys in associations with geotechnical and environmental work scopes conducted require assessment once a prospect is approved. Surveys to consider are:

1. Preliminary desk study,
2. Shallow geophysical survey,
3. Shallow-penetration geotechnical survey,
4. Deep-penetration geotechnical survey,
5. Metrological and oceanographic metocean survey,
6. Environmental base line survey, assessments, short- and long-term studies.

SITE SURVEY IN DEEP WATER

Project surveys take a more managed approach to assure that all metocean, environment, seabed, and surrounding conditions are attended to, and that all operational hazards, risks, and associated issues that exist are suitably worked and addressed.

Although metocean, seabed mapping, site and environmental survey is typically the standard norm to be acquired in some form for the majority of offshore projects, surveys are considered more difficult when water depths exceed 800 m (2625 ft), with costs spiraling significantly. Beyond 1300 m (4265 ft), standard survey equipment will often not work. More specialized equipment and more compliant fit for purpose vessels and systems are now demanded but are often limited in supply, and come at far greater costs. Another factor is that it is often impractical to mobilize for a one-off deepwater site survey. To determine specific project needs in the short and long term, a full assessment of all deepwater site survey requirements has to be met, ranked, valued, risked and prioritized, with key issues then outlined, managed, discussed, and to be decided as follows:

1. *Workscope*—Clear defined site survey work scope to meet project needs.
2. *Local legislation*—Are there specific requirements for site surveys? Can an alternative approach to site hazards be justified? Example: By drilling a pilot hole.
3. *Regulations, standards, and practices*—It is not normal for operators to conduct conventional site surveys in deepwater, although some do so as a matter of course.
4. *Drilling contractor insurance requirements*—Contractor needs may have to be satisfied. *Example*: A full assessment of shallow hazard and description of typical seabed conditions may need to be assessed using best available data.
5. *Delivery/outcomes required*, i.e., safe, effective, and efficient operations result.

The output from simple desk studies and all other data gathering methods can support assessing specific site survey requirements to meet each project's specific needs. All factors are then gathered to ultimately result in a "Site Survey Assessment" and "Drilling Constraint Appraisal" documents to serve as an auditable, managed, controlled, and documented evident process. These would include all metocean and site survey information as required by the Operator, Drilling Contractors, and insurers in conjunction with any metocean or environmental project needs.

IMPORTANCE OF DEEPWATER SITE SURVEYS

Should metocean, seabed, shallow hazards and risks, as outlined in Chapter 2 and supplemented in Table 4.2, not be suitably identified, evaluated, and risked early in the project. A lack of prevention or mitigation can result in lost time, cost overruns and negative operational impacts, e.g., *unable to jet, conductor slumping, riser, drillstring or casing failure*, etc.

Poor operating outcomes often result directly due to the lack of information obtained from all metocean and site survey work deemed critical to take account for:

1. All regional and well site–related hazards
2. Risk assessment of well locations that pose a threat to vessels and operating integrity
3. Risk prevention and mitigating measures to minimize operating loss time events that can often result.

Visibility

Poor visibility above and below sea level has resulted in operating difficulties in deepwater.

TABLE 4.2 Deepwater Site Survey Shallow Hazard Risks and Mitigations

Area of Interest or Source of Risk	Source of Data and Mitigation of Risk
Shallow water flow or gas assessment	3D seismic calibrated by high-resolution seismic. This method will depend on the quality of seismic data available for reinterpretation. It should be sufficiently accurate to provide a shallow flow/gas assessment. Extensive high-resolution survey can be justified to assist selection even for a low-risk spud location, e.g., if the area is prone to shallow flow or gas
Shallow soils	Use regional data if available for anchor holding assessment and conductor design. In wildcat areas, it may be necessary to survey seabed with drop cores to get estimation of seabed conditions. This can be combined with the Environmental Survey if required
Seabed slope	Admiralty or maritime charts may provide adequate mapping of seabed in some areas. The 3D and high-resolution seismic can also provide bathymetry
Obstructions	Conduct desk study to check for obstruction in the seabed area and ensure that anchors (if used) are not placed near such obstructions. Survey seabed with the ROV prior to spud to avoid local obstructions such as boulders
In situ hydrates	Assess the 3D and high-resolution seismic for evidence of hydrate layers below seabed. If possible, avoid drilling through known hydrate zones
Shallow flows	Review regional data and examine the 3D and high-resolution seismic for evidence of dewatering events to assess risk of encountering a shallow water or gas flow
Seabed environment conditions	A survey taking seabed samples and recording ROV video footage of areas of interest on the seabed may be required unless regional data are considered adequate

EXAMPLE

During Greenland exploration campaigns, significant fog was risked at a 20%–30% probability based on historic data during May to July peak periods with visibility envisaged <0.5 nautical miles. The period for fog also coincided with peak iceberg management requirements. The key operational issue in this respect was that it is far more difficult to manage icebergs via sonar. However, the central issue was regarding helicopter crew change that could not be conducted for extended fog-bound periods. The only alternative was vessel to vessel transfer that was in this case feasible due to two evident reasons. First the operator had in country a multipurpose support and "hotel vessel" capable of conducting large crew changes. The second reason was that median wave height in the summer operating periods offshore Greenland is <1 m for extended periods that permitted safe risk-based personnel transfers to result. This serves as a reminder that complimentary metocean conditions can enhance well operations.

Other examples in fog-infested areas are well known and often result in summer operating periods and in far more remote exposed regions, e.g., *offshore Canada, North Sea, Norwegian areas. Persistent fog and far greater median wave heights create real crew change challenges for operator***s** *on a frequent basis. Higher waves also result in iceberg alleys, at times being almost impossible to manage with greater wave height severely restricting radar detection and monitoring capabilities.*

Visibility subsurface is also problematical at times due to metocean conditions that can exist and result. *Example: Plankton blooming seasons (Offshore Namibia and in other natural maritime habitats) or after specific storm disturbances on the seabed. Events reduce ROV visibility to than 1–2 m restricting operating capabilities unless contingent plans are in place*, i.e., *use of high-resolution sonar methods for operations to safely continue despite the lack of visibility.*

Wind, Waves, and Tides

WIND

Wind is a major structural force and has a direct influence regarding metocean sea states and current circulation effects. It can also affect nontidal surge elevation. Wind conditions also are important when evaluating operational planning, station keeping, crane, helicopter, well activities, and safe operating limits. It is also important to consider regional, local, and seasonal wind variations and conditions where operations are conducted. (For metocean wind applications, Elsevier*'s Offshore Operations and Facilities: Equipment and Procedures*, written in 2014, Chapter 1, pages 3–12 covers wind theory principles and practices in explicit detail.) The imperative for offshore operations in respect to wind is to define the reference elevation (above the sea level) and duration basis of wind speed.

The generally quoted reference level of 10 m (33 ft) and 50 m (164 ft) above sea surface level is used unless otherwise defined, e.g.*, Helideck may be the reference used.*

Wind speed is often quoted as a scalar value associated with one-hour vector-average wind velocity, or as a defined gust speed. In meteorological forecasting, wind speeds are commonly quoted as 10-min mean values. General wind terms and definitions are outlined in Table 4.3 and further illustrated in Figs. 4.5–4.8.

TABLE 4.3 Wind Terms and Definitions

Wind Terms	Description
Gust	A sudden, brief increased wind speed (duration <20 s)
Gale	Winds up to Beaufort force 8 (34–40 knots). Gusts reaching 43–51 knots
Severe gale	Winds of force 9 (41–47 knots) or gusts reaching 52–60 knots
Storm	Winds of force 10 (48–55 knots) or gusts reaching 61–68 knots
Violent storm	Winds of force 11 (56–63 knots) or gusts of 69 knots or more
Hurricane force	Winds of force 12 (64 knots or more)

$$\begin{bmatrix} 30\text{knot} \\ 40\text{knot} \\ 50\text{knot} \\ 60\text{knot} \\ 70\text{knot} \end{bmatrix} = \begin{bmatrix} 15.4 \\ 20.6 \\ 25.7 \\ 30.9 \\ 36 \end{bmatrix} \frac{\text{m}}{\text{s}}$$

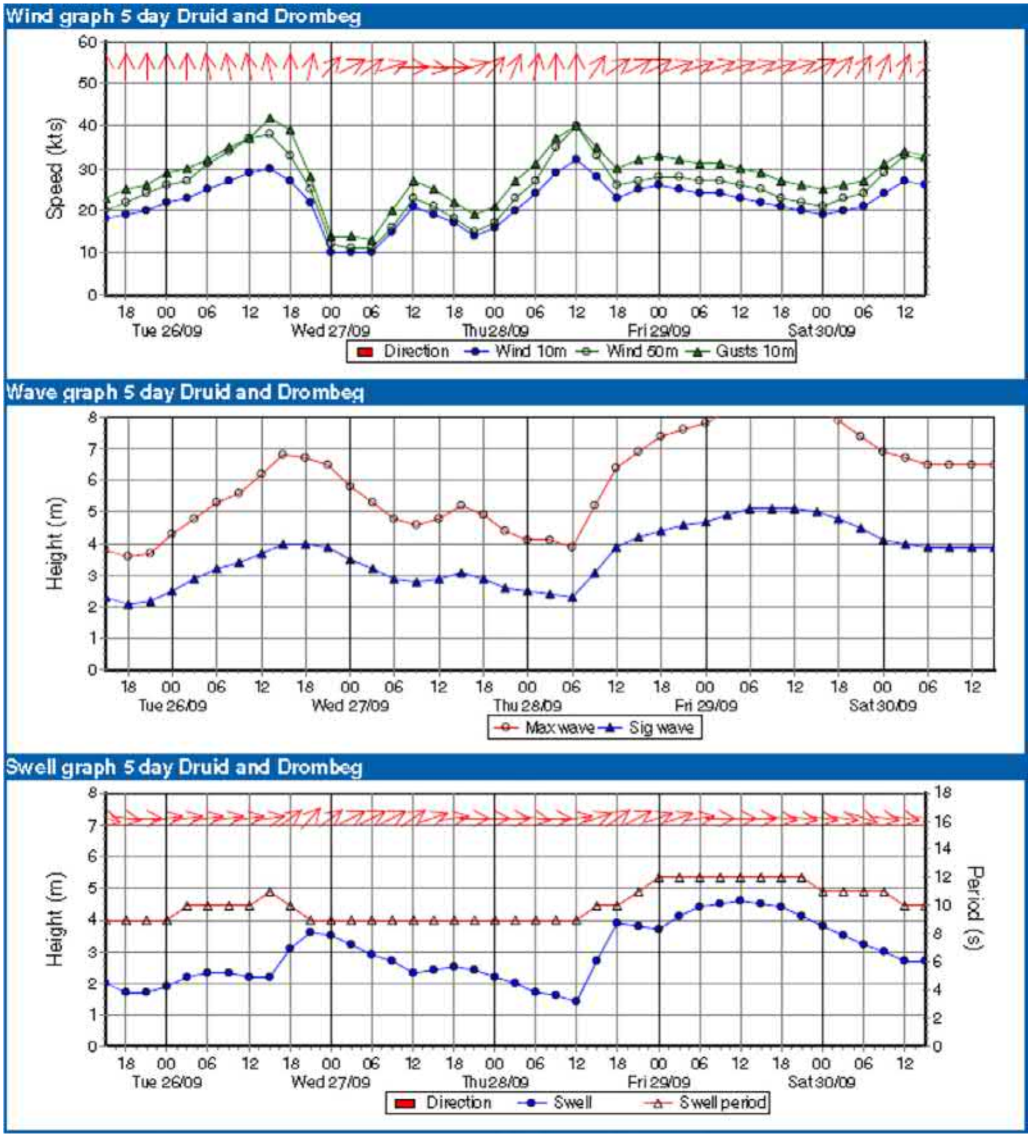


FIG. 4.5 Deepwater meteorological forecast. *From MeteoGroup, offshore@meteogroup.com.*

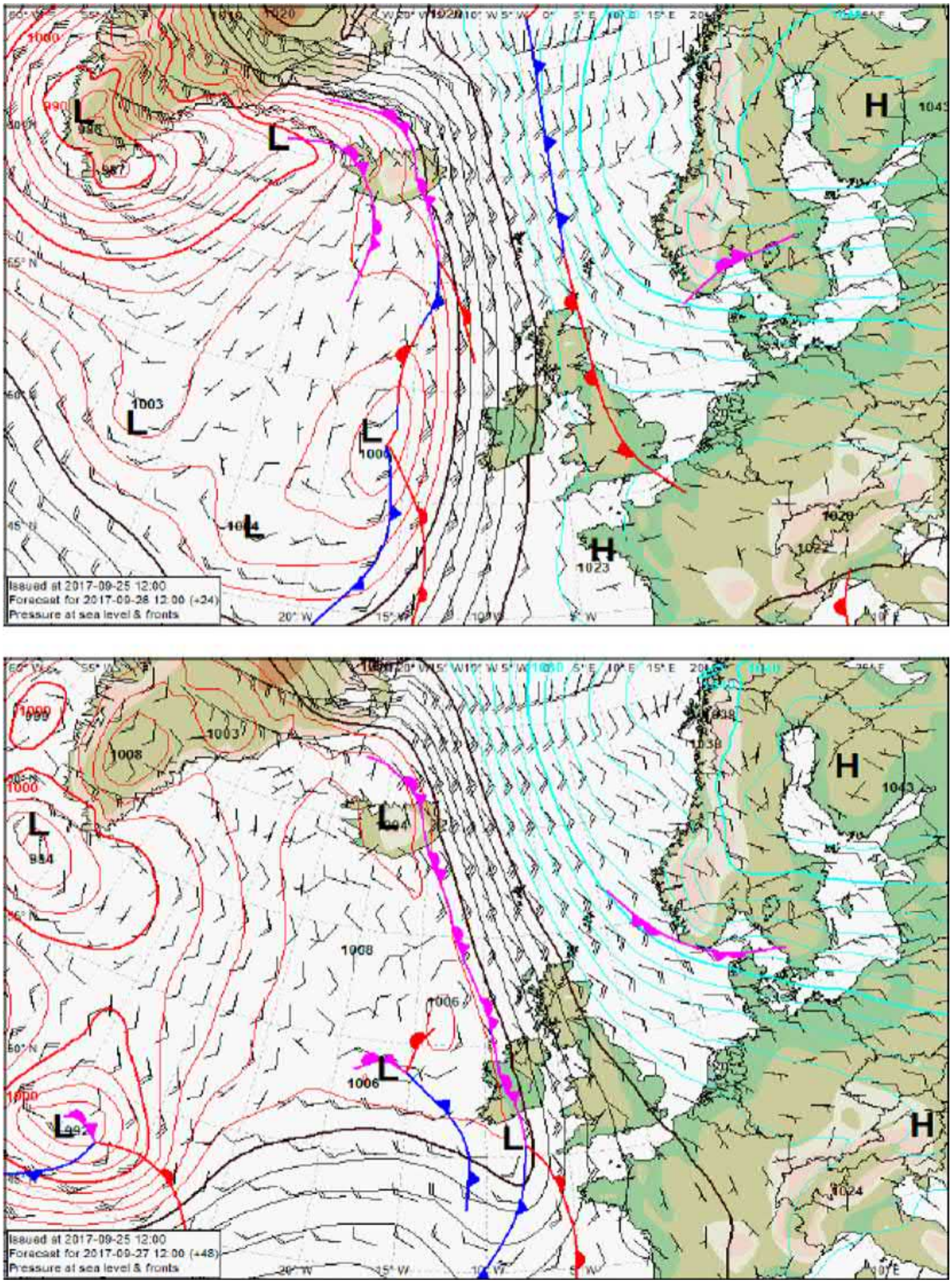
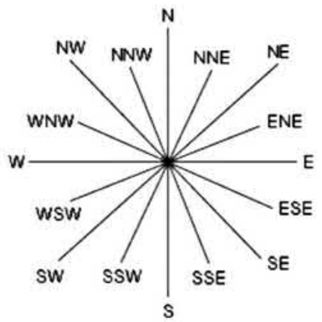


FIG. 4.6 "Atlantic margins" Synoptic charts for forecasted period. *From MeteoGroup, offshore@meteogroup.com.*

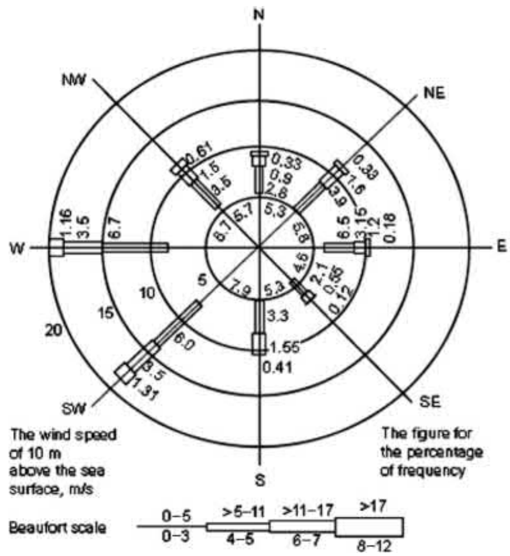
Wind scale	Wind name	State of the sea	Sea Wave Height, m		Equivalent wind velocity		
			General	Highest	n mile/h	km/h	m/s
0	No wind	As a mirror			<1	<1	0
1	No wind	Wavelet	0.1	0.1	1–3	1 5	0.3–1.5
2	Breeze	Small wave	0.2	0.3	4–6	6–11	1.6–3.3
3	Gentle breeze	Small wave	0.3	1.0	7–10	12–19	3.4–5.4
4	Moderate breeze	Light waves	1.0	1.5	11–16	20–28	5.5–7.9
5	Cool breeze	Waves	2.0	2.5	17–21	29–38	8.0–10.7
6	Strong breeze	Big Wave	3.0	4.0	22–27	39–49	10.8–13.8
7	Moderate breeze	Billow	4.0	5.5	28–33	50–61	13.9–17.1
8	Gale	Wild waves	5.5	7.5	34–40	62–74	17.2–20.7
9	Strong gale		7.0	10.0	41–47	75–88	20.8–24.4
10	Whole gale	Turbulent	9.0	12.5	48–55	89–102	24.5–28.4
11	Storm wind	Can't imagine	11.0	16.0	56–63	103–117	28.5–32.6
12	Hurricane		14.0	>16.0	64–71	118–133	32.7–36.9
13			>14.0		72–80	134–149	37.0–41.4
14					81–89	150–166	41.5–46.1
15					90–99	167–183	46.2–50.9
16					100–108	184–201	51.0–56.0
17					109–118	202–220	56.1–61.2

Note: 1 n mile 1852 m.



The wind direction is that from where the wind comes fron
In meteorology, 16 azimuths are usually used to describe w
direction that in a clockwise direction are described as:
N (North), NNE (North of Northeast), NE (Northeast), ENE (East of Northeast), E (East), ESE (East of Southeast), SE (Southeast), SSE (South of Southeast), S (South), SSW (South of Southwest), SW (Southwest), WSW (West of Southwest), W (West), the WNW (West of Northwest), NW (Northwest), and NNW (North of Northwest), as shown

FIG. 4.7 Wind, sea-state, and wave height classification and velocities. *Source: Offshore Operations Facilities: Equipment and Procedures, 2014 Elsevier.*



The Wind Rose illustrated, presents the wind direction, velocity (strength), and the percentage frequency of the wind in a region

1. **Wind direction**: is typically illustrated via 16 directional lines on the wind rose graphic, with each line representing one of the wind directions. In this illustration only 8 wind directions are presented
2. **Wind strength**: The width of the rectangles along the 8 directional lines sections of the wind rose state the strength of the wind. Strength can be shown by the wind velocity, and/or the Beaufort wind scale. The rectangle width expresses the graduated scale of wind strength. The scale illustrated is the Beaufort wind scale from 0 to >17. The rectangular length represents the wind velocity (m/s) at 10 m above the sea surface, marked on the right of the rectangle
3. **Frequency percentage of the wind**: The equally spaced concentric circles in the wind rose graphic represent the percentage frequency of the wind. Starting from the center of the circle, each interval is 5%. In this illustration four numbers (5%, 10%, 15%, 20%) are represented by concentric circles to display the wind frequency percentage, and the numbers marked out near the center of the first concentric circles represents the percentage frequency of wind in the eight directions corresponding to the eight lines

FIG. 4.8 Wind Rose example and explanation. *Source: Offshore Operations Facilities: Equipment and Procedures, 2014 Elsevier.*

STORMS

Extreme storms are a major metocean operating concern particularly in situations with dynamically positioned or moored vessels, where if warnings can be forecasted in sufficient time, vessels can move off location and out of harm's way as operating systems are designed to accommodate planned or emergency events. The time to secure well(s) and recover the subsea BOP and marine riser may also be required before beginning the evacuation procedure before a storm's extreme path impacts the operating installation, well infrastructure, or location. Methods to shorten the location abandonment time in such situational events, such as the use of Cameron's proven and award winning "freestanding drilling riser," as illustrated in Fig. 4.9.

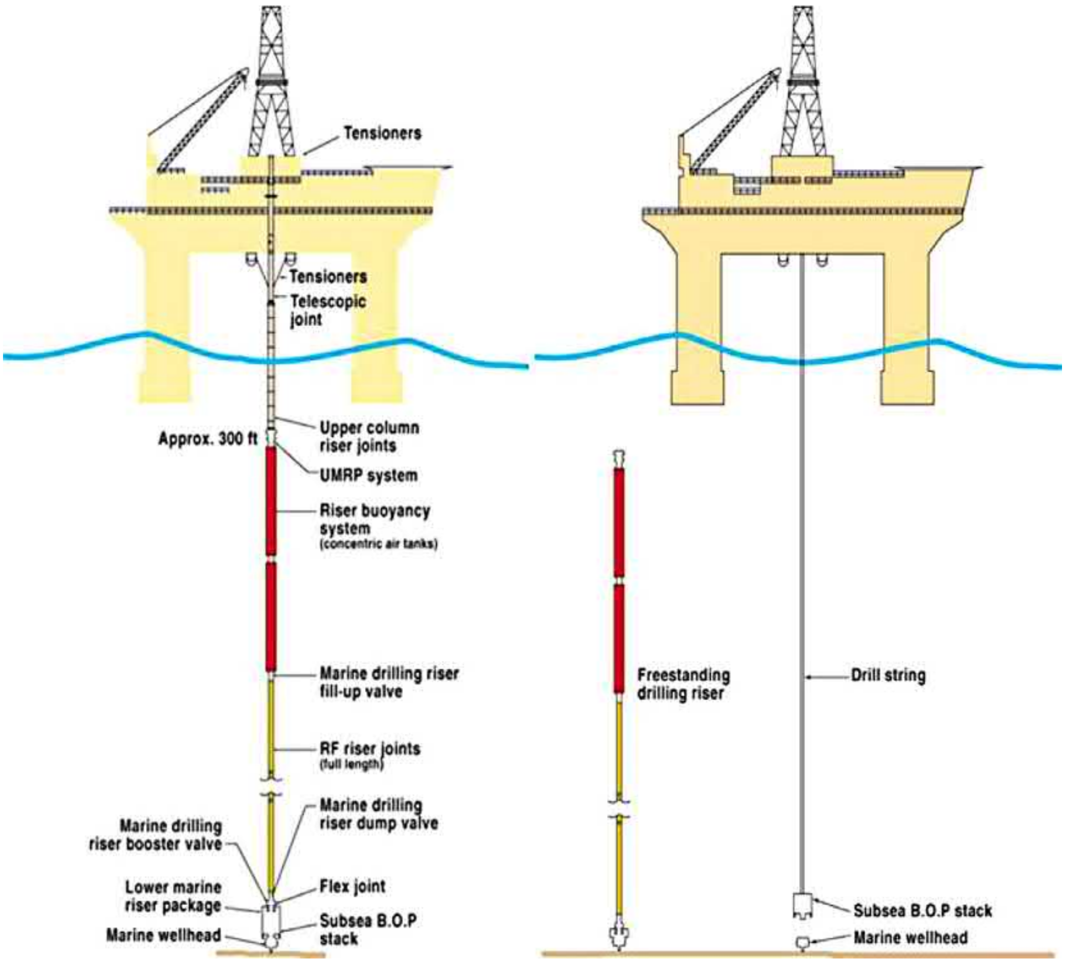


FIG. 4.9 Principle of Cameron's free standing drilling riser system. Left image: operating configuration; Right image: after disconnect. *Source: http://www.offshore-mag.com Editor Leonard Le Blanc 03/01/1998.*

The magnitude and character of storms also vary greatly across operating regions as illustrated in this chapter. What remains the same is that design and operating criteria for extreme situational events can primarily be derived via hindcast modeling to provide a reasoned degree of accuracy as to worst-case limits that evidently can exist, which is then compared to extreme event real-time data that results.

EXAMPLE

During early West of Shetland frontier Deepwater Exploration drilling in the 1980s, the forecasts experienced at the well locations often bore little resemblance to the forecasts received from the meteorologists. However, with time real data provided from the rigs, models, data sets and forecasting quickly improved.

Another example is that during a 1998 Falklands offshore exploration drilling campaign hurricane winds were forecast once every 10 years. What resulted in the basin during the drilling operating period where six wells were drilled were *three hurricane wind events experienced in less than 6 months*.

CYCLONES AND HURRICANES

Tropical cyclones are natural hazards that have caused significant lost time deepwater operational delays. As these operating conditions frequently exist, they must be better understood, planned, and accounted for.

Hurricanes tend to form in the Atlantic or Northeast Pacific, typhoons in the Northwest Pacific. In the Indian Ocean and South Pacific, these events also result and are termed as cyclone or tropical cyclone events (Fig. 4.10).

Note: These events are not commonly experienced offshore Canada/Greenland/UK/Norway and other deepwater regions. Fig. 4.10 represents worldwide distribution and Fig. 4.11 presents data from the South China Sea areas over a 50-year period.

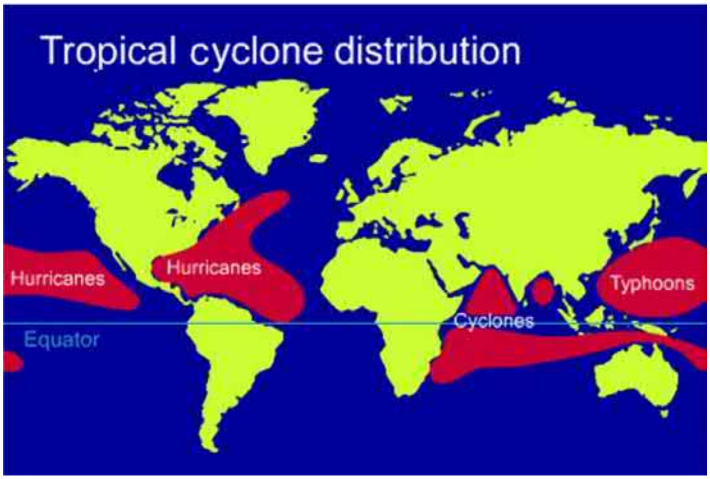


FIG. 4.10 Worldwide tropical cyclone distribution. *From Kingdom Drilling training construct.*

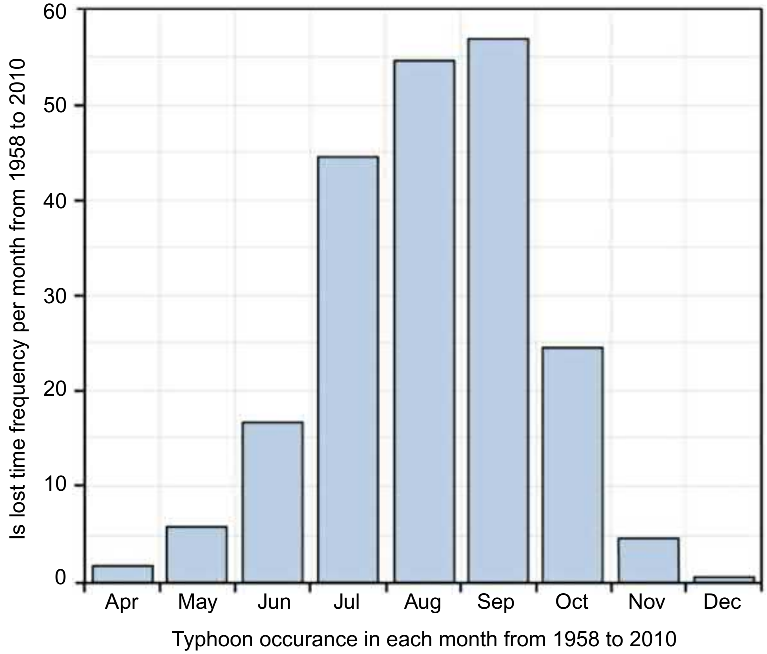


FIG. 4.11 Typhoons in South China Sea (April to December from 1958 to 2010). *Source: Xu Liangbin, Jiang Shiquan, Zhou Jianliang. Research Institute, Beijing, China, 2013.*

Wind Forecasting

Wind forecasting provides the most common sources of wind data from *coastal weather stations*, although stations are too distant from offshore deepwater locations.

VESSEL OBSERVATIONS

Vessel observations are the most accurate but may not experience the maximum storm conditions.

HINDCAST STUDIES

Hindcast studies develop wind information, which is input for wave generation. Since wind is not the ultimate objective, the information may be questionable.

WIND LOADS

The wind load generally assesses the horizontal tractive force of the wind pressure acting on the vessel facility and/or engineering structures, inclusive of the torque force on the fixed end.

Waves

WAVES SOURCES

Improvements of numerical simulation models for deepwater waves and winds have been carried out in several steps.

EXAMPLE

In 2006 Norwegian bodies developed a new and improved hindcast model based on an original third-generation wave model, to improve both wind and sea temperature fields and a more exact ice border movement. A new hindcast archive was also completed in 2009 covering an area from west of Ireland to the Kara Sea. Data are now available in 10-km grids with a database archive covering a period from 1957 to 2016. Verification and improvement is now being performed continuously with this model now the standard in Norway and regional use.

When modern models are not afforded, vessel observations and hindcast studies remain the best available information sources for wave data. Key terms and definitions of waves are further outlined in Table 4.4 and illustrated in Fig. 4.5.

VESSEL OBSERVATIONS

Are averaged and broken down into cumulative percentage of occurrence and plotted on log-type charts.

HINDCAST STUDIES

When available are used to determine 80% weather and the 1-year, 10-, and 50-year waves.

Note: *Elsevier's Offshore Operations and Facilities: Equipment and Procedures, written in 2014, Chapter* 1 comprehensively covers: Tides, currents, and current forces theory principles and practices in detail from pages 13–24, addresses waves and random wave spectrums in pages 23–51 and wave theory, wave forces, and ocean waves in pages 51–93.

Deepwater Sand Waves

Recent sea bottom surveys carried out in a project in 2009 at the continental margin within the western part of the Barents Sea discovered asymmetric sand wave patterns up to 6 m (20 ft)

TABLE 4.4 General Wind and Sea State Terms and Definitions

Wave Terms and Definitions		Sea States	
Significant wave height (Hs)	The average of the highest one-third wave heights in a given set of waves. (Approximately equal to visual estimation of wave height by a trained observer.)	Very rough wave height	4–6 m (13–20 ft)
Expected maximum wave height (Hmax)	A statistical estimate of the maximum wave height occurring in a given set of waves. The ratio of expected maximum to significant wave height depends on the number of waves in the set and is approximately 1.9 for a 3-h time period	High wave height	6–9 m (20–30 ft)
Significant wave period (Ts)	The average period of the highest one-third of waves in a given set of waves. The period of the highest wave in the set is approximately equal to the significant period	Very high wave height	9–14 m (30–46 ft)
Moderate wave height	1.25–2.5 m (4–8 ft)	Phenomenal wave height	More than 14 m (>46 ft)
Rough wave height	2.5–4 m (8–13 ft)		

Source:Kingdom Drilling 2018.

in height at 450–700 m (1476–2297 ft) water depth. The Norwegian deepwater program (NDP) then established a crossdisciplinary study, and as costs were shared between governmental bodies and NDP, new and histrionic information on deep-water drifting of these sand waves was obtained.

Because the role of sea and ocean currents is critical for both the formation and the maintenance of sand wave fields, and a combined effect of the Norwegian Atlantic Current, internal waves moving up and down the slope and spatially and temporally changing eddies were interpreted to cause eroded sand to accumulate.

Good agreement between current measurements and current modeling, in an 800-m (2625 ft) grid size, contributed to the surprising results obtained.

Solitons

Hazardous events with reported costly disruption to offshore operations in the Andaman Sea, East Coast deepwater India, and documented journal paper events within the China Sea have led to the ongoing research being conducted today to better recognize and identify the cause and effects and better understanding of solitons *(also referred to as internal solitary waves or IWs.)*

EXAMPLE

In the western South China Sea CSC, internal solitary waves (IWs) have been reported to have amplitudes of 170 m, half widths of 3 km, and phase speeds of 2.9 ± 0.1 m/s. Other similar events reportedly appeared over continental shelf regions and where brackish water overlies salt water at the outlet of large rivers, such as the Estremadura Promontory off the West Iberian Coast and Mascarene Plateau of the Indian Ocean.

In the context of metocean, solitons are solitary, large-amplitude, high-frequency internal gravity waves, associated with strong oscillating and rapidly varying currents. They are recognized as quite common worldwide internal metocean dynamics features within continental slope and shelf regions within seas and oceans, represented as a singular wave that travels within a stratified (sea water) fluid medium with different masses, density interface water levels, and not at surface. Solitons exist, it is currently understood, from two resulting sets of conditions:

1. Stratified seawater where density must increase continuously or discontinuously with water depth due to changes of temperature and/or salinity.
2. Disturbance of the seawater by currents flowing over a rugged seabed, by a moving submarine navigation or triggered by a marine earthquake.

Solitons often have ranges of *Wave Lengths* from dozens to hundreds of kilometers long, *Period*s from dozens of minutes to several hours, and *Large Amplitudes* from several to hundreds of meters. *Example, as experienced in the western South China Sea.*

Solitons are further understood to be generated where water is flowing over areas of uneven topography, characterized by strong currents in both horizontal and vertical direction that occur infrequently but due to the extent of their water flow are understood to be tidal or similar events in origin. These waves can cause strong shear flow in seawater during development spreading, and exert strong shearing forces as well as a large lateral deviation to a drilling vessel or riser in a rapid escalating event, that in a worst-case situational event could establish conditions that could result in a marine riser or drillstring failure. Guo et al.

researched the dynamic responses of a top tensioned riser under combined excitation of a singular wave, surface wave, and vessel motion. Deng et al. (2015) also proposed a quasistatic procedure to evaluate the impact of such a wave on a connected drilling riser under combined loads of ocean currents, surface and internal solitary waves. These references contribute to remind drilling and subsea engineers to be alert to all hazards and risks that can exist and then to assure that effective design shall account for internal wave effects.

To date the focus is on the generation, distribution, and impact of these waves on theoretical cylindrical piles and risers where scope remains for further analysis of how internal waves influence deepwater operations, notably in regard to riser dynamics excited by internal waves and countermeasures to prevent, reduce, or eliminate risks.

Advanced warning is believed to be the main mitigating measure to reduce soliton risks prior to operational arrival and to minimize lost time or negative impacts that can result. *Examples: Vessels listing, being forced off station, operational delays, DP/mooring systems placed under greater station keeping requirements, ROV difficulties, hazardous operating conditions, situations,* etc. As solitons approach from an established direction, early detection and mitigation can take effect to timely act to reduce risk imposed at the work place via a real-time moored monitoring system placed to record current speed profile data and the direction of soliton approach.

Predicting location and intensity of soliton hazards is today a further deepwater challenge where existing methods are highly conservative. Projects do however exist to quantify the soliton hazard in operating regions through using field observations to evaluate a more detailed numerical model with the intent to be able to better predict currents at any location within the study areas. Data then can be put to good effect to improve aspects of deepwater operational activities.

SOLITONS, 2017 RESEARCH INSTITUTE CONCLUSIONS

The Research Institute of the China National Offshore Oil Corporation provided a coupling dynamic method for floating drilling vessels riser system (Fig. 4.12) that is concluded to be closer to the real situation than a single riser model. The method considers an extreme hydraulic situation, i.e., the combined excitation of ocean currents, surface waves and internal waves, and the force from vessel surge in a same 2D plane. The governing equation is calculated by FEM and the Wilson-algorithm. The preconditioned GMRES, which could improve the precision and efficiency of the numerical solution, is adopted to solve the large, sparse nonsymmetric linear system each time during domain iteration.

Case studies from the South China Sea revealed that internal solitary wave exists as a two-layer seawater model that generates an increase in the flow velocity and accelerates in the upper seawater layer with an inverse flow in the lower seawater layer.

The shearing flow profile resulted to increase the drift amplitude as it contacts the floating vessel and riser system to result in rapid and increased station holding difficulties, with higher resultant forces to the top and the bottom of the riser system.

What was concluded was that a better design is needed be to run slick larger and thicker-walled riser joints in adjacent upper seawater layers in the subsea interval where internal waves exist, i.e., *in this case stated as the riser joints in the depth range 0–200 m under sea level should be strengthened.*

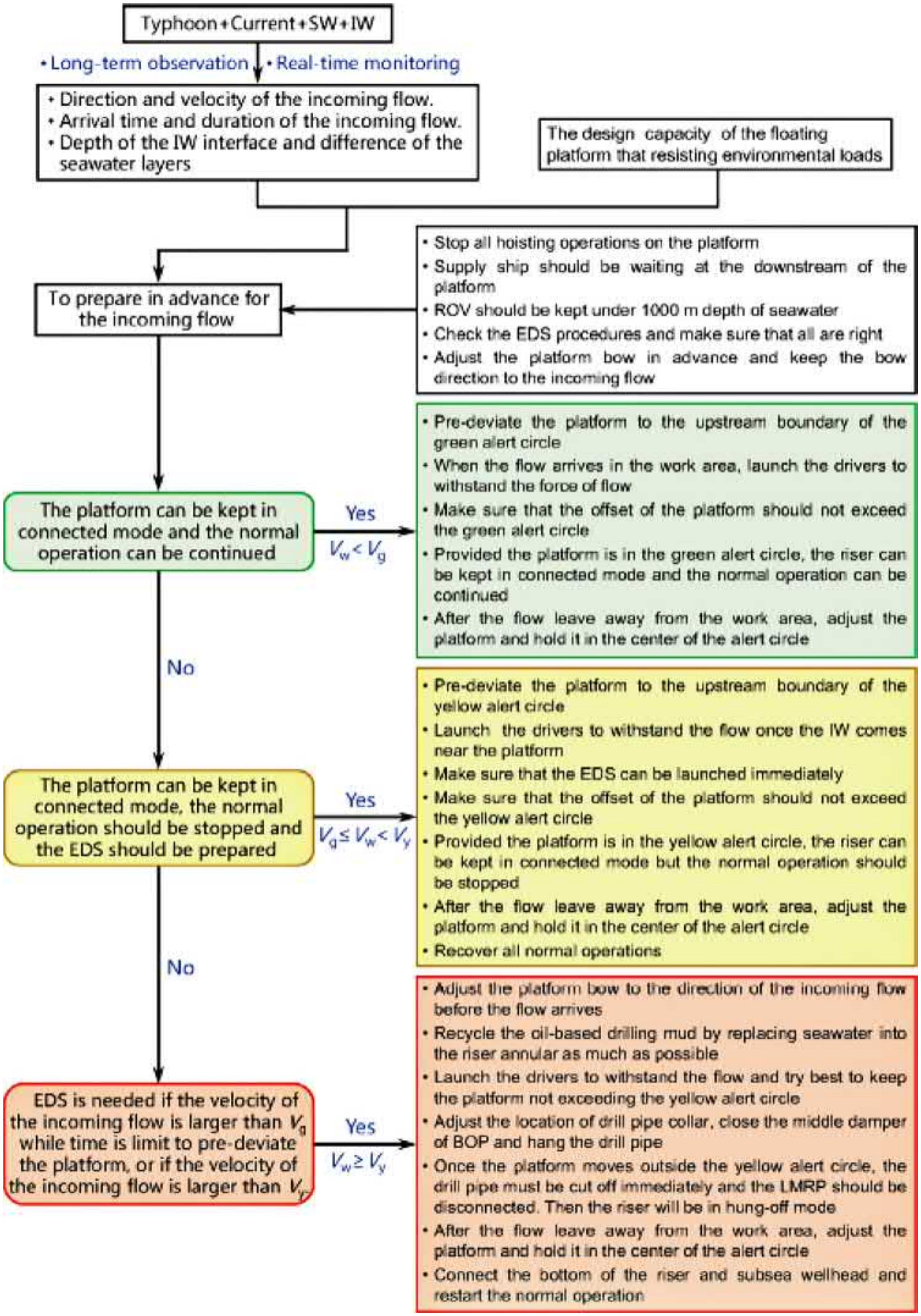


FIG. 4.12 Vessel station keeping, well specific operation limit guideline when an internal wave "IW" arrives. *Source: Research Institute of the China National Offshore Oil Corporation.*

The "hysteresis effect" defined for the first time in the institute's analysis findings also implied that the maximal riser stresses resulted for "tens of seconds" due to inertial effects after the maximal drift amplitude of the floating vessel resulted. This added hysteresis time affords an extended operating window during a planned or emergency disconnect, and therefore is beneficial from an operational safety standpoint.

Countermeasures proposed to reduce the impact force of internal waves and vessel positioning could result through the provision of early warning and proactively offsetting the vessel in the most preferred direction versus reacting with passive control after wave arrival.

The result would afford more probable outcome that vessels can remain connected even if the flow velocity and resulting load initiated a yellow alert to be able to then prevent a red alert level disconnect. Therefore, lost time could be more effectively prevented, reduced, and mitigated on the premise of higher safety, and operational results could be affected through greater awareness of all crew and how systems needed to be operated.

Tides

Astronomical tides are predicted for deepwater well locations and provided to the rig by the operating company generally through a third party–provided service.

GEOGRAPHIC EFFECTS

In deepwater the further into open water a location is, the lesser the tidal range and effect would be. However as daily tidal ranges, these can range from >1 m to several meters.

Tide shall always be accounted for by the well site teams, particularly when measuring wellhead or downhole depths where precise and accurate below the drill floor, sea level, or seabed measurements are required.

Currents

CURRENTS—GENERAL

The dynamics of ocean current and circulation is complex. For deepwater offshore design, engineering and well operational purposes, sufficient description of local current conditions can generally be provided by local measurement, regional knowledge, numerical model simulation, and application of empirical procedures. Knowing worst-case trends, what depth and variances exist is the most important data to acquire and understand.

EXAMPLE

A deepwater exploration campaign in a frontier area did not identify prior to drilling that high shallow currents existed at the well location. On arrival, the impact of the high current and persistence experienced directly resulted in several weeks of lost time, tens of millions of dollars of added well costs, where "a few ounces of prevention would have been preferred to the tons of cure in this case required."

Currents require one to measure and manage current information where data is very limited. Current surveys and devices can be deployed and data gathered before project planning begins. Variations of magnitude and currents at various depths can be assessed so that "fit for purpose" equipment and operations are assured. If data sets are still lacking, remote operating vehicles (ROVs) can be fitted to collect current and other required data from the start of a well, where this has proven to be a simple and practical way to acquire information warranted. When current hazards and risk exist, meters and devices can be deployed and installed rig-site to assist in understanding and evolving mitigating measures and to enable more value-added decision making to result.

Where practicable, a complete and accurate current profile is preferred to be known so that all operational problems can be identified so that plans assure for risks envisaged.

EXAMPLE

Running casing, marine risers, vortex-induced vibration, equipment fatigue, station-keeping failures that can and have resulted in deepwater wells due to associated current cause and effect problems.

Where current risks exist, they must be mitigated and addressed to assure systems, environments, and operating conditions can be safely managed during all related operating activities at minimal loss/waste.

EXAMPLE

During a two-well 2002 North Atlantic deepwater program, it was predicted that strong current would exist where deepwater ROVs could only hold station over the well during tidal changes where still waters tended to exist. To mitigate this risk, a simple T bar device was made to fit on the lower pressure wellhead housing. The ROV then held on to the T bar ready to guide and assist drillers to guide tools and equipment in/out of well as required. Approximately 12–24 h of well time ($400–$800 K) operating costs were estimated saved based on offset well comparison data.

Current velocities can vary with time due to the reversal of tidal flows and location. In the open oceans, current may vary only gradually with location. Within deepwater continental slopes, complex spatial variation in flow patterns in the region of transition between shallow shelf sea dynamics and deepwater ocean circulation conditions can exist. In summation, current velocity profiles must be considered in relation to: *position in the water column, geographical location, and variation with time.*

Factors that influence water movement include:

- Astronomical tidal forcing (predictable)
- Large-scale ocean circulation
- Seasonal flow patterns (i.e., monsoon drift)
- Regional eddies
- Local bathymetry and coastal shape (headland effects, etc.)
- Density structure of the water column
- Local wind forcing (near-surface)
- Frictional effects (near-bed)
- High-frequency effects such as solitary wave propagation

LOOP CURRENTS

Are unique to deepwater specific areas such as the Gulf of Mexico (GOM) as illustrated in Fig. 4.13. Surface current speeds being recorded up to 4 knots with mean speeds of ±1 knot. Loop current flows are generally restricted to the upper 800–1000 m (2625–3281 ft) of the water column.

The direct influence of Loop Current eddies is detectable and predictable to similar depths, although there is some evidence for a coupling of the deep flow and eddies above. Secondary cyclonic eddies are also numerous and believed to be formed by the interaction of Loop Currents and other ring effects within the bathymetry. The unstable nature and associated countercurrents that then spin off can occur rapidly and are extremely unpredictable. Loop currents cause complications and difficulties for vessel operations. The most prevalent are *during running and pulling the subsea BOPs, trying to reattach the lower marine riser package (LMRP) after disconnecting*. Loop currents further increase the drag on the marine riser by two or three times to result in far greater fatigue, i.e., bending and cyclic stresses to the riser and associated components.

HIGH CURRENTS

High currents exist in specific offshore deep-sea environments and can exceed 4 knots, making station keeping of the vessel or operations far more difficult and challenging to manage and control. High current can be caused by ocean tides, rivers, and streams flowing into open seas. To combat and mitigate operating risks, equipment that has evolved to counteract high current effects includes riser fairings, restraint systems, casing strakes, false rotary/floating drill floors, improved riser management and station keeping system capabilities, etc.

HIGH CURRENT CONSIDERATIONS In a disconnect situation, the operating vessel shall be displaced a known horizontal distance from the well. The midstroke location of the slip joint would have moved down the barrel due to that horizontal displacement. As the dis-

FIG. 4.13 Gulf of Mexico loop currents. *From https://en.wikipedia.org/wiki/Loop_Current#/media/File:Loop_current2.jpg.*

connect situation has perhaps resulted due to a metocean effected drift-off, the vessels riser system could be heading to a situation where stroke or bottom-out of the slip joint can result.

In high current regions where the flow and direction can be predicted, moving the operating unit upstream and drifting the rig into the current can reduce or eliminate lower ball joint angles. This practice is very practical while in the dynamic positioning (DP) mode. The DP operator can readily change the set points for the surface location and station keeping watch circle. In strong nonuniform in direction currents, vessel movement may also be practical. The operating vessel's well specific criteria specify permissible metocean design and operating conditions.

Majority of current inputs would be expected to be one to two knots or less. If a prospective well location experiences greater currents, a DP holding analysis should be performed. Such analysis can be an inexpensive mitigating check to evaluate wind, waves, current and combined effects vs. a costly post incident dynamic analysis.

Interference with the diverter housing as illustrated in Fig. 4.14, and/or side loading the traveling assembly in the derrick while running and retrieving the drilling riser can also create operating problems and concerns when working in high current environments. These again can be moderated to some extent through positioning the vessel up-current from location and

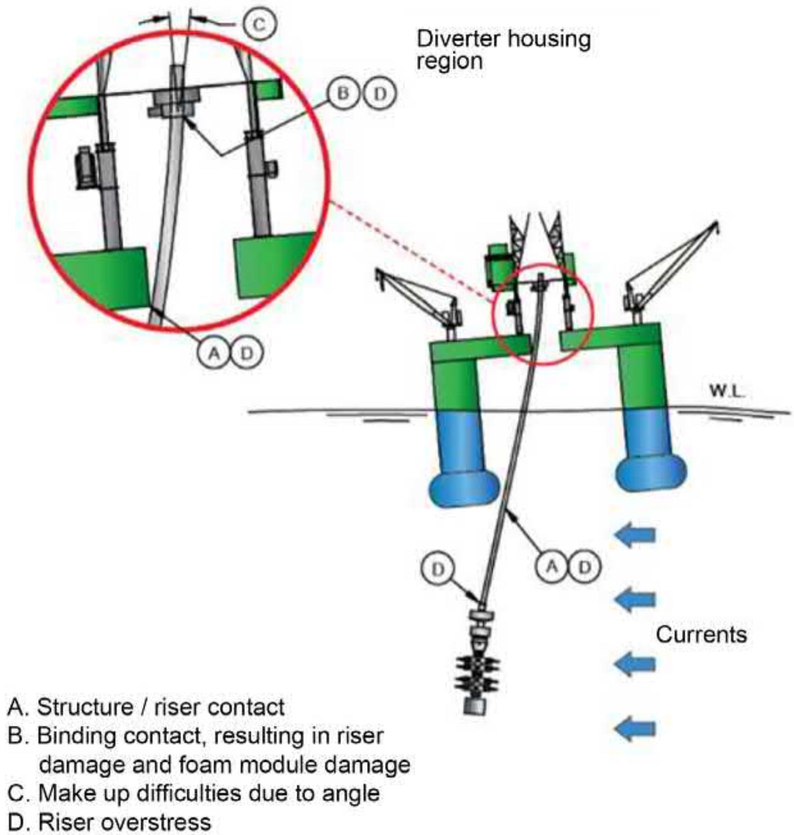


FIG. 4.14 Diverter interference due to high currents. *From Kingdom Drilling training construct.*

running the riser, casing or drilling string while drifting the vessel. After the subsea BOP is landed, problems with controlling flex joint angles usually occur when the current exceeds 2 knots.

EXAMPLE

Operator was required to pull and repair a subsea BOP stack for repairs in an area of severe loop currents. The operator conducted operations offsetting the vessel 30 miles off location (up-current), and drifting back at the required speed to the well location while running the subsea BOP stack and riser. Drifting onto location with a more vertical subsea BOP stack enabled the successful latch onto the subsea wellhead with minimal loss time resulting. Similarly, a 36-in. (91.4 cm) conductor casing was being run through a 15-ft (5 m) long diverter housing with a 50-in. (127 cm) internal diameter, with current producing such a side loading effective force on the suspended string that at the rotary table and drill floor the net effect was that that the string could not be slacked off. This was resolved by offsetting the vessel off location and drifting with the current to reduce the diverter housing interference and thereby being able to continue to run the casing.

When running long strings, beacons are placed on the end or midriser (*or on casing strings*) to be monitored and tracked on the DP and/or a computer system. Because accurate string position is known and the intended landing location (*the well head*), programs can be utilized to determine and evaluate how to intersect the two points, direction and speed to move the vessel to the set point. Drifting operations therefore require a full understanding of the metocean conditions and very careful preplanning organization, implementation, and controls to be in place between all drilling, marine, ROV, and DP personnel to avoid equipment damage or unnecessary lost time delays. This means adhering to the best practices company or drilling contractor has established for using the vessel to drift a riser or casing string in high current environments.

EXAMPLE

To prevent multithread connectors from vibrating loose, there is generally a requirement to torque them to a maximum value and/or assure antirotation devices are properly assured.

Problems Associated With High Currents

Deepwater operational issues that exist and are affected by high currents are illustrated in Figs. 4.15–4.17.

Problems can result throughout all well operating activities, i.e., *during spudding wells, drilling pilot holes, top and surface holes, landing guide bases, Xmas trees, running and landing, and retrieving the blowout preventer and marine riser.*

Currents—Vortex Shedding and Vibration

All environmental loads are primarily *horizontal*, but have *noticeable vertical components*. Current loads can have significant *cyclic components* and significant *irregularity.* The most significant of these in terms of an operating risk is Vortex-induced vibration (VIV) that can result to drill strings, casing strings, marine risers, ROV umbilical, etc. if the rate of the produced

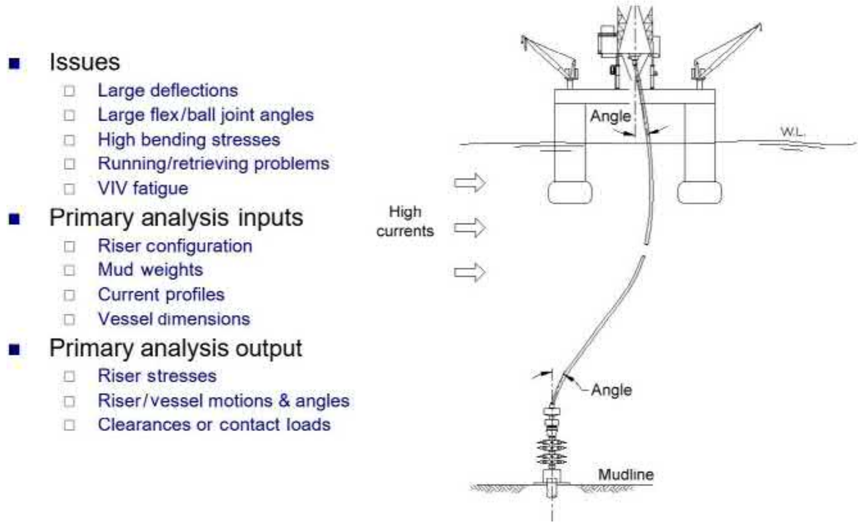


FIG. 4.15 High current issues and riser analysis requirements. *Source: Kingdom Drilling training, 2006.*

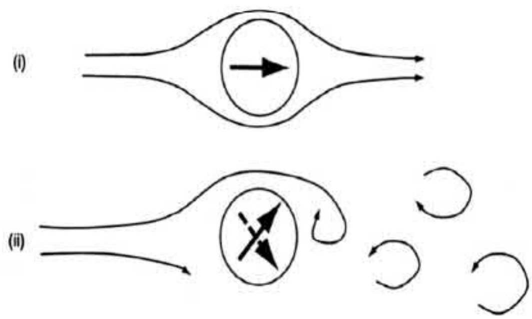


FIG. 4.16 Illustration of vortex shedding and vibration and mitigating measure that can be installed on a marine riser. *Source: Kingdom Drilling training.*

vortices matches the resonant frequency of the cylinder or shape and/or length of the system, where fatigue and potential failure can result.

Fig. 4.16 illustrates vortex shedding, i.e. (i) presents the flow of seawater past a cylinder (riser or casing string) in plan-view, at low Reynolds number, that confirms a smooth stream and steady force acting on the cylinder due to drag and inertia (Morrison equation); (ii) present flow of seawater past a marine riser in plan view, at high Reynolds number, that could under certain operating conditions result in the development of vortices in the water and act as oscillating forces on the cylinder. *Note*: VIV to be further discussed within the well design chapter.

To surmise, currents can present a metocean environmental factor of greater importance as activities move into deeper waters with floating structures systems development (*notably risers and anchor lines that are drag dominated*).

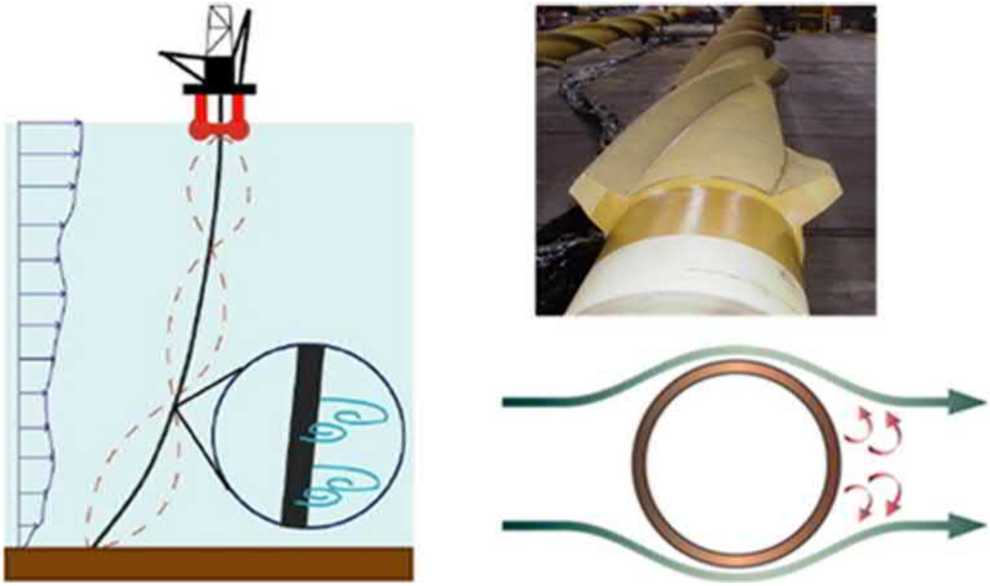


FIG. 4.17 Vortex shedding and vortex-induced vibrations as a wave or current pass a vertical cylindrical pipe. *Source: Kingdom Drilling training 2006.*

In such circumstances, it is likely necessary to perform specific current measurements of general characteristics to establish short- and long-term period fluctuations to determine, for instance, vortex shedding as further illustrated in Fig. 4.17 and mitigations that can be applied, and long-term causation on operating activities, systems, and components exposed to current effects.

Environment and Ecosystems

General

Norway is an important maritime nation where government bodies, agencies, institutions, and operators take a very responsible and accountable approach to marine environment, life, habitats, and ecologies. Other deepwater operators (note: Norway defines deepwater as water depths >400 m) would do well to follow a similar approach as ably demonstrated by the NPD program since initiation in 1996 to current date. Since inception, multiple joint industry projects have been created and supported to assure due and diligent environmental preservation and care of all “Blue Planet” aspects while continuing to operate oil and gas facilities in a safe, effective, and efficient manner in ever deeper, remote, hostile, and extreme environments.

The NPD deepwater drilling and environmental program projects started with prestudies to define the environmental processes required, such as departure from ideal gas behavior, formation of gas hydrates, dissolution of gas in water, and bubble and droplet size distribution. Research during early years concentrated on the fundamental questions of blowout and worst-case oil spill modeling scenarios and the potential impact to the environment and ecosystems, and if oil ever could ever reach the shore what the impact could be. Models were then further developed for deep-sea oil and gas blowout discharges and oil spill situational events. Multiphase plume models, inclusive of hydrate formation have since been generated from as early as 1998. In parallel with initial work, joint industry projects were initiated with field trials conducted offshore Norway to simulate both oil and gas flows to physically monitor real-time evidence based spill results supported through two separate joint industry projects. A summary from the NPD 2016 summary report follows.

> Oil and gas was released at 840 m (2756 ft) water depth in the Norwegian Sea 250 km (155 miles) to the northwest of Kristiansund. 60 m^3 (377 bbl) of marine diesel and 60 m^3 (377 bbl) of crude were released from a discharge platform lowered down to the seabed. The release also included 18 m^3 (636 ft^3) of liquefied natural gas (LNG), which was equivalent to 10.000 m^3 (353147 ft^3) of gas at atmospheric pressure. Oil surfaced and started forming a slick about one hour after start of the discharge and the surface slick built up in size with time as oil droplets of diminishing size arrived at the surface. The surface slick had variable thickness and the water-in-oil emulsion formed thicker patches of the crude oil slick. *The gas discharge behaved differently as gas bubbles did not reach surface, probably due to dissolution of gas in seawater. No hydrate formation was observed*.

These projects, DeepBlow and DeepSpill*, were run in parallel to have a significant impact on further deepwater environmental and operational work conducted within the Norwegian programs. In recent years, the main tasks are (1) to further develop and improve current models, where several updates have been implemented via improvements in numerical models and software programs, and (2) to further assess environmental risks of deepwater activities and support appropriate management decisions required in emergency or significant lost time well control or situational events. A DeepRisk program is now being developed and established to work in conjunction with both blowout and oil spill models.

**DeepSpill is part of a JIP involving the U.S. governmental agency Minerals Management Services and 22 oil companies with interests in the U.S. Gulf of Mexico and Norwegian Sea deep waters. SINTEF was the main contractor, responsible for planning and conductance of all aspects of the experiment.*

Further ecological studies are also initiated during the last decade to address the lack of knowledge on deep-sea organisms and biological effects of and responses to toxicity. Identifications of "Valuable Ecological Components" and target resources for risk have also been studied in Norway for many years, where several long-lived species have been devoted considerable work. Taxonomy of deep-sea fauna is another issue where long-term development and knowledge transfer of competence and capacity within morphologic and molecular taxonomy of the deep-sea fauna in deep-sea waters are ongoing.

Practical applications of deepwater modeling therefore must include all environmental risk assessments, oil spill response, ecological and operational safety aspects. The risk assessments cover predicted concentrations of oil and gas in the water masses and form the basis for assessments of possible adverse effects on sensitive marine resources. Further, the oil spill response predicts the surface distribution of oil and forms the basis for assessment of alternative response strategies and planning of oil spill counter measures. Lastly, the safety aspect predicts gas flow to the surface and forms the basis for defining safety zones. The quality of these predictions is assured by verification in field trials as shown and continues to be updated based on recent findings to contribute to the evaluation of oil spill emergency and contingency plans for deep water releases.

The environmental projects within Norway have a long tradition of cooperation with governmental authorities and institutions and national industry organizations. A series of workshops have been held with support from the Norwegian deepwater programs that have led to extensively delivering the following in such subject matters:

- Benthic baseline surveys combining bottom fauna, analyses of organic matter in the sediments, grain size distribution, soft bottom fauna, total hydrocarbons, metals, importance of knowledge of sediment characteristics.
- Oil spill contingency and plans for drilling in deep water related to plume behavior, and stricter requirement of the oil spill contingency plans were introduced.
- Mapping of vulnerable resources, hydrographical conditions, and vertical distribution of nutrients, chlorophyll, plankton, and nekton in the eastern Norwegian Sea, focusing on the Viking Plateau.
- Large-scale mapping of sponges and cold water corals by using Underwater Hyperspectral Imaging Technology (*NDP as JIP partner in PETROMAKS 2014–2017 project*, www.ecotone.com)

NDP Environment Project Provision Summary

The following summary of the environmental and operating aspects of the Norwegian deepwater program serves as a good guide to present for deepwater consideration:

- Probable blow out behavior from the seabed and implications on oil spill containment required.
- Improved numerical models of the flow of gas bubbles and oil to the surface, and a map of surfacing gas flow rates, then used as input to atmospheric dispersion models for explosion danger analysis.
- Improved environmental risk analysis through mapping of species and effect studies.
- Support to academic institutions to improve knowledge on deep-sea biodiversity, and increased capability to perform environmental studies.
- Increase knowledge on how to map deep-sea biodiversity.
- Applied knowledge of models and input data for oil spill risk assessment and operational follow-up.
- Improved safety within the operating workplace by providing a surface void fraction map to help define exclusion zone for vessels.
- Aiding permitting and consent processes to explore and develop licenses by having a more thorough understanding and commitment to not harm marine life.
- Application and efficiency assessment of deep water remote and in situ monitoring technologies.
- Provision of data and how to monitor deep-water populations and communities.

Deepwater Environment Project Specific Requirements

Regulatory or company-based environmental studies, base line assessments, standards and reports of pre/post operations require a comprehensive well-researched investigative and well-documented process of all work to be conducted for deepwater areas. During preparation and planning, features that require special protection, or restoration should be emphasized. As complete descriptions to the environmental processes involved are too lengthy to detail, an outline of the major topics is listed:

1. Project Work Scope, Purpose, Goals, and Objectives
2. Description and identification of proposed activities

3. Regional extent, site-specific, and operating requirements
4. Description of Planned Activities (Equipment, Personnel, Time Frame, etc.)
5. Oil Spill Contingency Plan (to be discussed in later operational chapters in this guide)
6. Planned Environmental Protection Measures
7. Site Maps
8. Generation of Solid, Liquid, and Gaseous Pollutants
9. Description of affected environment
10. Geology, Sediments, Stratigraphy, and Structures
11. Bathymetry
12. Geologic Surface and Subsurface Hazards
13. Weather Patterns, Air Quality
14. Oceanography, Water Quality and Properties
15. Tides and Currents
16. Other Uses of the Area; Fishing, Shipping, Boating, Military, etc.
17. Pipelines and Cables
18. Archeological/Cultural Resources
19. Biological Resources, Plant and Animal Life, Endangered Species
20. Social and Economic Considerations
21. Coastal Resources, Effect on Community Services, Employment, Public Opinion, etc.
22. Impact of Operation on the Environment
23. Discharge of Drilling Mud and Cuttings
24. Oil Spills and Air Emissions

Ice Management

A further deepwater metocean aspect to contend with in the northern and southern parts of our seas and oceans is that of Ice Management. The West Coast of Greenland campaign in recent years serves as a notable example where both storms and ice situational events can result. This is because the polar convergence zone centered between Iceland and the southern tip of Greenland influences and governs the autumnal and winter winds that flow in a south-easterly direction. Short-term storms then result through these periods to produce combined winds more than 47 knots (87 km/h) and waves exceeding 9 m (30 ft). Storms can have a major, different, and very specific effect on ice drift in these operating areas. Ice it should be noted also tends to travel at greater speeds, often more than 3.0 knots (5.6 km/h) in such storm-based conditions. Iceberg meander also is greatly reduced nearing a 1:1 ratio. This reduces time for ice to be safely managed thereby increasing operating risks to the well, drilling, vessel, and persons on board. *Note:* Elsevier*'s Offshore Operations and Facilities: Equipment and Procedures,* written in 2014, Chapter 1, pages 94–129, comprehensively covers sea and ice loads theory principles and practices.

Iceberg Generation, Management Plan, and Operating Procedures

Icebergs result from the large number of glaciers that exist. *Example: West Greenland's Disko Bay and associated coastal areas north represent the primary calving grounds where significant icebergs form in a variety of shapes and sizes.*

Operators must prepare suitable ice management policies and procedures to support anchored and/or dynamic positioned (DP) vessel operations when ice presents a routine operational threat. In situational well operating events, all workflow processes and emergency plans must assure integration with other response systems, procedures, and operating documents required. As ice management strategies vary by location, a well-specific operating guideline (WSOG) document would define the well operating limits to assure:

1. No confusion exists in regard to an operator's ice management plans.
2. Operating policy as related to ice-infested waters.
3. A series of accepted procedures for ice avoidance and management.
4. Persons involved with the operator's well duties, roles, and responsibilities regarding ice operational management are briefed.

The operator should assure that necessary situational actions are safely undertaken so that the well, vessel(s), and operations avoid hazardous ice situations. This is achieved through early detection, suitable reporting and tracking of ice, ice deflection or securing methods, or in a worst-case scenario moving the vessel off the well and location if threats cannot be safely mitigated or managed. The operator should assure full compliance with any regulations and provide all personnel, resources, and equipment to effectively manage all well operational ice threats.

ICE-OPERATING PROCEDURES

It is important to note that it is the Offshore Installation Manager (OIM) and not the operator representative has the authority over the safety of personnel on board, the operating vessel and/or the well operating environments that could be threatened.

Procedures in any Ice Management Plan are designed to prevent hazardous ice in the form of either pack ice or icebergs reaching the well operating vessel(s) or to further reduce reaction time, assure well safety and effectively move the vessel(s) off location. To assure compliance, the operator would also make a copy of the plan available to all personnel involved in the ice management process.

Ice management plans should describe a series of management encroachment zones around the well with instructions that dictate the necessary actions to be taken. Example: Table 4.5 outlines zones starting at the well operating units and Table 4.6 offers a summary of issues that can exist and response actions required. Figs. 4.24 and 4.25 illustrate a typical ice management process and flow chart as to how ice threats are managed through various action responses. Iceberg and Sea Ice quick reference guides are further provided in Figs. 4.26 and 4.27.

TABLE 4.5 Ice Management Zones

Zone 1	Ice alert	Safety Buffer—Quick departure assurance
Zone 2	Reaction	Orderly departure of operating unit from well site and threat
Zone 3	Ice monitoring	Tracking and management

Source: Provincial Aerospace Ltd., Ice Management Plan Jan. 2010.

TABLE 4.6 Summary of Typical Ice Reponses

Zone	Drilling Operations	Marine Operations
Zone 3 Ice monitoring	– Continue normal well operations – Forecast well operations for next 24h – Calculate T-times every 12h – Be prepared to cease operations if ice enters zone 2	– Review Ice Status Reports – Supply vessel(s) deployed to report ice positions every 3h – Assess physical and management characteristics of any ice encountered – Calculate CPA of all known ice and inform – OIM if any ice will enter Zone 2 – Begin ice management operations – Record course and speed hourly, recalculate CPA Maintain contact with operational personnel
Zone 2 Drilling unit reaction	– Cease normal well operations – Start procedures to secure well in anticipation of departing location – Update T-time every time as significant securing operation is completed – Disconnect LMRP – Inform OIM when disconnect is complete – Prepare to move off location. – Assist marine or subsea personnel in anchor recovery or disconnect when/as applicable	– Monitor progress of well-securing operations – Recalculate Zone 2 each time there is a change in T-time – Standby vessel ready to start anchor recovery (if applicable) – Evaluate time available and effectiveness of ice management. Be prepared to discontinue ice management and recall vessel to speed up anchor recovery if not in DP Mode – Calculated CPA of ice and evaluate if it will remain in Zone 2. If ice will enter Zone 3 suspend operations and monitor – Upon completion of LMRP disconnect, start to recover remaining anchors (If applicable) – If there is a significant speed increase in ice, rig management team in consultation with Drilling-Supt will decide on the use of shear links (Anchored mode only) – Move off Location before ice enters Zone 1
Zone 1 Ice alert	– Normal in transit activities	– Operating vessel(s) proceed to a safe position and monitor ice – Assess when it is safe to return to location

Source: Provincial Aerospace Ltd., Ice Management Plan Jan. 2010.

DEEPWATER, METOCEAN, POSITIONING, AND RISER MANAGEMENT

Angles and Offsets for Floating Operations

Vessel Motions

Vessel motion is generated by a response, i.e., of transfer functions, to passing waves. Vessel motion is important for identifying loads imposed by a mass on or within a vessel's structure and/or its equipment such as:

- Sea fastenings for transporting goods and equipment from port to port, and,
- Specifying and sizing equipment for offshore operations.

Response Amplitude Operator

Response amplitude operator (RAO) refers to the movement of a floating vessel in six degrees of freedom: ***Surge, Sway, Heave, Roll, Pitch***, and ***Yaw*** due to a passing hydrodynamic wave (Ref. Fig. 4.18). RAOs are used as input data for calculations to define the displacements,

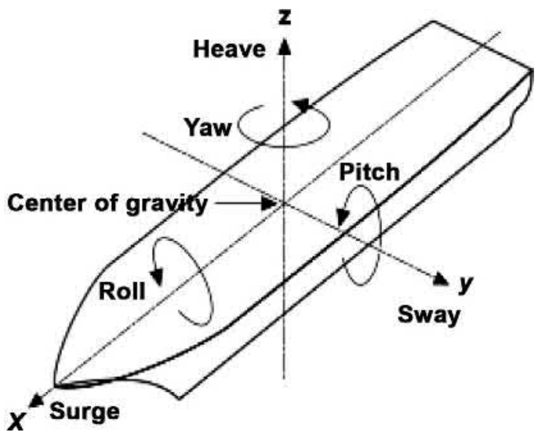


FIG. 4.18 Vessel's six degrees of freedom. *Source: Kingdom Drilling training.*

accelerations, and velocities at any given location on a marine vessel that in turn is used to identify forces imposed on structures and/or equipment. RAO data are also an essential requirement for riser analysis.

Surge, Sway, and ***Heave*** are *linear movements* in the *x, y, z* directions, respectively, and ***Roll, Pitch,*** and ***Yaw*** are *rotary movements* about the *x, y, z* axes, respectively.

Heave, ***Roll***, and ***Pitch*** are subject *to gravitational restoring forces* (stiffness or spring coefficients), which means that they can be oscillated at a natural frequency, *something to be avoided in practice at all costs.*

Surge, Sway, and ***Yaw*** are not subject to restoring forces, which means that they *cannot be oscillated at a natural frequency.*

The term Response Amplitude Operator comprises two parts:

1. ***Response amplitude*** refers to the degree of movement induced in a floating vessel due to a passing hydrodynamic wave. This movement is absolute (or actual).
2. ***Operator*** refers to a factor that must be multiplied by a specific value, e.g., wave height (or amplitude) to define the absolute (or actual) movement.

Metocean wave height, water depth, and period all affect a vessel's response.

RAO Calculations

RAO calculates response amplitudes in all six degrees of freedom, i.e., those with restoring forces and those without. RAO includes the effect of damping and added mass, which means that the relationship between the response amplitude and the associated wave height is not always linear. Therefore, RAO does not calculate *operators*, it calculates *actual* (theoretical) response amplitudes (RAs) at a given angle through a wave, i.e., you do not multiply RAOs calculated values by a wave height, amplitude, or slope. RAO includes a pictorial demonstration of the vessel's movement in beam, deck, and aft views relative to the profile of the passing wave.

RAO calculations as illustrated in Fig. 4.19 may deliver a pictorial demonstration of the vessel's movement in beam, deck, and aft views relative to the profile of the passing wave.

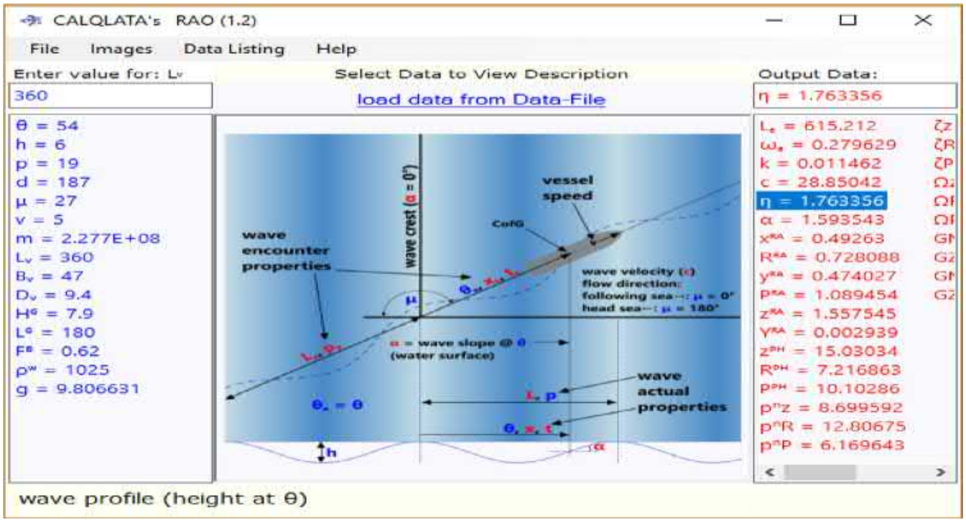


FIG. 4.19 Illustrative example of a RAO set of calculation for a specific vessel and metocean data input. *Source: Keith Dixon-Roche, http://calqlata.com.*

SUMMARY

Offshore vessels have unique motion characteristics as defined by RAO. This a key determinant to consider regarding optimum rig selection and operating conditions particularly in offshore deepwater regions, where extreme metocean conditions, water depths, and seabed conditions can limit, restrict or halt moored, dynamic positioning operations. In more challenging and extreme environments, the drilling vessel with the most capable RAO is the one most preferred, i.e., the one most capable to change its heading.

Determining Riser Profile

In vessel and well station-keeping operations, the target position is always a point on the sea surface vertically above the sea bed surface that correlates to latitude and longitude chosen as the well site. Horizontal displacement of the vessel above the wellhead is caused by the combined metocean forces. Though the vessel is held stationary on location by either mooring or dynamic positioning, it is always in motion. An oscillating or offsetting effect occurs around the target position. The stronger the metocean offsetting forces, the bigger will be the displacement from vertical.

The vessel is anchored via the marine riser well head connector and integral with the well structural strings and engaged and locked once the Subsea BOP stack is run. Because the vessel is constantly moving around the wellhead target position, the riser is continuously changing shape. The riser shape can be a simple bow, an "S," or more complex. The riser shape configurations are caused and effected by different metocean currents at different depths that change with time (Ref. Fig. 4.20). The riser (3) is coupled to the vessel through a diverter housing (1), and upper flex joint (4), a telescopic or slip joint (5) that is attached and tensioned (6) to the upper riser down to the upper part of the subsea BOP termed the Lower Marine

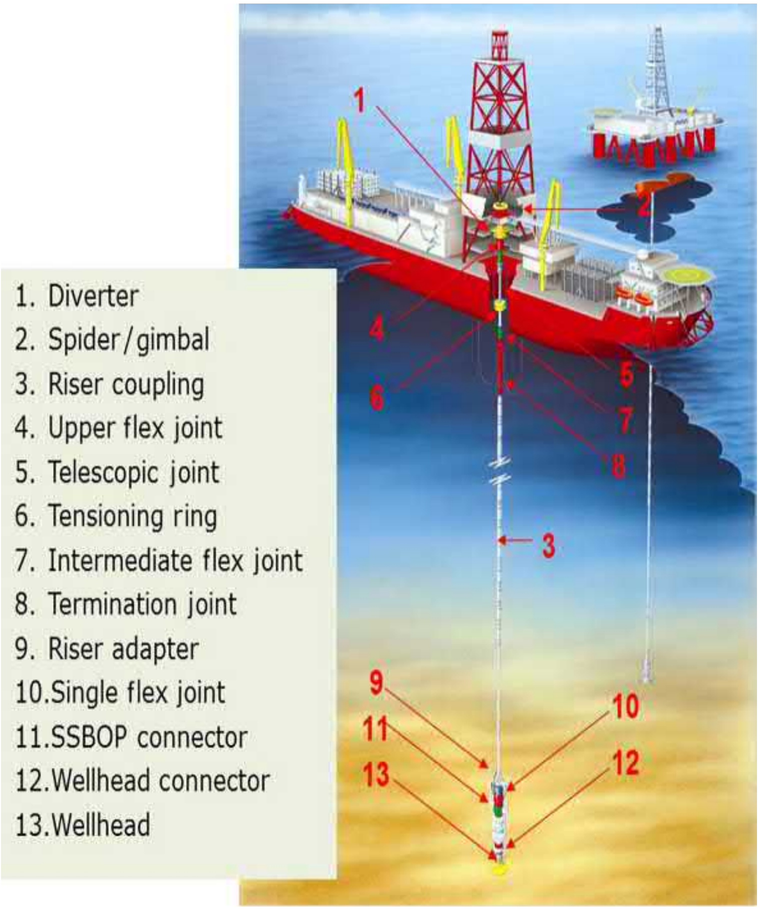


FIG. 4.20 Deepwater subsea and marine riser component illustration. *Source: Modified by Kingdom Drilling training from a 1999 ABB Vetco deepwater training presentation.*

Riser Package (LMRP) that is connected to the subsea BOP via a subsea BOP hydraulic connector (11), with the main subsea BOP connected to the well via a similar wellhead connector (12). True alignment of the riser is indicated by the lower flex joint angle (10) and is read as a differential angle between the tilt of the wellhead (13) and subsea BOP and the tilt of the location for the vessel becomes the new target location for carrying out operations. Once the target is determined, the positioning or "watch circles" are set to establish the well specific operating limits of horizontal offset permitted.

Using a riser profile system is the best method to achieve a representative view of riser behavior below the water line. A true riser profile must account for lower flex (ball) joint angle, slip joint (and/or upper ball joint) angle, tensioner stroke bottom out, and riser stress joint. Vessels may deploy and use Acoustic and/or Electronic Riser Angle devices to monitor and measure the ball joint angles, etc.

A riser profile management system may also use beacons installed at regular intervals along the length of the riser to be able to derive the visual shape of the riser string during operations. These technologies although not new are often not available or in use on the majority of deepwater vessels.

Devices can be installed within the riser management system to measure, manage, monitor, and afford more precise control of the lower ball joint angle and other key factors to determine safe horizontal offset limits to be met. Operating angle limits usually limited to 2 degrees. At an angle greater than 5–6 degrees, it is generally impossible to now disconnect the riser from the LMRP. Should a lower ball joint angle become greater than 8–10 degrees, this can result in seriously damaging the riser, riser connections, or the subsea BOP.

Operating disconnect limits and times are determined and evaluated through conducting drift-off analysis (Fig. 4.21) and establishing safe operating zones of each vessel based on water depth, time for disconnect, wind and current forces, mud weight, and riser tension.

The tensioner stroke is the most direct measurement criterion for disconnect in a drift-off situation. Impact of currents on riser profiles can be minimized by increasing tension positioning the rig into the current, and installing mitigating devices onto the marine riser. However, in ultradeepwater, excess tension may not be available. Any position off center furthermore reduces the reaction time to rig position limits.

Station Keeping

Station Keeping—Deepwater Moored Vessels

For a ***moored vessel's departure*** from a well location, <2%–3% of the water depth in a 10-year storm and no more than 5%–6% of water depth is a general standard to apply. After sizing the mooring system to meet the operating criteria, the riser analysis will further determine the

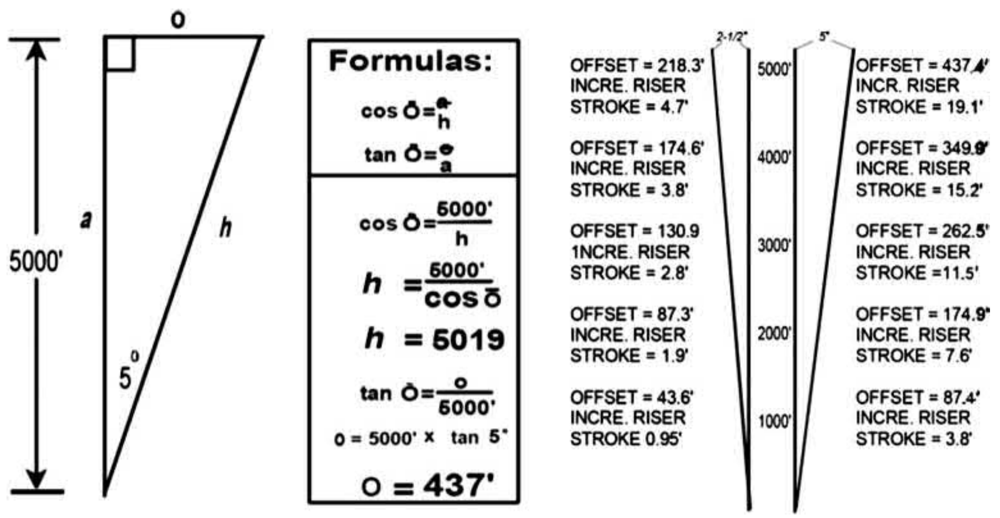


FIG. 4.21 Illustrative effect of vessel drift angle in regards to offset and incremental riser stroke. *From Kingdom Drilling training construct.*

required tension to manage angles no >3–5 degrees design conditions. Once a 5 degree lower angle, or if upper ball *joint angle* increases past 3–4 degrees, a planned riser disconnect is required.

Station Keeping—Deepwater Dynamic Positioned "DP" Vessels

Fig. 4.22 and Table 4.7 (both below) present general station keeping watch circle where preparation for a riser disconnect may begin at 2.5% "yellow alert" of water depth, with a ***dynamic positioned*** disconnect resulted at 5.0% "red alert" of the water depth.

As watch circles are calculated as a percentage of water depth that with increasing water depth affords a greater "comfort zone" for vessel offset. As water depth increases, the interaction of the riser and the vessel in fact is often more complex and requires increasingly greater monitoring for station keeping and positional operations. So deeper is not necessarily safer. *Operator well specific offset limits for alarm status are illustrated in* Table 4.7.

Watch circles must allow adequate time for the equipment systems to safely disconnect and separate from what will remain on the seabed, before the weakest component has reached its designed operating limits. Many considerations therefore dictate when to disconnect an LMRP, subsea BOP, and/or marine riser. All affected by the position of the vessel relative to the fixed wellhead and subsea BOP to remain on the seafloor. Considerations to be assessed are *lower ball joint angle limits, slip joint stroke, riser operating limits, weather conditions, vessel heave*, etc.

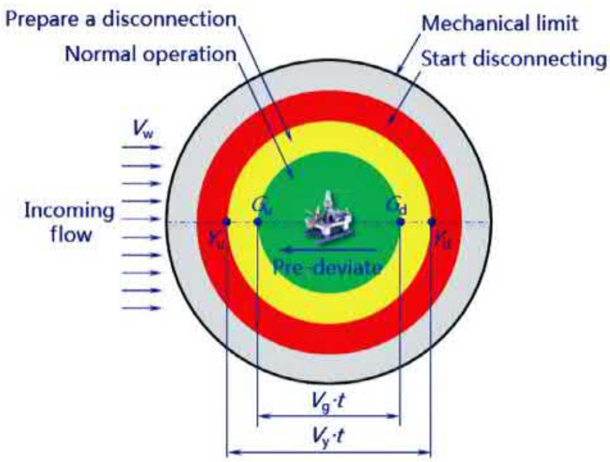


FIG. 4.22 Deepwater station keeping watch circles.

TABLE 4.7 Station Keeping Riser Management Operating Limits

Operating Status	Water Excursion Depth (%)	Ball Join Angle Limit (Degrees)
Normal operations	<2	<2
Operator alert	2	2
Yellow alert	3	3
Red Alert	5	5

Planned and Unplanned Disconnects

Before beginning well operations at a location, a vessel's positional analysis shall be performed to develop a set of well-specific operating guidelines and limits (WSOG) for anticipated *green, (advisory) yellow, and red zones* worst-case metocean conditions (example provided in Table 4.8).

Should situational and conditional events require the riser to be released from the well during operations or should the riser's relative position to the wellhead and vessel not be safely maintained over the well. A planned disconnect is required.

Disconnect Limits and Procedures

DISCONNECT SEQUENCE

In extreme metocean conditions, i.e., outwith the WSOG limits as stated in Table 4.8, well operations shall be suspended with any operational string present safely secured and suspended within the subsea BOP and marine riser. The Lower Marine Riser Package (LMRP) and riser is removed through initiating and executing a ***planned disconnect sequence***.

In an ***emergency unplanned disconnect***, a similar but automatic emergency situational sequence is initiated to affect safe LMRP and riser removal from the subsea BOP. For such a situation, all DP rigs have a riser disconnect function to assure that a quick departure from location can be executed during a *Red Alert* (termed as a ***emergency disconnect sequence*** (**EDS**)) event.

The EDS operating systems sequence is initiated at timed intervals, in some cases prior to the completion of a previous function, as deepwater DP subsea control systems tend to be

TABLE 4.8 Typical Deepwater Well-Specific Operating Guidelines "WSOG" Example

Activity Description	Single Amplitude Heave (m)	Roll (deg)	Pitch (deg)	Wind (knots)	Surface Current (m/s)
Drill/trip and end of riser running	5.0 Riser: 3.5	4.0 Riser: 2.5	4.0 Riser:2.5	45	Drill/Trip:1.5 m/s Riser: 1.5 m/s
Run casing/liners	Csg < 13⅝″:4.0 Csg > 13⅝″:3.0	Csg < 13⅝:3.0 > 13⅝″:2.0	Csg < 13⅝:3.0 > 13⅝″:2.0	30	Csg < 13⅝: 1.5 m/s >13⅝: 0.75 m/s
Landing SSBOP/ reconnect LMRP	2.0	2.0	2.0	19	1.5 m/s
Disconnect LMRP	4.0	5.0	5.0	24	N/A
Survival (connected)	7.0	5.0	5.0	30	N/A
Survival (disconnect)	8.0	5.0	5.0	80	N/A
Cranes (in board lifts)	4.0	4.0	4.0	30	N/A
Crane work, vessels	3.0	4.0	4.0	30	N/A
Gantry crane	4.0	4.0	4.0	40	N/A
Landing helicopters	5.0	3.0	3.0	50	N/A

Source: Stena Drilling 2017.

multiplex. Completion of an individual systematic operation may take only seconds, e.g., 6–8 s to close a pipe ram. The total time to complete the entire automatic disconnect sequence should be in the range of 30–45 s. A final and important note regarding an emergency disconnect sequence is that during a drift-off, storm, or equipment-related event failure, the riser tension acts as the moored point to maintain vessel on location.

Note: The forces generated can if not controlled, cause severe and permanent impact damage to the well, subsea BOP, and riser system if disconnect is not completed in the designated period. Generic disconnect guide procedures to be developed for well-specific DP operations events.

Dynamic positioning systems have enhanced reliability, but incidents still result where the well must have a mandated number of safe operating barriers so that the riser can be safely disconnected and removed before damage results to the wellhead or any of the BOP stack, lower marine riser package (LMRP), slip joint, moonpool, or riser tensioner components. The following steps must be assured if station keeping is threatened or lost during well operations:

1. Hang off the drillpipe on pipe rams or close blind shear rams.
2. Effect a seal on the wellbore.
3. Disconnect the LMRP.
4. Clear the BOP with the LMRP.
5. Dissipate any energy in the riser/riser tensioning system.
6. Safely capture the riser.

The timing of operations is critical, especially steps 1–3. In addition, riser design must afford the capacity and mechanical strength for the maximum water depth and worst-case metocean conditions anticipated.

Most factors that dictate disconnecting the riser in shallower water apply in deepwater operations. All are affected by the position of the vessel relative to the wellhead fixed point just above the seabed. Key considerations are lower ball joint angle limits, slip joint stroke, riser operating limits, weather conditions, vessel heave, and other aspects.

EXAMPLE

During a storm or equipment failure related drift-off, the riser tension serves as the mooring point to keep the vessel on location. Mooring forces can cause severe and permanent damage to the well, subsea BOP, and riser system if the disconnect is not completed within the designated period. Similarly, in a disconnect situation, as the vessel is displaced a horizontal distance from the well, the midstroke location of the slip joint will stroke out and could potentially bottom out. Thus, many deepwater DP vessels supply a 65-ft stroke slip joint with the riser.

DP vessels generally have a single-button emergency riser disconnect (EDS) function to assure a quick departure from location during a (Red Alert) disconnect situation. This button is in the driller's console within easy reach. It is important to assure that all operator and contract people who need to be involved in the disconnect process sequence are in close communication both before and during the actual disconnect. Because the people involved need expert advice under stressful decision-making conditions. Be sure to review and discuss all disconnect procedures regularly during safety meetings and the specific roles and responsibilities of each person involved in the process.

Drive-Off and Drift-Off

Deepwater rig operations must be prepared for a positioning system failure at any time. The most serious positioning system problems are a ***drive-off*** or ***drift-off***.

A ***drive-off*** results when the positioning system directs the rig away from the location. The same result could be caused by the thruster system misinterpreting its commands. A drive-off can be caused when the DP sensor elements send the DP control system conflicting information or when a subsystem fails and causes loss of ability to hold position. In this situation, the subsea BOP must seal off the well and release the riser before the riser system, wellhead, or casing is damaged.

A ***drift-off*** occurs when the rig loses power and the environmental forces push the rig away from the location. Again, the riser must be disconnected, and the well integrity protected. A drive-off can become a drift-off by cutting power to the thrusters.

In a planned, unplanned or drive-off event, all equipment must be assured as "fit for purpose" and be tried, tested, and reliable to assure this process works right first time, within the specific period and to assure that nothing will break or fail.

METOCEAN LOST TIME ANALYSIS

Why Measure Metocean Lost Time

Deepwater drilling is far more expensive on a day-rate basis than conventional offshore well operations. This demands that every single metocean aspect of "well-specific operating guidelines" as illustrated in Table 4.8 should be appropriately applied to assure that optimal operational safety results. This process is made far more difficult since deepwater vessels, equipment, systems, metocean and operating environments rarely exist in "like for like" operating standards, specifications, appearance, or compliance shapes or forms as one would suspect. Vessels may be operating; others likely have been out of service in warm or cold stacked modes, to challenging operating companies that the best of the best for respective well projects exists.

One unit may offer the lowest day rate. When accounting for predicted or probable loss/waste time impact that could potentially result due to metocean and weather-related events, the lowest cost unit may not evidently rank as the preferred choice. Suitable analysis in terms of metocean impact must similarly be performed to an adequate degree of accuracy during a rig tendering, contracting selection process, and particularly when conducting an offset well or operational review in the early project planning phase. Metocean analysis would ultimately assign and predict the waiting lost time evaluated to impact well operations for the operating period.

During well operations when metocean limits are exceeded, the assigned Well-Specific Operating Guidelines limit as illustrated in Table 4.8, as agreed by both the drilling contractor and operator management, would be followed and complied with.

Note: Vessels are certified for operation worldwide as a ship with no restrictions relating to weather or ability to survive—limitations are operation specific. Limit values in the table above take into account Environmental Effects and Operational Limits.

The persons in charge on the operating vessel, typically the Rig Manager, Offshore Installation Manager, and/or Senior Toolpusher shall have to communicate and collaborate to make a judgmental decision to restrict or suspend well operations.

Atlantic Margins Case study

In the context of "waiting" loss and "fitness for purpose" analysis, deepwater lessons resulting from a 21-well, Atlantic margin exploration study are highlighted in this section. It is first evident that 4th-generation vessels withstood the metocean challenges far more effectively than 3rd-generation counterparts where far greater operating loss and waste resulted as shown in Figs. 4.28–4.30.

The Pareto chart also constructed in Fig. 4.23 presented that >70% of all the drilling phase operating lost time resulted in top-hole, surface, and the abandonment phases of the well. (Note: Viewed as the three most direct phases to metocean conditions and why this relationship is evident.)

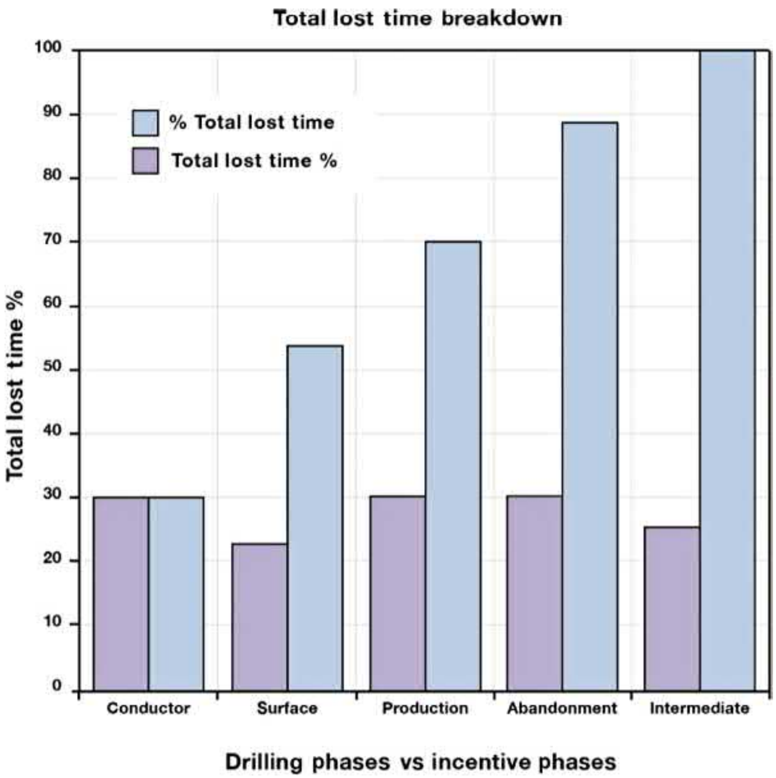


FIG. 4.23 Pareto chart, North Atlantic, total lost time, 1993–1996 21-well study, representing the 5 drilling phases conducted on these wells. *Source: Kingdom Drilling 1997.*

Porcupine Basin and Rockall Trough—Case Studies

The North Atlantic deepwater well-operating margins illustrate the extent of extreme metocean seasonal exposure as shown within wave height exceedances recorded (Figs. 4.31–4.33) from within the center of the Porcupine and Rockall Basins. *Note: Rockall metocean data include conditions very similar with a slightly greater winter severity.*

The Porcupine Basin's 30-well data sets were all operated during spring to summer periods, where 20% or 6 wells incurred more than 5 days of weather downtime within a range from 0 to 30 days. The maximum days experienced by a 2nd-generation DP vessel in 1978 clearly demonstrated the extent of metocean lost time that can result if a nonfit for purpose vessel is exposed to this area even in the most operable period. A total of 106.3 waiting days resulted due to metocean lost time events at an average of 3.3 days per well.

Note: No comparative operative study was undertaken regarding Drillship vs. Semisubmersible in these regions. However, this is viewed as a important topic to evaluate further in the context of extreme operating conditions.

Further assessment of Fig. 4.33 indicates that metocean weather lost time is evidently greater when wells started early or extended late into the autumnal periods. *Note: Significant lost time events were removed from this data set to assure a best represented chart was presented.* Exceptions of note from this assessment were both regarding 4th-generation semisubmersible units, where one 1997 well experienced minor lost time delay operating to mid-November. The second exceptional well operated through the 1998 summer period resulting in no related lost time. This well event again provides supportive evidence for a semisubmersible vs. drillship in terms of rig-operating preference in these environments regarding waiting lost time.

Further lessons learned in respect to newer-build harsh environment rig's and operations utility were:

1. The operating time component of more recent wells drilled is far less than historic averages in the basins. Rig selection concluded to be driven far more than just considering the drilling aspect of the well. Far more evident and important operational aspects therefore evidently exist, notably tubular and pipe handling capabilities.
2. If a drillship is the only candidate, be assured to commence operations at the end of spring and plan to complete by the end of summer in these environments.
3. New-build harsh environment semisubmersibles resulted in less waiting lost time irrespective of operating periods based on data set reviewed.

Rockall wells also analyzed were operated during April to September periods and had not experienced excessive metocean lost time delays to date. UK wells operated and drilled in the Rockall area in this period are included in the study. Data suggest winter operations are possible if using heavy-duty semisubmersible rigs; however, lost time events are more excessive with an increased risk of storm damage to rig and associated equipment. Ocean currents also are viewed as more critical during drilling, with variant and changing loads being imposed on the riser in these periods.

In one project, a yearlong current monitoring program was conducted prior to drilling the well. Results stated that moderately strong current eddies were detected over the data collection period. Overall currents from the study were evidently less severe than observed in the more northern UK wells where, of further note, no issues in respect to riser, wellhead, and foundation design failings have existed to date.

Eastern Canada Harsh Environment—Case study

Another data set of wells operated and drilled within extreme metocean environments is derived from a 2016 Offshore Canadian study to assess operating periods, well delivery, drillship versus semisubmersible trends and comparisons. Although not that many deepwater wells have been drilled in over 1000 m (3281 ft) in this region, the data provides representative evidence to conclude key trends as follows.

Summary and Conclusions

Atlantic margins lessons from deepwater East Coast of Canada wells conclude that:

1. Waiting lost time is evidently reduced in the spring and summer (3.5%) operating periods as compared to an (11.5%) average for autumnal and winter drilling periods.
2. Drillships, due to their pitch, roll, and heave effect, are evidently not the preferred operating choice in extreme metocean conditions and environments.
3. The Drilling time component (Ref. Table 4.9) for wells has reduced significantly from the '80s to '90s, probably due to technology advancements evident in this period. Overall there is little evident improvement in well delivery performance. A key fact to be further evaluated (Figs. 4.24–4.33).

TABLE 4.9 2016 Report Summary of Deepwater Wells Drilled Offshore Canada

Description	Well 1 1979%	Well 2 1987%	Well 3 2010%	Well 4 2006%	Well 5 2009%	Well 6 2013%
Operating period	Spring summer			Autumn Winter		
Water depth (m)	1486	1577	2602	2338	1890	2475
Depth below mud line (m)	4800	3000	3000	3780	4400	3250
Total well time (days)	125	60	130	235	187	185
Rig type	2nd Gen D.ship	3rd Gen S.Sub	6th Gen D.ship	5th Gen S.Sub	6th Gen D.ship	6th Gen See note (1)
Drilling time (%)	36	29	9	15	10	9
Nonproductive time (%)	21	2	34	38	20	1
Waiting time (weather, ice, currents) (%)	2	2	6	1	19	14
Data acquisition (%)	5	3	10	3	2	3
Other rig operations (%)	36	64	41	49	43	59
Comments	1st well East basin	South basin	Orphin basin	Orphin basin	South basin	East basin

Note 1: 2013 well S.sub drilled top/surface sections in 22 days, arch 2013. Drillship drilled remainder of well from July 2013.
Source: Compiled by Kingdom Drilling, based on data extracted from within a 2016 study report prepared for Nalcor Energy – Oil and Gas Prepared by: NSB Energy Consulting August 2016.

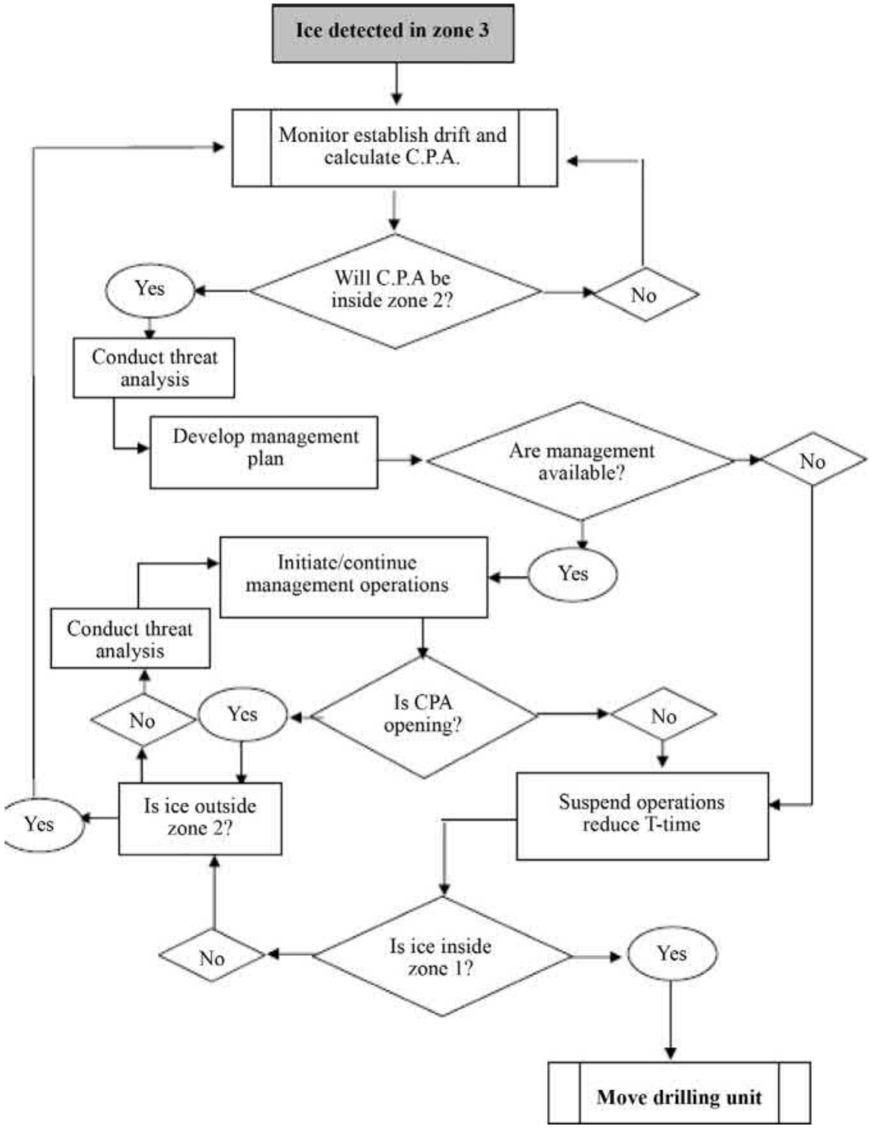


FIG. 4.24 Ice operations. *Source: Provincial Aerospace Ltd., Ice Management Plan Jan. 2010.*

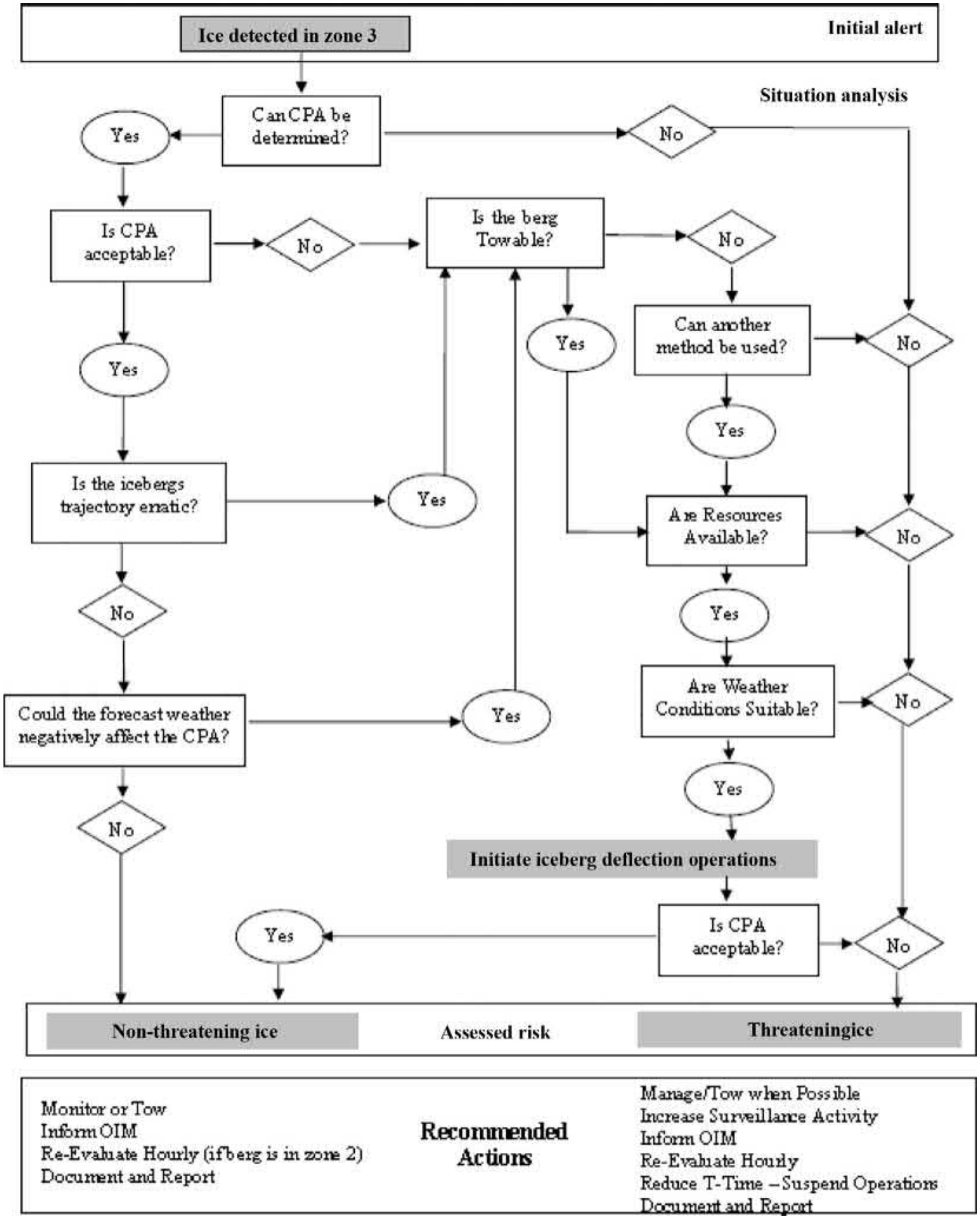


FIG. 4.25 Ice threat analysis flow chart. *Source: As per Fig. 4.24.*

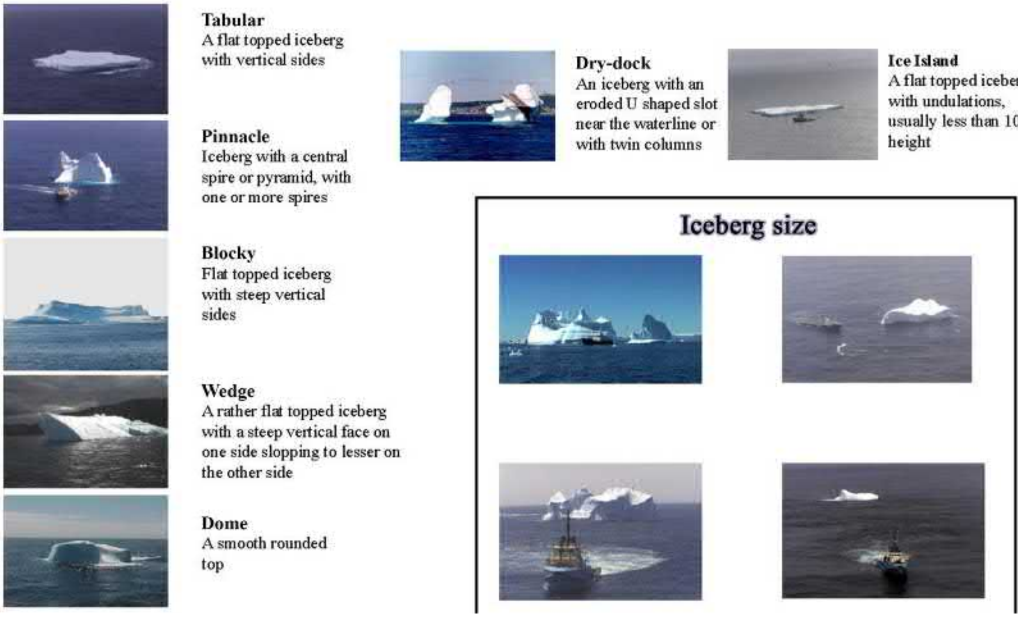


FIG. 4.26 Iceberg Quick reference guide. *Source: Provincial Aerospace Ltd. Ice Management Group 2010.*

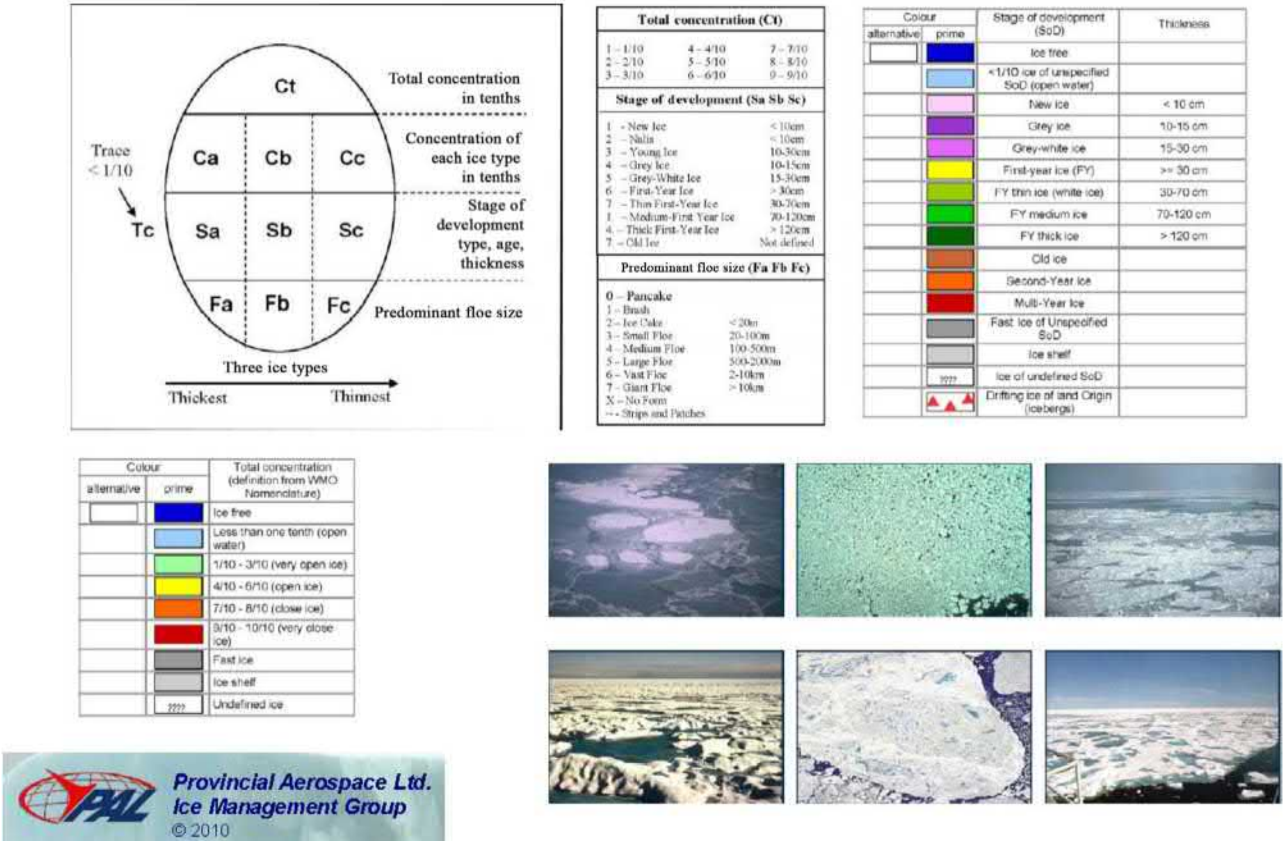


FIG. 4.27 Sea Ice Quick reference card. *Source: Provincial Aerospace Ltd. Ice Management Group 2010.*

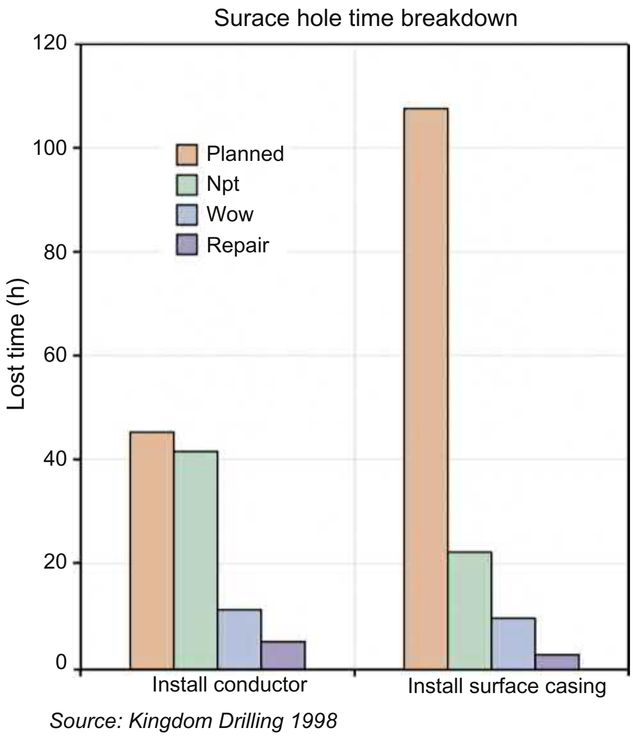


FIG. 4.28 Top and surface-hole phase lost time breakdown. *Source: Kingdom Drilling 1998.*

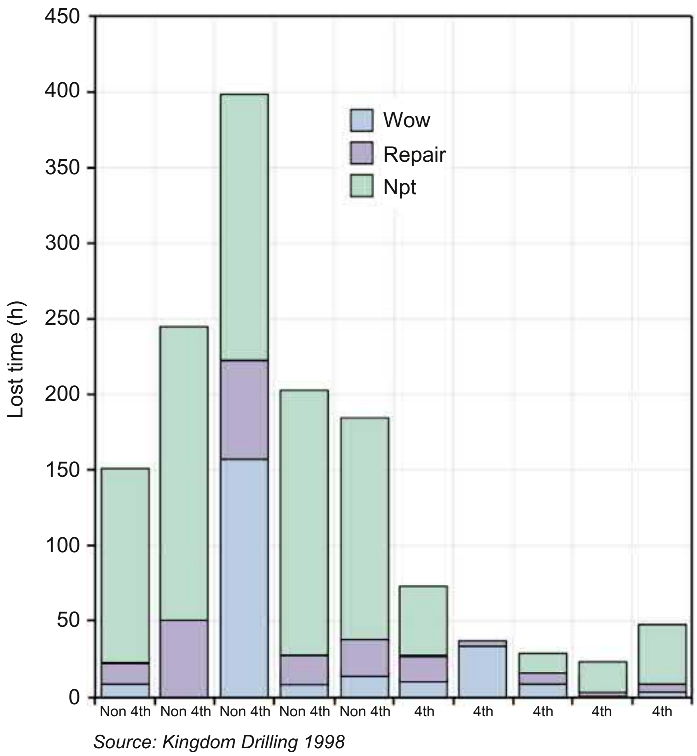


FIG. 4.29 Surface-hole, lost time, summer months, 4th - & 3rd-gen rigs. *Source: Kingdom Drilling 1998.*

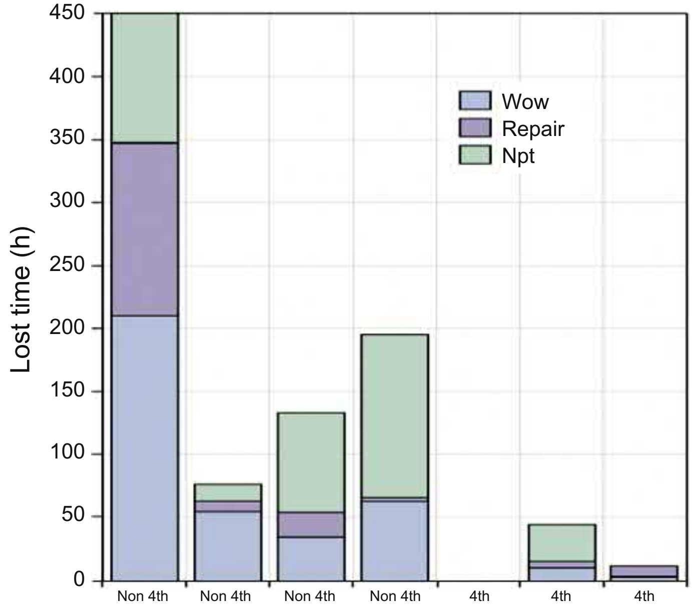


FIG. 4.30 Surface-hole, lost time, winter months 4th - & 3rd-gen rigs. *Source: Kingdom Drilling 1998.*

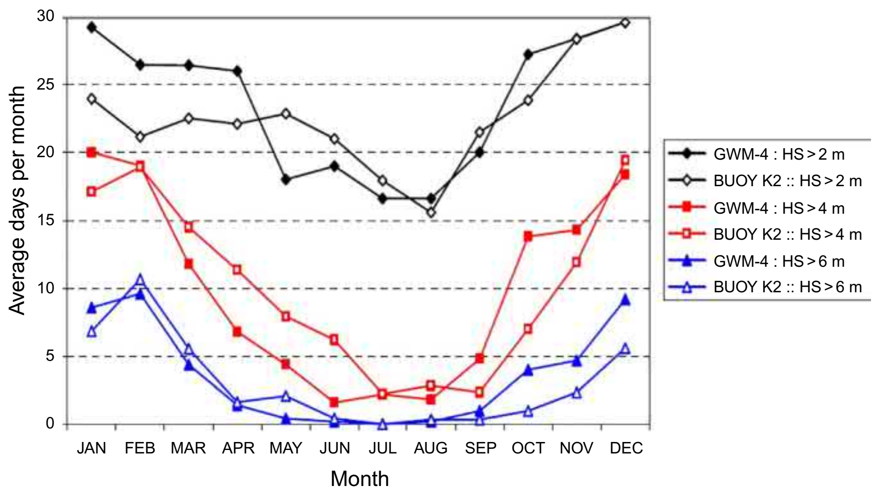


FIG. 4.31 Seasonal wind speed exceedance in Porcupine Basin, Offshore Ireland. *(ISPG) Engineering Downtime Analysis & Cost Effective Drilling study, October 2004.*

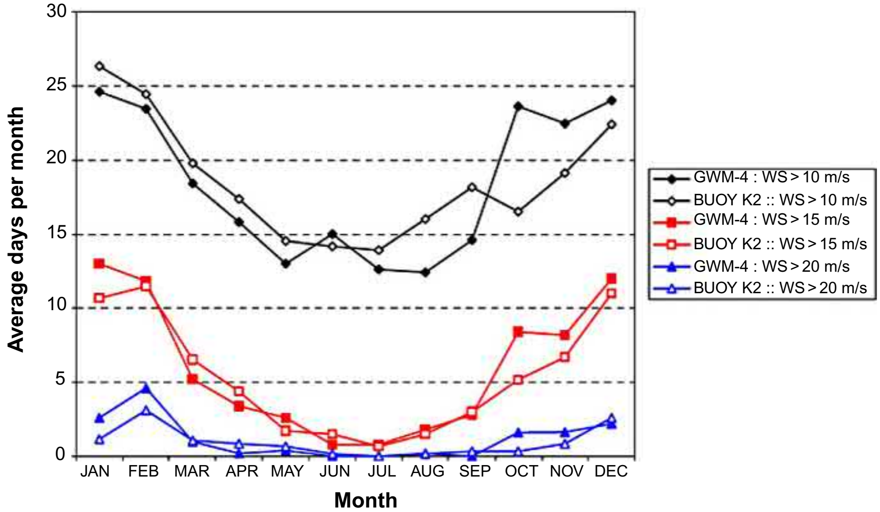


FIG. 4.32 Seasonal wave height exceedance in Porcupine Basin. *(ISPG) Engineering Downtime Analysis & Cost Effective Drilling study, October 2004.*

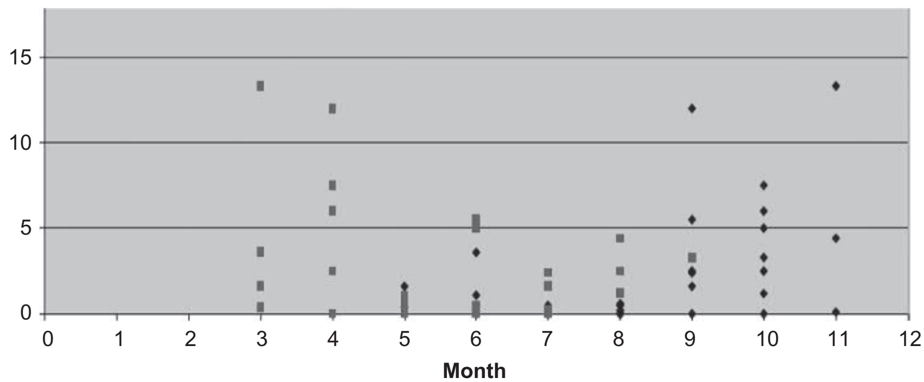


FIG. 4.33 Weather downtime Porcupine Basin, offshore Ireland. *(ISPG) Engineering Downtime Analysis & Cost Effective Drilling study, October 2004.*

REFERENCED STANDARDS

API RP 96 Deepwater well design and construction.

ISO 19901-1, & 4 Metocean design and operating considerations, Geotechnical and foundation design.

ISO 19901-6, 7, & 8: Marine operations, Station keeping systems and Marine Soil Investigations.

ISO 19905-3 Site Specific assessment of mobile units.

Norsok Standard D-101 Rev. 4, June 2013, Well Integrity in drilling and well operations.

Reference

Deng, S., Li, C., Fan, H., Wang, Z., Peng, Q., Feng, X., 2015. Impact evaluation of Internal Solitary Waves on a Drilling Riser College of Petroleum Engineering, China University of Petroleum, Changping, Beijing, China. In: Proceedings of the 25th International Ocean and Polar Engineering Conference, Kona, Big Island, Hawaii, USA, June 21–26, 2015.

Further Reading

Bruhn, C.H.L., Pinto, A.C.C., Johann, P.R.S., Branco, C.C.M., Salomao, M.C., Friere, E.B., 2017. Campos and Santos basins: 40 years of reservoir characterization and management of Shallow to Ultra deepwater, Post and Pre-salt reservoirs, historical overview and future challenges. . Petrobras E&P. OTC-28159-MS, Rio de Janeiro, Brazil.

Buchan, Steve and Kenji Shimizu. High Frequency Internal Solitary Waves – Measurement and Modeling. kshimizu@graduate.uwa.edu.au

Chevron/BP Drilling Training Alliance, 2007. Floating Drilling & Deepwater Drilling Manuals.

Fang, H., Duan, M., 2014. Offshore Operations Facilities: Equipment and Procedures, first ed. Elsevier.

Guo, Y., Zeng, H., Qui, Z., Jin, F., Wang, X., Zhang, J., Wan, Q., 2014. Metocean survey of deepwater areas in the South China Sea for a semi submersible drilling platform. In: Proceedings of the 24th International Ocean and Polar Engineering Conference, Busan, Korea, June 15–20, 2014. Institute of Engineering &Technology. China Oilfield Services Limited, Beijing, China.

Haao, J., Vangen, S., Tyapin, I., Choux, M., Hovland, G., Hansen, M.R., 2012. The effect of friction in passive and active heave compensation of Crown Block Mounted Compensators. University of Agder, Department of Engineering, Grimstad, Norway IFAC Proceedings 45 (8), 316–320.

IADC (International Association of Drilling Contractors), 2015. Floating Drilling & Equipment Operations, first ed.

Jeans, Gus and Mark Calverley, William Jeffery, Chris Jackson, Vasiliy Vlasenko, Al Osborne. 2012. Worldwide Internal Soliton Criteria Oceanology International Conference, March 14, 2012.

Petroleum Affairs Division, Irish Shelf Petroleum Studies Group (ISPG), 2004. Engineering Downtime Analysis & Cost Effective Drilling.

Qi, Y., LED, P.S., 2009. Calculation of the extreme wind, wave and current in deep water of the South China Sea. In: Proceedings of the Third International Deep-Ocean Technology Symposium, Beijing, China, June 28–July 1, 2009. South China Sea Institute of Oceanology, Chinese Academy of Sciences Guangzhou, Guangdong Province, China.

RAO Calculator (response amplitude operators). http://calqlata.com/productpages.

Skjaeveland, H., and H.J. Saetre. Norwegian Deepwater Programme 1996–2016 Summary Report. CSIRO Oceans and Atmosphere.

Xu, L., Shiquan, J., Jianliang, Z., 2013. The Challenges and Solutions for Deepwater Drilling in the South China Sea. CNOOC Research Institute, Beijing, China. OTC 23964.

Xu, L., Zhou, J., Li, C., Sheng, L., Wang, Y., Hao, X., 2017. Influences and Countermeasures of Internal Solitary Waves on Deepwater Drilling in the South China Sea. Research Institute, China National Offshore Oil Corporation, Chaoyang District, Beijing, China, In: 27th International Ocean and Polar Engineering Conference, San Francisco, CA, USA, June 25–30, 2017.

CHAPTER

5

Deepwater: Essentials and Differences

DEEPWATER PORTFOLIOS, PROGRAMS, AND PROJECTS

Portfolio

A company's deepwater portfolio is considered as the total set of programs and standalone projects undertaken by an organization.

Deepwater Program

A deepwater program life span (e.g., the drilling/appraising, to development, production/injection of wells) can be several years for exploration or appraisal programmed campaigns or in a discovery case a field development program can last for 25–30 years or more (Fig. 5.1). Programs usually require the commitment and active involvement of several organizations to achieve the desired outcomes.

Deepwater Projects

Deepwater Projects (Figs. 5.2–5.4) are of shorter duration (e.g., drilling, completing a well, well intervention, or workover) a few weeks to months perhaps focused on the creation of a set of deliverables within agreed cost, time, quality parameters and meeting required Health, Safety and Environmental HSE standards and requirements.

Deepwater programs profit when productive (income) result as illustrated in Figs. 5.2–5.3.

Out with operating production, programs are capital spend events driven by metrics of: *Time, Cost, Quality, Health, Safety, Environment, and Human factors* as presented in Fig. 5.4.

Within each deepwater project, drilling and completion are estimated to account for up to *50%–65% of the total program spend*, i.e., *one or two to tens of billions of dollars*. The importance to SEE how vital optimizing *deepwater drilling projects* are cannot be overstated. Furthermore due to the high overall costs, significant recoverable reservoir volumes must exist for a satisfactory return on a project's investment to result.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00005-3

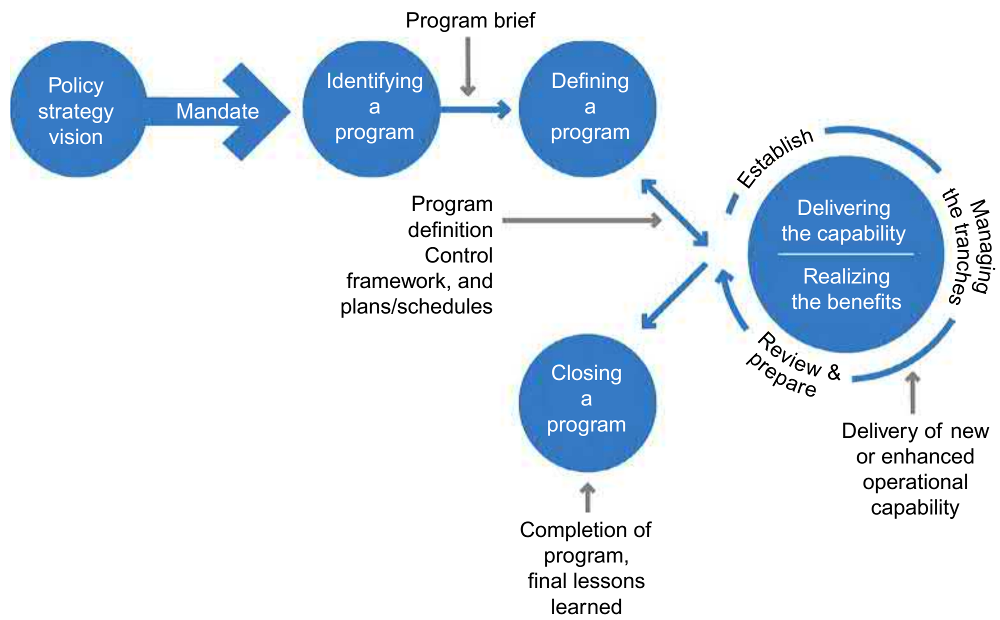


FIG. 5.1 Deepwater transformational flow processes. *Source: Kingdom Drilling.*

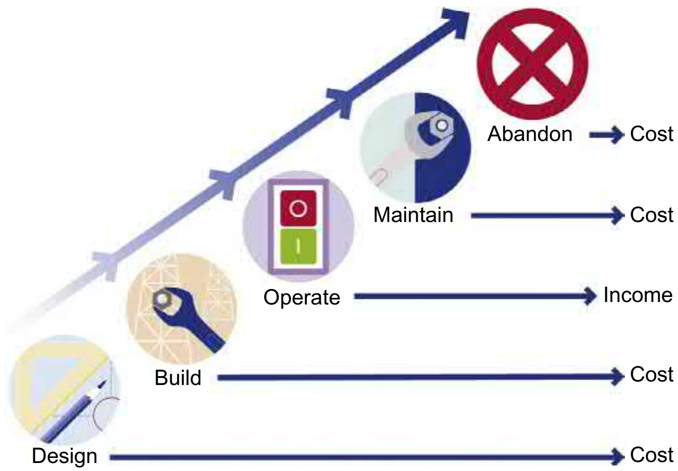


FIG. 5.2 Deepwater well life cycle. *Source: Kingdom Drilling.*

If deepwater programs are managed, and operated in a "same as" conventional manner, outcomes and benefits shall not likely be realized at the results desired. A more reformed and open-minded approach is needed to improve total safety (loss prevention) and operational delivery aspects.

Deepwater Programs and Projects produce a sequence of events to be managed, measured (from a safety, loss prevention, and operational perspective), and controlled from project start

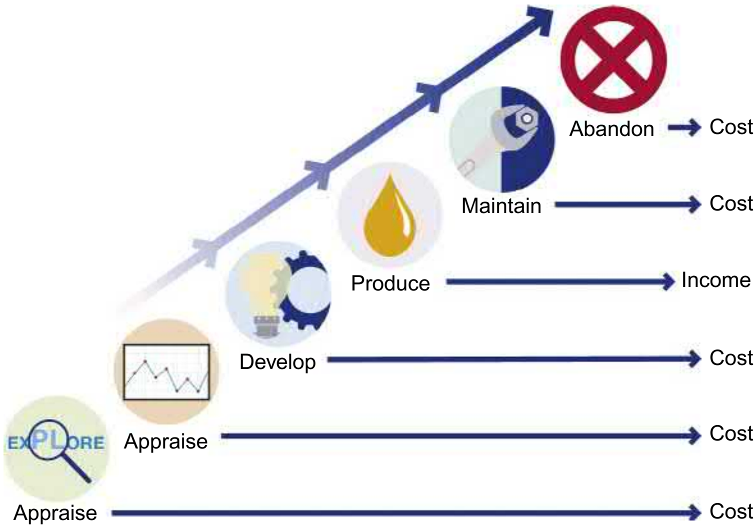


FIG. 5.3 Deepwater reservoir life cycle. *Source: Kingdom Drilling.*

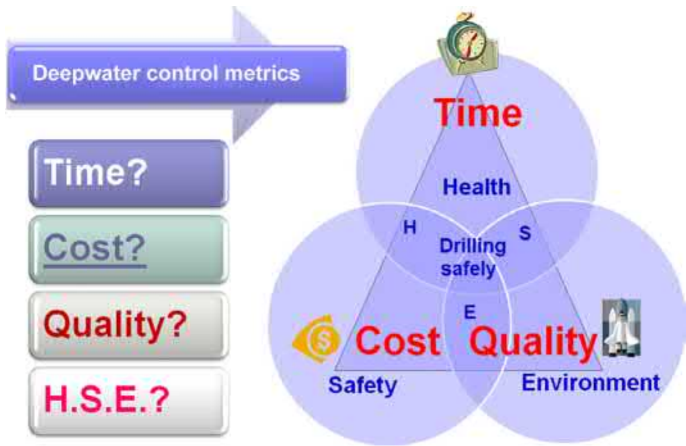


FIG. 5.4 Project metrics. *Source Kingdom Drilling.*

to end. *Note*: Some Program and Project costs may *not be accounted for in original budgets.* Safety, operational, and Project gaps can exist, to require a more progressive step change of transformational flow processes as shown in Fig. 5.1.

In summary, due to the highly technical, demanding, and challenging safe-operating environments required in deepwater, improved program and project management solutions must result, with essential changes instigated and corrected. Before change can be introduced, the key and fundamental differences and essentials that exist in deepwater programs from the standard norm are attended to in this chapter.

KEY BUSINESS DRIVERS

For deepwater programs and projects to survive, operators must rediscover, innovate, or adapt newer management and technology methods, without compromising project *operating safety or the environment*. Key driving areas to pursue are:

1. Improve project Inputs, Outputs, Outcomes, and Benefits.
2. Reduce formation damage, increase wellbore recovery and productivity.
3. Improve global environmental aspects, compliance, reputation, and image.
4. Step change transformational project/process flow incrementally or through key technology use.

In all of the above, Program and Project Management must change and act by first scrutinizing all existing norms to make a prioritized list, to act upon and correct to assure businesses' growth and prosperity in what could be a very uncertain future.

Additionally, Drilling Contractors and third parties, rather than having no or little "skin in the game," must be offered more win-win options for deepwater to more likely succeed. *Example: How can fixed day rate contracts benefit operators to realize maximum value growth or set a more level playing field for all to participate in a new deepwater future that needs changes to survive?*

Organizationally, program and project change must result, with the emphasis on process, metrics, people, empowering all to implement a new, improved, innovative technology-driven tomorrow via the business changes warranted. In this 21st century digital, robotic, big-data, and cloud-based age, a more assured program and project strategy is needed to operate safely, on time, add and sustain value to succeed in the future.

ESSENTIALS AND DIFFERENCES—INTRODUCTION

General Introduction

Seismic technological evolution and progression (as shown in Fig. 5.5) is a key and central driver to operate in deeper water in the search for oil. That, in association with the changing environments and conditions found, required a new generation and further evolution of "fit for purpose" vessels, standards, systems, equipment, and people skills to safely operate. The six recognized phases of offshore Brazil's seismic evolution are summarized as follows:

- *Phase 1*: *1960–1970s*, *2D* seismic in shallow water, with single streamers <1000 m long.
- *Phase 2: 1978*: *3D* seismic in shallow water with single digital streamer.
- *Phase 3: 1989: 3D* seismic in deepwater with multiple streamers.
- *Phase 4: 1999: HD3D* seismic in deepwater.
- *Phase 5: 2004: 4D* seismic in deepwater.
- *Phase 6: 2015–2017: 3D and 4D*, azimuthal and multicomponent seismic.

Significant capital was invested in high-density seismic data and used for Seismic characterization, 4-D seismic, monitoring of turbidite reservoirs, azimuthal and multicomponent technology to improve imaging complex geology. *Example: Recent presalt discoveries have very specific geological, geophysical reservoir, and petroleum characteristics that could not be interpreted*

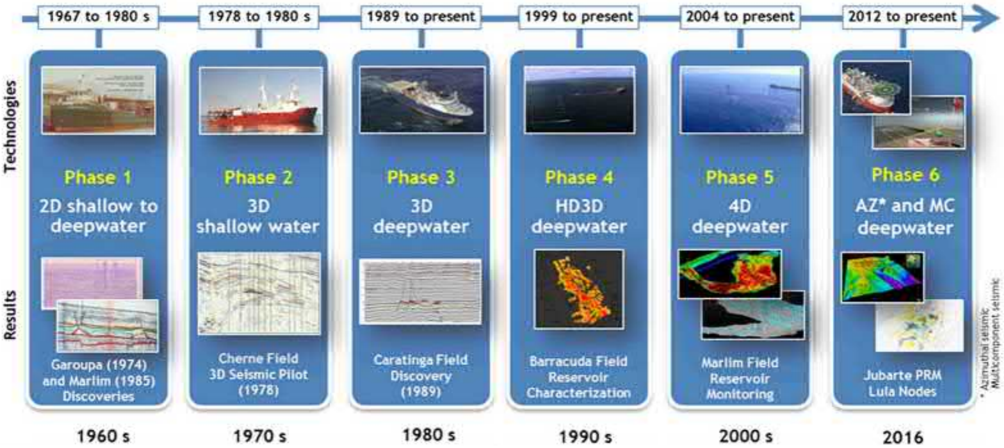


FIG. 5.5 Evolution of seismic technology within Brazilian marginal basins and correlation to oilfield discoveries, reservoir characterization, and monitoring. *Source: Extract illustration taken from Petrobras E&P, SPE/ANP.*

without seismic technology advancement and significant resource investment made in this area. This allowed continuous drive to enable and improve program life cycle value, deliver greater profit, and benefits.

Deepwater Vessel Utilization and Development

Shallow offshore project operations are conducted from fixed installations. Deepwater operating vessels must be designed and constructed to "float." The two essential drilling differences are that vessels remain stationed over subsea facilities, e.g., *wells, either through a moored or dynamic positioned (station keeping) system*. Once the Subsea BOP (SSBOP) is installed, operations are conducted through the marine riser forming an integrated safe system.

Deep and ultradeepwater drilling vessels are categorized into 3 water depth ranges, i.e.:

1. *Shallow water*: <400 (1312 ft)–610 m (2000 ft) water depth.
2. *Intermediate or mid-deep water:* 600 (2000 ft)–1500 m (4.921 ft).
3. *Ultradeepwater:* 1500 m (4921 ft) to 3000+ m (9843+ ft).

Deepwater Convention

Principal influencing factors of deep water are illustrated in Fig. 5.6. Emphasis is that operating organizations in deeper waters *utilized and adapted conventional subsea-wells' designs* vs. strategically adapting alternative change, processes, solutions, or methods. The relevance of staying with convention is what directly resulted to upsize drilling vessels, systems, operating specifics and limits (as Fig. 5.6 and examples will show) to *reduce project benefits and opportunities of time, cost, quality, and often increasing HSE issues*, etc.

Why conventional conservative, risk-averse, same-as, reluctance to change strategic program approach was taken? Was in fact that this was an industry awash with profit (oil price had skyrocketed) managing and resting on its laurels, vs. awakening to the evident truth

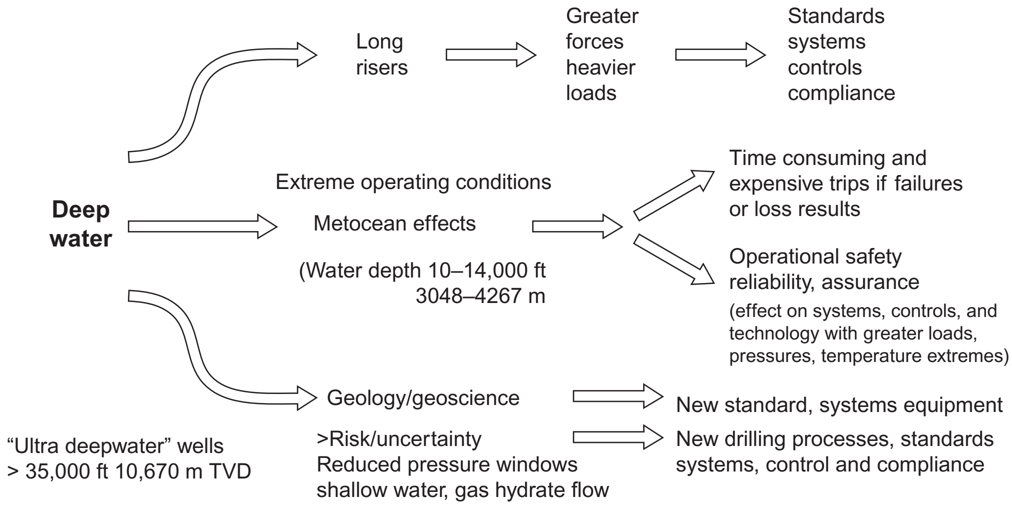


FIG. 5.6 Driving influences of deep and ultradeepwater. *Source: Kingdom Drilling.*

that deepwater was not operationally safe nor delivering outcomes and benefits desired. E.g. *Reflect on Macondo outcomes, the hundreds of thousands of industry employees that consequentially lost their jobs, recent oil price decline, vessels laid up awaiting work, programs and projects delayed or canceled;* as testimonial evidence to management failings on display.

Deepwater Geology and Reservoir Characteristics

Hydrocarbon petroleum geology and reservoir characteristics examples from Brazil's deepwater basins are presented in Table 5.1 and Fig. 5.7. They provide a generalized yet illustrative overview to *key features, variances, and differences*, from well-established and highly developed deepwater operating basins. These characteristics and features have presented Petrobras and their operating partners a need to evolve, progress, and purpose-build the innovative, advanced, adaptive technologies, and associated standards, systems, and best-practice outcome solutions to assure further positive program and project changes results.

Other Essential Deepwater Differences

Other essential factors and difference noteworthy to consider are:

- Operators downsized in the '80s, and farmed out in-house specialists in the '90s to become consultants that were often taken on hire the next day. *Note*: A highly skilled consultant market still dominates today.
- The big crew change of this priceless resource is now retiring, leaving an increasing gap and risk to programs and projects if not addressed.
- In this high oil price period of profitability, a missing generation gap and little recruitment resulted.
- Majority of operators' R&D capabilities were dismantled in this period.

TABLE 5.1 Main Characteristics of the Campos and Santos Reservoir Basins

Stratigraphic Setting	Age	Main Reservoir Sedimentary Facies	Structural and/or Depositional Setting	Geometry	Average Petrophyscial Properties *(Porosity and Permeability)*	Oil (API)	Maximum Initial Production Rates *(bopd)*
Marine regression	Middle Eocene to Early Miocene Late Albian to Middle Eocene	Gravel/sand-rich or sand/mud-rich turbidites	Deposition control by faults, which are soling out on underlying Aptian evaporates	Channel complexities through-confined or unconfined lobes	15%–30%, 10's mD (mud-rich turbidites) to 10,000 mD (gravel/sand-rich turbidites)	13–31	6000–40,000 (>25–31API) 3000–7500 (13–25API)
Shallow marine carbonate	Early to mid Albian	Grainstones and packstones containing oncolites, peloids, oolites, and rare biocasts	Shallow marine carbonate platform.	Marine elongated shoals composed of shoaling-upward cycles	20%–35% (matrix-free calcarenites) 100 mD (average) to <2000 mD in fracture karstified zones	20–32	5000–40,000 Bopd
Transitional (sag) Lacustrine, Evaporite	Aptian	Microbialites and associated calcarenites, calcirudites, and travertines	Lacustrine deposits concentrated on relative structural highs of typically elongated mounds	Elongated mounds and banks	10%–20% (mostly intergranular and vugular). 10'smD to 6000 mD in fractured karstified zones	27–30	20,000–40,000 Bopd
Continental rift	Barremian	Coquinas (bioaccumulated calcarenites and calcirudites composed of pelecypods, ostracods and gastropods	Lacustrine environments confined to rapidly subsiding asymmetric half grabens	Prograding clinoforms and elongated banks aligned with structural highs	10%–20% (mostly intergranular and vugular) ranging from <1 mD to >500 mD (matrix free poorly cemented calcarenites and calcirudites)	28–33	20,000–40,000 Bopd Ultra-deep
	Neocomian	Fractured microcrystalline and vesicular basalts and basaltic breccias	Open fractures rift-related extensional faults		Porosity of open fracture, high permeability.	28–32	6000 bopd

Source: Petrobras Conference Paper 2017.

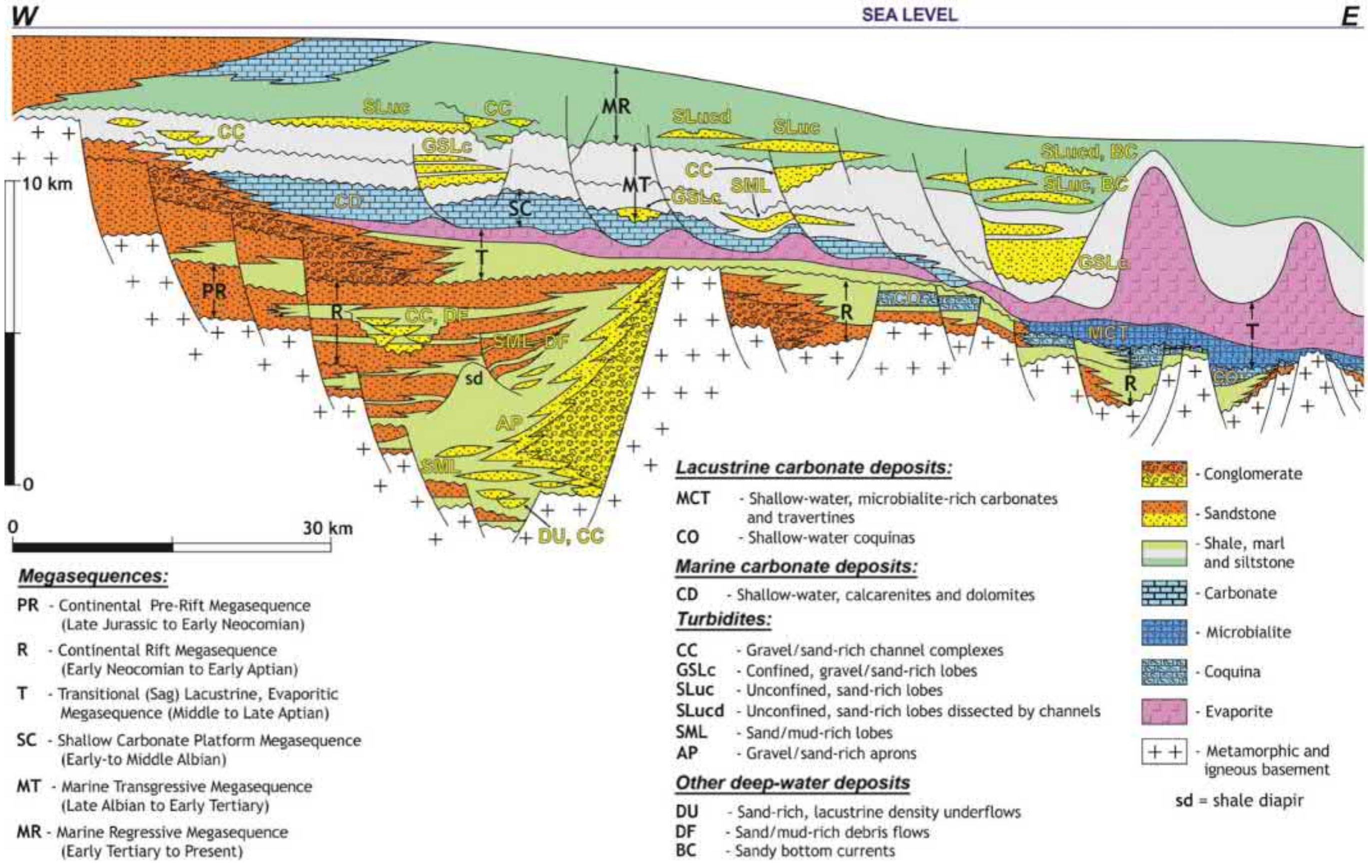


FIG. 5.7 Generalized geological section for Brazilian deepwater marginal basins. The section was developed to illustrate the geology and present the different types of oil and gas reservoirs within this region. *Source: Extract from Petrobras Conference Paper 2017.*

- Programs and projects focused more on shareholder value vs. better operating business outcomes, benefits, and safe operational, technology improvements. ("No one was hurt today was the most common hollow safe operational acceptance speech.")
- Industry and academia was expected to take up all of the slack, yet find means to fund and often govern the progressive program, or project, safety, operational, and technological changes demanded.

DRILLING DEEPWATER WELLS

Deepwater Drilling—Planning

A basic introduction to a deepwater drilling project is summarized in this section to afford a first glance review of the necessary well and operating understanding to key and essential differences raised in this section. Deepwater drilling projects can be of such diversity that multiple variations exist, some like for like and others that are completely different.

Failure in deepwater drilling projects is rest assured a far more painful and costly experience than a standard norm, with far more emphasis to be placed on the 7 P's of project planning:

- Proper Prior Planning Prevents Poor (*People & Product*) from Performing.

An example of the step change in project planning from standard norms resulted in the late '90s, when drilling supervisors, i.e., *this author at that time*, toolpushers, third-party specialists, operations geologists, supervisors, leaders, and other key players were resourced into a designated office space, to be more aligned and integral to *front-load*, *preplan,* and *plan* in far greater depth and detail than before utilizing a project managed-based approach.

What resulted based on this author's extensive experience of transformation processes that resulted was that projects were far more consistently *delivered as planned* with better practices, outcomes, and benefits realized vs. evident historical counterparts.

The key and concluding statement of this approach was to assure and establish high-quality people, communication, teamwork, and a far greater emphasis is placed on safe (loss free) operability, from project start to end. *This actually works!*

Rig Readiness and Mobilization

The start and end of projects are in fact often neglected or ignored areas until they appear on the executable horizon. This missing gap recognized and attended to within the preplanning project phases to the extent that person(s) were assigned to lead miniproject scope's to attend to these operating phases in far more detail. More attention was afforded to assigned project person's roles, responsibilities and accountability, and importantly to assure drilling contractor and third-party specialist personnel's value was integrated and aligned into the project processes at the earliest possible stage. Essentially far more project front-loading, preplan, planning, prespud, transformational processes resulted to produce far higher-quality inputs, outputs, outcomes, and benefits regarding *vessel selection, audits and inspections*, *well and rig safety cases, bridging documents, programs, rig-readiness to drill*. The evident proof was that during project delivery far better outcomes and benefits did in fact result.

Foundation, Conductor, and Surface Wellbore Phases

Locating a vessel in the middle of an ocean to establish a precise well location in 2000 (6562 ft)–3000 m (9843 ft) water depth on the seabed is far different to locating, positioning, and commencing a well at surface where things are far more visible. Different project systems standards, best-practice procedures must be afforded to address this. That once completed and with the vessel and the well location verified and confirmed. A Project's Drilling operations implementation phase can begin where due to the inherent softer nature of the seabed conditions that exists, three methods (**A**, **B**, and **C** as shown in Fig. 5.8) are assessed to install and verify the initial foundation and conductor pipes required.

As a function of water depth, a deepwater wells structural pipe design has to essentially larger in diameter or thicker in wall thickness to resist the increased cyclic bending and axial (fatigue) loads that can exist. What results is that deepwater and ultradeepwater line-pipe will typically range from 30 to 36″ OD and 1½–2″ wall thickness vs. traditional 30″ OD × ½″ − 1″ as used on standard offshore wells.

Size and length of foundation (conductor) structural pipe design in deepwater is driven by *life of well, well design, number of strings required, length, weight, size, loadings, type of well, to be permanently abandoned or retained as a potential production well*, etc. *Note*: A typical deepwater riserless drilling sequence (cuttings are returned and discharged at the seafloor) with typical shallow hazards is illustrated in Fig. 5.9.

One surface casing is all that is required in deepwater operating regions. If however shallow hazards, operating problems or associated difficulties exist (as shown in Fig. 5.9), two (26″ and 20″ (660.4–508 mm) as illustrated) or more surface casing strings are installed. The final surface string, i.e., the 20″ (508 mm) casing in Fig. 5.9, shall be drilled to the structural designed depth to afford the well integrity to accommodate the subsea BOP and ensuing

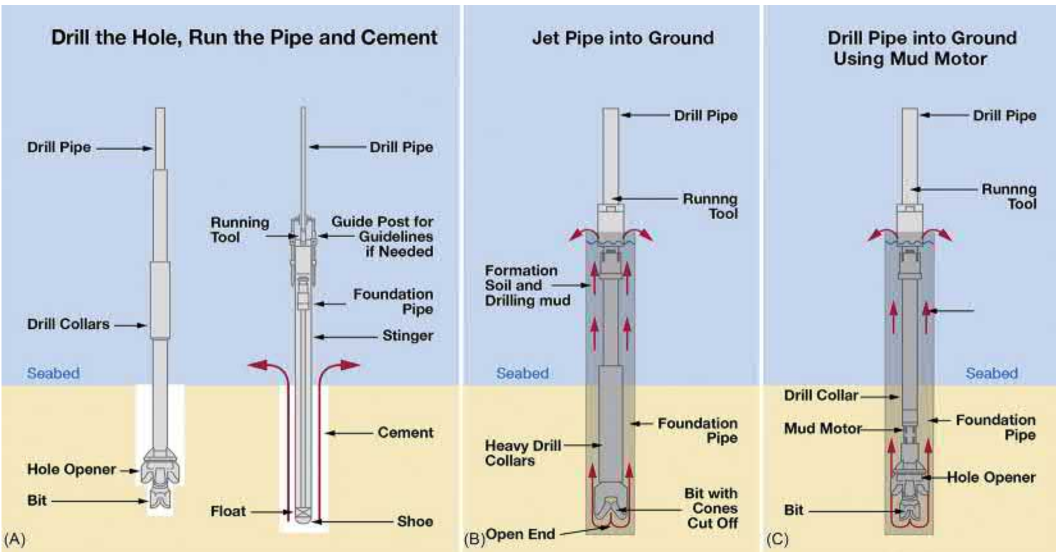


FIG. 5.8 Deepwater foundation pipe options. *Source: Mark Childers.*

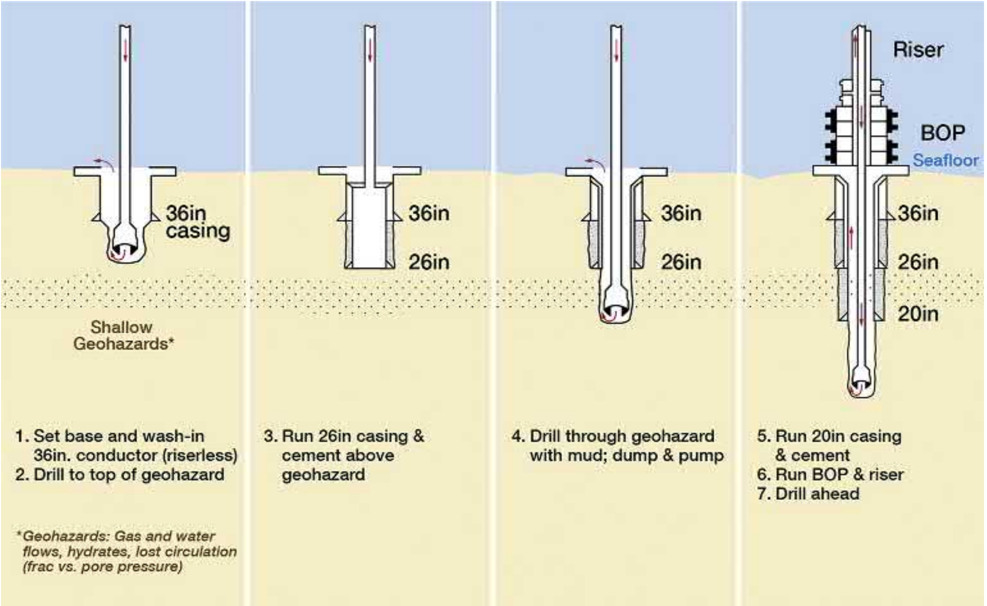


FIG. 5.9 Riserless drilling sequence. *Source Kingdom drillng training 2002.*

intermediate and production casing strings, liners and their axial loads to be safely and operationally supported.

Note: During the surface casing drilling phases, the subsea BOP and mud would also be surface tested, verified, and prepared for running deployment and utilization.

Drilling Below Surface Casing Strings

Once the subsea BOP is run, installed and verified, drilling continues below the surface casing string in a similar process to existing onshore and offshore drilling with the exception that all operations are conducted through the large marine riser (typically 18.75″ (476.3 mm) inch through-bore diameter) that would contain a large and significant volume of mud volume as per riser length as shown. *Note*: Large fluid volumes that exist in the well throughout to be accommodated by both supply and drilling vessels before, during (*in the case of disconnect where mud may have to be taken back to rig for an interim period*), and after drilling the well.

$$bbl = 42\ \text{gal} \quad d = 18.75\ \text{in.}$$
$$Lr = 7500\ \text{ft} \quad Lr = 2286\ \text{m}$$
$$Vol = \frac{\pi \cdot d^2}{4}\ ; \quad Lr = 407\ \text{m}^3$$
$$Vol = 2561\ \text{bbl}$$

The subsea BOP sits vertical and rigid above the seabed with associated control, choke, kill, and boost lines integrated into the attached marine riser, that is maintained in tension and connected to the rig in the moonpool via a slip joint, riser load ring, riser tensioners, diverter housing, choke and kill-line draped hoses, etc.

Pressure temperature and volume regimes and all routine operating tasks and activities are to be best practiced and implemented, often requiring very *different sets of operating standards* in regards to drilling situational, environmental, and conditions that exist.

One or two intermediate sections drilling phases are typically required to the first pressure regime, problem zone, or potential hydrocarbon targets. All casing or liner strings to be accommodated within the subsea wellhead and well design. With each string verified and confirmed to required well integrity standards before drilling deeper.

With abnormal or subnormal pressure regimes and/or the presence of hydrocarbons penetrated, in association with geology, narrowing operating drilling margins. One, two or three, *production casing string and liners* are needed to add project rig days, costs, and well design, standards, program, and operating requirements. Unique challenges such as Post and Pre-salt, Carbonate, Bitumen, Higher pressure, temperature, exceedance of conventional margins and limits all result in advanced technology methods are demanded.

In summary, projects in deep and ultradeepwater can require from as little as three or four casing strings (Ref. Table 5.2 and Fig. 5.10) in normal pressured environments where less operating challenges, hazards, and risk exist. To more challenging situations, conditions, and operating environments that require several casing strings (Table 5.2 and Fig. 5.10) and

TABLE 5.2 Generic Differences as Projects Extend Into Deeper Operating Environments

Key Areas	Platforms Shallow Floating Drilling	Floating Drilling Deepwater	Floating Drilling Ultra Deep Water
Project metrics			
Time	15–45 days+	25–60 days+	40–120 days+
Cost	<US25m+	US25–70 m+	$US35–100 m+
Drilling environments			
Water depth	<1500 ft	2000–5000 ft	5000–12,000 ft
Total depth	10,000–15,000 ft	10,000–25,000 ft	12,500–35,000 ft
Temperature/pressure	48degF (5–10 K psi)	36degF (10–15 K psi)	30degF (10–20 K psi)
Operating windows	4–6 ppg	3–5 ppg	1–3 ppg (*Note 1)*
Operating practice			
Top hole drilling	1000–2000 ft	1500–3000 ft	2000–4000+ ft
Surface string needs	9⅝–20 in.	13⅝–20 in.	16″–24″
Casing strings (*Note 2)*	3–4 Strings	3–6 strings	4–9 Strings
Technical challenges			
Drilling units	Platforms jack ups	2nd–6th Gen	4th–7th Gen
Wellheads	Standards 5–10 K psi	water 10–15 K psi	15–20 K psi
SSBOP systems	Hydraulic 3000 psi	Electronic (5 K psi)	(Electronic) (5 K psi)
Choke, kill, boost line	3″	3.5″–4.5″(+Boost line)	4″–4.5″ (+Boost line)
Offline capability	Single activity	Single/dual activity	Dual activity plus
Drl and land strings	5″ standard.	5½–6⅝″	5⅞–6⅝ (heavy duty)
Drl & Rig Eqpt ratings	250–350 ton 3000–5000 psi	350–500 ton 5000–7500 psi	500–750 ton 5000–7500 psi

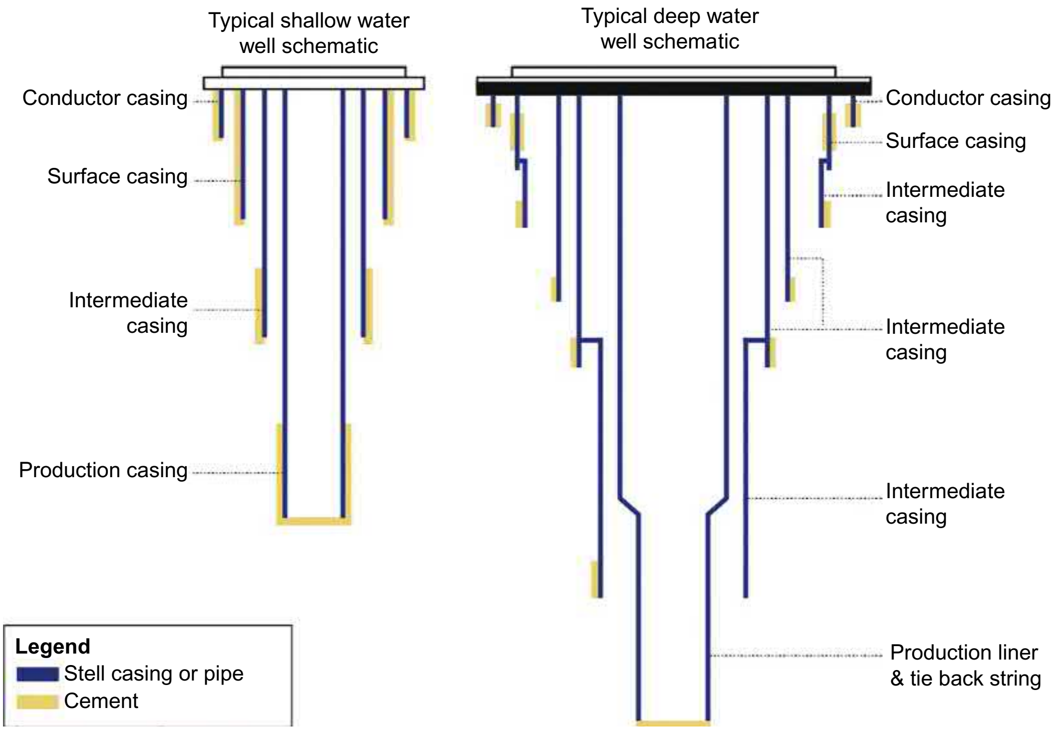


FIG. 5.10 Well schematic differences of a shallow water and deepwater well. *Source: Kingdom Drilling training.*

liners to assure safe project integrity is verified and maintained. When conventional limits are exceeded as is often the case in more extreme deepwater wells, unconventional, adaptive and/or technology methods from floating vessels are then recommended.

Well Abandonment

Abandoning deepwater wells, setting cement plugs is much the same as shallower offshore floating drilling operations. Balanced, unbalanced plugs for sidetracks, abandonment, plug back, are used and set the same with the same problems. UK Oil and Gas, Norsok D-010, API RP 96, BSSE, all offer specific abandonment guidelines to assure safe well suspension or abandonment. In many regions where no marine activity exists, wellheads are commonly left in situ as this is shown and proven by far to be the *safest and lowest environmental impact solution to result.*

Note: Some regions have regulatory standards only for shallow shelf drilling, where multiple marine activities exist. Here it is understandable that all wells and infrastructure must be physically removed at the end of the well life cycle. Deepwater dispensation is needed for wells to be left in situ *where no marine activities exist.*

KEY AND ESSENTIAL DIFFERENCES OF DEEPWATER

Project, Environment, Practice, and Technical Differences

Table 5.2 summarize key differences of deepwater in terms of *Projects, Operating Environments, Best Practice, and Technology Challenges* vs. shallower norms. Source: Modified for Kingdom Drilling training.

Note 1: When operating windows are <1 ppg, conventional methods may not be operationally safe where advanced methods are required.
Note 2: Includes contingent strings often required and needed.

Project Metrics Time, Cost, and Quality Assurance

Deepwater Times

It can be appreciated from Tables 5.2–5.4, and Fig. 5.10 that numerous factors exist in terms of project times, costs, quality, situations, and circumstances in deepwater. Factors that then drive resulting *well design, number of casing strings, rigs, tools, equipment, people, systems, standards* desired and required, with "like-for like" comparisons that are often very difficult to realize. All examples and references in this guide serve to offer generalized conclusions in regards to deepwater well times, costs, and operating metrics for example:

1. *Water depth and trips required to and from the seabed* impacts deep and ultradeepwater well times and costs more so perhaps than any other factor.
2. *Normally pressured, deep transitional, and constant gradient* deepwater wells (Ref. Fig. 3.3) require fewer casing strings impacting to reduce well times considerably.
3. *Conventional deepwater designs* require more of everything particularly as water depth and wells deepen. More requirements add more days, risks, and costs to wells.
4. *More complex wells, notably continuous narrow margin, and ricochet profiles*, as illustrated in Fig. 3.3, result in more casing string and liners, more trips, more safety operational awareness issues, etc. All to result in more project days and costs added.
5. *More complex wells or specific operating problems* often cannot be drilled using conventional methods. Nonconventional methods can more often than not ultimately result to reduce project days on wells or add better outcomes and benefits value.

Deepwater Costs

Greater costs differentiate floating deepwater convention and unconventional well projects and operations from shallower fixed installation wells. Factors driving this as outlined result to add time cost, quality, HSE, and specific people issues to projects. *Example: During oil price highs, deepwater daily vessel costs could exceed $650,000–$850,000 per day, with total project daily costs often exceeding $1 million to $1.2 million per day. What often resulted was single (complex wells) could eat into 100–200 days of rig time to costs in excess of $100 –> $200 m+ dollars. Appraisal and development of deepwater fields cost from a few billion to tens of billions of dollars over a several-year period from discovery before production results.*

However all wells, even the more complex, with the right leaders, SEE principles, common goals, and well-aligned team(s), need not be that time consuming or that expensive. More progressive, adaptive, nonconventional technology-driven approaches as exhibited in Tables

5.3 and 5.4 evidently prove significant step change differences can result. Example: Surface BOP deepwater drilling projects in conjunction with adaptive and innovative technologies have resulted in more than *200+ wells successfully drilled in the 1990s to 2000s.* This example perhaps sets the safe operating bar benchmark standard as to how ordinary people can achieve extra ordinary results in deepwater operating environments.

Many operators, programs, and projects on the other hand lag behind in terms of benefits that technology innovation has realized in Table 5.3. Key conclusions in respect of generalized deepwater well costs are:

1. *Conventional wells* generally require bigger, more modern vessels, more capacities, volumes, heavier, and more of everything inclusive of people and higher costs.
2. *More casing strings require more trips*, take more time to result in more well costs.
3. *Deepwater water and well depths* commonly result in more time that in turn adds more to project costs.
4. Considering the *actual offshore drilling component* of wells has improved up to three fold in the last three decades, benefits are not that well reflected in overall well times and costs due to less positive outcomes and benefits that has evidently resulted in other key areas. Notably flat spot times, and general pipe and tubular handling.
5. *Suitably skilled, trained, and wider developed skills set* of people, with the deepwater know-how, and experience, early involvement, and empowerment is viewed to contribute to the reduction of well costs more so than any other singular item.

Quality Control and Assurance (Deepwater Programs/Well Assurance and Integrity)

Quality assurance is the means and methods used (Fig. 5.11) to prevent mistakes or defects in deepwater programs through problem avoidance when delivering project solutions or services to meet operating clients' expectations. Essentially the term *Well assurance* or *Well integrity* is often used instead of quality assurance to sit in equal importance alongside program management and best-practice engineering. It is therefore an essential element to manage and measure particularly in deepwater (where *failure prevention is an absolute priority*) due to the fact of what catastrophic quality failure consequences can have on human lives, deepwater program (times/costs), environment (harm), or impact and loss to company reputation. Quality (Well) assurance shall be performed to deliver maximum program/project value and viewed as an intrinsic part of all organizational, budgetary input, output outcome, and benefit results. Adding value in deepwater through quality assurance shall often exist as a far higher priority to other project management objectives to further assure stakeholder requirements are met in full, e.g., a trouble-free well through its full operating life cycle. Key conclusions in respect of deepwater programs and well assurance are:

1. *Value addition, capital efficiency, and delivery effectiveness* in deepwater projects is viewed as far more important than operating time/cost savings.
2. *Quality and technology application* issues need to be identified and prioritized early within the project life cycle for suitable prevention to be assured.
3. *Specialist resources* are required to assure all quality management issues are addressed within deepwater projects.

To surmise, failure in deepwater should not be an option where everything feasible and practical must be assured to prevent and mitigate project failure, damage, and loss of any or all significance.

TABLE 5.3 Deepwater Surface SSBOP Exploration Costs From the '90s

Well Cost Summaries

	Description	Well 1	Well 2	Well 3	Well 4	Well 5	Average	%	Ultradeep	2002 Well Estimate	
1	Casing wellheads	$241 K	$250 K	$311 K	$210 K	$303 K	$263 K	6%	$270 K	$900 K	> Cost
2	Bit	$88 K	$88 K	$88 K	$88 K	$88 K	$88 K	2%	$90 K	$90 K	
3	Rig	$2430 K	$1890 K	$2295 K	$1485 K	$1620 K	$1944 K	43%	$2970 K	$3750 K	> day rate
	Rig day rate	$135 K/day	$135 K/day	$135 K/day	$135 K/day	$135 K/day	$135 K/day		$135 K/day	$150 K/day	
4	Directional, LWD	$524 K	$533 K	$742 K	$407 K	$704 K	$582 K	13%	$530 K	$530 K	
5	Mud	$222 K	$229 K	$310 K	$182 K	$300 K	$249 K	6%	$231 K	$400 K	> Cost
6	Cement	$155 K	$161 K	$217 K	$127 K	$210 K	$174 K	4%	$190 K	$250 K	> Cost
7	Rental	$36 K	$28 K	$34 K	$22 K	$24 K	$29 K	1%	$44 K	$50 K	
8	Logging	$137 K	$139 K	$180 K	$117 K	$175 K	$150 K	3%	$170 K	$170 K	
9	Mud logging	$29 K	$22 K	$27 K	$18 K	$19 K	$23 K	1%	$33 K	$20 K	
Shut off device estimated cost per well									n/a	$1000 K	
11	Survey	$20 K	$20 K	$20 K	$20 K	$20 K	$20 K	0%	$20 K	$20 K	
12	Logistics	$180 K	$140 K	$170 K	$110 K	$120 K	$144 K	3%	$220 K	$1250 K	$50 k/day
13	Supervisors	$90 K	$70 K	$85 K	$55 K	$60 K	$72 K	2%	$110 K	$110 K	

15	Prelay	\$540K	\$420K	\$510K	\$330K	\$360K	\$432K	10%	\$660K	\$1250K	\$50k/day
16	Mooring systems	\$100K	\$100K	\$100K	\$100K	\$100K	\$100K	2%	\$100K	\$100K	
17	Overheads	\$235K	\$199K	\$249K	\$159K	\$200K	\$208K	5%	\$286K	\$286K	
	Total cost	\$5027K	\$4289K	\$5338K	\$3430K	\$4303K	\$4477K		\$5924K	\$10,176K	
								100%			
	Days on well	18 days	14 days	17 days	11 days	12 days	14 days		22 days	25 days	
	Meters drilled	2218 m	2293 m	3096 m	1818 m	2997 m	2484 m		2300 m	2200 m	
	m/day	123 m/day	164 m/day	182 m/day	165 m/day	250 m/day	173 m/day		105 m/day	88 m/day	
	Water depth	945 m	1235 m	942 m	1118 m	961 m	1040 m		1500 m	1900 m	
		\$279K/day	\$306K/day	\$314K/day	\$312K/day	\$359K/day	\$311K/day		\$269K/day	\$407K/day	

Source: Peter Aird, 2002.

TABLE 5.4 Illustrative Deepwater Well Design Factors for Different Operating Regions

Deepwater Region	Water Depth (ft)	Environment Metocean (ft)	Drilling Depth (ft)	Csg Run	MWmax (ppg)	BOP (Ksi) (k)	Mud *(bbl)* Storage	Well Cost ($MM) (m)
Gulf of Mexico	5700–6700	Eddies/loop	23,000–28,000	7–8	14–15	15–20	4–6000	100+
	4300–7000	Eddies/loop	20,000–26,000	6–7	14	15	3–4500	60+
	4200	Eddies/loop	13,000–16,000	4–5	13	10	2–4000	35+
Angola	3900–5300	Benign	6500–10,000	3–4	8.8–10	10	2.5–3500	25+
	6000–8000	Benign	9000–12,000	4–5	9–12p	10	3.5–6000	20+
Brazil	4000–6200	High currents	12,000–18,000	3–7	14–15p	10–15	3–6000	25+
Norway	5300	Harsh	11,800–13,500	4–5	9–12p	10–15	2.5–4000	40+
UKCS	3600	Harsh	10,500	4–5	9–12p	10–15	2–4000	35+
Azerbaijan	<2500	Fairly benign	8000–23,000	6	11–18	15–20	2.5–4500	25+
Egypt	250–6000	Fairly benign	8000[a]–15,000	4[a]–6	10[a]–17	10[a]–15	3–4000	25+
Indonesia	<3500	Soliton	8000–10,000	3–4	10–14	10	2–4000	20+

[a] *Majority of wells.*

FIG. 5.11 Quality assurance in deepwater programs. *Source: Compiled by Kingdom Drilling Feb. 2018. From illustrations by unknown authors as licensed under* CC BY-SA.

NONCONVENTIONAL FLOATING DRILLING

Staying with convention shall not likely progress deepwater programs to where it wants to be. This section serves to introduce essential technology advancements to assure competitiveness results in deepwater to assure and deliver as required.

There are numerous adaptive, world-class unconventional concepts, methods, systems, and technological opportunities (for example on unconventional land projects) to consider for deepwater floating well operations, particularly in wells or areas when convention cannot be physically implemented or has repeatedly failed. Key alternate technological options requiring consideration and attention for all the right reasons are:

Dual Gradient Drilling (DGD)

Utilizing a dual gradient drilling (DGD) in deepwater is illustrated in Figs. 5.12 and 5.13. In terms of deepwater project safety, and operability, key benefits are:

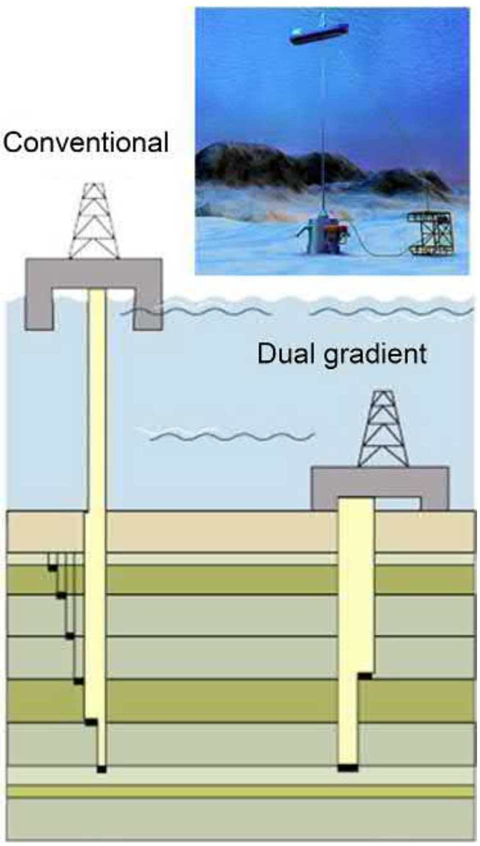


FIG. 5.12 Conventional and dual gradient drilling.

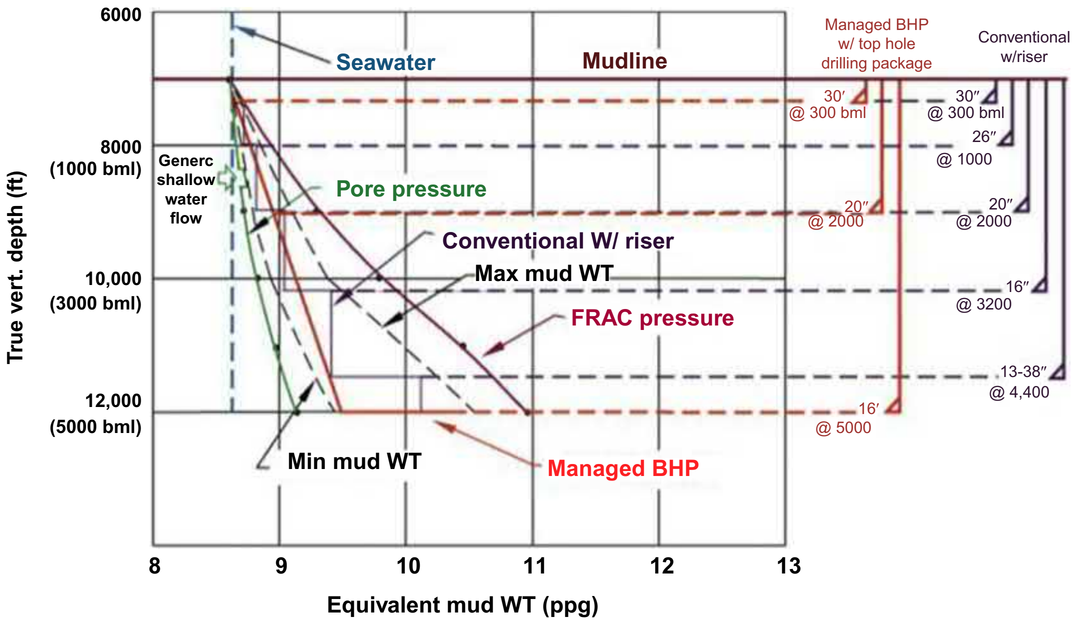


FIG. 5.13 Conventional vs. dual gradient and managed pressure drilling.

1. Extends casing depths
2. Eliminates need for casing string add liners (time and often costs reducing benefits)
3. Bigger wellbore size at well TD (more production benefits, often easier access to wells)
4. Enhanced well control integrity, barrier control assurance

Several IADC, API, and other industry standards and best practice documents are available for managers and engineers to consult in this field.

Managed Pressure Drilling (MPD)

Managed pressure drilling (MPD) offshore or in deepwater is in principle no different to what has been used onshore in thousands of successful step changing applications. Except that project systems, standards, compliance, and controls have to be tailored and suited to meet offshore, subsea, and deepwater safe operating circumstances, well situations, and related conditional events.

The essential difference of MPD is that the well construct now adopts a *closed loop pressure-managed system* approach as shown in Fig. 5.14. The closed system facilitates the fact that all downhole wellbore pressures are now more precisely measured and controlled using a choke and/or pumping device to prevent problems from resulting and safe operating results to be delivered. Notably in narrow operating windows where conventional delivery presents far higher risks.

FIG. 5.14 Deepwater manager pressure drilling.

In problematic deepwater regions (Caspian, Mediterranean, SE Asia, West Africa, Gulf of Mexico to state a few), MPD is used and initiated generally driven by people who have previously experienced and can SEE to initiate the changes needed. Deepwater areas such as Gulf of Mexico, West Africa, SE Asia, and particularly Brazil slowly realizing the added value benefits to bottom line benefits to be gained from MPD when appropriately applied.

Surface BOP Drilling

Surface BOP (SBOP) drilling in deepwater commenced perhaps by default in the '80s and '90s in SE Asia due to limited choice of conventional deepwater rigs, lack of infrastructure, systems, and a requirement to drill a series of wells using an affordable continuous approach.

A CAN-DO innovative solution then was formed with a decision to proceed. Since then it is estimated that >200 deepwater wells have been successfully managed using this method when the right situational, circumstances, and conditions are presented to deliver wells from suitable floating, moored, or DP-operated vessels. Illustrative examples of Surface BOP can be reviewed in Figs. 5.15 and 5.16. *Note*: Such is the validity and verification of surface BOP as a viable alternative that IADC Surface BOP Guidelines document for Floating MODUs exists.

Environmental Aspects of Deepwater Drilling

One of the consequences of operating offshore within seas, oceans, and far more distant from standard onshore landfill or processing facilities is that modern-day technological solutions had to be evolved to protect the offshore environment and to meet company, operating and often regulatory standards and compliance required. General issues to be addressed in full are illustrated in Fig. 5.17.

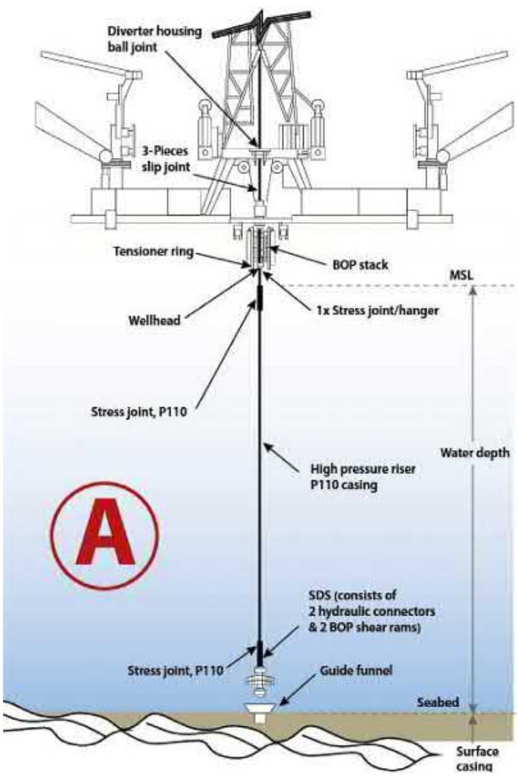


FIG. 5.15 SBOP from a floating drilling vessel. *Source: IADC Floating drilling/equipment operations 1st Ed. 2015.*

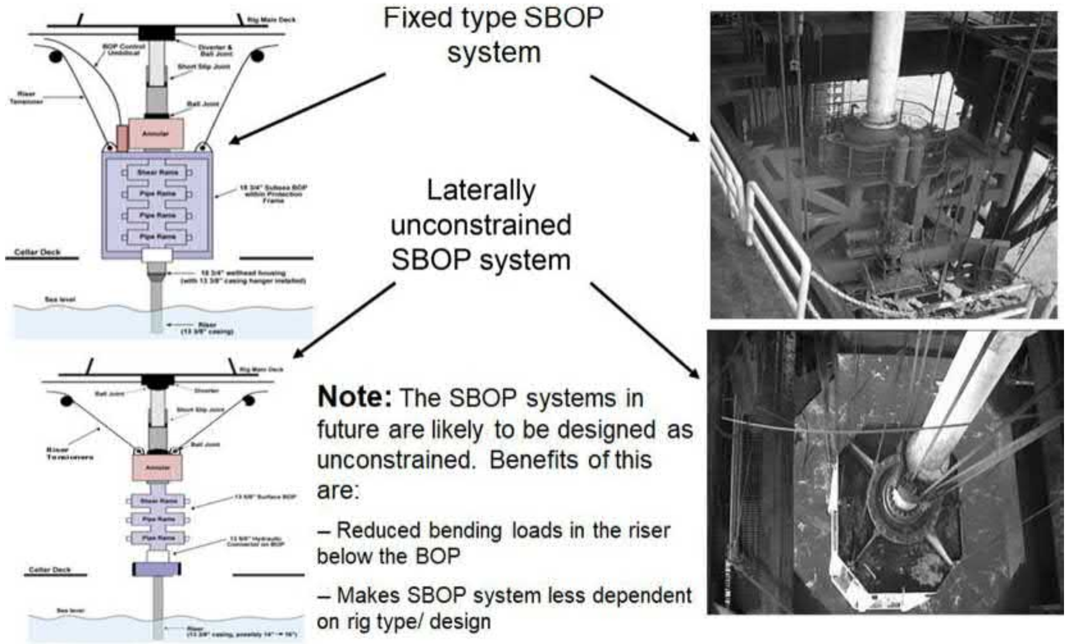


FIG. 5.16 Surface BOP. *Source: Kingdom Drilling training 2005.*

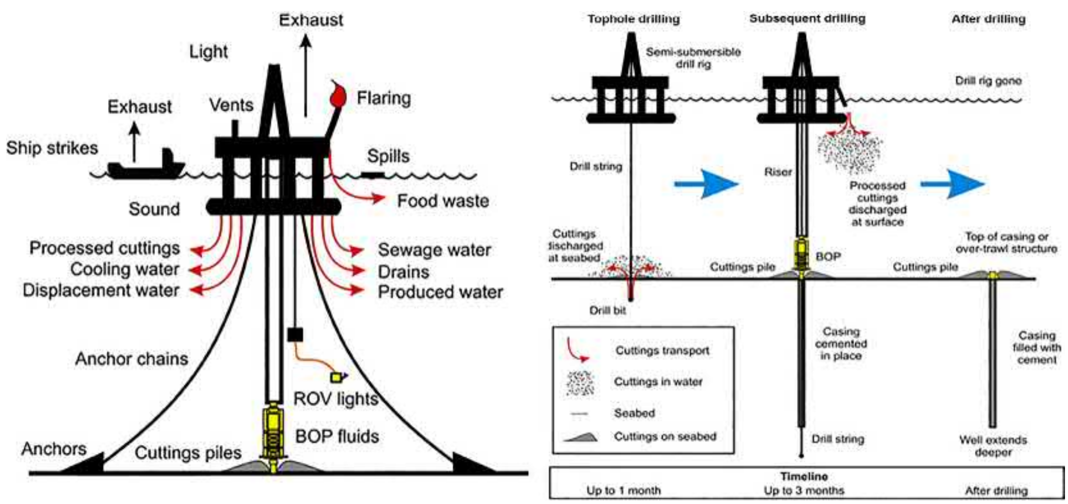


FIG. 5.17 Environmental aspects of offshore operations. *Source: Unknown authors as licensed under CC BY-SA.*

VESSEL SELECTION AND RIG UTILIZATION

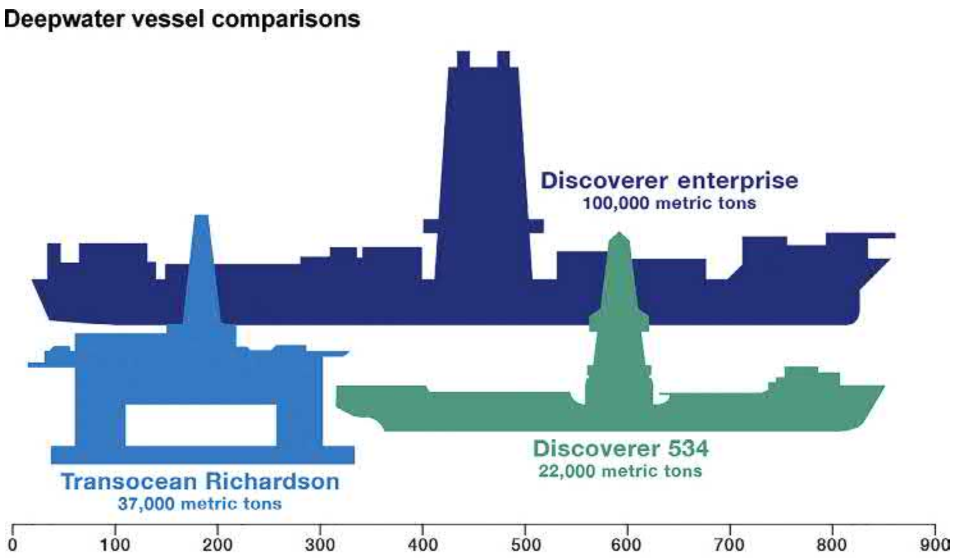
General

A general progression of deepwater vessels and difference is illustrated in Figs. 5.18 and 5.19. Modern vessels today must meet a required standard of safe operating fitness for purpose, driven by all subjective, objective, and project-specific deepwater challenges as presented in this guide.

Key vessel selection and utilization considerations in terms of work scope, well design, best practice, and safe well operability include:

1. Clear work scope, program definition, and contract requirements.
2. A full assessment of deepwater area, location, and operating conditions.
3. A project process that establishes early concept design(s), with further assessment to determine well, vessel, operating systems, and equipment to best fit each project.
4. Evaluation of the rig market and inquiry into what vessels, equipment, systems, and drilling contractor(s) are available to deliver wells as planned. (Often compromise is needed.)
5. A project rig audit, inspection, monitoring and assurance program is well scoped, planned and scheduled.
6. Due consideration given to the scope needed and implementation plans. If there is a well and rig safety case, bridging documents are required to meet and assure scope delivery.
7. Program and/or Project end of well and close plan outlined and discussed at an early stage. (This is important at project beginning, but often left to the end.)
8. Getting the right people to best suit and fit each program and project specifics.

FIG. 5.18 Offshore to deepwater drilling installations history progression 1896–2010.



Vessel name	Richardson	Discoverer 534	Enterprise
Vessel type	Anchored semisubmersible	DP drillship	DP drillship
Displacement, metric tons	37,000	22,000	100,000
Length, ft	336	534	835
Width (beam), ft	282	80	125
Variable deck load, short tons	4080	6000	20,000
Engines, hp	18,180	22,200	52,800
Thrusters, hp	Two 3500	Six 3000	Six 6700
Fuel storage, bbl	10,500	19,000	25,000
Drilling fluid, bbl	5600	4200	15,000
Riser, ft	5000	6000	20,000
Substructure height, ft	42	35	60
Moon pool, ft	21.5 by 42	26 (diameter)	80 by 30
Personnel	100	128	200

FIG. 5.19 Deepwater vessels comparisons. *Original Source: Oil and Gas Journal.*

Deepwater Vessel Selection and "Fitness for Purpose"

Taking a vessel directly on hire without a direct visit, audit or inspection is not to be recommended. Therefore deepwater vessel selection and intake is a demanding, challenging process with lots to gain or lose. Selecting the right rig for the right reasons *burdens those accountable to use a strict, rigorous, and disciplined approach.*

Vessel selection and utilization is principally based *on prior experience with the contractor, people (specialists) who have familiarity of rig types, specific operating disciplines, physical, systems, people, paper Information from previous operator, and/or those who can sift thoroughly to review all the evident facts.* Vessel selection requires due consideration and attention to the program or particular project design complexity, operating situations, and specific conditions that can result.

Deepwater to ultradeepwater vessel specifications as shown in Fig. 5.19 often require the best-fit vessel to meet a project's specific needs. *Note*: General specifics of a newer build 6th generation vessels is illustrated in Table 5.5.

TABLE 5.5 Ultra Deepwater 6th-Generation Semisubmersible General Rig Specifications

Item	Description	Item	Imperial	Metric (m^3)
Water depth	10,000 ft 3000 m	Fuel	25,160 bbl	4000
Drill depth	40,000 ft 12,000 m	Drill water	12,580 bbl	2000
Payload drilling draft	13,500 mt 53,000 mt displacement	Weighted mud, surface	9435 bbl	1500
Payload* Transit draft	7000 mt *Payload is VDL plus column loads	Weighted mud pontoons	9435 bbl	1500
Positioning	DP-2 + 8 pt mooring (provision for 12 pt)	Brine	4718 bbl	750
Power	8 × 4800 kW (38.4 kW: 51,800 hp)	Base oil	4718 bbl	750
Personnel	180 persons	Bulk mud	24,000 ft^3	680
		Bulk cement	24,000 ft^3	680

Operators use in-house or third-party inspection companies to assist with the vessel selection and intake assurance process. The objective is to ultimately deliver a safe, loss-free, uninterrupted project from initial vessel award until contract completion. Although constraints often exist beyond the operator's control, i.e., *rig availability, government policy, regulations, restrictions, or other unique circumstances*, this section intends to provide a better understanding to the vessel selection and intake process.

Selecting a deepwater vessel for a project can be time and resource consuming. During this process, no corners should be left unturned to fully assure the vessel, its systems, and the supporting organizations meet the specific project scope criteria. The process in itself shall raise several important project scope issues to be later addressed by the team(s) assigned. Rest assured early vessel acquisition, assessment, audits, and selection are key project milestones to be met and done well.

Vessel Selection and Intake Process

Deep and ultradeepwater conventional floating drilling projects require compliant specialized and suitably rated operational capabilities that are often tagged with added well complexity times and costs as illustrated in this guide. Irrespective of high or low rig rates, the focus on a vessel's selection, utilization standards, and systems delivery should not change. At the lower day rate, operators and contractors have to prioritize to deliver the same with less, perhaps better prioritize to assure quality and safe operating delivery. Key example areas in this are:

1. *Capability to deliver wells* safe (loss free), effectively and efficiently. Drilling contractors should be asked to provide performance records to assure evidence exists.
2. *Pipe handling, rig up rig down, tripping* capabilities, efficiencies/deficiencies identified.
3. *Flat spot time, other offline operating capability* benefits, pitfalls, failings.
4. *Riser management systems.* Notably, safety critical assurance aspects of these key items.

5. *Compensation and tensioning system*s. (Floating vessels have special needs in this area.)
6. *Subsea system and operating limits*: recent test records, inspections, verifications, etc.
7. *Mooring and dynamic positioning systems.*
8. *Deck loads, bulks, and auxiliary systems*.
9. *ROV* launch and recovery limits.
10. *People,* **skills sets, and competencies.**
11. *Systems, standards, QHSE, controls*, and compliance to all of the above.

Rig Preliminary Selection

The choices in the rig selection and intake process are listed below, with each option to be worked to best suit each specific project.

1. *Build a new generation 7th- or 8th-Generation rig* (smaller leaner, meaner, technology driven).
2. *Use latest 5th-, 6th-generation* deepwater new build rig.
3. *Upgrade older 2nd-, 3rd-, 4th*-generation rigs.
4. *Select rig already in service.* (availability, scheduling).
5. *Consider a warm or cold stacked rig* (address further intake issues required).

Rig Audit Plan

What results from the preliminary tender and resulting bid process is a short list of rigs to retrofit to the best-suited audit plan (as outlined in Table 5.6) results. As selection is closely aligned with inspection, it is important to coordinate the audit and acceptance processes with the assigned persons in charge. A well performance/loss assessment template is also recommended within the bid technical requirement to assure safe well operating measurement, and delivery capability is verified and confirmed. This provides the basic operating data to review vessel and organizational strengths, weaknesses, performance, loss prevention, and learning opportunities.

TABLE 5.6 Rig Audit Types

Types of Audit	Purpose of Audit	Key Points
Shortlist of rigs • Team of I to 3 persons with required skill sets · • Timing: 6h to 2days	• General opinion of the rig and the contactor's safe operational practices • Develop a shortlist for rig selection	• The rig should preferably be in an operational mode • Review the safety record of the contractor • Visually inspect the rig • Discuss operational, safety, loss control aspect with management of rig • Perform a high-level review to verify systems, standards, processes, control, and compliance assurance to these

Continued

TABLE 5.6 Rig Audit Types—cont'd

Types of Audit	Purpose of Audit	Key Points
Preliminary rig audit • Team of 2–5 persons with required skill sets • Timing: I to 3 days	• Verify compliance with drilling policy • Confirm condition of the rig and to identify operating deficiencies • Verify contractor has the proper systems, standards, compliance, control and processes in place and is safely applying these • Assess competencies of all personnel	• Rig should be in operational mode if possible • Review safety record of the contractor • Visually perform a detailed inspection of the rig • Assess potential for testing and internal inspections of equipment • Review the contractor's systems, standards, process, and controls • Discuss operations, safety and loss control management of rig • Review the maintenance program, Observe the crews working. Talk with crew members as much as possible • Debrief company personnel
Detailed rig audit • Rigorous testing of equipment and systems • Team of up to I0 persons with required skill sets • Timing: 1 week or more	• Verify compliance with drilling policy • Confirm that the rig can commence work and identify deficiencies to be corrected before the rig goes on contract • Verify that the contractor has the proper systems, processes controls in place and is in compliance with these • Assess competency of all personnel	• QHSE audit to review operational safety record and aspects of the contractor data of rig well's safety (loss) control aspects and capabilities • Visually inspect the rig in detail • Conduct an integrated and agreed acceptance test program that would simulate drilling conditions where/as practicable • 3rd-party equipment verification, etc. • Discuss operational safety and loss control with management of the rig and observe people at work, performing their duties • Review in detail the contractor's processes • Review the maintenance inspection and repair program • Observe crews working • Talk with crew members • Debrief company personnel

Source: Modified by Kingdom Drilling from BP/Chevron deepwater training alliance manual.

Rig Evaluation Criteria

Noteworthy is that initial result from the rig intake process is probably inconclusive as it is typically difficult to select the best suited contractor and vessel to meet the work scope needs based on tender bids and paperwork alone. However, initial outcome shall eliminate vessels least likely to meet project specifics required. The evaluations of the remaining vessel candidates are now to be appropriately measured, qualified/quantified, with all variances and differences assessed: e.g. *A minimum acceptable bid* vs. *an "all singing, all dancing" expensive rig bid. Some rigs may further not meet acceptance criteria and require cost alternatives to modify vessel to meet the project specific scope*. With so many critical items left open to people's interpretation, the end result is often difficult to conclude, with more evidence based work scope generally needed. *Example: How to equate project value or risk if a high-tech 6th-generation rig, rig crew are all to be changed out due to the fact rig shall have to move to the new operating area and required to hire new local crews.*

In summary, a more formal, systematic, planned, well organized, and evidence based auditable vessel audit and inspection process is employed to assure bids focus on project safety and operability at the fore. The final evaluation evidence must weigh up and account for both the technical and commercial bid aspects. How these are aligned appropriately must be given some thought and be agreed by the operator before tenders are issued to prospective bidders. Critical items for each project work scope delivery item are to be assigned with minimum-maximum values agreed. The bids are then scored, evaluated for each individual technical and commercial based item that results from within all the bid information, data, audits, and inspections conducted.

Commercial considerations must be separated from the technical aspects yet combined in a way that normalizes for example aspects of a simple day rate bid and a bid that includes modification costs. Once both technical and commercial evaluations are complete, the merge should have no evident bias to assure the preferred bid is chosen for all the right and evident reasons. *Note*: The vessel awarded may not be the newest build, the most specified, the lowest or highest priced, or the one that best meets the period required. It should be the most evidently suited, qualified, and quantified "fit for purpose" product of people, organization, rig, systems, and equipment to add the most value and benefits to the project scope.

Whatever the outcome, a rig inspection audit of some form is to be recommended regardless how clear-cut a bid evaluation is to assure all project benefits are realized in regards to rig selection and utilization.

7TH- AND 8TH-GENERATION ULTRADEEPWATER VESSELS

Key area for value addition for the next-generation of program well manufacturing vessels in deepwater is illustrated in Fig. 5.20. Majority of current builds remain in the "bigger is better" camp awaiting operators, drilling contractors, and system providers to build the step changes to what a future deepwater demands. That is to design for intended operations, delivering greater mission equipment and improved vessel design versus essentially a boat with a derrick on top, satisfactory for drilling but not for deepwater well manufacturing (i.e. drilling completion, intervention, workover, and subsea installation work).

What is needed? *Higher specified technology driven vessels, in conjunction with more adaptive and innovative well designs and systems, would require less people, tools, equipment, materials, time and costs per well, and reduce fuel consumption, emissions, waste and environmental discharges.*

Note: One of the added benefits of a welded box structure tower design as shown in Fig. 5.20 is that most machinery is inside to reduce drop objects potential and to facilitate a

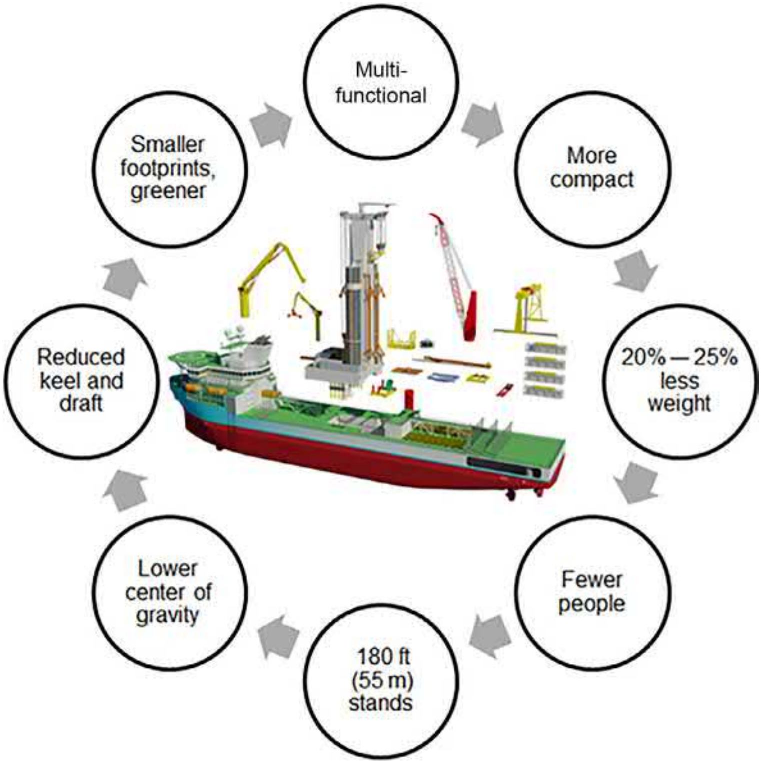


FIG. 5.20 Future deepwater vessels. *Source: Kingdom Drilling/Huisman 2017.*

more comfortable, safer, and operable working environment to deliver a "digital evolution" of inspection, repair, and maintenance desired.

The layout of the system and work space at one level also eases offline operations, performed on the 2nd side, at other safe working areas distant from the main working side.

Interventions and Seabed Drilling

Key features of what could result in the future if all technological options outcomes and benefits are better realized are illustrated in Fig. 5.21. The ability to step change technological systems, tools, standards, and systems is viewed as a key determinant as to how long and profitable deepwater operations can continue to survive and outlast other competitors.

Note: Within the next 10–15 years, operators have stated to target having a viable technological working seabed system capable of drilling deepwater wells as shown in Fig. 5.21 (right image).

Pipe and Tubular Handling

It should be evident from within deepwater well time breakdowns accessible that a far greater proportion of operating time, costs, and opportunities that exist are out-with the

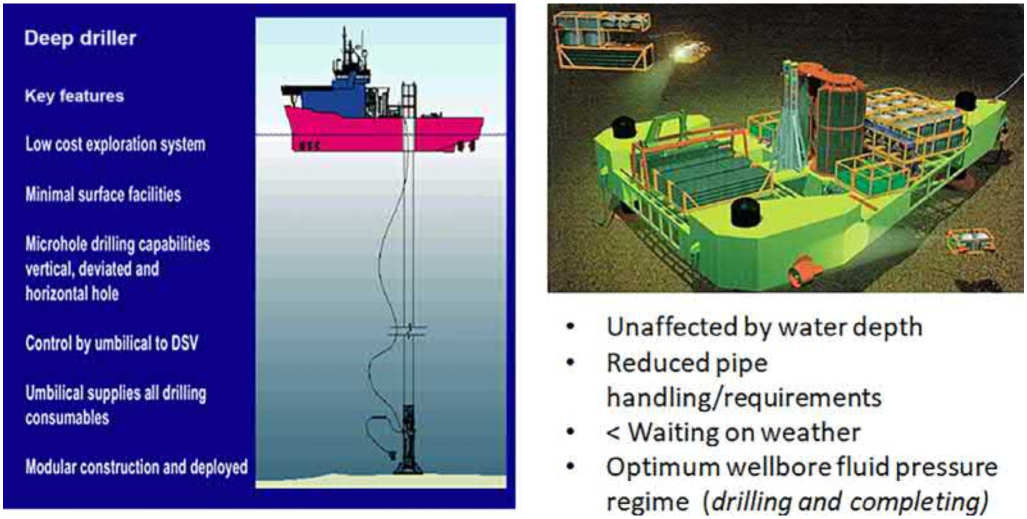


FIG. 5.21 8th generation rigs, sea floor automated drilling concept. *Source: Kingdom Drilling training presentation slide compiled in 2002.*

physicality off on-bottom drilling. In ultradeepwater, it is a fact that wells have to be tripped perhaps 20,000 ft (6096 m) or more just to get a tubular string of pipe to and from its current depth, to highlight the significance that these components part of pipe and tubular handling systems contribute to well delivery. The exact scope of all related tubular tasks and activities in fact presents the biggest time/cost and quality assurance components standards within these projects.

It can indeed be viewed how the offshore drill floor has changed from early 1980s in (Fig. 5.22) to what modern and technological outcomes and benefits could achieve.

Pipe handling was indeed more labor intensive through the '80s and '90s from the pipe-decks to the drill-floor and to/from the seabed within wells. Conventional processes replacing manpower that still remains and may appear operationally unsafe at times to uninitiated outsiders. However this process in many operating theaters is still the most viable, preferred, and comparatively operational safest (loss free) all round option, to best

FIG. 5.22 1980's, '90s Drillfloor pipe handling illustration. *From Kingdom Drilling 2014.*

meet business needs. *Example: Few 4th-, 5th-, or 6th-generation rigs running (quads of pipe) in current drilling contractor's fleet could match a SEDCO 600/601, 2nd-generation basic and simple drilling hoisting system, and a people-power-driven drill-floor when it came to tripping (triples of pipe) in and out of deepwater wells.*

In terms of general rig activities in this specific deepwater operating area, and in comparison to 5th- and 6th-generation mechanized and/or partially automated machines, and despite having only 93 ft (28.35 m) stands of pipe vs. 124 ft (37.78 m) available on the newer build systems, today's modern vessels often average often at best only 40%–50% of older vessels' pipe handling capabilities.

High-tech vessels introduced a new project safety and operational "stop" dimensional mode with resultant multiple high-technology damage, failures loss, and waste events that many operators and drilling contractors fail to recognize, analyze, or identify as safety or business-related loss which it evident is. The deepwater operating challenge and solution is how to resolve and outperform well drilled crews both on the pipe decks or drill floors with far more capable people-machine robotic, digital new technology interfaces to deliver benefits desired. Putting this into the context of metrics to be accounted for, today's focus target is how to improve operational flat-spot times, tasks, nondrilling activity time components of projects. The focus on the nondrilling phases is the absolute project imperative in deepwater, with technologies and pipe and tubular handling at the fore, to deliver:

1. *Less trips to and from the seabed* as is practically possible for each well.
2. *Improved noninterrupted tubular running and handling* at increased safety, effective, and efficient outcomes and benefits. Less involvement of personnel in terms of tripping pipe. The machine and robotic systems should do it.
3. *A new generation of well operations "process controllers"* to oversee the process including geological and formation conditions, pressure management, directional control, optimizing operations, to deliver improved outcome and benefits.
4. *Reduced or prevention of flat spot time* to assure a well's programs and projects are more transformational, continuous, and consistent process and flow events.
5. *More technology investment,* with use of step-changing alternative technologies, robotics, digitalization, big data, as already proven in several other industries.

Illustrations of what exists today and what the future could hold are presented in Figs. 5.23 and 5.24, with further offline capabilities in order of preference viewed as:

1. *Offline bucking machine. Note: few vessels have this facility that has been shown in recent campaigns to add significant value to offshore pipe and tubular handling well operations.*
2. *Offline pipe handling* (Fig. 5.23, right image), tubular stand, BHA, casing, completion assembly and stand building, pick up lay down offline capabilities.
3. *Dual activity rig* (Fig. 5.24). *Note: this is not a one-suit-to-fit all deepwater well options*.

Huisman Deepwater Towering Ambitions

To illustrate recent innovations, the Huisman Innovation Tower (HIT), was commissioned and built to validate and demonstrate the integrity of automated operations of the latest Dual Multi-Purpose Tower (DMPT) design.

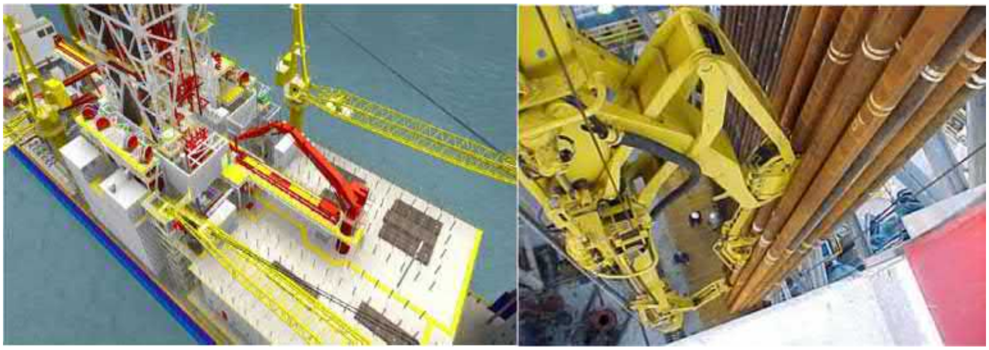
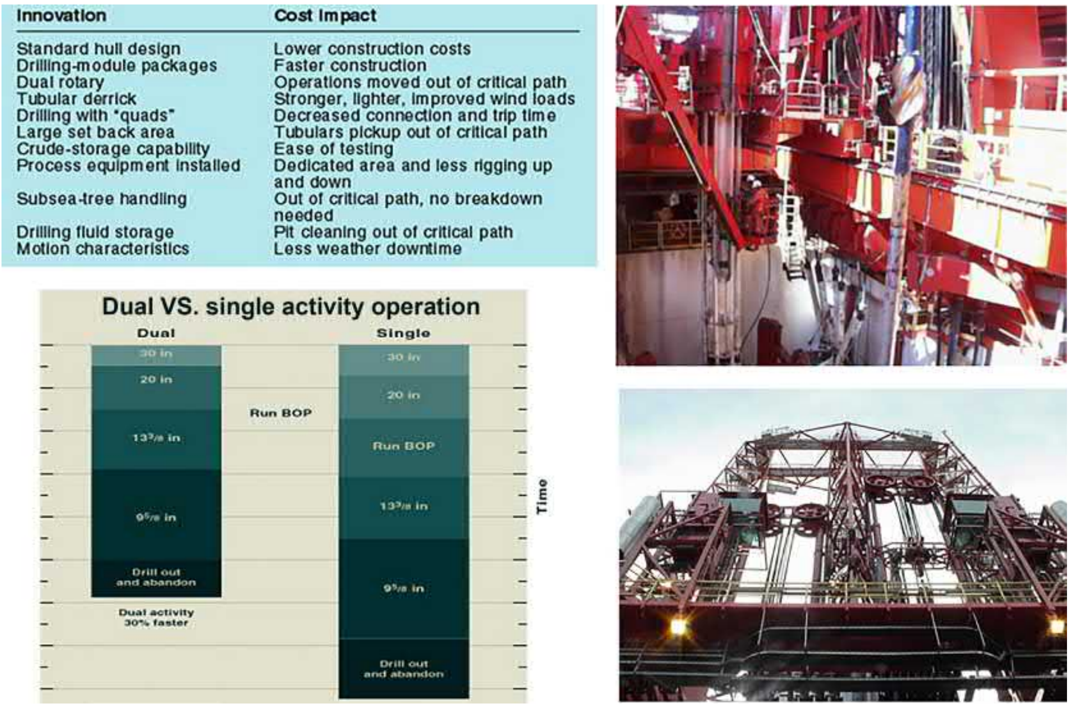


FIG. 5.23 Left image: Akker systems, main pipe deck layout with a hydraulic pipe handling system and transfer skate to transport pipe to and from the drill floor. Right image: NOV Offline pipe handling system, where it can be seen how casing has been made up and racked back in stands typically while drilling operations continue. *Source: Kingdom Drilling training 2002.*



Innovation	Cost Impact
Standard hull design	Lower construction costs
Drilling-module packages	Faster construction
Dual rotary	Operations moved out of critical path
Tubular derrick	Stronger, lighter, improved wind loads
Drilling with "quads"	Decreased connection and trip time
Large set back area	Tubulars pickup out of critical path
Crude-storage capability	Ease of testing
Process equipment installed	Dedicated area and less rigging up and down
Subsea-tree handling	Out of critical path, no breakdown needed
Drilling fluid storage	Pit cleaning out of critical path
Motion characteristics	Less weather downtime

FIG. 5.24 Ram-Rig, deepwater dual activity drilling operations. *Source: Kingdom Drilling 2003.*

The systems are designed to perform and simulate under dynamic (±2°) roll operating conditions, with required flow, pump pressure, rotation, and automatic pipe handling of (180 ft (55 m)) drilling stands and marine drilling risers (150 ft (46 m)).

The tower includes a 400-m wellbore and actual future field operating features of: *dual drawworks, split-table blocks; a full, 3.6-million-pound hook load capacity; a full-sized setback drum; up to eight, robotic manipulators; heave compensator systems.*

Robotics

In conjunction with these systems, the drill floor consists of robotic multifunctional manipulators to be used in conjunction with new design modular power slips, to replace conventional dedicated pipe racking and tubular running and pulling systems.

The complete system has a proven to be capable to handle stands of tubulars at 5600 ft/h (1700 m/h) in simulated vessel roll motions conditions. If realized in the field, this shall change well times to make a significant impact difference.

The new robotic manipulators functional capability offers remote changing of operating tools mounted at the end of the arm from a designated tool rack with no manual intervention whatsoever.

The manipulators shall also deliver simple automated movements to rotate, extend, and move up and down the corners of an enhanced dual multipurpose tower (DMPT) drilling system to conduct further tasks and activities required.

Two or three synchronized manipulators, outfitted with grippers, shall act as the pipe racking system to move stands of drillpipe, casing or smaller completion or well test tubulars, etc. to and from the well centers.

The potential improvements resulting in drilling deepwater wells could be reduced by as much as *20%–25% less total time* compared with current alleged state-of-the-art units.

COMPENSATION AND TENSION SYSTEMS IN DEEPWATER

Compensation Systems

Four main types of drillstring compensation systems (DSC) have evolved for floating and particularly deepwater vessels:

1. *Inline system*, the hoisting load is between the traveling block and the top drive (DSC).
2. *Crown mounted*, i.e., in the crown of the derrick or rig (CMC).
3. *Integrated* within the drawworks (drawworks motion compensation) (DMC).
4. *Hydraulic or ram-rig (*integrated compensation system) (ICS).

Floating vessels require compensation (Fig. 5.25) to minimize the effect of vessel motion relative to several downhole well drilling-related operating activities, etc. The system's purpose is to compensate for vessel movement relative to the seabed or wellbore when items are connected to the drill floor traveling assembly. The goal is to achieve heave compensation with minimal load variation at low or higher operating loads that result.

Initial floating vessels drillstring compensation systems (DSC) were designed for approximately 200,000 lbs (200 ton)–600,000 lbs (300 ton) capacity and an 18-ft (5.5 m) stroke, with a

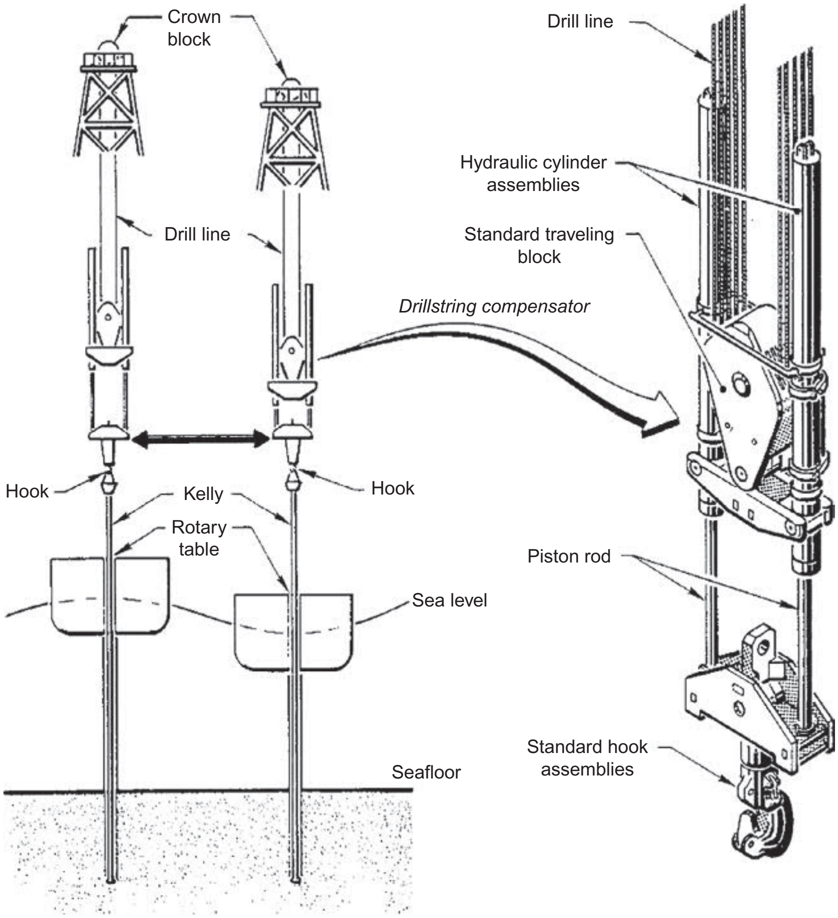


FIG. 5.25 In line drillstring compensation system (DSC). *Source: Kingdom Drilling training 2002.*

locked nonmotion compensation rating of 1 million lbs. Ultradeepwater systems require far higher load compensation and locked load ratings up to 2.5–3 million lbs. The disadvantage of the integral hoisting system is that the traveling assembly carries the weight continuously, to reduce drilling line life that requires more slip and cut of the wire-line to add operating time and cost. As operational and traveling block loads became heavier and to safely compensate in deep and ultradeepwater, new technology systems had to evolve for deep and ultradeepwater.

Crown-Mounted Compensation (CMC)

CMC systems (right image Fig. 5.26) have far higher load rating (ranging from 600,000 lbs (300 ton) up to 2000,000 lbs (1000 ton)) that work independently with conventional hoisting systems. Locked rating ordinarily equals that of the drawworks and/or that of the derrick structure.

FIG. 5.26 Hydraulic ram rig compensation (left image) and Crown-mounted compensation system (right image). *Source: Kingdom Drilling training 2009.*

The CMC systems are far less weight within the traveling system but add weight at the top of the derrick structure to exert a greater effect on vessel stability. The system is also more difficult to access and maintain. The largest CMCs are generally 1.5 million lbs (750 ton) with a locked nonmotion compensation rating of 2 million lbs (1000 ton).

Drawworks Traveling Block Compensation (DMC)

As DSC and CMC "passive" compensation systems are the most ideal deepwater floating vessel compensating system, drawworks-based motion compensation systems (DMC) were developed to actively and more precisely compensate vessel heave over a much larger range of hook loads and different wave trains. The DMC load limit equals that of the drawworks and can be up to 2.5 million lbs (1250 ton) to fit ultradeepwater conventional well requirements.

Initially it was envisaged that DMC would reduce drill-line life. However, due to the size of the drawworks on these vessels (up to 9000 hp continuous and 12,125 hp intermittent) with 14 or 16 lines (2⅛″ to 2½″ lines) strung to the hoisting system, ton mile life, slip and cut requirements are not a major problem. The drawworks have however large footprints, i.e., *48-ft (14.6 m) long, 12-ft (3.5 m) wide, and 17-ft (6 m) tall*, and weigh more than 340,000 lbs (170 ton) driven via six AC motors, each producing 1500 hp continuously.

The main DMC advantage is when handling larger (subsea BOP or casing) loads. It is important to note that DMC systems must be designed and integrated to each vessel's RAO characteristics.

Over the last 20 years DMC development and design has proven reliable and perhaps now to be viewed as the primary "active" motion compensation system for ultradeep systems, with passive system only utilized during critical well-testing operations.

Tensioning Systems

Wireline Tensioner

Wireline tensioners are required on floating vessels to provide (upward) tension to the marine riser and compensate for the relative motion between the riser and the drilling rig (Figs. 5.27 and 5.28).

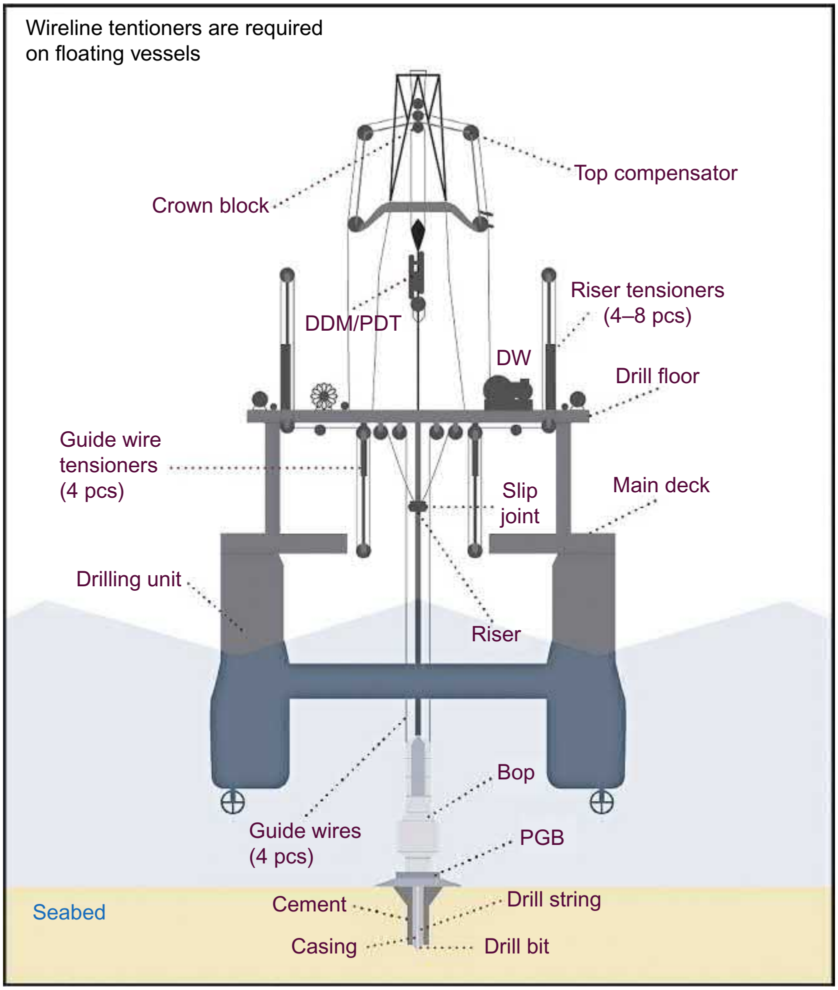


FIG. 5.27 Marine riser tensioner systems. *Source: Kingdom Drilling training 2002.*

Marine riser tension systems (MRT) are installed on the floating vessels to maintain a preselected vertical tension in the riser due to vessel heave, pitch, and rolling effect resulting from waves, currents, and combined wind effects. They apply tension at the riser tensioner ring, located on the outer barrel of the slip joint. They are installed diametrically opposite one another to avoid any lateral forces on the tensioner ring and provide suitable fleet angles on the down comer sheaves.

Wireline tensioners generally exist in single or dual operating units with ratings from 60,000 (30 ton) to 250,000 lb (125 ton) rating with up to a maximum stroke of 50 ft (15.24 m) of wire rope. Dual 250,000 lb (125 ton) units are more common within deepwater vessels with high-strength independent wire rope core (IWRC) land lay construction sizes varying from 1½″ to 2½″ (38.1–63.5 mm).

FIG. 5.28 Wire and hydraulic in line deepwater tensioning systems. *Source: Kingdom Drilling training 2009.*

Systems should be designed to offer sufficient safe operational redundancy so that one pair of tensioners can readily be taken out of the system for inspection, repair, or maintenance.

Inline Riser Tensioners

Inline systems or rod tensioners (Fig. 5.28) apply a similar constant upward force to the marine riser via the riser tensioner ring located on the outer barrel of the slip joint—the upward force maintained to account for vessel heave (pitch and roll) movements.

Systems typically consist of tension member cylinders with ratings varying from 400,000 lb (200 ton) to more than 800,000 lb (400 ton) depending on the total tensioning force required as driven by water depth.

Guideline Tensioner

Guidelines tensioner systems (typically consisting of four lines) can be used with moored vessels only, up to approximately 4500 ft (1372 m) in specific deepwater applications to guide bits, casings, and other items in an open wellbore or during intervention and/or workovers.

They are also used to guide landing of subsea BOP stacks, Xmas trees, or subsea components. They are mainly found on older vessels.

The standard size is 14,000 (7 ton)–16,000 lb (8 ton) tension rating with ½–¾″ (12.7–19.1 mm) wire rope. Their operation is same in principle as wire rope marine riser tensioners.

SUBSEA BOP AND ASSOCIATED OPERATING EQUIPMENT

Subsea BOP Systems

Deepwater operating and metocean effects require specialized subsea equipment systems, components, standard, and practices as outlined in this section. Figs. 5.29–5.34 illustrate the essential features, differences, and requirements.

The Subsea Blow-Out Preventer System (SSBOP) is a safety critical and integral component part of a deepwater drilling operating system. It is located between the wellhead and the marine riser system and is designed to provide well control assurance in the event of taking a well-kick or should a major loss circulation event result, through providing safe, effective, and efficient closing-in of the well. In addition, it is used to confirm well integrity barriers operating standards can be met, i.e., the subsea BOP exists to serves as the final well barrier(s) to prevent an uncontrolled or environmental fluids loss from the well into the sea or ocean.

The three major components of the Subsea BOP (SSBOP) system are:

1. A Lower Marine Riser Package (LMRP).
2. A Lower Subsea BOP stack.
3. A Subsea BOP control system.

Deepwater Diverter Systems

Free gas in a deepwater marine riser can present a hazardous situation on a vessel from a safety standpoint, i.e. *a small influx of free gas can expand as it approaches the surface to produce very significant gas volumes at surface.*

History has shown that a sufficient gas volume can unload violently as it approaches the surface if not detected, managed and controlled appropriately.

In deepwater drilling, the essential difference is that a far greater probability of having to *divert* and/or handle gas via a MGS shall result in comparison in shallower water. A typical deepwater gas handling is illustrated in Figs. 5.30 and 5.34.

Marine Riser and Surface Mud Gas Handling (MGS) Systems

A deepwater marine riser and surface gas handling MGS system is illustrated in Fig. 5.35.

The system provides safe handling of specified gas influx volumes that has passed the SSBOP stack when gas entry is not realized until gas has migrated into the marine riser.

Drilling Riser System

Deepwater Marine Riser Basics

Deepwater Marine riser components are illustrated in Figs. 5.36 and 5.37. The system provides a large-diameter wellbore connection between the wellhead through the drilling riser to the drilling vessel surface facilities, to permit safe drilling of a well from a floating drilling vessel.

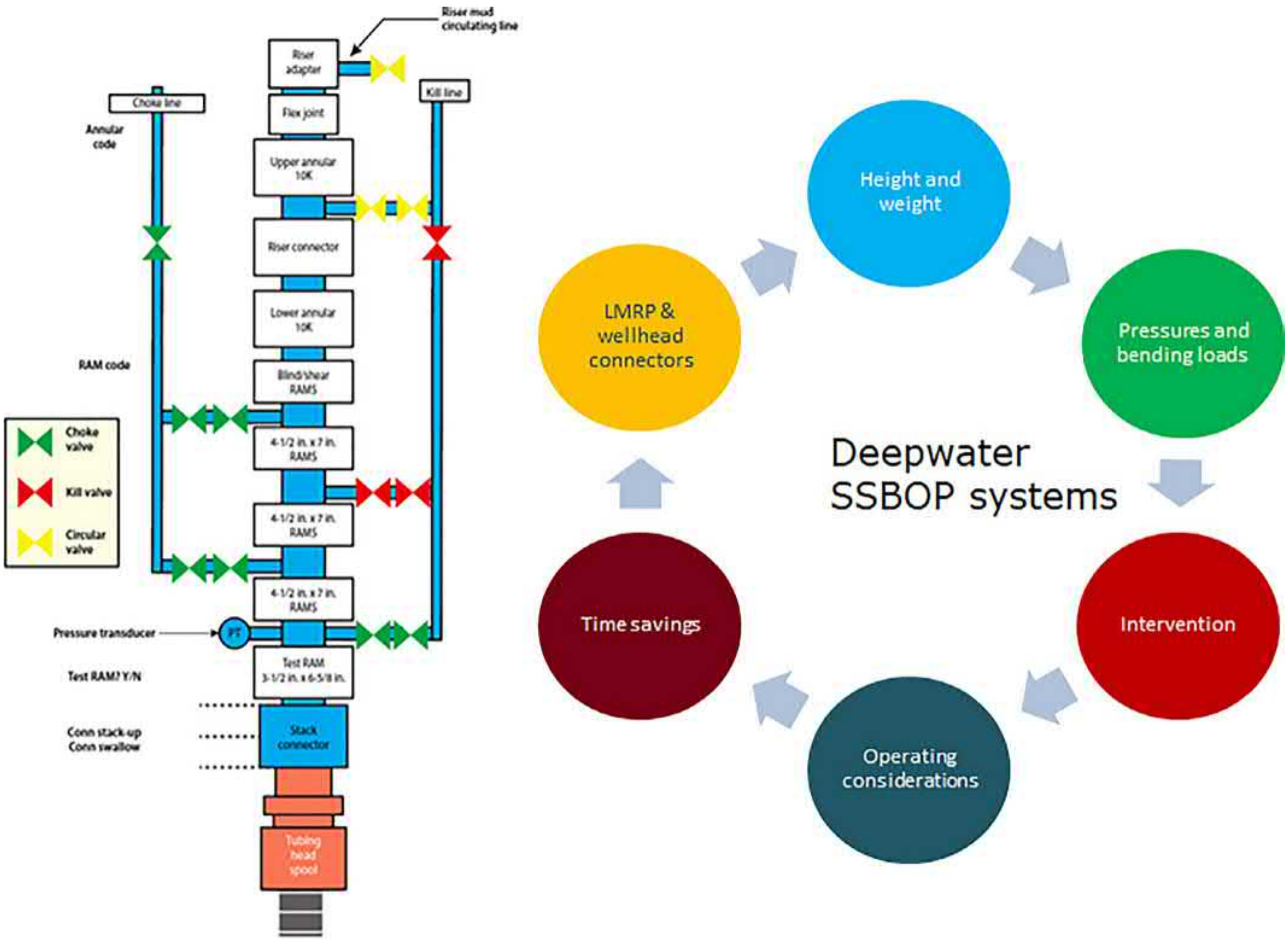


FIG. 5.29 Deepwater SSBOP components and key issues. *Source: Kingdom Drilling training 2009.*

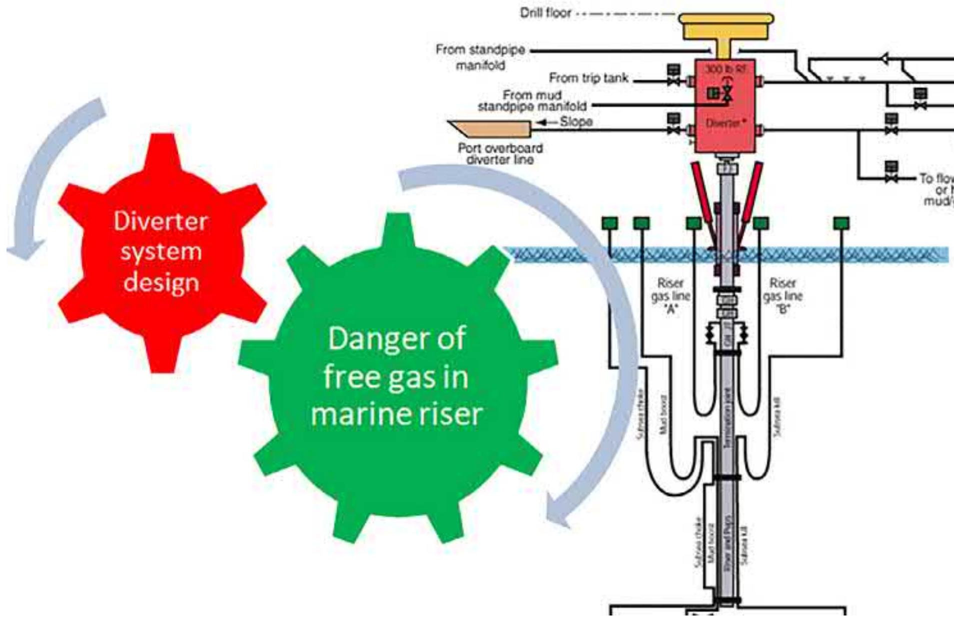


FIG. 5.30 Conventional vs. deepwater diverter systems. *Source: Kingdom Drilling training 2009.*

Attached to a deepwater marine riser are five conduits consisting of two hydraulic control lines, a high-pressure choke line and kill lines, and a circulating boost line. The data required to analyze well loadings imposed on wellhead SSBOP and marine components are divided into three (3) categories.

(1) *Riser data*: the data include all the information required to define the configuration of the riser system.
(2) *Vessel data*: include all of the information required to model the motions and interfaces between the vessel and the riser.
(3) *Environmental data*: include all of the information required to define the metocean, sea states, and currents that the riser may be subjected to.

RISER SYSTEM CONSIDERATIONS

Riser system considerations and operating conditions to be considered during a deepwater project are:

- *Riser components*: deployment and retrieval
- *Handling and lifting gear capacity*, hang-off, connector limits
- *Burst pressure*, collapse/fillup valve
- *Drift-off/drive-off*
- Recoil response
- *Riser, wellhead and conductor strength*, torque loads due to heading change

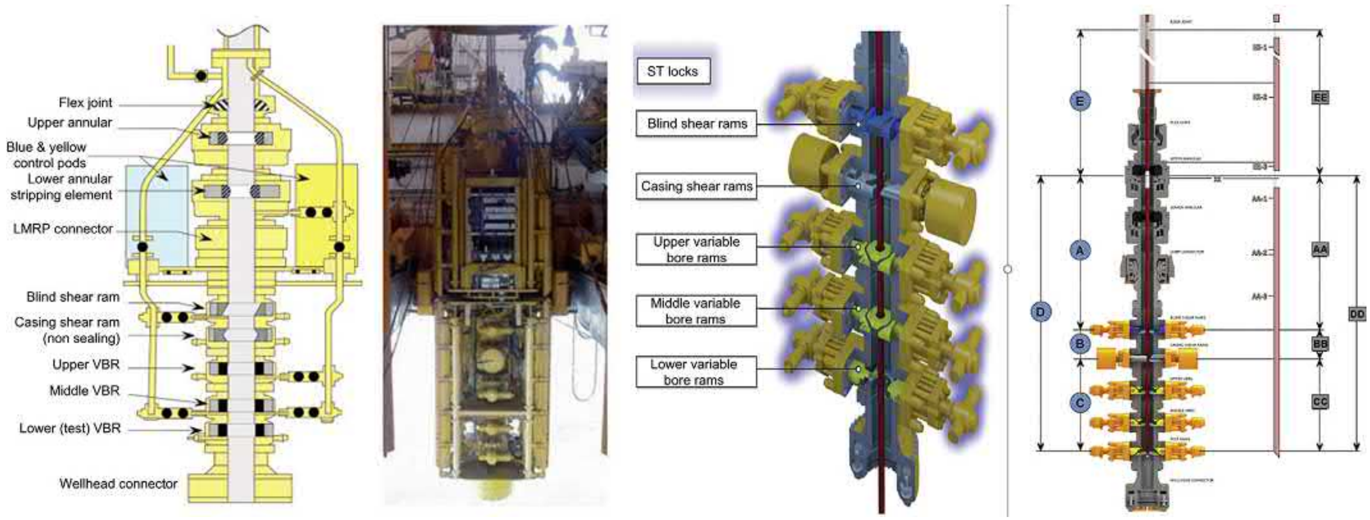


FIG. 5.31 (Left images) Simplified illustration and photograph of a deepwater Subsea BOP stack. (Right image) Cutaway illustration of SSBOP. *Source: Kingdom drilling DWE training 2015.*

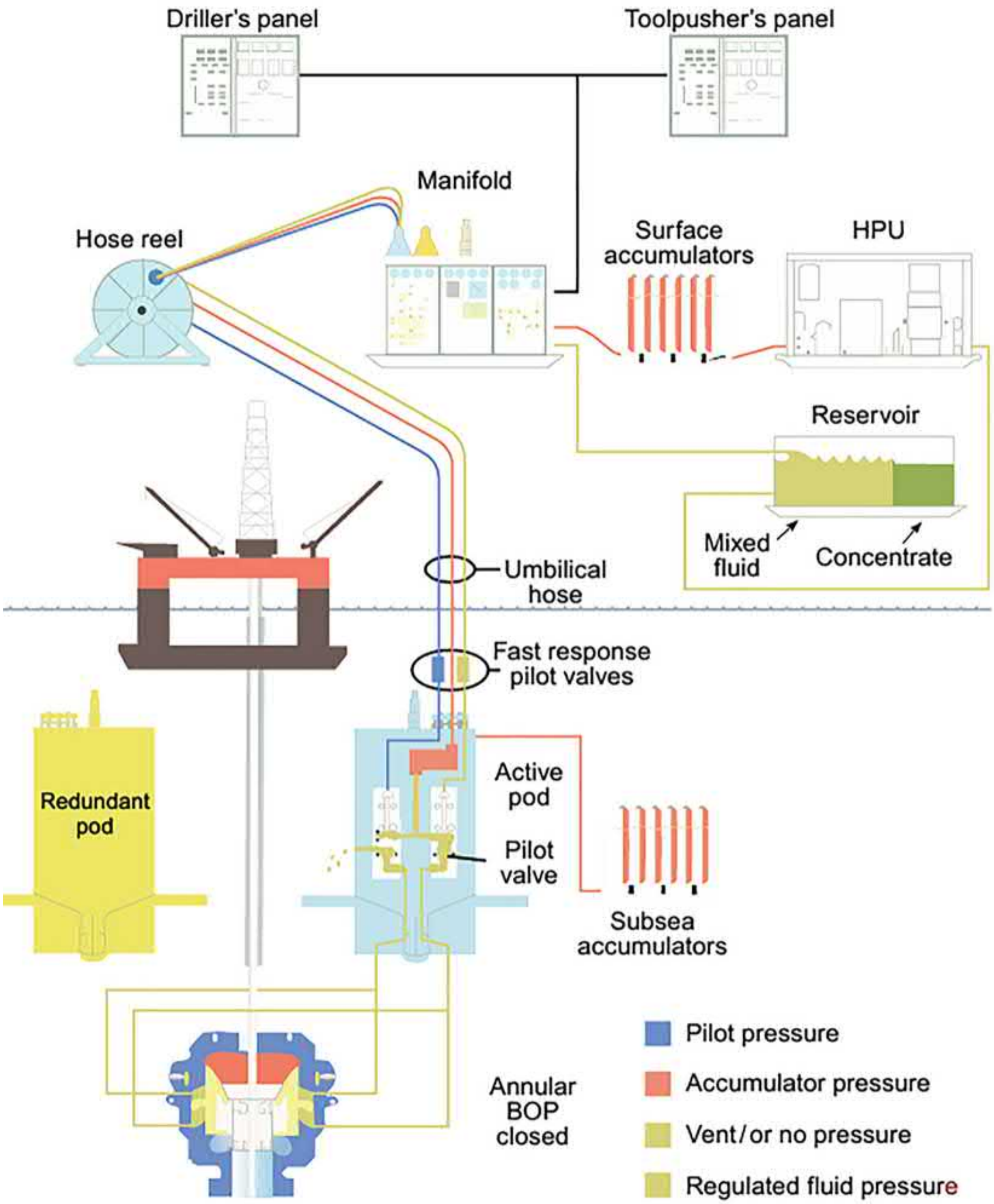


FIG. 5.32 Schematic of an all-hydraulic SSBOP system. *Source: Kingdom Drilling Training 2014.*

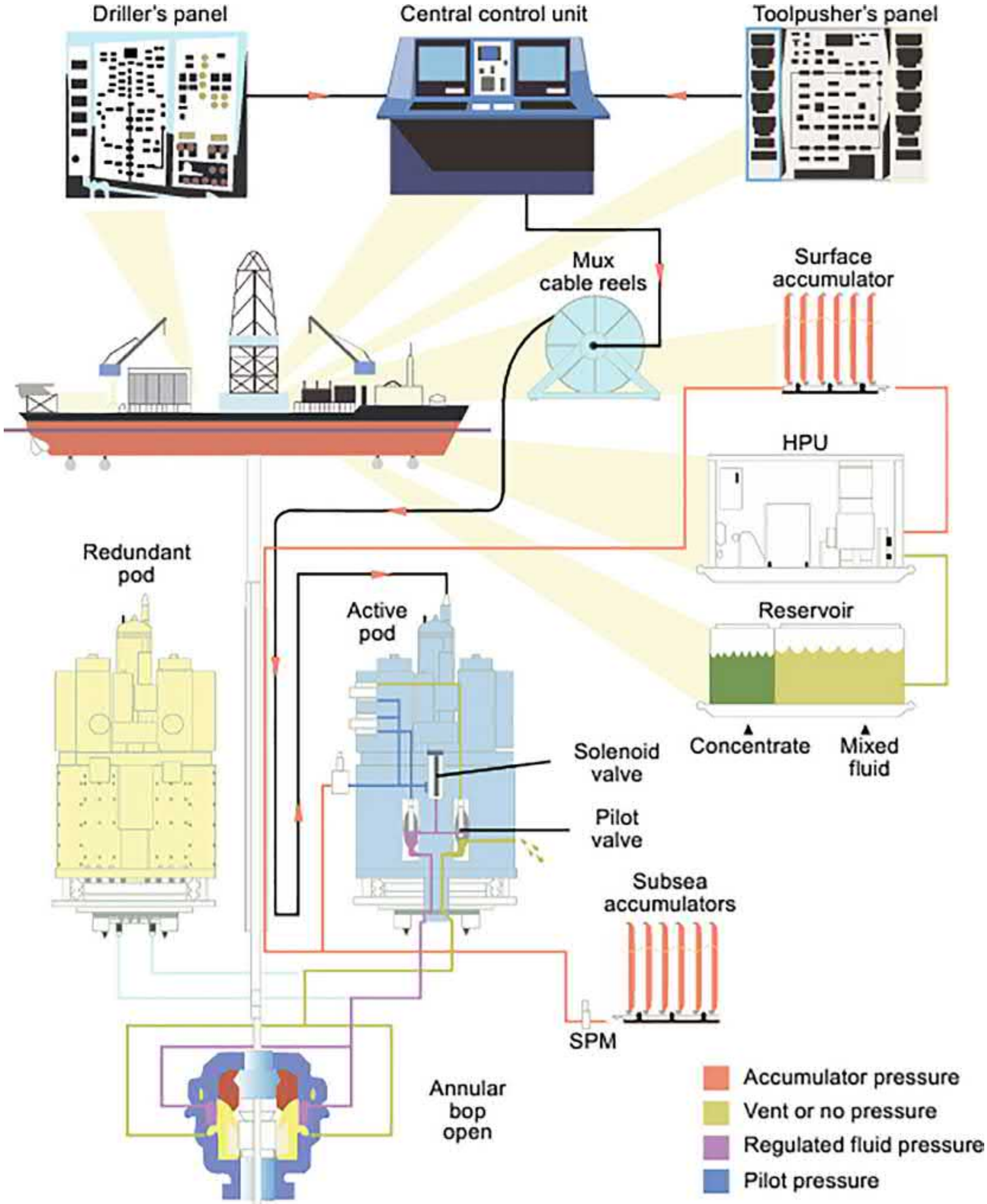


FIG. 5.33 Schematic of a multiplex (MUX) SSBOP control system. *Source: Kingdom Drilling Training 2014.*

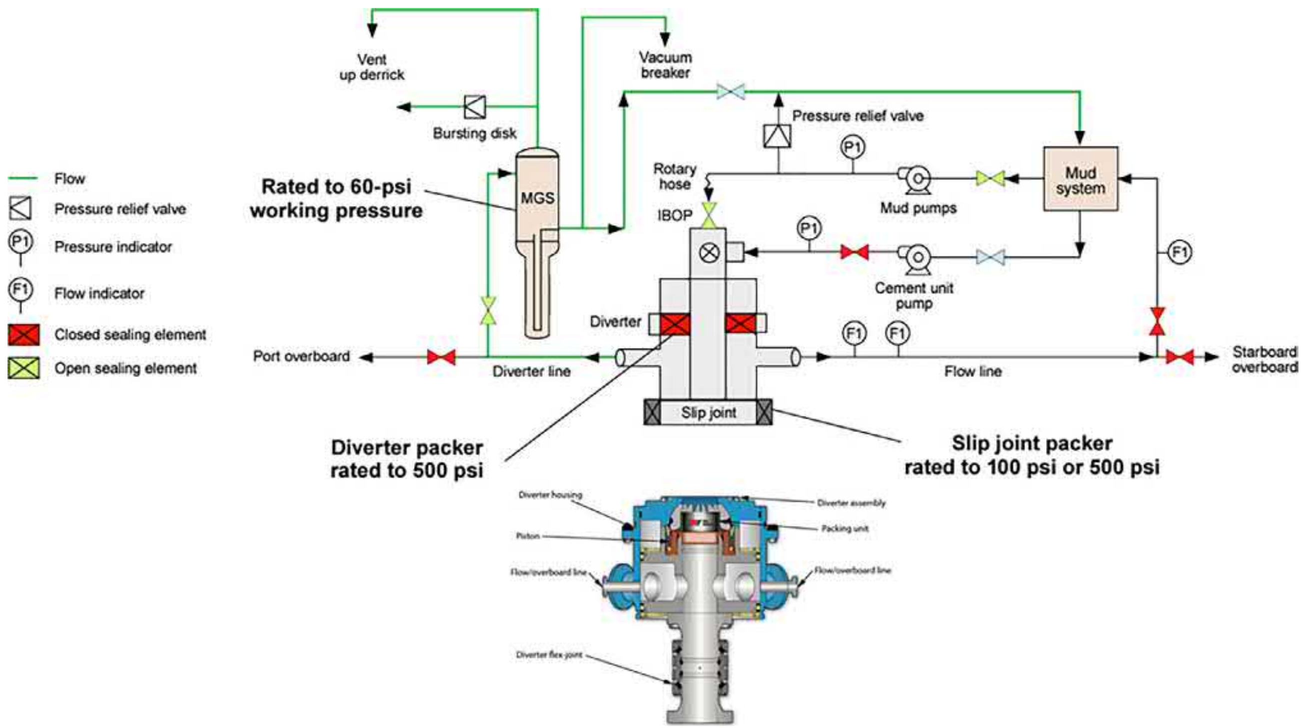


FIG. 5.34 Deepwater mud gas handling and diverter system. *From Kingdom Drilling training construct.*

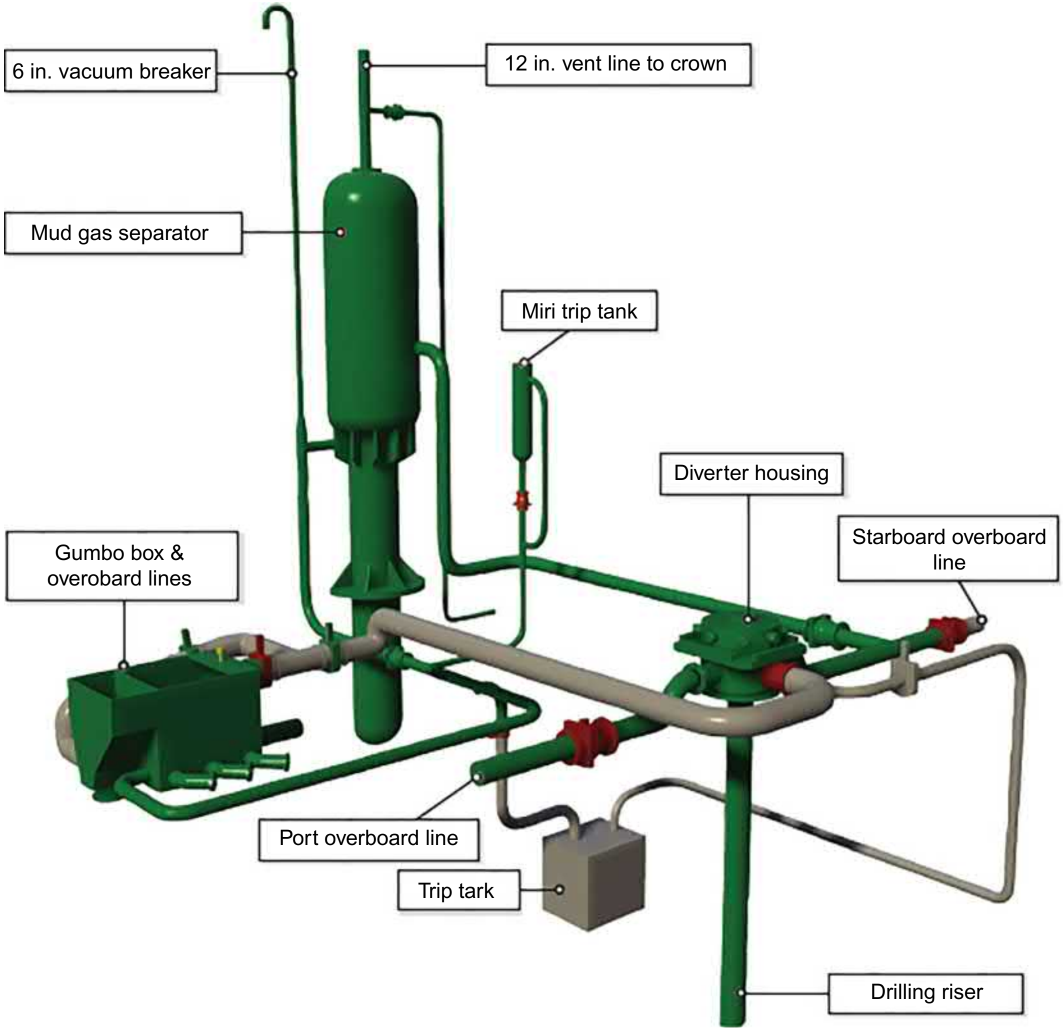


FIG. 5.35 Deepwater mud gas handling system. *From Kingdom Drilling training construct.*

- *Riser vortex-induced vibrations* (VIV) and fatigue
- *Monitoring* systems and *inspection* methods

RISER ANALYSIS

Riser analysis covers the complete riser system from the conductor to the upper flex joint or ball joint (Fig. 5.36).

The primary drilling riser response of concern occurs at the ends of the riser, i.e., *upper end* where the primary issues are riser tension, tensioner stroke, and top riser angle. *Lower end* of the riser, the primary issues are riser angle and loads applied to the SSBOP stack/wellhead.

The drilling riser is essentially a tensioned string that acquires stability, lateral load

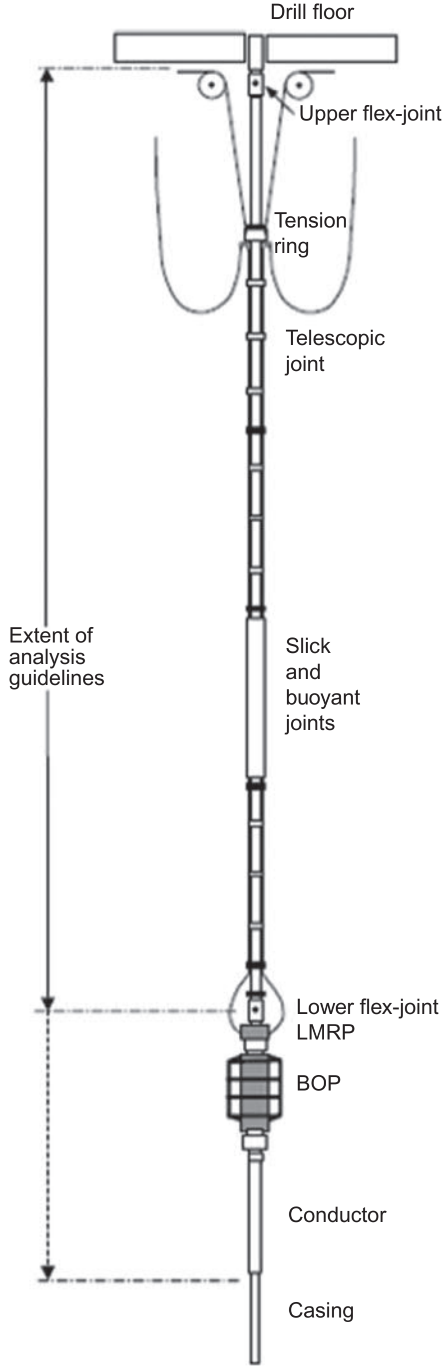


FIG. 5.36 Generic diagram of Equipment analyzed in a typical marine riser, Subsea BOP, wellhead and conductor study. *Source: Kingdom Drilling Training 2009.*

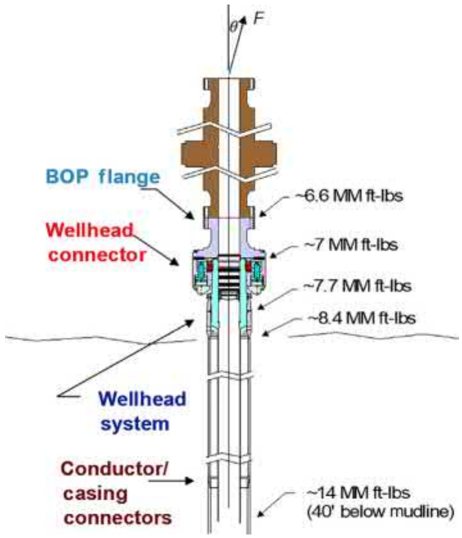


FIG. 5.37 Deepwater wellhead system. *Source: Kingdom Drilling training 2008.*

resistance, and structural integrity through tension. A small component is also a riser's ability to resist lateral environmental loads within its structural dimensions. In most situations, once a riser is deployed, the adjustment of the riser's top tension is the only controlling parameter that controls riser behavior.

Riser tension is the single most important parameter in the operation of a drilling riser. *Note*: every time the mud weight is changed, the riser tension must be changed.

Key difference in deepwater is that majority of operating and equipment systems are now placed under far greater load, stress and strain due to the longer lengths, weights, environmental and operating conditions, and new standards required for the life of a well.

Wellhead Systems

Subsea Wellhead Systems

Conventional subsea 10k and 15k wellhead systems are used in many deepwater applications, with increasing water depth, wellbore pressures, well design, and number of string that result. Design ratings required a new generation of bigger bore wellhead systems for deepwater higher pressure and more complex well regimes to evolve as illustrations that follow show (Table 5.7; Fig. 5.38).

New designs permit the use of larger diameters casing strings that can accommodate more casing strings and liner hanger systems. A typical deepwater wellhead system is illustrated in Figs. 5.37 and 5.38 and Table 5.7 to provide and accommodate the following:

1. SSBOP Flange, Wellhead Connector, and Subsea Wellhead System
2. Conductor Sizing (Analysis), Conductor/Casing Connectors
3. 15,000–20,000 psi (H2S) rated pressure
4. 7,000,000 ft-lbs. Bending @ 15,000 psi

TABLE 5.7 Influence of Deepwater Rig Features on Wellhead and Riser Design

Feature	Wellhead	Wellhead Connector	Drilling Riser
Longer, larger vessel hulls	Minor influence	Minor influence	Minor influence
Drilling riser joints are longer	Increased tension and bending capacity	Increased tension and bending capacity	Longer riser joints Stronger connections Greater buoyancy Stronger tension joints
Larger drill floors	Minor influence	Minor influence	Minor influence Larger diameter diverters
Taller, stronger derricks	Minor influence	Minor influence	Longer riser joints
More mud pumps	Minor influence	Minor influence	Larger C/K lines
Larger volumes	Minor influence	Minor influence	Larger C/K lines
Dynamic positioning	Reentry funnel size could change	Reentry funnel size could change	Reentry funnel size could change
Drawworks	Minor influence	Minor influence	Minor influence
Larger choke and kill lines	Increased tension and bending capacity	Increased tension and bending capacity	Larger C/K lines
Larger BOP stacks	Increased tension and bending capacity	Increased tension and bending capacity	Minor influence
Larger rotary tables	Minor influence	Minor influence	Drilling riser and buoyancy OD's increase
DP redundancy	Minor influence	Minor influence	Minor influence
Automated pipe handling	Minor influence	Minor influence	drilling handling tools

Source: Kingdom Drilling/ABB-Vetco deepwater training presentation 2002.

Remotely Operated Vehicles (ROV)

Remotely operated vehicles (ROV) (Fig. 5.39) are used in conjunction with floating vessel operations to provide and deliver work and observation elements. ROVs are piloted tethered submersible vehicles controlled from the vessel via a reinforced umbilical cable as the main tethering device. The tether provides both the electrical power and allows the transfer of data between the vessel and ROV to be transmitted. Motion of the ROV is controlled by several thrusters that allow movement and manipulation in all directions and speeds up to ±2 knots. Camera and sensors provide critical data and visual information to be relayed back to the rig personnel to observe seabed and operating subsea, well, drilling-related tools, equipment, and surroundings. Sensors provide feedback on water depth, temperatures, currents, and ROV orientation. A typical unit is about 12 ft long, 7 ft wide, and 7 ft high (4 m × 2 m × 2 m).

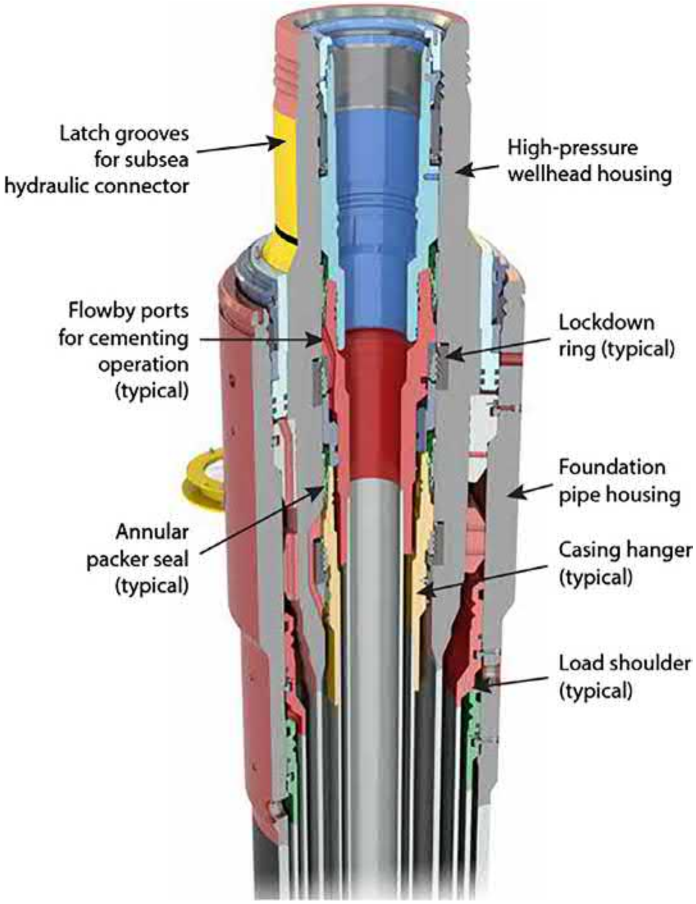


FIG. 5.38 Deepwater "Big-Bore" system. *Source: Kingdom drilling/ABB training course 2006.*

Primary function of an ROV in deepwater would be: *Drilling observation support (notably during riserless drilling and abandonment well phase), SSBOP, subsea systems, riser monitoring and inspection, control system inspection for leaks, Shallow gas, water flow, hydrate monitoring. Hydrate removal in some cases. General operating tasks to be conducted: Retrieving, cutting, cleaning, clearing, washing, inspecting, confirming, inspecting.*

On floating vessels, the system's major components are Launch and recover system, Tether management system, ROV, Winch, Hydraulic power unit, Control cab, Maintenance unit, Separate electrical power supply. ROV systems can also include *a tooling, survey and/or a SSBOP intervention skid. The intervention skid designed to operate a secondary SSBOP control system to meet API standard ram operating and closing times.* When installing an ROV, location, deck structure, power, electrical and operating safety aspects should be considered. Some vessels and operators have two separate units installed, particularly during high-intensity work scopes during batch drilling, development, workover, or intervention operations.

FIG. 5.39 Insert typical deepwater ROV system here. *From https://en.wikipedia.org/wiki/Remotely_operated_underwater_vehicle#/media/File:ROV_Hercules_2005.JPG.*

STATION KEEPING

Maintaining a marine vessel over wells is the unique feature of floating drilling. The three systems of station keeping recognized are **spread moored**, **dynamic positioning** *systems, and a (less common)* **moored system with thrusters and/or propulsion assist** to facilitate the ability to assist moored vessel to move in any direction through thruster use.

DP Capabilities

Floating vessels during deepwater station keeping are exposed to six degrees of freedom (Fig. 5.40). Every vessel displays its own unique Response Amplitude Operator (RAO) motion and movement characteristic to be considered based on operating conditions that exist. Operational limits would be analyzed, verified, and confirmed using mooring or DP operational programs, software analysis, capabilities plots, or DP (RAO) operating footprints. What results is a set of well-specific operating guidelines (WSOG) for each project.

Moored Versus DP

When assessing and evaluating deepwater safe and operational tradeoffs between conventional moored and dynamic positioned (DP) rigs, it is to understand the important and inherent advantages and limitations of each unit considered.

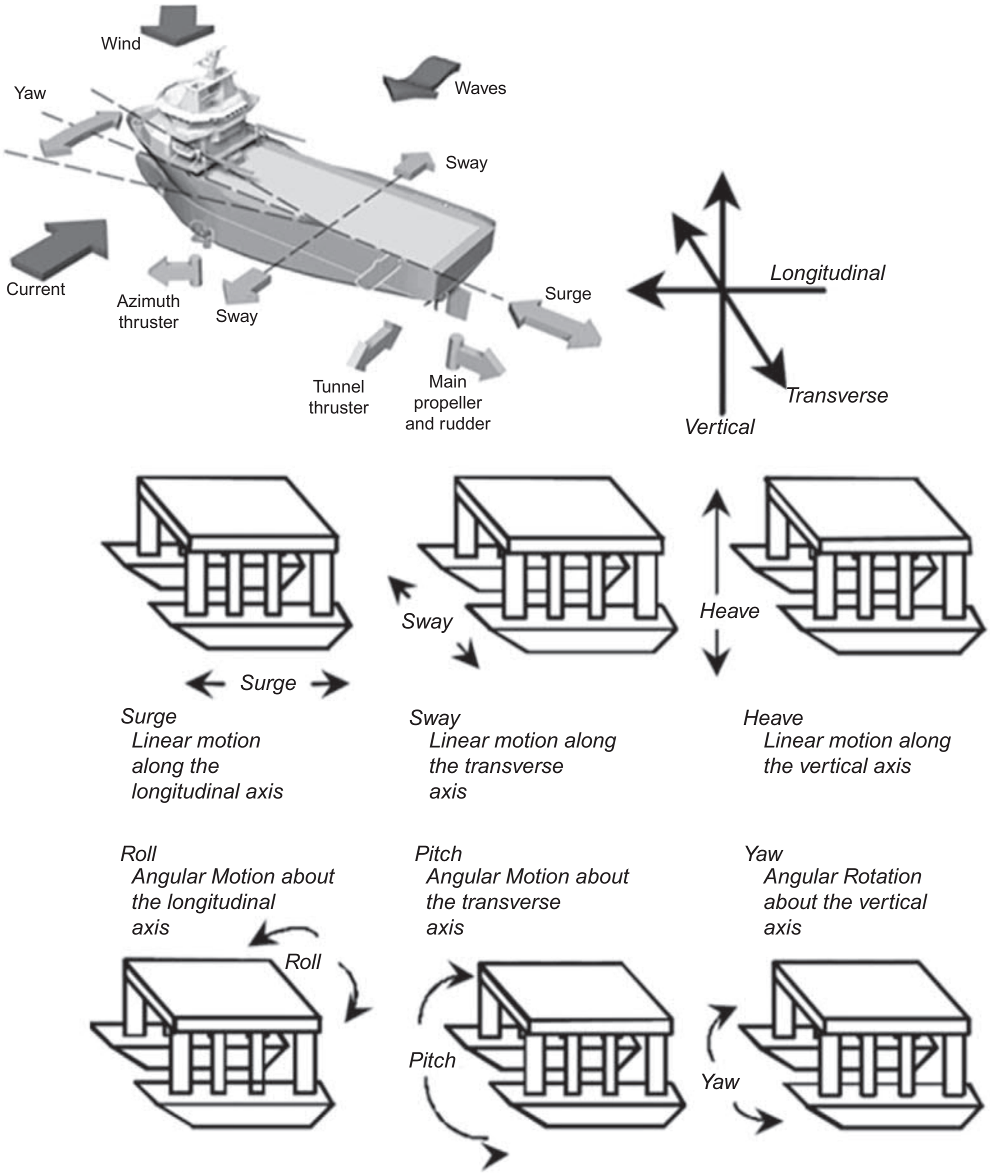


FIG. 5.40 Six degrees of freedom of a deepwater vessel. *Source: Constructed by Kingdom Drilling for training purposes 2002.*

Mooring Options

Water depth and mooring patterns are what determine the type, rating, and size of anchor handling vessels, crew, sets or spreads, anchors, lines, and associated equipment needed to be deployed on the seafloor to the vessel. Patterns will depend on the shape of the vessel, weather metocean and seabed bathymetry, topography, and hazard and operating risk-based conditions (Fig. 5.41).

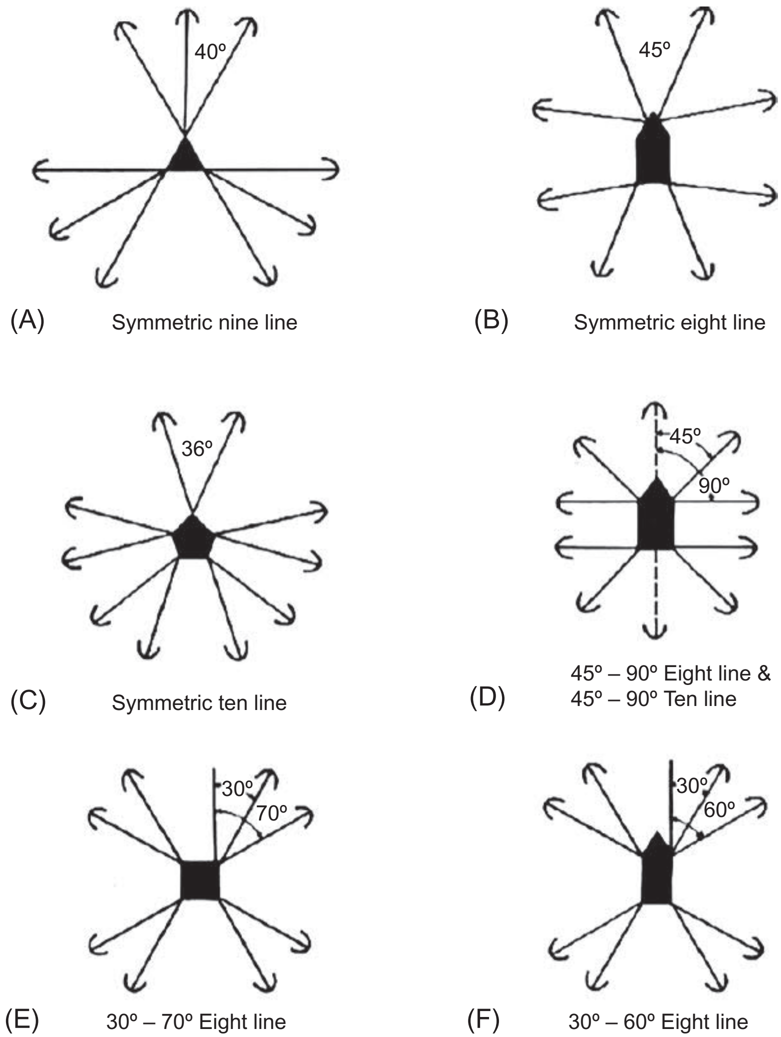


FIG. 5.41 Typical drilling unit anchor mooring patterns. *Source: Penwell: The Technology of Offshore Drilling, Completion and Production.*

Anchor Handling

During mooring, anchor handling vessels (AHV) are general required, at least two to move a vessel on and off location. Sometimes AHVs will serve also as the supply vessel for the duration of a project. To improve mooring efficiency or to get a rig to work much more quickly due to a small operating weather window, up to three or four AHVs have been known to be utilized dependent on availability and cost. The key aspect of deepwater is that vessels had to be upgraded as water depth loads and operating specific ratings increased. Seabed conditions, vessels anchoring capabilities, higher weights and tensions are some of the issues that resulted with the onset of deeper water depth that then led to the development of a new generation of deepwater mooring and anchoring vessels and systems.

Mooring Capabilities in Deepwater for Moored and DP Vessels

Mooring capabilities can be generalized as follows:

- *Catenary Mooring Systems*, up to 5000 ft (1524 m)
- *Catenary Mooring Systems with Synthetic Rope* instead of Steel Wire Rope. Extended to 6500 ft (1981 m)
- *Taut Leg and Semitaut Leg Mooring* Systems, up to 8000 ft (2438 m)
- *Dynamically Positioned* MODU, currently I0,000 ft (3048 m)

Illustrations of catenary and taut deepwater systems and prelay systems are provided in Figs. 5.42–5.44.

Mooring a vessel and running guidelines are illustrated in Fig. 5.42 as a further option when water depth and current conditions present this method as a safe and viable option. *Example: During development drilling phases, in deep-to-medium water depths, where fuel savings and environmental benefits are potentially significant.*

DP System Classification

Dynamic positioning is also the drilling contractor's responsibility under direct command of the vessels person in charge. Based on historical deepwater DP failures, particularly offshore Brazil, DP standards and guidelines evolved and developed to prevent, reduce, and mitigate further DP incidents. DP systems as a result of all failure learnings have now very extensive design, redundancy, back up hardware, software, and demand more competency training and skills development to assure more reliability than ever. Current DP operating systems, standards, procedures, and competencies that resulted derived from multiple decades of DP operating learnings, where DP today generally operates at four different status levels as follows:

1. *Green* or normal status
2. *Advisory* (e.g., the wind is noted to be steadily increasing)
3. *Intermittent* yellow alert
4. *Emergency* disconnect Red alert

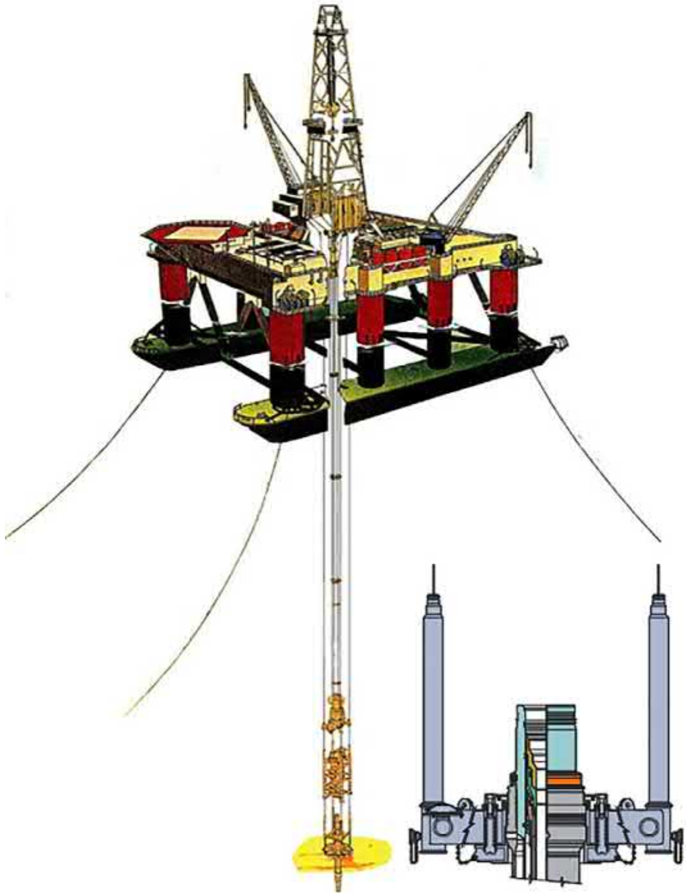


FIG. 5.42 Deepwater moored vessel rig with guidelines and retrievable guidebase system illustrated. *Source: Kingdom Drilling training 2009.*

DP system classes are presented in Table 5.8. Majority of deepwater vessels including supply, anchor handling, lightweight intervention vessels, etc. are generally class 2 or 3.

Emergency Disconnects

When the emergency disconnect red light is presented and raised on the drill floor, the person in charge must follow the required course of action, i.e., *initiate the emergency disconnect system (EDS) to physically disconnect from the well*. During the *EDS* sequence the subsea control system follows the predetermined disconnect process. One of the major difficulties of these systems is that surface testing is difficult and can be hazardous. Each contractor and operator

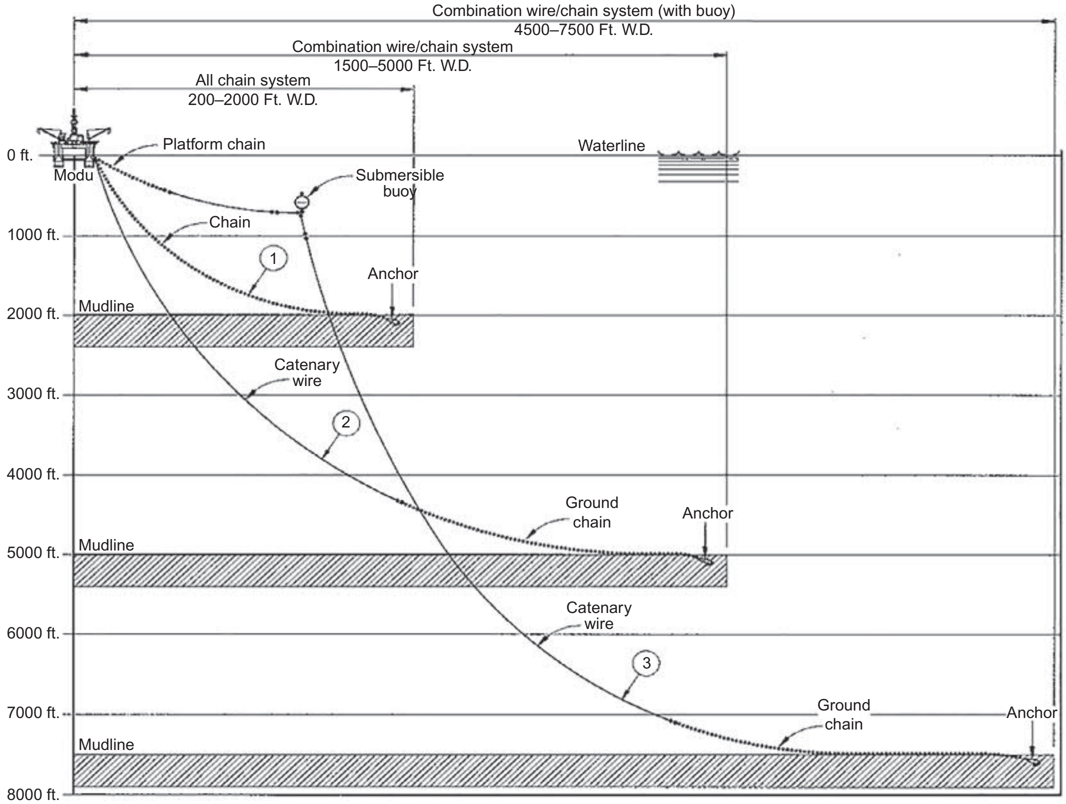


FIG. 5.43 Catenary deepwater mooring examples. *Source: Kingdom Drilling training 2002.*

must assure an acceptable scheme exists to verify and confirm the EDS functions as designed in an unlikely but possible emergency. *Notes: Generally, these systems are not tested subsea, but could be if hazard/risk concerns demand. Also the EDS is a last resort system; once activated, it cannot be stopped. It is essential and mandatory for safe floating operations. Note: Emergency Red alert circumstances can include:*

Note: Emergency Red alert circumstances can include:

- Complete loss of all motion and position reference systems.
- Predetermined marine riser angles have been exceeded.
- Available power is insufficient to hold well location and watch circle.
- On-board emergency, i.e., fire or flood to threaten a vessel safe operability.
- A collision with another vessel (or Iceberg) is imminent.
- Loss of well control has resulted, endangering personnel on board and vessel.

Loss of Location

Although it is stated that DP is far more reliable today, floating vessels can on occasion suffer a consequential sequence of events to result in a drift-off or drive-off from the

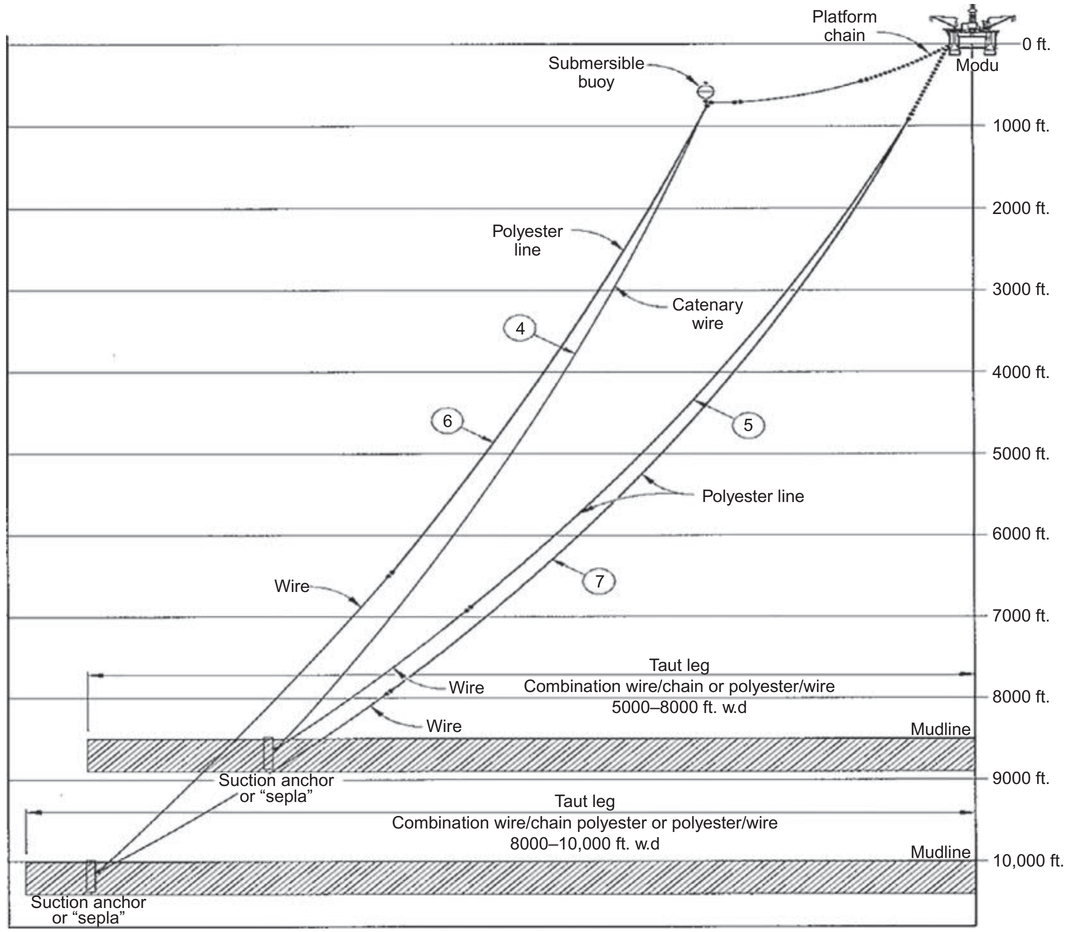


FIG. 5.44 Taut deepwater mooring systems example. *Source: Kingdom Drilling training 2002.*

TABLE 5.8 DP Vessel Classification

Class	Operating Criteria
Class 0	Only one console Wind sensor One position measurement sensor, i.e., DGPS, Acoustics, etc. One heading sensor (heading)
Class 1	Only one console Wind sensor One position measurement sensor, i.e., DGPS, Acoustics, etc. One heading sensor (heading) One vessel motion sensor (VRU or MRU)
Class 2	Must have redundancy in all system components that are tied to DP
Class 3	Must have redundancy in all system components that are tied to DP Plus: Must also have compartmental redundancy (for fire and flooding) on major system components

intended location. Because events are unexpected, persons in charge on the bridge of the vessel and drill floor must know, understand, prepare, learn, and have studied an action plan of what to do.

All circumstances have to be provided for by having plans in place and guide actions to consider. During floating vessel events, station must be maintained *at all times*. There is little time for another meeting and/or a decision-making discussion. Response and action must be preprogrammed and immediate where some brief conversations may likely be required.

SUPPLY CHAIN AND LOGISTICS

Supply chain and logistic issues are also very different yet important and vital to support deepwater programs and projects versus more amenable onshore or shallower offshore installations. The following Figs. 5.45–5.47 serve to illustrate essential deepwater program and project issues to be addressed.

FIG. 5.45 Deepwater programs, supply chain and logistic support functions. *Source: Illustration from unknown author as licensed under CC BY-SA.*

FIG. 5.46 Search and rescue (top left), crew change (top right), ice management (bottom left), supply vessel (bottom right). *Source: Photographs are from unknown providers as licensed under* CC BY-SA.

FIG. 5.47 Supply (top left), intervention (top right), stand by/emergency response (bottom left), rig move (bottom right) vessels. *Source: Photographs are from unknown providers as licensed under* CC BY-SA.

REFERENCE STANDARDS

IADC Floating Drilling and Equipment Operations, 1st Edition 2015.

IADC Deepwater well control guidelines, 2nd Edition, 2015.

REFERENCES

Bruhn, Carlos H. L., Antonio C. C. Pinto, Paulo R. S. Johann, Celso M. Branco, Marcelo C. Salomao, and Ednilson B. Friere, Petrobras E&P. 2017. Campos and Santos Basins: 40 years of Reservoir Characterization and Management of Shallow to Ultra-Deep Water, Post-and Pre-Salt Reservoirs – Historical Overview and Future Challenges. Offshore Technology Conference, OTC Brazil, Rio de Janeiro, Brazil, Oct. 24–26, 2017.

Chevron/BP Drilling Training Alliance relevant chapters. Floating Drilling Manual 2007.

Chevron/BP Drilling Training Alliance relevant chapters. Deepwater Drilling Manual 2007.

Department for Business Innovation and skills: Guidelines for managing programs. Understanding program and program management, November 2010, Publication available at http://www.bis.gov.uk/.

Department for Business Innovation and skills: Guidelines for managing projects. How to organize, plan and control projects. November 2010. Publication available at http://www.bis.gov.uk/.

Drilling Performance Review, Offshore Newfoundland and Labrador prepared for Nalcor Energy – Oil and Gas by Michael Critch and Jenna Murphy from NSB Energy Consulting. Technical review and guidance by Doug Hunt. August 2016.

Gas in Riser Modeling, Stan Christman. IADC Sub Committee meeting, Nov. 30, 2016.

IADC (International Association of Drilling Contractors) Floating Drilling & Equipment Operations. 1st Edition 2015.

Macondo Well Incident, Transocean Investigation Report, Volume I, June 2011.

Wijning, Dieter, Huisman. Dual multi-purpose tower engineered to cut ultra-deepwater well delivery costs. April 2015. *World Oil* magazine.

CHAPTER

6

Deepwater Programs, Safety, and Loss Control

DEEPWATER PROGRAMS AND PROJECTS

Deepwater Current and Future

The oil price decline from a peak of $115 USD in June 2014 (Fig. 6.1) cut deep to impact deepwater programs, e.g., *operational vessels now idle, hundreds of thousands of specialized people who have lost their jobs, companies that have postponed or canceled projects.* Couple that with slower than predicted growth, lower revenue, falling demand, and evident greater technological, geological challenges, and higher capital expenditures—all combining to present genuine and real concerns that a tipping point could result where deepwater maintenance, repair, inspection, and safe operating risks will be compromised.

Although not the first time this industry has been subjected to rapid price variations, this is the first notable deepwater cost-cutting period and that, with added risks imposed, demand for change, increased loss exposures, and many other issues, add considerable to-be-managed elements in terms of business impact, reputation, and loss. Extreme caution and capital efficiency shall be the resulting approach to pursue.

Furthermore, in light of learnings from recent deepwater disasters, those responsible should be taking full notice of the major findings recommended, e.g., *there is a wide scope to improve within current processes to ensure that lessons are learned not just from major accidents but from every incident/lost time event inclusive of all near-misses and unexpected occurrences*.

Now more in demand is greater management control of safety, loss prevention, and the ability for people to change and learn. A deepwater future needs to immediately start to confront and address all challenges to be overcome in order to survive and flourish vs. falter, decline, or fail.

Past Learnings and a New Norm

With oil price fluctuations and uncertainty a probable future risk, any strategic change in deepwater must adopt a cautious, measured, and controlled approach. *Example: If capital cuts extend too deeply into organization finances, with further staff reduction and low-tech strategic implementation, this could have a profound negative effect in terms of business outcomes that ultimately may add more problems and issues to rectify than initial cost savings envisaged.*

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00006-5

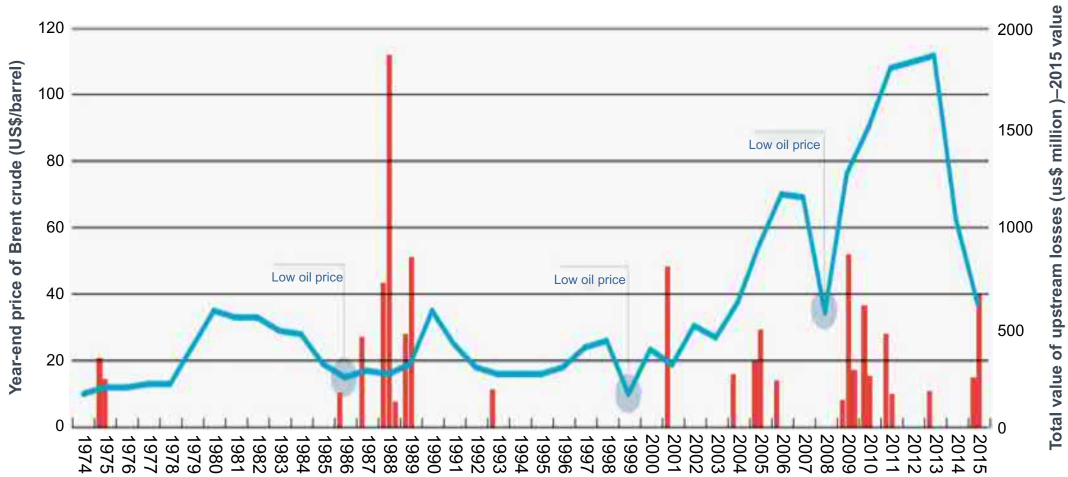


FIG. 6.1 Oil price vs upstream losses by year, 1974–2015. *Source: Marsh Research.*

To progress forward, transformational change must have a clearly defined purpose and intent to deliver the outcomes and benefits to deliver overall savings, safety, and operational improvements required. Likewise the pursuit of adaptive technology, the ability to develop wider skill sets and evolve recognized best-practice methods needs to result. The companies that can discover the ways, means, and methods to do more with less, those seeking the hidden opportunities, to spend and resource more, seeking far greater capital efficiency not less, without compromising safety or quality, shall be the ones to deliver greater returns on investment.

Changing people is another issue to resolve. Only the best are capable to embody and embrace the transformational change required if all opportunities can be harnessed. The companies with the right strategy, people, technology, and transformation plans are the ones most likely to emerge as worthy deepwater winners if oil price rebounds. With all the opportunities that exist, there is no reason not to be optimistic of a more prosperous deepwater future.

Human Factors

Human Factors—General

This section characterizes the facts that *human factors complement the causes of all deepwater event outcomes more than anything else that* must be afforded the scope attention demanded. Human factors comprise a well-debated factor within deepwater that involves people, in multiple complex high-tech conditions and environments that have a systematic influence on work performance and operating loss (Fig. 6.2).

Human factor causation is attributed to people involvement in everything that goes right or wrong, good or bad within work-related outcomes. This includes corrective actions that precede every event, finger-pointing, blame-assignation, excuses, lack of control, or

FIG. 6.2 Systematic influence on human factors. *Source: Kingdom Drilling.*

noncompliance use of regulations, standards procedures, or plans that would impact or compromise a fundamental deepwater operational safety-first, loss-free approach.

Causes and Dirty Dozen of Human Factors

CAUSES

Human factor causes can be attributed to the following:

- Memory lapse that may occur at any time
- Judgment and reasoning that can be reduced due to many factors
- Lack of attention, due to failure to remain attentive
- Delayed or failed senses that could otherwise stimulate a response to avoid the accident
- Lack of skills, competence, and experience
- Personality that can often be compromising while others are hardliner
- Attitude: Negligence, arrogance, boldness and overconfidence, etc.
- Poor risk perception due to poor knowledge and experience
- Individual behavior characteristics: Anger, temper, curiosity, etc.

DIRTY DOZEN OF HUMAN FACTORS

The dirty dozen of human factors contributing to lost time events are recognized and credited to be due to the lack of: (1) communication, (2) teamwork, (3) norms, (4) pressure, (5) complacency, (6) knowledge, (7) distraction, (8) resources, (9) awareness, (10) assertiveness, (11) fatigue, (12) stress.

Human Factor—Prevention

How human factors can contribute to deepwater project success, to be considered are:

1. Adequate training and awareness
2. Supervision, leadership monitoring, and controlling
3. Feedback, reporting, investigating (commendation and correction)

4. Frequent inspections and audits
5. Wider skills (technical and soft skills) development
6. Education, knowledge, and experience (for this there is no substitute)
7. Assuring decision and problems are resolved through best practiced risk assessment and/or management of change methods
8. Learning and investigative skills

Intelligence Trap, Emotional Intelligence, and the Big Crew Change

THE INTELLIGENCE TRAP

There are many components of what is seen as the intelligence trap in oil and gas organizations; some are sociological, operational, and may even be physical. Key points extracted from an article resourced within www.forbes.com are:

1. The highly intelligent person can construct a rational and well-argued case for virtually any point of view. The more coherent this support for a particular point of view, the less the thinker sees any need to explore the situation. Such a person may then become trapped into a particular view simply because they can support it.
2. Verbal fluency is often mistaken for thinking. An intelligent person learns this and is tempted to substitute one for the other.
3. The ego, self-image, and peer status of a highly intelligent person are too often based on that intelligence. From this arises the need to be always right and clever and orthodox.
4. The critical use of intelligence is always more immediately satisfying than the constructive use. To prove someone else wrong gives you instant achievement and superiority. To agree makes you seem superfluous and sycophantic. To put forward an idea puts you at the mercy of those on whom you depend for evaluation of that idea. So, too many brilliant minds are trapped into this negative mode (because it is so alluring).
5. Highly intelligent minds often seem to prefer the certainty of reactive thinking (solving puzzles, sorting data) where a mass of material is placed before them and they are asked to react to it. This is called the "Everest effect" since the existence of a tough mountain is sufficient reason for the best climbers to react to it. In projective thinking, it is the thinker who has to create the context, the concepts, and the objectives. The thinking has to be expansive and speculative. Through natural inclination, or perhaps early training, the highly intelligent mind seems to prefer the reactive type of thinking.
6. The sheer physical quickness of the highly intelligent mind leads it to jump to conclusions from only a few signals. The slower mind has to wait longer and take in more signals and may reach a more appropriate conclusion.
7. The highly intelligent mind seems to prefer—or is encouraged—to place a higher value on cleverness than on wisdom. This may be because cleverness is more demonstrable.

Intelligence is also less dependent on experience. Not all highly intelligent people are caught in this trap. It can be avoided by chance, upbringing, or conscious effort.

The danger that remains is to be cautious and *not to accept an automatic assumption that high intelligence means effective thinking* in complex deepwater well projects.

EMOTIONAL INTELLIGENCE

Emotional intelligence research findings on the other hand have stated that "people with average IQs outperform those with the highest IQs 70 percent of the time" with decades of research to support that emotional intelligence is a critical factor of star performers vs. the rest of the pack. Emotional intelligence, although somewhat intangible in everyone, is important, as it affects how people manage behavior, navigate social complexities, and make personal decisions to achieve positive results. It has core skills to pair up with the two primary competencies, i.e., *personal and social competence.*

Personal competence comprises self-awareness and self-management skills, focusing more on individuality than interaction with other people. It is the ability to stay aware of emotions to manage behavior and tendencies.

Social competence is made up of social awareness and relationship management skills; social competence is one's ability to understand other people's moods, behavior, and motives in order to respond effectively and improve the quality of relationships.

To not confuse things, intelligence is the ability to learn and is the same at age 15 or 50. *Emotional intelligence*, in contrast, is a flexible set of skills that can be acquired and improved with practice. Although some people are naturally more emotionally intelligent than others, you can develop high emotional intelligence even if you aren't born with it.

Personality is the final piece of the puzzle, defining each person as the result of hard-wired preferences, such as the inclination toward introversion or extroversion. However, like IQ, personality can't be used to predict emotional intelligence. Like IQ, personality is also stable over a lifetime and generally doesn't change. IQ, emotional intelligence, and personality each cover unique ground and help to explain what makes each person tick.

What is important is that emotional intelligence impacts one's professional success a lot. It's viewed as a powerful way to direct one's energy with tremendous results. *Example: Companies tested emotional intelligence alongside 33 other important workplace skills, to find that that it is the strongest predictor of performance, explaining a full 58% of success in all types of jobs. One's emotional intelligence is the foundation for a host of critical skills—it impacts most everything we do and say each day. Of all the people studied at work, it is found that 90% of top performers are also high in emotional intelligence. On the other side, just 20% of bottom performers are high in emotional intelligence. One can be a top performer without emotional intelligence, but the chances are slim.*

The key point to all of this is for: *Deepwater programs and projects to assign the right type of skilled people with all the right stuff to assure a high performing team result.*

THE BIG CREW CHANGE

Fig. 6.3 illustrates the big crew change taking place that may profoundly affect a deepwater recovery. Additionally, unlike onshore high-technology programs that have already restarted at lower oil prices, offshore and particularly deepwater may lack the competencies, the technological innovation, and capital investment infusion required when more favorable conditions exist. If one combines operating and service company layoffs that claimed an estimated 100,000+ jobs lost, the current market talent pool of all ages adds more complexity to the next resource and recruitment drive. Adding in technology will likely take a back seat in deepwater programs, as budget holder decision makers shall likely choose to pay the current bills to maintain projects in the black vs invest in an industry crying out for more technology investment programs. *Technology and people shall lose out*. To increase risk factors despite all the

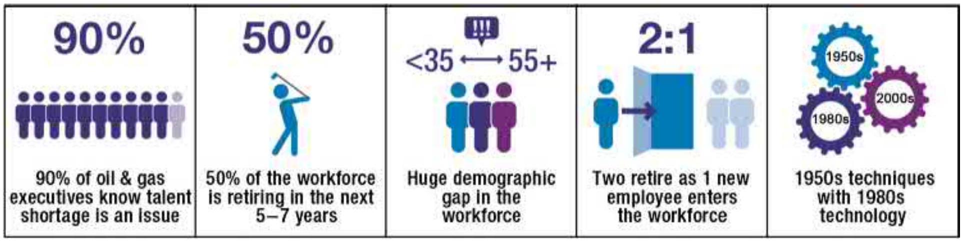


FIG. 6.3 Oil and gas industry by numbers. *Source: https://info.drillinginfo.com, translated for this guide by Kingdom Drilling 2018.*

evident facts that support technology and people (competency) is one of the key areas identified to drive deepwater transformation, change, progress, and learning needed.

However, the launch of the world's first digital drilling vessel by Noble Corp. and GE in February 2018, appears to be a concrete step to unlock the immense potential of digital solutions for offshore drilling operations. It suggests that the industry downturn has, in fact, challenged deepwater drillers to look for innovative ways to achieve expenditure reductions and perhaps greater operational excellence. The expansion of data-driven operations support could pave the way toward a new era of more autonomous drilling, ultimately enabling enhanced predictive maintenance leaving offshore personnel to focus on maintenance activities that are truly needed. The digitization, as described, will connect all targeted control systems, including the drilling and well's control network, power management, and dynamic positioning system. Noble expects reduced unplanned downtime, maintenance cost savings, and improved well delivery but will be watching the return of analytics as it plans to digitize three other vessels during 2018.

Triangle of Success

Deepwater change is inevitable, so an improved framework is needed to assure that future great companies and people can be developed (as illustrated in Fig. 6.4). Progress that shall result if the several gaps identified are bridged. *Example: If Fig. 6.4 is to be taken as proportional, the two bottom tiers evidently present >65% of what drives a great business to do the right things and get things right first time. "There is no substitute for knowledge and experience" comes to mind.*

The evident gap aspects identified to discuss with respect to the triangle of success are:

1. Persons may have in abundance specialized deepwater knowledge, skills, and experience. Experience is not enough by itself to provide progressive, technical, safety leadership, or soft skills training in the key areas that deepwater demand. Large gaps exist. This is not right.
2. Persons employed from other industries or direct from academia are similarly not afforded enough front line people skills, knowledge, and specific vocational experience to learn how business things really worked or failed. Large gaps exist. This is not right.
3. The impact, relevance, and significance of these two gaps and the disconnect that exists between the fundamental people elements to drive business success cannot be overstated. Add in human factors, intellectual and emotional intelligence as stated and one may readily understand why best practices commonly fail to result. (Fig. 6.5 serves as

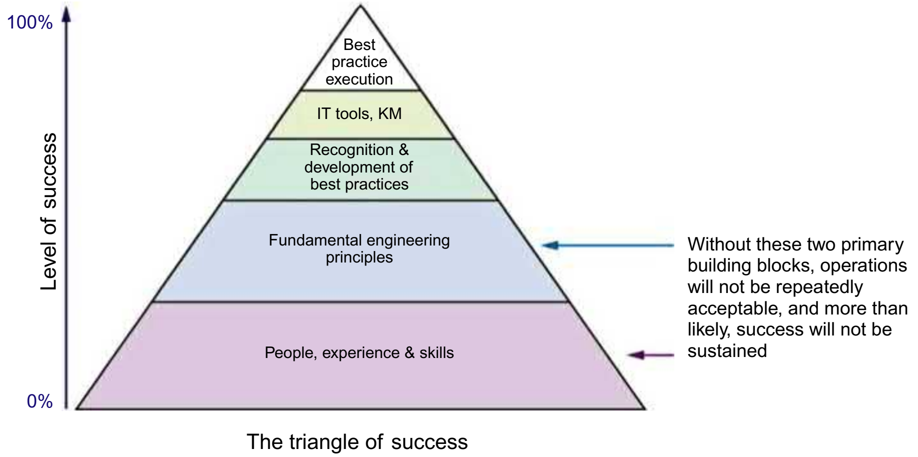


FIG. 6.4 Successful energy practices. *Source: Holland & Davis International LLC.*

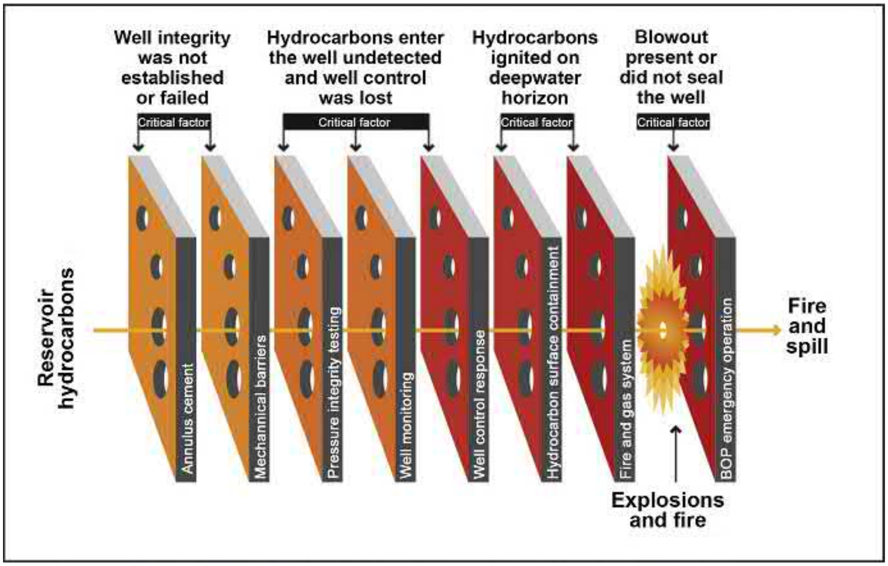


FIG. 6.5 Macondo barriers breached and the relationship of barriers to critical factors. *Modified from Deepwater accident report, Sept. 8, 2010.*

the poignant reminder how badly things can go wrong when all deepwater failure factors exist) and why more often than not "best practice" is far distant from really *gets done*. *Note*: Only executive management has the vested power to address these issues. Another problem that is just not right.

4. The fourth tier represents modern progression, communication, knowledge, project management, learning, etc. that is undeniably important. Dimensionally as shown in Fig. 6.4, the reality of this factor is often intellectually blown out of proportion. What is needed is

simply more and better scope to assure delivery greatness and how this can be achieved: *personnel development, change, improvement, and assurance that all human factors are met.*

5. The fourth tier is under the complete control off office based intellectuals who generally expand project matters into far bigger, complex, and unfit for purpose use, in the context of underlying principles and objectives of any triangle of success. The end project metrics stating typically no one was hurt, despite the project loss ran $50–$100 million over budget, and hailed as a technical and safe operating success. How projects have become so misaligned, mismanaged, and miss measured, with meaningless metrics? Is just not right.
6. Simple modern-day project and operating processes with technology driven value-adding protocols and highly skilled people is the solution most needed. Not to be under total control of executive or managerial intellectuals but driven by a project manager and team leaders listening and responding to people who can deliver with best practices as planned (There is no I in Team). Where this smallest element (*best practice execution as planned*) is by far where the most endemic problems reside—that only management have the vested power to resolve. We know this is not right.
7. Best practices execution as planned shall result when all tiers in the triangle are proportionally and correctly balanced to meet all purpose and intent. In summary too many projects exceed time and costs and fail due to these major and other gaps that exist.

How to bridge the gaps and imbalance that exist to deliver best in class world projects will be further outlined and discussed in this guide.

Managing Successful Programs

One of several recognized project management methods, Managing Successful Programs (MSP™), is used in this section as a general guide. MSP comprises three main elements:

1. Principles
2. Governance themes and
3. Transformational flow processes.

Principles

Early in a deepwater program company executives and managers shall recognize and analyze the most suited principles to meet the work scope needs, including:

1. Alignment with corporate strategy
2. Leading changes desired
3. Envisioning and communicating a better “safe operational” future
4. Focusing equally on benefits and threats
5. Designed to deliver rational and clear capability
6. Learning from knowledge and experience
7. Adding value, translating and sustaining learning, value and business growth

Once agreed principles would then be applied and orchestrated to assure that desired benefits result. Of note is that deepwater programs are likely to be:

- More crosscutting and multidisciplinary.
- Fraught with greater risk, uncertainties, and unpredictable outcomes *that are more difficult to manage, measure, and control and why more formal processes are needed.*

- Of longer duration than more standard oil and gas program norms.
- Influenced by a wider range of vested parties of different degrees of commitment.
- Affected by far more stakeholders, some who benefit and others who may not.
- Liable to require management changes of direction, from experience, learning, uncertainties, and external events that shall reside, exist, and result throughout each program scope element.

Governance Themes

Nine governance themes within MSP are used to plan, design, manage, implement, and control the framework to deliver change, assure learning, and manage the scope. They are:

1. Organization
2. Vision
3. Leadership and Stakeholder Engagement
4. Benefits Realization Management
5. Blueprint Design and Delivery
6. Planning and Control
7. Business Case
8. Risk Management and Issue Resolution
9. Quality Management

Transformational Flow Processes

Once a deepwater program or project is defined, a strategic company initiative is communicated from the top down by the sponsoring group involved. One person is typically assigned as the responsible program owner, i.e., *in MSP as Senior Responsible Owner (SRO).* The six transformational flow processes that exist to consider are:

1. Identify program (*used to appoint the SRO*)
2. Define a program (*Program Manager appointed*)
3. Manage the life-cycle
4. Deliver the capability
5. Realize the benefits
6. Close the program

The point to all of this is that there are persons responsible who must correct and commend that all persons employed in complex projects are suitably trained, skilled, and qualified to meet the business program and project management outcomes desired. Where is the evidence of this competency training and skills sets on people's resumes? This commonly is just not right.

Deepwater Program and Project Management Essentials

Project Management Essentials

From within the three principle elements described in the previous section, an essential management framework is developed for each and every deepwater program. What results is that rather than keeping the management process simple as outlined in the governing documents that MSP, PMI, Prince 2 methods propose, oil and gas often falls into the intelligence

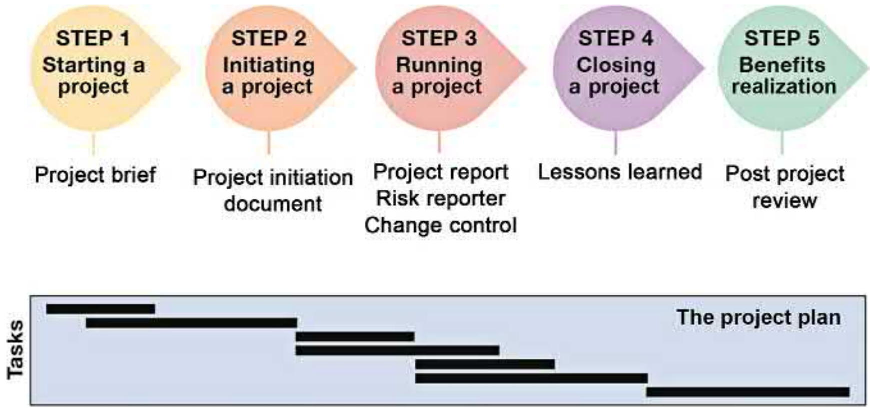


FIG. 6.6 Typical project life cycle. *Source: Kingdom Drilling 2018.*

trap as evident by the size, magnitude, and complexity of systems developed and that exist in companies today.

Example: Project management stage gated processes and flow charts that exist are often several times more elaborate and complex in oil and gas than originally intended as illustrated in Fig. 6.6. In summary, simple project management is preferred.

For example, a simple project management handbook and framework is strongly recommended for each deepwater project, one that is sufficient enough for highly skilled, trained, developed, and technically competent people to take, use, and apply what is needed to enable, manage, and control a project to deliver as planned.

Deepwater Strategic Planning

The need to have strategic program objectives in deepwater highly capitalized projects is a given. For this to result and done well, managers and leaders must be in full communication with all key stakeholders, internal and external organizations involved to assure that common, aligned, and agreed objectives exist to meet all program scope specifics and deliverables.

SUCCESSFUL STRATEGIC PLANNING

Strategic plans are rarely created equal and require an awareness to avoid the most common, critical mistakes that doom many project plans to fail. Keys aspects to success are:

1. Total team commitment
2. Get the right people involved
3. Focus on the big picture
4. Make an honest assessment of where you currently are
5. Consider realities that exist
6. Change is continuous and must be managed
7. Set SMART goals and timelines
8. Plan to do-check-act to deliver as planned

9. More assured accountability
10. Measure, monitor controls and correct deviations observed.

Deepwater Project Development

A deepwater project is often wide ranging, diverse, varied, with a multitude of new and unchartered territories to cover. Close and detailed development of the project scope and plans needs to be linked with clear well-defined and specific strategic objectives to assure maximum project value results. All outcomes and benefits to be well articulated from start to end with clear visible links to promote success. Note: Much of the management effort across each life-cycle shall be driven by the program/project owner/sponsor.

In order to succeed project or assigned managers shall be competent to draw and use all the skills, knowledge, experience, fundamental engineering/science principles, to derive recognized best practices, from large sets of multidisciplinary individuals and teams, both within and out with the organizations, partners, contractors, third parties, and suppliers.

This is a mammoth and titanic challenge and why such a well managed, measured, and controlled approach is necessary. Fig. 6.6 and Table 6.1 present a generalized summary of standard project phases, process, and flow aspects to consider. *Note*: Step 3 in Fig. 6.6 is the likeliest most resourced component, where care and effort must be devoted at start up and initiation Step 2 where a *significant contribution to overall success* can result if implemented and executed well.

Sound knowledge, experience, engineering principles, best-practice judgment, people power savvy, and a whole lot of "Common sense today that may not be that common" is needed. People with self-starting power, that are empowered, motivated, enthused, and energized to assure maximize individual and team-oriented success at minimal loss is rest assured several times more important than the process itself.

Communication

It is vital to sell the benefits and involve the people most affected during the work scope processes and outcomes that result. Implementing new technology, standards, systems and assuring compliance requires that all end users fully understand why and what the benefits are. Regulators, procurers, consumers, customers, practitioners, clients, and customers all must be convinced of the safety/operational advantages or benefits of anything new, adaptive, innovative, or nonstandard aspects to be instigated. *Example: Communicating the message why specific work scope is evident best-practice helps to counteract human factors such as resistance or reluctance to change.*

Resources

Adequate resources must be assured in place from start to end. Internally, this should involve senior management assuring that appropriate tools, hardware/software are in place, and to recruit and approve the necessary people and kick off the process with the right people involved at the right time. Then measure, assure, manage and assess skills, competencies, or shortfalls that exist. There also needs to be allocated budgets, finances, insurance, liability cover as well as appropriate timelines for project completion.

TABLE 6.1 Key Management Elements to Consider and Address Within a Deepwater Project

Start Project

- What shall define and justify this project?
- What qualifies and quantifies desired project outcomes and benefits
- Who is suitably qualified for the role as Project Manager?
- How to assure the reasons and a statement of requirement are well defined?
- How is project to be aligned with strategic / business plan?

Initiation

- How to deliver project outcomes and benefits?
- How to manage relationships with key stakeholders?
- How to project manage the delivery process?
- What resources are needed and when are they required?
- What plans and work are needed to justify project deliverables, time, cost and risks etc?
- How will project be managed (PM specific document to be produced)?

Run Project

- When are people needed to do the work and deliver and enable the required outcomes?
- How to plan, monitor and control the work and resources of the project?
- How to manage risks and issues as they occur?
- How to maintain communications with those impacted by the project and its outcome?
- How to report progress and issues?
- How to decide viability and manage any change requirements?
- How to assure deliverables are fit for purpose to enable benefits to be realised?

Close Project

- How to measure and evaluate outcomes of the project are against requirements?
- How to assure lessons learned are translated?
- When, how to release project resources?
- How to measure and assess benefits achieved?

Benefits (Value) Realisation

- How to measure and evaluate outcomes of the project are against requirements?
- How to assure lessons learned are translated?
- When, how to release project resources?
- How to measure and assess benefits achieved?

Source: Kingdom Drilling adapted from MSP 2018.

People

No manager should be required to work in isolation. With many stakeholders involved, roles, responsibilities, and accountability shall be clearly defined with personal commitments well aligned.

Key stakeholders to assure success are viewed as:

- ***Program or Project Sponsor***: The sponsor is the person who defines the business objectives that drives the program or project. The sponsor can be a member of the senior management team or someone from outside of the organization.
- ***Program and Project Manager***: A professional manager that creates the program or project plan and ensures that it meets the budget, schedule and scope determined by the sponsors. Managers are also responsible for risk assessment and change management.
- ***Project Team Members*****:** These can include subject area specialists, members of departments, external professionals, and new recruits. Anyone offering a positive contribution to the project in terms of knowledge, experience, and technical, engineering, leadership capabilities is to be considered as a good team member.

Standards

Standards in highly specialized areas such as deepwater are central and crucial to assure precise technical, scope, definition of safe operational project delivery. Compliant standards assure projects are easier to manage, monitor, and control in an increasingly globalized industry of several thousand standards, plus the added company specifications that exist. Most of the regulators use standards in defining their schemes, regulations, guidelines or other documents.

To develop and maintain well operating standards requires a lot of user and stakeholder resources. From an operator's point, the ideal situation would be similar global requirements with necessary national adaptations at the operating location.

Note: International Oil & Gas Producers published a report (based on 14 national regulators use of standards) to emphasize the development and use of offshore petroleum specific standards. The report's main conclusions are:

REPORT CONCLUSIONS

1. Standards are an important role in the regulators' technical definition of safe operations.
2. The diversity provides a challenge for international operators in understanding and applying correctly all of the reference differences for actual E&P activities in different countries.
3. Duplication of standards needs to be avoided with an objective to reduce numbers covering the same subject.
4. As the industry is able to directly influence the content of 380 of the standards listed in the report, the industry is now largely responsible for further development and maintenance.
5. While the references to international standards by the regulators on a global basis have increased to 21%, more standardization is required.

DEEPWATER STANDARDS

In the context of project management and standards, deepwater standardization shall be viewed as a key goal for individuals and organizations to address whenever this is needed.

Although more deepwater standards exist (*generally as a result of major accident failures that have resulted*), there remain several areas where large gaps and uncertainty remain as identified within the IOGP report.

Required deepwater standards that can reduce people, process, product, time and cost required, reduce loss, improve safety and more assure projects are deliver as planned. Hence, a standards and agreement review is merited early for each deepwater project.

Risk Management

Project risk management in deepwater as represented in Fig. 6.7, is particularly important as it is essentially a task to assure that everyone formalizes and affords a hands-on attitude, culture, and behavioral skills-set that best suits each project, with everyone aligned to from the project start to its end.

Hazard and risk management is particularly important when dynamic change results to be often quickly and appropriately addressed to assure positive outcomes result. Hazards and risks are covered in more detail in Chapter 10.

Change Management

Almost every physical aspect of a deepwater project can be interrelated to other aspects of the overall design and delivery outcomes. A change in one area or aspect generally requires consideration of the impact of change on all other relative project matters.

A common reason for changes may emanate from concept design, planning process, final design or during the operational delivery phases success failures or shortfalls , that when combined with a poorly defined work scope, a lack of clear goals, objectives, roles and responsibilities all need to be effectively managed and controlled.

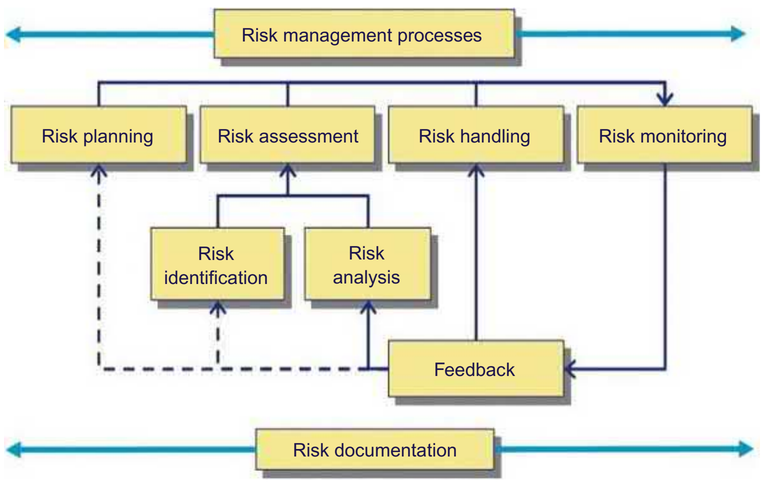


FIG. 6.7 Risk management guide. *Source: U.S. Department of Defense University 2003.*

As outcomes become clarified, the requirement to meet goals and objectives may change. Engineering may demand change where, as each aspect of the scope is optimized, other scope aspects can be impacted and affected (both in positive and negative ways).

Change must be regarded with a critical eye and considered from all perspectives. Decades of research have shown that subsequent actions taken must assure that the full influence of all people in their individual transitions ensues.

Cost Control

Cost control is geared to each individual project requirements to establish and track costs as a whole and for each individual work element attached to it. It needs to be properly structured into all work packages and formally used and addressed by all those responsible for the execution of the work. It shall generate budgets, performance reports, and forecasts against budgets. Key elements are: *Establish budgets; control commitments; monitor expenditure; assess variance; forecast final costs; take corrective actions.* Cost control deals with information that is timely to allow quick response to take corrective actions when/if/as necessary.

Benchmarking

Benchmarking deepwater well operations is an important consideration that is not just a matter of making a visit to another organization. Benchmarking must be valued as a *structured, analytical, and continuous process*, seeking to assure best standards, systems, engineering, people skills, and operational practices are employed to deliver project benefits desired. That can be enhanced through more measured methods and improved processes. Such an exercise should not only benchmark competitors, but should assure all standards, systems, human factors, and best practices to be adopted or improved from whatever sources derived from are both applicable and practicable. The process method outlined in Fig. 6.8 outlines benchmarking principles to consider:

Note: The purpose and goal of any benchmarking process is not to copycat what others have done, but to improve deepwater project specific aspects required as the exercise evolves.

Benchmark success factors to consider in deepwater are:

1. Total commitment from senior management.
2. Willingness to share information with benchmarking partners, etc.
3. Openness to new ideas and readiness to change processes inputs, outputs, and outcome.
4. In-depth knowledge and understanding of existing processes, engineering principles, people/organizations strength/weakness, and best practices or area lacking in these.
5. A realization that best practices continually change; hence, the need for regular review.
6. Benchmarking to be viewed as a best practice to continuous benefit realization.
7. Adhere to the benchmarking process as outlined in Fig. 6.8.
8. Conform to the ethics of benchmarking, i.e., *A Code of Conduct*

The ultimate goal of deepwater benchmarking is to effect CHANGE that delivers BENEFITS through using and applying the process. A *willingness to change by people* concerned is essential. Finally, *never ask for something one would not be prepared to share in return.*

FIG. 6.8 Benchmarking process. *Source: Kingdom Drilling 2004.*

DEEPWATER—SAFETY AND LOSS CONTROL

Deepwater Safety

The impact and benefit of attending a loss control safety leadership course in 1988 has remained embedded within this author's beliefs, that the more modern world of industry adopts the concept of safety as "the control of all accident loss" at work vs. the oil field mantra of "let's not hurt anyone today" approach.

It's an approach that has plunged the majority of oil and gas noninjury-related accident events (things that go wrong) into a big black hole that (as Figs. 6.9 and 6.10 present) may one day awaken management to walk the talk, investigate, and evidently learn from every project (safety) event that goes wrong. We know this is not right.

Safety—The Control of Loss

In today's progressive high-tech world, many industries demonstrate that *"Safety"—the control of loss*—is the only strategic safe operational business choice. Total safety viewed with a purpose and objective to deliver profitable business at minimal loss: Safety, accidents, incidents, near-miss events all defined within an encompassing safety management ethos (as shown in

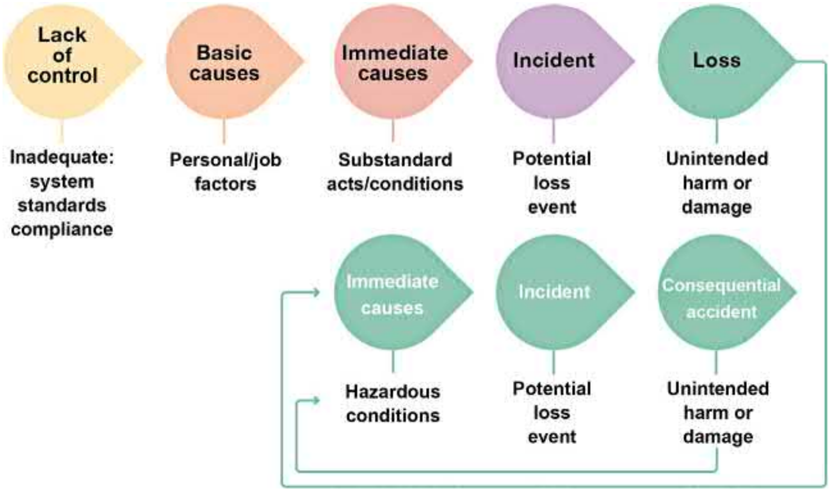


FIG. 6.9 The consequential accident sequence. *Source: The property damage accident (the neglected part of safety). Bird & Germain, 1997.*

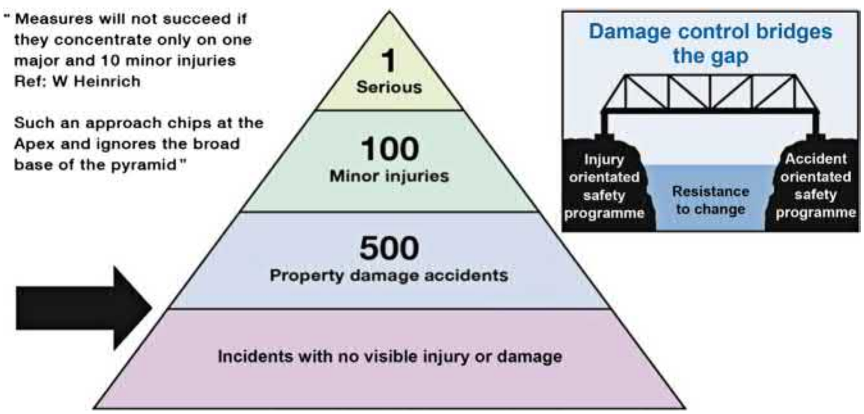


FIG. 6.10 Loss control, safety pyramid compilation. *Source: Kingdom Drilling 2018.*

Table 6.2 and Figs. 6.9–6.11) that can be more readily measured and controlled for individuals, organizations, and businesses to deliver superior project results at minimal loss.

Furthermore despite Lukens 1965 study and Heinrich's conclusions as stated within Fig. 6.10, oil and gas remains entrenched in occupational safety and nonproductive time metrics that consistently fail to serve or address the 95%–97% of underlying noninjurious safety and project-related day-to-day problems that result to ask, Can deepwater afford this? *Change is surely needed*.

The most neglected area by far is the "*S*," i.e., *operational Safety* component of HSE as illustrated in Fig. 6.10, where the evident majority of noninjurious accidents/incidents reside, that

TABLE 6.2 Safety (Loss Control) Defined

Safety: The control of loss					
***Accidents*: Things that go wrong (outcome = loss); (damage, failure, loss, waste (invisible loss))**					
People	Property	Plant	Productivity	Process	Environment
Injury harm	D/F/L/W	D/F/L/W	F/L/W	F/L/W	D/F/L/W
***Incidents*: Things that are going wrong (outcome: loss)**					
People	Property	Plant	Productivity	Process	Environment
Injury harm	D/F/L/W	D/F/L/W	F/L/W	F/L/W	D/F/L/W
***Near miss*: Precursory events to warn and signify things that are likely to go wrong (outcome: minor loss)**					
People	Property	Plant	Productivity	Process	Environment
Injury harm	D/F/L/W	D/F/L/W	F/L/W	F/L/W	D/F/L/W

Source: Kingdom Drilling Feb. 2017.

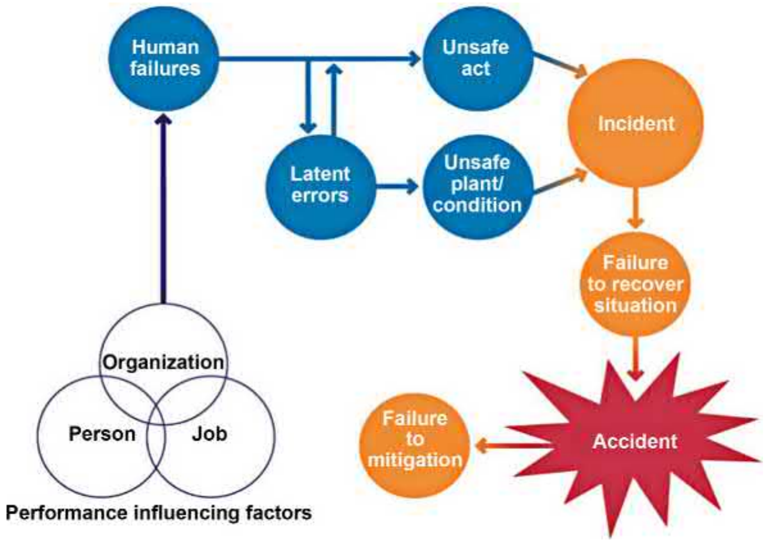


FIG. 6.11 Accident model. *Source: UK HSE Human factors in accident investigations; Kingdom Drilling 2018 based on UK HSE illustration.*

sit well below management's current metric thresholds, yet often *reside clearly within companies risk matrices*, to present a significant uninsured proportional "iceberg" block (Fig. 6.15) of *business opportunities to be corrected*.

As practical, loss-control safety leadership in oil and gas is generally not a management requirement to address and correct the significance of loss time events that exist. This is not right.

Note: Det Norsk Veritas (DNV) procured Bird/Germain's International Loss Control Institute's (I.L.C.I.) "Practical Loss Control Safety leadership" 1986 copyright. This program since evolved to its current 3rd 2014 copyrighted edition. www.dnvglstore.com. DNV now offer this program as a self-study course.

Human Factors View of Deepwater Accident Causation

Deepwater accidents/incidents as illustrated in Figs. 6.9–6.11 are rest assured caused through *Active failures* or *Latent conditions* led by human error or physical (parts) or paper work standards or systems violations.

- ***Active failures*** are acts or conditions that precipitate the incident situation. They usually involve the front-line workers. The consequences are immediate and can often be prevented by design, training, or operating standards, systems, and best practice.
- ***Latent conditions*** are the managerial influences and social pressures that make up the culture, that influence the design of equipment standards or systems, and define supervisory inadequacies. They tend to be hidden until triggered by an event. Latent conditions can lead to latent evident failures, human error, or violations. Latent failures may occur when several latent conditions combine in an unforeseen way.

Note: People make errors irrespective of how much training and experience they possess or how motivated they are to do things right.

The Human Contribution to Deepwater Accidents

People cause or contribute to accidents and mitigate consequences in a number of ways:

- Through a failure a person can directly cause a deepwater accident.
- People can make disastrous decisions even when they are aware of the hazards and risks.
- On the other hand, we can intervene to stop all potential accidents.
- The degree of loss (damage, injury or harm) can be reduced by the emergency response of systems, operators and crew.

Note: Consequences of human failures can be immediate or delayed.

Active failures have immediate consequences and are usually made by front-line people. In a situation where there is no room for error, these active failures have an immediate impact on business (profit/loss) health and safety.

Latent failures are made by people whose tasks are removed in time and space from operational activities, e.g., *engineers, decision makers, and managers*. Latent failures are typically failures in business, health and safety management systems, e.g., *controls, design, implementation or monitoring.*

Examples of latent failures are:

- Poor design of plant and equipment;
- Ineffective training, required skills development;
- Inadequate leadership and supervision;
- Ineffective communications;
- Inadequate resources (e.g., people and equipment); and
- Uncertainties in roles and responsibilities.

Latent failures provide similar, if not greater, potential danger to the business, health and safety as active failures. Latent failures are hidden within organizations until triggered by an event likely to result in consequences.

Investigating the Causes of All Accidents (Incidents)

All accidents (incidents) involving business or human failure in any deepwater project must be mandated by executive management to be investigated (*according to the majority of company safety policies*) to find the underlying causes and contributing factors, and attempt *to understand why all evident failures occurred*.

As the evident majority of failed and loss event reports do not exist, how organizations discover the immediate and underlying latencies and causes that are central and key to prevent all accidents through better and more effective loss preventative measures remain to be seen. Examples of immediate causes and contributing factors for failures are:

1. ***Job factors*****:** Illogical design of equipment and instruments; constant disturbances and interruptions; missing or unclear instructions; poorly maintained equipment; high workload; noisy and unpleasant working conditions.
2. ***Individual factors*****:** low skill and competence levels; tired, bored, or disheartened personnel; individual medical problems.
3. ***Organization and management factors***: poor work scope planning, leading to high work pressure; lack of safety systems and barriers; inadequate responses to previous incidents; management based on one-way communications; deficient co-ordination and responsibilities; poor project management of scope, health and safety; poor health and safety culture.

How to Reduce Deepwater (Accident (Incident)) Loss

Loss Control—Defined

Loss control is defined in this guide as an integrated process into current management systems serving to prevent and reduce all accident, injury, illness, and property damage loss and waste (invisible loss) in the workplace. It is directly related to human factoring, resource (people) management, engineering, risk, change, management, and best-practice. It is used in any organization and achieved through commitments of everyone. It emphasizes and encourages cultivating safety standards, systems procedures and practices, training and monitoring. Loss control includes the following:

1. Implementation of loss control policy
2. Assignment of duties and responsibilities
3. Review of investigations and claims data
4. Audits, monitoring and inspections
5. Accident/incident reporting and investigation
6. Communications development and review of emergency and contingency plans

Loss control is viewed to provide the following program/project benefits:

1. Safe operating value-adding work environment
2. Greater work effectiveness and efficiency through uninterrupted and often improved product, process, and services
3. Minimized losses of equipment and property while protecting assets
4. Minimized frequency and severity of accidents
5. Reduced expenditures of insurance claims

6. Minimized interruptions of services provided to the public
7. More job satisfaction environment for employees
8. Resistance against claims of negligence
9. Profitability (through the reduction and prevention of loss)
10. Business goodwill

The ISMEC Process

The fundament of loss control is shown via the **ISMEC** process as outlined in Fig. 6.12.

- ***I Identify*** scope required to achieve program, project, and (loss control) objectives.
- ***S Standards*** established to be conducted for all work activity required, i.e., deepwater.
- ***M Measurement*** to be conducted and compliance required to standards established.
- ***E Evaluate*** time, cost, quality, HSE metrics based on standards and measurements required then communicate these to those held accountable.
- ***C Commend*** what went well and ***Correct*** deficiencies that result.

Additionally, the UK HSE provides a safety management outline for business organizations to consider as shown in Fig. 6.13.

The loss control ISMEC and UK HSE framework processes are achieved by adopting an integrated proactive approach to prevent and mitigate all work-related failures, interruptions, loss and waste in the workplace to deliver and assure *increased quality, added value, and greater profitability* through *loss prevention*.

No organization should tout itself a "high quality safe operating business" until it can physically demonstrate evident loss control principles and measures exist and are being actively managed, measured, and controlled in regards to all business and QHSE aspects and not just injury prevention.

A safety leadership approach is certainly to be commended on the front lines to serve and demonstrate loss prevention is active, alive, and kicking and used at the point of contact.

Company executives and management must assure that they are held responsible and accountable that personnel are obliged to work in full compliance with existing company policy, management, safety systems, standards, regulatory, laws, and appropriate guidelines that exist—as opposed to all evidence to state this does not get done. We know this is not right.

Example: Regulators or Inspectors who visit the workplace shall undoubtedly want to know all safety and operability aspects are duly maintained, controlled, and measured, to demonstrate safe working conditions exist. Also how accidents, incidents and/or near misses (inclusive of noninjury events) are placed under scrutiny, reported, and investigated as part of their essential scope of work. *How well would individuals and people within organizations stand up to a full-on loss control prevention safety examination?*

Why Adopt a Loss Control Approach?

Deepwater events that result as illustrated in Figs. 6.9–6.11, 6.14, and 6.15 do not simply happen; they are caused, from where causes can be determined. All deepwater events, whether there is an injury or not, moreover directly expose workers to the same work-related risks that result in any potential escalating Swiss-cheese effect as shown in Fig. 6.14 where consequential events can potentially result in personal injury or at worst fatalities.

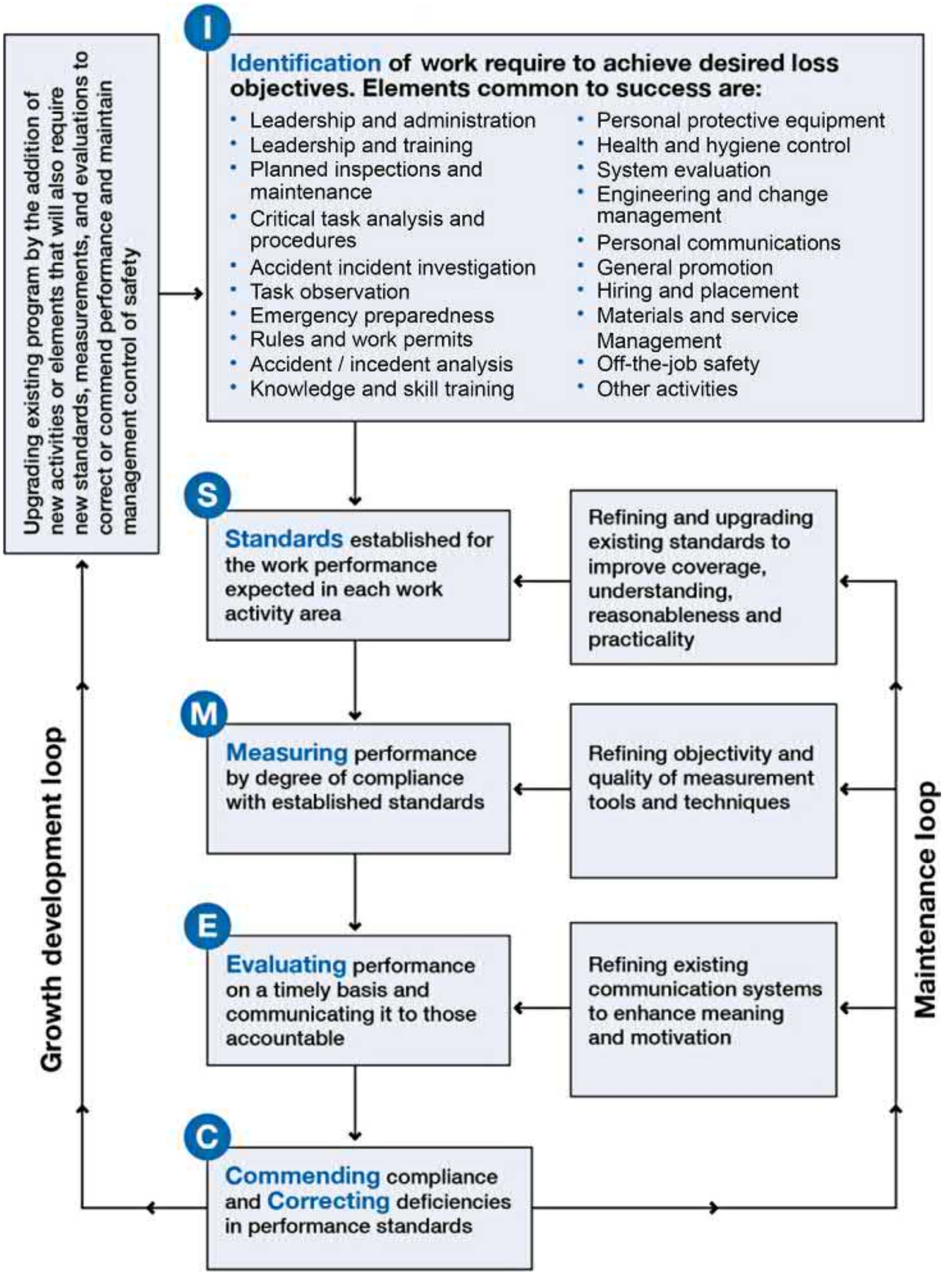


FIG. 6.12 ISMEC process. *Source: I.L.C.I. Bird & Germain, 1997.*

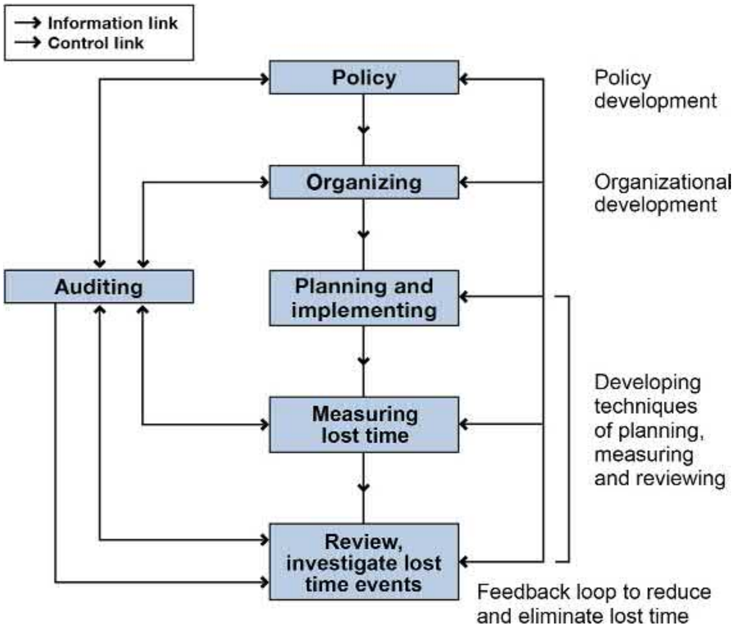


FIG. 6.13 Managing projects. *Source: UK HSE on line guideline, 2015.*

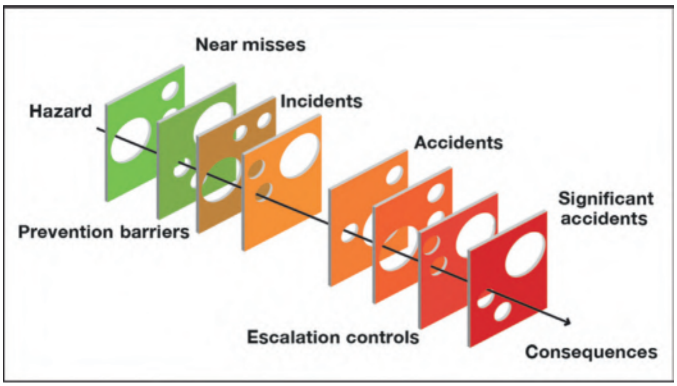


FIG. 6.14 Swiss cheese principle. *Source: Kingdom Drilling 2018.*

loss time events result to compromise the safe operability of time/cost/quality that directly affect all project benefits, e.g., *interruptions, delays, failure that then affect business safety profit and loss.*

Deepwater programs must provide liability insurance cover not only for injuries but against all work-related loss events that frequently result, e.g., *vessels, wells, equipment, systems, and possibly third-party and asset insurance for damage, failure/loss.*

Policies generally cover only a proportion of costs of all events, with the vast majority of uninsured costs not covered to be accounted for at company expense (Ref. Fig. 6.15).

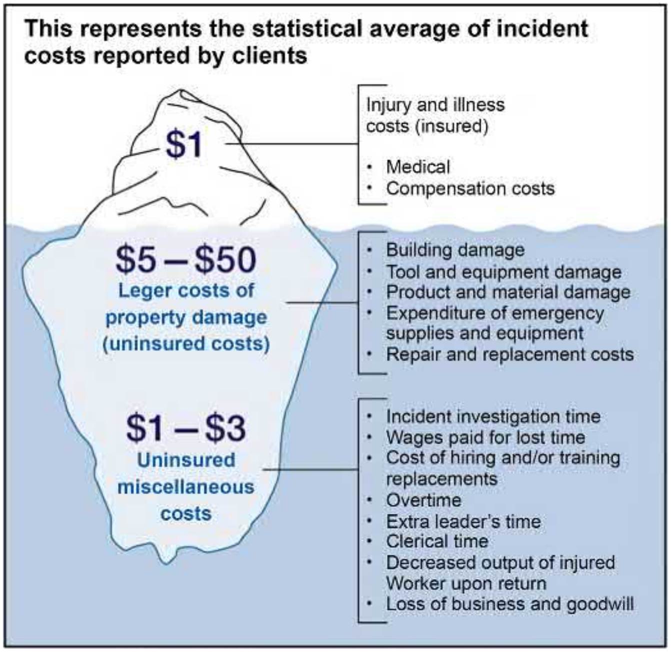


FIG. 6.15 Cost of accidents and incidents at work. *Source: Bird Germain 1997.*

As the program owners are responsible to manage and control all safe, operational, and environmental aspects that result in the deepwater well's workplace, why should any accident (incident) loss event be viewed as any different?

Reasons to change and integrate loss control into existing deepwater well operating safety systems to consider are:

1. Loss control is well proven and evolving in multiple industries for many decades. It currently forms the backbone of many successful companies' management programs and systems.
2. Strategic loss control efforts can assure greater hazard and risk identification to prevent, reduce, and mitigate further loss.
3. Loss control is viewed by many as a process business simply cannot afford to do without.
4. Analyzing all loss (and waste) affords more opportunities to identify, investigate, and correct operating hazards and risks that exist. *Note: Amazing as it is, noninjurious occurrences within well operations are the exact same events to incur or prevent injury.*
5. Loss control assures the identification of unwanted or unintended change, i.e., *a deviation from something supposed to be right and go right first time*.
6. All loss has an immediate potential to add more consequential accident loss (Figs. 6.9–6.11, 6.14) and probably establishes more proximal causes to deliver more severe consequential loss to result.

7. 90%–95% of loss events are machine or people-made. People can be trained, skilled, and developed to prevent vs. cure problems that result. Practical loss control safety leadership is to be endorsed as the proactive and progressive step change to prevent all future loss. No safety stone or avenue shall be left unturned using this method.
8. A loss strategy assures desired barriers and controls are more likely to be in place to prevent consequential event causation sequences after initial or greater loss has resulted. *Example: Uncontrolled blowout could introduce immediate and metamorphic outcomes to the structure, damage, failure, or loss.* Assured barrier provision provides immediate and improved safety and reduced risk into the system.
9. Evidence from industries demonstrates improved safety over lengthy periods. In parallel productivity improvement also has resulted. *If this fails to motivate management, what will?*
10. When work is focused to prevent or reduce loss, this eliminates the same causes of personal injury or harm. Prevention is the man-trap to reduce harm, injury, or fatalities that can result.

How to Implement a Loss Control Program

Implementing a Loss Control Program

A deepwater loss control program must be "fit for purpose" for each organization. This would start by conducting a hazard identification and risk management review to determine the evident extent of business loss that exists. Results then used to evaluate and act on what is viewed as the main corrective areas. Leaders are then selected and trained to develop a loss control plan, to provide advice and prioritize all issues to resolve the underlying hazards and risks identified from within the process. Another task could be to review all systems, standards, controls, processes, and competencies programs with a mandated directive to change and continual improvement.

A simple step sequence to consider initiating a deepwater loss control program would be:

1. Benchmark current performance (loss and waste that exists).
2. Establish the need and want to change and improve.
3. Executive commitment and buy in to define and roll out the loss control benefits to be realized.
4. Select and use best means, methods, and resources that best fit to be able to diagnose the extent of loss and waste.
5. Assure suitably skilled, trained people are in place to investigate the underlying causes and latencies of all event failures (loss) that result.
6. Define and test solutions to accomplish improvement benefits desired.
7. Produce a loss/waste control corrective and commendation plan.
8. Identify and overcome resistance to change.
9. Implement, translate and sustain change (again a difficult task to do well).

More detailed analysis of past and current operations may also result to highlight major to minor areas of loss exposure that exists to lend more support to address problem areas. The final output is to propose a loss prevention implementation strategy presenting key outcomes and benefits to be had. Internal or external specialist(s) then assigned to work within each organization to develop solutions and action plan recommendations into existing safety and operating management systems. Specialists can assist the organization to monitor future operations to assure all corrective actions and metrics are suitably translated to sustain desired results. Specialists shall assist in other safety or operating areas, needs, concerns, or areas where change is identified. Specialists should be suitably selected and trained for multiple business operations to provide the required level of safety and operational decision solutions to result from within such multifunctional and multidisciplinary organizations.

Specialists can offer online technical reference, support, training, and researched proposal's to allow organizations to stay in touch with key loss issues that most impact the safety of conducting operations within the business.

WHAT LOSS CONTROL IMPROVEMENT IS NOT

Loss control Improvement is not about using fancy sets of tools, software, or techniques; most of what is needed already exists and is currently in use. How key elements are being managed, measured, and controlled often present the latent "people" and change problems needed to be changed and resolved. Improvement is not going to result through the motions of organizing improvement teams and training people. Improvement is a people-change result only to be commended when an *EVIDENT reduction in measurable loss* exists to demonstratebenefits are being realized.

WHY IS LOSS CONTROL IMPORTANT TO DEEPWATER PROGRAMS?

All deepwater program activity should be directed to manage, control, and improve. Programs should be devoting considerable effort to prevent loss, create, and realize change when needed, through all improvement means. If business is failing, competitive edge is lost. Loss prevention is far more attainable to work, maintain, and improve at the pace needed and stay ahead in current global dynamic, changing business markets.

WHEN SHOULD LOSS CONTROL BE STARTED?

Every standard, system, and program shall be provided to assure and address a loss control implementation and improvement cycle. This, akin to any process, should start at the beginning, and then be worked and maintained to the end. Every work scope task and activity should be targeted to evaluate what is to be corrected when/as needed.

How to Use Loss Control at Work?

WHERE DO LOSS CONTROL OPPORTUNITIES AND IDEAS COME FROM?

If the organization has identified and prioritized critical success factors, i.e., *the handful of things to deliver better*, loss control focus should attend to these for a defined period to result in the most probable major benefits.

WHOSE RESPONSIBILITY IS IT?

No one person in the organization, from top to bottom, is exempt from the responsibility for loss control implementation. It should become a normal daily component in all employees' job descriptions to SEE and realize ways to improve at work through loss prevention. No one should be expected to do this without help and support from each other.

HOW DOES A COMPANY ORGANIZE FOR LOSS CONTROL IMPLEMENTATION?

Most loss control programs are executed by teams required to diagnose problems, determine causes, derive learning and then act, implement, translate, and sustain change. Teams in deepwater tends to be departmental, multidisciplinary, and crossfunctional. In this, a steering group of leaders is likely needed to direct individuals and teams toward desired goals, and above all create and develop the culture and environment desired that promote operating benefits to drive safety success.

How to Investigate and Learn Things That Go Wrong (LCA)

When an organization recognizes and analyzes the levels of loss and waste that evidently exists within current deepwater projects (*Example*: The standard deepwater drilling project norm loss/waste, is typically 50% per well), the evolutionary step is then how to assure learning from the 50% of things that go wrong on a standard norm, well-by-well basis to correct, , translate, and sustain learning into future projects.

How to Learn From Things That Go Wrong?

When things go wrong on a daily work basis, human nature seeks the nearest person to point the finger at and blame. This is not right. A better approach to finger-pointing and blame assignation is needed. Years of searching to find a method to best suit resulted in 2013 Latent Cause Analysis (LCA), http://www.failsafe-network.com/.

LCA is an EVIDENCE-based gathering process evolved over the last three decades from root-cause analysis (RCA) methods that lead people to understand why things went wrong without assigning blame. People then changed through the corrective evident demands that are then placed on themselves.

LCA is an easily used, worked, and applied evolved root cause analysis method. Note: no software exists, to permit people at work to be proactive to take an immediate investigative lead as soon as anything is wrong no matter how big or small an failure or loss event results at work. Events are then investigated by individuals at a mini level, or a group/team, for a midi to maxi event level, by simply peeling back to reveal each layer of (People, Physical (Parts), or Paper) based evidence as it unfolds to present the evident facts, figures, data, and truth that exists in every event before more consequential accident sequential loss events kicks in (Fig. 6.9). The objective of LCA is to LEARN, always starting with oneself, to initiate corrective CHANGE, i.e., *within the trails of EVIDENCE that exist.*

In summary, deepwater programs have a choice to let all the operational safety fires that are currently simmering, igniting, or burning, continue via the standard safety (occupational safety) norm or adopt a very different strategic approach to deliver far better outputs and benefits through a loss control and LCA practical safety leadership approach. The intent and goal being to change people, e.g., by adopting a more introspective, proactive, evolved, tried and tested approach that is readily implemented at the workplace and within existing systems to address all loss and waste issues to fully understand why things go wrong, to then translate and sustain learnings to prevent future and similar loss/waste events.

Learning From Evidence?

As in daily life, nothing can be realized without evidence existing in one form or another. Evidence is a word used to describe how individuals, teams, or organizations become aware as to how all project work-scope events manifest themselves, etc. Evidence contains *everything people need to know* about good or bad event outcomes. Without evidence, people can hypothesize, theorize, speculate, and discuss the causes of an event.

The LCA root cause analysis investigative method is chosen for this guide as it is simple, straightforward, and 100% evidence driven through the following trains of evidence:

- *3 P's*: People, Physical, and Paper evidence
- *4 P's*: People, Physical, Parts, and Paper evidence

To be further reviewed and more fully explained, please consult www.failsafe-network.com.

ADOPTING A VECTOR APPROACH TO EVIDENCE GATHERING

Bias is the enemy within current forms of Root Cause Analysis (RCA) methods, which is not intentional but still a concerning human factor to address due to the multifaceted and multidisciplinary forms of the 3 or 4 P's of evidence that exist within deepwater project events. RCA software programs, processes, or system methods generally do not work that well, with the end result generally whatever people want them to be. What is needed is a more practical investigative method that is easy and ready to use for all deepwater project mini-maxi events. At the higher more consequential event level, the process remains the same, with simply a few more people, and more formal shape required.

People have life experiences that tend to taint the truth. When events result at whatever level, it is paramount for all to do what is necessary to reveal the evident truth. The effective way to achieve this is to take full advantage of the 3 P's. The vector approach achieves this by people taking separate evidence-gathering paths, e.g., *one for each of the 3 P's.* Assigned persons are *not allowed to discuss, talk, or share information* until the event leader aligns all people assigned and evidence together. This assures *no bias exists* and that everything is *EVIDENCE* based.

The Order of Fragility

The order of fragility defines the order evidence evaporates. People evidence evaporates the fastest, then the physical and lastly paper evidence. The most important task is to gather the most fragile evidence first, i.e., *the people evidence.*

What to Do When Things Go Wrong?

To surmise, when things go wrong in deepwater projects, an evidence-gathering investigative plan shall exist. The standard format recommended in this guide is to use the LCA evidence-gathering method, featuring:

- Individuals for all mini-event levels,
- Groups or teams for midi to maxi event levels.

What has to be gathered FIRST in all events (as soon as is practicable to do so) are these **five items**: How to deliver these items are fully explained @ www.failsafe-network.com.

1. A statement
2. A schematic

3. Relationships defined
4. A summary of sequences
5. All oddities observed and noted.

Key Takeaways

Deepwater programs, people, and organizations must first measure the full extent and face the evident truths of gaps and the extent of loss and waste that exists when reporting and acting on **all** things that go wrong. Then, assure and enable methods to learn from all lost time events through a more superior safety leadership loss control and investigative approach to realize the potential gains.

1. The process of conducting mini, midi, or maxi LCA events are all similar. The key difference as events escalate is that more people are involved and involvement must be more formal.
2. Greater problems require nonbiased outsiders and more structure imposed.
3. Without evidence a LCA (mini, midi, or maxi) is impossible.
   (a) It is vital to gather evidence as soon as is practicable to do so.
   (b) Let each form of evidence speak for itself and do the finger pointing.
   (c) PEOPLE evidence is the most important of the 3 P's.
4. Seek all emerging symptoms (*there are always missed warning signs*).
5. Keep the 3 P's separate to counteract bias.
6. Mundane things often contain a wealth of evidence so seek these out.
7. It is critical to look at the evidence like looking through a prism.
8. 80% of the time of an LCA is evidence gathering and summarization.
9. EVIDENCE pulls people to the truth without assigning blame.

REFERENCE STANDARDS

Bird, Frank E. Jr., and George L. Germain. Practical Loss Control Leadership. International Loss Control Institute, First Edition, March 1986.

Bird, Frank E. Jr., George L. Germain and M. Douglas Clark. DNV-GL Loss Control Management, Practical Loss Control Leadership, Third Edition. ILCI 2004.

C. Robert, Nelms. A recommended corporate approach to profound learning. www.failsafe-network.com.

IOGP, Regulators' use of standards, reports. https://www.iogp.org/.

Managing Successful Programs (MSP™). *Note*: MSP TM is a trademark owned by the UK office of government commerce (OGC).

References

Bird, F.E.J., Germain, G.L., 1997. The Property Damage Accident, the Neglected Part of Safety. ISBN-0-9656516-2-2.

Department for Business Innovation and Skills, 2010a. Guidelines for Managing Programs. Understanding Program and Program Management. Publication available at http://www.bis.gov.uk/.

Department for Business Innovation and Skills, 2010b. Guidelines for Managing Projects. How to Organise, Plan and Control Projects. Publication available at http://www.bis.gov.uk/.

HSE (Health and Safety Executive) (Eds.), 2002. Developing and Maintaining Staff Competence. ISBN 0 7176 17327.

https://www.forbes.com/sites/travisbradberry/2015/01/07/why-you-need-emotional-intelligence-to-succeed/.

Managing Successful Drilling Operations, The Triangle of Success, White Paper. Holland and Davis LLC, www.HDINC.com

Mearns, K., Whitaker, S., Flin, R., Gordon, R., Paul, O.'.C.H.S.E., 2003. (Health and Safety Executive) Books RR061. Factoring the Human Into Safety: Translating Research Into Practice, Crew Resource management Training for Offshore Operations. Volume 3 (of 3) Industrial Psychology Group, University of Aberdeen King's College.

Robert Nelms, C., 1992. What You Can Learn From Things That Go Wrong. Failsafe Network, Inc.

Robert Nelms, C., 1993. The Dynamics of Inculcating the Root Cause Mentality. Failsafe Network, Inc.

Robert Nelms, C., 2013. Four Significant Problems With Root Cause Analysis, and One Life-Changing Alternative. Failsafe Network, Inc.

The 100 largest losses, 1974–2015, Large property damage losses in the hydrocarbon industry. 24th ed. 2016. Marsh Report.

Wright, M., Turner, D., Horbury, C., 2003. HSE (Health and Safety Executive) Books RR086. Competence Assessment for the Hazardous Industries. Prepared by Greenstreet Berman Ltd. for the Health and Safety Executive.

CHAPTER

7

Deepwater Well Planning and Design

DEEPWATER WELL PLANNING

General

Introduction

This guide recommends simple management and best-practice methods to *plan, organize, implement,* and *control* deepwater well's projects whereby people and teams working together can and have delivered extraordinary results.

This section does not intend to delve deep into standard project management, well planning and design aspects that are well documented as shown in Fig. 7.1. This focus is to target "what else" is explicit and relevant for deepwater. Emphasis is placed on both central and core project planning aspects as shown in Fig. 7.2 and through this chapter to include:

1. A well-defined deepwater project work-scope
2. Customer and stakeholder wants
3. Project time, cost, quality, and HSE deliverables
4. Loss control prevention and investigative assurance of all minor to major events
5. Project resources, that require wider multidisciplinary* skills sets developed
   Note: **Results indicate a 30%–50% reduction in work force effort can be achieved and delivered through assuring enhanced team integration with greater individual focus placed on work skills, knowledge, and experience*
6. How project individuals, specialists, teams collaborate, participate, and are engaged
7. Organizational safe operational risk management and change
8. Project knowledge, information, data, and learning

Deepwater Well Planning

Well planning from standard to complex deepwater wells does not need to be elaborate or complicated as only one binding product is delivered, i.e., a **S**afe **E**ffective and **E**fficient well.

What is important is the unqualified statement that people drive projects to success far more so than disproportionate project management that is often intellectually over complicated and hyped. The deepwater project planning priority is to assure it is fully resourced, aligned and integral to a highly skilled, multidisciplinary work force that is furthermore enabled and empowered to drive all critical scope and control planning aspects from inputs to output results desired. Another affirmation is that the same people are provided with the

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00007-7

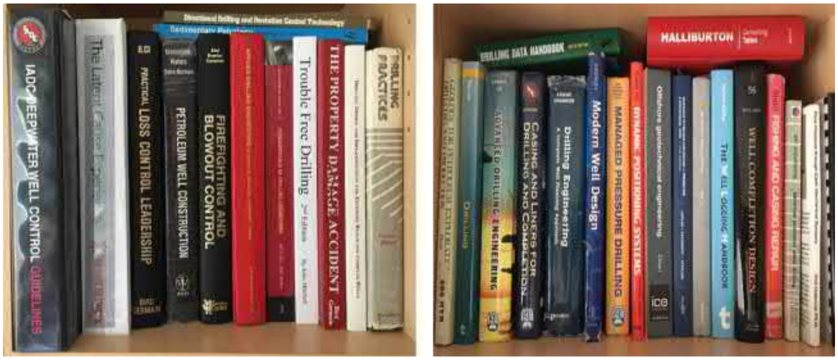


FIG. 7.1 Representative well planning, construction, design, and engineering library.

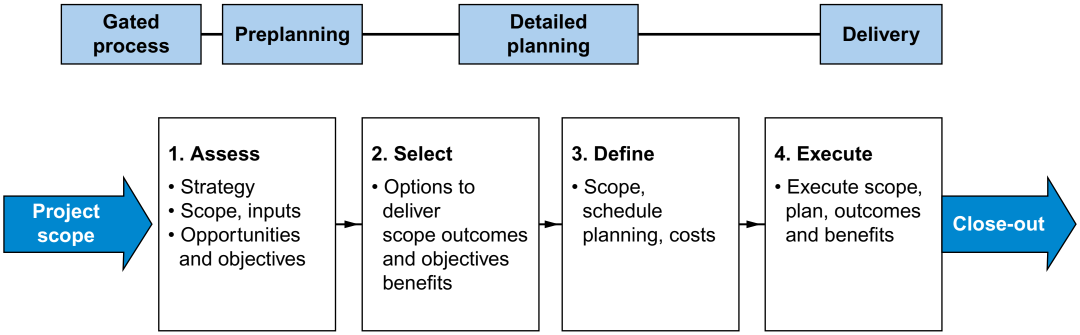


FIG. 7.2 Generalized planning and delivery process for deepwater projects. *Source: Kingdom Drilling.*

necessary tools, skills, development, and support so that the work scope, process and flow is crystal clear in terms of who is doing what, when, how, why, from start to end as presented in Figs. 7.2–7.9.

In today's more complex well's project's, processes, plans, and work flow are far more achievable than in the past due to the "Digital Internet, knowledge base, and accessibility of things" awaiting to be grasped, enabled, and utilized at a far more rapid big-data pace that exists across all multidisciplinary technological industries like never before. Many industries that are undeniably undergoing transformational and rapid change including oil and gas sectors *seeking opportunities for data-driven solutions to boost project planning, improve performance, and loss prevention metrics in order to deliver outcomes and benefits desired.*

In summary, lots of digital data exists (often too much of them) that needs to be put to valued use if time and effort is resourced to do this. How project value-addition is created through better "big data" use is a major challenge to resolve.

Detailed Well Planning—Workflow Process Map

Typical deepwater well-planning processes are illustrated in Figs. 7.2–7.4 and Table 7.1. Specifics are expanded and aligned as shown in Figs. 7.5–7.9.

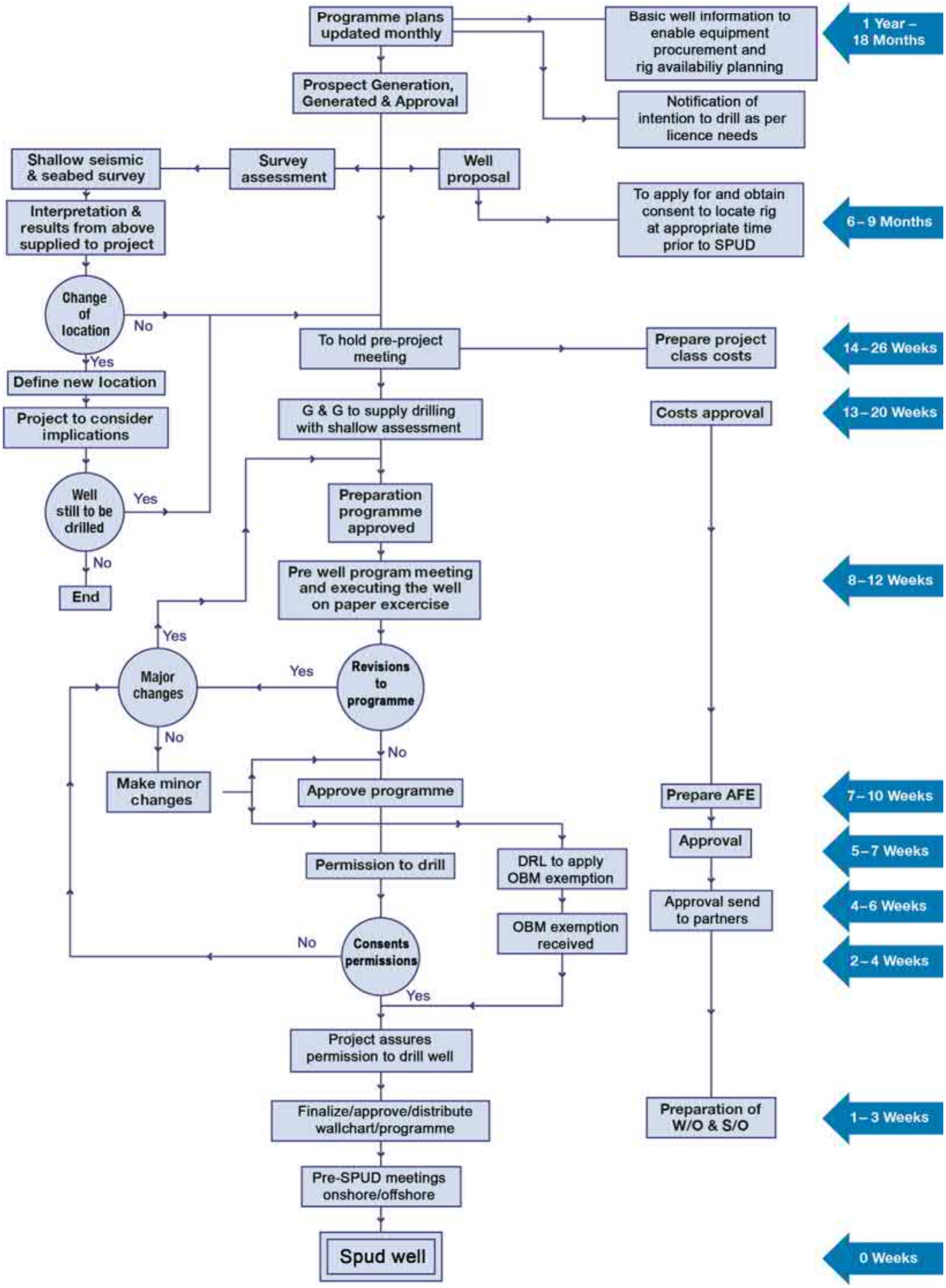


FIG. 7.3 Generic offshore well-planning sequence of events. *Source: Kingdom Drilling 2018.*

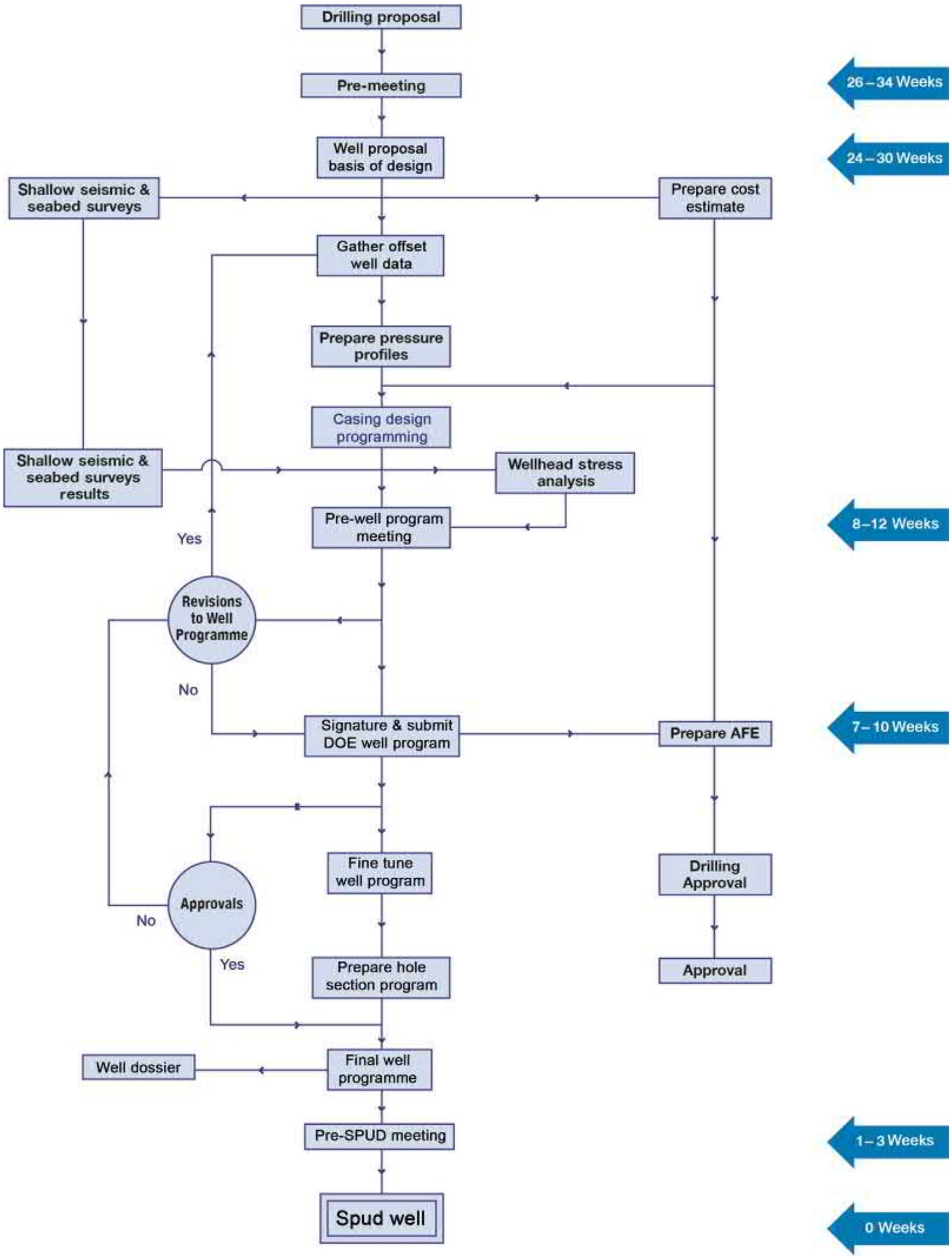


FIG. 7.4 Generic offshore drilling well-specific series of events. *Source: Kingdom Drilling 2018.*

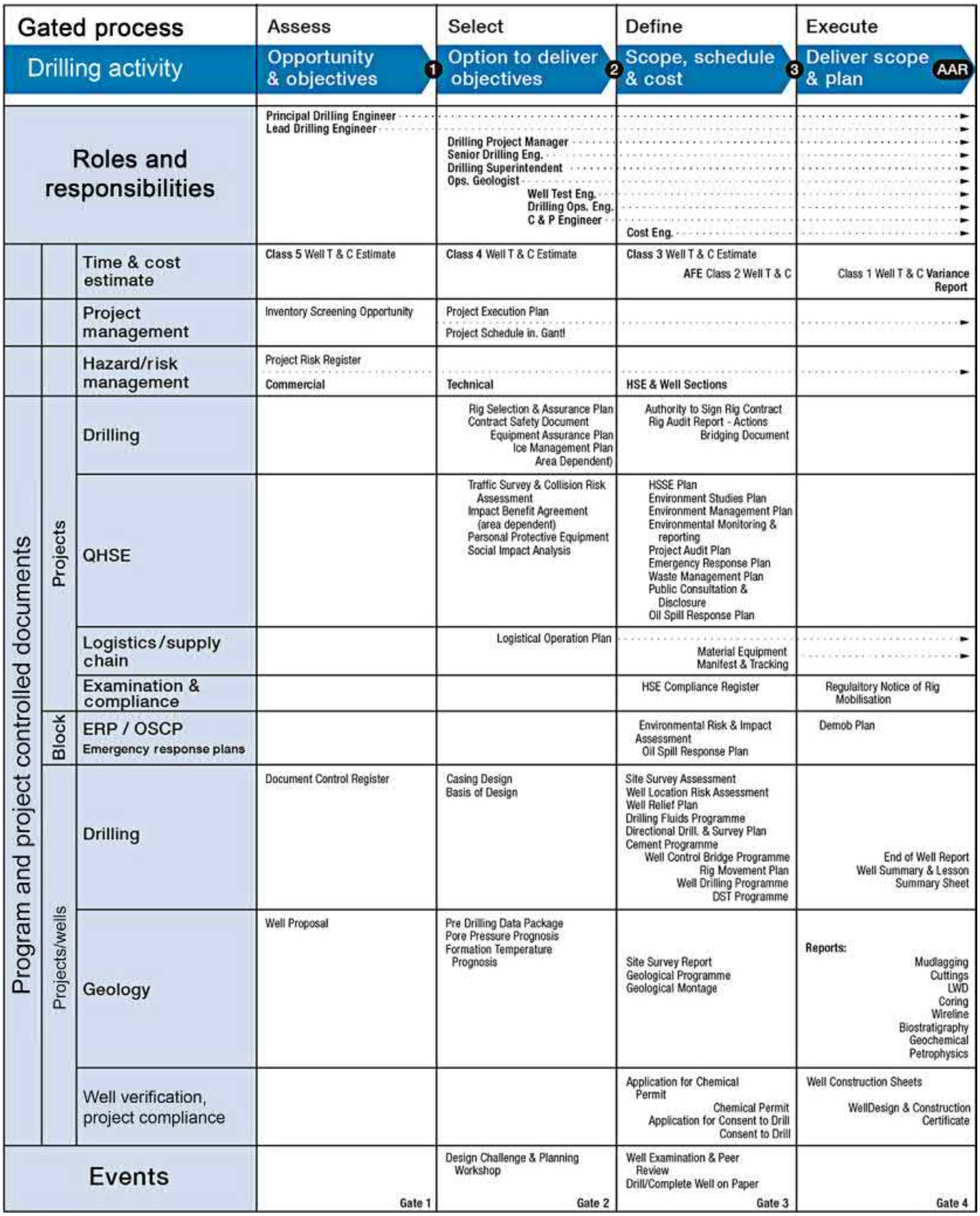


FIG. 7.5 Generic deepwater well's project gates scope process and flow summary. *Modified from Operators, Well Management System as a generic template, Kingdom Drilling 2018.*

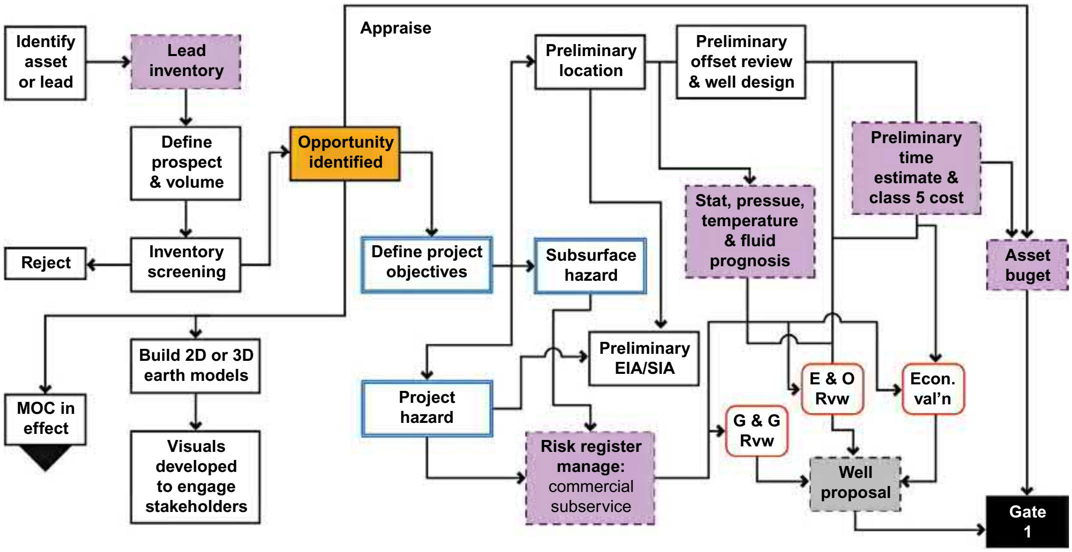


FIG. 7.6 GATE 1: Appraise work flow process outline. *Source: Kingdom Drilling training 2018.*

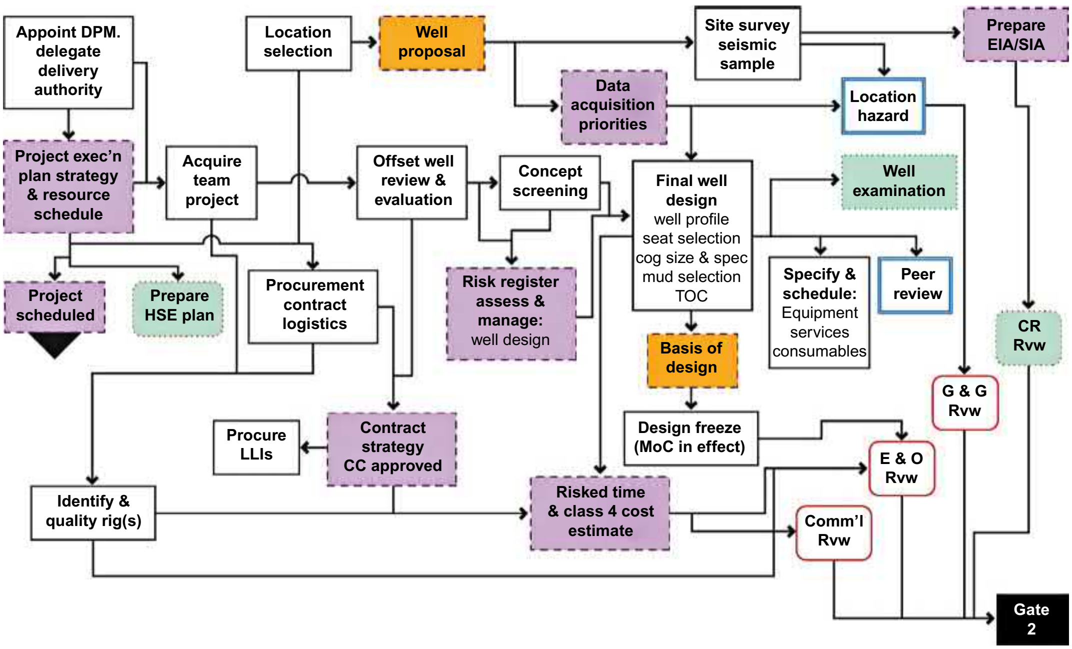


FIG. 7.7 GATE 2: Select work flow process outline. *Source: Kingdom Drilling training 2018.*

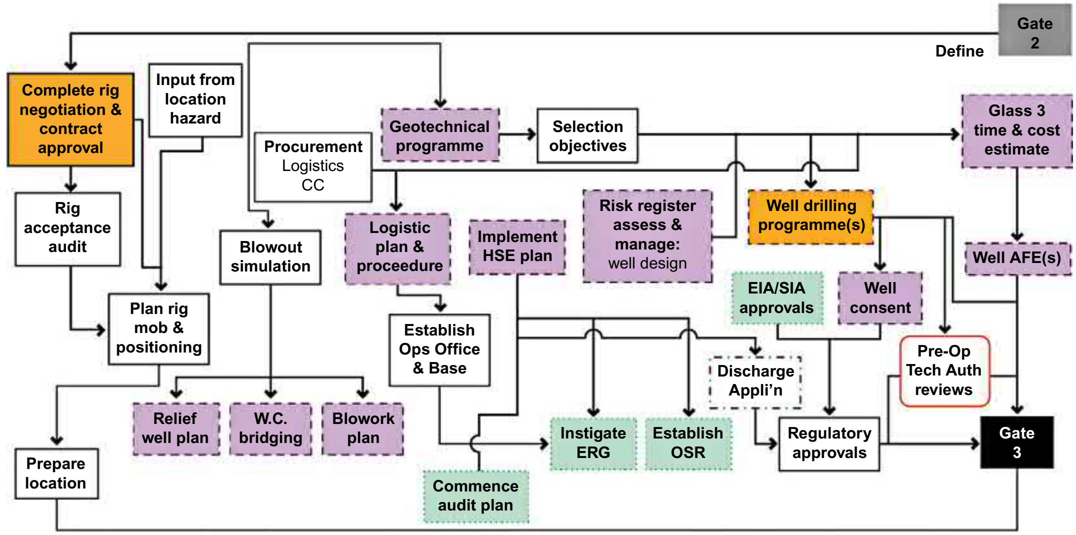


FIG. 7.8 GATE 3: Define work flow process outline. *Source: Kingdom Drilling training 2018.*

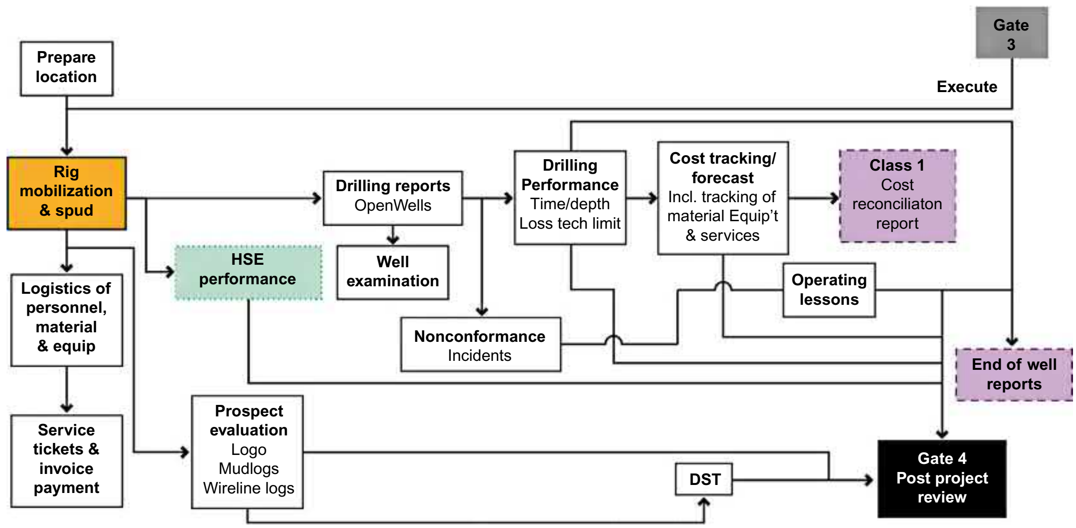


FIG. 7.9 GATE 4: Execute work flow process outline. *Source: Kingdom Drilling training 2018.*

TABLE 7.1 Deepwater Well-Planning Critical Activities

Critical Activities	Time Prior to Spudding
Preplan meeting	12–18 months before spud
Finalize and submit to project	
Gather offset wells data, review, analysis	8–12 months
Pressure and wellbore stability analysis	
Concept and main well design	4–8 months
Project planning and well engineering	
Safety case, programs, bridging documents	2–4 months
Major accident response plans	
Pre-execute well programs on paper meetings	
Submit project programs, Management to assess risk, and all plans	1–2 months
Complete well examination, AFE, approvals, consents, permits to drill, etc.	
Prespud meetings	2–4 weeks before start
Readiness to execute program	
Implement and close out program	As per program schedule.

Source: Kingdom Drilling 2018.

The essential scope comparison differences to a standard norm are that deepwater complexity generates more specialist requirements that adds significantly more scope, and detailed planning to drive the added resources, time, and costs to execute all work related deliverables desired. Note: At each scope stage closeout, it is essential for all deliverables to be fully assessed, i.e., either ahead or behind the plan, to identify, prioritize, or act upon variances or deviations (good or bad) to be changed.

The appraisal phase presented in Fig. 7.6 shall deliver a list of priorities from all business and project specific opportunities identified. The most prospective would undergo technical, risk and commercial scrutiny to select the best to approve or reject. Once selected the prospect is managed, planned, and controlled through the appraise phase as shown in Fig. 7.6 to deliver a well(s) proposal and project budget cost assessment estimate at Gate 1.

A pertinent aspect is to continually ask and evaluate: "Do sufficient scope, data and information exist?" If not, more scope must be created to meet specific project process and workflow needs. *Note*: In a new operating area the HSEQ group may also assess for issues related to corporate responsibility and regulatory compliance.

The select phase presented in Fig. 7.7 shows that the project shall review the work scope proposal, offset wells review, and any statement of requirement inputs required. Then work that needs to be done has to be well defined and aligned prior to closure of the select Gate 2 as shown.

At Gate 2, the main output to be fully understood and comprehended by all, is that a fully developed base case and contingent design plan shall result to exist and that all peer reviews, assists, initial well examination and a design freeze shall be signed off by managers involved at this stage.

Note: Process and flow key for Figs. 7.6–7.9 is illustrated as follows:

Key	Primary phase input / output	Formal milestone event or evening	CR, HSEQ & compliance	Document output	Function technical review

Further consideration is to assure that levels of project confidence, risk, and uncertainties have been *selected* and that all scope reviews details and opportunities are fully realized prior to initiating and commencing the *define* and detailed planning phase. The *define* phase founds the heart, breadth, depth, and detail of the scope review, assessment, and evaluation conducted to assure project plans are fully developed into the well's safety case, programs, and bridging documents required to deliver the "execute as planned" outputs as shown in Fig. 7.8. At the end of the define stage, a final review and analysis should take place to assure that all primary and contingent programs, plans, issues, and preparations are in a state of readiness.

Management and partner peer reviews, hazard, and risk assessment of *project definition, assignation, and deliverable well programs* and all supporting documents and plans compiled would be conducted to assure project execution can be delivered as planned.

During the execution stage as outlined in Figs. 7.5 and 7.9, management control aspects shall be continually checked that the project is measured, assessed, and appraised throughout execution to meet goals, objectives, outcomes, and benefits desired, including what is being learned and that commendation or corrective values are being effectively translated and sustained. After Gate 4, an integral project *post review* shall be conducted to assure all project scope aspects are attended to and closed.

To guarantee vigilant well-planning results, the following aspects are to be considered:

1. Gather and analyze all evident data, pertinent information, and facts.
2. Afford time and resource to clearly define the project scope. This is titanic.
3. Break scope into manageable work structures. RACI charts are used.
4. Sequence and schedule work scope using a simple wall chart or basic project plan.
5. Establish technical and commercial challenges, opportunities, and constraints that exist.
6. Identify internal, external and specialist resources, or studies that may be required.
7. Detail and deliver precise resource, time, sequences, milestones, and cost estimates.
8. Project delivery and loss must be continuously measured and benchmarked analyzing all inputs and outputs. Trouble areas evaluated, changed, and improvement assured.
9. Assure primary and contingent courses of action, i.e., *always try to have a plan B.*
10. Determine measurable checkpoints for key project elements and variations expected. Assess how project shall assure learning is translated and sustained.
11. Examine what else deemed as appropriate to each individual and often unique project.

In conjunction, a gap analysis in regards to deepwater specific standards, systems, and best practices norms is strongly recommended. Areas of review considered as:

1. Management systems and operations policy statements
2. Policy dispensation and/or management of change
3. Hazards and risk management process compliance
4. Project cost management practices
5. Well examination and well integrity management
6. Lessons learned and knowledge management

7. Integrated loss control safety leadership program, nonconformance, and investigative reporting
8. Industry standards, systems guidelines, and best practices compliance
9. National regulation and guidelines compliance.

What will result through the project planning stages is that well-informed decisions and choices as the work scope progresses and evolves through each stage will have to be made. The ability to compromise and/or manage change is an important fact that shall inevitably result particularly when new, or prevalent project information or data arises. What also challenges projects are the multiplicity of daily and often quite complex iterations of data-streams, work process, and flow of information that exist. For people to do the right things and get things right the first time, many of the challenges to be overcome can be achieved by assuring that all core team members are assigned to work together in a suitably provided office space.

Assuring the right decisions result can become increasingly difficult and constrained as work scope time throttles in at the end of each stage. Project deliverables rely heavily on getting the scope right at the project start, gathering the most reliable, evident and value-adding data, with all inputs and outputs to be managed, processed, and controlled to deliver the results required. Persons and complex groups of people and multidisciplines involved also need to work on the best ways to communicate, collaborate, and cooperate both as individuals and as teams.

What results with the multiplicity of systems, documents, and project data overload, is that everything generated and produced shall be controlled, administrated, and compliant to project standards and further assured to be well communicated and maintained to meet all end-user requirements. What is preferred is to have someone with suitable administrative and technical skill to be assigned (as a project controller) as one of their roles and responsibilities to meet each project's demands.

Finally, all crucial and critical aspects should be clearly captured, outlined, and mandated to assure compliance within a project. A Project-specific Management Handbook should exist for early use in appraisal or define stage.

Deepwater Planning Key Learnings/Case Studies

Project Planning Learnings

Some key planning learned from reviewed case studies, project documents, journal papers, and industry articles to further consider are listed in no order as follows.

1. Do not plan and execute as two distinct projects. It is one total project from start to end.
2. Management must work to streamline and optimize projects through continuously assessing data acquisition requirements, digesting existing data, and fine tuning based on data, knowledge and value acquired, evaluated, and assessed.
3. Incentive contracts can be a vital and central element to improved project delivery through aligning goals of operator, third parties, and contractors to affect a win-win for all. A long-term continuous incentive contract also affords more value adding risk management.
4. Become a learning organization seeking alignment between contracts and business goals.
5. Deepwater case histories prove that flaws in well design are rare, but many significant operational problems that result stem from problems created due to the inattention and inadequate planning, risk management, and the very fine level of detail demanded.

6. Project teams shall not produce coherent result unless carefully selected, properly structured, and detailed work process and flow are well defined. This takes skills, experience, and specialist advice.
7. Significant value is added to projects taking a simple phase approach and adhering to key project management practices and principles as outlined in this guide and supporting references stated.
8. Detailed planning involving all can deliver significantly improved project results. Extending this detail to foreseeable contingencies assure prompts quicker recovery.

Case Study Examples

Deepwater Program Case Study 1: In the late 1990s, teams were beginning to test deep water and beginning to appreciate the stone cold facts that complex wells required more devil-in-the-details and a scrutinized managed and controlled approach. At project onset, an external guru was resourced by the operator lead, and tasked to observe how the well's team performed as they applied their project work. In summary, the most important learning was that essentially very little time was afforded at project start or during planning to *clearly define the project scope*.

Deepwater Program Case Study 2: (2 years later from Case Study 1): Core project persons were provided a preproject agenda and requested to attend a 2-day get together at a hotel retreat (at the operator's expense). The purpose and intent was to gather, work, and execute a clearly defined project scope in the depth and detail required. All input, output, outcomes, and benefits resulting from this typical upfront loading, preplanning process will be revealed later in this section.

Offset Well Study and Analysis

An offset well's or similar project study and analysis is considered important, e.g., *benefits to be gained from within a report would be viewed as:*

1. Multidiscipline research exercise, to produce more informed well proposals, plans, designs, risks, and operational best practice standards, programs, and guidelines;
2. Budgeting, scheduling, project work scope realization;
3. Look-backs and reviews and what was good and bad in previous or similar project work.

A standard report produced shall provide a high-value-level snapshot of comparative offset or analogue well's review of essentially everything of relevance from bit records, mud, cement, and mud log records and time, mud, drilling, geological, LWD log summaries, etc. to create required time versus depth, pore-pressure, and fracture curves, make well comparisons, identify key problems areas, hazards and risks to assure learning and best executable practices result. Evident facts and figures are likely to be sparse in a program's beginning. Prevalent well data usually can exist and be put to highly valued use, often requiring to be cherry picked from within several different areas until the first well's project is delivered.

Planning and design aspects generally in the beginning must rely quite heavily on seismic data interpretation or, through extrapolating from regional wells, suitable analogue data, etc. Should poor quality or lack of data and information exist, this increases project risk and uncertainties with a more conservative design and costly executable project to result. When high-quality, reliable, or well data exist to deliver higher confidence and offer well-reasoned plans to reduce risk, the value of this task is appreciated.

Offset Well Case Study. *Recognizing the importance of all of the above, in the mid-1990s the core project team assemble and decide what inputs, outputs, outcome, and benefits were desired from a well's prospect, and priority of data and relevant information that would be collected, collated, and acquired to meet project needs. A template draft resulted that was then circulated, refined, agreed upon, and developed. Once agreed the project team worked to populate and generate the data and information into the offset well's report that resulted. That was then utilized by the project when/as required.*

To close, in this digital "big well's data" age, more than ever before can be captured, made readily accessible, and awaiting to be put to greater use than in the past, e.g., *an offset data analysis process should form the knowledge and experience platform to simplify data aggregation, preparation, access, and analysis through extracting what is evident and relevant from multiple technical sources, including well report databases, rig sensor files and surface parameters, downhole* log *files, technical documents, risk assessments, and problem databases that would exist.* Using modern processing platforms and machine-learning capabilities, subject-matter experts can quickly run analytics, search, and render the data needed into a compiled offset report to add project value and benefits.

Preplanning

The importance of preplanning is recognized to influence project value as illustrated in Fig. 7.10. Aspects to consider:

1. Have all key disciplines engaged to participate in sessions required?.
2. Facilitate each session: this assures key crucial and critical points are raised, lessons are captured and then translated and sustained throughout.
3. Continuously develop the process to deliver added improvements during all subsequent project phases for both current and future projects.

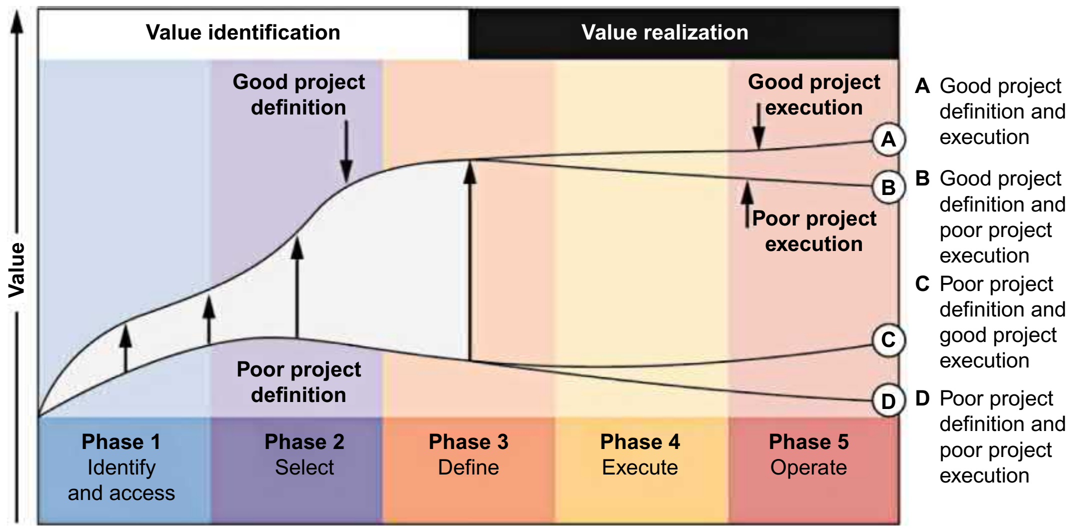


FIG. 7.10 Influence of front-end development on the value of a project. *Source: Hutchison and Wabeke 2006.*

4. Consider all work-related best practices that can benefit through a more focused multidisciplinary preplanning work process and flow approach.
5. Coaching and mentoring of individuals and teams in soft skills are critical to assure maximum value from within all team members.

Preplanning is viewed as crucial to identify important project issues early to enable a more effective and efficient workflow of later deliverable aspects. It can also eliminate within the project scope nonvalued work efforts, e.g., *multiple iterations and one-off reviews that often result* by assuring commonality and more central alignment. It affords better outcomes and benefits to result through a more structured, aligned, and formal approach at an early commencement stage and in compliance with project standards, systems, and controls meeting project needs.

The benefits of preplanning are to:

1. Accelerate a more effective closure of the assessment stage.
2. Reduce work-in-progress needed, with greater clarity, well-defined and fully understood goals, objective, roles, responsibilities, etc.
3. Enhance team alignment, more individual and team focus in greater depth and detail.
4. Reduce time and resource efforts (30%–50% has been stated).
5. Achieve a greater sense of individual and team accomplishment (team building). Embellish motivation, enthusiasm, and satisfaction that can help pull a new project together. (Norming, storming, reforming, performing.)
6. Allow and afford all the right people to be engaged and participate in all project aspects at an early stage to generate far more effective and efficient results.

Other aspects to consider:

1. Clarify well's purpose and intent, usually from geology/geophysics petroleum and/or the reservoir management stake holding perspectives.
2. Generate a list of required data and information required for preplanning, who will bring what, when, expectations, outputs, outcomes, and benefits to be comprehended.
3. Create and agree a process and scope-flow agenda including a close-out session for this stage.
4. General questions to consider at preplan stage gatherings are:
   - **(a)** How does the project fit with the company strategic objectives?
   - **(b)** What are the requirements for reservoir length of interval, zone, any geologic hazards such as faults, lost circulation zones, etc. to be avoided?
   - **(c)** What is the target shape? What are the high-level constraints on this?
   - **(d)** Vertical or deviated well? If deviated, where is the kick off point, both geologically and in hardware terms?
   - **(e)** Formation evaluation issues: early MWD, LWD, Wireline view, base case, and contingencies anticipated.
   - **(f)** Major project, location, well, specific operating hazards or constraints envisaged?
   - **(g)** What does the offset well data indicate in regards to key operating hazards/risks?
   - **(h)** Consider a SWOT analysis: Strength, Weakness, Threats, Opportunities envisaged?
   - **(i)** What are the error bars, levels of uncertainties, key risks? Prepare contingent options, options, and options!
   - **(j)** Scope, scope, scope, in required detail and depth.

Project Organization

Although organizational principles can remain the same, a single shape is fundamentally flawed for complex well projects. High-performing teams generally select their own members, build their own structure, define their own work processes to develop a high level of team spirit, ownership, and commitment to make things work whatever the limitations. Each team therefore is built to suit each specific set of project requirements.

Project Organization—General

Project organization aspects to consider are viewed as (but not limited to):

1. Identify, analyze, and review all job tasks and activities to implement the project.
2. Clearly define roles, responsibilities, accountability and authority and make sure clear lines of communication, processes, and protocols exist for everyone.
3. Distinguish between people involved and responsible within the project.
4. Establish competencies demanded for each and every project position and determine what is needed to bridge the gaps that will surface.
5. Determine and evaluate allocation of all resources.
6. Ensure everyone has similar workloads and areas of work are to a large extent independent.
7. Emphasize early the concept that different individuals from different departments and disciplines all have a part to play in the project, either individually or collectively.
8. Encourage more compliance and greater efforts to collaborate.

Organizational and central elements to be administered and controlled are viewed as (but not limited to) those presented in Table 7.2.

Deepwater programs and projects evidently require more people and more disciplines. This presents more organizational control issues that have to be well collaborated, coordinated, communicated, and continuously managed.

People involved also need to be self-starters and administered to assure greater understanding of their respective roles and responsibilities to deliver precision for work assigned.

TABLE 7.2 British UK BS6079 Standard of Project Management Process

1. Business/strategic objectives
2. Prioritizations
3. Plans
4. Organization
5. Controls
6. Deliverable and execution
7. Analysis (studies, investigation)
8. Feedback, change
9. Improvement, learning, change
10. Continuous improvement, change

Each individual and team to be afforded identified skills training and development of gaps in the following subject matters to the depth and detail deemed required, e.g.:

1. Deepwater geology and geophysics,
2. Deepwater drilling design, construction and operations,
3. Project management practices and principles,
4. Hazard/risk and uncertainty management,
5. Practical loss control leadership,
6. Investigative training such as latent cause analysis.

Deepwater Organizations

Deepwater organization and interaction of personnel assigned to each project is central to the effective and efficient transfer of project information so that well-reasoned understanding of all outcomes and benefits can result. The best practice requirement is that each company develops its own organizational project specific business structure as illustrated in Figs. 7.11 and 7.12. This can be simple to meet all needs or can often be over populated to the extent where "too many cooks shall simply spoil the broth."

Smaller to midsize operating companies shall likely organize and plan to outsource and rely far more on third-party and contractor specialists working for a team lead engineer and geologist with a consultant supervisor, an operations geologist, a contract and logistics

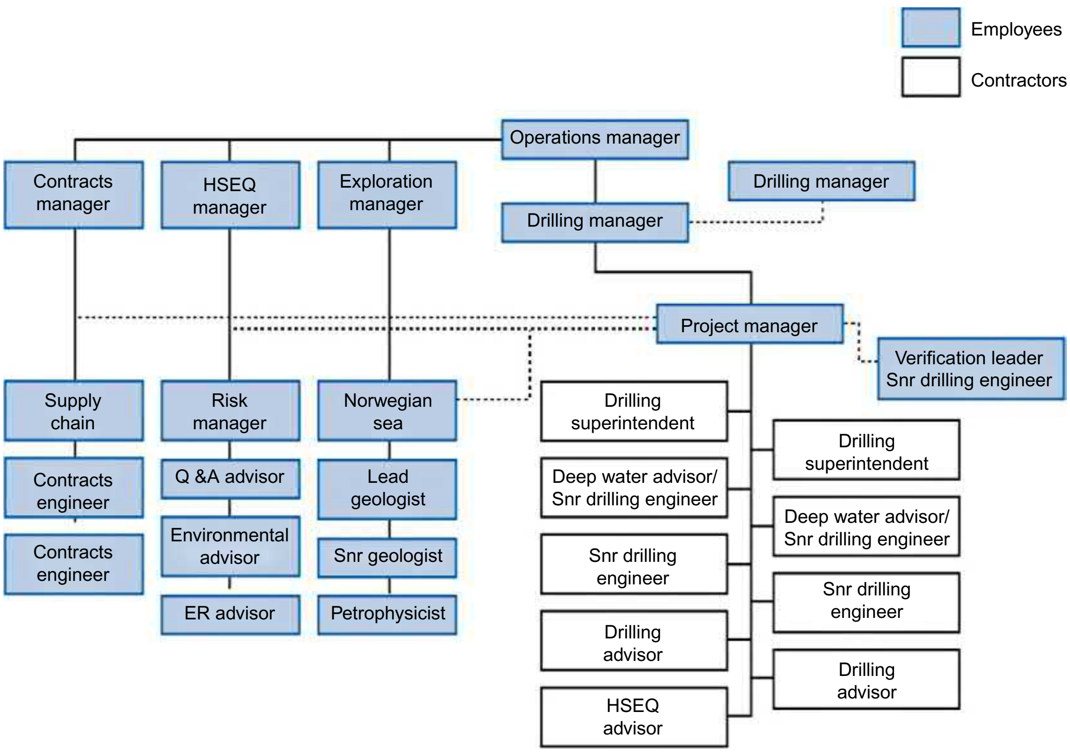


FIG. 7.11 Modified deepwater project organization chart. *Source: Kingdom Drilling training 2017.*

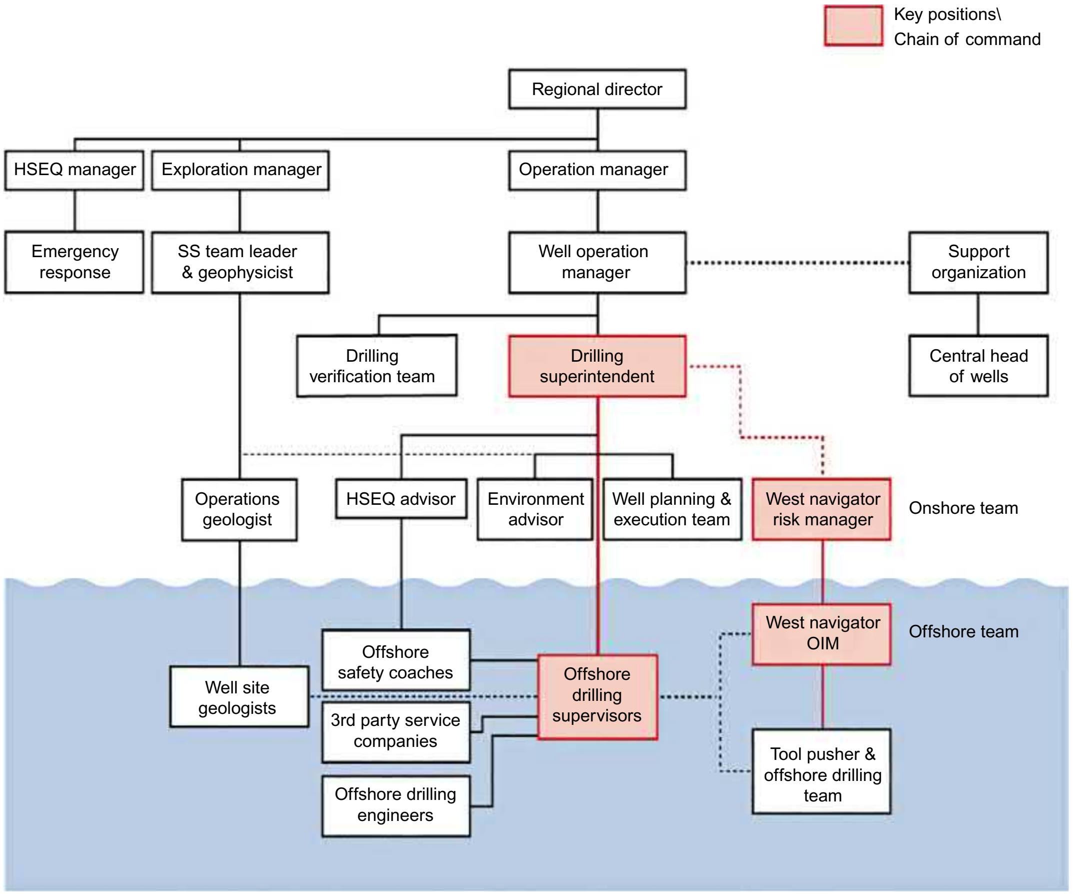


FIG. 7.12 Modified onshore/offshore deepwater project organization chart. *Source: Kingdom Drilling training 2017.*

person often indoctrinated into the operator's teams and ways of working. Larger operating companies' existing structure may be overpopulated in some ways but fall short in others.

What is important is that each organization structure meets the specific "fitness for purpose" needs and full compliance to each project's *work scope needs*. Typical organization structures would include geology/geophysics, well construction (which includes well engineering and drilling operations), petroleum, reservoir engineering, subsea, completion, well testing, well services and production (which includes production and facilities maintenance operations and planning).

Organizational Standards

If there are inadequate organizational standards, failing to organize and plan shall more likely result. Standardization is recommended for organizations where feasible to reduce people, process, products, time, and costs required, to prevent loss (increase profit), and add quality project value.

ORGANIZATIONAL LEARNING

How organizations learn is important. Please review and complete the organizational learning exercise as provided in Appendix 1 of this guide.

Project Delivery (Execution)

Key elements of project delivery during each stage of the process, in no particular order, are:

1. Find, hire, train, develop, and use the right people (internally or externally) and retain them.
2. Assure people fully comprehend and buy into assigned roles and responsibilities.
3. Develop individual and team objectives that are mutually agreeable.
4. Coordinate measure and demonstrate leadership control of all on-going activities.
5. Deliver outcomes and benefits according to goals metrics and targets as planned.
6. Provide and assure realistic contingencies exist for all key project delivery aspects.
7. Avoid making problems worse through ill-thought intellectual responses. Use reason.
8. When things do not go to plan, it is paramount that suitable contingency standards and recovery plans exist to follow and be adhered to for minimal loss to result.
9. To access, assess, and enable the use of adapted proven technology and systems.
10. Project team capable to truly assess risk and willing to change even the most fundamental parts of the plan, i.e., no matter how big or small.
11. Rig operating effectiveness and efficiency is one of the great challenges and critical obstacles that operators today face to assure significant added deepwater project value.
12. Collaborative teams are critical to delivering deep and ultradeepwater success, aiding to facilitate lessons learned, problem identification, resolution, and knowledge transfer.

Project Controls

1. Assign someone in the project to this specific role.
2. Measure progress (objectives, organization, planning, controls).
3. Take appropriate commendation and corrective actions (improve, add value).
4. Clearly define the standard and metrics, then measure and manage appropriate consequential events before they escalate.
5. Constantly review and reflect on objectives and if these are being met or not. If not take appropriate actions.

Post Well Review

Allocating sufficient time and resource to conduct a full and effective post well review simply aligns with basic fundamentals of a learning organization and should be viewed as a vital and important part of modern industry best practice. Purpose and intent of this phase is to:

1. Review and analyze all project key events, when significant project loss and waste results
2. Assure commendation and corrective actions (that require revision and updating) to be acted upon and completed (who, when, how, etc.).
3. Critically analyze stage gate process from start to end.

4. Review technical progress and value by conducting a detailed feedback survey with all project internal and external team members.
5. Conduct project close out meeting to review key feedback areas to be discussed and addressed.
6. Establish the improved baselines for the next project.

Note: The importance of maintaining common and well-aligned yet simple project standards, collaborative systems and methods, and training people in their application cannot be overstated enough. Otherwise key controlling metrics and specific operating activities shall not be delivered at a far higher standard required, e.g., substandard metrics, actions, documents, reports, reconciliation of loss, waste, cost data, etc. shall inevitably result.

Finally the close-out process must have full and aligned organizational ownership by all project teams. This final stage if done well should grow and evolve as people and organizations become more versed in value and benefits added, i.e., Safe Effective and Efficient wells.

DEEPWATER WELL DESIGN—ESSENTIALS

The design chapters are not definitive deepwater guides. They serve to raise pertinent issues in respect to deepwater-specific *planning, design, construction, and well life cycle application*. The review of deepwater well design processes, principles, best practices, and norms shall provides a consistent and sound well design basis, to include theoretical, practical discussion, and awareness of specific applications.

Any deviation from the well design, engineering, and operating processes/methodology described must seek respective program, project and/or drilling manager change approval.

Deepwater Well Design—Introduction

The majority of deepwater wells are vertical or low inclination stand-alone wells, installed from a single satellite or from an integral component part of a small modular subsea template of wells. Appreciating that future wells, particularly through development, shall become more complex to require a separate and more advanced guide.

Essential Design Differences

Design differences are essentially that deepwater wells are recurrently more complicated and challenging even when drilling the same formation sequence as shown in Figs. 7.13 and 7.15–7.18. It is concluded that different well designs result as water depth, operating conditions, and environments change. Other variant degrees of design risks and operating uncertainties exist versus the standard design norms, e.g., *standard equipment, tools, systems, and technologies are not suited to deepwater environments and operating conditions.*

Greater water depths can affect well design to require more casing strings, reduce operating windows, and stretch conventional practices to their limits where nonconventional and alternative technological design solutions and opertional methods are then demanded. Deepwater well design data aspects to consider as water and total depths increase and conditions change are:

1. Deep and ultradeep water and total depths (Figs. 7.15–7.18)
2. Seabed, subsurface, weather (wind waves, currents), and environmental conditions

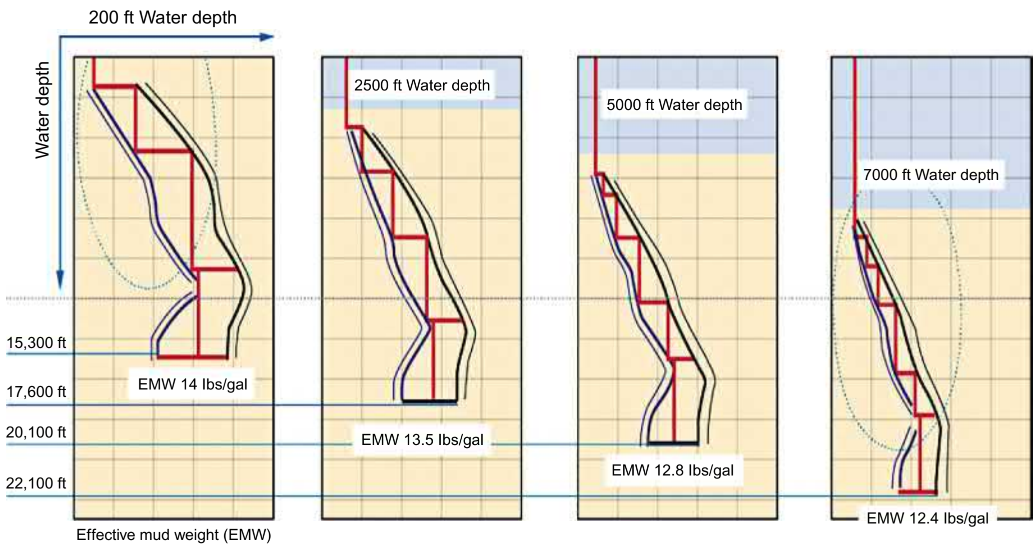


FIG. 7.13 Deepwater well design that can result in similar stratigraphy with > water depth. *Modified from training example, Kingdom Drilling 2018.*

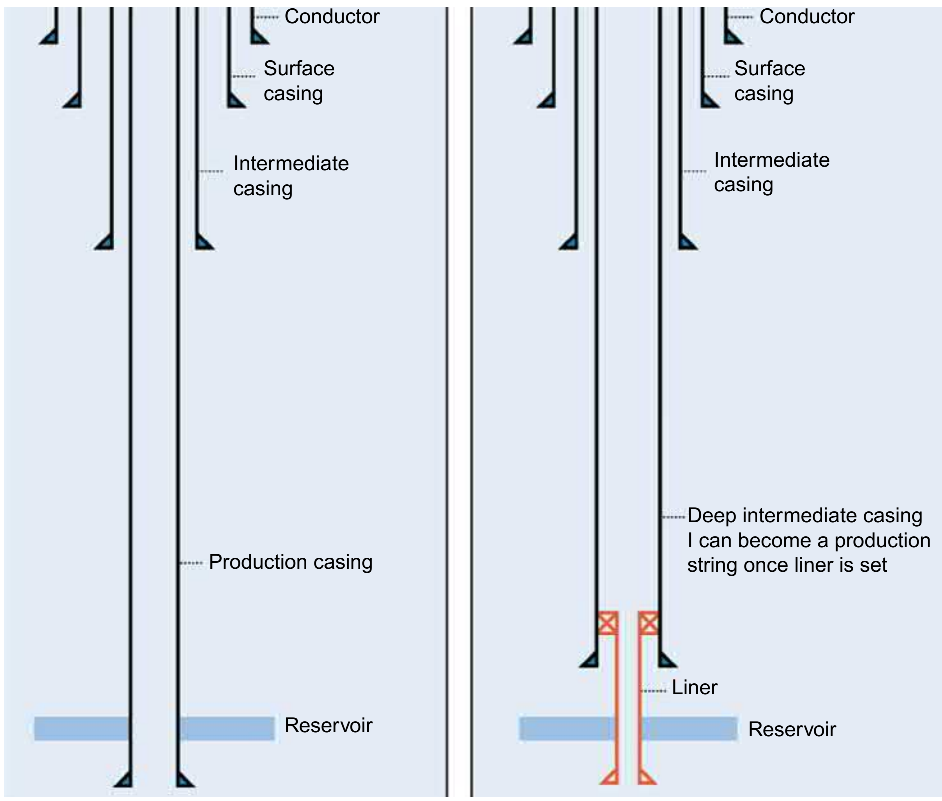


FIG. 7.14 Deepwater casing string categories, types. *Source: Kingdom Drilling training 2015.*

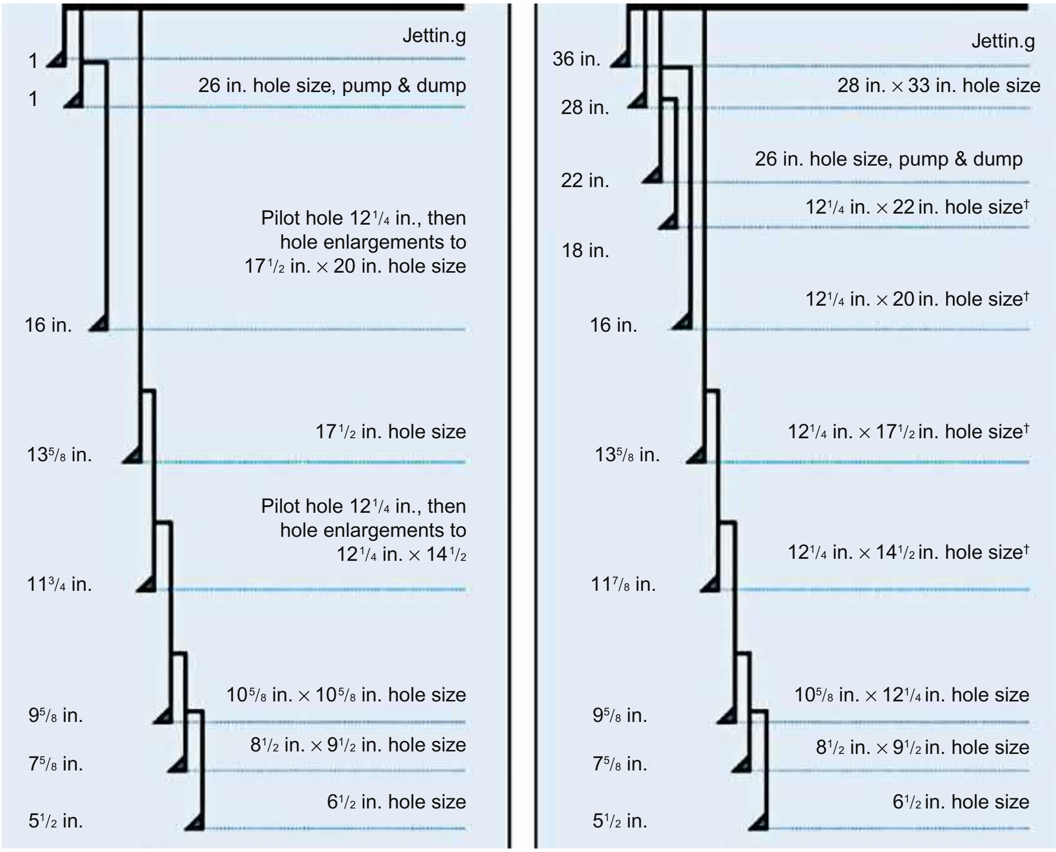


FIG. 7.15 Deepwater, i.e., 500–1000 m (1640–3281 ft) water depth (left illustration) and Ultradeepwater, i.e., >1500 m (4921 ft) water depth (right illustration) designs from Gulf of Mexico field development example. *Source: Kingdom Drilling training 2018.*

3. Rig selection, capabilities, constraints, well-specific operating limits
4. Narrower operating margins that often result (Figs. 7.15–7.18)
5. Increasing burst pressure at the wellhead and shoe
6. Higher mud weights and shut in pressures that add design and operating difficulties
7. Equipment limitations above the mudline, e.g., wellheads and drilling risers to consider
8. Other associated and specific factors to consider are:
  (a) Geology, geotechnical or geomechanical issues, e.g., above or below salt intervals
  (b) Down hole equipment and systems, e.g., liners, hangers, float, and shoe equipment
  (c) Well types, e.g., *Exploration (no test)*, *Appraisal (with test)*, *Development well*, etc.
  (d) Press and temperatures regimes risk and uncertainty
  (e) Well-specific casing, drilling fluid, and cementing programs
  (f) Normal versus tight tolerance casing designs
  (g) Wellhead, subsea BOP, and associated subsea equipment, e.g., remote-operating vehicles

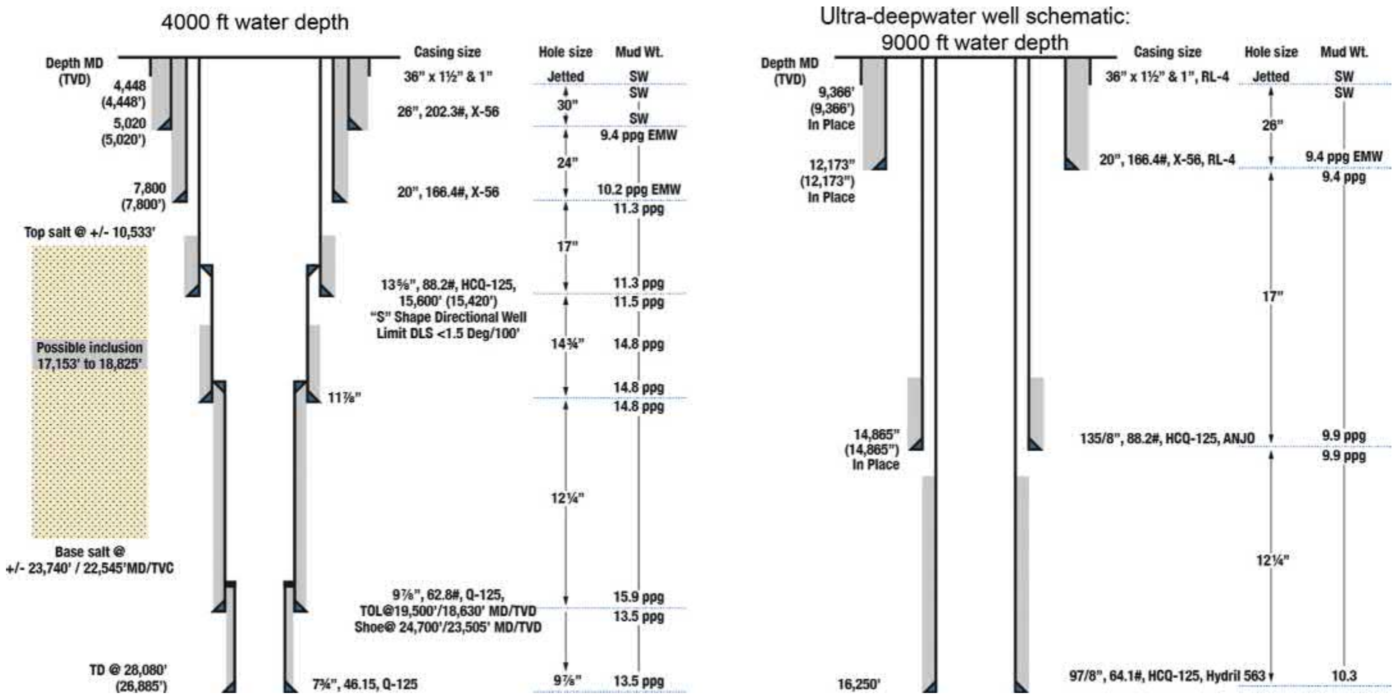


FIG. 7.16 Deep/ultradeep water depths. *Note*: complexity is this case more apparent in shallow WD. *Generic illustration reconstructed by Kingdom Drilling training, 2017.*

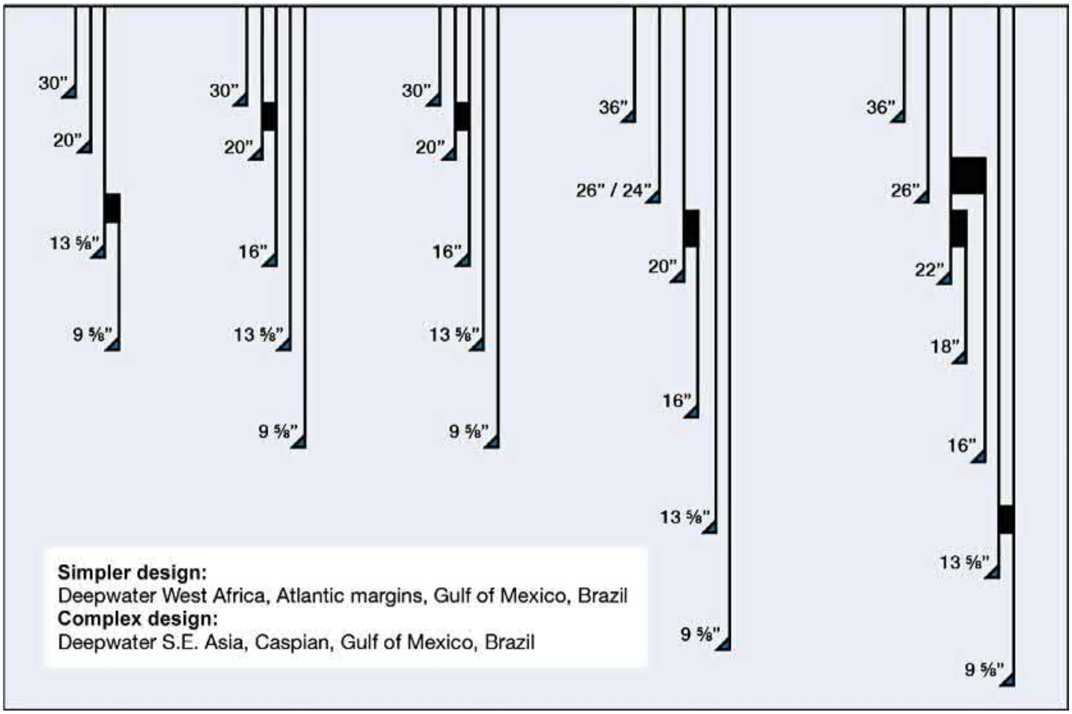


FIG. 7.17 Standard range of common deepwater well designs. *Source: Kingdom Drilling training 2017.*

(h) Standards, best practices compliance to be further developed
(i) Well suspension and abandonment that may have some gaps to address
(j) Greater skills set, training, and development gaps.

Deepwater Wells and Design Categories

Deepwater well designs presented in Figs. 7.14–7.18 can be categorized by type, e.g., *oil or gas, pressure regime, corrosive fluids, location,* etc. Pressure regimes generally classed as:

1. *Normally pressured wells*: low risk
2. *Abnormally pressured wells*: medium risk
3. *Complex wells*: high risk

Deepwater Well Design Methodology

Well design starts with a review of the geological well's proposal and relevant offset or well data obtained. Once a prospect is selected with location and target depths confirmed, the concept, base case, and contingent case design(s) process can begin. Initial exploration wells are designed to essentially gather and acquire data. Appraisal wells can have further design elements to accommodate a production test where wells may be retained for

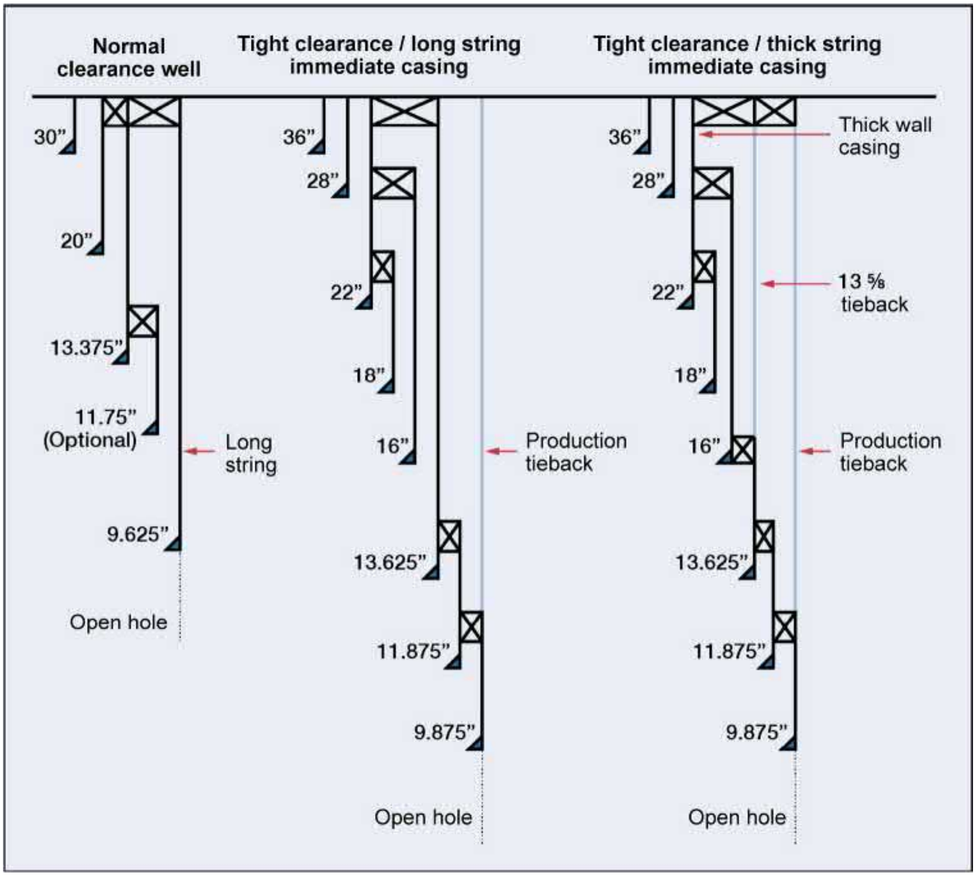


FIG. 7.18 Deepwater (more complex) well design examples. *Generic illustration reconstructed by Kingdom Drilling training, 2017.*

later development use. Development is required to meet a well's field life cycle in terms of design, integrity, and barrier containment, i.e., Too add maximum value and productivity during full field life at minimum costs and avoid well servicing, intervention, or workover requirements.

With increasingly more complex and challenging operating conditions, deepwater well designs require fine tuning of size, type, grade to accommodate the total number of base-case and contingent strings required in a very different way than a standard well's norm. Yet despite these challenges deepwater wells are being designed, constructed, and operated in water depths >10,000 ft (3048 m) and at hole depths >35,000 ft (10,668 m).

DEEPWATER STRING CLASSIFICATION AND TYPE

Deepwater casing string classification and categories are stated in Table 7.3 and Fig. 7.14.

TABLE 7.3 Deepwater Casing String Classification and Categories

Type	Description
Conductor	The first string jetted or drilled and cemented below the mud line, i.e., *foundation pipe and/or marine conductor*. These strings isolate unconsolidated formations and protect against hazards such as shallow flow water/gas/hydrates. Usually the string on which the casing low pressure well head housing is supported. Design of these strings is very case specific and more explicit than standard norms for engineers to consider
Surface	Depth and design provide blowout protection, isolate porous, permeable, and weak formation intervals and prevent lost circulation. The last string set before running the subsea BOP to assure adequate shoe strength to drill into higher pressure transition zones. In deviated wells, casing can isolate build sections to prevent formation instability or key seating resulting during. Typically cemented to the seafloor
Intermediate	Depth and design to isolate unstable wellbore sections, lost circulation zones, low pressure zones and production zones. Often set in the transition zone from normal to abnormal pressure. Top of cement top must isolate any pressured, permeable, and/or hydrocarbon zones. Some wells require multiple intermediate strings. Some can be production strings if a liner is run beneath them
Production	Casing used to isolate production zones and contain formation pressures in the event of a tubing leak. Design must also account for bullheading, injection, or simulation pressures if required. A good primary cement job is frequently critical for this string
Liner	A casing string, which does not extend back to the subsea wellhead, but instead is hung inside the lap of another casing. Liners are used to improve safe operating windows when drilling deeper, they also permit use of larger tubing above the liner top, and do not present a tension limitation for a rig. Liners can be intermediate or production strings. Typically cemented over their whole length

Purpose of Design and Casing Application

In deepwater, two central aspects of design and application exist as opposed to standard wells, i.e., structural and main well casing design. Notes:

- Conductor and surface casing strings are primarily structural. Design considerations and principles are very case specific and differ from those applicable to standard casing design.
- The Subsea BOP is generally run and installed after final surface string installation.
- Chronological sequence phases of intermediate, production string and liners are conducted with a weighted mud system, with the Subsea BOP and marine riser installed.

STRUCTURAL STRING DESIGN (CHAPTER 8)

In deepwater due to soft seabed and shallow conditions that normally exist, structural well design aspects for foundation, conductor and surface strings/liners must be considered separately on a well-by-well basis by the engineer assigned and in conjunction with other specialist wellhead, subsea BOP, and riser component analysis.

MAIN WELL CASING DESIGN (CHAPTER 9)

More traditional casing design results after the subsea BOP is installed, i.e., all intermediate production casings, liners, well test, and completion tubular strings. The engineer would conduct the preliminary design. If more complex analysis is required, the work may be outsourced to specialists. To assure complexity issues are fully addressed in a deepwater well's design, a range and variety of deepwater architectural well designs and constructs have emerged as shown in Figs. 7.15–7.18.

Deepwater Well Design and Integrity

Well Design and Integrity Considerations

Deepwater casing design, well and barrier integrity, as previously stated, should be viewed as no different to other offshore wells. The priority in deepwater is to assure that a robust fail-safe and integrated well design results to meet the required depths, pressure, temperature regimes, operating conditions, and environments for each life cycle through utilizing the most cost-effective number of casing strings.

The evident facts are that more primary and contingent strings are required for the structural top hole foundation, conductor, and surface casing (s) and liners, then supported by the main central well design notably as water depths, well and operating complexity, hazards/risks, or wellbore inclination increase. Within each well design, integrity and barrier, issues are verified for deepwater similar to any other offshore standard or best practices, in order to:

1. Require well integrity (designed strength, operability, and reliability)
2. Isolate problem or hazardous formations
3. Provide a suitable well integrity pressure-control system
4. Confine and contain drilling, completion, produced fluids, and solids
5. Act as a conduit for all operations to be conducted with tools of known dimensions, etc.
6. Provide structural wellhead support of subsequent strings, subsea BOP, Christmas tree, capping stack, intervention or workover equipment required during the well cycle.

All well design stages shall assure that *Maximum load concepts* are accommodated for each well's life cycle. The principle goal of each design is to assure that under no sets of operating circumstances, situation, or conditions shall a well design fail. Generic deepwater sequences of design work are viewed as:

1. Preliminary well concept design
2. Detailed well casing base case and contingent designs
3. Prepare well safety case (if required), in conjunction with required bridging documents, operational programs, in full compliance with well examination and all operating standards
4. Execute well program(s) and manage any design or construction changes required
5. Analyze outcomes and benefits to translate learning and sustain design and integrity improvements identified.

TABLE 7.4 Casing Design Process

Design Process	Description
Preliminary design	The preliminary design encompasses the data gathering and interpreting phase and the selection of casing sizes and shoe depths
Detailed design	The detailed design phase consists of selecting the pipe weights, grades, and connections for each casing string. The selection process consists of comparing pipe ratings with design loads and applying minimum acceptable safety standards, i.e., design factors. Detailed Design Criteria and Considerations are included in the following section and Chapters 8 and 9

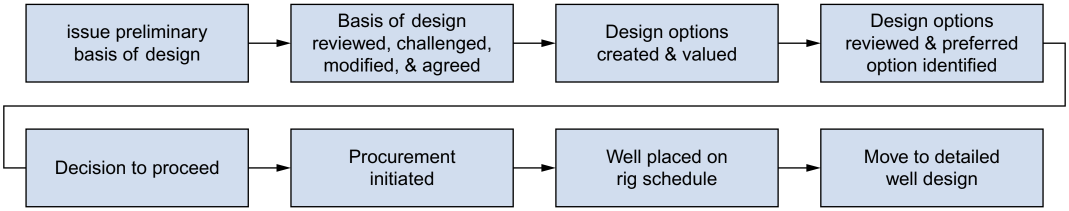


FIG. 7.19 Generic preliminary well design process. *From Kingdom Drilling training construct.*

Preliminary and Detailed Design

Deepwater preliminary and main design processes are outlined in Table 7.4, Fig. 7.19, sections and chapters that follow in this guide.

Deepwater Well Design and Construction Objectives

Objectives to be achieved and delivered are:

1. Add value by delivering safe, robust, effective, and efficient well design(s).
2. Integrate well design and barrier planning to assure reliability and integrity of each life cycle.
3. Assure compliant design, construct, and integrity standards meet best practice and guidelines.
4. Assure workable contingencies exist for critical design and operating aspects.
5. Eliminate any historical deepwater well's design problems, issues, and failures identified.
6. Assure people are competently trained, skilled, and developed with the skills set required to design, implement, and deliver each project as planned.
7. Assure any design learnings are translated and sustained to assist in future well design.

Results shall demonstrate a full understanding of all subsurface operating conditions and environments that exist through each life cycle, as each well is specifically designed, standardized, yet affords assured quality to meet all requirements.

For example, interpretations of local geologic structure, geopressure, and formation strengths derived from regional, similar analogues, or seismic data often require a more conservative approach until wells are drilled and real and evident data obtained.

Chapters 8 and 9 that follow shall review the specific details and core aspects of deepwater structural and main well casing design.

REFERENCED STANDARDS

API RP 96 1st Edition March 2013, Deepwater Well Design and Construction.

API RP-2A-WSD. Recommended Practice for Planning, Designing and Constructing Offshore Platforms—Working Stress Design. Rev. 21. October 2007.

Den Norske Veritas. Recommended Practice, DNV-RP-E303. Geotechnical design and installation of suction anchors in clay. October 2005.

IADC Deepwater well control guidelines 1st Edition, 1998 with 2000 supplements.

IADC Deepwater well control guidelines 2nd Edition, 2015.

Well Integrity in drilling and well operations, Norsok Standard D-010, Rev. 4, June 2013.

SPECIFIC REFERENCES

Aird, Peter, and F. Stene. Frontier deepwater exploration in the Norwegian Sea. SPE/IADC Conference, New Orleans. February 2000.

Aird, Peter. Deepwater well design overview. March 8, 2001. Kingdom Drilling, Rev. 1.0.

Bouska, R., C. Jeffery, D. Ramnarace, National Oil Well Varco; C. Brinkman, J. Jorgense, S. Vasylyev, Shell Oil. An Alternative Systems Approach to the Successful Execution of a Deepwater Program. IADC/SPE. March 2014.

Cunha, J.C. Innovative Design for Deepwater Exploratory wells. IADC/SPE. March 2004.

Dribus, John, Global Geoscience Advisor, Schlumberger. Integrating New Seismic Technology and Regional Basin Geology Now a Must. JPT, October 2012.

Hinkel, R.M., G.S. Bush and R.A. Bell, Unocal. Improving Drilling Performance Through Continuous Operations – A World-Wide Study. SPE/IADC 1994.

Luiz, J.C., Alberto S. Rocha, P. Junqueira and J.L. Roque, Petrobras. Overcoming Deep and Ultra Deep Drilling Challenges. OTC Houston, May, 2003.

Rheaume, G.T. Drilling a Deepwater Wildcat off the North Coast of Brazil: A Case Study. BP PLC, OTC 17970, May 2006.

Sparkes, B.M., J.S. Wellings and G.T. Rheaume, BP, plc. Drilling a Deepwater Well off the North Coast of Brazil: A case study. OTC, May 2006.

Thorogood, John L., Michael D. Jackson and Ole Henning Thorsen. Delivering world class exploration drilling – Integration of design, planning and execution. BP Amoco Norge UA. IADC/SPE, 59205 February 2000.

Vallejo, Victor G., Aciel Olivares, Octavio Saavedra, Pemex; Juan R. Lopez, Manuel E. Torres, Schlumberger. Drilling Evolution of the Ultra Deepwater Drilling Campaign in Mexico, Perdido Fold Belt. OTC-25030, March 2014.

Watson, P.A., A.W. Lyoho, R.A. Meize and J.R. Kunning, SPE, Andarko Petroleum Corp. Management Issues and Technical Experience in Deepwater and Ultra-Deepwater Drilling. OTC 17119, May 2005.

CHAPTER

8

Deepwater Structural Design

DEEPWATER STRUCTURAL STRING DESIGN

Introduction

Function

Deepwater structural design forms the foundation of the wellbore dictated by various loads pressures and conditions that dictate the well's configuration. The standard design of wellbore tubulars used and loads to be applied, e.g., *burst, collapse, axial and combined operating and service and wear and tear loads*, remains the same.

Structural design for deepwater wells must account for all *drilling and production* life cycle loads imposed in *static and cyclic* modes. Operational loads driving *drilling* structural casing design are *lateral (shear)* force, *axial* load, and *bending* moments.

Production well and field life cycle loads then need to be determined to conclude the stress concentration factors and spectral loads applied to evaluate fatigue life and other aspects of the well's operating systems, e.g., *wear, annular pressure volume, temperature effects as appropriate.*

Design Method

Deepwater standards recommend a simple design practice method as outlined in API RP 2A-WSD, 22nd Ed., Nov 2014, for structural piles as used in offshore platform design. This approach analyzes structural strings by assuming a point of fixity below the mud line to calculate a bending moment, assuming no soil interaction with the tubulars installed.

In new methods used, the structural string design is treated as a beam column with the soil replaced by a series of nonlinear spring-type mechanisms. The axial and tensional stresses are determined based on the operational loads, e.g., *shear, moment*, *and axial* imposed at the flex joint of the subsea BOP system. The system is generally modeled as a pile with ID, equivalent OD, heights and buoyant weights, using the pile analysis software program. The soil pipe interaction is determined using specific or a range of *P-Y* determined and evaluated soil data as outlined in this chapter.

Deepwater structural design varies in difference from conventional shallow offshore wells since stress levels are significantly greater, *even with the same rig type*. All structural designs must determine and evaluate all calculated critical loads imparted by the metocean, operational and situational effects, to marine riser, subsea BOP, wellhead, and well structural components.

https://doi.org/10.1016/B978-0-08-102282-5.00008-9

Structural Design Verification

The axial and bending stresses are calculated incrementally along the length of the pile. The stress should not exceed the yield strength of the pipe and the unit check, the sum of axial and bending stresses, should be one or less as shown in Eq. (8.1) and an example as shown. *Note*: This is more rigorous than considering bending stress in a structural string.

API AND AISC SPECIFICATION FOR THE DESIGN, FABRICATION, AND ERECTION OF STRUCTURAL STEEL FOR BUILDINGS

$$\frac{f_a}{(F_s * F_y)} + \frac{f_b}{(F_s * F_y)} \leq 1.0 \tag{8.1}$$

where:

- f_a = computed axial stress, psi f_b = computed bending stress, psi
- F_y = yield stress of steel, psi
- F_s = factor of safety, recommend a 0.8 for axial tension and 0.9 for bending.

Example calculation of API and AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings as stated in Eq. (8.1) is illustrated below to represent a deepwater well's *maximum load conditions.*

Data Input		
fa = computed axial stress, psi		
fb = computed bending stress, psi	$\frac{f_1}{F_{sa}+F_y} + \frac{f_b}{F_{sb}+F_y} \leq 1.0$	
Fy = yield stress of steel, psi		
Factor of safety, recommended	$F_{sa} := 0.8$	$F_{sb} := 0.9$
• 0.8 for axial tension (F_{sa}) • 0.9 for bending moment (F_{sb})	$M := 5500000 \cdot \text{ft} \cdot \text{lbf}$	$AL := 6000000 \cdot \text{lbf}$
M = Maximum bending moment, lbf*ft	$Od := 36 \cdot \text{in}$	$id := 33 \cdot \text{in}$
AL = Maximum axial loading lbf		
Od = External diameter of tubular, inches		
Id = Internal diameter of tubular, inches		
Maximum load conditions example		
Step #1: Calculate the 2nd moment of inertia of the tubular, *I*, in^4	$I := \frac{\pi}{64} \cdot (Od^4 - Id^4)$	$I = 24234.197\,\text{in}^4$
Step #2: Calculate the cross-sectional area of the tubular, *Csa*, ft^2	$Csa := \frac{\pi}{4} \cdot (Od^2 - Id^2)$	$Csa = 1.129\,\text{ft}^2$
Step #3: Calculate axial stress, f_a, psi.	$f_a := \frac{AL}{Csa}$	$f_a = 36905\,\text{psi}$
Step #4: Calculate bending stress, f_b, psi.	$f_b := \frac{M \cdot Od}{I}$	$f_b = 98043\,\text{psi}$
Step #5: Calculate combined stress on the tubular (S_s), with safety factors applied to ensure that S_s is less than 1.0.	$Ss := \frac{f_a}{0.8 \cdot f_a + X80} + \frac{f_b}{0.9 \cdot f_b + X80}$	$Ss = 0.92$

Structural Design Analysis

In summary, structural string design must consider the penetration below the mud line, the type of soil, the pipe wall thickness, diameter, length, material strength and installation method. Analysis performed must determine and evaluate the nonlinear behavior of the soils loads, strengths, and resulting load deflections of the structural pipe.

Structural Design Capacity

Structural design capacity is designed to maintain material stress levels within allowable limits as subjected by primary bending and axial loads imposed during well life cycle operations as illustrated in Fig. 8.1 and Table 8.1.

Note: Fatigue life and analysis are more complex issues to be understood and appreciated. These aspects and are not addressed in detail within this chapter and guide.

Axial Loads

Axial loading of structural pipe is the result of vertical loading at the flex joint, buoyed subsea BOP weight, buoyed wellhead, and casing weight.

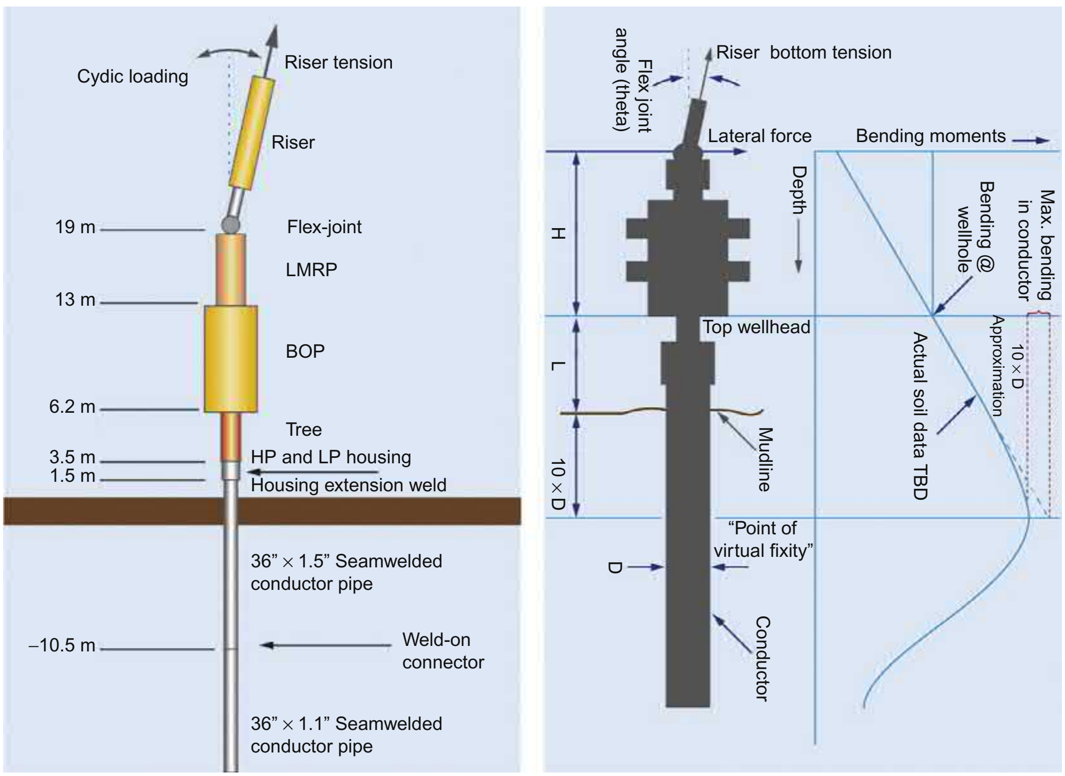


FIG. 8.1 Bending loads on a deepwater well. *Source: Kingdom Drilling (2018).*

TABLE 8.1 Key Factors Influencing Deepwater Axial Bending and Loading.

Factors Influencing Bending and Axial Loading	
Bending	Lateral loads at flex joint due to riser loads
	Wellhead and BOP stick up above the mud line (including subsea tree)
	Soil strength below the mudline
	BOP and wellhead angle (will effect vertical loading and bending)
	Production loads (fatigue and snag loads)
Axial loading	Vertical loading at flex joint due to riser loads
	BOP weight (buoyed)
	Wellhead and casing weight (buoyed)
	Casing(s), Subsea tree, Capping stack weights

Source: Kingdom Drilling Training 2006.

Bending Loads

Bending is the result of lateral loading at the flex joint due to riser loads, wellhead, and BOP stick up above the mudline, soil strength below the mudline, weight of the BOP, and angle of the BOP and wellhead. Note: Bending strength contribution by the inner string is usually relatively small. Bending loads applied are a function of the conditions imposed by the height of the lower marine riser package (LMRP), flex joint above the mudline, riser tension, and maximum angle of the flex joint.

The depth below the mudline at which combined stress is at a maximum is usually located at the maximum bending moment, Ref. Fig. 8.1.

Lateral

Lateral loading is the result of bending at the flex joint. In the real world as component parts are not truly vertical, vertical (axial) and horizontal (lateral or shear) force components shall exist at the top of the subsea BOP. *Note*: Riser tension with rig offset is the main cause of lateral or horizontal loading of the structural casings. Contributing factors are deep water, severe weather, currents, and poor station keeping and/or riser management.

Lateral loads are obtained via the riser analysis and based on the operating conditions and specifics of each vessel.

Marine Riser Bending Loads

Bending results from loads imposed by the rig and the marine riser system. In view of this, a riser and structural string design analysis shall consider the following factors*: Metocean conditions*, *vessel offsets*, *BOP stack*, *and mud weight*. Aspects that affect structural bending loads include:

1. Bending moment and shear force increase below the mudline, reaching a maximum at a distance of 5 to 30 pipe diameters below the mudline, depending on soil strengths. The bending moment and shear force decrease below the maximum point and reduce to zero at depth (Fig. 8.1).

2. The higher the well head housings stick up above the seafloor affects flex joint height to result in higher bending moments there.
3. Wellheads, structural casing, conductor, pipe body, and casing connectors must be designed to accommodate bending moments and shear forces that exist.
4. Wellhead and structural casing deflection when the drilling riser is removed.
5. Added bending loads that can result if a capping stack is installed. *Note*: This may be the highest free standing load to consider.
6. The maximum mud weight expected in the well as this affects riser tension.
7. The type of rig-positioning system, i.e., *dynamically positioned or moored* and water depth, as these both affect the maximum angle of the flex joint.
8. Any deep currents near the mudline that can increase bending moment loads.
9. Soil types and effects on wellhead deflection and bending moment loads.

Notes: The maximum load scenario is generally a failure to disconnect the lower marine riser package (LMRP) with the loss of station keeping, e.g., *drive-off under power, or drift-off* under environmental loads. In view of this, a riser failure analysis (also known as a weak point analysis) is conducted by both operator and drilling contractor to assess potential well integrity risks, operating failure loss, and potential opportunities to mitigate maximum loads.

Wellhead, BOP Stick Up, and Inclination

The height from the seafloor to the flex joint as stated impacts bending imparted to the structural conductor and casing(s).

STICK UP

The total height of the high-pressure wellhead housing stick-up design above the seafloor for a standalone well is *as low as operationally practicable.* Ideally ± (10–12 ft) 3–3.7 m, ± (18 in) 0.5 m to accommodate ROV and well-life-cycle work required.

WELLHEAD AND SUBSEA INCLINATION

Despite API RP 16Q establishing a drilling limit of 2 degrees for the flex-joint situated above the subsea BOP, best-operating practice final inclination is desired at less than <0.5–1.0 degrees off vertical, to minimize operational wear and/or damage risk to wellhead, subsea BOP, and marine riser components resulting from notably drill pipe rotation. *Note*: All other design loads imposed on the structural pipe due to inclination must be considered.

Soil Strengths Below the Seafloor

Soils offer less resistance to lateral deflection that may result in bending the structural pipe. Under a lateral load, soils, especially clays, behave as a plastic material where there is little relationship of pipe lateral deformation and soil resistance. Lateral soil resistance-deflection *p-y* curves as illustrated in figures shown are used in the structural design model to predict the behavior of pipe under various load conditions and type of soils. Generic soil, low, mid, and upper range strengths, shall be developed for each deepwater region.

MODELING SOIL RESISTANCE TO LATERAL LOADS AND BENDING

Modeling soil and pipe interaction is important in designing structural casings. The three factors most influencing *p-y* curves are ***soil properties***, ***pipe diameter***, and ***nature of loading***.

Several methods have been published in technical literature by many authors to analyze piles (pipe) loaded by lateral force to prove the versatility and application theory that finite difference methods can be used to evaluate highly nonlinear soil-pile interactions.

As a considerable volume of soil is removed during jetting, the loss of surrounding soil if excessively jetted can have a significant effect on the soil response. Best-practice, local knowledge, and experience must apply and plays an important part.

The p-y method is applied through proprietary software modeling by specialist companies to accurately model casing bending and soil interface issues. *Note: Maximum load bending results at a predefined depth below the seafloor as shown in* Fig. 8.2.

The physical defection of soil resistance p_j is shown in Fig. 8.3C. This represents an installed pile (*that assumes no bending so that soil stresses and depth x_i are uniformly distributed*) and a thin slice of soil at some depth x_i (Fig. 8.3A) below the mud line. If the pile is loaded laterally with a deflection y_i at depth x_i, the soil stresses could yield the soil resistance with increasing deflection to a point where p would reach an evident and limiting value (Fig. 8.3B and C). *Note*: Soil strengths vary with depth.

In view of nonlinearities, numerical methods are utilized to obtain suitable results. The pile is subdivided into a series of increments (Fig. 8.4) with equations formed with solutions to proceed as illustrated in Fig. 8.5.

Fig. 8.5A shows a pile subject to lateral load.

Fig. 8.5B presents a family of *p-y* curves. The dashed line illustrates the deflection of the pile either assumed or computed based on estimated soil strength.

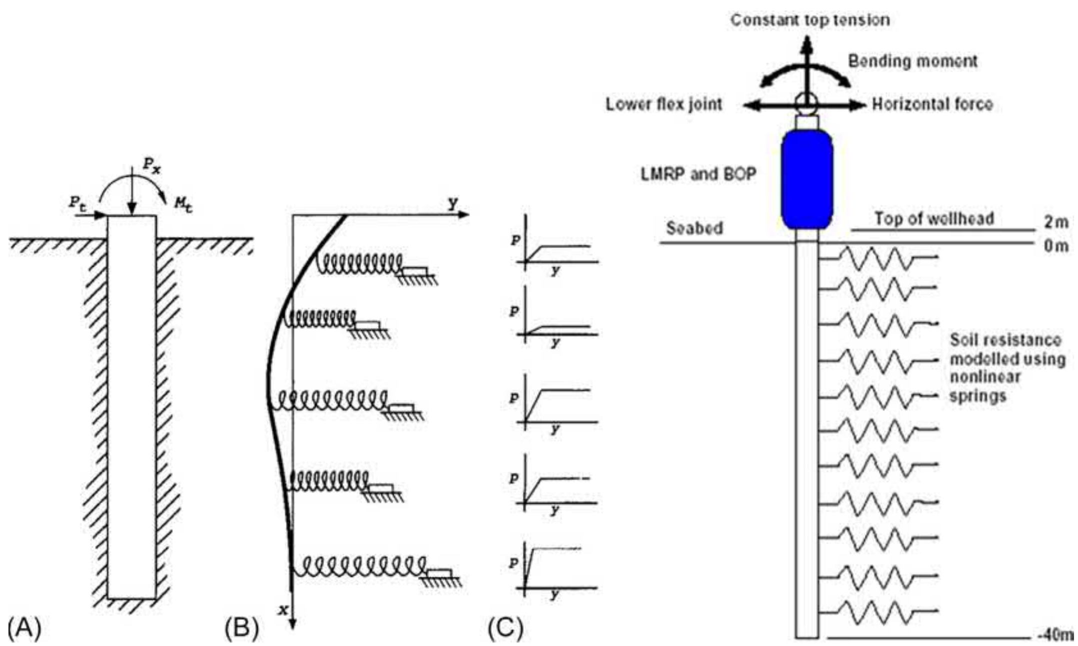


FIG. 8.2 Soil pipe interaction illustration using a range of specific *P-Y* soil data. *Source: Kingdom Drilling modified Deepwater casing design manual, 2014.*

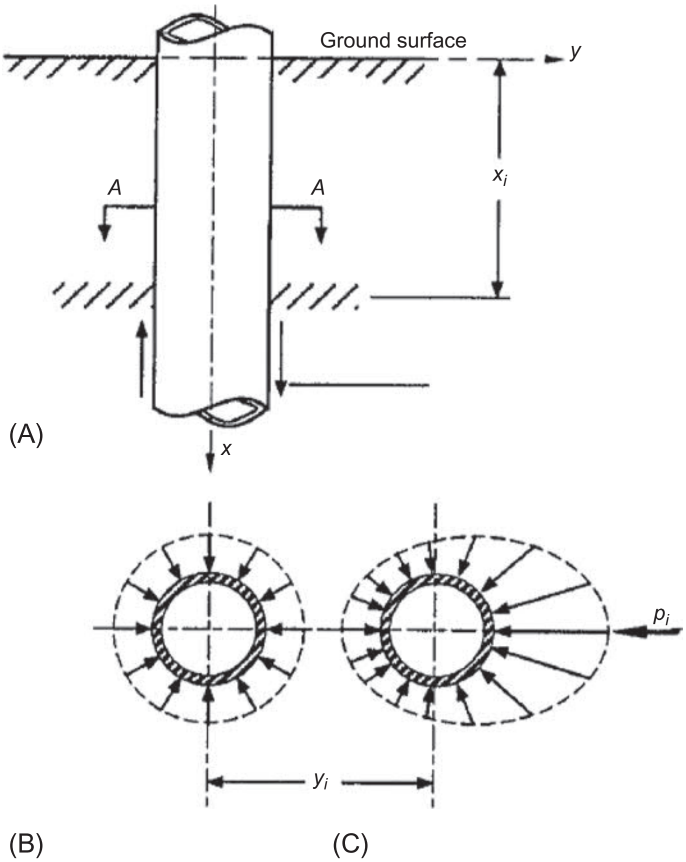


FIG. 8.3 Definition of p & y as related to the response of an installed pipe to lateral loading. *Source: Kingdom Drilling modified Deepwater casing design manual, 2014.*

Fig. 8.5C shows the upper p-y curve enlarged with the pile deflection at that depth represented by the vertical dashed line.

Fig. 8.5D shows the value of E_s plotted as a function of x. After deflection is computed different equations are computed to evaluate rotation, bending moment, shear, and soil reactions as a function of x.

In summary if p-y curves are available, a computed solution to a given deepwater structural installation problem is obtained with little difficulty.

Load-Bearing Capacity of Clay

Studies conducted in the US Gulf of Mexico by the Navy derived load-bearing capacity in standard clay as having strengths of *60–80 psf (lbs per square foot) at the seafloor*. Support capacity then increases each linear foot of penetration as per bounded conditions shown in Fig. 8.6.

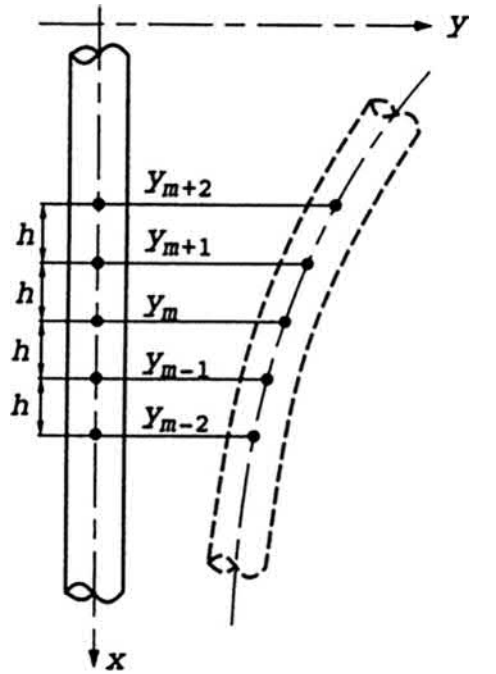


FIG. 8.4 Representation of a deflected pile. *Source: Kingdom Drilling modified Deepwater casing design manual, 2014.*

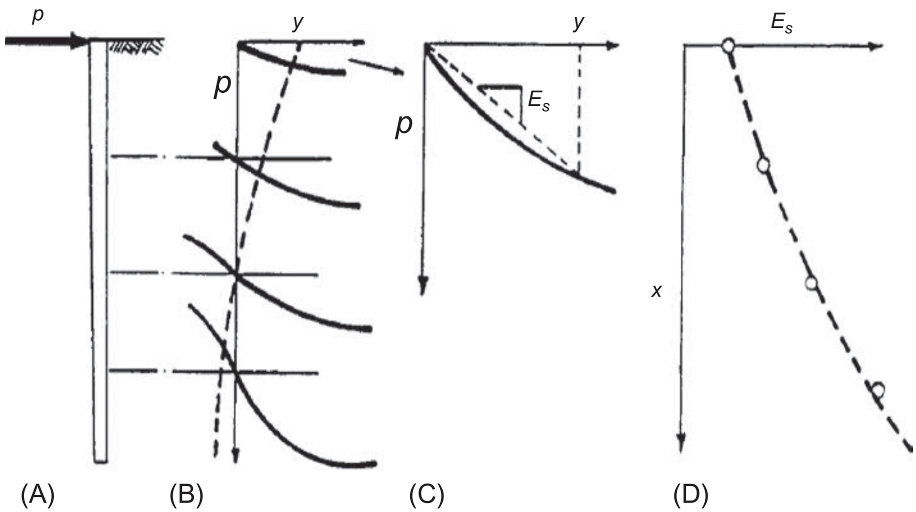


FIG. 8.5 Illustrated representation of solving for response of a laterally loaded pile. *Source: Kingdom Drilling modified Deepwater casing design manual, 2014.*

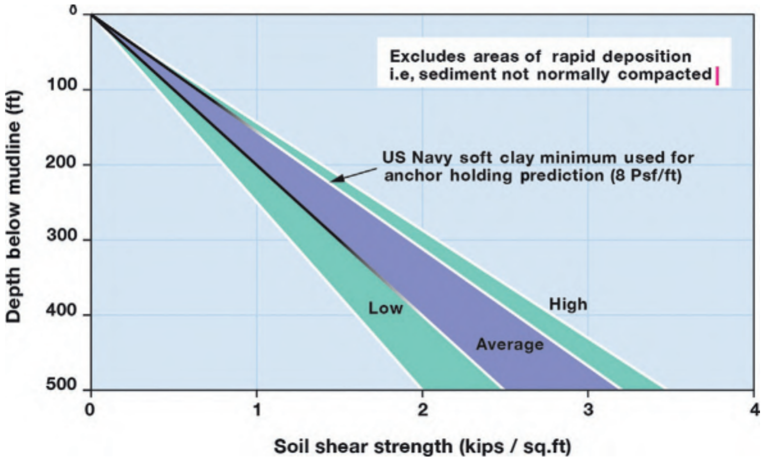


FIG. 8.6 Typical Gulf of Mexico soil shear strengths. *Source: Kingdom Drilling training 2018.*

Note: Deeper water depths can result in weaker and less or stronger and greater support capabilities to be accounted within each individual design evaluation.

Installation Methods—Design Impact

Installation Methods

As installation methods impact the axial capacity of all structural strings, the most common deepwater method is jetting a conductor string, penetrating through soft clay sediments below the seafloor to the shallow depth settings required. If hard ground, glacial till, debris, gravel beds, or nonclay particle grain sizes are present, structural strings are installed in a standard norm, i.e., through drilling a wellbore, running the string and grouting (cementing) it from set depth to the seafloor.

Of all methods utilized, jetting causes the greatest degradation in axial capacity. If the structural pipe is not designed or is not installed properly, the potential for the structure to slump and fail under axial and bending loads is greatly increased as many evident documented cases have proved.

Axial capacity is consequently highly dependent on the soil strength, type, interval length, soil constituent nature, the disturbance of each soil interval, and best practices used as each string is jetted to depth required.

Soil disturbance depends on *the rate of jetting (pumping), the degree to which the connector's OD exceeds the casing OD, the amount of reciprocations conducted, and the time allowed for the soil to recover from the jetting operation. Note*: Flush connectors can greatly improve skin friction development due to less geometrical disturbance (as pipe diameter is flush with no protrusions to disturb the soil).

The jetted pipe design criteria once at depth must initially support its own buoyant weight and in part the weight of the inner drillstring bottomhole assembly until it is deemed operationally safe to be released.

Note: Mud mats (hydrate deflector) support a *small component part of the axial support weight required* as illustrated in the example as shown to serve little purpose. The evident purpose of mud mats or hydrate deflectors used in many cases to be questioned as to what exactly is the purpose, outcome and benefit intent.

Length of mud mat (Ql (ft))	$Ql := 12 \cdot \text{ft}$	$Qw := 12 \cdot \text{ft}$
Width of mud mat (Qw (ft))	$Ss := 80 \cdot \frac{\text{lb}}{\text{ft}^2}$	
Soil strength at mud line (Ss (lb/ft^2))		
Step # 1; Calculate the approximate axial support capacity of the mud mat, Q, Klbs	$Q := (Ql \cdot Qw) \cdot (Ss \cdot 2.5)$	$Q = 28.8\,\text{Klbs}$
Length of mud mat (Ql (m))	$Ql := 4\,\text{m}$	$Qw := 4\,\text{m}$
Width of mud mat (Qw (m))	$Ss := 400 \cdot \frac{\text{kg}}{\text{m}^2}$	
Soil strength at mud line (Ss (kg/m^2))		
Step # 2: Calculate the approximate axial support capacity of the mud mat, Q, tonne	$Q := (Ql \cdot Qw) \cdot (Ss \cdot 2.5)$	$Q = 16\,\text{tonne}$

Once jetting delivers pipe to the setting depth. The soil shall quickly reconsolidate its strength around the pipe notably in the first 2–4 h. The jetted pipe shall likely support its own weight if not immediately then certainly after a few hours of soaking (to be determined at the end of each jetting application).

Note: The full weight of the surface casing string must also be accommodated by the jetted pipe (by design) a few days later after installation. When axial loads meet these principal needs, the waiting-on-cement time for mechanical strength development of the surface casing is eliminated due to the evident facts that the axial loads provided by the soil around the pipe is capable to support all structural axial well loads at this time.

After the cemented surface string compressive strength is achieved (assuming cement to the seafloor), all subsequent critical axial and bending loads (from all casings/liners, subsea BOPs, capping stack) for the remainder of the well are now capably supported through the combined and integrated capacity of the structural strings. The load that a given string can carry depends not only on its axial resistance, but also the degree of which the load is transferred to the surrounding formations, installation method, and best practices executed. *Note*: Refer to API 2A-WSD.

If a structural risk is raised regarding string capacity, then after running the subsea BOPs and before drilling ahead, a "slump" subsidence test can be considered. This test can afford imposed test loads by using the subsea BOP stack weight available and reducing riser tension to meet loads required.

Wellhead and Axial Structural String Evaluation

The axial capacity of a structural foundation or conductor string can be simply estimated by assuming the skin friction (adhesion) is equal to a linear soil shear strength integrated along its length as shown in Eq. (8.2). *Note*: End-bearing load is not included.

$L1 := 2\,\mathrm{m}$

$L2 := 84\,\mathrm{m}$

$z := 0$

$cs := 8\,\dfrac{\mathrm{lb}}{\mathrm{in}^2}$

$OD := 30\ \mathrm{in}$

$\int_{2\mathrm{m}}^{84\mathrm{m}} cs\,\mathrm{d}z = \left(4.612\cdot 10^5\right)\dfrac{\mathrm{kg}}{\mathrm{m}}$

$Q := 0.5\cdot\left(\pi\cdot OD\cdot\int_{L1}^{L2} cs\,\mathrm{d}z\right)$

$Q = 552$ tonne

$Q2 := 0.25\cdot\left(\pi\cdot OD\cdot\int_{L1}^{L2} cs\,\mathrm{d}z\right)$

$Q2 = 276$ tonne

Note: Reduction factor b depends on soil disturbance during installation*, e.g., for jetting, factors for a highly disturbed soil, if viewed as low taken as 0.25* (Beck and Jackson, 1991). If minimal disturbance results, reduction factor can be used up to 0.5 (Beck and Jackson, 1991). After installation, soil reconsolidation strength in clay can restore and increase to almost unity, as it heals.

AXIAL CAPACITY OF STRUCTURAL CASING ESTIMATION

$$Q = b * \pi * OD * \int_{L1}^{L2} cs\,dz \tag{8.2}$$

where:

- A = structural string axial capacity (tonne)
- b = reduction factor dependent upon soil disturbance.
- OD = outside diameter of the tube, in.
- $L2$ = length of structural string below the first point of resistance FPR ($L1$) below the seafloor
- cs = soil shear strength, $\mathrm{lb/in}^2$

STRUCTURAL DESIGN CRITERIA

Bending Stress

The stress in the structural casing due to maximum load bending is calculated by applying Eq. (8.3).

STRESS IN STRUCTURAL CASING DUE TO BENDING

$$f_b = \frac{M * OD * 6}{I} \tag{8.3}$$

where:

- f_b = bending stress, psi
- M = bending moment, ft-lb
- OD = Outside diameter of the tube, in
- I = moment of inertia of the tube, in^4

Axial Stress

Once the wells axial load is calculated, the axial stress (Eq. 8.4) in the structural casing due to the axial load is then determined.

AXIAL STRESS IN STRUCTURAL CASING DUE TO AXIAL LOAD

$$f_a = \frac{P_a}{A} \tag{8.4}$$

where:

- f_a = axial stress in the tube, psi
- P_a = axial load in casing, lb.
- A = cross-sectional area of the tube (nominal ID), in^2

Engineering Line Properties of Line Pipe

Burst

The Barlow equation in API Specification 5C3, for the burst of a tube, is dependent on the wall thickness, wall thickness tolerance, yield strength, and diameter of the tube. *Note:*For casing, API Specification 5CT allows a 12.5 percent wall thickness tolerance. The wall thickness tolerance specified in API Specification 5L for line pipe is dependent on the size of the pipe, type manufacture (seamless or welded), and grade.

For 20 in. and larger line pipe, the API wall thickness tolerance is shown in Table 8.2.

API Specification 5L specifies the tensile requirements for line pipe (yield and ultimate strength). The standard line pipe grades and yield strengths are also shown in Table 8.3

MINIMUM YIELD STRESS

$$P_i = T * \left(2 * Yp * \frac{t}{\mathrm{OD}}\right) \tag{8.5}$$

where:

- P_i = minimum internal pressure (burst), psi
- T = minimum wall thickness tolerance reduction factor
- Y_p = minimum yield stress, psi
- t = nominal wall thickness
- OD = Outside diameter of the tube, in

TABLE 8.2 API Line Pipe Tolerances

API Line Pipe Tolerances		
Outside diameter and type of pipe	Wall thickness tolerance percent	
	Grade A, B, A25	Grade X42 to X80
20″ and larger welded	−10%	−8%
20″ and larger seamless	−12.5%	−10%

TABLE 8.3 API Line Pipe Grades

Grade	Yield Strength (psi)
A25	25,000
A	30,000
B	35,000
X42	42,000
X46	46,000
X52	52,000
X56	56,000
X60	60,000
X65	65,000
X70	70,000
X80	80,000

Step # 1 Calculate the minimum internal yield pressure (burst) for the information as provided above

$$Pi = \begin{bmatrix} 3080 \\ 3850 \\ 6160 \end{bmatrix} \text{psi}$$

An example of structural pipe burst evaluation pressure for various pipe wall thicknesses used is illustrated below.

$$To = (-10.0)\% \quad Wt = \begin{bmatrix} 0.5 \\ 0.625 \\ 1 \end{bmatrix} \bullet \text{in} \quad Od = 20 \bullet \text{in} \quad Pi = (1 - To) \bullet \left(2 \bullet X56 \bullet \frac{Wt}{Od} \right)$$

Collapse

Collapse rating of line pipe is calculated from equations included in API Bulletin 5C3.

Majority of line pipe in deepwater structural design is of a larger OD and wall thickness (t). The OD/t ratio is therefore high with casing strings and usually in an elastic or transition collapse region as illustrated in Fig. 8.7.

Five Key point of pipe collapse are:

- Thinner wall (higher OD/t) line pipe falling in the elastic collapse pressure region will have a rating, which is not dependent on the minimum yield strength of t steel.

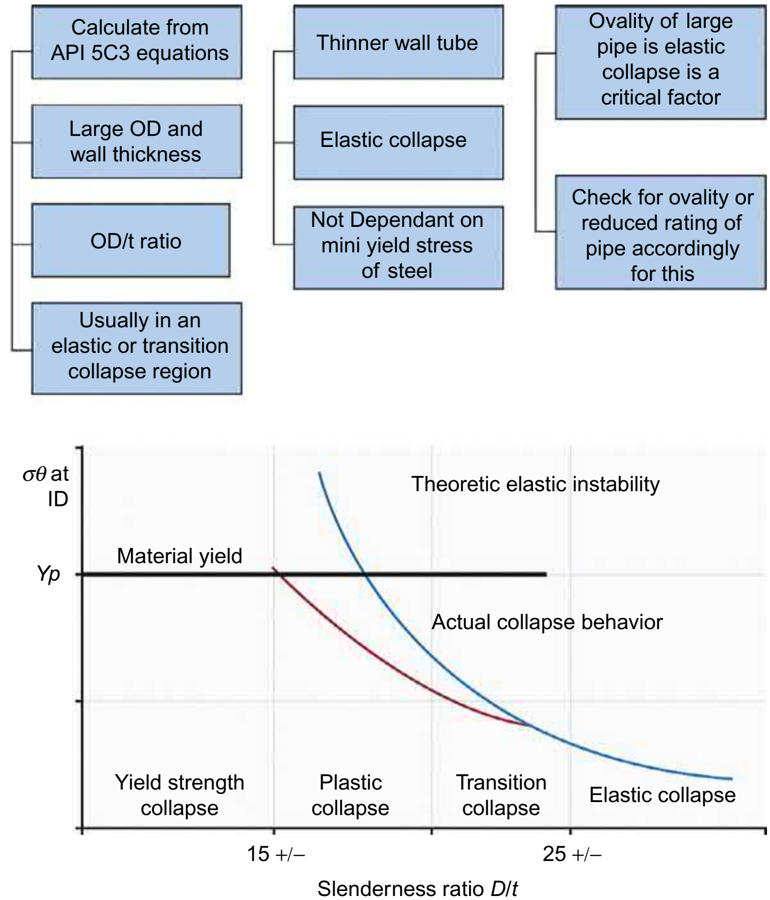


FIG. 8.7 Elastic and transitional collapse. *Source: Kingdom Drilling.*

- Ovality of large line pipe in the elastic collapse pressure region is a critical factor.
- Line pipe must be checked for ovality as collapse rating of the pipe is reduced should poor ovality exist.
- All ratings are adjusted due to axial tension, which will impact the applicable collapse region of line pipe.
- The collapse rating of a tube is normally calculated based on the nominal wall thickness of the tube.

Tension (+)/Compression (−)

The pipe body strength of line pipe is normally calculated by the product of the nominal pipe body cross-sectional area and the minimum yield strength of the steel. The compression rating of a tube is assumed to be the same as in tension.

Nominal wall thickness rather than minimum wall thickness is generally used to calculate line pipe tension/compression ratings.

Note: When conductor landing strings or surface strings are washed or circulated down to land within their respective wellhead housing, the axial stress in the string above the subsea wellhead components must be maintained positive, i.e., an upward tensional force should exist, to assure tubular pipes above the wellhead (at the seafloor) do not buckle.

If this is not maintained (note: particularly if vessel is heaving significantly and compensation is poor or ill afforded), pipe failure can result in significant operating loss to the project.

Foundation/Conductor Lengths

Design lengths to be installed are primarily driven from data available. If little evident data exist notably on first wells executed in a new basin or area, a bottom hole drilling assembly penetration test and/or in conjunction with a pilot hole (if planned) can be conducted to assess and obtain soil type and characteristics of the first ±100 m (328 ft) below the seafloor to determine optimal foundation and/or optimal conductor lengths.

Setting lengths, diameters, means, and methods are highly dependent on the shallow soil conditions and depositional environment present. Installations can range in deepwater from as short as a few meters of varying diameters (2–5 m (7–16 ft)) for *self-penetrating foundations pipes* to 8–15 m (26–49 ft) in length for conductor anchor node CAN type units that can range from 3 to 6 m (10–20 ft) in diameter are self-penetration and then pumped (suctioned) to depth, to more lengthy foundation pipes that can range from 36 to 42 in or more in pipe diameter and up to 20–30–50 m (66–98–164 ft) in length and installed in different ways. The key design issue is that each design is fit for purpose and fully compliant to meet intended installation and operational requirements.

In deepwater applications, jetted or drilled and cemented conductor pipe is the most commonly used method ranging from ±40–50 m (up to 164 ft) (as used in conjunction with a foundation, CAN unit, etc.) and up to ±80 m (262 ft) to 100 m (328 ft) in specific ultradeepwater environments. Again a one-suit solution does not fit all.

In summary, *subsurface deepwater structural design* solutions must be *individually assessed* to assure a *fit-for-purpose structural design* results.

Surface Casing Setting Depths

The primary structural surface casing design operational objective is to obtain a fracture gradient that affords the necessary operating window to enable drilling, casing, and cementing of the first intermediate casing at a safe design, operating and casing setting depth. The essential difference is that once the marine riser is installed, the exposed wellbore formation strengths must additionally support: *the full pressure effect column of all hydrostatic weighted mud, circulating, cuttings, and all other static/dynamic pressure effects that exist within the subsea BOP and marine riser* and be able to operate with full returns to the rig.

When primary well control, situations or operating conditions reach the safe set-point limits, casing strings must be run. Well design must meet this criterion. General rule of thumb for surface casing setting depth in a normal risk deep and ultradeepwater environment is:

1. ±600 m (1970 ft) below the seabed for 1000 m (3280 ft) water depth (WD)
2. ±800 m (2625 ft) below the seabed for 2000 m (6560 ft) WD and
3. ±1000 m (3280 ft) below the seabed for 3000 m (9840 ft) WD.

Note: If surface string is set too shallow, greater risk can exist to induce fracture and losses below the surface pipe casing shoe and can mask pore pressure and/or hydrocarbon detection. Setting surface casing at ALARP depths is important to assure optimal design and operational outcomes and benefits can result.

The juncture of successfully achieving delivering the final surface casing string at the optimal depths prior to running a subsea BOP is therefore a key and significant milestone in deepwater versus an overconservative and poorly risked-based design that can be counterproductive and result in more problematical terms of consequential loss not less.

Load-Bearing Capacity

Soil resistance and axial load bearing capacities calculation and evaluative examples are illustrated in the example that follows.

Bending Load Rating

Bending load rating is the stiffness of the conductor casing. This assumes the casing is set deep enough below the mud line to be rigidly fixed. For structural casing, bending is a primary design consideration. The bending yield strength of a circular tube can be calculated with Eq. (8.6) and example as shown.

BENDING LOAD RATING

$$\text{Bending rating ft} - \text{lbs} = \frac{(Y * I)}{\left(\frac{OD}{2}\right)} \tag{8.6}$$

where:

- Y = yield strength of the tube, psi
- OD = outside diameter of the tube, in
- ID = inside diameter, in.
- I = moment of inertia, in4, i.e., (π/64)*(OD4-ID4)

Bending load rating for an ultradeepwater conductor pipe example.

Minimum yield strength (obtain from grade matrix)		
Outside diameter of tubular *Od*, inches		$\begin{bmatrix} Od \\ Id \end{bmatrix} := \begin{bmatrix} 36 \\ 33 \end{bmatrix} \cdot \text{in}$
Outside diameter of tubular *Id*, inches		
Step # 1 Calculate the 2nd moment of Inertia for the tube.	$I := \frac{\pi}{64} \cdot \left(Od^4 - Id^4\right)$	$I = 24234.197\,\text{in}^4$
Step 2 Calculate the bending load rating of the tubular fb, lbf.	$fb := \frac{(X56 \cdot 0.9) \cdot I}{\left(\frac{Od}{2}\right)}$	$fb = 5654646\,\text{ft} \cdot \text{lbf}$

Deepwater structural design load-bearing capacity "jetting" evaluation of a 30-in and 36-in conductor of differing wall thicknesses and lengths is presented in examples that follow.

Load bearing axial capacity examples

This exercise evaluates the soil resistance calculations and axial loading capacity for a foundation string based on structural dimensional properties and a linear formation shear strength.

$S_d := 0.283 \cdot \frac{lbf}{in^3}$ $\quad Klbf := 1000 \cdot lbf$

Example 1 Data Input.

Foundation length, FL (ft)
Foundation outside diameter Fo, (in)
Foundation wall thickness Fw, (in)
Density of steel, Sd, lb/in3

$F_L := 60 \cdot m \quad F_o := 30 \cdot in \quad F_w := 1 \cdot in$

$F_i := F_o - 2 \cdot F_w \quad F_i = 28\ in$

Step 1; Calculate dry foundation string weight (Fsw) lbs/ft from dimensions listed above

$$Fs_w := S_d \cdot \left(\frac{\pi}{4} \cdot \left(F_o^2 - F_i^2\right)\right) = 309\ \frac{lbf}{ft}$$

Step 2 Calculate the soil shear strength resistance (ρo) lbs/ft based on the following relationship *(Ref IADC deepwater well control guidelines.)*

$$\rho_o := \left(\frac{1600}{180} \cdot \frac{lbf}{ft^3}\right) \cdot F_L = 1750\ \frac{lbf}{ft^2}$$

Step 3 Through evaluating soil shear strength (ρo) lbf/ft2 in step 3. Calculate the avergae soil shear strenght for the section length to be jetted below the mud line (*assume 0ft conductor stick up*)

$$\rho_{av} := \frac{\rho_o}{2} = 875\ \frac{lbf}{ft^2}$$

Step 4 Calculate ultimate axial loading capacity on the foundation string for undisturbed (Uu) and disturbed (Ud) conditions Klbs. ***Note:** figure for average soil resistance over conductor length has been assumed.*

$$U_u := 0.50 \cdot \rho_{av} \cdot \pi \cdot F_o \cdot F_L = 676\ Klbf$$

$$U_d := 0.25 \cdot \rho_{av} \cdot \pi \cdot F_o \cdot F_L = 338\ Klbf$$

Example 2 Data Input.

Foundation length, FL (ft)
Foundation outside diameter Fo, (in)
Foundation wall thickness Fw, (in)

$F_L := 70 \cdot m \quad F_o := 36 \cdot in \quad F_w := 1.5 \cdot in$

$F_i := F_o - 2 \cdot F_w \quad F_i = 33\ in$

Step 1; Calculate dry foundation string weight (Fsw) lbs/ft from dimensions listed above

$$Fs_w := S_d \cdot \left(\frac{\pi}{4} \cdot \left(F_o^2 - F_i^2\right)\right) = 552\ \frac{lbf}{ft}$$

Step 2 Calculate the soil shear strength resistance (ρo) lbs/ft based on the following relationship *(Ref IADC deepwater well control guidelines.)*

$$\rho_o := \left(\frac{1600}{180} \cdot \frac{lbf}{ft^3}\right) \cdot F_L = 2041\ \frac{lbf}{ft^2}$$

Step 3 Through evaluating soil shear strength (ρo) lbf/ft2 in step 3. Calculate the avergae soil shear strenght for the section length to be jetted below the mud line (*assume 0ft conductor stick up*)

$$\rho_{av} := \frac{\rho_o}{2} = \left(1 \cdot 10^3\right)\ \frac{lbf}{ft^2}$$

Step 4 Calculate ultimate axial loading capacity on the foundation string for undisturbed (Uu) and disturbed (Ud) conditions Klbs. ***Note:** figure for average soil resistance over conductor length has been assumed.*

$$U_u := 0.50 \cdot \rho_{av} \cdot \pi \cdot F_o \cdot F_L = 1105\ Klbf$$

$$U_d := 0.25 \cdot \rho_{av} \cdot \pi \cdot F_o \cdot F_L = 552\ Klbf$$

Conductor Analysis Methods

General

Calculation of the minimum required depth of the structural string (conductor) is based on delivering the required capacity to resist the maximum computed axial bearing loads with an appropriate factor of safety (FOS) as shown in Eq. (8.7) and as shown in previous worked example.

FACTOR OF SAFETY EVALUATION

$$\frac{Q_A}{F_A} \geq FOS \tag{8.7}$$

where

- Q_A = ultimate bearing capacity of the conductor foundation
- F_A = maximum computed axial bearing loads

The analysis considers installation methods. Methods to estimate axial capacity for jetted and drilled and grouted (cemented) strings are described in this section.

Axial Capacity for Jetted Conductor Systems

The axial capacity is largely dependent on the shaft friction developed between the conductor walls and the soil. No end-bearing resistance is considered. The overall axial capacity is equal to the initial capacity immediately after installation plus added components arising from soil restoration set-up time. The basic design expression utilized in the analysis is based on the equation proposed by Jeanjean (2002) [4], which is used extensively throughout the industry as presented in Eq. (8.8).

AXIAL CAPACITY AS A FUNCTION OF SOIL RESTORATION WITH TIME

$$Q_t = Q_o + \left[\Delta\alpha_t * \left[2 + \log(t)\right] * \pi * D * L * S_{u(ave)}\right] \tag{8.8}$$

where

- Q_t = Axial capacity at time t after conductor installation
- Q_0 = Axial capacity immediately after conductor installation
- D = Conductor outside diameter
- L = Depth of conductor tip below mudline
- t = Time in days after the completion of jetting
- $\Delta\alpha_t$ = Set-up per cycle of time derived from observed proof loadings
- $Su(ave)$ = Average undrained shear strength of soil over the embedded length

IMMEDIATE AXIAL CAPACITY (Q_O) of the jetted pipe is equivalent to the load required to penetrate the pile, during or immediately after installation. Physically, the last Slack off Weight (SOW) soil resistance noted on the drill floor during installation equals the immediate capacity, Q_0. Maximizing the SOW during jetting is important regarding best-practice delivery and is independent of soil properties and dictated by the jetting practices applied. The design method utilized assumes the SOW is calculated by adding the self-weight of the conductor casing to the assumed weight of the Bottom Hole Assembly (BHA) with a 0.8–0.9 safety factor to afford safe and conservative operating limit. If the utilization ratio, R, is different than that assumed in this design, i.e., *the SOW at target depth is lower or higher than anticipated* the results should be recalibrated using the actual final SOW to determine the new installed capacity.

During installation, best practice is to deliver the maximum SOW deemed safe and operable to maximize axial capacity as pipe approaches its final depth. The slack off weight (SOW) installation above method is mathematically expressed as:

SLACK OFF WEIGHT PERMISSIBLE INSTALLATION METHOD

$$Q_o = SOW_{\text{final}} = R * \left[W_{\text{cond}} + W_{WH} + W_{BHA} \right] \tag{8.9}$$

where

- SOW = Slack off weight
- R = Utilization ratio
- W_{cond} = Cumulative wet weight of conductor
- W_{WH} = Wet weight of wellhead
- W_{BHA} = Wet weight of BHA (based on length of conductor and BHA components used)

TIME-DEPENDENT CAPACITY (Q_T) factor to evaluate is the rate and value at which soil consolidates and sets up with time. The method illustrated is more accurate than simplified techniques and accounts for soil types, profiles, conductor diameter, and length.

$\Delta\alpha_t$ (used in Eq. 8.10) is the measure of change in average friction along the installed pipe at a given time, t, due to setup. It is based on site-specific field measurement of actual conductor capacity variations over time, i.e., *proof load tests for wells with similar conductor configurations and installation procedures,* such that:

Deepwater values of $\Delta\alpha t$ shall vary significantly and depend largely on the amount and distance of pipe reciprocation, i.e., *up and down movement* exercised during pipe installation. Based on experience in deepwater, a range of $\Delta\alpha t$ values of 0.028–0.04 is recommended for use and application. The ultimate foundation capacity then calculated to an assumed set-up time anticipated based on value used.

CHANGE OF AVERAGE FRICTION ALONG A JETTED PIPE AT A GIVEN TIME, AFTER INSTALLATION

$$\Delta\alpha_t = \frac{Q_t - Q_o}{\pi * D * L * S_{u(ave)}} \tag{8.10}$$

Ideally the jetted pipe is preferred to meet a design and installation capability to support the buoyed landed weight of the conductor string and the first surface casing run into the hole and probably displaced to seawater prior to cementing. This results two to four days after the initial jetted pipe is installed.

FACTOR OF SAFETY to be used for the jetted section remains with the operator. Jeanjean suggests a minimum safety factor of 1.3.

Worked Examples

Examples of deepwater jetted conductor and surface string land-out are presented in the Mathcad worksheets that follow or downloaded at https://www.kingdomdrilling.co.uk/downloadfreelinks.aspx.

Worked example 1: Estimating conductor length and safety factor.

This field units worksheet exercise illustrates the safety factor on conductor required to support a defined length of a subsequent structural support string while landing off prior to cementing.
Note: Mud outside and seawater assumed inside structural string assumed.

$S_d := 0.283 \cdot \frac{lbf}{in^3}$ $\quad Klbf := 1000 \cdot lbf$ $\quad bbl := 42 \cdot gal$

Data Input.

Steel density, Sd lbf/in3
Surface length, SL (ft)
Surface casing external diameter Sco, (in)
Surface casing wall thickness, Sw, (in)
Mud weight ρmw,
Sea water gradient ρsw
Surface casing internal diameter Sci, (in) is calculated as shown opposite
Conductor OD, and wall thickness Co, Cw (in)
Conductor Id, Ci, (in) calculated as shown
Conductor Length Cl (ft, m)

$S_L := 1200 \cdot m \quad S_w := 0.675 \cdot in \quad Sc_o := 20 \cdot in$

$Sc_i := Sc_o - 2 \cdot S_w \quad Sc_i = 18.65\ in$

$\begin{bmatrix} C_o \\ C_w \end{bmatrix} := \begin{bmatrix} 36 \\ 1.5 \end{bmatrix} \cdot in \quad \begin{bmatrix} \rho_{mw} \\ \rho_{sw} \end{bmatrix} := \begin{bmatrix} 8.6 \\ 8.6 \end{bmatrix} \cdot \frac{lbf}{gal}$

$C_L := 70 \cdot m \quad C_i := C_o - 2 \cdot C_w \quad C_i = 33\ in$

Step 1; Calculate dry weight of surface casing strings (Scw) lbf/ft entered above

$Sc_w := S_d \cdot \frac{\pi}{4} \cdot \left(Sc_o^{\,2} - Sc_i^{\,2}\right) \quad Sc_w = 139\ \frac{lbf}{ft}$

Step 2 Calculate buoyancy factor for mud (Bfm) (dimensionless)

Step 3 Calculate buoyancy factor for seawater (Bfs) (dimensionless)

$Bfm := 1 - \left(\frac{\rho_{mw}}{65.5 \cdot \frac{lbf}{gal}}\right) \quad Bfs := 1 - \left(\frac{\rho_{sw}}{65.5 \cdot \frac{lbf}{gal}}\right) \quad Bfm = 0.869 \quad Bfs = 0.869$

Step 4 Calculate the volume (Hv, gal / ft) inside structural support string

$H_v := \frac{\pi}{4} \cdot Sc_i^{\,2} = 14\ \frac{gal}{ft}$

Step 5 Calculate the weight per ft (Wtc, lb/ft) for sea water inside each structural support string joint

$Wt_c := H_v \cdot \rho_{sw} = 122\ \frac{lbf}{ft}$

Step 6 Calculate buoyant volume load effect (Hvo, gal /ft) acting on bottom of the casing string

$Hv_o := \frac{\pi}{4} \cdot Sc_o^{\,2} = 16\ \frac{gal}{ft}$

Step 7 Calculate the buoyant load effect of mud (Wtco, lb/ft) acting on surface string

$Wt_{co} := Hv_o \cdot \rho_{mw} = 140\ \frac{lbf}{ft}$

Step 8 Calculate the nett weight effect of casing sea water and mud buoyant loading effect

$Nw_e := Sc_w + \left(Wt_c - Wt_{co}\right) = 121\ \frac{lbf}{ft}$

Step 9 Calculate the dry weight for the foundation string

$C_v := S_d \cdot \frac{\pi}{4} \cdot \left(C_o^{\,2} - C_i^{\,2}\right) = 552\ \frac{lbf}{ft}$

Step 10 Calculate the bouyant weight of conductor string

$Cv_w := C_v \cdot Bfs = 480\ \frac{lbf}{ft}$

Step 11 For conductor string length selected (CL) calculate the average soil resistance (ρav, lbs/ft) using the following IADC general equation.

$\rho_o := \left(\frac{1600}{180} \cdot \frac{lbf}{ft^3}\right) \cdot C_L \quad \rho_o = 2041\ \frac{lbf}{ft^2} \quad \rho_{av} := \frac{\rho_o}{2} = 1021\ \frac{lbf}{ft^2}$

Step 12 Calculate loading on foundation (Lf) lbs when structural string is landed

$L_f := S_L \cdot Nw_e + Cv_w \cdot C_L = 586\ Klbf$

Step 13 Calculate ultimate axial loading capacity on the foundation string, Uc Klbs. **Note:** figure for average soil resistance over conductor length (ρav) is assumed.

$U_c := 0.5 \cdot \rho_{av} \cdot \pi \cdot C_o \cdot C_L = 1105\ Klbf$

$U_{cd} := 0.25 \cdot \rho_{av} \cdot \pi \cdot C_o \cdot C_L = 552\ Klbf$

Step 14 Calculate safety factor on the foundation (Sf) for undisturbed (u) an disturbed (d) soil conditions.

$Sf_u := \frac{U_c}{L_f} = 1.89 \quad Sf_d := \frac{U_{cd}}{L_f} = 0.94$

WORKED EXAMPLE 2: EFFECT OF SET UP TIME

The exercise determines and evaluates the set up time required for a conductor string based on formulae derived from SPE paper 77537. The worksheet evaluates, soil strength, conductor diameter, length and the impact of support strength if the jetted soil formation has been disturbed or not during the jetting process.

Data Input

$Kip := 1000 \cdot lbf$ $\quad Klbf := 1000 \cdot lbf$ $\quad S_d := 0.283 \cdot \frac{lbf}{in^3}$

Density of steel , Sd, lbf/in3
Conductor length, CL (ft, m)
Conductor outside diameter Co, (in)
Conductor wall thickness Cw, (in)

$C_L := 280 \cdot ft$ $\quad C_o := 36 \cdot in$ $\quad C_w := 1.5 \cdot in$

$C_i := C_o - 2 \cdot C_w \qquad C_i = 33\ in$

Set up time formula and calculations

Step 1; Calculate conductor dry string weight (Fsw) lbf/ft from dimensions listed above

$$C_{sw} := S_d \cdot \frac{\pi}{4} \cdot \left(C_o^{\,2} - C_i^{\,2}\right) \qquad C_{sw} = 552\ \frac{lbf}{ft}$$

Step 2 **C**alculate a soil shear strength resistance (ρo, lbf/ft2) lbs/ft based on the following IADC deepwater well control guidelines formulae;
Note; Use regional data if available.

$$\rho_o := \left(\frac{1600}{180} \cdot \frac{lbf}{ft^3}\right) \cdot C_L \qquad \rho_o = 2489\ \frac{lbf}{ft^2}$$

Step 3 Calculate average soil shear strength resistance for the foundation string (ρav, lbs/ft)

$$\rho_{av} := \frac{\rho_o}{2} \qquad \rho_{av} = 1244\ \frac{lbf}{ft^2}$$

Input bottom hole assembly components;

Outside and inside diameters of drill collars (in)
Length of drill collars (ft, m)
Safety factor. (sf), dimensionless
Weight of wellhead, Wellhead, Klbf
Weight of drill ahead tools, Drillahead, Klbf

$$\begin{bmatrix} Dco & Dci \\ Dco2 & Dci2 \end{bmatrix} := \begin{bmatrix} 9.5 & 3 \\ 8 & 2.812 \end{bmatrix} \cdot in$$

$$\begin{bmatrix} Dc1 \\ Dc2 \end{bmatrix} := \begin{bmatrix} 220 \\ 60 \end{bmatrix} \cdot ft \qquad sf := 0.85$$

Note: Drill collar 'BHA' components will cover the full conductor length to be jetted. Hence drill collar length should equate to length of conductor being jetted.

$$\begin{bmatrix} Well_{head} \\ Drill_{ahead} \end{bmatrix} := \begin{bmatrix} 5 \\ 3 \end{bmatrix} \cdot Klbf$$

Step 4 Calculate buoyancy factor for steel (conductor, drilling tools etc.) in seawater.

$$B_f := 1 - \frac{8.66 \cdot \frac{lbf}{gal}}{65.5 \cdot \frac{lbf}{gal}} \qquad B_f = 0.87$$

Step 5 Calculate maximum weight on bit (WOB, Klbf.) for conductor bottom hole assembly (BHA, ft) run.

$$Dc_{w1} := S_d \cdot \frac{\pi}{4} \cdot \left(Dco^2 - Dci^2\right) \cdot Dc1 \qquad Dc_{w1} = 48\ Klbf$$

$$Dc_{w2} := S_d \cdot \frac{\pi}{4} \cdot \left(Dco2^2 - Dci2^2\right) \cdot Dc2 \qquad Dc_{w2} = 9\ Klbf$$

$$WOB := B_f \cdot \left(Dc_{w1} + Dc_{w2}\right) \qquad WOB = 49\ Klbf$$

Step 6 Calculate the Maximum Slack Off Weight on bit (SOWmax) that can be safely applied during jetting, i.e. based on length of conductor, BHA, wellhead and drill ahead tools weight to be jetted. ***Note:*** *No allowance for stick up or first point of resistance has been accounted for in this example.*

$$SOW_{jet} := \left(WOB + \left(\left(Drill_{ahead} + Well_{head}\right) \cdot B_f\right) + \left(C_{sw} \cdot C_L\right)\right) \cdot sf \qquad SOW_{jet} = 179\ Klbf$$

$$SOW_{max} := \left(WOB + \left(\left(Drill_{ahead} + Well_{head}\right) \cdot B_f\right) + \left(C_{sw} \cdot C_L\right)\right) \qquad SOW_{max} = 211\ Klbf$$

Step 7 Calculates theoretical conductor setting strength capacity at (t, days) based on
a.) Maximum load set down after jetting i.e. WOB.max
b.) Formulae as derived. ***Ref SPE 77357; Innovative design for deepwater surface strings***)
Then evaluate restored conductor strength after input time periods entered, (t, day).

$$t := \begin{bmatrix} 1 \\ 2 \\ 4 \\ 12 \\ 24 \\ 240 \end{bmatrix} \cdot hr$$

$$t_1 := 0.055 \cdot \left(2 + \log\left(\frac{t}{hr}\right)\right) \qquad t_1 = \begin{bmatrix} 0.11 \\ 0.1266 \\ 0.1431 \\ 0.1694 \\ 0.1859 \\ 0.2409 \end{bmatrix} \qquad Q_t := SOW_{max} + (t_1 \cdot (\pi \cdot C_o \cdot C_L \cdot \rho_{av})) \qquad Q_t = \begin{bmatrix} 572 \\ 626 \\ 681 \\ 767 \\ 821 \\ 1002 \end{bmatrix} Klbf$$

Step 8 Calculates theoretical resistance based on further applied safety factors.
Ref. *IADC deepwater well contrl guidelines, section 1.1.5, (Ref Beck & Jackson, 1991)*

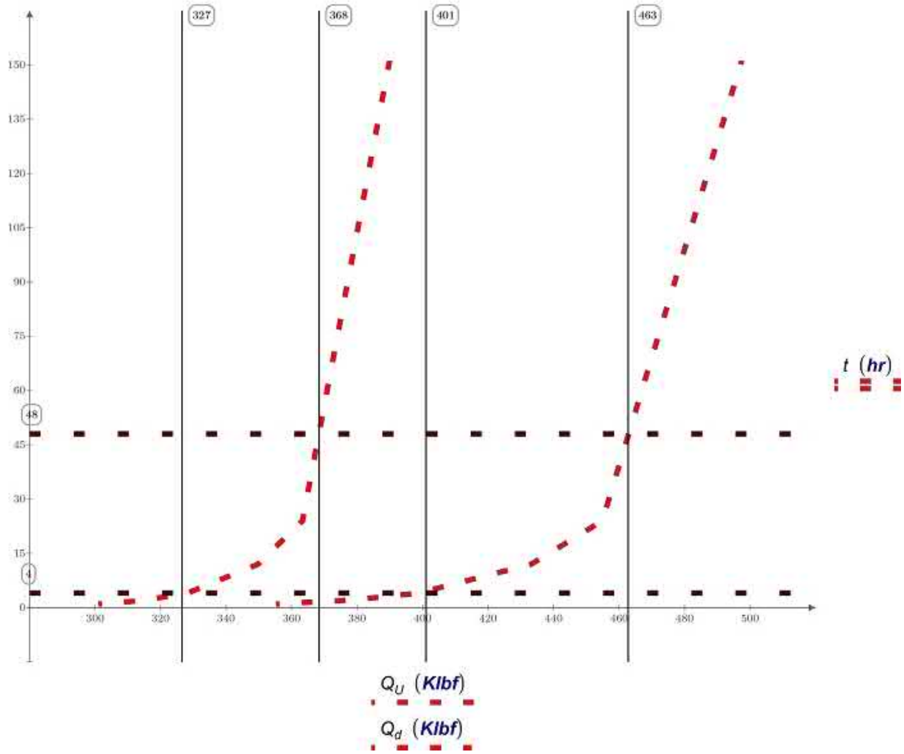
8a. Calculates conductor strength that will be achieved (QU). *Jetting conducted with problem and little reciprocation.* 0.4 safety factor applied.

$$Q_U := SOW_{max} + (t_1 \cdot (\pi \cdot C_o \cdot C_L \cdot \rho_{av} \cdot 0.4)) \qquad Q_U = \begin{bmatrix} 355 \\ 377 \\ 399 \\ 433 \\ 455 \\ 527 \end{bmatrix} Klbf$$

8b. Calculates conductor strength achieved (Qd) , *Jetting requires more reciprocation and if operational problems experienced*, 0.25 safety factor applied.

$$Q_d := SOW_{max} + (t_1 \cdot (\pi \cdot C_o \cdot C_L \cdot \rho_{av} \cdot 0.25)) \qquad Q_d = \begin{bmatrix} 301 \\ 315 \\ 328 \\ 350 \\ 363 \\ 408 \end{bmatrix} Klbf$$

Step 9 Plots time vs. conductor support strength.



Axial Capacity for Drilled and Grouted (Cemented) Systems

METHOD

Drilled and grouted (cemented) axial capacity is based on the API RP 2A-WSD static (time independent) method for computing the ultimate bearing capacity of pipe piles, casings, and conductors. The ultimate bearing capacity of for a given depth, *Qd*, below the seafloor, is the sum of the bearing capacity due to the skin friction on the conductor's embedded surface and the end bearing capacity on the tip as shown in Eq. (8.11)

AXIAL CAPACITY FOR DRILLED AND GROUTED PIPE INSTALLATIONS

$$Q_d = Q_f + Q_p = f * A_s + q * A_p \tag{8.11}$$

where:

- Q_f = Skin friction resistance capacity
- Q_p = Total end bearing capacity
- f = Unit skin friction capacity
- A_s = Side Surface Area of Conductor (Embedded Section) = πDL
- q = Unit end bearing capacity
- A_p = Gross end area of conductor

When applying the above equation to compute ultimate bearing capacity, the end bearing capacity is assumed insignificant in comparison to end load result. A modified formula for total bearing capacity of the installed structural pipe Eq. (8.12) is used:

MODIFIED AXIAL CAPACITY FOR DRILLED AND GROUTED PIPE INSTALLATIONS

$$Q_d = Q_f = f * A_s \tag{8.12}$$

The unit skin friction capacity, f, calculated at any point along the pipe, Eq. (8.13):

MODIFIED UNIT SKIN FRICTION CAPACITY, *F*, AT ANY GIVEN POINT ALONG INSTALLED PIPE LENGTH

$$f = \alpha * S_u \tag{8.13}$$

where

- α = empirical strength factor
- S_u = Undrained Soil Shear Strength at the point in question

For normally consolidated soil conditions, the empirical strength factor is given by $0.5 \leq \alpha \leq 1.0$ in accordance with the API RP 2A-WSD methods.

DRILLED AND GROUTED SURFACE CASING AXIAL CAPACITY COMPUTATIONS

Once the surface casing is confirmed cemented to the wellbore formerly drilled below the installed structural pipe, the API RP 2A-WSD method is utilized to calculate the axial bearing capacity of the drilled and cemented surface casing once the grout (cement) is set. Soil profiles that are simply extended to the surface casing installed depth for the purpose of the surface casing axial capacity calculations use.

However, the shear strength data used API computations for the drilled and grouted (cemented) surface casing calculations are reduced by a sensitivity factor of 2; i.e., $f = 0.5S_u$.

FACTOR OF SAFETY

All surface casing axial capacity assessments will conform to API RP 2A-WSD recommendations to ensure that an adequate axial bearing capacity is achieved to resist the maximum computed axial bearing loads with an appropriate factor of safety (FOS). *A FOS of 2.0 is commonly used when considering API RP 2A-WSD methodologies. This approach is somewhat conservative.*

Loading Stages

Three critical loading stages exist for a standard deepwater well design, construction, and delivery process to be evaluated, as shown in Figs. 8.8 and 8.9 (for jetted configuration only). An overview of these stages is:

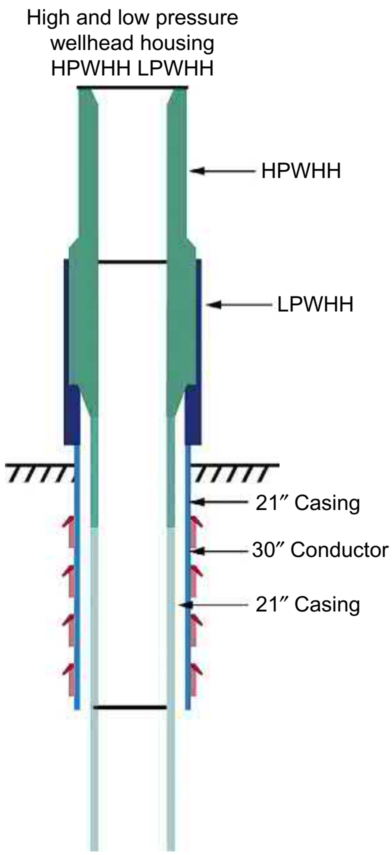


FIG. 8.8 Standard deepwater configuration of critical structural well loadings. *Source: Wood Group Kenny 2017 Deepwater riser analysis report.*

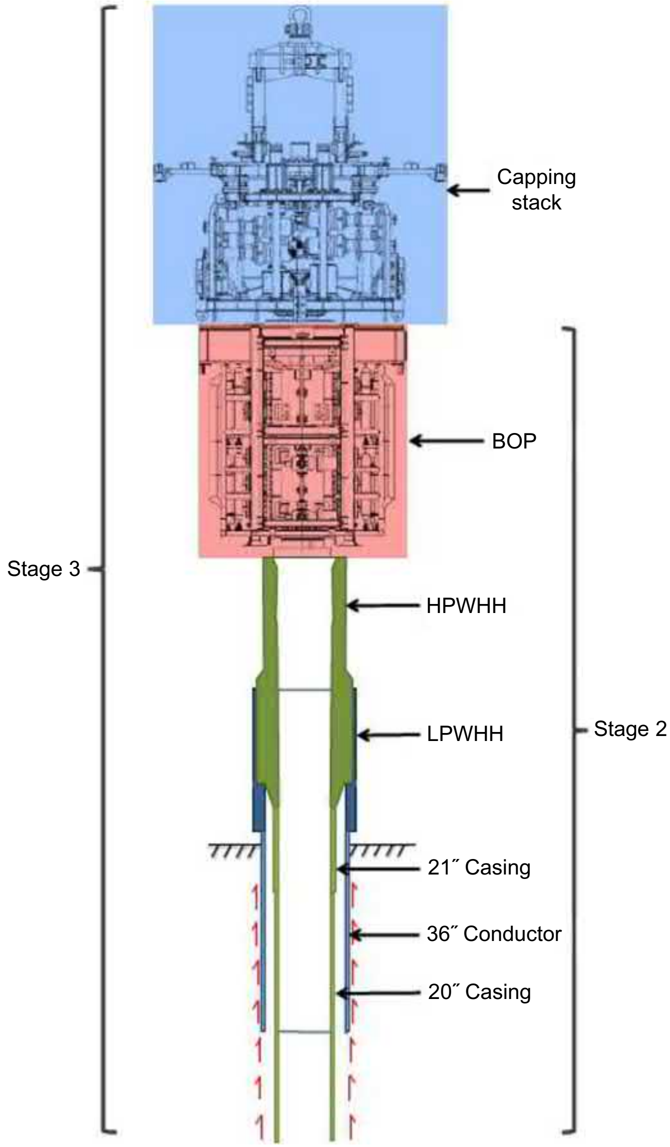


FIG. 8.9 Standard deepwater configuration of critical structural and casing design well loadings. *Source: Wood Group Kenny 2017 Deepwater riser analysis report.*

LOADING STAGE 1: SURFACE CASING HANG-OFF (JETTED CONFIGURATION)

The conductor and low pressure wellhead housing is installed followed by the surface casing (installed and cemented) and a high-pressure housing landed and confirmed to be latched. The cement is assumed to have not yet set. At this stage, it is assumed that 50 percent of the surface string weight is developed at the low pressure wellhead hang off. All the weight of the wellhead and majority of the surface casing weight is assumed to be supported by the conductor. It is conservatively assumed that the self-weight of the cement in the annulus between the surface casing and conductor is also supported by the conductor.

LOADING STAGE 2: BOP LANDED (JETTED CONFIGURATION)

Surface casing is fully grouted and set, i.e., cement returns verified by the ROV, and confirmed via samples taken, measured, and evaluated. The casing is assumed to be supporting weight as it is transferred via skin friction to the soil beneath the conductor. The subsea BOP weight is supported through conductor, surface, and wellhead pressure housings load sharing. The high-pressure housing would be locked or rigidly locked down to the low-pressure housing at this stage.

LOADING STAGE 3: BOP AND CAPPING STACK

The surface casing is fully grouted (cemented to seafloor) and set in place. The surface casing is assumed to be supporting weight as it is transferred via skin friction to the soil beneath the conductor. The subsea BOP and the intended Capping Stack weight is supported through conductor, surface casing low, and wellhead pressure housings load sharing.

Deepwater Wellheads

The deepwater wellhead system is designed to handle all drilling and production operating life-cycle loaded conditions and situational analysis. Bending and fatigue at wellhead and all other integral constituent parts verified to determine sizing and safety stress concentration factors (SCF) of all load ratings of components required.

Due to water depths and combined loads increasing and resulting during an ultradeepwater well life cycle, wellhead bending rating design was increased by API design standards to meet greater applied loading capabilities. Manufacturers provide options of rigid lockdown of the high- and low-pressure housings to enhance fatigue life effects on the wellheads and surface casing(s) designs.

Bending load is governed by *wall thickness* and *outside diameter* of the high-pressure housing at the connection to the subsea BOPs and also based on how the high- and low-pressure wellheads are locked, preloaded, and interact together.

A standard deepwater wellhead system (as illustrated in Fig. 8.8) has a high-pressure housing OD of ±27″. To obtain higher bending capacity, the high-pressure housing OD is increased to as much as 30″–36″ to strengthen the high-pressure to low-pressure wellhead housings integration.

The bending strength of wellhead connectors depends upon the axial load and the internal pressure. Most standard wellhead connectors are limited in bending strength to 3000–4000 kip-ft. Vendors do provide connectors for higher bending loads up to seven to eight million ft-lbs.

Liner Hanger Subs

Liner hanger subs are required when additional casings, e.g., 18″ casing liner is to be drilled, run, and set as illustrated in Fig. 8.10.

The sub can be welded directly below the 18¾″ wellhead housing extension or into a joint of 21″ casing as illustrated. Latter option advantage is during abandonment, avoiding a need

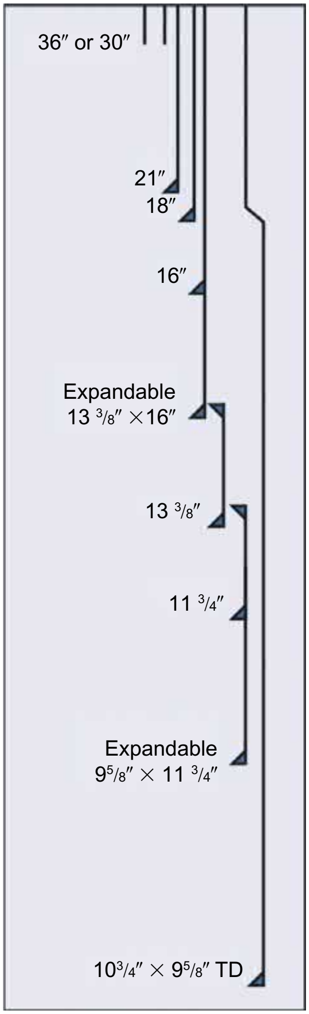


FIG. 8.10 Deepwater well with several contingent string requirements.

to cut the 16″. Where the 18″ is hung inside the 21″, care should be taken to ensure that the 21″ burst rating is not the limiting factor, in the event that a higher than expected leak off is obtained at the 18″ shoe. *Note: It should also be noted that some liner hanger subs have a restricted ID of 17⅜″, which is unsuitable for 17½″ bits.*

If a restricted ID sub is used, a 17″ or 17⅛″ bit is required to drill out of the 20″. Should a latching-type hanger be used, the ID will allow a 17½″ bit to be used.

Although the latching-type hanger provides the ability for the casing to be cemented when landed out (and the no-go type does not), there is considerable risk of the profile becoming packed with cuttings and not allowing the hang-off dogs to engage. In this case, the hanger may pass through the profile without hanging-off the casing. For this reason, it is usually recommended that a no-go type hanger should be used.

Connectors

A well-engineered structural design results through a proper combination of both the line pipe and connector mechanical strengths. Rated performance of connectors is decreased if subjected to combined loading, i.e., *concurrent axial tension and bending.* Safety factors should be further applied to connector properties as it is not recommended to stress connectors to yield strength.

Operationally, conductor and surface casings are commonly run with modern and advanced internal or external handling tools provided by 3rd-party companies who specialize in these operations.

Conductor connectors generally have lower bending and internal pressure (burst ratings) than the line pipe tube to which they are usually welded unless otherwise specified. It is also recommended that a safety factor is applied to connector properties since it is not recommended to stress a connector in service to its yield strength.

Connectors for surface strings can be the same as those for 30″ or 36″ conductors with the exception of being flush ID and having an external upset to assure required bending strength. Having the flush ID does not restrict future casing strings. The external upset eases running with side door elevators.

Generally, the threaded connection is welded on to the tube. The connector is designed to exceed the capacity of the tube. The connectors can also have a flush OD to reduce so soil disturbance and interference during jetting to assure more optimal load bearing and support capacity.

Connectors are preferred with a minimum turn make up. This affords easier pipe installation and generally minimizes the amount of equipment needed to run it.

The pipe connectors are often run box up/pin down. Antirotation keys also are quite common to install after make-up.

Conductor Section

SIZING OF FOUNDATION AND CONDUCTOR LINE PIPE

Selected standard and non-API line pipe can range from 16″, 18″ to 20″ to 28″ and up to 30″, 36″, and 48″ with wall thicknesses ranging from ¼″ to 1¼″, ½″–1¼″, and ¾″ to 2½″, respectively. Design must account for line pipe specifications of: *wall thickness, grade, and weld-on connectors*, threaded or a squinch type.

Some conductor casing has handling pad eyes for running that have to be cut off and removed typically at the rotary table prior to running. This is rig time and cost consuming. Conductors that are readily picked up, installed, made-up and run are therefore preferred.

SIZING OF CONDUCTOR PIPE AND SURFACE CASING

In sizing structural pipe, the minimum yield strength of the pipe must not be exceeded based on the bending analysis performed. If exceeded, stronger pipe is selected with increased wall thickness and/or grade of pipe. If not achieved, the outside diameter (OD) of the pipe is increased. This increased weight can create rig and operational handling, running and installation issues to be resolved.

In deep to ultradeep water, conductors normally range from 30″ to 36″ OD with wall thickness of 1¾–2″ thicker joint installed for the two or three joints below the wellhead joint, and ¾″–1½″ wall thickness for all remaining intermediate joints to required depth. Yield strength/wall thickness for the pipe is designed and selected to exceed the calculated peak stress in a worst operating case condition, i.e., *a drive-off or drift off*.

Surface casing ranges from *24″, 20″, 18⅝″, 16″ in diameter and 0.5″ to 1.25″ in wall thickness* down to 13⅝ or 13⅜″ premium pipe if a *slender or slim well desig*n can be used.

JETTING INTRODUCTION

As can be concluded within this chapter, jetting is not exactly an exact engineering process, science, or standard. Best practices must exist to assure compliant outcomes and benefits result.

The elected design pipe shall first self-penetrate through its own weight to a specific distance below the seafloor dependent upon subsurface soil conditions until a first point of resistance (FPR) is observed. From this point, slack of weight (SOW) will be zeroed and jetting will commence.

Soil is then jetted by pumping sea water through the drilling bit located inside the bottom of the conductor string as shown. The jetted soil is then removed from the wellbore bottom, transported, and circulating out through the internal conductor pipe ports to exit at circulating ports provided on the top of the low-pressure wellhead housing as further shown in subsea snapshot enclosed.

Major jetting installation hazards are *setting too short a conductor length that cannot support the required axial load or running too long a length. Where if jetting proves difficult to get the conductor pipe to the required setting depth, i.e., excessive reciprocation is required, soil strength and holding capacity can be severely and permanently damaged and unknown.*

If jetting practices are excessive in certain soil types and conditions, broaching outside the structural casing *can result in soil liquidation, slump failure, and respud of wells*.

Best jetting practices are discussed in more detail to prevent such failures in a later chapter.

DRILL-AHEAD TOOLS

Once jetted to depth, a "drill-ahead" tool is utilized to release the drilling assembly from inside the conductor to the surface casing drilling phase to deliver one uninterrupted drilling operating sequence as shown. This eliminates time-consuming and costly pipe trips to deliver a safer, effective, and efficient top and surface wellbore phase delivery with one integral dual-purpose jetting and drilling ahead assembly.

RISERLESS DRILLING

The structural wellbore sections that follow jetting are drilled "riserless," i.e., fluids such as, *sea water, viscous sweeps, or pump and dump (PAD muds)*, are pumped and returned with formation cuttings to be deposited and dispersed at the seafloor and surrounding area. Riserless drilling is covered in more detail in chapter 12 of this guide.

Structural Design Summary

A structural design guide summary is outlined as follows. Well and operating specifics shall guide change and deviations required.

1. Gather all relevant and evident deepwater well data, including soil properties, with loadings to include magnitude and nature (static or cyclic).
2. For all operational structural designs, use a static mode.
3. Select a pile for analysis. For deepwater applications, a good place to start is 30″ or 36″ (762–914.4 mm) OD and 1–1.5 inch (25.4–34.1 mm) wall thicknesses and X-52 to X-56 line pipe.
4. Determine the modulus (E), moment of inertia (I), cross-sectional area (sq inches), OD (inches), and ultimate bending moment (ft-lbs) of the pipe analyzed.
5. Select an appropriate set of soil *p-y* curves, i.e., lower, mid, or upper range.
6. Evaluate a series of solutions starting with loads from the riser analysis at 2, 4, and 8 percent of offset.
   a. Offset is defined as a percentage of water depth.
   b. The riser loads at the flex joint—lateral load, moment, and axial load—are input in the analysis.

Note: A more detailed riser analysis is generally to be conducted by both operator and drilling contractor to meet and assure specific operating needs.

7. Obtain curves of bending moment versus depth and lateral deflection versus depth from specialist providers.
8. Determine the adequacy of the pipe and the wellhead system under the three loading conditions—2, 4, and 8 percent offset. Change the pile as required, re-run analysis.
9. Determine pipe with appropriate safety factors based on the riser loads at flex joint.
10. Check loads at the wellhead and adequacy of the wellhead system. Check combined stress levels. Stresses should not exceed pipe minimum yield strength.
11. Other design criteria to consider are:
    a. Subsea wellheads and connectors may require higher bending capabilities, i.e.,
       i. Increase pipe OD,
       ii. Strengthen LP & HP housing interface.
    b. Deepwater bending requirements
       i. Up to several million pound of bending can be required.
       ii. Rigid lock down is preferred to mitigate fatigue.
12. Fatigue analysis. The riser/structural pipe interaction should be analyzed for the drilling and production riser arrangements. (*Note*: Fatigue analysis of structural pipe and production riser interaction is outside the scope of this guide.)
13. Inclination, stick up, and wear
14. Operational considerations.

CONDUCTOR AND CONDUCTOR ANCHOR NODE "CAN" BEHAVIOR

Synopsis

A suction-installed foundation unit Conductor Anchor Node (CAN) illustration in Figs. 8.11–8.13 consists of a cylinder that is open at its base and closed at its top, with a vent in the roof with ring or longitudinal stiffeners inside. Once lowered to the seabed, it shall self-penetrate a distance due to its own weight to reach equilibrium with the soil resistance conditions.

FIG. 8.11 Conductor Anchor Node "CAN." *Source: Neodrill 2018.*

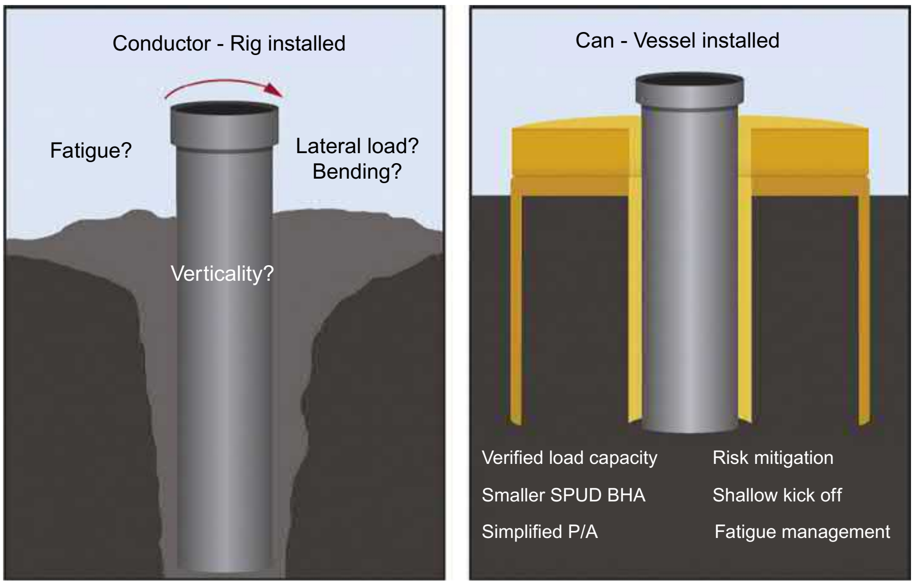


FIG. 8.12 Conventional conductor installation, versus CAN/CAN-ductor options. *Source: Neodrill 2018.*

FIG. 8.13 CAN recovery and re-use. *Source: Neodrill 2018.*

Water is then pumped out from its interior (by means of an ROV installed or carried pump) lowering and creating a differential pressure inside the cylinder across the unit roof, and soils surface to create a suction force that pulls the unit further into the seabed. Sufficient pressure is applied to overcome the soil resistance but not too much suction force that the soil inside the CAN fluidizes.

Suction anchors have been widely used for deeper water applications (Anderson et al. (2005) reviewed methods and data from 485 anchors installed at 50 sites.) Installation almost always successful although in some cases, repeat attempts had to be made at different positions on the seafloor before successful installation was achieved.

Installation Overview

Installation methods for sands and clays are described in API RP 2SK. Design and Engineering calculations involve equating downward force due to suction inside unit with wall friction resistance on the sides and end-bearing loads of the unit. Possibility of sand boiling or fluidization inside unit also is assessed.

Installation occurs in two phases. First is self-penetration with the roof vent open. Unit penetrates below seafloor due to its buoyant self-weight (W) (Fig 8.12).

In the following suction-assisted phase, roof vent is closed, and pumping applied to reduce the internal water pressure by some amount, creating a pressure differential (underpressure) ΔP across the roof. The driving force and ultimate axial pile capacity are expressed in Eq. (8.14).

Side resistance results from the shear stresses along the inner and outer walls of the unit, normal stresses on the base of the wall and that applied by the soil to the protuberances such as pad eyes, stiffeners, and/or any change in wall thickness.

DRIVING FORCE FOR SUCTION UNIT INSTALLATION

$$F = W' * \frac{\pi * Di^2}{4} * \Delta P \tag{8.14}$$

where:

- F = Driving force klbs or tons.
- W = Buoyant self-weight of unit, tons
- Di = Internal diameter of unit, in
- ΔP = 0 for self-weight penetration. (psi)

Penetration in each phase is determined by equating the driving force F to the soil resistance Q. The latter determined by adapting a method for calculating the ultimate axial pile capacity as shown in Eq. (8.15).

ULTIMATE AXIAL PILE CAPACITY

$$Q = Q_{\text{side}} + Q_{\text{tip}} \tag{8.15}$$

where:

- Q_{side} = side resistance (klbs)
- Q_{tip} = end-bearing resistance (klbs)

Once installed, the CAN top may be closed off or left open. If closed and if can be guaranteed for life of design, the unit can be considered as a buried shallow gravity foundation with a weight equal to the buoyant weight of the unit and the material enclosed within.

It is to be noted that for exploration wells, as part of the P & A process, the rig will cut the surface casing (and the Conductor, if deeper set than the CAN skirt tip). Then depart from the location.

A CAN installation/recovery vessel can when convenient locate to the well, prepare for, pump out, and recover the CAN, and bring it to shore for refurbishment and reuse for another well (Fig 8.13).

Thus, expensive rig time can be saved, especially if using a CAN with preinstalled conductor, thus not requiring any conductor cutting for the P & A.

The Set-Up and Consolidation Effect

Set-up and consolidation occurs more dominantly in clayey soils versus silts or sands. In suitable clay environments suction units, e.g., a conductor anchor node (CAN) self-penetrates a distance to disturb the soil that shall temporarily lose strength. From there, the component would then be pumped to the required penetration (vertical) installation depth. At depth and with a function of time, the disturbed clay shall reconsolidate to its initial shear strength that can take from a few hours up to 1 month or more, depending on the exact soil constituent components.

As all soils are not the same around each unit or CAN installation. As a function of length and as each interval penetrated is not disturbed the same, the set-up effect factor is generally less than the sensitivity index to determine that higher safety factors should be applied. This is because the disturbance reduces the soil resistance parallel to the installed device. On reloading, the parallel soil resistance regains strength, the unit or CAN loading will increase, and a larger load to move and remove the installation if required shall result. Equilibrium dictates that the normal load, i.e., *the bearing soil resistance to the foundation installation*, increases; consequently, the axial and bending loads that can be applied at the seabed increases also with the setup factor. Evident case studies on unit CANs for a 3- to 4-week consolidation time demonstrate a typical set-up effect factor = 1.5.

Ultimate Capacity

API RP2SK classifies the analysis and design tools to determine suction anchor capacity as:

1. Finite element methods (probably the most rigorous general method, potentially capable of identifying soil failure mechanisms automatically)
2. Limit equilibrium or limit analysis methods, usually employing the concept of failure mechanisms.
3. Simplified empirical methods such as a *p-y* analysis

For deepwater conductor or suction unit such as a Conductor Anchor Node, simple empirical methods with a suitable safety factor generally meets all design installation and operational requirements.

REFERENCE STANDARDS

IADC Deepwater Well Control Guidelines 1998, 1st Edition with 2000 supplement.

IADC Deepwater Well Control Guidelines 2nd Edition. 2015.

API RP-2A-WSD Recommended Practice for Planning, Designing and Constructing Offshore Platforms – Working Stress Design. Rev. 21. October 2007.

API RP-16Q. 1st Edition. November 1993. Re-affirmed August 2001. Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems.

API-RP-16Q, API RP 2SK. 2nd Edition. April 1, 2017. Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems.

Den Norske Veritas. Recommended Practice, DNV-RP-E303. Geotechnical design and installation of suction anchors in clay. October 2005.

Reference

Jeanjean, P., 2002. Innovative design method for deepwater surface casings. In: Society of Petroleum Engineers Technical Conference, SPE 77357. San Antonio, Texas.

Further Reading

Andreson, A., Berre, T., Kleven, A., Lunne, T., 1979. Procedures used to obtain soil parameters for foundation engineering in the North Sea. Mar. Geotechol. 3 (3), 201–266.

Beck, R.D., Jackson, C.W., Hamilton, T.K., 1991. Reliable Deepwater Structural Casing Installation Using Controlled Jetting, SPE 22542. Society of Petroleum Engineers.

Dean, E.T.R., 2009. Offshore Geotechnical Engineering: Principles and Practices. Soil Models Ltd ICE PublishingISBN: 978-0-7277-3641-3.

Hollinger, G., Trauner, S., Dupuis, C., Wendt, A.S., Breivik, D.H., Myrvoll, O.H., 2017. Transformation of mindset– cost-effective collaborative well engineering & operation delivers record horizontal appraisal well in the barents. In: SPE/IADC 184654, Conference, the Hague, March 14–16, 2017.

Mathis, W., Strand, H., Hollinger, G., 2017. Case history: how to enable the horizontal development of shallow reservoirs. In: SPE/IADC 184667. Conference, The Hague, March 14–16, 2017.

Sivertsen, T., Strand, H., 2011. New well foundation concept, as used at a Norwegian Sea well. In: Presented at the SPE Arctic and Extreme Environments Conference & Exhibition, Moscow, Russia.

Wood Group Kenny, 2017. 400506-01-DR-TEN-002_RevB-Axial Stability Assessment.

CHAPTER

9

Deepwater Well Design

WELL DESIGN—ESSENTIALS

Introduction

This chapter outlines deepwater casing and liner design for exploration, appraisal, and development wells. Loads, strength calculations, and key design method aspects are outlined, from concept through to base case designs. Note: Computer software programs, then verify original hand-made design calculations.

Deepwater Well Design

General

Three responsibilities are to be met when conducting casing or tubular design:

1. Assured well and barrier integrity is fully compliant to industry standards and operating needs through delivering basis of designs that account for ***Maximum Load Concepts*** to be applied for each well's operating life cycle.
2. Design casing and tubular strings so that maximum life-of-well operating value results.
3. Provide clear and evident basis of design documents for operational personnel's use to assure life of design operating envelopes shall not be exceeded.

Variance within deepwater well designs exists as illustrated in Figs. 9.1, 9.2 and Table 9.1. Well design standards, loads, and best practice operating and engineering requirements, functions, and definitions for drilling and production strings and tubulars used are covered in this section.

Deepwater standard clearance casing designs range from low to medium risked normally pressured regimes. Fewer casings are required to deliver these wells to total depth objectives. Standard wellbore sizes and casing connections (Fig. 9.2) are more readily accommodated with little well bore enlargement needs.

To optimize specific well design cases, higher grade casing, e.g., 13⅝″ to 14″ (346.1–355.6 mm) casing to accommodate casings or liners (Fig. 9.2), to open windows of utilization opportunity for adaptive expandable tubular and liner technology. This then permits less subsequent casings and trips as the ultimate prize.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00009-0

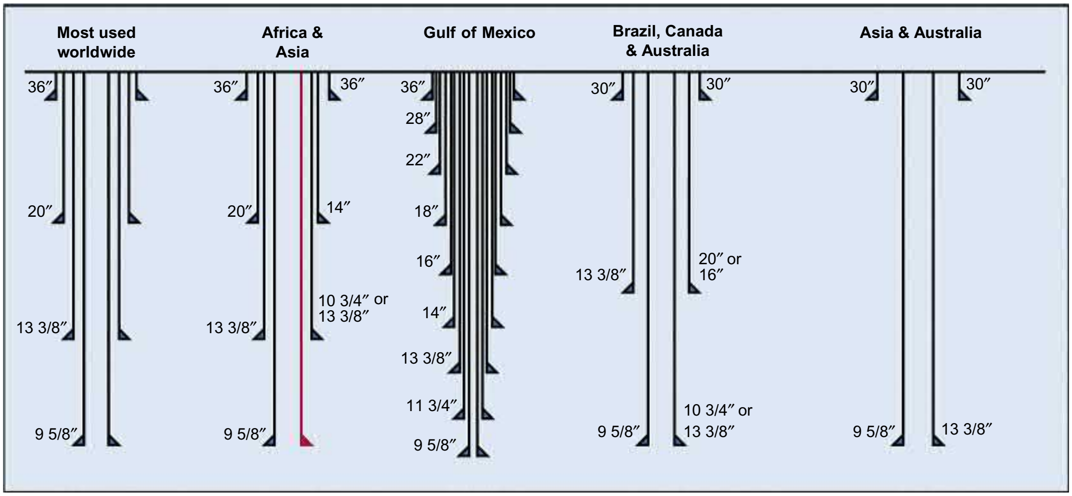


FIG. 9.1 Worldwide deepwater well design configurations. *Source: Ridge Engineering 2017.*

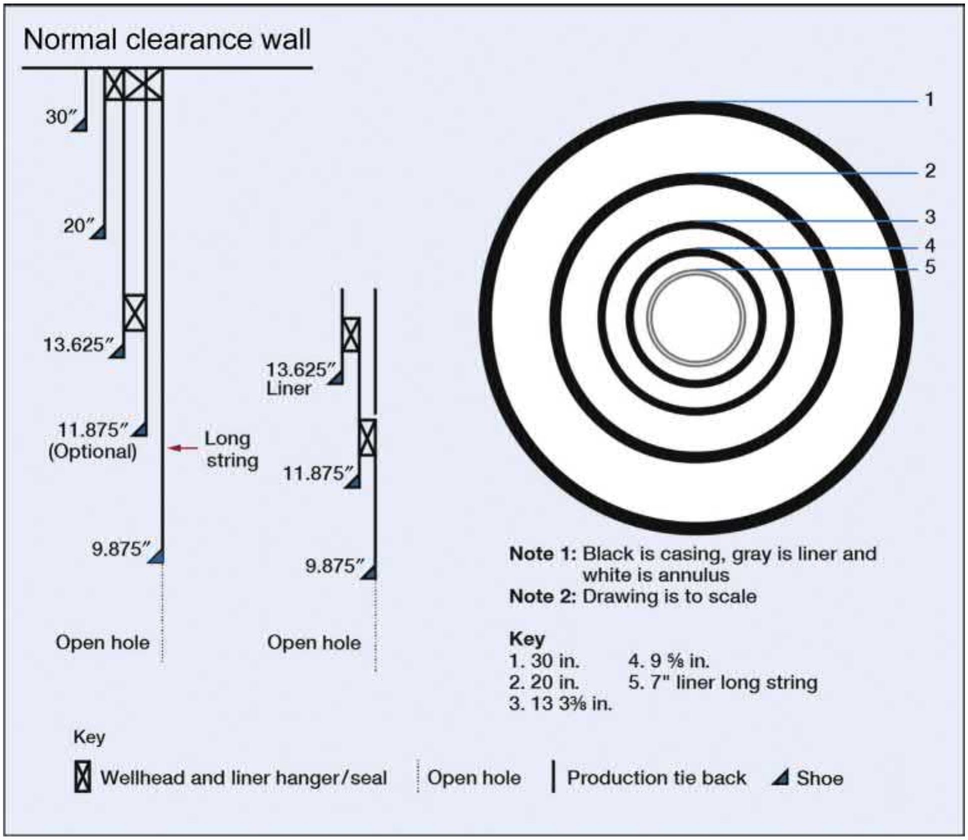


FIG. 9.2 Normal-clearance deepwater casing/liner well design examples. *Source: Kingdom drilling training 2018.*

TABLE 9.1 Deepwater Casing Types Sizes Clearances and Description

Casing	Description	Nominal & Tight Clearance Casing OD (in)	
Structural conductor and/or surface	Large OD casing; jetted in or drilled and cemented	36, 30″	42, 36″
	Additional casing run below structural casing, i.e., *for shallow flow risks*	26″	26, 28″
Surface	Casing including HPWHH: first casing string attached to subsea BOPs	20″	22″
Surface liner	Large diameter pipe run as a liner and hung off in a casing profile within the surface casing. *Often referred to as "surface extensions"*	n/a	18, 16″
Intermediate casing	Long casing string *12¼″ drift, sizes range 13⅜″ to 14″* with casing hanger in the subsea wellhead housing	13⅜″	13⅝″
Intermediate liner	Liner hung below intermediate casing/liner	n/a	13⅝, 11⅞″
Tieback string	Casing run from top of liner to the subsea wellhead housing, i.e., for increased pressure capacity and/or casing wear considerations	n/a	13⅝″ optional
Prod casing	Full string of production casing from below the objective interval with casing hanger in the subsea wellhead housing	9⅝″	n/a
Prod liner	Production casing run from below the objective section and hung in the intermediate casing or intermediate liner	n/a	9⅞″
Prod tieback	Casing from top of the production liner to the subsea wellhead housing	n/a	10¾″ × 9⅞″

Note: Table provides ***examples only***. Wells have variations in number of casing strings and sizes. Naming conventions also vary. Heavy-wall surface casing designs are used in certain cases. 13⅝″, 9⅝″, and other casings are often run as liners.

Well Design Problems and Complexities

Deepwater well problem design areas to recognize, identify, and consider are:

1. *Extended water and total depths* demand greater pressures, mud weights, volumes, and capacities to meet well design needs.
2. *Abnormal and subnormal pressure* regimes create reduced operating margins to exist.
3. *Increased burst* pressures at the wellhead and shoe can result.
4. *Equipment rating* and limitations both above and below the mudline must be fully assessed.
5. *Subsurface-specific geology* hazards/risks, e.g., shallow flow hazards, in situ hydrates, unstable zones, pressure transition intervals, salt, and regression zones all to be assessed.

6. *Metocean* (heave compensation) effects notably as operating conditions and environments deteriorate must be fully addressed.
7. *Extended operational durations* where casing wear and heat checking can then result due to extended drill pipe rotation and side loads must be accounted for.
8. *Thermal fluid expansion*, trapped annular pressure build up "APB," and wellhead growth loads.
9. *Greater wellhead and hanger load capacities* and reduced annular clearances that can result.
10. *Subsea BOP limitations,* e.g., shear limitations in regards to high-strength tubulars, annular elements sealing on large outer diameter (OD) casing, and potential for casing collapse.
11. *Presence of* H_2S, CO_2, accelerated corrosion due to colder seabed temperatures.
12. *Salt, wellbore inclination horizontal and extended reach* lengths that then further challenge and impacts design and safe operating window that exist.

To address potential design problem issues that often combined to increase complexity and challenge design, a variety of adaptive, innovative, and technological constructs have emerged to deliver safer designs.

For example:

1. *More casing strings solutions* required to deliver well objective at total target depths.
2. *Nonstandard casing sizes* to assure best-fit solutions result.
3. *Wellbore enlargement* often necessary to enable and deliver safer operating margins.
4. Use of *flush joint casing* connections and specialized centralization required to deliver a better technical solution without compromising operating integrity.
5. Some designs prefer a 13⅝″ casing in deepwater *vs.* standard 9⅝″ casing setting depth to reduce annular circulating friction pressures to safe operating levels.
6. *Liners run versus full casing* strings to the wellhead to deliver similar operating benefits.
7. Longer *heavier landing strings*, required due to resulting higher casing loads, and subsequent increased axial loads and hydraulic drillstring requirement that then exist.
8. Subsea wellheads are limited to a certain number of strings. Therefore, adaptive innovative and *new wellhead solutions* had to evolve to accommodate added strings required.

Deepwater Well Design: Guidelines

Deepwater design best-practice guidelines to consider are:

1. Designs shall be in accordance with existing operating standards practices, rules and regulations.
2. *Standard designs may not work*. The principle goal remaining is to assure that each design meets a well's intended safe, effective, and efficient use.
3. Initial wells must account for *maximum concept loads*, notably: burst pressure, based on full gas gradient from wellhead to at the casing or liner shoe.
4. Deepwater well design requires intimate *knowledge and experience* of pressure and subsurface wellbore mechanical stress regimes and well operating conditions. Until more accurate data exist:

(a) *Pressure estimation is predictive* based on the risk and uncertainty of seismic profiles data, from ranges established from similar wells.
(b) *Wells are more conservatively designed until proven data exist* for pressure regimes, H_2S, CO_2, well geological, and operating factors.
(c) *Pressure and wellbore stability models are derived and used* to aid more precise information to enable improved design management needs and delivery.

Further deepwater casing design aspects to be viewed are:

1. *Well-engineered and cost-effective designs* can result despite higher risks and uncertainties, notable if high-quality input data are met.
2. The ability to *meet all design objectives* and safely reduce the number of casing strings can have a substantial impact on well-life costs, again recommending a strong case for higher quality data acquisition to aid better interpretation to deliver more optimal designs.
3. Precise and *accurate selection of casing shoe depths* is paramount to drive the number of casing strings, design integrity, and operating life cycle success.
   (a) can add more casing strings, larger diameter wellbores, increased volumes, weights, capacities and associated rig, systems and operating requirements that result.
   (b) Risk-based designs that lack sufficient contingencies can on the other hand be far worse, e.g., *as exhibited by multiple wells that failed to reach target depths*.
4. Striking the right technical, innovative, and adaptive solutions balance by assuring competent persons are assigned is to be viewed as valued added, e.g., *use of close tolerance technological, expandable tubulars, liners, and innovative adaptive designs.*

Pressure Management and Design

Pressure management is a central driving design issue driven by the weakest wellbore exposures in conjunction with operating hazards *predicted* and *detected* as drilled. Design standards, rules, regulations, or best practices may not work that well in some cases where greater design skills and sensitivity analysis are required to be conducted to assure all risk, safety, and operating factors result in a fit for purpose design.

When reduced operating margins exist, far more precise engineering is demanded where personnel assigned must again identify and evaluate the specific limits when to *stop operating, run and set casing is the only safe option.* Key pressure-related elements are:

1. *As water depths increase*, the effect of the sea water hydrostatic gradient column adds less to overburden than the formation pressure. If higher pore pressures exist, additional casing strings are likely required.
2. *Fracture gradients* vary greatly depending on lithology and pore pressures that exist.
3. *Operating pressure windows* can be driven by regulations/standards, by well hydraulics, temperature, mud, cement and operating pressure effects. All to be carefully considered and accounted for.

Specific pressure management and well design aspects to be considered are:

PORE PRESSURE

1. Initial well designs are determined and derived from seismic interpretations. Note: These then further refined directly from well's drilling data, e.g., *resistivity and sonic plots, RFT pressures, well kicks, DST, and drilling parameter results.*
2. For seismic-derived pore pressure, matrix stress techniques in conjunction with interval velocity data obtained during drilling have been successfully used.
3. Velocity data from seismic shot points can be interpreted to predict initial pore and fracture pressure *vs.* depth trend.
4. Stacking velocities are considered less successful in estimating formation pressures.
5. At least, 800–1200 m of normally pressured clastic formations is estimated to be required to establish normal trends.
6. Formation pressures shall vary depending on the geological distance from the main pressure depositional centers. This to be accounted for in each well's design stage.

FRACTURE GRADIENT AND OVERBURDEN

1. *Fracture and temperature gradients* data are estimated in some degree via seismic data.
   - **(a)** Until compaction trends exist, temperature is estimated via interval velocity trends.
   - **(b)** Temperature profiles will change in abnormal or subnormal pressure zones and as a function of distance from main depositional centers.
   - **(c)** Below the top of the overpressure, temperature gradients may increase due to increased fluid content within the under compacted sediments.
2. *Leak-off tests or actual formation pressures* can be refined to offer predictive estimates.
3. *Overburden pressures* can be estimated reasonably if pressure curves are accessible from similar shallower basins that may exist. *Note: This method assumes similar formation densities. Actual densities are then used as wells are drilled.*
4. *Stress ratios* can be used to estimate using existing correlations as they are primarily a function of the overburden stress.
5. Using pore pressure estimations via geophysical methods, *fracture pressure* can be calculated using overburden pressure and stress ratio estimations. *This technique can be considered if valid data can be extrapolated from similar shallow water areas.*

Concept to Basis of Design Process

Outline

A fit for purpose deepwater well-design can be delivered by conducting a concept to basis of design scope review, design analysis and selection recommendation process as illustrated in Fig. 9.3.

Once the evident well data is gathered and assembled in the assess project phase. A *first phase right-scoping* pass or fail exercise is conducted as illustrated in Fig. 9.3 and Table 9.2. The output and outcome being to deliver recommended well designs to further process and evaluate. The first pass stage as represented in Tables 9.2 and 9.3 outlines the initial *right scoping* process to deliver a series of concept designs as shown in Fig. 9.4.

Options are one by one reviewed via a more refined process utilizing all project disciplines to scrutinize, determine, and evaluate that all evident and relevant design aspects, goals, values, and drivers are met. The final output from the refined stage assures that the best-fit designs result based on value, safety, risk, and technical rating. In the case as illustrated,

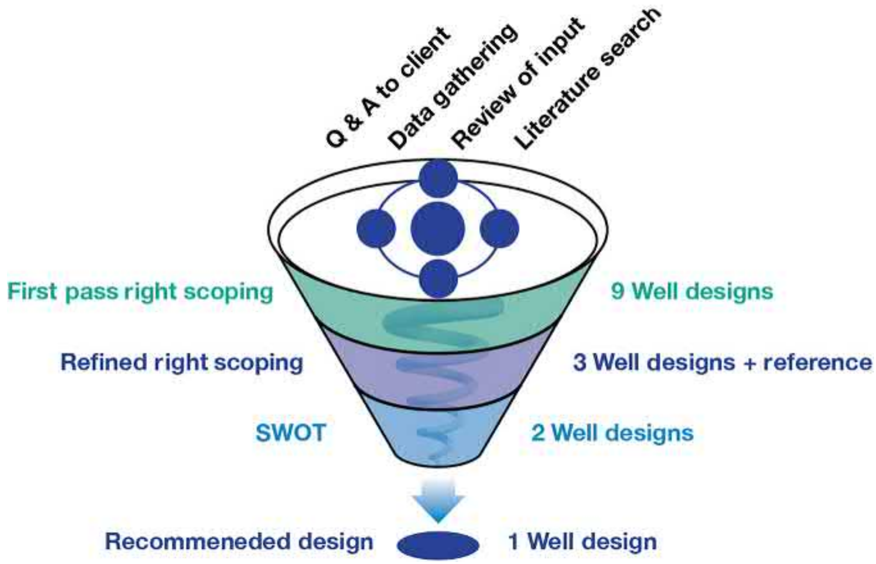


FIG. 9.3 Concept to basis of design process. *Source: Ridge Engineering 2017, reconstructed Kingdom Drilling training 2018.*

TABLE 9.2 Concept Design Drivers and Value Ranking Exercise

Priority	Driver & Value Issue	Explanation/Rationale	Weighting
1,2,3 etc.	• Safe well operation • Data acquisition • Well assurance/integrity • Technology application • Time/cost/quality • Standards, compliance	Each driver and value to be explained with rationale evidently provided	Weighting to be assigned to each key driver

three options resulted in addition to a comparative conventional design as shown Fig. 9.4 and Table 9.4.

These final design options then undergo the final detailed planning, design, well engineering, and operational assessment to select a base case and contingent design(s) through assuring all involved do the right things for all the right design reasons. *Note*: A conventional design is included in Fig. 9.4 to serve as a comparison standard to measure, assess, and evaluate base case and contingent designs that evolve against.

The first pass final scope design(s) selected in Figs. 9.4 and 9.5 (Fig. 9.6) are then worked and strengthened to deliver a base case option as shown in Fig. 9.7 Successful delivery of the final design is dependent on several evidence based factors, e.g.:

- Is site-specific survey data available to refine the well's structural construction installation, and design.
- High front-end-loading and engineering expertise.

TABLE 9.3 Right Scoping Summary Outcome From Assessment and Evaluation Work Conducted

Main Issue	Subissue/Requirement	1. Conventional Design	2. Conventional Design w/ Liner	3. Deep Set Conductor	4. CAN Ductor	5. Conventional + Expandable Casing	6. "Deep 16" Liner	7. CAN Slender	8. Slim Hole Design No Surface Casing	9. Slim Hole Design No Intm Casing
Safe well operation	Different well designs carry different safety exposure. The chosen design should keep the safety exposure (incl. HSE, well control, and well integrity) as low as reasonably possible	5	7	8	8	6	6	7	5	5
Data acquisition	The concepts affect the risk of achieving data acquisition differently. The solution should minimize risk of losing any reservoir information, and should maximize the delivery of data acquisition well objectives	8	8	8	8	9	6	8	8	8
Adaptive technology and Robustness	The well design should allow for contingencies. Concepts that minimize number of firsts, new technology development and "edge of technology" are considered beneficial, as is the "do-ability" or "ease of application" of the concept. However, the design should be checked against various deep water designs used worldwide and technology are considered robust if this has been successfully used on similar wells	8	10	4	10	6	5	7	5	5

Time, Cost & Quality	The well design should minimize CAPEX, by using cost-effective solutions as basis of design performance oriented and maximize market opportunities (manageable risk, efficient installation, low cost, compatible with well objectives), but compromising the main target of a safe well operation	5	7	6	9	4	5	9	8	8
Compliance to deep water standards	Ensure that the selected design is in compliance with existing standards.	10	10	10	10	10	10	10	10	10
Total weighted average		6.7	8.0	7.2	8.6	6.9	6.0	7.7	6.6	6.6
Rank		6	2	4	1	5	9	3	7	7

Source: Ridge Engineering 2017, Kingdom Drilling 2018.

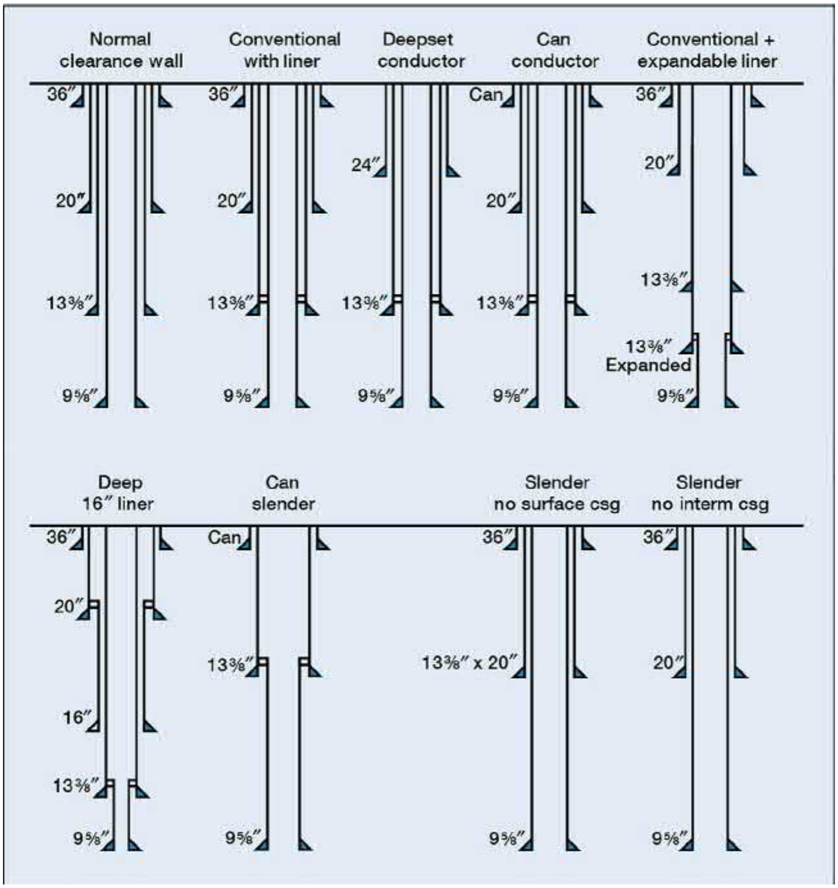


FIG. 9.4 Deepwater well designs concluded at the end of 1st concept design assessment phase. *Source: Ridge Engineering 2017, Kingdom Drilling training reconstruct, 2018.*

- Competence and experience of required service providers.
- Assured and diligent project hazard and risk management is applied.
- Continuous QA/QC of all engineering and service provisions conducted.
- Optimal casing setting depth selection.
- Riser margins duly considered.
- Kick tolerances and operational sensitivity fully assessed.
- Contingency priorities fully considered and addressed.

Fig. 9.8 presents the contingencies potentially required for the base case design selected. A due and diligent decision-making process again to apply to evaluate, recommend and select the contingency options for all the right reasons, e.g., *the reservoir sections to be drilled or where greatest operating hazards/risk are envisaged*. Final selection is also based on optimal reservoir, wellbore production diameter, and formation damage needs to fully assure effective and efficient design solutions are met.

TABLE 9.4 Refined Scoping Detailed Assessment Results

Main Issue	Subissue/Requirement	1. Conventional Design	2. Conventional Design w/Liner	3. CAN Ductor	4. CAN Slender
Safe well operation	Low Health Risk (reduced use of yellow and/or red fluids and chemicals, reduced manual handling, reduced pressure testing, less manual handling, less PCG)	7	8	9	10
	Low Safety Risk (less complex rig-up, reduced (heavy) lifts, reduced dropped objects, less logistics, less well control/integrity issues, Reduced tripping to reduce wear on riser, low risk of damage to reputation)	4	8	9	8
	Low Environmental Risk (Low risk for fluid spilt to sea, no emissions, reduced use of chemicals, low risk of damaged reputation)	6	8	8	9
Data acquisition	Allow for Data Acquisition according to geologist requirements (Concept which is designed to improve data acquisition and best possible reservoir description)	8	8	8	8
	Allow for Secondary Target implementation into the program (Concept which would allow for safely and cost efficient drilling of the Drombeg target will be highlighted)	8	8	8	8

Continued

TABLE 9.4 Refined Scoping Detailed Assessment Results—cont'd

Main Issue	Subissue/Requirement	1. Conventional Design	2. Conventional Design w/Liner	3. CAN Ductor	4. CAN Slender
Adaptive technology and robustness	Capitalize on Proven Technology and Concepts (ideally use technology with proven value/experience from industry both locally and international)	9	10	8	6
	Contingency Plans readily available and reduce the risk of needing to respud well to reach TD (Reduced risk of hole problems, flexibility to incorporate contingency plans without compromising the geological targets)	7	7	8	6
	Robustness of new technology solutions must be evaluated. Proven technology would reduce the need for contingencies in place	10	10	10	6
Time, Cost, & Quality	Effective Operations with low operational risk for NPT	6	7	8	9
	Avoid/Minimize Additional Cost for Drilling (risk increase/reduced casing design, fewer trips, etc.)	6	7	9	6
	Increased well design delivery Quality at the expense of added cost	5	7	9	6
Compliance to deep water standards	Ensure that well is in Compliance with all relevant standards and guidelines	10	10	10	10
Total weighted average		7.1	8.2	8.6	8.0
Rank		4	2	1	3

Source: Ridge Engineering 2017, Kingdom Drilling 2018.

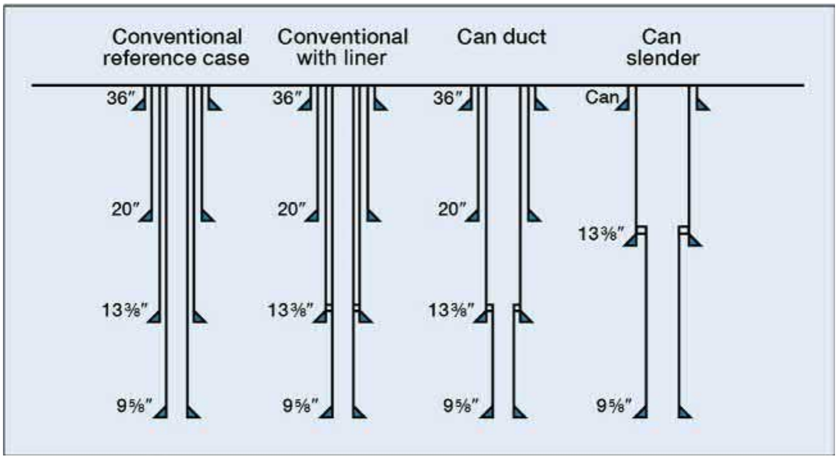


FIG. 9.5 Concept design after more refined and detailed scoping evaluation phase. *Source: Ridge Engineering 2017, Kingdom Drilling 2018.*

DEEPWATER DESIGN METHODOLOGY

Design Methods

Deepwater wells are designed for *maximum load limits and conditions anticipated*. This method will generally overdesign somewhat to secure that no casing element or component shall be exposed as the limiting (Failure) factor should a serious well control event ever or probably result. Later in development stages, when more precise and evident data exists. Only then shall less conservative design approach be approved. Further directives of well life-cycle design loads and magnitude that the tubular string or components will experience are:

1. *Establish capacity and suitability* of each individual tubular component in respect to loaded direction and underlying environmental and operating conditions.
2. *Compare load capacities at anticipated conditions*. Casing and tubulars then to be judged as acceptable for each application and that capacity exceeds anticipated loads.
3. Make sure *quality assurance, controlled inspection programs*, and well-defined design and operational criteria, standards, and limits are applied and compliant throughout.
4. Determine that all *design processes and string capacities exceed expected loads* with an additional safety factor applied.
5. As casing select options tend to be more restricted as water depths and total depths increase, or if an H_2S service is required, an appropriate design and risk assessment shall determine if H_2S-resistant casing grades is required or not.
6. Each string shall be built on the previous section's design, either isolating it from an internal load (*long-string*) or extending it further, e.g., *liner*.
7. A *systems design approach should be enforced* throughout to assure a fit-for-purpose integrated design is adopted.

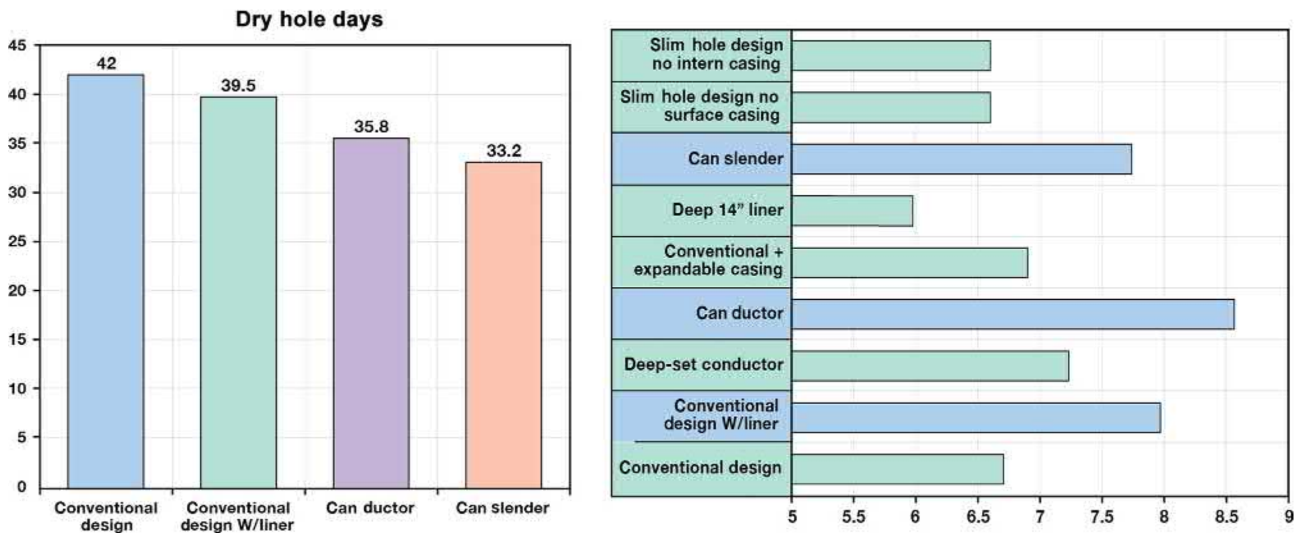


FIG. 9.6 Concept design, operational "dry hole" time estimates, and evaluation summaries. *Source: Ridge Engineering 2017, Kingdom Drilling 2018.*

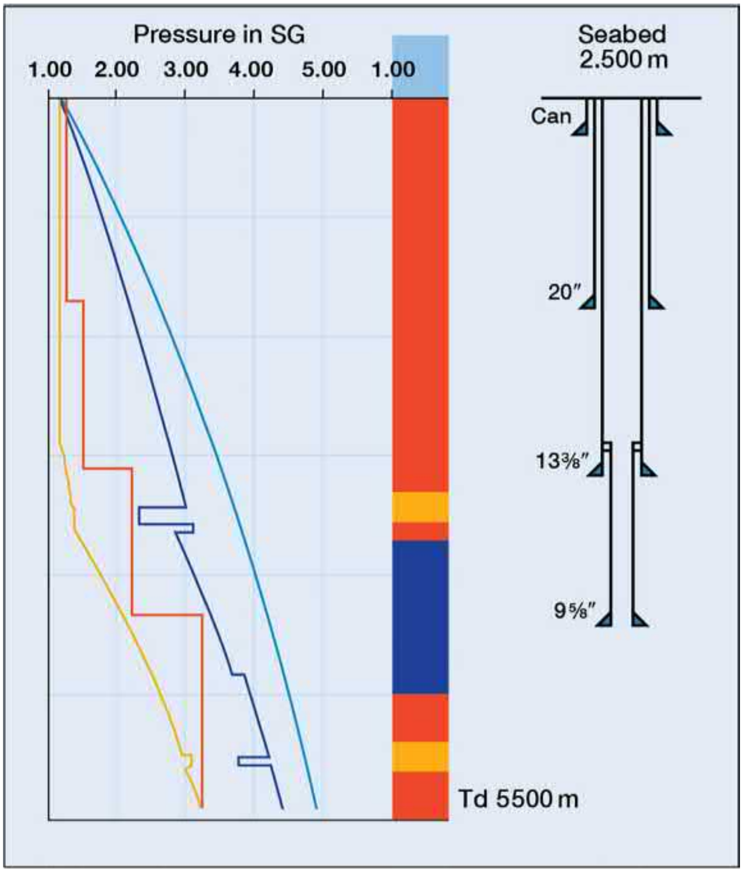


FIG. 9.7 Deepwater base case concept select design process. *Source: Kingdom Drilling 2017.*

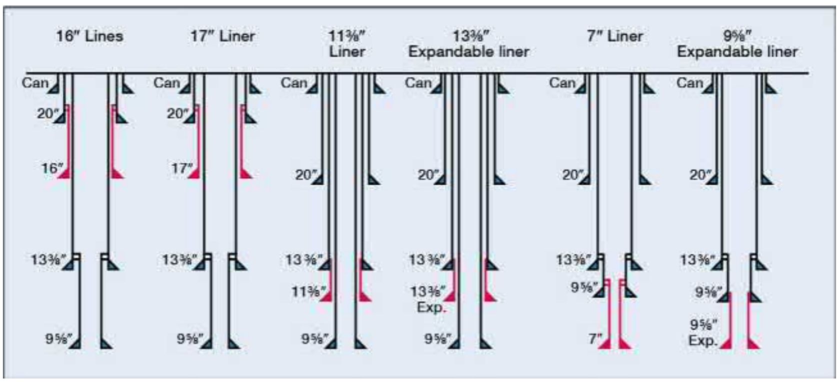


FIG. 9.8 Contingencies to be considered for base case design. *Source: Ridge Engineering 2017, reconstructed Kingdom Drilling training 2018.*

Note: All the above can vary during different stages of each well construct, design and operations phases, such that any well life cycle or operating change must be fully accounted for; e.g., *pressure loads on the well are typically lower during well exploration and construction vs. production, intervention and/or workovers.*

Deepwater Loads Theory and Application

Deepwater wells are designed for given sets of loading conditions as presented in this section. Loads are driven and based on company design standards, government regulations, component design, reliability considerations, local experience or field specific rules, considerations, and other best-operating practice factors.

Internal Loads are generally the first to be evaluated and then combined with ***External Loads*** so that ***Effective Loads*** result. Effective loads are then compared with casing and tubular strings available, associated systems, components and equipment ratings to ensure all design and operational application factors are compliantly met. ***A design factor approach*** is then further applied to assure effective, proven, and reliable well-life-cycle integrity outcomes and benefit result.

For ***exploration*** **and** ***appraisal loads***, well design construction, is typically shorter-duration loads and fit to serve this purpose, e.g., *partial well evacuation for collapse, deterministic kick volume for burst follow next sentence on from this one*.

Production loads on the other hand are much longer more variant and have to be well defined for a specific well-life-cycle duration, e.g., *burst based on shut-in pressures, collapse based on depletion loads, artificial lift, and thermal production loading or treating*.

Deepwater Design Strategy

Deepwater casing design consists of preliminary (concept) design and then a more detailed base case design as previously outlined. The intended use of the well is important with operating hazards, risks, and uncertainties fully addressed to optimize and assure well value and cost (Table 9.5). The loads used for design must accommodate all *life-cycle* changes at this stage of the design process. Various deepwater drilling and production loads can be divided into:

1. *Structural design*, i.e., *the well foundation, conductor, and structural strings.*
2. *Intermediate and production casing design*, i.e., *once the subsea BOP is installed.*

Wells are categorized on type and can be broadly categorized into three pressure groups, i.e., *normal*, *abnormal*, and *critically (complex) pressured regimes.* Irrespective of category, operating loads in deepwater require a far more detailed and rigorous design, based on hazards, risks, operating complexity, and life of well's design specific challenges.

Critical and more complex deepwater wells include wildcats, remote outpost wells, wells in sensitive environmental areas, with hydrogen sulfide, e.g., *with partial pressure >0.05 psia (NACE Standard—See MR0175-93),* wells in ultradeep waters and greater bottom hole depths, in conjunction with high bottom hole temperatures and shut in wellhead pressures >8000 psi.

Wells categorized as critical are far more exposed to greater design and operating hazards and risks than normally pressured wells. Irrespective of criticality, the planning and design of all deepwater wells shall incorporate a full assessment of the probability of well failure

TABLE 9.5 Generic Data Required for Preliminary and Detailed Well Design

Preliminary Design	Main Design
Formation properties	*Formation properties*
Pore pressure	Pore pressure
Formation strength (fracture pressure)	Mud weight
Temperature profile	Fracture gradient
Location of squeezing salt and shale zones	
Location of permeable zones	
Regions where formation stability is sensitive to mud chemistry, weight and exposure time	
Lost circulation zones	
Shallow gas	
Location of fresh water sands	
Potential for H_2S and/or CO_2 and/or hydrocarbons	
Directional data	*2D Well path design*
Surface location	2D build/hold profile
Geologic target(s)	Dogleg Severity
Well interference data	Dogleg Overrides
Minimum diameter requirements	*Design loads*
Minimum size to meet drilling objectives.	Burst Load definition
Logging tool OD	Collapse Load definition
Tubing size(s)	Axial Load definition
Packer requirements	
Subsurface safety valve OD (offshore well)	
Completion requirements	
Test equipment requirements	
Production test data	*Special considerations*
Packer fluid density	Connections
Produced fluid composition	Casing Wear
Maximum loads which may occur during completion, production, stimulation, and workover operations	Buckling
Annulus-operated test pressure requirements	Temperature deration
	Combined loading (Triaxial analysis)
	Squeezing salt and shale formations
	Annular pressure build up
Other	
Available inventory	
Regulatory requirements	
Rig equipment limitations	

(risks) that may prevent accommodating each well's life-cycle design or operating objectives. Common data required to perform the preliminary and detailed design stages are listed in Table 9.5.

PRELIMINARY DESIGN

Preliminary design gathers and interprets the relevant data and information gathered to selection initial concept design(s) casing sizes and shoe depths. The quality of the data has a significant impact on the casing and shoe depths selected. The greatest opportunities to be effective and efficient is should be stated is delivered during this task, e.g., *reducing the size and number of the casing strings required.*

DETAILED DESIGN

Detailed design phase is directly after the base case, contingent options and associated pipe weights, grades, and connections are selected for each relevant casing string. This process consists of comparing pipe ratings with *maximum design loads*, in compliance with company or specific safety (design) factors to be met.

Additional Aspects of Design

Key points when performing casing design are:

1. Precise selection of the required number of casing strings and each setting depth is critical to delivering an optimal yet robust deepwater well design. Too conservative can result in larger diameter pipes and significant added time/costs resulting. To be weighted against the alternate consequence of a less-than-conservative design and poor risk assessment where well outcomes and benefits may be severely compromised.
2. General guidelines for shoe selection depths are outlined. Local practices and experience for each operating area should be used to refine this process. To determine an initial estimate, a low, mid, and high pore pressure/fracture gradient/mud weight plot shall be constructed.
   - **(a)** The high case predicted pore pressure is expressed as an equivalent mud weight (EMW) plotted against depth. Lithological (formation tops, pressures, hazards, and major risks, etc.) information should also be noted.
   - **(b)** The predicted fracture gradient profile is similarly plotted. The fracture gradient profile is then offset to the left (at a less than designed predicted value) by safe operating to account for kick tolerance and all other associated pressure effect (AOPE) that can result during drilling, circulating, casing running, and cementing. Recommended offset value commonly applied are *0.3 ppg–0.5 ppg (36–60 kg/m^3) EMW.*
   - **(c)** The mud weight profile based on pore pressure and fracture gradient data is plotted. Generally, the optimal mud weight to be based left of the medium mud weight principle to afford both sufficient trip margins and to account for any wellbore stability issues that could potential result.
   - **(d)** If mud weights, formations related or well integrity pressure information is available from offset wells, these should be included on the plot for additional reference.

Shoe Depth Preliminary Selection

Using a generalized plot as illustrated in Fig. 9.9, initial casing shoe depths are determined, i.e.,

1. Start with an estimated operable mud weight at TD (A) *plus a safe operable pore pressure margin*, e.g., *0.3 ppg (36 kg/m^3)*, draw a vertical line until it intersects the design fracture gradient (B), *minus a safe operating fracture gradient margin*, e.g., *0.3–0.5 ppg (36–60 kg/m^3).* The intersect now represents the approximate shoe setting depth of the potential casing string.

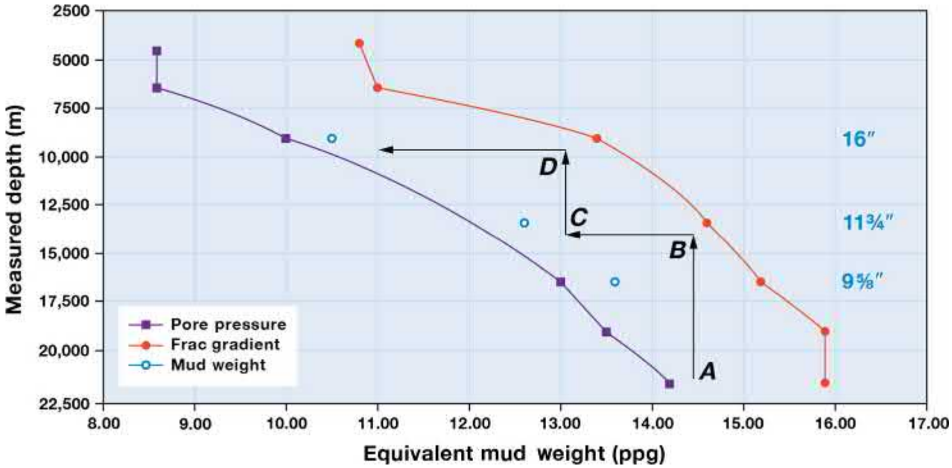


FIG. 9.9 Preliminary casing design: pore pressure, fracture gradient and mud weight graph versus depth.

2. In a similar fashion, using similar safe operating margins, draw a further horizontal line until it intersects the mud weight curve (C) and move up vertically until it again intersects the design fracture gradient curve (D) to deliver an approximate shoe depth of the next casing string.
3. Repeat the steps until all shoe depths are determined based on the mud weight and fracture gradient, safe operating limits and constraints to be applied

Once preliminary shoe depths are selected, sensitivity checks are required to validate the degree of operating kick tolerances that exist. Kick tolerances are defined as the maximum kick size that can be safely circulated out of the well via the subsea choke line without fracturing the weakest exposed wellbore formation.

In deepwater wells where narrower operating margins exist, standard operating or regulated kick tolerances are often impossible to achieve. Compromise, management of change and further risk mitigation, e.g., sensitivity analysis, then should be discussed, addressed, and resolved to address this issue.

Other factors that can impact shoe depths are:

- *Operating and regulatory requirements*, to be fully understood prior to commencing design.
- *Pressure management and wellbore stability concerns*. This can be a function of mud weight, deviation, or stress uncertainties within specific formation interval sections.
- *Shallow geohazards*.
- *Deeper geological*, *reservoir*, well conditions or operationally related *hazards*.

A flow chart of wellbore and casing size Fig. 9.10 is used to select and assess combinations to use. Due to the increased number of strings often required in deepwater, wells can demand several larger diameter strings due to the low soil strength, fracture gradients, and subsurface issues such as shallow water flows, geopressures, and geohazards that exist. As wells deepen added requirements of pore pressure increase, narrower operating margins, hydrocarbon presence, operating limits or difficulties all cumulate to result in more casing strings required.

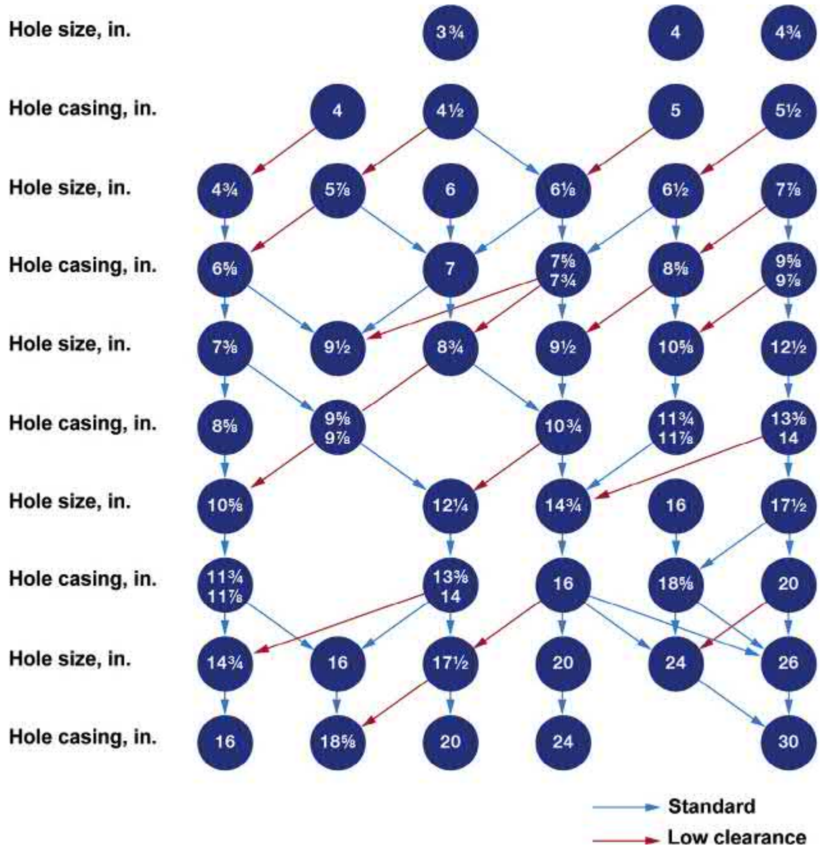


FIG. 9.10 Generic casing and wellbore selector chart. *Source: Kingdom drilling, deepwater casing design manual.*

Well objectives and subsurface issues are dictated through an appropriate geological program issued for a particular well's project. Subsea development wells to be designed based on a bottoms-up acquisition reservoir or petroleum production requirement, e.g., *to deliver an 8½″ wellbore planned total depth* as illustrated in example wells shown in Fig. 9.11.

Typical Deepwater Casing Program

Well design and casing programs must address all ***installation, drilling***, and ***production*** conditional load perspectives. ***Installation*** shall consider running, cementing, and plug bump loads. ***Drilling*** should additionally consider pressure testing, the maximum drilling mud weight (MW), and all well control assurance issues, i.e., *safe operable kick tolerances taking into account type of kick (liquid or gas), kick intensity, wellbore geometry and volumes, lost circulation, and loss/gain risk-based operating scenarios.*

Production well design (*that is not reviewed in any great depth in this guide*) shall consider tubing leaks near the wellhead, water injection down the casing, drill stem testing work, shut in pressures, and associated collapse loads.

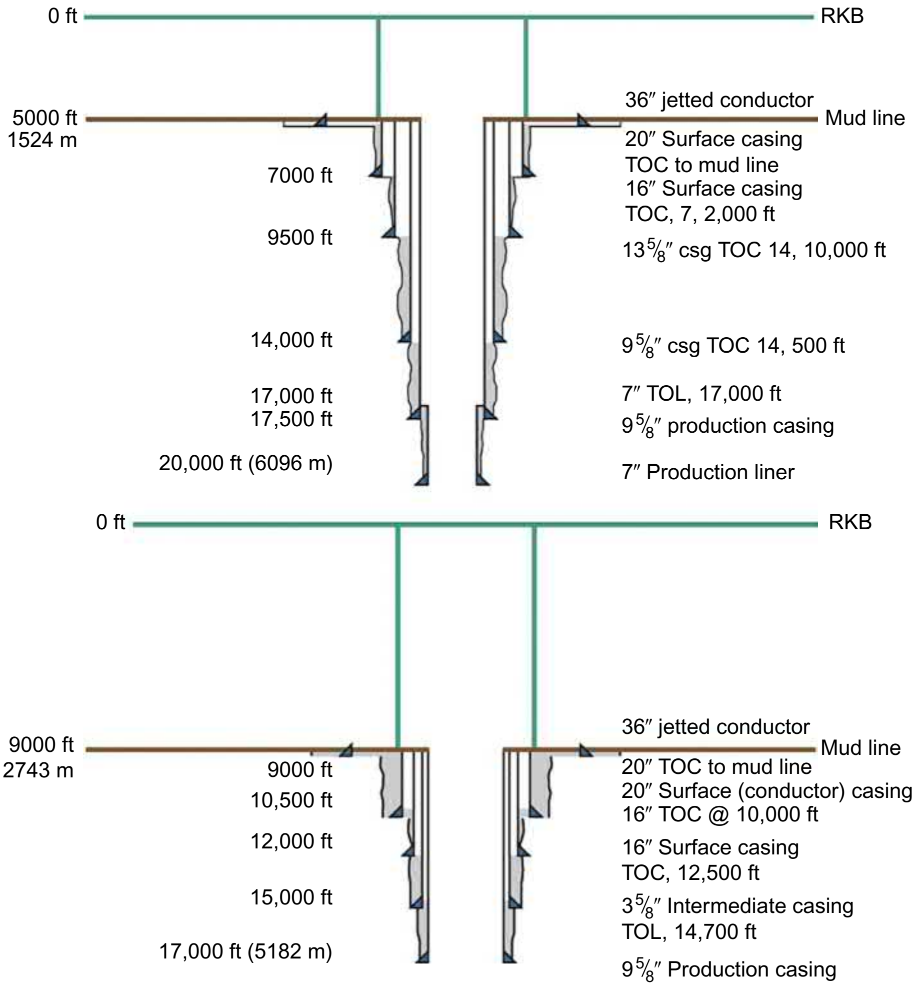


FIG. 9.11 Sketches of two example deepwater "Base-case" well programs for 5000 ft (1524 m) and 9000 ft (6096 m) WD BRT.

Adopting this approach, all maximum loads are thereby accounted for by design. Each string addressed using the terminology for casing strings as defined in their order of installation, e.g., *drive* or *structural (foundation)*, *conductor (structural)*, *surface*, *intermediate* and *production casing and liners*, as illustrated in wells shown Fig. 9.11.

Maximum Anticipated Wellhead Pressure "MAWP" Method

The maximum anticipated pressures for deepwater casing design as applied in this guide, uses a modified method approach that considers the percent of mud and gas present in the wellbore based on depth of the sediments where the wellbore's weakest fracture is expected to result, i.e., typically but note *not always* the casing shoe. As presented in Table 9.6, and Figs. 9.12–9.15.

TABLE 9.6 Mud and Gas Factors as a Percentage of Mud or Gas in Subsea Wellbores

Depth TVD_{td}	Mud Factor "MF" (%)	Depth TVD_{td}	Gas Factor "GF" (%)
Up to 12,000 ft (3658 m)	30	Up to 12,000 ft (3658 m)	30
12,000–15,000 ft	40	12,000–15,000 ft	40
≥15,000 ft (4572 m)	50	≥15,000 ft (4572 m)	50

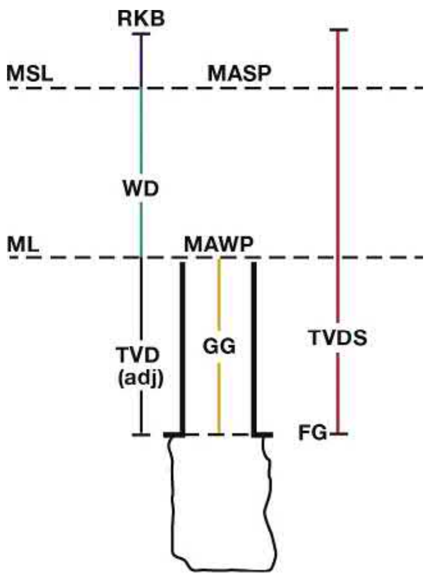


FIG. 9.12 Fracture at casing shoe less mud/gas column.

The maximum annular wellhead pressure (**MAWP**) that results at the subsea wellhead is a net burst pressure *vs.* a maximum anticipated surface pressure (**MASP**) standard, as normally used. Assumptions to calculate MAWP for *drilling* and *production strings* are as follows.

– ***Drilling strings*** are defined as the *structural, conductor, surface, intermediate, and associated liners* not exposed to production operating conditions and environmental loads.
– ***Production strings*** are all casing s and liners run and installed thereafter.

The designer predicts *bottom-hole wellhead and surface pressures* for *each string* based on *pore-pressure, fracture gradient*, and *mud weight* profiles to be applied. Well designs and permits submitted to the regulators and well examiners, shall indicate the maximum anticipated surface pressure (MASP). For deepwater wells should further address the maximum allowable wellhead pressure (MAWP) for all relevant strings during the life of the well. In the planning process, the designer shall assure that maximum loads are used in regards to influx "kick or loss circulation" conditions that could result, e.g.:

1. *One-third replacement of mud with gas*, fracture gradient less a gas column,
2. *Kick tolerances*, fully demonstrating sensitivity analysis are accounted for,

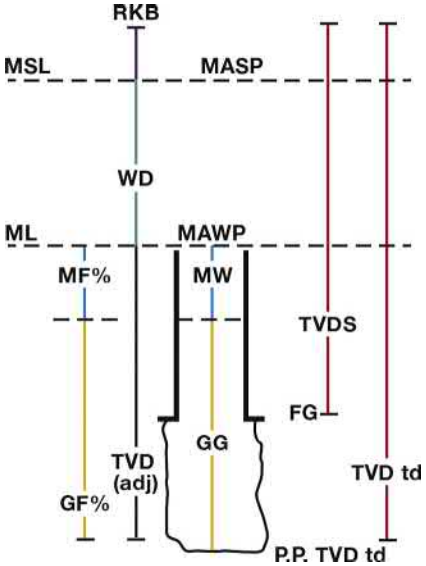


FIG. 9.13 Bottom-hole pressure less mud/gas column.

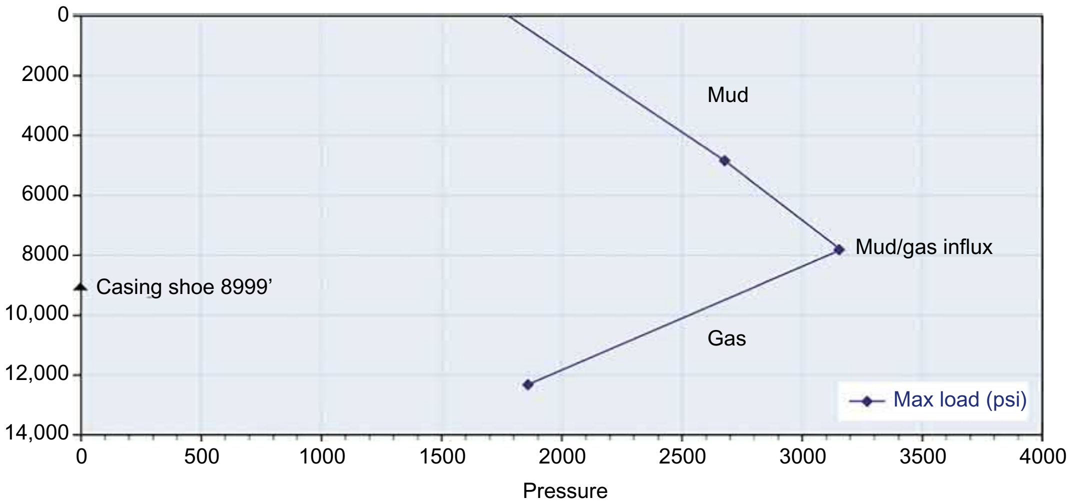


FIG. 9.14 Deepwater well design; MAWP; mud over gas representation.

3. *Pore pressures* less gas mud columns,
4. *Bottom-hole pressure/shut-in surface pressure* of a gas well using the first approximation of the integral.

All aspects are used to calculate *maximum anticipated surface* and *wellhead pressures*, where there is currently no universally accepted standard assurance for deepwater w.r.t influx, shoe, weak point, wellhead or exactly how to determine and evaluate anticipated surface pressures.

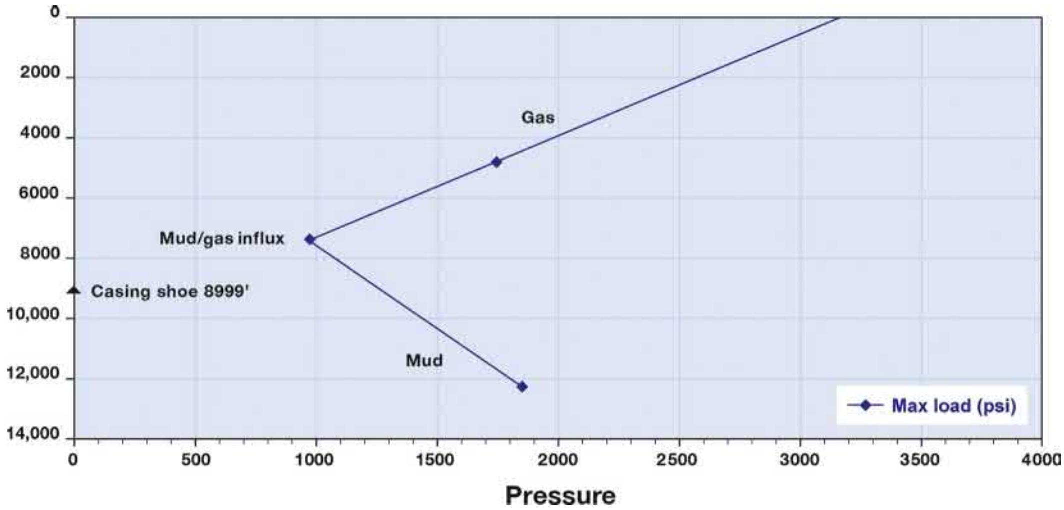


FIG. 9.15 Deepwater well design; MAWP; gas over mud representation.

MAWP evolved for subsea floating drilling wells to define *net burst pressures at the mudline*. ***MASP*** now inappropriate as well-related events are not evidently associated with surface pressures related to the subsea wellhead and casing strings. In summary, MASP and MAWP as illustrated in Figs. 9.12 and 9.13 provides a more precise determination of all evident pressures at subsea wellheads for subsea and deepwater wells.

Definitions

MAWP is the "maximum anticipated wellhead pressure" (*net burst pressure*) at the mud line based on the pore pressure, fracture gradient, and mud weight profile of a well. MAWP considers the impact of water depth on the burst load (*net burst pressure*) at the wellhead.

MASP is the "maximum anticipated surface pressure" based on the pore pressure, fracture gradient, and mud weight profile of a well. MASP is a shelf (shallow water) term and is reported along with MAWP for subsea wells.

MASP subsea (MASPss) for maximum load assessment assumes choke lines are gas filled while handling a well influx. The method takes a broad view of the influx volumes based on *total depth and depth below the mudline* of the well.

MAWP for Drilling Strings

The *MAWP* method takes a wider scoped interpretation regarding influx volumes based on depth, i.e., *total and depth below the mudline* of a deepwater subsea well. Standards and assurance assume that:

1. The influx volumes become reduced as the well gets deeper.
2. Full evacuation of a subsea *drilling casing* string shall not result.
3. *MAWP* model assumes *mud over gas* to project the maximum pressure the casing shall be exposed. Note: As in line with maximum load casing concept used on all subsea strings.
4. The $MASP_{ss}$ subsea rig assumes *gas over mud*.

MAWP and $MASP_{ss}$ events are modeled at two distinct times as they result.

1. ***Mud over gas*** (Fig. 9.14) occurs when the well is initially shut in during some type of well control event where the maximum loading is imposed on the casing.
2. ***Gas over mud*** (Fig. 9.15) occurs later in the well control event where the load on the casing is less but the *MASP* becomes larger.

The assumptions (*basis of TVD in calculations, depth of mud gas interface, impact on casing*) in determining ***MAWP*** and ***MASP*** are different as these two events result at distinct and different times in the drilling life of the well.

The attached diagrams are *net loads* (*Net load, the difference between internal and external loads*) with 8.6 ppg (1031 kg/m^3) seawater fluid gradient as the backup. See attached diagrams. Note: To model an influx, in deepwater a broader assumption is made as to the volumes of mud and gas present in the wellbore (based on well TVD_{td}) from the resulting influx or circulating out the kick.

MAWP ASSUMPTIONS

1. Depths to 12,000 ft (3658 m) TVD_{td}—*70% gas and 30% mud.*
2. Depths 12,000 ft (3658 m) to 15,000 ft (4572 m) TVD_{td}—*60% gas and 40% mud.*
3. Depths below 15,000 ft (4572 m) TVD_{td}—*50% gas and mud.*

A broad assumption as to the gas gradient is made as a function of depth.

1. Depths to 10,000 ft (3048 m) TVD_{td}—*0.1 psi/ft (231 kgf/m^3)*
2. Depths below 10,000 ft (3048 m) TVD_{td}—*0.15 psi/ft (346 kgf/m^3)*

MAWP calculation assumptions (Figs. 9.14 and 9.15):

1. Pore pressure based on TVD_{td}.
2. % mud and % gas in the wellbore and mud gas interface based on TVD_{adj}.
3. The depth used to determine the % gas and % mud in the wellbore based on TVD_{td}.
4. Gas gradient based on TVD_{td}.
5. ***Subsea—****mud over gas* columns to the mud line. (*Assumes kick doesn't enter the riser*.)
6. The *MASP* for subsea assumes choke/kill lines gas filled *gas over mud* during *handling/circulating out an influx; use gas gradient based on well depth (TVD_{td}).*

FRACTURE GRADIENT METHOD EXAMPLE

$$MAWP = \left(\left(FG \times 0.052 \times TVD_s\right) - \left(GG \times TVD_{as}\right)\right) - \left(WD \times 0.052 \times 8.6\right)\right)$$

Terms defined:

- FG = fracture gradient expressed in ppg
- TVD_s = true vertical depth of the casing shoe, feet
- TVD_{as} = true vertical depth in feet of the casing adjusted for water depth and RKB (TVDs minus (WD plus RKB))
- GG = gas gradient in psi/ft; above 10,000 ft TVD_s use 0.1 psi/ft; 10,000 ft TVD_s or below use 0.15 psi/ft
- WD = water depth, ft

$$\text{MAWP} = (\text{PP} \times 052 \times \text{TVD}_{td}) - (\text{MF} \times \text{MW} \times 0.052 \times \text{TVD}_{adj}) - (\text{GF} \times \text{GG} \times \text{TVD}_{adj}) - (\text{WD} \times 8.6 \times 0.052)$$

Bottom Hole/Pore Pressure Method

Terms defined:

- PP = pore pressure expressed in ppg
- TVD_{td} = true vertical depth in feet from RKB to point where pore pressure is located
- TVD_{adj} = true vertical depth of the deepest hole that the casing will be exposed to drilling loads adjusted for water depth and RKB
- MF = mud factor as a per cent mud in *wellbore* based on TVD_{td} of well. Well bore subsea does not include riser or choke/kill lines (Figs. 9.14 and 9.15)
- GF = gas factor as a per cent gas in well bore based on TVD_{td} of the well. Well bore subsea does not include riser or choke/kill lines

A mud gas interface assumes mud over gas and is defined by: WD + RKB + (TVDadj × MF)

- TVD_{td} = true vertical total depth RKB of well, ft
- TVD_s = true vertical depth RKB of casing shoe/ft
- TVD_{as} = true vertical depth of casing shoe (TVD_s − WD − RKB)
- TVD_{adj} = true vertical depth in feet of deepest hole that the casing will be exposed to drilling loads adjusted for water depth and RKB; (TVDtd − WD − RKB)
- GG = gas gradient in psi/ft; use 0.1 psi/ft to 10,000 ft; below 10,000 ft use 0.15 psi/ft
- WD = water depth in feet
- Density of seawater = 8.6ppg
- MAWP = maximum anticipated wellhead pressure, psi

Subsea MASP

Subsea (ss) $MASP_{ss}$ is calculated assuming the choke/kill lines are *gas over mud* filled with the gradient a function of well depth. MASP for subsea wells will use the terminology MASP at the rig floor or $MASP_{rf}$

$$\text{MASP}_{rf} = \text{MAWP} - ((\text{WD} + \text{RKB}) \times \text{GG}) + (\text{WD} \times 0.052 \times 8.6)$$

- MSL—mean sea level
- ML—mudline

$$\text{TVD}_{adj} = \text{TVD}_s - \text{WD} - \text{RKB}$$

- Depth of mud gas interface = WD + RKB + (TVDadj × MF)
  Example calculation:

- Casing depth TVD_s = 8999 ft, FG = 12.5 ppg
- TVD_{td} = 12,263 ft, MW_{td} = 12 ppg
- MF = 0.4, GF = 0.6
- PP = 11.5 ppg GG = based on $TVD_{td} \rightarrow$ 0.15 psi/ft
- WD = 4795 ft, RKB = 72 ft

Fracture (FG) at casing shoe less gas column

$$
\begin{aligned}
\text{MAWP} &= (\text{FG}\times 052\times \text{TVD}_{s}) - (\text{GG}\times \text{TVD}_{as}) - (\text{WD}\times 0.052\times 8.6)\\
&= (12.5\times 0.52\times 8999) - (0.15\times 4132) - (4795\times 0.052\times 8.6) = 3085\,\text{psi}
\end{aligned}
$$

Bottom hole pressure/pore pressure (BHP/PP) less a gas mud column

$$
\begin{aligned}
\text{MAWP} = {} & (\text{PP}\times 0.52\times \text{TVD}_{td}) - (\%\text{Gas}\times \text{GG}\times \text{TVD}_{adj})\\
& - (\%\text{Mud}\times 0.052\times \text{MW}_{td}\times \text{TVD}_{adj}) - (\text{SW}\times 0.52\times \text{WD})
\end{aligned}
$$

$\text{TVD}_{adj} = 12{,}263–4795–72$ $\text{TVD}_{adj} = 7396$ ft

MAWP = (11.5 × 0.52 × 12,263) − (0.6 × 0.15 × 7396) − (0.4 × 0.52 × 12 × 7396) − (8.6 × 0.52 × 4795)

MAWP = 2677 psi

Mud gas interface = 4795 + 72 + (7396 × 0.4) = 7825 ft

MASP_{rf} = (11.5 × 0.052 × 12,263) − (0.6 × 0.15 × 12,263) − (0.4 × 0.052 × 12 × 12,263)

$\boldsymbol{MASP_{rf}}$ **= 3168 psi**

MAWP Production Strings

MAWP ASSUMPTIONS

Production casings are to be designed using *MAWP* based on predicted pore pressure minus a gas gradient to the wellhead unless sufficient and compelling data exist to design otherwise. These exceptions will probably be rare. The approach is conservative, but not excessively so. As the production casing must be able to withstand the internal pressure resulting from a tubing leak, and if designed using an oil gradient-based MAWPp, this may not be suitable if a gas completion is subsequently required.

For exploration and delineation wells, as uncertainty to the type of hydrocarbons that may exist in potential target reservoirs, it is safer to apply the maximum load case and design for gas, e.g., *numerous instances of wells encountering gas when oil was expected*. Furthermore even during field development, uncertainty often remains about reservoir drive mechanisms, gas cap extents, and fault block and permeability boundaries. Gas could also be encountered unexpectedly, or an up structure well could gas-out at a relatively high reservoir pressure. If a tubing leak occurred in any of these cases, and the production casing is designed on an in situ oil gradient, *the production casing and barrier element required* shall be inadequate.

MAWP Calculation Methodology

In order to calculate the internal burst pressure exerted by a gas column, an accurate gas gradient is required. A gradient, which is a function of formation pore pressure and depth, is preferred, since assumption of a constant gradient (*such as 0.1 psi/ft (231 kgf/m*^{3})) can lead to significant errors as depths and pressures increase. The recommended method for calculating the *MAWP* of a full column of gas, which is a modification of a major's operational method developed as illustrated in this section and presented via examples and further spreadsheet examples as shown in Tables 9.7 and 9.8. Note that due to the inclusion of the final term in the

TABLE 9.7 MAWP Spreadsheet Example for Drilling Strings Subsea Wells

Maximum Anticipated Wellhead Pressure Calculations Drilling for Subsea Wells

Casing 13.375* @ 8999′ WD 4795′ Rig RKB 72′ TVD_{td} 12,263′

Fracture at casing shoe less gas column

MAWP= ((FG 0.052 * TVD_s) – (GG*TVD_{as}) – (SW*0.052*WD))*

FG	Fracture Gradient at shoe, ppg	12.5 ppg
GG	Gas Gradient	0.15 psi/ft
TVD_s	TVD of Casing Shoe	8999 ft
TVD_{as}	TVD adjusted to well head using shoe depth, water depth, and RKB	4132 ft
SW	Sea water density, 8.6 ppg	8.6 ppg
WD	Water depth, ft	4795′ ft
MAWP	3.085 psig	
MASPrf=	4500 psig	

Notes: Gas gradient will be 0.1 psi/ft for depths above 10,000′, a gradient of 0.15 psi/ft will be used below 10,000′

Bottom hole pressure less gas mud column

*MAWP= ((PP*0.052* TVD_{td}) – (%Gas* GG* TVD_{adj}) – (%mud * 0.052* MW_{td} * TVD_{adj}) – (SW*0.052*WD))*

PP	Pore pressure @ deepest depth drilled below casing	11.5 ppg
%Gas	Gas percentage use in Calculations	60%
%Mud	Mud percentage use in Calculations	40%
MW_{td}	Highest MW used below the referenced casing, ppg	12.0 ppg
TVD_{td}	TVD of deepest hole the casing will be exposed to	12,263 Feet
GG	Gas gradient, psi per ft	0.150 psi/ft
TVD_{adj}	TVD adjusted to well head using water depth and RKB	7396 ft
SW	Sea water density, 8.6 ppg	8.6 ppg
WD	Water depth, ft	4795 ft
MAWP 2677 psig		
Mud/Gas Interlace = ft		
MASPrf 3169 psig		

Notes: For depths above 12,000′ a 70% gas column will be used. Between 12,000′ and 15,000′ a 60% column will be used, and 50% for depths 15,000′ or deeper. Gas gradient will be 0.1 psi/ft. for depths above 10,000′; a gradient of 0.15 psi/ft. will be used below 10,000′.

Maximum Anticipated Wellhead Pressure

MAWP = 2677 psig

TABLE 9.8 MAWP Spreadsheet Example Calculations for Production Casing for Subsea Wellheads

Maximum Anticipated Wellhead Pressure Calculations for Production Casing for Subsea Wellheads
Casing 9 5/8 @ 18,000′ MD WD 4920′ TVD_{td} 16,000′ Rig RKB 80′
Modified Method for Calculating Net $MAWP_p$
Notes:

- Net $MAWP_p$ is calculated using the Modified Chevron Method (given below)
- Internal (burst) component of $MAWP_p$ is based on expected pore pressure less a gas gradient to the wellhead
- External component of MAWPp is the hydrostatic pressure of seawater (the final term in the equations below)

For TVDadj < 2500′
$MAWP_p = (0.052*PP_{TVDtd}*TVD_{td}) - (0.03075*SG_{gas}*TVD_{adj}) - (0.052*WD*8.6)$
For TVDadj > 2500′
$MAWP_p = (C_1*SG_{gas}*TVD_{adj}) + (C_2*PP_{TVDtd}*TVD_{td})) + C_3 - (0.052*WD*8.6)$
$MAWP_p$ = Net Maximum Anticipated Wellhead Pressure (i.e., @ mudline) for production casing (psi)
TVD_{td} = True vertical depth of well (feet)
TVD_{adj} = True vertical depth of well below the mudline (feet)
SG^{gas} = Gas-specific gravity (if unknown, use 0.65)
PP_{TVDtd} = Formation pressure gradient (ppg)
WD = Water depth (ft)
$C_1 = -0.161$
$C_2 = 0.0488$
$C_3 = 260$
Calculations of maximum anticipated wellhead pressure (production)

TVD_{td} = True vertical depth of well (or zone of interest) (ft)	16,000′
TVD_{adj} = True vertical depth of well (or zone of interest) below the mudline (ft)	11,000′
SG_{gas} = Gas-specific gravity (if unknown, use 0.65)	0.70
PP_{TVDtd} = Formation pressure gradient (ppg)	13.0 ppg
WD = Water depth (ft)	4920′
RKB = Rig KB above mean sea level (ft)	80′

MAWPp = 6970 psi

equations, the *MAWP* calculated using this method is a net pressure; i.e., *the calculated internal pressure of the gas column is reduced by the static head of the seawater column.*

For $TVD_{adj} > 2500$ ft:

$$MAWP_p = \left(C_1^* SG_{gas}{}^* TVD_{adj}\right) + \left(C_2^* PP_{TVDtd}{}^* TVD_{td}\right) + C_3 - \left(0.052^* WD^* 8.6\right)$$

For $TVD_{adj} \le 2500$ ft:

$$MAWP_p = \left(0.052^* TVD_{td}{}^* PP_{TVDtd}\right) - \left(0.03075^* SG_{gas}{}^* TVD_{adj}\right) - \left(0.052^* WD^* 8.6\right)$$

Where:

- $MAWP_p$ = Net maximum anticipated wellhead pressure, production casing (psi)
- TVD_{adj} = True vertical depth of well (or zone of interest) below the mudline (ft)
- TVD_{td} = True vertical total depth of well from RKB (ft)
- SG_{gas} = Specific gravity of gas (if unknown, use $SG_{gas} = 0.65$)

- PP_{TVDtd} = Pore pressure anticipated at TVD_{td} of well (or zone of interest) (ppg)
- WD = Water depth (ft)
- $C_1 = -0.1610$; $C_2 = 0.0488$; $C_3 = 260$

MAWP DEEPWATER CALCULATION EXAMPLE

The $MAWP_p$ for a reservoir encountered at TD of a well drilled from a semisubmersible rig given the following information is illustrated as shown:

Wellhead Location = Mudline.

RKB = 80 ft; WD = 4920 ft
MD_{td} = 18,000 ft; TVD_{td} = 16,000 ft
PP_{TVDtd} = 13 ppg; SG_{gas} = 0.70

(1) *Calculate TVD_{adj}*

TVDadj $= TVD_{td} - WD - RKB = 16{,}000 - 4920 - 80 =$ **11,000 ft**

(2) *Calculate $MAWP_p$*

Since $TVD_{adj} > 2500'$,

$MAWP_p = (C_1 * SG_{gas} * TVD_{adj}) + (C_2 * PP_{TVDtd} * TVD_{td}) + C_3 - (0.052 * WD * 8.6)$
$MAWP_p = (-0.1610 * 0.70 * 11000) + (0.0488 * 13 * 16{,}000) + 260 - (0.052 * 4920 * 8.6)$
MAWPp $= (-1240) + (10{,}150) + 260 - (2200) =$ **6970 psi.**

Well Integrity/Pressure Testing

The designer should check the adequacy of the design relative to *MAWP* (Note: *MASP if using deepwater surface BOP stacks*) and casing pressure test. Regulators generally prescribe a pressure test of each casing string prior to drilling cement plug (*or production casing and liners where drill out is not planned*) to 70%–80% of the minimum internal yield pressure of the casing or as otherwise approved or required by the regulator or operator's well examiner.

The casing pressure test is also used as a calibration for tests for well integrity tests, e.g., a leak off test at the casing shoe. Pressure tests are applied on top of a column of fluid, typically drilling mud, in which the casing was run. The casing test pressure *must consider both* **internal** *and* **external fluids** to determine the test pressure shall not exceed minimum internal yield at any point in the casing string. The casing shoe is generally exposed to the largest load applied surface pressure. Thus, the casing test pressure shall be calculated and performed considering the fluids anticipated in the hole. During operations if fluids and pressure change test pressure must be re-evaluated. Casing test pressure = 70% of minimum internal yield − (MW in well—backup fluid) × 0.052 × TVD_s). *Note*: The backup fluid is typically assumed to be a 9.0 ppg (1078 kg/m^3), i.e., normally pressured fluid gradient.

Another regulated approach may be to test to the MAWP or 70% of internal yield. If this approach is taken, the MAWP should be increased, i.e., *typically 500 psi (3447 kPa) above the calculated MAWP*, to provide suitable margins for the casing LOT, which may be in the same pressure range as the pressure test. The pressure test must be higher than the casing shoe LOT to eliminate any concerns in regards to well integrity of the casing string and LOT pressures.

Precision in predicting pressure integrity tests of casing shoes typically uses a 0.5 ppg (60 kg/m^3) accuracy that should be less than *MAWP* plus 500 psi (3447 kPa)margin. The case for using *MAWP* rather than 70% of internal yield may also appear when one designs a string but utilizes inventory, which is considerably over designed for the application.

In this case, the casing pressure test is defined by lesser of MAWP x 1.1 or MAWP +500 psi (60 kg/m^3) and the applied surface pressure is:

$$\text{Applied surface pressure} = \text{MAWP} \times (< \text{of } 1.1 \text{or} + 500) - (\text{MW ck} / \text{kl} \times 0.052 \times \text{WD})$$

The applied surface pressure to test casing or the casing shoe imposes a large piston force at the float collar and results in a severe surface axial load. The casing may be pressure tested immediately after bumping the plug (green cement test) or just prior to drill out of the float collar and shoe. *The preferred method is to pressure test just prior to drill out.* The burst loading due to pressure testing at drill out would be higher based on the assumptions of the external fluid or back up fluid. The green cement pressure test considers the cement hydrostatic pressure outside the casing where the pressure test prior to drill out assumes pore pressure or cement mix water backup.

External Loads

Pressure gradient that exists in the annulus behind each casing string shall depend on several well life cycle factors of each well, e.g., *after cementing operations, the gradients are those of the drilling fluid, cement spacers, and liquid cement*. However, complex changes result as cement sets and mud degrades with time. These changes shall be considered through more detailed design, notably on more complex exploration and more so for development wells, to determine and evaluate long-term backup resistance. Note: The external pressure at the wellhead is typically assumed as a seawater gradient for deepwater wells.

Because of uncertainty in the annular pressure gradient over extended times (*particularly within the cement column*), assumptions may be made that represent a conservative case. Time-dependent assumptions include the gradient of the drilling fluid above the TOC, which can partially degenerate (*due to settling of the weight material*) over time. The settling tendency of the weight material depends on fluid type, rheological properties, weight material characteristics, and well conditions (i.e., *temperature, geometry*) and can be difficult to predict. In an open hole, the amount of gradient reduction is limited by the pore pressure. In a closed casing-by-casing annulus, the fluid gradient in the uppermost portion of the well can approach that of the base fluid.

Collapse Design

For collapse design, use of the original mud gradient behind the casing should be considered (*vs. using a partly or fully deteriorated mud gradient behind the casing*) to avoid underestimating the driving external collapse pressure.

The effective gradient in cement (*assuming it is semiplastic as it sets and is capable of transmitting pressure*) in the open hole will equal the pore pressure of the adjacent formation.

Point Loading

Advanced casing design may in addition investigate the effect of point loading on collapse and wear. In vertical and low angle wells, i.e., <40-degrees inclination where directional control is suitably managed, point loading and accelerated wear unlikely to be required unless *a significant dogleg resulted during drilling where design must be risked assessed and further evaluated.*

Burst Design

Less is known about the burst design backup provided by set cement within a casing-by-casing annulus (*cement in the casing overlap or behind a tieback*). Once cement becomes a solid, it no longer transmits fluid pressure. However, when burst pressures are applied to the pipe, the solid cement provides a mechanical backup, and the net loads on the tubular may be lower. Various models are available to estimate the structural contribution of the cement to the tubular burst resistance. An alternative approach is to use the cement mix-water density to define the backup fluid gradient for burst design calculations.

Note: The settled weighting material may create a barrier in the annulus, restricting APB pressure relief to a noncemented open-hole interval below the previous shoe. Refer to API65-2 for further details about cementing.

Fatigue Analysis Method

Fatigue analysis of structural pipe and production riser interaction is outside the scope of this work. The following summary outlines the key points required for a detailed analysis. The riser/structural pipe interaction should be analyzed for the drilling and production riser arrangements. The soil stiffness based on the appropriate P−Y soil is modeled with the structural pipe OK and the setting depth of the structural pipe.

The riser is modeled as an equivalent single string using pipe elements. Key properties of an equivalent single string model are:

- Bending stiffness—sum of stiffness of riser pipe and internal tubing
- Axial stiffness—stiffness of the riser pipe
- Mass—sum of the weight of the riser pipe, tubing, and fluid in tubing
- Internal diameter—ID of riser pipe
- Buoyancy diameter—diameter

The boundary conditions applied depend on the operating condition, drilling, or production, being analyzed. A preliminary analysis should be performed to highlight any technical challenges and address issues that may drive the riser and conductor design.

The analysis is an iterative process (see flow chart) and considers:

- Extreme storm analysis
- First-order fatigue analysis
- Vortex-induced vibration analysis
- Clearance analysis

First-order fatigue analysis of top tensioned risers is carried out using a spectral fatigue analysis approach. Fatigue damage is based on time domain random sea analysis of riser response. Second-order fatigue of top tensioned risers is carried out using a statistical approach. The fatigue damage due to low-frequency pitch and surge motion is calculated (Fig. 9.16).

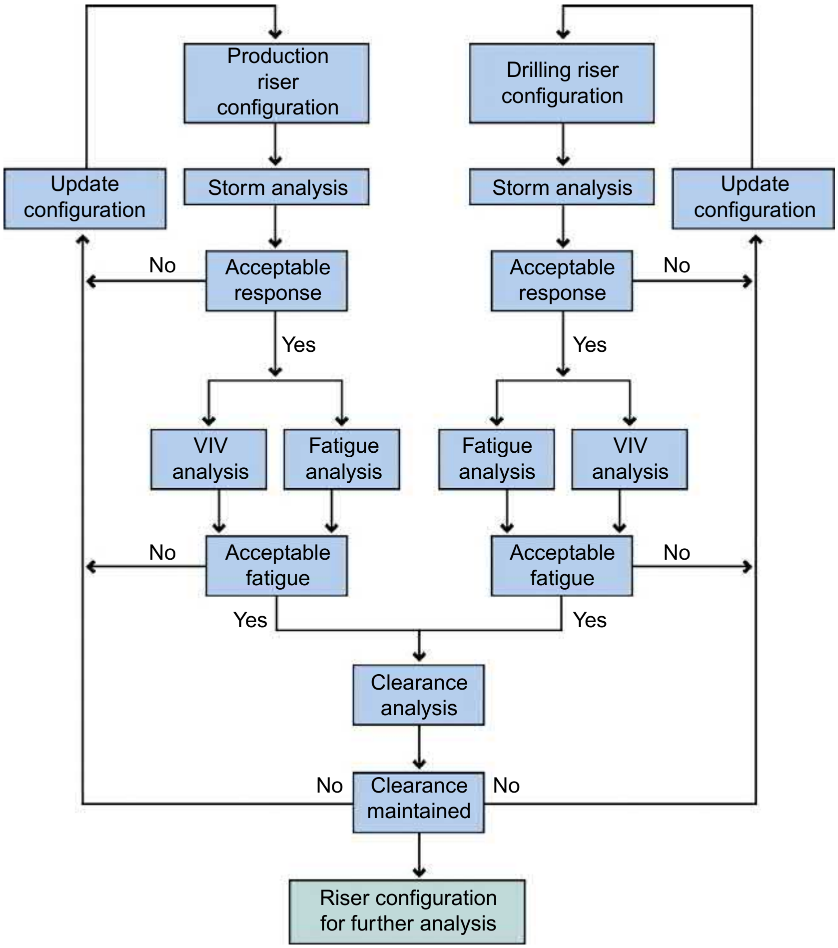


FIG. 9.16 Preliminary analysis flowchart. *Source: Kingdom drilling deepwater design manual 2006.*

Vortex induced vibration (VIV) is generally conducted for a range of current profiles representative of long term loop, submerged eddy and bottom current loading. Clearance between adjacent production risers and a production riser and drilling riser is evaluated considering the effects of wave effects, VIV and interference. The riser analysis, production or drilling and resulting loads is used to design and analyze the structural pipe.

STRESSCHECK Design Methodology

General

A deepwater well's example is presented in this section to show the typical outputs generated via a computer design tool as used for deepwater casing design and analysis. The loads and methodology outlined are part of the STRESSCHECK design package. Design criteria are to be risk based and realistic, i.e., *using Maximum load burst, collapse, and axial load conditions.*

STRESSCHECK Design Method

The following approach is generally adopted for the design method:

1. Determine accurate and precise *pore pressure, fracture gradient, and mud weight* plots. The plots are used in determining the casing seats and the pressures used in the various burst, collapse, and axial load design cases.
2. *Determine wellhead pressures* using the methodology outlined in the section on *MAWP*. For *burst loading*, the internal load is maximized and the external backup load is minimized.
3. For *collapse loading*, the external load is maximized and the internal backup load is minimized. The design line is the *difference* between the external and internal loads (the actual load line or resultant load line) with the design factor incorporated.
4. The *external load for "burst"* is pore pressure w/seawater and the *external load for "collapse"* is fluid gradients w/pore pressure.
5. *Load cases of the same type (burst or collapse) are then combined* into one load line of maximum load as a function of depth rather than each load case compared on an individual basis.
6. *Axial loading* is based on the buoyant weight, abrupt deceleration of the pipe while running some overpull, bending, and dogleg severity.

Load Cases, Safety, and Design Factors

LOAD CASES AND SAFETY FACTORS

Load cases and corresponding design safety factors are the criteria used to judge the suitability of a design. Dividing the pipe rating by a corresponding load delivers a safety factor. If the safety factor is greater than the design factor, then the pipe is acceptable for use for the load applied. The standard load cases as shown in the following example represent an operator's deepwater minimum standards design basis. If design is based on other standards criteria, design must be checked against the additional loads. If design is not met, management shall be advised of the discrepancy in regards to operator's normal practices with all engineering and operational consequences then discussed.

Using sound judgment, *weights, grades,* and *connectio*ns are selected from the design results. The design consists of load cases applied using corresponding design factors, which are compared to the pipe ratings.

Load cases are typically ***burst*** and ***collapse*** (drilling and production loads), and ***axial*** (running cementing and servicing loads). Rather than compare each loads case profile to the pipe rating on an individual basis, the approach is to ***combine load cases of the same type*** *in a load line of maximum load as a function of depth.*

DESIGN FACTORS

Design factors applied account for uncertainties in material properties and load predictions that can result from inaccurate or insufficient well data and the well type. The important aspects that have a direct effect on the key design factor values are:

1. *Selection of load cases and the assumptions used with load cases considered (notably: limited kick data vs. a full displacement to gas, kick volumes, intensity used, bending due to doglegs or shock loads, mud over gas*, versus *gas over mud*, etc.*).*
2. The assumptions used to calculate the *pipe's load resistance or rating (whether a no*min*al or minimum wall section is used or yield stress is derated as a function of temperature).*
3. How *wear and corrosion* are then further considered within the design.

Historically design loads cases are selected based on two criteria: ***maximum loads*** and ***ease of calculation***. Should the standard case not consider all loads to be experienced by the casing, factors are increased accordingly. In general, design factors became accepted over time based on the limited number of failures associated with their use. Should failures result the design basis is then examined with design factors or load cases made more conservative to prevent future events. With computing power now available more complex load scenarios are today far more readily evaluated instead of relying on single case maximum load scenarios. Risk calibrated design is now used to arrive at far safe yet economic design.

In order to make direct graphical comparisons between the load line and the pipe's rating line, the design factor must be considered:

$$\mathrm{DF} = \mathrm{SF}\,\min < \mathrm{SF} = \text{pipe rating} / \text{applied load}$$

Where:

– DF = design factor (the minimum acceptable safety factor).
– SF = safety factor.
– DF × (applied load) < pipe rating

By multiplying the load line by the DF, a direct comparison is made with the pipe rating. As long as the pipe rating is greater or equal to the modified load line (or design load line) the criteria applied are deemed satisfactory. Two other effects to consider that may impact increasing the design load line are:

1. ***Reducing collapse strength due to tension*** (a biaxial effect). The load line is increased as a function of depth by the ratio of the uniaxial collapse strength to the reduced strength.
2. ***Derating material yield strength due to temperature***. Like the effect of tension on collapse, the load line is increased by the ratio of the standard rating to the reduced rating.

After performing main casing design based on ***burst, collapse,*** and ***axial*** load considerations, the detailed design assessment shall then address the issues of **connections, wear,** *and* **corrosion**. Following these final design considerations and depending on the criticality of the design, the final issues to review and consider are:

1. ***Triaxial stresses*** due to combined loading such as ballooning and thermal effects. This is also called service life analysis (life cycle).
2. *Other* ***temperature effects***
3. ***Buckling.***

Some further advanced deepwater casing design considerations are discussed in the closure of this chapter.

STRESSCHECK Deepwater Worked Example

Examples of burst internal and external loads, net or differential burst loads and burst design follow. One load case is selected to illustrate the methodology used to determine the design line. When using multiple load cases, the load case which dominates at a specific depth shall generally dictate the required design.

GRAPHS OF BURST LOAD CASES

The pressure test load case is used to illustrate the methodology to determine net/actual burst load (Figs. 9.17 and 9.18).

The differential load (actual load line) is the difference between the internal and external pressures (Fig. 9.19).

Depth (ft)	Differential Load (psi)
85	5565
4225	8274
9138	11,490
13,452	14,314

The design line is the actual (net) load multiplied by a 1.1 design factor. The burst of the pipe to be selected must be greater than the design line to satisfy the design (Fig. 9.19).

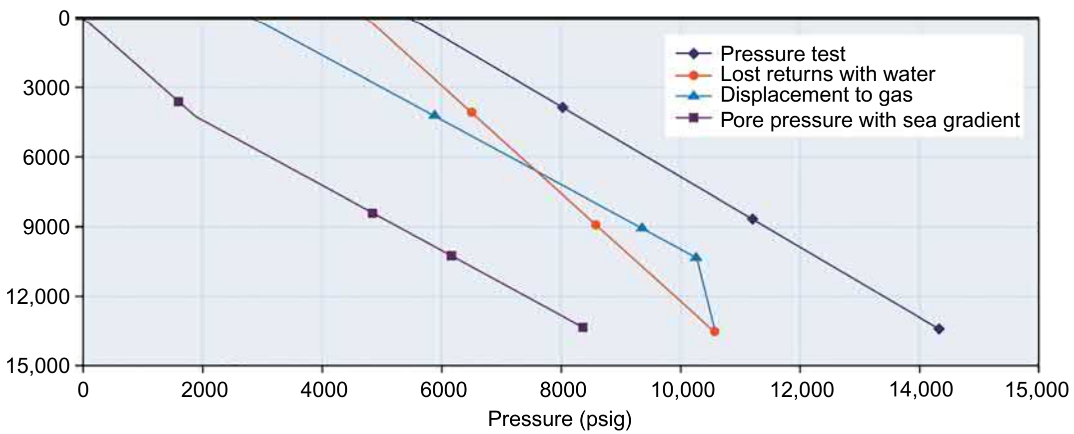


FIG. 9.17 Graphical burst load cases expressed as pressure profiles versus depth (below the drill floor).

Depth (ft)	External Pressure (psi)	Internal Pressure (Pore Pressure)
85	5565	0
4225	8274	1850
9138	11,490	5330
13,452	14,314	8386

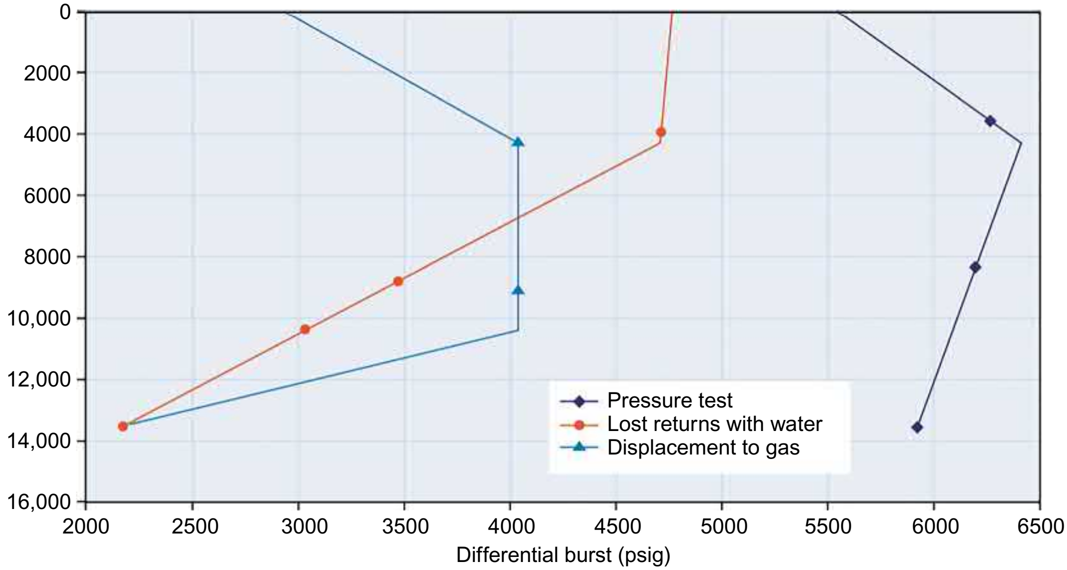


FIG. 9.18 Graphical illustration of differential burst loads.

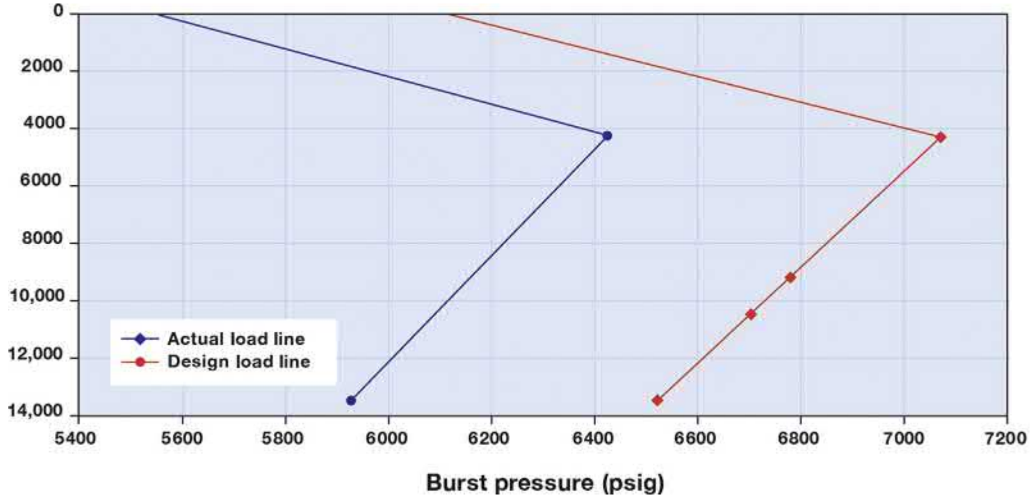


FIG. 9.19 Graphical illustration of burst design line.

Depth (ft)	Actual Load	Design Load
85	5565	6121
4225	6424	7066
9138	6160	6776

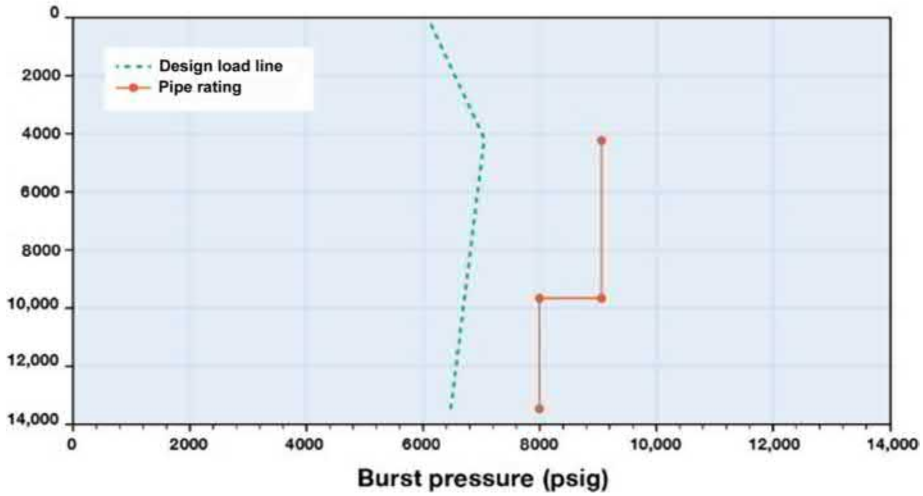


FIG. 9.20 Graph of burst design line.

Depth (ft)	Actual Load	Design Load
13,452	5928	6521

GRAPHS OF COLLAPSE LOAD CASES EXPRESSED AS PRESSURE PROFILES

The API collapse strength calculations are convoluted and somewhat confusing. The Collapse design is determined using the API calculations and the graphical methodology used for burst. Using the Lost Returns with Mud Drop load, the load cases to determine the collapse design line are outlined (Fig. 9.21).

Depth (ft)	External Pressure (Fluid Gradients) (psi)	Internal Pressure (Lost Returns w/ Mud Drop
4225	2765	1867
9138	5981	5338
9138	5981	4747
13,452	8386	8386

The change in external pressure profile occurs at a casing seat or top of cement where the pressure profile changes from fluid gradients to a pore pressure or a different fluid gradient profile (Figs. 9.22 and 9.23).

The collapse load (actual load) is adjusted to consider the effects of internal pressure on collapse resistance (Fig. 9.24).

The collapse design line is the actual load multiplied by a 1.0 design factor. The design load line is adjusted to consider the effect of axial stress due to tension on collapse. The collapse correction due to axial tension is made in the design line rather than the pipe properties.

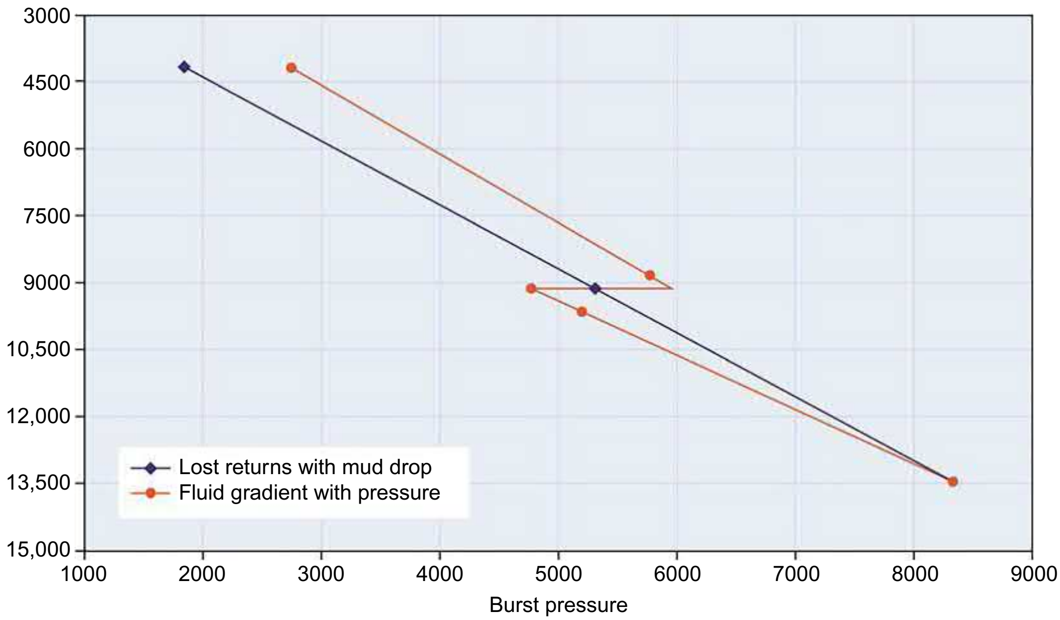


FIG. 9.21 Graph of collapse loads expressed as pressure profiles.

GRAPHS OF AXIAL LOADS (FIG. 9.25)

The axial service loads model the drilling and production loads, which occur after the casing has been cemented. The initial conditions to determine the service load are based on the cementing and landing conditions (Figs. 9.26 and 9.27).

The design load line is the axial load considering the drilling and production burst and collapse loads multiplied by the axial design factor 1.3 (Figs. 9.28 and 9.29).

Advanced Deepwater Casing Design

Salt Loading on Well Casings

GENERAL

The resulting nature of salt deforming a casing string during field-life-cycles is considered more detrimental than beneficial.

EXAMPLE

In laterally extensive subsalt reservoirs that lie in close vertical proximity to the reservoir formations, there can be a tendency for the salt to flow laterally to fill "subsidence bowls" formed by compaction of the reservoir interval. This lateral movement can jeopardize the integrity of well casing run through the deforming salt drilled interval because of the anisotropic loading and induced shears conditions resulting at the bounding formation interfaces.

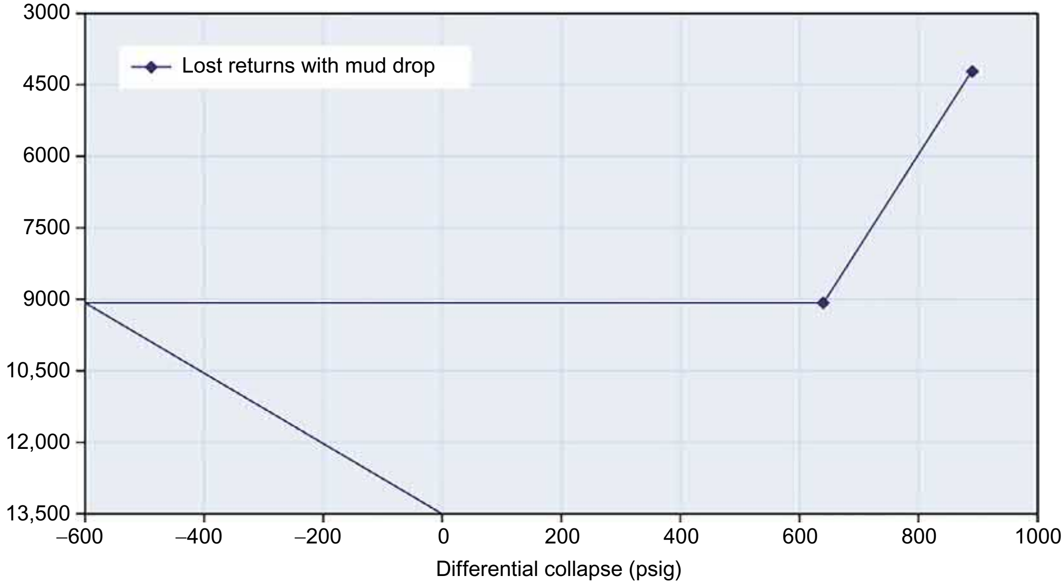


FIG. 9.22 Graphical illustration of collapse differential loads.

Depth (ft)	Differential Load (psi)
4225	898
9138	643
9702	−591
13,452	0

Salt can be encountered at relatively shallow depths below mudline in deepwater wells, as well as deep, collapsed, or ruptured casing well failure caused by salt loading may result in losing an entire well. That in deepwater would have a significant economic hammer blow to any well's program where wells must be designed not to fail. Loading by salt shall therefore be properly defined and incorporated by persons responsible within the well's casing design.

CASING DESIGN PERSPECTIVES

Industry and geomechanics communities, assessment of salt behavior concerning well design principally fall into one of four classifications as follows.

1. Experimental
2. Incorporating of nonuniform loading effects into casing design.
3. Field-proven experiential solutions to salt-loading problems.
4. Numerical analysis based on advanced constitutive modeling of salt.

More details of these classifications that can be expanded from within the SPE/IADC 74562, journal paper used in the main to derive this advanced well design chapter section.

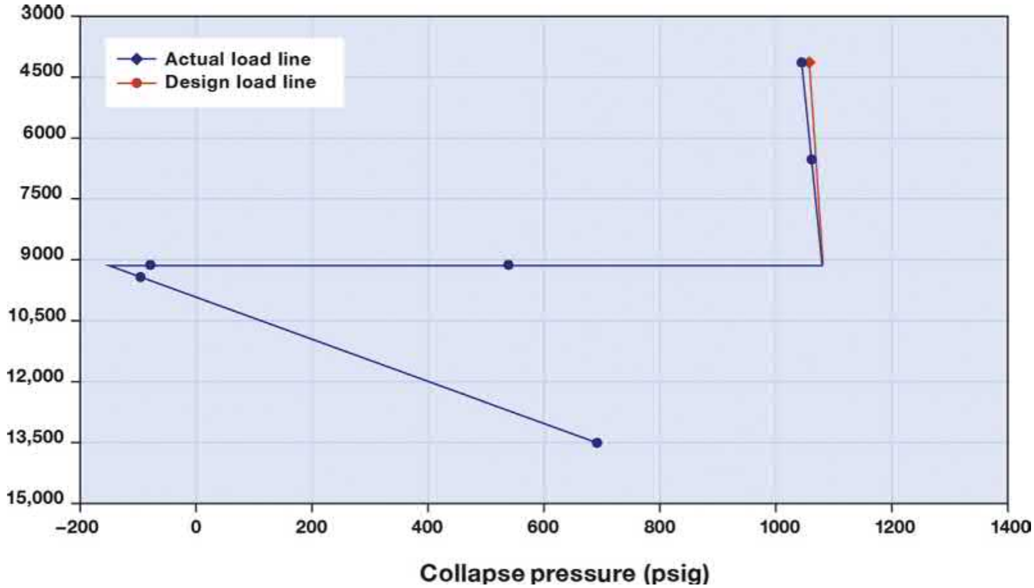


FIG. 9.23 Graphical illustration of collapse load.

Depth (ft)	Load Line (psi)
4225	1053
9138	1087
9138	−146
9702	33
13,452	699

WHAT MAKES A PROBLEM SALT?

Salts like shales result in a number of variants where, not are all problematic from a drilling or well design perspective. Salt mobility itself depends on depth of *burial, formation temperature, composition, water content, presence of impurities (clay), and extent of differential stress applied* to the salt body. Chloride and sulfate salts containing water *bischofite, carnalite, kieserite, and sylvite* are the most mobile. Halite is relatively slow-moving, and anhydrite and the carbonates *calcite, dolomite* are essentially immobile.

In summary, casing loading problems do not result in massive "clean" salts. Excessive movement reported (up to 1 in. (2.54 cm) per h) 1 in./h is limited to "dirty" salts, Example: high clay impurities or salt intervals, interbedded with shale.

Salt topography is also a factor. *Example: At anticlines, well failures are stated as more prominent where the salt thickness is irregular and has high stratigraphic dips. Where the salt is thicker, more uniform, and relatively flat, well failure rates is far lower.*

Problem salts additionally have high moisture content, impurities, and/or are interbedded. The causes are different in each case and the key statement is three types of Salt are classified as follows.

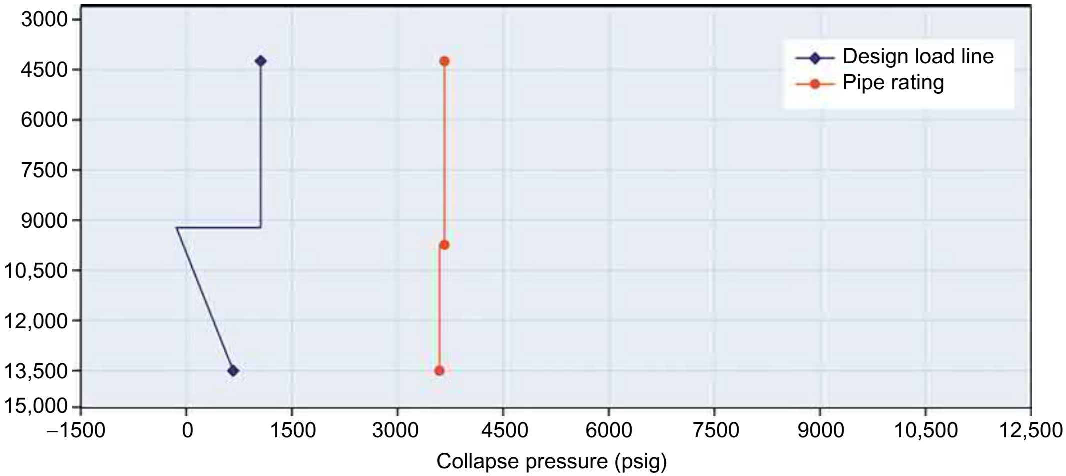


FIG. 9.24 Graphical illustration of collapse design line.

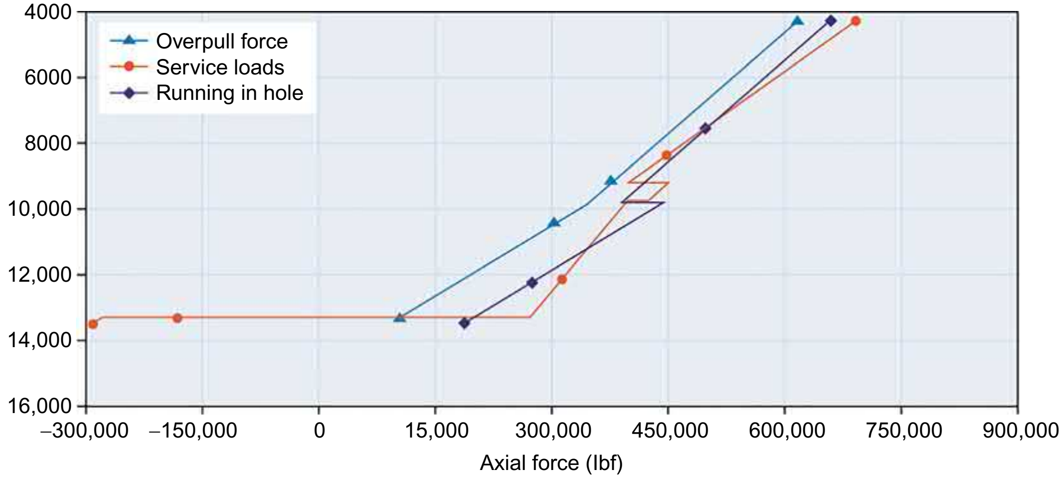


FIG. 9.25 Graphical illustration of axial Loads.

Depth (ft)	Overpull (lbs)
4225	618,925
9138	379,777
13,452	100,000

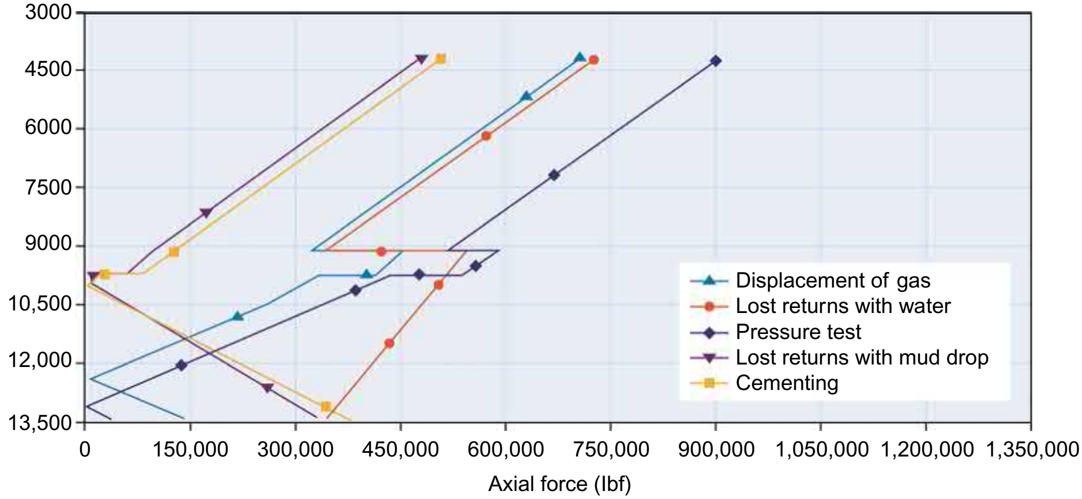


FIG. 9.26 Graphical illustration of axial service loads.

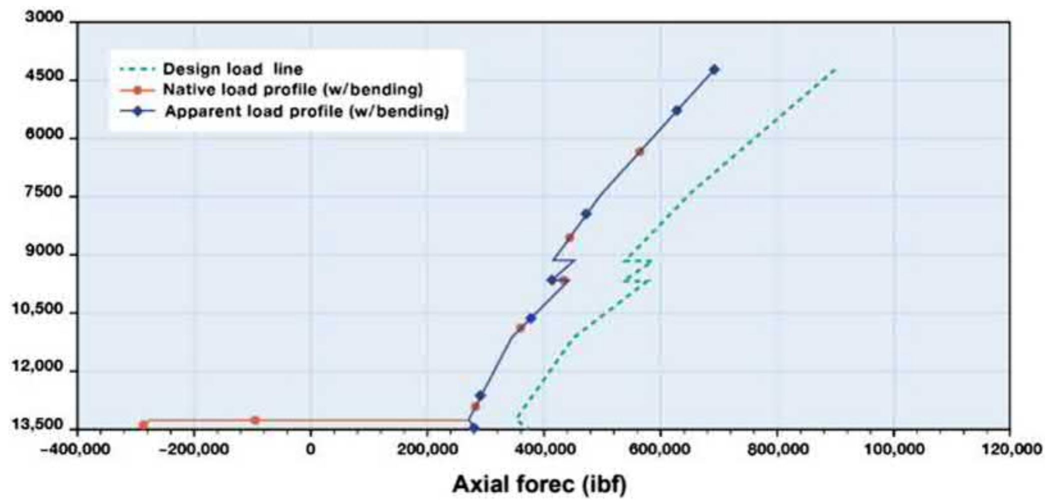


FIG. 9.27 Graphical illustration of axial design loads.

1. *Type 1*. Is the most problematic salt and consists of poorly sorted and brecciated siltstone with mudstone forming the matrix and prominent micro- and macrofractures filled with halite. *Example: the end product takes the form of salt stringers, 2 to 10 ft (+/– 0.61–3.1 m) thick.*
2. *Type 2*. Consists of poorly sorted and brecciated siltstone and mudstone, both cemented by and in a matrix of halite. This type of salt occurs up to 200 ft. (61 m) thick at the top of an interval.
3. *Type 3*. Consists of almost pure halite with minor impurities, and thicknesses of up to 1000 ft. (304.5 m) are typical.

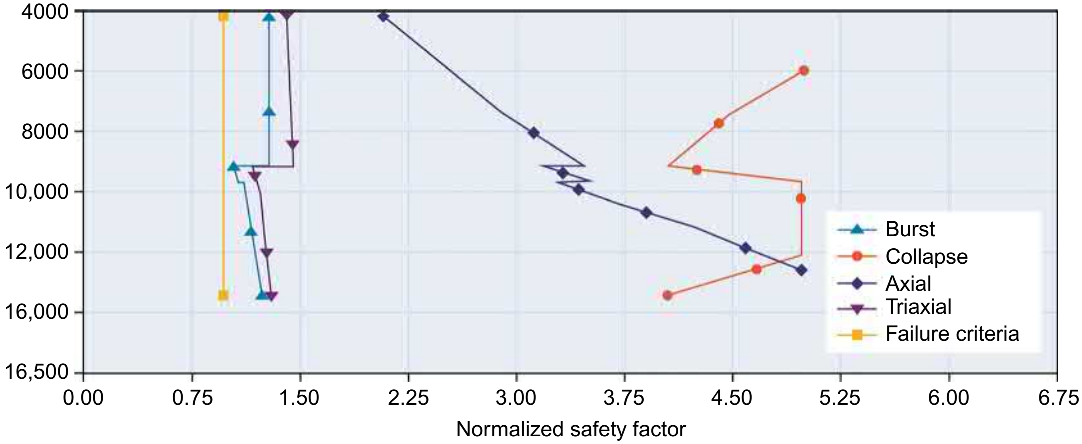


FIG. 9.28 Graphical illustration of triaxial design checks.

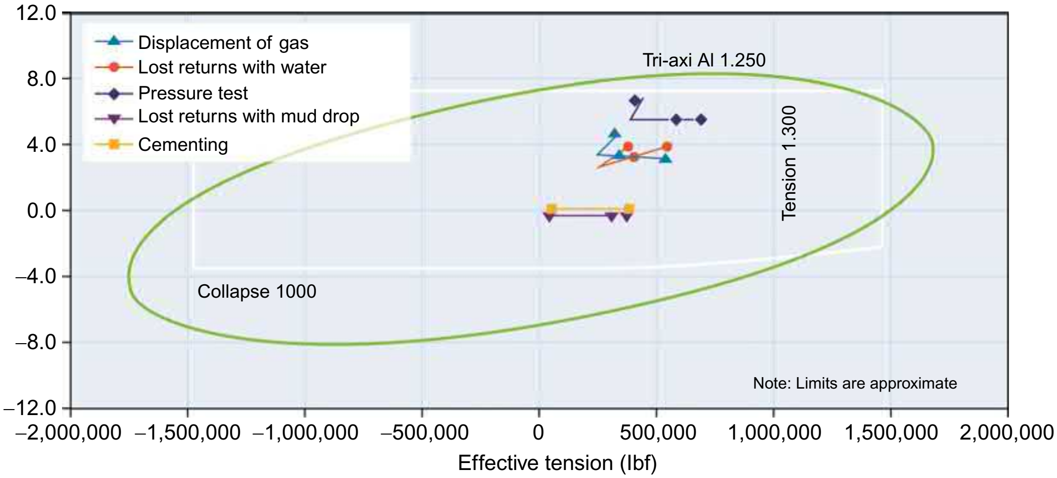


FIG. 9.29 Graphical illustration of tri-axial design checks.

Note: In contrast to the *Type 1*, *Type 3 is essentially immobile*.

The problem sediments are largely comprised of mudstone and siltstone, rather than salt minerals to exhibit a complex response while drilling. *Example: Dissolution or weakening of the bonding in halite salt causes severe washouts as the mudstone breccia becomes loosened*. More importantly, the salt types differ because they sustain different stresses to behave more like conventional argillaceous sediments rather than pure salts.

For a pure salt body to be in equilibrium and to maintain continuity with the surrounding formations, the interface stress state of a *Type 1* salt with the main salt body can be highly complex and variable, with differential stresses existing in the salt/clay layers that can significantly affect salt deformation. Should a 2000-psi (13.8 MPa) differential stress exist (all else maintained constant), the creep rate of a pure salt can increase by up to 5 orders of magnitude. For this reason, stuck-pipe problems resulting within notorious salt formation sequences are usually highly stress-related rather than caused by physical properties or chemical composition changes between more stable and notorious salt formations. *Example: In one field, the same halite salt occurs in both Type 1 and 3 salts.*

The risk and uncertainty of encountering deformable salts has resulted in developing casing-design criteria for anticipated problematic squeezing salts in one location to be applied elsewhere with little recognition that the character of the salt may be changed.

A particular emphasis of any well and casing design work now recognized and analyzed to identifying the appropriate conditions, in terms of the magnitude of the loading as well as the time during which it occurs.

ISSUES IN DEEPWATER WELLS

In deeper targeted and overpressured, overburdened deepwater horizons, the requirement for more casing strings and liners should now be well understood. To meet such needs, the salt sections to be drilled throughout the Gulf Of Mexico region as an example *(where extensive deepwater Salt issues exist) ranges from relatively larger bit sizes and casings*, i.e., *as big as 24″ (20″ casing) to as little as 12¼″ (9⅝″ casing or liner).*

Annular clearance between the borehole and casing is generally considerably larger than that experienced on land or shallow offshore wells. This larger clearance tolerance in deepwater environments delays the closure of the salt around the well's casing.

Another factor is the effect of increasing downhole temperatures that result during drilling or later well operations*, this can accelerate salt movement and reduce the time* for salt to close and impinge on a well's casing giving rise to *earlier conditions of near-uniform loading*.

Where salt occurs within a few thousand feet of the mudline, there are benefits, from a drilling perspective, to setting casing a sufficient distance into the salt so that the increased fracture pressure is used to advance the setting depth of the next casing string as deep as possible. Issues of salt mobility and loading in design must however be fully addressed. Primarily at what confidence risk or uncertainty level the salt interval drilled will remain in-gauge for operations to proceed without the risk of tight-hole wellbore problems resulting. Second, should a low fracture gradient zone exist on exiting salt, this "weaker" zone may prevent cementing the annulus between the casing and salt because the cement operating window may be inadequate to hold a column of even a remedial foamed cement job.

Thus, with a deep-set casing through the salt, it is probable that the salt/casing annulus is some cases is uncemented, raising concerns of longer-term salt movement and casing loading adjacent to the salt.

There is also a significant downside of being too conservative in the casing design. *Example: If a cemented annulus is specified through the salt, casing will have to be set a relatively short distance after exiting the salt. Here, the fracture gradient may be close to or even lower than that existing at a shallower depth.*

Thus, a casing string or liner tieback may have to be committed without necessarily advancing the well significantly toward its target depth. In this situation, it is necessary to set another liner that then reduces the wellbore size to advance the well to the same depth as that achieved in a more aggressive design described previously. Therefore, there are many benefits of not cementing the salt/casing annulus and to deep-set casing, where possible, if design can permit and afford this.

SALT MECHANICS SUMMARY

In terms of understanding salt, deformation models were developed based on interpretations of physical and mechanical aspects of the problem and on laboratory-generated databases that were independent of any assumed or measured underground response. This independent technology was then validated through careful comparison supported by an extensive collection of in situ stress data on spatial closure and salt displacement from the underground in situ tests conducted at facilities used.

What was validated and observed from all studies in terms of behavior compared to model studies. It can be concluded that current salt modeling now conducted is adequate to predict the deformations and stress fields of wellbore structural configurations for the range of temperatures and stresses that exist. Note: Some deepwater Gulf of Mexico fields and wells are more severe but, still fall within the range of stress and temperature ranges for which the salt models have been developed. In summary, there is now little need for oil and gas to further fundamental salt-model development. Moreover, existing databases developed for salts are used directly in analyses specific to deepwater subsalt and near-salt Gulf of Mexico field developments.

SALT COMPOSITION IN DEEPWATER GOM

To date there is no evidence that problematic (*Type 1*) salts have been encountered in the western over thrust belt in the Gulf of Mexico wells. To further characterize the behavior of Gulf of Mexico salts, rotary sidewall plugs were obtained from deepwater well's and concluded of sufficient quality that creep behavior rates could be determined reliably through appropriate testing applied. The response of salts recovered and tested from an engineering standpoint, simply presented that rates showed only a small variation. Based on these derivations, prediction of *hole closure rates* and casing loading in an noncemented wellbore (for circular and noncircular wellbores), and prediction in cemented wellbore sections can be reliably determined and evaluated in regards to consequence impact upon casing design to conclude the following.

SALT LOADING ON DEEPWATER CASINGS CONCLUSIONS

1. Deepwater Salt forms many different types of which not all present drilling problems.
2. Salt encountered along the U.S. Gulf Coast is often >94% halite and the least mobile.
3. Simplified hole-closure and casing-design guidelines are unduly conservative when applied to Gulf Coast halite. As many designs do not conform to the known deformation mechanics of salt and are suspect for critical deepwater GOM subsalt wells.
4. The substantial body of knowledge resulting from technical investigations and support conducted is directly applicable to the assessment of salt loading on well casings in the Gulf of Mexico (and other predominant halite salts around the world). This knowledge is generally underused by the oil industry.
5. If wellbore quality can be assured through best practices. It is not considered necessary to cement the casing/borehole annulus through the salt. The subsequent uniform casing loadings presenting no long-term threat to drilling operations or impingement on the inner casing strings.

6. If wellbore quality deteriorates with significant ovality, to result in nonuniform loading that can result in more excessive casing deformation. A fully cemented annulus is required to transform the nonuniform situation into uniform loading.
7. Significant benefits accrue from casing and well designs that include the proper magnitude and duration (timing) effects of salt loading. In specific cases, difficult cementing jobs and liner tiebacks can be omitted.
8. Well's casing depths can be better designed, with casing strings or liners not needing to be set when exiting the salt. To result in a more simplified design, thereby eliminating potentially troublesome operations with greater well benefits.

Annular Pressure Build Up

DEEPWATER ANNULAR PRESSURES

Deepwater well designs can be susceptible to large temperature increase changes from installed temperature that can be as low as the mudline temperature, 38–40°F (3.3–4.4°C) to formation temperatures that can exceed 200°F (93°C). Development wells in particular can produce at high flow rates to result in bottom hole static temperatures (BHST) to be transferred through time to near the mudline where the fluid gradient and properties in the well's annulus shall change from initial conditions due to:

1. Gas migration due to imperfect cement job.
2. Over time, the solids suspended in the annulus fluid can settle.

Note: The settled weighting material could potentially create a barrier in the annulus, restricting APB pressure relief to an uncemented open-hole interval below the previous shoe.

TRAPPED ANNULUS PRESSURE

In a trapped and sealed subsea wellbore casing to casing annulus exposed to potential pressure from the open hole below the deepest shoe, any increase of temperature of any trapped fluid shall cause the fluid to expand. The pressure increase dependent on the types of annular present fluid and the temperature change from initial conditions. This set of situation and conditions referred to as trapped annulus pressure or annular pressure build-up (***APB***).

Furthermore as illustrated in Fig. 9.30 as subsea wellheads have no direct access to the majority of outer annuli, any pressures build up that can result throughout a well's life cycle *cannot be monitored*. Only the production "A" casing annulus, can be monitored and capable of releasing any trapped pressure. Trapped casing annuli areas are presented in Fig. 9.30.

A well's design capacity to withstand the pressure volume and temperature change cause and effect during well construction and production operations must therefore be considered for the life cycle conditions for each well. The casing design should reflect the *APB* severity, risk, and implement any mitigation strategy. Notably temperature increase shall result in what can be significant annular pressure increase such that measures must be taken to manage, control, and mitigate this pressure increase. Considerations should be taken to managing or mitigating this pressure increase.

DESIGN CONSIDERATIONS

In regards to *APB* can cause both a burst load on the outer casing and a collapse load on the inner casing string. The increased annulus pressure can also cause a piston-effect axial load to

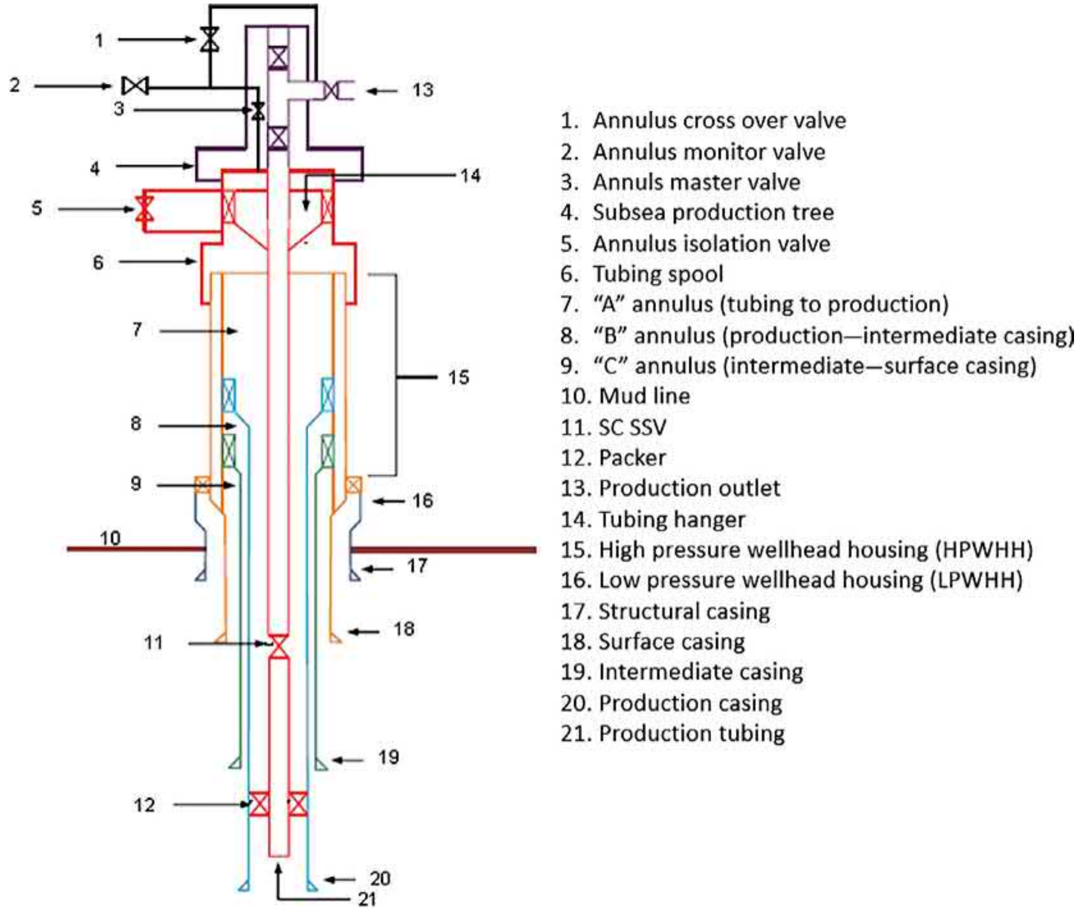


FIG. 9.30 Subsea Tree with Tubing Head and "A," "B," and "C" Annuli. *Source: Kingdom drilling training reconstruct 2017.*

be exerted on the hanger. The backup fluid gradient for the burst or collapse case could be as high the original mud or as low as the solids-free fluid.

APB MITIGATIONS

Potential APB mitigation may include the following.

1. Avoid a sealed annulus by leaving the TOC a sufficient depth below the previous casing shoe to prevent the annulus from being trapped from the open hole by either cement or settled mud solids (refer to regulatory requirements to ensure conformance) and/or using a solids-free fluid, such as a weighted
1. Installing a compressible gas or fluid in the annulus.
2. Installing crushable material on the outside of the casing, such as syntactic foam.
3. Using rupture disks in the casing to protect either the outer or inner casing string.

STANDARDS REFERENCE

API 5CT "Specification for Casing and Tubing", 6th Edition, American Petroleum Institute, Washington, DC, April 15, 1999.

API Bul 5C3, "Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties", 6th Edition, American Petroleum Institute, Washington, DC, October 1, 1994.

API 2A-WSD, "Planning, Designing and Constructing Fixed Offshore Platforms – Working Stress Design."

API 2A-LRFD, "Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Load Resistance Design Factor."

API RP 96, "Deepwater Well Design and Construction", 1st Edition, March 2013.

NACE Standard MRO175-93, "Standard Material Requirements, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment", January 1993.

Norsok Standard D-101 Rev. 4, June 2013: "Well Integrity in drilling can completion operations."

Design References

Byron, T.G. Casing and Liners for Drilling and Completion, Design and Application. Gulf Publishing Company, Houston, Texas, 2007.

Bourgoyne Jr., Adam T., Martin E. Chenevert, Keith K. Millheim, F.S. Young Jr. Applied Drilling Engineering, 2nd Edition 1991.

Economides, Michael J., Larry T. Walters, Shari Dunn-Norman. Petroleum Well Construction. John Wiley & Sons, 1998.

Mitchell, Robert F., Stefan Z. Miska, SPE Textbook Series Vol. 12, Fundamentals of Drilling Engineering, 2011.

Prentice, Charles M. Maximum Load Casing Design, Journal of Petroleum Technology July 1970.

Prentice, Charles M. Casing Operations Handbook, Prentice Training Company, Inc.

Wilson, S.M., B.P. America, A.F. Fossum and J.T. Fredrich. Sandra National Laboratories, Albuquerque, New Mexico. Assessment of Salt Loading on Well Casings. IADC/SPE drilling conference, Dallas, Texas, Feb. 2002.

C H A P T E R

10

Operating: Key Aspects of Deepwater Planning and Project Implementation

REGULATIONS PROJECT STANDARDS AND GUIDELINES

Offshore Well Design & Construction Regulations, Standards, and Guidelines vary greatly from region to region. Several useful deepwater standards, rules and regulations exist to be used as an appropriate starting reference.

A general start requirement is to assure that a safe operating framework exists through all well and life cycle programs and projects undertaken. Each project scope to be detailed through an appraisal, assessment, design, planning, and implementation phased approach.

Offshore regulations and standards may provide recommended guidelines for operators to prove and oblige in matters concerning:

- Assessment of subsurface conditions
- Well design, integrity, barriers, and materials
- Well control assurance
- Well suspension and abandonment
- Well verification and examination
- Information, instruction, training, and supervision
- Provision of well operations, information regarding (QHSE, etc.)

The UK offshore continental shelf regulations for offshore wells as an example states that wells are to be "*designed, commissioned, constructed, equipped, operated, maintained, suspended and abandoned so that as far as is reasonably practical there can be no unplanned escape of fluids from the well and that the risk to the health and safety of persons from it, anything in it, or in the strata to which it is connected, are as low as reasonably practicable.*"

Once a deepwater program is sanctioned and project go-ahead is approved, detailing the project scope to completeness is the first priority, which is then worked and implemented from project start to close to assure that all desired outcomes, benefits, and learning results.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00010-7

Specific areas of importance in relation to deepwater programs and projects delivery not covered through well's design, planning, and engineering standards and processes prior to well commencement are covered in this section.

Licensing and Legislation

Companies engaged in deepwater to explore and drill for hydrocarbons must obtain license or lease agreements in several ways that will vary regionally. Operators viewing to enter into deepwater should adopt a quite cautious approach in regards to offshore laws, rules, regulations, and standards. Particularly when regarding deepwater specific terms that may exist or not. Because offshore reference terms and conditions are constructed for continental shelf and shallow offshore water operations with deepwater specifics stated if at all. Operator persons assigned shall have to deal with a number of different governmental or legislative bodies that may not be that well versed in deepwater specific issues required.

Regarding all matters early project engagement is strongly advised.

As a general rule, specific offshore licensing, legislative, and regulatory standard requirements for deepwater should be very carefully screened, clarified, with gaps identified, communicated, and translated to all concerned. The completed scope is then worked into the project schedule to suitably control and mitigate hazards, risks, and change issues that may arise in terms of:

1. Application and approval to conduct a site survey.
2. Environmental risk assessment and impact assessment (EIA) or statement
3. Application and approval to locate a rig in deepwater
4. Application and approval to drill a well in deepwater (generic well proposal may be required)
5. Application for a Permit to Use and Discharge Added Chemicals
6. Nonproduction (rig safety case submission and approval)
7. Well work safety case submission and approval
8. Specific rules, regulations, and standard that must be applied
9. Approved emergency procedures
10. Approved oil spill contingency plans
11. Approval to test a well in deepwater
12. Approval to complete a well
13. Approval to abandon or suspend a deepwater well
14. Safety case, bridging, data acquisition, evaluation, and program documents
15. Application for equipment and radio operations
16. Safety and operational aspects of flights in connection with the servicing of drilling units
17. Independent Competent Body submission application and well verification

The following regulatory submission and notifications required during drilling and abandoning a deepwater offshore well typically would generally include:

1. Movement of drilling unit into territorial waters
2. Final geographic location of a well
3. Well evaluation logging

4. Formation samples and analyses
5. Application for Approval to Plug and Abandon
6. Clearance of abandoned locations (inc Seabed Clearance Certificate & Plugging Record)
7. Accident, Incident, Well control and/or Oil spill reports
8. Drilling and Geological Reports

Finally, general submission and notifications required after well operations are:

1. Plugging Record
2. Final Well Report
3. Associated well reports and logs
4. Use and Discharge of Chemicals/Preparations report
5. Mud audit
6. Seabed clearance certificate
7. Completion Report (Environmental Aspects)

Licensing requirements may require operators to acquire specific well data from offshore areas that may enforce project scope add-ons to existing continental shelf operating, laws, regulation, and standards.

This can add significant expense, where dispensation, clarity, and approvals need to be resolved early in the project appraisal or define phases to assure project issues arise sooner rather than later in the schedule. One benefit, should a regulatory well's database exist, is that evident well data can be of informed practical use, particularly in new frontier areas. Reality is that remote, deepwater regions shall have few laws, regulations, or standards with limited (poor) seismic and well data sets available in deepwater. The operator must then take charge and lead the licensing, regulatory, and legislative aspects and to assure that more weighting is emphasized to the project scope items deemed most crucial in terms of operational management and safe project delivery.

Safety Cases and Project Risk Management

In addition to regulatory and industry deepwater standard requirements, operators would have to assure that the management of health, safety, environment, and the control of all major accident hazards are compliant as stated within the Regulatory and Legislative Schedule. For example, as stated within the UK offshore installation (safety case) Regulations 2005 (Explanatory note) at http://www.legislation.gov.uk/uksi/2005/3117/note/made. In specific operating regions, an operating vessel's and a well safety case, and a more focused risk and change management approach is required to be demonstrated as illustrated below from a UK directive for a nonproduction installation.

Safety Case Requirements (Nonproduction Installation)

UK Offshore Installation Safety Case regulations are summarized as follows:

1. The name and address of the owner of the installation.
2. A summary how installation safety representatives are consulted with regard to the revision, review, or preparation of each safety case pursuant to required offshore regulations.

3. A diagrammed description of the main and secondary structure of the installation and its materials, plant, and the layout and configuration of its plant.
4. Particulars of types of operation, and activities in connection with operations, which the installation is capable of safely performing.
5. The maximum number of persons expected to be on the installation at any time, and for whom accommodation is to be provided.
6. Particulars of the plant and arrangements for the control of well operations, including those to control pressure in a well, prevent uncontrolled release of hazardous substances and minimize the effects of damage to subsea equipment by drilling equipment.
7. Describe how duty holder has ensured, or will ensure, compliance with other regulations.
8. Describe arrangements for protecting persons on the installation from major accident hazards at all times other than during any period while they may need to remain on the installation following an incident, which is beyond immediate control.
9. Describe measures taken or arrangements for the protection of persons on the installation from hazards of explosion, fire, heat, smoke, gas, or fumes during any period while they may need to remain on the installation following an incident, which is beyond immediate control and for enabling such persons to be evacuated from the installation where necessary.
10. Describe main requirements in the specification for the design of the installation and its plant, to include any limits for safe operation or use specified therein; a description of how the duty holder has ensured, or will ensure, compliance with appropriate regulations for Offshore Installations and Wells Design and Construction, etc. and describe how the duty holder has ensured, or will ensure, the suitability of the safety-critical elements.
11. Particulars of environmental conditions limits beyond which the installation cannot safely be stationed or operated; properties of the sea-bed and subsoil, which are necessary for the safe stationing and operation of the installation; and locations where the installation is to be stationed and safely operated.
12. A description of arrangements to identify routes and locations of pipelines, wells, and other subsea equipment and assess the risks they pose to the installation.
13. Particulars of any combined operations which may involve the installation.

Note: Well and operational vessel's safety cases outlines provide a useful ready-made project QHSE check list whether required or not, but in all cases best-practice applications from within standards and guidelines proposed should always be used, considered, and preferred.

Well Verification Scheme

Well verification schemes are recommended in certain operating areas for all offshore wells' operating environments to demonstrate companies design and operate wells in full compliance to the regulations, standards, and recommended best practices in terms of "Arrangements for well verification." Project personnel involved through well planning design, construction, and operation in these operating areas must be well versed and familiar with well verification requirements that exist to be used.

Objective and Scope

The requirements state an Independent Competent Body (ICB) shall be appointed with sufficient knowledge and experience to undertake a detailed well verification scheme for each well's project. Schemes are essentially founded on assuring due and diligent risk and change management principles are applied that should allow each independent competent body to use their verification skills, during well design, construction and operations to assure measures are in place to mitigate risks, to ALARP (as low as is reasonably practicable). Managers must assure that project personnel are familiar and compliant to all relevant regulatory and well verifications to be met. To deliver requirements, it is paramount to assure that project management, leadership, and supervisory personnel involved are all suitably trained, skilled, and developed as a minimum with the founding principles on which this approach is to be used and applied.

Provision of a Well Verification Scheme

As an example, the UK Offshore Installations (Safety Case) Regulations 2005, schedule 7, well verifications scheme provisions shall demonstrate:

1. Principles applied by the duty holder for the installation in selecting persons to perform functions under the scheme and to keep the scheme under review.
2. Arrangements for the communication of information necessary for the proper implementation, or revision, of the scheme to the persons assigned.
3. The nature and frequency of examination and testing.
4. Arrangements for review and revision of the scheme.
5. The arrangements for the making and preservation of records showing, the examination and testing carried out; the findings; remedial action recommended; and remedial action performed.
6. Arrangements for communicating the matters specified to an appropriate level in the management system of the duty holder for the installation.

Well Verification Process

Verification schemes provide a processed assurance as stated below. Verification is the direct responsibility of the duty holder. Schemes typically require that:

- Design and operating boundary envelope of wells are managed throughout their life cycles.
- All pressure containment equipment forming part of each well is assured as fit for purpose.

Verification schemes and well records should form an auditable trail so that:

- Aspects can be verified,
- When verification is to be performed,
- How findings and recommendations are communicated to the project respective teams,
- How changes shall be implemented as a result.

Note: As deepwater well design and construction activities are generally associated with nonproduction installations, there likely would exist an overlap between a well verification (examination) scheme and the verification of an installation as shown Fig. 10.1, to be further addressed.

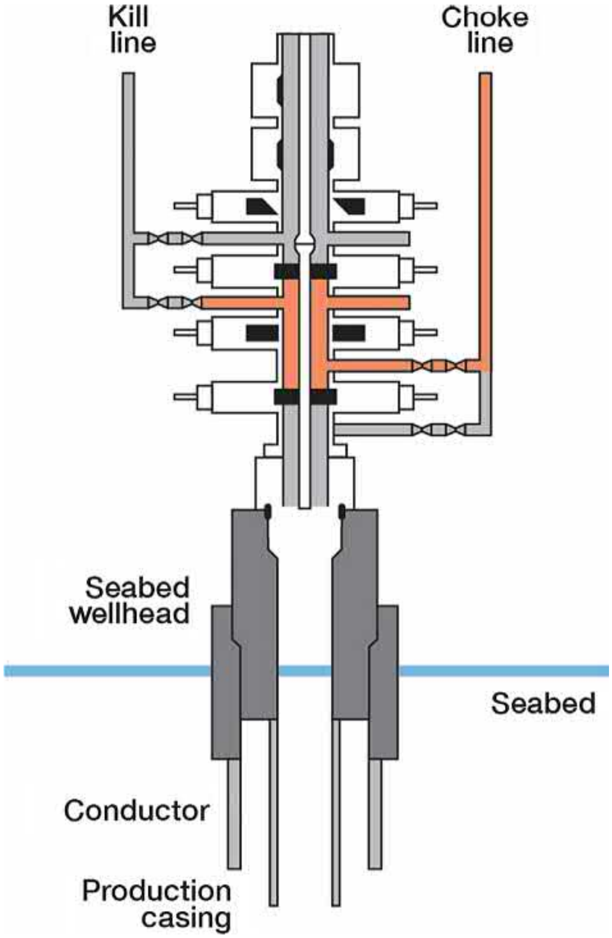


FIG. 10.1 Well verification (examination) scheme for subsea well operations conducted by a nonproduction installation. *Source: Kingdom Drilling Reconstruct 2018.*

Regarding well operations work undertaken with a nonproduction installation, should conflict arise between the operator, drilling contractor, and key third parties. Conflict is far easier to address if identified during early project planning phase. Then it can be controlled within appropriate interface or bridging documents generated and developed for this purpose.

The operator generally assigns a technical authority to ensure that well verification exists throughout the life cycle of all project phases.

Roles and Responsibilities

The well owner is assigned and directly accountable for each program or project, supported by internal operator and/or external appointed contract and/or service providers to undertake required scope activities through each project phase. The owner has the authority to stop any nonplanned project or well operating activity event at any time if there a potential to compromise well integrity, barrier, operational, personal safety, loss, or environmental harm.

The well owner shall further assure actions are conducted during well projects and operating activities to the effect that:

- Operations are performed as specified in the program and conducted by competent personnel working within a clearly defined safety management system.
- Adequate data are included in the daily well construction reports, etc. to allow completion of the well verification sheets.
- All wells are designed, modified, commissioned, constructed, equipped, operated, maintained, suspended, and abandoned so that there can be no unplanned escape of fluids from them and that the risks they pose to personnel are as low as reasonably practicable.
- Sufficient resources are available to cover the costs and requirements of all activities to be performed on the well including integrity monitoring and maintenance.
- That well(s) are formerly handed over to the service providers (drilling and completion, facilities engineering, etc.) in compliance with an approved well handover procedure.
- Retains well integrity and accountability is retained until formally handed over to another appointed well owner. Liabilities for abandoned wells remain the responsibility of the company performing the abandonment.

Roles and responsibilities involved should be detailed and clearly assigned to:

- Well owner, drilling manager/supt., well verification examiner(s),
- Operators or project management/well management manager/team leaders,
- Drilling engineer/completion engineer/well engineers, offshore wellsite leaders/supervisors,
- Chief executives and financial managers,
- All other personnel deemed involved in the project scheme.

Well Verification—Design Operations

Well verification shall examine well design, engineering, and operating aspects to ensure:

- Compliance with operating and industry approved policies, standards, and best-practice procedures.
- Where work is undertaken by a project or well management company, operator will approve all personnel, processes, and support services that undertake well design, engineering, construction, and operating activities on their behalf. This may include well-site operational management and leadership at the wellsite for the duration that the nonproduction installation is at the wellsite, and to enable and assure well integrity and barriers are suitably maintained during each well life cycle.
- Inclusion of initial well design, through well construction (drilling, testing and completion), well work activities (workover, maintenance, and intervention), production and suspension to final abandonment.

Well verification shall require access to various documents such as:

- Safety case, well proposal, or basis of design;
- Application to locate a nonproduction installation;
- Rig move, station keeping, emergency disconnect procedures;
- Shipping survey (if applicable);
- Basis of design and casing, riser design, engineering documents;
- Details of offset wells, analog data used;
- Site survey and shallow hazard assessment;
- Well work and rig safety case (if/as applicable);
- Well programs, bridging, SIMOPS documents, and amendments (if applicable);
- Minutes of any HAZID, HAZOP, risk assessment, or preoperational meetings;
- Expected well operating parameters, conditions and working environments;
- Noncompliance Investigation management of change evident documents;
- Dispensations from policy, standards, and recommended guides;
- Handover, test, verification documents and certificates;
- Auditable training program, competency assessment, skills, and development records.

Following review of final signed-off programs and prior to well operations commencing, a Verification Certificate is submitted to the operator. This would complete the initial well verification design process for each project's well operation in question.

Well Verification—Well Construction and Operations

After examining the well design, well verification construction sheets, are generated, e.g., in the form of a detailed checklist, with all well-related safety critical operations to be performed for the well operations required. As project execution commences, the verifying person shall complete the checklist to confirm daily operations are met as planned and, if not, what actions are being taken to assure well and barrier integrity is maintained.

If well-related safety or operational critical changes result, further risk assessment, change management, or dispensations that result will be revised and reissued within the designated well construction sheets.

In some operating areas, it may be a requirement that verification, persons shall make at least one verification visit to the wellsite to witness safety critical operations as detailed within the well verification construction sheets, e.g., *running, installation, cementation and pressure testing of casing string, subsea BOP function, and pressure testing after installation on the well* supported by a physical, people, and paper review of all existing evidence.

During well construction project operations verification shall require access to specific documents and reports, e.g.:

- Activity reports,
- Copies of completed handover certificates,
- Final well schematic,
- Final wellhead schematic (if applicable), and
- Well incident reports (if applicable).

All documentation examined is entered into a list of documents to be further verified in the well verification end of operations report. Verifier shall engage in verbal or e-mail communication and issue formal comment sheets if operating concerns arise.

Should it be necessary to temporary suspend well operations, procedures shall comply with Operators and Regulators approved abandonment and suspension of wells. If suspended for extended periods, it shall be necessary to verify how wells are to be monitored and maintained.

Well Verification, End-of-Operations Reports

Once well operation tasks or items subject to verification are complete, a well verification end of operations report is produced to provide operators with a formal auditable record to demonstrate full well compliance is met. The report shall comprise, as a minimum:

1. Copies of the completed well verification sheets and certificates;
2. Closed out formal comment sheets;
3. Copies of any dispensations from policy issued, and;
4. A listing of all the documentation and correspondence reviewed.

The verifier shall submit the report for a final review before issuing to respective managers and leaders for signoff and formal filing to complete the well project verification process. As well verification extends through a well's complete lifecycle, each report is retained (inclusive of all relevant supporting evidence) for a specified period following permanent well abandonment.

Well Verification Scheme Review

The well verification process shall be subject to annual review. Records of meetings held to review the scheme shall be kept on file. These shall document agreed actions, the parties responsible for completing the action, and details of the subsequent close out.

HAZARD, RISK, AND CHANGE MANAGEMENT IN DEEPWATER WELLS

In any well, regulatory, standard, and best practice compliance must be proportionate to the magnitude of hazards, risks, and uncertainty that exist. Deepwater projects generally require a more comprehensive recognition analysis, identification, and evaluation process to clearly define all the project work scope: risks, reduction solutions, mitigating actions to deliver all project benefits desired.

The first component in the process is to *identify, rank and file all project hazards*. Secondly, to duly evaluate and associate risks both qualitatively and quantitatively to reduce exposure through assuring ALARP measures, i.e., as is reasonable practicable, result as illustrated in Fig. 10.2. Functional requirements are also to be set as shown in Fig. 10.3.

To illustrate risk management requirements from one specific area, the UK Offshore Regulations require duty holders to demonstrate that:

1. All hazards with the potential to cause a major accident are identified;
2. All major accident risks are evaluated, and measures taken to control risks as per statutory provisions;

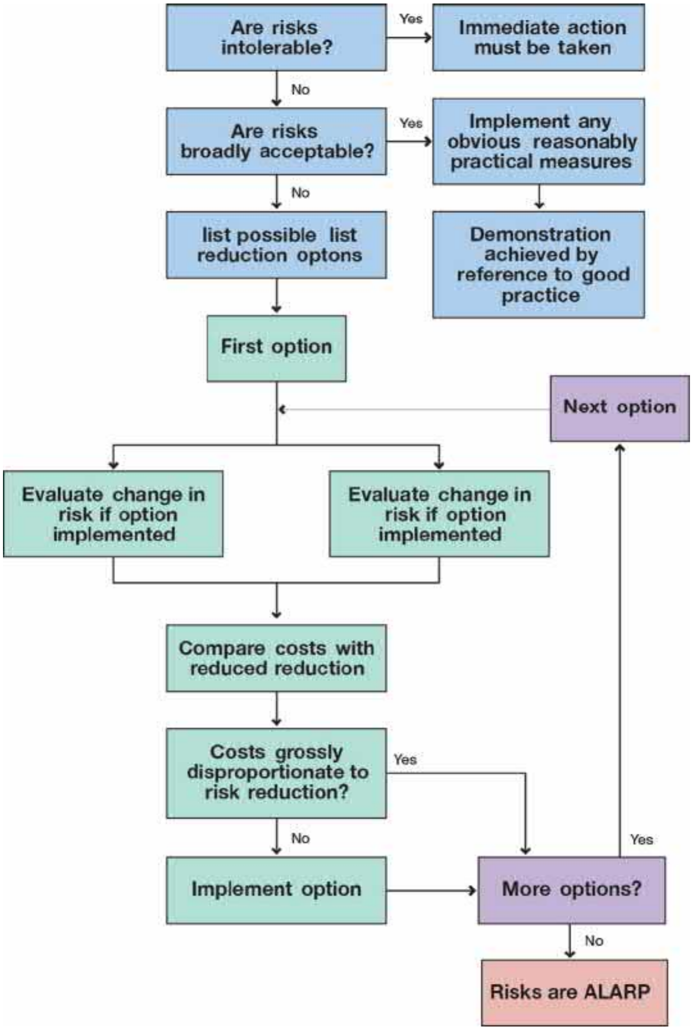


FIG. 10.2 ALARP determination process. *Source: UK HSE.*

3. Duty holders are compliant with safety and operational provision requirements for: *offshore installations, emergency response, wells design, construction and engineering, and all other associated well's project scope* relevant to the control of major accident hazards and risks.

Statutory requirements are qualified by phrases such as ALARP. Legal duties that use these qualifying phrases generally demand that appropriate tests and measures must be applied. In using ALARP wording, the duty holder must demonstrate well-reasoned evidence and justification to support nothing else can be done to reduce ALARP risks further.

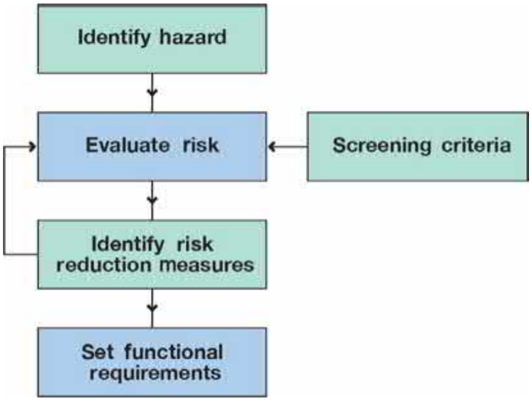


FIG. 10.3 Risk management process. *From ISO 1999:2013, Acoustics—estimation of noise-induced hearing loss. Reproduced with the permission from International Organization for Standardization, ISO and obtained from https://www.iso.org/. Copyright ISO.*

Meticulous Hazard and Risk Assessment

Reducing methods to work must be capable, effective, and efficient to enable the detailed ranking of all problems (hazards) and associated risks to ALARP. Objectivity of risk assessment is to be proportionate to the priority and complexity of project problems to be managed and controlled through well-thought reasons, particularly when regarding impact and consequential loss that can potentially result. The expectancy is that risk assessment shall progress through the following stages:

(a) **Qualitative** (Q), where frequency and severity are determined purely qualitatively.
(b) **Semiquantitative** (SQ), frequency and severity are approximately quantified within specified and appropriate ranges.
(c) **Quantified** risk assessment (QRA), full risk quantification results.

This approach reflects lowest Qualitative (Q) to highest Quantified risk assessment (QRA) range. The preferred choice must take dimensional account of:

(a) Refined estimates of the probability of risk (and its proximity to the limits of tolerability).
(b) The complexity of the problems (hazards) and/or difficulty in answering the question of whether more or less needs to be done to reduce associated risks to ALARP.

In term of risk metrics, dimensions, and levels to be used, an example is illustrated in Fig. 10.4. It is common to use qualitative assessment in high hazard-risk situations. Results can be initially high, to identify and assure that the most important project scope risks are mitigated, worked, and reduced to ALARP acceptance. Note: A more cautious approach must be exercised when justifying risks that reveal significant deviation from standard offshore or deepwater operating norms.

In deepwater due to all the essential difference as outlined in this guide, there exists many deviations from the standard norm, and why due and diligent risk management and change is so vitally important in these projects.

Persons responsible must be suitably *qualified, experienced, and of sufficient seniority* to appropriately manage and control all risks identified and be accountable for all corrective actions to be effected.

Hazards and risk assessment must begin right at the project start and can add significant value as appropriate in the early project screening stage to generate early awareness to

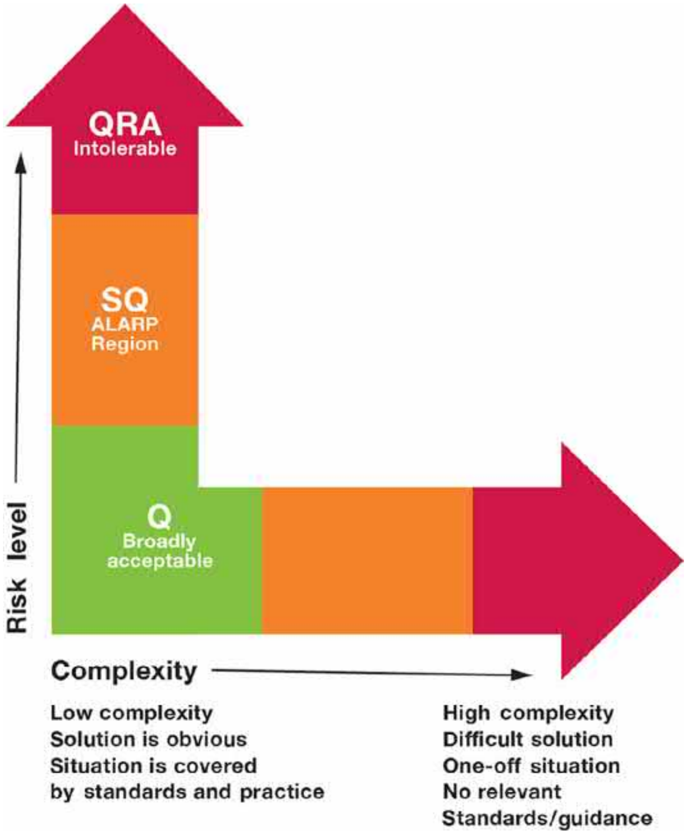


FIG. 10.4 Hazard and risk assessment progression. *Original Source: HSE Information sheet, Guidance on Risk Assessment for Offshore Installations Offshore Information Sheet No. 3/2006. Illustration reconstructed Kingdom Drilling 2018.*

pertinent project scope issues identified to thereby afford maximum time to reduce risks to ALARP levels.

In deciding the appropriate level, a qualitative approach is first used followed by further methods when this level is unable to offer the ALARP outcomes required, reference Fig. 10.4 where project persons need to fully comprehend and grasp:

(a) The required understanding of the hazards/risks;
(b) Discrimination between the hazards/risks of different events, or
(c) When to seek assistance to decide if more needs to be done, i.e., through more compliance judgment to reduce risk.

General Guidance for Project Risk Assessment

Figs. 10.4 and 10.5 present that risk estimation assesses the severity (consequence) and frequency (likelihood, probability) of project scope hazardous events to then identify measure and evaluate existing and further reduction methods to be added to achieve ALARP levels as illustrated in Tables 10.1–10.2.

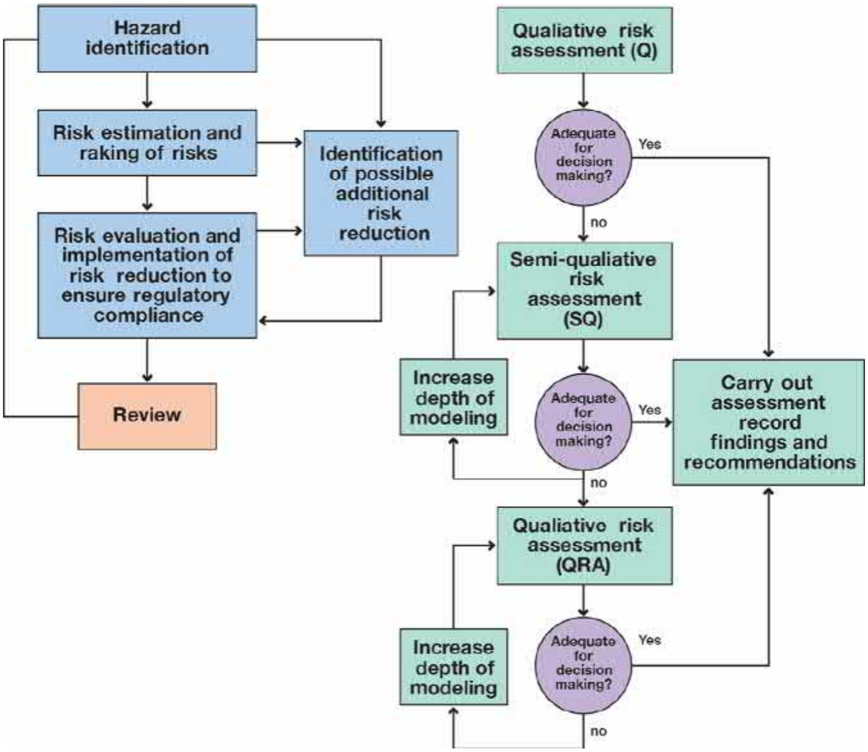


FIG. 10.5 (Left illustration) Main stages in the risk assessment process. (Right Illustration) Screening to determine appropriate risk assessment level. *Source: HSE Information sheet Guidance on Risk Assessment for Offshore Installations Offshore Information Sheet No. 3/2006.*

TABLE 10.1 Risk Matrix—Likelihood and Consequence Assessment Table

	Consequence Severity				
Likelihood of Loss Control	**5 Severe**	**4 Major**	**3 Serious**	**2 Minor**	**1 Negligible**
5 Very high	X	X	X	X	O
4 High	X	X	X	O	O
3 Average	X	x	O	O	=
2 Low	X	O	O	=	=
1 Very low	O	O	=	=	=

X: Unacceptable high risk. Operator must reduce through prevention, mitigation, reduction. O: high risk. Operator must address QHSE, cost, value benefits of further risk reduction. Peer review/specialist assist to verify standards, procedures, guidelines, and controls are in place. =: Acceptable risk. No action required.
Source: Kingdom Drilling modified April 2018.

TABLE 10.2 Project-Based Risk-Matrix Category Definitions

Likelihood Scale (Probability)		Consequence Scale (Based on Deepwater Operating Costs of £500,00 per Day)
1	**Very low**. Failure never heard of in industry. Almost impossible on a well's project. $<10^{-4}$ per year	**Negligible**. Minor impact on personnel, negligible project failure, damage, loss, environment harm. <£10,000, <½h, <1 bbl spill
2	**Low**. Failure heard of in the industry. Remote, but possible during projects. $<10^{-3}$ per year	**Minor**. Medical treatment for personnel, minor project damage, failure, environmental harm. <£150,000 cost. ½–6 h lost time, 1–50 bbl spill
3	**Average**. Failure results on company projects. Occasional, could occur during a project. $<10^{-2}$ per year	**Serious**. Serious injury to personnel (LTI), project stoppage, delay, interruption, environmental harm. <£500,000 cost. 6–24 h lost time, 50–500 bbl spill
4	**High**. Failure is evident several times a year in company projects. Possibility isolated incidents in individual projects. $<10^{-1}$ per year	**Major**. Permanent injury/health effect, major project damage, delay, loss, environmental harm. <£1,000,000 cost. <1–2.0 days, 500–5000 bbl spill
5	**Very high**. Failure evident several times a year on specific wells. Repeated incidents on certain project types. $>10^{-1}$ per year	**Severe**. One or more fatalities, severe project, damage, failure, loss, environmental harm. >£1,000,000 cost. >2.0 days lost time, >5000 bbl spill

Modified from generic sources, Kingdom Drilling May 2018.

The purpose of the matrix is to readily fit and rank real risks in a reasonably precise accurate and ALARP manner.

Due to the qualitative factors, degrees of uncertainty and conservatism that might prevail, specialist peer reviews and assists are recommended. For example, if several hazardous events result into the same risk matrix category, specialist judgment is more likely to assure more fitting ranking results.

The amount of detail and effort required increases from qualitative (Q) to quantified risk assessment (QRA). For the Q or SQ and SQA approaches, the risk matrix and tables as shown to provide the most convenient method to present, rank and evaluative metrics levels and limits to use and apply.

To close this section, it is important to note that risk matrices must be capable of discriminating between real project hazard and risks likely to exist. If not, they need to be changed.

Matrices must afford a well-reasoned rationale and detailed election of *severity and frequency,* matrix categories as outlined. In practice, a 5×5 matrix affords greater opportunity for discrimination vs. a 3×3. Frequency categories must also cater for the range and relevance of severity that exists.

Bow-Tie Diagrams

Bow-tie diagrams are used and viewed as better suited to hydrocarbon, refining, processed safety downstream business requirements.

They are used to:

(a) Identify and document the "lines of defense" or "safety barriers" that are in place,
(b) Facilitate a qualitative assessment of any gaps,
(c) Help inform an assessment of event likelihood for semiquantitative analysis.

Source guidance on the use of bow-tie diagrams is:

(a) CCPS (2001). "Layer of Protection Analysis—Simplified Process Risk Assessment". American Institute of Chemical Engineers, New York.
(b) Amey VECTRA (2002). "Lines of Defence/Layers of Protection Analysis in the COMAH Context", www.hse.gov.uk/research/misc/vectra300-2017-r02.pdf.

The concluding view on bow-tie diagrams in this guide is that they can be used but have limited application in multiple and complex evident facets of deepwater well operations and situations.

Hazards, Risk, and Uncertainties

To reduce hazards, risk, and uncertainty at ALARP results desired, regular peer reviews, assists and specialist advice shall have to be planned for, resourced, and scheduled to support any risk management approach undertaken. High-end modeling of specific deepwater project hazard/risk consequences as identified through major accident hazard weaknesses identified must also be worked to assure that the right decisions for all the right risk-based reasons result. Note: Deepwater well operations can frequently be extremely complex involving multiple disciplines, where getting as true handle on the degree of real risk and uncertainty that prevails rest assured is not an easy task.

One way of dealing with risked uncertainty is to improve all aspects of standardization used throughout each project, e.g., use more generic and reliable data, metrics, and controls. Inputs of uncertainty within any frequency analysis results are more cautious when using more conservative norms. However, this may present a double-edged sword. For Q and SQ approaches, significant conservatism in terms of risk shall likely result. QRA analysis on the other hand can be pitched within a more accurate range vs. conservatism. If it is apparent that conservatism is far too great to support reasoned, rationale, ALARP decisions (safe operating kick tolerances to be <100 or 50 bbl as per company standards, as the classic deepwater drilling example), it is essential and necessary to refine analysis to remove conservatism as it may not be practical.

Note: Refinements in more critical circumstances, e.g., well operations, well integrity, well control assurance, etc. require far more precise screening, sensitivity analysis, and evident details to justify the end result and withstand scrutiny that may later result.

Sensitivity analysis is another simple operating technique that in the right hands is employed to scrutinize more extreme magnitudes of risk and uncertainty. In specific cases, e.g., kick tolerance safe operating limits, a small number of carefully chosen sensitivity analysis studies and scenarios would be conducted via a technical well control assurance specialist. This is considered far more proficient than costly black box QRA modeling or Monte Carlo exercises.

Keeping it simple is the best practice approach to approximate risk assessment (in terms of the accuracy of any quantification) and can be more useful to a project for later decision making, particularly if the risk assessor has the wider deepwater knowledge and experience, skills set required. The important statement here is that reality checks must apply at each and every project stage for all risk assessment conducted.

Relationships With Risk to Safety Management Systems

Risk assessment alone shall not reduce all evident deepwater hazards and risks (where they are often too many unknowns) if the process is viewed as an end to itself. Problem solving and risk reduction merits are only realized when persons involved act in a collaborative, systematic, logical and rationale manner, using the tools, techniques, and skills provided to continuously manage control and reduce risks. It is important to note that project scope associated hazards and risk can change at any time. Management change and dynamically conducting further risk assessment is now crucial with critical aspects to address. Active engagement and the ability to readily manage project change, from start to end, require a complete understanding of all risk inputs and outputs desired. Risk management is to be encouraged at each and every project stage until the final scope item is completed and closed.

Identification of Potential Risk Reduction

All risk-reducing measures should entail detailed thought processes in regards to how project-related problems and scenarios can unfold the physical interaction with the layout, the people, the task at hand, the rig, the well, the equipment, systems, conditions, environments, etc. Ranking and prioritization are then essential via a systematic and sequential hazard and risk-reducing approach, led by adopting a multidisciplinary thought process approach to assure all skills, knowledge, and experience are used to deliver more qualified results. A hierarchical approach to risk reduction is designed to:

(a) Eliminate and minimize hazards by design (inherently safer design),
(b) Prevent (reduction of likelihood),
(c) Detect (transmission of information to control point),
(d) Control (limitation of scale, intensity and duration),
(e) Mitigate consequences (protection from effects), and
(f) Emergency response plans (spill, well control, blow out, drive off/drift off, etc.).

Risks must be assessed from highest to lowest, to assure ALARP reduction measures result.

Operating Relationship With Third Parties Employed to Carry Out Hazard and Risk Assessment

Regarding third parties hazard and risk assessments, the operator is responsible that all project-related risk studies are conducted, collated, duly assessed, and acted upon, including:

(a) Initiating the process of project hazards and risk assessment;
(b) Scoping of any risk assessment as outlined in this section;
(c) Subcontracting appropriate aspects, e.g., leadership of hazard identification, quantification, to specialist contractors, if appropriate;
(d) Providing the necessary inputs and members of brainstorming teams to the subcontractors;
(e) Providing all necessary resources and support;
(f) Reviewing outputs to ensure project operating details are appropriate, and to obtain an understanding of the hazards, potential consequences, and risks;
(g) Making use of the results of the hazards and risk assessment as part of the continuous improvement of safety, e.g., by using it to identify and evaluate possible remedial measures;
(h) Reviewing the hazards and risk assessment periodically and updating it as required.

What may be needed to settle differences in methods is that a balance is struck (e.g., within contracts) to decide and assure the hazard and risk assessment approach best to use.

The ownership of the risk assessment method selected then to be retained by the operator to carefully consider how to supply all inputs and outputs to and from each contractor, including details of all associated project-related rig and well operations information.

In all cases, personnel carrying out the risk assessment should have knowledge of:

(a) Equipment, process, and/or activity to be assessed,
(b) Hazards present,
(c) Probability/likelihood of the failure scenarios realizing a hazard,
(d) Consequences of exposure to the hazards present or produced.

All consultants or contractors employed within a project shall be competently trained and expected to conduct hazard and risk assessment, and their scope of work shall include this task with the operator retaining responsibility to evaluate and assure all needs are met in this respect.

Unscheduled Work

For unscheduled or unplanned work, the person in charge or delegate, and an operator senior person must ensure that all hazards and risks are identified, assessed, highlighted, and controlled to ALARP levels desired.

Management of Change

Management of change would include changes of material, process, activity, equipment, or personnel that could affect the safety of the project, the installation, the project scope, rig, or personnel involved.

The project persons in charge responsible for the various aspects of geology, basis of design, rig intake, well's programs, etc., shall initiate change requests and should be responsible to manage these after written approval is provided by the original accountable person. Prior to change, amendments and implementation of change must be discussed with the appropriate personnel involved. Persons responsible shall communicate changes made to manuals, programs, well verification schemes, instructions as required. Any changes to operating standards, company, or project-specific procedures must be communicated through the correct channels.

Material Change

Guidance on what constitutes a material change revision is primarily based on the *original design, program, or verification accepted*. Changes must merit a reappraisal of hazards/risk management aspects and appropriate control arrangements, whether or not they require the adjustment of measures to be taken. In practice, revisions considering material change should have *Direct or Indirect potential to affect major accident risks or associated control measures.*

Direct effects

(a) modifications or repairs to the structure, plant, or equipment,
(b) an increase in hydrocarbon inventory,
(c) new technology, processes, or operational complexity,
(d) new types of combined operations, or new activities in connection with an installation,
(e) new operational risk controls.

Indirect effects

(a) new ownership or operatorship, introducing a change in the management system,
(b) a major change of contractor, and
(c) extension of the use of the installation or its components beyond the original design life.

These are examples and *do not limit what might constitute material change.*

Regulatory guidance should be available to advise duty holders how to decide what constitutes material change for their installation, well safety case, designs, or programs. For example, regulators may challenge a duty holder's decision whether a safety case or well design revision constitutes a material change. Regulators can at any time call for an inspection, and have powers to direct a revision, then assess, and decide whether they can be accepted and any proposed changes implemented.

The project duty holder is encouraged to engage early with regulatory focal points, to minimize the risk of delays or process complications. Regulatory assessment and decision acceptance will relate to the proposed material change. It is also appropriate to assure that change revisions are accounted for in regards to other parts of project scope that could be impacted.

WELL PROGRAMS AND SAFE OPERATIONS MANAGEMENT

Deepwater Programs

A well's program is essentially a schedule of plans, activities, standards, procedures, and best practices that are fully risked assessed, to be followed, complied with, verified, confirmed, and evaluated throughout.

A drilling program's purpose is to provide a documented assist and support to deliver stakeholder requirements, within a set of specific objectives, hazards, and risks, mitigations that are clearly identified and stated for each work breakdown schedule.

A program should not be that operationally detailed as a multitude of other support material aspects shall contain this level of detail. The program should simply summarize, and state the details of key subject and evident project related material matters and who is responsible to do what, why, when, and how.

Well programs are best served if maintained short, concise, and succinct to contain all relevant data and information that permits a project to be delivered as planned. A generic Deepwater Program table of contents is illustrated as follows:

1. Management of well operations
  (a) General
  (b) Well verification
  (c) Reporting requirements
  (d) Organizational charts
2. Well summary
  (a) Executive summary (purpose and objectives)
  (b) General well information
  (c) Well integrity, barrier, well control, and QHSE policy

3. Well geology
   (a) General (location, targets, etc.)
   (b) Geological hazards/risks
   (c) Pressure, temperature, and reservoir management
   (d) Shallow hazard and risk assessment summary
   (e) Data acquisition and formation evaluation summaries
4. Well information
   (a) General well data (inclusive of key operating hazard, risk, and mitigations summary)
   (b) Well operations summary, timings, and sequencing
   (c) Well design and engineering technical summaries
   (d) Drilling metrics targets and deliverables
   (e) Well operations summary.
5. Appendices
   (a) Rig-operating specifics
   (b) Bit and bottom hole assembly technical summary and schematics
   (c) Short program (1–2 page summaries) of rig move, cement, fluids directional/ surveying, etc.
   (d) Well barriers, provisional plug and abandonment schematic
   (e) Well verifcation (examination) requirements summary
   (f) Summary of contingent, interface, and emergency repsonse support documents
   (g) Contacts list

Caution must to be exercised to assure that the program aligns with other key project documents—namely, well proposal, basis of design, risk assessments, and project specific developed interface, and bridging documents. Otherwise during project implementation, greater management of change shall be required than should be necessary.

Consequence Considerations

Optimization of all deepwater well programs must include the analysis of all possible responses to planned and unplanned events.

The more complex the operations are, then the greater the tendency will be to review more options in greater depth and detail. That is not to say that only complex operations need submit to this type of review but rather to indicate the increased probability of "knock-on" effects in these environments. In fact, every specific operation can benefit by application of "worst-case, a what-if and Murphy's Law" scenario approach to each well's program aspects.

Consequential analysis should weight results to assure a best-fit response plan (plus contingent options) result, with the initiation of key and important contingency plans aiding to be ready to deliver assured project success, should things not go as according to plan A.

As serious complications can result due to unplanned events, every aspect of the project scope and work programs from the simplest to the most complex should be submitted the "what if" questioning. Some of the simplest, most straight forward jobs are unfortunately all exposed to Murphy's law where things can and have gone quite wrong resulting in major project loss.

Significant time, cost, and value-adding project savings shall result through having predetermined response plans available on-site that need to be well understood by all front line well site leadership and supervisory personnel.

Service companies shall also be made aware of essential requirements to assure similar response prearranged plans are ready, for example with backup tools service and personnel available for urgent call-out needs.

Personal Responsibilities

Management within all companies have a duty to ensure safe operational systems of work are implemented, that company's goals are achieved, and ensure that all regulatory requirements and standards are met, including accident prevention and the elimination of harm to personnel, the environment, and equipment.

All project personnel have a duty to take responsibility for their own personal safety and those working with them and to work in accordance with documented health, safety, and environmental practices, and appropriate procedures and work instructions.

Program Change

Every aspect of a deepwater well's program can be interrelated to project scope integration design, engineering, and successful ALARP risks management delivery. A change in one area or aspect must consider the impact change shall have on all other project scope aspects.

All team members must strive for consensus in terms of priorities and criticality for each project scope item, goal, and objective as defined. Even if everything is clearly and concisely laid out prior to actual planning commencement, there always remains a potential for change through every subsequent stage gate process.

Change must be considered with a critical eye to ensure that the implication and impact of change is considered from all different perspectives.

Interface "Bridging" Documents

Interface Organization Chart

The interface between various companies and management structures within projects must be considered and controlled through appropriate project channels and resulting interface "bridging" documents. Detailed project organization charts are prepared to clearly define respective operators, drilling contractors, third parties, and project-specific project management systems, roles, responsibilities, and controls to effectively identify all positions instrumental to securing project demands.

Company Roles and Responsibilities

All parties shall confirm that operational support functions meet deepwater scope goals and objectives as planned, as demonstrated within their standard management system documents or project specific interface documents required.

Interface "Bridging" and Control Documents

Projects develop interface bridging documents to address the management systems standards, procedures, and best-practices gaps and conflicts that can exist between the operator drilling contractor and all third parties for the entire project scope. Interface documents produced must demonstrate all parties have the required plans, preparation, and organization in place to implement a safe system of work to meet the project scope. Typical drilling contractor and operator project reference documents to be interfaced and listed as follows:

Drilling contractor generic illustrative documentation

1. Quality Policy Manual
2. Health Safety Environment Case
3. Rig safety case (if required)*
4. Safety Policy Manual
5. Standard Operating Procedures Manual
6. Rig Operations Manual
7. Engineering Change Request Form
8. Incident Reporting and Investigation Policy*
9. First Report of Incident Form
10. Permit to Work Policy
11. Well Control Procedures*
12. Emergency Response Plan*
13. Shipboard Oil Pollution Emergency Plan
14. Third-Party Mobile Equipment Manual

Operator generic illustrative documentation

1. Guidelines for Systematic Hazard/Risk Assessment*
2. Safe Operating Procedure, Responsibilities, Handover, and Control of Subsea Field Activities
3. Safe Operating Procedure, Heavy Lift, and Dropped Object
4. Emergency Response Plan*
5. Management of Safety, Health & Environmental Systems
6. Marine Operations Manual
7. Permit to Work Manual
8. Well control Procedures*
9. Drilling operating guidelines*
10. Well design and Operations management Policy manual*
11. Well Design and Operations Standards*
12. Casing design manual
13. Well safety case (if required)*
14. Oil Spill Contingency Plan*

Notes: * denotes key documents that will be exchanged between companies. All other documents will be available for discussion and review between the companies on request.

To address any interface or controlling issues, areas of potential conflict must be reviewed, agreed upon, and documented. Items of conflict are to be evaluated, and corrected to resolve all issues identified in a controlled best practice approach.

Resolution to bridge gaps shall be clearly worked, addressed, and adhered to within project specific interface bridging documents produced. This is particularly important when companies have never worked together. Reviews are recommended to be conducted to assure controls and interfaces result to close any gaps identified to ALARP levels required.

Bridging of operators, drilling contractors, and third-party management systems documentation essentially agrees to the division of roles and responsibilities required, i.e.: Who does what, when, where and more explicitly how for project-specific issues that deviate from the standard norms.

Well Control Bridging Document

A project-specific well control bridging document is particularly important for complex deepwater well projects due to the inherent facts that the operator and contractor may have separate and different well control manuals where neither may be ideally suited to the DEEPWATER specifics required.

The divisionary gaps that exist must be suitably assigned to the responsible persons that project specific best practice plans, organizational roles, and individual responsibilities are well laid out, corrected, and bridged appropriately.

What can result within this document is outlined from a 2017 deepwater project as illustrated in Table 10.3.

The operator is responsible and accountable for the well's integrity, barrier control, and safe operating conditions and elements within the well, i.e., everything below the subsea BOP and marine riser. Operator personnel must be qualified and skilled in facets of DEEPWATER well control, project-specific issues identified where unique demands have to be met.

Through the project planning the operator will consult and collaborate with the drilling contractor to assure all well control hazard and risks identified are addressed for the drilling contractor's vessel, all well control equipment, standards, operating procedures, best-practices organization roles and responsibilities required, i.e., within the well control bridging document.

TABLE 10.3 Generic Well Control Bridging Document, General Table of Contents

Review of well control management	*Well-specific well control guidelines*
• Purpose, scope, and responsibilities	• BOP test on installation and prior to drilling into transition and reservoir zones
• Well control policies	• Finger printing
• Well control principles	• Narrow margin procedures
• Well control equipment	• Use of BOP pressure and temperature gauge
• Well kick indicators	• Difficulties during a well kill
• Shut in procedures	• Critical zone drilling technique
• Well kill procedures	• Rig crew checklists for deepwater
• Special operations and procedures	• Hydrates in deepwater operations
• Shallow gas	• Ballooning, breathing, or supercharging
• Use of oil-based mud	• ROV intervention
• Deepwater-specific well control	• Shallow water flows
• HP-HT specific well control	• BOP safety systems, emergency disconnect sequences AMF, acoustic
• Drill stem tests, completion, and workovers	
• Well control drills formulae conversions	

Source: Kingdom Drilling 2018.

The evident fact is that the drilling contractor is ultimately responsible through maritime law for the safety of the vessel, and personnel on board. The primacy of this document begins with the duty holder, with the drilling contractor and the preferred use of the drilling contractor's well control manual and all associated well control equipment as the starting reference. Once a primary well control situation results that escalates to a secondary level 2 tier event, the subsea BOP is closed, to safely barrier off the operator's well and isolate the well control event from the rig. The duty holder drilling contractor must assign a person in charge to take control of the well control event. The operator shall provide well control support when asked or requested by the drilling contractor to do so.

To address all well control and rig-related assurance issues, it is important that pre-empted plans exist to what probably can go wrong in terms of well control events, and that a collaborative communicative environment is established, managed, maintained, and controlled by all parties concerned, notably operator, drilling contractor and key third-party personnel. All personnel potentially involved in a deepwater well control and operational incident must be familiar, trained, qualified, and suitably conversant in how to utilize each project's well-specific bridging document as applicable in the context of individual roles and responsibilities.

Note: Advanced drilling simulators exist today to provide a detailed level of wells and multidisciplinary team training—perhaps more is needed for these wells than ever before.

Service Company Interfaces

Interface requirements between the service company and the operator shall also be established.

The extent is dependent on scope and nature of work required, with the project manager to resource and plan for any interface needs to be addressed. For example:

- It may be necessary to choose a service company long before other aspects of the project have been finalized to ensure interface requirements are meet, e.g., an ROV company interface might need to be established early in the design phase of a subsea project to ensure ROV compatibility with well design features.
- Interface issues always exist between the contractor and service companies. These may be as simple as the handling procedures for service company equipment by rig personnel or as complicated as full HAZOP and risk assessment studies needed to conduct combined operations.

Communication

Five lines of communication should be considered and evaluated between operator, drilling contractor, and associated project parties.

1. Routine communication,
2. Hazards, risk management and management of change,
3. Contingency and emergency response planning,

4. Quality assurance, Health, Safety, and Environment management,
5. Accident /incident/near miss and subsequent loss control, and/or nonconformance reporting, learning, and knowledge management systems.

All party management must ensure that all personnel (including all subcontractors) are notified of, and are familiar with, all project scope and program activity aspects and that everyone will abide by all relevant regulations, standards, and project-specific rules and precautions to be undertaken. The methods to establish and maintain effective lines of communication between offshore, onshore, and onshore/offshore communication shall be well defined and clearly specified to then be best practiced by all concerned.

Key technical information within the project scope shall also be circulated to all relevant operator and contractor personnel, with priority elements to be discussed by relevant parties at dedicated meetings, both onshore and offshore, prior to starting each relevant work scope item. Managers, leaders, supervisors, and individuals must be assigned detailed work-specific roles and responsibilities to assure that detail required within each and every work activity element is full addressed, conducted and implemented as planned, i.e., meeting project quality, time, cost, and HSE requirements. This includes addressing all hazards, risks, and change management that may be further demanded.

Monitoring, Reviewing, and Auditing Process

Detailed monitoring, auditing, and review process for operator, drilling contractor, and associated third parties should be clearly specific within the respective QHSE management systems. Project-specific issues are to be clearly laid out, presented, and addressed within the designated project management handbook and interface documents that result.

Appropriate controls shall be in place to assure that all corrective actions arising within monitoring, review, and audit processes are applied. Project persons assigned shall manage so that those responsible assure that all actions are implemented and closed out in a timely manner.

Monitoring

All project, safety, and operational aspects shall be monitored through agreed interface requirements of operator, drilling contractor, and third-party QHSE management systems and project specific metrics as agreed.

Reviewing

Management systems review and interface processes as agreed shall be maintained through the duration of each contract. Any relevant information resulting from interface arrangements resulting from monitoring and auditing processes shall be reviewed by the respective assigned persons at regular meetings planned with appropriate actions agreed.

Auditing

Within the contract period, audits may be conducted onshore or at the offshore installation by all parties concerned. Parties shall agree and commit to required audits and facilitate these events and assure any agreed findings are implemented via their respective corrective action processes. Copies of all third-party audit reports shall be provided to the project, operator and drilling contractor's operational and QHSE managers in this respect.

EMERGENCY RESPONSE PLANNING

All parties through the project planning and implementation stages must consider what, when, and how emergencies can arise and how to respond. Then who, how, and when are to be dealt with and addressed should an emergency response situation arise. The respective company must therefore describe and outline an emergency response organization to operate within the following guidelines:

- Drilling contractor rig and well-specific Emergency Response Plans.
- Operators supporting Emergency Response Documentation.

The purpose of these documents is to provide written guidance for the response actions to be taken by both offshore and onshore personnel in a deepwater location emergency.

The drilling contractors Emergency Response Plan shall apply on the installation at all times unless otherwise stated. Drilling contractor shall handle the onshore response to any emergency which has the potential to affect the integrity of the rig or the safety of any personnel, with operator providing the technical expertise required, via the drilling contractor's Emergency Response Room. Onshore actions and responsibilities in an emergency are detailed in the respective company's emergency procedure plans.

The rig manager/OIM shall direct the prime response to any emergency situation and has the authority to take whatever measures are necessary to meet the emergency. This includes deployment of the offshore emergency teams and engagement of external assistance.

Accident /Incident/Loss Reporting

Drilling contractor is responsible for reporting any notifiable event to the appropriate authorities in accordance with applicable legislation.

Operator shall report any notifiable accident event according to their procedures.

All reportable events shall be recorded in operator and drilling contractor's reporting systems, according to the procedures detailed in their respective management system documents.

All events big or small should be thoroughly investigated as described in operator's and drilling contractor' safety or loss control investigation guidelines. Investigation must result at the earliest opportunity following an event, with the chosen team consisting of operator, contractor, and 3rd-party personnel as required.

It is recommended that projects adopt a analysis investigative no-blame method approach. Details can be previewed @ www.failsafe-network.com.

ERP Organization

The organizational interface between the emergency response team's should be well presented via a suitable chart, with detailed responsibilities contained in the relevant HSE management systems documents. Operators' and drilling contractors' emergency response teams will depend on event specifics and, for some, be mobilized to provide rig support.

Primacy

Drilling contractor has primacy and overall responsibility for the coordination of emergency response unless clearly stated otherwise. Coordination shall be conducted from a designated emergency response room in an appropriate regional office. The Emergency Response Plan shall form the base plan for a typical installation or well-related emergency.

- The drilling contractor has primacy in an emergency situation that endangers the integrity of the installation or the safety of personnel. The operator has primacy in an environmental incident that does not endanger the integrity of the installation or the safety of personnel.
- Drilling contractor will handle any spills that *are contained* on the installation using the project-specific Oil Spill Contingency Plan (OSCP).
- Operator shall handle the onshore response to an environmental emergency *not contained* on the rig, with drilling contractor providing support if requested by the operator's emergency response team.
- Drilling contractor has primacy for major trouble or lost time events involving vessels within the 500-m zone of the installation *(and outside the zone if it is believed to pose a direct threat).*
- Operator shall assume responsibility for all trouble or lost time events relating to marine vessels outside the 500 m zone that pose no threat to the vessel.
- Drilling contractor shall assume responsibility for all direct communications to the rig, ensure that communications are established with operator and ensure relevant information is distributed to operator, regional authorities, and agencies as applicable.
- Drilling contractor shall inform all relevant bodies of any reportable major event on board the installation and shall liaise with other bodies such as police, civil aviation authority, medical authorities, HSE, etc.
- Operator shall assume responsibility for all major events, relating to marine vessels or helicopter support.
- A separate document would be generated on a project basis to cover onshore emergency response procedures in greater detail.

ERP: Communications

Initial operator and drilling contractor on-duty emergency response contact numbers and assigned personnel would be provided on a weekly administered roster sheet. In the event that a major occurrence results offshore, the rig person for the emergency shall first contact as an example, the Coast Guard before contacting their onshore duty manager. The person in charge would then ensure that the operator's representative is then immediately advised of the situation and details known and unknown.

The onshore managers shall establish appropriate contact, as dictated by the situation and in accordance with the drilling contractor's emergency response plans. They shall contact the persons responsible to mobilize the drilling contractor emergency response organization appropriate for the situation.

The operator emergency response center shall be contacted by the assigned operators. The operator duty manager shall assess the operator mobilization requirement and implement their plan as outlined within their procedural documents.

The drilling contractor emergency response team shall establish and maintain communications with the Rig Installation Manager/OIM via a dedicated line. A direct line of communication between the drilling contractor emergency response center and operator center and (hot line) shall also be established. All calls from the rig medic to shore doctors shall be directed to the Emergency Medical Center associated with the dedicated hospital as per the plan.

ERP: Notification

Drilling contractor is responsible for performing all the duties detailed in the emergency response plan, e.g., they are responsible to notify the classification society in the event of stability problems or vessel structural damage.

In the event of an oil spill, the person assigned shall send the appropriate notification to regulatory and statutory bodies in the format required. Operator shall be provided with all such notifications.

The operator duty emergency response persons shall ensure all duties, as detailed in their emergency procedures, are performed as planned.

Other ERP Issues to Deal With

Other issues to be addressed would be but not limited to:

Liaison with the Coast Guard	Medical Services
Liaison with the Police	Handling of Evacuees
Contact with the Media	Handling of Relative Enquiries
Emergency Response Plan	POB List

Oil Spill Response Planning

In an oil spill event, in conjunction with the safety-related emergency situation, primacy in the emergency response will remain with the drilling contractor as detailed previously.

This will continue until the contractor's emergency response team and rig person in charge determine no further risk is presented to personnel or the installation, at which point control of the pollution response will revert to the operator.

The drilling contractor designated person shall prepare and send the appropriate regulatory/statutory notifications, with a copy issued at the same time to the operator.

Should an oil spill *not endanger the integrity of the installation or the safety of the personnel*, operator will initiate the Oil Spill Contingency Plan (OSCP) through the appointed oil spill response contractor. Operator shall keep the drilling contractor emergency response team apprised of the oil spill response situation.

Contractor shall handle any spills *contained* on the rig as per the agreed OSCP. Operator conversely shall handle the onshore response to an environmental emergency *not contained* on the rig, with the drilling contractor providing support, if requested by the operator emergency response team.

In the event of a third tier, i.e., significant spill, senior government or regulatory persons may locate to the drilling contractor and/or operator's emergency response rooms where management of the spill will be coordinated.

Generic oil spill rig and project readiness outline plans are stated in Chapter 11.

SPECIFIC REFERENCES

Department of Energy & Climate Change (DECC), https://www.gov.uk/government/organisations/department-of-energy-climate-change

[Note: Department of Energy & Climate Change became part of Department for Business, *Energy & Industrial Strategy* in July 2016]

https://www.gov.uk/health-and-safety-executive

Department of Energy & Climate Change, Policy Paper, 2010 to 2015 government policy: energy industry and infrastructure licensing and regulation. https://www.gov.uk/government/publications/2010-to-2015-government-policy-energy-industry-and-infrastructure-licensing-and-regulation

Marathon Oil UK Bridging and Interface documents examples. 2009.

Offshore Information Sheet No. 2/2006; Offshore Installations (Safety Case) Regulations 2005, regulation 12—Demonstrating Compliance with Relevant Statutory Provisions.

Offshore Installations (Safety Case) Regulations 2005, Statutory Instrument 2005 No. 3117 http://www.opsi.gov.uk/si/si2005/20053117.htm

Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, http://www.legislation.gov.uk/uksi/2015/398/contents/made

Offshore Safety Directive Regulator (OSDR), http://www.hse.gov.uk/osdr/index.htm

UK HSE Offshore Oil and Gas, http://www.hse.gov.uk/offshore/index.htm

CHAPTER

11

Readiness to Drill

DEEPWATER OPERATIONAL PLANNING

General

The best drilling operational plans ever conceived and agreed upon won't solve problems until plans are put into action, i.e., *until the rig is taken on hire and well operations commence.*

Deepwater-specific drilling "operational plans" will detail who will do what, using what, by when, who and how. Plans will organize the tasks required that implement the decisions to be made in the real world distant from the onshore project office, i.e., *at the rig site.* Timing, personnel, and other resources must have been considered and choreographed for action. Setting loss prevention standards, SMART quality and HSE targets, plus follow-up monitoring, assurance and control mechanisms are vital to ensure that project operational plans are properly executed as planned.

Murphy's Law

Plans shall always consider Murphy's Law: *That which can go wrong, will.* No matter how well we think we can predict the future, think through the sequence of deepwater drilling times, material, resource and operations required, as these shall rarely go as conceivably planned in this author's working experience. It is necessary to anticipate drilling operational problems and prepare as best as one can for them. Best practice must include contingent plans to avoid Murphy's worst effects.

Is Planning Worth the Trouble?

"*Why bother to plan at all*?" The answer is simple; plans assure individuals and teams are better prepared and organized to adapt and respond when things go right and wrong. Deepwater operational planning must allow for timely risk/change adjustment response and wise reactions that need to result versus a rigid, nonflexible pattern for the future.

https://doi.org/10.1016/B978-0-08-102282-5.00011-9

Value of Operational Planning

Value of operational planning is outlined in Table 11.1. For each deepwater drilling project, tick off the items that best assist to implement the correct operational decisions and solutions to result.

Drilling Operations Planning Checklist

Prior to finalizing a deepwater project's operational plans, before submitting them for rigsite approval, evaluate these using the planning check list provided in Table 11.2. Checking and testing these against the 14 listed criteria, project and individuals can simply sense the relative effectiveness and completeness of deepwater plans proposed. *Note: The best planners religiously play devil's advocate with their draft work, and adjust it whenever necessary until it has the highest chance of being executed without a hitch.*

TABLE 11.1 Value of Drilling Operational Planning

Value of Drilling Operational Planning		**Agree**
Realistic actions	1. Translate decisions into realistic actions that personnel can identify with	
Concrete programs	2. Nail down abstract ideas into concrete programs that are deemed achievable	
Specific assignments	3. Provide specific assignments so individuals know what to do and when	
Clear expectations	4. Create clear expectations so personnel know how they are to be evaluated	
Effective delegation	5. Divide responsibility for effective delegation in a simpler way	
Mutual commitment	6. Build agreement and establish mutual commitment to plans	
Coordinate action	7. Coordinate action and thus contribute to team building and teamwork	
Effective follow-up	8. Provide, effective follow-up mechanisms by mapping future free checkpoints	
Objective metrics	9. Establish a basis for objective more meaningful and measured results	
Defined responsibility	10. Contribute clear accountability by identifying who is responsible for what	
Save time	11. Save time by coordinating action and translating decisions into tasks	
Support workers	12. Guide management to know how to better lead and support workers	
People involvement	13. Provide more opportunities for people and team involvement in planning	
Ensure results	14. Ensure results are focusing resources in the best possible way	

Source: Kingdom Drilling 2018.

TABLE 11.2 Deepwater Drilling Operational Plans Check List

Criteria: Does Your Drilling Operations Planning Specify?		Yes	No
1.	Specific actions? (who, what, where, when, how)		
2.	Clear responsibilities, targets and standards?		
3.	Realistic timings?		
4.	Realistic resource estimates?		
5.	A coordinated sequence of executable actions?		
6.	Flexibility to change?		
7.	Checkpoints for routine follow-up?		
8.	Reliable measurement of results?		
9.	Required personal development?		
10.	Correctly emphasized priorities?		
11.	Feasible contingency plans?		
12.	Workable agreements for all involved?		
13.	A realistic and workable program?		
14.	A high probability of achieving desired results and targets?		

Source: Kingdom Drilling 2018.

READINESS TO DRILL

In deep water, the assessment of shallow hazards can be generated from existing high-resolution 3D or 2D seismic rather than from a dedicated shallow seismic survey. Justification not to perform a well-specific shallow seismic shall be well prepared by the shallow hazards specialist assigned and signed off by the assigned project managers. When surveys are to be conducted, the following should apply.

Well-Specific Site Survey

A well-specific site survey can provide vital data input for the Structural Well Design and development of operation procedures within well programs to mitigate potential seabed, shallow and environmental hazards, and risks to ALARP levels. This section presents what are considered general company standards, guidelines, and practices in terms of information acquisition and assessment required.

1. Geophysical and geotechnical site survey contractors shall be accredited to the required standards required, e.g., *ISO 9001 or other similar standards.*
2. The site survey (both geophysical, geotechnical, and environmental) must be completed in a suitable time frame so that to all hazards, risk, and concerns are fully evaluated and that any required changes to location, designs, or operations can be addressed and fully implemented and mitigated prior to starting a well.

3. For the site survey operation itself, a designated company representative generally:
   (a) Oversees the data acquisition program on site to ensure it is conducted as planned and in accordance with the contract's work scope terms and conditions.
   (b) Assesses the initial quality of the data acquired, and ensures they meet company and/or industry standard or to manage changes needed, e.g., request repeat acquisition or a change of scope if/as appropriate.
   (c) Reports back to the operations base and team on survey progress, to advise on any anomalies apparent during data acquisition.
   (d) Modifies the planned data acquisition program if justified to further investigate any critical or unexpected anomalies or potential hazards.
   (e) Monitors downtime loss or waste resulting during survey operations and advises if this is to company or contractor account as per contract.
4. The operator's or operations or project geologist/geophysicist are generally responsible for compiling the Site Survey Assessment. This document would detail all the information pertinent to project-specific deepwater drilling operations required.
5. The assigned persons may also use the services of external independent consultants to review and assess both geophysical and geotechnical survey data.

Management and Control of Site Survey Operations

A site survey program, e.g., *shallow seismic, seabed clearance, geotechnical coring and/or environmental sampling*, involves several operations that if not properly managed and controlled can create further hazards and risk to personnel and the environment. The safety management involved is generally the responsibility of the vessel owner who shall assure that operational safeguards are in place to minimize risks. The operator representatives then affirm the necessary safeguards, e.g.:

1. An adequate contractor safety management system exists and is being applied. This confirmed prior to contract award, with audits carried out as required.
2. Necessary operating and environmental permits, approved prior to operations commencing.
3. Emergency response plans are verified to exist for the vessel prior to operations commencing.
4. All events that occur during the survey must be compliantly reported and investigated with appropriate actions to result.

Site Survey Assessment

The Site Survey appraisal shall be ready well before commencing operations, to provide a concise summary assessment of the shallow soil and seabed conditions and potential hazards that can be expected at the drilling location. A document often referred to as a "Drilling Constraints Appraisal" is prepared by an independent specialist, who interprets all the shallow seismic and geotechnical information presented.

Management of Site Survey Operations

Site survey operations are managed by the project but shall require input from the subsurface and drilling teams. Here it is critical that each Scope of Work is reviewed and approved by all involved, to confirm that the survey is centered on the correct well location, area, and the operational work to be covered, planned or executed.

Work required must also be reviewed by the project HSEQ advisor to ensure all required environmental, sampling, or other associated work obligations are met and complied with to meet local legislation and address all environmental assessment requirements.

The company representative on board will monitor data quality and acquisition parameters to ensure that the survey meets requirements. Persons assigned to manage the survey operation on a day-to-day operational basis shall report daily to the assigned manager.

Bathymetry Survey

As it is important to have a contoured map of the seabed, either from published data such as shipping charts, or from the 3D and high-resolution seismic surveys taken over the location of interest. A bathymetry survey will measure water depths, map and identify seafloor hazards, e.g.*, unevenness, slopes, fluid expulsion features, and collapse to* generate a detailed mapped chart for the area of interest and identify hazards or risk exposures. *Example: Seabed topography, if extreme, can affect mooring and can raise concerns over long-term stability of the ocean floor.* Where a significantly dipping seabed is present, further geotechnical work, including penetrometer testing and boreholes, would be assessed for long term notably if production wells or subsea infrastructure are to be installed.

Geophysical and Geotechnical Site Survey Requirements

In areas where the shallow soil characteristics are not well understood, and if higher risk and uncertainty exists that could affect well operations, a geotechnical borehole is the only reliable method considered of obtaining appropriate soils data to a depth to be able to determine load-bearing capacities. Note: It is important to provide prospective drilling contractors with relevant site and soils data at the time of issuing the rig tender invitation.

The borehole itself shall comprise alternating sample recovery and in situ testing of the soil properties as outlined in Fig. 11.1. Programs can be modified as required by actual conditions to ensure that the most representative dataset is recorded.

Soil properties (most critically, relative density and undrained shear strength) can be estimated from the in situ cone penetration tests (CPT) and additional laboratory tests conducted on the recovered core samples. These parameters all are used to estimate penetration potential of foundation and conductor string and assess the risks of slumping and broaching conductors as discussed in Chapter 12 of this guide.

Geotechnical Data for Conductor Analysis

For a single exploration well, geotechnical shallow soil data extrapolated from seabed cone penetrometer tests (CPTs) may be adequate for design of the conductor installation. The CPT data will be considerably less costly to acquire than deep geotechnical cores as they can be acquired using a standard survey vessel as opposed to needing a ship equipped to drill a geotechnical borehole.

The data may be gathered either directly or indirectly from regional offset wells or geotechnical boreholes previously drilled. If no suitable data exists, then shallow geotechnical risk shall be assessed. Note: Geotechnical boreholes with shallow cores provide the most accurate method of assessing shallow sediments and operational risks but at a higher cost.

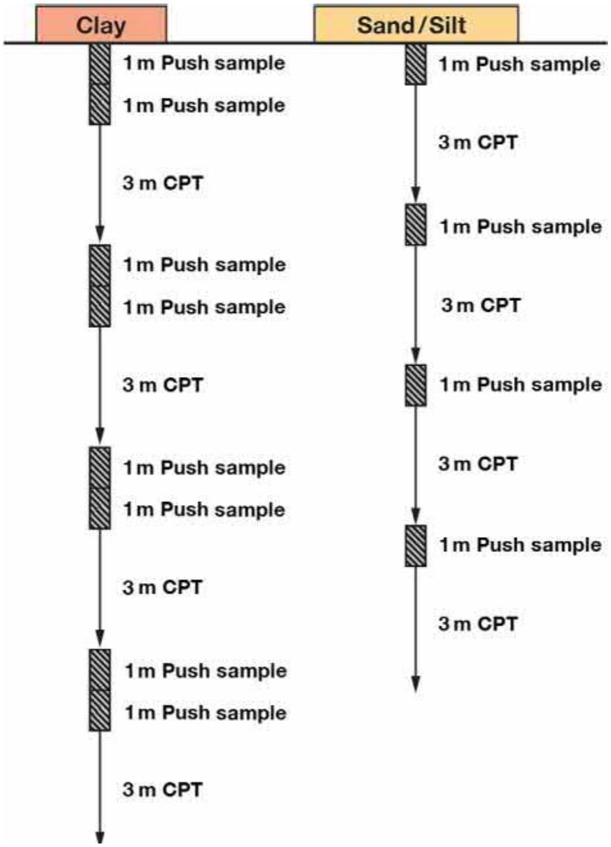


FIG. 11.1 Typical geotechnical borehole drilling and test program.

Where shallow sediments are unconsolidated mud and clay dominant, jetting of the conductor is likely to be the most effective installation. If gravel, silt and/or sand beds or even boulders exist, e.g., in *Northern Atlantic, Norwegian Barents Seas, Offshore Greenland, East Coast of Canada*, or other deepwater regional seabed instances where hard ground exists within the shallow soils, jetting is not practicable. Drilling a wellbore, running and cementing a conductor is then required.

Equipment and Operations Prior to Mobilization

In order to assure a desired SEE, safe, effective, and efficient, start to well operations on arrival, operating vessels are commonly preloaded with tools, equipment, and resources prior to or during transit to location to load up with all work scope items needed to set and deliver the initial riserless casing string phases, i.e., up to and including the subsea BOP and marine riser installation. This shall depend on resources available and what can physically be loaded dependent upon:

- Rig type (drillship can carry a great deal more than a semi)
- Transit distance/duration of move

- Towing draft of semisubmersible drilling rig
- Expected weather conditions
- Mooring plan (do anchors have to be brought on to the rig deck as part of deployment)
- People and equipment already on the rig (drillpipe, riser, service company units, etc.)
- People, systems, and equipment needed to conduct the initial well's workscope

To meet these ends, the drilling contractor shall be consulted early in the well preparation and prespud planning phases as to how much people, variable deck load weights, volumes, and capacities can be carried for the given conditions prior to the transit to location. The planning, drilling engineers, supervisors, drilling contractor, and lead 3rd-party personnel then prioritize all resources required to be preloaded, e.g.:

- Anchoring and supply vessels
- Extra anchors, pendant lines, buoys, and hardware
- Marine surveyors and equipment
- Mooring plan and equipment
- Exact surface location
- Contracts to be available rig-site and understood by all
- ROV equipment (space and equipment for manned diving gear)
- Wellhead, subsea equipment
- Casing, cement, mud material, equipment associated items and all accessories
- Jetting and surface hole assemblies
- Miscellaneous equipment
- Permits—contingency plans, notifications, bridging documents, emergency procedures
- People (mud, cement, ROV, wellhead, survey specialists, etc.)

Prior to Establishing Location

The operator's representative would assure that at contract start all vessel names, horsepower ratings, fuel, lube oils, bulk, materials, and equipment accompanying the rig to location are recorded and signed off on by respective owners. Other operational aspects considered and discussed before operational commencement would include:

- Anchor winch and mooring specifics
- Mooring and station keeping meeting with all parties
- Prespud meetings with all personnel
- Inventory of all consumables conducted, verified, and checked
- Fill out initial tour report
- Start preparing drilling and kill mud fluids
- Picking up drillstring, BHA's (bottom hole assembly) pipe requirements (dependent on rig draft and crane requirements as to whether this operation can occur prior to the completion of anchor tensioning)
- Wellhead preparation, conductor strings, running tools, and any associated items to be used.
- Continue with BOP and control systems readiness, inspection maintenance, and repair.
- The well start time agreed, i.e., when the first anchor or transponder is dropped to seabed etc.

Rig Move Plan

Operator shall provide all site survey and shallow subsurface data with details of the well location and proposed timing for the move. Operator, drilling contractor, and specialized third parties shall generate specific rig move and well positioning procedures, in coordination with the marine, survey, and drilling contractor's department management. Prior to issue, the rig move procedures will be jointly reviewed and approved by the operator's and drilling contractor senior marine person and/or project managers.

The drilling contractor onshore manager shall ensure that the rig manager /offshore installation manager (OIM) and others responsible shall review the rig move program, procedures, and guidelines. Approval from the insurance surveyor is also required. The rig manager/ OIM shall assure all rig move telefax messages notifying authorities are sent to the relevant parties required.

Designated assigned operator, drilling contractor and marine representatives shall review the plans prior to the rig move and assure any issues are resolved, changed, and amended for the onboard personnel. *Example: Rig management has the authority to make minor modifications to suit rig, location and well-specific mooring and positioning needs*.

The operator shall be responsible to network with any local groups affected by the rig move and the route, e.g., *fishermen, coast guard, naval, military, conservation groups,* etc. Note: When a move requires crossing of International boundaries, the rig move shall afford for the varying jurisdictions and emergency response procedures/contacts.

Establishing Well Location

Rig Move and Arriving on Location

Satellite navigation, differential global positioning systems (DGPS), and an on-board drilling contractor and 3rd-party positioning system with dynamic graphic capabilities are used for all offshore rig moves. The DGPS antennas are located in optimal areas to assure full functionality and reliability. The reference measurements and the rig heading, derived by gyrocompass, will be applied to the DGPS antenna positions within the positioning system computer. The master computers on board the rig will display the proposed rig location, existing pipelines, and known hazards. Note: For offshore dynamic positioning (DP) vessels, there shall be *at least two methods* of acquiring DGPS positioning information.

SURVEYING RIG ON TO LOCATION

With the navigation/positioning system operational, the moored or DP capable vessel is managed and controlled by persons on board to the preferred location displayed on the computer monitors as well as displaying existing pipelines and any known hazards. All vessels involved are equipped with remote positioning systems so that the vessel's operators can see in real time the relationship of the rig to each vessel, the proposed location and any other hazardous or risk based features of interest.

TAKING THE FINAL RIG AND WELL POSITION

Once at location, positional data are logged for approximately 1 hour. The average position derived during this period then recorded as the *surface location for the well*. If not already conducted prior to vessel arrival, a method (that typically utilizes the ROV) is used to box in and establish the well spud seabed location within a ±1–3 m survey accuracy.

Deepwater Moored (Anchoring) Operations

Before rig arrival and mobilization, the bow heading is required to intersect the planned target, traveling into any prevailing winds waves and current conditions. Note: This is more important for ship shaped vessels vs. semisubmersibles due to the broadside effects waves have on a ship shape vessel.

Once a safe distance from the proposed location is verified, anchor deployment is to commence. Deployment performed by the anchor handling vessels (AHV) with buoy and pennant equipment is dependent on the rig's mooring systems, water depth, and location-specific requirements. With AHV established at a set distance from the anchor setting location, a stern anchor is typically lowered to 50′ (16 m) off the sea floor. The AHV upon reaching the target area lowers the on the seabed bottom with the drilling vessel paying out the mooring system as it moves to its desired location. As the stern anchor becomes embedded into the seabed the mooring line is then tightened, with the drilling vessel's forward momentum then halted. As each anchor is laid and set, the survey company monitors the position of the drilling vessel with each anchor set. The information is recorded and provided to the operator. The final position is not determined until the drilling vessel is ballasted down with all anchors confirmed holding at required working tensions.

Prespud Readiness

With the vessel moored and/or DP positioned at desired location, the final survey, station keeping, and quality control checks are verified and approved. While this is ongoing, all personnel on board shall be making ready, preparing, planning, and organizing to make ready to spud the well.

Establish Water Depth

The combined drillstring and ROV utilization is probably the most accurate and commonly used method to establish water depth. As the drillstring is lowered, the ROV shall continuously monitor the position of the drillstring with its side-scan sonar. Water depth readings from ROV and drillstring measurements can be correlated to a desired degree of accuracy, i.e., within a few feet. The ROV cameras then monitor that the drillstring and bottom hole assembly (BHA) is not being swept away by an abnormal current or deflected by an unknown solid seabed. The ROV therefore assures that a vertical penetration of the drillstring results into the soft seabed before pumping and drilling commences, termed as spudding the well.

Health, Safety, and Environmental Information

Prior to taking a vessel on contract, operator shall have provided all the relevant health, safety, and environmental information, e.g., permits, approvals, notices, alerts, reports, etc., to the operator drilling supervisors, representative and the rig manager, and/or offshore installation manager (OIM).

Management shall ensure that all relevant HSE information, e.g., alerts, bulletins, etc. are provided to the rig management and leaderships teams, that HSE notices are suitably collaborated and communicated throughout the rig, via preshift/job meetings, weekly safety meetings, and notice boards. Finally checks and measures shall assure all programs planned contingencies are in place for operational hazards or risks predicted:

– Metocean effects, winds, waves, currents
– Shallow hazards gas
– Emergency move off, rig evacuation
– Operational safety meetings with all personnel and discuss drills that shall be performed
– Duties and responsibilities - station bill

Note: It is a general mandatory requirement that all personnel (including subcontractors) attend the pre-tour, daily and weekly rig safety meetings.

Changes to Project Work Program Plans

Any material change deviations to a well's program plans shall be subject to an agreed project management of change process. This shall involve a suitable reassessment of hazards and risks deemed to exist. Short-term or minor operational changes to any program aspect shall be implemented after receipt of written instructions from the operator's or drilling contractor's respective management persons.

Execution of Work Programs

Operational Procedures

Daily operations are conducted in accordance with the operator's project work program, drilling contractor, and 3rd-party's safety policy manuals, corporate, standards and/or deepwater operating procedures/work instructions documents. The operator's and the contractor's senior persons are responsible to continually assess the suitability of each programs standards, procedures, and guidelines, and to recommend change amendments required.

Rig-specific procedures amendments must be approved by the appropriate drilling contractor manager prior to implementation.

Well operations procedures amendments must be approved according to operator's policy, standards, incorporating risk and management of change procedure.

Well control assurance shall be interfaced in accordance with the project specific well control bridging document developed to meet all deepwater well-specific operational requirements. The rig manager or OIM shall have overall responsibility in terms of major well control assurance, kick and kill operations, and must be kept advised of any well control problems that result. The operator's drilling supervisors and the assistant rig manager and/or senior tool pushers, etc. shall collectively oversee well control operations specifics. As required, well assurance, and integrity tests shall be conducted in accordance with operator's deepwater procedures and/or industry best practices.

Should a major waiting, equipment or wellbore failure or lost time event result, responsible persons shall be accountable to assure a latent cause analysis or similar no-blame investigative process is kicked off as soon as is safe and practicable to do so.

Permit to Work (PTW) System

A permit to work (PTW) system shall control all operations identified as being critical to the safety of personnel, environment, rig, or well program. The drilling contractor's system shall be used for all well program activities to be conducted on the rig as described in respective safety and operating standards and documents.

Crewing Manning Levels and Training

Drilling contractor is responsible for all aspects of personnel management of its employees, and for assuring the deepwater competence of all services they are providing. Formal inductions shall be organized and carried out by the drilling contractor. Deepwater job and task-related familiarization and training shall be their responsibility as described in associated training and development documents.

Crewing levels for drilling contractor personnel should be detailed within the drilling contract. Additional third party and contractor personnel are required, at various work scope stages of the contract, for maintenance, rig projects, training, and audit purposes.

Operator third-party personnel crewing levels shall be in accordance with contract requirements, along with any specific deepwater operational requirements and competencies envisaged. The operators tendering process must ensure competence, selection, and training of third-party personnel. Operator crewing levels may vary.

The operator's project owner shall ensure that personnel cover is adequate to maintain deepwater operational safety. On a regular basis, the operator's representatives, rig manager, and/or OIM shall discuss operating resource requirements to ensure that space is available on the rig for the required personnel. They shall monitor crewing levels and report status to onshore personnel via the morning reports and calls.

Third-party personnel shall be evaluated on their own personnel evaluation forms which, when completed by the various company representatives, are then returned to their own company. Prior to commencing any well's project work on the installation, third-party personnel are often requested by the operator's and drilling contractor reps to complete a competency checklist upon arrival, which is then returned for review/action as appropriate. Dialogue between the operator supervisor and the onshore superintendent, manager, and service company managers enable changes in service company personnel to take place, as required.

The drilling contractor manager is responsible to assure for all personnel are suitably trained in the application and use of the drilling contractor's safety management processes, notably permit to work system, job-specific and hazard/risk-based assessments required.

Deepwater Equipment Assurance "Fitness for Purpose"

PLAN AND DEEPWATER EQUIPMENT CONSTRUCTION STANDARDS

The drilling contractor's installation is constructed in accordance with the rules for building and classifying deepwater mobile offshore vessels as laid down by the relevant classification authorities standards that currently exist.

DEEPWATER MODIFICATION CONTROL PROCEDURES

Should a significant deepwater modification be required to a vessel, an appropriate safety and operational engineering analysis shall be performed in accordance with the relevant drilling contractor's standard procedures and corporate safety policy to design control. Any modifications requested by an operator must likewise follow the same process.

MAINTENANCE

Drilling contractor shall be responsible for ensuring that all tools, equipment, facilities, and other items for use in the performance of the operations are maintained in a safe, serviceable condition, and can perform the functions for which they are intended. Their maintenance system shall be verified to assure standards are in place for plant and equipment whose failure can affect health, safety, and the environment.

MATERIALS

All materials shall be fit for purpose in accordance with the requirements of both parties HSE specifications, to ensure that work programs are safely executed. Contractors shall ensure that for substances classified as toxic, harmful, corrosive or an irritant, a systematic program to assess and control, including health surveillance where indicated, shall be carried out. Likewise, operator shall ensure that the above is carried out for materials ordered by operator for use in drilling the well.

To ensure continued safe operations, contractor shall be responsible for ensuring that the minimum stock levels of both critical and noncritical spares are maintained, complete with any relevant certification. Likewise, operator shall ensure that the necessary equipment, fit for purpose and duly certified, is available in a timely manner to fulfil the work program.

Third-Party Equipment Standards

Each third party is directly responsible for utilizing their equipment and assures it is suitably certified, fully compliant, and fit for purpose. Under no circumstances should work be carried out with any equipment that does not comply with standards required. All third parties shall be required to satisfy to all parties that:

- The maintenance inspection and repair as applied to their equipment is at least equivalent to those of the drilling contractor and operator's standards.
- The equipment is fit for purpose and conforms to all relevant statutory requirements and construction standards of the installation in accordance with the drilling contractor's third-party mobile equipment requirements.

During well's project scope duration, operator and drilling contractor shall use vendor qualification reviews that evaluate the suitability of contractor's provision of goods and services to the project as per contract terms and conditions. Where conflict and gaps exist, appropriate management of change should be exercised.

Management of Change

Senior operator drilling contractor, and third party contractor representative shall advise the responsible persons involved of any significant change and vice versa. This includes changes of material, equipment or personnel that could affect the safety of the rig or its personnel.

The person responsible for the well program shall issue significant changes required to the program, after written approval by the original program approvers. Prior to implementation, the amendments shall be discussed with the appropriate personnel.

Assigned operator and drilling contractor persons are responsible for communicating changes made to personnel, manuals and instructions as required. Any changes to operator procedures and well project programs must be communicated through the correct channels.

Marine Procedures

Marine operations relating solely to the vessel shall be conducted in accordance with respective marine standards and operations manuals. A drilling contractor manager must approve all unit specific procedures prior to implementation.

Rig move, stand-by, and supply vessels shall be provided and managed by the operator and supported by third parties. They will operate in accordance with operator's marine policy/guidelines and in compliance with regional regulations and standards.

Lost Time Event Reporting and Investigation

Drilling contractor and operator representatives are responsible to report any notifiable accident /incident/major lost time event to the appropriate authorities in accordance with applicable legislation or (the operating contract). Copies shall be made available to the onshore contractor and operator's personnel as soon as convenient to do so.

Operator representatives shall additionally report any notifiable accidents /incidents/lost time events in compliance with policies and procedures in place.

All loss control, nonconformances, or near misses no matter how small or seemingly insignificant, shall as per best practice, be recorded within the drilling contractor and operator loss control, nonconformance reporting systems, *in compliance* with all mandates as detailed in respective management systems, safety and operational documents and as per contract agreements.

Contingency and Emergency Procedures

The drilling contractor emergency response plan (ERP) shall take precedent and be used unless specified and referenced to other specific project-derived documents. The rig-designated person shall direct the prime response to any emergency and has the authority to take whatever measures are necessary to meet the emergency. This includes deployment of the offshore emergency teams and engagement of external assistance.

The drilling contractor shall also handle the onshore response to any emergency, which has the potential to affect the integrity of the rig or the safety of any personnel, with operator personnel providing necessary technical expertise and support if/as requested, via a typically established Emergency Response Room.

Drilling contractor shall handle spills contained on the rig using their oil spill contingency plan (OSCP).

Operator shall handle the onshore response to an environmental emergency *not contained* on the rig, with the drilling contractor's assigned personnel providing support if requested by the operator's emergency response team (ERT). Onshore actions and responsibilities in an emergency are detailed in the respective company's emergency procedures.

Deepwater Work Programs and Standard Operating Procedures

Deepwater work programs fall into two separate categories:

1. Those generated by the drilling contractor to maintain the safe operation of the rig.
2. Those generated by the operator in connection with safe project well operations.

Operator personnel shall ensure that all parties concerned review the appropriate well's work programs at premove, prespud, pretest, abandonment and post well critique meetings. Operators ensure that all approved well programs are issued in a timely manner.

The type of work generally to be conducted on the offshore installation can be classified as rig move operations, simultaneous operations, drilling, completion, well testing operations, well servicing, intervention or workover operations, and well suspension or abandonment operations.

Before any work and activity programs or operations can commence, all involved parties shall review the work programs, schedules, resources, hazards/risks identified at meetings held both onshore and offshore. Any conflicts or questions shall be resolved at this time and amendments made as required.

Operator is responsible for hazard identification, risk management, and change assessment of all deepwater well operations programs provided.

Well Plan

Well operations planning will be conducted in accordance with operator's drilling and well design and operations policy, standards, and recommended industry practices (unless clearly stated otherwise). The programs will explain variations applied, and any dispensation to policy shall be obtained and attached to the program prior to being issued as required.

Operator personnel preparing project well plans shall take into consideration hazards as surface location, proximity to obstacles, shallow hazards, well integrity, and potential for lost circulation, kicks, unpredictable overpressure, and toxic gas. The well plans shall also discuss well formation integrity tests necessary to establish the required kick tolerance, wellhead, gas in riser, diversion, and all associated subsea blowout preventer specifications. Plans shall further specify the relevant interface documents such as well control, well testing, coring, rig move, changes to the well work scope or program.

Contingency plans shall be included (but not necessarily detailed) in all respective well program plans.

Changes to Work Program

Changes to a work program shall be clearly specified within the project interface bridging documents or operationally controlled through a risk and change management process.

Execution of Work Program

Execution of the work program shall be performed as per respective company standards, policies, and procedures. No work shall be conducted in any way that raises conflict unless prior agreement is obtained and required deviation approved. When conflict exists, work shall be stopped when safe to do so by the assigned persons in charge and the work program, standards, and guidelines reassessed, changed, and amended as required.

Notification of Well Operations Example

Prior to work commencement, notification must be provided and approved. The following summarize the UK Offshore Installations (Safety Case) Regulations 2005, schedule 6 (Reg. 17) regarding what to include in a notification for an offshore well's operations.

1. The name and address of the well operator.
2. Where the well operation is to be carried out
  (a) from an installation, the name of the installation and the name and address of the duty holder for that installation; or
  (b) by means of a vessel, the name of that vessel.
3. Particulars of the fluids to be used to control the pressure of the well.
4. Particulars of any plant, not described in the current safety case for the installation, which is to be used in connection with the well operation.
5. Particulars of the type of well, its number, and slot number, and the name of any field development of which it may be part.
6. A description of the well operation and a program of works, which includes
  (a) the date on which each well operation is expected to commence and finish; and
  (b) the intended operational state of the well at the end of each well operation.
7. A description of
  (a) any activities on or in connection with an installation or a vessel during the well operation described pursuant to paragraph 6, which may involve any hazards with the potential to cause a major accident; and
  (b) such hazards.
8. In the case of the well to be drilled are
  (a) particulars with suitable diagrams, of
    (i) the location of the top of the well;
    (ii) the directional path of the wellbore;
    (iii) its terminal depth and location; and
    (iv) its position, and that of nearby wells, relative to each other;
  (b) particulars of the geological strata and formations, and of fluids within them, through which it will pass, and of any hazards with the potential to cause a major accident, which they may contain;
  (c) the procedures for effectively monitoring the direction of the wellbore, and for minimizing the likelihood and effects of intersecting nearby wells; and
  (d) describe the design of the well, including the limits on its safe operation and use.

9. In the case of an existing well
  (a) a diagram of the well;
  (b) a summary of earlier operations in relation to it;
  (c) the purposes for which it has been used;
  (d) its current operational state;
  (e) its state of repair;
  (f) the physical conditions within it; and
  (g) its production capacity.

10. Where well operation are carried out by means of a nonproduction installation or a vessel
   (a) particulars of
      (i) the meteorological and oceanographic conditions to which that installation or, as the case may be, vessel may foreseeably be subjected;
      (ii) the depth of water; and
      (iii) the properties of the seabed and subsoil at the location at which the well operation will be carried out; and
   (b) a description of how the well operator and
      (i) the owner of the installation;
      (ii) or the operator and owner of the vessel involved in the well operation will coordinate their management systems so as to reduce the risks from a major accident to comply with the relevant statutory provisions.

Well Verification Construction Sheets

Prior to well operations beginning, a project-specific set of "well verification design sheets" are provided in specific operating areas to the delivery team (Fig. 11.2). These shall be completed on a day-to-day operational basis to assure an auditable record of the well design construction, well operation, and engineering delivery meet project outcomes required.

During well operations delivery, should verification issues, queries, or concerns arise and not be responded to suitably in a timely manner, a formal comment sheet is issued by the persons in charge responsible to the independent competent body assigned, with copies also sent to others responsible to ensure a timely response can be met. Once concerns are raised and required process is complete, a comment sheet is returned to the verifying person as soon as is practicable to do so. The independent verifier will maintain a register of all email correspondence exchanged and any formal comment sheets issued and/or closed out.

In cases of dispute where verification comments are not accepted or there is a failure to agree, the verification person shall raise the matter with senior persons who shall consult with persons responsible for making a final decision.

Copies of work program amendments issued shall be further sent for verification to assure all details are entered on the well verification design sheets and that issues remain open and live until project's well operations activities are fully addressed, verified, and completed.

OPERATIONAL EMERGENCY PROCEDURES

Major accident hazard components of deepwater blowout, relief well plan, and capping intervention must adhere to International industry standards and best practices.

The principle of any response plan is to act to any major accident/incident ***without delay***.

Capping and Relief Well Intervention

Prior to the Gulf of Mexico deepwater oil spill in 2010, only relief wells were deemed as the most viable response solution. It was generalized that subsea capping was near impossible to achieve and equipment required was not that readily available. As a result of the 2010 event

Well Name:	**Installation:**			**Date:**		
Document Reviewed	**Information Examined**	**Information Verified**	**Correct Acceptable or Date [1]**	**Date Reviewed**	**Comment Sheet Issued**	**Comment Sheet Number**
Well Proposal Basis of Design(s)	*Co-ordinates*	Verify from maps provided Is the well location within 200m of pipelines or other infrastructure? Will rig anchor spread cross pipelines or infrastructure? Is the well location within xxx ft, xxx m of license boundary? Licence exception/restrictions Any collision risk issues – shipping survey required?				
	Approval	Any environmental conditions				
Site Survey Shallow assessment	*Seabed Conditions*	Are problems likely? – mooring, station keeping, seabed, ROV operating conditions favorable etc. Mooring, pilot hole, jetting, conditions favorable?				
	Seabed Hazards	Any seabed hazards identified?				
	Shallow Hazards	Shallow hazards, risks, identified? Mitigations				
Rig Move Program	*Seabed and Meteorological Hazards*	Mooring arrangements Weather (current, waves, winds, combined) limitations Rig move hazards, Station keeping, positioning				
Notifications	*Application Permits, Consents*	General details correct? (water depth, rig name, well name etc.) Application date sent, verified, approved and confirmed.				
	Directional Program	Check target/surface co-ordinates				
	Material Changes	Any changes to original notification? Date of notification, Earliest spud date – allowed Check target depth, tolerances, positional uncertainty Check directional plot correct, annotated correctly , anti-collision, etc.				
	Survey Program	Tool performance and degree of positional uncertainty				
	Casing Design	General review of offset data, Pressure data, Fracture, LOT and FIT data				
	Temperature data	Temperature data				
	H_2S, CO_2, etc.	Possible damaging gases (H_2S, CO_2,etc.) – accounted for in casing design				

FIG. 11.2 Well design/program verification sheets example, prepared prior to well operations implementation. *Source: Kingdom Drilling.*

(Continued)

FIG. 11.2—CONT'D

Well Name:	**Installation:**		**Date:**			
Document Reviewed	**Information Examined**	**Information Verified**	**Correct Acceptable or Date** [1]	**Date Reviewed**	**Comment Sheet Issued**	**Comment Sheet Number**
	Design Standards	Design criteria conforms with standards				
	Design factors used	Correct standard, and design factors used Kick tolerance conforms with standards Casing used conforms with design Casing pressure test conforms with design standards and ops needs.				
	Mud Program	Confirm mud weight range adequate, accounting for pore & fracture gradients, riser margin				
	Cement Program	Casing cementation conforms with casing design				
	Wellhead Program	Seals, wellhead pressure tests conforms with design standards				
	Drilling Hazards	Check all hazards affecting well integrity have been included – mechanical, pressure and environmental Check shallow and seabed hazards identified and mitigations in place Check maximum BHT and surface temperature included Check maximum surface pressure included Check toxic gas hazards have been included				
	Equipment	Check that well control assurance equipment aspects are specified, and in compliance with required standards Adequately configured for operations, duty, pressures and temperatures expected Well specific operating envelopes are clearly defined and meet intended program standards, needs and requirements Are all proposed activities covered by the rig – installation and/or well safety cases?				
Daily drilling reports	***Final rig and well position***	Pilot-hole and/or main well final positions and offsets. Location UTM…(m) N/S, Location UTM…(m) E/W				
	Top and surface hole	Pilot-hole depth, inclination, final displacement details. Main well total depth, casing depth, displacement mud details. Casing depth, cement volumes, well verification				

Notes: *1 – Information is correct or acceptable (i.e. within required compliance parameters) or is the date of acknowledgment, consent, or expiry.*

(that evidently proved a cap was readily installed), offshore operators must now plan and provide for each well's operating area, a subsea capping solution in addition to relief well plans. Multiple capping devices are developed, constructed, and located in worldwide strategic positions at various operator-owned or consortium commercial terms.

However, this author and others have concluded that to meet the prerogative to respond to an environmental spill without delay, a more technologically and advanced engineered, yet practical, cost, and environmentally condusive step change is needed via a capping device capable of deployment in the shortest possible time frame to minimize the oil or gas *spill risk that exists* at ALARP outcomes and benefits desired.

In summary, an operator is required to have two response plans for well control operations:

1. A well control emergency response plans (WCERP) designed to prevent a *major well control* event from transition reaction (24h) to a blowout contingency plan (BCP) intervention.
2. A blowout contingency plan (BCP) to suitably intervene should a blowout result.

This philosophy is outlined in Figs. 11.3 and 11.4 via a milestone time line sequence.

Well Control Assurance Strategy

Of all the offshore hazards that an operator undertakes, none surpasses the impact of a hydrocarbon release into the oceans or seas. This event can also threaten life as well as damage the physical assets as well as the reservoir. All well control problems begin as an unintended influx of formation fluids into the wellbore that should be detected early and response actions quickly taken to resolve and minimize the size and difficulty to handling and prevent further escalation. For example, a 3-barrel (0.5 m^3) influx can be handled with relative ease as opposed to a high-pressure gas influx of 120 barrels (18 m^3). In the latter case, the margin for error in handling the kick is very low while a small kick this margin for error is very high.

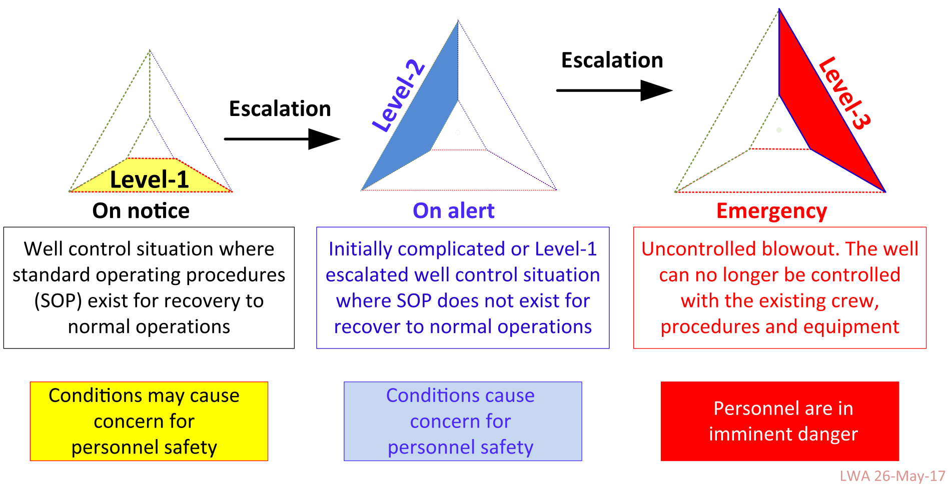


FIG. 11.3 Definition of 1-2-3 WC levels. *Source: Abel Engineering 2017.*

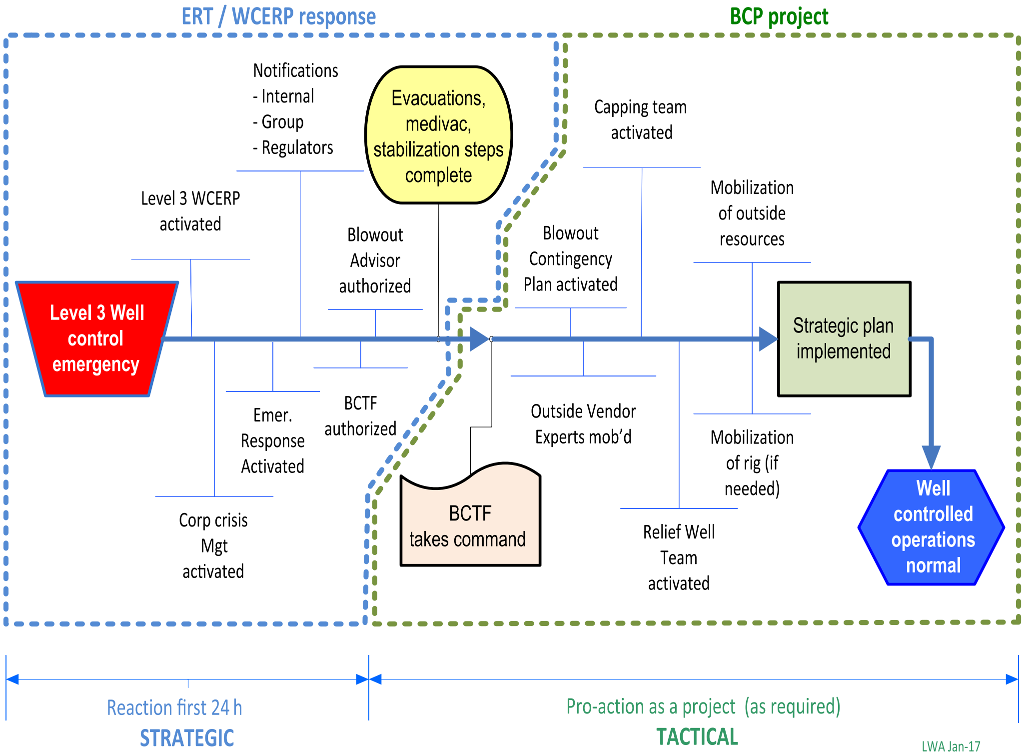


FIG. 11.4 Well control Emergency Response Strategy. *Source: Abel Engineering 2017.*

Thus, people can assure that the well control risk is ALARP if an influx can be avoided or its size minimized. Nothing else impacts the reliability of well control and assurance more than a small kick volume.

A well control assurance strategy should attend to the following basic elements:

1. ***Equipment design***: Casing, wellhead, and subsea BOP equipment is verified to be fit-for-purpose for the worst-case well conditions (a shut in wellhead pressures including bullhead margins, casing can sustain capping SI to stop flow, rated for the PVT reservoir fluids that may be encountered (H2S, etc.)).
2. ***Kick prevention and detection***: Kick control methods and systems are capable of prevention, detection and reaction in such a way that the volume of a kick is kept at a very low value 3–5 barrels (0.5–0.8 m^3) as a principle goal.
3. ***Operating control emphasis***: The drilling program sets forth the expatiations of kick control and outlines the manner in which this it be achieved (e.g., there is a discussion of well control in the program and not merely left to the general guidelines of the rig owner well control procedures) for the particular well to be drilled.
4. ***Onboard team on constant alert***: Onboard a dedicated team member is assigned as the responsible persons for well control operations (e.g., take this responsibility off the well site supervisors so they can address drilling of the well).

Well control assurance preparedness onboard is essentially instilling within the onboard team a healthier respect for deepwater well control operations both in prevention of kicks and their quick and effective reaction. This does not mean controlled drilling with slow ROP and frequent circulation bottoms up, but assuring that attention is given at ALL times to kick prevention, detection and steps taken to limit the kick size. In summary, deepwater well control onboard is best done by avoiding the kick in the first place (best practices for tripping to avoid swabbing effects, kick detection equipment in good working order and personnel keep a constant vigil for monitoring warning signs) and then be trained for a quick and effective response to a kick.

Well Control Emergency Response "WCERP" and Blowout Contingency Plan "BCP"

Operators generally provide two specific plans for well control operations:

1. ***Well control emergency response plan*** *(WCERP)* is the tactical plan designed to prevent a major well control event and if needed to transition from reaction (24 h) to the Blowout contingency plan (BCP) intervention.
2. ***Blowout contingency plan*** *(BCP)* that is the strategic project-oriented plan to intervene should a loss of control occur where both direct wellhead intervention and a relief well(s) are outlined.

The WCERP interfaces to the general company ERP but is expanded to address specifically well control issues. The ERP usually addresses things like man overboard, medivac, etc., where the WCERP is the tactical plan that utilizes the resources at hand with intent to ramp up to an appropriate level of reaction. While it is always better to over react than under react to an emergency, there must be a rationale for the reaction.

Thus, it is recommended that a ramp up by levels of well control intensity be the policy as defined in the Fig. 11.3. The general idea is that *Level 1* response is designed to prevent escalation to a *Level 2* and hopefully that Level 2 never escalates to *Level 3* as presented in Fig. 11.4.

Should there be an escalation to a *Level 3* out-of-control event, there is a handover from the ERP response team to a project oriented or Incident Command structure. Various operators may identify this project team as "Source Control," "Blowout Task Force," or "Incident Command Team," but essentially it is the drilling team expanded to include specialists in relief well and capping operations.

The project team made up of the drilling team plus outside specialists merge both the local well and operational theater parameters with the unique intervention experience needed for capping, pump to control, ranging services to allow a successful relief well with support for the unique operations surrounding a well control intervention effort.

Fig. 11.5 illustrates a decision tree escalation format from reaction to proaction.

Blowout Contingency Plan "BCP"

As it is not practicable to reduce the total probability that loss of well control cannot result, relief well and subsea capping intervention is required to complement and support a Blowout Contingency Plan (BCP). The following section provides a high-level technical and

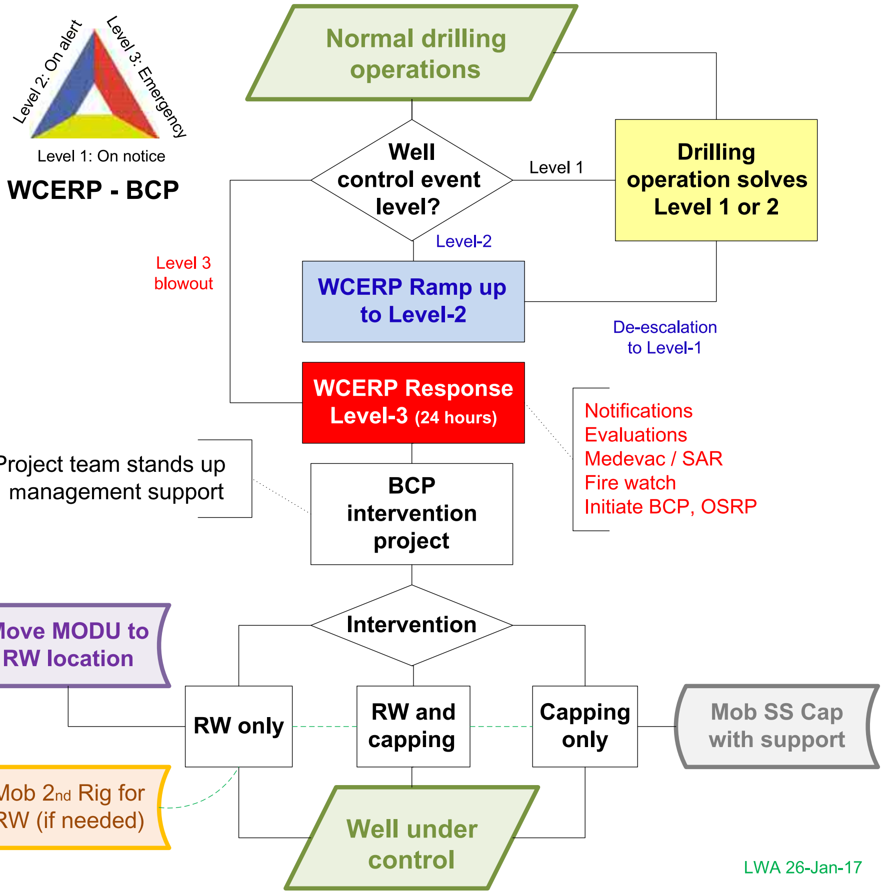


FIG. 11.5 Well control emergency response transition from reaction to proaction example. *Source: Abel Engineering 2017.*

implementation overview of the essential components of a BCP. The first step is to estimate the probable worst-case scenario(s) where it is generally accepted that release rates shall consider and consist of:

1. Full reservoir exposure potential(s) flowing at any given time into the wellbore
2. That the flow path to the sea and/rig floor is:
   b.1: Through the drilling assembly bore to the rig floor (prior to shear and disconnect).
   b.2: Release to the seabed via a failed SS BOP where no work string is in the wellbore (that is assumed totally evacuated with no SS BOP restriction or choking effect except seawater hydrostatic).

Therefore a worst-case discharge (WCD) results from within reservoir and well geometry of cases b.1 or b.2 above for the wellbore section intervals to assess (Fig. 11.6). For these WCD cases defined, two intervention options are addressed:

1. *Capping at the wellhead* where direction intervention occurs by placing a cap on the flow and either performing a soft closure to stop the flow or choking back the flow to minimize the release while a relief well is drilled. *Note*: The preferred objective is

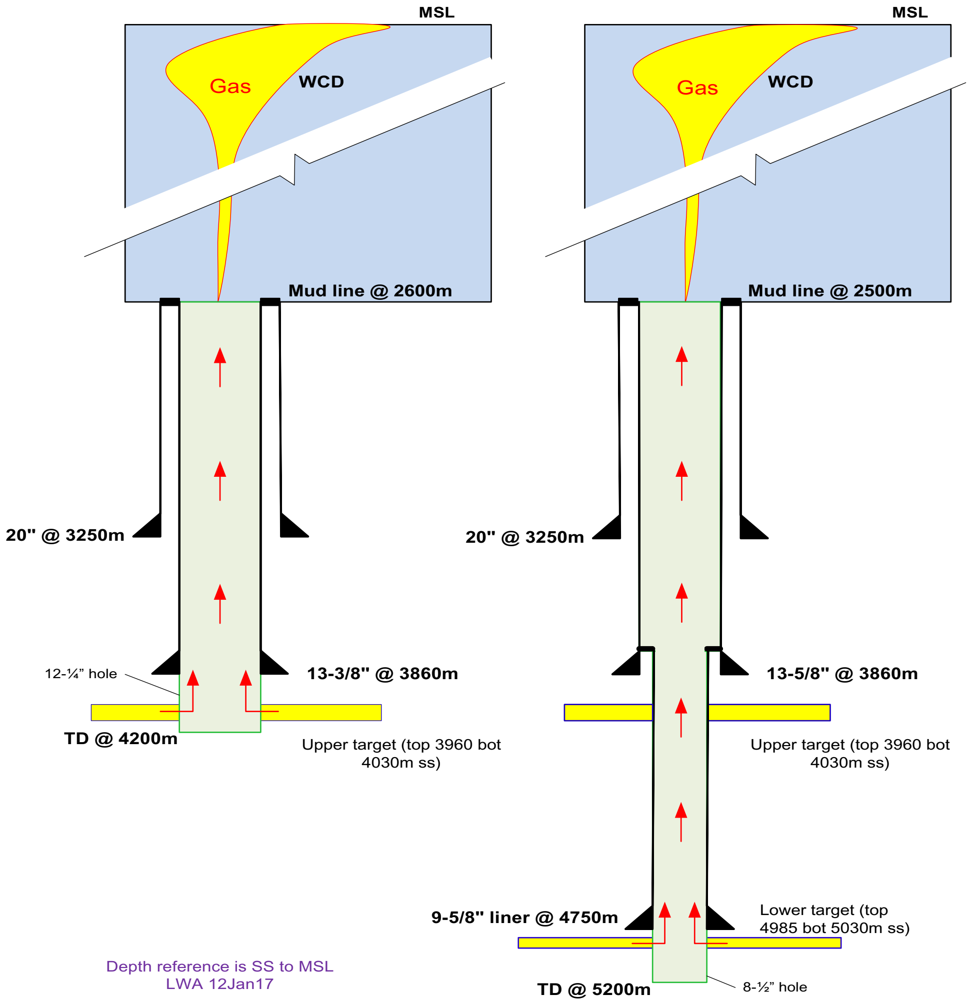


FIG. 11.6 Deepwater relief well dynamic kill basis of design and dynamic kill assessment. *Source: Abel Engineering 2017.*

Cap-and-Kill. The cap stops the flow. The well is then bullheaded or lubricated into the column to achieve effective hydrostatic control of the well.

2. ***Relief well(s)*** where offset well(s) intercept the blowout well at a depth that allows control fluid to be pumped to dynamically control the flow and bring the well back to hydrostatic control.

Capping Versus Relief Well Discussion

As a result of the 2010 event (that proved deepwater capping is feasible), operators currently plan and provide for subsea capping solutions in addition to relief well plans. Multiple capping devices now constructed are located in worldwide positions at commercial terms via various operators and consortiums agreements. While sharing the cost for capping units among various operators is a current solution, the location of the unit to the actual well does not meet a well's ***without delay*** optimal response requirements. (Example: In 2018 the closest unit to New Zealand is Singapore. Mexico is covered by stacks stored in Norway or Aberdeen, Falklands, etc.) In these cases the response, environmental impact and spill time shall be several days if not weeks to cap stop pollution and kill a well.

In addition to the high environmental spill cost resulting, the majority of capping assemblies are subsea BOP look-alike, and not air freight "friendly" due to massive size and weights (Ref. Fig. 11.7 that illustrates of the various subsea capping units specifics in the market place as of 2018). From Fig. 11.7, it can be concluded that majority of caps are very heavy to impact the time to move these units by air and require unique handling, deployment systems and very specialized resources (if deployed on wire from a vessel or if required to be transferred to the MODU for deployment). If metocean winds, waves, current and heave exists, this shall all add to capping risks.

Given that pollution hazards, risk and impact is time dependent, i.e., days of release duration, and maximum value for an operator is concluded by reducing capping to an absolute minimum ALARP time-line.

The concluding assessment is to have a suitably 'fit for purpose' engineered and designed capping unit dedicated to the project, ready in country, at the supply based quayside (or on a deepwater supply vessel, ready built and/or in containers as currently catered for should a major loss circulation event result, where LCM contingencies are already retained on vessels to mitigate and reduce impact time and risks.). The end result is that future capping

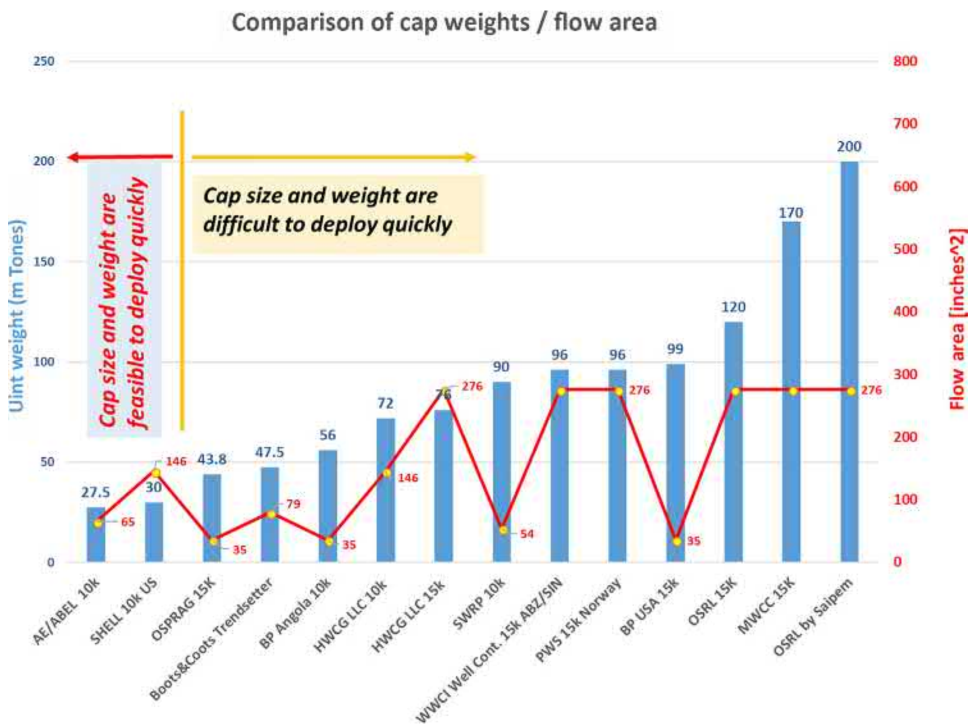


FIG. 11.7 Comparison weights and flow areas for SS capping units. *Source: Abel Engineering 2017.*

deployment can take effect in 1–2 days versus deploying a regionally stored unit (as designated to projects in 2018 capping strategic plans).

The ALARP for stopping a flow and spill after the well goes out of control would be have a capping unit available quayside on a support vessel or the drilling rig; optimization of the design for ease of handling is further needed (which was not done in the first caps that came onto the market after 2010).

Existing philosophy as planned in 2017 is shown in as a time line sequence in Fig. 11.8 with significant milestones; one can see that this time line can be significantly compressed to stop a spill and environmental impact if the air mobilization and the procurement of a deployment vessel is <1–2 days as stated.

BASIS OF DESIGN

The basis of design for these plans would be generated from the project scope; e.g., metocean information, casing details, lithology, location, PVT data of expected reservoir fluids, reservoir properties, worst-case discharges envisaged, and so on. Capping shall consider worst-case discharges conditions of maximum gas flow release rates to assess landing forces present. Planned wellbores would also be considered to assess relief well dynamic kill requirements as illustrated in Fig. 11.6.

No Go Exclusion Zones/Plume Behavior

A release to the sea can create hazards impacting the relief well and the subsea capping intervention.

A full and well-developed understanding of the plume behavior, wind and tide effects, gas dispersion must be known so that any relief well is placed in the most optimal and practicable risked location to facilitate continuous 24/7 operations as illustrated in Fig. 11.9.

The capping operation then is performed by placing the designated vessel above or adjacent to the well center. An exclusion zone is generated by considering the effects to wind, tide, current, plumb behavior for the various worst-case discharge cases as modeled.

An example is shown below for a case in 2600 m of water where current wind and tide as well as the computational fluid dynamics (CFD) plumb behavior analysis is considered:

The modeled location wind, current, and wave roses used in the formation of the Exclusion Zone (Fig. 11.10) is also represented. Here the current profile considered for the Exclusion Zone in this case is illustrated in Fig. 11.11. This considers a 95% probability case to be input into the plume model. In this case, the current profile should move any oil or gas that is released and surfaces to be offset due to the near surface current. If this current profile did not result, i.e., a low probability occurrence, gas or oil might surface if the flow is very high. Should this result, there may exist a need to suspend deployment and wait for favorable conditions. The data from the metocean reports will generally guide one in such recognition, analysis, and decision-making assessment.

Computational fluid dynamics (CFD) is often used to predict plume behavior. Fig. 11.12 presents results of deepwater CFD analysis where the plume is predicted to create a current pattern, which is also very minor at well center or the relief well location.

Therefore, dynamic positioning of the vessels in <1.0 m/s velocity is not an issue and well within the capability of modern deepwater vessels. Figure below shows this current pattern.

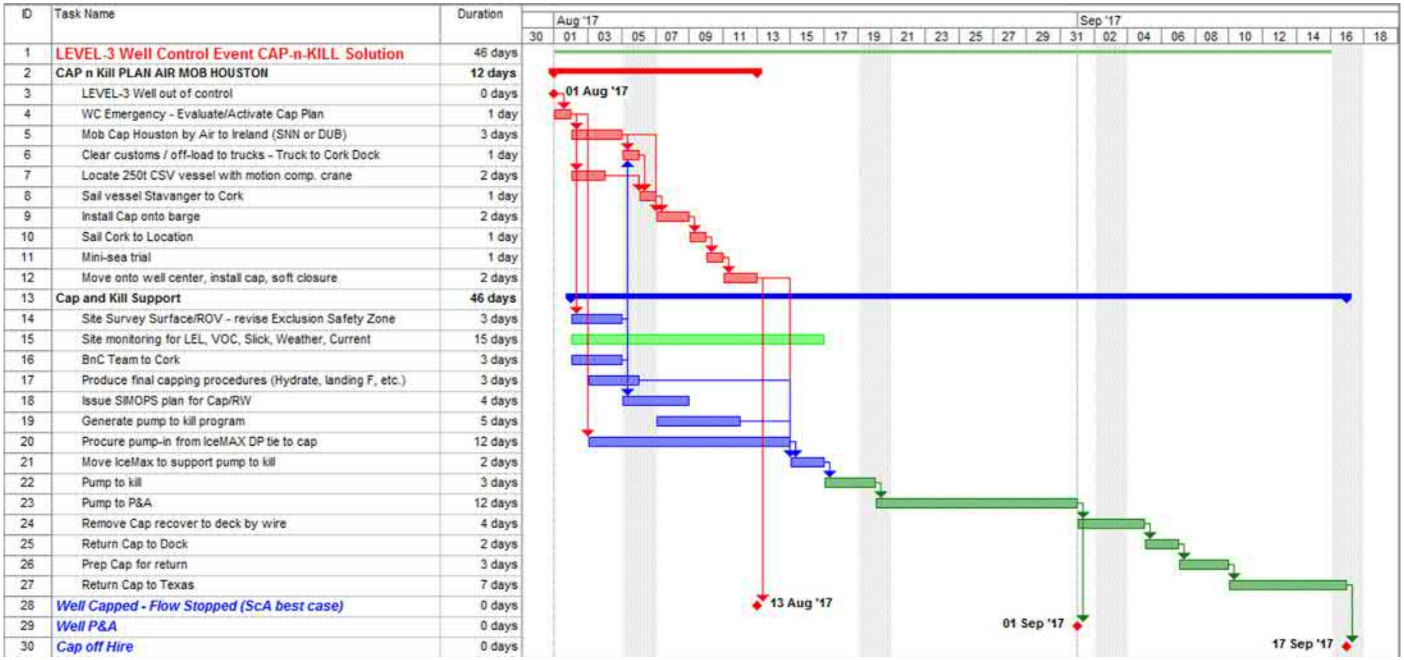


FIG. 11.8 GANTT chart for capping considering air mob (using a light weight capping unit). *Source: Abel Engineering 2017.*

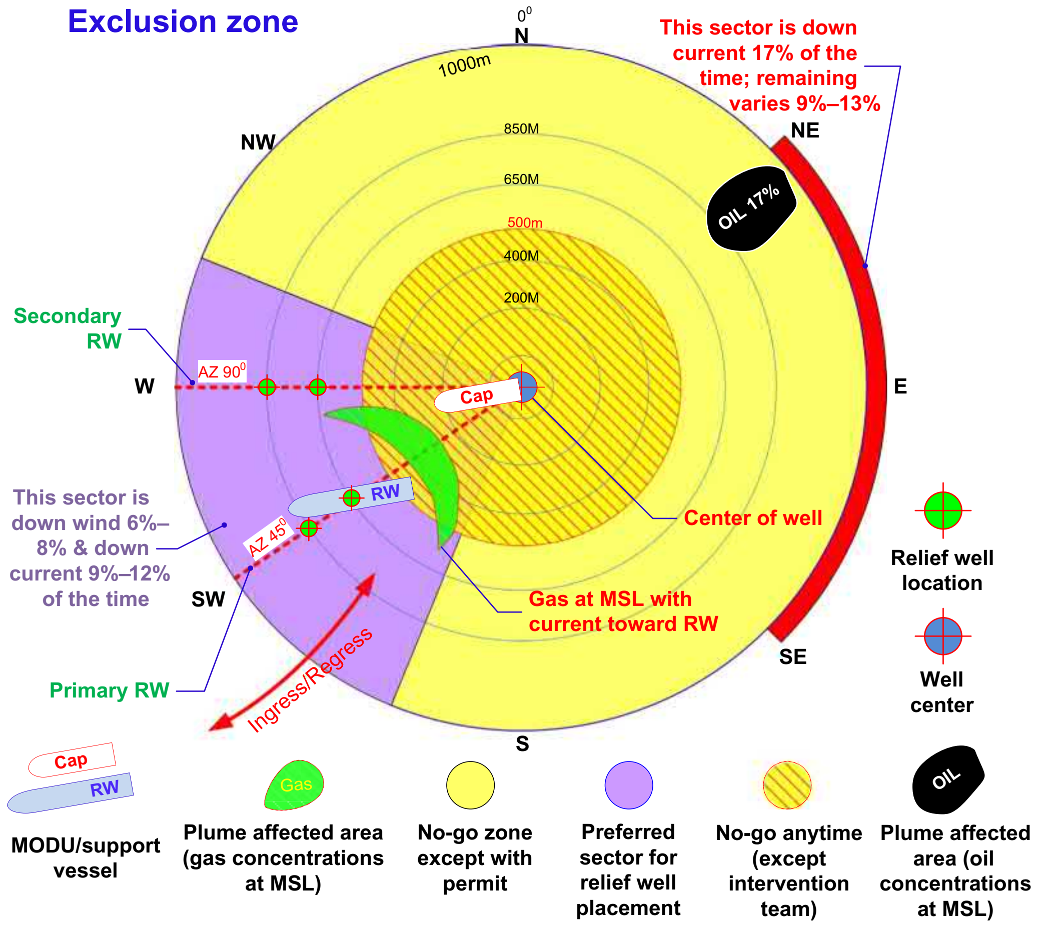


FIG. 11.9 Relief well and capping exclusion zone. *Source: Abel Engineering 2017.*

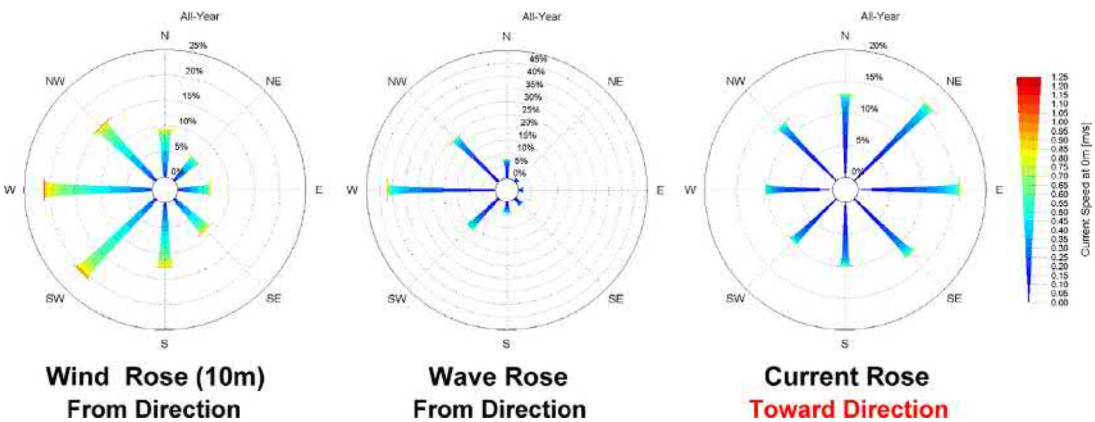


FIG. 11.10 Metocean conditions. *Source: Abel Engineering 2017.*

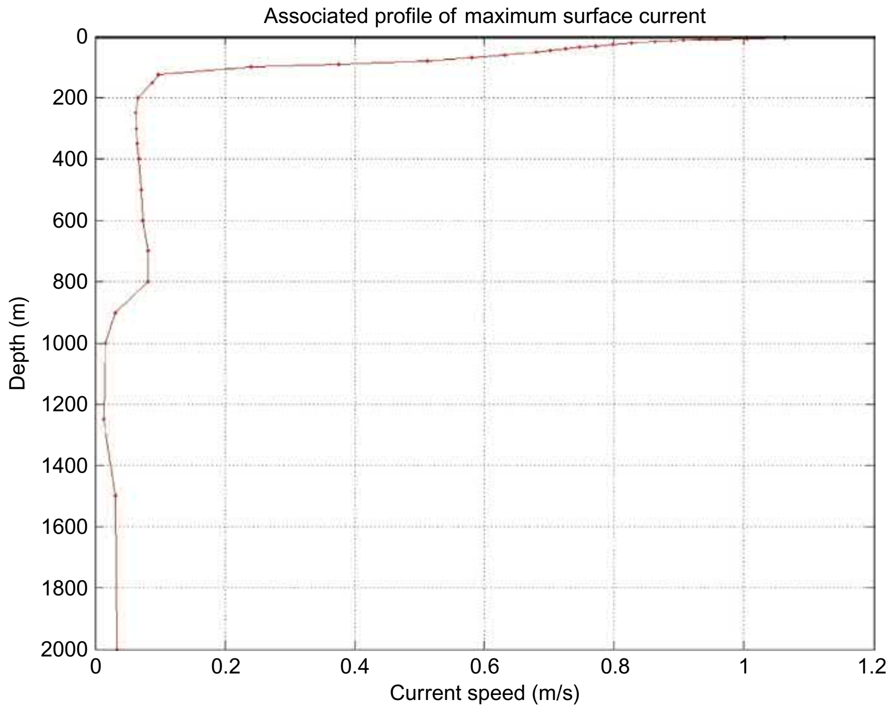


FIG. 11.11 Deepwater current profile. *Source: Abel Engineering 2017.*

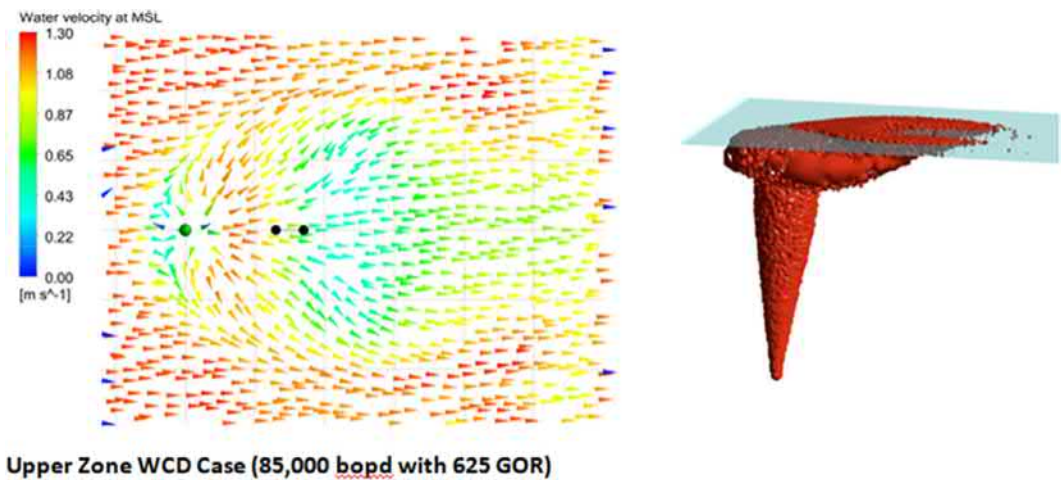


FIG. 11.12 Computational fluid dynamic plume modeling. *Source: Abel Engineering 2017.*

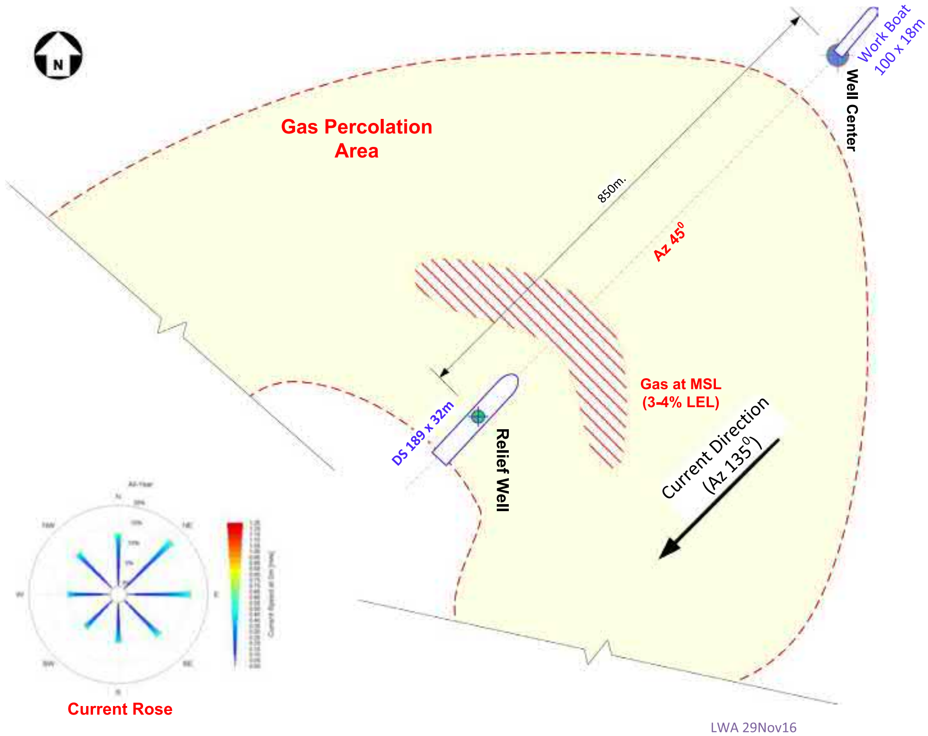


FIG. 11.13 Worst-case discharge scenario. *Source: Abel Engineering 2017.*

The impact from plume modeling for project scenario illustrated is presented in Fig. 11.13. In a water depth of 2600 m of water with a gas release rate of 1.2 BCF light gas, the worst case is when the current direction is toward the relief well (which will happen about 10%–12% of the time per this example's metocean data). In this scenario, gas at surface exhibits a lower explosive limit (LEL) well below the 25% threshold limit to suspend operations or raise concerns should no dispersion effects from wind at the well (which is predicted to be very high 90% plus of the time for the example) persist at the well location. The conclusion is that gas does not present a hazard to relief well or capping operation in this specific worst case.

Well Control Emergency Scenarios

In deepwater wells, the following scenarios (Figs. 11.14 and 11.15) for major well control events are:

1. ***Rig disconnects and is undamaged,*** subsea BOP remains latched on to well, BOP is vertical but leaking, connection mandrel is exposed for direct capping allowing capping without delay.
2. ***Subsea BOP is damaged and leaking, debris over well*** obscuring connection mandrel for capping (dropped riser, not vertical, etc.) therefore debris removal needed.
   - **(a)** *Complex case*—downed rig, riser dropped, subsea BOP not vertical—extensive work is needed to recover access for capping (longer removal time required).
   - **(b)** *Moderate case*—downed riser with minor debris obscuring the subsea BOP, moderate work needed to gain access for capping (less removal time envisaged).

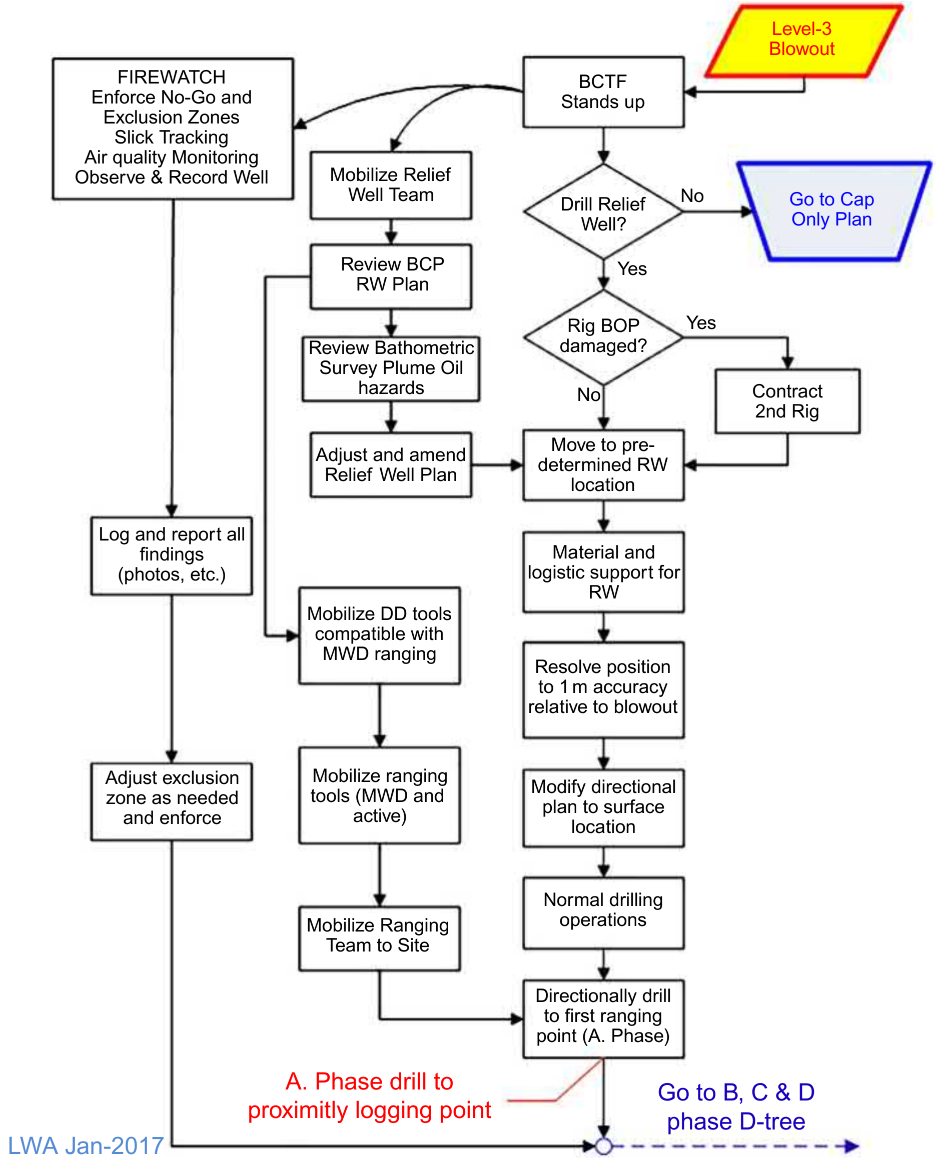


FIG. 11.14 Generic deepwater relief well operational guideline. *Source: Abel Engineering 2017.*

Once well control is lost, two major interventions and one other possibility exists:

1. *Relief well* subsurface interception and communication to the blowout well where fluid is then pumped to regain hydraulic well control.
2. *Capping operations* install a BOP onto the SS stack and either shut in the flow and/or contain and collect the effluent.

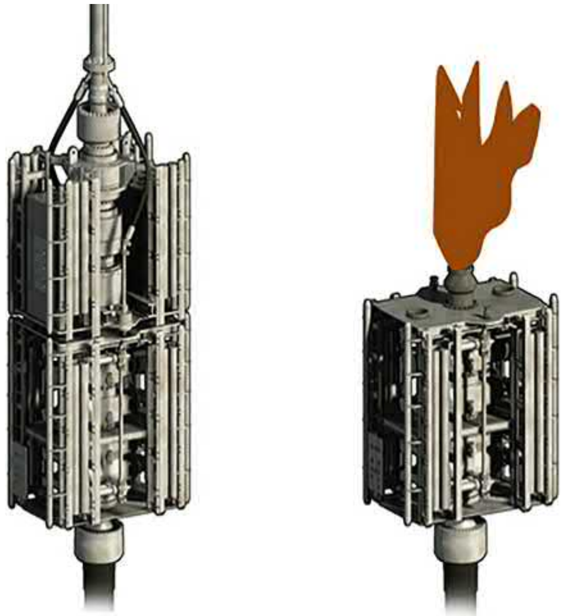


FIG. 11.15 Deepwater blowout and capping scenarios. *Source: Abel Engineering 2017.*

3. ***Combination of Relief Well and Capping Operations*** (rare case) where capping is performed but well cannot be killed via the cap and relief well is the means to control/P&A the well.

Based on actual flowing conditions, either or both the relief well and capping operations can be implemented. In extreme cases, operator may choose to cap and drill a relief well. The decision to effect both options simultaneously is left to the Blowout Control Task Force and operator's executive management.

The following plans (Fig. 11.16) must be catered for in Well Control Emergency Response and for each Blowout Contingency Plan.

- ***Relief well***—The drilling installation (after disconnecting) will move to the designated relief well location and without delay commence the relief well. Note: If the exiting rig is needed to deploy the cap or is damaged, a backup plan to mobilize a second rig to the field is to be provisioned for.
- ***Capping plan***—The subsea cap is mobilized using the most expedient method practicable to reduce environmental spill impact, deploy, cap, and kill the well. Note: Abel Engineering has a newly patented design and operational method proving that this can physically be achieved in a shorter time frame than previously envisaged, i.e., to offer all operators, regulators, and bodies concerned a more viable ALARP and affordable alternatives to mobilize, deploy, cap, stop hydrocarbon release, and kill a well.

1. ***Wire deployment***: Cap is mobilized, installed on a vessel of opportunity or construction support vessel equipped with a motion compensated crane capable of live dynamic installation loads required for well's water depth and loads envisaged. Vessel is sailed to site to cap the well by landing cap on subsea BOP via wire.
2. ***DP deployment***: Cap is mobilized as above and transferred to the field on normal supply boat as freight and then taken offshore to be transferred to the drilling installation (lifts may have to be broken down to accommodate rig crane capacity). The cap is then assembled on the rig, run and deployed via drillpipe, and landed using the rig's normal procedures for landing subsea equipment onto a subsea BOP or wellhead with modifications for a flowing well condition.

- ***Simultaneous capping and relief well plan*** where both relief well and capping are initiated where the first to succeed would result in other operation to cease.

WELL RELEASE CONDITIONS

Worst-case discharges consider gas and oil release with two possible exit points:

1. ***CASE A***: a release through drillpipe to the rig floor (DP bore without surface restrictions).
2. ***CASE B***: a release at mud line (casing bore hole evacuated (no pipe) without restrictions at the BOP for both oil and gas cases).

Intervention will generally address mud line release, as Case A: riser or drillpipe blowout would revert to Case B after the rig was abandoned or sunk (as per Macondo case).

The reason that the vessel is abandoned in Case A is for personnel and vessel safety priority.

Examples: A dynamic positioned vessel without power cannot maintain station and shall drift off to ultimately result in riser failure and a drillstring string left in the well. A riser or drill pipe blowout case with flow exiting onto the rig cannot be sustained and would result in the riser and/or or drill pipe requiring to be released and dropped.

To avoid an onboard fire, a riser hydrocarbon flow and/or the risk of explosion, Case B is the most viable scenario, i.e., to release at the mud line.

The case assumption (to model worst case discharge conditions) is that the wellbore is evacuated with no drill string present in the well. The subsea BOP has failed to open, offering no choking resistance effect. The flow is directly up through the casing from the reservoir without resistance, restrictions, or choking effect to reduce maximum flow to represent the most difficult case to assess a dynamic kill. Note: A very conservative approach for planning purposes.

In exploration wells, a P10 and P50 percentile probability of gas and/or oil as the reservoir fluid are to be evaluated. The underground blowout case is not considered as deepwater casing design are generally overdesigned not to fail as described in Chapters 8 and 9. Note: Should an underground blowout exist, a relief well is required as capping cannot likely resolve this case.

Worst-case discharge cases of interest are therefore input in the design stages to assess for:

1. plume effects and
2. dynamic kill required from a relief well.

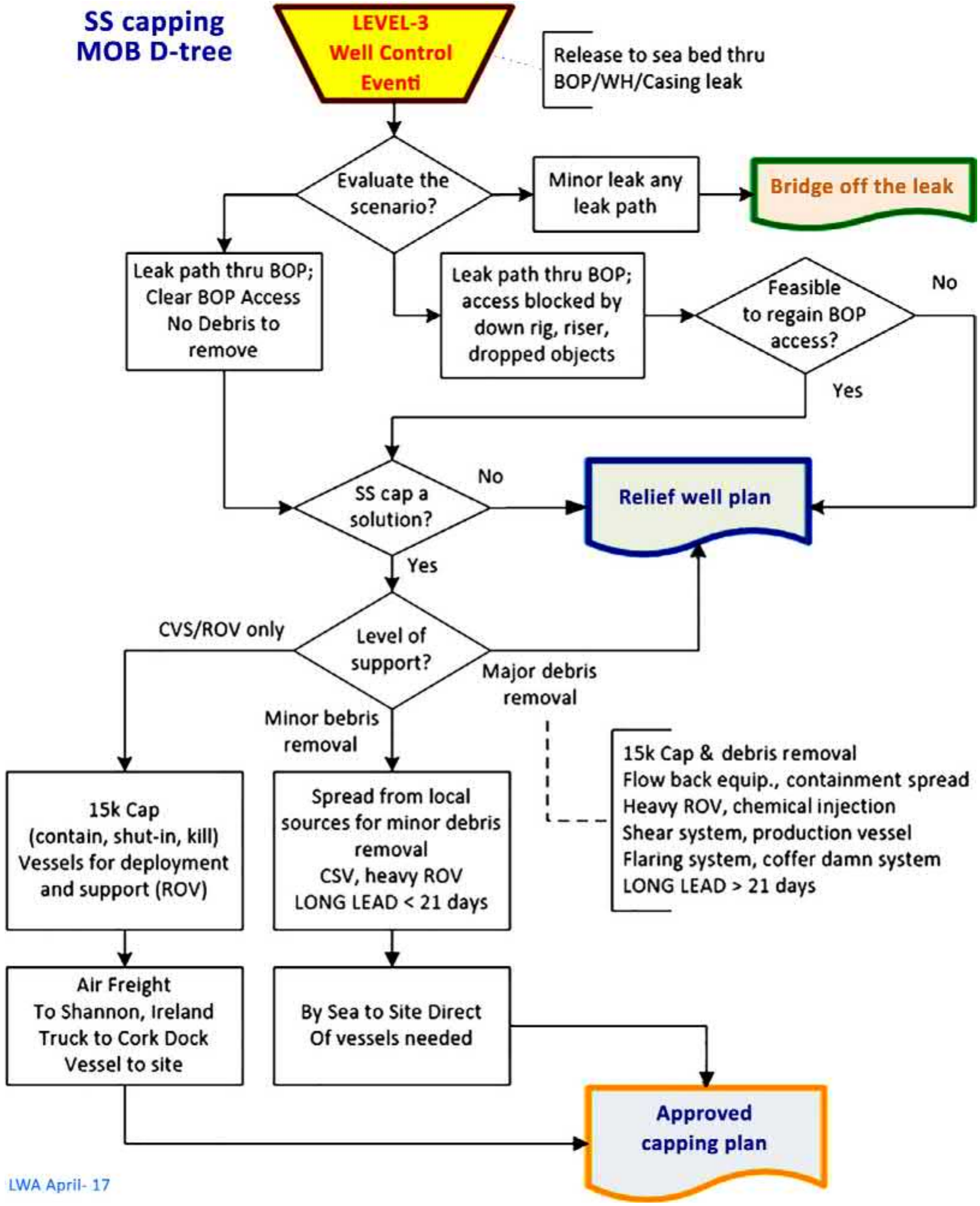


FIG. 11.16 Decision tree for deployment (2017 Irish Atlantic Margins Drilling capping strategy example). *Source: Abel Engineering 2017.*

PLUME BEHAVIOR IMPORTANCE

In new operating regions, environments, and conditions, a plume study of release behavior is considered during the planning phase to aid relief well location selection and to feed results into oil spill contingency plans, based on how gas concentration of gas and oil will rise and surface from release at the mud line to mean sea level.

Modeling determines if toxic gas, explosive mixtures, and presence of oil on the water create hazards to the relief well and capping operations. To determine the plume behavior, computational fluid dynamic (CFD) modeling is also performed to predict column effects from the leak point to mean sea level, i.e.

1. aerial extent of gas/oil
2. gas/oil concentrations
3. current patterns created by the plume.

The results of this analysis predicts safe operating conditions at the predetermined relief well locations and over well center for deployment of a capping stack.

Relief Well Phases

A relief well strategy is to intercept the blowout well in the least possible time with minimal risks of failure. The interception depth is decided where a pump-to-kill operation is most feasible. To support a relief well, a drilling program is required that is performed in four phases.

1. ***Phase A***. Normal directional drilling—Directionally drill to the first ranging point where collision avoidance is the main objective, i.e., ranging must be performed when CF < 1.5, and placement of the well where it is within the range of the proximity tools in use.
2. ***Phase B***. Ranging to locate casing—The relief well trajectory takes the well to a convergence point where the ranging tools are used to locate the blowout well trajectory (casing is normally run prior to risking unplanned intercept).
3. ***Phase C***. Line up to intercept—Well trajectory parallels the well then turns and converges toward the intercept target by lining up for interception. The target well must remain within passive ranging capability during this phase (well is usually cased off at the end of this phase).
4. ***Phase D***. Intercept and communication—The trajectory of the relief well is such that it is lined up for final approach and interception (via touch, perforation, and/or milling).

Further key aspects to be planned, prepared, and considered for relief well drilling are listed as follows.

1. Relief well trajectory
2. Ranging strategy
3. Intersection point
4. Communication method
5. Perforation casing to casing
6. Borehole position uncertainty
7. Wellhead geodesy
8. Wellbore surveying

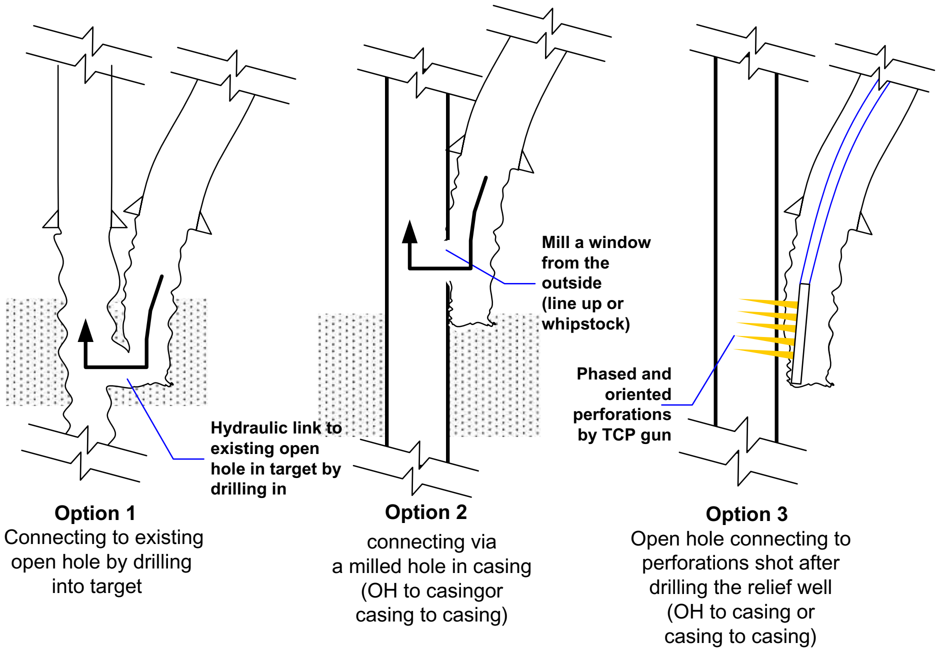


FIG. 11.17 Communication paths for relief wells. *Source: Abel Engineering 2017.*

9. Relief well directional plan
10. Ranging techniques
11. Directional program
12. Specific reservoir scenarios
13. Relief well trajectory discussion
14. Relief well hole size & casing design
15. Wellhead requirements
16. Pump and kill methods

In terms of communicating with the existing well, options to establish a path from the relief well to the blowout well are illustrated in Fig. 11.17. Other central aspects of relief well drilling are addressed in more detail later in this guide.

Well Control Complications/Emergency Response Considerations

Other complication and emergency procedures to consider for deepwater well operations are listed but not limited to the following. Both operator and drilling contractor shall collaborate, communicate, and act to assure that suitable and appropriate emergency response plans are in place and well understood by all concerned for such events, however improbable.

1. Dropping the drillstring
   - **(a)** Recommended practices for dropping the drillstring.
   - **(b)** Recommended practices for dropping drill collars/BHA drillstring.

2. Shearing drillstring
3. Shearing nonshearable items
4. Disconnecting LMRP. *Note*: There are several situations that could arise during well control operations that require disconnecting the LMRP and moving off the well:
   (a) If high annulus pressures approach the safe working pressure of the subsea BOPs or because of equipment failure.
   (b) Vessel movement due to adverse weather conditions (anchor chain or DP failure).
   (c) Impending vessel collision or fire.
5. Bullheading and emergency disconnect
6. Emergency disconnect (no bullheading)
7. Reconnection to SSBOP or well, following an emergency disconnect
8. Blowout/underground blowout
   (a) Stage 1: Early Response
   (b) Stage 2: Containment
   (c) *Stage 3: Control*: Requires the assistance of specialists and would involve several services and disciplines, e.g., well capping, relief well planning, HP pumping vessels/equipment, logistics, operations support/contractor personnel, pollution control, news/media interface, regulatory authority interface, insurance adjusters, police.

Note: An underground blowout occurs when formation fluids flow from one subsurface zone to another. The majority of underground blowouts have been the result of fracturing a shallower, weaker zone when shutting in on a kick originating from a deeper, more highly pressured zone. If an underground blowout is confirmed, the operator and rig representative must be notified immediately.

9. Flow to a lower pressured fracture zone above a higher pressure zone
   (a) Here a decision tree for identifying and dealing with an underground blowout of this type is typically generated.
   (b) If an underground blowout is suspected, no attempt should be made to control the well using standard techniques.
   (c) If the annulus is opened, reservoir fluids will be allowed to flow up the well to surface, thereby increasing surface pressures.
10. Flow to a fracture/loss zone below a high-pressure zone
   (a) Flow down the wellbore from a high-pressure zone usually occurs when drilling into a naturally fractured, cavernous, or structurally weak formation. The resultant losses reduce the hydrostatic head of the drilling fluid to such an extent that a permeable zone higher in the wellbore begins to flow.
   (b) When the well is shut-in, it is unlikely that any pressure will be recorded on either the drillpipe or the casing, although the casing pressure may increase if gas migrates up the annulus. Pumping mud down the annulus will prevent this rise in pressure.
11. Recognizing an underground flow
12. Kill methods, practices, and procedures to employ
13. Flow to a fracture above and high (abnormal) pressure zone. (Spotting and placement of heavy pills, barite, or specialized plugs.)
14. Flow to a fracture/loss zone below a high (abnormal) pressure zone
15. Ask and consider what else is required to assure each project scope specifics are met.

Oil Spill Contingency Plans Generic Outline

General

An Oil Spill Contingency Plan (OSCP) provides operator and drilling contractor with the information and procedures to oversee an effective response in the event of an oil pollution incident originating from drilling operations associated from a well.

Plans are generally written in compliance with the regulatory and statutory requirements for each region where wells are being operated and drilled. IPIECA-IOGP provides a series of Good Practice Guides (GPGs) on oil spill preparedness and response. From these generic guidelines, up to 15 areas of commonly required response capability can be used to mitigate the consequences of an oil spill, as defined in the IPIECA-IOGP GPGs.

Note: GPGs are available on the oil spill response joint industry project (JIP) website at http://oilspillresponseproject.org and on the IPIECA and IOGP websites at www.ipieca.org and www.iogp.org, respectively. OSCPs are designed around a three-tiered approach to oil spill preparedness and response, as follows:

- ***Tier 1*** capabilities describe locally held resources;
- ***Tier 2*** capabilities refer to regional or national resources necessary to supplement a Tier 1 response or support an escalating response;
- ***Tier 3*** capabilities are globally available resources that further supplement Tiers 1 and 2.

Operationally, an OSCP covers an oil pollution incident originating from:

1. The drilling and subsequent plug and abandonment of a well's program;
2. The installation vessel while on location at well's locations;
3. Vessels operating within the vessel's 500-m safety zone.

The key priority in the event of an oil pollution incident is to take measures to ensure the safety of personnel and to secure the installation in order to prevent escalation of the incident. Where an oil pollution incident is part of a major emergency situation such as a blowout, fire or explosion, then the emergency aspects of the incident must be addressed as a priority and reference should be made to Well Emergency Response Plans and relevant bridging documents.

If an operational well event resulted in oil pollution, operator main response objectives, to guide a suitable strategic course of response actions, are summarized as follows:

- Stop the source of the spill as quickly as possible;
- Minimize environmental and socioeconomic impact;
- Minimize the risk of oil reaching the shore;
- Safeguard the safety and health of people.

Objectives will vary dependent on the operating circumstances and specific of each spill.

OSCP Structure

OSCP are commonly split into four parts:

1. Part A: Offshore Response Actions
   - **(a)** Aims to guide offshore emergency response personnel through the actions and decisions required in an oil pollution event originating from well operations.

2. Part B: Onshore Response Actions
   (a) Provides guidance to the operator onshore emergency response teams to determine and enact appropriate responses in the event of an oil pollution incident originating from well operations.
3. Part C: Response Data
   (a) Provides supporting data to be referenced by response personnel in the event of an oil pollution event, including facts, emergency contacts database, notification requirements, environmental and commercial sensitivities, and a list of available tiered response resources.
4. Part D: Nonoperational Guidance
   (a) Contains information to be used to develop operator oil spill response strategy for each well's project. Serves as a useful reference source for response personnel involved in planning and execution.

All operations personnel likely to be involved shall be required to read, understand, and be familiar with the procedures outlined in this OSCP. In addition, further OSRL Field Guides should be provided within the OSCP as they are useful aids for field response personnel, e.g.:

- Aerial Surveillance Field Guide
- Containment and Recovery Field Guide
- Dispersant Application Field Guide
- Dispersant Application Monitoring Field Guide—Tier I Visual Observation
- Dispersant Application Monitoring Field Guide—Tiers II & III
- Shoreline Operations Field Guide
- Vessel Dispersant Application Field Guide
- Waste Management Field Guide

REFERENCE STANDARDS

API RP 96 Deepwater well design and construction.

IADC Deepwater well control guidelines, 1st Edition, 1998, 2nd Edition, 2015.

IOGP, Regulators' use of standards, reports. https://www.iogp.org/.

Norsok Standard D-101 Rev. 4, June 2013, Well Integrity in drilling and well operations.

SPECIFIC REFERENCES

Abel, Bill. Well control emergency response, blowout contingency and relief well planning document references, as prepared for various projects, 2009–2018. http://abel-engr.com/.

Aird, Peter. Deepwater Drilling Best Practices documents compiled for various projects from 1996 to 2018. Kingdom Drilling Services Ltd. http://www.kingdomdrilling.co.uk/default.aspx.

IADC (International Association of Drilling Contractors). Floating Drilling & Equipment Operations, 1st Edition 2015.

Chevron/BP Drilling Training Alliance relevant chapters. Floating Drilling Manual 2007.

Chevron/BP Drilling Training Alliance relevant chapters. Deepwater Drilling Manual 2007.

Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015. http://www.legislation.gov.uk/uksi/2015/398/contents/made.

Thorogood, John L., Michael D. Jackson and Ole Henning Thorsen. Delivering world class exploration drilling – Integration of design, planning and execution. BP Amoco Norge UA. IADC/SPE, 59205, February 2000.

CHAPTER

12

Deepwater "Riserless" Drilling

Note: These operating sections are *not definitive guides*. Regional knowledge and experience shall always be applied to assure best well practice is used.

GEOLOGY, GEOSCIENCE, AND PRESSURE MANAGEMENT

General

Earlier chapters introduced the essential aspects and difference of deepwater wells versus the standard offshore norms for best practice. Preceding chapters attend to operational aspects starting with the riserless sections.

To be used in conjunction with the operational chapters to assure no stone is left unturned, it is recommended that readers afford themselves accessibility to the various deepwater IADC, API, and International oil and gas producers (IOGP) standards, best practices guidelines, and technical documents that have resulted from various joint industry projects and initiatives.

The Riserless Phases

With the vessel and people on board prepared and ready to commence operations at a deepwater location, as outlined in Chapter 11, the riserless phases and operational sequence in deepwater shall include:

1. Pilot hole and penetration test at a safe distance from the main well location if required.
2. Spudding the main well on the seafloor, i.e., with a typical error tolerance of $\pm$1–3 m.
3. Installation of foundation (in ultrasoft formations) and/or a conductor casing strings, in soft to medium clay conditions to the required structural depth (Fig. 12.1).
4. Drilling, tripping, installing, and cementing the surface casing strings or liners to subsurface design and engineered depth to afford running the subsea BOP and marine riser and the first intermediate section to its optimal design depth.

Notes: The final surface string contains the high-pressure wellhead housing (HPWHH) that engages and locks to or is preloaded to rigidize with the LPWHH.

Well control must be assured throughout this phase with the necessary contingent casings and operating plans in place to meet unknown hazards that can arise and any operational challenges or changes required.

https://doi.org/10.1016/B978-0-08-102282-5.00012-0

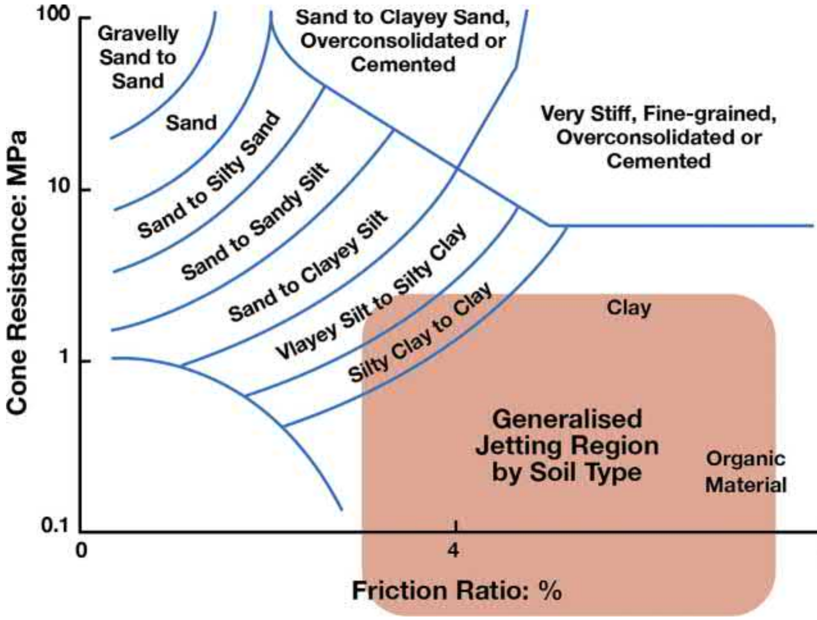


FIG. 12.1 Soil jet-ability. *Source: Correlation for soil types. Jetting shaded generalized region included by Kingdom Drilling 2018.*

Riserless "Deepwater" Subsurface Operating Characteristics

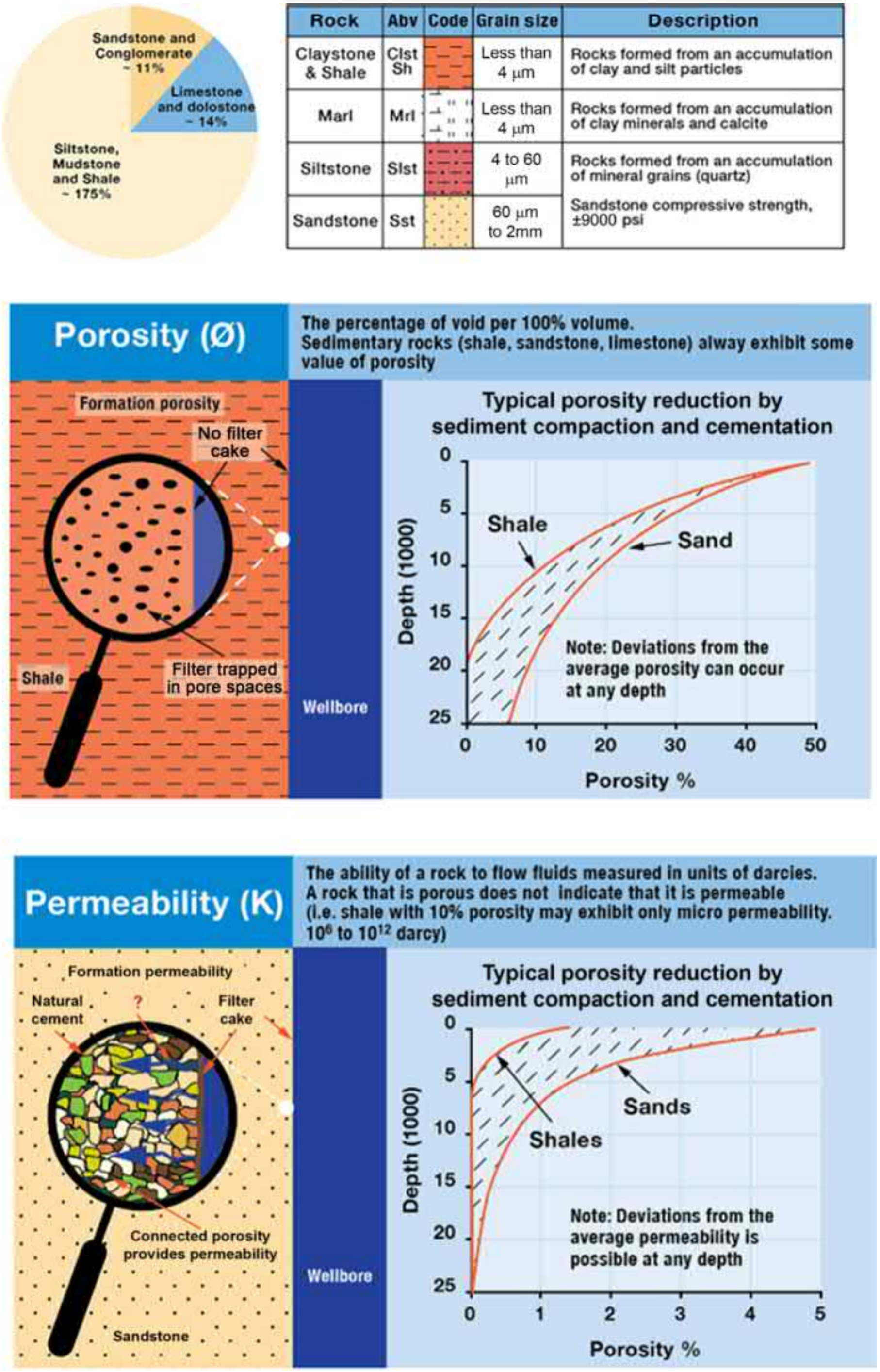
In normal deepwater sedimentary: *transportation, depositional environments, and compaction trends*. Very soft homogeneous clay largely subsists at the seafloor. Should no seismic or wells data exist, an upper and lower bound range of soil strengths are determined from soils classification as provided in Appendix 2.

Notably clay grains, due to their inherent nature, will initially act to push each other apart at the seafloor to result in very high porosity and permeability (Holbrook, Phil) as illustrated in Fig. 12.2. With burial depth and compaction, this relationship rapidly changes in comparison to nonclay (notably sand grains) that sit at the opposite end of the Wentworth classification scale further presented in Table 12.1.

The reality of deepwater sedimentation is that a complex mix of grains and variant stressed regime interval lengths shall subsist within each well's riserless subsurface sections below the seafloor. Should higher depositional rates and structural traps exist, overpressure hazards could be present. During operations best practices must be utilized throughout to *predict*, *detect*, *monitor*, *control*, outcomes desired.

As design plans and operational failures cannot be tolerated in deepwater and why a loss prevention approach is merited. During active operations, it is imperative to constantly measure and control the project metrics of time, cost, quality, that then in turn drive all goals, outcomes, and benefits required.

The ability to make the right decisions requires more resources during planning and execution to assure people achieve *the right things*, *right first time*, e.g., presetting structural strings and conducting environmental base line and all operational surveys required before the main vessels arrival.



Rock	Abv	Code	Grain size	Description
Claystone & Shale	Clst Sh		Less than 4 μm	Rocks formed from an accumulation of clay and silt particles
Marl	Mrl		Less than 4 μm	Rocks formed from an accumulation of clay minerals and calcite
Siltstone	Slst		4 to 60 μm	Rocks formed from an accumulation of mineral grains (quartz)
Sandstone	Sst		60 μm to 2mm	Sandstone compressive strength, ±9000 psi

FIG. 12.2 Characteristics of sedimentary rocks. *Source: Kingdom Drilling 2018.*

TABLE 12.1 The Canonical Definition of Sediment Grain Sizes as Defined by Geologist Chester K. Wentworth in a 1922 Article in *The Journal of Geology*: "A Scale of Grade and Class Terms for Clastic Sediments"

Millimeters (mm)		Micrometers (µm)	Phi (ϕ)	Wentworth Size Class	
	4,096		-12.0	Boulder	Gravel
	256		-8.0		
				Cobble	
	64		-6.0		
				Pebble	
	4		-62		
				Granule	
	2.00		-1.0		
				Very Coarse Sand	Sand
	1.00		0.0		
				Coarse Sand	
1/2	0.50	500	1.0		
				Medium Sand	
1/4	0.25	250	2.0		
				Fine Sand	
1/8	0.125	63	3.0		
				Very Fine Sand	
1/16	0.0625	63	4.0		
				Coarse Silt	Silt
1/32	0.031	31	5.0		
				Medium Silt	
1/64	0.0156	15.6	6.0		
				Fine Silt	
1/128	0.0078	7.8	7.0		
				Very Fine Silt	
1/256	0.0039	3.9	8.0		
				Clay	Mud
	0.00006	0.06	14.0		

When presetting is not viable and greater seabed or subsurface shallow hazards are predicted to exist, a pilot hole and/or a penetration test is considered the next best practice prior to the drilling the main wellbore. Note: If jetting cannot be conducted, for whatever reason, structural casings shall then be drilled, cased, and cemented to the seafloor in a conventional norm.

Boundary Limits of Deepwater Riserless Drilling

The *boundary limits* of the riserless sections can be evaluated by considering a theoretical 100% *clay* (lower risk) and/or *100% sand* (higher risk) intervals as the operating limits. The practical reality is that a mixed and variable content of sand/silt/clay interbeds and variable section lengths would exist.

Add several "force majeure" interbedded stringer intervals to challenge and assure well-site drillers are attentive and alert throughout these phases. Add the cause and effect of hazards and risks of shallow overpressured flows, unconsolidated formations, significant heave, high and variable currents, a newly hired rig drill crews and drilling team to execute the work scope required.

Realize that all project goals, objectives, and standard must still be fully attended to. A murky reality picture of all the deepwater riserless operational challenges to be faced, met, and delivered is now more crystal clear.

With conditions favorable to jet a conductor string and drill a probable claystone dominant section to the required surface casing setting depth, the clay sediments (due to their micron grain size), when jetted and drilled, are effortlessly washed, circulated, and removed from the wellbore using seawater as the primary operating fluid.

Clay disperses to form a simple mud that develops a natural wellbore wall filter cake. Clay is readily transported and removed from the wellbore at exceedingly high transport efficiencies, as presented in Appendix 2 Fig. A2.7 (note: settling velocity at the clay/silt boundary shown at: *0.0014 cm/sec or 1.65 ft/hr*).

Caution: Soft to medium *clay has an approximated defined drilling limit of 4%–6% of cuttings concentration* as shown in worked example that follows.

In contrast, sand at the other end of the Wentworth scale presents cannonball-like grains that can be extremely difficult to remove using a seawater medium alone and where alternative fluid and transport removal methods are required. E.g., Settling velocity at silt/sand boundary, for coarse sand stated in Wentworth scale as: *0.329 cm/sec or 39 ft/hr*), and *15 cm/sec 1772 ft/hr.*

What results when larger particle size, density, and mixed concentrations, e.g., silts/sands exist, is that sea water cannot effectively clean and remove the heavier denser mix alone from the well that will then build up and overload the annulus if no corrective action is initiated. The wellbore can quickly fail, breakdown, and collapse through an *induced fracture,* notably when large sand interval lengths are penetrated and no action is taken.

To counter, prevent, and mitigate the induced fracture risk, *more frequent, higher circulating rates, or larger volumes of an alternative operating fluid, for example high-viscous sweeps, pump and dump mud, must be progressively used* to aid and remove the denser constituents for safe operating conditions to result.

In the extremes subsurface margins, i.e., should large >6 in (150 mm) "dropstones" or larger boulders exist that cannot be circulated from the wellbore once drilled, in this case, operating conditions can display erratic torque/drag during rotating and moving pipe. Here it is considered best practice to slow down and work the pipe through these sections.

Rough drilling can additionally result due to the inherent interbedded and variable nature of formations and coarser constituents that exist.

In all such circumstances, drillers must be prepared to stop rotation, and *not unwittingly backream as a matter of course*, but must fully *understand and appreciate the most purposeful* approach to resolve each situation. E.g.: stop rotation, pick up off bottom, change parameters by slowing rotary, increasing weight and/or pumping far more frequent and larger sweeps.

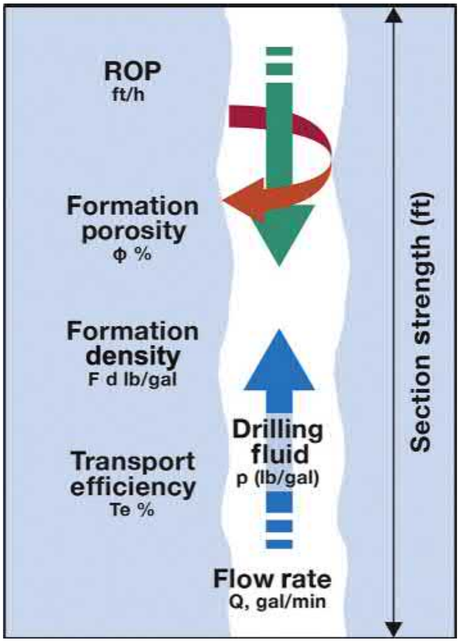
Importance of Pressure While Drilling Tools

The provision of an annular pressure while drilling tool (APWD or PWD) in these sections is essential as this provides precise and accurate physical wellbore evaluation of cumulative downhole equivalent mud weight (EMW) and annular wellbore pressures resulting with each foot drilled. Physical real-time well conditions that are relayed directly to the supervisors, drillers, and mud loggers to assure corrective actions and changes can be made immediately as needed. E.g., if high EMW trends result, best-practices responses can be discussed and initiated to combat downhole wellbore conditions to prevent problems escalating. Conversely when operating windows of opportunities exist (example: when drilling 100% clay intervals), greater effectiveness and efficiencies can result utilizing PWD tools through outcomes, benefits and value gained.

Riserless "Clay" and "Sand" Engineering Illustrative Example

The worked example presented serves to present a generalized outlook of typical downhole riserless operating wellbore drilling limits (a 26-in wellbore in this case) that could exist at a point in time at a depth considering both a 100% clay or 100% sand is being drilled. Graphical results present (for penetration and pump rates as shown) to demonstrate clay and sand limits that exist.

26-in wellbore, drilling @ 2700 m (2000-m water depth)



Worksheet data input

ϕ = Average porosity of formation(s) interval drilled (%) *note: Values can range from 40% for a quarts sandstone to as high as >80% for Claystones at the seabed. Clay values that then decrease far more rapidly than sand with depth, burial lithification, etc.*

Fd = Formation density for clays, silt, sand, etc.

ROP = rate of penetration

Q = drilling pumping flow rate

ρ_{pm} = Pad mud weight being pumped equivalent density noted at surface.

$single$:= 10.3 m (31 ft)

D = hole size drilled
d = drill string diameter
stand := 31 m (93 ft)
W_o = hole enlargement factor %
SI = section length from seabed to depth if interest
ϕ := 30%
Note: Lower porosity generally chosen to model maximum load case.

$$\begin{bmatrix} Fd_c \\ Fd_s \end{bmatrix} := \begin{bmatrix} 2040 \\ 2220 \end{bmatrix} \cdot \frac{\text{kgf}}{\text{m}^3} = \begin{bmatrix} 17 \\ 18.5 \end{bmatrix} \frac{\text{lbf}}{\text{gal}}$$

$$\text{ROP} =:= \begin{bmatrix} 1 \\ 2 \\ 5 \\ 25 \\ 350 \end{bmatrix} \cdot \frac{\text{ft}}{\text{hr}} \quad \begin{bmatrix} Q1 \\ Q2 \end{bmatrix} := \begin{bmatrix} 1000 \dfrac{\text{gal}}{\text{min}} \\ 1600 \dfrac{\text{gal}}{\text{min}} \end{bmatrix}$$

$$\rho_{pm} := 9.2 \cdot \frac{\text{lbf}}{\text{gal}} \quad \begin{bmatrix} D_h \\ d_p \end{bmatrix} := \begin{bmatrix} 26 \\ 5.875 \end{bmatrix} \cdot \text{in}$$

$$W_o := 100\% \quad \text{SI} := 700 \ \text{m}$$

Determine sediment annular loading volumes

Based on porosity hole size and formation density input. Steps #1, #2, & #3 determine cuttings volume (Ah), concentration (Cd) per evaluated lengths drilled. *Note: for noncirculating conditions.*

Step # 1: Determine the wellbore volume drilled for hole size, (Dh), average porosity (ϕ%), and volume per distance (ft/m) drilled (as input.

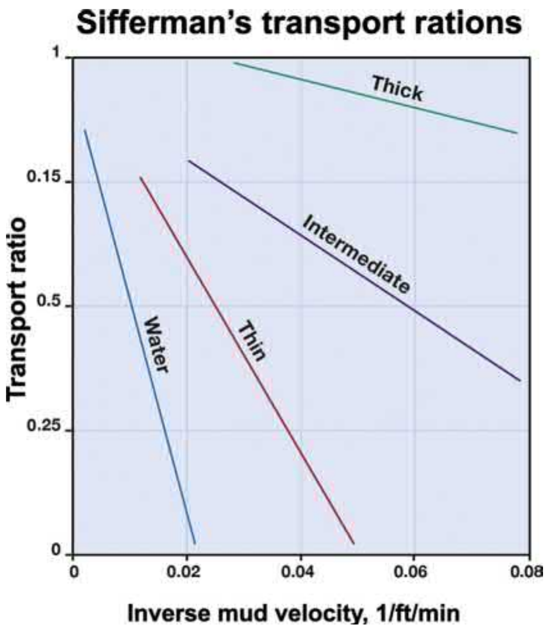
$$Ah := \frac{\pi \cdot (1-\phi) \cdot D_h^2}{4} = 0.46 \frac{\text{bbl}}{\text{ft}}$$

Step # 2: Calculate the sediment or cuttings concentration (Cd) based on the volume of cuttings drilled and generated based on wellbore volume (Ah) and formation density (Fd) as input.

$$Cd := Ah \cdot Fd_s = 357.7 \frac{\text{lbf}}{\text{ft}}$$

Step #3: Convert the sediment or cuttings loading and/on(Cd) into a more meaningful "as drilled" metric, e.g., *per drill pipe single or a drilling stand length drilled based on data as input*.

Transport efficiency



Step # 4: Determine annular velocities (Av) for flow rate(s) (*Q*1, *Q*2), wellbore diameter (Dh), drill string (dp), as input taking into account estimated wellbore enlargement (Wo)

$$Cd = 6\frac{tonf}{\text{single}} \quad Cd = 18.2\frac{tonf}{\text{stand}}$$

$$Av := \frac{Q1}{\left((D_h - W_o)^2\right) - d_\rho^2} = 9.1\frac{\text{m}}{\text{min}} \quad Av = 30\frac{\text{ft}}{\text{min}}$$

$$Av2 := \frac{Q2}{\left((D_h - W_o)^2\right) - d_\rho^2} = 14.6\frac{\text{m}}{\text{min}} \quad Av2 = 48\frac{\text{ft}}{\text{min}}$$

Step #5: To be able to use Siffermans tables one first has to determine the inverse of annular mud velocity (1/Av) to then use value obtained in *Step # 6*.

$$\frac{1}{Av} = 0.033\frac{1}{\frac{\text{ft}}{\text{min}}} \quad \frac{1}{Av2} = 0.021\frac{1}{\frac{\text{ft}}{\text{min}}}$$

Step #6: Using values obtained in *Step #5*, Siffermans tables can be used as a simple method to derive a transport ratio through plotting the inverse mud velocity (1/Av) and intersecting this line for a selected drilling fluid as shown. Transport ratios (Et. %) then obtained based for each pump and annular flow rate, based on hole size and drillstring geometries, etc. as input. Example output values (for water and a thin fluid) as typically used in the riserless section based on 1/Av and 1/Av2 inputs derived are illustrated below.

$$SeaWater : Et_1 := 35\% Et_2 := 55\%$$

If we were to model sea water at the flow rates input. One can conclude the wellbore cleaning (transport efficiency) effect of the higher flow and annular velocity outcomes and benefits presented. Should we also consider a 100% Clay and/or 100% sand sequence is drilled. These two cases alone can present the outer max/min drilling boundary limits that could exist.

$$Et1_{sand} := 35\% Et2_{sand} = 55\% Et1_{clay} := 70\% Et2_{clay} := 85\%$$

Cuttings concentration

Step #7: Concentration of drilled sediments or cuttings (Ca) in the wellbore is determined for rates of penetration and parameters input as follows; *Note: the results present the effects of drilling ROP, circulating rate, drill string hole dimensions for pump rate and transport efficiency as input*.

$$Ca_{c1} := \left(\frac{ROP \cdot \frac{\pi \cdot (1-\phi) - \left(D_h^2 - d_\rho^2\right)}{4}}{Et1_{\mathrm{clay}} \cdot Q1} \cdot 100 \right) = \begin{bmatrix} 0.04 \\ 0.09 \\ 0.22 \\ 1.09 \\ 15.27 \end{bmatrix}$$

$$Ca_{c2} := \frac{ROP \cdot \frac{\pi \cdot (1-\phi) - \left(D_h^2 - d_\rho^2\right)}{4}}{Et2_{\mathrm{clay}} \cdot Q2} \cdot 100 = \begin{bmatrix} 0.02 \\ 0.04 \\ 0.11 \\ 0.56 \\ 7.86 \end{bmatrix}$$

$$Ca_{s1} := \left(\frac{ROP \cdot \frac{\pi \cdot (1-\phi) - \left(D_h^2 - d_\rho^2\right)}{4}}{Et1_{\mathrm{sand}} \cdot Q1} \cdot 100 \right) = \begin{bmatrix} 0.09 \\ 0.17 \\ 0.44 \\ 2.18 \\ 30.53 \end{bmatrix}$$

$$Ca_{s2} := \frac{ROP \cdot \frac{\pi \cdot (1-\phi) - \left(D_h^2 - d_\rho^2\right)}{4}}{Et2_{\mathrm{sand}} \cdot Q2} \cdot 100 = \begin{bmatrix} 0.03 \\ 0.07 \\ 0.17 \\ 0.87 \\ 12.14 \end{bmatrix}$$

Annular pressure (fracture) effects

Step #8: Based on values obtained in *Step #7*. Equivalent annular mud weight for sand extremes in a can be determined within the wellbore from conditional data as input. The output values then used to evaluate the drilling and fracture limits for the well should a sand section interval be drilled.

$$\rho_{\text{sand}1} := \langle Fd_s \cdot Ca_{s1} + \rho_{pm} \cdot (1 - Ca_{s1}) \rangle = \begin{bmatrix} 10 \\ 10.8 \\ 13.3 \\ 29.5 \\ 294 \end{bmatrix} \frac{\text{lbf}}{\text{gal}} \quad \rho_{\text{sand}2} := \langle Fd_s \cdot Ca_{s2} + \rho_{pm} \cdot (1 - Ca_{s2}) \rangle = \begin{bmatrix} 9.5 \\ 9.8 \\ 10.8 \\ 17.3 \\ 122.5 \end{bmatrix} \frac{\text{lbf}}{\text{gal}}$$

Step #9: Further determines the annular wellbore volume, for the actual section length (SI) to be drilled to the depth of interest and accounts for hole enlargement as input (Wo %).

$$Oh_v := (SI) \cdot \left(\frac{\pi \cdot \left(D_h^2 - d_\rho^2 \right)}{4} \right) \cdot W_o = 1431.1 \ \text{bbl}$$

Step #10: Determines cuttings "bottoms up time (*BU*)" from the point of interest to the seabed based on the open hole wellbore volume (Ohv), flow rate (*Q*), and transport efficiency (*Et*) input for both a clay and/or sand sequence.

$$BU_{c1} := \frac{Oh_v}{Q1} \cdot \frac{1}{Et1_{\text{clay}}} = 85.9 \ \text{min} \quad BU_{s1} := \frac{Oh_v}{Q1} \cdot \frac{1}{Et1_{sand}} = 171.7 \ \text{min}$$

$$BU_{c2} := \frac{Oh_v}{Q2} \cdot \frac{1}{Et2_{\text{clay}}} = 44.2 \ \text{min} \quad BU_{s2} := \frac{Oh_v}{Q2} \cdot \frac{1}{Et2_{\text{sand}}} = 68.3 \ \text{min}$$

Cuttings concentration and section length

Step #11: Cuttings concentration are now re-evaluated based on inputs and outputs of section length and bottoms up time for various rates of penetration an flow rates *Q*1, *Q*2 as input

$$Ca_{c1} := \left(\frac{ROP \cdot \frac{\pi \cdot (1-\phi) \cdot \left(D_h^2 - d_\rho^2 \right) \cdot W_o}{4}}{Et1_{\text{clay}} \cdot Q1} \cdot \frac{BU_{c1}}{\text{hr}} \right) = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 2 \\ 22 \end{bmatrix} 1\%$$

$$Ca_{c2} := \left(\frac{ROP \cdot \frac{\pi \cdot (1-\phi) - \left(D_h^2 - d_\rho^2 \right) \cdot W_o}{4}}{Et2_{\text{clay}} \cdot Q2} \cdot \frac{BU_{c2}}{\text{hr}} \right) = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \\ 6 \end{bmatrix} 1\%$$

Annular Pressure effects for section length

Step #12: Based on sand cutting concentrations (Ca) in *Step #12*. The effective annular weight due to cuttings concentration (ρ), based on section length, bottoms up time, rates of penetration, for sand is determined for flow rates input at the depth of interest.

$$AP_{loss} := 1\frac{bar}{SI} = 14.6\frac{kgf}{m^3}$$

**Annular pressure loss value is obtained from standard friction loss equations.

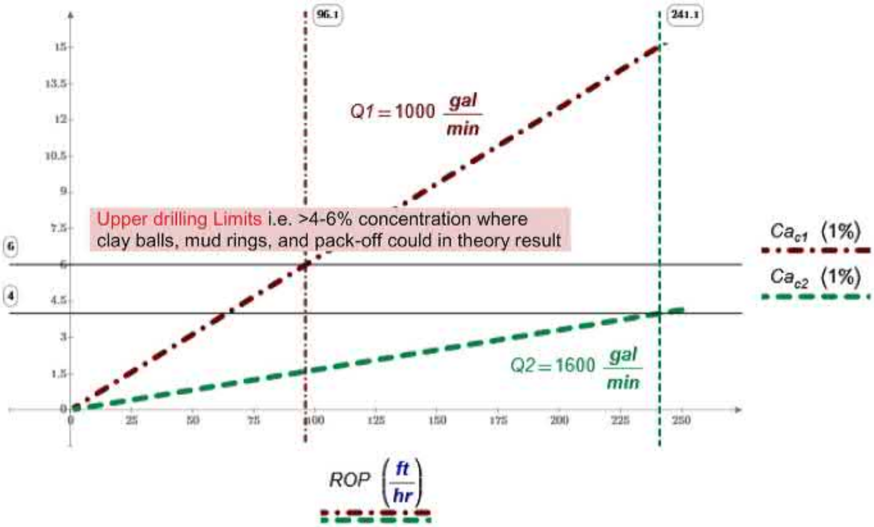
$$\rho e_{s1} := Fd_s \cdot \langle Ca_{s1}\rangle + \rho_{pm} \cdot (1 - Ca_{s1}) + AP_{\text{loss}} = \begin{bmatrix} 10.1 \\ 10.9 \\ 13.4 \\ 29.7 \\ 294.1 \end{bmatrix} \frac{lbf}{gal} \quad \rho_{s2} := Fd_s \cdot \langle Ca_{s2}\rangle + \rho_{pm} \cdot (1 - Ca_{s2}) = \begin{bmatrix} 9.5 \\ 9.8 \\ 10.8 \\ 17.3 \\ 122.5 \end{bmatrix} \frac{\text{lbf}}{\text{gal}}$$

Riserless Drilling Conclusions

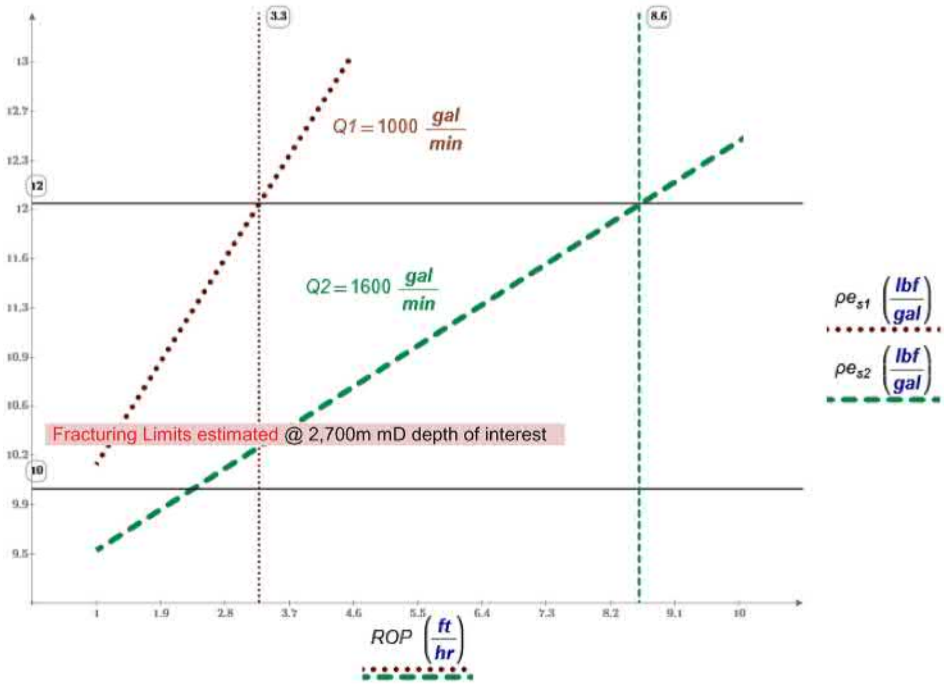
What can be concluded from this worked riserless drilling example and field operating experiences as applied are:

1. In large riserless wellbores, i.e., > 17½″, well-defined limits to *clay and sand* boundary conditions can be readily represented and shown based on data inputs and outputs graphs presented. Limits must be met through best drilling practices utilized throughout to avoid operational problems, difficulties, and wellbore failure resulting.
2. High rates of penetration can be delivered in clay dominant formations particularly if high pump rates can be attained.
3. Sand due to its significant particle size presents the greatest challenge to remove from the wellbore. Particularly if suitable fluids mediums, high pump rates, and controlled drilling is not adhered too.
4. Wellbore-induced fracture can readily result should inputs and outputs (suitable fluids, pump rate, wellbore quality, annular pressures, and controlled drilling best practices) not be attended to.

26in wellbore @ 2,700m MD 'Clay' cuttings concentration limits based on parameters as input



26" wellbore @ 2,700 m MD drilling with PAD mud, presenting fracture limits assuming a "100% sandstone' is being drilled as per parameters input.



Shallow Pressure Prediction

The riserless drilling operations example illustrates the importance to physically and accurately measure and monitor annular pressures limits, taking full account of overburden, pore and fracture gradient pressures regime to prevent operating difficulties (notably self-induced fractures) that can result. This section outlines best practice methods to identify and act to the riserless pressure challenges presented.

The essential hazards are that the wellbore annulus can overload to induce a wellbore fracture, and/or primary well control is lost by penetrating an *overpressured*, *trapped* interval allowing the well to flow. In these cases, additional strings of contingent protective casing(s) and best operational practices must exist to meet and mitigate all operating hazards and risks presented.

Pressure fundaments to consider:

1. A well drilled *directly* at the crest of a large overpressured structure presents greater risks of mechanical and operating failure resulting.
2. Drilling on structural crest should be avoided.
3. Large sand packages in larger-sized wellbores cannot physically be drilled with sea water alone.

Note: Deepwater *overpressured* hazards cannot physically exist until sufficient formation burial and lithification depth, mechanical and structural capability exists to contain a pressurized fluid column at a specific depth, for a structure, trap, and pressure source to exist. This physical limit is often a few to several hundred meters below the seafloor. Knowing where problems physically could begin below the seafloor thus an essential feature to emphasize in the drilling program.

Other pressure related factors are:

1. Models for prediction require precise values of the overburden pressure trends.
2. Pressure measurements must cater to enable accurate detection for as-planned operations to result.

Problems Arising From Overpressure

The evident advantages to predict and detect abnormal over pressures in the riserless horizons cannot be overstated. The importance of detailed studies and assessment of local conditions to permit the delivery of these sections can only be planned and delivered through:

1. More effective well programming.
2. Assessing maximum ROP with minimum mud weight, flow, and pressure management in place.
3. More economical and optimal selection of casing points.
4. Primary well control assurance and integrity issues fully addressed.
5. A better understanding of local geology, drilling problems, and best practice application.
6. Application of nonconventional methods as the preferred risk reduction method when all evidence demands this.

Best practice shall dictate the degree of practical primary well control that can be permitted for the formation pressure intervals predicted plus a suitable working margin that can be as little as 50–100 psi. Reasons for assuring more precise, accurate, and tighter tolerance margins are:

1. To minimize the risk of self-inducing wellbore fractures,
2. To minimize the risk of differential sticking,
3. To optimize wellbore and formation quality (perfect cylinders throughout),
4. To maintain optimum (loss free) operational performance,
5. To assure primary well control is maintained throughout all operational activities. *Not just while drilling*.

Accurately Determining Pressures

Methods used to predict abnormal pressure in shallow trapped compartments are:

1. Accurately determine pore pressures in each shallow (sand) trapped hazard compartment.
2. Determine if overpressure is present, regardless of its magnitude.

Determining sand or nonclay porous permeable pore pressure intervals is a critical issue to resolve. If predrilling is inconclusive, then during drilling in theory tests could be performed through executing a series of flow-kill activities using a variety of mud weights in the wellbore and observing the wellhead via the ROV. In summary, this method consumes considerable rig time, is costly and impracticable to implement or justify unless significant project value can be gained from this.

The best practice method is to *predict* and *detect* pore pressure as outlined in this guide within a degree of operable accuracy prior to and during the riserless sections. The principal pressure management goal is that primary well control is assured and maintained to *reduce induced fractures, select appropriate mud weights to prevent shallow flow, assist to design more stable cement slurries, and eliminate any confusion that may arise over wellbore fluid pressure storage in trapped subsurface compartments that exist*.

Should offset wells data exist, pore pressure (in sands) can be derived to a certain degree for proposed locations. In some cases, pressures can be mapped, correlated, and projected to the proposed well location horizons using standard techniques and appropriate formation fluid gradients for the region.

DETERMINE IF OVERPRESSURE IS PRESENT

The most common prediction method to determine overpressure (in a predicted sand) prior to or during well operations is the second method. Note: The physical magnitude of overpressure cannot be determined until the section depth is drilled and met. The method is not suited for development wells where precise pore pressure data are needed to minimize hazard interactions that exist between closely spaced wells. How to determine overpressure is aided by the fact that these sections do not require an accurate knowledge of the pore pressure.

Knowing a subsurface overpressured compartment is prognosed within a plus or minus depth error bar is all that is required to raise a red flag and then to assure primary well control best-practiced plans are used throughout. Each red flag compartment identified must have two essential elements: a pressure *Source* and a structural containment *Trap*. The most common pressure source is from *rapid sedimentation* or mass transport deposition mechanisms as shown in Fig. 12.3 identified as hazardous anomaly from seismic interpretation and correlation. Other causes of over pressure are related to *sand collapse, gas charging, and/or salt tectonics*.

Sedimentation Rules of Thumb

The general deepwater sedimentation rule of thumb derived in the Gulf of Mexico in the '90s *(Note: All other deepwater regions sedimentation rates to be suitably derived)* is:

1. If sedimentation rate is less than 500 ft (152.4 m) per million years within the sand footprint being interpreted, *overpressure is not likely*.

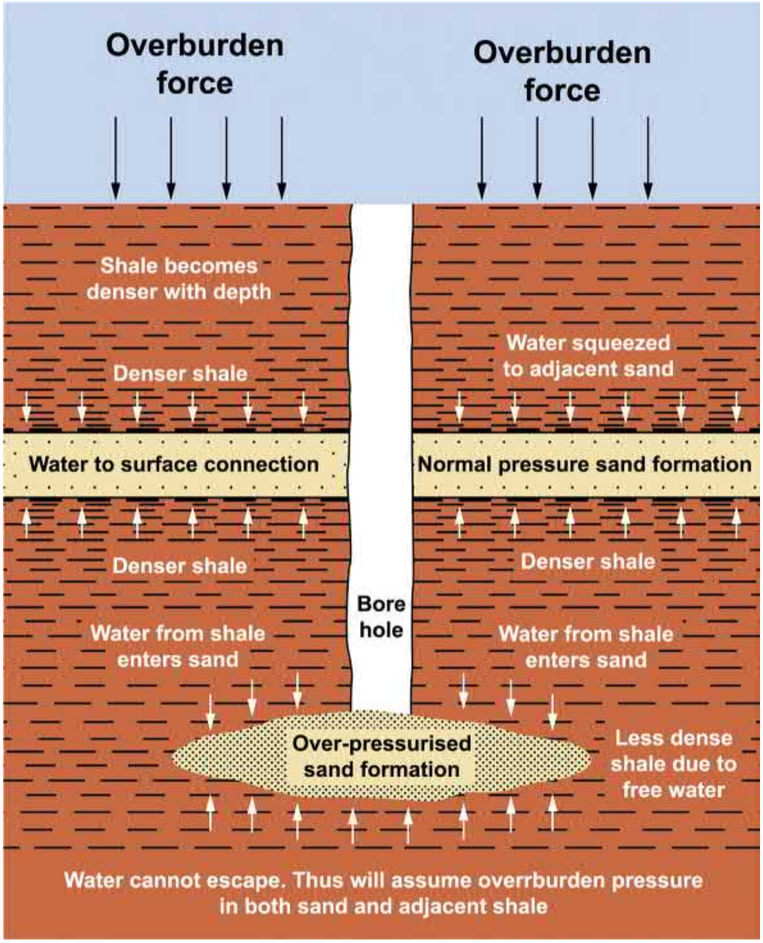


FIG. 12.3 Drilling riserless over pressure. *Source: Kingdom Drilling training 2002.*

2. If sedimentation is above 500 ft (152.4 m) per million years, *seal quality can determine if pressure is trapped.*
3. Seals can be identified from seismic data (*typically very bright, continuous parallel reflectors*). Seals need to be concluded as regionally continuous and not to have been breached by channels, slumps/slides, or faulting in the vicinity of the proposed well.
4. If *seals are present* and *sedimentation rate is above 500 ft (152.4 m) per million years*, consider *sands below the seal as pressured* for planning design and operating purposes until otherwise verified when drilled.

Fracture Gradient Prediction

It is paramount that precise prediction and detection of fracture gradients in conjunction with overburden and pore pressure as outlined in Chapter 3 are established, to determine the degree of safe operating windows present to meet precise equivalent mud weight (EMW) and primary well control best practice assurances during all operations.

The standard deepwater requirement is to predict the fracture gradient for each shallow horizon anomaly and in addition conduct sensitivity analysis to support actions required. Any dispensation that results from the standard norm then to be in place (for example to permit the use of lower (0.2–0.5 ppg (24–60 kg/m^3)) pore pressure and fracture gradient safety margins) for the sections required to be drilled, cased and/or cemented.

2D & 3D Seismic Interpretation

Shallow subsurface hazards are best mapped with high-resolution 3D seismic. The next best choice is a combination of seismic data from mini airgun or water guns and either high-resolution 2D or conventional 3D seismic, to provide better resolution in the interval not covered by the miniseismic systems. Predictions resulting from 2D or 3D conventional seismic data must be properly reprocessed for shallow hazard use. Restoring high resolution can enhance the ability to image shallow sands. Closer trace spacing can further enhance the ability to image highly dipping objects such as rotated slide blocks or channelized sands as shown in Fig. 12.4. 3D migration can reduce the number of out-of-plane objects to misinterpret as shown when using only the 2D data. Should sand prone facies be mapped, the probability of pressure then has to be established.

FIG. 12.4 Gulf of Mexico, 3D seismic, channelized sand "shallow flow" hazard presence. *Source: Kingdom Drilling training 2002.*

Seismic Rules of Thumb

1. The best practice for assessing the potential for shallow hazards in a deepwater well is through a predrill combined seismic stratigraphic analysis using 3D and high-resolution seismic data.
2. Offset well information is used to correlate known hazards or nonhazard sediments, but the available data may be limited, and/or the offset wells may be distant.
3. The final risk assessments for shallow hazards are necessarily qualitative as they are most often made with limited information and are so far based on simple models.
4. Nevertheless, predrill assessments can be reasonably effective for identifying potential hazards sediments in order to be avoided, or planned for during the well design and engineering phases.

DEEPWATER "RISERLESS DRILLING"

Essential differences in comparison to land, surface offshore, subsea, and deepwater riserless sections are illustrated in Fig. 12.5. Key factors to consider prior to commencing operations as illustrated in more depth and detail in earlier chapters are summarized in Fig. 12.6. All factors then to be analyzed, hazard and risk assessed with change needed acted upon based on what each project's scope and deliverables require.

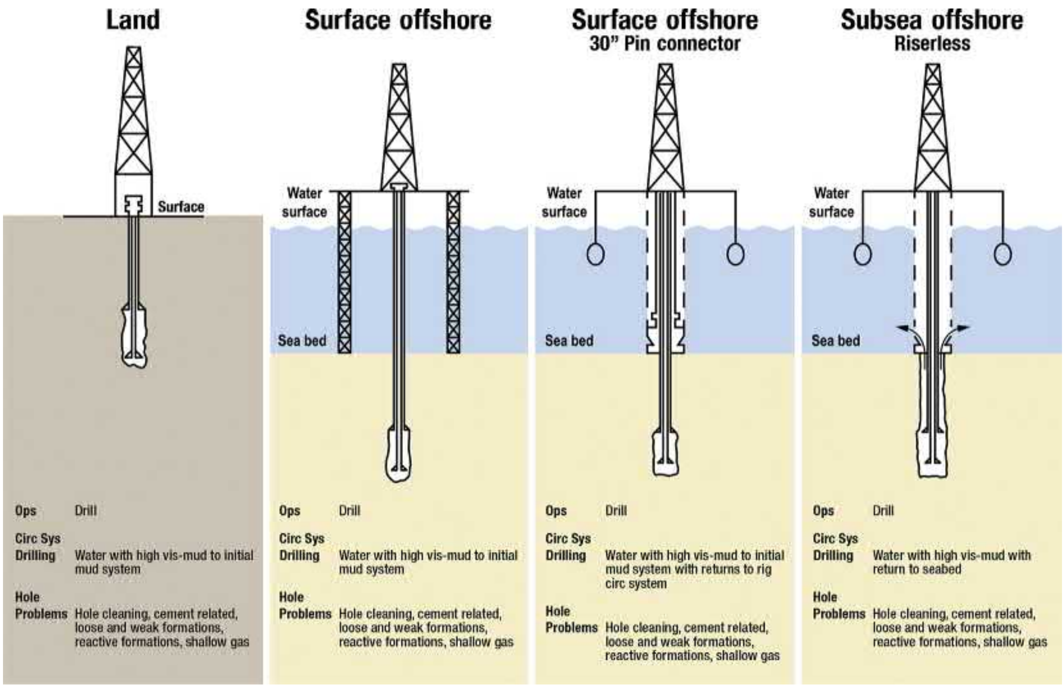


FIG. 12.5 Top and surface wellbore drilling for different drilling applications. *Source: Kingdom Drilling training 2002.*

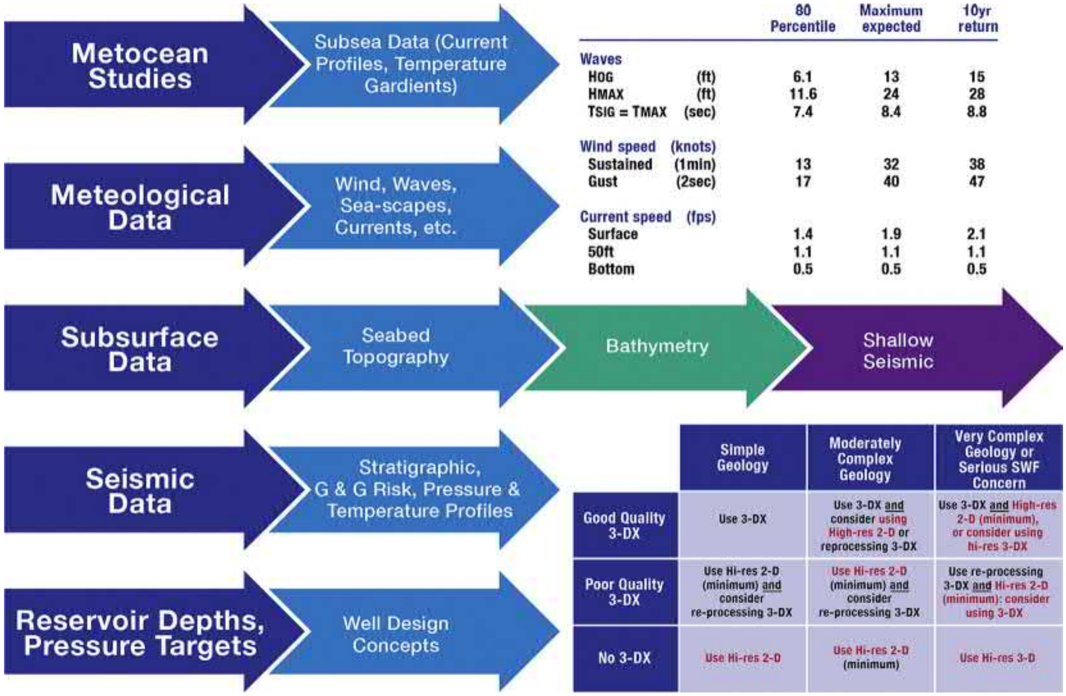


FIG. 12.6 Deepwater riserless drilling data gathering, interpretation, and assessment factor summary. *Source: Kingdom Drilling 2018.*

INDUSTRY STANDARD AND PRACTICES

General

Deepwater standards and best operating practices exist to assure that operators deliver the structural casing sections without a subsea BOP or marine riser installed using industry, operator, drilling contractor, and third-party prevalent riserless solutions that exist.

Should a pilot hole be required (in a new frontier region) or to meet a regulatory requirement to gather subsurface data to enable safer and more informed operating decisions. The pilot hole is drilled in a wellbore diameter <12¼″ that in theory, should primary well control be lost, and a flow results. Flow can be dynamically killed (as modeled). With deepwater pilot-hole practicalities of today *widely questioned* as an effective solution, "dynamic kills" must consider all reasonable facts and rationale as follows:

1. Modeling can confirm that pilot-hole sizes do not generate that much frictional resistance at kill pump rates obtainable via deepwater standard rig mud pump equipment. E.g., Lengths of wellbore intervals are too short for significant friction pressures to result.
2. The limiting pumping factor may additionally be severely prohibited[1] by the downhole measurement while drilling tools. (PWD/LWD/Motors used) to <1000–1200 gpm (3.8–4.5 m^3/min).

1 Unless high flow rate tools are exclusively used >1400 gpm (>5.3 m^3/min).

3. Influx volume required to initiate initial flow is less in smaller pilot holes.
4. Wellbore size and numbers may work in theory. In practice, 8½″ and 9⅞″ pilot holes shall probably erode and enlarge deepwater formations significantly.
5. Pipe rotation and catenary in open water, in conjunction with bit and bottom hole assembly components (stabilizers) can further circumnavigate a wellbore to further increase wellbore size.
6. Shallow flow zones can have a wide extension and a near-infinite structural compartmentalized charge deliverability (if suitable pressured and trapped). Pumping equipment on a standard deepwater rig may not have sufficient capacity to deliver pump rates required to deliver a successful dynamic kill.

From blowouts reported where wells have quickly unloaded often at highly charged rates, the dynamic kill of a shallow flow can only succeed if the well has not unloaded or the source pressure and volume flow is low enough. Based on field experience, *sufficient time may not exist to recognize the situation and respond quickly enough*.

The contingent operation with the highest probability of success is considered as not to pump a fixed weight fluid volume but, according to specialists, immediately pump a pre-engineered and suitably modeled *heavier weighted* fluid at a required *pump rate*, preceded by the required *kill mud weight* fluid volumes required. Note: Field resolution and experience gained in a 12¼″ pilot hole where the wellbore unloaded to a full gas flow for several hours demonstrated that this method worked.

Riserless Hazard and Risk Mitigation

The hazards and risks to be managed and prioritised in the deepwater riserless sections generally arise from *abnormally pressured shallow water/gas/hydrate*, nonclaystone intervals. Hazards can then affect and delay operating planned activities, often significantly.

Avoidance is the primary goal and prevention secondary where best practices, *primary well control compliance*, *assurance*, and *contingent structural casing string(s)* are required to safely isolate hazardous intervals and conditions that can exist.

Primary well control is exercised through drilling at safe optimal drilling maintaining cuttings "pressure" loads with the wellbore annulus limits that exist. When pressure management issues arise, these then are supplemented and supported by pumping and adding viscous and weighted mud sweeps into the wellbore annulus. As depth progresses and this method cannot afford primary control, a pump and dump, i.e., (PAD) drilling fluid method is utilized as illustrated in Figs. 12.7 and 12.8. This consists of using a highly weighted fluid that is (shear) mixed with seawater to deliver the required mud weight that is pumped and displaced through the drilling string, into the wellbore, through the bottom-hole assembly and drill bit. The end-product of mud and drilled cuttings is returned to the seafloor. Case studies of pump and dump (PAD) drilling fluid methods follow.

Pump and Dump Case Study 1

This first well is a semisubmersible conducting riserless drilling in a known Gulf of Mexico shallow water flow area. A total of 26,000 bbl (4134 m^3) of a solids-free "ballast stored fluid" was used to drill 2105′ (642 m) of 26″ hole below the mud line. The 11.4 ppg (1368 kg/m^3) premixed fluid was mixed in an onshore liquid mud plant then shipped and stored in the rig's ballast system to eliminate waiting and shutdown risks due to weather or logistic supply chain concerns. The planning objective and

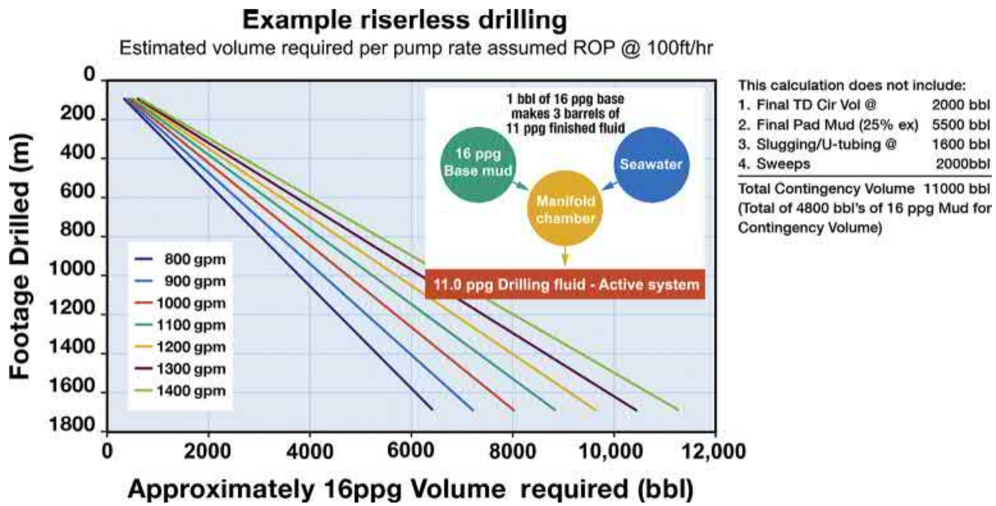


FIG. 12.7 Example of using pump and dump mud method. *Source: Kingdom Drilling training 2006.*

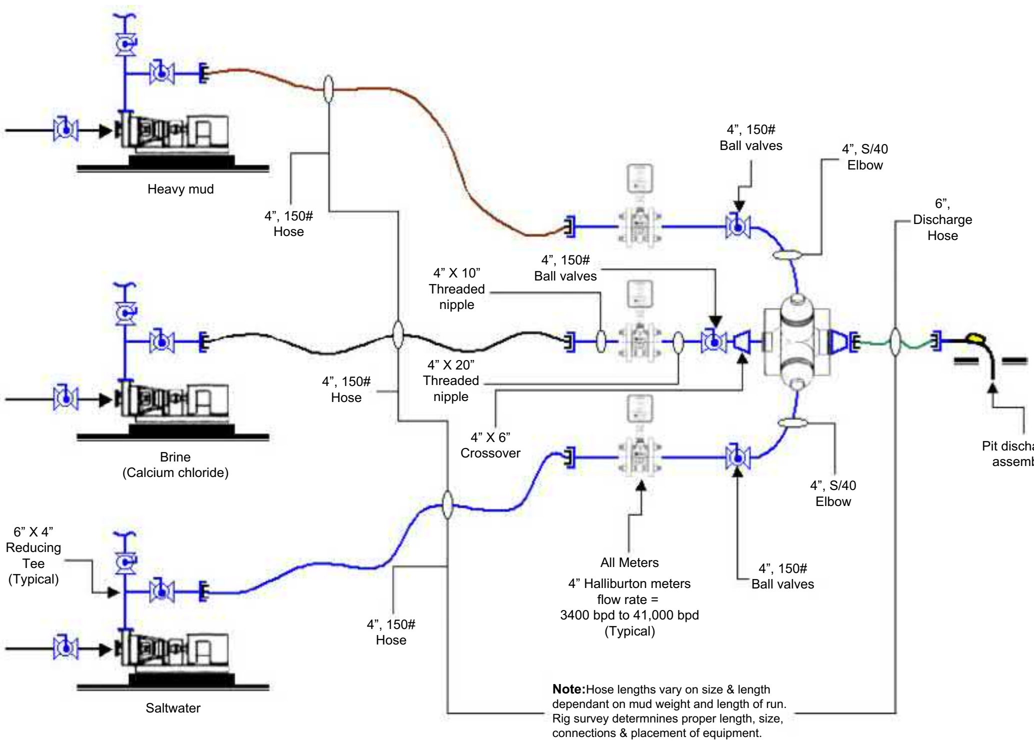


FIG. 12.8 Drilling fluids, low- and high-pressure mixing systems schematic, and pumping method. *Source: Kingdom Drilling training 2006.*

essentials are summarized below. The section was successfully drilled with surface casing run and cemented with no operating difficulties resulting.

PLANNING OBJECTIVES

1. Provide hydrodynamic pressure control to prevent shallow water flow while drilling
2. Provide effective hole cleaning
3. Optimize conditions for running 20″ casing
4. Maximize potential for a successful primary cement job on 20″ casing
5. Implement effective planning, communication and logistics to minimize delay of rig operations.

ESSENTIALS

1. Document procedures and contingencies
2. Calculate minimum flow rate for hole cleaning and maximum allowable ROP to ensure adequate hole cleaning and hole stability and eliminate any bit balling/pack off tendencies
3. Calculate minimum volume of fluid required, including contingency kill volumes.

Pump and Dump Case Study 2

The second well's example also used a semisubmersible in the Gulf of Mexico to implement a pump and dump (PAD) method where conventional operating methods were concluded from the hazard and risk assessment as too high. Safety outcomes and benefits of the PAD method were concluded to far outweigh the environmental impact concerns of significantly larger volumes of riserless water based mud fluids being discharged to the seafloor. Drilling operations were conducted with seawater and viscous sweeps for the first 1035 ft (316 m) below the sea floor to an error-bar above the targeted risked horizon. Pump and dump proceeded for the remainder of the section, i.e., 765 ft, (233 m) to deliver a total section length of 1800 ft (549 m). PAD mud was introduced at a vertical depth of 9185 ft (2800 m) due to expected pore-pressure increase prognosed (Figs. 12.7 and 12.8).

Weighted 16ppg (1917 kg/m^3) premix was vortex mixed with seawater to produce a 11–13 ppg (1318–1558 kg/m^3) mud to be pumped into the wellbore annulus. The anticipated environmental impact of drilling a 500-ft (3000–3500 ft BML), interval was estimated to be 10,000 bbls of 16.0 ppg (1590 m^3 of 1917 kg/m^3) mud lost to the sea. The mud diluted with seawater produced a total mixed operating volume of ±20,000 bbls of 13.0 ppg (3180 m^3 1558 kg/m^3) PAD mud. Environmental impact was further mitigated by not pumping high viscosity sweeps. Where, 100–200 bbl (16–32 m^3) high viscous sweeps would be typically pumped in this interval every 100 ft (31 m) with conventional methods applied. Lessons learned and opportunities noted were:

1. Riserless drilling using the PAD method enabled the rig team to set the 21¾″ casing string 3600 ft (1097 m) below the sea floor versus 2500 ft (762 m) typically set.
2. The Vortex Mixer worked exceptionally well in this application; however, good communication with the pump room and a minimum of 3 personnel on the Vortex mixer is required at all times.
3. Supplying mud engineers with real-time PWD information would streamline the process.

4. The rig experienced difficulty taking surveys while drilling with the PAD mud due to resulting U-tube effect and mud falling in the drill pipe.
5. Mud volume must be crystal clear in regards to "mud discharge" issues. (In respect to dilution volumes with seawater prior to being pumped and actual "volume" of mud physically discharged to the seafloor is open to interpretation.)

Dual Gradient Drilling

The deepwater progressive and ultimate goal is to be capable to implement a full dual gradient drilling (DGD) system as illustrated in Fig. 12.9.

Future DGD techniques and methods as shown in Fig. 12.10 (*note: that shall be more probable required during field and later development drilling*) to be developed, integrated, and adapted with managed pressure drilling (MPD) technology systems to reduce, and mitigate all operating hazards and risks are illustrated in Fig 12.10. The ultimate prize is represented in Figs. 12.11 and 12.12.

Riserless Technology Application

Geological and operational technical complexity further challenges deepwater exploration, appraisal and development drilling wells, as illustrated in Fig. 12.13, where ROV snapshots present a series of overpressured and variant hazardous flow zones resulting from various formation depth intervals that existed in a ±2525 m water depth well. Technological

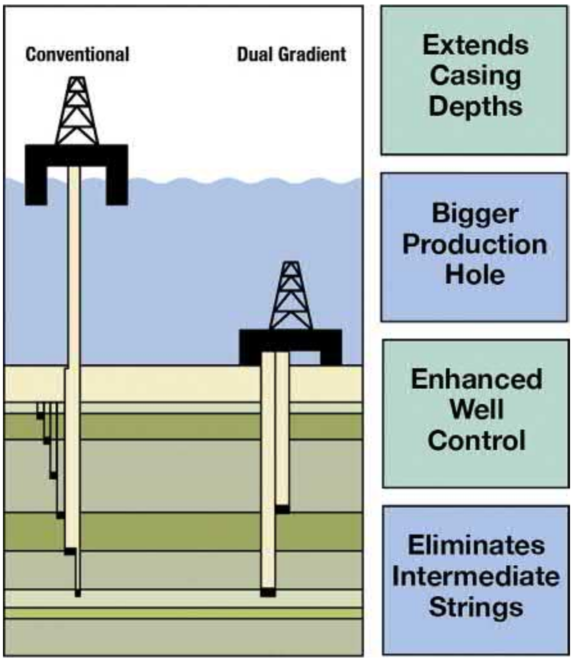


FIG. 12.9 Benefits of dual gradient drilling in deepwater wells. *Source: Kingdom Drilling training.*

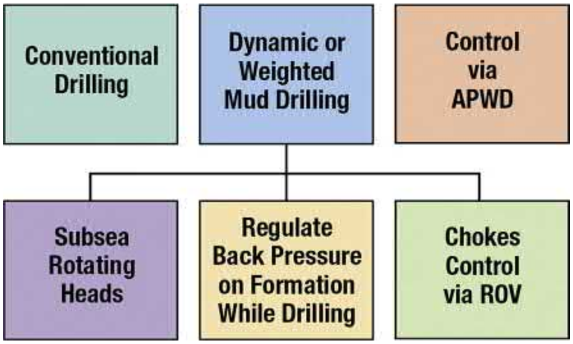


FIG. 12.10 Deepwater riserless drilling, past, present, and future options. *Source: Kingdom Drilling 2014.*

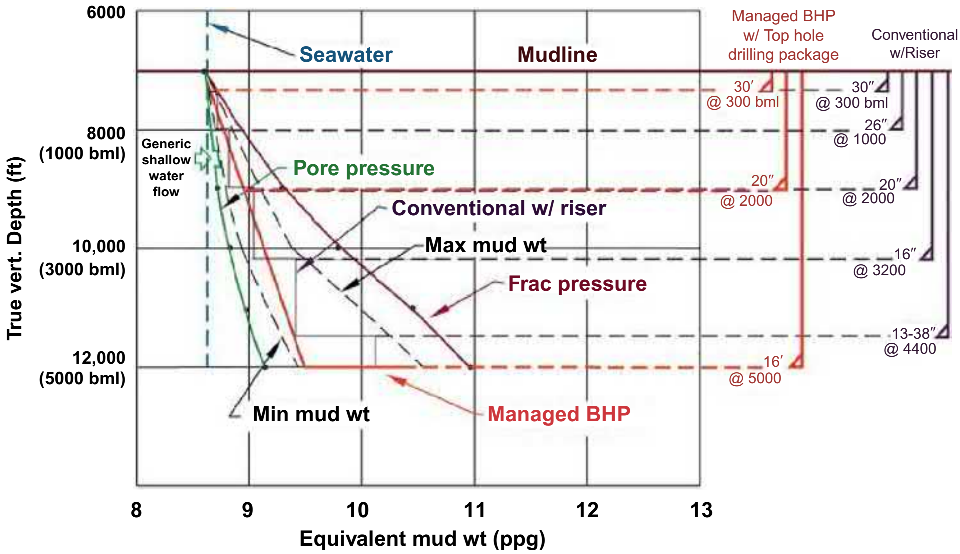


FIG. 12.11 Benefits of dual gradient drilling in hazardous deepwater shallow drilling environments. *Source: Kingdom Drilling training 2002.*

preventative methods as previously highlighted could have been used to counter measure the significant loss events that resulted in these wells.

Well Inclination

The conductor low-pressure wellhead housing (LPWHH) must be jetted or installed into a vertical well to sit at less than 0.5–1 degrees. Monitoring wellhead inclination is verified through slope indicators fitted to the structural casing, wellhead, running strings, and/or subsea BOP during installation. Verticality thereafter verified routinely of the wellhead,

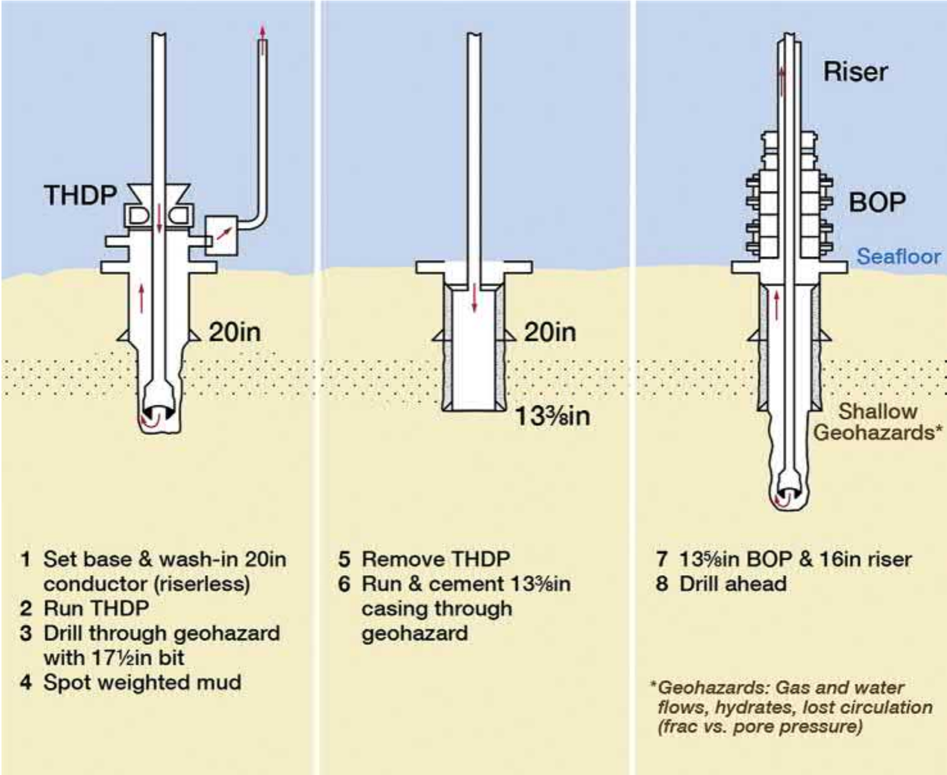


FIG. 12.12 Future technology developments planned for deepwater using dual gradient drilling systems techniques and adaptations from within current industry innovations. *Source: Kingdom Drilling training 2002.*

SSBOP, and marine riser systems during ROV planned dive inspections. To mitigate the risk of associated wear, company policy generally requires that operational well construction and design wear factors are accounted for.

RISERLESS BARRIERS

Safe barrier standards shall exist as per industry (Norsok D-010 or API RP 96 deepwater well design barrier requirement) for all operational phases and activities conducted where the premise as stated is to maintain *primary well control containment* throughout all operational sequences that exist.

Should overpressure or hydrocarbons exist, further barrier requirements must be enforced. All project team members to be familiar with barrier standards and practices required. Additionally, to assure contingent and safety responses are in place to rapidly detect and react to any loss of primary well control, it is essential that the remote-operated vehicle (ROV) is stationed at a safe and adjacent operating well location, i.e., above the seafloor nearby each well, to continuously monitor and assure primary well control conditions prevail. Should

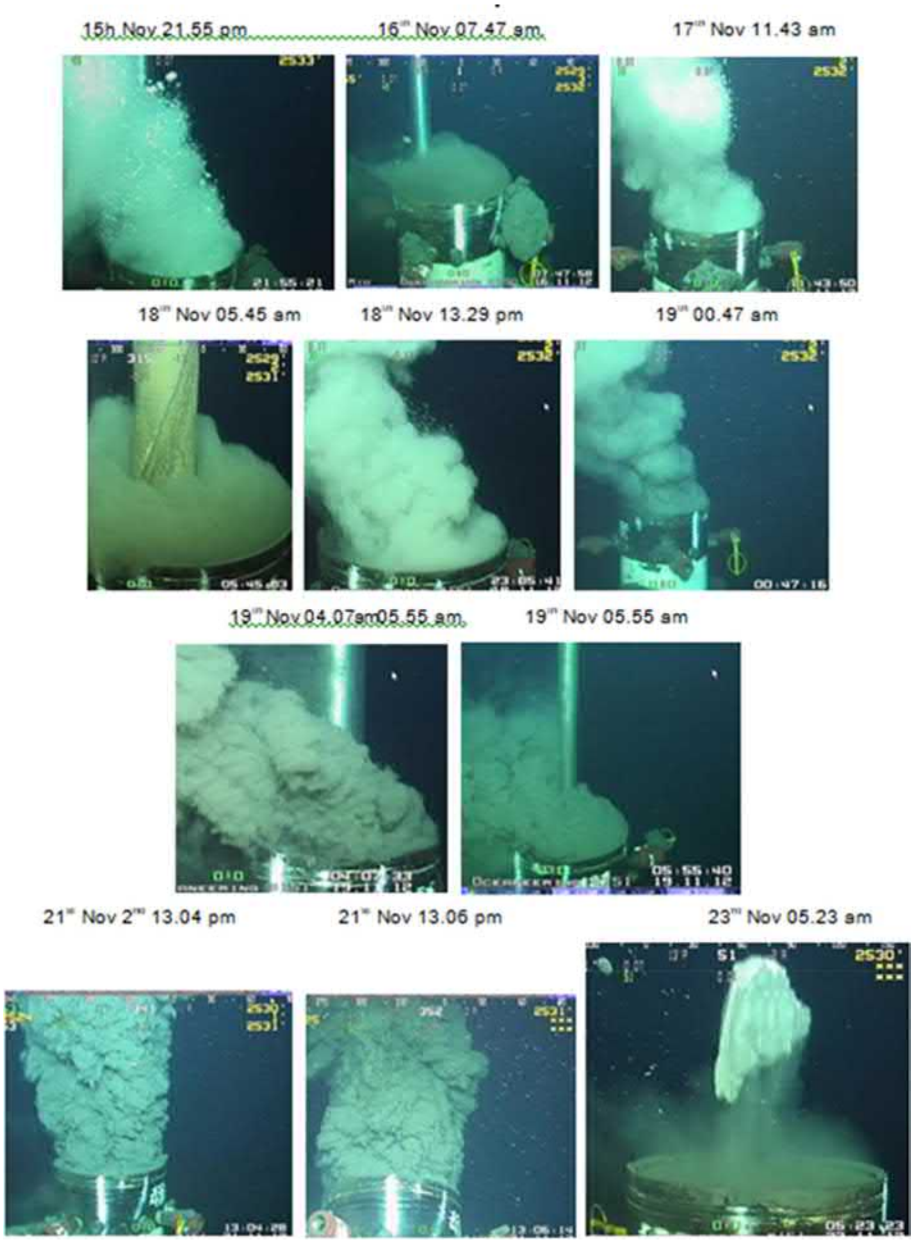


FIG. 12.13 Deepwater well in 2533-m water depth where a series of thin flatly horizontal water gas and hydrate zone bedded intervals were penetrated. *Source: Kingdom Drilling training 2014.*

flow result, *early warning and recognition* is the critical response to enable and react to assure safe operational success.

Generic riserless decision trees are illustrated in Figs. 12.14 and 12.15. Note: Real-time ROV video monitoring and sonar scanning systems are hooked up and connected to various monitoring screens throughout the rig, e.g., on the drill floor, the bridge, in the company representative office, etc. Both camera system and high-resolution sonar equipment shall monitor well returns and in conjunction with annular pressure monitoring. The means provides the principled method to quickly respond and react to assure primary well control is maintained and to detect abnormal pressure management situations should they arise, through:

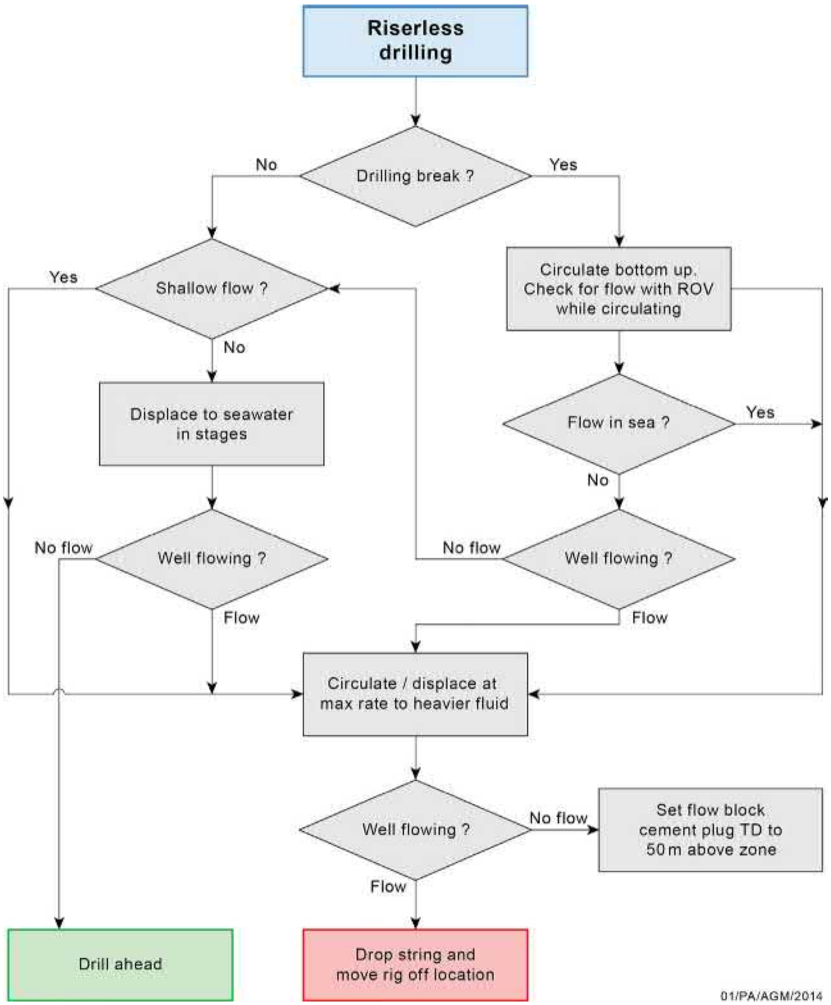


FIG. 12.14 Deepater generic riserless drilling decision tree. *Source: Kingdom Drilling 2017.*

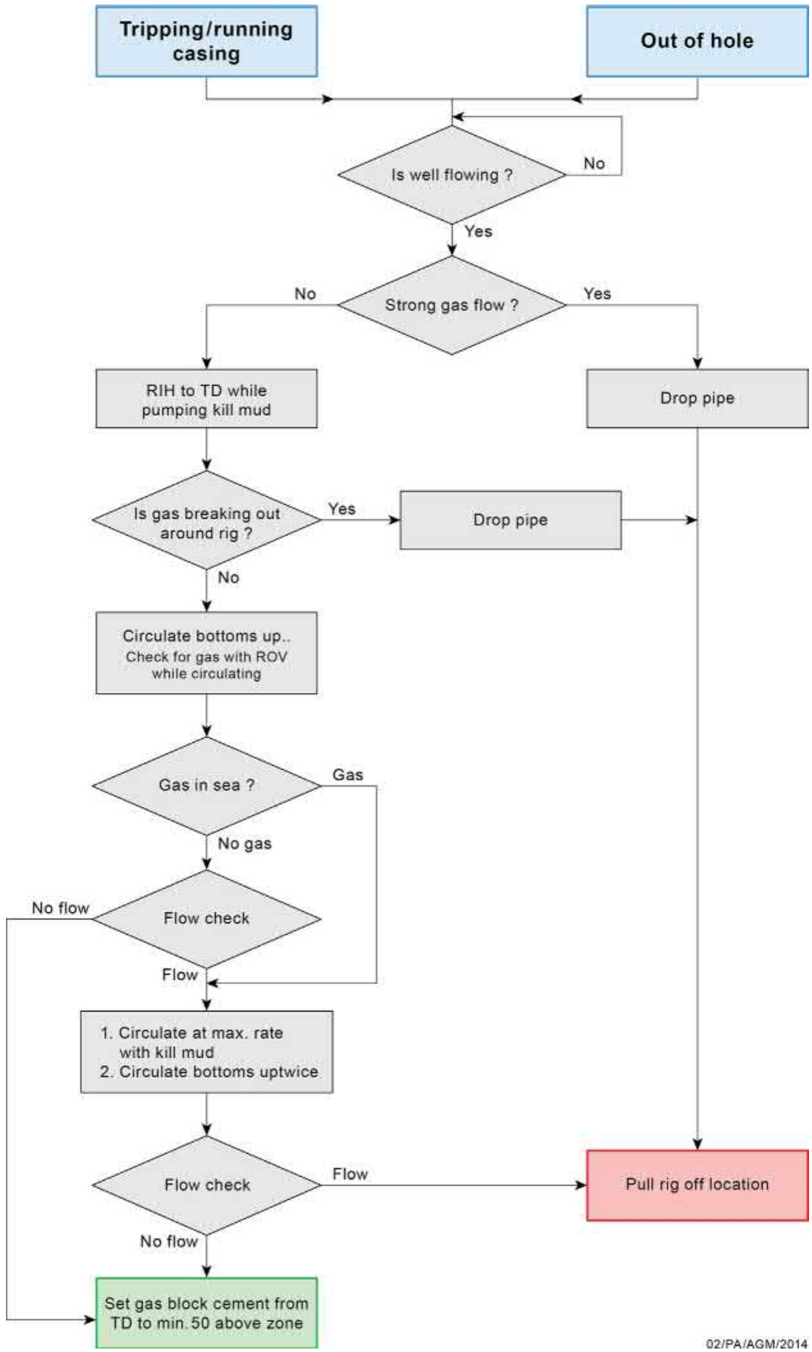


FIG. 12.15 Deepwater generic riserless tripping, casing running decision tree. *Source: Kingdom Drilling 2017.*

1. Observing the well and surrounding areas at the mudline during drilling, tripping, and re-entry of the well with tubulars, and
2. Monitoring returns to mudline during drilling and cementing (*observing for such things as excess returns, loss of returns, cement returns, flow checks, etc*.).
3. Gas detection as first observation of flow from a well would identify via the ROV's high-resolution sonar equipment, i.e., white cloud shall appear on the sonar screen.

The inherent advantage of riserless operations is the seawater hydrostatic pressure provides an inherent safety cushion to the rig and personnel on board. Riserless operations conducted in accordance with safety operating margins required, formation strength, and structural casing setting depths to afford optimal well integrity to install the subsea BOP and marine riser and first intermediate section to required program depth.

Should primary well control be lost, and a worst-case pressurized and highly charged shallow gas flow result, gas is unlikely to migrate to surface in a hazardous nature within the vicinity of the rig or the personnel. The vessel has more time to relocate to a safe area, and due to gas solubility and dispersion in the seawater and the water depth column present, reduce risk to rig and personnel on board. Should a well gas flow result into the open sea, flow dynamics in majority of cases shall not likely break down the well, and should due and diligent procedures be adhered to in terms of regaining control. Primary control can be safely regained with no underground blowout resulting to minimize environmental impact and reputational loss that can result.

As an added note, moored and dynamically positioned drillships or semisubmersibles can operate safely in the majority of deepwater shallow gas situations. Perceived risk of buoyancy or stability loss due to gas concentrations around the rig are reduced as plume studies show. Moored vessels modeled to demonstrate ALARP risks for most deepwater hazard gas-flow scenarios. Note: In an absolute worst-case condition (no current or apparent surface wind conditions), appropriate emergency and safety response plans must exist for this low probability but potentially higher risked consequential event.

STANDARD DEEPWATER LOSS

In addition to the major hazards experienced as outlined in this chapter so far, it is also prudent to review what can be considered as a more standard norm set of deepwater riserless operating results. In this, a data set of deepwater exploration wells drilled in 1996–97 emphasizes operational best practice and things that evidently can go wrong to conclude the importance to translate, sustain learnings, and prevent recurrence. The ability to learn and resolve inherent problems in principle should be straightforward but, as presented, is evidently not.

What is important in the wells data set presented is that NO *shallow water, gas, or hydrate flow* hazard events resulted. In riserless complexity index terms, these wells are classed as low-medium with often very few and less major problems as shown in Table 12.2.

Deep "Open Water" Loss

Table 12.3 summarizes all riserless loss time from all 21 deepwater exploration wells, West of Britain using 3rd- and 4th-generation drilling vessels. Key areas and lessons learned concluded as:

TABLE 12.2 Riserless "Best of the Best" Lost Time Well's Case Study

Well	*Date*	*Rig*	*WOW*	*Repair*	*NPT*
18	Jul-95	4th-Generation rig	0	1	0
19	Sep-94	4th-Generation rig	0	0	0
No of hr lost			0 hrs	1 hrs	0 hrs

Source: Kingdom Drilling 1997.

1. 70% of all well's operating loss existed in the riserless drilling phases.
2. Repeated difficulties resulted when locating and re-entering top-hole foundation/conductor wellbores. *Note: Jetting is not practicable due to glacial drift sequences that exist in the shallow subsurface.*
3. Contracted vessels respudded or had frequent riserless difficulties on 1st wells drilled.
4. Some licence block's experienced more consistent riserless problems than others, e.g., wellbore collapse, stuck pipe, and consequential respud. Once stuck (notably in massive sand intervals), pipe was rarely worked free.
5. Critical equipment impacted loss significantly. Notably: *Top drive systems, remote-operated vehicles, heave compensators, high pressure and tubular handling equipment experienced problems in the riserless sections.*
6. Fit-for-purpose critical equipment systems are demanded for the harsh operating frontier environments that existed. (*ROVs, heave, tensioning compensation, anchoring equipment)*
7. Irrespective of operating periods, 3rd-generation rigs experienced nine times greater operating loss than 4th-generation counterparts, to conclude the importance of fitness of purpose in these operating environments and conditions presented.
8. Multiple crosscurrents impacted operations more than any other metocean condition.
9. Well re-spuds generally resulted through the use of inappropriate practices that often result in stuck pipe—and respud notably in massive sand intervals, i.e., >100 m in length.
10. Wellbore problems were noted to result evidently more so during connections.
11. Backreaming during tripping was a direct contributor to lost time events.
12. Wellbore consolidation, quality and primary control maintenance was concluded a priority objective to ably manage, maintain, and control loss when difficulties resulted.
13. Noncompliance to best practice standards evidently existed on several wells.
14. How to address extent and magnitude of latent failures and human factors contributors that resulted is a concern to correct.

Key Open-Water "Loss" Subject Areas

Tables 12.2–12.4 conclude loss time event as attributed to three central subject areas: *Wellbore*, *Waiting*, and *Equipment*. These are then subdivided into specific subjective problem areas as shown. A key fact of this wells data set is that although the riserless sections only accounted for ±25% of all well operations, *70%+ of all wells operational loss events* resulted in these phases, emphasizing the importance of delivering phases "right first time."

TABLE 12.3 Deepwater West of Britain Case Study, *Riserless Phase Loss Time Summary*

Well	*Date*	*Rig*	*Wait*	*Eqpt*	*Well*
Block 204/19					
1	Jul-95	Non-4th-generation rig	2	12	86
1a	Respud		12	13	60
2	Sep-94	Non-4th-generation rig	3	5	70
2a	Respud		6	14	106
3	Jan-95	Non-4th-generation rig	64	3	127
4	May-95	Non-4th-generation (Respudded twice)	158	65	176
5	Aug-95	4th-Generation rig	3	0	12
Block 204/20					
6	Sep-93	4th-Generation rig	2.5	8	0
7	Oct-94	4th-Generation rig	12	3	20
8	Oct-94	Non-4th-generation	35	19	78
9	Mar-95	Non-4th-generation	54	10	12
10	Apr-95	4th-Generation rig (Horizontal well)	4	1	1
11	Jul-95	Non-4th-Generation rig (Respudded)	9	13	130
Block 204/24a					
12	Feb-94	Non-4th-generation	210	135	102
13	Jun-94	4th-Generation rig (Deviated well)	5	4	39
14	Jul-94	4th-Generation rig	0	2	22
15	Jul-94	4th-Generation rig	0	4	4
Other Blocks					
16	Aug-94	4th-Generation rig	8	9	12
17	Jul-95	4th-Generation rig	35	1	0
18	Jul-95	4th-Generation rig	0	1	0
19	Sep-94	4th-Generation rig	0	0	0
20	Jun-95	4th-Generation rig	10	18	47
21	Jul-95	Non-4th-generation	0	50	196
No. of "riserless" days lost			26	16	54
Total "riserless" days lost			**97**		

Source: Kingdom Drilling 1997.

TABLE 12.4 Riserless Top and Surface Casing Wells Summary

Well Phase	*Total Riserless Phases Duration*	*Avg Duration/Well*	*Lost Time*	*% Loss by Phase*
Conductor	96 days	4.6 days	43 days	45%
Surface casing	154 days	7.3 days	54 days	35%

Source: Kingdom Drilling 1998.

Why Is Open Water Loss More Exclusive in Deepwater?

Deepwater riserless sections are somewhat different from a standard offshore operating norm that afford more forgiveness and tolerance. First, one must consider the inherent nature of deepwater sedimentary—constituents, transportation, deposition, burial, compaction—and then add specific conditional settings and environments that can develop, trapped, over-pressurized, loose, unstable, very variable interval sequences. Also, formation and wellbore characteristics can quickly deteriorate to become enlarged, washed out, or unconsolidated, and collapse should certain operating conditions and practices be applied.

It is therefore paramount that the inherent weakness and fragility of deepwater riserless sedimentary formation characteristics are recognized to surmise exact and explicit risk uncertainty and susceptibility, where mechanical, hydraulic, and combined cause and effects will far more readily incite damage loss and failure if not duly managed via *best practice application and compliance*. Personnel also need to be trained, skilled, and educated to the inherent nature and unique set of *deepwater operating conditions* that exist.

Due to the fact that deepwater project loss and failure is not the preferred outcome, problem solving, decision making, more fit for purpose tools, equipment, systems guidelines, instructions, and *supportive engineering* are all required to deliver improved results. In summary, delivering deepwater riserless sections has many different compliant facets to be met than the standard offshore norm.

Wellbore Condition Lost Time

Fifty-four days of wellbore-related problems resulted within the riserless sections conclude that several events resulted directly from poorly initiated or inappropriate applied drilling practices, a general lack of detailed engineering, plus associated human factor skills gaps to correct to prevent repetitive loss events.

Waiting Lost Time

Fig. 12.16 presents waiting loss, where 70% of waiting is not surprisingly within the riserless phases where operations are most exposed to the metocean and other elements present. Waiting was concluded to be evidently more related to variable subsurface currents in this particular operating area than weather itself. In addition, nonfit for purpose systems, tools and equipment, people skills, knowledge, and experience are lacking at this time. Latent failure cause and human effect factors all must be deliberated as to how the greater extent of waiting loss time events that resulted could be prevented and mitigated in future. Note: In harsh environments, there are times when the only option is to wait

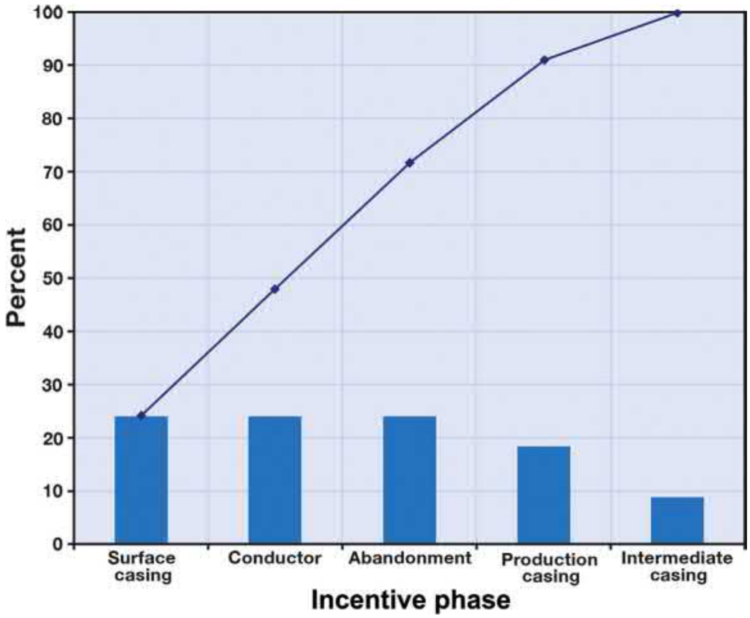


FIG. 12.16 Waiting: deepwater wells lost time summary, West of Britain. *Source: Kingdom Drilling 1998.*

until safe operating limits exist to resume operations, e.*g., waiting on slack tide to be able to stab a drillstring into the well.*

Waiting in many instances, can be eliminated through better foresight, preplanning, preparation, organization understanding, and monitoring of the environment.

Where through improved design and assuring more fit for purpose equipment, practices and people skills exist to meet anticipated environment and conditions predicted, benefits can be realized, e.g., *new generation of ROVs, active/passive heave compensators, using 4th- & 5th-, and newer-generation rigs that are purpose built for each operating region and environment.*

Finally in regards to vessel contracted arrangements, a key objective is always to try and conduct any drillship activity out with North Atlantic autumnal and winter periods. That is evidently supported by historical waiting loss that has resulted in these operating periods.

Equipment Lost time

Repair and equipment failure of all well operation loss is shown in Fig. 12.17.

There is insignificant data to suggest equipment failure resulted more in the riserless phases. What can be stated is that equipment and repair failures directly accounts for *±5% of total well's loss.* The majority of associated equipment lost time and costs results from the trips, repairs, and impact of failure events factors crucial and critical in terms of total loss. In simple terms, any deepwater equipment failure is not a preferred option. The principal rule is to try and maintain a "keep it simple" approach and avoid if possible over complex, mechanized, semiautomated, high-tech, and unnecessary added jewelry that is often misplaced and used

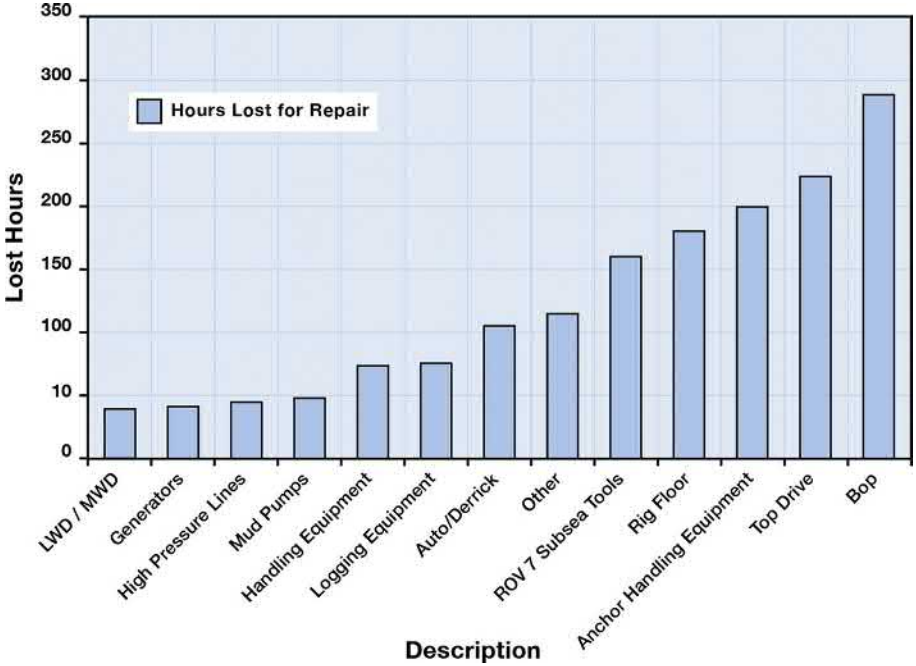


FIG. 12.17 Equipment: Wells loss time summary, West of Britain. *Source: Kingdom Drilling 1998.*

within these operating environments. So there is a double-edged technology sword to be better addressed and managed. What results should failure exist is that a far heftier price has to be paid in deepwater than a standard offshore norm. Quality assurance, control, reliability, robustness, and fit for purpose are all essential keys to successfully addressing equipment and associated systems failure-related issues.

It is also evaluated that the simplicity of equipment, systems reliability, and robustness is a driving principle to future deepwater drilling rigs, equipment, and technology systems development particularly in the area of *tubular handling* that presents by far the greatest improvement opportunities (as there is far more pipe footage to trip and tubular handling on deepwater wells than anything else).

Anything that can achieve and deliver a more simplified man-machine and automotive process and flow improvement as essential to the SEE principles in these areas, benefits, and value adding gains to result. Where, 25 years later how far has the industry progressed in this respect? Further studies as demonstrated in recent 2016 offshore East Coast of Canada wells indicate not that far forward, if at all.

Case Study: First Deepwater Norway Wells Campaign, 1995–99

To close this section, Fig. 12.18 illustrates the Norwegian riserless challenges and results during initial 1996–99 deepwater well campaigns. A key lesson is that if key hazard/risks are not predicted and flagged prior to spudding wells, hefty riserless losses and failures evidently resulted.

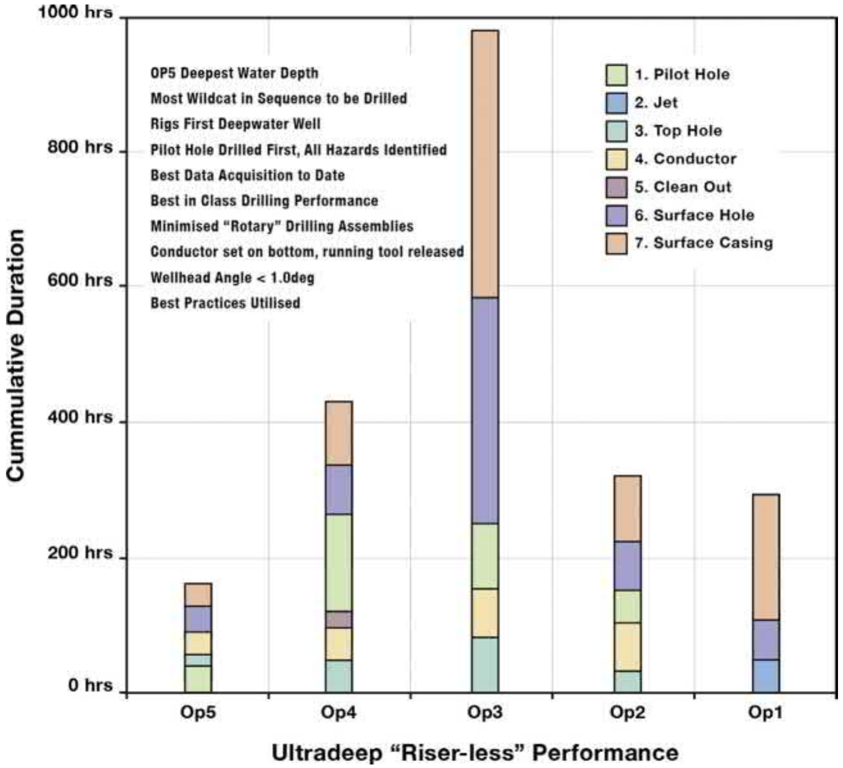


FIG. 12.18 Norwegian Deepwater 1995–98 "open" water drilling operations summary. *Source: Kingdom Drilling, SPE workshop presentation, Stavanger 2002.*

Operator 5 delivered a reversal in this trend with perhaps even more challenges required to be overcome, the well's project at outcomes and benefits desired.

What project 5 initiated to deliver improved results? Notably, in the riserless phases as shown in Fig. 12.18, is captured within a journal paper that outlined the very different project management approach taken from start to end.

SPECIFIC REFERENCES

Aird, Peter. Deepwater Drilling Best Practices documents compiled for various projects from 1996–2018. Kingdom Drilling Services Ltd. http://www.kingdomdrilling.co.uk/default.aspx

Akers, T.J., 2008. Jetting of structural casing in deepwater environments: Job design and operational practices. Society of Petroleum Engineers. SPE 102378. San Antonio, Texas.

Chevron/BP Drilling Training Alliance relevant chapters. Floating Drilling Manual 2007.

Chevron/BP Drilling Training Alliance relevant chapters. Deepwater Drilling Manual 2007.

Evans, T.G, Feyereisen, S., Rheaume, G., 2002. Axial capacities of jetted well conductors in Angola. 5th Offshore Site Investigation and Geotechnics – Diversity and Sustainability. Society for Underwater Technology (SUT), London.

IADC (International Association of Drilling Contractors). Floating Drilling & Equipment Operations, 1st Edition, 2015.

Internal Report AFP drilling review. 1995. Peter Aird for Dresser Drilling & Production services.

Stene, Flemming (Norske Hydro) and Peter Aird (Kingdom Drilling Services Ltd.) Frontier Explorations Drilling. Society of Petroleum Engineers. SPE 59810. New Orleans, February, 2000.

Jeanjean, P., 2002. Innovative design method for deepwater surface casings. Society of Petroleum Engineers. SPE 77357, San Antonio, Texas

Thorogood, J.L., Jackson, M.D., Thorsen, O.H., 2000. Delivering world class exploration drilling – Integration of design, planning and execution. BP Amoco Norge UA. IADC/SPE, 59205, February 2000.

CHAPTER

13

Deepwater Riserless Best Practice

Note: Chapters are *not definitive*. Regional knowledge and experience shall always be used to assure best well practices are applied.

TOP AND SURFACE HOLE OBJECTIVES

The riserless objectives shall be executed in accordance with *SEE* principles and assure that primary well control is maintained throughout all activities conducted to deliver program, design, engineering, and operating value as planned. Pilot-hole top and surface-hole program objectives generally considered are:

Pilot-Hole Objective

1. Gather data to detect, identify, evaluate, plan, prevent, and mitigate unknown hazards and operational risks that exist.
2. Obtain geological, pore, and fracture pressure data to make more informed and value addition decisions.
3. Determine and evaluate optimal design, engineering, and operating requirements.

Note: For wildcat or important exploration and/or appraisal wells, acquiring pressure and logging while drilling (PWD/LWD) data is often a key well objective to be obtained from the pilot-hole.

Top and Surface Hole Objective

1. Maintain verticality and optimal cylindrical wellbore quality.
2. Provide structural integrity to trip, run, install, and cement all structural casing strings.
3. Afford sufficient shoe strength to safely drill the first intermediate section to its required depth.
4. Incur no operational damage, failure loss, or harm to the environment.

Note: Optimal well delivery requires a "*in gauge*" symmetrical and cylindrical wellbore that is readily tripped, cased run, and cemented at ALARP operational loss.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00013-2

HAZARDS AND RISKS

Hazards and risks *drilling shallow wellbore intervals* (as illustrated in Table 13.1) is the focus of this section in regards to the key and critical issues that can cause, affect, and impact deepwater operational methods the most. Best practices considered to prevent and mitigate detrimental hazard effects as opposed to remedial cures are presented in this chapter.

Prior to drilling wells, a full hazard, risk and uncertainty assessment, and required sensitivity analysis is warranted. Practical steps then are taken to prevent and limit all operating loss that should include an appraisal process method of how to model, monitor and control in situ wellbore stress behavior for all operations conducted. That is through gathering the critical well's data and evident information provided to derive formation (sand) strengths, shallow XLOT, LOT data, formation pore pressure, and seismic properties of any pressured package.

From Table 13.1, it is concluded that each interval unit is individual risked, assessed through the use of fluid mechanics, petrophysics, geoscience, geomechanics, pressure evaluation, and material (formation) strength and stress regime factors. Note: "Risk" classifications (where interpretation can be spurious) were presented in Chapter 2, p. 11.

TABLE 13.1 Illustrative Deepwater Preshallow Hazard and Risk Assessment

Horizon	Depth Below Sea Floor	Unit	Seismic Stratigraphic Interpretation	Lithology	Risk Assigned
Seafloor	0 ft,	Seawater gradient and pressure based on water depth			
A	0–199 ft,	I	Hemipelagic muds	Clay	
A1	199–429 ft,	II	Debris flows and slumped turbidite features	Clay, silt	
B	429–479 ft,	III	Sand rich basin floor, fan turbidites	Sand, clay and sily	Low
B sand top	479–1106 ft,	IV upper	Slumped turbidites	Clay silt and sand	Negligible
B sand base	1106–1196 ft,	IV a	Turbidite channel fill	Sand	Medium
C	1196–1556 ft,	IV lower	Slumped turbidites	Clay silt and sand	Negligible
H	1556–2002 ft,	V	Slumped and channeled turbidites	Clay silt and marl	
H1	2002–2362 ft,	VI	Midslope turbidites	Clay and marl	
Base of study	2362–3600 ft,	VII	Deep marine turbidites	Sand, shale and silt	Negligible

Source: Kingdom Drilling Reconstruction 2018.

Hazard Operating Strategies

General strategies to prevent key shallow hazard problems resulting can be classed in order as:

1. Avoid the hazard
2. Set casing above the hazard
3. Tag the hazard
4. Maintain primary well control through the hazards
5. Train personnel with the wider skills set demanded.

The key issue in respect to a worst case *permeable porous pressurized hazardous interval* is that these are generally the *weakest fracture zones*. Clay intervals offer stronger fracture strengths and why casing shoes are preferred to be set there. Setting casing above hazard intervals can leave weaker formations interval exposed below that still remain to be drilled cased and cemented. Setting below does isolate the section and in specific cases can afford a safer and lower risk of setting casing shoes deeper. The key determinant is factoring that primary well control *risk*, *confidence*, or *uncertainly* shall not be compromised through all well activities, not only drilling but often more importantly during cementing. In all cases, contingent options and having as a minimum a plan B are recommended.

Avoid Well-Developed Hazards

Sites shall be avoided if the risk probability of shallow hazards is high. In some areas, location can be moved a short distance to miss anomalies without program compromise.

Set Casing Above the Hazard

When geopressured hazards cannot be avoided by well placement, and operating methods to maintain primary well control is impracticable. Casing must be set above the zone, another section drilled, a contingent casing set and/or the riser run.

Tag the Hazard

If there is a risk of overpressure, it may be necessary to set casing as safe operating margins cannot be met. If it is safe and practicable to weigh up and tag the interval prior to penetrating, this can also be a viable option.

Maintain Primary Control Within the Hazard

When ALARP decisions cannot be readily met, the best risked-based option may be to set the surface casing through the hazard interval(s). This should be qualitatively and quantitatively surmised as the right thing to do.

Training of Personnel

Deepwater hazards events may not fit with traditional well bore influxes and require more specific training development and skills response that is usually aligned to an emergency response plan. To assure best practices result personnel must be educated and skilled to understand all central aspects of shallow hazards, with emergency response assured to be well rehearsed by all.

Regulations & Vessel Aspects

Operators and contractors must take measures to assure that hazards are managed at ALARP levels. Regulations often supplement best-practice industry standards, rules, and guidelines in terms of how hazards and risks are mitigated, e.g.,

1. Use of overbalance (mud) as a barrier against unintentional outflow.
2. Use of a suitably engineered subsea riserless (dual gradient (DGD) or managed pressure drilling (MPD) methods) or a *subsea seabed diverter system* to minimize the well operational safety risks of a possible riserless or underground blowout.

Other important subjects to consider also viewed as:

3. Requirements of control system for activation and release of subsea systems
4. Pilot-hole benefits, pros and cons
5. Operating best practices used/applied in conjunction with pressure and logging drilling equipment measurement
6. Use and application of dual gradient and managed pressure drilling, technologies.

The essentials offshore are that blowouts (notably shallow gas in shallower waters) have resulted in more mobile offshore drilling units to be lost, with consequential loss of lives, than any other type of shallow well control accidental loss time events. In deepwater, due to the more favorable length and distance of the drilling vessel to the seafloor in conjunction with the metocean conditions and facts presented, shallow gas risks to the installation and persons on board are significantly less. The questionable condition, hazards, and risk aspects to address are the rig equipment, mooring, station keeping, and systems capability to safely move and whether emergency response plans are suitably in place.

Rig and well location selection for hazardous areas must account for:

1. Selection of a "safe" operating well location.
2. A well-engineered drilling program and well design that affords priority to maintain and assure primary well control.
3. Vessel and personnel capabilities, of best practice and emergency response compliance.
4. Rig equipment and systems all evidently work, are reliable with no identified risked items should a well site have to be abandoned immediately due to a hazardous event.

Shallow (Water) Flow

Types of shallow flows include *induced fractures, induced storage, geopressured* formations (sands), and the *transmission of geopressure* formations through cement channels. Geopressured intervals can originate from several different mechanisms the most common is through ***rapid sedimentation***.

Note: The most common fluid flow events that result in these phases are in fact through induced fractures resulting via inappropriate practices or misunderstandings that arise.

Major shallow flow events are well documented to highlight the magnitude and extent of lost time and associated consequential problems that can result. Prime examples are:

A shallow water flow resulted during a deepwater well operational phase where the operator lost a complete development template site consisting of several wells at significant capital, operating and *production expenditure loss. Deepwater studies from the Gulf of Mexico in the late 1990s also estimated an average of $1.6 million was lost per well due to shallow water flows.*

To prevent these problems, prevention and mitigating areas to consider are:

1. Assessment, site-specific surveys, and added planning for the purposes of identifying shallow geopressured sands and safely locating wells to prior to drilling.
2. The utilization of measurement and pressure while drilling tools, personnel.
3. The requirement to drill, trip, run, install and cement more surface casing strings.
4. Pilot holes when/as required.
5. More time-consuming and more controlled "best practices" demanded.
6. The use of specialized drilling, operating, and cementing methods.
7. The use of a marine riser to drill some specific deeper shallow sections.
8. Alternative riserless well operating methods and technologies.

Note: In some regions dependent upon subsurface hazards presented. Accurately predicted and modeled minor flows in exploration or appraisal can be tolerated. *E.g., small thin lenses are commonly drilled are readily managed, controlled and allowed to flow to deplete in a few hours with normal drilling resuming thereafter.* Minor flows in *development wells* on the other hand must be fully *risked assessed.*

Shallow Flow Operating Methods

Best Practice techniques and methods to comply with and assure are:

1. Provide information about the quality and position of shallow flow porous, permeable formation intervals,
2. Identify an appropriate casing point in relation to a shallow flow zone,
3. Eliminate/minimize charging normally pressured formation sands, silts or porous, permeable zones,
4. Check for shallow flow, and
5. Provide mud properties for cementing.

The desired outcome is to minimize a shallow hazard event occurrence through assuring that primary control is maintained throughout. Best practices are to be applied through evaluating all aspects of:

1. Geophysical prediction
2. Pore pressure and fracture pressure prediction
3. Drilling and cementing techniques
4. Mechanical shut off devices
5. External casing packers
6. Subsea-diverter devices
7. Pump and dump and more advanced pressure management (e.g. DGD, MPD) methods
8. Casing while drilling
9. Chemical alternatives.

Note: Details of these practices are well referenced within current industry standards, journal papers, and third-party publications. Items 1–4 for example are outlined in the IADC Deepwater well control guidelines, 1998, 1st Edition; Chapter 1 Well planning, Section 1.2, Shallow water flow guidelines, pp. 1–33 to 1–65.

Remedial Shallow Flow Concerns

To close, it is generally difficult to dynamically kill and stop a shallow hazard flow once unloaded. Pressure Identification and understanding of the flow interval and mechanism that drive best practices to prohibit and detect flow early is paramount. If the precise depth cannot be determined to prevent, mitigate and stop the flow. Or if flow has later in the well cycle resulted behind casing, due to a failed cement job. This can be extremely time consuming, costly, and highly problematical.

Once flow has stopped, operations that follow, casing and cement must be suitably placed to set, and seal the annulus zone for the expected life of well. This cementing can be just as if not more challenging than the standard norm. Providing application for designer cements that now exist, e.g., foam and light weight mixtures to be used when greater risk and uncertainty exists to isolate shallow deepwater riserless drilled hazardous zones intervals that are regarded as difficult to cement.

Shallow Gas

Shallow gas can potentially be a hazardous risk-based event in specific deepwater environments. Realism must take precedence for all offshore emergency scenarios. Case histories disclose that, once a well has unloaded to gas, there is a lower probability to recover primary well control, before the well may collapse at costly remediation expense.

To prevent shallow gas escalation, the operator shall construct with the drilling contractor realistic emergency procedures that work inherently and in conjunction with early flow detection. Offshore operating best practice must account and contemplate to prevent a shallow gas event. In addition, prespud meetings, drills, etc. should be authorized and conducted to enforce emergency procedures are known, understood, and implemented, and assurances taken that emergency equipment is working and reliable.

Shallow Gas Defined

Shallow gas is defined as biogenic (methane gas) resulting from (namely, sand) prone intervals encountered at contained depths below the seafloor where fracture gradients are lower and where kicks cannot be controlled through conventional BOP shut in techniques.

Shallow Gas Origins

Generalized origins of offshore shallow gas are:

1. Trapped accumulations can exist in "*Normal*" or "*Abnormal*" pressure regimes.
2. Accumulations exist in varying quantities, pressures, and in formations with different porosities and permeabilities.

Notes: No matter the conditions, shallow gas is *ALWAYS* to be treated with caution.

Shallow Gas Interpretation

Shallow gas interpretation derived from seismic data and involves the accumulation of all predictive evidence. The more anomalous the seismic indicators of gas presence, raises the risk. Factors branding shallow gas areas as more difficult and operationally challenged are:

1. Uncertain prognosis of the pressure at the top of the potential gas bearing zone(s), often due to the "gas effect" dictated by zone thickness and/or natural dip. *Pressures in exploration are unknown, until drilled, seismic surveys, generally cannot offer accurate interval section length or in situ gas (pressure charge) concentrations.*
2. Low formation fracture gradients that predominantly factor in shallow gas operations.
3. Uncertainty and associated risks because until drilled there is no certainty to what exists.

Best practices must be incorporated into delivery plans. Factors stated in the previous sections on shallow flow all similarly are to be applied to reduce operating risk loss and waste that can quickly result should wells unload through:

1. Minor hydrostatic head loss,
2. Errors in equivalent mud weight, mud weight and all other pressure management planning,
3. Uncontrolled rates of penetration, too low—well flows, too high—annulus can overload or enlarge, with further problems of collapse, bridging, or an underground blow out resulting.
4. Poor quality and reliability of kick detection shall only serve to increase risks.

Emphasis of detailed careful *planning* and compliant *best operating practice* must therefore be fully afforded throughout all well planning, execution, and delivery activities.

Shallow Gas Detection

Shallow gas detection falls into phases, of prior to and during well operations. Prior to well operations, seismic interpretation, site surveys and/or offset well reviews should be conducted. Contingency plans must assure how to penetrate each hazard interval identified and what optional outputs and outcomes must be fully accounted for.

All rig-site leaders and supervisors shall ensure during all operating activities that wellbore conditions are continually monitored with preventative methods and actions to be taken fully comprehended and understood. During operations detection would consist of:

1. Seabed monitoring by ROV via camera, and/or high-resolution sonar maintained at a safe distance from the well, to provide visual and constant monitoring support.
2. Obvious changes in drilling parameters (drilling break), detected at the drill floor.
3. Identifying immediate gas break out at seabed. (ROV sonar screen monitoring)

Upon detecting a shallow gas flow, secondary well control best-practice measures must be immediately initiated. The vessel then placed on immediate standby for potential well abandonment. Designated personnel shall implement shallow gas kill instructions as prepared for each wellbore horizon.

Case Study Shallow Gas Flow

Background to a deepwater shallow gas 12¼″ pilot-hole case study is presented as follows:

1. Well was sanctioned leaving a shorter than normal time to plan, organize, implement, and assure required risk controls were in place due to the evident facts that a pilot hole was planned.

2. Shallow hazard risk assignation was not prognosed, worked, nor identified in that much detail within the geological proposal or drilling program to the well site personnel.
3. Seismic slides reviewed at well site did raise several anomalous hazard and risk features at specific depth horizons that were conveyed to the drilling contractor and drillers on board and the management onshore. (There was a level of rig-site operational preparedness.)
4. Offset well had experienced shallow gas and used pump and dump to safely manage zones at deeper depths.

The 12¼″ pilot hole commenced at 03.52h as presented in Fig. 13.1 (left image). Eight hours later, at 11.53 a small gas flow was noted via the ROV sonar while making a drilling stand connection. Fig. 13.1 (right image) present the flow 4min into making the connection, where at 11.57h, gas flow was noted to be increasing. *Note*: No inference or indication of flow had resulted during lead up drilling to this indicating flow zone pressure was somewhere between hydrostatic and maximum (PWD) pressure readings noted while drilling, i.e., 8.6 – 8.8+ ppg (1031–1054kg/m^3) EMW. During making the connection and with the loss of pumps off annular frictional pressure afforded the physical and evident mechanisms for the well to flow.

On resuming circulation and drilling, gas flow quickly vanquished as observed via downhole PWD and ROV sonar. Primary well control then readily maintained through assuring controlled drilling ROP and cuttings in the wellbore annulus exceeded the anomaly zone(s) pore pressure. Prior to and during connections an additional weighted pill was spotted within the wellbore annulus to assure primary well control was maintained. Note: This practice is in fact a very simple form of dual gradient drilling.

No gas flow was thereafter noted on connections in the several hours of more cautious drilling that proceeded. Visual observation of the well at 13.57 after a connection did show a slight flow of gas from the well as shown in Fig. 13.2.

At 18.30h it is suspected that a new formation interval was penetrated at a higher than normal pressure to immediately flow. Initial flow was not detected until the company supervisor reacted to the fact the pressure while drilling equivalent mud weight was evidently noted to be taking a nosedive trend over a few minute time period. The person on the drill floor then immediately instructed to pump the prepared kill mud as per the dynamic kill plan.

As this action was not initiated at the first sign of flow, in addition to the kill mud pumped at *operating drilling* rate, these two factors were likely insufficient to stop the gas zone unloading.

FIG. 13.1 Deepwater 12¼″ pilot hole to evaluate presence of shallow hazards. *Source: Kingdom Drilling training 2014.*

FIG. 13.2 Deepwater 12 ¼″ pilot hole to determine and evaluate the presence of shallow hazards. *Source: Kingdom Drilling training 2014.*

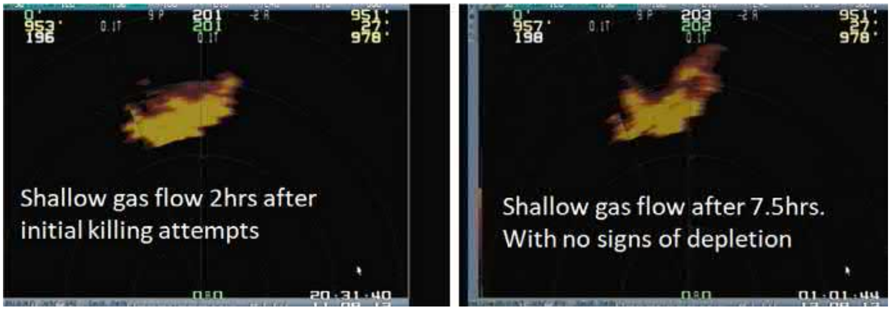


FIG. 13.3 Uncontrolled shallow gas flow from ROV sonar screen w.r.t 12¼″ pilot hole. *Source: Kingdom Drilling training 2014.*

What resulted is presented in Fig. 13.3, i.e., a fully unloaded shallow gas flow with a pressure while drilling, equivalent mud weight pressure of 6.6 ppg (791 kg/m^3) noted.

After taking a time out to reflect on the wellbore condition, and after discussions with the drilling contractor, onshore drilling manager and a well control specialist, a second dynamic kill was conducted at 04.00 a.m. consisting of pumping a 350-bbl (100 m^3) heavy-weighted 16 ppg pill (1917 kg/m^3) and dynamically chasing this at *maximum pump rate practicable* with remaining 9.3 ppg (1114 kg/m^3) PAD mud.

What resulted was after pumping the heavier fluid and dynamically chasing this with the lighter fluid, the annular pressure EMW was noted to constantly increase from the 6.6 ppg returning to 9.1 ppg (1091 kg/m^3) at 05.21 h (Fig. 13.4, lower right image) with the well evidently killed. The well was then later displaced to a 9.3 ppg (1114 kg/m^3) suspension mud, with the vessel moved to the main well location.

General comments noted from this event were:

1. MWD/LWD assemblies restrict flow rates to be pumped to effectively deliver the dynamic kill rates required. Contracts or agreement must be agreed beforehand that higher flow rates shall be initiated.
2. Shallow gas was a risk in this area as per geological, structural environments presented.

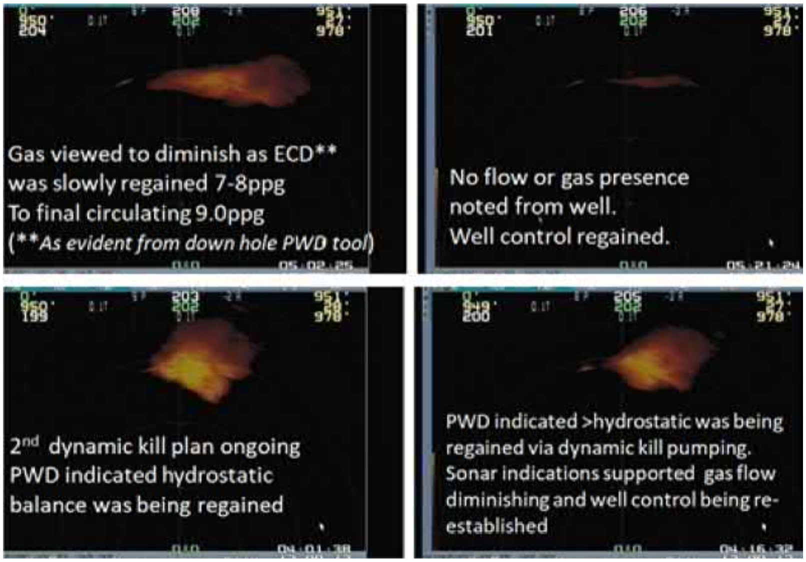


FIG. 13.4 2nd 12¼″ pilot hole, shallow gas dynamic kill. *Source: Kingdom Drilling training 2012.*

3. Sonar and pressure while drilling (PWD) proved and were evidently effective early warning tools to detect shallow gas. Drilling team must however react quickly and immediately if equivalent mud weight trends on a reducing pattern.
4. Kill and displacement mud weights, dynamic flow rates, etc. need to be better worked, modeled, and more fully understood by all prior to spudding future wells.

Note: The conductor and 26″ wellbore that followed on the main well, was successfully drilled, cased, and cemented with no shallow gas indications.

"Riserless" Stuck Pipe Prevention

There are few cases of stuck pipe in the riserless sections that are impossible to prevent. Avoidance resulting through more detailed planning preparation and organizational care prior to and during operating at the well site.

The Driller remains the primary person responsible during operations to prevent stuck pipe. Project teams must work to assure best-practiced operational plans and an effective fluid's strategy can deliver pristine cylindrically wellbores that can be drilled tripped, cased, and cemented with no stuck pipe and little operating loss or waste resulting.

Should problems exist, the key aspect must be that the rig team (as shown in Fig. 13.5) work to react quickly to solve what is evident within the wellbore operating situations and conditions to: do the right things to do and get things right first time. Appropriate corrective action is critical where time always plays a major factor to prevent loss.

The greater people comprehend and understand each specific issue situation and condition that can arise in deepwater, then the greater the probability that stuck pipe shall not result.

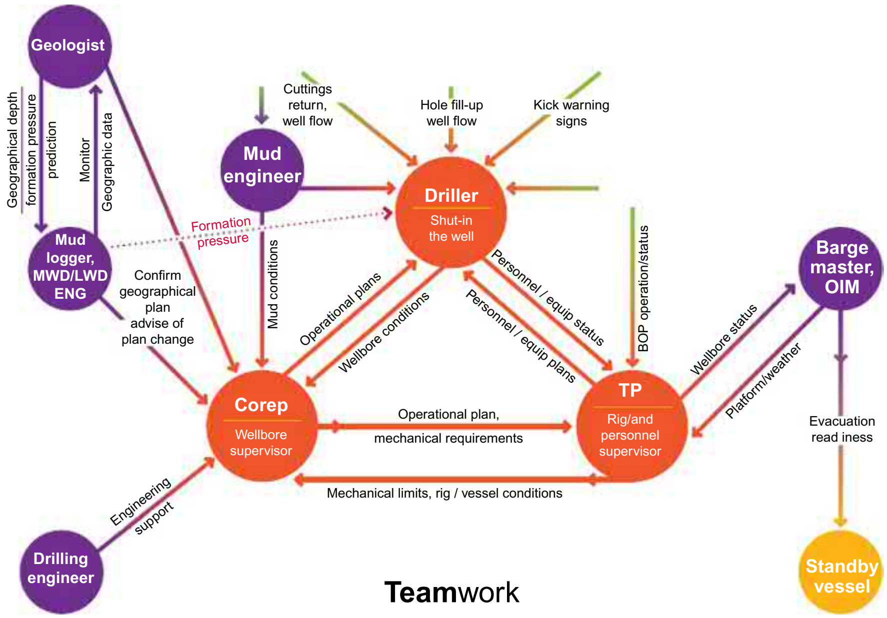
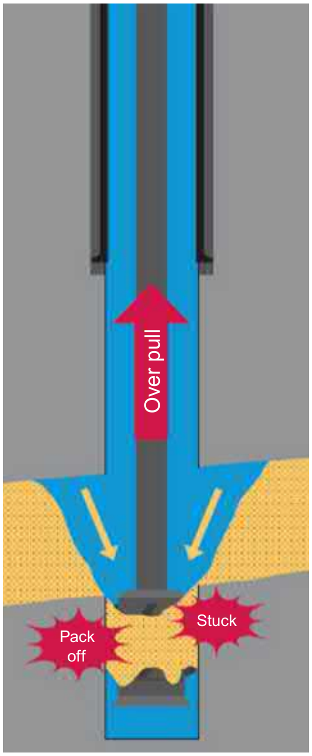


FIG. 13.5 Stuck pipe prevention team. *Source: Kingdom Drilling stuck pipe course 2015.*

General best practices to consider are:

1. Well design shall ensure that each wellbore section can be safely effectively and efficiently drilled with stuck pipe considered. Without compromise, contingent casing shoe depths shall be planned to case off troublesome formations that exist and used when/as needed.
2. Communicate effectively, plan-ahead, and listen to the wellbore constantly.
3. Maintain good mud. Careful consideration of the fluids used, sweeps, and mud systems weight and properties will be rewarded via pristine wellbore-operating conditions resulting.
4. Plan optimal bit/bottom hole assemblies (based on a run what is needed principle)
5. Keep the drillstring moving at all times (avoid excessive circulation at one depth)
6. Avoid drilling faster than each wellbore section and interval (notably sand) can be cleaned.
7. Don't drill a wellbore that cannot be easily tripped, cased, and cemented. Deliver perfect in gauge cylinders to assure optimal outcome and benefits shall result.
8. Be aware of open-hole time for each section. Reduction reduces likeliness of stuck pipe.
9. Take early action when warning signs and indicators arise. There are always signs!
10. Implement corrective action and right first-time contingent plans AQAP (as quickly as practicable).

Deepwater riserless wellbore hazards, risks, and potential stuck pipe scenarios that can result are presented with causes, warnings, indications, first actions, and prevention as shown in Figs. 13.6–13.8.



Cause:
- Little or no filter cake.
- Unbounded formation (sand, pea gravel, etc.) cannot be supported by hydrostatic overbalance.
- Sand/pea gravel falls into the hole and packs-off the drill string.

Warning:
- Likely to occur as the formation is drilled.
- Seepage loss likely.
- Increase torque & drag pump pressure fluctuations.
- Hole fill on connections & trips.
- Shaker and desander overload.

Indications:
- Generally occurs in surface hole.
- Can occur while drilling or tripping.
- Sudden pack-off without warning.
- Circulation impossible.

First action:
- Apply low pump pressure 200–400 pain.
- Jar down with maximum trip load, apply torque with caution.

Preventive action:
- Control fluid loss to provide an adequate filter cake.
- Control drill suspected zone.
- Use high vis sweeps.
- Spot a gel pill before pooh.
- Minimize trip speed.

FIG. 13.6 Common deepwater stuck pipe scenarios (*unconsolidated formations*) in the riserless sections. *Source: Kingdom Drilling 2014.*

Rig Site "Stuck Pipe" Best-Practice Precautions

EXCESSIVE DRAG

The primary reason for excessive drag deteriorating to stuck pipe in deepwater is due to *Improper practices, Excessive Over pull, Or Set Down Loads Applied*. Excessive loads to be applied only if all reasonable attempts to work the pipe have failed. In abnormal drag situations result, the rule is being patient. Time spent conditioning the wellbore in often not to be considered wasteful, but insurance against greater loss potentially resulting.

EXAMPLE

On a trip out the Driller may be reluctant to break circulation and disturb the slug, or displacement mud in the riserless wellbore: However, it is often easier and less risky to reslug the pipe or displace the well than free pipe once stuck. Drillers must be fully aware and conversant in precisely what to do if the riserless wellbore deteriorate, excess drag, or other unexpected problems are noted. If in doubt, simply ASK at the first signs of problems, the Operator's Company Representatives and Senior Toolpushers must be informed immediately.

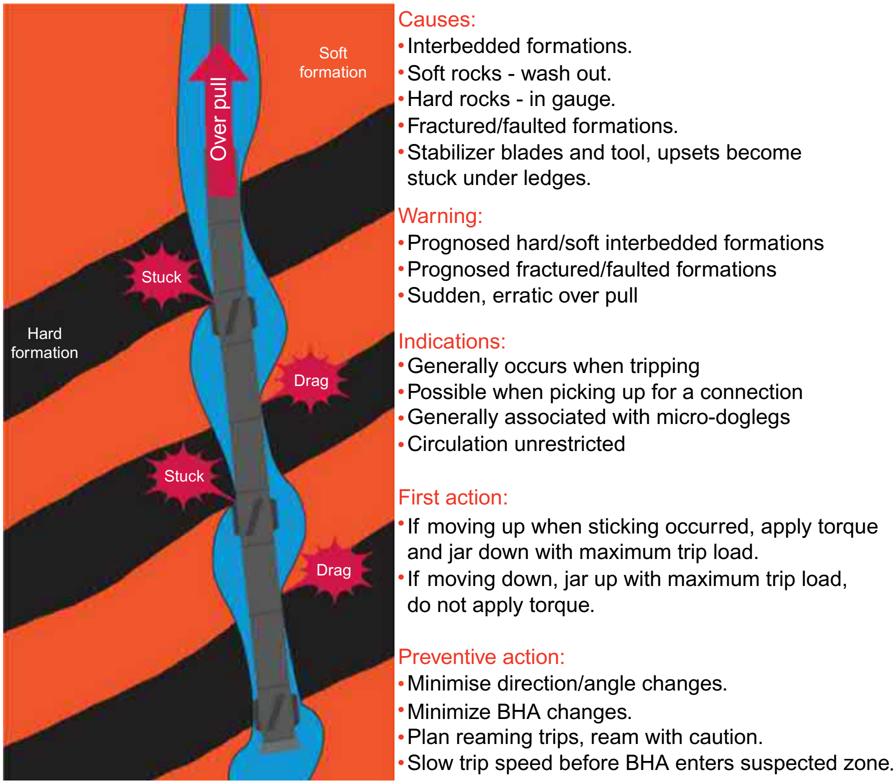


FIG. 13.7 Common deepwater stuck pipe scenarios (*ledges*) in the riserless sections. *Source: Kingdom Drilling 2014.*

Unavoidable Deepwater Riserless Hazards

Should the vessel be unable to *locate to the safest location* during well's development drilling: The riserless operational challenges are to negotiate all shallow hazard zones as illustrated in Figs. 13.9–13.11 considering the following best-practice methods, e.g.:

1. Conduct all riserless operations maintaining primary well control at all times, with fluid returns discharged to the sea floor.
2. Each surface string shall be set as deep as is safely practicable to do so.
3. Final surface casing string, i.e., 16″ as illustrated in Fig. 13.9, shall be set deep enough to afford drilling the next section to required intermediate casing setting depth with a weighted fluid following subsea BOP's installation.
4. Drilling with pump and dump (PAD) mud can be used as a basic dual gradient drilling (DGD) method to safely optimize well design and operating limits as outlined in this chapter.

Essential riserless drilling options are illustrated in Figs. 13.9–13.11.

Note: If mud recovery is practicable and feasible (note: this technology method has water depth limitations), this shall be considered as a preferred method of choice to deliver benefits to prevent and mitigate operating hazards and risks that exist.

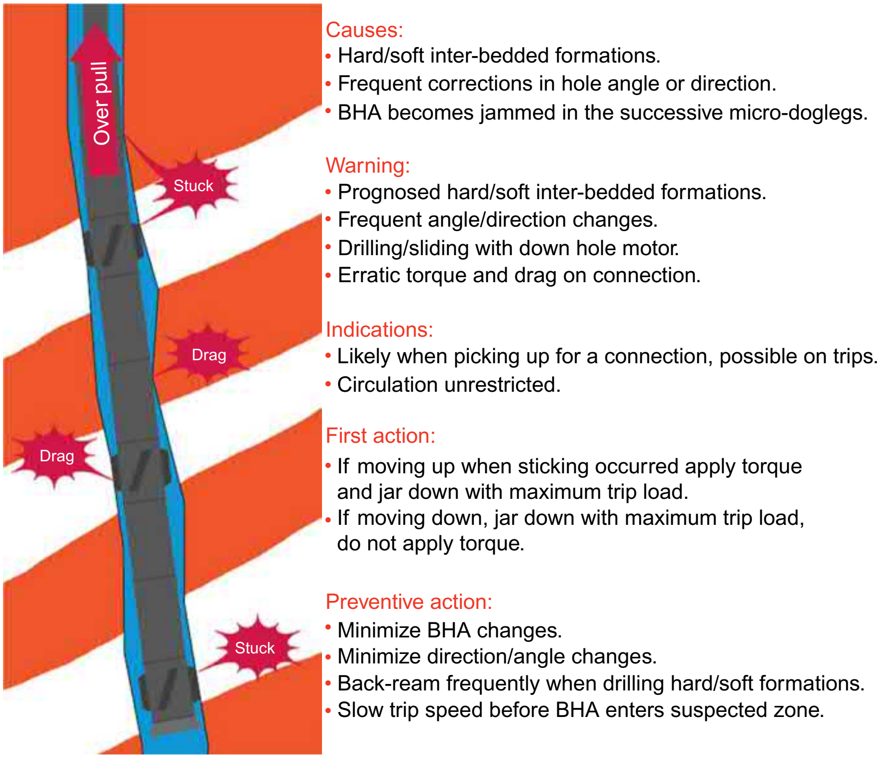


FIG. 13.8 Common deepwater stuck pipe scenarios (*micro-doglegs*) that can result in the riserless sections. *Source Kingdom Drilling Training 2014.*

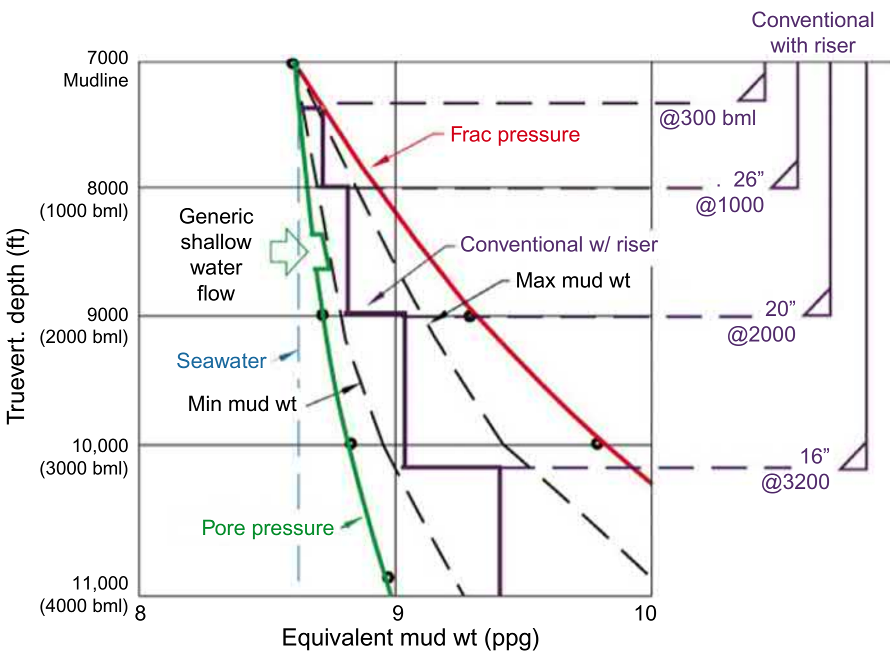


FIG. 13.9 Ultradeepwater riserless drilling (with shallow geohazard present). *Source: Kingdom Drilling training 2012.*

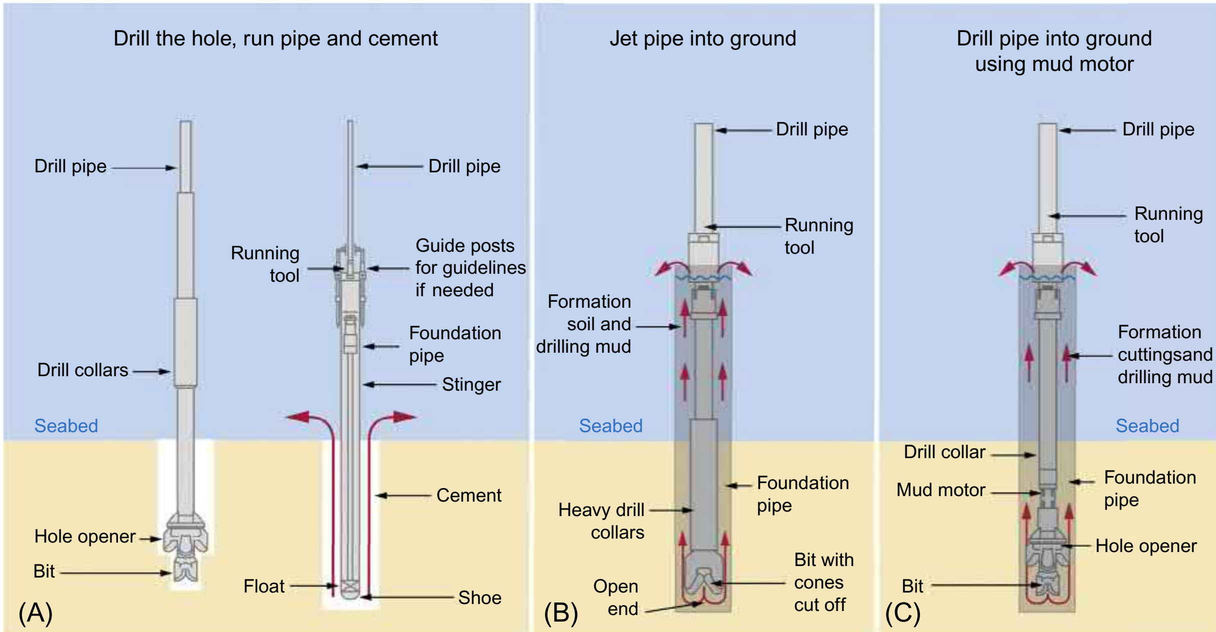


FIG. 13.10 Foundation and/or conductor drilling options in deepwater. *Source: Mark Childers.*

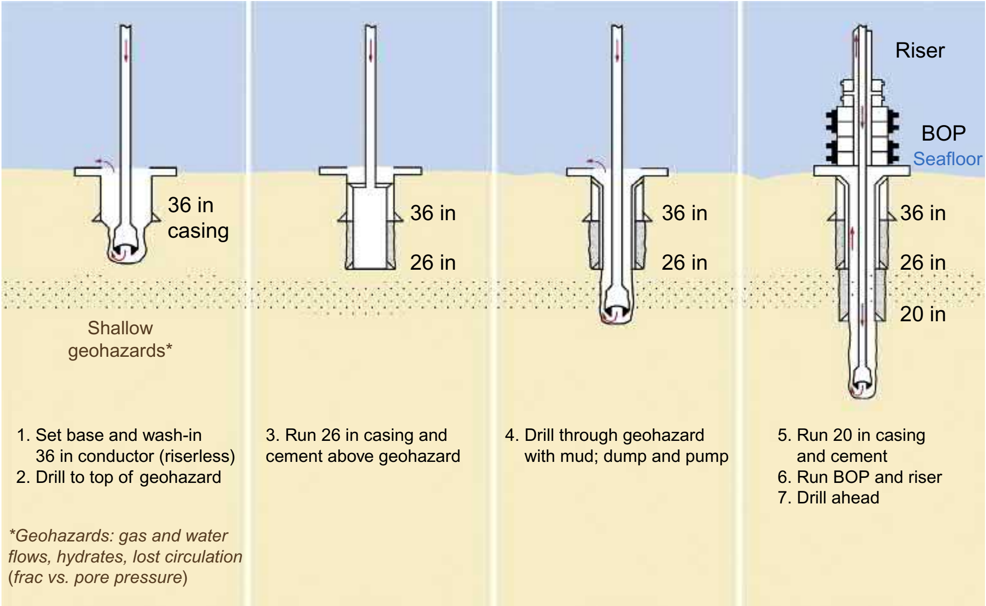


FIG. 13.11 Typical deepwater riserless sequence through a shallow hazard zone. *Source: Kingdom drilling training 2002.*

Penetration Test

In operating regions should poor seismic or no data exist, conductor failure events have often resulted. In certain areas, penetration tests are justified so that more informed 'data' driven decisions result to assure conductor length and depths are optimized and delivered loss and trouble free. Note: The purpose and intent of penetration tests is to evaluate the suitability of soil conditions and further establish formation characteristic differences over the depth interval required to jet the conductor pipe below the seafloor. The test data obtained are used to differentiate clay and nonclay (silt of sand intervals) by conducting a nonrotational drilling assembly penetration jetting test. *Example: One specific deepwater region conducts tests routinely due to historic conductor jetting failures when attempting to jet blind with no subsurface shallow wells data.*

Penetration test data obtained as illustrated in Fig. 13.12 is used to evaluate optimal conductor lengths required and assist best practice to employ in each well's specific case (Fig. 13.13).

A general guide to performing a penetration test is considered as follows:

1. Offset the rig a suitable safe distance from location at predetermined site.
2. RIH with a fairly stiff and rigid pilot-hole BHA, e.g. bit, D.C.'s (slick) on D.P.
3. Space out the string so bit is several meters below the seafloor on the first connection.
4. Establish water depth when tagging bottom. Penetrate until the first point of resistance (FPR) is obtained below the mud line, take note of FPR depth.
5. Use the ROV cameras to monitor tag.

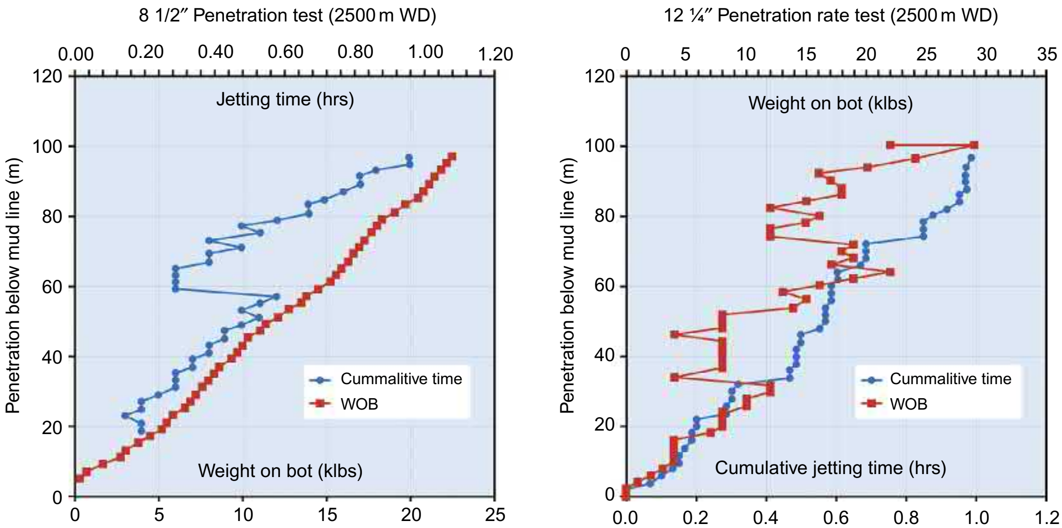


FIG. 13.12 Deepwater penetration tests examples. *Source: Kingdom Drilling training 2012.*

FIG. 13.13 ROV snapshot of a penetration test, in 1752 m water depth being and end 4 h, 45 min later. *Source: Kingdom Drilling training 2014.*

6. Engage mud pumps and jet the drilling string down without rotating following a slack of weight (SOW) chart as provided by the operator, to cover the required conductor length range required.
7. Penetrate to the required conductor structural jetting depth to be achieved.
8. If assembly can be successfully jetted in 2–4 h to the setting depth achieving using desired slack off weight (SOW), and obtaining the frictional resistance and trends desired. The casing is jetted and an optimal length determined.

Note: A slick or stabilized drilling BHA will react very differently to jetting a structural conductor much larger diameter string. Nevertheless, penetration test data and trends obtained have proved valuable should no subsurface data exist.

PILOT HOLES

The ROV will prepare the pilot hole and well location by presetting transponder and/or marker buoys, identify subsurface conditions, survey the area for debris and position the vehicle in a suitable location to monitor well continuously while drilling. A general best practice pilot hole should consider:

1. Pilot-hole assembly to run. Is a penetration test required?
2. Record the distance between seabed and rotary table, corrected to mean sea level. Record the drilling draft, water depth, and mean sea level.
3. Spud pilot hole, drilling with sea water, pumping high viscous pills when/as drilling formations operating condition and annular pressure dictate.
4. Take first survey once tool has penetrated below the mud line and/or after first stand drilled.
5. Maintain drilling parameters best suited to maintain wellbore verticality.
6. Control pump rates to best acquire data and not wash out the hole.
7. Once BHA is penetrated to a suitable depth and upon drilling ahead, establish a baseline equivalent mud weight density when cuttings are first anticipated at the seabed. Continuously monitor equivalent mud weight (EMW) and downhole pressure while drilling (PWD) readings for water/gas flow, instability or warning signs of solids loading.
8. Take inclination surveys as required to verify the section is vertical.
9. When at section depth, flow check, and circulate well clean.
10. Flow check and displace well with drilling mud.
11. Adhere to riser less operating guidelines as outlined in the previous section.
12. If drag is noted, apply stuck pipe best practices as presented in this chapter and consider pumping out of the wellbore to avoid swabbing tendencies (assure mud volumes are available for this).

Note: Follow *contingency guidelines* should a shallow flow(s), pressure or wellbore instability result.

FOUNDATION CONDUCTOR AND SURFACE CASING INSTALLATION

Jetting or drilling the conductor casing is generally the first critical part of the well program to deliver. Best installation practices for different soil types are:

1. *Very soft*
   a. Conductor may require a foundation, support method, e.g., conductor anchor node (CAN) or similar structural device.
2. *Soft to medium*
   a. Most suitable for jetting, no or shorter length foundation required.
3. *Medium to hard ground*
   a. Not suitable for jetting. Wellbore drilled and cemented.
   b. There may be a case for a temporary guide base to be considered.

Notes: Refer to Appendix 2. Deepwater shallow soil classification.

– For the majority of deepwater well's mud mats, and/or hydrate deflectors serve little purpose and are not required in the majority of applications used, as one suit rarely fits all.
– In specifics such as *slopes, river deltas, where were mass deposits exist* notably at required shallow depth below the seafloor, short self-penetrating foundation pipes or suitably designed and constructed conductor anchor node (CAN) may best-fit specifics and conditions required.

Jetting the Structural Casing

The concept of *jetting* is outlined in Chapter 8. Most of jetting configurations incorporate a drill-ahead tool integrated with the drilling and conductor wellhead housing assemblies as shown in Figs. 13.14–13.16 and Table 13.2. These are made as one unit and tripped on a suitable drilling string to above the seafloor. At the end of the jetting operational best-practice process conducted, the *skin friction* between the soil and conductor outer wall is required to develop an axial load resistance greater than the buoyant weight of the conductor. A few days later, the added strength should be built up to support the additional buoyed surface string and wellhead housing weight, prior to cementing. The intent of jetting and drilling ahead

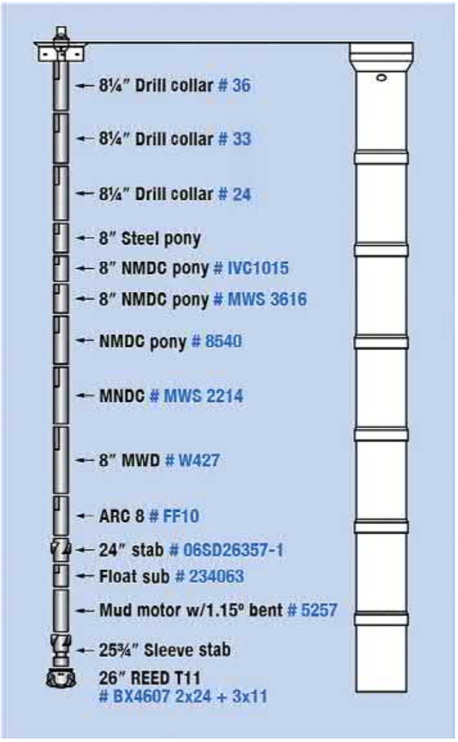


FIG. 13.14 Conductor/jetting assembly. *Source: Kingdom Drilling training, 2006.*

FIG. 13.15 Jetting a conductor in deepwater. *Source: Kingdom Drilling training 2014.*

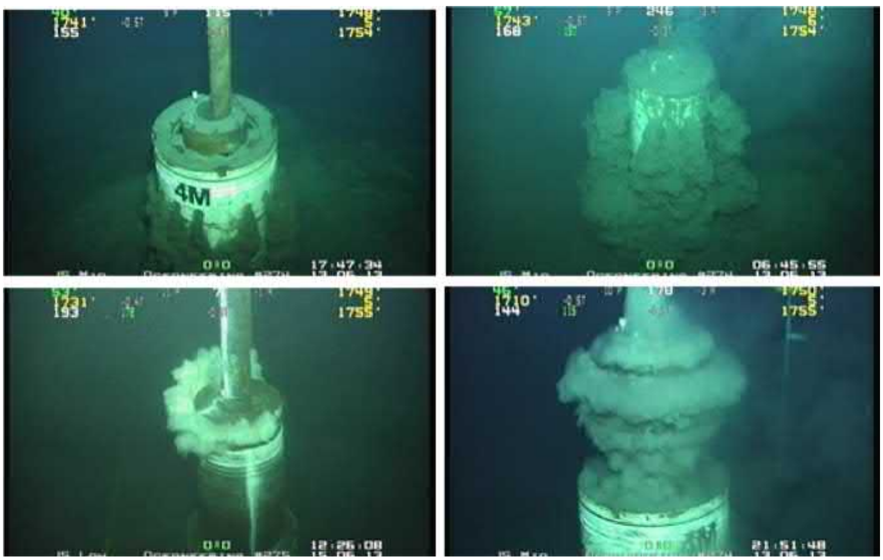


FIG. 13.16 Drilling ahead and releasing tool and pulling BHA at end of surface wellbore section drilling. *Source: Kingdom Drilling training 2014.*

TABLE 13.2 Conductor and Jetting BHA Data Sheet

36″ Conductor String with 36″ Low Pressure Housing													
Jt N°	**Description**	**Length Meters**	**Overall Length (M)**	**Bottom Conn.**	**Top Conn.**	**Grade**	**Pipe O.D.**	**Pipe I.D.**	**Conn. O.D.**	**Conn. I.D.**	**Wt (lb/ft)**	**Cum. Weight (lb)**	**Bouyant Weight (lb)**
A	35″ WH Housing	10.49	10.49	RL-4RB	RL-4RB	X-52	36.00	33.00	36.00	32	552	18999	16515
1	36″ Inter Joint	12.33	22.32	RL-4RB	RL-4RB	X-52	36.00	33.00	36.00	32	552	41330	35926
2	36″ Inter Joint	1234	35.16	RL-4RB	RL-4RB	X-52	36.00	33.00	36 00	32	552	63679	55354
3	36″ Inter Joint	12.32	47.48	RL-4RB	RL-4RB	X-52	36.00	33.00	36 00	32	552	85992	74750
4	36″ Inter Joint	1229	59.77	RL-4RB	RL-4RB	X-52	36.00	33.00	36.00	32	552	108250	94098
5	36″ Inter Joint	12.24	72.01	RL-4RB	RL-4RB	X-52	36.00	33.00	36.00	32	552	130418	113368
6	36″ Inter Joint	11.96	83.97	RL-4RB	RL-4RB	X-52	36.00	33.00	36.00	32	552	152079	132197
9	Cut off joint	12.02	95.99	Cut	RL-4RB	X-55	36.00	33.00	36.00	32	552	173849	151121

Item	**Tool Description**	**Serial Numbers**	**Length (M)**	**Length (Feet)**	**Overall Length (Ml**	**Overall Length (Feet)**	**Box**	**Pin**	**O.D. (in)**	**I.D. (in)**
1	26″ Bit		0.56	1.84	0.56	1.84		7 5/8″ Reg	26	
2	Motor	10114455	10.93	35.86	11.49	37.70	7 5/8″ Reg	7 5/8″ Reg	9 1/2	
3	9-1/2″ DC		9.36	30.71	20.85	68.41	7 5/8″ Reg	7 5/8″ Reg	9 1/2	3 1/16
4	26″ Stab	11838245	3.18	10.43	24.03	78.84	7 5/8″ Reg	7 5/8″ Reg	26	3 1/16
5	9-1/2″ DC		9.27	30.41	33.30	109.26	7 5/8″ Reg	7 5/8″ Reg	9 1/2	2 13/16
6	XO -Totco		1.10	3.61	34.40	112.87	7 5/8″ Reg	7 5/8″ Reg	8	2 13/16
7	4 x 8″ DC		37.86	124.22	72.26	237.09	6 5/8″ Reg	6 5/8″ Reg	8	2 13/16
8	8″ Jar	PN411-G- 63-003	6.92	22.70	79.18	259.79	6 5/8″ Reg	6 5/8″ Reg	8 1/5	2 1/2
9	8″ DC		9.46	31.04	88.64	290.83	6 5/8″ Reg	6 5/8″ Reg	8	2 13/16
10	36″ CADA Below		2.09	6.86	90.73	297.69	6 5/8″ Reg	6-5/8″ Reg	33	2 13/16
11	36″ CADA Above		0.66	2.17	91.39	299.85	6 5/8″ Reg	6 5/8″ Reg	33	2 13/16
12	4×8″ DC		37.87	124.25	129.26	424.10	6 5/8″ Reg	6 5/8″ Reg	8	2 13/16
13	XO		1.00	3.28	130.26	427.38	6 5/8″ Reg	5 7/8 XT 57	8 1/4	2 4/5
14	16x5-7/8″ HWDO		140.55	461.14	270.81	888.53	5 7/8 XT 57	5 7/8 XT 57	5 7/8	4 1/16

Source: Kingdom Drilling training 2014.

simply can save significant rig time and operating cost versus conventional methods.

Notes: Often overlooked, the drilling bit space-out and the nozzles selected are important to deliver and assure optimal jetting delivery.

– The use of externally flush connectors can additionally improve the end skin friction results developed as less soil is disturbed. This may be a key factor if soil jetting-ability is a risked issue in an area.
– Externally upset connectors shall disturb the formation far more and reduce skin friction far greater at the tube/soil interface. Too large upset connectors can additionally prohibit pipe penetration if more compacted soils exist.
– Pipe can also if improperly planned and designed reach *refusal* too early. A long and dangerous moment arm could now exist with wellhead protruding too high above the sea floor notably if pipe had to be worked. Note: Reaching refusal and stuck conductor pipe prior to reaching planned depth are possible disadvantages and hazards and risks of jetting.
– Broaching is another risk that can result when pumped returns are diverted externally out-with the conductor shoe casing versus returns transporting up and internally inside.
– Should broaching result around the: OD of the conductor shoe. Slumping risk is further increased as a result of poor frictional skin support and/or a weak incompetent shoe that can result.

Jetting Guidelines

Jetting as illustrated in Figs. 13.15–13.18 that follow and guidelines presented are more comprehensively covered in journal and industry-best practice papers and articles readily and easily resourced.

Generic jetting and associated operational best practices to consider are summarized as:

1. Very soft to soft jetting sequences require the bit slightly below the shoe.
2. Soft to medium sequences (siltier sandier clay soils) the bit is placed just inside the shoe.
3. Tag seafloor and record locations coordinates. Report the first point of resistance (FPR) water depth, RTE, and operating draft corrected for tide and vessel offset.
4. Apply string slack off weight (SOW) from the FPR noted permit the pipe to self-penetrate of the vertically downward at a feed off rate until a resistance trend is seen to increase.
5. Stage up pumps to deliver required jet velocity that enables optimal jetting to result. Exercise caution for first joint(s) jetted to avoid broaching if unfavorable formations exist.
6. Clay returns are visible via ROV, exiting the flow by ports in the conductor wellhead housing.
7. After initial penetration, monitor skin friction trends and follow the SOW plan.
8. Increase pump speed to optimal jetting velocities once penetration and SOW trends are well established and meeting considered best practice.
9. Monitor jetting returns continually with the ROV to insure returns are always flowing from inside the conductor casing and out through the conductor LPWHH ports.
10. Space out string to assure an optimal final run in length to desired setting depth. This enables a maximum skin friction build-up at optimal SOW. Driller may have to feed pipe faster and change parameters to meet desired results.

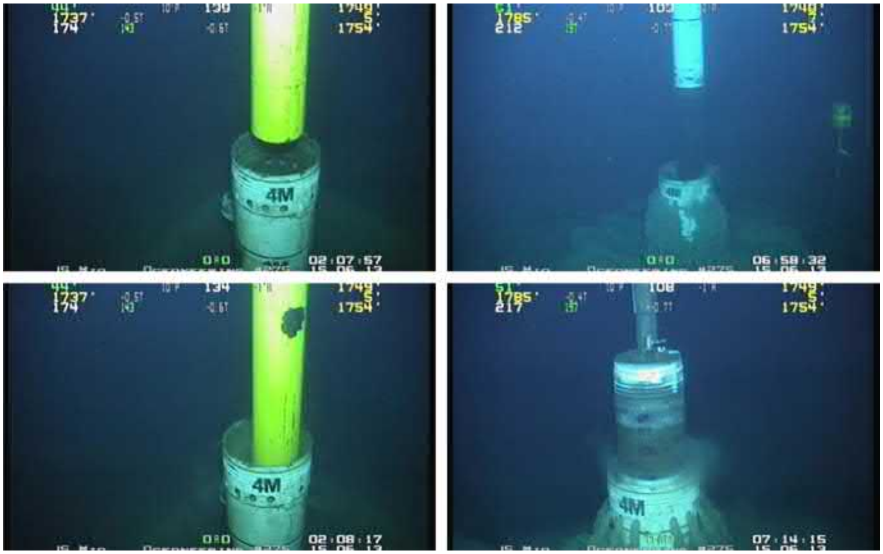


FIG. 13.17 Running and landing and cementing surface casing string. *Source: Kingdom Drilling Training 2014.*

FIG. 13.18 Deepwater Conductor jetting failures. *Source: Kingdom Drilling training 2014.*

11. Soaking time is decided based on final SOW. In some cases, no soaking is needed. If skin friction is less than required, a soak period is evaluated.
12. If very low SOW results, quickly assess if conductor is to be pulled and a respud required.
13. After drill-ahead tool is released (Ref. Fig. 13.16) exercise caution until the drilling assembly stabilizers are well clear of the conductor shoe, i.e., prior to staging up and optimizing drilling parameters.
14. Should nonclay sequences exist, assure a suitable sweeps strategy is in place and applied.

Problems and Solutions for Jetting

Problems arising and potential solutions to consider during jetting are:

1. *Conductor wellhead angle is greater than 1 degree*: Pull the conductor free and re-establish verticality to <1 degree.
2. *Cannot achieve required penetration or slack off weight required*: Retrieve the complete jetting assembly. Consider more weight in the drilling assembly and/or shorten the conductor length. If jetting is again unsuccessful, conventionally drill and cement the casing.
3. *Insufficient skin friction obtained to support surface string weight upon running and landing surface casing*: Support both casing strings with landing string while cementing and continue support until the cement until cement around the surface casing sets.
4. *Lose returns while jetting*: Reduce the pump speed in attempt to regain returns. If this is unsuccessful pull the assembly, reposition the jet head farther from shoe, and begin again.

DRILLING AND CEMENTING STRUCTURAL CASINGS

Drilling the Conductor Wellbore

The conductor phase is expected to be drilled and tripped in one pass. Stiffness and rigidity of the BHA and other best practices are to be utilized to assure optimal verticality and trouble-free operations result:

1. A staged hole-opening assembly is premade and sent to the rig with a handling sub, to save handling time.
2. In some areas large drill bits and a stiff, rigid stabilized BHA is preferred.
3. A nonported float valve is run in all BHAs.
4. Run the drilling assembly and drillstring to above seafloor filling string with seawater.
5. Position vessel and tag seabed (without pumping) at premarked well location. Monitoring and observing with the ROV, lower the BHA and drillstring to self-penetrate below the seafloor until the first point of resistance is observed (FPR).
6. Record and report, FPR, water depth, RTE and operating draft corrected for tide and vessel offset. Observe this operation with the ROV.
7. Slowly engage pumps and apply standard best practices, drill to a required depth to accommodate no of joints of conductor, wellhead housing, etc. as measured on deck. *Required depth to be confirmed with company drilling representative.*

Note: Typically a clear line can be painted on the drillstring joint to confirm the measured final drilled depth to the 36″ or 42″ hole-opener. This assures exact wellbore length is affirmed.

Note: *It is vitally important for all seabed conditions, to* prevent, mitigate, and avoid unnecessary wellbore washout at the seafloor. *Best practice viewed as common to start low and stage up pump rates and drilling parameters for the first shallow interval. Gradually increasing parameters over the first intervals length, based on each well's specifics*.

1. The section is drilled with sea water and viscous sweeps in size frequency and quantities required. E.g., *If clay is being drilled, few sweeps are needed if at all. For silt and particularly sand and larger particle sizes. Drilling rates must be controlled to limits evaluated with* larger and frequent sweeps *pumped to assure sediments are transported and removed from the wellbore to the seabed.*
2. Should extreme sand formation intervals exist, sweep volumes must be increased and if fill is further noted pills spotted on bottom and around BHA assured prior to connections.
3. *Critical rotary speeds*: Can be direct cause and effect of rough drilling observed at surface, or monitored downhole via vibration measurement tools. Drilling parameters must be quickly reacted to and changed to dampen prevent and reduce potential loss results.
4. *Surveying requirements*: Best practice if pipe is deemed vertical in the moonpool with no inclination risks evident as monitored by the driller and/or ROV at the seafloor. Drill until bit, hole-opener, and stabilizer are below seafloor, then confirm well inclination.

Notes: *MWD*/inclinometer survey readings due to distance behind bit, may not survey the wellbore. Spotting a viscous pill, may assist in obtaining satisfactory surveys.

5. If angle remains <1 degree, drill to TD taking surveys every stand and at sections total depth. Surveys to be consistently less than 1 degree.
6. If survey inclinations display >1.0 degree, discuss criticality with company representatives and discuss best practices to be applied to reduce angle.
7. *Total depth requirements*. Check and *confirm amount of hole drilled*.
8. *Circulate* the hole *clean and over displace* the wellbore with viscous displacement mud. Take a final off bottom TD, survey, and POOH to just below the seabed.
9. If no resistance or difficulties are observed during POOH, do not wiper trip section.

Wiper (intermediate check) *trip* only if EVIDENTLY necessary.

10. Best practice is to wait 1 h with BHA at seabed for the wellbore to stabilize.
11. RIH circulate, sweep with pills, note and clean out and any fill observed.
12. Redisplace the wellbore to viscous weighted mud with required excess.
13. Take off bottom TD survey.
14. POOH to run conductor.

Hole Marking

15. The wellbore throat is considered adequately marked with three marker buoys suitable provided and located for varying sets of seabed conditions that can exist. *Sufficient time should be taken to assure wellbore can readily located prior to pulling the BHA from the wellbore to the seafloor. Otherwise wellbores take time to be found.*

16. Buoys should be suitably weighted and tethered (generally 3–4 m in length so they can be viewed relative to wellhead housing positions), painted yellow and provided with clear identifiable marking, e.g., a triangle, circle, square to differentiate between each. One buoy, preferably two to be fitted with sonar reflectors and suitable tethered.
17. ROV should gather all data relative to buoy positions and ensure a location diagram is completed with well center that can be readily translated to the sonar screen. Note: The preference is for the ROV to remain on station until the conductor enters wellbore vs. as soon as the ROV moves, as accuracy of wellbore location *shall be less effective*

Drilling Surface Wellbore Sections

The surface casing sections are typically normally pressured formation interval sequences. Interbedded, unconsolidated sands, silts, oozes, and scree formation sequences can all be encountered below the seafloor in additions to clay formations that generally dominate. Close attention must be paid to wellbore pressure management, primary well control assurance, quality, cleaning, stability, ROP with all best practice steps taken to minimize the risk of difficulties, problems, and operating loss resulting.

More general drilling and operating guidelines for these sections can be found within via http://www.kingdomdrilling.co.uk/default.aspx where various deepwater well design, engineering, operational documents and case study files can be obtained and resourced. General best practices are:

1. Launch ROV as early as possible.
2. Establish wellbore verticality once penetration and depth achieved.
3. Drill section at max. ROP without compromising on verticality throughout.
4. Sweep wellbore with generous and frequent sweeps should nonclay conditions exist, e.g., in a worst-case massive sand sequence suitable fluids must be pumped to avoid wellbore difficulties resulting.
5. Maintain full pits of spud mud/viscous mud.
6. At TD overdisplace hole volume with mud by at least 50% prior to POOH.
7. *No resistance = No wiper trip required*.
8. Manage BHA components, e.g., If a 42″ hole opener is used, preplan how this is to be handled, made up and broken out or complete assembly laid down, from the drillfloor.
9. ACCURATELY establish hole position prior to pulling out of the wellbore.
10. Be aware, BHA critical rotary speeds may exist. *(longitudinal and torsional)* and are often coincidental with parameters used in top and surface holes.
11. If glacial drift anticipated (cobbles, boulders, etc.), run heavy duty tandem "boulder buster" assembly that has typically a 6-point hole opener and large drill collars, to result in a very stiff and rigid assembly to more assure and guarantee wellbore verticality.
12. Any 3rd-party additional tools recommended must be supported through evident data, value, and substance. Otherwise do not run these tools.
13. Apply best practices as defined in drilling dossier/manuals, etc.
14. Understand the nature and causes of problems encountered during drilling, connections, or while tripping. *Backreaming is a last resort* and avoided where practicable to do so.

Running 20" Casing and High Pressure Wellhead Housing

After successfully conductor casing the drilling the next section to accommodate the required surface casing string. These casings are normally set below the mud line at the required depth depending on *soil*, *pressure*, *fracture gradients*, and *shallow hazard* conditions. Note: Some deepwater drilling regional programs substitute the surface casing with both smaller casing (16in 13⅝″, diameter) or larger sized (28-in, 26-, 24-in strings).

The high-pressure wellhead housing is run as an integral part of the 20″ standard surface casing string most commonly run (Fig. 13.17). The housing provides a setting and sealing area for subsequent casing hangers and seal assemblies, an external latching profile, and a high-pressure ring groove for the BOP stack wellhead connector.

It affords transfers of weight and bending forces from the subsea BOP stack and riser system to the main structural conductor casing. Operational failures that have resulted during conductor jetting to be avoided are evident in Fig. 13.18.

Predrilling Precautions: Shallow gas, and water flow prevention must be in effect prior to drilling ahead. Drill crews fully briefed and trained on standard, procedures, and instructions required.

Surface Casings Prerunning Considerations

1. The priority of any section is to maintain the wellbore in pristine condition and maintain a perfect smooth in gauge cylinder to run and cement casing.
2. The casing is run to the required setting depth so that the high-pressure wellhead housing (HPWHH) is landed, latched, and locked and/or loaded (rigidized) into the conductor low-pressure wellhead housing (LPWHH).
3. Rat-hole lengths shall be discussed and agreed dependent on wellbore conditions, e.g., a longer rathole if fill is noted.
4. As a prevention a suitable displacement mud is have placed in the entire wellbore section prior to pulling out on the last trip, to decrease the possibility of fill and enable any to be washed and cleaned out as required, when running safely to bottom.
5. If a pilot hole was drilled and opened to the a larger size, and to prevent casing landing out early, assure the larger diameter main wellbore is drilled deep enough for the length of casing to be installed (plus a suitable rat hole).

Cementing Surface Structural Casing

The key to successful conductor/surface casing cementing is to improve drilling fluids management, shorten slurry transition times, and make drilling fluids and cement slurry weight compatible with formation pore and fracture gradients. Containment is complicated by weak formations that can fracture and cause loss of mud and cement returns.

Design parameters for deepwater cementing include pump time, free water, fluid loss, rheology, transition time, density, compressive strength, and compressibility.

1. The surface casing with HPWHH cemented provides the main load distribution of the well when it is landed out via the LPWHH landing shoulder and via locking and/or further preloading mechanism used (in ultradeepwater applications).
2. With the surface casing adequately designed and cemented to the seafloor with a single slurry.

3. If fracture gradients in the area do not permit circulation of a heavy slurry back to the seafloor, then a combination light weight (for upper section) and heavier tail slurry used.
4. The final surface casing shoe must have full circumferential competent cement between the casing and the wellbore. *Note*: This is first casing shoe to be exposed to shut-in kick pressures should a well control event result in the next drilling section.
5. The running tools for the HPWHH (is commonly 18¾ but can be 16″ or 13 5/8″ if slim line or high-pressure surface BOP risers are used).
6. Typically a pin connection exists on the bottom of the HPWHH running tool so that a tail-pipe cementing stinger can be run below. The stinger is necessary to keep cement away from the running tool and the casing hanger pack-off sealing areas inside the housing during the cement job. The stinger can be used to wash the wellhead and seabed area of cuttings that may have built up, e.g., ROV snapshots of sand pyramids have resulted.
7. The wellhead bore protector is generally preinstalled with the HPWHH.
8. To assure good cement is achieved around the surface shoe, optimal cement practices must be employed to assure mud gel removal. Centralization and optimal displacement rate results through suitable design, best practice application, and execution.

SHALLOW FLOW CEMENTING

The objective of cementing in shallow flow areas is to:

1. Achieve a competent seal that will prevent fluid movement, and
2. Provide structural support to the casing.

Cement System to Consider

Two cement systems have been developed for shallow water flow control as follows:

1. *Microfine cement in combination with microspheres*, provide lightweight high-performance cement slurry. It permits density control to prevent formation fracturing, thereby enabling full returns during placement to provide transition times of about 30 min, low fluid loss to maintain hydrostatic, and delivers compressive strengths needed at low densities (from 11.0 ppg to 14.0 ppg (1318–1678 kg/m^3) for the lead with base slurry for tail at 15.2 ppg (1821 kg/m^3)) and temperature environments that exist.
2. *Nitrogen-foamed cement* provides variable density high-performance slurry. It allows control of density and transition times of ±45 min, provided low fluid loss control, free water, superior compressive strength, and improved ductility at low densities for low-temp environments to prevent flow. It provides efficient mud displacement. Densities range from 11.0 ppg to 12.5 ppg (1318–1498 kg/m^3) for the lead with base slurry for tail at 15.2 ppg (1821 kg/m^3). Density is easily changed by the amount of gas injected and can be varied throughout the column. Special dry blends are not required. Limitations are: Requires additional specialize equipment, software, and personnel expertise; requires cryogenic fluid on deck; has higher friction pressure losses; and refrigerated test equipment is limited.

In general, all techniques used in deepwater cementing plus the following are to be considered.

Rules of Thumb Shallow Flow Cementing

1. Centralize casings to prevent the formation of channels. E.g., Standoff efficiency to afford required centralization from the shoe to at least 50 ft (16 m) above or below any sands.
2. The lead cement should be designed to set after the tail cement thereby maintaining hydrostatic pressure until a seal is formed.
3. Tail cement should be placed across the flow interval.
4. The cement should be pumped in place as fast as possible.
5. Minimize seawater circulation prior to cement job.
6. Cement additives can be useful as a visual aid as it is frequently difficult to distinguish cement from mud with the ROV. Dyes may improve the ability to recognize cement.
7. Use ROV to capture cement samples at the mudline to determine if cement returns reached mudline and for future cement volume adjustments.

REFERENCE STANDARDS

API RP 96 Deepwater well design and construction.

IADC Deepwater well control guidelines, 1st Edition, 1998, 2nd Edition, 2015

Norsok Standard D-101 Rev 4, June 2013, Well Integrity in drilling and well operations.

REFERENCES

Aird, Peter. 1995. AFP Drilling Review. Internal Report for Dresser Drilling and Production services.

Aird, Peter. Deepwater Drilling Best Practices documents compiled for various deepwater projects during 1996–2018. Kingdom Drilling Services Ltd. http://www.kingdomdrilling.co.uk/default.aspx.

Akers, T.J. 2008. Jetting of structural casing in deepwater environments: Job design and operational practices. Society of Petroleum Engineers. SPE 102378. San Antonio, Texas.

Chevron/BP Drilling Training Alliance relevant chapters. Floating Drilling Manual 2007.

Chevron/BP Drilling Training Alliance relevant chapters. Deepwater Drilling Manual 2007.

Evans, T.G., S. Feyereisen and G. Rheaume. 2002. Axial capacities of jetted well conductors in Angola. In: Proceedings of 5th Offshore Site Investigation and Geotechnics – Diversity and Sustainability. London: Society for Underwater Technology (SUT).

IADC (International Association of Drilling Contractors) Floating Drilling & Equipment Operations. 1st Edition 2015.

Jeanjean, P. 2002. Innovative design method for deepwater surface casings. Society of Petroleum Engineers. SPE 77357, San Antonio, Texas.

Stene, Flemming (Norske Hydro) and Peter Aird (Kingdom Drilling Services Ltd.) Frontier Explorations Drilling. Society of Petroleum Engineers. SPE 59810, New Orleans, February 2006.

CHAPTER

14

Deepwater Subsea BOP and Marine Drilling Riser

SUBSEA BOP AND MARINE DRILLING RISER

Due to the facts that significant technical and operational challenges, costs, and loss exists within deepwater Subsea BOP (SSBOP) and marine drilling riser systems, the purpose of the chapter is to expand the key and essential: systems components, analysis, and operational aspects to prevent operational loss and waste that can result. Topics presented are based upon industry standards and references as stated in this chapter.

The SSBOP and marine drilling riser provides the necessary well integrity, safety barrier, and well control assurances to be able to close in and isolate well control or operational problems that can exist. This is the drilling contractor's equipment that they are primarily contractually responsible for to assure systems are safe, effective, efficient, and reliable.

The marine drilling riser is a long slender steel vertical cylindrical pipe system that is run directly from above the SSBOP to just below the drill floor as shown in Fig. 14.1. It provides the necessary conduit to be able to operate wells from the offshore vessel. Different drilling riser types and technologies have been developed for variant water depths, conditions, and environments exceeding 3048 m (10,000 ft).

The SSBOP and riser operational components can be run and connected to wells for long and extended periods, i.e., up to several months. During their working life, they must be designed, analyzed, maintained, and manufactured to be durable to withstand the repeated deployment and retrieval conditions and environments they are subject to, delivering all operational and contingent needs should a well kick, equipment failure, emergency disconnect, or a hang-off in severe weather result.

To comply with required well life cycle design principles, raises several SSBOP and riser analytical procedures and challenges to be met. All operational and peripheral standards, equipment and systems essentials of these are covered in this chapter.

Deepwater Reliability

Deepwater control system failures and repairs that require a full recovery of the SSBOP usually result in significant operating loss, cost, and reputation in comparison to the majority of issues that can be resolved in situ, i.e., subsea and above the seabed.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00014-4

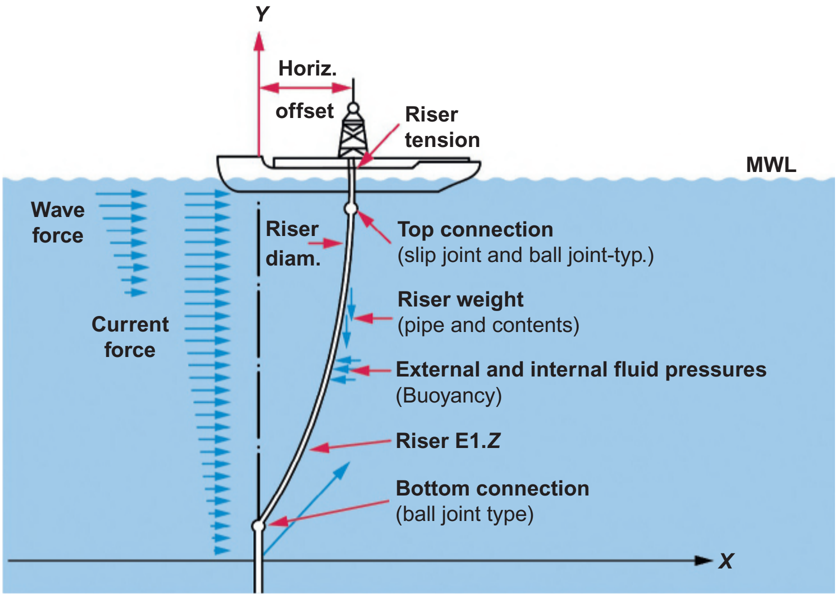


FIG. 14.1 Vertical tensioned drilling riser [*Note*: ball joint (or flex joint) is also located just below drill floor]. *Source: Elsevier.*

An important and singular quality control aspect resides in the planned maintenance assurance programs (PMP), where operator resource specialists are tasked in conjunction with the drilling contractor's own teams to verify and validate all such matters, particularly all safety critical issues. Rig site representatives also are tasked to conduct and exercise an active assurance role throughout all project planning, rig tendering, rig intake and operating stages, to assure all subsea systems work programs are fit for purpose, deliver as intended, and do not fail. In the past, contracts, programs, checks, and assurance did not afford nor account for these in the necessary depth and detail demanded. After Macondo, everything has changed, where a major reversal and operating vigilance now exists in terms of all such subject matters to assure contractors' maintenance, verification, and subsea systems assurance programs are being attended to, to meet work program, and safety critical equipment and system needs.

SSBOP and Marine Drilling Riser Maintenance

This section affords guidance in regards to the minimum maintenance requirements of these systems to be conducted. In harsh and remote-operating environment, further attention is ideal. The safe operational critical areas to assure standards, systems maintenance, and quality control checks, tests, and assurance programs exist are within:

1. The subsea BOP (SSBOP)
   a. Rams/Ram cavities, configurations
   b. Annular preventer
   c. Wellhead/LMRP connectors

- **d.** Control pods
- **e.** Failsafe valves
- **f.** Compensation
- **g.** Choke/kill/boost/rigid conduit lines, spools, and connectors
- **h.** SSBOP function and pressure testing
- **i.** Handling and testing tools

2. Subsea control systems
- **a.** Mixing system
- **b.** Hydraulic power units
- **c.** Control pod, panels, systems
- **d.** Uninterruptible power supplies
- **e.** Multiples control system
- **f.** Safety critical systems (EDS, Deadman, AMF, etc.)
- **g.** Emergency dedicated accumulators
- **h.** ROV intervention, systems controls
- **i.** Acoustic systems, controls

3. Mariner riser equipment
- **a.** Boost line, valves
- **b.** Choke, kill, hydraulic lines seals and faces,
- **c.** Riser mud saver valves
- **d.** VIV suppression devices
- **e.** Trip savers
- **f.** Telescopic, stress joints
- **g.** Marine riser tensioner, compensation systems
- **h.** Riser tension ring
- **i.** Upper, Lower, and Intermediate Flex Joints (as appropriate)
- **j.** Riser hang off analysis
- **k.** Riser analysis (weak point identification)
- **l.** Coupled drilling riser/conductor analysis
- **m.** Recoil system analysis
- **n.** Angle indicators
- **o.** Handling and testing tools
- **p.** Riser wear

4. Diverter systems
- **a.** Diverter housing assembly
- **b.** Diverter valves
- **c.** Diverter and gas handling systems
- **d.** Diverter functions, testing
- **e.** Handling and testing tools

5. Compliance, certificate of conformance for all of the above.

Note: API RP 53, 4th Edition, states that all equipment must be inspected and maintained. Therefore, if this is assured as a contractual safe operating requirement, there is no immediate need for further certification unless other standards or specific well operating plans and conditions exist.

SSBOP Pressure Ratings

When designing ultradeep water SSBOP tests, the effect of the differential pressure of the mud weight in the riser and the external seawater must be accounted for. *Example*: In 3048 m (10,000 ft) of water with a 15-ppg (1797 kg/m^3) mud, the subsea BOP body is subjected to a differential pressure of 3325 psi (22.92 MPa). For a BOP rated to 15,000 psi (103.42 MPa), the maximum test pressure under these conditions must be limited to (15000 − 3272 psi) = 11,675 psi (80.5 MPa).

SSBOP Elastomers

SSBOP elastomers are subjected to a wider range of operating temperatures in deepwater environments. Seabed ambient temperatures often approach freezing point, at which temperature-resilient elements can fail to extrude and flex properly to compromise sealing capability. On occasions, annular preventers have to be repeatedly functioned to "warm up" and loosen the elastomer to seal and obtain a test. During deepwater testing operation and depending upon reservoir depth, temperature, and test flow rates, elastomers can be subjected to higher temperatures. All potential operating service range extremes from low to high are to be considered to assure suitable elastomer materials are used in deepwater subsea- operating environments.

SSBOP Control Systems

As drilling progressed into deeper water, SSBOP control systems are more complex, time is more critical, rendering conventional, hydraulic systems unsuitable because of slower response times. This section reviews the major issues to evaluate in the design, use, and application of deepwater SSBOP control systems.

Working Pressure

A higher working pressure of 5000 psi (34.5 MPa) is required for ultradeep water SSBOP control systems, due to the inefficiency of accumulators and systems functionality in these water depths and due to the high Nitrogen precharge pressure required. Accumulators charged to 5000 psi (34.5 MPa) differential above the sea floor must also be vented before retrieving the SSBOP to surface to prevent a risk of a burst failure from overpressure as the hydrostatic pressure previously exerted by the seawater column cannot be reduced.

Closing Times

Ultradeep water dynamically positioned drilling vessels are outfitted with *Electro Hydraulic* or *MUX (multiplex)* SSBOP control systems. These systems have almost instantaneous response times, allowing the SSBOP control commands (close, open; disconnect sequence, etc.) to be initiated to meet regulatory and operating standards. With the MUX-control systems, sufficient hydraulic storage must exist on the SSBOP/LMRP packages to allow for a disconnect sequence to function without requiring recharge from surface.

Operating Fluid Volumes

Published standards specify the amount of usable fluid to be available in an accumulator system. These requirements are only for overall accumulator, surface, and subsea volumes.

There is no regulatory requirement for the number of accumulator bottles to add to an SSBOP to enhance closing times. Given the fast response times of the pilot signal in MUX systems, it is feasible to eliminate bottles on the SSBOP. When accumulator bottles are eliminated there, the size of the control fluid line on the riser is now a major consideration, as a larger diameter line is needed to enhance the fluid flow transfer required. For dynamically positioned operations, any decision to eliminate bottles on the SSBOP should be exercised with caution and must consider the fluid volumes required for any planned or unplanned emergency disconnect sequence.

Given

Water depth: 3000′
Subsea accumulator capacity: 35 gal bottles
No. of subsea accumulators: 4
Sea water gradient: 0.445 psi/ft
Control fluid gradient: 0.43 psi/ft
Calculate pressures
Precharge: 1000 psi + (0.445 psi/ft × 3000 ft) = 2350 psi
Full charge: 3000 psi + (0.43 psi/ft × 3000 ft) = 4290 psi
Min. operating: 1200 psi + (0.445 psi/ft × 3000 ft) = 2550 psi

Terms

P_1 = pressure at precharge
V_1 = nitrogen volume at precharge
P_2 = pressure at full charge
V_2 = nitrogen volume at full charge
P_3 = minimum operating pressure
V_3 = nitrogen volume at minimum operating pressure

Volume calculations

$$P_1V_1 = P_2V_2 = P_3V_3$$

$$V_2 = \frac{P_1V_1}{P_2} = \frac{2350\,\text{psi}(35\,\text{gal.})}{4290\,\text{psi}} = 19.2\,\text{gal. of nitrogen}$$

$$\text{Control fluid} = \underline{35 -} 19.2 = 15.8\,\text{gal. at full charge}$$

$$V_3 = \frac{P_1V_1}{P_3} = \frac{2350\,\text{psi}(35\,\text{gal})}{2550\,\text{psi}} = 32.2\,\text{gal. nitrogen}$$

$$\text{Control fluid} = \underline{35 -} 32.2 = 2.8\,\text{gal. at minimum operating pressure}$$

Useable fluid = 15.8 − 2.8 = 13.0 gal. per 35 gal. bottle

Total useable fluid = 13.0 × 4 = 52.0 gallons

Subsea Accumulator Requirements

The usable volume of fluid contained in the subsea accumulators is critical, depending on the type of control system used. When water depths exceed 500–1000 m (1640–3281 ft), it can take 30–60 s or more for the surface accumulators to recharge the subsea accumulators after a single ram function.

In deep water, the calculation of usable subsea volume is complicated by the fact that Nitrogen is used for precharge and does not behave as an Ideal Gas. If there is a substantial difference in surface (precharging) versus subsea temperature, no matter the water depth, a significant error results in usable volumes when ideal gas relationships are used. To conclude, hydraulic storage must be assured to be available on the SSBOP/LMRP to allow for the disconnect sequence to safely function and operate without requiring recharge from the surface.

Usable fluid calculations in deepwater subsea are similar to those for a surface BOP (SBOP) in that gauge pressure is used. The lowest recommended or minimum accumulator operating pressure must be known for the calculations. In order to determine the usable fluid, calculate the volume of nitrogen within each bottle at any pressure. Subtract the nitrogen volume from the bottle capacity for hydraulic fluid volume as per examples in previous section.

Subsea accumulator precharge must be adjusted for water depth. Along with stack-mounted bottles, a subsea accumulator dump function is needed. As the stack-mounted bottles form an integral part of the entire subsea control system. When opened and online with the surface accumulator bank, they retain an internal (control fluid hydrostatic head) pressure higher than the surface reading. Without this dump relief provision, subsea bottles shall experience higher actual pressures when the stack is pulled. A dump function to vent this pressure thus demanded.

SSBOP Control Systems and Redundancy

The SSBOP control systems on deep and ultradeep water drilling vessels are electrohydraulic (EH) or multiplex systems (MUX). The latter greatly improves SSBOP operating response times.

(1) Hydraulic pilot-operated (Chapter 5, Fig. 5.38) and
(2) Electrohydraulic and multiplex, (Chapter 5, Fig. 5.39)

Notes: All other control systems are adaptations of these. Hydraulic and EH systems require a control bundle to send pilot signals to a particular function and hydraulic fluid supply (power fluid) to perform that function.

The MUX and EH systems send signals electronically through wire(s) within an armored cable. Their power fluid supply is generally sent through hard piping fixed to the riser. Apart from the type of signal transmission to the control pod, both systems operate similarly.

Electrohydraulic System

Electrohydraulic (EH) control systems differ from hydraulic pilot-operated control systems in the transmission method of the pilot signal for SPM pod valves. EH systems replace hose bundle pilot lines with individual wires inside of an armored cable. Electronic signals are sent through these discrete wires subsea to a bank of solenoids with valves attached atop each pod. The electronics package is mounted in silicon-filled, pressure-balanced chambers. After the solenoid trips, the attached hydraulic valve is pulled into position. Signal pressure at 3000 psi (20.7 MPa) is directed through the solenoid valve to the SPM valve. The SPM valve will then move off seat and power fluid is directed to the operator. The control bundle size for a typical electrohydraulic control system is 3–3½″ (76–89 mm) OD.

Multiplex System

Multiplex (MUX) control systems differ from the EH in signal transmission method only. All electronic solenoid signals are digitally encoded and sent down one common wire. From that point, a MUX processor subsea interprets the signals, then electronically trips the solenoids controlling the selected function. Downstream of the processor, MUX and EH control systems are identical. Signal pressure at 3000 psi (20.7 MPa) moves through the solenoid and trips the SPM valve. A MUX processor is mounted above each pod/solenoid rack in a one atmosphere bottle. A multiplex control bundle size is generally 1–1½″ (25–38 mm) OD. (The electronic signal and solenoid valve arrangement is analogous to a prepressured control line and extra pilot operated valve in a quick-response system.) EH and MUX pods are larger than hydraulic pods and are typically *not remotely retrievable*.

Acoustic Controls

Acoustic controls systems provide further redundancy to enable access to a wider range of subsea safety critical functions that include *LMRP connector release, blind shear rams close and hang off pipe ram close.* The system operates by sending encoded acoustic signals through the water to a receiver on the SSBOP stack. The information is decoded and electronic signals are sent through discreet wires to individual solenoids with valves that are grouped on a rack. The solenoid valves trip and allow power fluid to enter the secondary shuttle valves mounted on an operator.

For the system to operate, a large supply of power fluid must be available via subsea accumulator bottles on the SSBOP stack. Because of the limited power fluid resource, it is important in design to plan every function sequence realizing the advantages and disadvantages of any attempted function.

To afford maximum flexibility, SSBOP-mounted acoustic control systems and associated subsea accumulators are preferred as SSBOP mounted, and not attached to the LMRP. The downside of SSBOP mounting is the associated framing, brackets, and access restrictions then presented. LMRP subsea bottle positioning generally costs the contractor less.

SSBOP Pressure and Temperature Gauges

SSBOP-mounted *pressure gauges* are used to measure the pressure upstream of the choke, to assure more precise subsea and bottom-hole pressures readings, while bringing the pumps up to speed and taking returns via both choke and kill lines. *Temperature gauges* mounted on the SSBOP are useful. Due to the smaller EMW margins that can exist in deepwater, provision should be afforded to higher-quality and appropriate ranged gauges.

Cold Weather Considerations

Subsea operations in *subzero temperatures* dictate additional considerations, i.e., the use of glycol-water fluid mixtures. Lubricants and grease should also contain low-temperature additives. Sharp impacts or loads on elastomers should also be avoided, as their brittle nature in such temperature regimes can cause them to shatter. *Note*: A storage temperature range for rubber goods is generally considered as 40–80°F (4.4–26.7°C).

Cathodic Protection

Deepwater conditions tend to accelerate corrosion where *cathodic protection* is needed to minimize corrosive degradation caused by electrolytic action on all subsea systems. This is achieved through installing sacrificial anodes on the guide frames and around the control pods, etc. It is important to evaluate the degree of protection, assess condition, replace, and space-out anodes accordingly.

SSBOP, Subsalt Considerations

Drilling subsalt formations with saturated salt mud systems can create problems with salt crystal building up on the SSBOP components, particularly valve gates and seats. Proper maintenance (greasing) programs of the valves must be adhered to. For SSBOP failsafe valves, one valve or one set (2 valves) should be disassembled, inspected, and serviced after an average well (assuming 12–20 weeks for a well). API recommends one spare valve of each size and type be kept on board (RP53 9.4), so a swap out is usually more efficient between wells, with the service performed while the stack is on bottom. Through large subsalt sections, this standard may not be sufficient. Here all valves should be considered to undergo a complete service prior to use on wells that utilize a salt-saturated mud system and drill theses sections. Due diligence for both choke and standpipe manifold valves maintenance is also warranted.

ROV Intervention

To afford SSBOP operation in the event of loss of EH or MUX capability, it is certainly recommended that there must be an *ROV intervention capability* for major operating functions such as:

- Shear and pipe rams.
- Unlocking of the LMRP connector and retrieval functions of LMRP, e.g., choke and kill stabs.
- Unlocking of the wellhead connector for BOP retrieval.
- LMRP and wellhead gasket release.
- Dumping pressure from subsea accumulators.

ROV Stabs

ROV Hot Stabs and Receptacles as illustrated in Fig. 14.2 are used to power hydraulic tools, transfer fluid, perform chemical injections, and monitor pressure. There are two API design and manufacturing specifications of ROV Hot Stabs and Receptacles, *API 17H* (also referred to as ISO 13628-8) and *API 17D.* Both are manufactured at ROV company intervention and engineering state-of-the-art machine shops.

Subsea BOP and Marine Riser Preparation and Running

Subsea BOP preparation and riser running and retrieval are reviewed in this section.

SSBOP and Marine Drilling Riser deployment and retrieval

Currents and vessel motions can damage the marine drilling riser during deployment or retrieval. This is notably true when a shorter length (depth) of marine riser is submerged with the LMRP and SSBOP closer to the water's surface. Here, current loads and vessel motion can cause the riser to bind as it is being run through the diverter housing to cause impact loads between the riser and vessel as illustrated in Fig. 14.3. This can cause damage to the

Receptacle dimensions	
Length	10 in.
Width	6 in.
Weight in air	12 lbs
Weight in water	10 lbs
Receptacle performance data	
Depth rating	Full ocean depth
Receptacle hydraulic data and performance	
Hydraulic fluid	any
Max operating pressure	10,000 psi version available up to 20,000 psi
Max operating flow	7 gpm
Min operating flow	0 gpm
Receptacle materials	
Nitronic 50	
Hot stab dimensions	
Length	24 in.
Width	2 in.
Width in air	9 lbs
Width in water	6 lbs
Hot stab performance data	
Depth rating	Full ocean depth
Hot stab hydraulic data and performance	
Hydraulic fluid	any
Max operating pressure	10,000 psi version available up to 20,000 psi
Max operating Flow	7 gpm
Min operating Flow	
Hot stab materials	
API 17D	API 17H
316 SS	Nitronic 60
Ampco 45	Ampco 45
	316 ss (t-handle)

FIG. 14.2 ROV subsea hot stabs and receptacles. *From Kingdom Drilling training construct.*

riser (particularly the buoyancy modules) or to the vessel. Relative vessel and riser motions can induce stress-related problems near the top of the riser notably when it is hanging during running or retrieval. Vessel motion can also make it difficult to make up or break out the next riser joint on the rig floor.

Running heavy SSBOP and marine riser systems and stopping the mass motion abruptly can generate in dynamic loads as shown in Fig. 14.4 that could exceed the lifting equipment's capacity. Heavy SSBOP and marine riser loads must be handled with best practices applied, using the appropriate running, handling, and lifting gear provided.

Dynamic loads generated by the vessel motions and handling operations shall increase the loads transmitted to the lifting gear. Estimates of the maximum operating and dynamic loads to be estimated for the lifting gear systems used. Any analysis should include the axial natural frequency response of the riser and lifting gear system for the range of conditions prognosed.

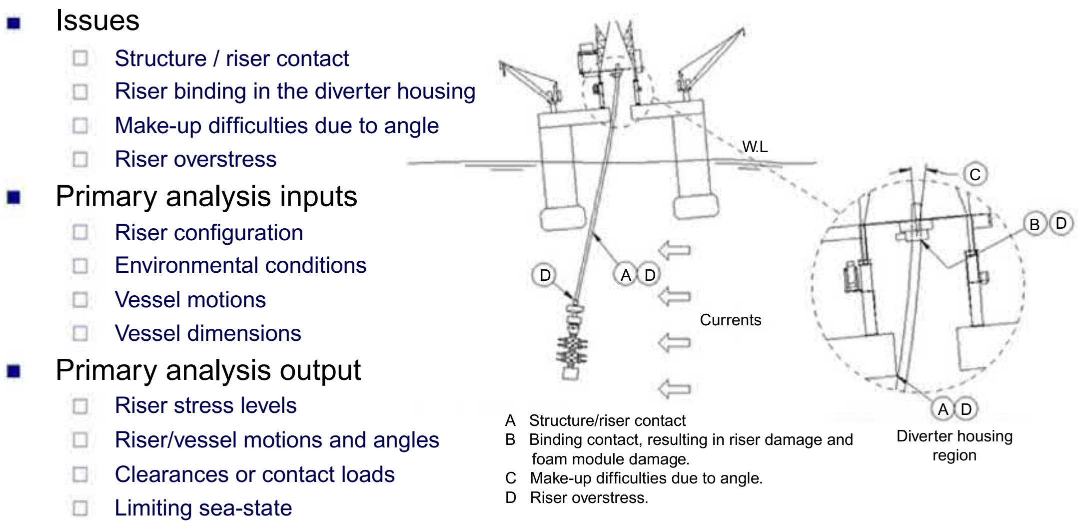


FIG. 14.3 Deepwater riser running and retrieval issues, primary input and output analysis.

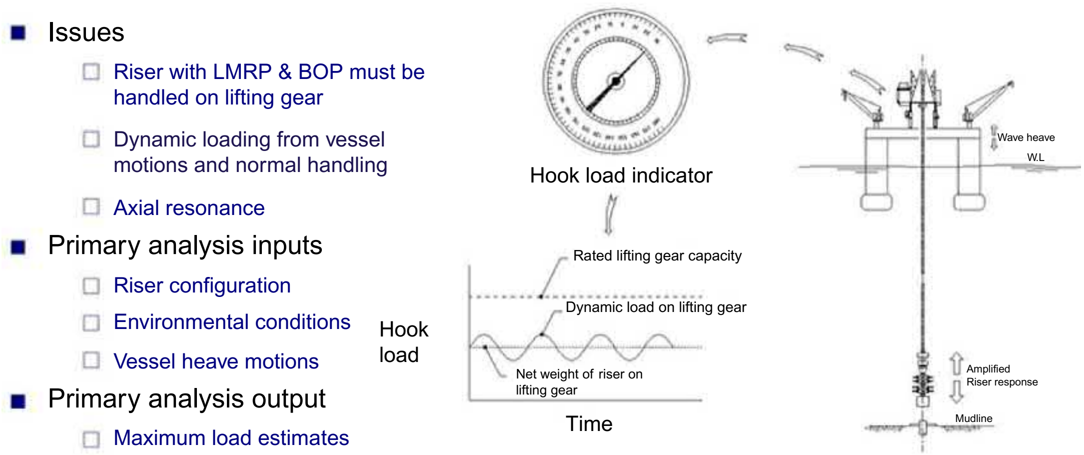


FIG. 14.4 Riser handling, lifting, and running capacity.

Notably when the riser is suspended and hanging from the lifting equipment as shown in Fig. 14.4. A worked example illustrating dynamic loads and natural frequency of a SSBOP and marine riser system can be downloaded at http://www.kingdomdrilling.co.uk/downloadfreelinks.aspx.

Fig. 14.5 presents an SSBOP and marine riser running plot of gross hook loads. The plots show the effect of a buoyancy loss of 4% and the maximum static plus dynamic loads expected for three vessel headings. The allowable static plus dynamic load is 1500 kips. The maximum anticipated static plus dynamic load in figure shown is circa 1400 kips and occurs for the 45 degree storm heading.

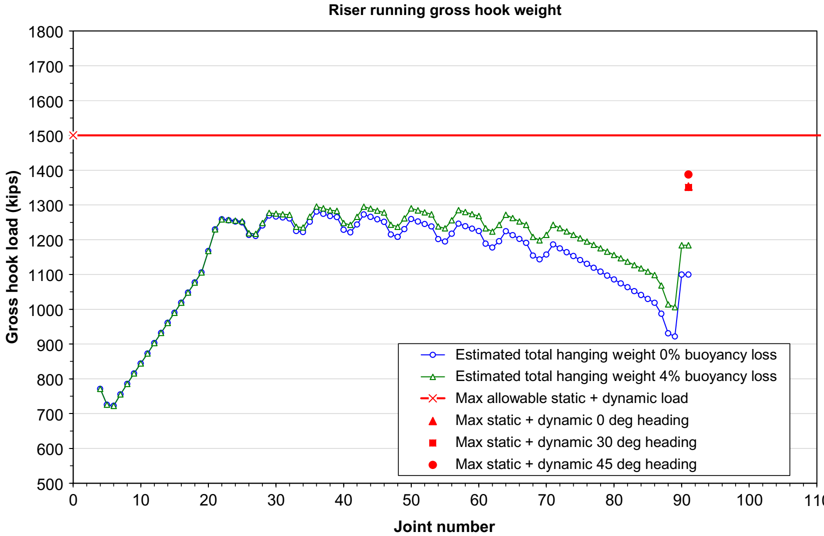


FIG. 14.5 Estimated hook load while running a deepwater marine drilling riser. *Source: Kingdom Drilling training 2006.*

SSBOP Stack Preparation

While the structural casings are being installed, concurrent rig activities include inspection, testing and readiness preparation of the SSBOP, associated control systems, and the marine drilling riser. All work is conducted by the drilling contractor's subsea engineering and support teams and witnessed by an operator's third-party specialist and/or company representatives who verify and assure work performed. Operational time constraints, contract acceptance, and/or well program conditions will determine the detailed level and depth of each project required. The following work scope is usually conducted:

- Open all ram preventers and visually inspect all critical sealing areas and seal components for damages as well as the bore for wear.
- Visually inspect sealing elements on both annular preventers, ball joints, and flex joints.
- Disassemble some/all of the stack-mounted choke and kill valves to visually inspect and verify all valve-sealing components for damages or defects.
- Visually inspect the hydraulic wellhead and LMRP connectors and ensure that new seal ring gaskets are then correctly installed.
- Detach all control hoses from the SSBOP stack and LMRP. Use a test pump and chart recorder to test all shuttle valves and operating chambers on the ram preventers, annular preventers, choke and kill valves, and the wellhead and LMRP connectors to manufacturer specifications.
- Reattach all control hoses. Apply a low operating pressure (300–400 psi (2.1–2.8 Mpa)) and function test all stack functions to verify proper hose assignment.
- Adjust the manifold and annular regulators to agreed pressures and operate all stack functions. Visually inspect for leaks in all control system connections. Decrease the manifold and annular regulator pressures to a lower as-agreed pressure and repeat the function and other tests. Record the control fluid volumes and times required to operate each stack function.

- Perform a hydrostatic pressure test, using a test pump and chart recorder, of the LMRP and SSBOP stack. Each component should be tested to a low pressure for 5 min to be held at constant pressure.
- Ram preventers and choke/kill valves should be tested to their rated safe working pressure for 10 min at constant pressure. Annular preventers should be tested to 70% of their safe rated working pressure for 10 min.
- Perform an accumulator drill to verify there is sufficient capacity to close and open all rams and one annular preventer with 200 psi (1.38 MPa) pressure above original precharge.
- Perform necessary functional check to assure *safety critical systems do work* ALARP.
- Any damages or problems during the inspection and testing should be rectified or captured[1] so that the SSBOP stack is ready for deployment when/as operationally needed.

SSBOP and Marine Drilling Riser running and landing guideline

The following is a generic sample list of prejob checks: Check that…

- Metocean forecasts are suitable for crane operations and all subsea operations.
- Optimal riser space out and pup joints required are checked, and verified.
- Riser beacons and stack beacons fully charged
- Inclination beacons are wired up correctly and ready to deploy
- Riser running tools and diverter handling tool serviced, checked, and ready
- Riser spider and gimbal in good working order
- Equipment for handling risers are verified, checked, and ready
- All seals and interfaces inspected and replaced as required
- All riser joints have protectors in place
- All locking dogs in working order
- Inventory of riser joints on board up to date
- Lengths and running sequence is made up
- Adequate spare seals for riser connectors and kill and choke lines on board
- Rotating dogs in support ring are operating freely
- Kill and choke test boxes have correct fittings
- All tools prepared and ready on drill floor
- Public announcement and telephone system are in full working order
- Standby boat is informed of operations and in close vicinity down current of vessel

Running operation of an SSBOP and marine drilling riser is dependent upon vessel, well, operating specifics, equipment, systems, control's practices, and procedures. The following therefore represents an example of a deepwater SSBOP and marine riser deployment:

- Make up 2 joints of marine riser and leave hanging in the elevator. This enables to run and submerge the stack in one continuous pass of the SSBOP through the splash zone and to a safe distance below the vessel's structural elements.
- Move the stack to the running position directly below the rotary table.

[1] A punch list is generally created to indicate all critical, major, medium, and minor issues outstanding and an action plan to rectify system defects prior to use.

- Ensure a new ring gasket is in place in both LMRP and wellhead connector.
- The routine to get the LMRP/SSBOP stack ready to run will depend on rig and contractor specific equipment, systems, and procedures required.
- Install the control systems (if not already in place) and function test the entire system alternately on each system, from both the driller's station and the remote station. This test must be witnessed by the third-party specialist and/or the drilling supervisor or engineer. Ensure the bore of the SSBOP is unrestricted following the function test.
- Lower the 2 joints hanging in the elevator and make up to riser adaptor on LMRP. Ensure locking mechanism is fully engaged and made up to manufacturers' recommendation.
- If practicable install riser beacon clamps, *riser* beacons, and stack beacons all offline. Install and check visual bull's eyes with an accurate spirit level.
- Check beacon offset, ensure beacon is switched on and working verified. If two beacons are fitted, only one should be left switched on.
- Subsea engineer will be responsible for cellar deck organization. One person will be stationed at each Mux control system winch. Further personnel positioned as required.
- Lower stack through splash zone. Land off upper riser joint on riser spider. It is common best practice not to stop to fit lines and clamps, etc. onto first two joints.
- Fill up choke, kill, and boost lines with water. Fit test cap. Test lines to required test pressures.
- Continue to run stack. Make sure riser connectors are fully engaged and made up correctly to manufacturer's specification.
- Fill up kill and choke kill and boost lines with water each joint and pressure test as per agreed running and testing schedule.
- With SSBOP approximately 200 ft (60 m) below sea level, check with control room that beacons are sending positive signals. Ensure beacon depths are fed into the system and monitoring procedures for these are adhered too.
- Continue running riser as per contractors standing operating procedures, pressure testing system as agreed.
- Install required riser (space-out) pup joints as per agreed running plan.
- The last riser joint is the telescopic joint (slip joint) in a locked position.
- Pick up slip joint and make up to riser. Lower slip joint and land in spider on support ring flange. Make up riser landing joint.
- Lower slip joint to a point where the riser tensioner lines can be fitted.
- Attach kill and choke line hoses, as per systems provided prior to landing.
- Recheck beacon readings and ensure bias still valid.
- Take weight of SSBOP/riser as per excess required on tensioner lines. Activate the When weight compensator as per contractor procedures. Adjust compensator to required stroke.
- Lower SSBOP stack and marine riser with ROV assisting final maneuver to position and assure stack funnel is central over the high-pressure wellhead housing.
- Land stack and slack off weight as required on wellhead housing.
- Latch wellhead connector, observe indicator flag, and ensure correct amount of control fluid is used. Pull ±50 kip by pressuring up on compensator to verify connector locked.

- Charge up riser tensioners to required tension to meet system, water depth, and operating conditions.
- Bleed down compensator and reduce guidelines to required working tensions.
- Release inner barrel stroke out and land in spider. Remove landing joint.
- Make up diverter assembly on inner barrel. Flush and test diverter system.
- Pick up, remove riser spider, and land off in diverter housing.
- Remove handling tools and hook up diverter hydraulic control.
- Observe all riser and wellhead bull's eyes are <1 degree prior to standing ROV down.

Riser Space Out

Preparing to run a marine riser and how to assess a site-specific marine riser length determination is outlined in standards that exist. As water depth is established as outlined in Chapter 11. The wellhead elevation above the mud line is precisely measured after installation. The marine riser length and the number of specific joints required are then determined. The optimal riser length is then planned so that the telescopic slip joint shall be as near as practicable to its midstroke length when the SSBOP is latched to the wellhead. Due to the fact that the shortest length of riser pup joints to be used for riser space out are 5 (1.5 m)–10 ft (3.0 m), rarely can an exact midstroke be achieved. *Notes*: This inexact match-up becomes a consideration for emergency disconnect and riser recoil that are discussed later in this chapter. A worked example of a deepwater riser space can be obtained from; http://www.kingdomdrilling.co.uk/downloadfreelinks.aspx.

DEEPWATER MARINE DRILLING RISERS

Marine Drilling Risers

Sections review the main components and present an overview of deepwater riser analysis, operating and well integrity issues related to these systems as illustrated in Figs. 14.6–14.13.

The riser is supported by the vessel through the combination of a *telescopic (slip) joint* and *upper flex joint* in an opening in the vessel called the "moonpool."

The *tensioning ring* at the top of the "outer barrel" of the telescopic joint provides the connection point for *riser tensioner lines*, to maintain relatively constant tension of the *marine drilling riser* through their connection to the compensating tensioner units.

Top tension variation is minimized through the use of the *tensioner units* that are based on hydraulic or pneumatic systems as presented in Chapter 5, Figs. 5.32 and 5.33.

The *upper flex joint* is located above the "inner barrel" of the telescopic joint where it provides lateral restraint and reduces rotation through elastomeric stiffness elements.

The *diverter housing* and system is located just above the upper flex joint and below the drill floor to permit all returning fluids from the well to be transferred through a simple gravity feed line to the mud-processing system. As shown in Chapter 5, Figs. 5.36, 5.40, and 5.41, and Fig. 14.7.

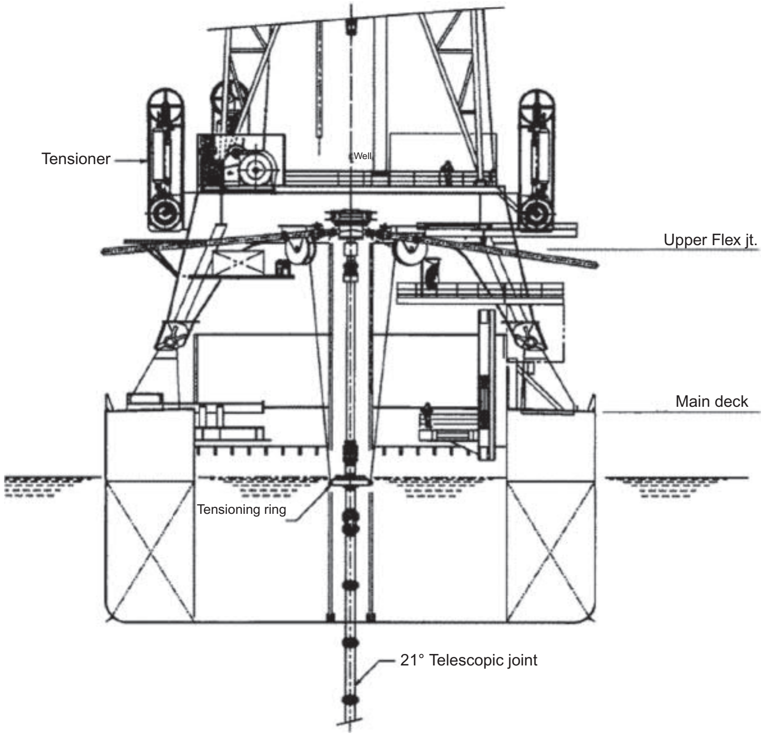


FIG. 14.6 Vessel moonpool and riser arrangements. *Source: Elsevier.*

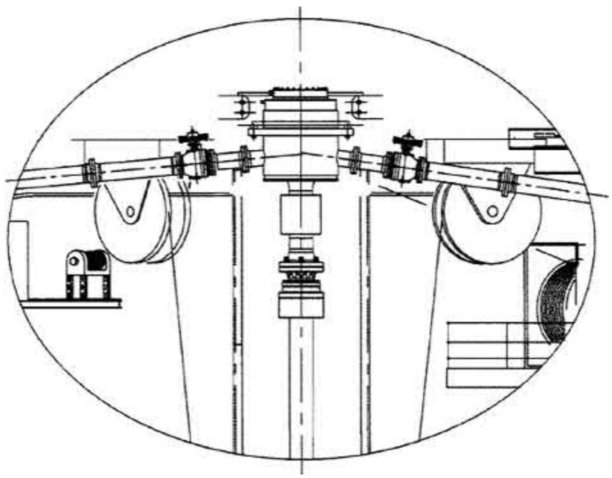


FIG. 14.7 Riser upper flex joint, diverter, and turn-down sheaves. *Source: Elsevier.*

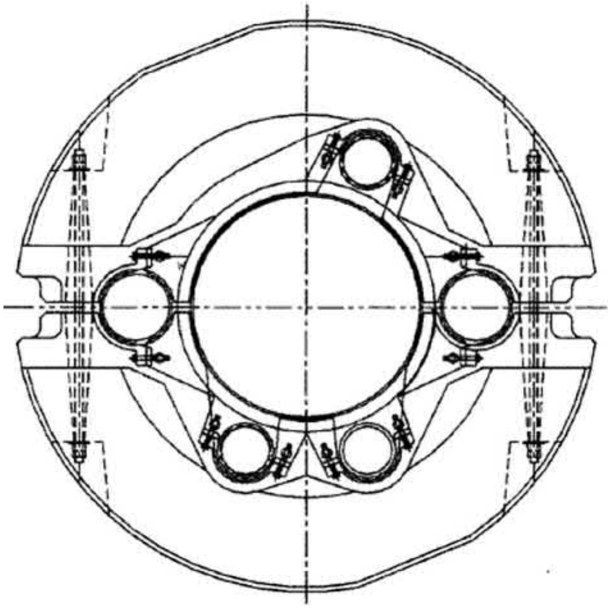


FIG. 14.8 Typical riser joint cross-section. *Source: Elsevier.*

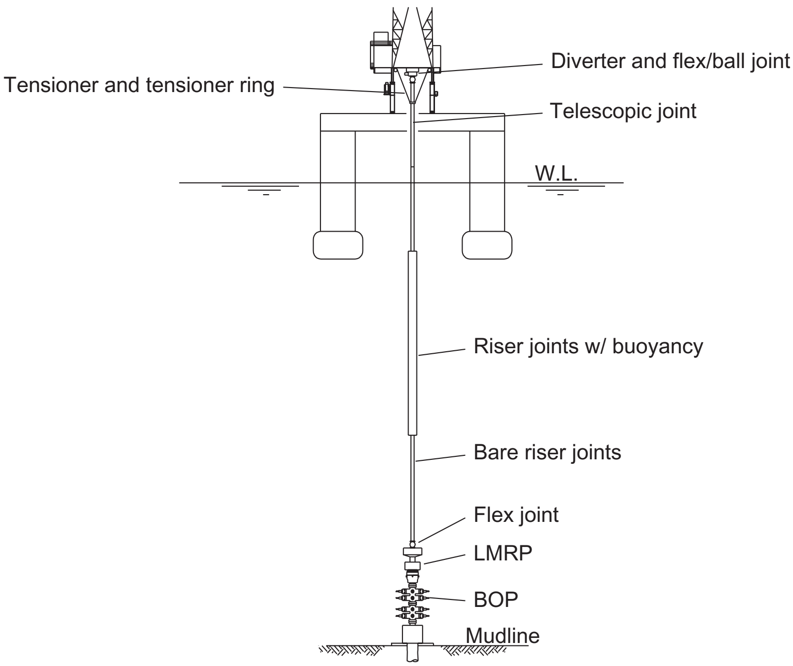


FIG. 14.9 Marine drilling riser main system components.

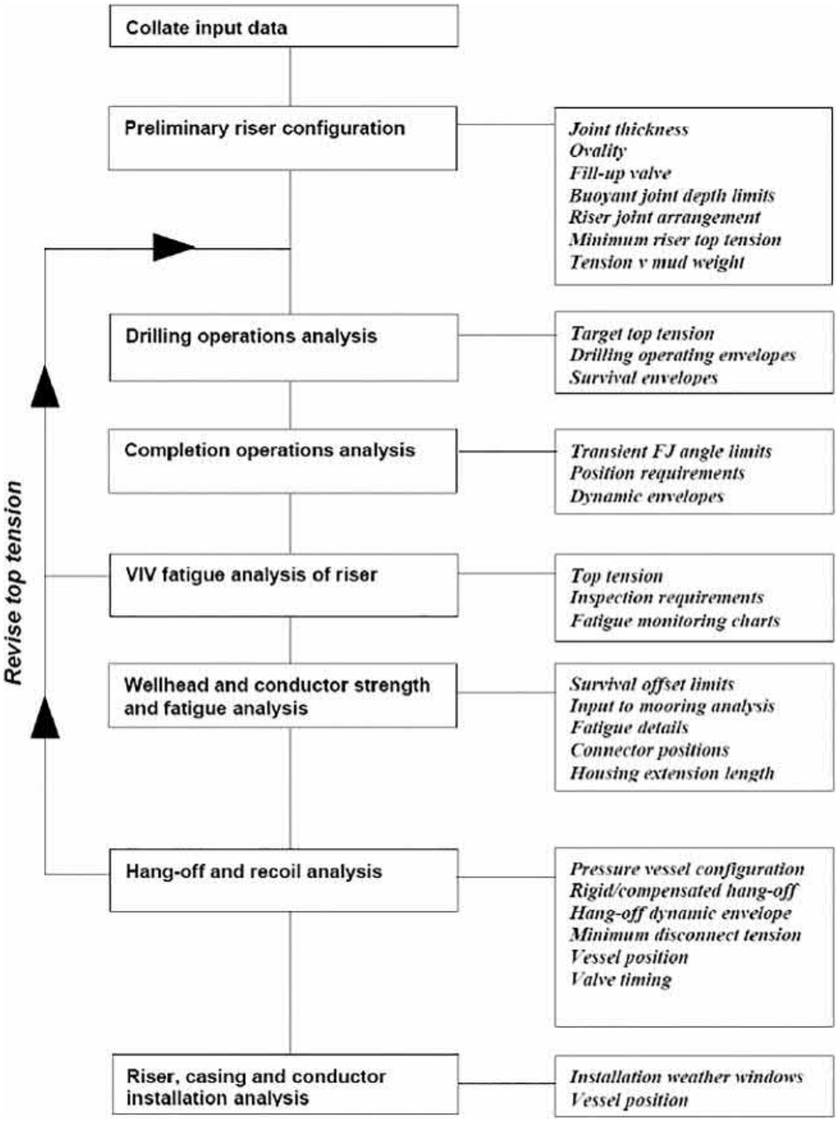
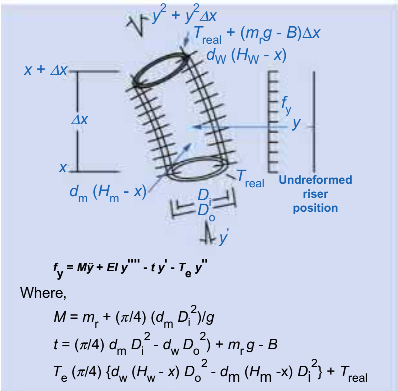


FIG. 14.10 Overview of standard riser analysis. *Source: Drilling Riser Management in Deepwater Environments 2H Offshore.*

The *riser string* consists of “joints” (segments) connected at the drill floor and run (deployed) through the water column. *Ultradeep water riser joints* can be as long as 90 (28 m)–135 ft (41 m) in length with a continuous steel riser pipe down the middle. Joints can be slick or have pairs of buoyancy modules strapped on the outside and at each end. The riser joints carry additional auxiliary lines, and thus are made up together with bolted flange, dog-type, or other nonrotating advanced, e.g., Akker’s clip type, boltless riser connections.

Governing differential equation of motion



Terminology in the equations

B	Buoyant force per unit length
D_h	Hydrodynamic diameter
D_o D_i	Outside and inside diameter of the riser pipe
d_m d_w	Weight density of the mud and seawater
E_I	Flexural rigidity of the riser
f_y	Distributed hydrodynamic force acting in the "y" direction
g	Gravitational acceleration
H_m H_w	Total depth of the mud and the seawater
M	Total mass (riser and mud) per unit length
m_r	Mass of the riser (including Buoyancy) per unit length
T_e	Effective tension
T_{real}	Actual tension in the pipe wall
t	Variation of the effective tension
x	Vertical coordinate measured from the bottom of the riser
y	Horizontal riser translation at station "x"
(˙)	$\partial / \partial t$
()'	$\partial / \partial x$

FIG. 14.11 Differential element analysis of the marine drilling riser. *From Kingdom Drilling training.*

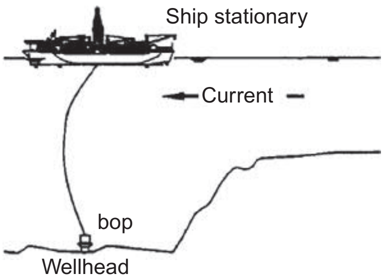


FIG. 14.12 Excessive top and bottom angles on connected riser. *Source: Elsevier.*

The cross-section of a typical riser joint is shown in Fig. 14.8. This shows all the auxiliary lines that are clamped to the riser pipe. That includes choke and kill lines for well control, a riser boost line that is used to pump and circulate fluids into the riser annulus just above the SSBOP stack, a spare line, and a hydraulic line for subsea functional control. Buoyancy material is further strapped around the riser joint with external slots provided within the buoyancy for attachment of multiplex (MUX) control cables.

Just above the seabed, the SSBOP is landed latched and locked onto the well's wellhead to assure structural well integrity is maintained for all metocean and operating conditions and forces that can apply. The associated lateral motions from the vessel are also imposed at the top of the riser. In addition to the external forces and motions, drill string rotation and other operations can impose wear and other degradation within the riser to be managed.

Major drilling system components, from the seafloor up (refer Fig. 14.9), are:

- Wellhead Connector[2]
- Blow-out Preventer, BOP[2]

[2] Not technically part of the drilling riser.

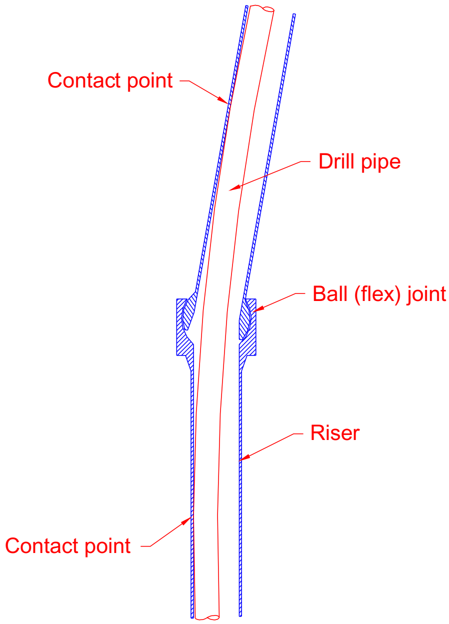


FIG. 14.13 Lower flex joint angle. *Source: Kingdom Drilling training 2006.*

- Lower Marine Riser Package, LMRP[2]
- Lower Flex/Ball Joint
- Drilling Riser (Bare (slick) and Buoyancy joints)
- Riser tensioner and tension ring
- Telescopic (Slip) Joint
- Diverter Housing
- Tensioner System

The riser is held in tension to assist bending and fatigue resistance placed by all environmental and operating loads. Riser tensioners provide the mechanical means of tensional support aided by syntactic foam and/or air or other buoyancy devices run within the riser system to reduce surface tensional loads required.

Note: Modern riser technology alternatives to conventional systems exist to address some of the inherent operational riser problems within the current generation of deepwater vessels.

Examples are the Akker clip riser and Dril-Quip's new deepwater riser systems where benefits offered are: *Quicker, hands-free riser connections can step change riser running and pulling, safety, effectiveness, and efficiencies; systems afford higher strength, ease of use, maintenance and field replacement of critical components, etc.*

Deepwater Riser Analysis

Analysis has to clearly define the operational limits and top tension requirements under maximum service load conditions to assure that flex joint angles, component capacities, met-ocean and fatigue damage is safely managed. Riser analysis can address strength, fatigue, and clashing issues during in-service operations, hang-off, recoil, installation, and retrieval. Fatigue damage due to load sharing between main pipe and auxiliary lines is further addressed.

Uncertainties can exist due to variations in environmental conditions, complex response characteristics, and in design input parameters. Monitoring of all riser systems can address these uncertainties through allowing real-time comparisons to result from measured and predicted response to better calibrate existing design models. This section covers standard riser analysis as shown in Fig. 14.10.

Following a riser analysis exercise, operators and drilling contractors shall review the input data methods and modeling applied to use output results to best meet operational and well integrity use. The primary drilling riser responses of concern occur at the ends of the riser. At the upper end the primary issues are *riser tension*, *tensioner stroke*, and *top riser angle*. At the lower end of the riser the primary issues are *riser angle* and *loads and stresses applied* to the SSBOP stack and wellhead system.

The primary and influential parameters that influence riser behavior to be analyzed are *water depth, top tension, mud weight, environmental loads, riser properties, and vessel offset and dynamic motions.*

Notes:

- The riser tension is the single most important parameter in the operation of a drilling riser.
- Every time the mud weight is changed, the riser tension must also be changed.

Water Depth

As operating water depths increase, the importance of the marine drilling riser has grown. Effective analytical support of the riser and the related operations indicate it can evidently reduce the cost and risk of drilling offshore wells, where the potential of a riser incident and event can presents high consequences. The cost of a marine drilling riser system can be tens of millions of dollars, but the cost of operational downtime associated with a riser loss or failure can exceed more than one hundred million and therefore avoided mitigated and prevented.

Riser Tension

All of the marine drilling riser structural integrity and stability is provided by resisting all axial and lateral loads through tension. Only a very small amount of the riser ability is to resist lateral environmental loads resulting from the riser's structural dimensions. In many situations, once a riser is deployed, the adjustment of the riser's top tension is the only parameter used to control riser behavior. Fig. 14.11 represents a free body of a small portion (differential element) of the riser string.

Fig 14.11 illustrates the external and internal forces and pressures applied to the riser elements. The governing differential equation of motion used to analytically determine the response of the riser is also given in the figure. The *effective tension and variation in effective tension* are both included in the differential equation.

Criteria That Defines Operating Tensions

The limits used for the operational tensions criteria are defined in API RP 16Q. The key areas to consider are:

- Maximum tension criterion
- Minimum tension criterion

- Effective tension
- Lower flex joint angle criterion
- Upper flex joint angle criterion
- Stress criterion

Maximum tension (T_{max}) is set to prevent damage and failure of the riser tensioners reaching their limits. The limit according to API RP 16Q is equal to 90% of the tensioner's manufacturer rating.

$$T_{max} = 0.90\,\text{DTL}\left(\text{DTL} = \text{Dynamic tension limit,manufacturer rating}\right)$$

Use of this limit permits some fluctuation in the tensioner's pressures caused by the dynamic response of the vessel and riser without exceeding the manufacturer's rating. It is desirable to reduce this limit further for more severe locations, situations, or environmental conditions that could cause large fluctuations in the tensioner pressures.

Minimum tension is established to prevent buckling of the riser through established design standards that provide guidance to prevent the minimum acceptable effective tension (at the lower flex joint) in the riser from going below zero, i.e., the riser's effective tension remains positive over the entire riser length. Margins are further afforded to account for the uncertainties in the weight of the riser steel, the lift of the riser buoyancy and adequate tension in case a tensioner fails. Standards distinguish the rated capacity of a tensioner and the vertical tension applied at the top of the riser. All of these factors are considered in the calculation of the minimum tension used to prevent buckling. API RP 16Q provides an equation to use to calculate the minimum tensioner setting (T_{min}).

$$T_{min} = T_{SRmin}\,N / \left[R_f\left(N - n\right)\right]$$

where

- T_{SRmin} = minimum slip ring tension
- N = number of tensioners supporting the riser
- n = number of tensioners subject to sudden failure
- R_f = fleet angle and mechanical efficiency factor (usually 0.9–0.95)

Example:

Let $N = 8$, $n = 2$, and $R_f = 0.90$, then $T_{min} = 1.481\ T_{SRmin}$
Note, $n = 2$ assumes the tensioners are connected and operated in pairs.

The losses in the tensioner system must be accounted for when calculating the minimum tensioner setting. The API equation uses the variable "R_f" to account for these losses. API suggests values between 0.9 and 0.95 be used for "R_f." The minimum tension calculation must account for the number of tensioners subject to sudden failure. *Note*: The API equation uses the variable "n" for these purposes. Since the tensioners are generally tied together in pairs, one tensioner failure usually results in the loss of tension from two tensioners. For this condition, the variable "n" is equal to 2. Equal to the effective weight of the marine drilling riser, calculation of ***TSRmin*** according to API RP 16Q is as follows:

$$T_{SRmin} = W_s\,f_{wt} - B_n\,f_{bt} + A_i\left[d_m H_m - d_w H_w\right]$$

where

- W_s = submerged steel weight of the riser above the flex joint
- f_{wt} = weight tolerance factor (min. value = 1.05 unless accurately weighed, if accurately weighed a value of 1.0 can be used.)
- B_n = net lift of buoyancy material
- f_b = buoyancy loss factor (max. value = 0.96)
- A_i = internal cross sectional areas of riser including choke, kill, and auxiliary lines
- d_m = drilling fluid weight density
- H_m = height of drilling mud column above the flex joint
- d_w = seawater weight density
- H_w = depth of flex joint measured from the mean water level

T_{SRmin} is equal to the effective weight of the riser. API RP 16Q has an equation that can be used to calculate T_{SRmin}. This equation includes the submerged steel weight of the riser above the lower flex joint, the buoyancy forces provided by the buoyancy modules along with the effective weight loads provided by the drilling mud and the seawater outside the riser.

The manufacturing wall thickness tolerances used for the riser tubulars generally result in riser joint steel weights that are heavier than the nominal weights calculated using the nominal riser dimensions. This is especially true when the cost of the riser pipe is based on the weight of the riser pipe. Because of this, API requires that a weight tolerance factor be included in the T_{SRmin} calculation unless accurate weights (obtain by weighing the riser joints) are known for each riser joint.

If accurate weights are not known, a tolerance factor no <1.05 must be used when calculating the submerged weight of the steel. The buoyancy forces generated by the syntactic foam modules will degrade with time due to absorption of water by the modules. There may be a loss of buoyancy because of damage to the modules. API requires the use of a buoyancy loss factor where this factor should be no larger than 0.96.

Effective tension concepts are important and often one of the most confusing issues to be understood in order to comprehend riser behavior. Riser effective tension combines two parameters that have significant influence on riser behavior. They are:

1. The ***first parameter*** is the tension load applied to and carried by the riser. The tension loads along the length of the riser are directly correlated to the amount of tension applied at the top of the riser and the weight and buoyancy loads applied to the riser.
2. The ***second parameter*** includes the lateral forces applied to the riser by the internal and external pressures applied to the riser. The riser's internal pressure is generated by the hydrostatic head of the mud and the pressure generated by well control situations. The riser's external pressure is generated by the hydrostatic head of the seawater.

The lowest effective tension (usually at the bottom of the riser) is calculated as the top vertical tension minus the in-water weight of the riser plus the contained mud. The weight of the riser string and the mud column in the riser must both be supported by the tensioners to avoid riser buckling. To calculate the weight of the mud column, an estimate is made of the capacity of the riser pipe and the other lines (choke and kill lines and boost line) that contain mud.

Riser Angle Limits

Standards establish the riser angle limits for drilling and nondrilling operations with the riser connected. The basis required to minimize wear during rotation and tripping of the drill pipe. Limits are also necessary to assure safe operating conditions for landing casing hangers, subsea, and production equipment. When no operations are conducted, limits can be relaxed to avoid bottom-out of the flex joints. Fig. 14.12 represents a large riser angle on a connected riser during high currents.

Lower flex joint angles to be managed and controlled as low as operationally practicable to prevent excessive wear resulting (Fig. 14.13).

For design purposes and to define the operating envelopes and tensioner settings, the mean flex joint angle is limited to 2 degrees and the maximum flex joint angle (mean + dynamic) is limited to 4 degrees.

For operations performed when the riser is still connected to the SSBOP but the drill string is not turning, the maximum flex joint angle limit is 90% of the available flex joint angle. *Note*: Flex joints can have an available angle of 10 degrees the limit is usually 9 degrees.

***Upper flex/ball joint* angles**: An allowable criterion, is similar to that used for the lower flex joint angle. As there is no direct mechanism to monitor the upper flex/ball joint angle during operations, criteria are only used to define the riser operating envelopes and tensioner settings. In the field, adjustments may be made to the vessel offset or trim if problems are observed while performing drilling operations. Upper flex joint criteria are:

- Prevent excessive wear during drilling operations
  - Mean angle <2 deg. for design
  - Maximum angle <4 deg. for design
- Permit running of large diameter tools
- Reduce difficulty with drill pipe and casing makeup operations
- Reduce wear on the slip joint packing element
- Prevent damage to flex/ball joint during suspended operations
  - Maximum angle <90% of available flex/ball joint angle
- Prevent contact/impact of the riser, choke and kill hoses or tensioners with the vessel

Stress criteria are only used to define the riser operating envelopes and recommended riser tensioner settings. The stresses are calculated in the riser analyses performed for the various operating scenarios. There is no in the field monitoring of the riser stresses. The stress criteria are set to:

- Prevent structural deformation and possibly failure of the riser
- Prevent fatigue failure of the riser
- Stresses used to define the operating limits are determined from computer analysis

Maximum riser stresses (that check axial bending and hoop stresses) are generally limited to 67% of yield strength to ensure that the maximum tension applied to the riser is within the capacity of the riser connectors. In addition, alternating stresses are limited as per standards with the intent to limit the fatigue damage in the connector and the riser pipe. *Note*: More explicit fatigue analysis is typically conducted to better assure fatigue damage in a riser under wave loading conditions. *Note*: *VIV fatigue analysis* is generally considered more severe than wave loading and is therefore conducted on risers to check the fatigue damage done under high current conditions.

Minimum top tension *in a connected riser* can be governed by riser recoil consideration limits identified from within an analysis. Here, top tension must be high enough to ensure that the LMRP will unlatch cleanly from the SSBOP during an emergency disconnect. The limiting value is the clearance between the LMRP and the SSBOP after disconnect, if and when the LMRP cycles back downward toward the SSBOP due to vessel heave motion. A reasonable clearance is chosen to avoid damage based on the physical dimensions of the LMRP and SSBOP.

Maximum top tension based on riser recoil is limited to no more than the value that could cause excessive slack in the tensioning lines as the riser disconnects and moves upward. This effect can be stopped by a combination of the riser recoil system and an arrangement in which the tensioners bottom out before the telescopic joint collapses. This arrangement provides for the riser having no force applied to it after the tensioners have bottomed out. This provides some assurance that the riser does not apply force to the rig floor even at relatively high tensions. *Note*: These topics are discussed with riser recoil later in this section.

Riser Operating Limits

Standards and maximum load operating conditions expected define design and operating limits used for marine drilling risers for top tension flex joint angles, maximum stresses, and dynamic stresses (Table 14.1). Different limits for each one of these riser parameters/responses are provided for three different riser operating conditions. These include:

TABLE 14.1 Marine Drilling Riser Operating and Design Guidelines

	Connected Riser Operations		
Design Parameter	**Drilling**	**Nondrilling**	**Riser Disconnected**
FLEX JOINT CRITERIA			
Mean flex/ball joint angle (upper and lower)	2.0 deg.	N/A	N/A
Max. flex/ball joint angle (upper and lower)	4.0 deg.	90% Available	90% Available
STRESS CRITERIA			
Method "A":			
Allowable stress (mean + max. dyn. stress amplitude)	$0.40\ S_{yield}$	$0.67\ S_{yield}$	$0.67\ S_{yield}$
Method "B":			
Allowable stress (mean + max. dyn. stress amplitude)	$0.67\ S_{yield}$	$0.67\ S_{yield}$	$0.67\ S_{yield}$
Allowable sig. dyn. stress range			
at SAF < 1.5	10 ksi	N/A	N/A
at SAF > 1.5	15 ksi/SAF	N/A	N/A
TOP TENSION CRITERIA			
Minimum top tension	T_{min}	T_{min}	N/A
Dynamic tension limit	DTL	DTL	N/A
Maximum tensioner setting	90% DTL	90% DTL	N/A

DTL, dynamic tension limit, defined as the vessel's maximum tensioning capability; *Syield*, riser pipe yield stress; *SAP*, stress amplification factor, defined as the ratio of the local peak alternating stresses to the nominal alternating stress in the pipe wall.
Source: Kingdom Drilling training.

- ***Riser connected—drilling, criteria*** are used when drilling operations are being performed and the drill string is rotating.
- ***The riser connected—nondrilling***, criteria are used when drilling operations have been suspended.
- ***Riser disconnected,*** criteria are used when the riser is not connected to the subsea wellhead and is hanging from the vessel.

Riser disconnected may occur when running or retrieving a riser, with the resulting riser then hanging from the vessel to wait out a storm. Another disconnect is when the lower marine riser package (LMRP) is separated from the SSBOP in a *planned or unplanned*, emergency disconnect sequence as detailed later in this chapter.

Riser Analysis—Input data

The data required to perform the analyses of the various riser operations can be divided into three (3) categories: ***Riser, vessel,*** and ***environmental*** **data**.

Riser data define the configuration of the riser system and include all information required to model the various configurations to be evaluated. Information required to evaluate riser responses compared to the design criteria, such as material yield strength, must be provided. The proposed riser space-out and mud weights to be used during drilling operations must be provided. Here, it may be necessary to change the proposed riser space-out in order to satisfy the design criteria. Therefore, the riser analyst must be supplied with a complete list and description of the available joints on the vessel, so the appropriate space-out changes can be made. Mud weights to be used are also needed.

Vessel data include information required to model the motions and interfaces between the vessel and the riser analysis. This would include definition of the vessel's tensioner capacity, vessel motions (via RAOs; Example provided in Table 14.2), critical dimensions (such as the drill floor height), and the vessel offset ranges to be considered.

Typical data required are:

- Tensioner capacity
  - Number of tensioners and capacity of each
  - How many tensioners are operated together
- Vessel motion response amplitude operators (RAOs)
- Critical dimensions
  - Elevation of drill floor above mean water level
- Vessel offset ranges to be considered
  - Mean offset ranges with associated dynamic variation in offset

The example RAO table in Table 14.2 is provided for a 0 degree weather heading.

The RAO values along with the RAO phase angles are needed for the riser analysis. Therefore, the phase angles must be provided to the analyst with the RAO amplitudes. The sign convention used to generate the vessel RAOs must be provided with the RAOs to make sure the RAOs are interpreted correctly (Fig. 14.14).

Environmental data vary from region to region as outlined in Chapter 4 (Fig. 4.2 and Table 4.1) and must include all information required to define the sea states and currents that riser may be subjected to. It shall include the water depth, definitions of the sea states

TABLE 14.2 Example RAO Table for a Deepwater Semisubmersible Drilling Vessel

Weather Heading = 0 degree												
	Surge RAO		Sway RAO		Heave RAO		Roll RAO		Pitch RAO		Yaw RAO	
Period (s)	RAO (ft/ft)	Phase (deg.)	RAO (ft/ft)	Phase (deg.)	RAO (ft/ft)	Phase (deg.)	RAO (ft/ft)	Phase (deg.)	RAO (ft/ft)	Phase (deg.)	RAO (ft/ft)	Phase (deg.)
30.0	0.8886	89.5	0.0000	0.0	1.0502	7.8	0.0000	0.0	0.0237	−87.5	0.0000	0.0
28.0	0.8776	89.6	0.0000	0.0	1.0675	9.1	0.0000	0.0	0.0332	−88.5	0.0000	0.0
26.0	0.8614	89.6	0.0000	0.0	1.1030	11.6	0.0000	0.0	0.0456	−89.1	0.0000	0.0
24.0	0.8428	89.6	0.0000	0.0	1.1657	15.6	0.0000	0.0	0.0582	−89.4	0.0000	0.0
22.0	0.8211	89.6	0.0000	0.0	1.2868	23.6	0.0000	0.0	0.0713	−89.6	0.0000	0.0
20.0	0.7885	89.7	0.0000	0.0	1.5648	54.9	0.0000	0.0	0.0886	−89.7	0.0000	0.0
18.0	0.7483	89.7	0.0000	0.0	0.5318	131.4	0.0000	0.0	0.1069	−89.8	0.0000	0.0
16.0	0.6873	89.7	0.0000	0.0	0.1918	−19.5	0.0000	0.0	0.1292	−89.9	0.0000	0.0
14.0	0.5945	89.6	0.0000	0.0	0.3399	−10.7	0.0000	0.0	0.1531	−90.1	0.0000	0.0
12.0	0.4538	89.4	0.0000	0.0	0.3239	−5.5	0.0000	0.0	0.1704	−90.3	0.0000	0.0
11.0	0.3697	89.4	0.0000	0.0	0.2831	−2.7	0.0000	0.0	0.1718	−90.4	0.0000	0.0
10.0	0.2530	89.7	0.0000	0.0	0.2102	1.7	0.0000	0.0	0.1633	−90.0	0.0000	0.0
9.0	0.0963	93.5	0.0000	0.0	0.1072	68	0.0000	0.0	0.1321	−87.1	0.0000	0.0
8.5	0.0433	97.4	0.0000	0.0	0.0767	7.9	0.0000	0.0	0.1165	−85.0	0.0000	0.0
8.0	0.0433	−95.6	0.0000	0.0	0.0392	9.8	0.0000	0.0	0.0864	−80.0	0.0000	0.0
7.5	0.1083	−73.4	0.0000	0.0	0.0093	42.8	0.0000	0.0	0.0411	−63.2	0.0000	0.0
7.0	0.1268	−66.5	0.0000	0.0	0.0102	150.1	0.0000	0.0	0.0135	−43.9	0.0000	0.0
6.5	0.0944	−63.8	0.0000	0.0	0.0183	164.1	0.0000	0.0	0.0104	56.3	0.0000	0.0
6.0	0.0406	−78.1	0.0000	0.0	0.0175	−159.8	0.0000	0.0	0.0141	46.0	0.0000	0.0
5.5	0.0271	112.5	0.0000	0.0	0.0177	−71.6	0.0000	0.0	0.0157	22.5	0.0000	0.0
5.0	0.1321	98.9	0.0000	0.0	0.0025	−0.1	0.0000	0.0	0.0069	−58.6	0.0000	0.0
4.5	0.1003	129.6	0.0000	0.0	0.0126	−175.1	0.0000	0.0	0.0019	−30.4	0.0000	0.0
4.0	0.0109	−48.0	0.0000	0.0	0.0015	84.9	0.0000	0.0	0.0037	168.5	0.0000	0.0
3.5	0.0152	138.2	0.0000	0.0	0.0013	−109.4	0.0000	0.0	0.0011	−17.1	0.0000	0.0
3.0	0.0041	−132.0	0.0000	0.0	0.0002	156.4	0.0000	0.0	0.0003	166.1	0.0000	0.0

Source: Elsevier.

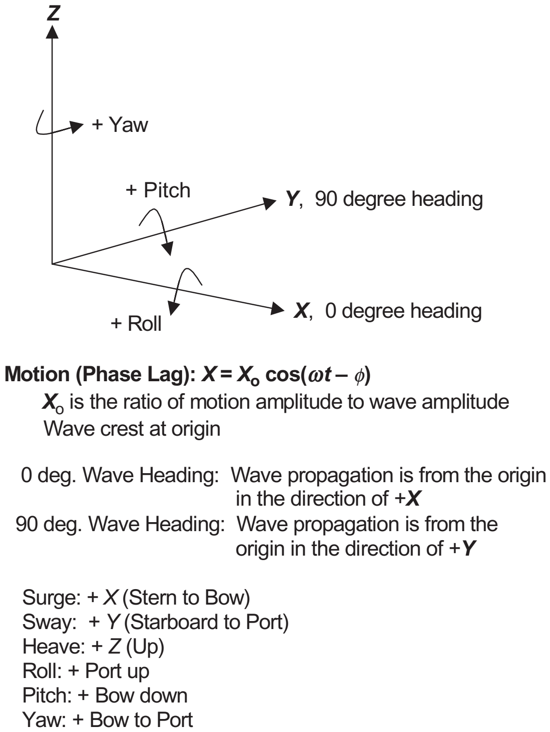


FIG. 14.14 RAO sign convention. *Source: From Kingdom Drilling training.*

and current profiles to be considered, and, in some cases, definition of the soil properties that may be required for: *Drive-off/drift-off analysis and/or to evaluate the strength of the wellhead and conductor strength*, to full appreciated the variance and diversity of conditions that can exist. A region's deepwater metocean design criteria as an example are presented in Table 14.3.

Accurate metocean data for a new region in regards to riser analysis are usually more difficult. Good data make a significant difference to assess if a well can be safely and economically drilled at a specific operating period or not.

The riser analysis is based primarily on the evident *wind, waves*, and *current profile* conditions for a specific well site. Whatever the case, a common understanding of the basis of conditions between the metocean and riser specialist is an important part of this process.

The current profiles often drive the analytical results used for determining when operations through the riser should be shut down. The steady current loading over its length influences the riser's deflections, top and bottom angles that restrict operations. Should high currents exist, problems can exist as shown in Fig. 14.15. *Note*: Current profile data at specific deepwater sites can be more difficult to collect than data on winds and sea states due to the large amount of data to be gathered throughout the water depth.

Furthermore, current features in many deepwater regions of the world tend to be more difficult to analyze due to a lesser understanding of what drives them.

Winds and waves are important when considering the management of riser operations in storms. Although not as important for determining the shape of the riser, the winds and sea

TABLE 14.3 Typical Metocean Data Criteria, Gulf of Mexico

	Riser Connected/Drilling						**Riser Connected/Nondrilling**				**Riser Pulled**	
	1-Year Winter Storm		**10-Year Eddy**		**Sudden Squall**		**10-Year Winter Storm**		**100-Year Eddy**		**100-Year Hurricane**	
Winds	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**
V_{wind} (1 h)	18.0	35.0	15.0	29.2	26.0	50.5	22.0	42.8	15.0	29.2	45.0	87.5
V_{wind} (1 min)	21.1	41.0	17.7	34.4	31.4	61.0	26.0	50.5	17.7	34.4	53.1	103.2
Seastate	m	ft	m	ft	m	ft	m	ft	m	ft	m	ft
H_s	4.9	16.0	3.5	11.5	1.5	4.9	5.8	19.0	3.5	11.5	12.5	41.0
T_p(s)	10.0		9.0		5.9		10.6		9.0		15.0	
Mean T(s)	7.7		6.9		4.6		8.2		6.9		11.6	
Current												

m	**ft**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**	**m/s**	**knots**
Surface		0.30	0.59	1.40	2.72	0.30	0.59	0.30	0.59	2.00	3.89	1.00	1.94
60	197			1.40	2.72					2.00	3.89	1.00	1.94
76	249	0.30	0.59			0.30	0.59	0.30	0.59				
77	253	0.15	0.30			0.15	0.30	0.15	0.30				
100	328			1.40	2.72					2.00	3.89	0.20	0.39
150	492			1.10	2.14					1.50	2.92		
200	656			0.80	1.56					1.20	2.33		
300	984			0.60	1.17					0.80	1.56		
500	1641			0.30	0.58					0.40	0.78		
Near bottom		0.15	0.30	0.20	0.39	0.15	0.30	0.15	0.30	0.20	0.39	0.20	0.39

Notes: Drilling can be conducted with mud weights of up to 16 ppg mud. Depending on the site specific current conditions, drilling could be limited for certain mud weights. Some level of vortex-induced vibration (VIV) could be experienced in the eddy conditions. Depending on the site-specific current conditions, vortex-suppression devices could be warranted.
Source: Elsevier.

states have a greater bearing on when the riser should be retrieved to surface, i.e., when station-keeping system is unable to maintain vessel at a safe operating offset distance from the well.

Connected Riser

The primary objective of the connected riser analysis is to define the tensioner settings required to maintain acceptable upper and lower flex joint angles and riser stresses for various vessel offsets, water depths, metocean conditions, and mud weights (Fig. 14.16).

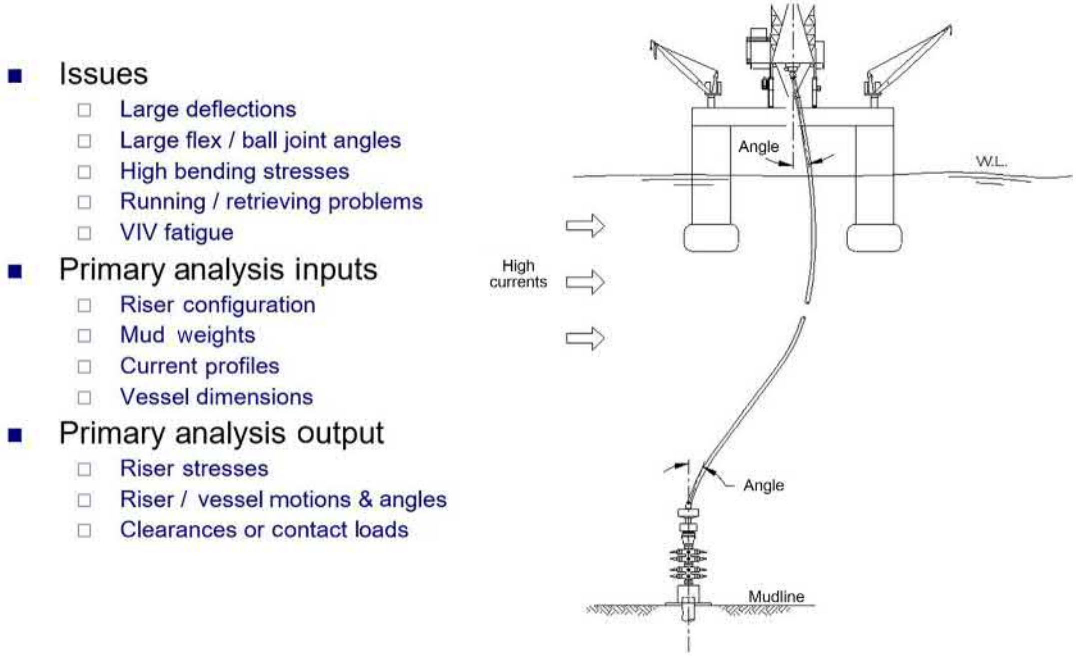


FIG. 14.15 High current primary input/output analysis.

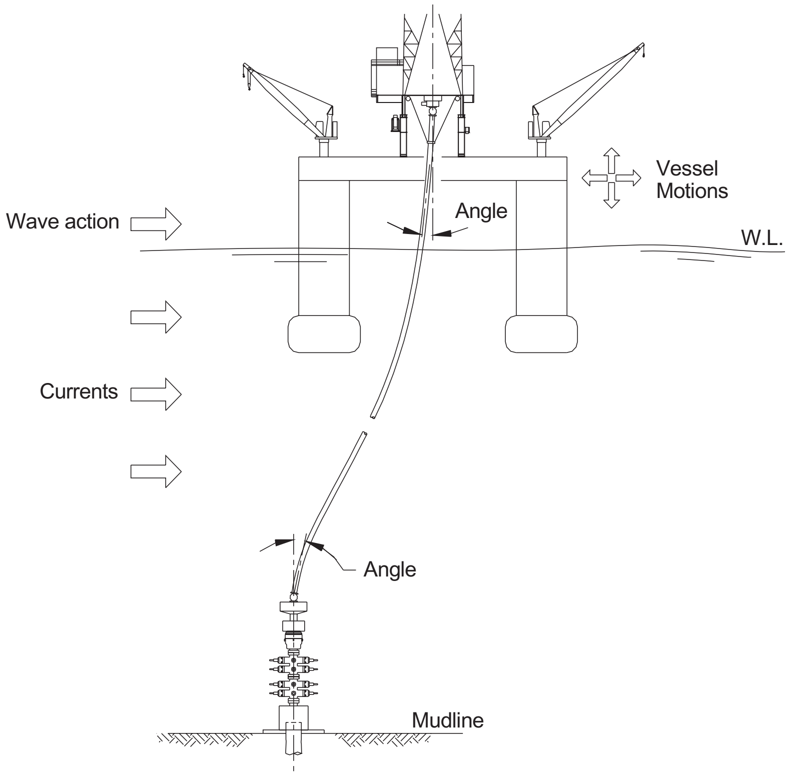


FIG. 14.16 Riser connected analysis. *Source: Kingdom Drilling training 2006.*

Results of an analysis are summarized in charts and tables defining the operating envelope(s) for the connected riser.

Operating envelopes are to be agreed and provided for normal drilling operations (drill string rotating) and connected nondrilling operations (drill string not rotating). Additionally, wellhead and flex joint loads are often given and are useful in evaluating wellhead, connector, and conductor capabilities. However, most riser analysts assume rigid soil conditions, so these numbers can be higher than actual. Loads at the flex joint are not sensitive to modeling of the soil and can be used to predict wellhead and conductor loading with alternate modeling programs.

Wellhead Housing

The standard bore sizes for deepwater subsea wellhead housings include 18¾″ (476.3 mm), 16¾″ (425.5 mm), and 13⅝″ (346.1 mm). The selection of the wellbore nominal bore facilitates the size of the casing liner strings tools and equipment that can be run through the wellhead and hung off in the wellhead housing. The most common nominal bore size in use today is 18¾″ (476.3 mm). The riser inner nominal bore diameter is then >18¾″ (476.3 mm) Most deepwater risers have a 21″ (533.4 mm) (or, in some cases, 22″ (555.8 mm)) outer diameter, leaving enough margin for riser wall thickness, nominal bore, burst, collapse, and design factors necessary for a deepwater riser.

Riser Design, Size and Specifications

Riser design size and specifications, outside and inside diameters, result from the project scope, water depths, and are based on reservoir information, the size of the casings and completion determined, the expected well flow rate, and a bottom-up well design. The wall thickness of each riser string is computed based on maximum load: shut-in pressures, drilling, and completion mud weights to assure design ***burst*** and ***collapse*** criteria required. The outside dimensions of all components that must pass through the riser pipe to determine the minimum internal through bore diameter. The maximum load hoop stress determined usually governs the wall thickness of the riser pipe.

In deepwater, the wall thickness is more dependent on the *axial stress*. The capped-end force generated by the internal pressure should also be considered in computing the axial stress. The *bending stress* is a determining factor at the upper and lower ball joints of the riser. In these areas, thicker riser elements are required to limit the stresses. The dimensions of the stress joint are more difficult to compute since they must be strong and flexible at the same time. Generally, a finite element program is used to determine bending maximum angle at these joints. Dimensions are then adjusted so that the required strength required for each component results.

Riser joint properties are based on weights in air, in water, with buoyancy, and without buoyancy. These weights can vary as the joints are deployed in deep water due to compression of the buoyancy and water ingress. Other properties include the joint length and the hydrodynamic properties such as drag diameter, drag coefficient, inertial diameter, and inertial coefficient. Typical values for the joint properties used in an ultradeep water riser model are shown later in a presented case study in Tables 14.4 and 14.5.

TABLE 14.4 Riser Joint Properties

Properties	22 in. × 1.125 in. Wall w/55.5 in., 3 k Buoyancy	22 in. × 1.125 in. Wall w/56.5 in., 5 k Buoyancy	22 in. × 1.125 in. Wall w/59.5 in., 7.5 k Buoyancy	22 in. × 1.125 in. Wall w/60 in., 10 k Buoyancy	1.125-in. Wall Bare Joint
In-air weight of bare joint (lbs)[a]	35,644	35,644	35,644	35,644	35,644
Joint length (ft)[a]	75	75	75	75	75
In-air weight/length of bare joint (lb/ft)[b]	475.3	475.3	475.3	475.3	475.3
In-air weight of buoyancy an joint (lbs)[a]	22,080	24,555	31,145	35,000	0
Net lift of buoyancy on joint (lbs)[a]	30,330	30,565	30,335	27,920	0
In-water weight of hare joint (lbs)[c]	30,975	30,975	30,975	30,975	30,975
In-air weight of joint w/buoyancy (lbs)[d]	57,724	60,199	66,789	70,644	35,644
In-water weight of joint w/buoyancy (lbs)[e]	645	410	640	3055	30,975
Buoyancy compensation[f]	97.92%	98.68%	97.93%	90.14%	0.00%
Drag diameter (inches)[a]	55.5	56.5	59.5	60.0	41.3
Drag coefficient[a]	1.00	1.00	1.00	1.00	1.00
Inertial diameter (in.)[a]	55.5	56.5	59.5	60.0	37.5
Inertial coefficient[a]	2.00	2.00	2.00	2.00	2.00

[a] *Information provided.*
[b] *In-air weight divided try joint length.*
[c] *In-water weight of bare joint equals 0.869 times in-air weight of bare joint.*
[d] *In-air weight of joint w/buoyancy is in-air weight of buoyancy plus in-air weight of bare joint.*
[e] *In-water weight or joint with buoyancy is in-air weight of a bare joint minus net lift of buoyancy.*
[f] *Buoyancy compensation is (in-water weight of bare joint minus in-water weight of joint with buoyancy) divided by in-water weight of bare joint.*
Source: Elsevier.

Burst and Collapse

For riser burst, water depth, highest mud weight, fabrication tolerances and the yield strength of the pipe are used to determine the minimum wall thickness of the riser. API Bulletin 5C3 (1994) is commonly used as the basis for this calculation.

Burst (Fig. 14.17) is checked to ensure that the riser can withstand the interior pressure from the drilling fluid (mud).

The bore of the wellhead housing dictates the bore (inside diameter) of the riser pipe, and resistance to burst and collapse pressures required dictates its wall thickness.

TABLE 14.5 Installed Weight of Riser String in 9000 ft of Water

Equipment Supported by Tensioners	Quantity	Unit Length	Length	In-Air		In-Water	
				Unit Weight	Total Weight	Unit Weight	Total Weight
Tensioner ring[a]	1	0 ft	0 ft	55,000 lb	55.00 kips	55,000 lb	55.00 kips
Slip joint outer barrel	1	75 ft	75 ft	45,052 lb	45.05 kips	39,150 lb	39.15 kips
Middle flex joint	1	75 ft	75 ft	52,060 lb	52.06 kips	45,240 lb	45.24 kips
10-ft pup joint	1	10 ft	10 ft	11,124 lb	11.12 kips	9667 lb	9.67 kips
20-ft pup joint	1	20 ft	20 ft	15,658 lb	15.66 kips	13,607 lb	13.61 kips
Joint with 3000-ft depth buoyancy	36	75 ft	2700 ft	57,724 lb	2078.06 kips	645 lb	23.21 kips
Joint with 5000-ft depth buoyancy	28	75 ft	2100 ft	60,199 lb	1685.57 kips	410 lb	11.47 kips
Joint with 7500-ft depth buoyancy	33	75 ft	2475 ft	66,789 lb	2204.06 kips	640 lb	21.11 tips
Joint with 10,000-ft depth buoyancy	13	75 ft	975 ft	70,644 lb	918.37 kips	3055 lb	39.71 kips
Bare joint with 1.125-in. wall	7	75 ft	525 ft	35,644 lb	249.51 kips	30,975 lb	216.82 kips
LMRP with one annular	1	15 ft	15 ft	225,600 lb	225.60 kips	196,046 lb	196.05 kips
BOP	1	40 ft	40 ft	500,700 lb	500.70 kips	435,108 lb	435.11 kips
		w/BOP	9010 ft	w/BOP	8040.75 kips	w/BOP	1106.14 kips
		w/LMRP	8970 ft	w/LMRP	7540.05 kips	w/LMRP	671.03 kips
		w/o LMRP	8955 ft	w/o LMRP	7314.45 kips	w/o LMRP	474.98 kips
Hang-off ratio of in-water weight to in-air weight of string w/LMRP:							8.90%
Top minus bottom pipe wall tension (all in-water weights except in-air weight for riser tube):							768.62 kips
Bottom pipe wall tension in riser string above LMRP (3000 k top):							2231.38 kips

[a] *In-air weights used.*
Source: Elsevier.

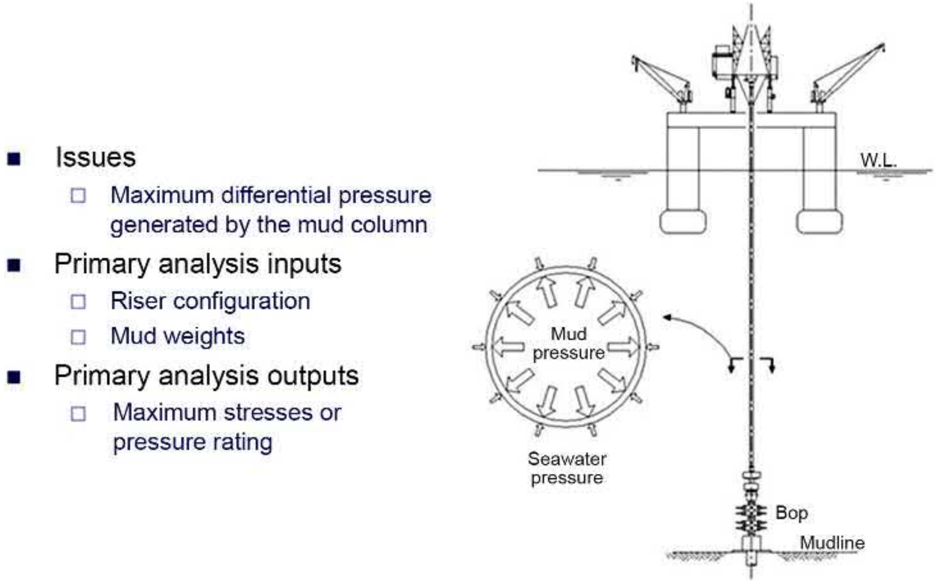


FIG. 14.17 Riser burst. *Source: Kingdom Drilling 2006.*

Collapse (Fig. 14.18) is checked to ensure the riser can withstand exterior pressure due to a specified voided condition within the riser and has sufficient resistance to meet the conditions imposed by the operator or drilling contractor. Deepwater risers can collapse while in operation if the riser's internal pressure falls significantly below the seawater pressure on the outside of the riser. This can happen due to loss of circulation, an emergency disconnect, riser evacuation, or because of a hole in the riser. The best prevention of this is for the riser's wall thickness to be thick enough to prevent this from occurring.

Unfortunately, this can become a significant problem for deepwater riser systems since the required wall thickness may be too large to be practical.

Collapse calculations using API 5C3 demonstrate that a 22″ (559 mm) riser with 1⅛″ (28.6 mm) wall thickness resists collapse, if it is completely void in 9000 ft (2743 m) of water. With fabrication tolerances of 8% on wall thickness, the riser resists collapse with the top 8000 ft (2438 m) of riser void. *Note*: The calculation depends on the voided depth of riser, the yield strength of the pipe (in some cases), and the fabrication tolerances of the pipe.

Fig 14.19 illustrates the external pressure resistance vs. depth compared to the applied pressure from the hydrostatic head of seawater. The riser's collapse resistance varies with depth due to a dependence on pipe wall tension.

For various wall thicknesses of 21″ (533 mm)risers and for various pipe wall tensions, calculations of water depth ratings of a voided riser pipe have been done based on the API *5C3*. The results are shown in Fig. 14.20. Curves are based on a "no margin" for fabrication tolerances.

Vessel Motions and Moonpool Dimensions

A vessel's response amplitude operators (RAOs) used in riser analysis can be analytical calculations or estimates derived from the model tests conducted (as shown in Chapter 4

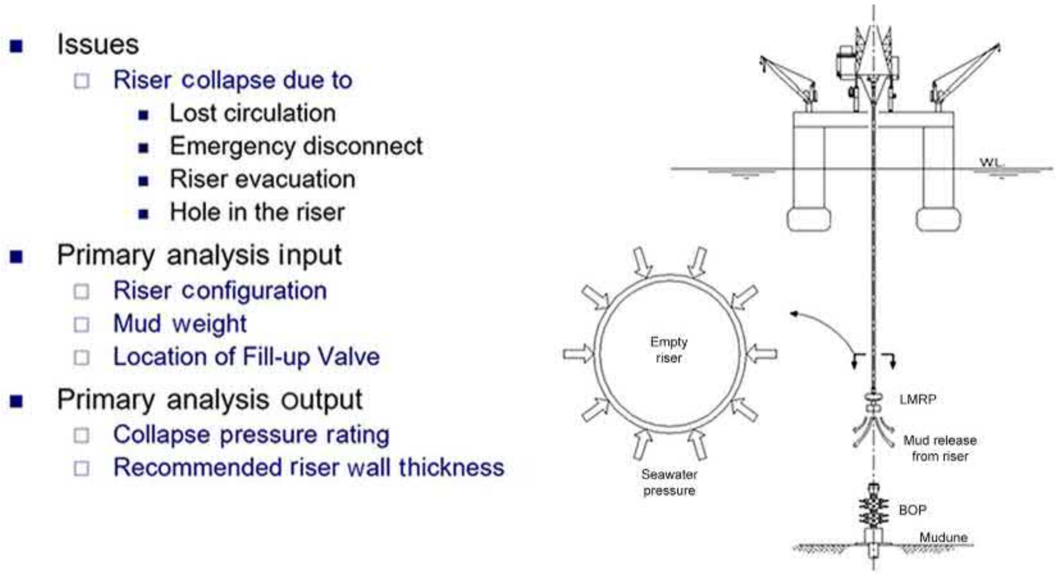


FIG. 14.18 Riser collapse. *Source: Kingdom Drilling 2006.*

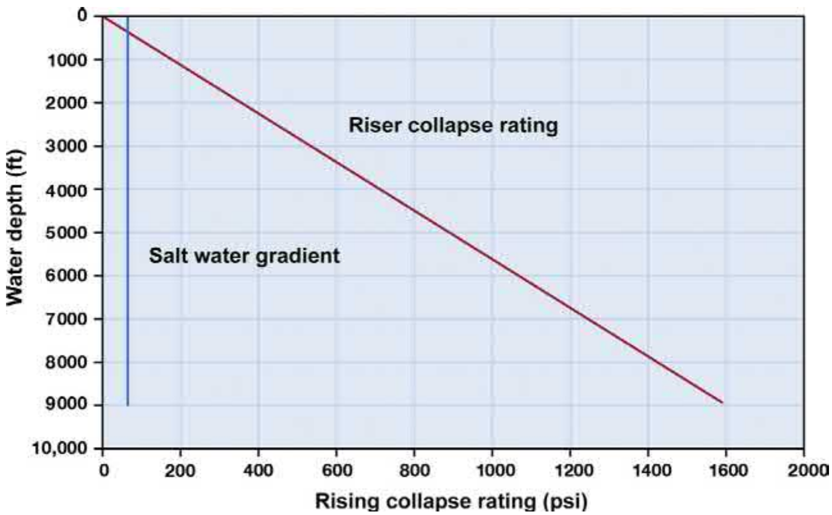


FIG. 14.19 Riser collapse (22 in. (558.8 mm) × 1.125 in. (28.6 mm) plus 8% machine tolerance). *Source: Elsevier.*

RAO calculations and Fig. 4.24 outline). A vessel's RAOs are converted into the format required by the riser analysis program. In cases in which the vessel is not in a head seas or beam seas heading, planar riser analysis programs require that the surge and sway motions be combined.

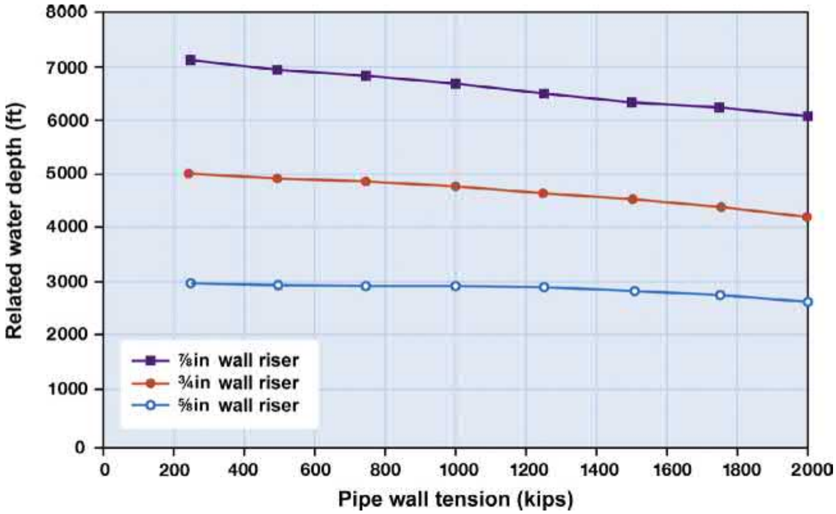


FIG. 14.20 Riser collapse ratings (21 in. (533.4 mm) nominal wall thickness). *Source: Elsevier.*

Dimensions used for the ultradeep water drillship riser model illustrated in this section are:

- Upper flex joint center above water line—63 ft (19.2 m).
- Drill floor above water line—85 ft (25.9 m).
- Vertical center of gravity (VCG) above baseline of vessel (keel)—47.55 ft (14.5 m).
- Draft of the vessel—29.5 ft (9 m).
- Height of the BOP stack—63 ft (19.2 m).
- Height of the BOP stack from wellhead connector to center of the bottom flex joint—*55* ft (16.8 m).

Note: These terms were used for the illustrated and associated figures that follow.

The riser stack-up (Fig. 14.21) consists of joints with lengths dependent on the drilling rig. Tables 14.4 and 14.5 present an illustrative example of riser joint properties and weight of each component of ultradeep water drilling rig and well. Each component listed has its submerged weight listed, with the exception of the tensioner ring, which is expected to be above the water line. The total weight of the riser without the LMRP is used for determining the top tension required to support the string. The total weights of the riser with the LMRP and with the full SSBOP are used to determine the hanging weight of the string.

Considerations in the joint stack-up of a riser string include assuring the riser is heavy enough to be deployed without excessive angles in the currents expected during deployment, and to assure the weight of the riser and SSBOP is within the hook load capacity of the vessel. This weight is regulated by slick joints or partially buoyant joints in the string. The slick joints are often placed at the bottom of the string to get full benefit from the weight as deployment of the string first starts. Another consideration to be discussed later in this chapter is riser recoil. When an emergency disconnect is carried out, the presence of slick joints in the string can improve riser behavior and increase the range of top tensions to meet specified performance criteria.

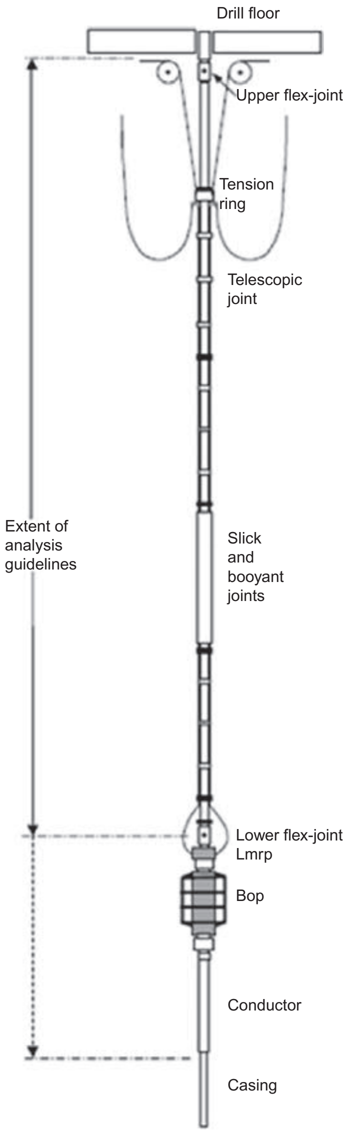


FIG. 14.21 Riser stack-up.

PERFORMANCE DRIVERS

The integrity of the connected drilling riser is largely driven by its deflected shape during the various operations that are carried out with it. During operations, restrictions are placed on the riser's deflected shape due to the need to rotate drill pipe or strip (run or pull) drill pipe through the drilling riser. When operations are suspended, restrictions on the deflected shape of the riser are reduced significantly. Due to its length, the stiffness of the riser is derived largely from its tension (similar to a cable), rather than its cross-sectional properties.

In the absence of current, the mean deflected shape of the drilling riser is driven by the applied top tension, the mean offset at the top of the riser, the in-water weight of the drilling riser ("effective" tension gradient).

A current profile applies force to the riser that further influences the mean shape. The dynamic motion of the riser is driven by the top motion of the vessel coupled with the fluctuating force resulting from the waves and current. Other factors such as end constraints at the top and bottom of the riser also influence the riser's mean shape and the dynamic motion.

OPERATING LIMITS

Table 14.6 shows based on the case study data applied, how the in-air weight of the mud column above the water line and the submerged weight of the mud column below the water line is added to the string weight to determine the riser string weights with mud. The API minimum riser tensions are calculated using the installed weight of the riser with mud. The values calculated are vertical tensions at the top of the riser. For this calculation, the following information was used:

- *Tolerances*—1% on the weight of riser steel and 1% on net lift from the buoyancy material.
- *Tensioners down*—Positive tension is maintained if one tensioner goes down.
- *Maximum tension limit*—API RP 164 guidance is that top tension should be no >90% of the dynamic tensioning limit (same as rated tensioner capacity).

Note: This tension multiplied by a reduction factor for fleet angle only (*note*: in this particular example, the tensioner system compensates for mechanical losses, so that the estimate is 0.99) gives the maximum API tension in terms of vertical tension at the top of the riser. A maximum tension limit 90% of the installed capacity prevents the relief valves from popping under most conditions. In practice, a lower maximum tension limit is generally applied.

Table 14.7 shows the calculation of minimum and maximum API tensions for a range of mud weights. Fig. 14.22 shows the plot of the results and a slightly higher tension than the API minimum tension at very low mud weights. In this range, a nominal tension (higher than the API minimum tension) is applied to the riser to assure that the riser can have a "planned" disconnect carried out successfully without increasing the tension.

This tension is sufficient to support the in-water weight of the riser plus the LMRP (excluding the weight of the mud in the riser). A further tensioning factor of an ultradeep water riser is compaction of the buoyancy material leading to a reduction in the net lift of the buoyancy.

Case study example: when comparisons were made to manufacturers' values, weights recorded during deployment of a riser showed that the actual installed weight of the riser string can be matched by using 1% additional steel weight and slightly more than a 3% decrease in net lift due to buoyancy. Although this is within the API tolerance levels, when compared to the manufacturers' values in 9000 ft (2743 m) of water, this can amount to 150 kips of additional weight for the entire riser string.

TABLE 14.6 Installed Riser Weight With Mud

Riser String Weight With Mud in Seawater	
Riser capacity (gal/ft)	18.23 gal/ft
Seawater density (ppg)	8.55 ppg
Length (ft) (FJ to WL)	8940 ft
Length (ft) (WL to DH)	50 ft
Wt. of riser string (kip)	474.98 kip

Mudweight	**Weight of Mud in Seawater From Flexjoint to Waterline**[a]	**Weight of Mud in Air From Waterline to Diverter**[b]	**Weight of Riser String With Mud in Seawater**[c]
ppg	**kip**	**kip**	**kip**
8.55	0.00	7.79	482.77
9	73.34	8.20	556.52
9.5	154.83	8.66	638.47
10	236.32	9.12	720.41
10.5	317.80	9.57	802.36
11	399.29	10.03	884.30
11.5	480.78	10.48	966.24
12	562.27	10.94	1048.19
12.5	643.76	11.39	1130.13
13	725.24	11.85	1212.08
13.5	806.73	12.31	1294.02
14	888.21	12.76	1375.96
14.5	969.71	13.22	1457.91
15	1051.20	13.67	1539.85
15.5	1132.68	14.13	1621.79
16	1214.17	14.58	1703.74

FJ, flex joint; *WL*, water line; *DH*, diverter housing.
[a] *Mudweight in seawater * riser capacity * length from flex joint to waterline.*
[b] *Mudweight in air * riser capacity * length from water line to diverter housing.*
[c] *Riser string weight + weight of mud (FJ to WL) + weight of mud (WL to DH).*
Source: Elsevier.

TENSIONER STROKE TELESCOPIC JOINT STROKE LIMITS

In an emergency disconnect sequence (EDS) or drift-off condition, the limits on tensioner and telescopic joint stroke become important, e.g., the amount of allowable stroke-out depends on how far the telescopic joint is stroked out when it is in its nominal (i.e., calm seas) position at the site. Several factors can cause this nominal position to be “off center” including

TABLE 14.7 API Riser Tensions—Vertical Load at Slip Ring for Various Mud Weights in 9000 ft (2743 m) Water Depth

API Riser Tensions—Vertical at Slip Ring—9000 ft of Water			
In-water weight of bare joints	30.97 kips	# of joints	117
Net lift of 3 k buoyant joint	30.33 kips	# of 3 k buoyant joints	36
Net lift of 5 k buoyant joint	30.57 kips	# of 5 k buoyant joints	28
Net lift of 7.5 k buoyant joint	30.34 kips	# of 7.5 k buoyant joints	33
Net lift of 10 k buoyant joint	27.94 kips	# of 10 k buoyant points	13
Remainder of string wt. (excl. LMRP)	162.66 kips		

Mud wt.	**Weight of Riser String With Mud in Seawater**	**Steel Weight Tolerance**[a]	**Buoyancy Loss/ Tolerance**[b]	**Minimum Slip Ring Tension**[c]	**1–250 k Tensioner Loss Factor**[d]	**API Min. Rec. Tension w/I-250 k Down (T_{min})**[e]	**Tension Required for LMRP Disconnect**[f]	**Min. Rec. Tension**[g]	**Maximum Slip Ring Tension**[h]
ppg	**kip**	**kip**	**kip**	**kip**		**kip**	**kip**	**kip**	**kip**
8.55	482.77	37.87	33.12	553.76	1.091	604.15	721.03	721	2673
9	556.52	37.87	33.12	627.51	1.091	684.61	721.03	721	2673
9.5	638.47	37.87	33.12	709.45	1.091	774.01	721.03	774	2673
10	720.41	37.87	33.12	791.40	1.091	863.41	721.03	863	2673
10.5	802.36	37.87	33.12	873.34	1.091	952.81	721.03	953	2673
11	884.30	37.87	33.12	955.28	1.091	1042.21	721.03	1042	2673
11.5	966.24	37.87	33.12	1037.23	1.091	1131.62	721.03	1132	2673
12	1048.19	37.87	33.12	1119.17	1.091	1221.02	721.03	1221	2673
12.5	1130.13	37.87	33.12	1201.12	1.091	1310.42	721.03	1310	2673
13	1212.08	37.87	33.12	1283.06	1.091	1399.82	721.03	1400	2673
13.5	1294.02	37.87	33.12	1365.00	1.091	1489.22	721.03	1489	2673
14	1375.96	37.87	33.12	1446.95	1.091	1578.62	721.03	1579	2673
14.5	1457.91	37.87	33.12	1528.89	1.091	1668.02	721.03	1668	2673
15	1539.85	37.87	33.12	1610.83	1.091	1757.42	721.03	1757	2673
15.5	1621.79	37.87	33.12	1692.78	1.091	1846.82	721.03	1847	2673
16	1703.74	37.87	33.12	1774.72	1.091	1936.22	721 03	1936	2673

[a] *1.0% In-water wt. of steel: 0.01 * (wt. of bare joints plus remainder of bare string).*
[b] *1.0% Net lift of buoyancy: 0.01 * (net lift from all buoyancy).*
[c] *In-water weight plus steel weight tolerance plus buoyancy loss/tolerance.*
[d] *Factor of 1.091 covers loss of one out of 12 250-k tensioners.*
[e] *Minimum recommended tensions that satisfy API 16Q guidelines for buckling stability: min. slip ring tension times tensioner loss factor.*
[f] *In-water string weight with seawater plus in-water LMRP weight plus 50 kips.*
[g] *Maximum values of 5 and 6.*
[h] *90% of dynamic tensioning limit (rated tensioners capacity) times reduction factor (0.99).*
Source: Elsevier.

FIG. 14.22 API Riser tensions—vertical load at slip ring for a deepwater semisubmersible in 9000 ft (2743 m) water depth. *Source: Elsevier.*

the placement of pup joints in the string leading to the outer barrel to be slightly high or low on the inner barrel.

As the telescopic joint is stroked out, a margin before complete stroke out of either the tensioners or the telescopic joint must be maintained to allow for wave-frequency variations and other uncertainties. To be clarified further in the EDS/drift-off sections.

SSBOP, WELLHEAD, AND CONDUCTOR LIMITS

The SSBOP, wellhead, and conductor pipe are designed to meet a maximum load case experienced during EDS/drift-off condition. The SSBOP manufacturers provide curves that indicate the rated capacity of the flanges when loaded in tension, bending, and pressure.

The wellhead manufacturer provides rated capacities for the wellhead. The conductor has its connectors and pipe rated for tension and bending. The riser analysis results (of SSBOP, wellhead, and conductor loading) are compared against these ratings to determine whether the rating of the key weak points in the system is exceeded (Fig. 14.23).

Analysis is conducted to determine whether riser loading at the bottom flex joint is within the capacity of each of the SSBOP connectors, the wellhead, and the conductor casing. The analysis is conducted for combinations of vertical load, lateral load, and pressure load conditions specified by the operator. Depending on the component designs, the highest loading occurs during drift-off and the weakest link for bending loads is often either the wellhead connector or the casing connector closest to the wellhead connector.

Note: Under operating limits, the assumption of a rigid, vertical SSBOP is generally a conservative approach for SSBOP component loads, and a more rigorous approach involves using a coupled analysis method.

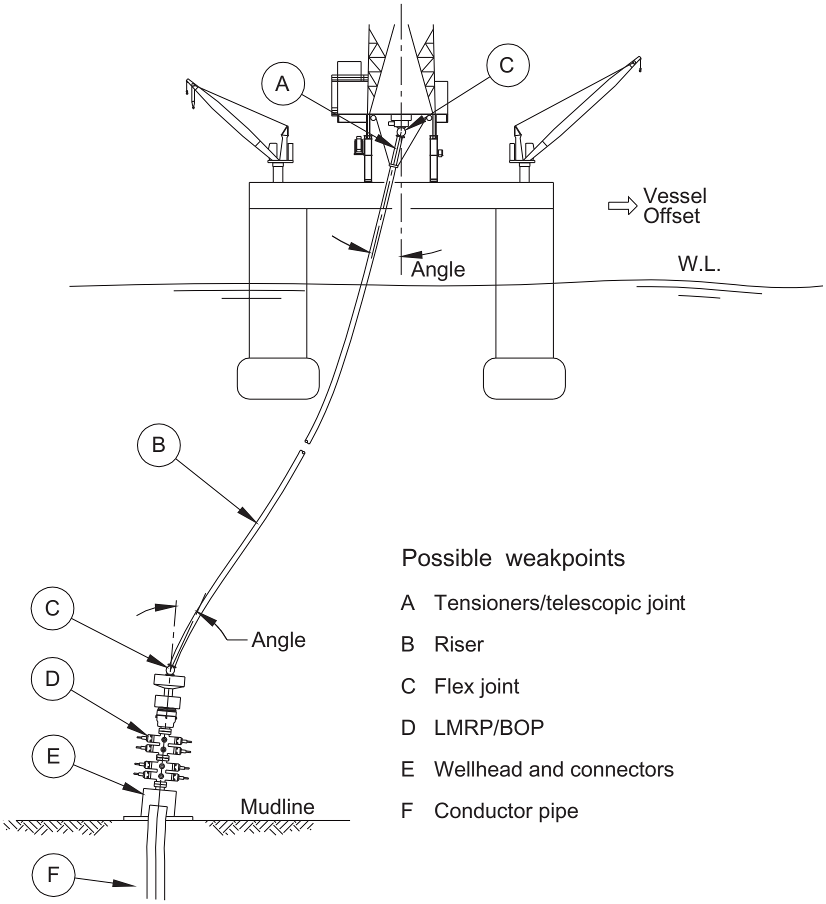


FIG. 14.23 SSBOP, wellhead, and conductor limits weak points.

After the rig is on site, the misalignment angle of the conductor casing from vertical could be large enough to warrant reanalysis to determine its influence on the component loads. This could assist in establishing a vessel position that would lead to improved bottom flex joint angles for drilling.

Another topic on operating limits involves torsional loading in special situations (Fig. 14.24) in which the vessel heading changes made by DP vessels can produce too much torque and stress problems in the riser and other components such as the LMRP/SSBOP and wellhead connections. It may also cause undesirable relative rotations between components, such as auxiliary lines, goosenecks, etc. Depending on the component designs, the weakest link identified due to torsional loading in the system would need to be acted upon if/as required. Heading changes should not cause much of a problem if the tensioner slip ring bearing reliably allows rotation or if the cumulative heading change in one direction is minimized.

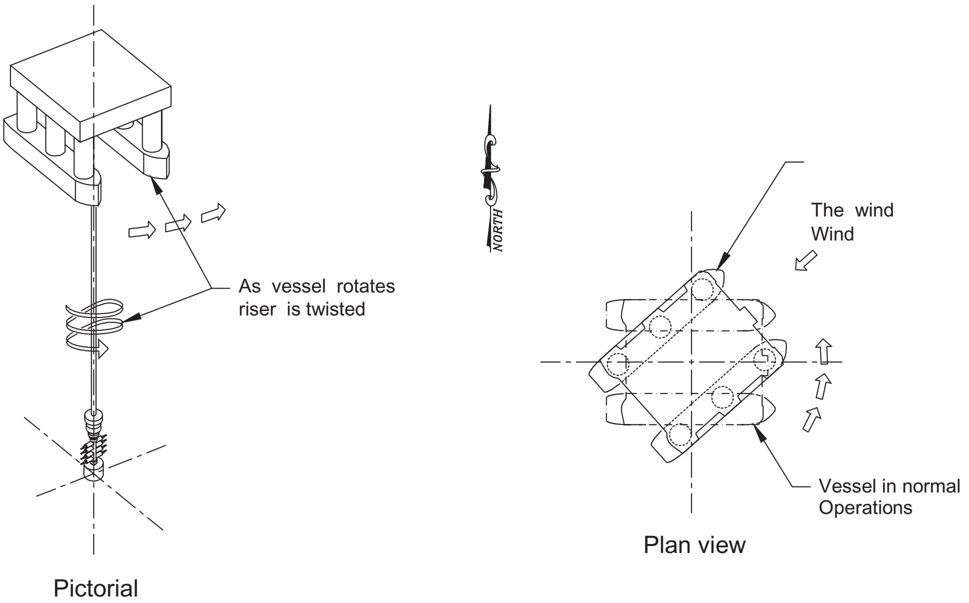


FIG. 14.24 Torsional loading in special situations.

TYPICAL OPERATING RECOMMENDATIONS

RECOMMENDED TOP TENSION VS. MEAN VESSEL OFFSET

Recommended riser top tensions are determined based on limits as outlined in this chapter except riser recoil that shall be introduced later in this chapter. The recommended top tensions are discussed in an example below.

Riser analysis for a connected riser configuration was conducted to determine if the top tensioning capacity is sufficient to support a riser in 9000 ft (2743 m) of water based on representative design metocean conditions, using up to 16 ppg (1917 kg/m^3) mud in a specific deepwater region. The riser stack-up as previously stated in the previous section was modeled using a typical riser analysis program. RAOs of the vessel (Table 14.2) and metocean conditions (Table 14.3) were used with analysis carried out for the following conditions, one with extreme waves and the other with extreme current.

1. *1-Year winter storm*—connected, drilling
2. *10-Year winter storm*—connected, nondrilling
3. *High currents*—connected, drilling
4. *Extreme currents*—connected, nondrilling

Of importance is the fact that the operational limits for the nondrilling conditions are greatly less restrictive than those that apply for drilling conditions. Also, high current conditions have a much different influence on the riser than the storm conditions. (*As high drag loads, vortex-induced vibration of the riser pipe causes increased riser drag coefficients, causing larger riser angles*.) For the input conditions, state-of-the-art riser analysis programs

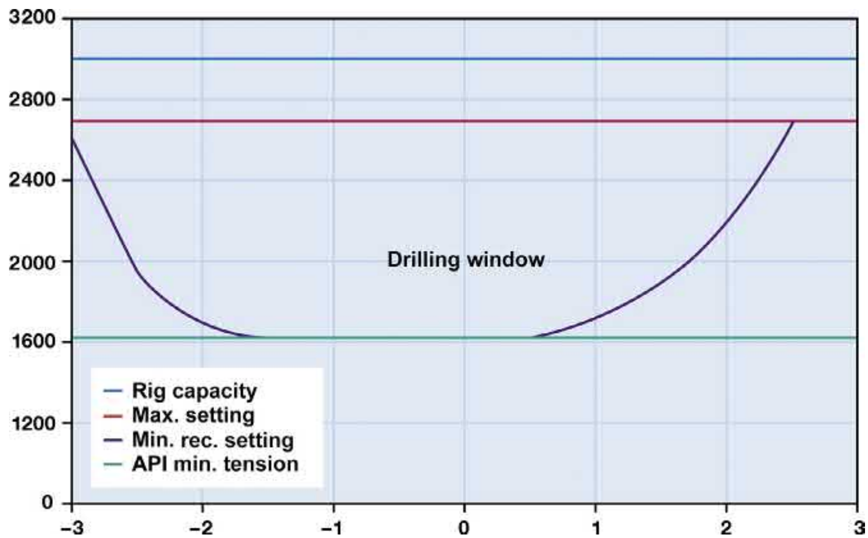


FIG. 14.25 Drilling operations 1-year storm. *Source: Elsevier.*

determine, evaluate, and calculate the riser's deflected *shape, angles*, and *stresses*. Output results are presented as parametric plots of *top angle* vs. *top tension, bottom angle* vs. *top tension, stress* vs. *top tension, and other relationships* for various mean vessel offsets and mud weights.

Top tensions that satisfy the operational limits for the case can be derived from these results. Fig. 14.25 shows a curve of tensions that satisfy drilling operational limits for various offsets. Tensions are within the API maximum tension for a range of offsets. If the vessel can maintain station within the range of offsets, operating tension can be established for that mud weight. *Note*: Moored systems can typically keep the vessel stationed within ±2% of water depth. If the riser angles are too large at these offsets, the vessel can be positioned at a more favorable offset by using "line management." The mooring lines of the vessel can be "managed" by being pulled in or payed out to position the vessel over the well. This requires additional action on the part of the crew and can be restricted under severe metocean conditions.

If a vessel is dynamically positioned, it can typically hold station within an offset circle of 1% of water depth from its set point (not always directly over the well). Given an offset circle of this size, the top tensions needed to satisfy the riser's operating limits vary with metocean conditions.

The top tension needed with 16 ppg (1917 kg/m^3) mud in a 1-year winter storm is about 1700 kips. In high currents (Fig. 14.26), the top tension needed to meet the same conditions is ±2400 kips.

TOP TENSIONS FOR VARIOUS MUD WEIGHTS

Curves are generated for various mud weights and plotted as top tension vs. mud weight. That is specific to each well, and is generally considered as a key plot to reference on the rig.

Fig. 14.27 shows a typical curve of top tension versus mud weight for a dynamically positioned vessel, including riser recoil limitations.

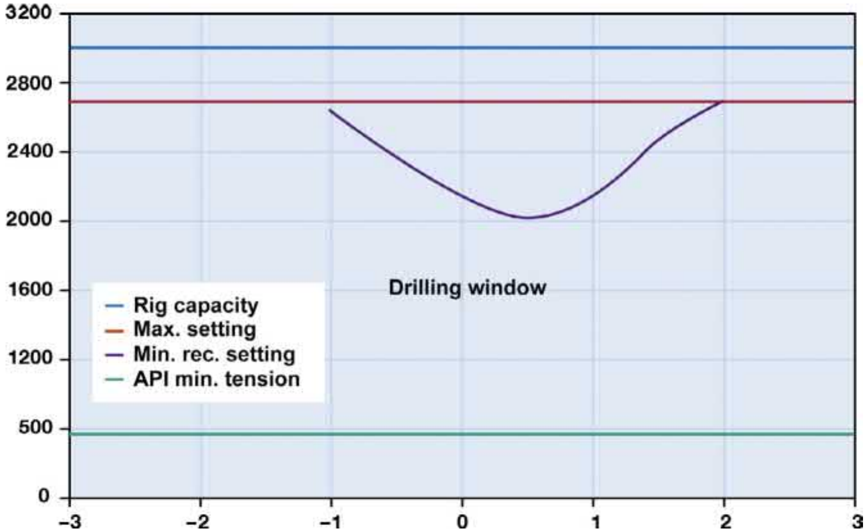


FIG. 14.26 Drilling operations window, high current. *Source: Elsevier.*

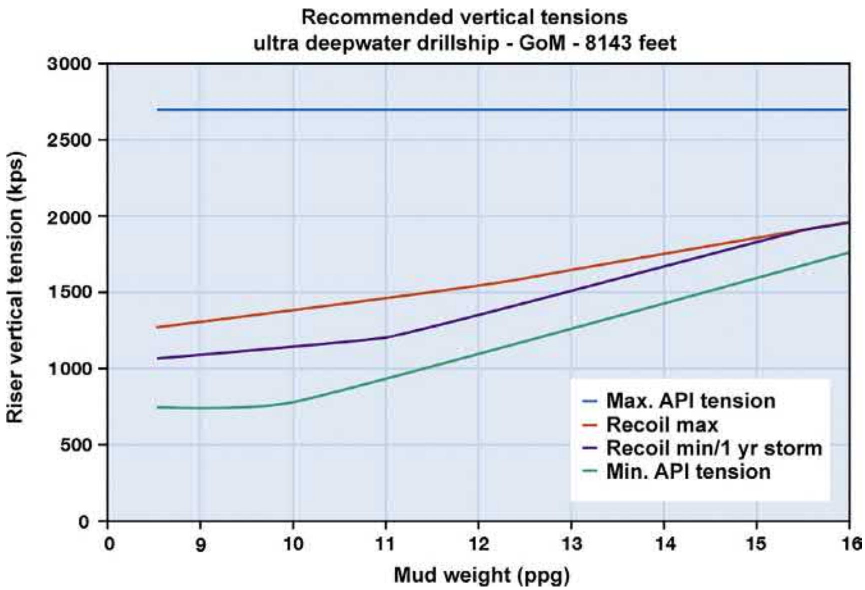


FIG. 14.27 Curve of operating tensions versus mud weight. *Source: Elsevier.*

Disconnected Riser

This section covers the response of the drilling riser in a *disconnected condition*. This condition can occur during running (deployment or installation) of the riser or during pulling (retrieval) of the riser. Additionally, the riser can be in this condition when the riser has been disconnected for operational reasons. Understanding riser response in these conditions is important to avoid damage to the riser and components on or around the riser that could lead to expensive repairs or ultimately loss of the riser or a compromise in safety.

Lateral force applied to a drilling riser causes it to move into a deflected shape. This shape depends on the distribution of the in-water (submerged) weight of the string, including that of the lower marine riser package (LMRP) or the full blowout preventer (BOP) on its bottom. The shape also depends on the current profile being experienced and the lateral velocity of the drilling rig. The effects of weight and drag force plus remedial measures such as "*drift running*" and *tilting* of vessel determine how well the riser can be deployed in the presence of high lateral loading. Other lateral loading factors to consider are:

- Lateral response during deployment and retrieval
- Deployment and retrieval limits
- Application of tensioned-beam analysis
- Drift running, solutions

Case History of "Drift Running"

A drillship experienced a block of submerged high current with a peak speed of 2.6 knots (1.3 m/s) and >2 knots (1 m/s) over a depth interval of 900 ft (274 m). This resulted in the riser/subsea BOP running operation, which normally would require 2–3 days, required 20 days. From this experience, the following guide was developed for running risers in similar conditions.

- Run the subsea BOP and riser when set up on DP at a location ±30 miles (48 km) from the drilling location.
- Run on DP mode until the drill floor informs the bridge of difficulties due to riser angle.
- When limit is reached, take the vessel off the DP and drift while running joints.
- Make attempts to put the vessel back on the DP while making a riser joint connection and revert to drifting while running it. Anticipate a stage in which the vessel would have to be on continuous drift to run the riser.
- Carry out continuous calculations to ascertain the cut off point for running the riser and using the remaining water depths for recovery.
- During the entire operation, the DPOs will log the times for running each riser joint, the drift distance, the current meter data for the depth of the subsea BOP, and the position of the riser/BOP relative to the moon pool.
- Based on the current profiles, estimate the depth at which the subsea BOP will be below the high current and the riser angle will decrease. If this depth cannot be reached by the calculated cut-off point, then recovery will begin.

Riser Hang-Off

The structural response of a riser that is hung off from a floating vessel can be a safety critical issue for operations (Vertical dynamic-heave loadings can result) in ultradeep water, for example: during deployment or retrieval of the riser or while the riser is secured in a hang-off configuration.

In ultradeep water, the axial dynamics of the riser are driven by the riser's increased mass and its increased axial flexibility when compared to a shorter riser. With these effects, vessel heave motion and wave and current forces cause riser tension variation, riser motions, and alternating stresses. If secured in a hang-off configuration, the riser can be put into a "hard" hang-off configuration in which it is rigidly mounted to the vessel or a "soft" hang-off configuration in which the riser is compensated. The advantages of a soft hang off include:

- peak hang-off loads are minimized;
- compression in the riser is avoided;
- motion of the riser is reduced;
- riser stress variation is minimized.

The limitations of the "soft" hang-off configuration are as follows:

- vessel heave motion does not exceed the stroke limits of the telescopic joint and tensioners
- on-board personnel are available to monitor/adjust the tensioners' set point

During the deployment or retrieval process, the riser is generally in the hard hang-off condition. Other factors to consider are:

- Performance during hang-off conditions
- Riser modeling
- Metocean conditions for hang-off analysis
- Design limits for hang-off analysis
- Interpretation of analysis results

Emergency Disconnect Sequence (EDS) /Drift-Off Analysis

Practical application of EDS and drift-off analysis techniques are covered in this section. Essentially when a dynamically positioned vessel loses power in ultradeep water, the resulting motion and rapid riser response depends on the intensity of the ***wind, waves***, and ***currents***.

EMERGENCY DISCONNECT SEQUENCE (EDS)

Analysis shows that the riser's deflected shape governs the time at which emergency disconnect limits are exceeded, i.e., the vessel and the riser during drift-off conditions are assessed to derive the emergency disconnect, yellow and red limit alerts (as illustrated in Fig. 14.28) to be set at specific vessel offsets and riser limits to assure an EDS can be conducted yet assuring the integrity of the drilling riser and its associated equipment.

Potential drift-off scenarios are analyzed to establish yellow and red alert defined-limits to guide the person in charge to the determined DP settings for each well. For example, a yellow alert circle includes a procedure for discontinuing drilling and hanging the drill pipe off in the SSBOP stack. A red alert circle signals the captain or the driller to "activate a red button" to start an automatic sequence that causes the shear rams to activate and shear the drill pipe in the SSBOP stack followed by a sequential LMRP and riser disconnect. EDS ensures the integrity of the riser and the related equipment, particularly the SSBOP stack, connectors, and conductor pipe that provide well pressure containment. The disconnect times are governed by exceedance of limits on top riser angle, bottom riser angle, slip joint stroke, wellhead moment, and conductor moment.

The example set of metocean conditions used for a state of readiness mode is, a 10-year winter storm with a 1-min wind speed of 50.5 knots (26 m/s), a significant wave height of 19 ft

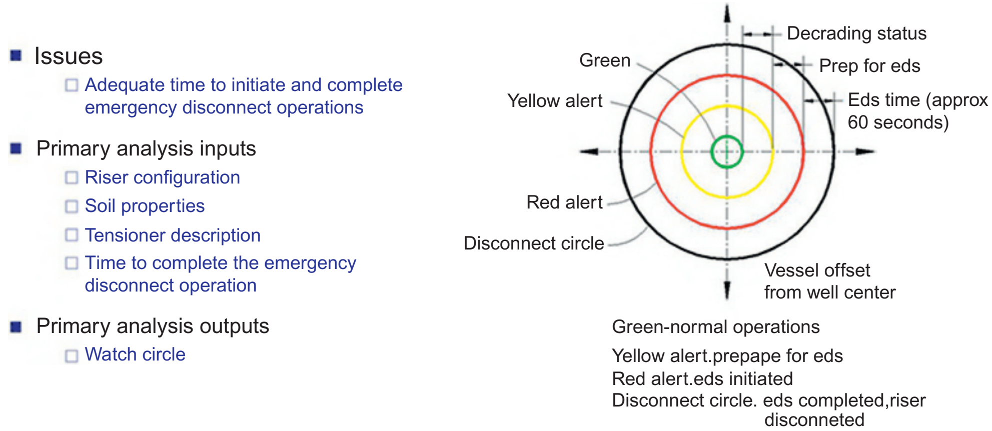


FIG. 14.28 Emergency disconnect sequence (EDS)/drift-off analysis. *Source: Kingdom Drilling training 2006.*

(5.8 m), and a surface current of 0.6 knots (0.3 m/s). An example set of conditions for drilling operations is a one-minute wind speed of 25 knots (12.8 m/s), a significant wave height of 7.6 ft, (2.3 m), and a surface current of 0.3 knots (0.15 m/s).

DRIFT-OFF DURING DRILLING OPERATIONS

Modeling analysis is used to predict various excursion scenarios and environmental (drift-off or power loss scenarios) and uncontrollable thrust excursions (drive-off) that can result. It is also possible to model the reaction of rig and subsea equipment during these excursions. Modeling is recommended for rigs going on contract that operators have not previously used. Items that may be critical during an excursion are:

- The LMRP connector/Lower flex joint angle.
- Moonpool clearance.
- Slip-joint stroke.
- Tensioner stroke limits.

When a “drilling operations” drift or drive-off results, the yellow and red alert circles are set using the time history of vessel motion and riser response that has resulted from the EDS/drift-off analysis performed. The point in time at when the first riser allowable limit is exceeded is termed the “point of disconnect” (POD). Disconnect at any later time would exceed a system allowable. With the POD as the basis, the vessel motions data time history is used to move backward according to the time required from “activating the red button” to the POD. The POD therefore drives the yellow and red alert circles and is governed by first exceedance of an allowable set-limit within the system. In this process, allowable well specific operating limits (guidelines termed ‘WSOL’ or ‘WSOG’) are set for any component whose integrity could be compromised as the vessel drifts off as previously outlined. Typical limits for top and bottom angles are 9 degrees (90% of the flex joint stop, per API RP 16Q) and stroke-out values of say 25 ft (7.6 m) based on some margin within a 65 ft (19.8 m) stroke capacity, for example.

CASE STUDY: EDS/DRIFT OFF ANALYSIS

In 4500 ft (1372 m) of water and 9000 ft (2743 m) of water in the Gulf of Mexico, summary results for an EDS/drift-off analysis in a reasonable set of metocean conditions to be used for drilling operations are evaluated as:

- 4500 ft (1372 m) *red alert circle*
  - = 225 ft (69 m) (5% WD); yellow alert circle = 72 ft (22 m) (1.6% WD)
- 9000 ft (2743 m) *red alert circle*
  - 360 ft (110 m) (4% WD); yellow alert circle = 180 ft (55 m) (2% WD)

In this example, the results in 4500 ft (1372 m) of water are governed by yield of the conductor pipe, whereas the results in 9000 ft (2743 m) of water are governed by stroke-out of the slip joint. As shown above, drift-offs tend to be *more difficult to manage in the shallower water* depths.

In 4500 ft (1372 m) of water, the size of yellow alert circle has reduced to a relatively low and level when compared to the larger more manageable yellow circle in 9000 ft (2743 m).

Fig 14.29 shows the more rapid drift-off results in ta 10- versus 1-year storm.

EDS/Drift-Off Analysis Technique

In addition, a transient coupled analysis technique to calculate drift-off of a dynamically positioned vessel and the associated effect on the emergency disconnect sequence for a drilling riser shall be assessed. The drift path of the vessel is calculated in the time domain, taking into account the transient response of the riser and the vessel's change of heading under the influence of current, wind, and waves. The effect of vessel rotation on horizontal motion is important in calculating the yellow and red alert offsets for the EDS. Also, the effect of riser restoring force on the vessel will be shown to be significant.

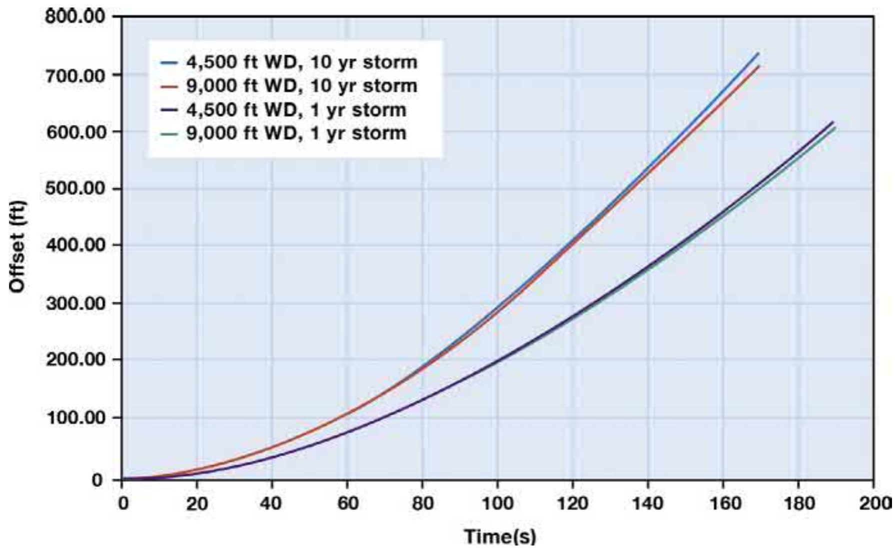


FIG. 14.29 Drift-off analysis time histories. *Source: Elsevier.*

RISER RESPONSE ANALYSIS

In terms of riser response analysis, typical results based on case study data inputs used are presented in figure shown.

Fig. 14.30 shows the time history of slip joint stroke for conditions associated with a 10-year storm (nondrilling, state of readiness) and with a reduced storm (drilling operations). Note that the slip joint stroke does not show any appreciable movement until about 50 and 100 s into the drift off, for the 10-year storm and the reduced storm, respectively. As shown, the rate of increase in the slip joint stroke is much higher for the 10-year storm. A typical allowable limit for slip joint stroke is between 20 (6.1 m) and 30 ft (9.1 m) depending on stroke limits, the water depth, the top tension, and the space-out of the pup joints.

Fig. 14.31 shows the time history of bottom flex joint angle for both the 10-year storm and the reduced storm. Note that the bottom flex joint angle does not show any motion until about 70–80 s into the drift off, regardless of the storm size. After the initial response, the rate of increase in flex joint angle is higher in the 10-year storm, as expected. A typical allowable limit used against this curve of bottom flex joint angle is 7–9 degrees.

IMPORTANCE OF COUPLED RISER ANALYSIS

The riser and vessel motions analysis programs are generally coupled to include the effects of riser restoring force on vessel motion. Depending on the water depth and specific conditions, this can provide a 15%–20% reduction of offsets in the time history of vessel motion. A simplistic coupled analysis would be to:

1. *First*, the vessel analysis is done with no riser loads.
2. *Second*, the resulting vessel motions are used in the riser analysis.

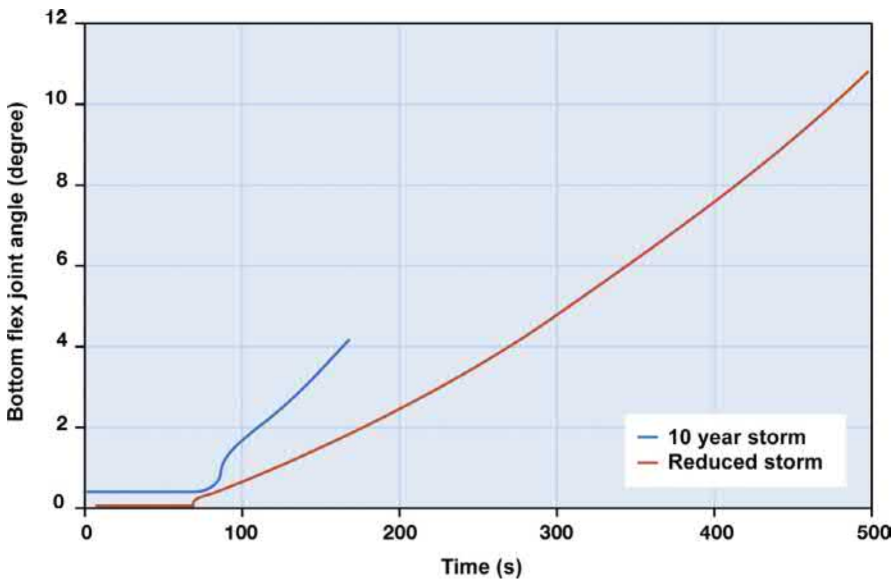


FIG. 14.30 Time history of slip joint stroke during drift-off. *Source: Elsevier.*

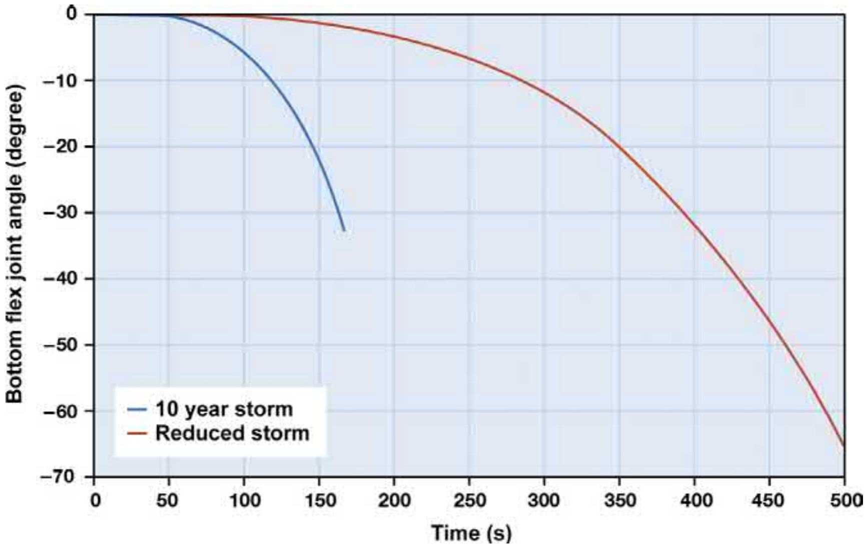


FIG. 14.31 Time history of bottom flex joint angle during drift-off. *Source: Elsevier.*

3. *Third*, the vessel analysis is redone with lateral riser loads from the previous riser analysis.
4. *Fourth*, the riser analysis is redone with the updated vessel motions.

A more sophisticated analysis approach could be run and analyzed to *solve for the complete system* (vessel and riser) at each time step. This would result in a fully coupled analysis.

IMPORTANCE OF VESSEL ROTATION

Vessel motion analysis depends heavily on the heading with respect to the incident wind, waves, and current. The force on a drillship is much lower when it is headed into the weather than when the weather is on its beam, i.e., turned by 90 degrees. To minimize force and vessel motions, the captain generally heads the vessel into the weather. When a vessel loses power, it will tend to rotate so that weather is on the beam, a stable orientation. The speed at which this rotation takes place is calculated via vessel's motion analysis.

Due to the differing force coefficients in the different headings, the rotational speed has an influence on how quickly the vessel translates away from its set point over the well. Example vessel characteristics are shown in Table 14.8.

TABLE 14.8 Vessel Principal Particulars

Length (perpendicular) (m)	210
Breadth (m)	36
Depth (m)	17.8
Draft (m)	9
Displacement (ton)	54,709

Source: Elsevier.

Trends in Analysis Results With Water Depth

EDS/drift-offs is generally more difficult to manage in shallow water than in deepwater as the specific amount of distance traveled by the vessel results in a lesser percentage offset and a lesser angle. Not all of this advantage can be retained, however, because of the shape of the riser and the different allowable limits involved. In waters shallower than 5000 ft (1524 m), the wellhead or conductor moment may be the governing limit that establishes the point of disconnect (POD). The POD moment values are determined by the soil properties and the dimensions and yield strengths used in these components. Fig. 14.32 shows a typical conductor pipe bending moment profile based on the drift-off trajectories for a beam sea and the rotating ship conditions.

Fig. 14.33 shows a summary of lift-off analysis results for a well specific site in 4227 ft (1288 m) of water in the Gulf of Mexico, with a riser top tension of 1371 kips and a mud weight of 10 ppg (1198 kg/m^3). The curve represents the horizontal vessel excursion (offset) vs. time. A vertical line is drawn at the time of POD, which is the minimum of the times at which the allowable limits for stroke, angles, wellhead bending moment, and conductor bending stress were reached.

In this example, the POD occurs at 254 s and the associated offset is 467 ft (142 m). If the time is reduced by 60 s (to 194 s), the red circle radius is established as 290 ft (88.4 m). If the time is reduced by a further 90 s (to 104 s), the yellow circle radius is established as 89 ft (27.2 m). In dynamic positioning operations, the yellow circle defines the offset at which drilling operations are suspended and the red circle defines the offset at which the EDS sequence is initiated.

Operational and Analytical Options

If the *yellow* or *red* watch circles are not set within practical operating limits, options may be available by looking at the system as a whole. A first option is usually to find an analytical fix

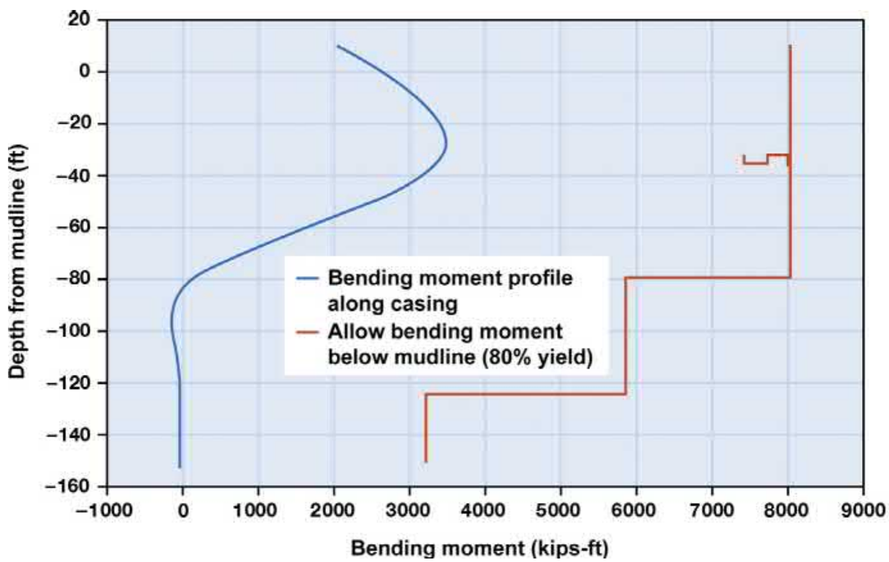


FIG. 14.32 Conductor pipe bending moment profile during drift-off. *Source: Elsevier.*

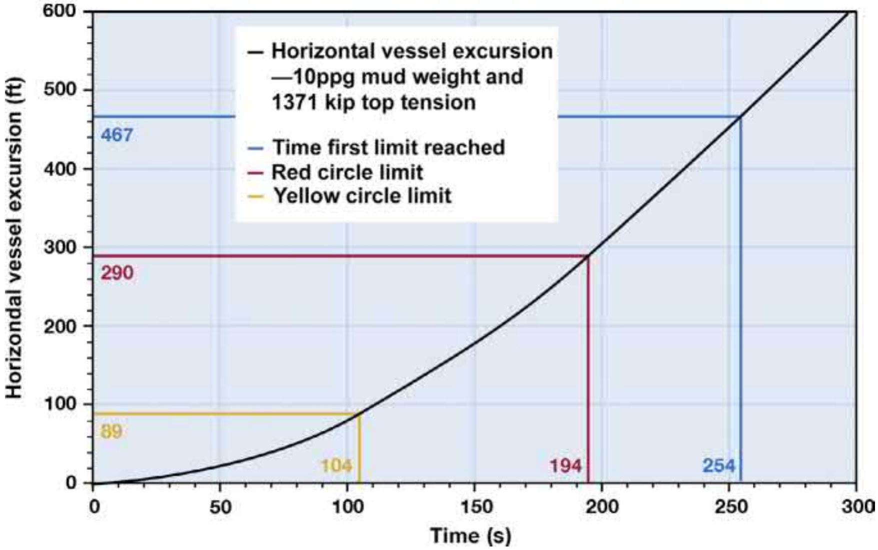


FIG. 14.33 Summary of drift-off analysis results. *Source: Elsevier.*

and the second to propose an operational fix. Analytical fixes can include exploring options for reduced top tensions, which if set too high initially, could cause difficulties in either riser recoil or connected riser recommendations. Reduced riser tensions and other such compromises may be needed to reduce the loads on conductors for EDS/drift-off, for example.

In many regions of the world, metocean conditions are so severe that they cause difficulties in managing the possibility of EDS/drift-off. In areas such as the Gulf of Mexico, Trinidad, Brazil, and the Atlantic margin, high currents can cause a vessel to drift off rapidly. If currents exceed conditions associated with a state of readiness mode, steps to provide operational management might be necessary such as positioning up current, or simply also difficult to manage due to the large angle that it will take on. In areas of the world that have high wave conditions that build rapidly, the possibility of an EDS/drift-off event poses another type of riser management issue. If the riser can survive EDS and hang-off in design-level wave conditions, the management issue is simply a matter of when to disconnect and ride out the storm. Disconnection of the riser protects the pressure-containment components, i.e., the SSBOP, wellhead, and conductor. However, when a site has design wave conditions in which EDS and hang-off can jeopardize the free hanging riser, the riser is pulled before the storm is encountered.

Depending on the water depth and the forecasted sea states, the riser pulling operations are begun well in advance.

When a severe storm is approaching, the riser is on occasion disconnected and hung from the vessel to ride out the storm (Fig. 14.34). The vessel heave motions produce tension variations in the riser and may cause excessive tension or buckling of the riser. The riser may also develop excessive bending loads from the lateral motions of the riser. The buoyancy modules adversely influence the riser hang-off response in two ways. The buoyancy increases the mass of the riser increasing the inertial loads and decreases the weight of the riser making it more prone to compression.

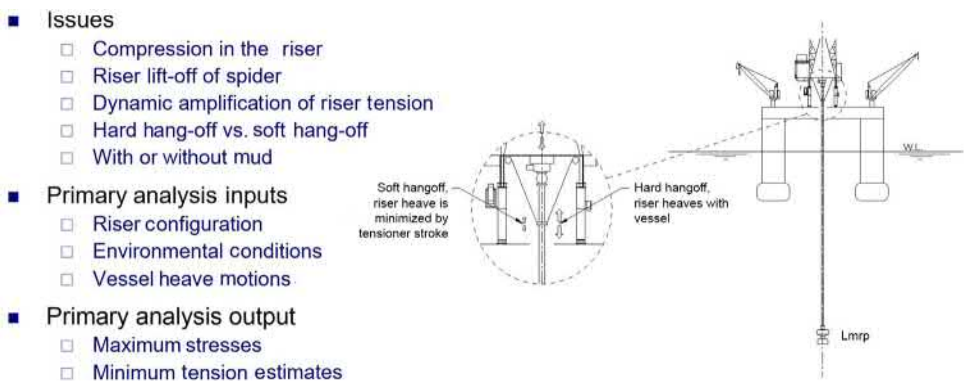


FIG. 14.34 Storm hang-off analysis and axial response.

Even without dynamic amplification, the riser can only sink as fast as its weight allows. Therefore, the foam buoyancy may cause the riser to fall so slow that the vessel heaves "out runs" the riser and causes riser compression. If riser is long enough to have natural periods in the range of the vessel motions, the dynamic amplification generated by excitation of natural periods will aggravate the situation.

Historically risers have been hung-off on a hard support point, thus the term "hard hang-off." Some operators have found a "soft hang-off" on the riser tensioners to be the more attractive alternative to reduce dynamic riser loads as illustrated in Fig. 14.34.

Riser Recoil After EDS

An understanding of the riser recoil systems process (Fig. 14.35) is important in order to maintain operational safety and avoid damage to the riser and its related components. Additionally, riser recoil considerations often dictate the top tensions that are pulled on the drilling riser. Recoil analysis is conducted to determine the riser axial response after an emergency disconnect of the LMRP from the SSBOP at the seabed. In practice, this analysis is used to optimize riser

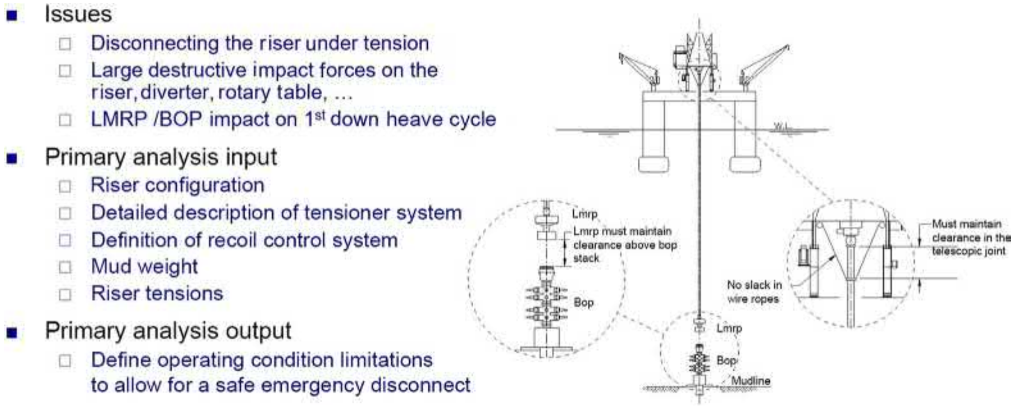


FIG. 14.35 Recoil response.

tensioner system settings and define riser top tensioning range to prevent excessive response of the riser. Typical allowable limits are aimed at ensuring the system behaves as follows after disconnect: the LMRP connector lifts off the SSBOP mandrel without reversal that could cause recontact; the riser stops before impacting the drill floor, and slack in the tensioner lines is limited. To check these limits, some form of riser recoil analysis is generally done for each well site.

This section provides a discussion of the riser recoil process, riser response analysis, allowable limits, results and interpretation of some example cases, and sample operational recommendations. General guidance, it should be noted, is provided in reality more highly dependent riser tensioning system and site specifics would be needed, guidance based on site, and the selected operating parameters that would exist.

Definition of Process

As the riser goes through the emergency disconnect sequence (EDS), it automatically disconnects near the seabed. This disconnect is conducted at the interface between the lower marine riser package (LMRP) and the lower portion of the SSBOP. As the riser releases, it responds with upward axial movement that is managed through the tensioners and the associated riser recoil system. Management of the riser's upward movement is carried out by adjusting the stiffness and/or damping of the tensioner system. This can be done in a variety of ways and the examples provided do not cover all. In one example system, the EDS has an automatic command to close air pressure vessels (APVs) normally kept open to maintain small tension variations during operations. This causes a sudden increase in the system's vertical stiffness. Also, a so-called riser recoil valve is shut to increase the damping by constricting the orifice for fluid flow. In another example system, the riser's upward movement is managed by changing the orifice size based on tensioner stroke or velocity, with no closure of APVs. Properties of the riser also influence the riser's vertical response.

1. *In-water weight of the riser string and LMRP* affect the dynamics. In certain cases, bare joints of riser are included in the riser stack up to help control the upward movement.
2. *Weight of mud contained in the riser* alters the response after disconnect; the frictional effects of the mud stretch the riser downward for some duration after disconnect.
3. *Stretch in the riser* can be significant (several feet) and this leads to a rapid upward response (slingshot effect) after disconnect.

When a riser is disconnected under tension, the tensioners will continue to lift the riser once disconnected. If this response of the tensioners is not controlled, the tensioners and riser can generate tremendous impact loads when the telescopic joint fully collapses.

If tensioners do not pull the riser up fast enough or allow the riser to fall back down too quickly or far, impact between the LMRP and SSBOP can occur to potentially damage the LMRP, SSBOP, and wellhead. In some situations, the riser recoil can cause the tensioners to temporarily lose tension.

For a wire rope tensioner system, this loss of tension produces slack in the wire ropes. For a direct acting tensioner system, the loss of tension may produce compression in the riser. If this occurs, the reloading of the tensioner element may cause damage to the riser, tensioners, and/or wire ropes. Detailed analyses of the riser recoil procedures are performed to determine riser operating limits (tensioner setting limits) to ensure that an emergency disconnect can be executed safely.

Riser Recoil Analysis

Riser recoil analysis is generally carried out assuming only axial response, with fluid flow through the tensioning system, vessel heave, effects of offset on vertical tension, and mud flow all playing a big part in the response. For this discussion, due to its rig-specific nature, the tensioning system is simply considered a spring-damper device.

Heave with its selection generally based on the vessel relationship to design storm condition is an important parameter. Top tension used is altered depending on the offset that is of interest. This is due to the build-up of tension that can be caused in some systems when the APVs close some time prior to disconnect. High mud weight flow is modeled to deliver higher frictional loads on the sides of the riser as they fall out, thereby pulling the riser downwards for some duration after disconnect.

Allowable Limits

The allowable riser recoil limits set the top and minimum top tensions to prevent the LMRP damaging the SSBOP during disconnect; maximum top tensions avoid slack in the tensioner lines just after disconnect and the riser impacting the drill floor.

Minimum tensions are limited by avoiding contact between the LMRP and the SSBOP, as the LMRP cycles after disconnect. This could occur if the disconnect were to result at the "worst phase" of a vessel's heave cycle and cannot be controlled due to the short duration (about 60 s) of the EDS sequence. Allowable limits on such motion are dependent on the subsea SSBOP equipment and the tolerance for damage. Having a few feet of clearance considered as ALARP.

Maximum riser top tensions are limited by avoidance of slack in the tensioner lines during riser recoil. The upward motion associated with this limit could be exacerbated if the disconnect were to occur at the "worst phase" of a vessel's heave cycle. As noted above, such phase considerations cannot be controlled because of the duration (about 60 s) of the EDS sequence. Reasonably small amounts of slack are allowed with certain systems, but no specific limits have been established. To avoid the riser impacting the rig floor, a "dead-band" might be available to provide further protection. Slack in the tensioner lines must be managed, and through means of the dead-band arrangement, further limits on maximum top tension can be avoided.

Operational Issues

Riser recoil analysis is generally required for each deepwater site. Due to the impact of the results on riser top tensions, sensitivity cases are sometimes run to investigate ways to allow a larger band of allowable tensions thus making better use of the rig's installed tensioner capacity. The nature of the sensitivity cases would depend on the rig's tensioner and recoil system. Examples of such cases could include closing varying numbers of APVs, thus altering the stiffness at the time of disconnect; or a larger orifice or a different program for changing the orifice size.

REFERENCE STANDARDS

American Petroleum Institute (API). Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems. First Ed. API-RP-16Q, November 2003.

API-RP-2RD, Design of Risers for Floating Production Systems and Tension Leg Platforms, First Edition, June 1998.

API-RP-2A, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms-Working Stress Design. Twenty First Edition, December 2000.

API-RP-53, BOP Equipment Systems for Drilling Wells.

API Spec 16F, Marine Drilling Riser Equipment.

DNV-RP-F206, Riser Integrity Management, April 2008.

DNV-RP-F204, Riser Fatigue, October 2010.

References

Aird, P., 2012. Mobile Offshore Drilling Units 'MODU' Drilling Riser Systems Training Presentation (Original Presentation).

American Petroleum Institute (API), 2003. Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems, first ed. (API-RP-16Q).

Brekke, J., Chakrabarti, S., Halkyard, J., 2005. Handbook of Offshore Engineering (Chapter 9). Elsevier Ltd.709–768.

Kavanagh, K., Dib, M., Balch, E., Stanton, P., 2002. New Revision of Drilling Riser Recommended Practice (API RP 16Q). OTC14263.

Long, Randy, J. Deepwater Drilling Riser Integrity Assurance Guideline. PN 007401JRL Prepared for BP Houston, TX. Stress Engineering, Houston, TX.

Hariharan, M., Thethi, R. Drilling Riser Management in Deepwater Environments. 2H Offshore Inc., Houston, TX.

Laughlin, R.B. Department of Physics Stanford University. http://large.stanford.edu/publications/coal/references/ocean/rovs/tools/

Thorogood, J., Amoco Norge, B.P., Adams, A., Hess, A., 2000. Atlantic Margin Joint Industry Group (AMJIG). Deep Water Drilling Riser Integrity Management Guidelines, Revision 2. 2H Offshore Engineering Limited.

2H Offshore Engineering Ltd., 2000. Drilling Riser Integrity Management Guidelines, Rev 2. Project Report for AMJIG Group.

CHAPTER

15

Deepwater Intermediate Wellbores and Pressure Detection

INTERMEDIATE SECTION OBJECTIVES

The deepwater intermediate sections are the first sections to drill with mud returning to the drilling vessel. These section(s) extend a well to a predefined horizon depth to set casing above or within the first pressure transition. Typical section objectives to be met are:

1. Safely make up and run the drilling BHA to its required depth.
2. Drill out the cement inside the shoe and clean out the rat hole.
3. Displace well to the desired weighted (water or oil based) mud system.
4. Obtain sufficient shoe integrity to get the next casing to its as-planned depth.
5. Drill and trip a vertical, quality wellbore, delivering a competent formation shoe.
6. Run and cement the casing to provide the barriers to meet all design and well integrity requirements by:
   a. Operating throughout and within required "safe drilling windows."
   b. Understanding and monitoring all barrier systems and elements in place.
   c. Managing pressure transition and reservoir zones at minimal loss.
7. Assure required contingencies are in place for things that can and may go wrong.

The key to delivering these sections is through constant and vigilant reassessment of all objectives, barriers, and controls in each and every phase job and task activity conducted.

OPERATING HAZARDS

Operating Hazards and risks can be quite unique to each project's set of teams, disciplines, drilling vessels, equipment, systems, operating environment conditions, and sets of situations existing in each wellbore section. The preventative and control processes begin at the project start and should adopt a remit to learning right through to the project end. By the time project implementation commences, risks should be prioritized, ranked, filed, and suitably mitigated to ALARP practicalities. Persons then assigned to own each and every one. Successful ALARP delivery is key and crucial to a project's success.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00015-6

What can exist at this stage is a large risk register that is far distant from front line application and cannot cut the cloth as demanded to insure SEE outcomes and benefits are realized. The risk register provides little use if the critical and priority executable risks identified cannot be translated and sustained by the rig persons on board, to deliver, use and apply the well program, equipment, technologies, systems, and people's knowledge and experience. What can be reconciled is to extract from the risk register the essentials identified and generate useable "Tornado charts" as shown in Table 15.1. These charts are then used by all persons during program implementation to assure that risks are proactively managed, owned, and controlled as operations progress. Also that dynamic risk assessment results and that contingent plans are in place to react to any evident warning of things that go wrong. A generalized list of deepwater hazards and risks featured in these well sections is summarized in Tables 15.2–15.4. Key definitions are:

- ***Hazard***: Danger, exposure, vulnerability
- ***Risk***: Possibility, gamble, chance, (probability × consequence)
- ***Contingency***: Risk, event, likelihood, probability, circumstance, odds, occasion.

INTERMEDIATE SECTION OPERATING OUTLINE

An operational outline of a deepwater intermediate section is summarized in this section.

Offline Preparations

Offline work typically conducted to reduce critical path activities are:

1. Lay down the casing cement stand to prepare for next casing cement job.
2. Make up and rack back the planned disconnect hang off assembly (if to be used).
3. Prepare landing joint to one trip wellhead hanger/seal assembly running tool. *Note*: Perform this operation offline on deck if possible.
4. Ensure agreed program guidelines for all forthcoming operational plans have been distributed.
5. Prepare drilling fluids and mud management action plans for next section.

TABLE 15.1 Risk Management Process Steps 3 and 4 That Then Can Be Used to Generate a Useable Tornado Chart as Shown

Step 3; Rank and File		Step 4; Plans and Mitigations to be initiated		
Risk No.	**Risk Magnitude Probability × Consequence**	**The Owner *(Responsible)***	**The Manager *(Accountable)***	**Plans/Mitigations**
3		Fishing/operator supervisors.	Drilling supt.	QA cert for all tools. Preassembled and tested onshore. Operating procedures reviewed and provided for rig supervisors. Fishing hand to be provided to rig, etc.
4				
2				

Derived by Peter Aird/Andy Stewart (Kerr McGee in 2006).

TABLE 15.2 General List of Deepwater Intermediate and Production Sections Hazards (problem area) to Consider

Wellbore	Equipment	Waiting
Well control	Main rig systems	Waiting on weather/Metocean
Wellbore problems	Rig tools and equipment	Waiting on spares, tools & equipment
Geology	Service company tools & eqpt	Waiting on permits, consent, orders.
Wellbore drag	Downhole tools	Amendment, change of program
Hole deterioration	Stuck in hole	Waiting on costs, PO's
Pore pressure	Quality Assurance	Waiting on People
Mud	Back up, contingency	Waiting on delivery
Cement	Critical spares	Deck space management
Data acquisition	Mechanical, hydraulic, vibration fatigue failures	Supply vessel
BOP/riser	Well barrier design failure	Helicopters
Subsea/ROV	Casing/tubing	Waiting on cement
Others?	Well control eqpt	Subsea/ROV
	Subsea/ROV	Others?
	Others?	

TABLE 15.3 General List of Deepwater Intermediate and Production Sections Wellbore Conditions/Hazards to Consider

Wellbore Related Hazards			
Washout	Enlargement	Unconsolidated	Fracture faulted
Doglegs ledges	Angle geometry	Barite sag	PVT effects
Abnormal pressure	Subnormal pressure	Ballooning supercharging	Clay/shale problems
Mud weight	Solids	Pack off	Differential sticking
Hydrates	H_2S/CO_2	Hole cleaning	Mud and cement contaminants
Formation fluids	Reservoir fluids	Torque and drag	Instability
Kicks	Lost circulation	Losses/gains	Open hole time
Casing wear	Heat checking	Others?	Others?

6. Prepare bore protector retrieval tool.
7. Make up the drilling string, and BHA components as directed by those involved.
8. Check IBOP's Gray valves, dart are all functional and fits into the dart sub. Make up and install any tool and equipment offline when practicable to do so.
9. Check gauges and gauge bit and all stabilizers to be run.
10. Test surface casing to required pressure against blind rams and cement.
11. Complete check lists that exist for various operational roles and disciplines.

TABLE 15.4 General List of Deepwater Intermediate and Production Sections Geological Conditions/Hazards to Consider

Geological Related Hazards			
Bit balling	Mud rings	Hole drag	Erosion washout
Hole drag	Sloughing/cavings	Pack off	Hole enlargement
Rock mechanics	Abnormal subnormal pressures	Borehole instability	Pore pressure penetration
Hydration stress effects	Open hole time	Pressure fluctuations	Hydrocarbons (oil/gas)
Hole cleaning	Max/min mud wt	Other pressure effects	Drillstring vibrations
Transition zones	Reservoirs	Under compaction	Narrow margins
Aquathermal	Aquifers	Charged sands	Tectonic loading
Salt diapirism	Mud volcanoes	Clay diagenesis	Others?

Predrilling Operational Sequence

A generic predrilling and operational intermediate wellbore sequence after subsea BOP and riser is installed is outlined in the following sections:

1. Make up and run BHA (filling pipe) through the marine riser and subsea BOP. Compensate string while running BHA through BOP. Once below, conduct final subsea function checks and tests that may be required.
2. Run BHA on drilling string (filling pipe) using the trip tank, to a safe distance above top cement plugs.
3. Make up top drive, break circulation, wash down and tag top of cement with drilling bit.
4. Drill out plugs, floats, and cement as per specific drill-out instructions. (*Note*: Torque is deemed the most evident indicator that the plugs drill-out is progressing as planned.)
5. When convenient displace well, kill/choke lines to mud as per mud engineer's written plan.
6. Conduct all well control assurances, best practice drills, and conduct crew training.
7. Drill the final shoe track length as per operator's specific instructions.
8. Clean out the rat hole and work string for *normal drag* to result.

Conduct Well Integrity Test

1. Drill 1.5–3 m (5–10 ft) of new formation.
2. Circulate cuttings above the SSBOP, condition and verify mud properties.
3. Conduct well integrity test as per operator's program requirements.
4. Record pump rates, pressures, bled back volumes in order to determine the equivalent mud weight (EMW) to meet the next section deliverables.

General Drilling Guidelines

1. Wash drilling string and BHA, tagging bottom, then establish and stage up parameters with drilling controls in place until main BHA has penetrated and progressed into a new wellbore.

2. Optimize drilling parameters and wellbore condition; establish baseline EMW pressures, stability, drilling parameters, and trends. Constantly monitor all metrics for wellbore or associated drilling operational problem indicators. Ref. worked example.
3. Survey as set and agreed for the section.
4. Maintain primary well control at kick-level 1 alertness until well indicators state otherwise.
5. Mud loggers and drillers to be fully aligned and conversant to monitor and record all drilling and downhole wellbore, pressure management, and operational trends.
6. Maintain mud properties as per program specifications.
7. Drill ahead at optimal parameters to required section depth maintaining parameters within preset safe limits. Should conditions change risk-assess and change accordingly.

During the operational phases, *contingent action*plans, as illustrated in Figs. 15.1–15.3, shall be prepared, ready, and in place to meet any work related issues, e.g.: *pressure management, wellbore instability, equipment failure, pack off, mechanical, differential sticking, primary and or secondary well control events.* Should significant operational change result, work plans may have to be managed and changed accordingly.

8. At section depth, circulate well clean, obtain a TD survey, and prepare to pull out.
9. Flow check well.
10. Pull first few stands wet to assure normal drag wellbore conditions exist.

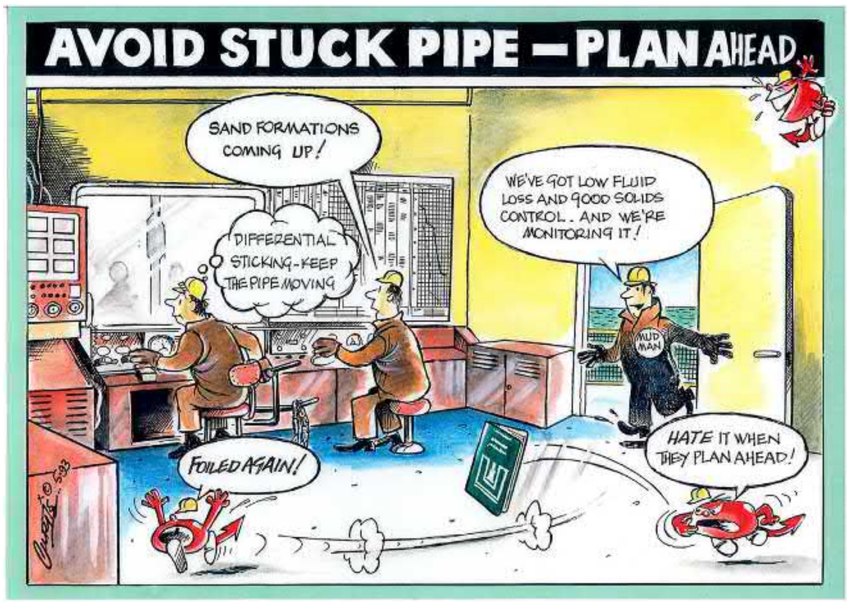


FIG. 15.1 Problem avoidance stuck pipe poster used in the '90s, illustrating importance of planning ahead.

Hole pack off/ bridging	Differential sticking	Wellbore geometry
Settled cuttings	Differential force	Stiff assembly
Shale instability		Key seat
Unconsolidated formations		Micro doglegs
Fractured formations		Ledges
Cement related		Mobile formations
Junk in hole		Undergauge hole

FIG. 15.2 Generic wellbore problem and difficulties to de-risk and mitigate prior to and during drilling operations.

Direction of pipe movement just prior to sticking	Pack-off or Bridge	Differential	Wellbore geometry
Moving up	2	0	2
Moving down	1	0	2
Static	2	2	0
Downward motion of pipe after sticking			
Down free	0	0	2
Down restricted	1	0	2
Down impossible	0	2	0
Pipe rotation after sticking			
Rotation free	0	0	2
Rotation restricted	2	0	2
Rotation impossible	0	0	0
Circulation pressure after sticking			
Circulation free	0	2	2
Circulation restricted	2	0	0
Circulation impossible	2	0	0
Totals			

FIG. 15.3 Generic drilling diagnostics and trouble-shooting chart.

11. With normal drag confirmed, pump a weighted slug and flow check well.
12. Pull out of the well on elevators observing drag and trip tank volumes to the previously set casing shoe.
13. If abnormal drag is observed, the operator supervisor shall instruct best contingent practices to progress operations safely through each wellbore issue accordingly.
14. At casing shoe, flow check and continue to pull out as per drilling contractor's cased hole, subsea BOP, and marine riser operating standards.

15. Flow check when BHA is below subsea BOP. Once affirmed,
16. Pull remaining string and BHA through the marine riser and out of the well. *Note*: Open compensator when pulling BHA through slip joint.
17. Rack back BHA and download tools offline if practicable as advised by third-party engineers.
18. Break off bit, clean, inspect, and grade.
19. Clear rig floor and prepare to pull bore protector and then run/cement the casing.

Identifying the problem mechanism aides to determine and evaluate the appropriate actions to be taken to ease the situation. Taking inappropriate action can generally make the situation far worse. There are four diagnostic indicators to consider

1. Direction of drillstring movement just prior to becoming stuck
2. Downward movement of drillstring after becoming stuck
3. Drillstring rotation after becoming stuck
4. Circulating pressure after becoming stuck

INTERMEDIATE SECTION CASE STUDY AND WORKED EXAMPLE

The following section highlights a case study and the physical elements of drilling a deepwater intermediate section, concluded as very different to the riserless example previously illustrated in Chapter 12. Engineering, operational aspects, and conclusions are based on ultradeepwater wells data as illustrated in this section. *Note*: The engineering worksheet produced for this section and others in this guide all can be downloaded at https://www.kingdomdrilling.co.uk/downloadfreelinks.aspx.

Background history: 17½″ wellbores that were previously drilled at similar >±2500 m (8202 ft) water depths, within similar stratigraphy and normally pressured environment conditions, had utilized inhibitive water-based muds that had resulted in significant operating problems, e.g., very poor wellbore quality, in multiples of significant time consuming and costly well-related loss time events (suspected from well overloading and self-induced fracturing of wells). To remediate, extreme restricted and controlled drilling was needed that added extended days to weeks of drilling to meet original as-planned objectives.

The operator then changed to a flat rheology synthetic-based mud, where wellbore quality and pressure management problems previously experienced were eliminated with a far wider and safer drilling operating window resulting, as exhibited by this singular technology change, as evident from the daily drilling reports summary as shown in the table below. With further evident support provided in the work sheet constructed and as summarized in Figs. 15.4, 15.5, and Table 15.5.

Last Casing and Depth	LOT
20″ at 3461 m	9.8 ppg

RT to mud line water depth 2500.2 m.

07:45	15:00	7.25	Drilled 17½″ wellbore from 4073 m to section TD at 4209 m. 15–25 K, 180 rpm, 1090/3890 psi, 5–20 kftlbs torque. Worked single prior to and performed surveys after connections. Mud weight increased to 9.2 ppg from 4175 m at 13.00 h. (*Note*: *Av ROP for bit run ±20 m/h.*) **Max EMW 9.49 ppg**.
15:00	18:45	3.75	Circulated bottoms up to obtain TD formation sample at 1050 gpm on the hole and 525 gpm on the boost.
18:45	21:00	2.25	Pulled out from 4209 m through shoe to 3461 m on elevators. Wiped intermittent drag as required. Good wellbore (drag) conditions observed.
21:00	21:30	0.50	Flow-check well-static. Meanwhile held trip drill with crew.
21:30	23:00	1.50	Ran in and performed (Operator requested) precautionary prelogging wiper trip from 3461 to 4171 m. Normal wellbore drag observed throughout.
23:00	23:30	0.50	Precautionary reamed from 4171 to 4209 m, no fill or drag observed.
23:30	02:30	3.00	Circulated bottoms up at 1050 gpm on the hole and 525 gpm on the boost.
02:30	02:45	0.25	Flow checked well-static.
02:45	03:30	0.75	Pulled out from 4209 to 3991 m on elevator and trip tank, normal 5-10klbs drag observed.
03:30	04:00	0.50	Pumped 45 bbls of 11.7 ppg slug.
04:00	05:15	1.25	Pulled out of hole from 3991 m back into shoe to 3436 m. Normal 5–10 klbs drag observed.
05:15	05:45	0.50	Flow checked well-static.

Conclusions from case study, worked example summaries, and data as illustrated in Figs. 15.4 and 15.5 and Table 15.5 are:

1. The intermediate section drilling limits using a flat rheology weighted mud system are concluded as very different to the previous riserless 26″ wellbore drilling example illustrated in Chapter 12.
2. Sands and clay drilling conditions as engineered shall exhibit clear defined boundary limits based on well data as input and as worked example presents, that can in practice be safely managed, controlled, and adhered to during operating these sections. *Note*: PWD real-time measurement delivering the physical and evident cumulative EMW wellbore pressure results.
3. Flowrate remains a key performance deliverable in this section but is commonly restricted by MWD/LWD tool capability that need to be capable to accommodate higher flow rates.
4. The evident benefits of the use of flat rheology mud on these wells cannot be overstated based on past historical well problems and difficulties experienced with water based mud. *Example*: Higher ROP and wellbore conditions exhibited trouble-free connections and normal drag trips out on elevators to tribute the value this technology provided.
5. Preceding the final trip out, all logging runs conducted were trouble free, followed by directly running and cementing casing as planned with no other operating or wellbore issues noted.

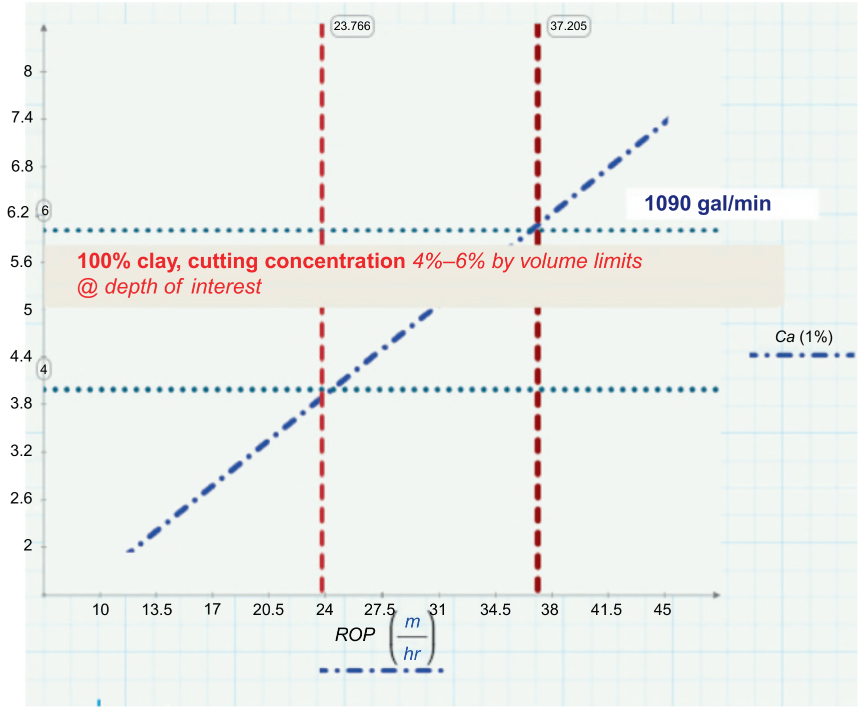


FIG. 15.4 17 ½″ Ultra deepwater wellbore clay drilling limits.

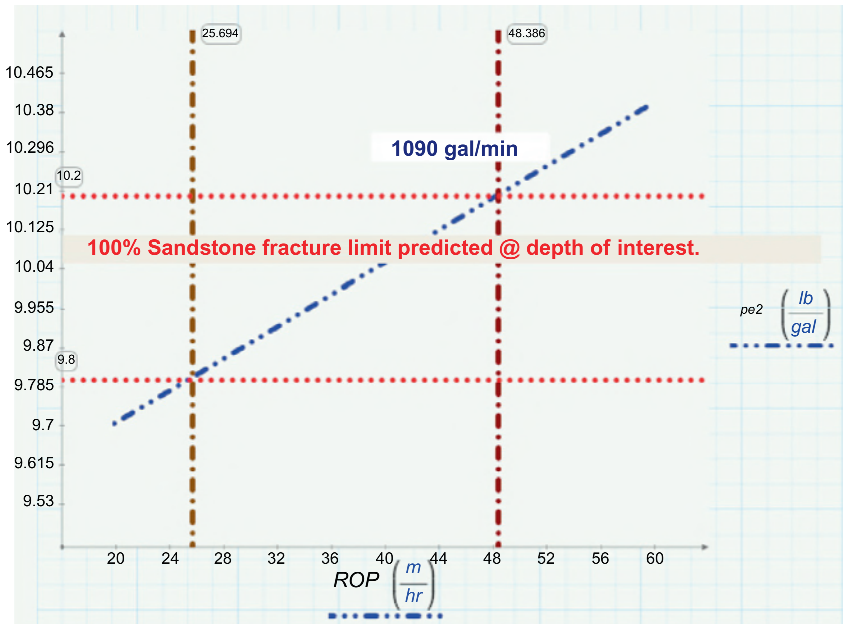


FIG. 15.5 17 ½″ Ultra deepwater wellbore clay drilling limits. *Source: Kingdom Drilling.*

TABLE 15.5 Deepwater Mud Report for Well

Drilling Assembly							Casing		Volumes		Pump Information					
Bit Gauge (in.)		**Mfr**		**Bit Model**		**OD (in.)**	**ID (in.)**	**Depth (m)**	**bbl**	**Model**	**Liner (in.)**	**Stroke (in.)**	**Eff (%)**	**Vol/Stk (bbl)**	**Stk rate (SPM)**	**Circ Rate (USgal/min)**
17 1/2				PDC		21	19 1/2	2500.00	Total Hole 4611.86	TPK 7 1/2	6 1/2	14.00	97.00	0.1393	90	527
Drill Collars			**Drill Pipe**			20	18 3/4	3462.00		TPK 7 1/2	6 1/2	14.00	97.00	0.1393	90	527
OD in	**ID (in.)**	**Length (m)**	**OD (in.)**	**ID (in.)**	**Length (m)**		17 1/2	4209.00	Active Pits 1601	TPK 7 1/2	6 1/2	14.00	97.00	0.1393	90	527
9 1/2	3	9.31	6 5/8	5 3/8	3976.27					TPK 7 1/2	6 1/2	14.00	97.00	0.1393	0	
8	2 13/16	74.60	5 7/8	4 1/16	74.87				Tot Active 6212.86							
8	2 13/16	48.05								**Circulation Times**						
									In Storage 6981	Surface to bit	14.9 min/2685 stks		Total system		190.8 min/51520 stks	
										Bottoms up	133.3 min/36,002 stks					
	Mud Properties				**Max Ann Velocity**						**Hole Information**					
Property	**1**	**2**	**3**	**4**	AV riser	76.76 ft./min	Standpipe pressure		3850 psi		Water depth		2500.50 m			
Sample from	Active pit	Flow line	Flow line	Active pit	AV casing	83.92 ft./min	Hole flow		1053 USgal/min		Riser booster rate		527 Usgal/min			
Check time	09:00	14:00	18:00	21:00	AV open hole	119.53 ft./min	**Solids Analysis**									
MD (m)	4088.00	4209.00	4209.00	4209.00	Vc open hole	410.43 ft./min	**Property**	**1**	**2**	**3**	**4**					

TVD (m)	4088.00	4209.00	4209.00	4209.00	Vc drill pipe	386.26 ft./min	LGS (%)	4.50	4.50	4.50	4.57
Bit depth (m)	4088.00	4209.00	4209.00	4209.00	**Min Ann Velocity**		LGS (sg)	0.12	0.12	0.12	0.12
Density (ppg)	9.10	9.15	9.20	9.20	AV riser	76.76 ft./min	HGS (%)	2.82	2.82	2.82	2.74
Funnel visc (s/quart)	123.0	125.0	128.0	127.0	AV casing	83.92 ft./min	HGS (sg)	0.12	0.12	0.12	0.12
Test temp (°F)	90.0	90.0	90.0	90.0	AV open hole	95.02 ft./min	Avg dens sol (sg)	3.2161	3.2161	3.2161	3.1997
Rheol temp (°F)	120.0	120.0	120.0	120.0	**Bit Information**						
PV (cP)	28	29	29	29	Size	17 1/2 in					
YP (lbf/100 ft^2)	30	31	30	31	Hours on bit						
10 s Gel (lbf/100 ft^2)	13	13	13	13	Bit Number						
10 min Gel (lbf/100 ft^2)	16	17	16	16	BHA number	5	**Rheology**				
30 min Gel (lbf/100 ft^2)	19	19	18	18	Depth inm		600 RPM	86	89	88	89
HTHP filtrate (cc)	2.0	2.0	2.0	2.0	Bit RPM	180	300 RPM	58	60	59	60
HTHP cake (in./32)	2.0	2.0	2.0	2.0	WOB	15.00 klbf	200 RPM	43	46	46	46
HTHP temp (°F)	250.0	250.0	250.0	250.0	Nozzles	2×14,8×15	100 RPM	34	35	34	35

(Continued)

TABLE 15.5 Deepwater Mud Report for Well—cont'd

Drilling Assembly							**Casing**		**Volumes**		**Pump Information**					
Bit Gauge (in.)		**Mfr**		**Bit Model**		**OD (in.)**	**ID (in.)**	**Depth (m)**	**bbl**	**Model**	**Liner (in.)**	**Stroke (in.)**	**Eff (%)**	**Vol/Stk (bbl)**	**Stk rate (SPM)**	**Circ Rate (USgal/min)**
HTHP pressure (psi)	500	500	500	500	**Bit Hydraulics**		6 RPM	13	13	13	13					
Retort water (%)	24.00	24.00	24.00	24.00	Nozzle Yel	201 ft./s	3 RPM	11	11	11	11					
Retortbase fluid (%)	67.00	67.00	67.00	67.00	Bit Press loss	333 psi										
Retort solids (%)	9.00	9.00	9.00	9.00	HHP/area	0.86 HP/in^2										
Corrected solids (%)	7.32	7.32	7.32	7.32	HHP	11.64%	**Hydraulic Analysis**									
Oil:Water ratio	74:26	74:26	74:26	74:26	TFA	1.6812 in.^{2}	Behavior index (n)	0.330								
Alk (whole mud-POM) (cc/cc)	2.1	2.1	2.2	2.1			Consistency index (k)	6.852 s^n 100 ft^2								
CI (whole mud-ClOm) (mg/L)	42,000	42,000	42,000	42,000			ECB @ bit depth	9.31 ppg								
Ca (whole mud-CaOm) (mg/L)	0	0	0	0			ECB @ casing shoe	9.30 ppg								

Excess lime (lb/bbl)	2.7	2.7	2.8	2.7	**Fluid Comments/Recommendations**
Brine density (sg)	1.19	1.19	1.19	1.19	Treated the active system with Carbomul & Omni Vert for emulsion stability. At depth 4175 m started increasing MW of active system from 9.1 to 9.2 ppg as advised. Pulled out of hole on elevators for wiper trip. Observed no fill at bottom; after running back in hole. Outings over shakers were firm, with PDC bit marks and dry from inside thus showing good inhibition. Outings volume over the shakers was proportional to employed ROP, observed no oil:water separation from HTHP filtrate, running cuttings dryer to recover mud lost on cuttings. Used base oil to fill the holding tanks at shakers and cuttings dryer area. Losses shown on centrifuge are from cuttings dryer centrifuge. Received chemicals from Altair as per the inventory. No HSE incident reported.
NaCl (% wt)	0.0	0.0	0.0	0.0	
$CaCl_2$ (% wt)	21.5	21.5	21.5	21.5	
Elect. stab. nV	411.0	421.0	427.0	422.0	
WPS	163,542	163,542	163,542	163,542	
Aw	0.81	0.81	0.81	0.81	
					Drilling Comments
					Continued drilling ahead from 3983 to 4209 m, Section TD, Circulated the hole and POOH from 4209 to 3455 m on elevators. Run back in from 3455 to 4209 m. Circulating the hole clean at report time.

2500 m water depth, drilling to 4209 m.
Source: Kingdom Drilling training 2014.

Intermediate Casing and Cementing Guidelines

A generic intermediate casing and cementing guide similarly follows.

Casing Preparations

1. Prepare casing tally. Caliper casing ID for cement displacement. Install centralizers as per final as instructed centralization program.
2. Record the serial numbers of Casing Hanger Seal assembly and submit a dimensioned drawing to the operator's drilling supervisor.
3. Confirm casing handling equipment is ready to be rigged up and has been previously function tested on site. Prepare as much equipment as possible on last trip out at TD.
4. Confirm casing hanger seal assembly running tool is premade to Hanger Seal assembly.
5. Confirm darts are loaded in subsea cement head system assembly with handling joint ready to be picked up and racked back.

Recover Bore Protector

1. Make up the wellhead running, test tool, and jetting assembly.
2. If not recovered on final trip out, RIH and recover bore protector using the designated landing string.
3. On approaching subsea BOP with the BHA, open the compensator. Record the landing string weight.
4. Land out and retrieve the bore protector as per recovery procedures.
5. Recover the bore protector. Lay down tools and equipment.

Casing Running

1. Rig up to run casing as per drilling contractor's procedures.
2. Run casing as per casing tally and as per operator program instructions provided.
3. Run the shoe track, check float shoe and collar (by filling with water/mud and observing joints drain). Baker-lock the first three connections.
4. Make up, run and fill casing every, observing hook loads and returns continuously.
5. With the last joint of casing in the slips, change to the drill pipe elevators.
6. Verify the number of joints left on the deck is as per final tally inventory and count.
7. Pick up the casing and wellhead hanger and carefully stab into the casing. Make up and check assembly as per wellhead rep's specifications.
8. Pick up and establish the weight of the complete string. With all satisfactory, pull the slips and pick up clear of the rotary to afford the ability to rig down.
9. Run the casing on the landing string through the marine riser until the casing shoe is above the subsea BOP filling landing string with required fluid as necessary.
10. Carefully run the casing shoe through the subsea BOP and wellhead.
11. As casing enters the subsea wellhead housing, adhere to running speed (surge) depth and interval schedules as casing penetrates and envelopes the surface casing string depths as it is run. Record hook loads, fill string regularly, and monitor returns via trip tank, casing and landing string loads continuously.
12. As casing enters open hole, similarly applied running speeds, filling, and monitoring practices are to be used. If welbore drag and string weights deviates from a standard norm, it is preferred to break circulation and stage up flow as required, then work or wash casing

until normal drag, hook loads, volumes pumped and returned trends must be reestablished prior to finally compensating and landing out casing hanger in the subsea wellhead.

13. The cement head assembly is picked up last. Evaluate the complete casing and landing string loads, then engage and compensate to run in and land casing hanger and string weight in the subsea wellhead as directed by the toolpusher and wellhead specialist.

Casing Cementing

Preparations

1. Confirm cement slurry volumes and requirements with operator's drilling supervisor.
2. Assure *Prejob Safety Check Lists* are completed before mixing and pumping cement.
3. Prepare the reverse circulating line for a quick rig up if/as required to be able to reverse out should an aborted cement job result.

Cement Operations

1. Stage up to optimal circulation (displacement rates) and pump more than the casing contents. *Note*: Incrementally increase the rate, monitoring for losses to a maximum rate.
2. Flow check via trip tank and simultaneously hold tool box talks and safety discussion required while also pressure testing, mixing, and pumping cement.
3. Cement example as follows:
   - **a.** Rig pumps shall generally pump required spacer volume plus the line capacity.
   - **b.** Close internal blow out preventer (IBOP) and pressure standpipe to required pressure.
   - **c.** Cementer shall be waiting and ready on drill floor to release the bottom dart from the top drive cement head. Once attended to,
   - **d.** Mix and pump light weight lead slurry as planned. *Note*: Slow down when bottom plug is expected to shear out and note actual volume pumped and shear pressure.
   - **e.** Continue to mix and pump total lead slurry volume at optimal rates.
   - **f.** Follow lead by mixing and pumping the heavier tail slurry using mix water assigned in one of the mud pits. (Be sure to chase cement with the line volume of spacer to flush line.)
   - **g.** Release the top from the top drive cement head, and line up to circulate and displace via the top drive, rig pump system, assuring the cement line is isolated.
   - **h.** A specified volume of tail spacer and then displacement mud is then pumped until the top plug is observed to shear at the subsea plug system and at the predetermined pressure and volume required. Once observed, physical cement displacement is then commenced.
4. Displace cement, e.g.:
   - **a.** Drill floor shall zero the pump stroke counter.
   - **b.** Displace required mud volumes (using designated mud pump efficiency) to theoretical landing out of top cement plug on the float collar (termed the *plug bump*).
   - **c.** *Note*: once cement turns the corner at the well bottom, i.e., the casing shoe, a linear pressure increase shall now result as heavier lead cement enters and travels up the wellbore annulus.
   - **d.** This pressure and volume return trends then monitored throughout observing for losses; if noted, the pump rate can be slowed down to mitigate the loss effect.
   - **e.** At end of the displacement, a final volume is assigned and pumped slowly to observe the "plug bump."

f. If plugs are not observed to bump, a standard practice is to displace half the shoe track volume and verify final volumes, differential and pump pressures, and returns to assure cement is in situ and placed as planned. The imperative is not to overdisplace the cement.
g. The final differential pressure prior to bump is critical to confirm a well-executed cement operation and shall be noted, recorded, and reported.
h. On plug bump, a casing pressure test can be conducted as per program and verified to be holding constant pressure for at least 10 min to meet minimum standard test requirements.
i. Following this, pressure is bled off with the system's returns volumes measured and checked for backflow at the cement unit.

5. Following cementing, the casing hanger and seal assembly are mechanically set and pressure tested in the subsea wellhead as per manufacturer's specifications.
6. After casing hanger setting and seal assembly testing, a subsea BOP and function test shall be conducted as per drilling contractors and operators program test procedures.
7. After further testing is conducted, the release and pick up the casing hanger and seal assembly running tool and landing string as specified.
8. Then followed by tripping out the casing hanger seal assembly running tool and landing string.
9. When convenient the cement head would be laid down for maintenance and prepared for its next utilization.

Install Wear Busing

1. Install required wear bushing in subsea wellhead prior to running the next drilling assembly *Note*: this can be run, installed, and recovered when/as desired using a specialized tool and method within the drilling assembly to save added landing string run and recovery trips.

Generic Section Reporting Requirements

Required reporting at the end of each wellbore section with copies retained in the onshore/offshore well files, are generally but not limited to:

- Well integrity Test Record and Charts signed/dated by cementer and DSV.
- Drilling, tripping assessment, after action review.
- Bit report and update bit record sheet.
- Casing "As Run" Tally Sheet.
- Casing Cementation Report.
- Hanger Seal Assembly Test signed/dated by Wellhead Rep and DSV.
- Drilling mud log.
- Casing running and cementing evaluation summary.
- Updated well/wellhead schematic.
- Contractor evaluation record.

WELL INTEGRITY AND BARRIER REQUIREMENTS

Once a subsea BOP is installed, the well's barrier elements to be considered for all operating conditions, situations and circumstances are summarized in the following *sec*tions.

Preventative Barriers

All personnel must be aware of the well integrity and barrier responsibilities to be established and maintained during a project's operational phases. Appropriate attention afforded to all preventative barriers, means and methods used (in terms of equipment, process, and people.) When things go badly wrong in deepwater, this usually results through a complex combination of well barrier failures. "What went wrong on Macondo?" *this author asked, with an immediate experts conclusion and response that was,* "Man, several things must have must have failed."

Events proving that human failure (to intervene on several occasions in this case) is often the last yet the most important line of defense to prevent major lost time events from resulting that if left to escalate can then lead to far more consequential results, e.g., a blowout, major spill or worse.

Escalation Barriers

Escalation barriers required are illustrated in Fig. 15.6 to present how people can quite readily control complex situations to limit loss severity. The objective understanding of these relationships is to assure multiple barrier layers exist for each and every well hazard suspected and that each barrier is independent of each other. If projects adopt a more assured stance in this respect, major events cannot be repeated. Loss prevention prevailing through greater barrier assurance and responsibility assigned to each individual hazard. The criticality of each and every well's barrier then assisting operational persons to better understand who, what, when and how to act to prevent, maintain, and contain the most critical live-well operational phases as attended to in this and subsequent chapters.

Fundamentally, a well integrity barrier strategy plan is required for each construction phase to ensure that each well-life-cycle has the required elements in place to meet all the environment, situations, and operating conditions that exist.

Particularly once the subsea BOP is installed and for each casing or liner set and cemented thereafter, all physical, conditional, and operational barriers installed, shall be verified, confirmed, monitored, and remediated should they fail.

For exploration and appraisal wells generally covered in this guide, a variety of short-term barriers are often employed with availability based on the specific operations to be performed. Irrespective of this fact, all wells must still be designed to have multiple physical and operational barriers assured against each potential flow path from the formations exposed, situations, conditions, and environments that exist.

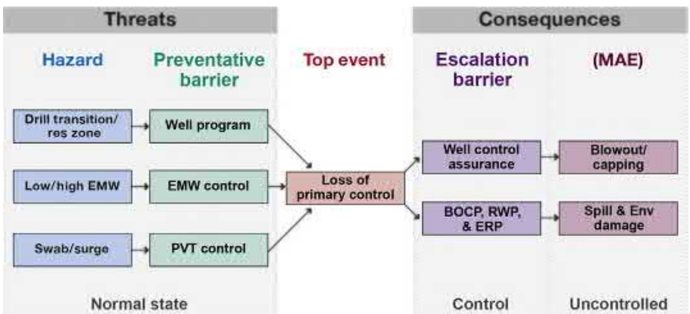


FIG. 15.6 Threat and consequence "Bow-Tie" illustration of a well control assurance event while drilling.

Number and Types of Well Barriers

It is generally accepted that a minimum of two physical barriers provide a required systems reliability. Should a deepwater situation or condition exist with less than two physical barriers, the operational barriers are then far more critical, particularly where *permeable formations, loss of riser margin, transition zones, or potential reservoir hazards and risks exist*. For example, while drilling a new wellbore, the hydrostatic barrier of the drilling fluid is the only physical barrier preventing flow to the rig floor.

The subsea BOP equipment once installed therefore forms and provides integral secondary and further additional physical barriers when closed and sealed. The reliability of this equipment as a physical barrier depends on operational barriers such as:

1. detecting an influx at the rig,
2. recognizing the need to respond,
3. responding appropriately,
4. proper design and functioning of the actuation system to close and seal the well.

Another common operation requiring extra focus on operational barrier elements is the removal of a physical barrier from the well. Examples of these operations include drilling out a cement plug, having no riser margin, or displacing the marine riser to seawater in a disconnect sequence. Here it is essential that the rig crew understand that the operational procedures are a critical part of the total well reliability and that practices for operations must be designed, documented, and tested in a manner similar to physical barriers. Whenever a well's physical barrier is disabled, it is important that field personnel understand the implications on safety and well operational integrity. The crew shall then proceed under the assumption that the well could flow when that barrier is removed and be prepared to quickly react with a ready to go contingent plan to any indication or presence of flow.

Barrier Standard and Assurance

General barrier standards and assurance by the well designer and operations personnel are:

1. Assume any single well barrier can fail, even those that are verified. Failure of each barrier is to be considered, with contingencies and responses fully accounted for.
2. Understand barriers actively in place when the rig is working on a well, regardless of the number of physical barriers in place and/or whether they are verified or confirmed.
3. If physical barriers cannot be verified by testing to anticipated loads, alternative verification methods are to be considered.
4. If placement of a physical barrier is not confirmed, additional operational barriers may be used to enhance well system reliability in accordance with local regulations.
5. Train personnel to understand not to deploy a planned barrier due to unexpected conditions, which shall increase the likelihood and risk of a well system failure.
6. If a physical barrier is deficient during the course of operations and cannot be repaired, reassess the remaining well system reliability in accordance with regulations. *Note*: The loss of a physical barrier can cause a significant reduction in the well reliability. In such instances, a management of change process, to replace (*if possible*), or install a supplemental physical barrier, or use an operational barrier should be considered.

Barrier Verification

Acceptance criteria shall be established for each barrier and clearly stated for each section. The levels of acceptance may result in classification of the barrier as being verified, either as a tested or a confirmed barrier, as defined. Barrier verification results shall be documented and retained as required by local regulations or by company operating policy. Generic well examples are illustrated in Tables 15.6–15.8.

Notes: API RP 96, IADC deepwater well control guidelines 2nd edition, and Norsok Standard D-1010 Rev. 4 June 2013, provided specific barrier standards, reference, and guidance.

TABLE 15.6 Generic Deepwater Well, Intermediate Wellbore, and Casing Barrier Summary

	Barrier Summary Drilling Intermediate Wellbore Section and Running Casing/Liner		
	Annulus Barriers	**Main Bore Barriers**	**Barrier Verification**
Primary	20″ cemented to seabed		Cement volumes: ROV to monitor cement returns and differential pressures.
	21″ HP WHH		Casing pressure tested as per program.
		Mud weight.	Monitor pit returns. Mud weight specification.
Secondary		Surface casing	Casing pressure tested as per program.
	BOP stack. Required well barrier integrity.		BOP and well integrity tests on installation. BOP test.

TABLE 15.7 Generic Deepwater Well, Production Wellbore, and Casing/Liner Barrier Summary

	Barrier Summary Drilling Production Wellbore Section and Running Casing/Liner		
	Annulus Barriers	**Main Bore Barriers**	**Barrier Verification**
Primary	Annulus cement		Cement volumes and differential pressures. Verified well volumes and returns.
	Seal assembly		Pressure tested seal assembly as per program
		Mud weight	Monitor pit returns. Mud weight specification
Secondary		Intermediate casing	Casing pressure tested as per program.
		Float valve in string.	NO evidence of flow on connections or on tripping via trip tank monitoring and measurements.
	BOP stack. Required well barrier integrity.		BOP and well integrity tests on installation. BOP test.

TABLE 15.8 8½ Production Wellbore Barriers

Barrier Summary Drilling Production Wellbore Section and Running Casing/Liner			
	Annulus Barriers	**Main Bore Barriers**	**Barrier Verification**
Primary	Annulus cement		Cement volumes and differential pressures. Verified well volumes and returns.
	Verified seal assembly		Pressure tested seal assembly as per program
	Mud weight		Monitor returns on active pit and mud weight specification
Secondary	Intermediate, production casing		Casing pressure tested as detailed in the drilling program
	Float valve in string.		NO evidence of flow on connections or on tripping via trip tank monitoring and measurements.
	BOP stack and WH installed		BOP and well integrity tests on installation. BOP tests.

PRESSURE DETECTION MANAGEMENT—POST RISER SECTIONS

Deepwater Pressure Detection

Deepwater pressure management as outlined in Chapter 3 is a critical element to manage during well operations once the subsea BOP is installed when low fracture gradients or abnormal pressure exists. In all cases, reliable well operational detection methods must prevail to assure SEE principles exist to mitigate and resolve difficulties that result.

No matter what complexity a deepwater well may be, the equivalent mud weight (EMW) is the singular, most evident, and important factor to assure that primary well control is maintained for all wells operating conditions. In simple terms, the EMW affords the *operationally safe* workable values above and below the highest permeable formation pore pressure and minimum fracture pressure to prevent inducing a formation fracture (losses), wellbore (kicks), and further operating difficulties resulting as illustrated in Fig. 15.7.

The EMW shall sit practically within the upper and lower operating limits to define the *safe mud weight window* for each section. The EMW values and components are used and applied to assess the key and critical operational aspects of kick tolerance sensitivity, drilling and riser margins, to define best practices to apply, and where to set the next casing or liner string. Should the EMW pressure margins change, risks are reassessed, derisked, controlled with operational parameters corrected accordingly.

To surmise the safe working EMW envelope is constrained by maximum pore and minimum fracture pressures. EMW is to be safely managed and controlled at all times between these limits to avoid operational wellbore problems resulting, of note:

- ***Swab pressure*** effects to be controlled >maximum pore pressure.
- ***Surge pressure*** effects to be controlled <minimum fracture pressure.

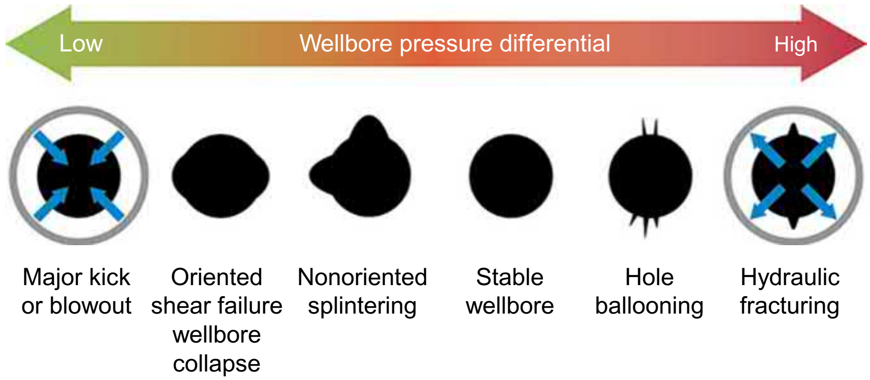


FIG. 15.7 Effect of wellbore pressure differential and modes of failure that can result.

Basic Elements for Detecting Overpressure

The basic operating elements to manage overpressure in deepwater are to:

1. Determine and detect hydrostatic pressure requirements.
2. Minimize manage, monitor and control all EMW, i.e., MW, ECD and AOPE variations.
3. Detect and prevent kicks/losses.
4. Control kicks/losses and any losses/gains (vicious circle) events.

DETERMINING AND DETECTING HYDROSTATIC PRESSURE REQUIREMENTS

This is achieved through constant detection, monitoring, and evaluation of all pore pressure indicators during all well operations. When there is sufficient evidence of underbalance or overbalanced conditions, EMW can be increased or decreased as per safe designated operating limits permit. Commonly used best practices are:

1. Mud weight (MW) is best managed somewhere suitable *below the median line* rather than above it. It is preferred as safer and more practicable to increase mud weight than reduce it.
2. Maintain weight-on-bit, RPM, pump rate, bit type as constant as possible when drilling critical intervals and zones.
3. Control drill if pressure transition, reservoir interval zones are abrupt (i.e., tens of feet).
4. ***Do not*** control drill if pressure transitions are not abrupt.
5. ***Do not*** overreact to >gas or gas cut mud. Stick to primary control principles and comprehend the physics of gas expansion and migration in water- and oil-based muds.
6. ***Do not*** misinterpret lost mud and then flow back to be a kick. Be fully familiar in *finger printing* in critical sections.
7. Focus on what indicators are the ***most reliable.*** (As stated in Chapter 3, Table 3.1.)

MINIMIZE PRESSURE VARIATIONS DEVIATIONS

1. Revisit all aspects of pressure management as attended to throughout this guide.
2. *EMW* = MW + ECD + AOPE, effects often shall be *independently assessed*.
3. Develop a full working understanding of all operating pressure management issues; remaining within EMW limits by carefully considering and understanding each pressure effect shall greatly reduce risk of wellbore problems resulting.

DETECT KICKS AND LOSSES

1. Initiate fingerprinting when under or overbalanced indicators are noted.
2. Observe and monitor for increased, decreased flow where downhole pressure tools are essentially a must-have aid for critical deepwater sections.
3. Watch for discrete drilling breaks and/or formation, drilling parameter changes:
   a. Drilling breaks do not indicate under balance, but can suggest more permeable porous formations are being drilled, so kicks are *possibl*e.
   b. Flow check each drilling break in higher risked pressure transition intervals.

CONTROL KICKS AND LOSSES

1. Prevention versus cure is the prerogative. Primary control practices shall prevent the majority of kicks or loss circulation events. This cannot be overstated enough.
2. Primary well control aspects are covered in more depth and detail in chapter 16 of this guide.
3. Swab and surge calculations shall be conducted with precision and accuracy.

Note: For intermediate casing strings, e.g.,11¾″ or 11⅞″ liners/9⅝″ or 9⅞″ or 10¾″, the associated restricted tolerances when running or circulating these strings, combined with low formation fracture gradients, substantially increase the likelihood of lost circulation. Far greater attention must be afforded to running speeds, swab and surge modeling, etc.

CONTINUED THE LOSS/GAIN VICIOUS CIRCLE

Should loss/gains result, it is paramount to establish if the flow back is mud lost (whatever the reason) or is in fact a formation fluid influx, (kick). Then assure "right first time" actions are taken to remediate each situation, e.g.:

- *Losses did not result* during drilling:
  - ○ Flow is not lost via mud flow-back. Treat as a kick, using standard secondary well control guidelines.
- *Losses resulted* during drilling:
  - ○ Monitor rate of gain on trip tank.
  - ○ If flow stops before a safe and manageable allowable volume of mud is bled (bled back volumes are generally based on rate of mud volumes lost)
  - ○ Flow is probably lost mud flow-back. Continue with normal operations.
- *Flow did not stop* after the allowable volume of mud is bled off:
  - ○ Shut-in well. Measure initial SIDPP, SICP.
  - ○ Open choke, and bleed fluid.
- *Flow stopped* before the allowable volume of mud is bled:
  - ○ Flow is probably lost mud flow-back.
  - ○ Circulate bottoms up. Flow check; if no flow, continue with normal operations; if flow, shut in well, and repeat previous steps.
- *Flow did not stop* after the allowable volume of mud is bled:
  - ○ Shut-in well. Measure shut in drillpipe and casing pressure, etc.

Pressure Detection

The detection of pore pressure, stress, and fracture gradients drives the need to monitor, log, and analyze all actual and real-time data measurements and parameters obtained. These are then compared to the predrill models to assess and evaluate the pressure precision of all implementation plans. Should evident data values deviate when navigating through *overpressure, transition or reservoir zones* appropriate risk and management of change processes shall take precedent.

Note: Pore pressure detection methods are not universally applicable and their effectiveness will often be controlled by the rigs, wells, people, and other equipment specifics. Key methods that can identify an increase in pressure, notably in the transition zone, are essentially based on three primary streams of "while drilling" data, i.e.,

1. ***Drilling parameters*—**observing drilling parameters and applying empirical equations to produce determinant results that are dependent on pore pressure.
2. ***Drilling mud*—**monitoring the effect of an overpressured zone on the mud, e.g., in temperature, influx of oil or gas.
3. ***Drilled cuttings*—**examining cuttings, to differentiate these from a pressured zone.
   Note: Additional data at the end of each hole section/trip section can also be integrated into a pressure prediction model, e.g., shear sonic data, density data, wireline measured pressures.

A list of essential predictive and detective methods to identify pore pressure trends, and indicators is shown in Tables 15.9 and 15.10. These can vary in effectiveness and need to be classified per a well's section based on the *basis of reliability*. Ideally each while drilling method should be used in conjunction with others to detect subnormal or abnormal pressure zones. **Lithology**, it should be stated, is a key determinant to correct interpretation and must be linked to each parameter independently.

Effective Pressure *Transition* Management

Pore pressure **prediction** and interpretation starts in the planning stage, with offset well information and seismic data used to develop predrill pressure estimates. During drilling,

TABLE 15.9 List of Predictive and Detective Methods to Identify Pore Pressure Trends

Source of Data	Parameters	Time of Recording
Geological	Regional geology. Offset data analysis. Pore pressure studies.	Prior to spudding well
Geophysical methods	Formation velocity (Seismic, 3D, hi-resolution, etc.),	
Drilling parameters	Drilling rate, lithology, WOB/RPM, torque, drag, pressure effects (swab/surge, ECD), d exponent, sigmalog, normalized data, MWD, APWD. People & equipment.	While drilling (real time).
Drilling mud	Gas content, mud weights in/out, "losses & kicks," temperature, drillpipe and annular pressures, pit volumes, flow rate, hole fill up	While drilling (real time). Delayed by time required for sample return
Drill cuttings	Lithology, shale cuttings, volume, shape size, density, shale factor. Cuttings gas.	
Well logging	Primary data; shear sonic (memory data) Electrical survey, resistivity, conductivity (real time)	At the end of the wellbore section.

TABLE 15.10 Pore Pressure Detection Reliability

Detection Parameter	Real Time Methods	Delayed (lag time) methods
Most reliable	Drilling rate (e.g., drilling break) Flow measurement. Losses and gains. MWD (neutron/density)	*Gas*: Drilled (background) gas. Connections gas. Reservoir gas.
Moderately reliable	MWD (GR/Res/DT(c))	*Gas*: Composition. Trip gas. Shale density, shale factor. Abundance, size, shape of cuttings.
Not very reliable	Pump pressure.	Mud temperature.

real-time data as outlined in this chapter are then used to **detect** and assure all SEE pressure interpretation benefits can result. Best practices, wider skills sets, and competencies all viewed as essential for effective pressure management to deliver:

1. Accurate interpretation of the pore and operational pressures at any given depth
2. Precise and accurate equivalent mud weights (EMW), mud weight (MW), equivalent circulating density (ECD), and all other pressure effects (AOPE). *Note*: All principles and practices to be similarly applied whether pore pressure is increasing or decreasing.

It is important to appreciate that, excessive EMW, pressures cause and effect can quickly change a balanced pressure situation to quickly escalate to a tier 2, kick or lost circulation event.

Other key points are:

1. Pore pressure interpretation begins in the planning stage, via interpreting offset well information and seismic data of value to use to develop predrill estimates. Teamwork and good communication is essential as illustrated in Fig. 15.8.
2. Real-time (and lag-time) data (ROP, gas units, LWD, etc.) is to be used to finetune the pore pressure interpretations and update the predrill PP model in real time, at the end of each section (with additional lag time data, e.g., shear sonic data). This shall be conducted at the well site by any pore pressure specialist or supervisory roles assigned.
3. As the accuracy of the predrill estimates decreases, so does the allowable margin of error for the real-time interpretations.
4. Good drilling practices constitute an important part of effective pore pressure management. E.g., *maintain drilling parameters as consistent as practicable enables optimal monitoring of all pressure indicators, trends, and indicators to result.*
5. All real-time pore pressure prediction results are used to update the section data using LWD data in conjunction with drilling parameters, gas, and cuttings data.
6. Data then used to construct a baseline pressure gradient at the well location.
7. Specialist persons are often resourced onsite for critical sections and shall update and compare the real-time data against baselines determined. Management must assure that appropriate pressure management and well control assurance competencies, skills, training and development are catered for.

While drilling critical pressure sections, prediction shall fundamentally rely on drilling parameters, the most reliable indicators, and drilling mud. LWD data and cuttings often provide

FIG. 15.8 Benefits of good communications and sharing information throughout the deepwater team.

little value notably in *highly interbedded, chalk, and other specific lithology that cannot be monitored for pressure using standard means and methods*.

To this end, all persons in charge shall have to work very closely with the pore pressure specialists and others are competent when drilling these specific lithology intervals. It is considered fundamental however that mud weight (MW) is not increased unnecessarily as this can result in fracturing weaker formations that may exist. Mud weight shall also *not be increased based on what a drilling program pore pressure curve or wellbore stability study results predict* but rather on what is concluded at the drill site through real-time analysis, to assure people do the right things to get pressure decisions right first time.

Drilling Critical Pressure Zones

Critical Pressure Zones—General

It is important to realize what is considered as best and inappropriate practices that lead to, cause, contribute, and effect lost time operational events such as:

- Wellbore enlargement, or deterioration
- Unwarranted mechanical/hydraulic in situ stresses within the wellbore,
- Unwarranted drillstring vibrations, fatigue mechanics,
- Generation of further cuttings and solids into the wellbore,
- Several stuck pipe and increased potential for wellbore or downhole equipment failure.

Best practices in deepwater also demand a far wider skills set above what is considered the standard norms that once established should not be deviated from unless there is strong and very evident reasons presented to then discuss, risks assess a need to change.

Drilling Best-Practice Methods

In the critical sections, EMW pressure effects must be managed, monitored, and controlled to prevent, mitigate, and reduce lost time operational events as per best practices to consider and discuss as follows.

BEST PRACTICE DRILLING METHODS—CRITICAL SECTIONS

1. The drill string shall not be moved in the open hole unless the pumps are running and return flow is observed. *Note*: *Swabbing remains the main cause of kicks.*
2. Drilling breaks, shall be flow checked until personnel are satisfied the well is stable (irrespective of a gain or loss trend is resulting.) as outlines in these sections.
3. Flow checks may be conducted after drilling the casing shoe to establish initial flow backs and fingerprinting trends of the system as required.
4. Flow checks shall be conducted on the trip tank with the trip tank pumps running until a normally considered trend is observed and agreed by personnel concerned.
5. Fingerprinted results shall be compared to conclude the well's control status. If a confirmed increase in flow is concluded, shut in the well and observe pressures.
6. Monitor flow back volumes during connections and compare to fingerprint established at the casing shoe to identify wellbore loss, gain, or trend effects.
7. Connection gas peaks are to be trended at each bottom's up. If gas increase trends are noted. Discussions shall kick-off in regards to potential mud weight change required.
8. If breathing is evidently apparent, i.e., "losses and then flow-back gains" and that volumes increase with depth. Drill the well in shorter intervals to ascertain breathing is taking precedent as opposed to the well flowing (more mud returned than lost).
9. When well is *not circulated with the mud pumps*, line up on the trip tank and circulate across the hole with the trip tank pump. (Follow the flow check procedure).
10. If hydrocarbons exist, on each trip to bottom the requirement to circulate a bottoms-up prior to operational recommencement shall be risk assessed in conjunction with circulating the last part of the circulation through a fully open choke with the annular preventer closed.

BACKREAMING

Despite the evidence that concludes there is very little merit to support the use of this method in most cases. With the introduction of the top drive, backreaming and continuous rotation of the drillstring and its components is often applied *as a matter of course rather than to serve a specific purpose*. The author's and many others experiences recommends to carefully consider *backreaming as a last resort*.

BREAKING CIRCULATION AND CONNECTIONS

It is important to use consistent execution practices during connections through safely managing and monitoring all pressure-related effects with more precision and control. E.g., ***When circulating***:

1. Restart circulation to assure minimum pressure cause and effects.
2. Consider rotating drill pipe before starting circulation.
3. Slowly stage pumps up to speed.

***During/making connections*:**

1. Minimize creating kicks, lost returns, stuck pipe problems during connections.
2. Wipe/ream last single before making a connection in difficult wellbore conditions.
3. Circulate as long as possible before a connection.
4. Start and stop drill string slowly.
5. Rotate drill pipe before starting circulation, then slowly bring pumps up to speed.
6. Keep pipe moving when there are concerns about differential sticking.

TRIPPING IN/OUT

1. Trip out of the well assuring necessary controls, i.e., without causing excessive swabbing, getting stuck, or taking a kick.
2. Circulate hole clean before tripping out.
3. Make clear the overpull limit prior to pulling out.
4. Pull out of the hole at a speed that avoids swabbing (run surge/swab software).
5. If overpull limit is reached, run in 1 stand, repeat hole cleaning procedure, and pull out of hole again. Repeat cycle if overpull limit is again reached.
6. Always run in with necessary control avoiding unnecessary surge, assure precise monitoring and maintain the well full at all times.
7. Determine tripping speeds and schedule from swab/surge pressure calculations.
8. If nonported float valves are run, fill the pipe consistently while running in. Flow check any discrepancies observed. Shut-in immediately if flow is observed.
9. When losses are a concern, consider washing down from the shoe or a safe operating distance back to bottom to minimize mud gel and any solids loading effects.

Down Hole Pressure Measurement While Drilling (PWD)

Downhole pressure while drilling (PWD) tools rely on acquisition and interpretation of downhole real-time data to recognize and analyze wellbore operating warning signs and indicators that evidently exist (Fig. 15.9). In addition, it is essential to monitor the associated drilling and geological data to full assess the bigger picture of ongoing operational activities to precisely and accurately interpret the PWD response.

Tools are considered to add value in respect to the following: *EMW increase, annular pressure increase/decrease; Borehole cleaning (good/poor); Provide kick detection and well control assurance indications; Flow back detection and flow back interpretation; Pumps off condition; Loss and gains; Well integrity tests (FIT, LOT, X-LOT); Drilling, fluid mechanics with pressure measurement; EMW responses; Cuttings loading mud rheology; Pressure related problems; Tripping, circulating, non circulating, reaming, backreaming effects.*

The following outlines key features and application of these tools. In summary, there is no doubt that there exists today a far greater scope to improve adaptation and application of this technology to greater value, benefits, and effects in deepwater wells:

- Combines downhole data with surface drilling and geological parameters to reduce EMW drilling operating problems, hazards, and risks.
- Drillstring rotation, i.e., above 50 rpm often can be seen to result in a stepped increase in EMW above the static mud weight vs. no rotation. *Note*: *wellbore size, geometry, lengths, and mud rheology dependent.*

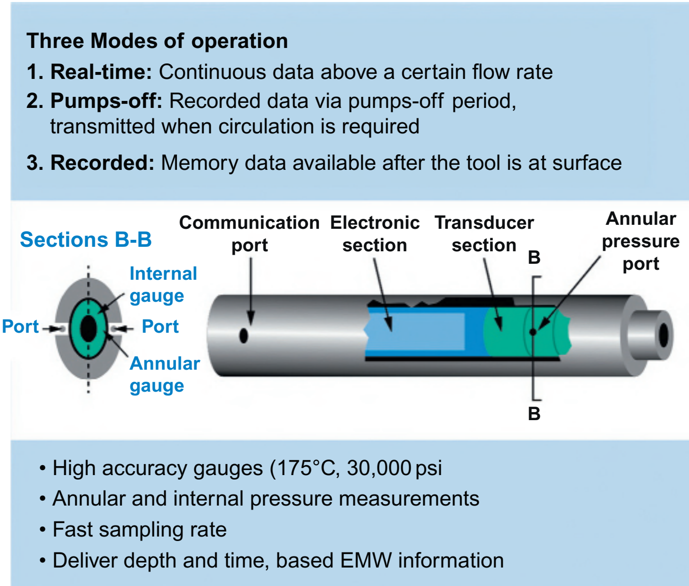


FIG. 15.9 Importance of pressure while drilling.

- Additional increase in EMW is observed during start of rotation, notably in higher angle, horizontal wells, mainly due to the resuspension of cuttings, etc.
- Large increase in EMW is observed when rotation is started after a longer steering interval, i.e., *a result of stirring up the cuttings bed, and suspending the cuttings again*. In such cases, EMW is controlled through rotational speed control in the start and through more controlled drilling rates until well comes clean, i.e., EMW meets the expected norm.
- EMW is often higher due to the fact that all other pressure, e.g., mud weight, PVT effects, circulation, pipe rotation, surge pressures effect together and where hydraulic models typically underestimate actual EMW observed.
- Reaming up/down continuously is too easily exercised with top drive systems (irrespective if required or not) and must be utilized with caution to minimize EMW surge/swab pressure tendencies and prevent self-induced lost circulation events. An important aspect is to bring up the pumps slowly in the first 15–30 s until the gel breaks.
- Accurate leak-off and formation integrity (LOT/FIT) test data are obtained from these tools.

Reasons and Rationale of Pressure Transition Problems

INSUFFICIENT MUD WEIGHTS (UNDERBALANCE)

While drilling pressure transition zones, inadequate EMW results from a combination of planning and operational problems as illustrated in Fig. 15.10. Sometimes pore pressures can increase abruptly in short transition zones with little forewarning, resulting in EMW outcomes being far more difficult to maintain primary control of the well.

Planning Problems

- Inaccurate predrill pore pressure and EMW predictive estimates (Fig. 15.10)
- Unexpected factures/faults

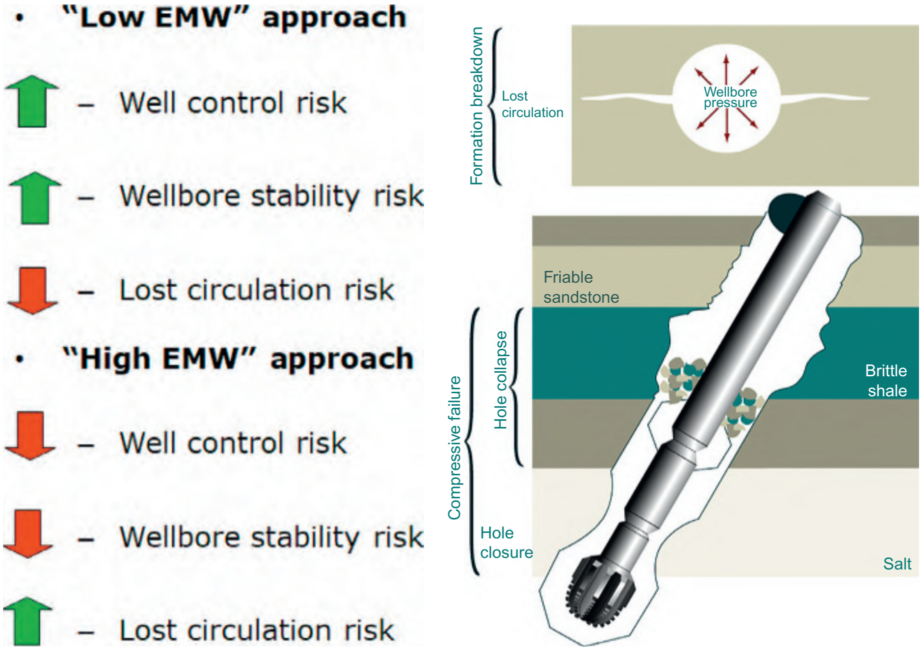


FIG. 15.10 Key problems and issues that result with a too high or too low equivalent mud weight (EMW).

Operational Problems

- Lack of appreciation of all EMW cause and effects
- Filling the hole with light mud
- Barite sag
- Excessive swab surge pressures
- Swabbed gas
- Geologic factors—short overpressure transition zones
  - Faults
  - Gas columns
  - Charged sands or similar intervals
  - Nonshale intervals

EXCESSIVE MUD WEIGHTS (OVERBALANCE)

Problems due to excessive EMW and operational overbalances can result in far more consequential impact and effects than similar issues due to insufficient or lack of mud weight as illustrated in Fig. 15.10. As with underbalance, excessive overbalance is frequently the result of poor planning or not identifying and reacting to operational problems quickly enough. Problems can however result due to abrupt pore pressure change within the formation or reservoir characteristics.

Planning Problems

- Inaccurate predrill pore pressure, lithology, formations prediction estimates (Fig. 15.10)

Operational Problems

- Lost mud flow back ("ballooning")

- Misinterpretation of EMW, pore pressure indicators
- Poor wellbore quality, ineffective, inefficient hole cleaning
- Geologic factors—pore pressure regressions
- Faults
- Depleted reservoirs
- Gas columns (gas caps)
- Salt, tar, bitumen

Best Practices for Managing Pressure Transition Zones

The consequences of pore pressure regression with excessive overbalance are suitably covered in Lost Circulation and Differential Sticking guidelines that can be readily obtained and reviewed. General best practices in this section focus on specific deepwater drilling strategies for pressure transition and reservoir zones. The basic principle elements to be understood, predicted, and prevented are considered as:

- Determine EMW mud weight requirements
- Minimize EMW variations
- Detect kicks/losses
- Control kicks/losses
- EMW Best practice

DETERMINE EQUIVALENT MUD WEIGHT REQUIREMENTS

- Monitor, maintain, and suitably control all pore pressure detection indicators; increase mud weight when evidence of under balance exists.
- While hunting pressure, maintain constant weight-on-bit, RPM, pump rate, etc.
  - Control drill if pressure transition zones are abrupt, i.e., tens of feet.
  - Do not control drill if pressure transitions are not abrupt.
- Do not over react to gas increases (better predict what to expect at surface).
- Do not misinterpret lost mud flow back "ballooning" to be a kick.

MINIMIZE EMW VARIATIONS

- Minimize swabbing while making connection and/or when tripping out.

DETECT KICKS AND LOSSES

- Run flow checks when underbalance is possible.
  - Watch for pit volume gains and drilling breaks.
- A drilling break does not indicate under balance; but it does mean a more permeable formation has been drilled, so a kick is *possibl*e.
- Run a flow check for drilling break in intervals where there is a risk of kicks.
- Prevent versus cure lost circulation is the preferred option (Fig. 15.11).

DEEPWATER LOST CIRCULATION PROBLEMS

- Estimated industry cost in the Gulf of Mexico: $1 billion/yr. Worldwide: ~$2–4 billion/yr.
- On average, 10%–20% of the total cost of drilling an HTHP well is expended on mud losses (U.S. Department of Energy)
- No consistent approach to manage lost circulation
- Nearly 200 products offered by 50 drilling fluid companies to control lost circulation

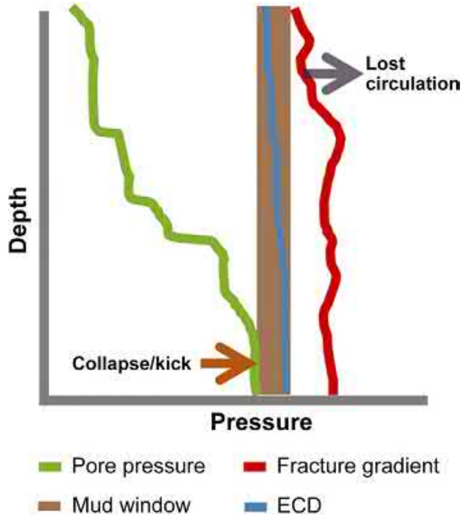


FIG. 15.11 Lost circulation the No. 1 deepwater enemy.

CONTROL KICKS/LOSSES

- This aspect is covered extensively within this document (refer Fig. 15.12).

BEST PRACTICES

- Covered in greater depth and detail throughout this guide.

Casing Setting Depth Criteria

An illustrated overview of a deepwater well's casing setting depth criteria for both intermediate and production string sections are outlined in this section (Table 15.11).

Casing Pressure Testing

Casing Pressure Testing—General

Casing test pressures are based on maximum allowable well pressures (MAWP) adjusted for 75%–80% of pore pressure corrected for mud weight in choke and kill lines during test. Casing test pressure shall be modified if the operational mud weight varies from that programmed. Persons in charge will recalculate test pressures based on actual mud weights and TVDs and confirm accordingly. Prior to commencing tests, persons in charge shall calculate the theoretical volume necessary to obtain test pressure (including compressibility). A running plot of pressure versus volume shall be maintained during conducting all tests, and/or if any other pressure test of the casing, SSBOP, or wellhead seals are in progress.

CASING PRESSURE TEST SUMMARY

A generic set of results from an ultradeepwater well, the casing pressure test rationale, and summary are presented in the Table 15.12.

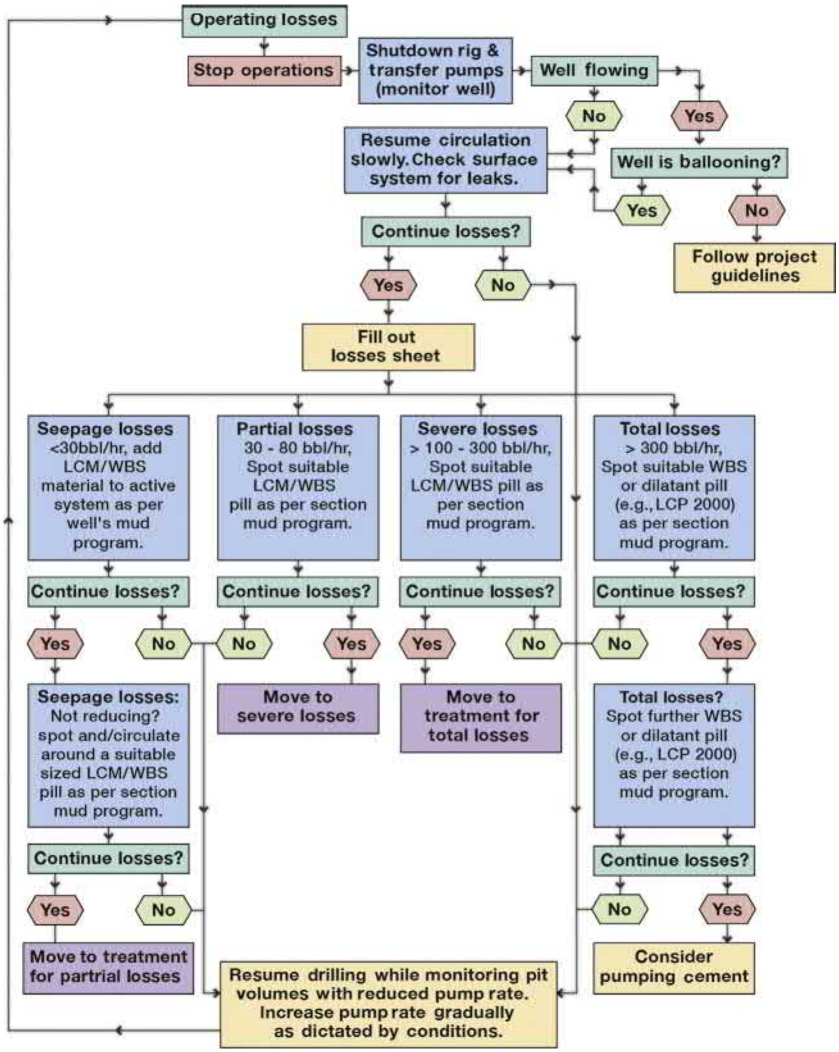


FIG. 15.12 Generic loss circulation decision tree and flow chart. *Source: Kingdom Drilling training 2018.*

CASING PRESSURE TESTS—EXAMPLE CALCULATIONS

Casing pressure test calculations based on generic deepwater well details as illustrated in Table 15.12 are determined as follows.

***20-in casing**, based on*:

- 0.12 * (3892 – 2265) / 0.3048 = 641 psi
- PP = 5680 psi (5800 psi High) Pout = 0.052 * 8.6 * (2265 – 32) / 0.3048 = 3276 psi
- 5800 psi – 641 psi – 3276 psi = *1883 psi maximum pressure (2000 psi test)*

TABLE 15.11 Casing Seat and Section TD Criteria

String	Criteria	Main Risks
Surface (structural) casing	*Rationale*: Provide landing point for SSBOP and to be able to drill next wellbore section to its optimal depth. Obtain sufficient shoe strength for drilling and cementing next wellbore section. *Method*: Drill to determined depth as per tally. Minimum TD. Claystone dominant sequence is the targeted depth. Optimal TD; Determined from pilot hole. Rat hole to be drilled to accommodate any hole fill.	• Low/poor formation strength • Wellbore instability, problems • Extensive faulting (low) • Water/gas flow (low) • Hydrates (low) • Waiting • Equipment failure
Intermediate casing	*Rationale*: Isolate open-hole drilled formations prior to entering wildcat primary target. Obtain sufficient shoe strength for drilling and cementing next wellbore section. *Method*: Drill to determined depth as per tally. Maximum TD. Geological uncertainty plus safety margin above primary reservoir target. Rat hole to be drilled to accommodate any hole-fill.	• Low/poor formation strength • Wellbore instability, problems • Extensive faulting (low) • Hydrocarbons oil/gas (low) • Kick/losses • Equipment failure • Waiting.
Production string and liners	*Rationale*: Set deep enough to provide adequate safe drilling and operating margins to be able to drill to well's TD in an optimal SEE wellbore. *Generally ≥8 ½″ is preferred.* *Method*: Drill to determined depth driven by pore pressure, fracture pressures and safe operating limits.	• Low/poor formation strength • Higher case pp. • Wellbore instability, problems • Faults/fractures • Hydrocarbons oil/gas • Kick/losses • Equipment failure • Waiting.
Production wellbore	*Rationale*: This wellbore size affords best pressure management conditions and accommodates standard tool sizes. It should be evaluated the most cost and operationally effective and efficient standard wellbore size. *Method*: Drill to determined depth driven by pore pressure, fracture pressures, and safe operating limits.	• Low/poor formation strength • Higher case pp. • Wellbore instability, problems • Faults/fractures • Hydrocarbons oil/gas • Kick/losses • Equipment failure • Waiting.

***13⅝ Casing,** based on*:

- 0.12(5232 – 2265)/0.3048 = 1168 psi
- PP = 9600 psi (10,700 psi High) Pout = 0.052 * 8.6 * (2265 – 32)/0.3048 = 3276 psi
- 10,700 psi – 1168 psi – 3276 psi = *6260 psi maximum pressure (6500 psi test)*

***9⅝ Casing**, based on*:

- 0.12(5232 – 3742)/0.3048 = 587 psi
- PP = 9600 psi (10,700 psi High) Pout = 0.052 * 8.6 * (3742 – 32)/0.3048 = 5443 psi
- 10,700 psi – 587 psi – 5443 psi = *4670 psi maximum pressure (5000 psi test)*

TABLE 15.12 Casing Pressure Test Summary

	Dry Hole Base Case (EXPECTED Case)		
Casing	**MW**	**Pressure Test**	**Comment**
Surface casing	9.3 ppg	2000 psi	Pressure tests for the detailed well design are based on the worst-case scenario (high pore pressure case) of full evacuation to gas for each of the strings.
Intermediate casing	9.3 ppg	6500 psi	Pressure tests for the detailed well design are based on the worst-case scenario (high pore pressure case) of full evacuation to gas for each of the strings. As the casing could be the last string ran back to the wellhead, the pressure test for this string is based on the high case pore pressure at well total depth, not section total depth.
Production casing Liner	10.2 ppg	5000 psi	Pressure tests for the detailed well design are based on the worst-case scenario (high pore pressure case) of full evacuation to gas for each of the strings. Production string in this example is run as a liner and requires to be tested to *5000 psi* corresponding to the worse-case scenario at the top of the liner.

REFERENCE STANDARDS

API RP 96 Deepwater well design and construction.
Norsok Standard D-101 Rev. 4, June 2013, Well Integrity in drilling and well operations.

References

Aird, P., November 2015. Stuck Pipe Prevention Managing and Freeing. Rev 1.1. Kingdom Drilling Services.
Chevron/BP, 2007a. Drilling Training Alliance Relevant Chapters. Floating Drilling Manual.
Chevron/BP, 2007b. Drilling Training Alliance Relevant Chapters. Deepwater Drilling Manual.
IADC Deepwater Well Control Guidelines, October 1998. International Association of Drilling Contractors, first ed.
IADC, 2015a. Deepwater Well Control Guidelines, second ed.
IADC, 2015b. Drilling Manual, 12th ed. ISBN: 978-8-9915095-0-8.
IADC Floating Drilling & Equipment Operations. first ed. 2015.

CHAPTER

16

Production Wellbore Drilling and Well Control Assurance

DRILLING DEEPWATER PRODUCTION SECTIONS, WELL CONTROL ASSURANCE

Production String and Liners Objectives

The production sections are operated within the pressure transition and hydrocarbons (gas, oil, and condensate) zones. Higher pressure, temperature, and volume effects place far greater limits and constraints to the safe operating drilling windows that invariably result. Since greater operating problems and difficulties can result in these phases. More effort is needed to assure standards, systems, best practice, and well control assurance, patience, and compliance are maintained throughout. Typical objectives of these sections are:

1. To safely make up and run the drilling BHA
2. To drill out the cement inside the shoe and clean out the rat hole.
3. To displace the well to any mud weight changes required.
4. To obtain sufficient well integrity to afford the desired kick tolerance/well integrity.
5. To drill a vertical, high-quality loss and waste-free wellbore.
6. To safely manage wellbore pressures and assure primary well control is maintained to deliver a high-quality wellbore throughout all operations
7. Set casing and liners at optimal depths and achieve a high-quality cement job.
8. To run and cement the casings/liner providing a competent shoe for drilling ahead and isolating the open hole annulus below the casing for well abandonment.
9. In a success case, log and evaluate (to meet all data acquisition (geology, petroleum, reservoir, completion) requirements prior to continuing the next wellbore section to depths as planned.

Supplemental aspects to consider for any special well or contingent operations are:

1. All mud weight changes shall be approved by the assigned managers.
2. An as-drilled connection, trip, or other associated gas events spreadsheet shall be maintained for all well operations conducted below the SSBOP.
3. Wellsite geologist shall verify and assure all transition and reservoir data are acquired, recorded, quality controlled, and checked correctly.
4. Assure contingencies are in place for things that are likely and can go wrong.

Deepwater Drilling
https://doi.org/10.1016/B978-0-08-102282-5.00016-8

Generic Operating sequence

A generic outline of a deepwater production drilling activity phase is presented in these sections.

Operating Hazards

Operating hazards are similar as outlined in Chapter 15 where the probability and consequential outcomes of key elements shall be very different if not managed and mitigated accordingly.

Section Predrilling Preparation

1. Predrill safety meeting is held to discuss all operations aspects for the section. This would include hazards, risks, operational expectations, objectives, of transition and reservoir drilling, and any environmental consequences of drilling with oil-based muds, etc.
2. If outstanding, a offline pressure test of the intermediate casing string to the program test pressure shall be effected when cement is confirmed set.
3. Ensure all well control systems are pressure tested as per contractor's and well program requirements.
4. Confirm final bit and BHA and advise all parties so that all offline preparations can commence.
5. Prepare the wear bushing and BHA running sub.
6. Confirm dimensions, lengths, etc. of all well operational items to be run through the rotary table to ensure compatibility with both, all strings tools and equipment run.
7. Cementer to assure storm packer assembly is on location. (Used as a further barrier requirement in an emergency situation if/as needed.)
8. Mud engineer to agree on mud management, lost circulation, and wellbore strengthening material plan prior to interval start. Also to verify mud system is within program specification and that the barite system is set up to increase weight as per expected program pressure scenarios.
9. Mud loggers to provide precise swab and surge estimate for all assembly tripping speeds.
10. Well site geologist (WS) shall verify calibration of rig and mud logger pit sensors. Also that the wireline tools, package, and rig up is ready to be used.
11. Casing hand shall assure handling equipment is onboard and ready for the online makeup.
12. Verify H_2S mini container is on-board prior to reservoir drilling operations. All key crew to be trained in the use of BA sets for H_2S prior to commencement of section.
13. Supervisors to assure all daily instructions including operational limits are signed off and distributed to all relevant on board rig parties ahead of the plan.

Drilling Guideline (Success Case)

1. RIH with the BHA (with wear bushing and installation/retrieval tool), filling pipe, as required.
2. Inform DPO and activate compensator when running BHA through the subsea BOP.
3. Set the wear bushing as per wellhead engineer's instructions.

4. RIH to a safe distance above theoretical top of cement (TOC).
5. If the plug set did not bump, safely wash down and/or slowly rotate to confirm top of cement by tagging and setting down weight as advised.
6. Drill out the cement shoe-track as instructed, leaving 3 m of cement above the shoe.
7. When most convenient conduct pit and well control drills.
8. Drill cement and the casing shoe. Verify the shoe track is drag free before proceeding ahead.
9. Clean out rat hole and drill 1.5–3 m (5–10 ft) of new formation.
10. Circulate cuttings above the BOP, verify mud properties, and pull bit inside the casing shoe.
11. Conduct well integrity test as per program.
12. Determine slow circulating rates, and all required choke and kill line friction losses.
13. Drill at optimum parameters once the bit and BHA enters new formation. Record any abnormal well conditions or indicators during drilling and/or on connections.

Note: Contingency plans should be prepared as illustrated in Figs. 15.1–15.3 of the previous chapter.

14. Assure all remedial plans are in place on the drill flor for key: *pack off, mechanical, differential pipe sticking, pressure management (losses/gains) and/or wellbore instability or well control problem*-related events that can result.
15. Drill to section depth using best practices.
16. Circulate the well clean of cuttings using riser boost as required.
17. Flow check well prior to commence pulling out.
18. Trip as per program and standard operating guidelines adhering to swab/surge analysis parameters.
    a. Note any abnormal drag in daily drilling reports.
    b. If abnormal drag is observed, inform company reps immediately and act accordingly.
19. Flow check at shoe and again prior to pulling BHA through BOP.

Note: Wiper trips are not considered as a planned event. If significant drag and resistance is noted on trip out, a wiper trip is decided at the discretion of the company rep.

20. If the next string to be run is a liner, at casing shoe, record pick-up and slack-off weights with pumps on and off to obtain actual flow rates and pressures.
21. Drift pipe if practical on trip out. (Drift size to be larger than the liner setting ball). Drillpipe can alternatively be drifted once racked back.
22. Retrieve the wear bushing when/as required following recommended practices to be applied.
23. Flow check prior to pulling BHA through BOP.
24. Inform DPO, activate compensator prior to pulling BHA through BOPs and slip-joint.
25. On surface, download data offline if feasible. Rack back and lay down BHA, grade bit.

Success Case Logging Program

1. Clear the rig floor and rig up for wire line operations as per engineer's instructions.
2. Run and complete open-hole wire line program. A detailed logging program will be in place on the rig, separate from the drilling program.
3. Rig down wireline and clear rig floor.

Liner and Cementing

Liner Preparation

1. Prior to rigging up to run the liner, hold a prejob meeting with all involved personnel.
2. Lay out liner and prepare running tally. Strap, drift, and conduct physical ID caliper check.
3. Check running tool and verify liner hanger and all components on deck.
4. Verify proposed linger hanger setting depth against the parent casing tally to allow setting of the liner hanger and packer near the middle of a joint of the parent casing.
5. Run liner on designated work string. Person in charge to ensure all running string tubulars components are drifted with a drift size greater that the liner setting ball.
6. Complete prejob checklist. Checklist is to be verified by person in charge.
7. Ensure that a minimum of two times the cement job material requirements are physically onboard and checked prior to job.
8. Cementer and company rep shall calculate cement job based on actual well depths.
9. Cementer to assure samples of additives and cement are sent to cement laboratory in good time to allow lab testing of slurries to be confirmed. Additionally to check remote valves in bulk system are correctly aligned and tested and shall inform control room prior to fluffing tanks to assure no supply vessel is alongside.
10. Persons in charge shall witness loading of the cement darts in the cement head and lay out the cement stand and verify cement head function all work as intended.
11. Check liner-handling equipment available and that it is fully commissioned.
12. Check casing fishing equipment is available onboard the rig.
13. Recheck space out for passing through subsea BOP and landing off in wellhead.
14. Prepare liner tally and independently check with the toolpusher and/or team.

Run Liner

1. Rig up equipment to run liner.
2. Pick up shoe joint, run below rotary. Make up the shoe joint to the intermediate joint.
3. Make up the float joint collar onto the casing string and check that it is fully functional.
4. R.I.H. with liner, monitoring pipe is autofilling (if used). Otherwise fill string regularly as run.
5. Complete losses/gains, hook load, and return volume running in record sheets to be used.
6. Pick up hanger assembly and make up as per specialists requirements.

Note: Confirm casing joints remaining on deck align to final tally.

7. Prior to pulling slips verify that the running tool assembly, etc. is capable of carrying the entire liner system weight prior to picking up fully, removing slips, and running in assembly.
8. Record the pick-up and slack-off weights. Lower the liner. Be careful to avoid damaging the assembly while passing through the rotary table.
9. Set slips on the handling pup joint at the top of the liner hanger assembly.
10. Make up a stand of drill pipe (as required) to the liner hanger assembly.
11. Fill the Polished Bore Receptacle PBR with suitable fluid (to be advised). Circulate a liner volume to ensure that there are no obstructions in the string while filling the PBR as per rep's specific instructions.

12. Run the liner in the well bore. Do not allow the pipe to turn while making up connections.
13. Once liner enters the subsea wellhead, run liner smoothly, avoiding any high acceleration and deceleration at running speeds required. Use active heave system if/as applicable.
14. At the casing shoe or once safely deeper than the known weak point in the well, make up the top drive, engage pumps, and slowly convert the autofill float assembly before RIH.
15. At casing shoe break circulation if assessed as *safe to do so*. Record pick-up and slack-off weights, torque and pressures at, respectively, rates before entering the open hole.
16. Observe pit levels for correct displacement and hook load weights for normal drag throughout. If losses are noted, stop the trip in hole and monitor the well.
17. When running in open hole, fill up the drill pipe minimum of every 3–5 stands.
18. If bridging or a high drag restriction is encountered, record the pick-up and slack-off weights, break circulation, and work (reciprocate) string with suitable controls.
19. If a ledge or dogleg cannot be negotiated, rotate string slowly to the right and try and RIH.
20. Make up cement head stand just prior to setting depth, RIH, and tag bottom with circulation.
21. Circulate the mud within well defined limits, at setting depth; if/as programmed, rotate to condition mud to improve mud-gel removal by the spacer and cement.

Liner Hanger Setting

1. At end of circulation stop pipe rotation, and place liner hanger at setting depth.
2. Release the setting ball from the remotely controlled cementing head.
3. When ball lands, allow pressure to increase to a minimum higher than that required (to be advised) to activate the hydraulic devices in the liner system.
4. With the setting pressure applied, slack off to check that the liner hanger has set.
5. When the liner hanger has set, slack off the liner weight plus a recommended set amount.

Releasing Running Tool

1. Place the running tool in slight compression (as advised), bleed pressure to zero.
2. Release the running tool from the liner hanger and pick up to verify release as instructed.
3. Slack off and apply recommended weight on the hanger.
4. Apply a slightly higher pressure than that required (as advised) and shear the shear ring. Once verified, ball seat is in the open position.
5. Circulate at least a liner contents to confirm ball seat has expanded and further condition well and mud to aide optimal cementation. *Note*: Only rotate the liner when circulating.

Cement the Liner

1. Hold a prejob safety meeting with all personnel involved in the cementing operations.
2. Circulate at least two bottoms up to ensure a uniform stable fluid in and out.
3. Establish low liner rotation parameters.

4. Mix and pump spacer as per cement program. Test lines during this phase.
5. Release the bottom dart from the cement head at surface, mix and pump cement at maximum pump rate as stated in the cement program.
6. Mix and pump tail cement slurry as per cement program.
7. Release top dart from cement head system. Displace with required volume of mud.
8. Mix and pump spacer behind cement as per program.
9. Displace all fluids at optimal rates to pump lead and tail spacers to sit both inside the running string, across liner hanger, and behind the plugs.
10. As needed, reduce displacement rates (to <EMW and lost circulation) yet continue remaining volume of drilling mud. Slow down the pump rate before end of total displacement. Note the displacement rate and pressure prior to and after this process.
11. Bump the wiper plug with required pressure to test the liner. Stop rotation immediately when the plug bumps and before applying the test pressure.
12. After test complete, bleed off pressure and check for back flow. Note the volume of returns.
13. Set the liner hanger packer and retrieve the running string as per the manufacturers and liner engineer's specific operating instructions.
14. Pull back sufficient pipe to place tool tail pipe a safe distance above the top of the PBR.
15. Lay out the cement head and space out to circulate conventionally. Circulate bottoms up.
16. Monitoring return volumes (for losses) circulate conventionally at maximum rate until clean returns are observed. Once confirmed:
17. Pull out liner running string.
18. Once at surface lay down tools and string, clear and clean rig floor.

Production Section 8½″ Wellbore Worked Example

The following section presents a typical deepwater worked example to highlight the physical elements and operational constraints that exist drilling a production wellbore section. Engineering, operational aspects, and conclusions are based on wells data as presented in this section and as contained in the worksheet that can be obtained and downloaded at: http://www.kingdomdrilling.co.uk/downloadfreelinks.aspx.

Illustrated example: The example modeled is an 8 ½″ wellbore drilled at 25,000 ft (7620 m) TVD in 8000 ft (2438 m) water depth using an 18¾″ marine riser, with a 13⅝″ full casing string and a 9⅝″ liner set (to reduce friction losses). The *drilling operating window* at the 9⅝″ casing liner shoe at 22,450 ft (6843 m) TVD is *1.0 ppg, i.e., 816 psi or (56 bar)*. This is based on a 13.0 ppg (1558 kg/m^3) shoe fracture gradient, a maximum wellbore pore pressure of 12 ppg (1438 kg/m^3), and a 0.3 ppg (36 kg/m^3) regulatory safe operating requirement. Minimum safe operating mud weight required is 12.3 ppg (1474 kg/m^3).

As wellbore size reduces below <12½″, all pressure, stability, and well control assurance management issues change dramatically. Drilling windows narrow quickly due to pressure and lithology variations presented. Every aspect of all other pressure effects (AOPE) must be managed and controlled to prevent self-induced wellbore problems and associated operating difficulties resulting. Prevention is resolute to avoid painful cure with full compliance to best practices adhered to at all times.

Conventional simply cannot often work for SEE results to be assured, where other alternative means, methods, and technology applications must be considered and employed as illustrated throughout this guide and later in this chapter. Conventional drilling results from this typical *vertical production wellbore section* are summarized in Figs. 16.1 and 16.2.

Results derived from this deepwater production wellbore worked example and figures presented demonstrate the constraints imposed from a conventional drilling window. To improve, i.e., reduce time, costs, number of casing strings, and prevent and mitigate operating hazards and risk to be overcome. What is required is that:

1. To drill section with circa 0.7 ppg, 816 psi (56 bar) drilling windows. Conventionally may seem an abundant margin. However, this is quickly and evidently consumed by EMW, ECD well control assurances, and all other pressure effects (AOPE) to leave a small operable; *±0.1–0.2 ppg. 120–230 psi margin* that must accommodate and take account of: *all pressure effects* plus any volume and temperature (PVT) changes that result to play a further devil's role in wellbore proceedings.
2. What is immediately concluded is that *flow rate is restricted* (as ECD is one of the critical factors in constrained drilling regimes where optimal drilling flow is not achieved). *Mud rheology is also supercritical.*
3. *People must change to "SEE" the evident benefits* when adaptive, proven tried and tested proactive methods such as closed drilling via managed and dual gradient systems, utilizing flat rheology mud, wellbore strengthening, etc. are used. *To increase safe operating drilling windows.*

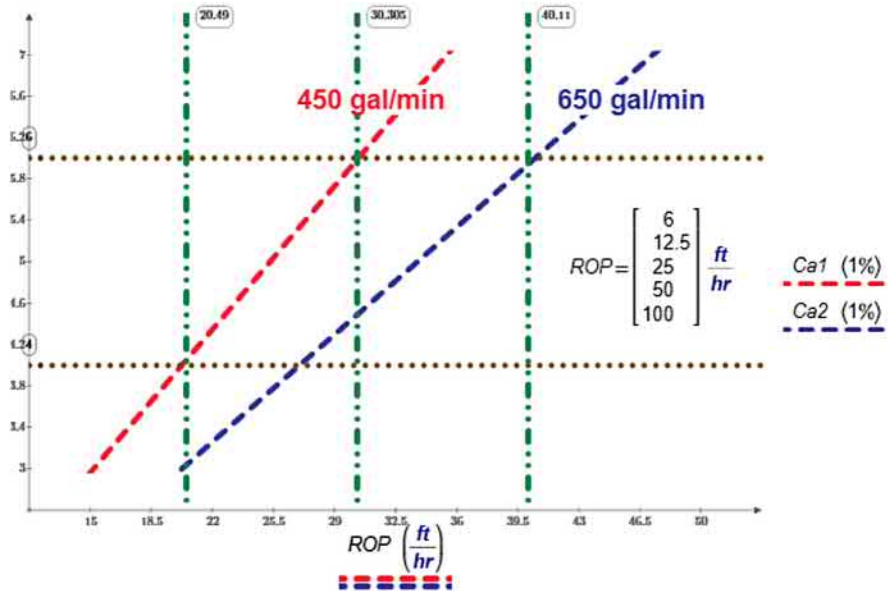


FIG. 16.1 Vertical 8½″ wellbore, cuttings concentration limits 8000 ft water depth, 25,000 ft TVD.

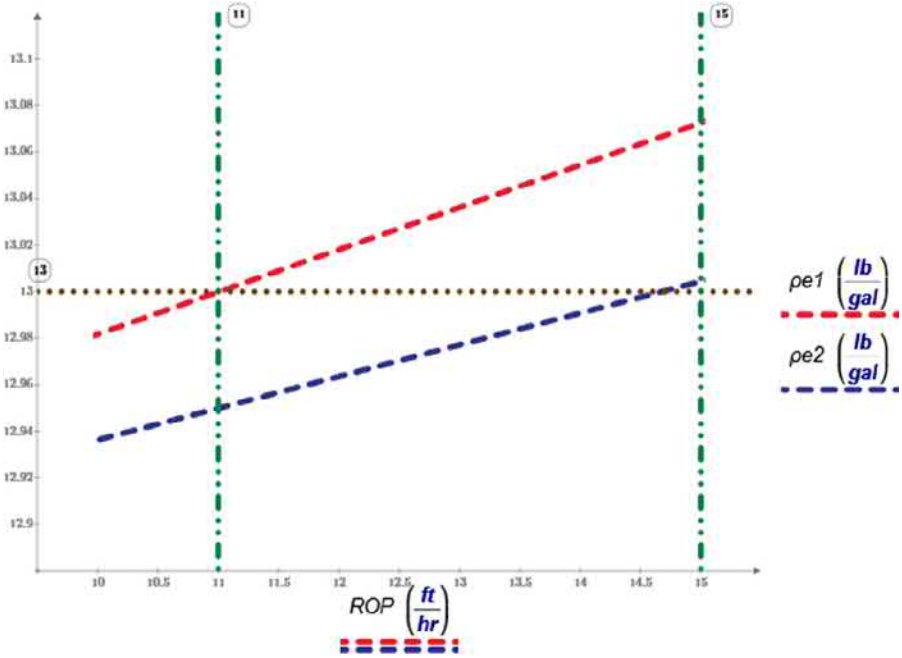


FIG. 16.2 Vertical 8½″ wellbore at 25,000 ft TVD, drilling fracture limit due to ROP, cuttings concentration, 8000 ft water depth, drilling at 25,000 ft TVD.

4. *Change from convention to nonconventional methods to improve*: Wellbore quality, pressure management, and well control assurance problems experienced conventionally are physically and evidently required.

5. To summarize, to reduce operating time costs, hazards, risks and reduced number of casing strings/liners required. All of the above demands must be met for deepwater drilling to become far more safe, competitive and effective within the production sections.

Pressure Management in Transition and Reservoir Zones

Well Barrier Considerations

With respect to well control operations, multiple barriers when properly installed and tested are fundamental to the high reliability and safety of deepwater subsea producing wells in all operating phases. They must always be available and exist to prevent an uncontrolled flow from a well during routine activities. When practicable, a single event or system failure shall not compromise the SEE principles where the loss of one barrier should not compromise the effectiveness of others. The consequence of barrier failure must be available for review in the barrier section of the operational risk managed and final well program and/or contingent plans. All barriers must have a proven integrity to meet the target well life design and operating load requirements including contingent and/or emergency situational events.

Barriers shall be compliant with industry standards and regulatory requirements. As these may differ, yet it is important to assure barrier requirements are detailed in each well's plans.

The primary industry recommendation practices can be found in API RP 96 and API RP 65-2. Other well used regulations of barrier guide practices are USA, CFR 250.420, UK UKOOA guidelines OPO69-OPO71, and Norway's Norsok D-010 well design and integrity standards.

Finally, it is important that the drilling contractor and operator have a clear agreement as to the standards to be used and applied with respect to well barriers through bridging documents required.

WELL BARRIER OPERATIONAL USE AND IMPLICATION

Barrier verification and confirmation shall be clearly stated in a well program. Should a change result, an appropriate risk assessment and management of change is to be approved by all parties concerned to meet well control assurances required, e.g.:

1. Well barriers shall be designed to cater for all geological risks and uncertainties prognosed.
2. Multiple physical and operational barriers shall exist for all normal well operating activities.
3. Suspension and abandonment require physical barriers, one of which shall be a mechanical barrier for both internal and annular flow paths.
4. Number of barriers shall meet the barrier standard for the well type as designed.
5. Quality control of a barrier starts at the preplanning, design, specification, manufacture, and inspection of equipment to be used on each well.
6. Cement shall be designed to a certain specification and formulation. Lab testing and manufacturing quality control is central to assure fit for purpose well cementing results.
7. Well barriers in drilling modes shall be clearly demonstrated in well schematics, standard guidelines, and instructions issued. Wellheads, casings, cementing, and drilling mud are examples of these barriers.
8. For well design and barriers to work as planned assumes all work is managed, conducted, utilizing best practice principles throughout.[1]

Finally, the production sections operating conditions and situations present greater inherent well control assurance risks than others. Common issues that change the overall well control hazards, and increase the requirement for secondary well control methods, equipment and use shall be required if hydrostatic pressure or any other well control barrier is compromised for the following:

1. Hydrocarbons presence in the well that may increase the importance of barriers with respect to: Open hole or behind casing scenarios.
2. Density changes and variation during drilling, cementing that require additional attention to assure the primary barrier of hydrostatic pressure remains in place throughout. (Precise calculation and simulations to be conducted to mitigate this risk)
3. Replacement of mud in the drilling riser to seawater results in loss of hydrostatic pressure to the well. Required barriers must be verified before the riser is circulated.

[1] Well control assurance standards, instructions, and guidelines are to assure well containment at all times. Where well control equipment provides the physical barriers. Kick detection, shut-in, and kick circulation provide the further operational barriers. Training skills, development, and drills increase the reliability of these important operational barriers.

4. If a barrier cannot be verified (Fig. 16.3). It should be replaced and reverified before operations can proceed.
5. When only one working barrier exists and should this fail and primary control is lost. *Example*: Within a normal pressured environment, with no hydrocarbons present, yet where porous and permeable formations exist. Plans are needed to restore the single additional barrier, e.g., run and set a contingent string.

   It is important to note that nothing is considered a barrier until it is ***Verified***. API RP 96 uses a process as shown in Fig. 16.4 to verify/confirm barriers.

- A ***Tested*** barrier has passed a test for maximum load anticipated from; *the direction of flow* (e.g., *a negative or inflow test)*
- A ***Confirmed*** barrier results from; *alternative pressure testing, physical testing, or inference for observations.*

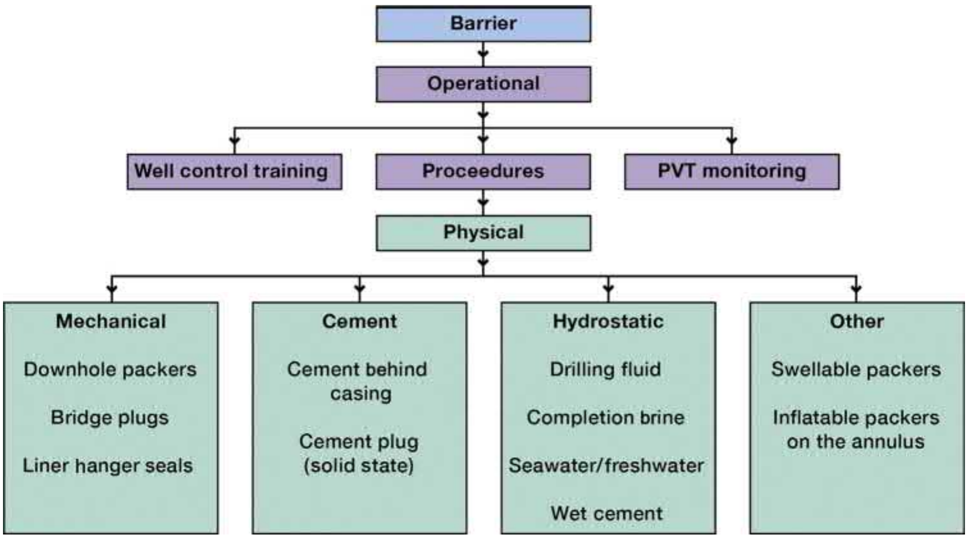


FIG. 16.3 Barrier components, operational and physical. *Source: Kingdom Drilling training 2018.*

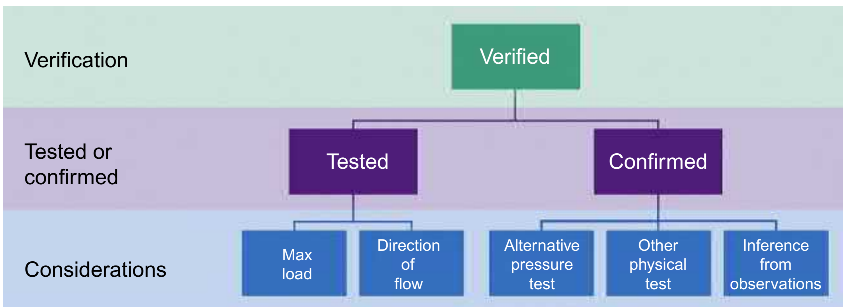


FIG. 16.4 Barrier verification methods.

Lessons Learned From Well Kick Analysis

Several deepwater kicks have been investigated in water depths ranging from 2000 to >6000 ft (610–1829 m). As a result of analysis conducted, well control assurance lessons and results derived to improved preparedness are:

- Designate a pore pressure detection team and have a planned strategy during the planning stage.
  - Consider utilizing a specialist person during executing critical well intervals.
- Determine the impact of high equivalent mud weight densities (EMW) in water-based and synthetic (oil base) muds and the importance of detecting small kicks on connections or during pumps off events to prevent riser entry.
- Determine the significance of mud compressibility in nonaqueous fluids and effects this will have on mud returns flowback and trip tank loss/gain readings.
- Measurement and recording of choke line friction pressures by pumping down the choke (or kill) line and up the riser.
- Develop how to add value from well integrity test notably *with oil-based mud*. As these can reduce the probability of initiating downhole fractures in sensitive formations, however small or seemingly insignificant.
- Develop better practices in regards to kick tolerances that account for all sensitivities to assure safe, control, monitoring and detection required.

Kick Detection/Behavior

Kick Detection in deepwater is difficult due to the pressure temperate, volumes, and constant downhole pressure changes involved, and additional motion (heave, swab, and surge) effects of a vessel. Plus, mud surges in fluid returns and movement to and from mud pits make the detection of small volumes further difficult to detect.

KICK DETECTION FOCUS AREA

- ***Flow check*** all connections and implement simulated connections.
- ***Fingerprint*** the ballooning/compressibility of flow back returns to establish well drilling flow check, connection, and pumps off "signatures."
- ***Monitor*** *measurement, logging, and pressure while drilling* (MWD/LWD/PWD) changes and flow check pore pressure indications.

KICK BEHAVIOR

- Determine the loss of synthetic oil based mud (OBM) on pump start up and gain or loss that can result on pumps off.
- Deepwater kicks can defy logic, so stay focused on primary well control and circulation/ pressure best practice principles and outlines within this guide.

Flow Check Strategy

Several factors combine to create "kicks or losses" in what are often critical and complex deepwater situational and conditional environments. The objective remains to quickly identify and discern the factors that are evidently not from those that are contributing to an event. Flow back or losses to/from well may be in fact induced by:

- Wellbore breathing, ballooning, supercharging, etc.

- Pressure, volume, temperature (PVT) effects and mud compressibility.
- Change in operating, e.g., *trip* versus *continuous drilling*, conditions, etc.

To evaluate precise and accurate flow back patterns, characteristics are carefully recorded and maintained each time an operation is halted or interrupted. The time required to check for flow depends independently on the specific conditions and situations encountered. *Examples*: If the formation in question is highly porous and permeable and significantly under balanced, flow is quickly and readily observed and assessed. Should underbalance be small and permeability is tight (very low), far longer periods are required to be able to detect a flow. The use of water base or oil-based muds can accelerate and/or prolong this detection period. Therefore, flow checking *until the well is deemed stable or has attained the predicted or desired flow back trend* is the specific method to use for all critical operations. *Note: A defined time period* or waiting on *a static trip tank* to result.

Note: Well flow indicators and expectations for specific critical wellbore sections, situations or events shall be *modeled, established, predicted, and understood* by all parties concerned prior to drilling out the casing shoe and initiating the next wellbore section. During critical operating events, the return flow at each connection, once the pumps have been shut down, shall be measured, recorded, trended, and analyzed. This to assure that *Early Detection* of a positive flow and *Rapid response* is the end result.

FLOW-CHECK GUIDELINES

In addition to preemptive compliance of what to expect, the reality of actual best practiced flow back results is:

1. Agreed methods shall be clear, concise, and consistently applied by all parties.
2. Drillers and mud loggers (if present) shall record the flow back volume changes with time and trend these. *Note*: Persons must be clearly responsible to who is accountable for processing, storing, and interpreting the data and information.
3. Flow checks are generally conducted via the trip tank, with the pump running so that any appreciable loss or gain rate is quickly and accurately identified.
4. The persons in charge shall be notified that a flow check has been.
5. The driller's prerogative is always; if in doubt, the *flow check is the priority*.
6. If there is then doubt regarding flow back and notable gains observed, the driller's safest option is *shut the well in*. Should a pressure build-up be observed, the logical step is then to verify if caused by a kick or other pressure-related effects.
7. If pressure stabilizes, bleed off to half the original shut in pressure but not more than an agreed volume. If pressure rises above original shut-in pressure, treat it as a kick.
8. After bleed back to half the shut-in pressure, if pressure does not increase.
   a. Bleed down to zero in stages, do not exceed a third of the kick volume.
   b. When volume is reached, shut-in and circulate bled back volume under controlled conditions form the well, and continue to bleed off in stages.
   c. Shut in and observe.
   d. If pressure increases are not noted, flow check and if deemed stable, open the well.

PIT DISCIPLINE

1. Pit discipline is a systems method of mud pit management that is important to operational aspect such as flow checks and finger printing, such that no operation is commenced that can affect mud pit volumes, etc. without the full knowledge of the

persons in charge, namely, the driller, mud engineer, and the mud logger. Where the driller must react appropriately to any unexplained pit gain immediately.

2. Pit discipline is important in critical well sections due to the consequences of the fact that smaller safety margins exist, and should *small changes not be identified and reacted to quickly, significant cause and effect can quickly result*. It is important to maintain active pit levels so small changes in volume are readily analyzed.
3. Additions to active mud systems are made only after the driller's approval. The mud loggers will be informed before and after additions. Driller and the mud loggers must be informed before any process pump is switched on or off.
4. A flowchart shall exist to present lines of communications for mud pit management.
5. Pit discipline guidelines shall be developed and agreed for drilling critical sections.

Finger Printing in Critical Zones

The fingerprint data for a given operation represent a wellbore pattern behavior that is compared directly to the same operation previously conducted, i.e., a connection or pumps off, or when a flow check event is performed. This process shall assure that all other key wellbore-related parameters remain constant and have not changed. Good communication between the driller and the mud logger is essential to assure accurate recognition, analysis, and identification when using this method.

FINGER PRINTING PRIOR TO DRILLING OUT TO THE CASING SHOE

The following trends measurements and indicators are commonly recorded as the base line indicators prior to commencing drilling operations.

- Trip sheet bbls per 5 stands factor:
- Trapped pressure and thermal effect:
- Compressibility test:
- Volume change effects:
- Drain back/flow back volumes:
- Well control response:

FINGER PRINTING WHEN DRILLING CRITICAL ZONES

The follow finger print trend standards and monitoring shall result for.

- Flow checks:
- Rotational effects:
- Swab/surge assessment:
- Equivalent mud weight (EMW), mud weight (MW):
- ECD (equivalent circulating density) and all other pressure Effects (AOPE):
- Connections, pumps off events.

Well Control Equipment

All equipment used in the critical wellbore sections must be assured to be compatible with respect to *temperature, pressure, H_2S exposure, drilling/wellbore fluids* including, but not limited to, elastomers in subsea BOP rams, downhole mud motors, mud pump parts, valves in the high pressure circulation system, etc., particularly when operating in the critical production (hydrocarbon) intervals.

Rig-specific lists of equipment with temperature and pressure limitations should be compiled and made available to rig personnel. Any well control equipment that is deemed critical needs to be changed out on a regular basis. Further inspection of subsea BOP and circulating system components is to result whenever the equipment is used for well control problems. In regards to specific well control equipment, key comments to be noted are:

- Wellhead pressure and temperature sensors were in use in the early wells and should be installed and used on all deepwater rigs.
- Working pipe through the annular causes rapid wear in the cold temperature environments that are common in deepwater.
- Caution is advised when planning to flush stack gases with lightweight fluids, and avoid topside differential pressures across the blowout preventer stack (BOP).
- Finally in regard to well control instrumentation, to obtain meaningful trends, indicators, and early warning sign detection, it is required that constant, consistent methods, standards, and operating instructions are used by all crews or individuals to accurately measure and record drilling parameters, particularly in the calibration and testing of such instruments.

Kicks in Oil-Based Mud

Fluids are the primary means of well control during the majority of operations with numerous book and technical papers available on deepwater drilling fluid systems. The key implication factors for well control in regards to fluids are:

- Density, viscosity, formation breathing, gas solubility, gas hydrates, and environmental considerations. *Note*: Oil-based mud behaves very differently to water-based fluids, e.g.:
  - When oil-based mud is used, small gas influxes will initially not show any pit volume increase due to the solubility of gas in oil, provided that standard overbalance is used.
  - Only circulated and approaching the surface, gas breaks out and expands rapidly and could, if not controlled, unload a large volume of mud to reduce BHP, the well's overbalance to introduce a new kick and flow at the bottom of the hole.
- Key drilling fluids strategies and decisions to be made in regards to drilling fluids are
  - Hydrates, gas solubility, well integrity testing, and lost circulation. (Gas solubility reviewed in oil-based muds as follows.)

SOLUBILITY OF GAS IN OIL-BASED MUD COMPARED WITH WATER-BASED MUD

Solubility of gas in oil-based mud is concluded from studies as follows:

1. Gas entering a well bore filled with OBM will dissolve into the mud such that the surface response is significantly dampened and reduced when compared to a WBM.
2. *Pit gain is the most reliable indicator* of a kick, but it is stressed that the pit level measurement system must be capable to detect small pit "kick"' gains.
3. The solubility of hydrocarbon gases in water is small compared to the solubility of same gases in oil. The amount in water is <1% of the amount soluble in oil, at the same temperature.
4. When the kick is circulated to the surface, it is concluded that oil-based mud and invaded gas mixture remains a liquid until the pressure is reduced to (±500 psi) 35 bar. At this pressure, mixture is at its bubble point. (*Note*: bubble point depends on the composition of the base oil and of the invaded gas). At lower pressures, gas then comes out of solution

expands, to produce a correspondingly large volume increase as the pressure further reduces.

5. *Conventional kick detection is more difficult in oil-based mud* than water-based because of the dampening effects of gas solubility. Surface parameters, such as annular flow rate, pit gain, etc., do not change as rapidly as they would in a water base mud.
6. Gas solubility does limit (EMW) pressure increase thereby reducing some wellbore pressure risk at the weakest wellbore formations exposed.

DEEPWATER WELL CONTROL

Deepwater Well Control—Introduction

In this last section of this guide, there should now be a degree of obligation that a deepwater well's scope needs to be treated with the intricacies required. Should all not be duly managed, what can result is significant and very costly loss time events that bring associated degrees of safety danger. If all are not suitably controlled through desired standards, systems, instructions, competencies and best practiced compliance *more accident loss shall result, not less*.

It should now be appreciated why deepwater difficulties are exacerbated by extreme depths of water and the unique geological risk and uncertainties that lie beneath the sea floor—that with deeper water, and the greater distance between the drilling rig and critical mechanical components located at the wellhead, impairing access. Add in deeper wells, and highly pressured complex reservoirs, far more well's operating hazards and risk exist. *Example*: The Macondo well serving to highlight what can result when a series of complex deepwater well problems escalate, combine, and align to trigger a multitude of far more catastrophic sequential accidental failures. Where experts are still disagreeing as to *which of the several failures that existed are most to blame?*.

What is pressing is that all persons involved need a far wider set of technical, science, and mechanical skills than currently afforded today, to be able to contend with the daily and escalating complexities of deepwater operating, well control and associated assurance issues that exist. The deepwater primary well control goal remains steadfast to *Detect early* and *Respond quickly* to resolve small problems before they escalate into bigger consequential ones as addressed in this chapter.

Rest assured each deepwater well is to be carefully planned, utilizing all available geological knowledge and drilling experience for the area. Anticipated well pressures and all other operational hazards shall dictate mud programs, casing design, setting depth, subsea BOP, downhole equipment, standards, procedures, and best practice to be applied. Should further hazards, risks, and uncertainties exist, well control and control risks shall simply increase and demand more assurance not less.

Deepwater Well Control

Well control in deepwater is viewed as both the art of engineering, science and applied common sense, applied to the three precepts described in this section (Fig. 16.5) to assure control of all pressurized formation liquids that may exist such as brine, drilling muds and hydrocarbons while drilling, operating, and constructing a well.

All well formation pressures are caused by the weight of upper rock layers, or *strata*, (Overburden) pressing down on each formation's porous, permeable strata that contain liquids. Methods to safely measure manage and control all pressure cause and effects are termed as "***Primary well control***." Drilling into a porous, permeable layer increases the risk that fluid pressure and flow can be released or lost, where primary well control is carefully monitored and fully assured. In summary, should too much equivalent mud weight pressure (EMW) exist during operations within a wellbore, losses can result. If not enough EMW pressure results, a kick and flow from the well's porous, permeable formations can result. ***Secondary well control*** now required.

Primary Control

Primary well control counteracts the pressure exerted by deepwater subsurface wellbore fluids, as well as the operating conditions exerted by the formation, thereby assuring pressure balance within well operations with the formation pressures. With no balance prevention or controls in place (the well is underbalanced), the greater formation pressure can produce wellbore fluids and hydrocarbons to flow and enter into the well often with great force if not contained.

Secondary Control

When primary control is lost, secondary control must be detected and responded to quickly and reliably so containment can result, i.e., the subsea BOP preventers are closed. Secondary control is the process and flow required to safely remove the fluids that have entered the well, and regain primary control of the well, generally through utilizing a driller's or wait and weight method. Secondary well control aims to isolate the magnitude and nature of pressure build up and fluid volumes resulting in a safe and contained manner. *Note*: Small kick volumes are far more readily dealt with than large ones.

Should primary well control fail, i.e., is inadequate against a kick, rig personnel shall activate the subsea *blowout preventer* (BOP) in a controlled and well-drilled manner, to initiate the secondary barrier operational controls to thereby contain and isolate the well pressures from the rig and stop the flow. Here each subsea BOP system includes an assembly of valves, along with control pods and system to activate them as outlined in Chapters 5 and 14. What is important is that personnel engage the subsea BOP to prevent primary and secondary well control events from escalating.

The process typically requires 40–70 seconds for the subsea barriers to close and seal the well, to provide the means required to safely control an influx of pressurized hydrocarbons, close in a well and prevent the kick from reaching the rig in noncontrolled manner.

Tertiary Well Control

Tertiary control methods result when secondary kill methods cannot be met or complications arise where Tier 2 or Tier 3 specialized circulating and noncirculating methods must be used.

Principles of all Well Control

The three main principles of deepwater and all well control, i.e., *Balanced*, *Overbalanced*, and *Underbalanced* conditions and situations are simplified and outlined in Fig. 16.5.

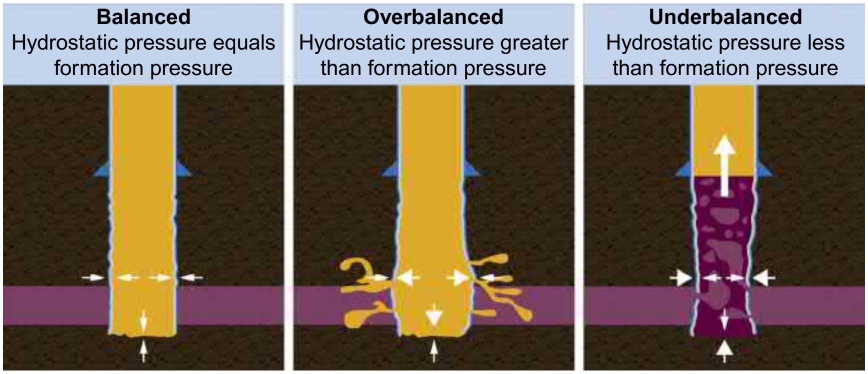


FIG. 16.5 A balanced, overbalanced, and underbalance well's pressure conditions as illustrated.

BALANCED WELL: EQUAL PRESSURE

A balanced well exists when the equivalent mud weight pressures (EMW) are safely controlled in a wellbore above the maximum formation pore pressure (pp) pressing from inside to the outside of a well (Fig. 16.5, left image). The EMW as long as it is maintained throughout all operations shall assure primary balance and control of a well.

OVERBALANCED (LOSSES)

Should the EMW pressure become greater than the weakest porous permeable formations pressing from the outside of the well, operating fluids (mud, brine, etc.) can be lost through these intervals (Fig. 16.5, middle image). The overbalanced pressure exists throughout the wellbore to endanger the integrity of other formations, once fluid is lost where time and cost overrun events can readily result.

UNDERBALANCED (KICKS)

If the formation pore pressure pressing from outside the well is greater than the EMW pressure within the well, formation of hydrocarbons fluids such as oil, gas, or condensate can enter and migrate up the well (even when on-bottom drilling), creating a kick and fluid influx to result. Should primary, secondary control and barrier failure causation result, a blowout can potentially develop at the seabed, at surface, or within the well itself.

Well Control Difference in Deepwater

Essential well control differences in deepwater reviewed in this section are:

- Maximum allowable surface pressure (MASP), and maximum allowable wellhead pressure (MAWP) with water depth
- Riser margin
- Choke and kill line friction losses
- Kick tolerance (and sensitivity analysis)

Note: Specific deepwater well control guidelines reference documents are further listed in the standards and reference section of this chapter.

MASP and MAWP With Water Depth

MASP and MAWP aspects were outlined in the well design Chapter 9. Essentially increasing water depths reduces the pressure differential between the mud weight required to control formation pressure and the pressure that will cause losses to the formations. *Example*: In reference to Fig. 16.6 (left Image), a casing is set 6000 ft from the drill floor. A 12-ppg mud is required to provide primary well control overbalance at 8000 ft. The fracture of the rock is 0.79 psi/ft. Should primary well control be lost and a kick result, the maximum allowable annular surface (MAASP) on the choke gauge at surface is 996 psi.

If the exact same formation conditions existed within at 900 and 2970 ft water depths (Fig. 16.6, middle and right images):

- In 900-ft water depth, the 12-ppg mud would give a maximum surface choke pressure of 624 psi.
- In 2970-ft water depth, it is not possible to circulate 12 ppg mud without losses.
  The 12-ppg mud afforded no kick tolerance, as operating pressure equals the formation fracture gradient.

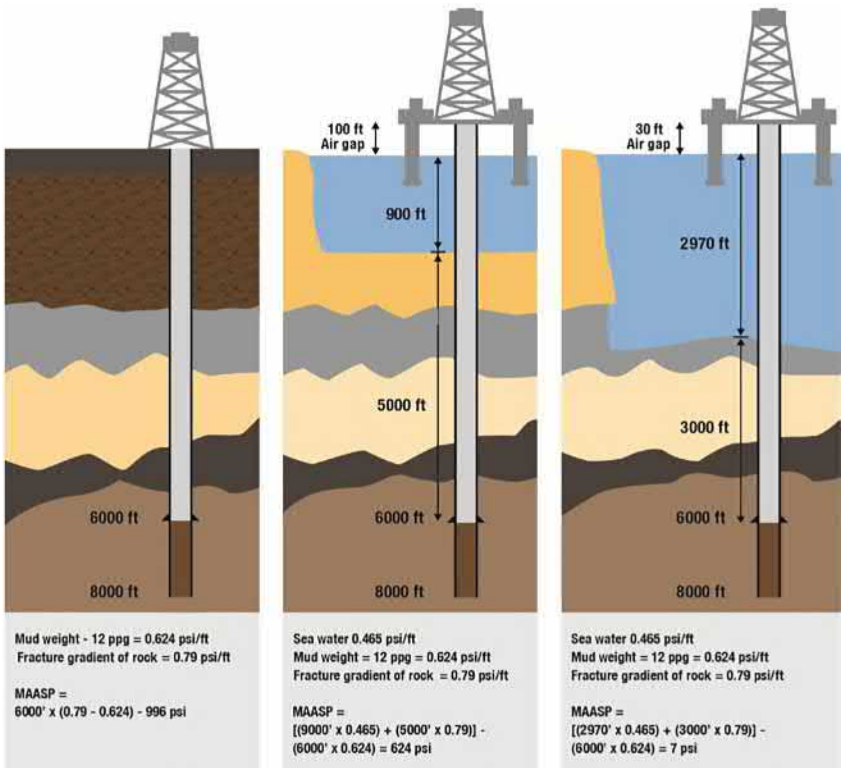


FIG. 16.6 MASP and water depth. *Source: Kingdom Drilling training 2018.*

Riser Margin

Riser margin is the minimum additional mud weight required to compensate for the loss of mud hydrostatics in the riser being replaced by sea water hydrostatics, if the riser was disconnected, or the connector failed.

- In Fig. 16.7 should the riser be disconnected, the bottomhole pressure is reduced by 64 psi. To compensate for this reduction in pressure, a mud weight of 12.17 ppg is then required.

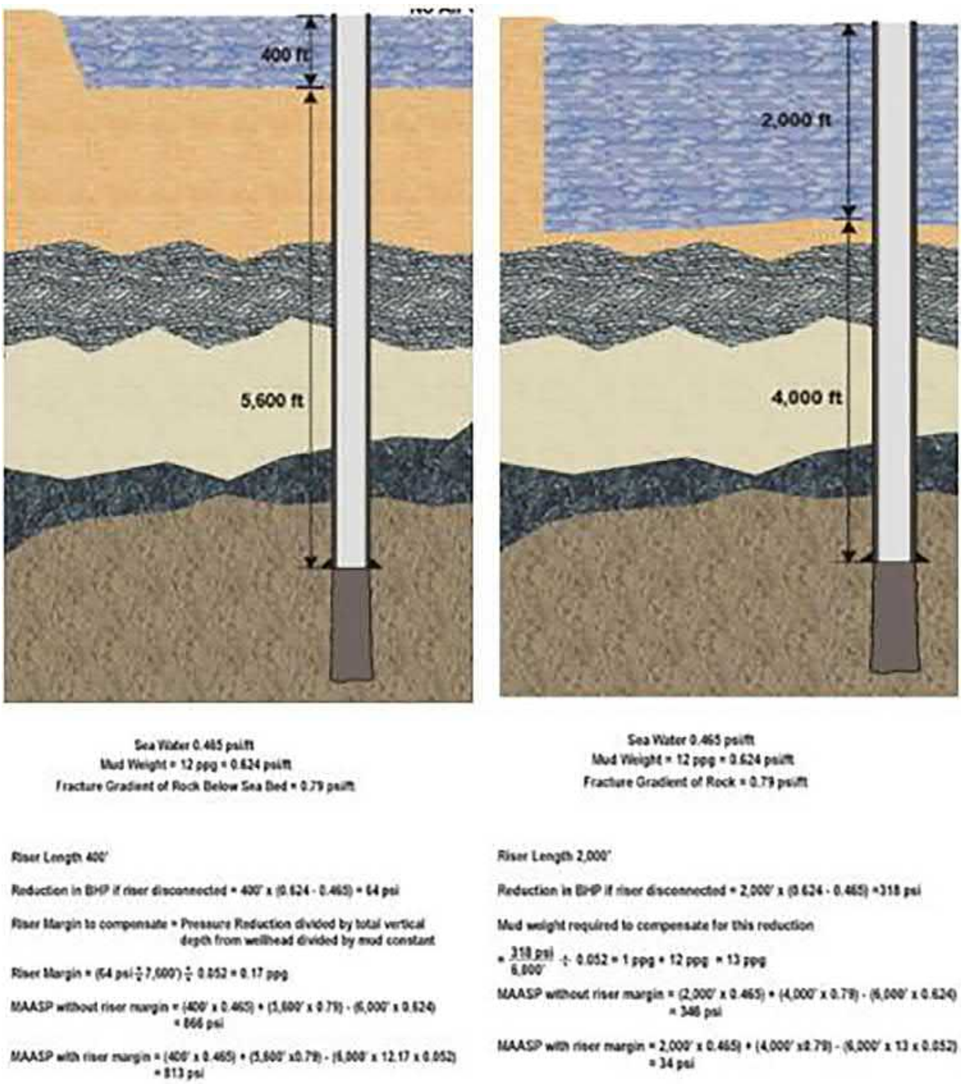


FIG. 16.7 Riser margin in deepwater (conventional drilling methods). *Source: Kingdom Drilling training 2018.*

- *Note*: In shallower water MAASP without the riser margin is 886 psi. With the riser margin included it is 813 psi.
- In deeper water, with the riser disconnected the bottomhole pressure is reduced to 318 psi. To compensate for this pressure reduction, a mud weight of 13 ppg is the required. (Fig. 16.7, right image.)

Choke Line Friction Loss

Choke Line Friction (pressure) Losses (CLFL) result when circulating through a choke line.

In deepwater, kicks are circulated to surface through much longer choke lines where it is important to know what friction losses exist at various low pump rates. Friction losses can be significant should deeper water and longer lengths result to be compensated for, i.e., notably at start of a kill operation when the pump is brought up to the required kill speed. Should a standard start-up be used, the friction losses that exist can exceed the weakest exposed formation fracture gradient to induce a failure in the well. This can in turn risk an underground flow to result. Two methods to mitigate this risk are:

1. As pump is brought up to kill speed, casing pressure is reduced by an amount equal to the choke line friction losses. At reaching kill speed, drill pipe pressure is maintained at the required initial circulating pressure. *Note*: This method is often difficult to physically handle and implement on some rigs.
2. The kill line is used as a pressure monitor (this assumes the fluid density is the same as that in the wellbore). As the pump is brought up to kill speed, the kill line pressure is held constant at surface. There is no pressure loss in this line, as no mud is circulated through it. With the pump at kill speed and drill pipe pressure at the initial circulating pressure, casing pressure shall have reduced by an amount equal to the friction losses.

   Note: If a subsea BOP pressure gauge exists, this can be used to hold bottom-hole pressure and verify that a safety factor is maintained, as it will read pressure taking into account choke or kill line circulating pressure effects.

If friction losses are greater than the shut in casing pressure, then the well is subjected to more over overbalance than the well can perhaps handle. That is represented by the pressure difference between the choke line friction losses (CLFL) and the shut in casing pressure (SICP). With the pump at kill speed the choke device is generally fully open. In order to avoid overpressurizing the well, slower pump rates and circulation can be routed through choke and kill lines, with increased flow area and reduced friction loss by approximately 50%.

Choke line pressure losses also change as the kick is circulated to surface. As the influx enters the choke line, friction losses will reduce, if gas reduction is significant, and must be compensated for by choke manipulation. When the mud displacing the influx enters into the choke line, the friction loss will return. When kill mud enters the choke line, friction loss will increase. These changes require planned choke adjustments to be put into effect.

Kick Tolerance Sensitivity

The key factors of kick tolerance sensitivity in transition and reservoir zones are:

1. Should a high pressure case arise,
2. or weaker formations exist to that predicted,
3. or drilling problems and difficulties result during the execution phases.

TABLE 16.1 Kick Tolerance and Riser Margin Examples Extracted From a Recent Ultradeepwater "Deep Transition" Well's High-Pressure Case Scenario.

Section	Casing	Depth (m)	MW (ppg)	PP (ppg)	FP (Ppg)	BHST (°C)	MW (ppg)	KT (bbl)	RM (psi)
12¼″	9⅝″	4680	11.2	10.8	12.3	100	11.5	79	**−234**
		4822	11.4	11.14	12.6	105	11.7	**31**	**−281**
8½″		5100	12.15	11.94	13.0	115	12.3	**31**	**−347**
		5150	12.15	11.71	13.2	116	12.3	**17**	**−368**

Source: Kingdom Drilling 2017.

Then standard safe kick tolerances (e.g., 100 bbl, 50 bbl (16–8 m^3)) and riser margins operating norms (200–300 psi (1379–2068 kPa)) can quickly diminish to require appropriate dispensation as to the safe working limits and conditions that can be managed and controlled, in agreement with a drilling contractor's ALARP standard operating procedures (as highlighted or clearly defined within the well program and/or well control bridging or assurance documents.) As illustrated from a deep transitional ultradeepwater case study well's summary results presented in Table 16.1 where potential production wellbores kick tolerances and riser margins trend standard operating norms.

Well Control Assurance Introduction

The principles of well control assurance in deeper or shallower waters are essentially that the same laws of physics, mechanics, science, and Murphy's apply as per the standard norms. What is different is that situational and conditional wells specifics of deepwater must be considered with far greater precision, detail, and finite analysis due to the far more evident operating limits and constraints facts that exist.

Critical aspects to consider in this respect and section are viewed as:

1. Figures in bold, spacing generally is too great in my view. Fit for purpose subsea BOP and associated well control equipment (Chapter 14)
2. Early kick detection, problem solving, and decision-making
3. Deepwater specific well control training, coaching, and understanding
4. Shut-in procedures
5. Kill methods
   a. Decision trees
6. Gas expansion in the marine (drilling) riser.
   a. Subsea BOP clean out (after a kick)
7. Nonshearable items across the subsea BOP
8. Choke line friction and hydrostatic replacement effect in the choke line
9. Well integrity testing
10. Gas migration during disconnect
11. Formation of hydrates
12. Wellbore strengthening

Each of the above-listed subject matters is now sequentially attended to and summarized in terms of well control assurance in this section.

Subsea BOP and Associated Well Control Equipment

Key subject areas in regards to this and associated subject matters are attended to in Chapter 14 and other sections of this guide.

Early Kick Detection

It is important to emphasize kick indicators as only three are considered positive:

1. Increase in flow from a well (when drilling)[2], continues or increase with pumps off.
2. Increase in surface volume (when drilling), or improper hole fill (when not drilling, tripping)
3. Positive flow check

Of all the above, early kick detection is critical in narrow margin deepwater wells where low and restricted safe operating margins exist. Assuring small kicks are taken is essential to reduce the expansion (gas risk) potential that can result as long marine drilling riser fluids migrate from the seabed to surface.

Note: Small gas volumes entering a well cannot be generally recognized until migration and expansion is detected above the subsea BOP and within the marine drilling riser. As a result, depending on the gas influx volume taken at source, the expansion in the riser can, if not safely handled, partially empty and collapse the riser or cause a serious incident at surface.

Hydrocarbon fluid entry into a well and the marine riser is therefore to be precisely prevented through a higher degree of vigilant kick detection practices, systems, and assurances that all personnel are better trained in gas detection, analysis, and gas in riser management.

Kick Alertness Guidelines

- Three kick alertness levels can be applied in deepwater wells as outlined in this section. These tailored to meet each wellbore section specific conditions and needs and are highly dependent upon the degree of *safe operating margins* that exist between the operating *EMWs, maximum pore, and minimal fracture pressures*.
- Appropriate level of safe operating kick tolerances is determined by the operators and drilling contractor project teams dependent on wellbore specifics, situations, conditions, and operating circumstances that exist.
- Prior to drilling into a transition or reservoir bearing zones, finger printing baseline and flowback trends serve as the best practiced methods to establish primary well control, pressure management, and wellbore stability assurance is safely and compliantly met for all operational events by personnel monitoring the well.

[2] A slow (influx) flow into a well may only be detected by a later positive flow check or by noting an increased flow at the next pumps off event.

KICK ALERTNESS LEVEL 1

Normal Well Operations (subsea BOP in place, kick tolerance >50–100 bbl (8–15.9 m^3) (0.5–1.0 ppg (59.9–119.8 kg/m^3)).

General Safety	
BOP shut-in drills	Weekly each crew
Pit/trip drills	Daily unless conditions do not permit
Preshift safety meetings	Daily for each shift
Weather	Forecasts twice per day from one station
T-time	*Minimum sequence*—Hang off, displace riser, release LMRP time estimates.
Kick tolerance	DSV's/engineers to use well integrity tests to calculate the kick tolerance at each casing shoe based on max hole depth of next interval. Calculations then updated daily or when significant mud weight changes result.
Kick Detection	
Active pit volume	Normal
PVT sensitivity	5–10 bbls (0.8–1.6 m^3)
Flow meter increase/decrease	Flow check for a minimum of 15 min
Gains	Shut in and check for pressure. If no pressure, flow check through choke. If no noticeable flow, open up well and flow check. If in doubt, circulate bottoms up, flow check at 75% bottoms up route flow through choke/MGS. Establish PVT trends prior to drilling ahead.
Positive/reverse breaks	Normal trip record procedures
Hole fill records	Flow check for a minimum of 15 min
Mud density checks	Every 30 min
Communications	Normal
Trip procedures	Normal tripping procedures apply. Flow check prior to POH, at the shoe and before pulling BHA through BOP.
Pressure Detection	
Pressure trends	Report significant trends.
Gas units	Calibrate mud loggers gas sensors each trip. Run calibration test on gas sensors daily. Run degasser if necessary.
Rate of penetration	Control drill if in transition zone.
Logs	As per program.
Simulated connections	As required to monitor gas trends.

KICK ALERTNESS LEVEL 2

Kick Tolerance > 0.5 ppg (>60 kg/m^3) (<50 bbl (<8 m^3) kick size) drilling in *transition* and potential *reservoir* zone.

General Safety	
BOP shut-in drills	Weekly each crew
Pit/trip drills	Daily unless conditions do not permit
Preshift safety meetings	Daily for each shift
Weather	Forecasts twice per day from one station
T-time	*Minimum sequence*—Hang off, displace riser, release LMRP times estimates.
Kick tolerance	Drilling engineer to use well integrity tests to calculate the kick tolerance at each casing shoe based on max hole depth of next interval. Calculations then updated daily or when significant mud weight changes result.
Kick Detection	
Active pit volume	500 bbls (79.5 m^3) (maximum) (+adequate reserve volumes)
PVT sensitivity	5 bbls (0.8 m^3)
Flow Meter Inc./decrease	Flow check for a minimum of 15 min
Gains	Shut in and check for pressure. If no pressure flow check through choke. If no noticeable flow, open up well and flow check. If in doubt, circulate bottoms up, flow check at 75% bottoms up, assess results, then hazard and risk assess to route flow through choke/MGS. Establish PVT trends prior to drilling ahead.
Positive/reverse breaks	Flow check (minimum of 15 min)
Hole fill records	Flow check for a minimum of 15 min
Mud density checks	Every 30 min
Communications	Normal
Trip procedures	Normal tripping procedures apply. Flow check prior to POH, at the shoe and before pulling BHA through BOP.
Pressure Detection	
Pressure trends	Report significant trends.
Gas units	Calibrate mud loggers gas sensors at casing points. Run Calibration test on gas sensors each shift. Check degasser response. Limit maximum gas by units by adjusting ROP and/or pump rate.
Rate of penetration	Control drill if in transition zone.
Logs	As required for pressure evaluation.
Simulated connections	As required to monitor gas trends.

KICK ALERTNESS LEVEL 3

Kick Tolerance < *0.5 ppg* (<60 kg/m^3) (<25 bbl (<4 m^3) kick size) in *transition* and potential *reservoir* zones.

General Safety	
BOP shut-in drills	Daily for each shift.
Pit/trip drills	Daily for each crew unless conditions do not permit.
Preshift safety meetings	Daily for each shift. Drilling Supervisor to be present.
Barite plug preparation	Mix water prepared and cement unit lined up. Formulation agreed to.
Kill mud	Mix rate test required. System must be capable of increasing system weight by 1 ppg (119.8 kg/m^3) in 1 circulation. If system does not meet this criteria, kill mud will be maintained on board. Base the volume and MW of kill mud on increasing the drilling MW by 1 ppg (119.8 kg/m^3) in 1 circulation in conjunction with mud mixing system.
Weather	2 forecasts each day from two stations at 6 hour intervals.
T-time	Bullhead, hang off, displace riser, release LMRP
BOP shut-in drills	Daily for each shift.
Kick Detection	
Active pit volume	Minimum workable volume
PVT sensitivity	Sensitivity 5bbls (0.8 m^3), shut in well on any gain.
Flow meter increase Flow meterdecrease	Shut-in well Flow check for a minimum of 15 min
Gains	Shut in and check for pressure. If no pressure flow check through choke. If no noticeable flow through choke, open up well and flow check. Circulate bottoms up, flow check at 75% bottoms up, based on results, hazard and risk assess to route flow through choke/MGS. Establish PVT trends prior to drilling ahead.
Positive/reverse Drl break	Shut in well using "Hard shut in."
Hole fill records	Drilling supervisor or engineer checks procedures.
Mud density checks	Every 15 min
Communications	Mud loggers and rig floor to have two means of communication.
Trip procedures	Tripping procedures for low limits to be applied apply. If heavy mud pills placed on bottom, this will be done after the wiper trip.
Pressure Detection	
Pressure trends	Report all trends.
Gas units	Calibrate mud logger gas sensors at casing points. Run calibration test on gas sensors every 6 hours. Run degasser as required. Limit maximum gas units by adjusting ROP and/or pump rate.
Rate of penetration	Do not have >90 ft (27.4 m) of sample being circulated out at any time.

Pressure Detection	
Logs	As required for pressure monitoring.
Simulated connections	Every 15 ft (4.6 m) if >pore pressure is indicated. Only one connection is preferred in the well at any one time. Otherwise conduct a dummy connections once every stand.
Pressure sampling	Consider prior to drilling into transition zones or if a long section of open hole is exposed. Test formation to predetermined equivalent mud weight values. Do not test to leak off.

Deepwater Training, Coaching, and Understanding

Personnel involved in deepwater planning and operations specifics require specific well control training. Personnel shall be trained to be familiar with the following aspects:

1. Pore pressure and practical wellbore stability management
2. Gas expansion in water and oil based mud fluids
3. Forming and prevention of of gas hydrates
4. Choke line friction losses
5. Possibility to carry a riser margin, precautions when none exists
6. Possibility to detect and response to a influx
7. Kill methods and variable MAASP, MAWP, and MASP
8. Other key aspects as identified in well program curriculums suggested.

Note: Personnel responsible for daily drilling activities are to be familiar with:

1. Measuring choke line friction losses
2. Mud rheology and frictional pressure losses at different set of PVT conditions
3. Shut-in procedures (generic illustration is provided in Fig. 16.8)
4. Tier 1 and Tier 2 kill standard and nonstandard methods
5. Gas replacement and the need for good choke control
6. Handling gas in the marine riser and subsea BOP
7. What to do if deepwater choke line friction loss exceeds SICP

Shut-In Methods

Shut-in methods should be agreed, assured, and captured within the relevant well control manuals and bridging documents used. Shut-in methods shall also consider and assure to account for the following:

- Hard versus soft shut in
- Annular shut in versus ram shut in (Table 16.2)
- Shut in while drilling
- Shut in while tripping
- Shut in during a connection
- Shut in with an assembly bit above the subsea BOP and
- Shut in while running the casing and liners

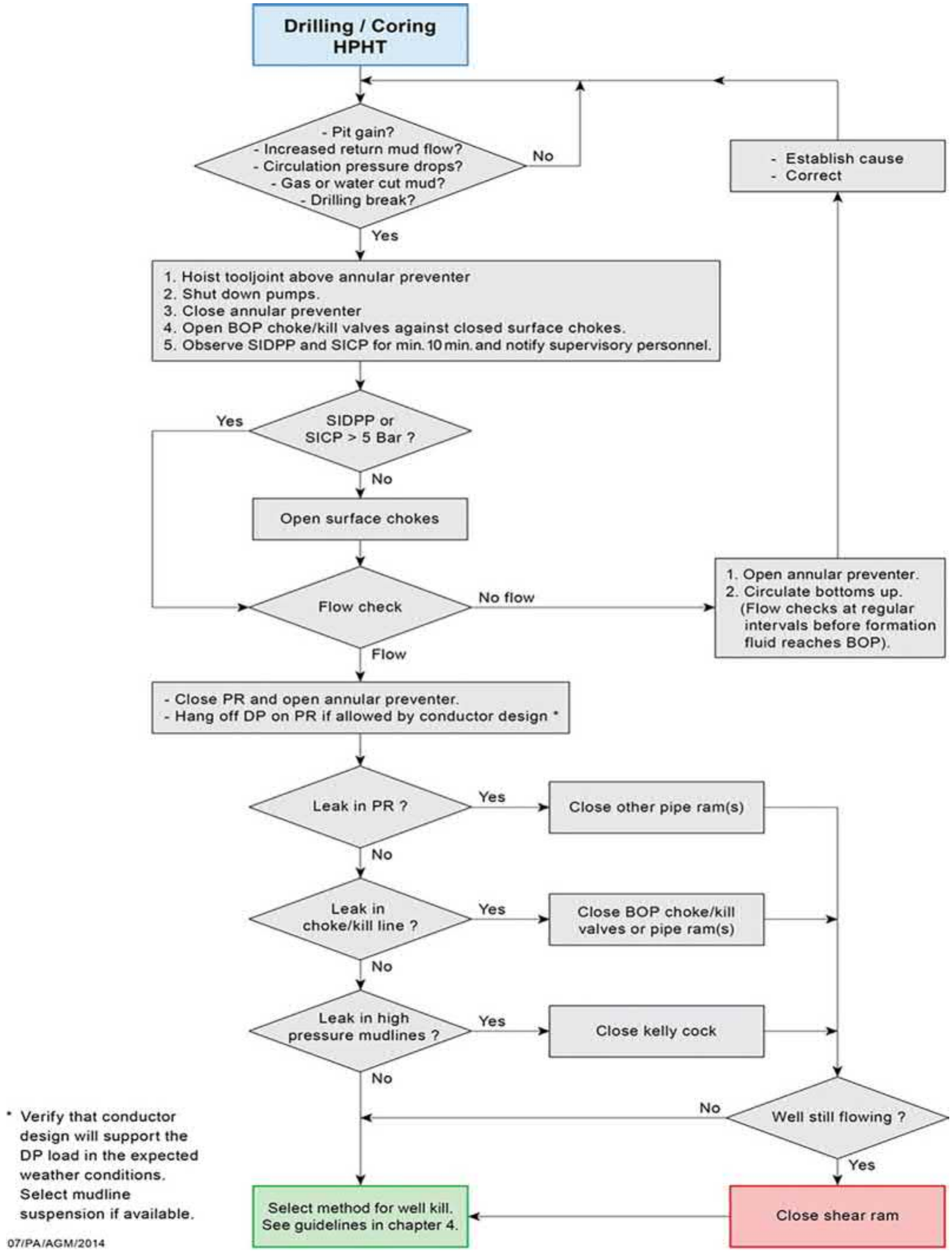


FIG. 16.8 Narrow margin (deepwater/HPHT) drilling "primary well control" decision tree. *Source: Kingdom Drilling 2015.*

TABLE 16.2 Annular Shut in Versus Ram, and Annular/Ram Shut In

Shut In Method	Constructive Factors
Annular shut in	• Eliminate requirement to have tool joints clear of a BOP ram (that is made more difficult in deepwater due to vessel offset, effect on length and more joints of pipe to consider). • Reduces ram damage risk through closing on a tool joint if space out is incorrect. • Provides a means to effectively shut in while allowing for movement of drillpipe reducing differential sticking risk. • Increases EDS on a DP rig.
Ram, shut-in and hang-off operations	• Permits quicker well closure. • Minimizes amount of gas that could become trapped in the subsea BOP. • Not recommended due to the possibility of shutting in around a tool joint. • Eliminates potential wear on subsea BOP due to rig heave.
Annular/ram shut in. Annular closure followed directly to ram hang-off.	• Defers need for tool joint near a BOP ram when execution speed is not critical. • Simplifies space out. • Minimizes amount of gas that could become trapped below annular. • Minimize risk of sticking will preclude hanging off the drillpipe. • May provide higher pressure limits than the annular. • Once hung-off, the well is more capable of dealing with an unplanned emergency. • Hang off is recommended for DP operations if there is a probability of station keeping issues

Secondary Control; Kill Methods

Operating Well Kill Methods and Decision Trees

Although there is valid reason and rationale to use the driller's or wait and weight method, in deepwater the driller's method is the most used as advantages permits immediate circulation of the kick, reducing the time for the well's and systems fluid to cool down at the wellhead and the time for gas to migrate. The following decision trees illustrated can be constructed for a deepwater project in regards to secondary control methods to use should primary well control be lost:

1. Shallow hazards (Fig. 16.9)
2. Well flows while drilling, tripping and out of the hole (Fig. 16.10)
3. Drilling or tripping kill method YELLOW (Fig. 16.11)
4. Tripping kill options method RED (Fig. 16.12)
5. Stripping kill options method WHITE (Fig. 16.13)
6. Volumetric/bullhead kill BLUE (Fig. 16.14)
7. Preventing lost returns and underground blowouts (Tables 16.3 and 16.4)

Note: A color coding system is often employed for ease of reference.

Factors related to methods of circulating a kick to surface are captured in Table 16.3.

An underground blowout can result when a weaker formation pressure is exceeded during a well kill operation. Fluid from the higher pressure zone shall now flow into the weaker zone. Well pressures can be monitored for such events as illustrated in Table 16.4. General procedures for detection and action to be taken in an underground blowout can be reviewed within the IADC Deepwater Well Control Guidelines, 2nd edition, Section 4.5.

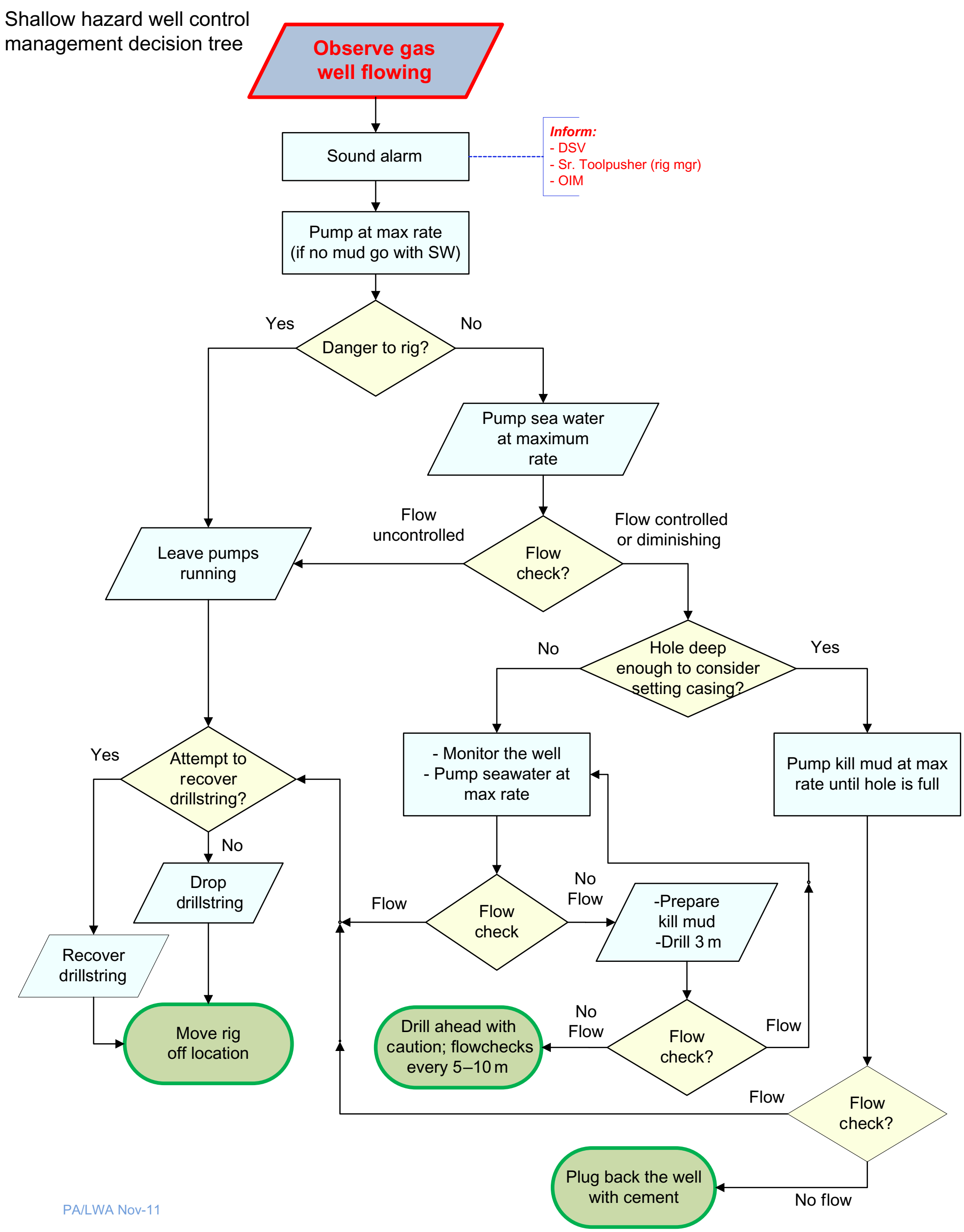


FIG. 16.9 Shallow hazards.

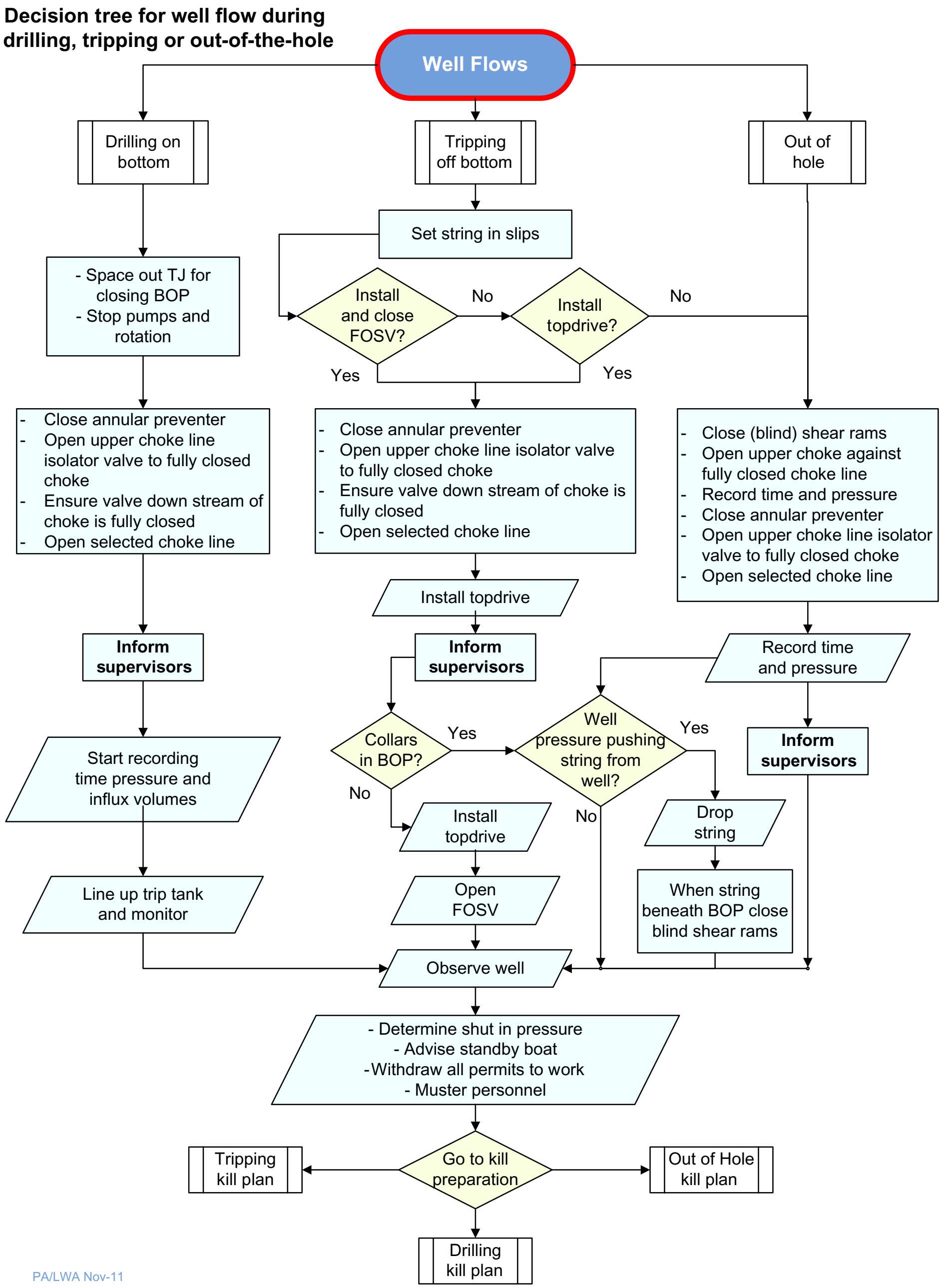


FIG. 16.10 Well flows while drilling, tripping and out of the hole.

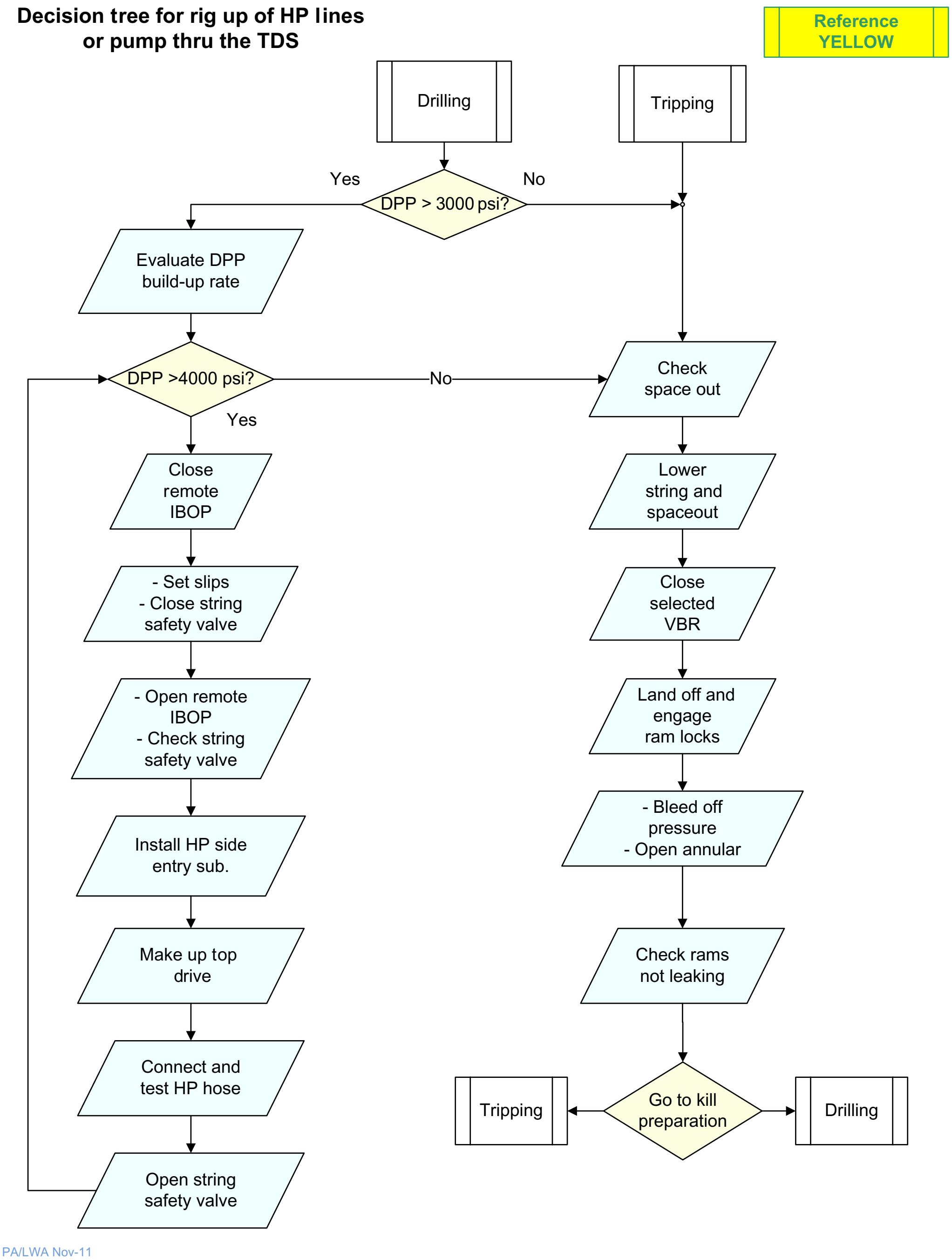


FIG. 16.11 Drilling or tripping kill method.

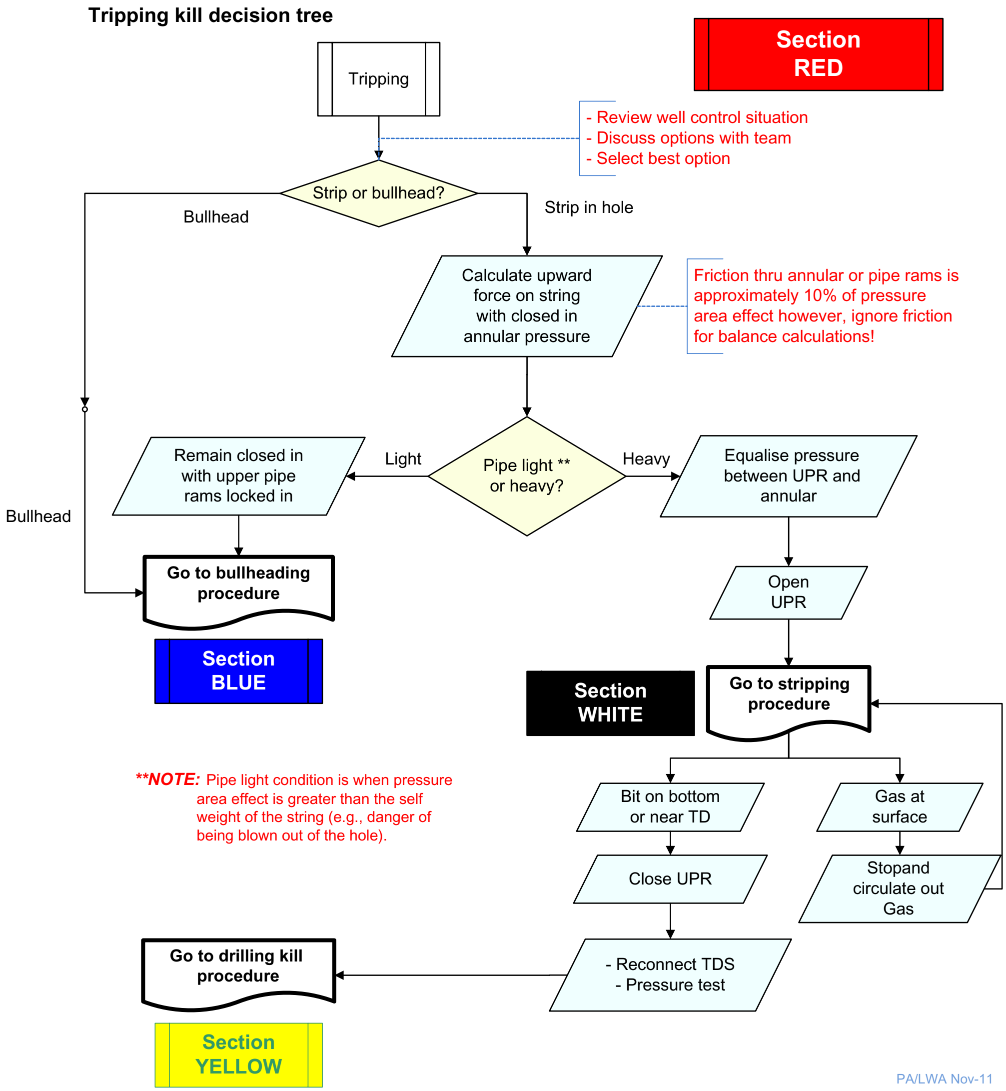


FIG. 16.12 Tripping kill options method.

Gas Expansion in the Marine Riser

The increased probability and consequential outcomes of a uncontrolable gas influx volume entering the riser in very deep water locations requires contingencies to safely reduce exposure to the rig and rig floor personnel (Fig. 16.15).

Examples: Gas influx has resulted into the riser during a well control event after the BOP is shut in. In these circumstances, gas in specific fluids and conditions may slowly migrate up the riser and not be noticed while other well control activities are taking place. The gas in a worse case scenario can at a specific shallower depth unload rapidly if not contingent actions

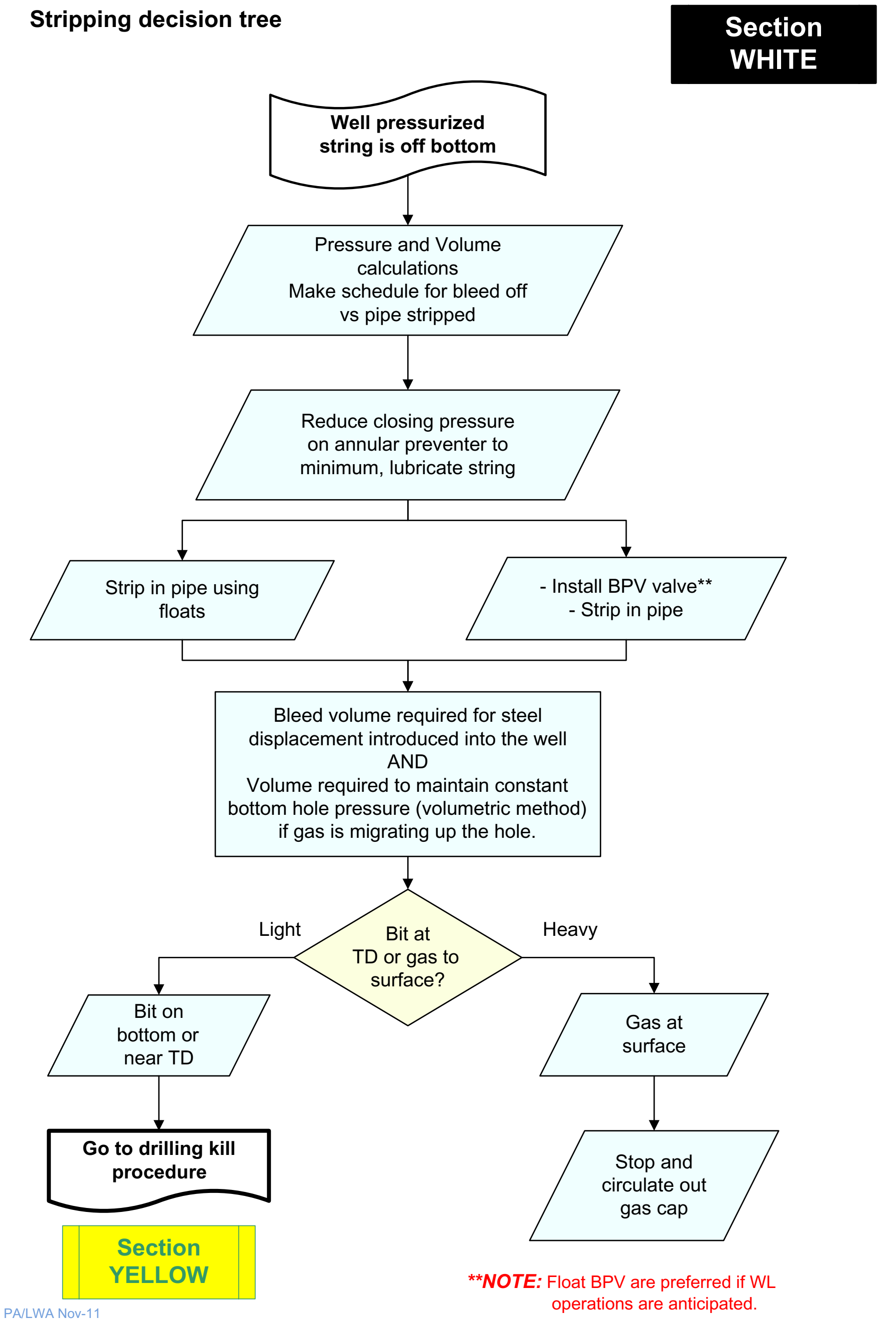


FIG. 16.13 Stripping kill options method.

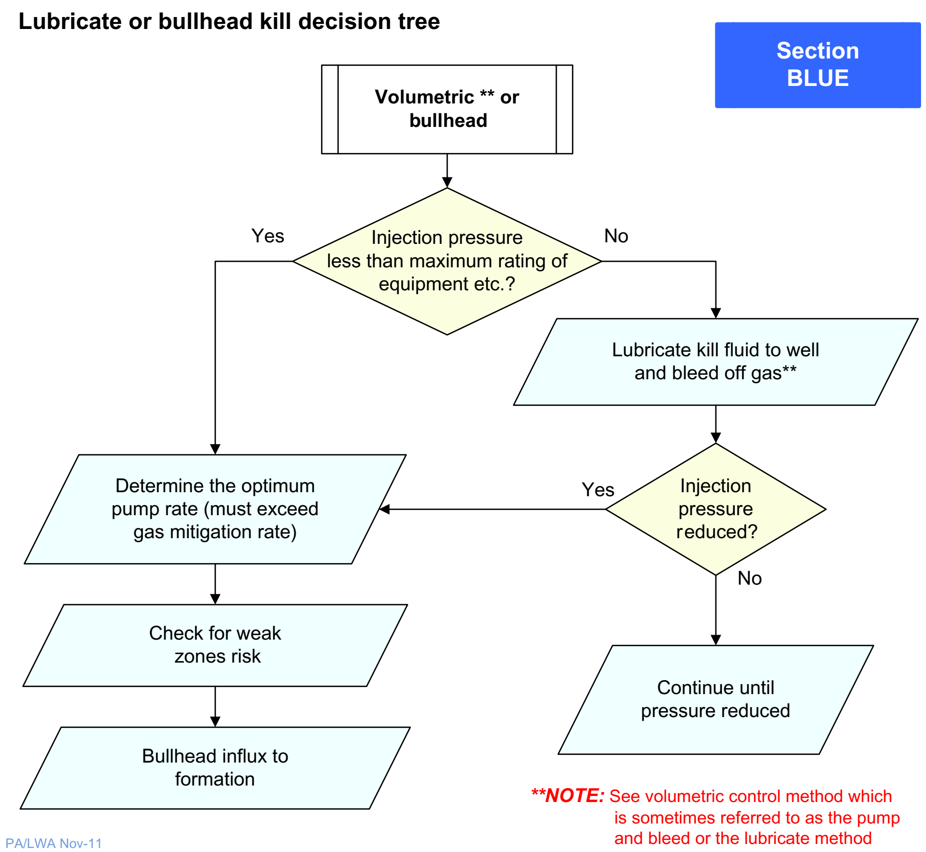


FIG. 16.14 Volumetric/bullhead kill method.

TABLE 16.3 Factors Related to Methods of Circulating a Kick to Surface

Factors	Considerations
Gas	• Gas migration and location at shut in condition w.r.t. casing shoe and open-hole length. • Immediate circulation to remove gas (drillers method) may be lowest risked option preferred. • H_2S, large gas influx volumes, and requirements to bullhead gas
Circulation rate	• Prerecord all slow pump data rates, pressures as related to maximum pressure that well's weak point (lowest fracture pressure) can accommodate. • Assess requirement to reduce circulation rate as influx and kill weight mud reaches the subsea BOP stack, kill/choke lines in order to offset and minimize resultant pressure increase at the casing shoe. • Assess requirement to circulate via one or two choke and kill line to reduce circulating pressure risks. • At pump start up, assure calculate ICP is reference and considered regardless of method used. If actual ICP is lower that calculated pressure, shut the well back in and re-evaluate.

TABLE 16.3 Factors Related to Methods of Circulating a Kick to Surface—cont'd

Factors	Considerations
Mud	• Mud viscosity, temperatures, gelation, inertia, data, and effects. • If C&K gel strength is high and operating margin is low, consider breaking C&K circulation.
Fracture gradient, MAASP, MASP, and MAWP	• Fracture gradients are generally lower in deepwater, particularly so with greater water depth. • Revise kick tolerance values as the well is drilled as physical parameters evidently change. • Systems and resources to be capable to detect small kicks at less volume that kick tolerance (if not assure contingent string are accommodate in the design, to be run when safety limits are reached).
Mud and gas separator capability	• May be required to be far more capable in deepwater. • Mud gas separator to be instruments to allow monitoring of internal pressure versus U-tube hydrostatic. • May need to be operated and run at very low circulation and kill rates (using the cement pump?). • Emergency mud gas separator bypass overboard lines must be installed. (Tied in with diverter system) • Gas shall be diverted overboard if any indicator approaches operating conditions or standard norms.

TABLE 16.4 Underground Blowout While Drilling

Well Pressures	Features/Characteristics, Corrective Actions
Shut in drillpipe pressure (SIDPP)	• Pressure will initially increase, but then notably decrease, at least for some time. • Drillpipe pressure may reduce to almost zero. • If there is no solid float in the drillstring, or if the float leaks or is ported, some drillpipe mud may be displaced with gas if pumps are stopped.
Shut-in casing pressure (SICP)	• Pressure will initially increase, but then notably decrease, at least for some time. • Able to strip drillpipe into the well with no change in annulus pressure. • Erratic pressure can slowly increase if gas migrates to surface. High pressure can result if annulus becomes gas filled. Casing mud is then displaced by gas migrating upward causing casing pressure to rise. If no corrective is taken, this rise can exceed casing pressure or cause fracture and an underground flow to result. *Note*: If casing pressure exceeds casing or subsea BOP ratings, appropriate densities must be pumped down annulus to combat gas migration to the surface and force annular pressures down.

is enforced. E.g., In a 14.0-ppg (1678 kg/m^3) environment in 1800 m (5906 ft) of water depth, 10 bbls (1.6 m^3) of free gas entering the riser at the seabed in theory expands to 4000 bbls (636 m^3) of gas at atmospheric conditions: that may unload violently as it approaches the surface.

Because of the higher risk that gas can be entrained in the marine riser, diverter and gas handling system design and practicable operability, become critical and important.

Attention must be afforded so that specific volumes of mud envisaged can (up to a certain well defined operating limit) be safely degassed and returned to the mud pits with the diverter element open or closed. This can only result via a suitably designed system capable of returning gas-free mud to the active system. Today this is achieved through a riser mud gas separator as part of the diverter system, or having mud return lines installed

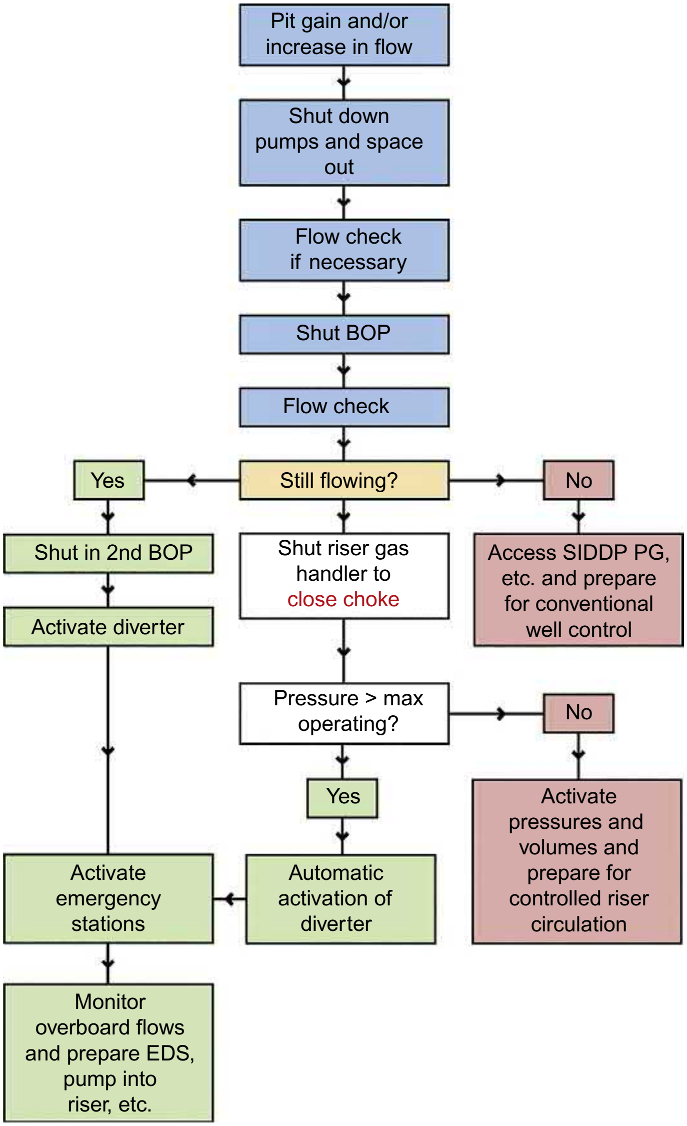


FIG. 16.15 Gas flow in riser above BOP.

beneath the diverter lines, allowing whole mud to be returned to the system while still allowing the gas to be vented up the derrick. In such a system, the slip joint packing remains as a low-pressure weak point and compromises the riser system integrity when handling gas. To meet these risks, equipment is now designed to allow installation of an annular element directly below the slip joint, to afford low pressure closed in capability of the riser so that mud can be returned to the choke manifold. *Example*: As described in the IADC Deepwater Well Control Guidelines 2nd Edition, 2015.

Gas in Riser Removal Guide

Rig- and well-specific procedures for gas in riser is provided within drilling contractor's standard operating procedures. General guide can be reviewed in the IADC Deepwater Well Control Guidelines, 1998 edition, Section 3.2.6 and 2015 2nd edition, Section 3.5.6.

Subsea BOP Clean Out

Similarly well-specific procedures shall be provided by the drilling contractor and operator to meet each set of specifics. If none exist, this should be captured in the well control bridging document.

Nonshearable Items Across SSBOP

Guidelines shall exist should a well flow and nonshearable items result across the subsea BOP. Should an emergency disconnect situation arise the IADC Deepwater Well Control guidelines recommend that:

- The time that the BHA is across the stack must be minimized.
- Heightened alert levels should be implemented during this time.
- A procedure for dropping the string should be designed, risk-assessed, and agreed on.

Three possible actions exist should an emergency disconnect be called for with nonshearable components across the shear rams.

1. Pick up drillpipe; run in until the desired drillpipe is across the casing shear rams (CSR). (Check whether the CSR are capable of shearing HWDP).
2. Pull back until the bit is above the LMRP connector.
3. Drop the drillstring (easier said than done)—the procedure could involve using the annular to support the remaining string weight to allow the elevators to open.

The alternatives of each should be examined, with a written instruction that drillers must know, such that at any stage of a trip (including RIH or POH) the first choice of action to take. An example guide is:

1. Assure accurate subsea BOP dimensional drawings are available on the rig floor at all times.
2. If well flows, shut in on SSBOP annular preventer as per shut in procedures.
3. If annular preventer cannot stem flow: *Actions must confirm to either drop, pull and/or strip nonshearable item and assembly above or below the shear ram so that it can be functioned.*
4. If item cannot be moved, e.g., *casing hanger in SSBOP area with casing stuck near bottom: Drop the drillstring* as per drilling contractor procedure.
5. *If drillstring cannot be dropped* for whatever reason, e.g., *stuck pipe*, know what to do, e.g.:
   a. Mark pipe at rotary table.
   b. Slack off or pick up to maximum limits.
   c. Based on results, assess which situation assures that the nonshearable item is clear of the shear ram. *Note: Pulling in tension would be preferred as this would assist shearing.*
   d. Function shear ram.
   e. Pull string above shear ram.

6. If item cannot be sheared with still flowing, safety of rig and personnel will take precedence.
7. Under instructions, emergency disconnect procedures would be initiated.

Choke Line Friction in Deep Water

As illustrated previously, pressure loss in line-pipe is proportional to length when all other parameters are constant. The increase in choke line lengths also reduces mud return temperature due to the cooling effect of the sea. Reduced temperature also increases mud viscosity, which in turn increases friction loss. Should the mud be allowed to gel in a choke line, a far greater pressure is needed to break the gel, increasing the danger of fracturing the weakest formation exposed at or below the casing shoe. What applies in deepwater are:

1. The kill/choke lines should have an inside diameter not less than 3″, 4″, or greater internal diameter is preferred.
2. Establish mud rheology also at low temperature.
3. Choke line friction should be established for typical values of slow circulation rates. The surge pressure to break the gel strength in choke lines should also be established.
4. Recommended to use pressure and temperature sensor at subsea BOP.

Well Integrity Testing

A rigid policy is not to be recommended on well integrity testing, where each particular case shall be judged on its specific merits. Of note is that well integrity formations pressures (of the same type) in deep water are generally lower compared to shallower water.

Wellbore fixed limit (FLT), Formation integrity (FIT), leak-off (LOT), and extended leak-off tests (X-LOT) are considered when there are no regional data, when there is doubt about previous initial test, or when it is critical and crucial to obtain specific wellbore pressure management, stability, or casing setting depth values. *Note*: Experience has proved that the initial formation leak-off test formation strengths often *improve with time for water and oil based muds.*

Should wireline logging, formation pressure, and fluid data sampling be conducted at the end of a drilled section, data obtained during this scope of work at weak point zones identified can be invaluable for future well integrity, operational planning and execution.

Gas Migration During Disconnect

Gas in the well can migrate when the well is static. If the LMRP is disconnected and the riser pulled, the gas can migrate to the BOP cavity. To prevent the formation of gas hydrates in the BOP stack, *the following guidelines apply*:

1. Prior to disconnect circulate the hole clean to reduce gas cut mud.
2. Pump spotting fluid to prevent forming of gas hydrates through lower kill line to fill stack area to upper annular.
3. Ensure the kill and choke line outlets are filled with the spotting fluid prior to disconnecting the LMRP.

Deepwater Hydrates

Deepwater hydrates have caused severe problems when gas influxes and kicks are present. In these well control situations, the gas kick fluid leaves formations at high pressure and temperature, and should an extended shut-in period result, and with a cooler seabed temperature regimes, etc. Should high enough hydrostatic pressure be ever present at the mudline, hydrates can form in the subsea BOP, choke/kill lines, and marine riser.

Temperature, pressure, and gas composition therefore determine the ideal condition for hydrate formation to exist. Solidification of the hydrate occurs as the temperature decreases and/or pressure increases with the proper amount of gas and water present. In a drilling situation, hydrates can form at temperatures well above freezing temperature of water due to the pressure exerted by the hydrostatic head. Hydrates in the presence of gas must be viewed as a genuine risk any time cold temperatures clash with high pressure. With the common condition in all hydrate formation experienced offshore are extended shut-in periods.

Well control operations must begin as soon as possible after recording the shut-in pressure parameters. The significant effects of the hydrate formation in drilling operations are:

- Plugging of choke and kill lines
- Formation of a plug at or below the BOP, preventing monitoring of pressures below the BOP
- Formation of a plug around drillstring in riser, BOP, or casing
- Formation of a plug in ram cavity of a closed BOP-preventing it from fully opening.

When exploring for deepwater gas in cold water locations, considerations must be afforded to *predict and prevent hydrates forming* during the planning phase that must take into account:

- Hydrostatic head plus maximum anticipated shut-in pressures at the coldest point in the system (i.e., mudline)
- Final maximum anticipated mud weight
- Mud line temperature

Items that can be impacted in the well plan due to possible formation of hydrates are:

- modifications to allow inhibitor injection at the subsea BOPs
- Inhibitor type, volume, and concentration
- Drilling fluid type to be used through the prospective zone of interest
- Choke manifold modifications to allow inhibitor injection at the choke.

Prevention is always preferred to any cure, as remedial curing actions are always time consuming, costly, and could risk the safety of the rig and personnel on board. Recommendations to avoid hydrate formation are generally considered as:

1. Kill and choke lines to be circulated at regular intervals when the bit is above the subsea wellhead (tripping, logging, etc.).
2. Use hydrate inhibiting mud. The drilling fluid can be used for hydrate inhibition.
3. If shut-in results, minimize to less than 1 h if possible. If expected to last more than 1 h, the subsea BOP stack and choke line should be displaced with an inhibitive fluid. After shut in, the inhibitor shall be injected into the circulation stream until all the gas has been removed.
4. At shallow depths, circulating rate and inlet temperature to be kept as high as practicable.

5. If a gas kick is taken, it should be circulated out at the highest acceptable rate as soon as practicable after the shut in. *Note*: mineral oil-based fluid can be spotted across the subsea BOP and in the choke/kill lines.
6. In the event of a gas kick when a water-based mud system is being used, be prepared to spot a glycol pill in the subsea BOP, choke/kill lines.

Improving Deepwater Pressure Outcomes

When narrow operating margins exist in deepwater, specific improvements to utilize are:

1. Improving control of (conventional drilling) methods
2. More use of low EMW Fluids (Micronized Barite)
3. Enhanced wellbore strengthening materials and methods
4. Nonconventional (adaptive/adoptive technology) methods, e.g.:
   a. Dual gradient drilling
   b. Manage pressure drilling
   c. Combined nonconventional methods and DUAL GRADIENT DRILLING
   d. Casing while drilling

Conventional Drilling Controls

Conventional method in deepwater is essentially utilizing all best operating practices, to prevent and mitigate risks and concerns as outlined in this guide. When narrow operating margins arise, extreme control measures have to be initiated that often result in time-consuming and costly consequential solutions to meet desired end results. The most assured well control plan shall have required contingent casing strings to be able to isolate the problems and difficulties that exist. This then affords safe and necessary operating window to proceed and deliver the next section as planned.

Low-Equivalent Mud Weight Fluids

Low (high-technology drilling fluids solutions) equivalent mud weights have opened up safer operating windows to deliver significantly improved conventional deepwater drilling methods and operational benefits.

The problems the remain is that the low temperatures experienced in deepwater radically increase downhole mud density, viscosity, and gel strengths, especially for nonaqueous fluids such as synthetic oil-based muds (SOBM) most commonly preferred.

These effects must be carefully monitored and offset to minimize excessive pressures while drilling, tripping, running casing and during cementing. Notable after *long static periods!* Problems then develop trying to maintain and control the constant dynamic and static variant changes of EMW pressures that result. *Note*: Where even apparent correct mud rheology can deteriorate to poorer downhole conditions that result (Fig. 16.16) with cause and effects changes such as *barite sag, pressure spikes, poor hole cleaning, higher EMW, MW & ECD, reduced ROP, increased solids, and progressive gel strengths that can all create operational risks and difficulties.*

All these low temperature issues, causes and effects can today be combated, reduced, and mitigated using new deepwater (technology driven) drilling fluids systems such as flat

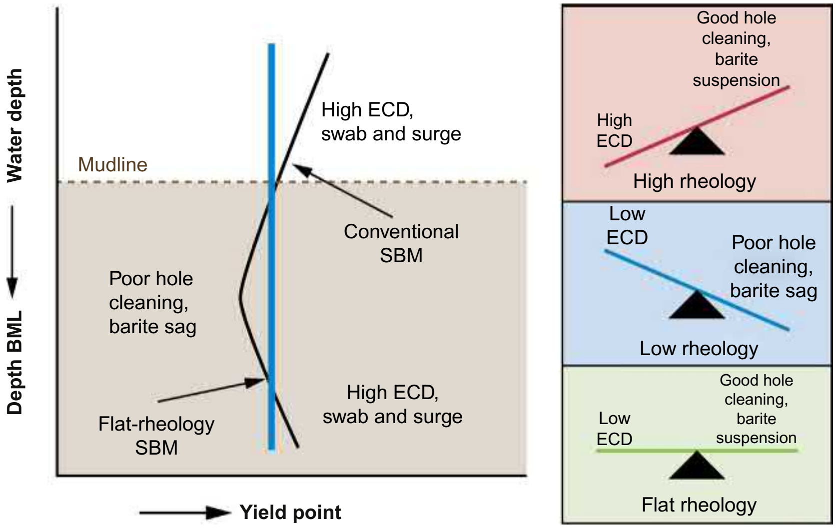


FIG. 16.16 Deepwater mud rheology at temperature extremes.

rheology muds, utilizing micronized weighting materials (<4 μm) to improve evident benefits as realized in deepwater. Where the smaller particle sizing slows the solids settling rate in the drilling fluids to making hole cleaning, pressure management and other operating facets far more controllable. What has resulted is simply a new and further definition for "MPD," i.e., *make problems disappear* with these fluids enhancing outcomes and benefits such as:

1. Higher ROP
2. Far lower fluid losses and EMWs for all cased, open and bottom hole conditions
3. Ability to drill with lower mud weight
4. Superior hole cleaning

Wellbore Strengthening

In addition to all technology proactive measures adapted in recent years to combat notably lost circulation in deepwater as illustrated in Fig. 16.17, the greater value addition is evidently wellbore strengthening.

Wellbore strengthening is arguably one of the top 5 technology value additions in the last decade to contribute more than any of the other proactive methods as illustrated to reduce lost circulation and other evident deepwater top tier problem events *to the minor leagues*.

The purpose of wellbore strengthening is ultimately to proactively extend the effective fracture gradient (EFG) of the weakest formations exposed.

In simple terms, the operating fluids (drilling mud) are treated with precisely and specifically engineered particle size distribution materials designed to superficially strengthen the wellbore walls. To date what materials are understood to work best and others that do not in specific operating environments as illustrated in Fig. 16.18.

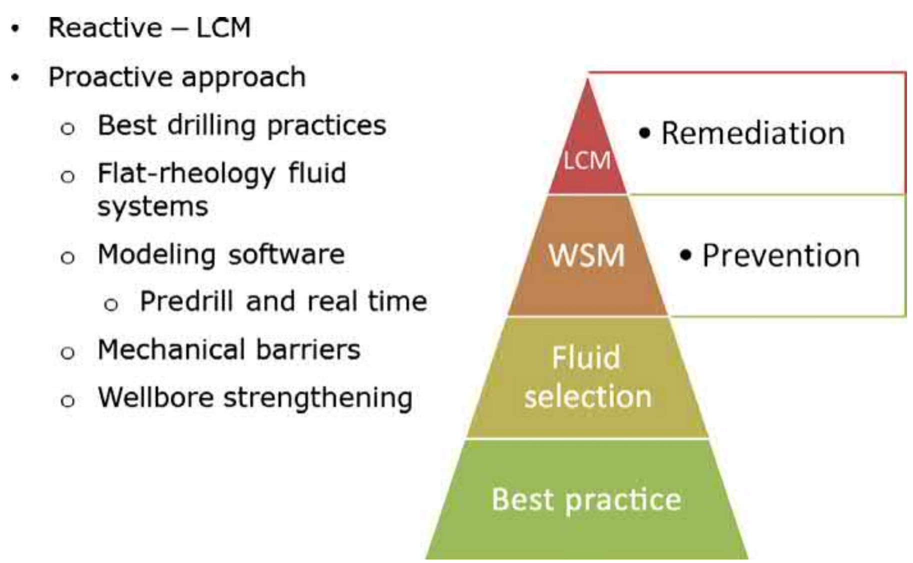


FIG. 16.17 Proactive approach to lost circulation in deepwater.

The characteristic of successful wellbore strengthening materials (WSM) is further illustrated in Fig. 16.19. Where although great inroads have been advanced in this area, scope exists for further improvement as:

- The industry apparently wants more; are there issues with ability to drill numerous wells in play around the world?
- Not simply bigger and bigger particle size distribution works, but this seems to help
- The role of fibers needs to be better understood
- Current models don't allow certain fields to be developed
- What about natural fractures?

Going forward, work is continuing to improve the industry's understanding in wellbore strengthening in all of the areas indicated and identified plus more…

In summary WBS is an excellent method and means to increase effective formation fracture gradient and increase the safe operating drilling windows through extending the stable fracture propagation range through adopting a proactive strengthening while drilling (SWD) approach that has realized:

- Continuous use in deepwater drilling fluids with continuous protection; no start-stop squeezes using wellbore pills.
- Continuous recovery and reintroduction of WSM materials using enhanced solids control and recovery equipment.
- Successful application on deepwater, high pressure, and subsalt/and near-salt wells.
- Mud loss reduction often >80% versus conventional norms.
- Lost circulation is no longer a top 10 of trouble time categories in several fields.
- Less associated well control assurance events to be managed and controlled.

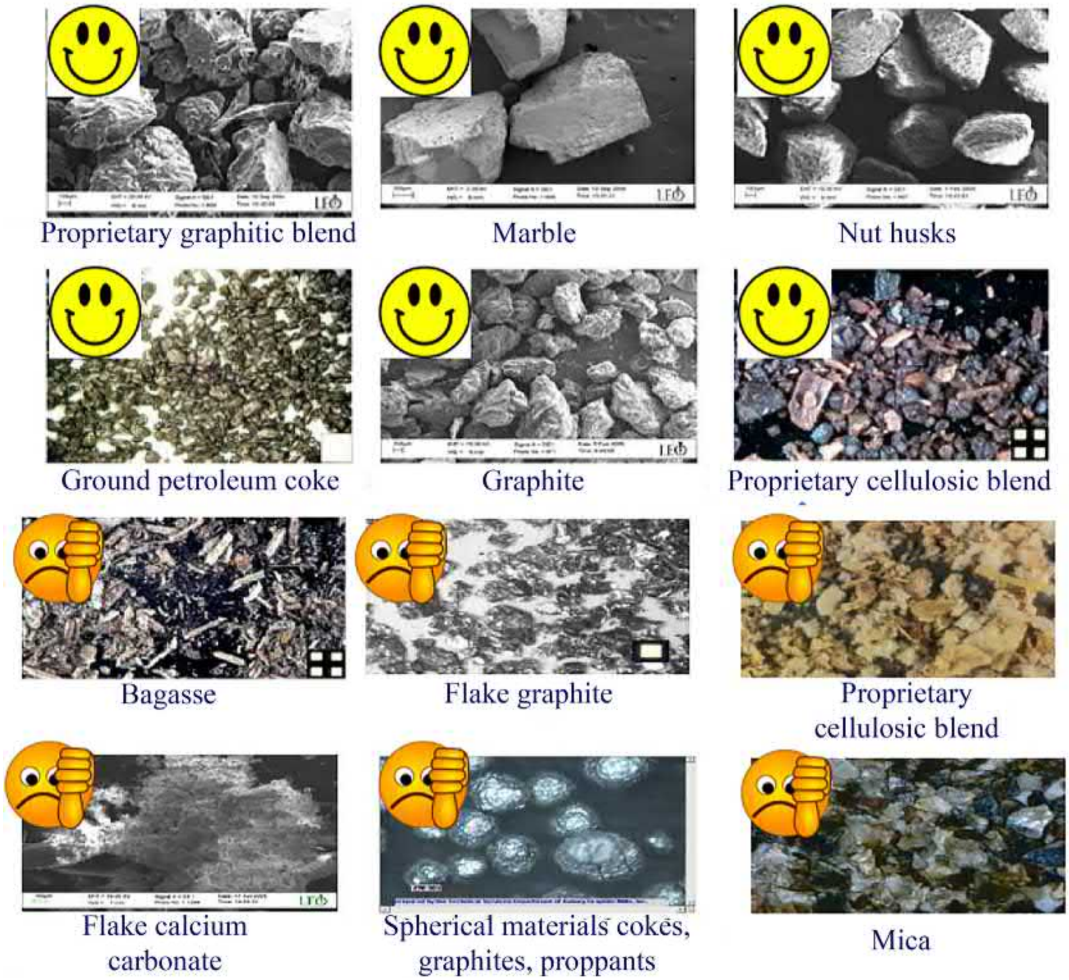


FIG. 16.18 Wellbore strengthening material that works and *does not work*.

In summary, adopting a wellbore strengthening material (WSM) and strengthening while (SWD) deepwater operating approach is considered to be universally applicable for prevention of lost circulation on any type of weak and/or depleted formations.

Nonconventional Drilling Methods

Finally, in addition to all methods highlighted in this guide, the future success and elimination of deepwater wellbore difficulties and well assurance issues lies in the further improvement of all nonconventional methods (tried, tested and proven application value added elsewhere) at a far greater pace than currently exists to deliver the technological competitiveness outcomes and benefits required.

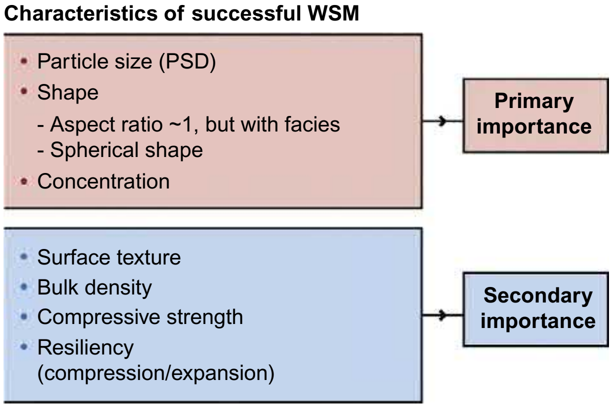


FIG. 16.19 Characteristics of successful WSM.

Although technology adaptation and adoption aspects have been touched on in this guide, these areas undoubtedly hold the future key to deepwater success where the greatest challenge is not the technology but perhaps a greater need for people to change.

When this happens, the evident outcomes and benefits that could result result within deepwater then to be captured in the next deepwater development drilling, workover and intervention guide series of chapters required to result.

REFERENCE STANDARDS

API RP 96 Deepwater well design and construction.
IADC Deepwater Well Control Guidelines, 1st Edition, October 1998.
IADC Deepwater Well Control Guidelines supplement, 2nd October 2000.
IADC Deepwater Well Control Guidelines, 2nd Edition, 2015.
Norsok Standard D-101 Rev. 4, June 2013, Well Integrity in drilling and well operations.

References

Aird, P., Abel, B., 2011. Deepwater Well Control, Revision 3.
Aird, P., November 2015. Stuck Pipe Prevention Managing and Freeing. Rev 1.1. Kingdom Drilling Services.
Chevron/BP, 2007. Drilling Training Alliance Relevant Chapters. Floating Drilling Manual.
Chevron/BP, 2007. Drilling Training Alliance Relevant Chapters. Deepwater Drilling Manual.
IADC, October 1998. Deepwater Well Control Guidelines, first ed. International Association of Drilling Contractors.
IADC, 2015. Deepwater Well Control Guidelines, second ed.
IADC Floating Drilling & Equipment Operations. first ed. 2015.
IADC, 2015. Drilling Manual, 12th ed. ISBN: 978-8-9915095-0-8.

APPENDIX

1

Organizational Learning

WHY BECOME AN ORGANIZATION THAT LEARNS?

Learning Organizational Checklist

To discover your organization's current learning climate, complete the following checklist: Check each statement that is true

Learning Organization Checklist	✓
1. Learning is integrated into everything I do	
2. Learning for learning's sake is encouraged, commended, and often rewarded	
3. Our organization strongly supports teamwork, creativity, empowerment, and quality	
4. Employees are trusted to choose the development courses they need	
5. People with different jobs titles from different departments learn together	
6. We promote mentoring relationships to enhance learning	
7. Learning is integrated into meetings, work groups, and work processes	
8. All individuals, regardless of position, have equal access to learning	
9. We see mistakes, failures, and operating loss as prioritized learning opportunities	
10. We initiate crosstraining and reward employees who learn a wider set of job skills	
Total ✓ = /10	

If all the boxes were checked, this is *Fantastic* as all ten items are found in true learning organizations.

If there are items without checks, *Congratulations*; you have just learned that your organization has opportunistic areas that need further development.

ORGANIZATION'S LEARNING CAPABILITIES

Reflect on the following questions to get a better understanding of how your organization, responds to the learning needs of the individuals in your teams.

Organizational Response to Learning	True	False
1. We work to remove barriers to learning		
2. We cultivate a learner-friendly environment		
3. We identify tools and skill needed to assure a more proficient learning organization		
4. We understand how adults learn. We use all knowledge to this advantage		
5. We use various tools to assess individual's leaning progress		
6. We acknowledge people learn from experience		
7. We recognize what type of learning is most appropriate for specific situation, conditions, and environments		
8. We encourage team members to become lifelong learners		
9. We encourage individuals to keep an open mind to learning		
10. We understand the factors that inhibit learning		
11. We know how to motivate people to learn.		

Note: Any False statement present areas that need to be developed to create and cultivate a better learning organization!

APPENDIX

2

Soil Classification and Testing

DEEPWATER SOIL CLASSIFICATION AND TESTING

Deepwater—General

Deepwater shallow marine sediments are to be broadly defined as the depositional geological structural environment to ±3300 ft (1000 m) or greater below the seafloor. In Deepwater environments, sediments can be soft, ductile, and weaker than those deposited deeper. Deepwater soils are classified as debrite, turbidite, or pelagic deposits. In some areas, soil profiles shall consist of alternating thicknesses and layers. Turbidites can be deposited quickly, particularly in fan zones if fed from a major river or deltaic systems. By contrast, pelagic deposition rate is often slow, i.e., *a fraction of a millimeter per year*

Deepwater sites are more commonly normally consolidate clay sites with relatively thin sand or silt layers. Clays can be underconsolidated implying rate of deposition is faster than rate of consolidation and where excess pore pressure has not yet dissipated.

Offshore Nigeria in clays at deepwater sites, Ehlers et al. (2005) reported existence of near seafloor 1–2 m thick crust zones with strengths up to 10 kPa, and sufficient to restrict structural string penetration. Investigation suggested crusts were the result of intense bioturbation or reworking of deposited soils by small creatures

Deepwater wells explored offshore the East coast of India during 2002–2014 also experienced occasional "hard ground" at or just below the seabed that restricted jetting

Shallow Penetration Geological Surveys and Site Investigations

The principle of a geotechnical site investigation is to determine the soil layering of the structures planned at the well location and measure the engineering properties, e.g., *density, strengths, and other characteristics* of the soils. Investigations form an important part of structural design work and are not required just to fulfill permitting needs. Investigation should include shallow sampling and in situ testing, laboratory testing offshore and later more onshore as required on a project-by-project basis.

API RP 2T recommends deepwater site investigation that includes a geology, geophysical survey, and geotechnical investigation covering the area that subsea systems are installed on or below the seabed to assess all relevant hazard, e.g. *as outlined in table below.* This is dependent upon area, sampling, and in situ testing conducted, based on requirement of size,

A B C D	E	F	G	H	I	J
Soil Description	Soil Log	Soil Depth (M)	Samples, Field Test and Comments			
			Samples	Test Depth	Cu/Cr (kPa)	Comments
Extremely low strength brown becoming light gray clay small black organic staining seen at bottom of core section		1.00	Core x 0.00 21.00 m	1.00	6	Torvane
Extremely low strength gray clay small black organic staining seen at top and bottom of core section		2.00	Core x 1.00 2.00 m	9.00	9	Torvance
Extremely low becoming low strength light gray clay small black organic staining seen at top and bottom of core section		3.00	Core x 2.00 3.00 m	2.88 3.00	11/3 16	Hand Vane Torvane
Extremely low strength light gray clay moderate amount of black organic staining seen at bottom of core section		4.00	Core x 3.00 4.00 m	4.00	19	Torvane
Extremely low strength light gray clay moderate amount of black organic staining seen at top and bottom of core section		5.00	Core x 4.00 5.00 m	5.00	12	Torvane
Extremely low strength light gray clay black organic staining seen at top of core section		6.00	Core x 5.00 6.00 m	6.00		
Very low becoming low strength olive gray clay black organic staining seen at top of core section		7.04	Core x 6.00 7.04 m	6.92 7.04	15/3 15/3	Hand Vane Hand Vane
Very low strength olive gray clay		7.24	Bag			

FIG. A2.1 Shallow samples summary illustration from a ±1500 m deepwater water depth location. *Reillustrated by One giant leap in 2018 from a well's example and used as a training slide by Kingdom Drilling from 2014.*

weight, and depth of subsea seafloor installations. Additional studies can further include *scour, sand waves, liquefaction, and seafloor slope instability.*

Should significant hazard and risk exist, the safest primary option is to move to the lower risk location. If not feasible, well assurance and design must assure contingent structural designs are planned.

Shallow penetration geological survey samples are obtained, evaluated, and interpreted through the use of the following methods as illustrated in Table A2.1 and Fig. A2.1.

DEFINITION OF TERMS USED TO DESCRIBE SAMPLES

Descriptive terms for soil classification and testing based on BS 5930: 1999 Amendment 2 (2010): Code of Practice for site investigation. Basic soils types as defined by particle size analysis presented in Tables A2.2 and A2.3.

Principle soil type is based on particle size distribution of the coarse fraction and of the fine fraction as determined by a series of specified hand tests supplemented by soil classification tests.

TABLE A2.1 Shallow Penetration Geological Surveys and Site Investigations Methods

Sampling Method	Depth of Investigation	General Comments
Grab sampling	A few inches below seafloor.	Grab samples are highly disturbed, and essentially provide only soil classification
Box core	Shallow investigation depth. Dependent upon shallow subsurface soil conditions.	Box samples can provide high-quality and reliable density, moisture content and strength tests on subsamples cored from the box sample on deck.
Test Tube systems	Up to 2.5 + m dependent upon shallow soils conditions.	Typically 1–3 m long and 8–10 cm in diameter. Nonreturn valve at top. Core catcher can be also installed to prevent loos soil from falling out.
Vibro-corer	Shallow investigation depth. Dependent upon shallow soil conditions.	Tube fitted with a light frame. Core partially disturbed due to vibratory motion. Density and water content assessment can be reliable, Strength often reduced due vibration effects.
Gravity corer (drop sampler)	Penetrations up to 6–8 m depending on clay strengths.	Mass of system to be deployed and dropped can be up to 1 ton. Tubes of 10 cm commonly used. Internal piston can be equipped to improve sampling quality.
Piston corer	Some systems claim up to 30 m of penetration can result.	Include a base plate that rests on seabed, linked to the corer to improve control of the piston.
In situ testing (Determines strength properties of the soils as they exist in the seabed, avoiding disturbance effects to soil during sampling.)		
Cone penetration	Shallow investigation depth. Dependent upon shallow soil conditions.	Cone-tipped tube is into the formation with end resistance and side friction measured through load cells within the body of the device. Advanced systems have also pore pressure transducers fitted.
Vane device	Shallow investigation depth. Dependent upon shallow soil conditions.	Cruciform vane is pushed into formation and rotated with torque and rotation measured.

Constructed by Kingdom Drilling for training 2014.

TABLE A2.2 Basic Soil Types by Particle Size

Type	Coarse Fraction	Particle Size (mm)	Type	Coarse Fraction	Particle Size (mm)
Gravel	Coarse	20–63.0 mm	Silt	Coarse	0.02–0.063 mm
	Medium	6.3–20.0 mm		Medium	0.063–0.02 mm
	Fine	2.0–6.3 mm		Fine	0.02–0.0063 mm
Sand	Coarse	0.63–2.0 mm	Clay	Coarse	<0.002 mm
	Medium	0.2–0.63 mm		Clay particles disperse and are easiest to jet/drill transport and remove from the well.	
	Fine	0.063–0.2 mm			

Created by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

Fine-Grained Soils

The identification and description of fine-grained soils is based entirely on a set of hand tests rather than the measurement of the particle size grading. These hand tests include *dry strength, plasticity, and dilatancy testing*. A fine soil can be described according to its consistency and plasticity as illustrated in Table A2.3 and Fig. A2.2.

TABLE A2.3 Soil Consistency Classification Parameters

Very soft	Finger easily pushed in up to 25 mm. Exudes between fingers.
Soft	Finger pushed in up to 10 mm. Molded by light finger pressure.
Firm	Thumb makes impression easily. Cannot be molded by fingers, rolls to thread.
Stiff	Can be indented slightly by thumb. Crumbles in rolling thread. Remolds.
Very stiff	Can be indented by thumb nail. Cannot be molded, crumbles.
Hard	Can be scratched by thumb nail.

Created by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

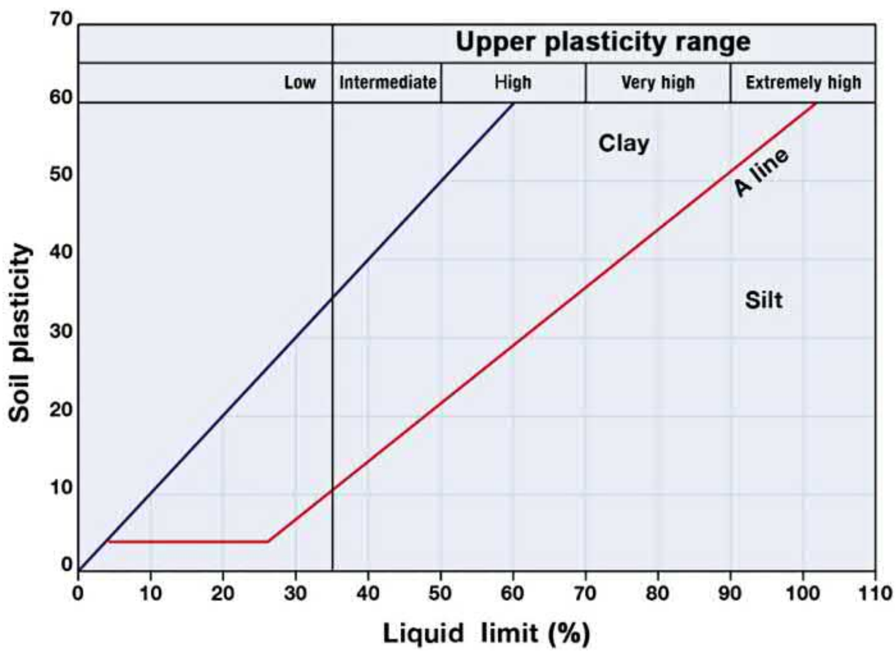


FIG. A2.2 Soil plasticity chart. *Reillustrated by One giant leap in 2018 from a well's site survey report and used as a training slide by Kingdom Drilling from 2014.*

TABLE A2.4 Soil Strength Classification Parameters

Undrained Shear Strength Classification	Undrained Shear Strength (kPa)
Extremely low	<10 kPa
Very low	10–20 kPa
Low	20–40 kPa
Medium	40–75 kPa
High	75–150 kPa
Very high	150–300 kPa
Extremely high	>300 kPa

Created by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

TABLE A2.5 Secondary Constituent Classification (Fine Soils)

Term	Principle Soil Type	Secondary Constituent
Very sandy or gravelly	SILT or CLAY	>65%
Sandy and/or gravelly	SILT or CLAY	35%–65%
Slightly sandy and/or gravelly	SILT or CLAY	<35%

Created by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

A soil lying above the A-line (see figure below) is generally identified as a *CLAY* and a soil below the A-line as a *SILT*; however, it is recognized that a soil above the A-line may be comprised of particles of *non-CLAY minerals*, i.e., <2-μm *size such as rock flour*; equally soils below the A-line are comprised clay minerals.

Soil is also classified by shear strength using the criteria presented in Table A2.4.

Secondary constituents within a fine soil further classified in Table A2.5.

Coarse Grained Soils

The description of coarse soils (*SAND* and *GRAVELS*) is *primarily performed by visual observation*. There are two problems recognized when describing *coarse soils*.

- *First*, one must consider the visual differences observed between volume and weight percentages of a sample;
- *Second*, is the correct application of the 2 mm between SAND and GRAVEL.

The correct visual description shall be in accordance with the "weight percentage," and is typically verified through conducting a laboratory particle size distribution test.

Secondary constituents within a *coarse soil* are classified (Table A2.6) as follows. All soil types described in the following order:

1. Consistency, or relative density or strength
2. Discontinuities, bedding, structure, fabric, texture

TABLE A2.6 Secondary Constituent Classification (Coarse Soils)

Term	Principle Soil Type	Secondary Constituent
Slightly sandy or gravelly	SAND or GRAVEL	<5%
Sandy or gravelly	SAND or GRAVEL	5%–20%
Very sandy or gravelly	SAND or GRAVEL	>20%
Sandy/gravelly	SAND/GRAVEL	About equal proportions
Slightly clayey or silty and/or sandy and gravelly	SAND and/or GRAVEL	<5%
Clayey or silty and/or sandy or gravelly	SAND and/or GRAVEL	5%–20%
Very clayey or silty and/or sandy or gravelly	SAND and/or GRAVEL	>20%

Created by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

3. Color
4. Grain size, secondary constituents
5. Minor constituents
6. Particle shape, grading, and composition of principal soil types
7. Principle soil type
8. Additional information

CLAY FURTHER CLASSIFICATION

Clay type soils are generally characterized by *the undrained shear strength, the submerged unit weight, the water content, and the plasticity parameters*. The consistency of clays is related to the undrained shear strength. However, of note is that the American (ASTM) and British (BS) standards do not use identical values (Table A2.7). The undrained shear strength values *S*u can be derived in the laboratory from unconfined unconsolidated tests (UU).

On site the values can be further estimated from the results of the *Standard Penetration Test (SPT) or Cone Penetrometer Test (CPT)*. An approximate relation between shear strength and the test values is shown in Table A2.8.

TABLE A2.7 Undrained Shear Strength (kPa)

Consistency of Clay	ASTM D-2488 (kPa/psi)		BS CP-2004 (kPa/psi)	
Very soft	0–13 kPa	0–1.9 psi	0–20 kPa	0–3 psi
Soft	13–25 kPa	1.9–3.6 psi	20–40 kPa	3–6 psi
Firm	25–50 kPa	3.6–7.3 psi	40–75 kPa	6–11 psi
Stiff	50–100 kPa	7.3–14.5 psi	75–150 kPa	11–22 psi
Very stiff	100–200 kPa	14.5–29 psi	150–300 kPa	22–44 psi
Hard	200–400 kPa	58–116 psi	300–600 kPa	44–88 psi
Very hard	>400 kPa	>116 psi	>600 kpa	>88 psi

Created and updated with field units by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

TABLE A2.8 Shear Strength and Test Values Relationships

S_u (kPa)	S_u (psi)	UU (kPa)	UU (psi)	SPT (N)	CPT (MPa)	CPT (psi)
0–13	0–1.9	0–25	0–3.6	0–2	0.0–0.2	0–29
13–25	1.9–3.6	25–50	3.6–7.3	2–4	0.2–0.4	29–58
25–50	3.6–7.3	50–100	7.3–14.5	4–8	0.4–0.7	58–102
50–100	7.3–14.5	100–200	14.5–29	6–15	0.7–1.5	102–218
100–200	14.5–29	200–400	58–116	15–30	1.5–3.0	218–435
>200	>58	>400	>116	>30	>3.0	>435

Created and updated with field units by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

TABLE A2.9 Mechanical Resistance of Sandy Soils; Approximate Correlations

Descriptive Term	Relative Density	Angle (φ)	SPT (N)	CPT (MPa)	CPT (psi)
Very loose	< 0.15	<30	0–4	0–5	0–725
Loose	0.15–0.35	30–32	4–10	5–10	725–1450
Medium dense	0.35–0.65	32–35	10–30	10–15	1450–2176
Dense	0.65–0.85	35–38	30–50	15–20	2176–2901
Very dense	>0.85	>38	>50	>20	>2901

Created and updated with field units by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

The mechanical resistance of sandy soils is predominantly characterized by the submerged unit weight and the angle of internal friction, φ. These parameters are established in the laboratory. An approximate correlation between the angle φ and the relative density of fine to medium sand is given in Table A2.9.

Undrained shear strength of clay soil can also be estimated based on manual tests, e.g.:

- In soft clay, the thumb will easily penetrate several inches,
  - Indicating an undrained shear strength *smaller than 25 kPa*.
- In firm *(medium)* clay, the thumb will penetrate several inches with moderate effort,
  - Indicating undrained shear strength *between 25 and 50 kPa*.
- Stiff clay will be easily indented with the thumb but penetration will require great effort,
  - Indicating undrained shear strength *between 50 and 100 kPa*.
- Very stiff clay is easily indented with the thumbnail,
  - Indicating undrained shear strength *between 100 and 200 kPa*.
- Hard clay is indented with difficulty with the thumbnail,
  - Indicating undrained shear strength *larger than 200 kPa*.

Further useful guides for soil type and CPT interpretation and assessment methods are further illustrated in Fig. A2.3.

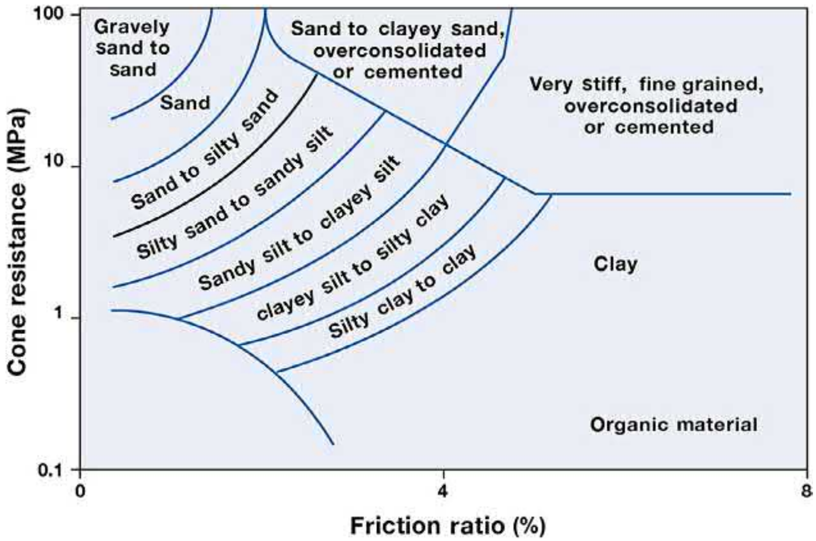


FIG. A2.3 Part of correlation for soil types (Robertson et al., 1986). *Reconstructed by one giant leap for Kingdom Drilling training. Source Offshore geotechnical engineering book principles and practices.*

ROCK STRENGTH

Rock mechanics analysis of shallow marine sediments concern mechanical properties such as Young's modulus, Poisson's ratio, cohesion strength, friction angle, and effective vertical stress. Variability of these properties factor because unlike the strength of other materials, sediment strength varies not only with depth but also with location.

Notes: Shallow marine sands containing little or no clay are frequently cohesionless with no tensile strength. Failure of sediments during an operational problem event, e.g., shallow water/gas flows, underground blow out, that can result in formation liquefaction (fluidization) should the vertical pressure gradient due to flow of formation fluids in the sand reaches or exceeds the static effective vertical stress present prior to the underground blowout.

In the upper section of the shallow marine sediments, the marine clays that predominant in many areas have low cohesion, tensile strength, and angle of internal friction. Sequences tend to behave plastically, making the effective matrix stress in the horizontal direction essentially equal to the vertical matrix stress.

Rock strength is generally described through compressive strength as presented in Table A2.10.

A rock strength classification system for soil based on the carbonate content and grain size of the soil *(Clark and Walker)* is also shown in Table A2.11.

Note: In the case of calcareous and carbonate sand layers, cone penetration results depend strongly on the degree of cementation and are highly unreliable indicators of strength. *Example*: An operational offshore pile installation went badly wrong with an estimated A$340 m loss

TABLE A2.10 Rock Classification by Compressive Strength (Included Field Units)

Descriptive Term	Compressive Strength *qv* (MPa/psi)	
Very weak	<1.25	<181 psi
Weak	1.25–5 MPa	181–725 psi
Moderately weak	5–12.15 MPa	725–1762 psi
Moderately strong	12.5–50 MPa	1762–7252 psi
Strong	50–100 MPa	7252–14,504 psi
Very strong	100–200 MPa	14,504–29,008 psi
Extremely strong	>200 MPa	>29,008 psi

Created and updated with field units by Kingdom Drilling based on BS 5930, 1999 amendment 2 code of practice for site investigation.

resulting to the operator to research and resolve the problem. Essentially CPT data had evidently indicated relatively strong sand. What was present was a weakly cemented soil that appeared to be strong via CPT but was in fact brittle. During subsequent pile installations, the first pile placed on the seabed consequentially fell 60 m into the seabed at the start of driving because underlying the sands were much weaker formations than interpreted and evaluated. The learning message is to assure good and evident data are obtained (*Note*: at times capital has to be spent to prevent expensive operating failure to achieve this). Precise assessment to be assured.

GEOTECHNICAL BOREHOLES

Geotechnical dynamically positioned drillships are not always ideally suited, available of affordable in regards to deep and ultradeep environments.

Deeper boreholes below the seafloor can take several days to complete and several boreholes may be required for a given location.

Technical standards include ASTM D 6032 (ASTM 2009) and BS 5930 (BSI 1999). All onshore technologies, techniques, and standard apply offshore (Lunne, 2001).

A good introduction to geotechnical borehole drilling for offshore wells is provided in Offshore Survey and Site Investigations, Chapter 3, pages 49–92, within the Institute of Civil Engineers book *Offshore Geotechnical Drilling*, by E.T.R Dean, reprinted in 2014.

Other In Situ Testing Devices

Other in situ testing devices to consider and assess on a geotechnical project basis are:

1. Natural gamma ray logger can be used to detect soil layering (Ayres and Theilan, 2001).
2. Electrical conductivity, for water content and related parameters (Campanella and Kohan, 1993).

TABLE A2.11 Rock Strength Classification System for Soil Based on the Carbonate Content and Grain Size of the Soil

Increased lithification	Cementation of soil	Approx. rock strength	Increasing grain size of particulate depositis →				Total carbonate content (%)
			0.002 mm	0.063 mm	2 mm	60 mm	
	Very weak to firmly cemented soil	Very weak	Carbonate clay	Carbonate silt	Carbonate sand	Carbonate gravel	90
				Siliceous carbonate silt	Siliceous carbonate sand	Mixed carbonate and non-carbonate gravel	50
			Calcareous clay	Calcareous silica silt	Calcareous silica sand		10
			Clay	Silica silt	Silica sand	Silica gravel	
	Well cemented soil	Weak to moderate weak	Cakilutite (carb. claystone)	Calcisiltite (carb. sandstone)	Calcarenite (carb. sandstone)	Calcirudite (carb. conglom. Or breccia)	90
			Clayery calcilutute	Siliceous calcisiltite	Siliceous calcarenite	Conglomeratic calcirudite	50
			Calcareous claystone	Calcareous siltstone	Calcareous sandstone	Calcareous conglomerate	10
			Claystone	Siltstone	Sandstone	Conglomerate or breccia	
	(well cemented rock)	Moderate strong to strong	Fine-grained limestone		Detrital limestone	Conglomerate limestone	90
			Fine-grained agrillaveous limestone	Fine-grained siliceous limestone	Siliceous detrital limestone	Conglomerate limestone	50
			Calcareous claystone	Calcareous siltstone	Calcareous sandstone	Calcareous conglomerate	10
			Claystone	Siltstone	Sandstone	Conglomerate of breccia	
		strong to extremely strong	Crystaline limestone or marble				50
			Conventional metamorphic nomenclature applies in this section				

Reillustrated by One giant leap in 2006. Used as a training slide by Kingdom Drilling from 2006.

3. Seismic cone, for shear wave velocity (Campanella and Davies, 1994).
4. BAT/GDP (deepwater gas probe), to sample pore water and pore gas (Mokkelbost and Strandvik, 1999).
5. Piezoprobe, to measure pore pressure and coefficient of consolidation (Dutt et al., 1995).
6. Nuclear density probe, to measure the in situ density of sands.
7. Hydraulic fracture test, to assess conductor setting depth (Aldridge and Haland, 1991).

DEVELOPING A GEOTECHNICAL SITE MODEL

A geotechnical model describes the conditions at the well site to form a sufficient basis for geotechnical design. API RP 2A and ISO 19902 indicate that the model should be based on an integrated assessment of geophysical and geotechnical data.

Model shall include:

1. a description of the site conditions,
2. how these were formed in the geological and recent past,
3. an assessment of how conditions may change over the design life of the well.

Model starts at the desk study stage, and evolves as data are obtained. Important aspects of the model include simplifying the soil sedimentary layering at the location, together with the engineering properties of each profiled layer. Some of the fundamentals required are:

1. Layer thickness
2. Submerged unit weight
3. Undrained shear strength for clay layers
4. Relative density and/or friction angle for granular layers
5. Carbonate content for granular layers.

Information will come from the site survey and then added to during the subsequent laboratory testing. Site results are normally present through a detailed borehole log as illustrated in Fig. A2.4 supported by graphs and charts.

Fig. A2.4 also shows the importance and variant types of response obtained in clay, sand and clayey sand and how data can then be interpreted to good effect.

Finally, a step-by-step example of geotechnical site model development is presented in Fig. A2.5.

Of prominent note is that soils data can be complex and not always as complete as ideally desired.

Conflicts between laboratory analysis and reports to assure anything of importance is included that may affect engineering calculations. Plus engineering ability to recognize and analyze design calculations that only use simplified models, demand sound engineering judgment, knowledge, skills, and experience to deliver a disciplined method and approach desired (Fig. A2.6 and Table A2.12).

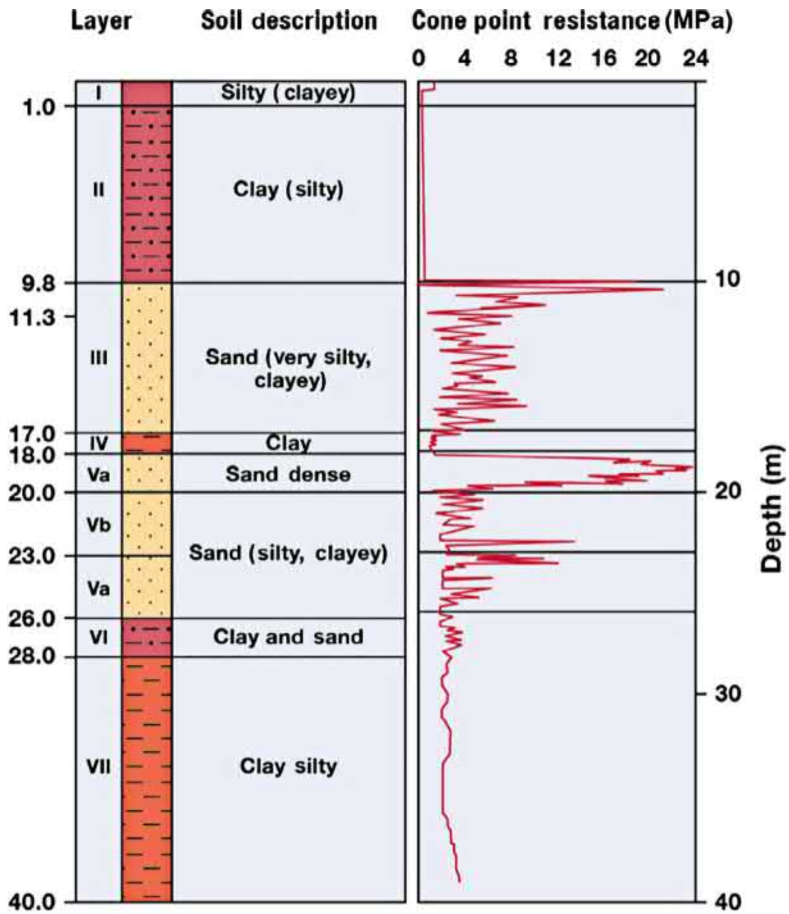


FIG. A2.4 CPT record assembled by joining several together. *Reillustrated by One giant leap in 2018 from a well's records assembled (Bayne and Tjelta, 1987) and used as a training slide by Kingdom Drilling. Original Source Offshore geotechnical engineering book principles and practices.*

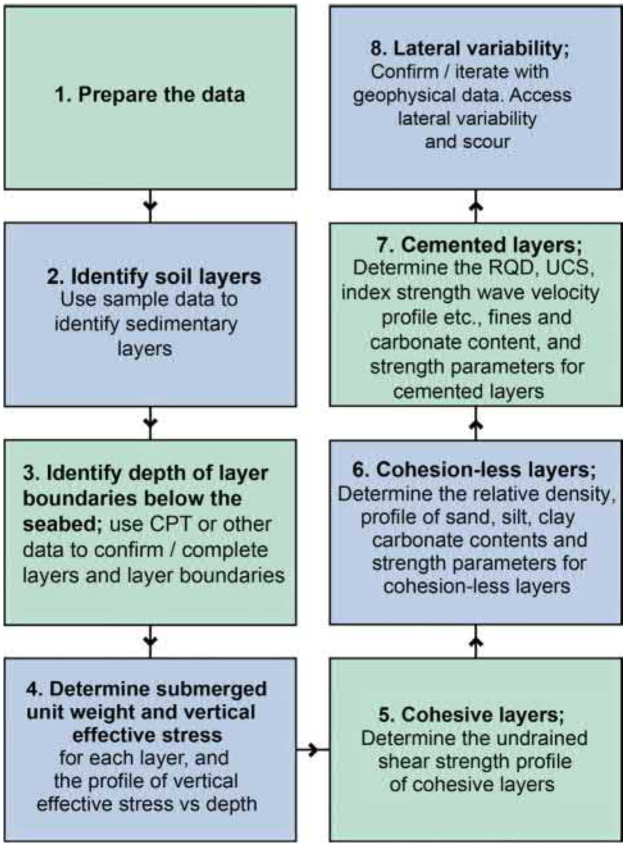


FIG. A2.5 Step for developing a Geotechnical model for an offshore (deepwater) well. *Reillustrated by One giant leap in 2018. Has been used as a training slide by Kingdom Drilling. Original source https://simple.wikipedia.org/wiki/Particle_size.*

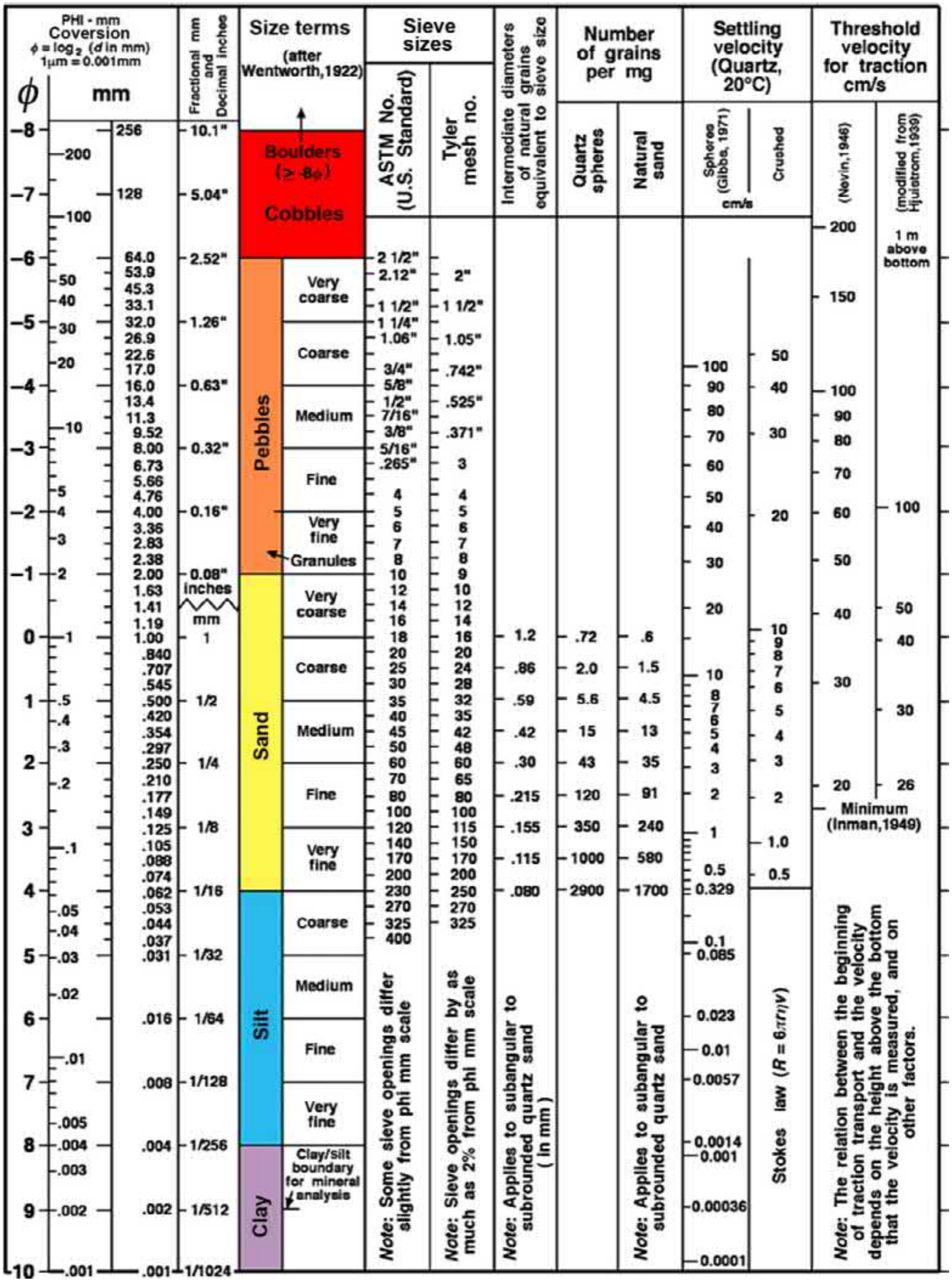


FIG. A2.6 Wentworth scale. *Source: https://pubs.usgs.gov/of/2006*.

TABLE A2.12 Particles Size (Grain Size)

φ Scale	Size Range (metric)	Size Range (approx. in.)	Aggregate Name (Wentworth Class)	Other Names
<−8	> 256 mm	>10.1	Boulder	
−6 to −8	64–256 mm	2.5–10.1	Cobble	
−5 to −6	32–64 mm	1.26–2.5	Very coarse gravel	Pebble
−4 to −5	16–32 mm	0.63–1.26	Coarse gravel	Pebble
−3 to −4	8–16 mm	0.31–0.63	Medium gravel	Pebble
−2 to −3	4–8 mm	0.157–0.31	Fine gravel	Pebble
−1 to −2	2–4 mm	0.079–0.157	Very fine gravel	Granule
0 to −1	1–2 mm	0.039–0.079	Very coarse sand	
1–0	½–1 mm	0.020–0.039	Coarse sand	
2–1	¼–½ mm	0.010–0.020	Medium sand	
3–2	125–250 μm	0.0049–0.010	Fine sand	
4–3	62.5–125 μm	0.0025–0.0049	Very fine sand	
8–4	3.9063–62.5 μm	0.00015–0.0025	Silt	Mud
>8	<3.9063 μm	<0.00015	Clay	Mud
>10	<1 μm	<0.00004	Colloid	Mud

Source: Created by Kingdom Drilling 2002 from general chart provided in Wikipedia. https://simple.wikipedia.org/wiki/Particle_size.

REFERENCE STANDARDS

API, 1997, RP2T, Recommended practice for planning, designing and constructing tension leg platforms. American Petroleum Institute.

API, 2000, RP2A, Recommended practice for planning, designing and installing fixed offshore platform's, 21st ed. American Petroleum Institute.

API, 2005, RP2SK, Design and analysis of station keeping systems for floating structures. American Petroleum Institute.

BSI 1990, BS 1377, Methods of test for soils for civil engineering purposes. British Standards Institution.

BSI 1999, BS 5930, Code of practice for site investigations. British Standards Institution.

DNV, 1992, Classification notes 30.4, foundations. Det Norske Veritas.

DNV, 2002, Design and installation of plate anchors in clay. DNV-RP-E302. Det Norske Veritas.

DNV-RP-C203, Fatigue design of offshore steel structures. Det Norske Veritas.

ISO, 2005, International Standard ISO 1901-7. Petroleum and natural gas industries. Specific requirements for offshore structures. Part 7. Station keeping systems for floating offshore structures and mobile offshore drilling units. International Standard Organization.

Bibliography

Aldridge, T.R., Haland, G., 1991. Assessment of conductor setting depth. Paper OTC 6713. In: Offshore Technology Conference.

Ayres, A., Theilan, F., 2001. Natural gamma-ray activity compared to geotechnical and environmental characteristic of near surface marine sediments. J. Appl. Geophys. 48 (1), 1–10.

Baldi, G., Bellotti, R., Ghionna, V., Jamiolkowski, M., Pasqualini, E., 1986. Interpretation of CPT's and CPTU's: 2nd Part: Drained penetration of sands. In: Proceedings of the 4th International Geotechnical Seminar, Singapore, pp. 143–156.

Bayne, J.M., Tjelta, T.I., 1987. Advanced cone penetrometer development for in-situ testing at Gullfaks C. Paper OTC 5420. In: Offshore Technology Conference.

Campanella, R.G., Davies, M.P., 1994. The seismic piezocone: a practical site investigation tool. In: Geophysical Characterization of Sites, ISSMFE; Technical Committee No 10 for XIII ICSMFE, New Delhi, India. Balkema.

Campanella, R.G., Kokan, M.J., 1993. A new approach for measuring dilatancy in saturated sands. Geotech. Test. J., ASTM 16 (4), 485–495.

Clark, A.R., Walker, B.F., 1977. A proposed scheme for the classification and nomenclature for use in engineering description of Middle Eastern sedimentary rocks. Geotechnique 17 (1), 93–99.

Dutt, R.N., Doyle, E.H., Collins, J.T., Ganguly, P., 1995. A simple model to predict soil resistance to driving long piles in deepwater normally consolidated clays. Paper OTC 7668. In: Offshore Technology Conference.

Ehlers, C.J., Chen, J., Roberts, H.H., Lee, Y.C., 2005. The origin of near seafloor 'crust zones' in deepwater. In: Gourvenec, S., Cassidy, M.J. (Eds.), Frontiers in Offshore Geotechnics (ISFOG 2005). Taylor and Francis, pp. 927–933.

Lunne, T., 2001. In situ testing in offshore geotechnical investigations. In: Proceedings of the International Conference on In Situ Measurement of Soil Properties and Case Histories, Bali, pp. 61–78.

Mokkelbost, K.H., Strandvik, S., 1999. Development of NGI's Deepwater Gas Probe, DGP. In: Proceedings of Conference on Offshore and Nearshore Geotechnical Engineering, Geoshore, Panvel, India, pp. 107–112.

Robertson, P.K., Campanella, R.G., Gillespie, F.G., Grieg, J., 1986. Use of piezocone data. In: ASCE Specialty Conference.

Index

Note: Page numbers followed by *f* indicate figures, *t* indicate tables, and *b* indicate boxes.

E

H

I

J

K

L

M

P

V

W

DEEPWATER DRILLING

WELL PLANNING, DESIGN, ENGINEERING, OPERATIONS, AND TECHNOLOGY APPLICATION

PETER AIRD

Deepwater Drilling is a planning, design, engineering, and operations guide for exploration and appraisal wells. Emphasis is based on the drilling and well operating challenges, hazards, and risks that exist in deepwater. This specialized guide provides field and project-based illustrations, checks, lists, practical examples, case studies, and step-by-step "how-tos" designed to deliver each deepwater work scope for managers, leaders, supervisors, and teams to meet safety, profit, and loss prevention benefits. Deepwater subject matters are scrutinized ranging from geological, seismic, pressure, metocean, project management, to the evident physical, people, and paper standards aspects of well planning, design, engineering, operating principles, and practices. Specific drilling guidelines cover the well life cycle of deepwater operations, data acquisition, pressure management, well control assurance, and integrity. Technology and advanced drilling adaption changes of rig equipment, systems, dual gradient, managed-pressure, and surface BOP drilling are among essential elements addressed. This first edition is driven by project and field operating experience. It offers a reference for organizations, teams, and individuals seeking knowledge and experience to widen the deepwater skills and development gaps that exist today.

KEY FEATURES

- Gain practical authored experience of know-how, leadership, training, well planning, design, engineering, and operational implementation
- Master the drilling and life cycle assurance of deepwater exploration and appraisal wells
- Develop the skills to SEE "Safe, Effective, and Efficient" deepwater wells

About the Author

Peter Aird (*CEng CMarEng MMarEST)* is a specialized drilling consultant based in Fife, Scotland. He formed Kingdom Drilling Services Ltd in 1993 to provide well design, engineering, and drilling operations training and consulting to serve an extensive list of operating and national oil clients worldwide (Shell, BP, Conoco, Kerr-McGee, Marathon, Maersk Oil, Total, Repsol, Norsk Hydro, Centrica, Enterprise Oil, Lundin, Cairn Energy, Sasol, Petronas, CNOOC, ONGC, PDVSA, Pemex). He is a UK Chartered Engineer with a master's degree in drilling engineering from Robert Gordon University (2002). Peter completed his Shell Round 1 and 2 drilling supervisory competency programs in 1982 and 1985, and has further marine engineering qualifications from the Edinburgh Nautical College and Glasgow Caledonian University (1979/1976). He has delivered world-class drilling team projects from 1987 and from 1998 has additionally produced and delivered drilling and well engineering skills training and development programs to widen his own personal skills gap to then share and translate to others.

Related Titles

- Handbook of Offshore Oil and Gas Operations by James Speight / 978-1-85-617558-6
- Offshore Structures: Design, Construction, and Maintenance by Mohammed El-Reedy / 978-0-12-385475-9
- Offshore Operations Facilities: Equipment and Procedures by Huacan Fang and Menglan Duan / 978-0-12-396977-4

Technology and Engineering/Petroleum

ISBN 978-0-08-102282-5

9 780081 022825

ELSEVIER

G|P
Gulf Professional Publishing
An imprint of Elsevier
elsevier.com/books-and-journals