DESIGN CONCEPT FOR A SUBSEA WELLHEAD SUBJECT TO ICEBERG CONTACT FOR MARGINAL FIELD DEVELOPMENT - GRAND BANKS OF NEWFOUNDLAND

MAZEN DOHA

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By

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A thesis submitted to the School of Graduate Studies in partial fulfillment of the requirements for the degree of

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Abstract

With the key drivers of rising energy demand and increasing prices, major operators are expanding their search for new hydrocarbon reserves, moving into deeper water, more hostile environments and targeting smaller pools and more remote reserves.

Thus, other type of challenges rise ahead, which require developing of new innovative, cost effective, and safe technology to put these fields into production.

One of Canada's important offshore areas that is expected to feed into the continental energy market is the East Coast offshore fields located on the Grand Banks of Newfoundland and Labrador. In addition to the conventional challenges that accompany any offshore field development activity, wellhead protection from icebergs remains one of the most important challenges and takes the priority in any intended development on the Grand Banks. So far, several design strategies for iceberg risk mitigation have been suggested, and some are being already adopted, such as the glory hole concept which proved to be an efficient protection measure but at a high capital cost.

The thesis work gives a general overview of the oil and gas industry on the Grand Banks with a focus on the various strategies and concepts for the protection of the wellheads on the Grand Banks, and their application for marginal fields' development.

The present study favors the use of a shear link wellhead as a protection mechanism against floating and gouging icebergs, and accordingly an evaluation study was done for this system.

A detailed structural analysis was conducted, by performing a study to determine the wellhead section stresses generated due to a floating /gouging iceberg wellhead accidental

interaction. The response of the well upper section (conductor and wellhead) to ice gouges and to floating icebergs events was analyzed by a 3-D finite element numerical model using ABAQUS software. The parametric computations and creation of the ABAQUS input file employed a MATLAB code. The result was a better understanding of the interaction mechanism between floating/gouging icebergs, soil mechanics and the subsea wellhead sections, where not much detailed engineering, structural and analytical work has been done previously.

The calculated stresses and their distribution along the wellhead sections were used to address the structural reliability and integrity of the well by highlighting the stress levels and loads on: the down-hole safety valves, the isolation valve on top of the hanger, the conductor stress limit (buckling), completion tubing stress limits (buckling and rupture), the shear key and the wellhead components. Another purpose for this analysis was to present a guide for the detailed engineering, which is not addressed in this thesis, of the shear link and the suggested isolation valve on top of the tubing hanger.

A detailed overview of well structure (Casing and Completion) and sealing barriers failure modes leading to leak paths and loss of well integrity is presented in the work where the probability of a leak occurrence in the event of X-mas tree displacement in the suggested system is done. Suggested intervention and work-over sequence to put the well into production following the event of an iceberg impact to the wellhead leading to the loss of the X-mas tree and the upper part of the well was discussed taking into consideration the safety of the operation and highlighting the practicality of the shear link wellhead system.

ACKNOWLEDGEMENTS

I would like to greatly thank Dr. Shawn Kenny and Dr. Faisal Khan, members of the Engineering and Applied Science at Memorial University for their supervision, guidance and patience during the completion of this work.

I highly appreciate the opportunity of being at C-CORE and the financial support that Dr. Shawn Kenny made it available for me, which was a big motivation to complete my work in a field of my interest, and gain a lot of knowledge and experience.

My thanks to Vincent Morgan and Tony King of C-CORE for guidance on a variety of technical issues that contributed to the thesis.

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LIST OF ABBREVIATIONS

BOP	Blow Out Preventer
CAPP	Canadian Association of Petroleum Producers
C-NLOPB	Canada-Newfoundland Offshore Petroleum Board
3D/2D	Three Dimensional/ Two Dimensional
FEA	Finite Element Analysis
FTA	Fault Tree Analysis
GBS	Gravity Base Structure
HMDC	Hibernia Management and Development Company
HOST	Hinge Over Subsea Template
IIP	International Ice Patrol
IWCS	Intelligent Well Completion System
JIP	Joint Industry Projects
Mbbls	Million Barrels
MODU	Mobile Offshore Drilling Unit
MSYS	Minimum Specified Yield Strength
MTTF	Mean Time to Failure
NGL	Natural Gas Liquids
NRV	Non Return Valve
OTC	Offshore Technology Conference
SSCSV	Subsurface Surface Controlled Safety Valve
Tcf	Trillion Cubic Feet
X-mas	Christmas Tree

1. Introduction

Booming world demand for oil and natural gas is expected to grow increasingly despite record high oil prices now a day.

The main driving momentum for oil demand is the continuous growth and development of the industrializing economies in Asia which is putting more pressure on the market, at a time where there have been a lot of geopolitical tensions in many places where oil and gas comes from.

The relatively easily accessible hydrocarbon reserves both onshore and offshore have been developed in the recent decades and most of the present producing fields have entered the mature region and are in a declining production stages which will lead to their depletion in the near coming years.

There is no question that Canada remains a future store house to help meet the world energy demand with the enormous available untapped reserves of oil and gas.

One of Canada's important areas for development and that is expected to feed into the energy market is the East Coast offshore fields located on the Grand Banks and Southern Labrador.

The Grand Banks, a submarine plateau rising from the continental shelf, combined with the Northeast Newfoundland Shelf from Laurentian Channel to southern Labrador, and including Flemish Cap, is about 450 000 km^2(Figure 1).

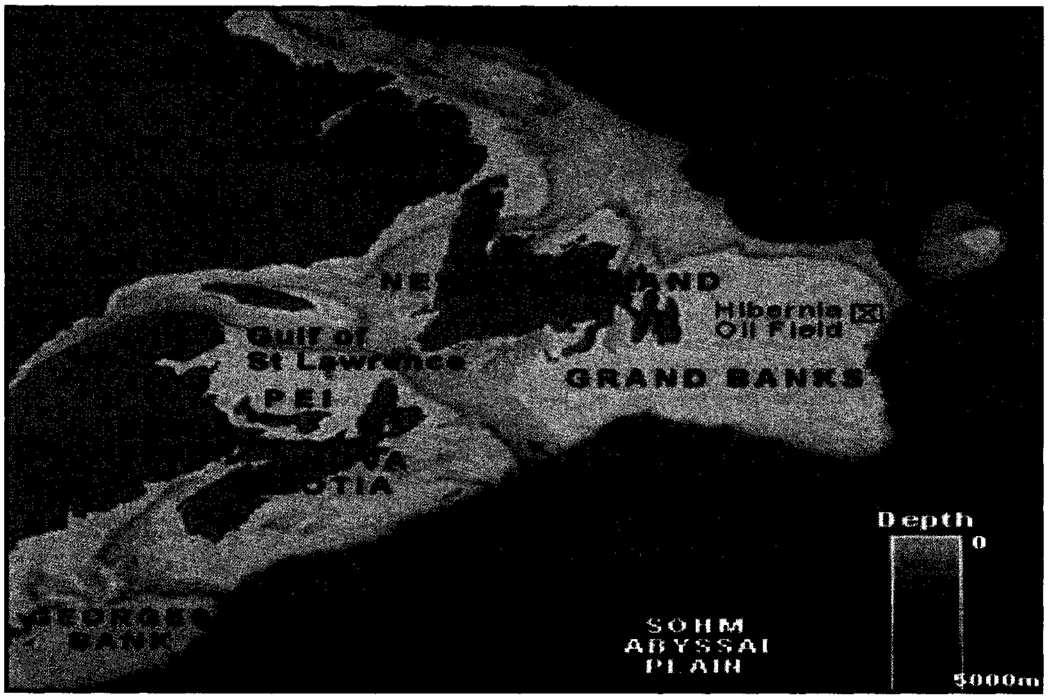


Figure 1 The Grand Banks and the Northeast Newfoundland shelf bathymetric (The Canadian Encyclopedia, 2006)

Water depths over the Grand Banks are generally less than 100 m, and the total area for water depths shallower than 200 m is 282 500 km^2.

This area is most known for its daunting offshore environmental conditions and presence of two major water currents.

The Labrador Current is a cold current which flows from the Arctic Ocean south along the coast of Labrador and passes around Newfoundland, mixes the warm, and swift Gulf stream that originates in the Gulf of Mexico (Figure 2).

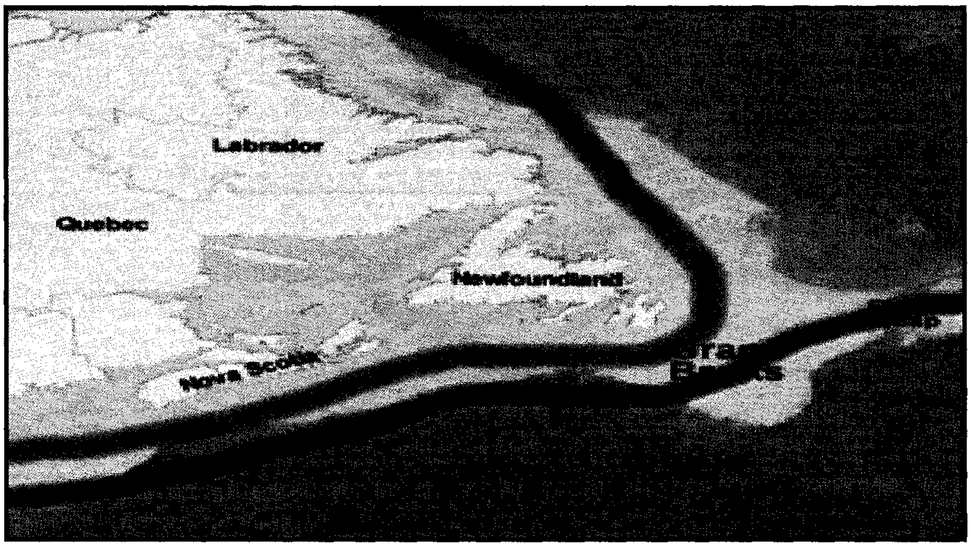


Figure 2 The Labrador Current and Gulf Stream paths flowing (Wikipedia Encyclopedia, 2007)

Intense storms are quite frequent, particularly during the winter months, heavy seas, dense blankets of fog resulting from the warm air masses moving out of the Gulf Stream over the colder Labrador Current water, vast migrating fields of sea ice and huge icebergs carried by the Labrador current mainly as a continuation of the West Greenland Current and the Baffin Island Current (Figure 3), all of those phenomena are very common features of the Grand Banks harsh environment.

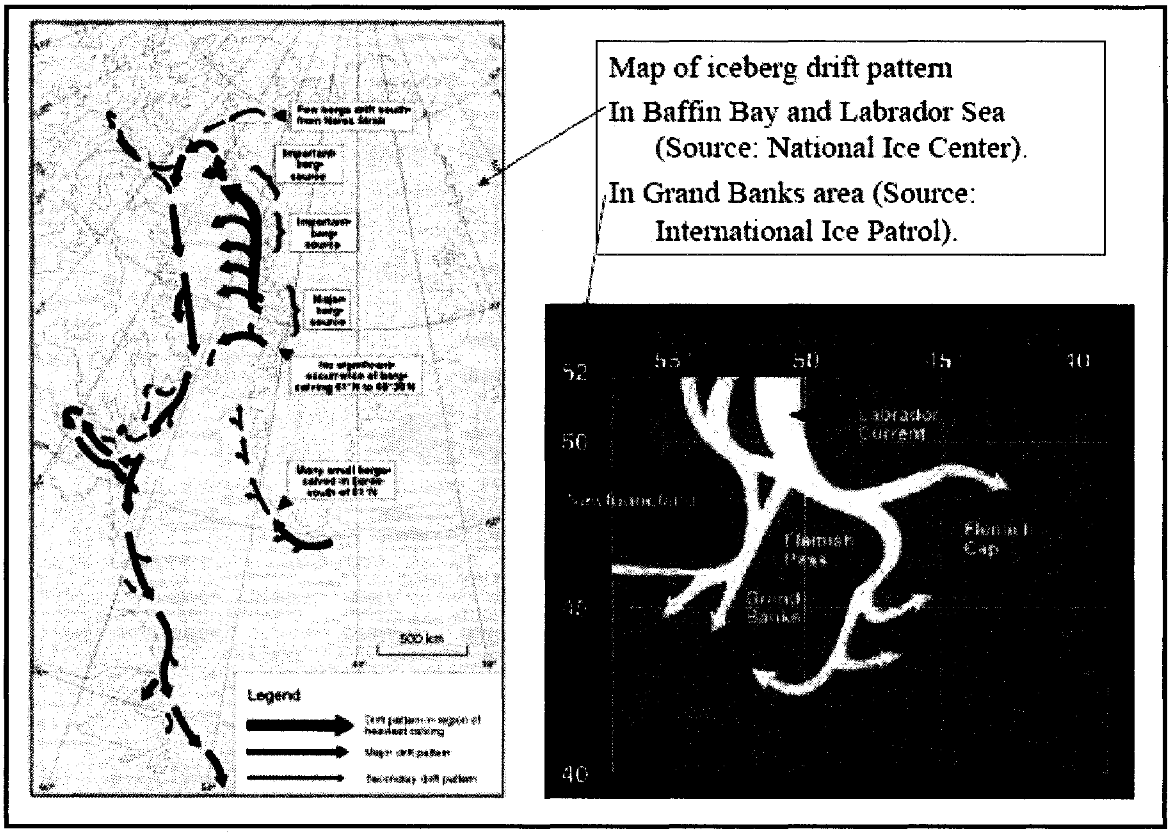


Figure 3 Overview of the with iceberg drift pattern in Labrador Sea and Grand Banks area (I. Peterson, 2005)

The Grand Banks have become a point of focus for oil and natural gas exploration, where considerable petroleum reserves have been discovered in a number of oil fields some of them are already in production and other fields are either in development, or are under technical and commercial study stages (CAPP, 2006).

1.1 Ice Environment Challenges

For the offshore oil and gas industry at the Grand Banks, the biggest challenge comes from the huge icebergs which are of enormous weights and dimensions, could range from several hundreds thousands of tonnes to small bergs weighing several hundreds of tonnes.

Traveling by the speed gained from the prevailing Labrador Current along Canada East Coast, icebergs could be either floating as shown in Figure 4 or some of bigger drafts could be scouring the shallow depth Grand Banks sea bed. (Egil Tveit et al., 2000)

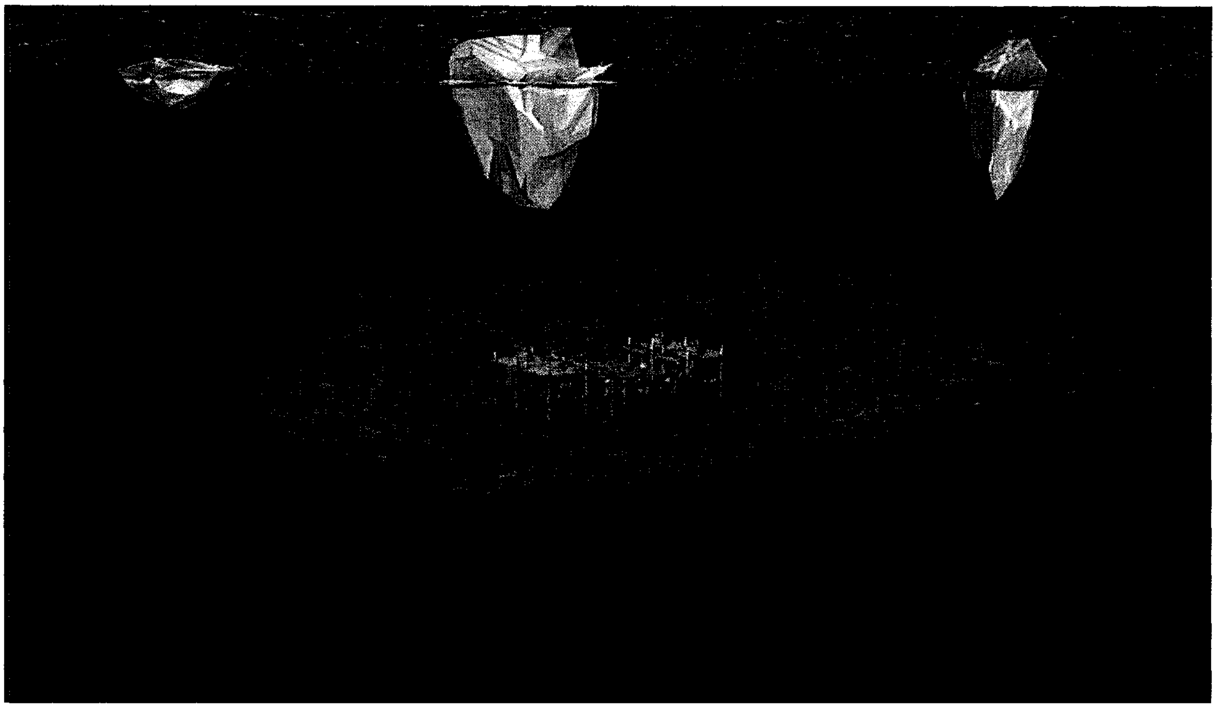


Figure 4 Artist's Impression of floating icebergs in the vicinity of a glory hole (Egil Tveit et al. 2000)

These icebergs can be a real threat not only for the above sea structures but as well to the subsea infrastructure.

It is obvious that any development plan for the offshore East Coast fields has to take into account management of the risk resulting from the traveling icebergs in the Grand Banks fields' vicinities.

Several iceberg interception methods and risk management techniques have been adopted so far to protect the existing production facilities on the Grand Banks and have proved effectiveness in wellhead protection as part of the subsea infrastructure such as:

- Iceberg towing for course deviation away from the oil fields.
- Floating facility planned disconnect upon the approach of any un-manageable iceberg (Terra Nova, Figure 5).

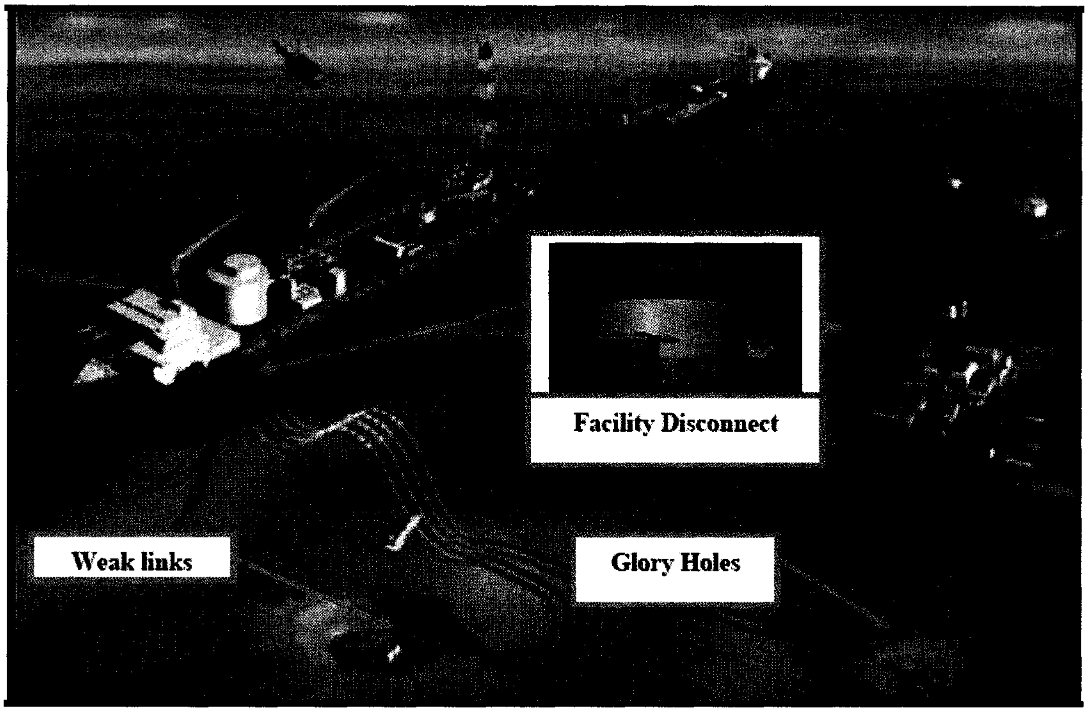


Figure 5 Terra Nova field layout schematic. (Offshore Technology Website)

Several alternative concepts have been suggested specifically for wellhead protection, such as the:

- Caisson Wellhead: Used on some exploration wells on the Grand Banks fields and later plugged and abandoned.
- Rock / Concrete Berms: Considered as an option at the beginnings of Terra Nova development and later was overlooked, due to the large masses required to absorb the iceberg impact energy and high associated cost (S. Allen, 2000).

- Disconnect–able X-mas tree: As suggested by Helge Skorve (ExxonMobil) to disconnect the X-mas tree and mobilize on the seabed by pulling once a serious iceberg threat interaction occurs.

1.2 Objectives

The aim of the presented thesis is to give a general overview of the oil and gas industry at the Grand Banks offshore Newfoundland and Labrador with focus on the challenges imposed by the ice environment on the development of marginal fields from the perspective of various subsea wellhead protection concepts. The study proposes the use of the shear link as a protection mechanism for production wells in marginal fields, and suggests the use of this concept for injector wells in major fields' development.

The case study considered a single completion wellhead and the available geotechnical reports to conduct a parametric engineering analysis study. It was assumed that the wellhead was subjected to displacement caused by different scenarios of gouging/floating iceberg. The analysis resulted in output of the stresses distribution along the wellhead sections.

The shear link concept at the wellhead section as a proposed protection measure, allows in the event of an iceberg impact with the wellhead, the X-mas tree located on the sea bed with a part of the conductor and completion tubing above the tubing hanger to get sheared at a certain pre-engineered connection (See Figure 6).

The risk of losing well integrity leading to a major leak in the occasion of wellhead iceberg interference and activation of the shear link was addressed in the thesis as well by suggesting the safe and practical location of the shear link within the wellhead sections.

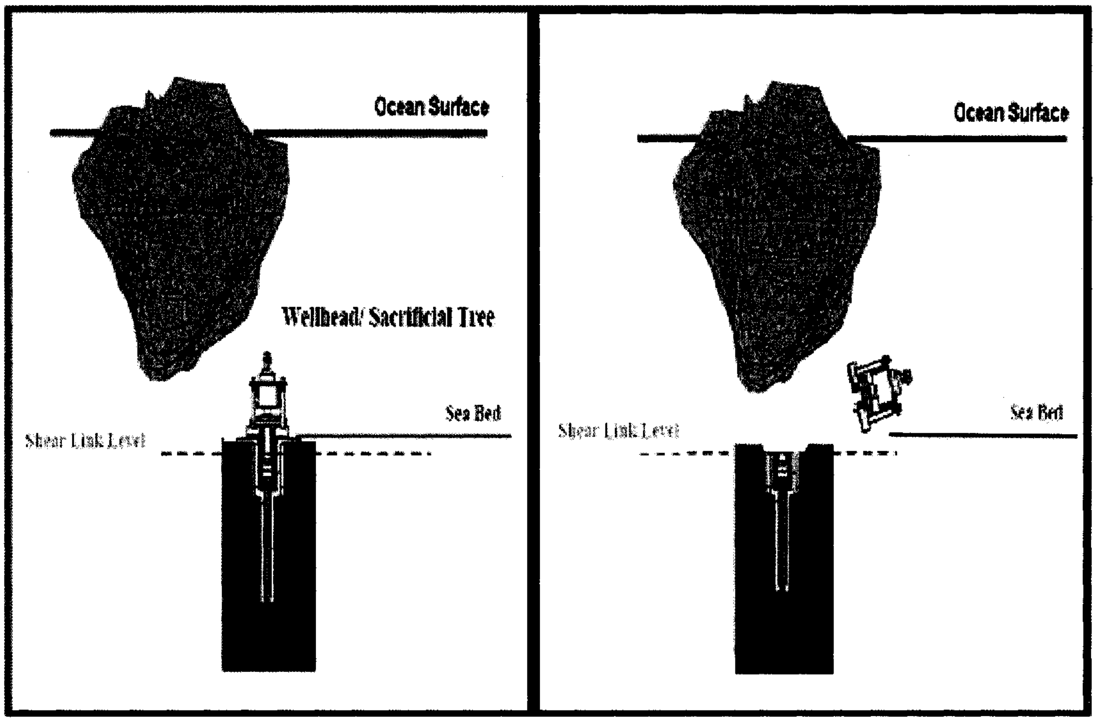


Figure 6 Illustration of wellhead shear link concept

The shear link concept is an economical solution for wellhead protection in marginal fields, since it can be installed during conventional drilling operations, and thus eliminating the costly and seasonal pre-drilling works such as dredging in preparation for the present adopted wellhead protection methods.

Another application for the wellhead shear link concept could be in major fields' development where stationary platforms are used to house wellheads or when subsea wells are placed in glory holes for floating production systems (FPSOs) developments.

The shear link can be adopted for injector wells used in reservoir flood operations for production enhancement in the major fields. Then, water injector wells can be moved outside the stationery platforms to optimum locations at the reservoir peripheries as subsea wells without the requirement for any additional protection measures such as the glory holes.

The advantage of this application will be improving the economics of the major fields employing stationery platform by freeing more slots on the platform for drilling of production wells.

For the major fields employing floating production systems, templates known as drill centers, having both production and water injector wells are placed in the glory holes for protection from icebergs. Employing the shear link concept for injector well will allow the relocation of these wells out of the glory holes to the reservoir peripheries and will result in two major benefits:

- Free the space for more production wells with in the drill center and thus improve the economics of the field by the optimum use of the costly glory holes.
- Reduce complications and costs of directional drilling operations for the injector wells.

The verification and application of the design concept of the wellhead shear link will add to the efforts and studies for the protection and risk mitigation strategies for subsea infrastructure in ice environment and open doors for cost reduction by verifying and presenting a safe, reliable and cost effective solution for standalone fields' development by improving the overall feasibility. The benefits of such study can be extended as well to improve the economics of the major fields when this concept is utilized for injector wells.

2. Grand Banks Oil/Gas Fields

2.1 General

The potential areas for hydrocarbon development within the offshore waters of Newfoundland and Labrador extend over a huge region from the Laurentian sub-basin, across the Grand Banks through the deeper waters of the Flemish Pass and Orphan Basin. (Figure 7)

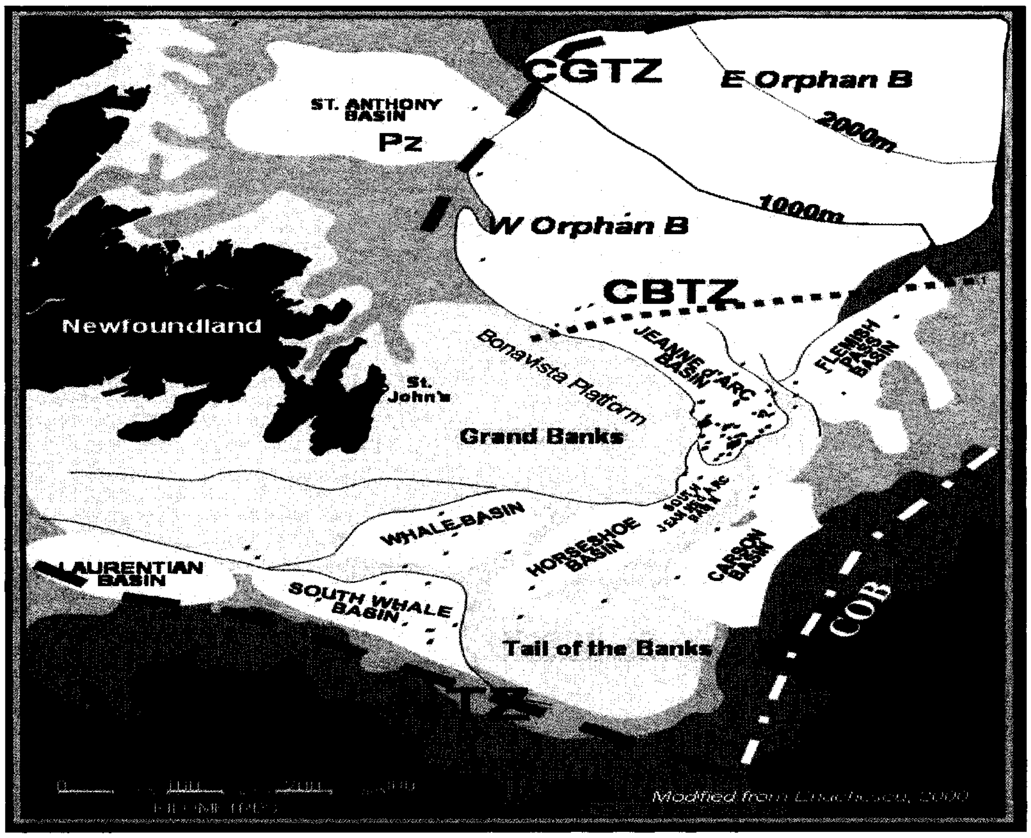


Figure 7 Distribution of Mesozoic sedimentary basins around the Grand Banks of Newfoundland (Government of Newfoundland and Labrador. Department of Natural Resources, 2001)

The first oil and gas drilling activities on the Grand Banks goes back to more than 40 years with the first well drilled in 1966 by Amoco (Government of NL and Labrador Department of Natural Resources, 2005).

After that the oil and gas exploration has gone through three major cycles during the 1970s, 1980s with the third cycle in the mid 1990s.

In 2005, hydrocarbon production from the Newfoundland and Labrador Offshore Area (The Grand Banks fields) accounted for 36% of Canada's total light crude production valued at almost $7.3 billion (C-NLOPB, 2005).

The main exploration and development focus through the past major offshore activities three cycles has been within the proven reservoirs and shallow waters of the Jeanne d'Arc Basin where the main present producing fields are located, although the recent land sales and the conducted seismic programs show that many the key players in the oil and gas industry have expanded efforts into untested areas, along the continental shelf of the Laurentian Basin, within the slope and deep water basins such as the Orphan Basin.

2.2 Reserves and Resources Estimates

According to Canada-Newfoundland Offshore Petroleum Board (C-NLOPB) June 12th 2006, the proven reserves of the Grand Banks are estimated to be 2.751 billion barrels oil of which have been produced around 622 leaving a 2129 of proven and probable reserves[(1)]/resources[(2)].

The estimated reserves[(1)]/resources[(2)] are about 10.234 Tcf. of Gas with 478 million barrels of associated liquids (C-NOPB, 2006). No gas has been produced for export purposes so far, where all the concentration of the investments is directed towards oil reserves development and production. Many studies, technical and economical evaluations have been or are currently being done in favor of developing gas fields (M. E. Enachescu, 2004).

A total of 18 fields have been discovered so far at the Grand Banks with a continuous seismic surveys activities and promising active exploration drilling programs which may lead to new discoveries or confirm more resources in the already existing fields.

More than half of the discovered 18 fields are minor fields with reserves ranging between 20 to100 Million bbls, which are not yet developed and represent a big challenge for the operating companies in their efforts to put these fields into stream, in line with the major present producing fields (Table 1).

Table 1 Estimated petroleum reserves/resources- Grand Banks (C-NOPB, 2006)

Field	Oil		Gas		NGLs[3]	
	$10^6 m^3$	Million bbls	$10^9 m^3$	10^9 cu. ft.	$10^6 m^3$	Million bbls
[redacted]						
Hebron	92.4	581	-	-	-	-
[redacted]						
West Ben Navis	5.7	36	-	-	-	-
Mara	3.6	23	-	-	-	-
Ben Navis	18.1	114	12.1	429	4.7	30
North Ben Navis	2.9	18	3.3	116	0.7	4
Springdale	2.2	14	6.7	238	-	-
Nautilus	2.1	13	-	-	-	-
King's Cove	1.6	10	-	-	-	-
South Tempest	1.3	8	-	-	-	-
East Rankin	1.1	7	-	-	-	-
Fortune	0.9	6	-	-	-	-
South Mara	0.6	4	4.1	144	1.2	8
West Bonne Bay	5.7	36	-	-	-	-
North Dana	-	-	13.3	472	1.8	11
Trave	-	-	0.8	30	0.2	1
Sub-Total	437.3	2751	169	5990	56.6	355
Produced[4]	98.9	622	0	0	0	0
Remaining	338.4	2129	289	10234	76.5	478

[1]Reserves are volumes of proven hydrocarbons that are considered to be recoverable.

[2]Resources are volumes of hydrocarbons, expressed at 50% probability of occurrence, assessed to be technically recoverable that have not been delineated and have unknown economic viability.

[3]Natural Gas Liquids.

[4]Produced oil reserves also included a small quantity of natural gas liquids. Produced volumes as of December 31, 2005.

[5]Fields that are already in production stage.

2.2.1 Drilling and Well Distribution

Although the first offshore drilling occurred in mid 1966, a total of 134 exploration and delineation wells (Figure 8) have been drilled in the Grand Banks and surrounding offshore area, most of which, 90 wells are concentrated in the Jeanne d'Arc Basin and Ridge Complex, which has been the primary focus area (C-NOPB, 2006).

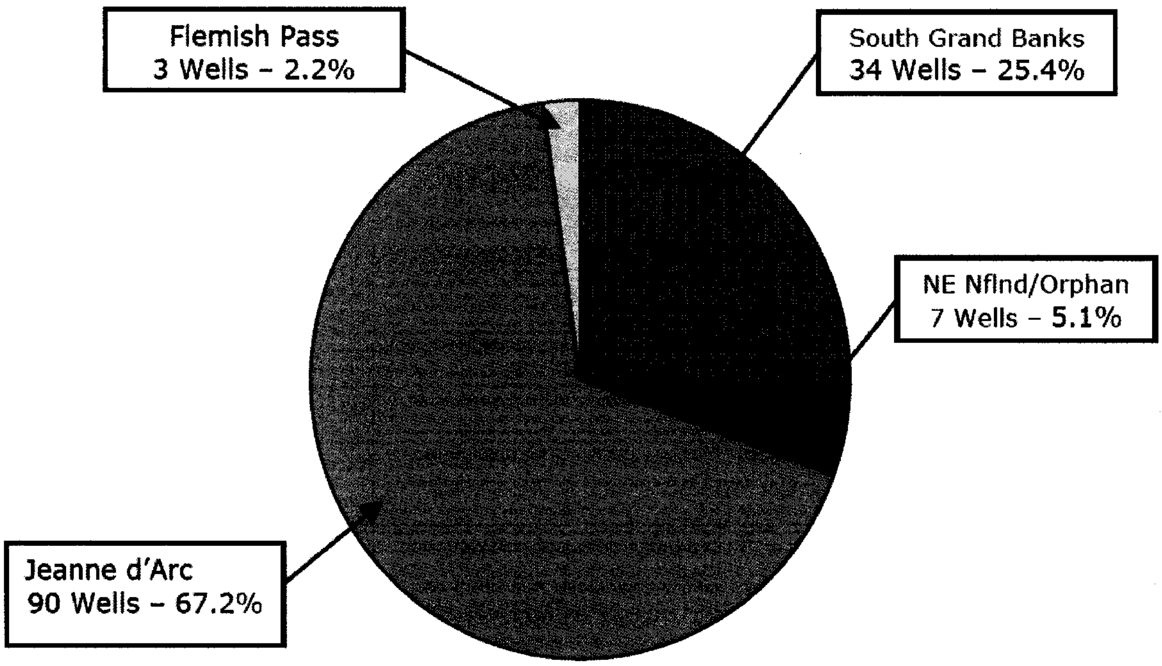


Figure 8 Well distribution on the Grand Banks. (C-NOPB, 2005)

Considering the vast areas of the Grand Banks combined with the Northeast Newfoundland Shelf around (450 000Km^2), it is very obvious that the well density is very low (one well per 5000 km^2).

These drilled exploration wells in the Jeanne d'Arc Basin and Ridge Complex have proved reserves in excess of 2.751 billion barrels of oil, and 10.234 Tcf (Table 1).

To get a better idea about the relation between the number of drilled wells (well density) and the proven resources we look at the North Sea as an example.

There are more than 2600 exploration wells in the North Sea (Department of Mines and Energy – Newfoundland and Labrador, 2001) which have proven resources of 55 billion barrels of oil and 200 Tcf of gas.

Studies of undiscovered oil resources in the Newfoundland and Labrador offshore area have focused primarily on the Northern parts of the Grand Banks and have resulted in estimates ranging from 6 to 12 billion barrels recoverable.

Studies and seismic surveys alone combined with few drilled exploration wells can not give a final and close to reality picture of the reserves.

It is obvious that extensive exploration drilling activities benefiting from the modern technologies will be employed in the near future for both the shallow waters of the Grand Banks and other Newfoundland offshore areas in effort to confirm the existing reserves and assess other major offshore basins.

As per the C-NOPB there were 85 requests for technical information processed during the 2005 – 2006 year majority of were for industrial purposes in preparation for offshore exploration activities.

2.3 Offshore Fields Characterization and Development

2.3.1 Major Fields

A major field or discovery is a field with confirmed recoverable big reserves that could support a stand-alone field development model from reservoir to export line and that can satisfy the requirements for profitability and thus justify the big expenditures on the infrastructure.

Usually it takes years of surveys, exploration drilling, technical and economical studies before any of the oil companies start any major development activities.

This is followed by an early planning phase of the project, known as Front End Engineering & Design (FEED) phase where around 80% of the entire costs are defined.

Plan for Development and Operation (PDO) of the field and a Plan for Installation and Operation (PIO) of production facilities and associated pipelines are part of the (FEED) and are very common in any offshore oil field developments.

As an example of a major discovery and development, the giant Hibernia field in discovered in 1979, a field that held more than 1244 Million bbls of oil and 1.794 Tcf of gas, was put on stream almost 18 years after it was first announced in November 1997, with an estimated cost of (CAD) $5.8 billion spent on the project (Canadian Center for Energy Information, 2004).

2.3.2 Marginal Fields

Marginal fields are fields that have low oil and gas reserves but are economically viable and profitable when produced with low capital cost.

Many marginal or minor fields on the Grand Banks, which include smaller reserves ranging between 20 to 100 Million bbls such as West Ben Nevis, Mara, Spring Dale and others (Table 1), require different approach for their development due to the prevailing ice environment challenges.

In general oil companies start to look into the development of marginal fields when the average or big size discovered petroleum reserves where initial big capital have been already invested to put these fields on stream start to decline after reaching maturity.

In other occasions the oil company operating a major oil field already knows about these marginal fields that are geographically close to an existing major oil production installation, and for economical or other reasons postponed the development of these marginal fields for later stages and has accounted for these plans by providing extra processing and storing capacity on their platforms.

The most cost efficient way of bringing marginal fields into production is by using a sub-sea production system utilizing a wet X-mas tree (Figure 9) and then connecting the marginal fields, to the production unit of the main field.

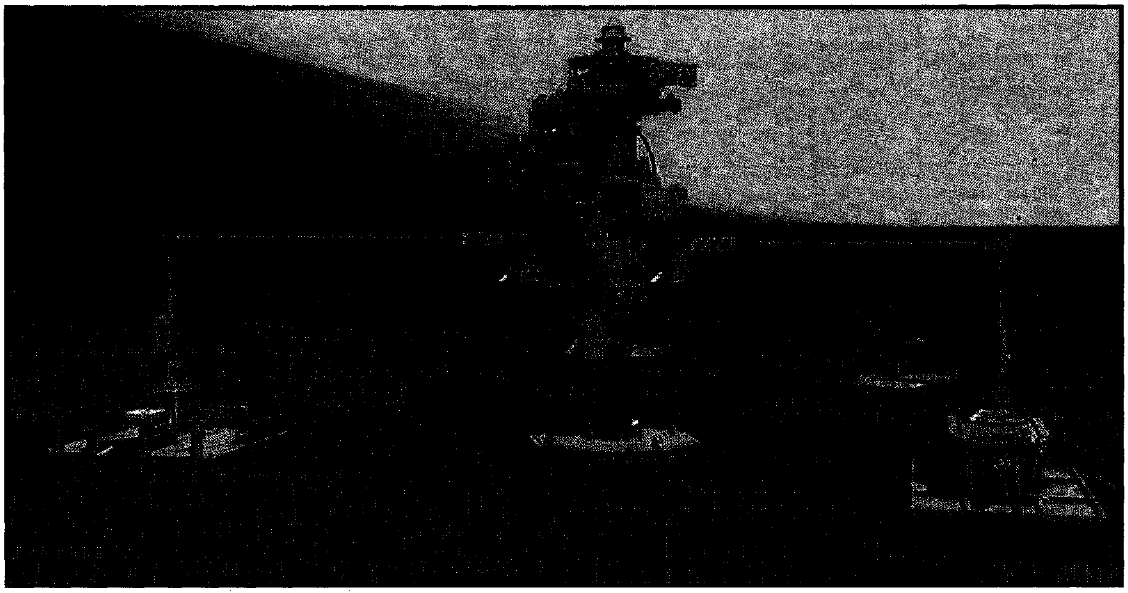


Figure 9 Schematic of a subsea tree (Offshore-Technology, 2006)

This technique is known as the tie back (Figure 10), and is widely used today in various parts of the worlds offshore areas.

New and fast developing technologies have made it economically viable to transform marginal fields into profitable assets and develop small satellite fields and tie them to the existing infrastructure of the main offshore facility kilometers away.

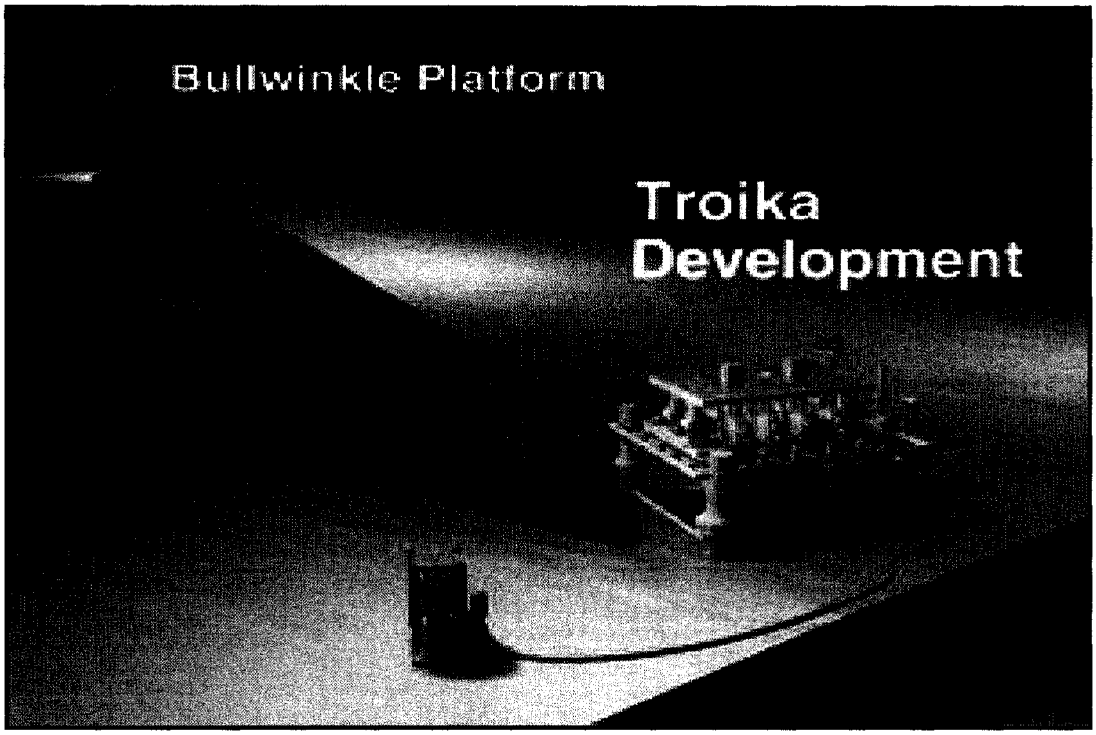


Figure 10 Troika Field Gulf of Mexico, tied back to Shell's Bullwinkle platform, 14 miles away (Offshore-Technology, 2006)

3. Icebergs on the Grand Banks

3.1 Origin and Paths

Icebergs are formed from the fragmentation or calving of huge slabs of ice at the glaciers edges that are weakened by the action of tides, and then enter into the marine environment.

The origin of the icebergs that reach the Grand Banks of Newfoundland are the 100 or so major tidewater glaciers West of Greenland where between 15,000 to 30,000 icebergs are calved each year (International Ice Patrol –IIP, 2006).

For an iceberg to reach the Grand Banks off Newfoundland, more than 2,175 miles to the south, it has to follow the dominating continental shelf currents, specifically the West Greenland, Baffin, Labrador current.

During the trip from the origin to the Atlantic Ocean area around Newfoundland, Icebergs follow different pathways. Three major paths have been identified (Marko et al. 1982; Marko et al. 1994).

Two of the paths follow the West Greenland current northerly one to Baffin Bay and the second till Davis Strait before changing direction southward towards the Labrador Sea (Figure 11). The third path which is characterized by the un-predicted movement of the icebergs that drift away the continental shelf edges in the offshore Baffin Bay and then move southward towards Labrador Sea.

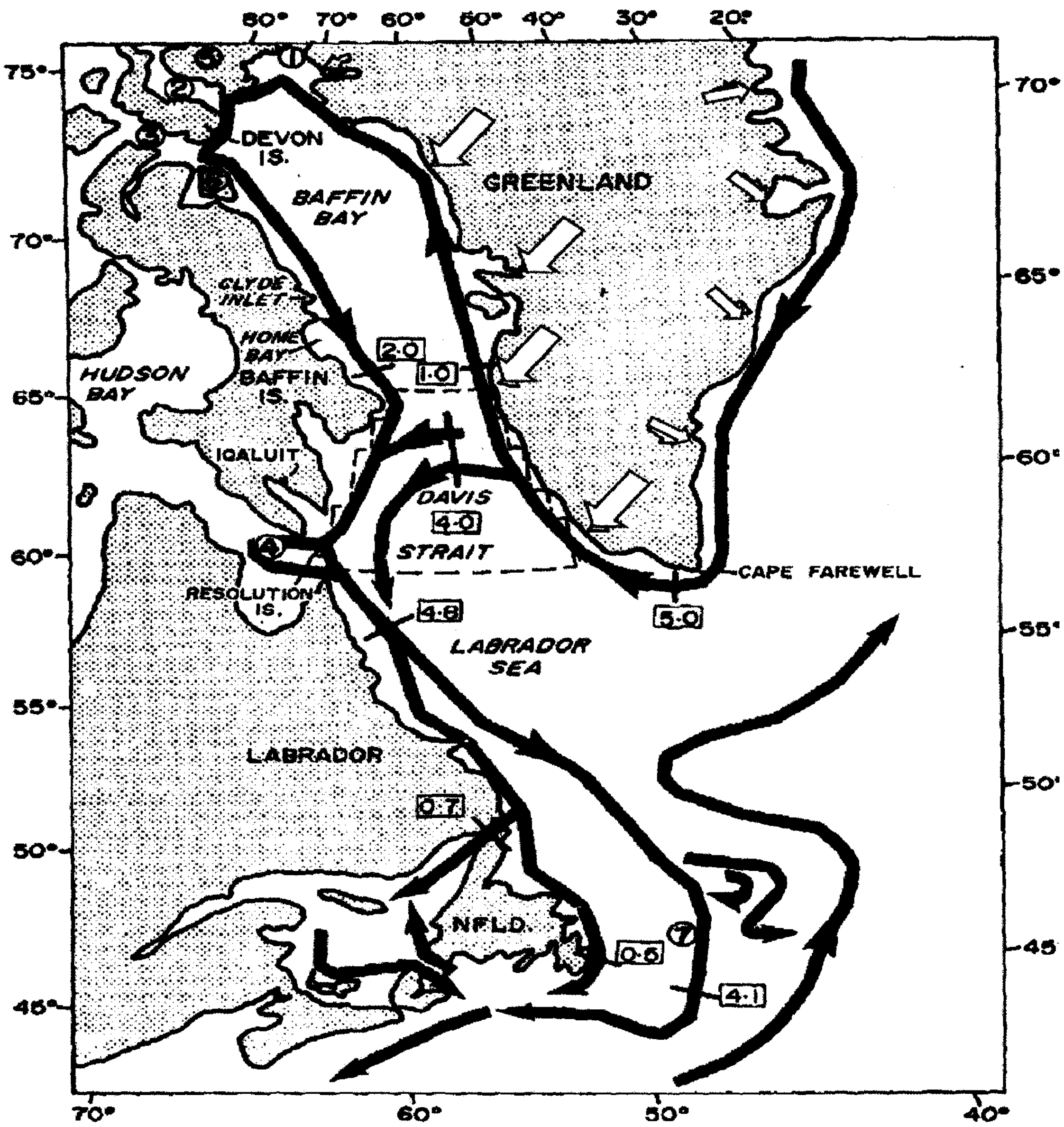


Figure 11 Icebergs origin at Greenland and transport path ways around Newfoundland (Compliments of Journal of Climate)

This is a long trip and most icebergs never make it and melt well before entering the Atlantic Ocean, where only one percent (150 to 300 icebergs) reaches the Atlantic Ocean (International Ice Patrol -IIP).

When icebergs reach the Atlantic Ocean leaving Labrador Sea, many travel along the Newfoundland coast (Figure 11), a small number of icebergs also traverse directly across the Grand Banks. The majority of the icebergs are funneled towards the eastern edge of the Grand Banks through the Flemish Pass in the area called "Iceberg Alley" located about 250 miles East to Southeast of Newfoundland (Figure 12).

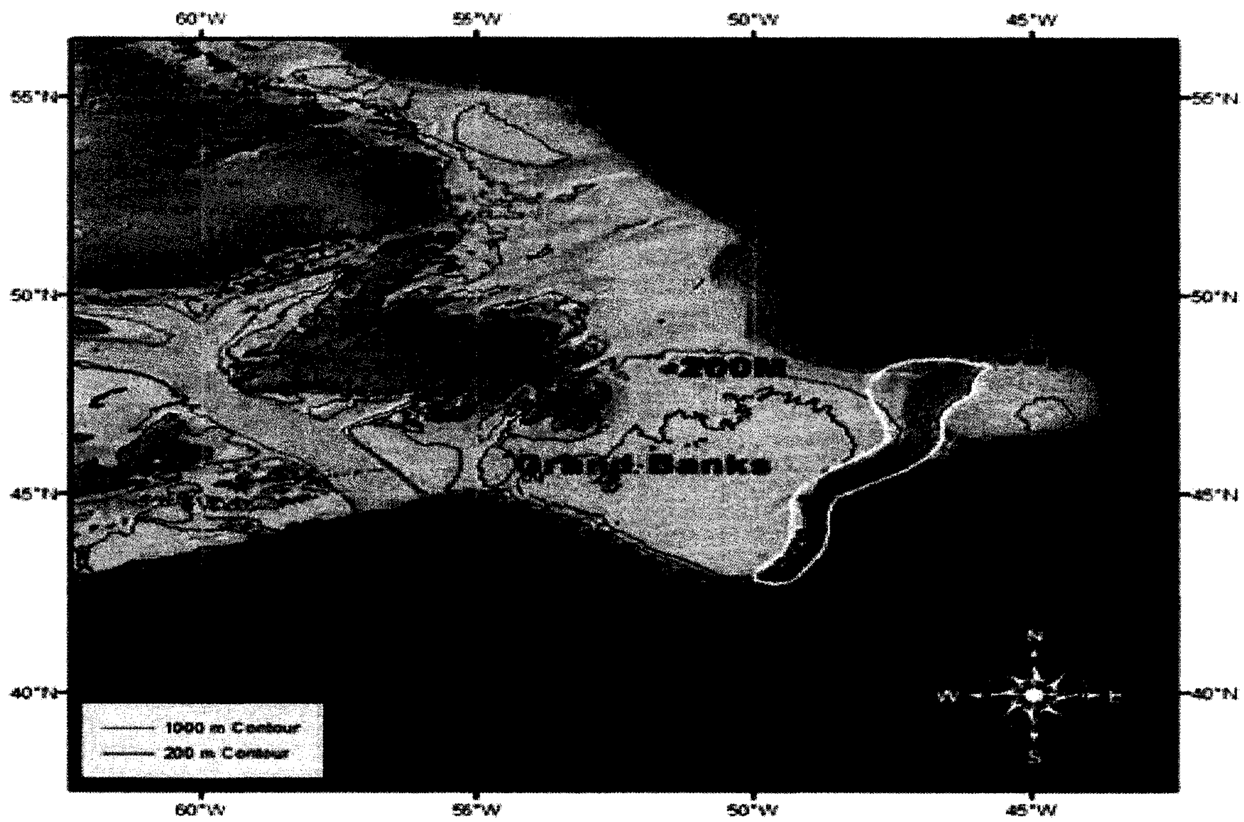


Figure 12 Iceberg Alley (International Ice Patrol, 2006)

This area extends approximately from 48 to 43 degrees North Latitude at 48 degrees West longitude. This area of the ocean is patrolled carefully and the 48 North Latitude is considered as the reference border to count the icebergs crossing South to the Grand Banks vicinity and the Atlantic Ocean.

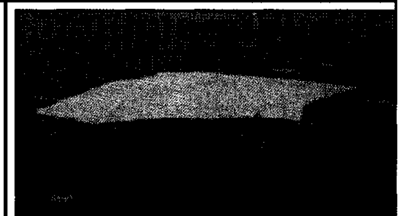
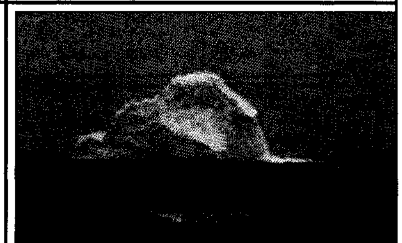
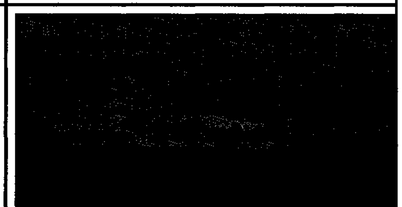
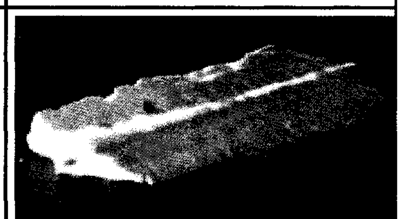
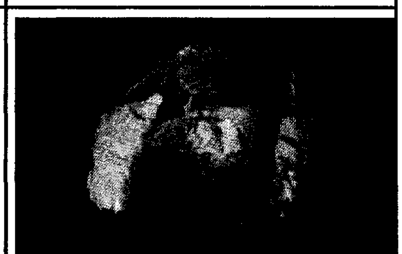
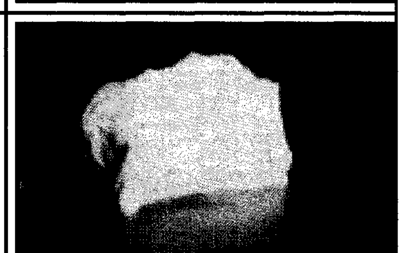
The maximum drift speed of icebergs off the north east coast of Newfoundland varies between 0 m/s to 1. 3 m/s with a mean speed of 0.26 m. Many factors influence the speed of iceberg drift, including iceberg size and shape, currents, and wind. In some occasions, for non-grounded bergs, speeds greater than 1.3 m/s have been recorded. Kinetic energy analysis of an iceberg analysis is done assuming a maximum speed of 1 m/s (Husky Oil Operations, 2000).

3.2 Icebergs Characteristics

Icebergs are usually described in terms of above water shape, size (dimensions) and estimated weights. There are variety of shapes which results from the different deterioration process of icebergs which start upon entering the marine environment, and rarely you find two icebergs having the same exact shape.

Icebergs are categorized into 6 main shapes observed above water where they are termed as: tabular, block, wedge, dome, pinnacle, and dry-dock (Table2).

Table 2 Iceberg shapes
(Iceberg Finder Website, 2007)

Shape	Description	Picture
Tabular	A flat-topped iceberg. Most show horizontal banding. Usually width is greater than 5 times height.	
Dome	An iceberg which is smooth and rounded on top.	
Pinnacle	An iceberg with a central spire, or pyramid, may have additional spires.	
Wedge	An iceberg with flat surfaces steep on one side and gradually sloped to the water on the other forming a wedge shape.	
Dry-dock	An iceberg which is eroded such that a U-shaped slot is formed near, or at, water level with two or more pinnacles or columns.	
Block	A flat-topped iceberg with steep sides.	

Icebergs off the coast of Newfoundland and Labrador range in size, from massive tabular and blocky bergs in excess of several million tonnes to small bergs weighing 1% of this. Various icebergs size and weight categories are shown below in Table 3 below.

An average estimation of 250,000 tonnes was given to the icebergs reaching the inside 100 m depth contour of the Grand Banks (Terra Nova Development Plan, 1996).

Table 3 Iceberg size definitions (International Ice Patrol, 2007)

ICEBERG SIZE / WEIGHT CLASSIFICATION			
Size Category	**Height (m)**	**Length (m)**	**Approximate Weight (Tonnes)**
Growler	**less than 1**	**less than 5**	**<53**
Bergy Bit	**1.5-5**	**5-15**	**<1,400**
Small	**5-15**	**15-60**	**91,000**
Medium	**15-50**	**60-120**	**730,000**
Large	**50-100**	**120-220**	**4 500,000**
Very Large	**Over 100**	**Over 220**	**Over 4 500,000**

3.2.1 Iceberg Count

As defined by the International Ice Patrol, ice count presents the number of icebergs that pass south of 48° N latitude each ice year, which extends from October through the following September, although the iceberg season offshore Newfoundland extends from

February until July. April and May are considered to be the peak months for icebergs drift south beyond 48° N.

In addition to the threat that these icebergs impose on the ships navigating the North Atlantic, they are as well considered as a threat to the Grand Banks oil and gas industry operational activities.

It is a huge effort to study, track and record the traveling icebergs, This mission is accomplished by the team work of more than 16 partners including the IPP, Coast Guard (Canadian and American), Provincial Air Lines (PAL), research centers (C-CORE), oil and gas companies active on the Grand Banks, and others, even the fishing vessels reporting any iceberg sighting.

The mean number of icebergs passing south of 48° N annually as per the count data (IIP and PAL) is 473 icebergs with a standard deviation of 492 icebergs (Figure 13).

The number of the icebergs crossing the 48° N parallel has annual fluctuations, for example during 2004, 262 icebergs crossed the 48° N, compared to 11 icebergs only during 2005 (International Ice Patrol, 2007).

The variability of the icebergs flow is subject to highly variable climatic factors, and largely determined by the sea ice conditions.

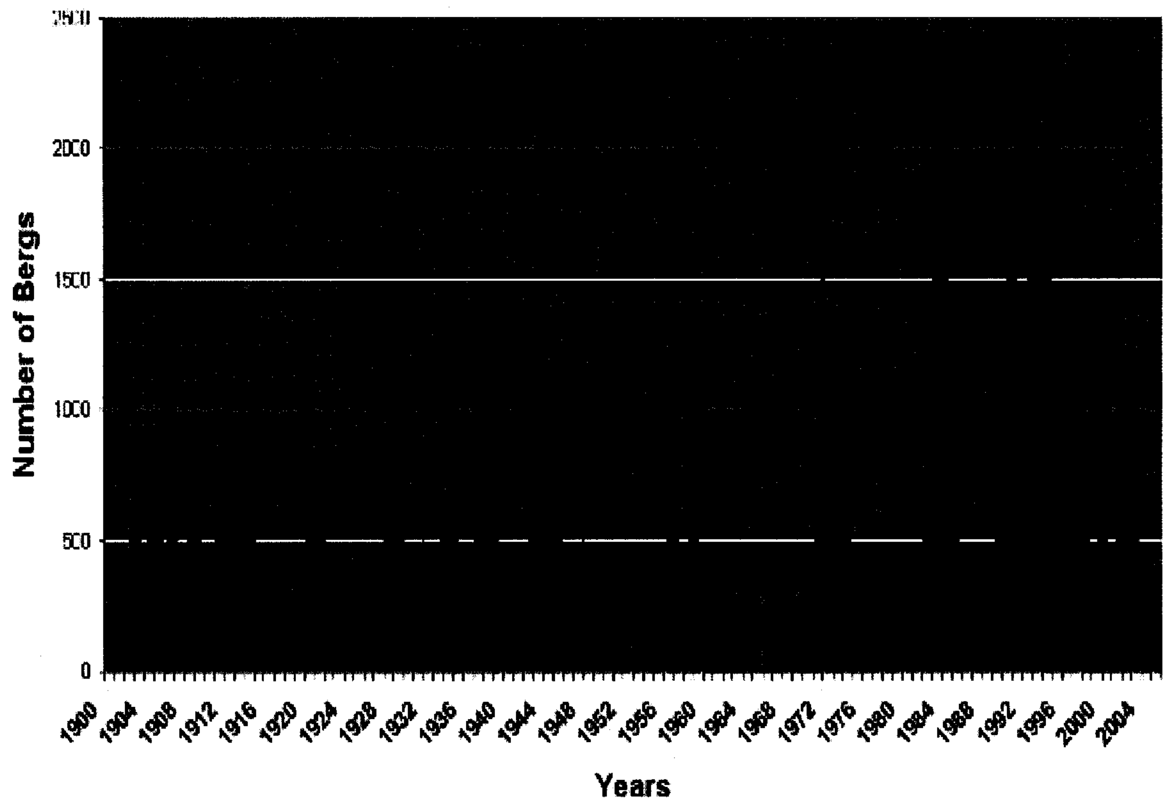


Figure 13 Total number of icebergs crossing South of 48°N Years 1900-2006 (International Ice Patrol, 2007)

Strong connections between icebergs presence have been always recognized and linked to the surrounding sea ice, only recently has it been proven that regional sea ice conditions considerably determine iceberg severity off Newfoundland (Marko et al., 1994). Additional sea ice in areas on and beyond the iceberg flow axis in the Labrador Sea, increase the probability for iceberg survival to 48° N.

3.2.2 Iceberg Distribution

Is a method of presenting the iceberg presence by geographic position of the total number of icebergs per 1° square (lat and long grid). The information used in iceberg distribution charts relies on the historical compiled data from sightings. Another term for the distribution charts is areal density charts, as the one shown below in Figure 14.

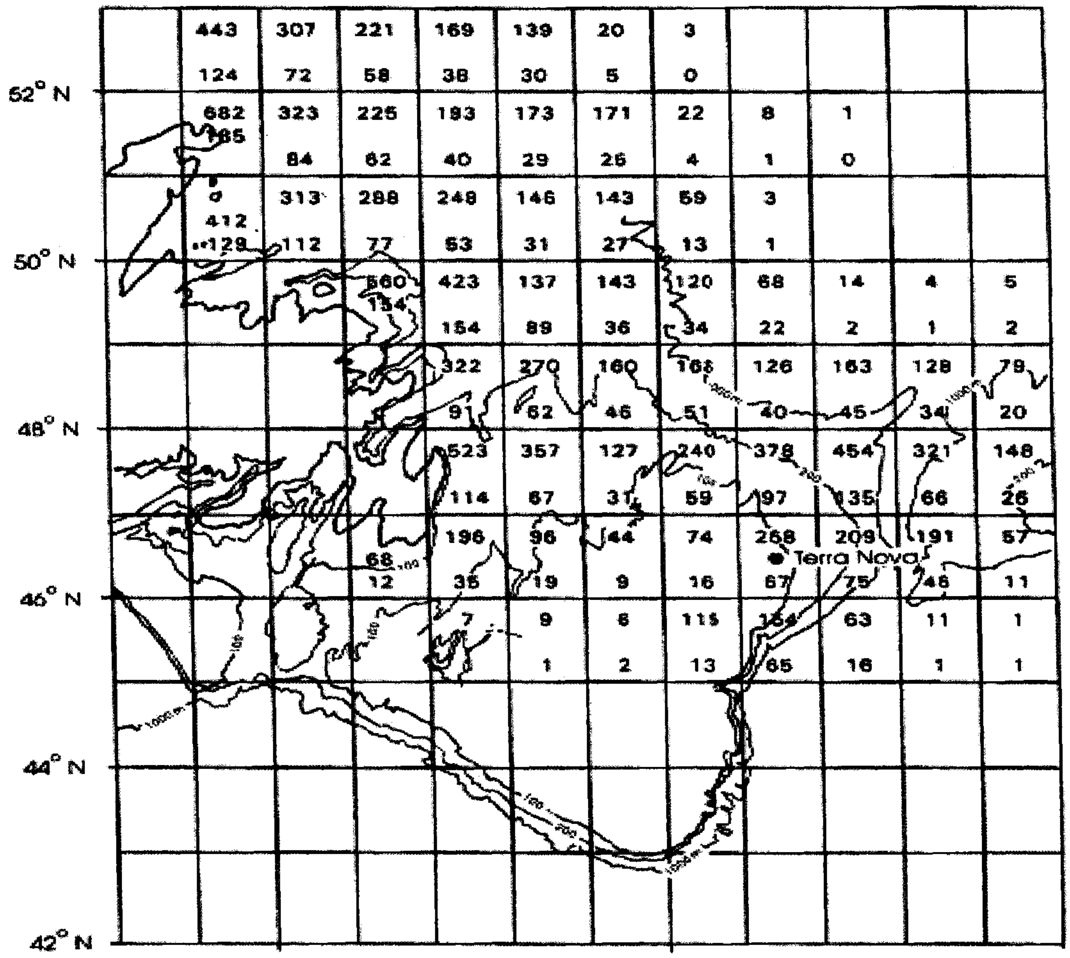


Figure 14 Areal density chart of icebergs cited in Labrador Sea and on Grand Banks. (Terra Nova Development, 1996)

The upper and lower numbers of the icebergs in each rectangle denote respectively sums of the maximum and the mean numbers of icebergs observed each month of the year.

The chart indicates clearly that the icebergs concentration is high in the Avalon Channel close to Newfoundland coast and over the Northern and Eastern slopes of the Grand

Banks adjacent to the present high activity oil and gas exploration and production area, the Jeanne d'Arc Basin and Ridge Complex.

3.2.3 Iceberg Size Distribution

The measurement certainty, depending on the method used, highly affects the accuracy of the physical dimensions of the icebergs. Recent work (Savage et al., 2000) has distinguished between iceberg lengths greater and smaller than 20 m and presented size distributions of the small calved ice pieces.

Dimensions of large icebergs can be well described by lognormal or gamma distribution. Using side-scan sonar's measurements for icebergs in the area of Terra Nova and surrounding area, The on- and off-shelf data, corresponding to water depth less and greater than 100 m respectively revealed a mean on shelf draft of 59.8 m and mean off shelf of 68.5 m (Figure 15).

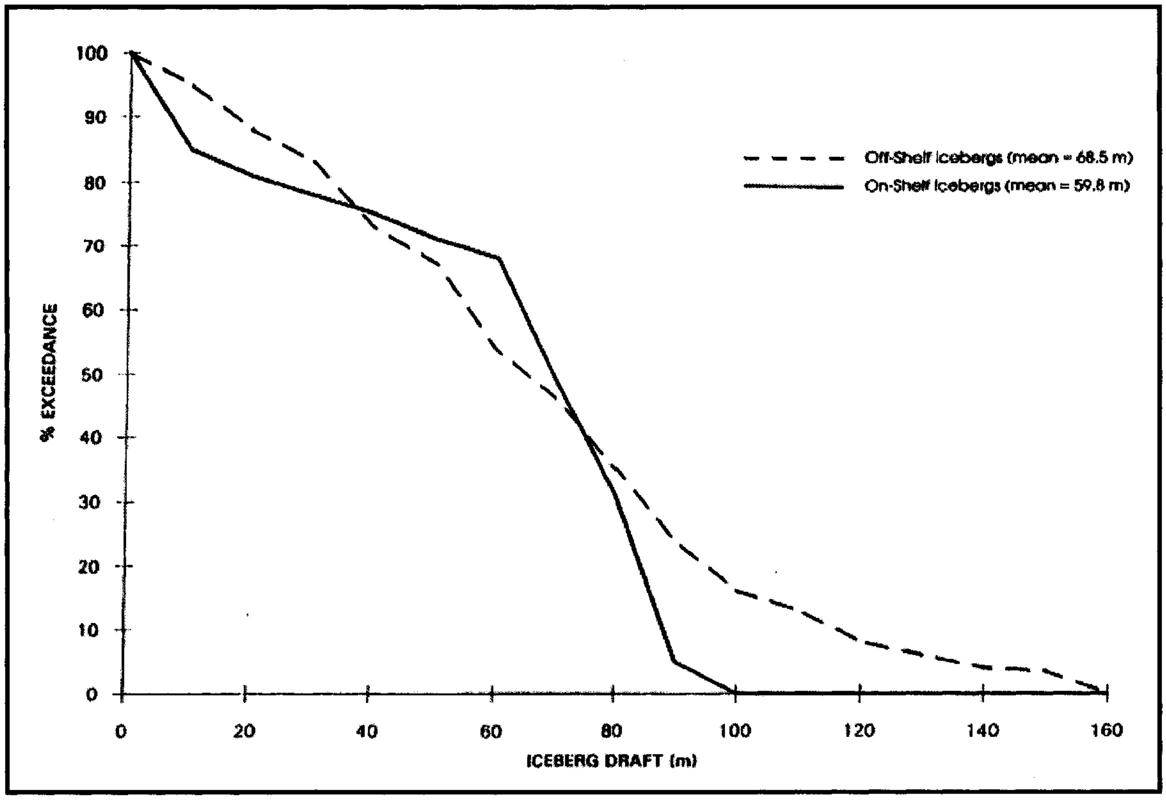


Figure 15 Icebergs draft distribution cited offshore Newfoundland and Labrador. (Terra Nova Development, 1996)

3.3 Iceberg Gouging

Due to the fact that about 7/8$^{\text{ths}}$ of an iceberg is below the water line, it is not un-expected to have contact between big icebergs and seabed in various offshore areas.

Icebergs with drafts exceeding the water depth of the Grand Banks will contact and disturb the seabed in a continuous manner or interrupted manner causing gouges or pits (Figure 16).

As stated earlier, the event of an iceberg interacting with the oil infrastructure on or below the sea bed is not desirable and is a potential for damage encountering one of the most serious threats on the integrity and safety of these facilities and the surrounding environment.

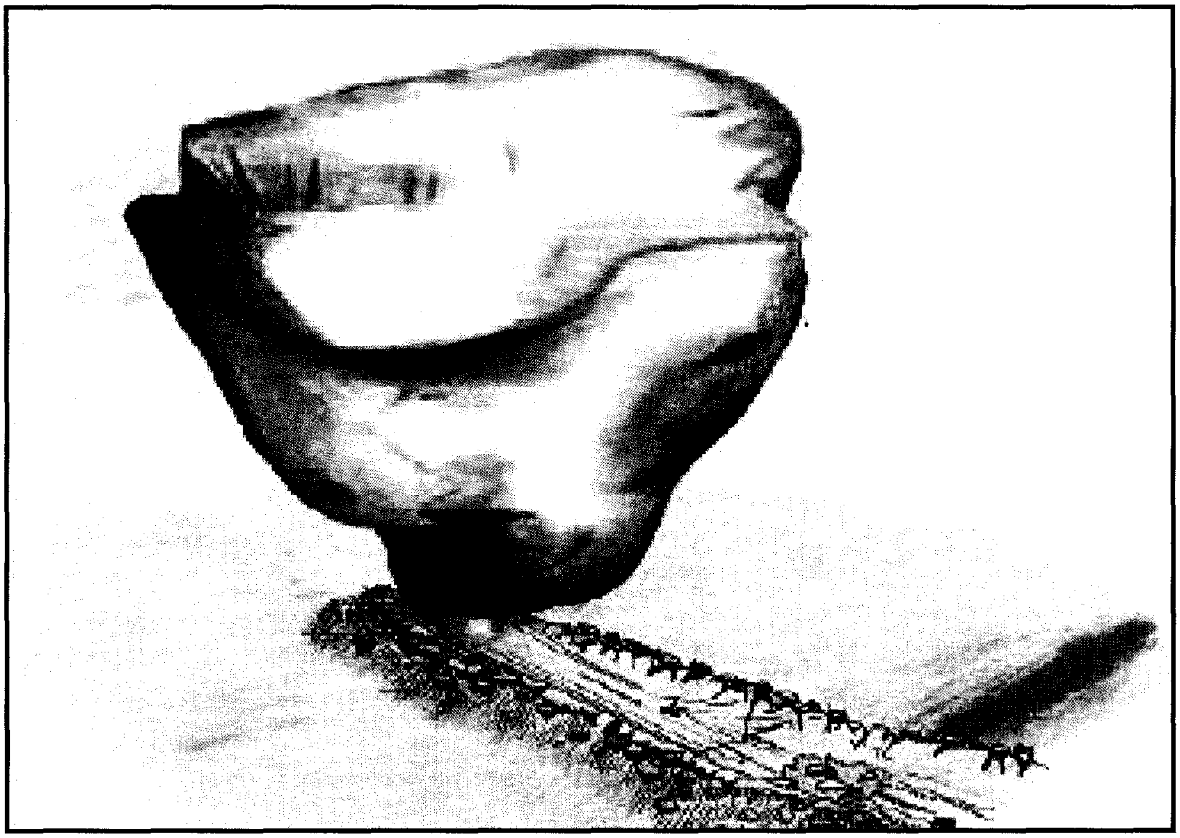


Figure 16 Artistic impression of a gouging iceberg (Kenny, 2006)

3.3.1 Gouge Density

There is no accurate pattern of gouge distribution over the Grand Banks, where the details of gouges are highly dependent on the iceberg shape and stability, drift pattern, seabed soil properties, and seabed topography (Presence of slopes or flat sea bed).

The gouge density which is defined as the number of gouges/km^2, is converted to the frequency of gouge occurring in a certain area.

The Grand Banks Scour Catalogue (GBSC) includes information characterizing the icebergs, their dimensions, location and the gouge marks on the sea. The data is compiled and updated since 1979.

The depth distribution of the gouge record changes as new ones are formed and existing ones are in-filled by sediment transport Infilling removes shallow gouges from the record and reduces the depth of others.

It was indicted that the Northeast Grand Banks (The Jeanne d'Arc sub-basin), Flemish Pass and western portion of the Flemish Cap a mean gouge density is 0.56 gouges/km^2 for the total survey coverage in water depths less than 110 meters, and 0.86 gouges/km^2 for the total coverage in water depths greater than 110 meters. The highest mean density, at 1.2-1.3 gouges/km^2, occurs between 100-150 meters water depth (Fowlow, C.D., 2006), at the areas closer to the Iceberg Alley where the icebergs population is the highest.

Approximately 100 gouges/100 Km^2 per year was estimated for Terra Nova and surrounding in water depths between 80 and 100 m (Terra Nova Development 1996).

Figure 17 shows the gouging density near Terra Nova relative to other Newfoundland offshore regions in form of contours.

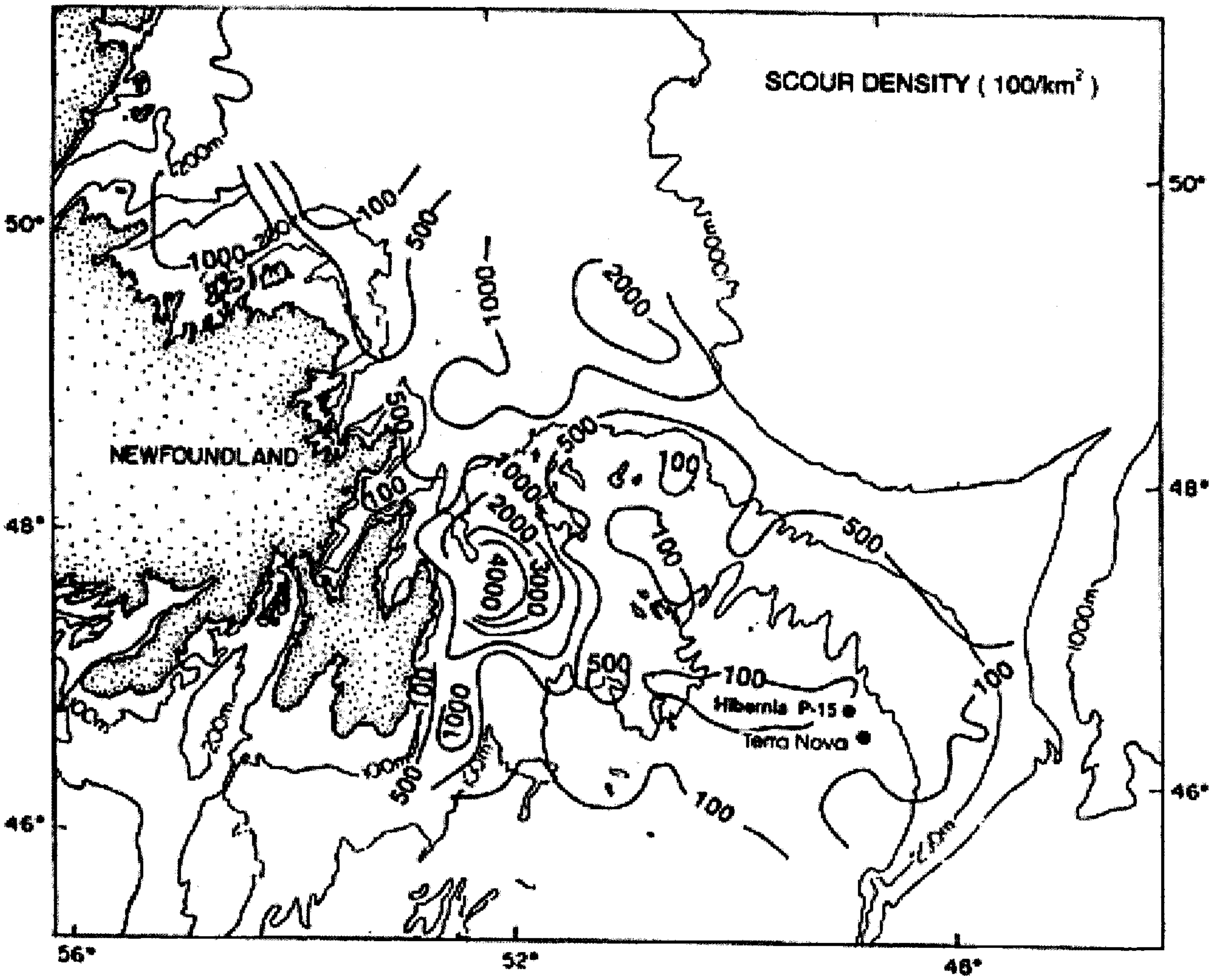


Figure 17 Contours of observed gouge areal densities (Terra Nova Development, 1996)

3.3.2 Gouge Characteristics

Gouge characteristic which are expressed as gouge dimensions: Depth, width and length combined with the rate that gouges occur are the key factors for load calculations of gouging ice keels, and for the design process of the subsea infrastructure intended to such an ice environment.

Obtaining the distribution and characteristics of gouge depth over the seabed is not an easy and simple job. It can take many years to build a sufficient database of gouges for a certain location.

Repetitive geophysical mapping is an efficient method to obtain this information and compile a distribution of gouges characteristics.

Using both newly formed and infilled gouges taking into consideration the age and the infilling rate, can give a reliable data.

Reports (Croasdale et al. 2000) in the Grand Banks Scour Catalogue produced by the Canadian Seabed Research Ltd. have quantified 3887 individual iceberg scours (Husky, 2005).

In the study area covering the Northern Grand Banks that includes the Jeanne d'Arc Basin, a maximum (very rare event) gouge depth of 7m occurring in the 160 m water depth range was reported (Westmar Report, 2000). For Terra Nova field area the average (mean) depth of the gouge was 0.6 m with a standard deviation of 0.3m (Terra Nova Development Plan, 1996).

In general, for the 90-110m water depth range, the maximum gouge depth is 3m with a mean depth of 0.48m (Croasdale et al. 2000). Mean gouge depth for the White Rose region worked out by C-Core is considerably lower at 0.34m.

A descriptive statistics for gouge depth, as one of the main characteristics for the Northeast Grand Banks (The Jeanne d'Arc Basin) according to water depth from various sources is presented below in Table 4.

Table 4 Comparison of gouge depths from various sources (C. Fowlow, 2006).

Source	Water Depth (m)	Scour Depth	
		Mean	Standard
C-Core	110-140	0.34	0.3
Croasdale et al.(2000)	≤ 110	0.5	0.4
Croasdale et al.(2000)	>110	0.88	0.82
Terra Nova (1997)	80-120	0.6	0.3

3.3.3 Gouge Frequency

The gouge dimensions and frequencies data are used to asses the probabilities of the un-desired iceberg infrastructure interaction.

It is not enough to rely on the gouge density for the risk assessment, but the probable rate of occurrence has to be included.

Gouging probabilities and gouge depths are assessed using a variety of techniques and data. Sedimentation rates or gouge degradation is one of these techniques where it was found that if the gouge and infill rates are constant over time and the depth distribution is exponential, the gouge depth distribution will remain constant (Lewis et al. 1977). Other approaches use the ages of existing gouges for the conversion of the gouge densities to gouging probabilities on the Grand Banks by employing the estimated age of 2500 years for the oldest gouge present on the Banks. (Scott et al. 1984, in Petro-Canada Development Plan,1996). An estimated frequency of 0.01 gouges/100 Km^2 per year is assumed for the Grand Banks, neglecting the substantial filling of the gouge by sedimentation (Lewis et al. 1987).

Another method is by using grounding models relying on the cumulative iceberg data (Numbers, drafts, velocities, areal densities) which have been developed to calculate the gouging frequency. A recent model was developed by King et al (2003).

In addition to the above mentioned methods, still direct sea bed repetitive mapping allows data compiling and distribution of gouge depths using both newly formed and infilled gouges which allows the calculations of gouge frequency.

3.4 Design Codes/Standards and Icebergs Risk Probability

The general regulatory requirements for the design and operation which covers as well the required reliability aspects of the oil and gas development facilities on the Grand Banks is set and defined by the C-NLOPB. Their rules refer to the national (Canadian Standards Association- CSA) and to other international offshore standards.

Absolute safety or zero risk probability does not practically exist. For high risk industries, such as offshore engineering operations, the main target will remain the safety of the personnel and the protection of environment. Principles, such As Low As Reasonably Practical (ALARP), and risk management strategies to reduce hazard frequency, conduct condition monitoring, perform options analysis and mitigate consequences are often used.

The offshore oil and gas industry has to deal with various issues of risk including environmental loads, which become more complicated and challenging when unconventional threats appear as the icebergs presence on the Grand Banks.

Up to day, there are no codes or standards that deal sufficiently in details with the iceberg sea floor infrastructure (specifically subsea wellheads) interaction criteria.

The CSA standard S471-04: General Requirements, Design Criteria, the Environment, and Loads, sets requirements and guidance on design principles, safety levels, and loads to be used in connection with the design, construction, transportation, and installation, of fixed offshore structures.

The standard mention in clause 4.5.2, covering the risk levels, two Safety Classes as follows:

Safety Class 1: Failure would result in great risk to life or a high potential for environmental damage, for the loading condition under consideration.

Safety Class 2: Failure would result in small risk to life and a low potential for environmental damage, for the loading condition under consideration.

Allyn (2000) performed a study that provided an overview of the use of various codes for ice loads and their reliability definitions for various offshore development facilities on the Grand Banks. The conclusion was that the CSA standard S471-04 is the only code that deals with icebergs loadings in some detail on fixed offshore structures. Another strong point of this code is that the acceptable risk and reliability levels are clearly specified.

When formulating the CSA standard, and in order to achieve a reasonable constant safety level the load due to an interacting ice berg with the resistance of the structure were treated as random quantities. The above approach led to an acceptable range of probability of failures per annum ranging between 10^{-4} to 10^{-6} which covers most of the anticipated events. For Safety Class 1, of the CSA, the main risk probability target of 10^{-5} per annum was set. (Figure 18)

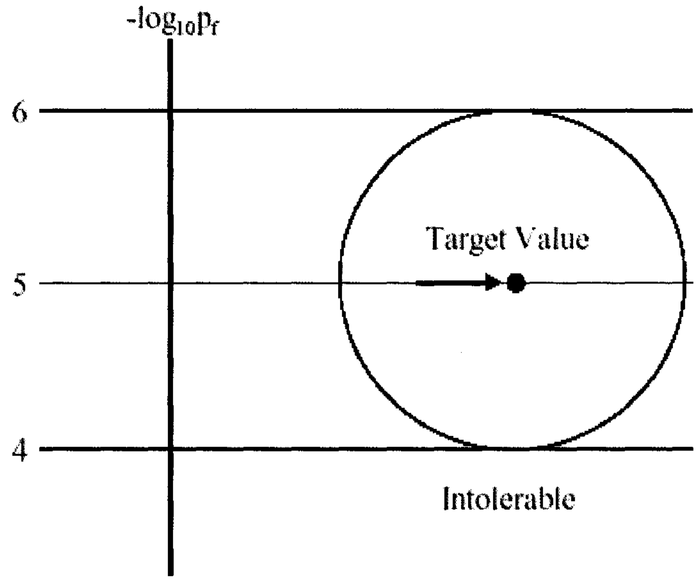


Figure 18 CSA safety target for Safety Class 1 (Allyn, 2000)

Safety class target that are specified in the CSA for fixed structure design code can be used to gauge the consistency in reliability targets for seafloor facilities including wellheads. (Allyn, 2000)

3.5 Established Iceberg /Infrastructure Contact Probability

For the oil and gas developments on the Grand Banks that employ an infrastructure above and below the seabed, annual probability of an iceberg interacting with a subsea infrastructure components was established by C-CORE taking into consideration the dimensions and elevation above seabed. (Figure 19)

4. Developed Fields Facilities and Infrastructure

4.1 General

Although the depth of the Grand Banks is shallow, which should be an advantage in an offshore development, and with a prevailing environmental conditions some how similar to the developed North Sea area fields, the seasonal presence of the icebergs imposes additional challenges on the oil and gas development plans.

For any offshore field development and production, one of several types of facilities might be used, which are termed loosely as oil/gas rigs. The most widely used facilities are:

- Fixed Steel Structure
- Concrete Gravity Base Structures (GBS)
- Floating Production/Storage Offloading Systems (FPO ; FPSO)
- Tension Leg Platform .(TLP)
- Semi-Submersible Vessel
- Single Point Mooring

At present, three major offshore fields on the Grand Banks have been put into stream: Hibernia, Terra Nova and White Rose fields, with composite average daily oil production of 304,847 barrels .(C-NLOPB, 2006) .

Special design features have been added to the facilities on the Grand Banks to cope with the unconventional environmental challenges and meet the safety requirements.

In this chapter, the existing developed and marginal fields on the Grand Banks are discussed with focus on wellhead protection measures and concepts.

4.2 Existing Producing Fields

4.2.1 Fixed Structure Development

Hibernia is located in the Jeanne d'Arc Basin, 315km east of St John's, Newfoundland, in 80m deep water. Hibernia is the largest oil field discovered offshore Canada so far. Production began in November 1997 with an average production rate of approximately 198,900 barrels per day (C-NLOPB, 2006).

The development cost of Hibernia was around (CAD) $5.8 billion, a big expenditure, which was justified because of the huge reserves of the field.

The Hibernia field was developed using a special concrete gravity-base structure (GBS). In comparison with floating structures, GBS structures have the advantage of supporting larger topside modules (processing, wellhead, mud, utilities, and accommodation) and other mounted structures (helideck, flareboom, piperack, main and auxiliary lifeboat stations, and drilling modules).

Hibernia platform on the Grand Banks (Figure 20) is a vital infrastructure with a function that goes beyond a production facility for the Hibernia field. It is a concrete island 300 km from shore, serving as a logistic base that is facilitating the exploration and development of other fields in the area.

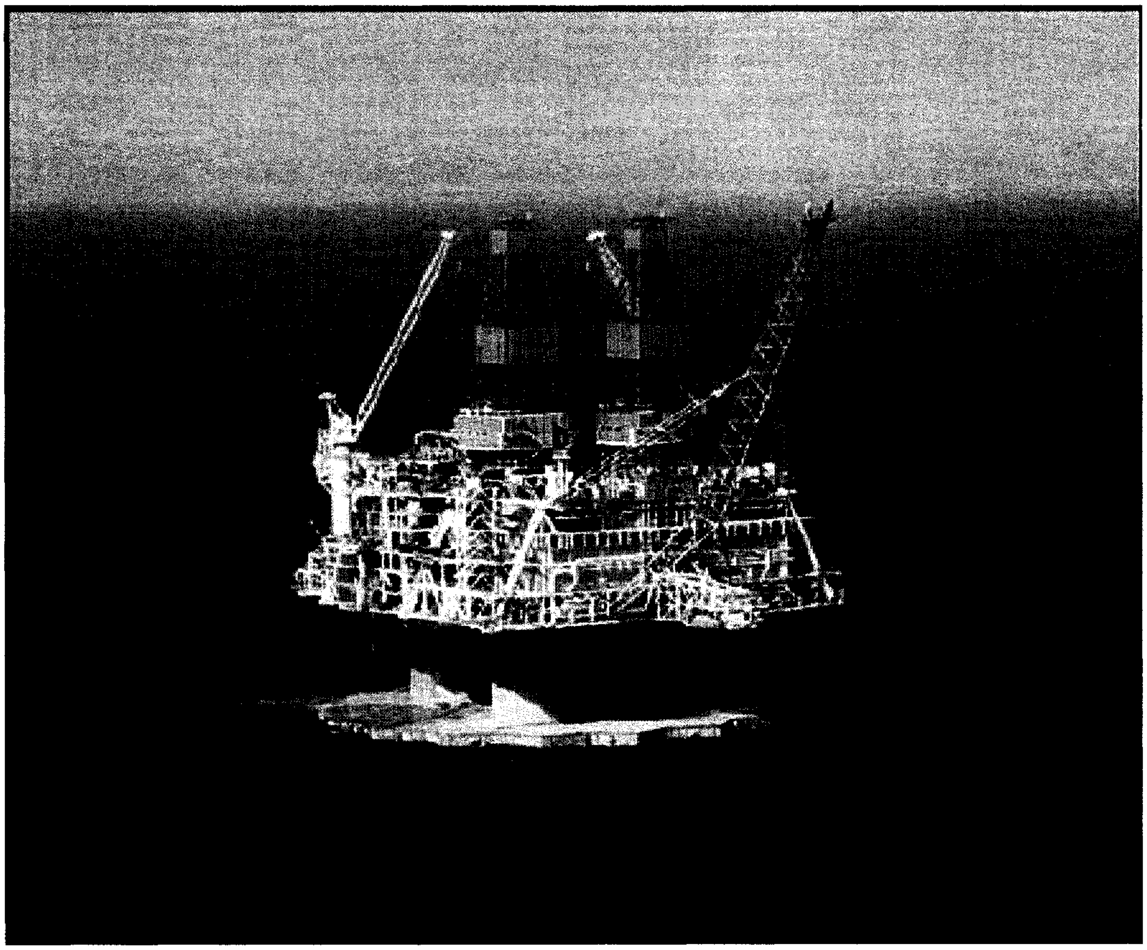


Figure 20 Hibernia Platform (Compliments of HMDC)

Another important feature which was extremely vital for the Grand Banks was the ability of the GBS to withstand the iceberg impact.

Hibernia's novel design of the 450,000t gravity base structure consists of a 105.5m concrete caisson; constructed using high-strength concrete reinforced with steel rods and pre-stressed tendons. The caisson is surrounded by an ice-wall, which consists of 16 concrete teeth.

The GBS platform of Hibernia (Figure 20) is strong enough to withstand a collision with a one-million-tone iceberg (expected to occur once every 500 years) and a direct hit with repairable damage from a six-million-tone iceberg (expected just once every 10,000 years).

Four shafts each of 17 m diameter run through the GBS from the base slab to support the topsides facilities: namely the utility shaft, the riser shaft and two drill shafts. Each of the drill shafts house 32 well slots and support a drilling derrick on the topsides. As of 2006, the total number of development wells drilled and completed at Hibernia is 55. This total number includes 29 oil producers, 19 water injectors and seven gas injectors. The Hibernia platform has a total of 64 well slots thereby leaving 9 more slots for future wells.

A GBS is a very robust and reliable offshore installation, but at a high initial capital cost. The main draw back of the GBS, is the predetermined number of well slots with in the structure of the GBS, which is a sort of limitation for any future developments that require more wells to be drilled after utilizing all the available slots. In this case, other options have to be considered, one of could be a tie back subsea development.

4.2.1.1 Surface Wellhead and Protection

For a fixed (Stationed) offshore installation such as the Hibernia GBS a surface wellhead with a dry X-mas tree is used (Figure 21).

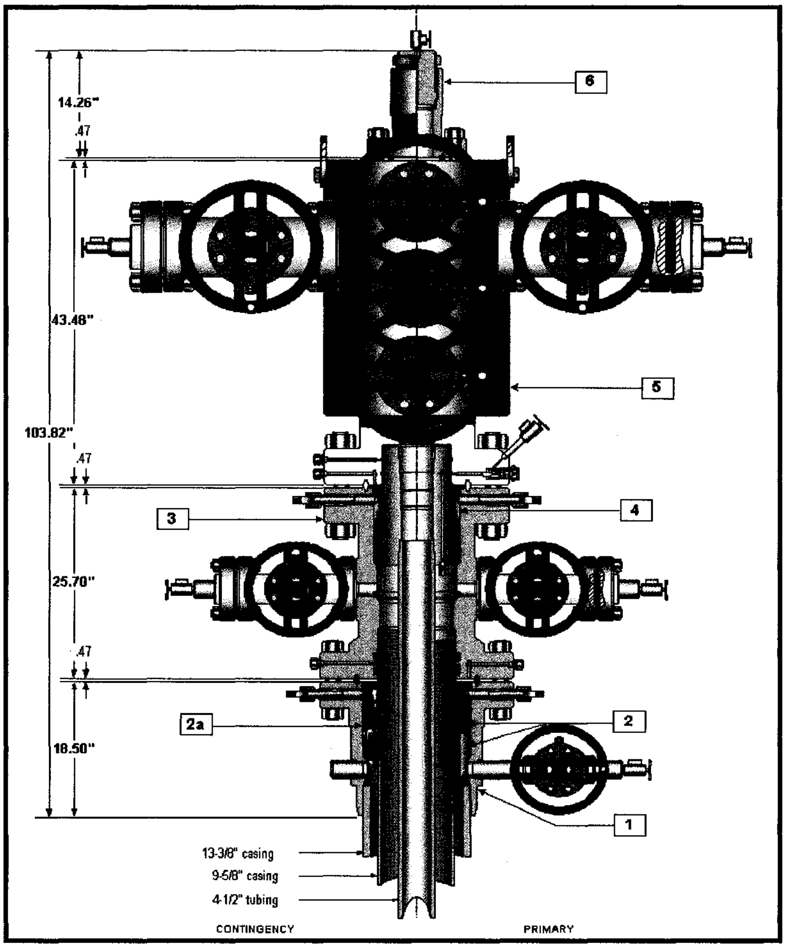


Figure 21 Surface wellhead and dry X-Mas tree

The wellhead assembly with tree will be situated on one of the decks (levels) of the wellhead and drilling module of the installation. The whole well structure (Wellhead and Casing) is supported by the conductor which is drilled through the seabed into the sea bed and extending up to the wellhead deck through a designated slot within the GBS platform.

In Hibernia, the conductor, casing strings and well completion for each individual well, are all housed inside two out of the four concrete shafts below the fixed drilling derricks, and occupy one slot of the total 64 available slots (Figure 22).

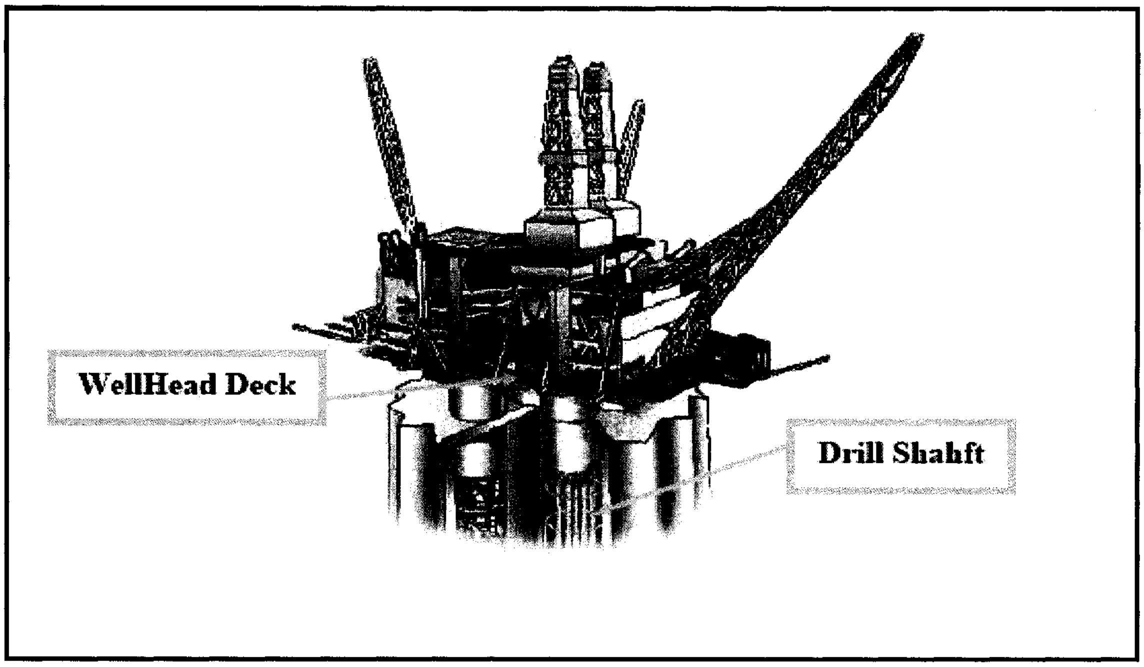


Figure 22 The Drill shaft and wellhead deck of Hibernia Platform

The surface wellhead and dry X-Mas tree do not require any special protection arrangement when using a fixed installation.

No specific measures are set to protect the wellheads on the GBS. The whole structure is being protected by the ice management policy set for the whole installation, which is achieved by collecting information by different means about approaching icebergs as a first step using :

- Air surveillance briefings.
- Data gathered by satellite and radar technology.
- Ice management trajectory modeling program.
- Using side scan sonar, mounted on the support vessels to record under water profile of the iceberg.

The second step will be tackling the icebergs of potential danger to the installation by encircling the iceberg with a long cable or rope and use tow the iceberg using the utility vessels into a different trajectory.

Shutdown of the production is the last option in case of unavoidable iceberg collision, where damage is assed afterwards to carry out the necessary repairs.

4.2.2 Subsea Development and FPSOs.

Two other fields on the Grand Banks have been developed using similar floating systems. A mono-hulled, double skin, floating production storage and offload system (FPSO) was employed to bring both fields into stream.

The Terra Nova field is located 35 km south of Hibernia, 350 km east southeast of Newfoundland in 95m of water. **Terra Nova** is operated by Petro-Canada (39.99%) with partners: ExxonMobil (22%), Norsk Hydro (15%), Husky (12.51%), Murphy (12%), Mosbacher (3.5%) and ChevronTexaco (1%). The field is estimated to contain over 480 Mbbl of oil in place, of which about 224 Mbbl of oil are recoverable.

Production by mono-hulled FPSO began in January 2002, with a daily production rate averaged at 99,200 barrels of oil per day (bbls/d) during 2005 with a total of 36.2 Mbbl produced during the year. As of March 31 2006, cumulative production exceeded 170 million barrels of oil (C-NLOPB, 2006). Field life is expected to be 18 years, and the development cost of the field was (CAD) $ 2.8 billion. (CAPP, 2006)

The White Rose Field approximately 50km from the Terra Nova and Hibernia fields, located 350km east of Newfoundland, in 120m of water. **White Rose** is operated by Husky Oil (72.5%) with partner Petro-Canada (27.5%). The field is estimated to contain over 318 Mbbl barrels of oil in place, of which about 220 Mbbl of oil are recoverable (C-NLOPB). Production by mono-hulled FPSO began in November 2005. As of March 31 2006, three production wells and six water injection wells were operating and the average production of 49,300 barrels of oil per day (bbls/d). The development cost of the field was (CAD) $ 2.3 billion (C-NLOPB, 2006 ; CAPP, 2006).

The increase of the FPSOs popularity and sub-sea development is largely due to the fact of that oil can be produced, processed, stored and exported from various depths at considerable cost saving when compared to other alternatives.

The combination of the FPSO with the state of art the diverless wellheads form a very efficient system for oil recovery from deep waters, marginal fields or fields that require unconventional and innovative approach such as the case of the fields offshore Newfoundland.

This conclusion was obvious in the development of the pioneer project Terra Nova and after that the White Rose project, where studies were conducted on various systems including a gravity base structure (GBS), and the final decision was a floating system (FPSO) and a subsea development (Figure 23) as the only viable alternative for economic and safe development.

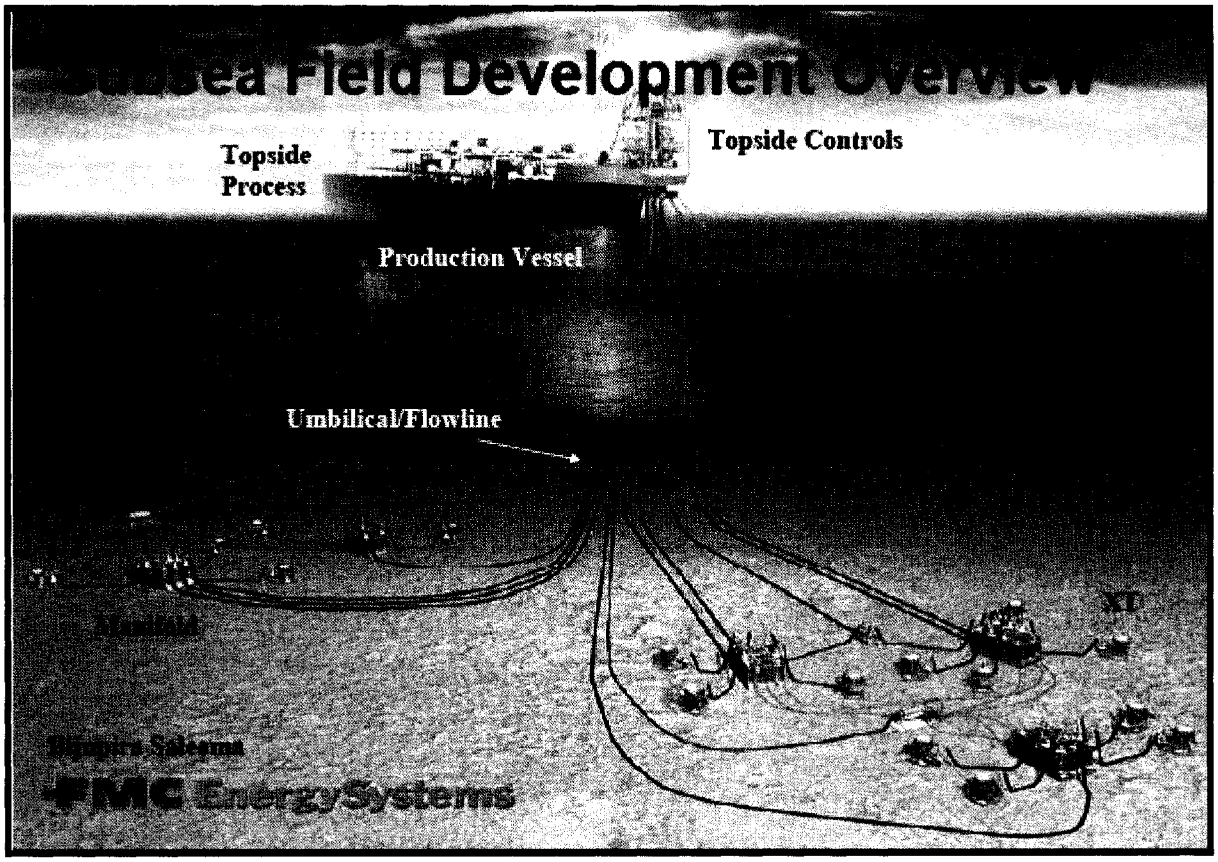


Figure 23 Typical subsea development overview (FMC Kongsberg Subsea, 2006)

The main components of a subsea field development infrastructure include:

- Templates
- Manifolds
- Subsea Wellheads
- Subsea X-Mas Trees
- Production and Injection Flow line
- Control Systems and Umbilicals

A general over view is given below to highlight the above components' characteristics and functions in general.

4.2.2.1 Templates

When a cluster or a drilling center is to be used in the drilling development stage (e.g. Terra Nova and White Rose), then the template will be the first component to be lowered to the seabed.

The template is a steel structure that could be piled or fixed by drilling and then cementing the main support middle post. The template function is to serve as guide frame through which wells can be drilled, and later to support the wellhead and X-mas tree.

Another function of the template in some applications is to be the foundation for the production manifold and the pig loop structure, as in the HOST template shown below in Figure 24.

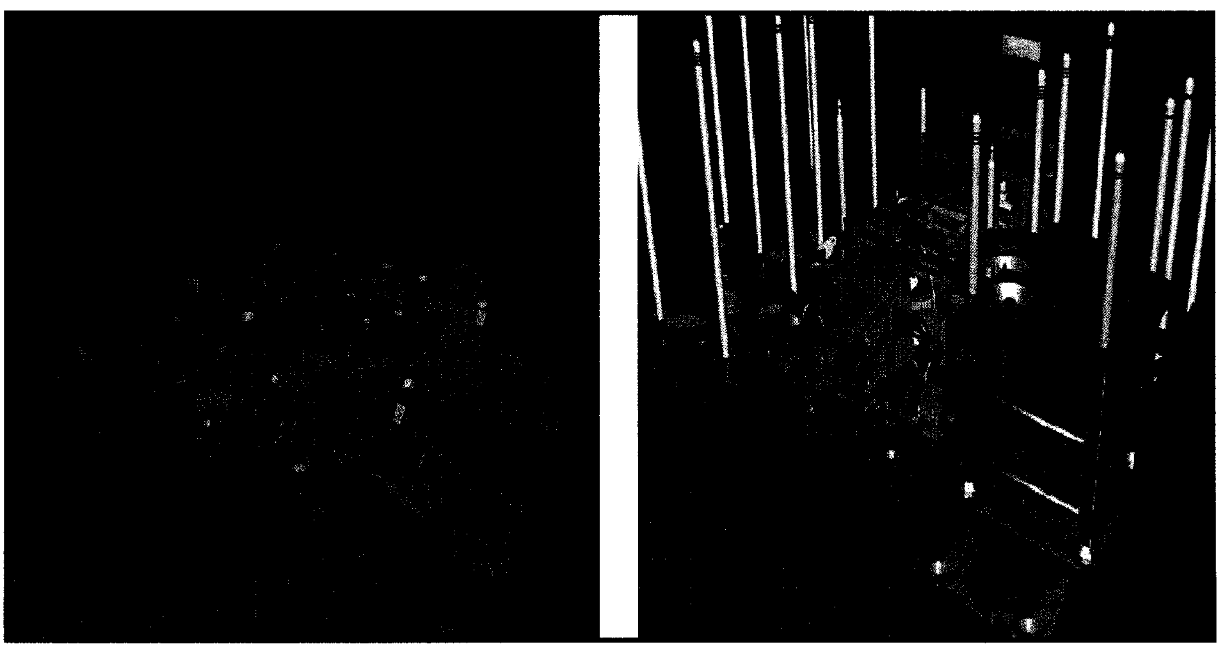


Figure 24 Typical Subsea HOST template during drilling and after X-Mas tree and manifold installation. (FMC Kongsberg Subsea)

4.2.2.2 Manifolds

Subsea manifolds (Figure 25) commingle fluids and control their flow. The selection of the location and types of the valves and other associated components on the manifold is very important. Accessibility, undependability, practicality and reliability, all are factors to be considered and engineered carefully.

The production manifold receives the oil produced from all the wells connected to it and then direct the flow to a single line connected to the process and storage facility. Utilizing manifolds is good practice to reduce the cost of construction of flow lines and their operation. Manifolds receiving flows from various wells require chokes and valves to assure pressure balancing, which is known as commingling.

A water or gas injection manifold receives the treated compressed fluid from the facility via a single line and then distribute the flow to the injection wells.

Figure 25 Typical subsea production manifold with a pigging loop (FMC Kongsberg Subsea, 2006)

Chemical injection manifolds are used for the distribution of chemicals to be injected into the well tubing for flow optimization within the well bore and in flow lines. The manifold and the piping system may be permanently integrated with the subsea structure or installed as one or several separate modules.

4.2.2.3 Subsea Wellheads

Wellheads are an assembly of heads, hangers, valves, adaptors, and other fittings and components used, to control the flow of oil and gas during drilling, workover and production of the well.

A wellhead provides support and sealing of intermediate casing strings, tubing and X-mas tree during production, and provide a base for the location of the Blow Out Preventer (BOP) during drilling or work over operations.

A subsea wellhead can be very simple, what the industry call basic wellhead, or it may be very complex and include terms like "Thru-Bore" or "Multiple String Completions", or "Mudline /Submudline Suspension Systems".

All subsea wellheads are manufactured tested and maintained as per API Spec 17D.

In the conventional subsea wellhead the casing hangers and the packoff (i.e. the sealing component) are both situated above the mudline as shown in Figure 26 below.

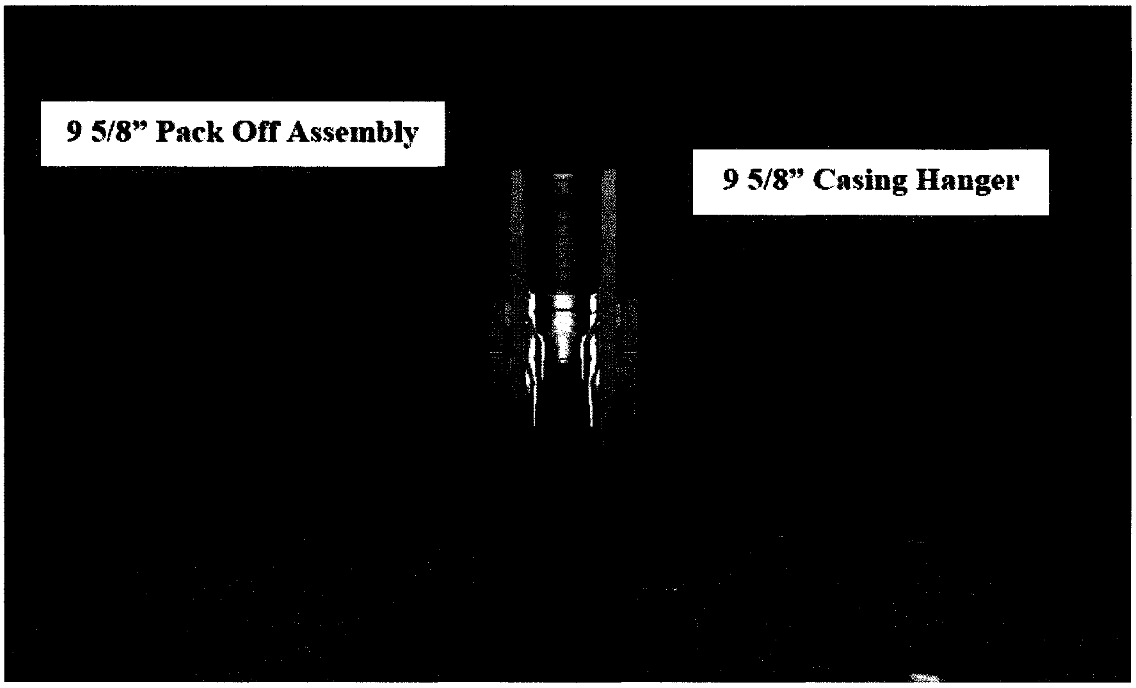


Figure 26 Conventional Subsea Wellhead (FMC Kongsberg Subsea)

The mudline or submudline suspension system as called by some manufacturers is another alternative for the conventional wellhead system (Figure 27).

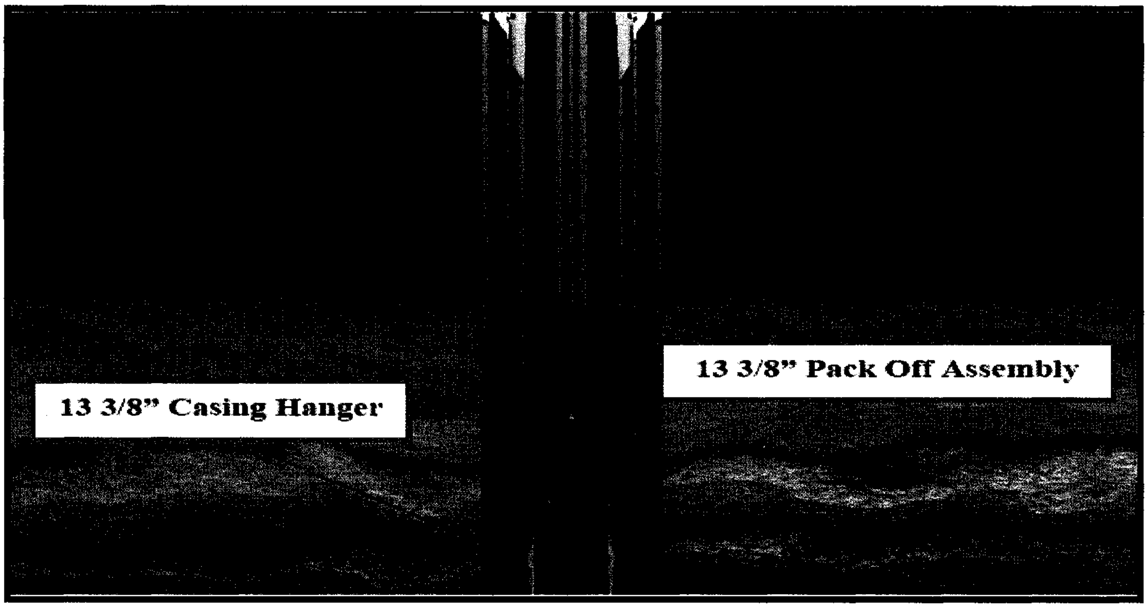


Figure 27 Mudline Suspension System for a Subsea Wellhead (FMC Kongsberg Subsea)

The landing sub shoulder which is incorporated with in the conductor at depth of around 30-50 feet receives the casing hanger and the pack off assembly of the intermediate casing in a stack down manner. Cementing followed by wash out jobs between the casings allows the release of the running tools and the tie back if required to the internal threads of the casing hangers (Figure 28).

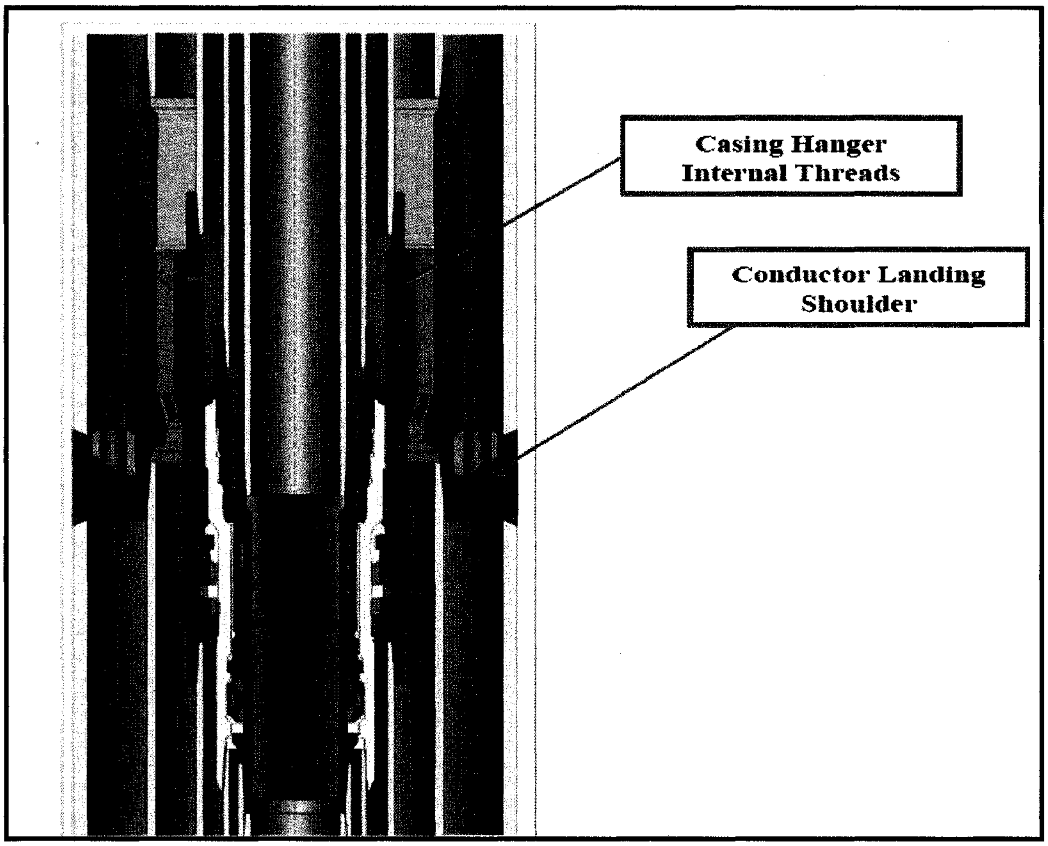


Figure 28 Conductor Landing Ring and a Tie Back Sub (FMC Energy Systems, 1994)

4.2.2.4 Subsea X-Mas Trees

The X-Mas tree is the last component to be installed on top of the well prior to production or injection commissioning. The X-mas tree permits the isolation of the reservoir products from the process equipment. The main functions of the X-mas tree can be summarized as follows:

- To shut-in production at the wellhead,
- To monitor annulus and production tubing pressure,
- To facilitate well maintenance (wireline or coil tubing operations),
- To provide a means for killing the well, and

- To provide a means for circulation and reverse circulation as a preparation for work over.

There is a big variety in designs, configuration and pressure ratings of X-mas. The main components of X-mas tree are:

- Wellhead Connector: The connector engages to the wellhead to provide a sealed connection between the production and annulus bores and the X-mas tree. Historically mechanical connectors were used that are now replaced by hydraulic connectors.
- Valve Blocks: Could be monoblock (Vertical Trees) or split block (Horizontal Trees).
- Tree Cap: Provides protection for the valve block from debris and corrosion. Sometimes serves as a secondary pressure barrier.

In general the subsea X-mas trees are divided into two main categories:

- Vertical Trees (Conventional).
- Horizontal Trees

Vertical X-mas trees have the three main valves integrated in the main block. The lower master, the upper master and the swab valves are all in line and on top a tree cap is installed.

This valve arrangement affects the dimensions of the tree by adding to the elevation. Vertical X-mas trees have lengths around 5-6 m (Figure 29) and up to 8 m when stacked up over the tubing head spool. The tubing hanger lands in the wellhead (Tubing Head Spool) when vertical trees are used.

Figure 29 Vertical X-mas tree lowered for installation (FMC Technologies)

Horizontal X-mas trees could have two valves in the main block and the third isolation barrier is achieved by installing a plug above the swab valve. The other master valve is installed in series with the wing production valve downstream of the side outlet. Having the master valves at the wing outlet leads to a more compact arrangement and thus leading to a smaller size X-mas tree, with and elevation of about 4-5 m (Figure 30).

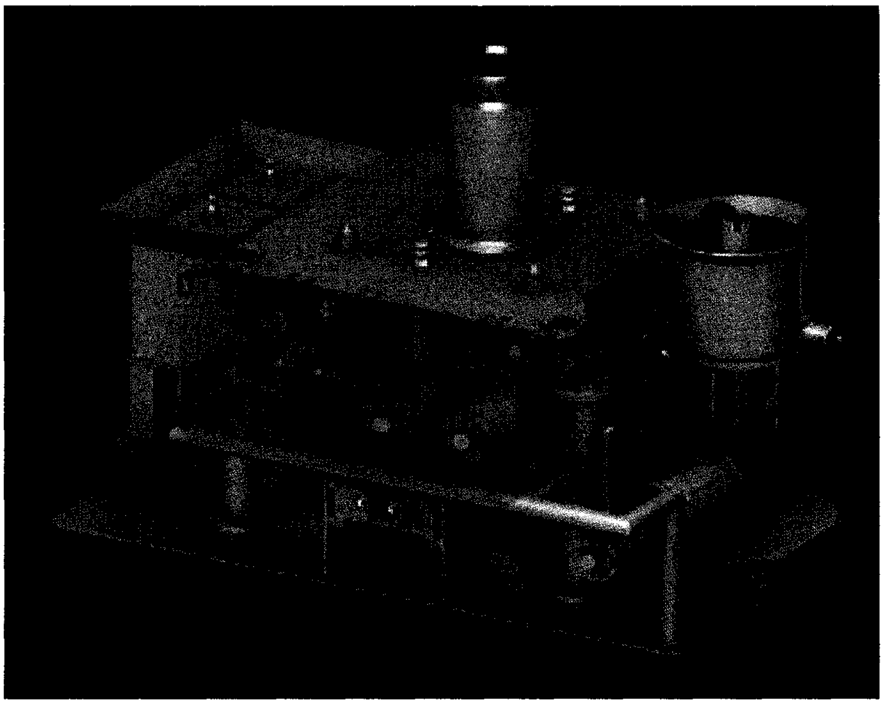


Figure 30 Typical horizontal X-mas tree (Cooper Cameron, 2007)

Some Horizontal Christmas tress use wireline plugs as vertical barriers and have the master valve installed in series with the wing production valve downstream of the side outlet. This configuration of horizontal X-mas trees does not have any valves located in vertical line with in the tree block. The tubing hanger lands in the machined profile of the horizontal X-mas tree after being suitably oriented (Figure 31).

Valve actuation and control of subsea trees could be mechanical using an ROV (old trees) or electro-hydraulic where signal are sent from the surface control unit to the subsea control module (SCM) which directs the signal to the targeted tree component via the tree control panel.

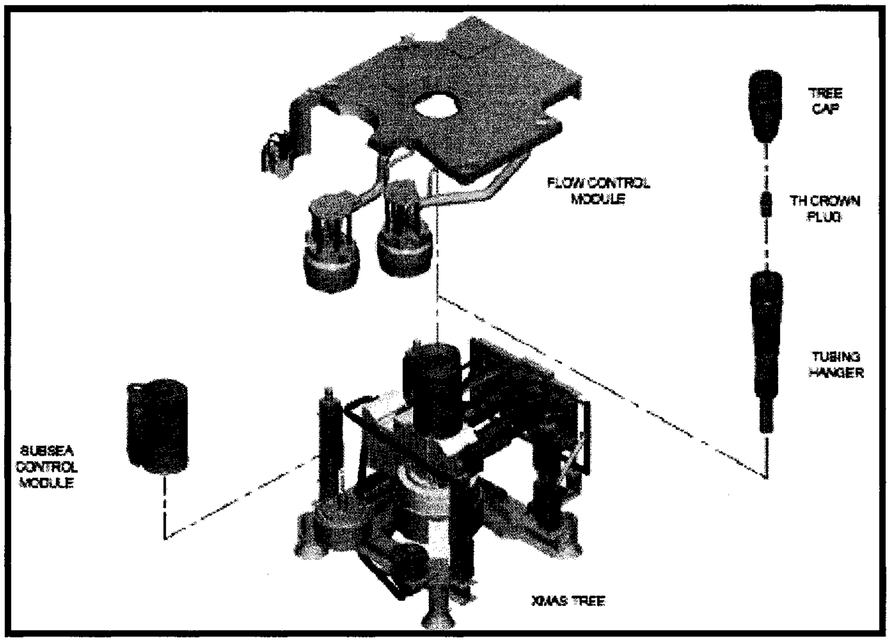


Figure 31 Horizontal X-mas tree arrangement details (FMC Kongsberg Subsea, 2006)

Still the services of the ROVs are required for electro-hydraulic controlled trees to carry out uncontrolled surface operations that require direct intervention, in addition to the routine inspection services.

4.3 Marginal Fields Development -Grand Banks

The development of marginal fields requires almost the same equipment required for a major field development. Some equipment and components might not be used in a marginal field such as the manifolds or templates when a single well is tied back to an existing facility (single or daisy chain arrangement).

So far, no marginal fields on the Grand Banks, have been developed employing a tie back technique, although the Jeanne d'Arc basin and adjacent Ridge Complex contain fourteen smaller discoveries and four major fields as marked on Figure 32 below. Geographically, most of these marginal fields are in close range to the major developed and producing fields where a stand alone development with a subsea tie back could be a feasible technical and economical option to use.

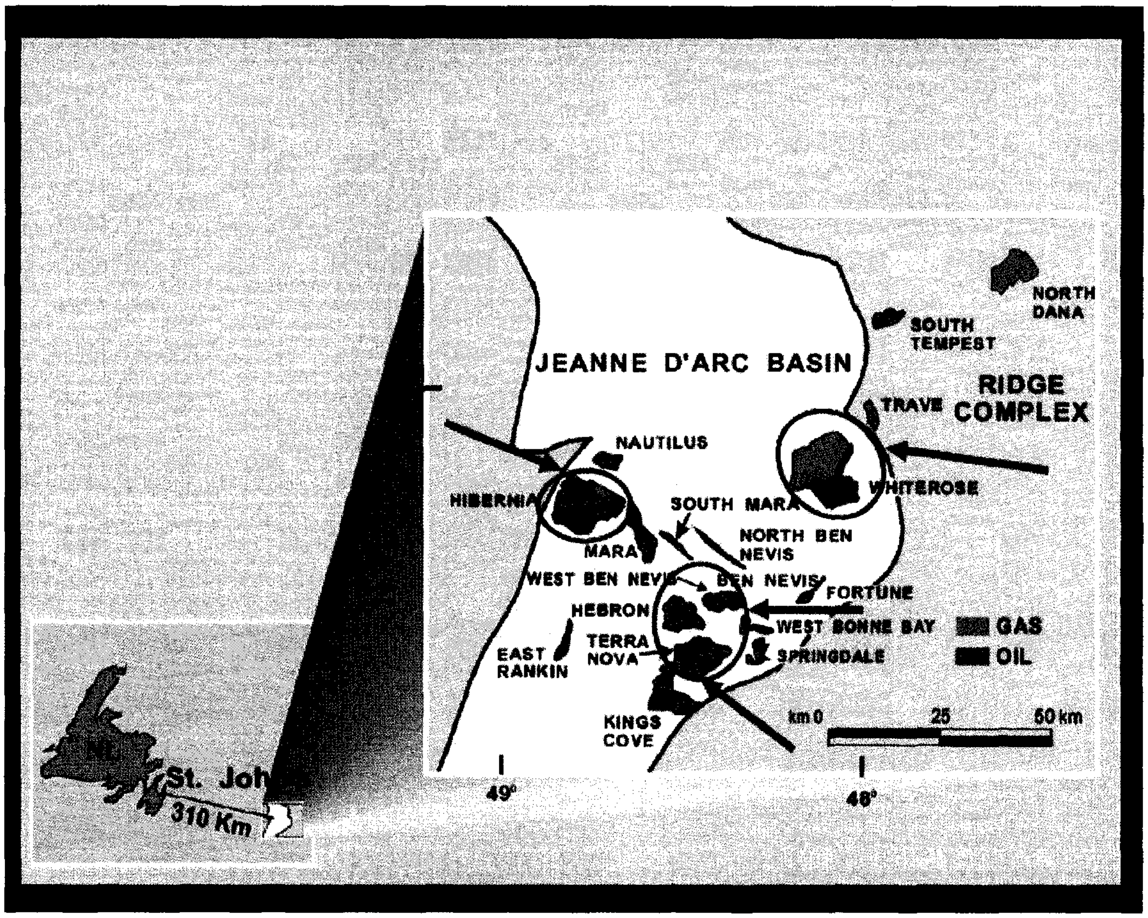


Figure 32 Significant (marked with red arrows) and marginal discoveries. (C-NLOPB, 2003)

Due to the unconventional threats imposed by the traveling icebergs, developing the marginal fields of the Grand Banks using a tie back, needs a careful economical and technical evaluation. New and flexible strategies are to be adopted to overcome the unconventional iceberg threats. Such Strategies has to take into consideration:

- Meeting the regulatory and industry safety standards.

- Improving the economics by maintaining acceptable production costs.
- Flexibility to accept and adopt new applications of techniques and employ cutting edge technologies.

The operating companies of the Grand Bank fields (Petro-Canada, Husky, Norsk Hydro and Hibernia Management and Development Company (HMDC) have all been studying the feasibility of developing marginal fields through tiebacks with existing facilities at the Hibernia Terra Nova and White Rose fields.

In any conventional tie back project, many key issues have to be studied and evaluated, such as: the effective subsea engineering, flow assurance, consideration to use of new expensive technologies such as the Intelligent Well Completion System (IWCS).

On top of the above mentioned issues, wellhead protection from traveling icebergs remains one of the most important challenges and takes the priority in any future intended tie back development on the Grand Banks.

Adopting any of the existing wellhead protection methods employed in the present producing fields, (pre-drilling of the Glory Holes) will increase the capital expenditures to produce the marginal fields and will negatively affect the profitability of the projects. Petro-Canada has done a study as part of Terra Nova plan (C-NLOPB, 2005) to develop the Far East area of the reservoir and has come to a conclusion that two different scenarios that might be applicable considering the available verified wellhead protection methods:

1. Excavating a glory hole to place a drill center and tie back the wells to the existing facility.

2. Using directional drilling from an existing drill center and risking the ability to produce the whole reserves.

The final result was that: for oil reserves less than 35 Mbbls with a margin of 10 Mbbls, a Glory Hole excavation to place a drill center and tie back to the existing facility would not be feasible and thus other alternatives had to be used, such as the directional drilling or new wellhead protection techniques.

4.4 Wellhead Protection – Decision Criteria

The decision of using a specific wellhead protection system is not based on a single factor. Such decision depends on many inter-related factors. Stating the most important of these factors as follows:

- Field size and estimated reserves
- Reservoir properties and dimensions
- Number of planned wells
- Type of production enhancement and fluid injection
- Hazard type, severity and frequency
- Risk and consequence
- Safety, environment and economics

On the Grand Banks a criteria could be established for wellhead protection method decision making based on observations of the already developed fields and as well the recommendations of the conducted studies for future developments.

Hibernia field with estimated recoverable reserves of more than 750 Mbbls utilized a GBS platform for development and accordingly the wellheads and dry X-mas trees were installed on the platform.

Hebron field which is in the last stages of technical and commercial evaluation (M. MacLeod, 2006) could be the second largest field on the Grand Banks with an estimated recoverable reserves ranging between 400-700 Mbbls and is planned to be developed using a GBS platform and similarly to Hibernia, the wellheads and X-mas trees will be installed on the platform.

For the other two producing fields, Terra Nova and White Rose ,with an estimated recoverable reserves of 224-354 Million bbls and 200-283 Million bbls respectively, a floating production facility (FPSOs) were utilized and the wellheads were installed as part of the drill centers in the Glory Holes.

In the development of the Grand Banks fields, the cost of the method used for wellhead protection was accepted and justified: Mainly economically based on the oil reserves, and then technically. Other factors such as technical uncertainty, public perception of risk, could be factors that played a roll in the decision making as well.

The summary presented in the table below (Table 5) relating the Grand Banks fields reserves, development cost, and the wellhead protection method, can give a good overview about the field development criteria and the adopted strategy for the Grand Banks fields.

Table 5 Grand Banks field development criteria

Field	Hibernia	Hebron	Terra Nova	White Rose	Tie Back	Tie Back
Reserves (Million bbls)	> 750	400-700	224-354	200-283	35	<25
Cost (Billion $)	5.8	3.2 -5.2	2.8	2.35	N/A[1]	N/A[1]
No. of Well Slots	64	46-54	28	19-32	N/A[1]	N/A[1]
Wellhead Protection Method	On GBS[2] Platform	On GBS[2] Platform	Glory Hole	Glory Hole	Glory Hole	

[1] N/A : Not Available.
[2] GBS : Gravity Base Structure.

The question mark is still pending for the reserves of 25 Million bbls or less where there was a recommendation raised by Petro-Canada to investigate and evaluate new ideas for wellhead protection other than the glory holes to reduce the subsea development cost for future tie-backs of these marginal reserves.

The suggested shear link wellhead concept presented in this thesis is in response for the industry need for new ideas to protect wellheads on the Grand Banks.

5. Subsea Wellhead Protection and Well Integrity

5.1 General

Terra Nova being the pioneer project for a subsea development on the Grand Banks, and after few years the White Rose project, both had to face the challenges of the harsh environment and the risk damage of icebergs to the floating and the subsea infrastructure.

Thousands of subsea systems are operating efficiently and safely in various areas around the world, but the case of the presence of icebergs in the vicinity of an oil field requires more careful and detailed design solutions to mitigate this risk.

As we could see from the discussion in Chapter 3, that the highest iceberg presence would either be alongside the cost of Newfoundland or funneled towards the eastern edge of the Grand Banks through the Flemish Pass in the area called the "Iceberg Alley". (Figure 14)

Still several floating or gouging icebergs (draught less than ~110 m) stray into the centre of the Grand Banks and thus impose a risk on the fields operations and infrastructure.

Although the probability of iceberg interaction with a subsea infrastructure remains low, as reflected in Figure 20 of Chapter 3, but still it does not meet the recommended annual target level of safety 1×10^{-5}. Accordingly, protection of the subsea infrastructure and adopting an ice management policy for the whole production/processing system remains highly important to meet the accepted risk values.

The focus in this subtitle and the coming chapters will be on the subsea wellhead protection, while the ice management policy and risk mitigation for the whole system was described in Chapter 1 and in Chapter 4.

5.2 Protection Methods for Subsea Wellheads

In general, the Protection Strategy of the subsea wellhead can be divided into 3 main categories:

- Preventing (avoiding) iceberg wellhead contact on a risk-based approach to meet the set acceptable risk probability.
- Protection (drill centers in Glory Holes)
- Sacrificial, accepting Iceberg wellhead contact and employ a risk based design concept of the wellhead to meet the acceptable risk level.

Several concepts and methods for wellhead protection from iceberg gouging have been studied and evaluated since the mid seventies when the industry started to look for oil in the offshore of the Arctic (Beaufort Sea) where Glory Holes were used at the beginning and then the subsea caisson, a more economical alternative, for BOP and wellhead protection was adopted. (G.A. Logsdon et al. 1983)

In this section the wellhead protection methods that were evaluated and considered safe and feasible by the operating companies on the Grand Banks will be highlighted and discussed. The suggested system by this thesis will be presented as an alternative as well.

Two systems were assessed as a probable subsea wellhead protection application for the Grand Banks: One was used to protect suspended wells that drilled as delineation wells. The other system was used for the protection of the wells used for field development.

5.2.1 Caisson Wellhead

Caisson wellhead systems (Figure 33) were first employed as a protection of the fishing trawlers damage in the South China Sea. Petro –Canada used caisson wellhead system for protection from iceberg gouge damage to complete five suspended delineation wells. The diameter of the caisson used was 1067 mm OD x 990 mm ID (Terra Nova Development, 1996). The system was preferred by Petro-Canada during the exploration stages of Terra Nova field since similar drilling equipment used for the subsea wellhead installation were used to drill and set the caisson wellhead below the seabed from the drilling rig itself.

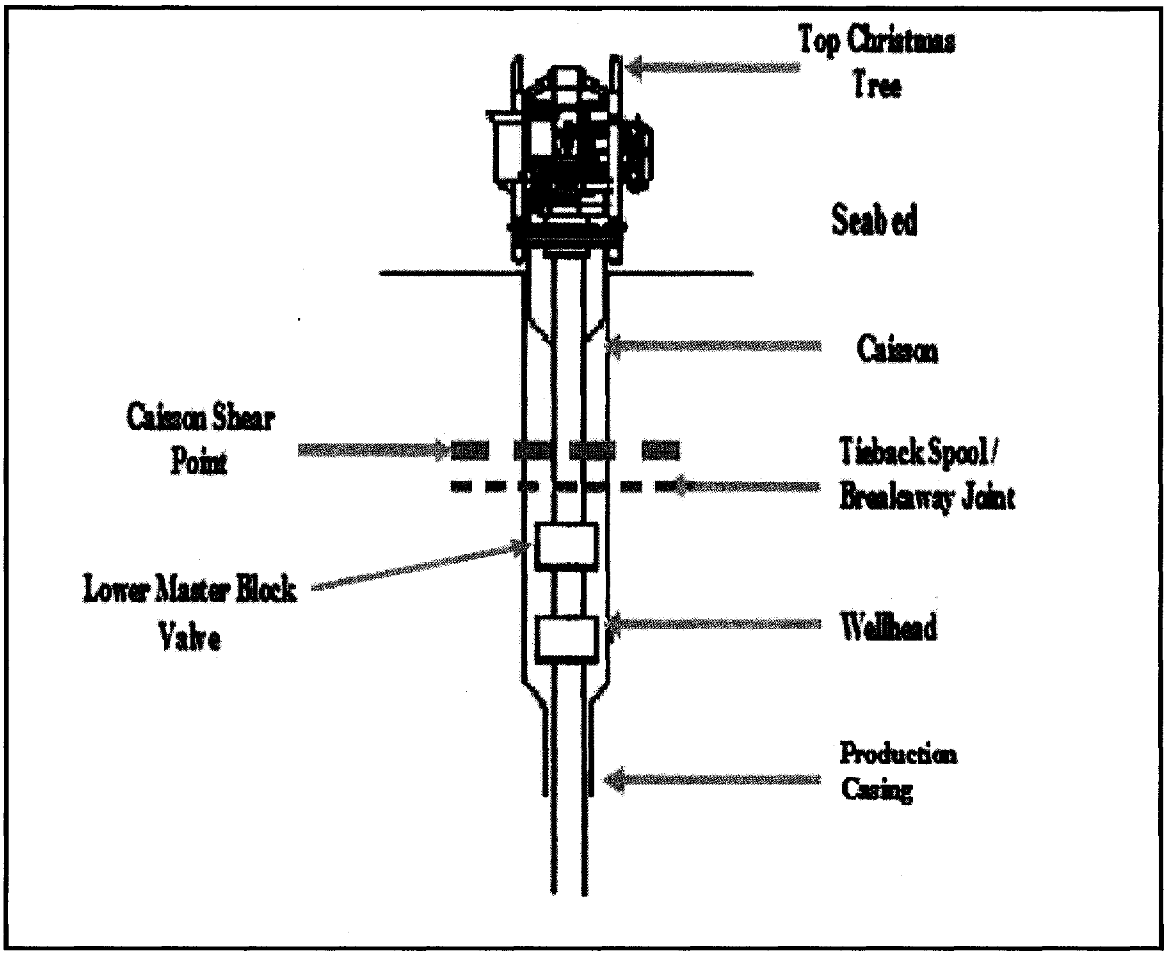


Figure 33 Caisson wellhead arrangement

The caisson assembly employs a sub-mudline suspension system for the casing hangers.

The well completion and tree configuration is different from the conventional subsea production tree where the tree valves are divided into two assemblies.

The lower assembly including the tubing hanger and a master block valve situated at the bottom of the caisson far below the ice gouging. The upper tree which is a conventional vertical tree with all the components (Valves controls and connections) is located on the sea floor. The caisson is manufactured to have a pre-designed shear point below the upper X-mas tree and above the lower assembly and tubing hanger. A tie back spool with a break away joint, attach the caisson master block valve to the Christmas tree located on the mudline.

If the system functions as intended, such wellhead arrangement guarantee the well integrity in case of any iceberg (floating or gouging) interacts with the X-mas tree or the upper part of the wellhead. The failsafe valves, which include the caisson master block valve and two subsurface safety valves will get actuated once the top X-mas tree holding the control panel is displaced leading to hydraulic pressure loss off the valves actuators.

Upon an iceberg impact and in the case of the caisson damage, the work over steps would be damage assessment and inspection as a first step to assure well integrity, and then followed by the other steps : displaced X-mas recovery and debris clearing, dredging the area around the caisson for accessibility, tie back to surface and installation of a new X-mas.

From the operational side of the X-mas, there is an advantage of having it on the seabed, where there is a good ROV access for routine visual inspection, operations and any required maintenance.

Having the master block valve located below the mudline as part of the wellhead can be considered as a draw back since the valve could only be serviced or replaced when major workovers are performed on the well. The functionality and practicality of the caisson completion concept has not been field tested, as there has been no recorded incident for any of the existing suspended delineation wells on Grand Banks.

5.2.2 Cased Glory Hole

This method involves the installation of a steel or concrete cylindrical casing of 7 to 8 m diameter, and to a depth of 10-12 m. A single wellhead and the X-mas tree are then placed in the bottom of the cased hole. The big round space that a cased glory hole provides is to accommodate the X-mas tree and it's components as well, in addition to enough space for the ROV maneuvering to carry out the required inspection and maintenance work.

The glory hole casing has a shear-point at a pre-determined elevation below sea level (Figure 34) which is normally located below the gouge depth (Terra Nova Development, 1996).

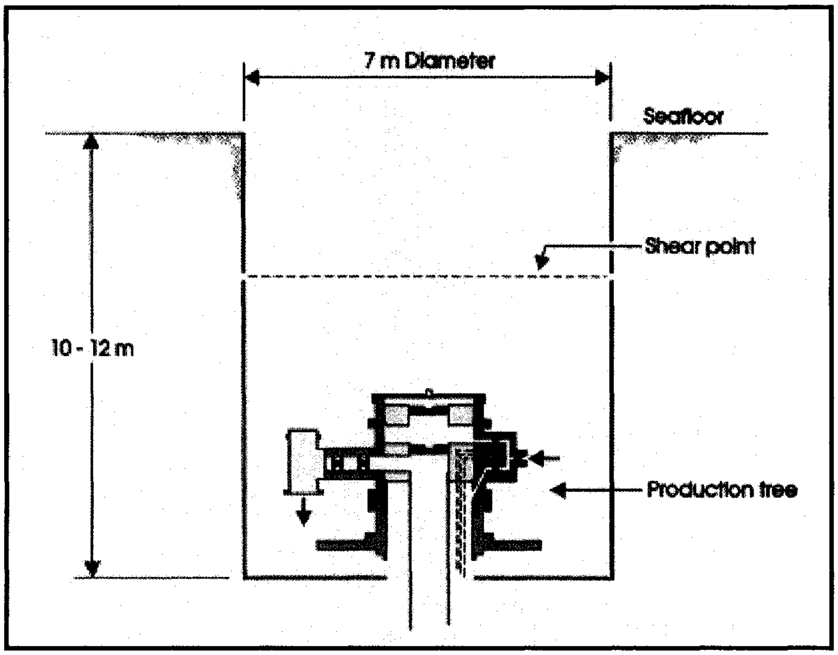


Figure 34 Cased Glory Hole arrangement (Terra Nova Development, 1996)

In the case of iceberg impact, the glory hole casing is broken at the shear point where the upper part of the glory casing is sacrificed, leaving the lower part, the wellhead and the X-mas tree undamaged.

The installation of the Cased Glory Hole can be done using a semi submersible drilling rig at the beginning of the well drilling, or using any other construction/service barge outfitted for this purpose, prior to the drilling operations.

If the caisson is to be lowered to the seabed through the moon pool, the opening in the vessel bottom, a dimension restriction could exist and other options to be considered such as a pass over as with other equipment on pipe lay barges.

Using the reverse circulation technique by flowing compressed air to the drill pipe, a large drill bit known as a the Glory Hole Cutter or Tornado glory hole excavation systems is used (Figure 35).

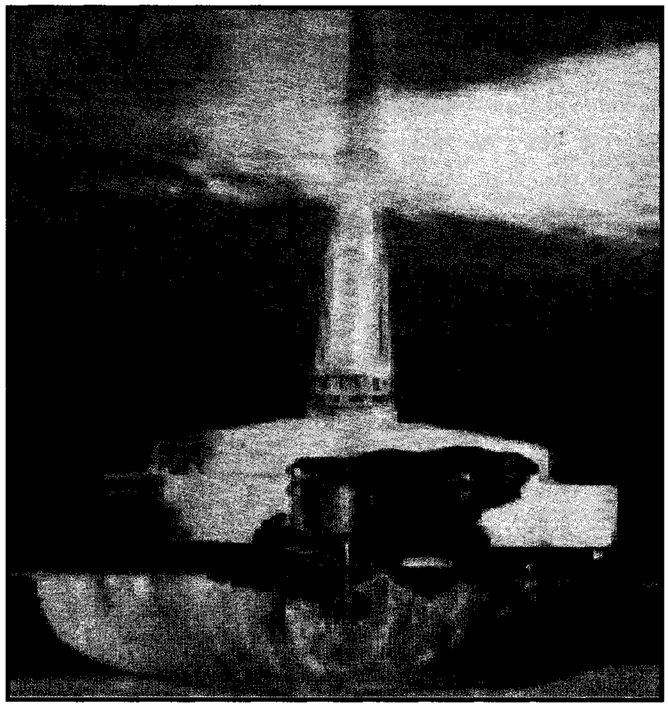


Figure 35 Glory Hole drilling system
(Canadian Petroleum Engineering Inc. 2007)

In some applications the cutter is lowered below the glory hole casing all on the drill pipe, and drilling is carried out to the required depth of 10 -12 meters. Once the desired depth is achieved the cutter is unlatched and retrieved leaving the glory hole casing in place. This technique allows time saving since both the drilling and installation are done in one trip.

In the summer of 1990, a field trial to install a cased glory hole at Terra Nova for technical and economical evaluation purposes.

Using a semi-submersible drilling unit, and after two trials, the program was stopped before planned drilling depth was reached and the full casing was installed.

One of the main problem that the cased glory hole construction on the Grand Banks is the presence of numerous boulders on the seabed and in the layers below, with a very high density of 2.8 ton/m³ and dimensions which could be considerably big up to 1.4 m long, 1.2 m wide and 1.1 m high and a total weight of 4.8 tons (Jan De Nul Group, 2003).

In the event of an iceberg impact, the X-mas tree and wellhead would not be affected as discussed earlier. The work over scope could consist of cleaning up the debris in the cased glory hole, installing a new top section of glory hole casing, and replacing the damaged flowlines and umbilicals or reconnecting the existing ones if still in a working condition.

There were concerns raised questioning the safety and practicality of the cased glory hole system upon interaction with gouging bergs It was concluded after conducting a numerical modeling that such interaction may lead to instability of the berg due to the significant loads on the it's keel leading to heave motion or capsize on top of the glory hole causing enormous damage to the glory hole and well structure (C-CORE, 1997).

5.2.3 Uncased Glory Hole

Known as open glory holes, are large dimensions excavations on the seabed, where templates, X-mas tree and wellheads are situated deep enough away from any gouging icebergs (Figure 36).

So far, the open glory hole method is the system adopted for the wellhead and X-mas tree protection for the subsea developments on the Grand Banks. The selection of the glory hole method was promoted for economical reasons based on the justified and acceptable cost when employed for major field development compared to other alternatives. Another factor was the availability of experience, proven technology and equipment, all accumulated and gained from many dredging activities in various places around the world.

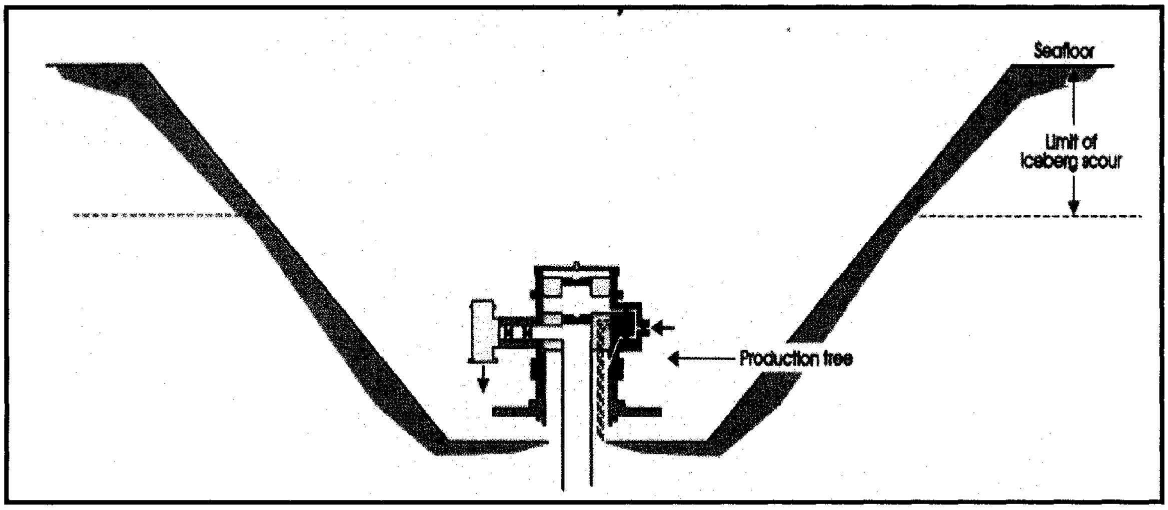


Figure 36 Un-Cased Glory Hole Arrangement (Terra Nova Development, 1996)

The size of the open glory holes is large, for example the size of the central glory hole of White Rose field was, 9 m depth and bottom dimensions of 50 m x 60 m (Jan De Nul Group, 2003).

This protected area allows the establishment of one or more drill center in each glory hole, (Figure 37) and thus drilling of several wells with in .The wells in the drill center, could be either production or injection wells. Flowlines and umbilicals connect the drill center manifold and control system components to the floating facility.

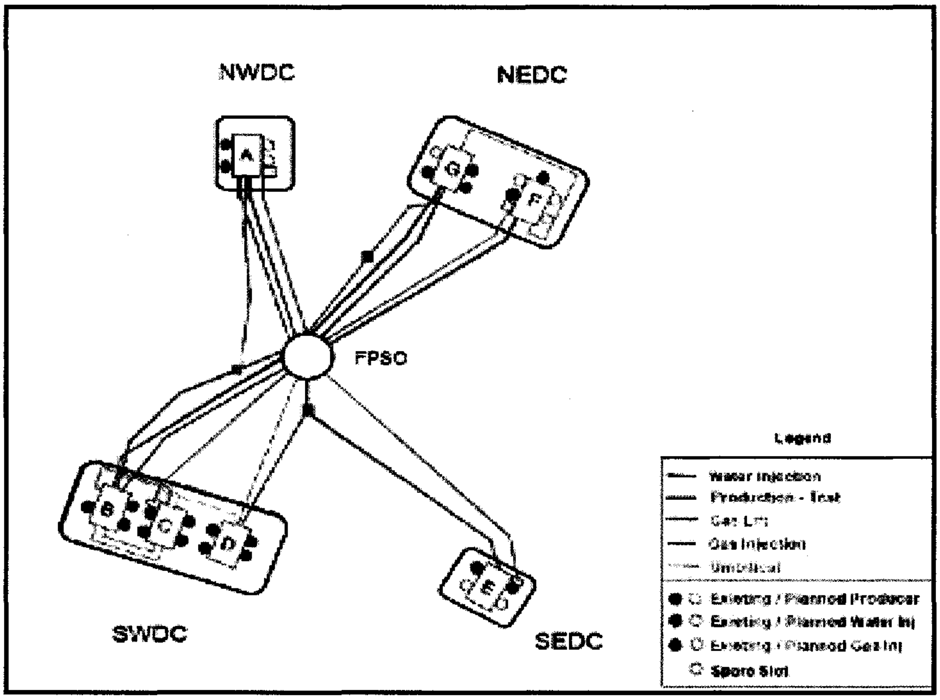


Figure 37 Terra Nova drill centers and slot utilization (C-NLOPB, 2004)

Open glory holes excavation on the Grand Banks is time consuming and costly operation which has to be carried out ahead of the drilling stage and during a seasonal operation, for example the glory holes for of Terra Nova had to be excavated in the summer season of 1999.

The seabed soil on the Grand Banks is characterized by it's variability from glacial till (rock debris from the ice age), clay, gravel, sand in addition to numerous boulders on the seabed and in the layers below with a very high density of 2.8 tonne/m^3 and dimensions which could be considerably big up to 1.4 m long, 1.2 m wide and 1.1 m high and a total weight of 4.8 tonnes.

This soil type in addition to the harsh sea state even during summer times made the glory hole excavation a very tough job and added to the cost of operation in terms of time, system design, and modifications.

These conditions imposed the need for a dynamic analysis to be done to determine the ultimate stresses and fatigue on the drag head and as well on the suction pipe and accordingly local and global reinforcements were added as part of the whole vessel structural integrity (Boskalis Offshore bv, 1999).

At the beginnings, dredging of the open glory holes in the Beaufort Sea were completed entirely using large diameter bits deployed from drill ships. Other dredging techniques were later introduced and are still in use now a day to improve the performance and economics of the operations, such as the rotary plow, trailer and hydraulic grab, trailing and suction hopper.

Utilizing a dredging vessel two methods were used in the dredging of the glory holes on the Grand Banks:

- Underwater Grab and Drag system (Grab Shell).

In this method an ROV-steered clamshell grab was especially designed and fitted to a "fall pipe vessel" to operate on the Grand Banks. The ROV operated grab transports the excavated material in a lateral way, shuttling at a short distance above the sea-bottom between dredging and dumping sites nearby.

The "grab and drag" system close to the seabed has the advantages of being less weather dependent and slopes can be kept steeper at the glory hole sides.

Another advantage is that dredging can be done in soils with numerous boulders and depths up to 1000 m. The disadvantage of such system is that is that the dredging rate is slower than the other system, the Trailing Suction Hopper.

- Trailing Suction Hopper Dredging.

A large diameter suction pipe extends from the dredging vessel down to the seabed having a draghead at its end (Figure 38). Powerful underwater pump provide necessary circulation and jetting to do the required dredging. The dredged materials were loaded into the hopper and discharged by dumping through the bottom doors at the agreed dumping location.

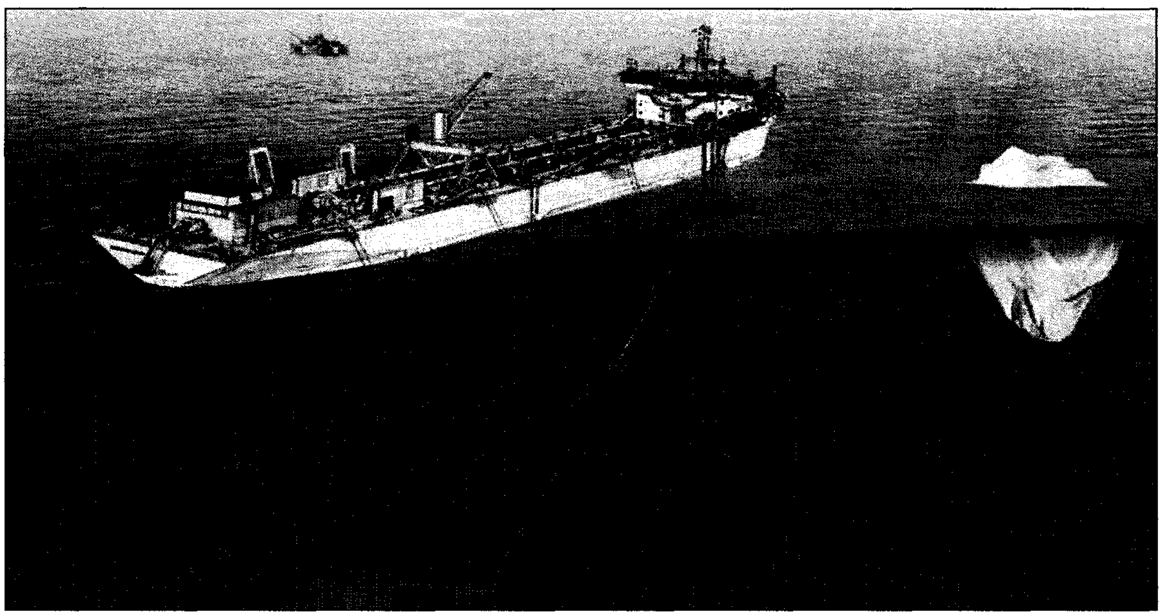


Figure 38 Artist impression of trailing suction hopper dredging (Compliments of Jan De Nul Group, 2003)

Using the trailing suction hopper dredging encounters problems when numerous big boulders persist. There is a limitation as well, on the depth for the above method to be used in the North Atlantic. Around 165 m is the maximum possible operational depth (Jan

De Nul Group, 2003). The main advantage of the trailing suction hopper is the achieved dredging rate which can far exceed the Grab Shell method.

The depth of the Glory Holes on the Grand Banks varies between 9 to 11 m. The open glory holes are dredged to a depth to provide enough draft for icebergs that might be gouging the seabed where entering the glory hole will not contact the top of the X-mas tree due to dynamic heave motion. Movements of the iceberg (heaving, pitching and rotation) once entering the glory hole are as well taken into count (Figure 39).

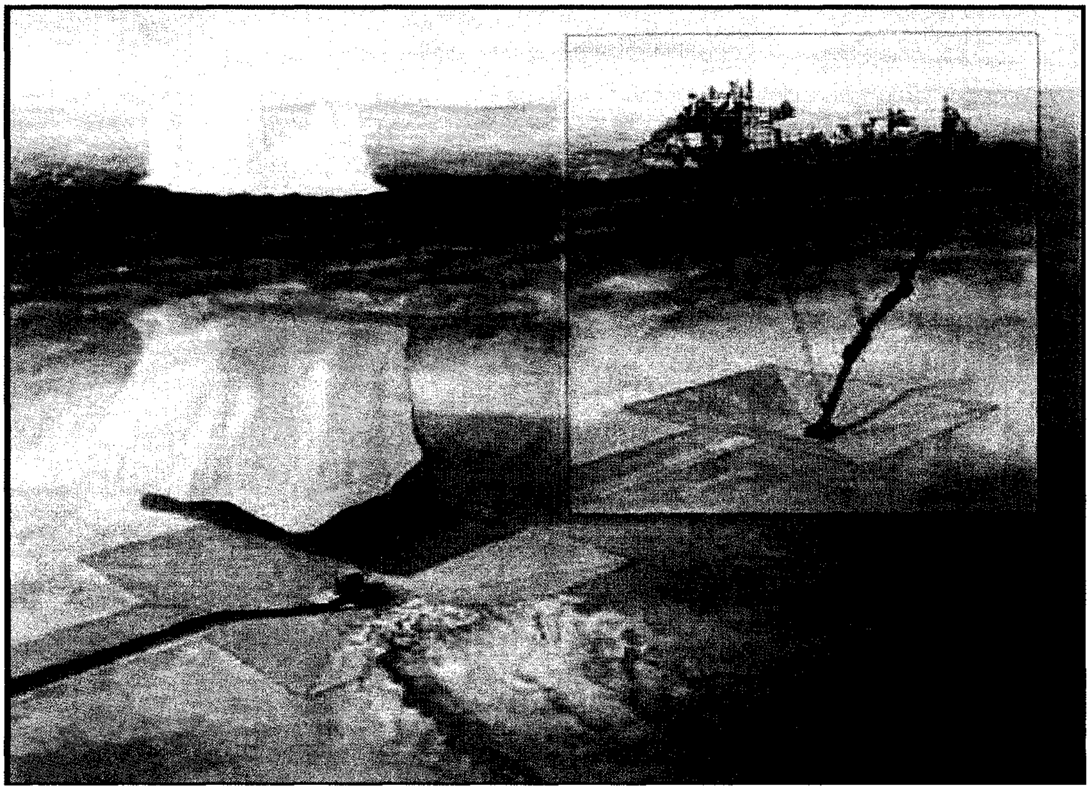


Figure 39 Artist impression of an iceberg passing a glory hole (Compliments of Boskalis)

The other feature of the Glory Holes is the sloped sides as required for stability of the excavation itself and provides a ramp for the flowlines and umbilicals. In the White Rose project the slope for the sides was 1:2 ; For the side where the flowlines and umbilicals exits from the glory holes to the seabed, a slope of 1:5 was achieved.

5.3 Shear Link Wellhead -Suggested System

Shear link wellhead is a similar system to the caisson wellhead system, where it employs a pre-designed shear link situated below the mudline to allow a controlled failure and release of the X-mas tree and part of the casing and completion tubing.

The proposed system is different from the caisson wellhead system, in the X-mas tree connection and support method. In the shear link wellhead, the X-mas tree is supported and connected to the conductor tie back sub joint. The completion tie back (extended neck) extends through the conductor and fits in the bottom of the X-mas tree, leading to have only two pipes (pipe in pipe) extending from the tubing hanger up to the X-mas tree. From the design, analysis and load behavioral, installtion and maintenance points of view, for iceberg contact events the proposed system has several advantages such as:

- The presence of two pipes (two strings) within the upper part of the well leads to better load relief achievement and activation of the shear link.
- Less probability of local damage (local buckling and collapse).
- Employing 30" conductor to house the sub-mudline wellhead eliminates the problem of size restriction imposed by the rotary table diameter.
- Using a standard size conductor with a shear link, allows continuity in drilling. Changing in casing diameter means to trip out of hole to change bit size, which is a time consuming operation.

- The presence of the isolation valve (Block Valve) on top of the tubing hanger and not as an integral part of it, allows the retrieval of this valve for maintenance/repair without the need to pull the completion in a major work over operation.
- Having the X-mas tree connected to the conductor by a clamp will provide an additional annulus pressure barrier.

Submudline casing hangers and tubing hanger are utilized to complete the well. The installation of this system does not require any specialized tools or extra excavation work, as well the requirement of any other vessel than the drilling rig.

All the equipment can be run from the rig floor, during the normal drilling operation. The production / water injection X-mas tree, which is a conventional horizontal tree with all the components (Valves controls and connections), is located on the sea bed level.

There is no lower X-mas tree in the Shear Link Wellhead, a ball valve with collared connections and integral end subs machined to specific tubing threads, is installed as part of the completion and will act as an isolation valve (Figure 40).

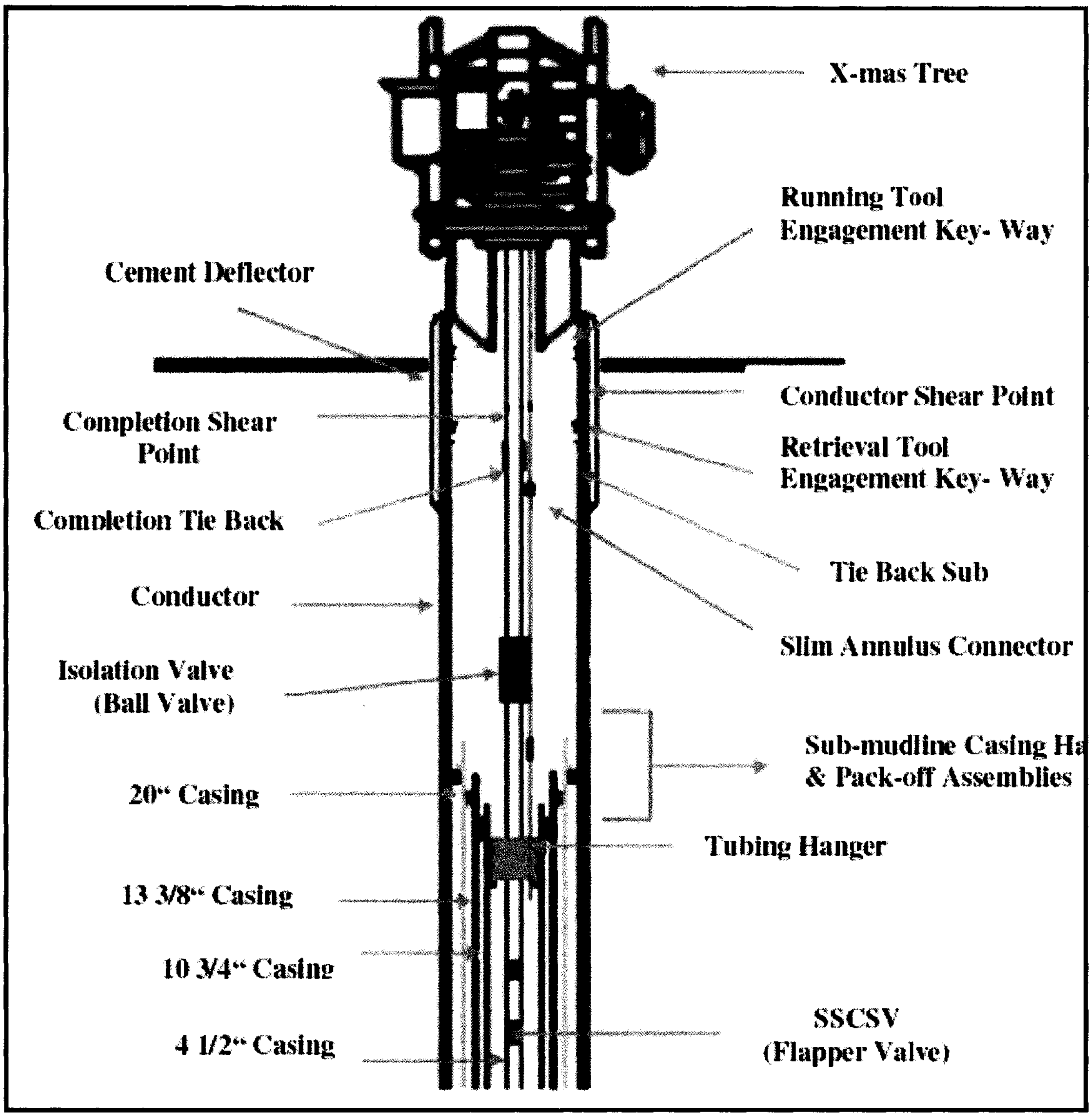


Figure 40 Arrangement of shear link wellhead system

The shear link/tie back spool is located between the mudline and the top of the isolation valve at an optimum depth that is determined by the stress and load magnitudes.

The drilling and installation of the sub-mudline wellhead equipment is some how similar to the conventional well drilling. Drilling can start with running a temporary or retrievable guide base to the seabed, a 36 inch hole is completed and the 30 inch conductor is run into the hole and then cemented. The conductor having a landing sub, with an internal landing shoulder will receive the hanger of the first intermediate casing, the 20 “. The last joint of the conductor has the tie back sub which is connected to the joint above the pin end .This sub connects the conductor to the retrievable tie back joint up to the seabed. The tie back sub is characterized by its low torque left hand threads to avoid the loosening of the conductor joint when released for retrieval (Figure 41).

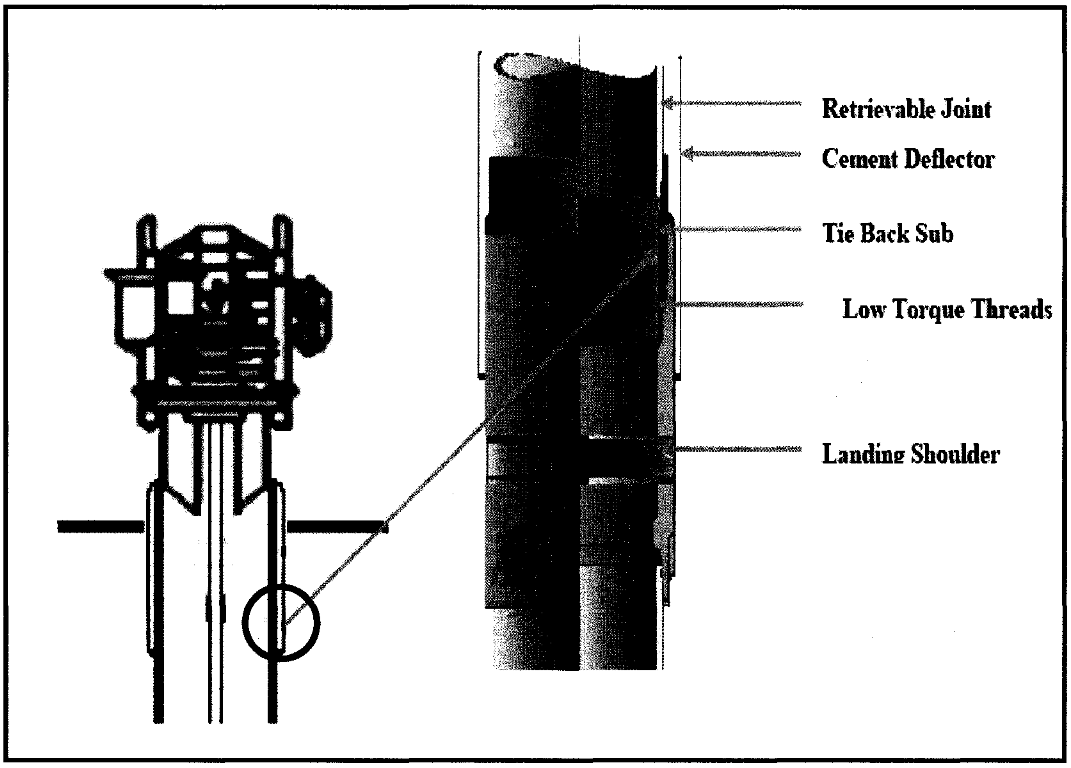


Figure 41 Conductor retrievable joint arrangement

The cement deflector is a steel sleeve extending from below the tie sub up to above the mudline. The cement deflector sleeve is covered from top by a sealed mushroom like cover which is welded to the conductor from one end, and from the other end closes to the end of the cement deflector sleeve with a sealed edge. The purpose of this plate is to prevent the entrance of any return cement when cementing the conductor. The cement deflector is not part of the well structural elements but rather an isolation component, and the distance between the conductor wall and the deflector is minimal (Figure 41).

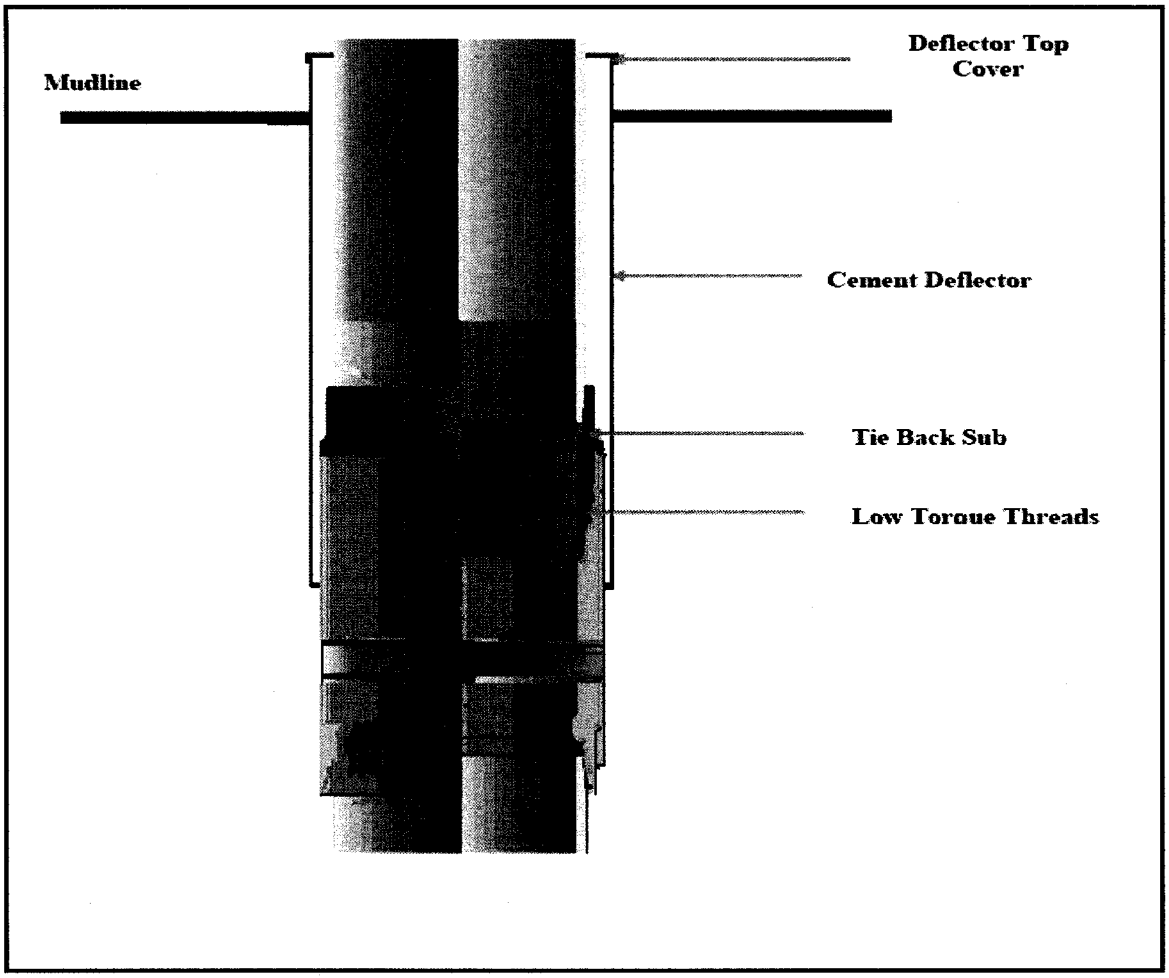


Figure 42 Cement deflector arrangement

Drilling is done using a conductor retrievable joint with no shear link, since considerable stresses are expected during drilling operations on the well string. The intermediate casings and the production casing with their pack-off assemblies are run and locked in place after completing each drilling stage. The tubing hanger is the last to go with the completion below, to get landed and locked in the polished surface of the production casing landing sub.

The landing subs of each of the casing hangers of the sub-mudline suspension system has wash ports, once opened by turning the casing landing joint allows circulation through the casing and the annulus, as discussed in Chapter 4 ,subtitle (4.2.2.3). With each casing string running and cementing job, the wash ports of the landing sub of the casing hangers are opened to circulate the annulus with a special cement retardant agent around the connection of the casing and up to the connection of the conductor retrievable joint to clear all the cement return and prevent any problems during replacement and tie back of the drilling conductor retrievable joint by the one having the shear link.

Once the well is completed and the tubing hanger is locked in place, with the isolation ball valve on top, the BOP is brought down, and the conductor retrievable joint is dismantled and retrieved back to surface. Finally, the conductor joint with the shear link is run into hole to be made up to the conductor sub and thus the well is tied back to seabed.

The tubing hanger has two necks extending out. One is the production line with the production isolation ball valve and the other is the annulus slim line connector (1 ½") with two isolation valves, both run parallel through the tubing hanger. The extensions for both the lines that have the shear links and tie both of them back to the seabed are run and made up to the X-mas tree extended necks, with a full bore landing nipple profile.

This profile will be used to land an isolation sleeve allowing the hydraulic oil pumped from the X-mas tree control panel to bypass the connection at the tubing hanger extended necks and flow to the pass way in the neck to reach the control lines connected to the isolation valve and the two SSCSV.

Once these extensions are in place the X-mas tree is ready for installation. The X-mas tree is lowered and then engaged to the top of the conductor retrievable joint and both the production line and annulus slim line are housed and sealed inside the Christmas tree bottom.

Running the mudline suspension wellhead, would not be a lengthy or complicated operation for a rig installing subsea wellheads. It is a similar operation to a conventional subsea wellhead installation, using the same running tools but, with a little bit longer length requirement for the landing joints.

In the suggested system, extra minimal extra time would be involved in opening the landing- subs' wash ports and circulating the return cement out of the annulus.

The suggested wellhead arrangement guarantee the well integrity in case of any iceberg (floating or gouging) contact and removal of the X-mas tree above the shear key. With in the completion there exist three redundant barriers, which include the isolation valve on top of the hanger and the two subsurface safety valves. These valves will actuate once the top X-mas tree holding the control panel is displaced leading to the hydraulic pressure loss and fail-safe close actuation of the well integrity valves. Similarly the annulus isolation valves will be actuated.

The expected damage scenarios and work over steps will be discussed in more detail in Chapter 9.

5.4 Well Integrity

5.4.1 General

Well integrity is one of the most sensitive issues that have to be taken into consideration when drilling, completing and operating a well. Well integrity is defined as the non presence of hydrocarbons beyond set barriers ,which could be drilling fluids, plugs, back pressure valves, and seals (metal or resilient) during drilling or as part of the wellhead and well completion equipment.

These barriers could be either temporary to carry out a certain work over or well repair or permanent as part of the well structure and completion. Barriers in general are categorized into two groups and are defined as follows:

- Primary Barrier: Is the seal barrier or the seal in direct contact with hydrocarbon all the time.
- Secondary Barrier: Is the seal or barrier that is the second in seal arrangement and will come into contact with hydrocarbons once the primary seal fails.

Some times a third category is added and known as the Tertiary Barrier which is defined as the third and last barrier or seal in the arrangement preventing the hydrocarbon from reaching the surrounding environment once the secondary seal fails.

The well barriers and seals associated with the well completion will be discussed under this sub-title to provide a better understanding of how well integrity can be preserved during iceberg contact and wellhead is subject to damage.

5.4.2 Casing and Well-Completion

5.4.2.1 Casing and Cementing

To reach the most of the hydrocarbon reserves, wells are drilled to depths between 7000 to 12000 feet (Angus Mather, 1995). Other deep reserves, mainly gas reserves are located at depths up to 15000 feet and more.

Drilling this deep is achieved in several stages, where in each stage the hole is reinforced by installing casing which is a major structural component. Casing is needed to ensure resistance against the external pressure created by the formation and the internal pressure created by the drilling fluids and thus to maintain borehole stability, isolate water from producing formations, and control well pressures during drilling, production and workovers. Casing supports the BOP, wellhead equipment and completion equipment as well.

The first stage in drilling will be the conductor installation by drilling and then cementing and securing it in place. The conductor is a large diameter pipe that will provide the support for the subsequent casing hangers.

Drilling of the second hole is done through the conductor and will be of smaller diameter. Similarly the second casing string, which is known as the first intermediate casing and is made up of several pipes connected together pin and box, will be run into the well through the conductor to reach the bottom of the hole. The casing is suspended in the conductor or in the well head by equipment piece known as the casing hanger and then the annulus between the conductor and this casing is cemented.

Subsequent drilling is done for the other stages and the intermediate casing strings are run, suspended each in the previous casing or wellhead depending on the type of the suspension system used, and then cemented. Drilling and hole casing is carried out until reaching the pay zone or the reservoir. Further drilling could be done within the pay zone with out running any casing, which is known as open hole drilling.

Pack off assemblies are run over the casing hangers, starting from the second intermediate casing, to act as a second barrier in case any leak occurs through the cement.

The last casing which connects the reservoir to the surface is known as the production casing, and at this stage is empty except for the drilling fluid (Figure 43).

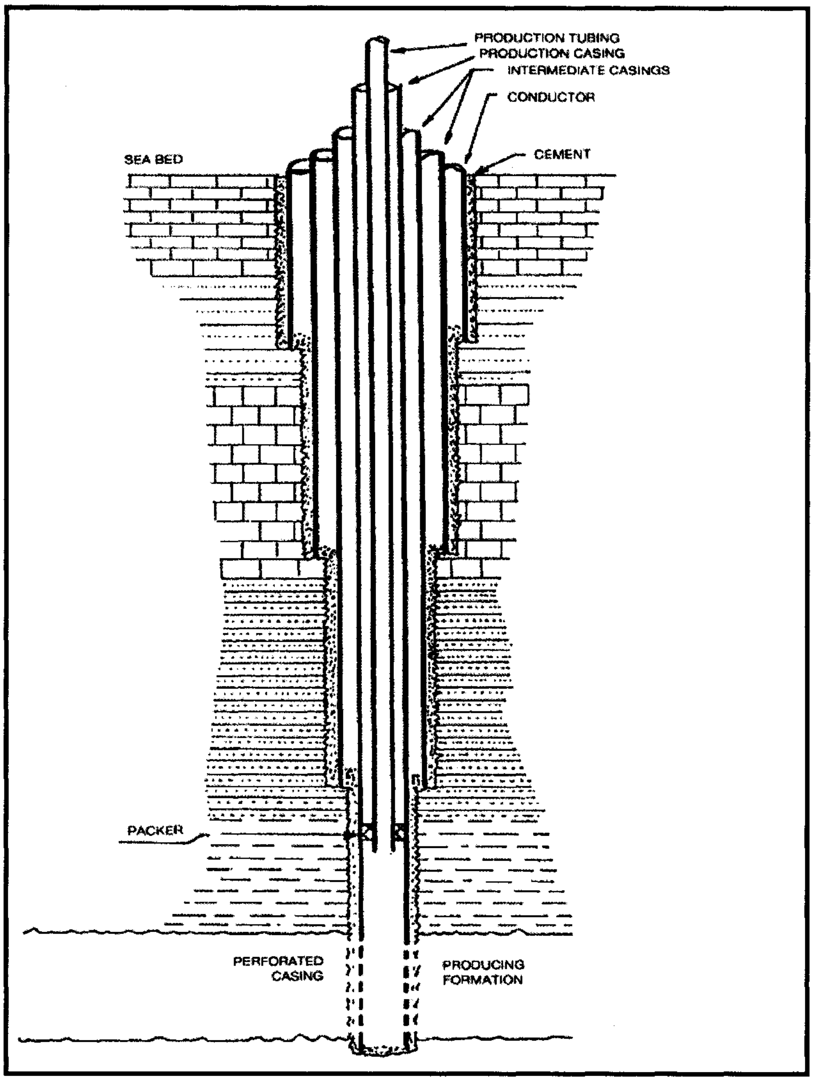


Figure 43 Typical Well Casing Arrangement.

5.4.2.2 Well Completion

Once drilling has achieved the targeted depth and the production casing has been run, the next step would be completing the well by running the production tubing, installing the X-mas tree and then perforating the casing at the level of the production zone as required.

The production tubing would be a smaller diameter pipe than the production casing, and is hanged by landing the tubing hanger and locking it in the wellhead (Figures 43, 44).

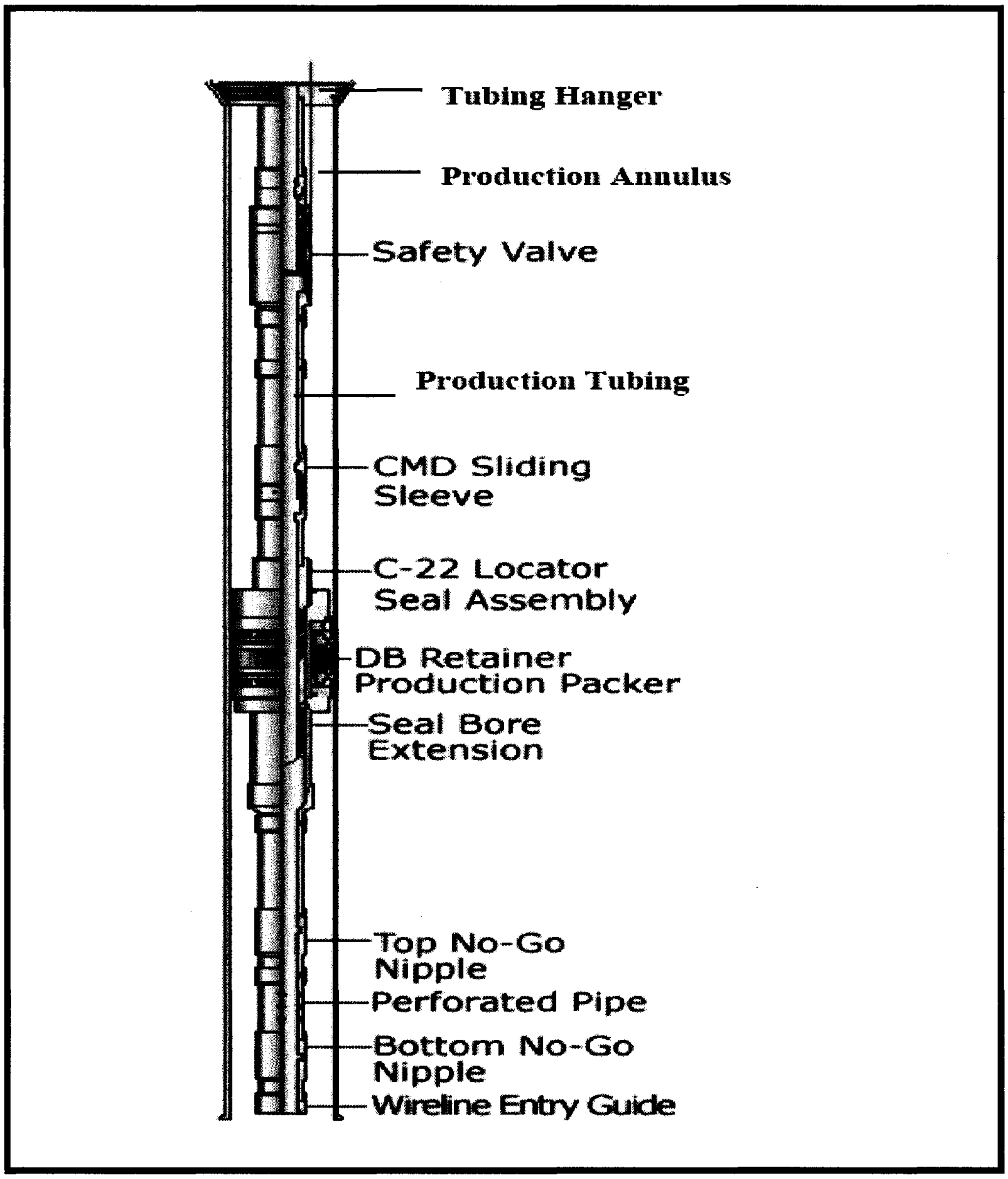


Figure 44 Typical Well Completion Arrangement.

The tubing hanger (Figure 45), with the sealing elements acting as barriers, to prevent the hydrocarbons that could be in the annulus, or the flowing in the X-mas tree to the wing production line, from leaking to other wellhead vicinities or to the outside environment.

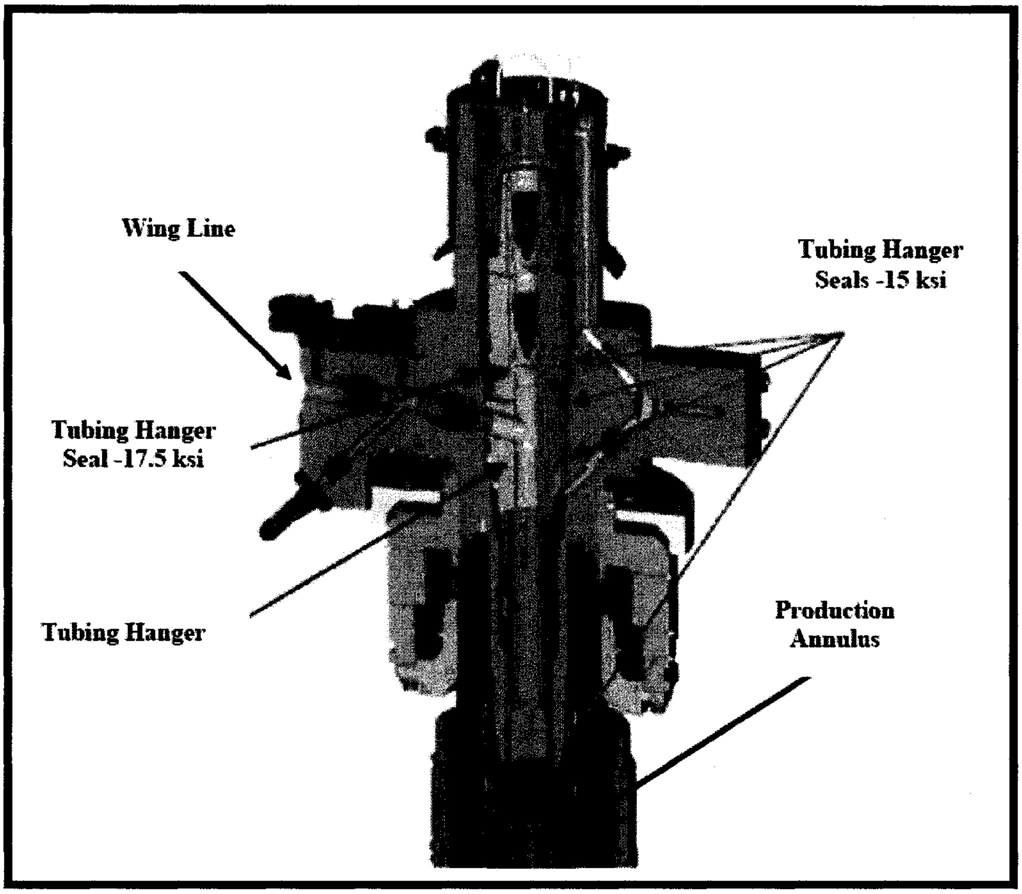


Figure 45 Wellhead and tubing hanger seal arrangement (Compliments of Vetco Gray)

From the bottom end of the production string , a piece of equipment known as the packer is made up and tightened to the required torque on the rig floor .The packer (Figure 46) is set and latched by steel slips to the production casing at a pre-calculated depth slightly above the pay zone.

The packer has the sealing element that prevents production annulus or the annulus between the casing and tubing of be subjected to the formation pressure and fluids. The packer and the tubing hanger act as two barriers to prevent the formation pressure from reaching the wellhead test vicinities, or sometimes called cavities.

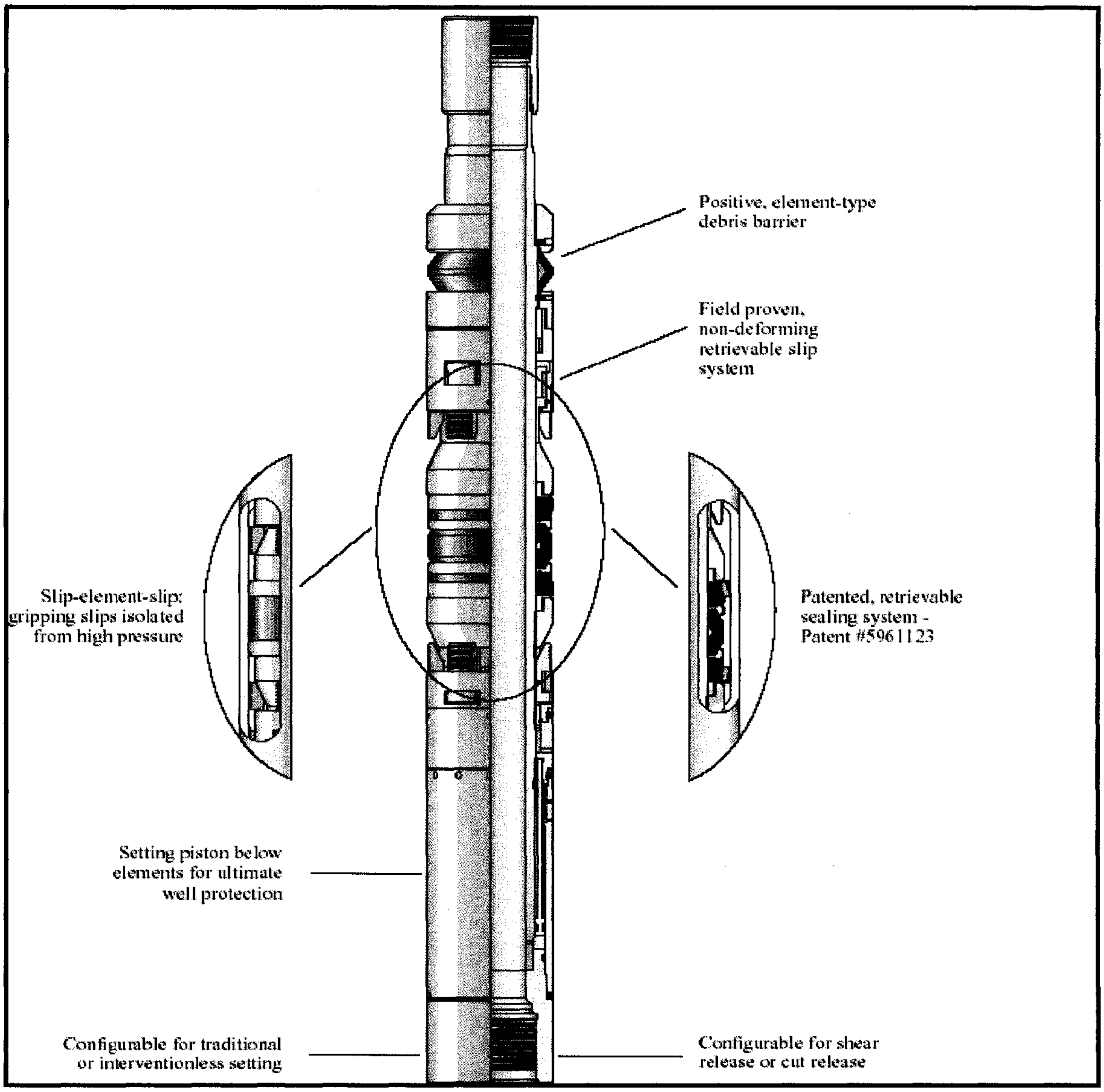


Figure 46 Hydraulically set packer and operating mechanism (Baker Hughes, 2007)

The production string, grooves, recesses, and nipples are made up and tightened to the required torque to the completion joints at pre-calculated space outs. Those components are designed to receive and lock various completion components necessary for well safety, production enhancement /monitoring and work over.

Down hole safety valves, steel plugs and sliding sleeves tools are typical equipment that can be run and retrieved with in the well completion as required. The down hole safety valve, with the X-mas tree as one component are considered the two well barriers for preventing the hydrocarbon fluid from reaching the surrounding environment.

For the subsea well completions on the Grand Banks, two down hole safety valves are used with in the completion string. These valves are, hydraulically actuated of fail safe type allowing only unidirectional follow (Figure 47). Flapper valves are widely employed in well completions as safety valves due to their smaller size when compared to other actuated wireline retrievable safety valves used for the same purpose.

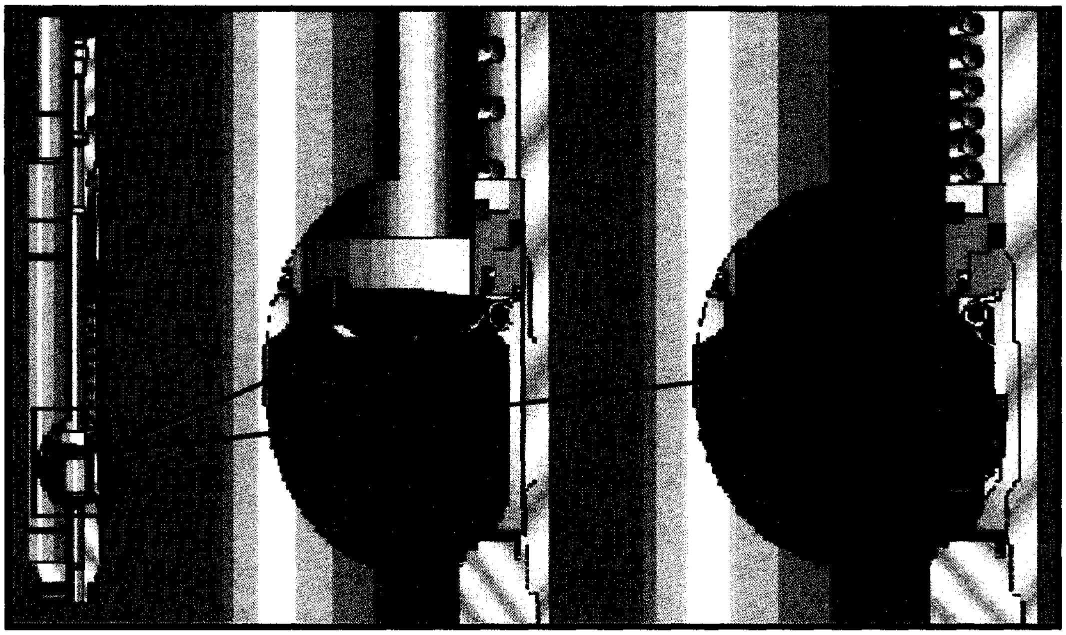


Figure 47 Typical flapper self equalizing down hole safety valve in closed and open positions (Baker Hughes, 2001)

Ball valves are more robust and reliable when compared to flapper valves especially when it comes to sudden closure, in addition to their ability to close and seal even in the case of partial plugging of the tubing due to the presence of paraffin or asphalt, where the flapper valves could not achieve this closure (Pers. Comm. Brian Geary; Baker Oil Tools Senior Completion Engineer, 2005).

The main disadvantages of ball valves (Figure 48) are their much bigger size than flapper valves, and this imposes a restriction to fit these valves in the casings, especially when theses valves are rated for high pressure. Another reason to use flapper valves is the ability to run and set a lock open device with in the valve, in case of a problem encountered in the operating mechanism or the connecting control line. This can not be done in case of a ball valve used as a SSCSV.

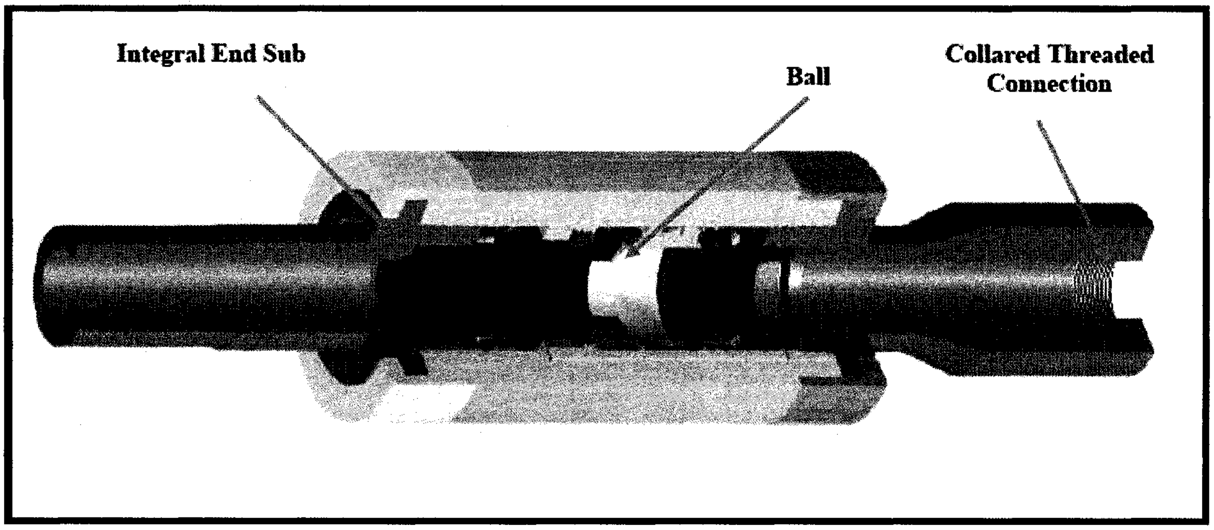


Figure 48 Typical ball safety valve

To give an idea about the dimension difference between safety flapper valves and safety ball valves a comparison table is showing below:

Table 6 Comparison of flapper/ ball SSCSVs.

Sl #	Valve Type	Model	Rating (Psi)	Size	OD	Manufacturer
1	Flapper	TSM(E) (1)	135000	5 1/2"	8.6" (213.44mm)	Baker Hughes
2	Flapper	FVQ(DM) (1)	15000	4 1/2"	7.8" (199.12 mm)	Baker Hughes
3	Ball	OWLV(2)	10000	5"	15" (381 mm)	Expro Group
4	Ball	OWLV(2)	15000	5 1/4"	18" (457 mm)	Expro Group

(1) Baker Hughes Safety Systems Package
(2) Expro International Group Products.

In the majority of the wells, the production casing is either a 9 5/8" or a 10 3/4" size, which make it impossible to run a ball valve as an SSCSV.

5.4.3 Barriers Failure and Leak Probability

It is evident from the above discussion that well integrity is maintained by at least keeping two barriers isolating the formation pressure and fluids from the surrounding environment or wellhead vicinities.

With in the production casing, the packer and the tubing hanger act as two barriers to prevent the formation pressure from reaching the wellhead seal test vicinities.

Leak could occur as well to the production casing through the connections of the completion string joints .Another source of leak could be the non return valves of the injection mandrels which are fitted in subs as part of the completion. Such leaks lead to pressure build up in the annulus in-between the packer and the tubing hanger.

When a major work over is to be performed, the X-mas tree is to be replaced by a Blow Out Preventer (BOP). With in the completion string, at least two isolation barrier have to be installed. (Norsok Standard, 2004)

Some companies' workover guidelines would not count the SSCSV, although of the high reliability SSCSVs have, as a barrier and would go for installation of plugs with in the completion below the packer, and a back pressure valve in the tubing hanger as a second barrier before replacing the X-mas tree by the BOP. Other companies would accept the SSCSV as a barrier in addition to another wireline set barrier. The presence of two SSCSV in series would be sufficient to at least count both of them as one barrier.

In the suggested shear link system intended to be used for wellhead protection, it should be clear that the tubing hanger act as a barrier and as a locking mechanism for the completion string, and should be away from any anticipated damage.

The X-mas tree and the top side of the tie sheared joint, once sacrificed and displaced due to an iceberg wellhead interaction, there will be a requirement to have an at least one barrier to be in line with the two SCSSVs. This is accomplished by placing a fail safe isolation ball valve above the tubing hanger, and away from the excessive stresses anticipated. There will be no size restriction in installing the isolation valve (ball valve) on top of the hanger since it will be housed in the 30" conductor.

The isolation ball valve with the two SCSSVs get actuated simultaneously once the X-mas tree is displaced with the control panel connected to it leading to loss of pressure in the valves actuators. It is assumed to have two annular safety valves placed series on the slim annulus line and act as a dual barrier.

5.4.3.1 Completion Components Failure Rate

In the analysis " Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, September 2000" Det Norske Veritas, indicated the following reliability failure rates figures for some subsea completion components (Table 7). The reliability is expressed as Mean Time To Failure (MTTF). The probability of leak through these components will affect the well integrity once the X-mas tree and the top side of the tie sheared joint, got displaced upon an iceberg interaction.

Table 7 Failure Rate Data Summary

Component	MTTF (years)
Packer	330
Chemical Injection Valve (CIV)	100
Tubing Joints (TBG)	17000/Joint
Subsea Tubing Hanger Seals .(HGR)	127
Subsea Isolation / Master Valves	1000
Surface Controlled Subsurface Valve (SCSSV)	89

Assuming a constant failure rate, the age related reliability R(t), at time, t, is calculated by:

$$R(t) = e^{-t/MTTF}$$

The probability of leak is:

$$\mathrm{P}(t) = 1 - R(t) = 1 - e^{-t/MTTF}$$

Where:

$R(t)$ reliability at time t

MTTF mean time to failures

$\mathrm{P}(t)$ probability of failure (leak) with in time t

The time "t" is taken as a 10 years period considering one major work-over operation on the well through the total well life time of 20 years in which all the components in Table 5 will be replaced.

The MMTF for tubing joints in Table 5 is given per joint. The total well depth (true depth) is assumed to be about 5500 m based on the data obtained from daily progress report for White Rose Field on the Grand Banks (C-NLOPB).

A conservative assumption is made of a total number of 550 joints to form the completion string (the average length of a completion joint is 10m), since joints below the packer should not be included as a probable leak source to the production annulus.

The two annular safety valves placed as barriers on the slim annulus are considered to have the same MTTF of the chemical injection valve, considering their size and function which is similar to the chemical injection valve.

The FTA shown in Figure 49 reveals the probability of hydrocarbon release to the surrounding environment as a top event in the case of X-mas tree displacement with the top sacrificial part of the wellhead due to a floating/gouging iceberg interaction.

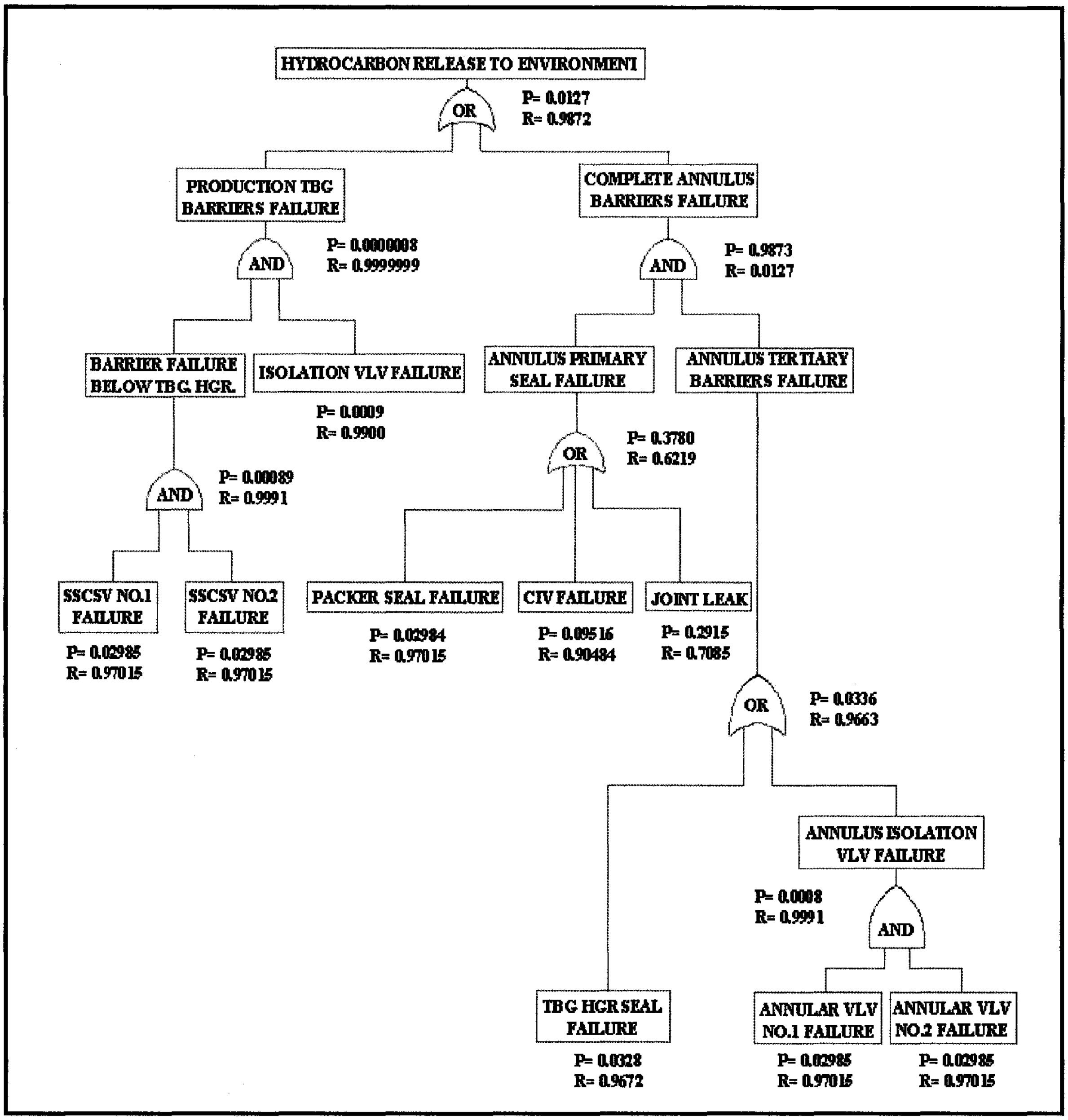


Figure 49 Fault Tree Analysis of barriers and seal failure

The situation of X-Mas tree with part of the wellhead being displaced from the well under the effect of a floating/gouging iceberg is not something common in the industry. For this reason, conservatism was considered in risk estimation by considering all the leaks to the annulus as major leaks. In the industry they differentiate between minor leaks (for example joint leak) and major leaks (packer seals leak). Minor leaks are assumed to have a low risk impact on the well safety and accordingly a factor is used to reduce the calculated leak probability and the resulting risk, which was not done in the above fault tree analysis.

5.4.3.2 Total Failure Probability Assessment

Based on statistical analysis of iceberg populations in the Northern area of the Grand Banks, the available infra-structure iceberg contact probability graphs (Figure 19) presented in Chapter 3, section 3.5, for floating and gouging icebergs combined with the leak probability calculation done above, a total probability of the extreme consequences scenario can be estimated.

An extreme scenario applies on a situation where an iceberg contacts the wellhead, causing the displacement of the X-mas tree and the sacrificial part of the wellhead resulting in the occurrence of a leak (minor or major).

As mentioned in the previous section, all leaks will be treated as extreme and major leaks of a blow-out magnitude with no factor of leak risk reduction is taken into account.

Considering the great risk to personnel life and high potential for environmental damage, Safety Class 1, as outlined in CSA S471-04 and discussed in Chapter 3, section 3.4 is applicable in our case and thus the annual target level of safety 1×10^{-5} should be met or exceeded.

The height of a horizontal X-mas tree varies from 4-6 m, with a dimension range between 2.5m $\times$ 2.5m to 4m $\times$ 4m. The world's biggest subsea horizontal X-mas tree has been installed during 2007 in the Norwegian Sea (Ormen Lange Project) with dimension of 4m $\times$ 4.5m $\times$ 3.9m. (T. Bernt, 2006)

Considering a similar tree to be installed one of the Grand Banks marginal fields, with the same high pressure rating, instruments and control features, it will result in a probable annual contact probability close to 0.001 or even less, referring to Figure 19 in Chapter 3. This contact probability may be reduced by 90% with the effective risk mitigation and iceberg interception activities to result in an annual probability of contact of 0.0001.

The probability of a leak occurrence from a live well adopting a shear link design upon losing the seabed barrier, (the X-mas tree) which is displacement due to an iceberg contact is 0.0127 (Figure 48). Combining both the annual contact probability and the leak probability will result in a final annual blow out probability of 1.27×10^{-6}. In this case $1.27 \times 10^{-6} < 10^{-5}$, and thus the annual target level of safety is achieved and even exceeded. In the absence of any iceberg risk management the annual contact probability is increased by 90% and the final annual blow out probability has a value of $1.143 \times 10^{-5} > 1 \times 10^{-5}$, and in this case the target level of safety is not achieved.

Based on the above calculations, the probability of a blow out from a wellhead, designed with a sacrificial wellhead top section and X-mas tree, on the Grand Banks due to iceberg contact, meets annual target level of safety. This analysis suggests that a sacrificial wellhead system may be a feasible and acceptable solution.

In the absence of any iceberg risk management, the probability of a blow out from a wellhead does not meet the set target level of safety and this leads us to conclude that iceberg detection and interception operations as a risk mitigation strategy should continue if a sacrificial wellhead system is used.

6. Analytical and Numerical Procedures

6.1 General

The major structural component of the well is the casing which provides integrity of the well and supports the BOP during drilling or work-over, and houses the wellhead components, casing hangers and the X-Mas Tree.

The well is drilled deep in the ground through different strata which could be weak and compressible or more compact and less compressible or even sometimes into rock, and accordingly the loads that might be imposed on the casing will be transferred to the surrounding different soil types. The resistance of the well casing to axial or lateral loads can be analyzed using pile theory.

Not all wells have the same casing programs and properties, not all wells are drilled in the same strata, and not all wells will be subjected to conditions where an accidental external load might be imposed. To address these variables, a parametric study was conducted with uniform soil conditions, including clay and sand, and representative soil strata from borehole logs and site investigations conducted on the Grand Banks. The wellhead was subject to lateral displacement to model the contact with freely floating icebergs and lateral displacement with sub-gouge deformations to model contact scenarios with gouging icebergs.

Such parametric studies with countless variables require numerous computations. A mathematical software (MATLAB) was employed to do the pre/post-processing calculations and operation to generate the input files for the engineering analysis and simulation software. The commercial engineering software package ABAQUS was used to simulate the interaction event and calculate the stresses, strains and various loads on the casing and conductor elements. Non-linear geometric and material analysis procedure was used.

6.2 FEA Numerical Model Overview

The response of the well casing and the production tubing to the displacement imposed by a floating and scouring icebergs was analyzed using a finite element numerical model considering a pipe in pipe case.

Five case studies were analyzed, four of, were for displacement imposed on the well by a floating iceberg in different soil strata as follows:

- Well casing in uniform low strength clay strata.
- Well casing in uniform high strength clay strata.
- Well casing in uniform sand strata.
- Well casing in layered soil strata.

The fifth case study was a displacement imposed on the well by a gouging iceberg as follows:

- Well casing in layered soil strata.

The numerical model for the floating icebergs included two main modules: soil/casing interaction, and finite-element formulation, while the scouring iceberg model included three main modules, soil/casing interaction, ice gouge/soil deformation relationships and finite element formulation.

The soil and pipeline interaction developed model is based on the Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Working Stress

Design API, (RP 2A-WSD) 20th Edition, July 1993. The model was idealized by approximating the soil response by a series of discrete springs in a three dimensional space (Figure 50).

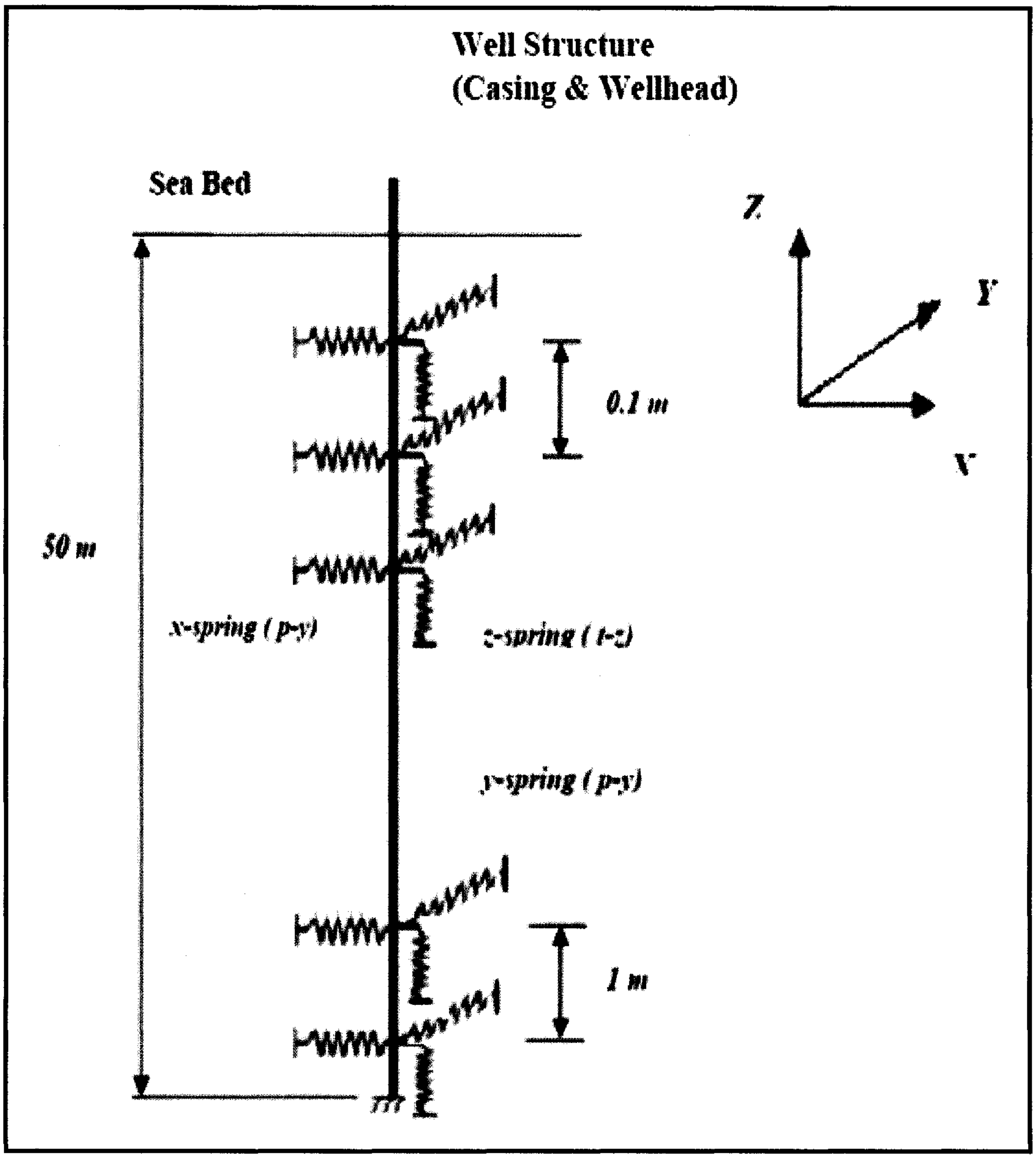


Figure 50 Schematic of Finite-Element Model

The stiffness terms, *T-z* and *p-y*, represent the axial and horizontal (in both the transverse and side directions) soil response components, respectively. The ultimate or yield conditions were based on API RP 2A-WSD (1993).

The software ABAQUS/Standard was used in the finite element analysis. The soil/pipeline interaction model was discretized by three-dimensional beam elements (PIPE32) and one-dimensional spring elements (SPRINGA).

Nonlinear spring elements were used to the soil response for the axial and the horizontal (transverse and side) soil deformation.

The total length of the well structure to be analyzed is 51 m, with 1 m extension above the seabed and is composed of an external casing (the conductor) housing an internal well completion pipe (production tubing) that transfers the hydrocarbon from the reservoir to surface . The nodal distance for the conductor was set at 0.1 m for the first 37 m. The remaining 14 m of the well structure below the seabed is discretized at a 1 meter distance. The discretization of the nodes for the completion pipe housed inside the conductor was done exactly as the conductor. A multipoint constraint was used to tie the translational degrees of freedom of the conductor nodes (master nodes) to the completion nodes (slave), considering that both the pipes are anchored together on the top by the X-mas tree and from bottom at a distance of about 15 m 20 m by the wellhead. Six degrees of freedom per node are active, and the behavior is defined by quadratic shape functions.

The casing was modeled using beam elements which were based on Timoshenko beam theory assuming the elements to be shear deformable. There is an assumption that the transverse shear stiffness of these beam elements are linear elastic and constant. In the non-linear simulations conducted by ABAQUS/Standard the area of these beam elements are formulated so that the cross- sectional area can change as a function of the axial deformation.

The analysis using the Pipe 32 element, adopts the Trapezoidal rule (Eight-point) integration method as a set default by the software.

The analysis was done assuming the well is on stream, and thus the internal pressurization of the completion pipe was considered and the hoop stresses and strain variables were taken into account.

There was an account for the cement around the conductor, in terms of the effective diameter of the conductor in the geotechnical calculations of soil resistance and imposed force on the conductor projected area. The cement was not considered to add the conductor strength.

For the floating bergs a displacement was imposed on the extension of the well structure above the seabed. The analysis approach of the scouring icebergs was based on the Pressure Ridge Ice Scour Experiment (PRISE) investigations and the reality that the seabed soil is heavily deformed, below the base of the scour and the empirical relationships defining the sub-scour displacement field presented in Woodworth-Lynas et al. (1996). Response functions to determine scour forces and sub-scour soil displacement relationships were derived from the analysis of the centrifuge modeling tests and experiments conducted by C-CORE.

It was concluded that the sub-gouge deformations result in two fields: the longitudinal distribution exhibited a bounded, peak central displacement with a cosine tail distribution. The vertical profile revealed an exponential decay with increasing depth.

Accordingly, model equations were developed based on the theory and experiments to calculate the imposed horizontal and vertical displacement fields caused by the iceberg sub-gouge and it was used in many projects, the first was the Northstar pipeline against ice scour conducted by C-CORE in 1999.

In the analysis of the case study of the well structure against the ice scour, the horizontal soil deformation was considered to have an effect on the well casing, and the vertical soil deformation was neglected.

It has been found that the displacement field is constant from the sea bed level to the base of the keel of the gouging berg and is a function of the gouging keel dimensions as follows:

$uo = 0.6\,(\mathrm{wd})^{1/2}$ for clay

$uo = (\mathrm{wd})^{1/2}$ for sand

Where:

uo	reference gouge displacement
d	gouge depth
w	gouge width

The lateral displacement profile which starts from the bottom of the iceberg keel and displays a decaying exponential profile is calculated using the following equation:

$$uh = uo \exp\left(-uh\_fac\left(Hs - d\right)/\, d\right)$$

Where:

uh	Lateral displacement at depth of calculation
uh_fac	Lateral displacement factor

Hs spring line depth

d gouge depth

The above equation reveals the soil displacement in the absence of any conductor in the soil strata. The analysis of the soil pipe interaction was carried out separately using the displacement field generated by the gouge on the soil strata. This is known as decoupling, where the ice/soil interaction is decoupled from the pipe/soil interaction.

6.3 Model Input File Calculations and Creation

Several runs were carried out within the study for different soils strata as discussed above. Each case required a full cycle starting by reading the data input file, performing geotechnical computations, calculations of the constitutive relationship for the pipe steel (Ramberg-Osgood correlation), PRISE model calculations for the sub-gouge displacement (for gouging icebergs), generation of the ABAQUS FEA analysis software input file, and then the last step was calling the ABAQUS to perform the analysis.

The MATLAB routine consisted of 11 modules (script files) including the batch file module. The computations and analysis sequence of these modules for floating and gouging iceberg is illustrated in the flow chart shown in Figure 51:

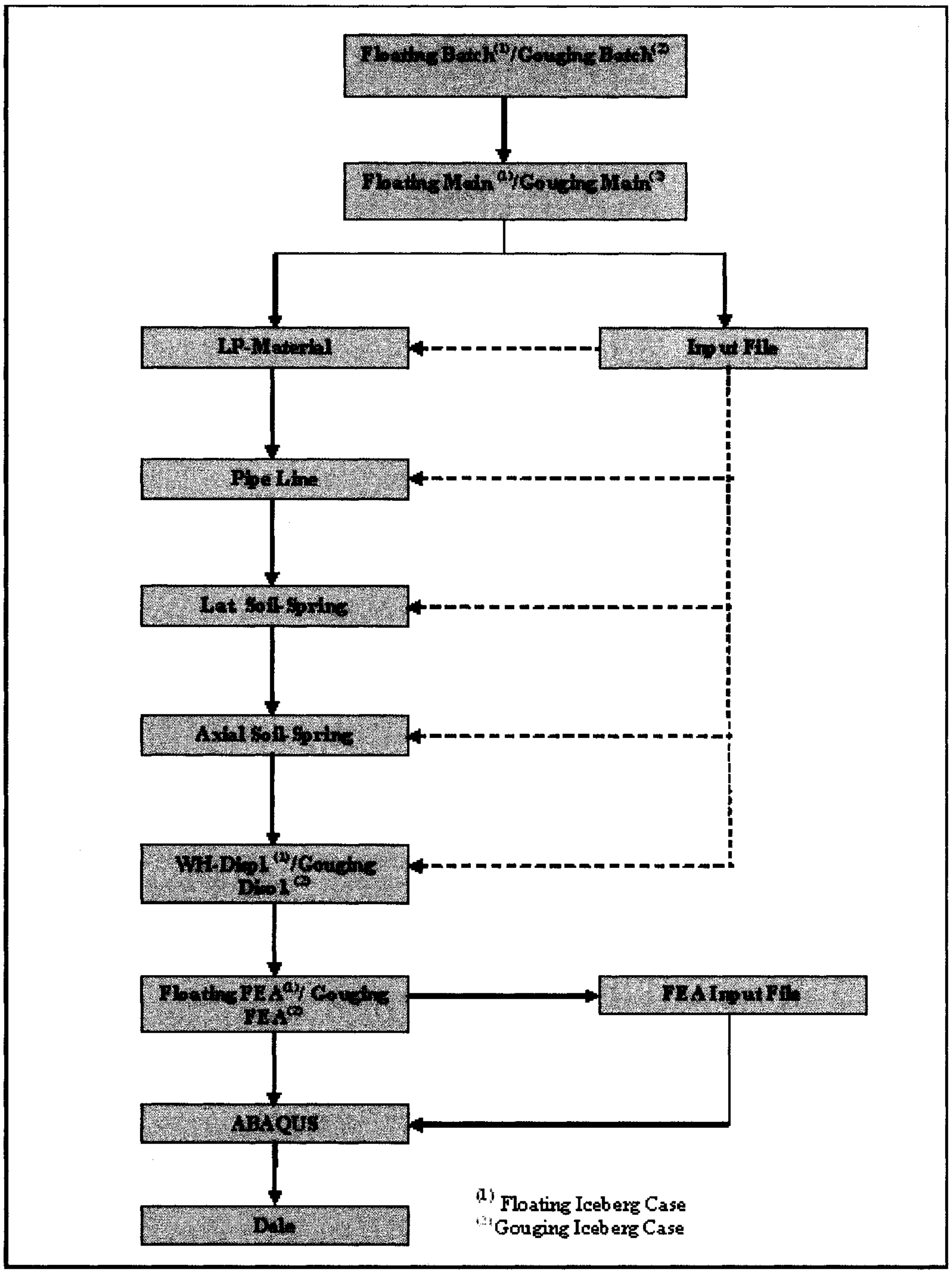


Figure 51 Flow chart diagram of MATLAB code

Von Mises stress diagrams , bending moment diagrams, shear force diagrams, axial strain diagrams, axial force, and lateral displacement diagrams were plotted versus depth for the conductor considering the maximum value at a specific section point for the last displacement increment prior to solution diversion and then tracing the values on this section point through all the solution steps.

Plotting was done at all displacement steps to give a clear idea about conductor/soil interaction and load response progression through out the whole stages till conductor pipe material failure.

Similarly the von Mises stress diagrams, axial force diagrams, axial strain diagrams were plotted for the completion tubing.

7. Soil Calculations and Model Properties Overview

7.1 General

The well conductor as a structure represents a single long steel tube pile that will be subjected to a lateral load. Large deflections will be imposed by a floating or gouging iceberg.

The lateral conductor displacement will lead to soil response in both the transverse directions at the horizontal planes perpendicular to the conductor, and as well in the axial direction due to the friction between the soil and the outer surface of the conductor.

The ultimate resistance of a vertical conductor to a lateral load and the deflection of the pile as the load builds up to its ultimate value are complex matters involving the interaction between a structural element and the soil, which deforms partly elastically and partly plastically.

The materials of well casing and conductor can be specified as the manufacturing and installation procedures are governed by specifications and code of practice requirements. On the other hand, the calculations of their load carrying capacity is a complex matter which is partly based on empirical methods and experimental data, as well on theoretical concepts derived from the sciences of soil and rock mechanics. (M. F. Bransby, 1999).

At small displacements, the main load is transferred from the conductor to the soil close to the surface which compresses elastically, but still such small displacements are enough to transfer some loads from the conductor to the strata at greater depths.

As the displacement increases at further stages, the soil yields plastically and transfers its loads to greater depths.

Eventually, the failure mechanism of the conductor assumed as a long pile with an infinite resistance at its lower part takes place when the conductor reaches the ultimate stresses and fails at the point of maximum bending moment.

7.2 Conductor Load Capacity

7.2.1 Non Linear Analysis and Code of Practice

To understand and predict the response and lateral movements of a pile to lateral loading, several approaches have been developed. One of these first approaches is the subgrade-reaction approach in which the continuous nature of the soil medium is ignored, and the soil deflection at any point along the pile is related to the soil reaction at this point (Pile foundation Analysis and Design, H.G, Poulos et al. 1980).

The above approach is based on Winkler theory (1867) of beams on elastic foundations, characterizing the soil as a series of unconnected linearly elastic springs.

In reality, the relationship between load and deflection at any point along the pile is non-linear, and to account for this nonlinearity an elasto-plastic Winkler model was employed and worked on by Mdhav et al. (1971).

On later stages, Reese and his co-workers developed an approach which is widely used and is known as the "p-y" approach where the method models the lateral soil-structure interaction with empirically derived non-linear springs attached between the piles and the far field of the soil.

A finite difference solution is obtained in this method to the equation below:

$$d^2\mathrm{M} / dz + (\mathrm{P}_z) d^2\rho / dz^2 - p = 0$$

Where:

ρ	deflection
M	moment at depth z in pile
z	depth
P_z	axial load on pile at depth z
p	soil reaction per unit length

Design procedure for constructing, the relationship "p-y" for various soil types have been developed based on field measurements on full sized instrumented piles, centrifuge experiments and actual data collected from various offshore structures.

These procedures have been verified, widely accepted and recommended by codes and practices for the design of piles and foundations and applies when the soil is acting plastically.

These procedures based on the API RP 2A code, were used in calculating the "p-y" curves for the different strata of the 5 study cases examined in this thesis as detailed in Section 7.2.2.1.

The axial pile capacity in general, is defined as the total resistance expressed in terms of the sum of the external shaft friction, the end bearing on the pile wall annulus, and the total internal pile friction.

Several procedures have been developed to determine the axial response of piles. The soil around the piles is idealized as a series of uncoupled springs attached between the pile and the far field soil, similarly to the lateral soil springs. The soil response along the pile surface may vary from linearly elastic -plastic, to non linear hyperbolic.

For the shaft resistance displacement (skin friction), the soil elements are commonly referred to as "T-z", and for the tip resistance displacement they are referred as " Q-z" .

The ultimate static bearing capacity of the conductor is considered as:

$Q_{ult} = \sum f_s A_s$

Where	Q_{ult}	ultimate static capacity
	f_s	unit outside shaft friction

The inside conductor area resistance was not included since there is no soil in the annulus between the conductor and the completion tubing. The end bearing capacity which is calculated at the bottom end of the conductor (the toe), referred as the " Q-z" curves was not taken into consideration due to its negligible effect in modeling a long and laterally displaced conductor.

The procedures to calculate the "T-z" for piles are outlined in the API RP 2A-WSD (1993) code and the attached commentary. These procedures were used in the calculation for the skin friction resistance of the conductor through the analysis of the five case studies as detailed in the coming section.

7.2.2 Cohesive Soils

7.2.2.1 Lateral Load Deflection (p-y) Curves

Soil resistance-pile lateral deflection "p-y" curves for cohesive soil were developed by procedure outlined by Matlock (1970) which represents the deformation of the soil at any given depth below the soil surface for a range of horizontally applied loads from zero to the stage of yielding of the soil in ultimate shear, when the deformation increases without any further increase of load. This represents the deformation of a discrete vertical area of soil that is unaffected by loading above and below this plane at depth. These procedures were developed for clays subjected to either short term static load or cyclic loading for a long period of time.

As per the API RP 2A, For static lateral loads the ultimate unit lateral bearing capacity of soft and stiff clay has been found to vary between 8c and 12c , where :

c	un-drained shear strength for the undisturbed clay soil samples

Pu increases from 3c to 9c as X increases from 0 to Xr, according to:

$$Pu = 3c + \gamma X + J\ (cX / D_e)$$

Pu	ultimate resistance (KPa)
c	the un-drained shear strength for undisturbed clay soil samples (KPa)
D_e	the effective pile diameter; Pile diameter plus the cement thickness (mm)
γ	effective unit soil weight of soil (MN/m^3)
J	a dimensionless empirical constant with a value ranging from 0.25 to 0.5 having been determined by field testing. A value of 0.25 is appropriate for the Grand Banks.
X	depth below surface (mm)
X_R	depth below soil surface to bottom of reduced resistance zone in mm For a condition of constant strength with depth:

$$X_R = 6D_e/((\gamma D_e/c) + J)$$

In general, minimum values for X_R should be around 2.5 pile diameter.

The "p-y" curves for the short-term static load case are generated from the following table, (Table 6):

Table 8 Load deflection relationship for "p-y" curves in clay

P/P_u	y/y_c
0	0
0.5	1
0.72	3
1	8
1	∞

Where:

P — actual lateral resistance (kPa)

y — actual lateral deflection (mm)

y_c — $= 2.5 * \varepsilon_c * D_e$ (mm)

ε_c — strain which occurs at one-half the maximum stress on laboratory un-drained compression tests of undisturbed soil samples , a value of 1 % (0.01) is considered.

7.2.2.2 Axial Bearing Loads (T-z) Curves

Axial load-deflection "T-z" curves are calculated using the procedures outlined and recommended by the American petroleum Institute in their recommended Practice RP 2A-WSD (1993).

The "T-z" curves for the short-term static load case are generated from the following table:

Table 9 Load deflection relationship for "T-z" curves in clay

T/T_{max}	z/z_{max}
0	0
0.3	0.16
0.5	0.31
0.75	0.57
0.9	0.8
1	1

Where:

T_{max} $= \alpha S_u \pi D_e$

S_u un-drained shear strength of the soil at the level of calculation (kPa)

α dimensionless factor, derived based on the main text of the API RP2A as shown below:

$\alpha = (S_u/P_o)^{-0.5}$ for $S_u/P_o \leq 1$

$\alpha = (S_u/P_o)^{-0.25}$ for $S_u/P_o > 1$

P_o soil overburden pressure at the level of calculation (KPa)

The value of Z_{max} at the peak resistance value T_{max} is considered as 1 % of the external conductor diameter as recommended by API.

7.2.3. Cohesion-less Soils

7.2.3.1 Lateral Load Deflection (p-y) Curves

Soil resistance-pile deflection "p-y" for cohesive soil were developed using the procedure outlined by O'Neill and Murchison and their report to the American Petroleum Institute (1983).

As per the API RP 2A, it has been found that that the ultimate lateral bearing capacity exhibits noticeable variation between shallow depths to deep depths as reflected in the equations below:

Similar to clay, the lateral soil resistance-deflection curve relationships for sand are represents a non linear relationship.

$$p_{us} = (C_1H + C_2D_e) + \gamma'H$$

$$p_{ud} = C_3D_e\gamma'H$$

Where:

p_u	ultimate resistance (force/unit-length; s = shallow, d = deep)
γ'	effective soil weight (MN/m^3)
H	depth (mm)
ϕ'	angle of internal friction of sand (degree)
C_1, C_2, C_3	coefficients determined as a function of ϕ'
D_e	average pipe diameter from surface to depth (mm)

Using input parameters including the submerged unit weight, angle of internal friction, and the initial modulus of the of horizontal subgrade reaction, the "p-y" data were calculated using the following expression:

$$P = A\, p_u \tanh\left[kHy/Ap_u\right]$$

Where:

A factor to account for cyclic or static loading condition, evaluated by:

A=0.9 for cyclic loading.

$A = (3 - 0.8H / D) \geq 0.9$ for static loading

p_u ultimate bearing capacity at depth H (kN/m)

k initial modulus of subgrade reaction determined as a function of angle of internal friction ϕ' (kN/m^3)

y lateral deflection (mm)

H depth (mm)

7.2.3.2 Axial Bearing Loads (T-z) Curves

As per the API RP 2A, the shaft friction "f" (kpa) for pipes or piles in cohesion-less soils, is calculated by the following equation:

$$f = K\ p_o \tan\delta$$

Where:

K coefficient of lateral earth pressure, ratio of horizontal to vertical normal effective stress. A value of 0.8 is assumed for both tension and compression loadings.

p_o effective overburden pressure at the point of question (kpa)

δ friction angle between the soil and the pipe wall

For long piles "f" is limited by a maximum friction value where it does not increase linearly beyond this limit.

The limiting factors are tabulated below (Table 8) and they do vary in relation with the sand properties.

Table 10 Design Parameters for Cohesionless Soil (API RP 2A)

Density	Soil Description	Soil Pile Friction Angle	Limiting Skin Friction Values (kPa)
Very Loose Loose Medium	Sand Sand-Silt Silt	15	47.8
Loose Medium Dense	Sand Sand-Silt Silt	20	67
Medium Dense	Sand Sand-Silt	25	81.3
Dense Very Dense	Sand Sand-Silt	30	95.7
Dense Very Dense	Gravel Sand	35	114.8

7.3 Soil Profiles and Parameters

Four different soil profiles were used to analyze five case studies. Two of these profiles were clay soils, representing high and low strength values, one was sand profile and the fourth one was a layered soil profile. The parameters and properties of the soil profiles for the case studies were chosen based on the interpretations of the borehole log and test results for the NW anchor pile of the White Rose field at the Grand Banks offshore Newfoundland.

The upper and lower bounds of the un-drained shear strength values considered for the two clay soils profiles, Case Studies no. 1 and no. 2 were based on the average minimum and maximum clay data of the NW anchor pile.

Similarly, the properties of sand profile, of case no.3, were considered based on the dominant sand parameters of the same borehole log and test results of the same location.

The Case Study No.4 and No.5 of the layered soil profile used the same data of the NW anchor pile report. The data of the borehole log and test results for the NW anchor pile covered a depth range from seabed till a depth of 36 m, of the total 50 m of the assumed conductor length in the Case Study No. 4 and No.5.

The bottom 6 m of the strata was a layer of clay with an upper bound of un-drained shear strength of value 225 kPa and a lower bound of 235 kPa. The same layer was assumed to persist the remaining 14 meters to the toe of the conductor to cover the remaining 14 m of the conductor and thus the whole 50 m of the conductor length.

The details of the case studies and soil parameters are highlighted below in the following subsections.

7.3.1 Clay Profiles

Two uniform soil profiles for two separate case studies were modeled. Case no. 1 was a uniform clay extending from seabed to a depth of 50 m: the un-drained shear strength "Su", and the unit weight of clay " γ " were chosen to be 170 kPa and 9.8 KN/m^3 respectively.

Case no.2 was uniform clay as well, but with different parameters .The un-drained shear strength " S_u ", and the unit weight of clay " γ " were chosen to be 230 kPa and 9.8 KN/m^3 respectively (Figure 52).

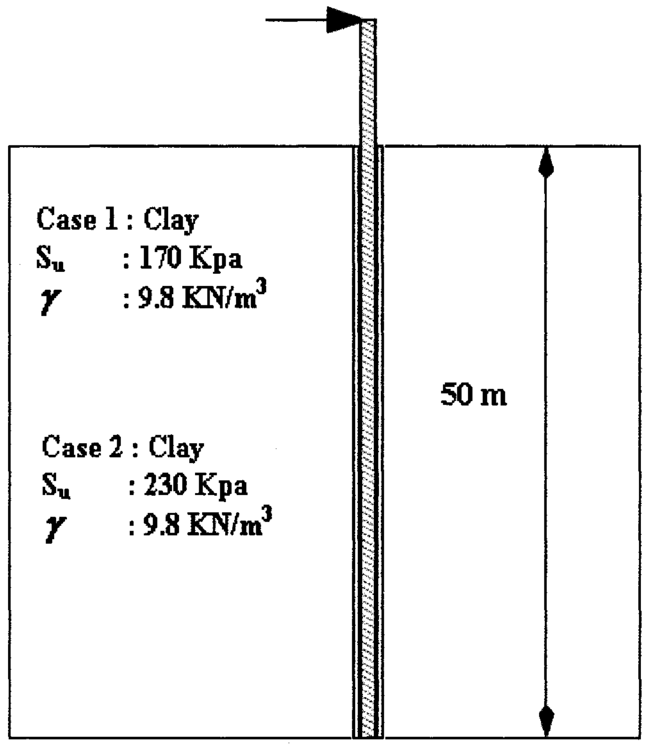


Figure 52 Conductor and soil layers dimensions/properties of Case no.1 and no.2

7.3.2 Sand Profile

One uniform sand profiles for one case study was modeled extending from seabed to a depth of 50m. The following parameters were used for the dense sand: Friction angle Φ of 40° and the unit weight γ of 8.3 KN/m^3 (Figure 53).

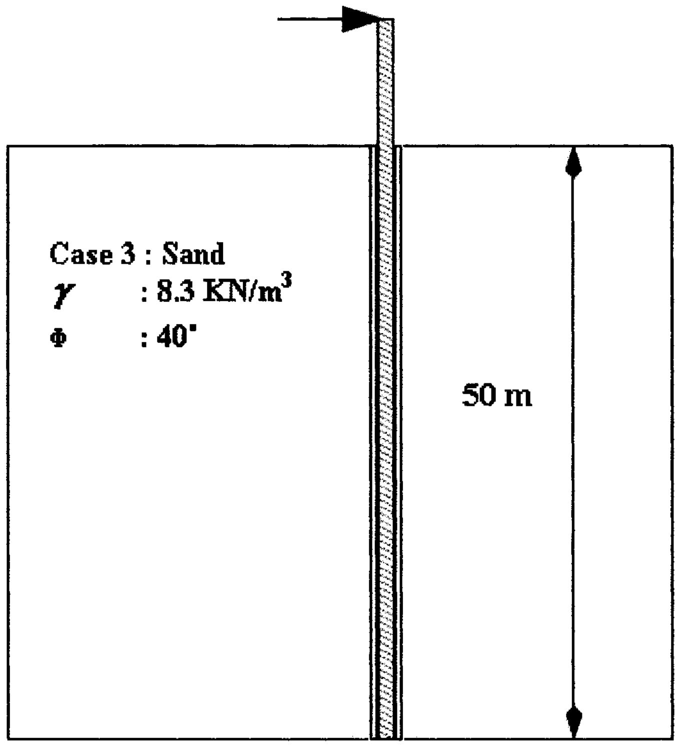


Figure 53 Conductor and Soil Layer Dimensions/Properties of Case no.3

7.3.3 Layered Soil Profile

The layered soil set up consists of total 11 layers of sand and clay. The top layers vary from dense sand to very dense sand at a depth of 9 m.

Thick clay layers are featured at the bottom of the sand layer and continue to be mostly dominating for the remaining depth up to 50 m with occasionally thin very dense sand layers embedded in-between. Detailed layering set-up is given in Figure 54.

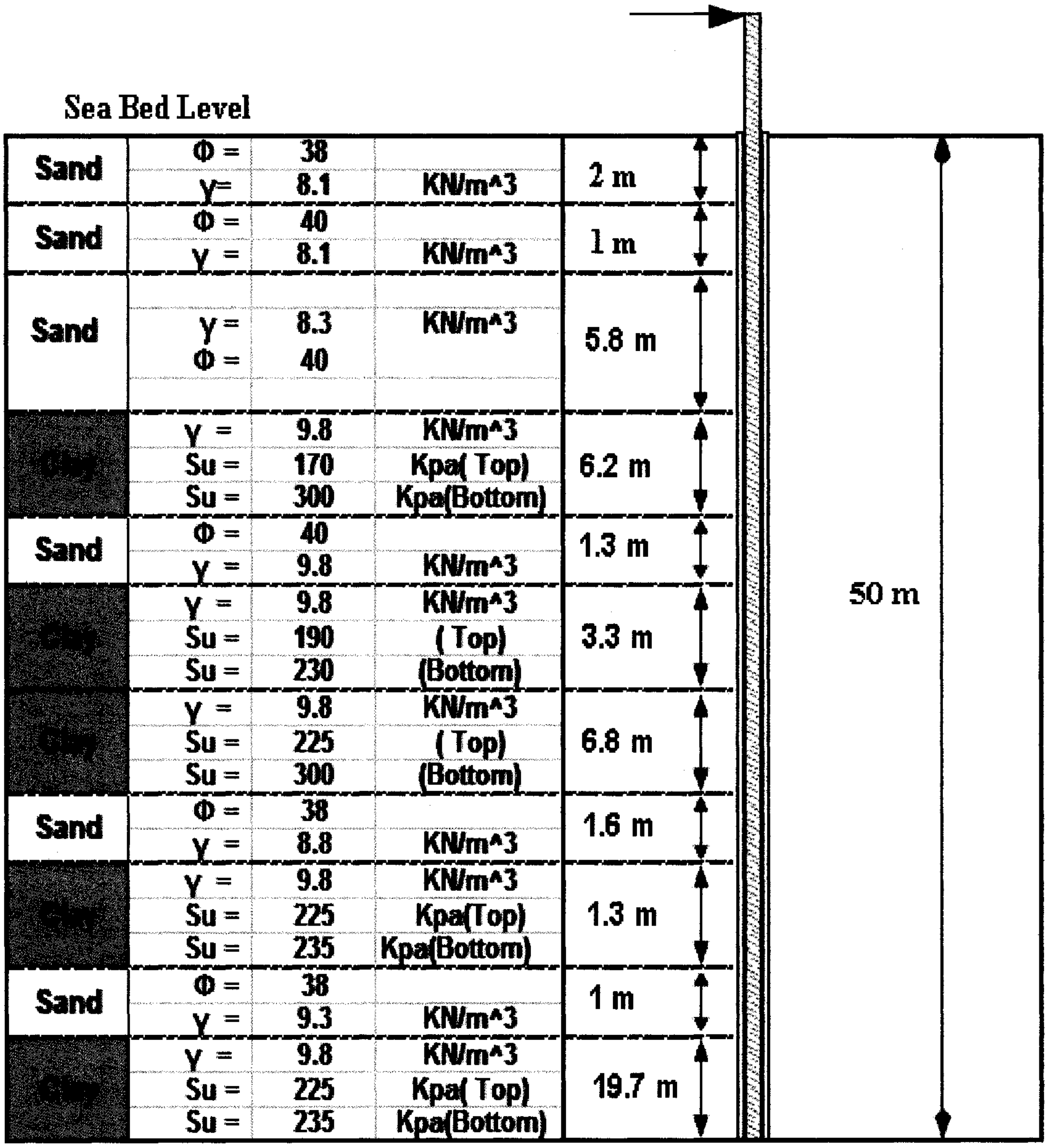


Figure 54 Conductor and Soil Layer Dimensions/Properties of case no.4 and no. 5

The "p-y" curves are calculated at intervals of 0.1m starting from sea bed up to depth of 37 m, and then at intervals of 1 m till the toe of the conductor at a depth of 50m. The "T-z" curves are calculated from sea bed up to depth of 16 m covering the tie back joint up to the wellhead assumed at the that depth.

7.4 Well Operating Parameters

Based on the production design conditions provided for the White Rose Oil field Project Description Document (Husky Oil Operations, March 2000) the operating parameters were determined as detailed below.

The maximum shut in pressure of the well was estimated to be 28000 Kpa (4000 Psi) and the flowing wellhead temperature had a range between 50 °C to 80 °C.

The shut in pressure was used in the analysis as the internal pressure in the tubing assuming that the well is shut down upon spotting an iceberg in the field vicinity and prior the iceberg wellhead interaction. The Maximum operating temperature was assumed as the average temperature 65 °C and the ambient temperature as 0 °C.

7.5 Well Structure and Design Criteria

7.5.1 Conductor and Tubing Material Properties

The conductor, or the first casing string in contact with the soil , is a pipe of 0.762m (30 inch) outside diameter, and wall thickness of 0.038m (1 ½ inch).

The material grade API X-80 or 550 grade pipe steel, of yield stress 550 MPa. The Young's modulus value had a value of 205 GPa and the Poisson's ratio of 0.3.

The tubing which is the pipe housed in the production casing string below the wellhead and in the conductor tie back sub above the wellhead, and carrying the product from the reservoir to the surface has a diameter of 0.114 m (4 ½ inch) and a wall thickness of 0.0083m (0.33 inch). The material grade of the tubing was similar to that of the conductor.

The constitutive relationship for the pipe steel was defined by the Ramberg-Osgood correlation. It provides a fit to the actual stress-strain values of pipe material that could be obtained if a real tension test carried on in a lab using the following formulae is:

$$\varepsilon = \sigma / \mathrm{E} + (\alpha \sigma o / \mathrm{E})(\sigma / \sigma o)^{N}$$

Where	ε	is the total strain (Elastic and Plastic)
	σ	is the applied stress
	E	is the material elastic modulus
	α	plastic yield offset
	N	hardening exponent
	σo	is the yield stress

7.5.2 Design Criteria

The design criteria adopted was a combination of stress/strain based design. Compressive strain limits for buckling and tensile strain limit for burst were considered for the conductor and the completion tubing.

The maximum allowable stress limit was not to exceed 90% of the SMYS at the critical highly stressed section. Accordingly the stress level, the lateral forces, the axial forces and the moments at the shear key level were evaluated.

Below the shear link, at the level of the isolation valve, the bending moment, the lateral forces and the axial forces were of importance to note. These loads at the isolation valve should not exceed the critical recommended load values (usually set by the manufacturers based on the customer requirements) so as not to affect the internal valve components and seals. Wellhead loads and stresses were noted as well.

Although the SSCSVs are set at depths exceeding 30 meters below mudline away from any anticipated high stress and loads, the amount of the stress was checked and verified. To check the stain value after which local buckling occurs due to primary and/or secondary loads, the strength limit was determined using Appendix C of Canadian Standards Association code CSA Z662-99 addressing the limit state design topic for oil and gas pipeline systems. As per the above mentioned appendix the requirement to prevent local buckling and longitudinal compressive strains, the minimum strength requirement is limited in accordance with:

$$\varepsilon_c^{crit} \Phi_{\varepsilon c}^{crit} \geq \varepsilon_{cf}$$

Where :

$\Phi_{\varepsilon c}^{crit}$	resistance factor for compressive strain ,a value of 0.8 is considered
ε_{cf}	factored compressive strain in the longitudinal or hoop direction
ε_c^{crit}	ultimate compressive capacity of the pipe wall

The compressive strain limit ε_c^{crit} may be taken as:

$$\varepsilon_c^{crit} = 0.5t/D - 0.0025 + 3000\ \left((\mathrm{Pi}-\mathrm{Pe})D/2t\mathrm{E}_s\right)^2$$

Where :

t	pipe wall thickness
D	outside pipe diameter
Pi	maximum internal design pressure
Pe	minimum external hydrostatic pressure
E_s	205 000 MPa

8. Simulation Results

8.1 Analysis Method

The loading on the conductor was in the form of a number of static pushover displacements in the lateral direction at the conductor head till the failure of the conductor pipe for the Cases No.1 to No.4.

For Case No. 5 referring to the gouging iceberg, displacement was imposed simultaneously on the conductor extension above the sea bed, to represent contact, and below the seabed mudline to model the effects of subgouge soil deformation. The soil subgouge deformations were calculated using the PRISE equations (Woodworth-Lynas et al., 1996).

A gouge depth of 0.34 m was used that represents the mean depth of gouging icebergs for the White Rose field on the Grand Banks (See Table 4). For gouging ice features, it is recommended to carry out further analysis for rare gouge contact events that may exceed 2m gouge depth.

Results from simulation tests on piles were used to asses the response of the conductor pipe and completion tubing to a similar situation upon floating/gouging iceberg wellhead interaction in different soil profile arrangements.

Consideration was given to stresses and forces values developed on the conductor sections below seabed at a depth starting of 1 m and downwards, assuming that the shear link will be situated below that level at a depth varying ranging between 3 m to 3.5 m. Reasons for selecting this depth are discussed in Section 8.3.

8.2 Conductor / Completion Response

8.2.1 Uniform Low Strength Clay Soil – Case 1

Figure 55, shows bending moments and shear forces respectively along the depth of the conductor in low strength clay soil. It should be noted that the maximum bending moment below the mudline, as well as the switching of sign for shear force, moves quite a bit from the depth of approximately 7 m all the way to the depth of 8.5 m below the sea bed with generally a good agreement between the shear force and bending moment diagrams. The maximum value of bending moment was of a magnitude of 9.2 MN m at a depth of 8.4 m.

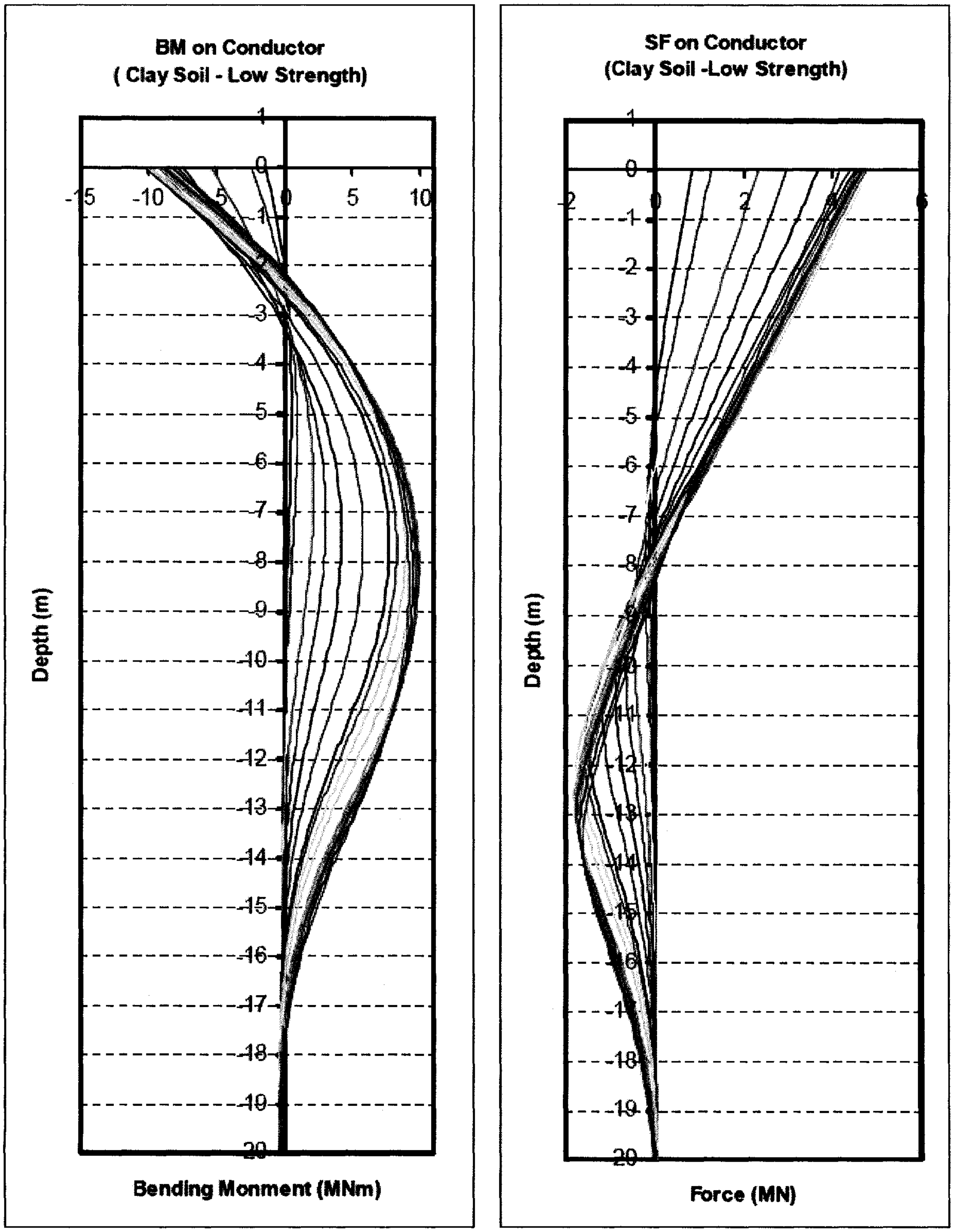


Figure 55 Bending moment and shear force distributions in uniform low strength clay soil profile – Case No. 1

Figure 56, shows the maximum von Mises stress distribution along the conductor length, at a depth range between 7 m to 9 m reaching the peak value of 569 MPa at a depth of 8.2 m.

Von Mises stress distribution is consistent with the bending Moment distribution through out the depth along the conductor length. The constant stress values below 20 m indicate a constant strain due to axial tension force. Stress and strain values exceeding yield and the implications are discussed in Section 8.3

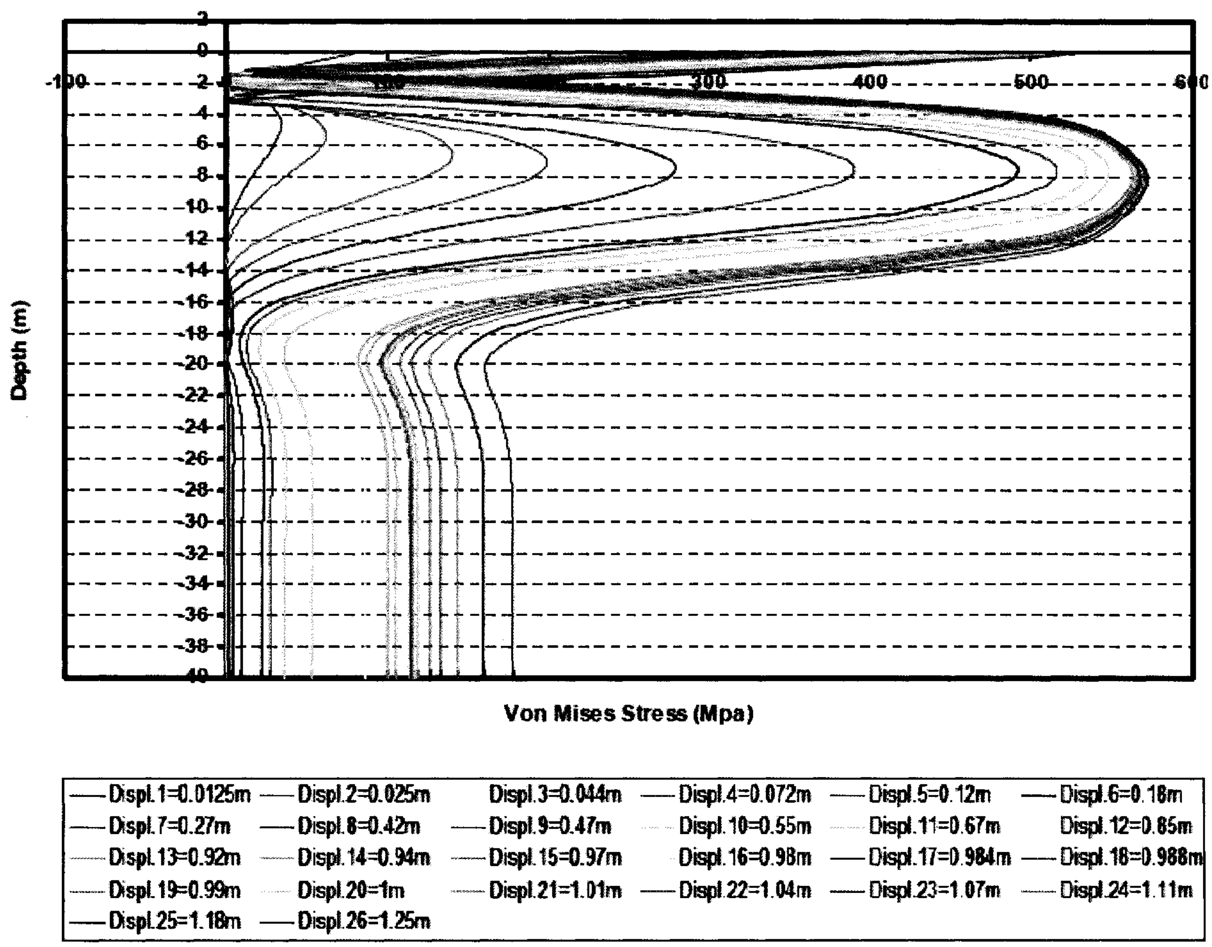


Figure 56 Von Mises stress distribution along the conductor in uniform low strength clay soil profile – Case No.1

The maximum axial strain occurred at a depth of 8.2 m of 1.33 % value (Figure 57). The switchover from the compressive strains to tensile strains moves from the depth of approximately 1 m to a depth of 2.5 m.

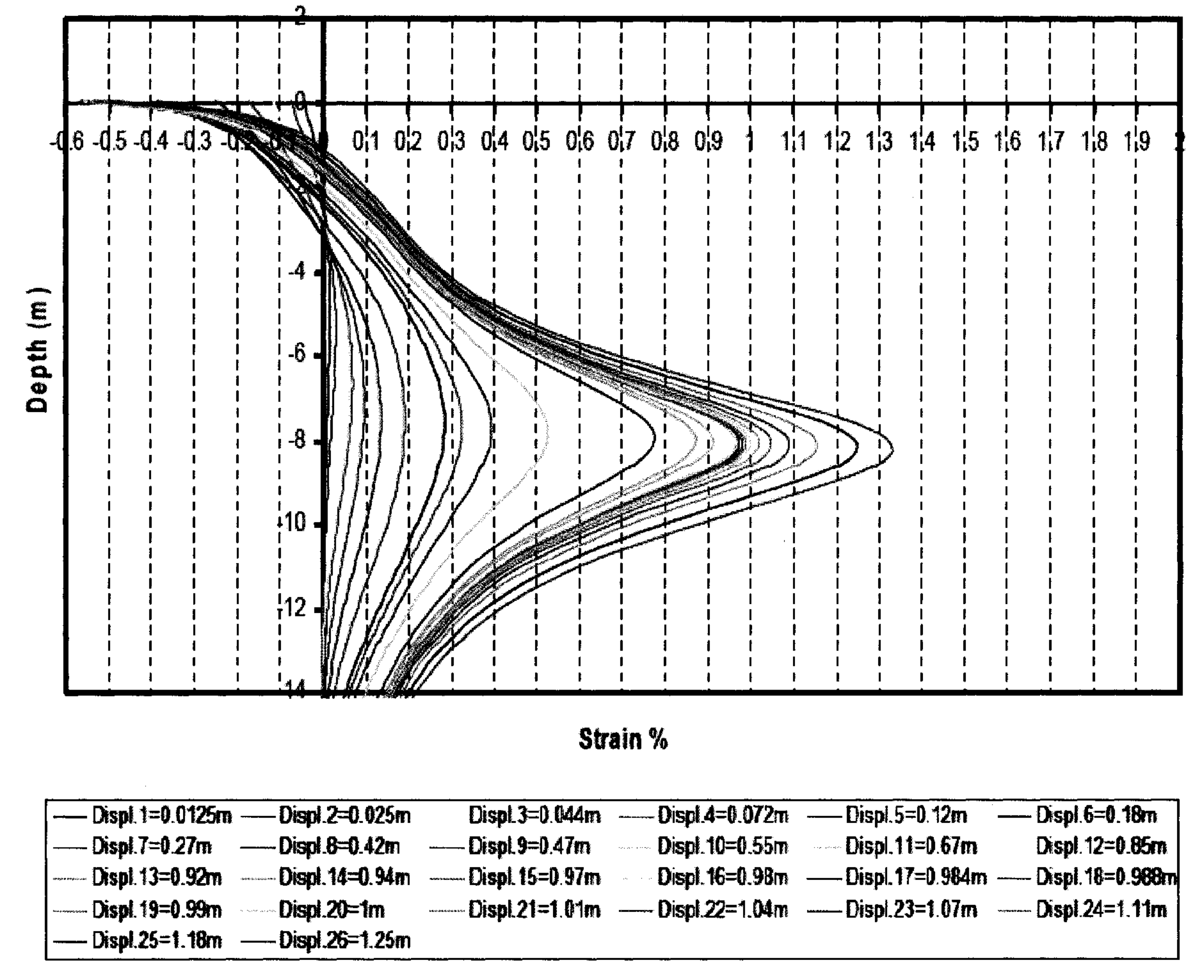


Figure 57 Axial strain distribution along the conductor in uniform low strength clay soil profile – Case No.1

For the completion tubing, the maximum von Mises stress distribution over the length, ranged between 7.5 m to 8.5 m (Figure 58), reaching the peak value of 550 MPa at a depth of 8.2 m

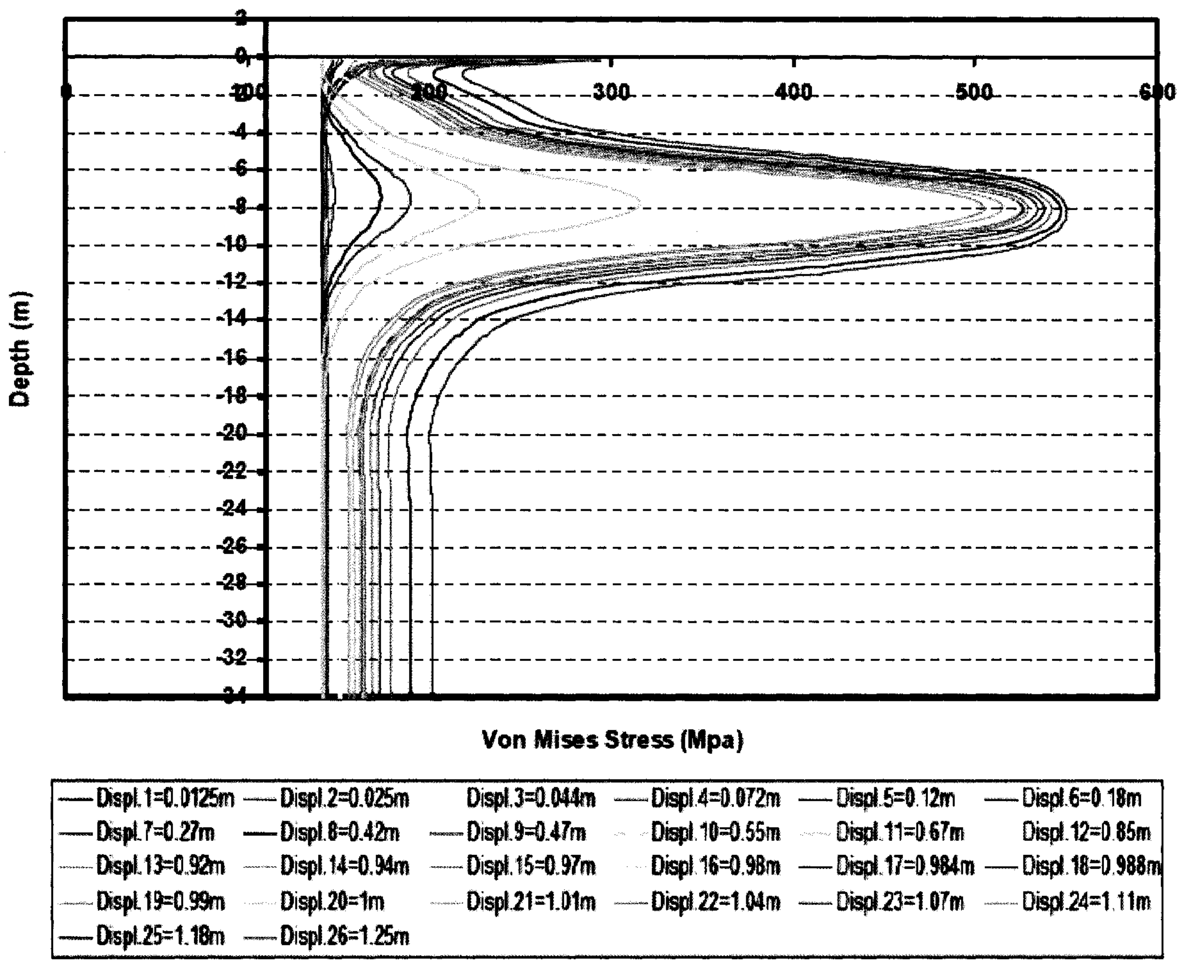


Figure 58 Von Mises stress distribution along the completion tubing in uniform low strength clay soil profile – Case No.1

The maximum axial force on the completion was of value 1.64 MN at a depth of 8.0 m. The distribution of the axial force along the completion length is shown in Figure 59. No significant moment or lateral force developed along the length of the completion.

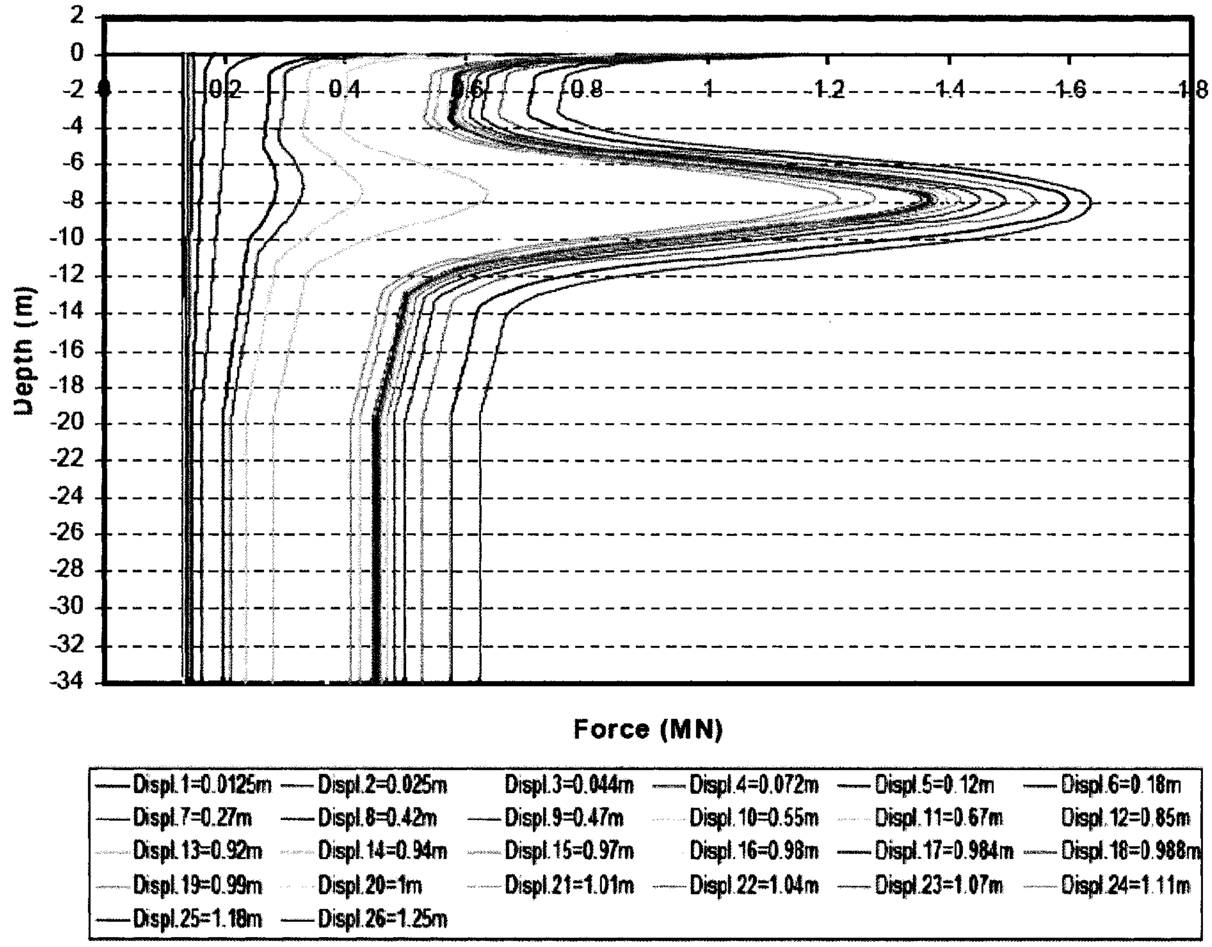


Figure 59 Axial force distribution along the completion tubing in uniform low strength clay soil profile – Case No.1

The maximum axial strain occurred at a depth of 8.2m of 0.561 % value (Figure 60).

A major difference could be noted in the values of the tensile strains of the completion compared to that of the conductor. The conductor had a bigger tensile strain distribution along the length.

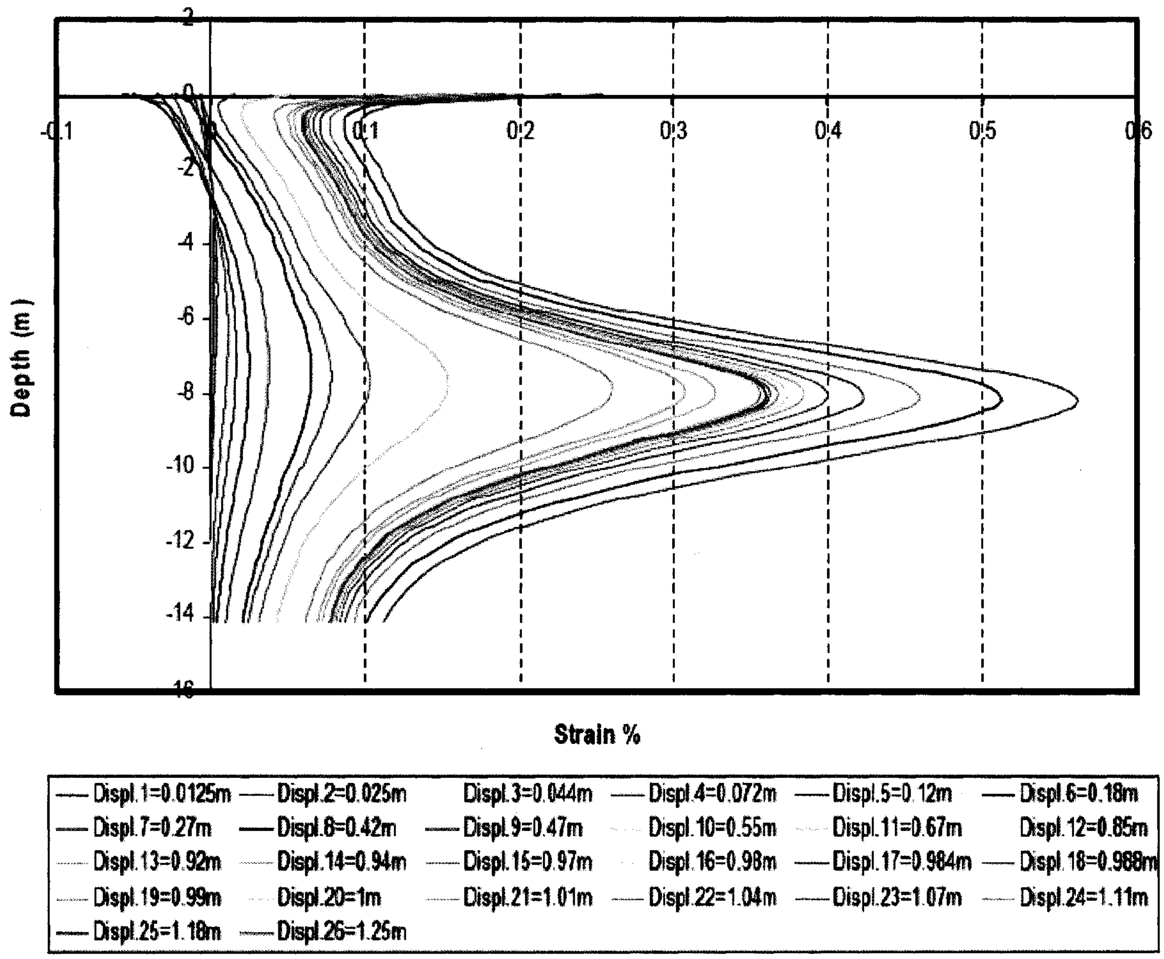


Figure 60 Axial strain distribution along the completion tubing in uniform low strength clay soil profile – Case No.1

The distribution of displacements for the uniform low strength clay is shown in Figure 61. It is observed that the clay layer allowed big displacements of the conductor head at sea bed level starting from 0.0125 m at the first load step to a displacement of 1.2 m at the last load step. The other observation is that the point of rotation for the conductor (point which does not move as the loading is applied) is at a depth of 13.9 m.

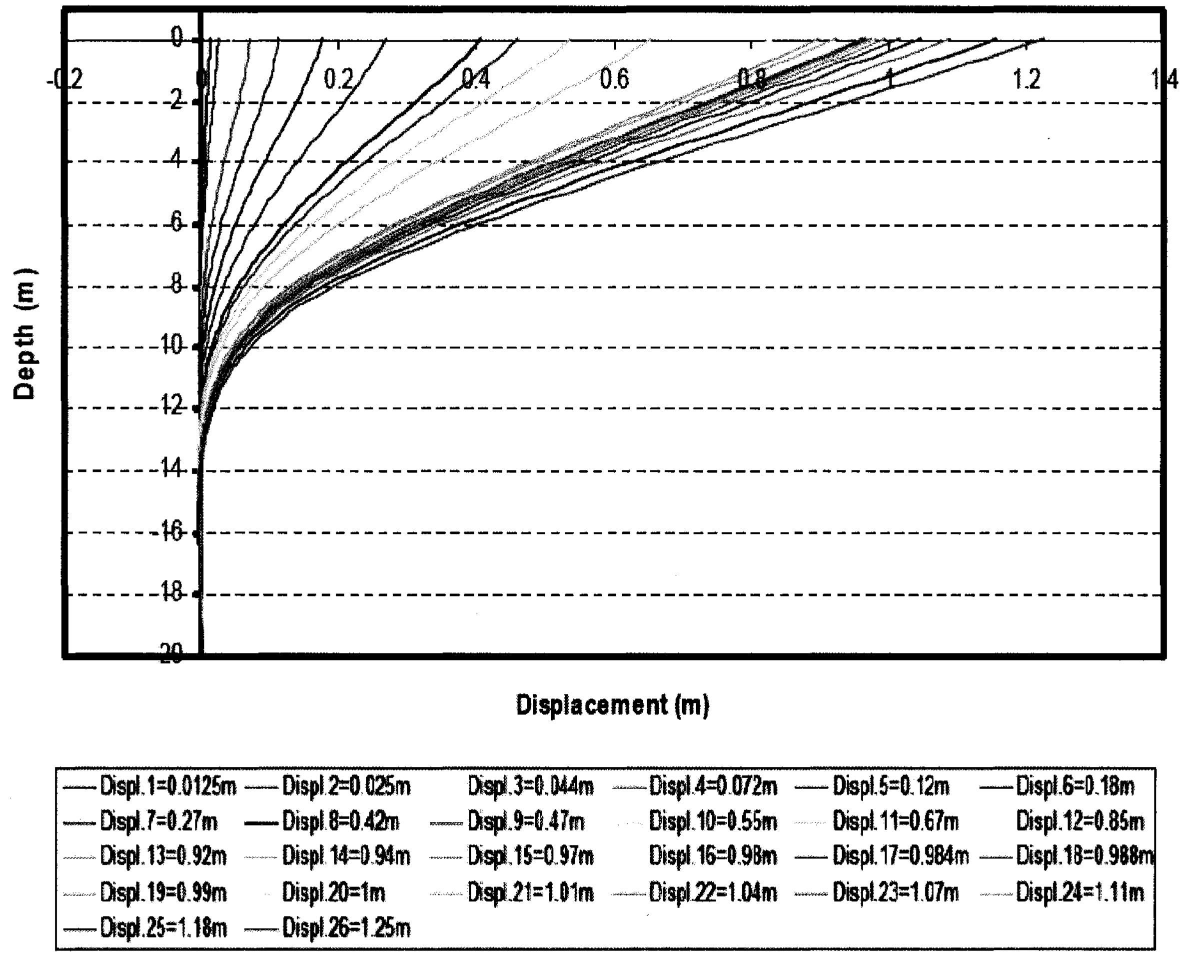


Figure 61 Displacement distributions along the depth in uniform low strength clay soil profile – Case No.1

8.2.2 Uniform High Strength Clay Soil – Case 2

Figure 62, shows the bending moments, and shear forces respectively along the depth of the conductor in high strength clay soil. It should be noted that the maximum bending moment below the mudline, as well as the switching of sign for shear force, moves quite a bit from the depth of approximately 6 m all the way to the depth of 8 m with generally a good agreement between the shear force and bending moment diagrams.

The maximum value of bending moment was of a magnitude of 9.3 MN.m at a depth of 7.2 m.

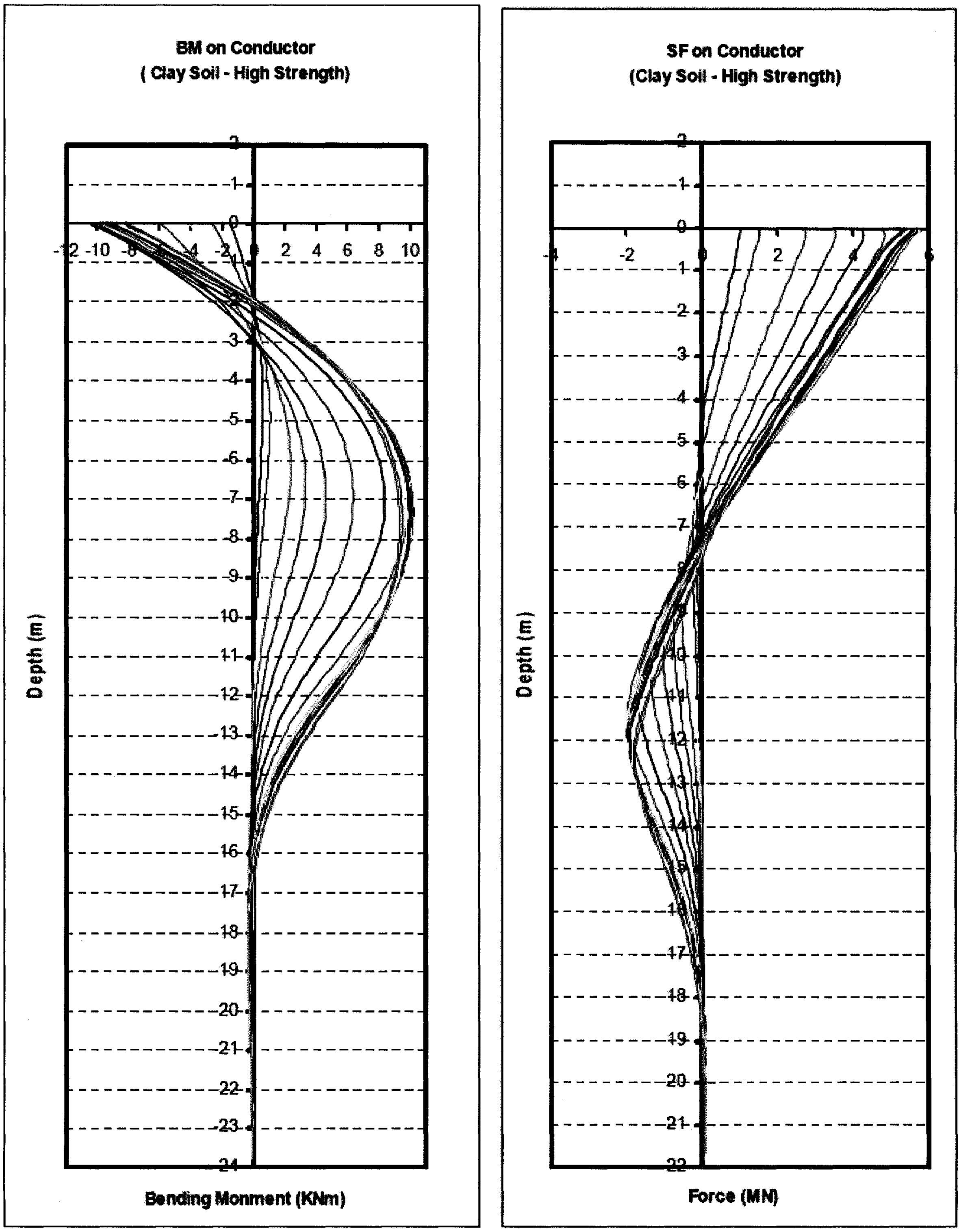


Figure 62 Bending moment and shear force distributions in uniform high strength clay soil profile – Case No.2

Figure 63, shows the maximum von Mises stress distribution along the conductor length, at a depth range between 6.5 m to 8.5 m reaching the peak value of 578 MPa at a depth of 7.4 m.

Von Mises stress distribution is consistent with the Bending Moment distribution through- out the depth along the conductor length. The constant stress values below 18 m indicate a constant strain due to axial tension force.

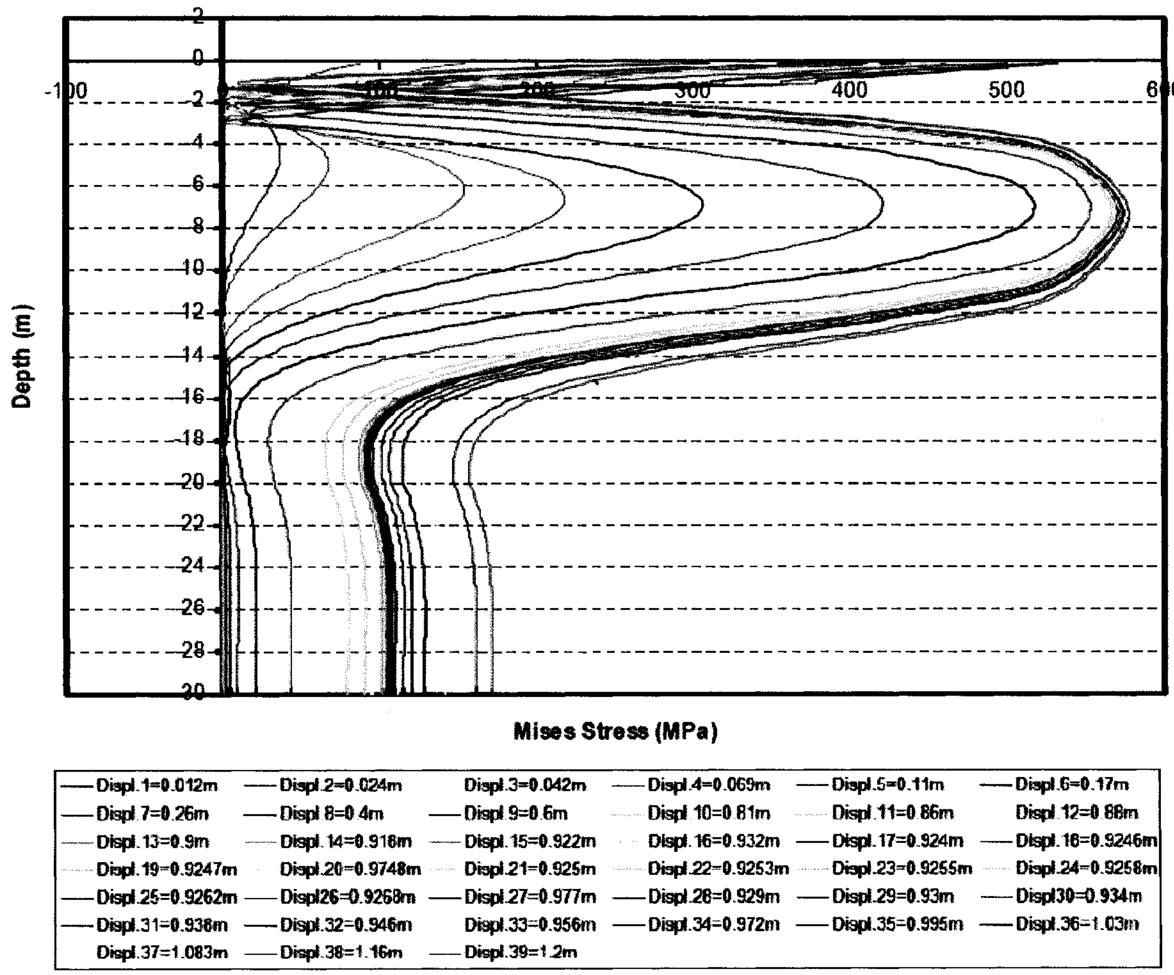


Figure 63 Von Mises stress distribution along the conductor in uniform high strength clay soil profile – Case No.2

The maximum axial strain occurred at a depth of 7.36 m of 1.72 % value (Figure 64). As expected, the strain magnitude distribution along the conductor increased when comparing low strength clay soil to high strength clay soil.

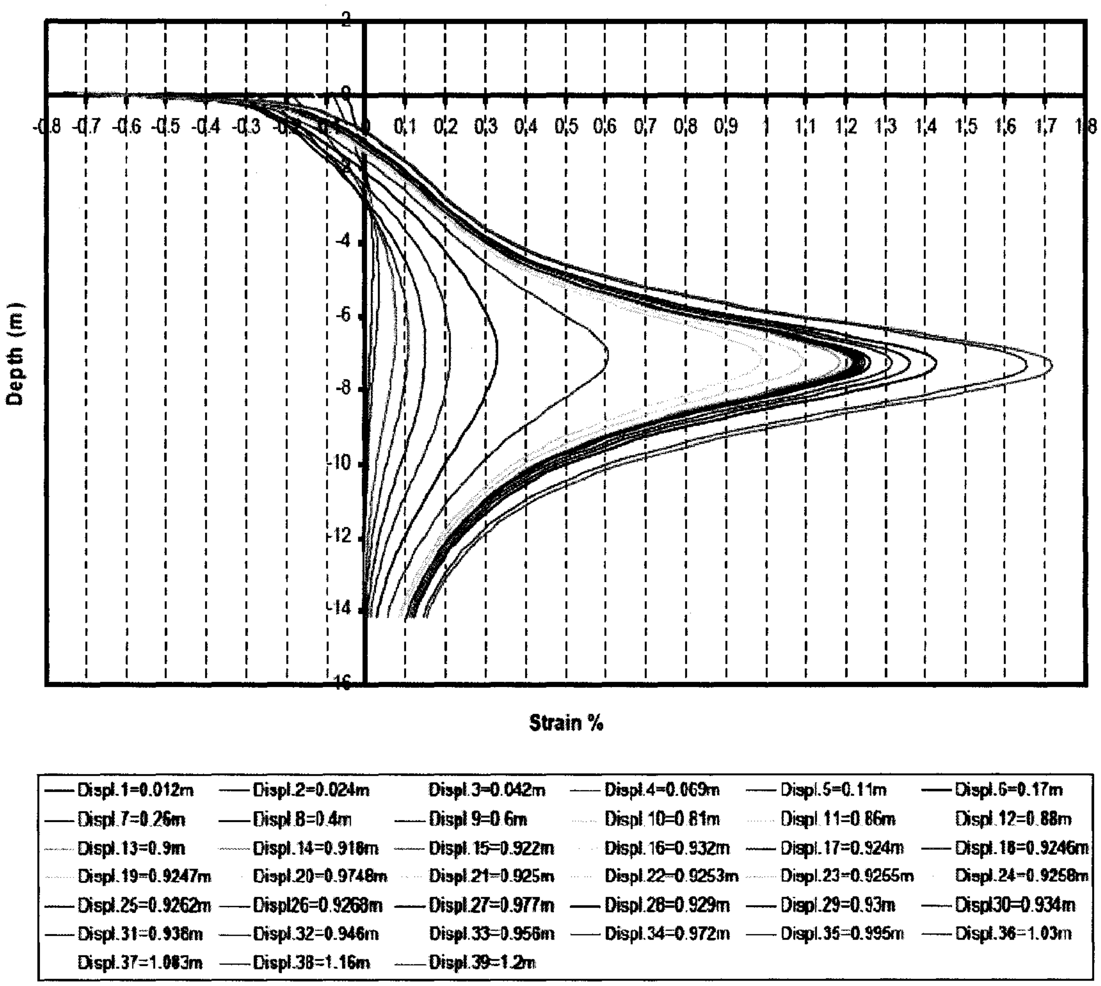


Figure 64 Axial strain distribution along the conductor in uniform high strength clay soil profile – Case No.2

For the completion tubing, the maximum von Mises stress distribution over the length, depth range between 6 m to 8 m (Figure 65), reaching the peak value 558.7 MPa at a depth of 7.36 m.

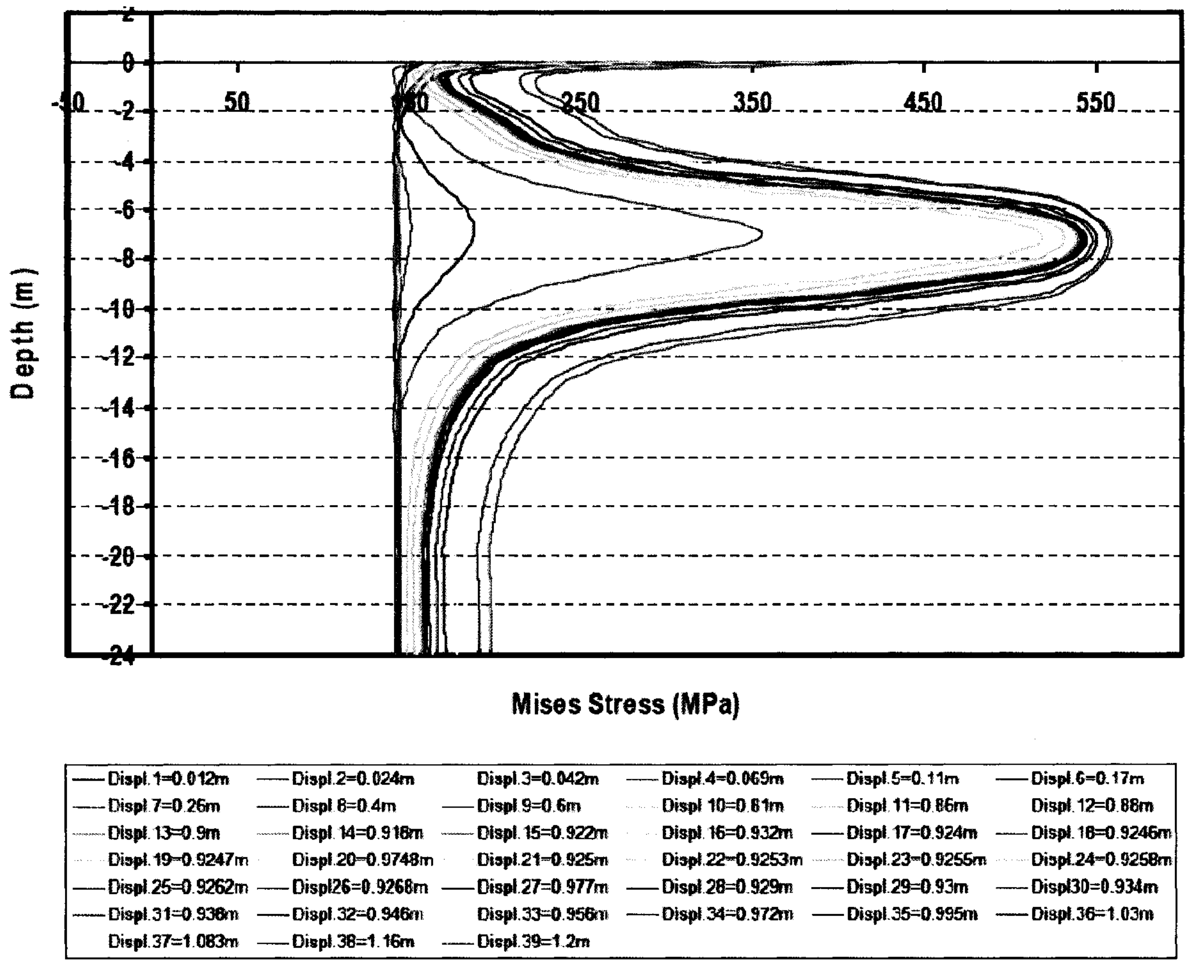


Figure 65 Von Mises stress distribution along the completion tubing in uniform high strength clay soil profile – Case No.2

The maximum axial force of 1.68 MN occurred at a depth of 7.6 m. The distribution of the axial force along the completion length is shown in Figure 66. A constant axial force could be observed starting from a depth of around 20 m and below.

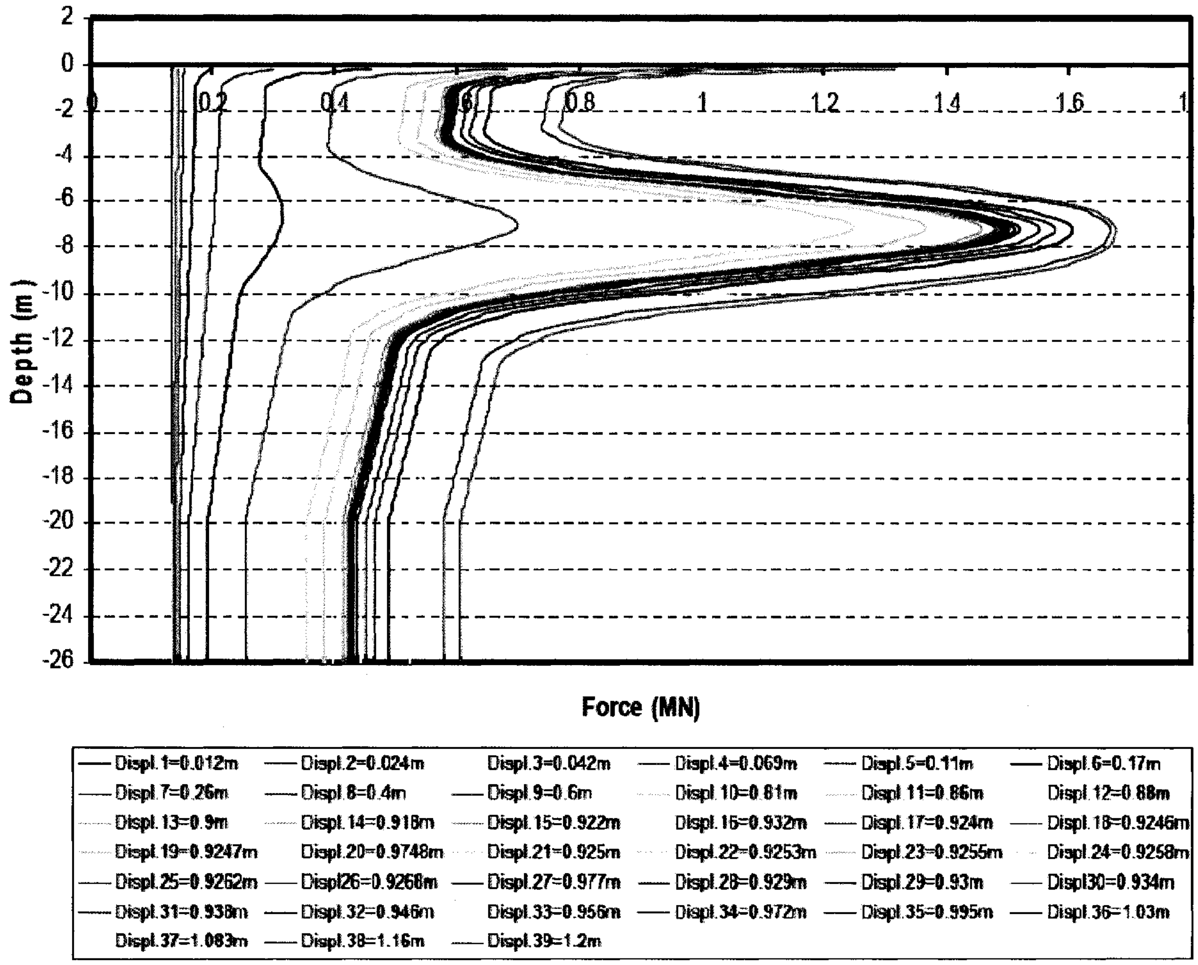


Figure 66 Axial force distribution along the completion tubing in uniform high strength clay soil profile – Case No.2

No significant moment or lateral force developed along the length of the completion. The maximum axial strain occurred at a depth of 7.4 m of 0.72 % value (Figure 67). In the uniform high strength clay soil profile, axial strain distribution on the completion exhibited larger values than those on the completion in low strength clay soil profile.

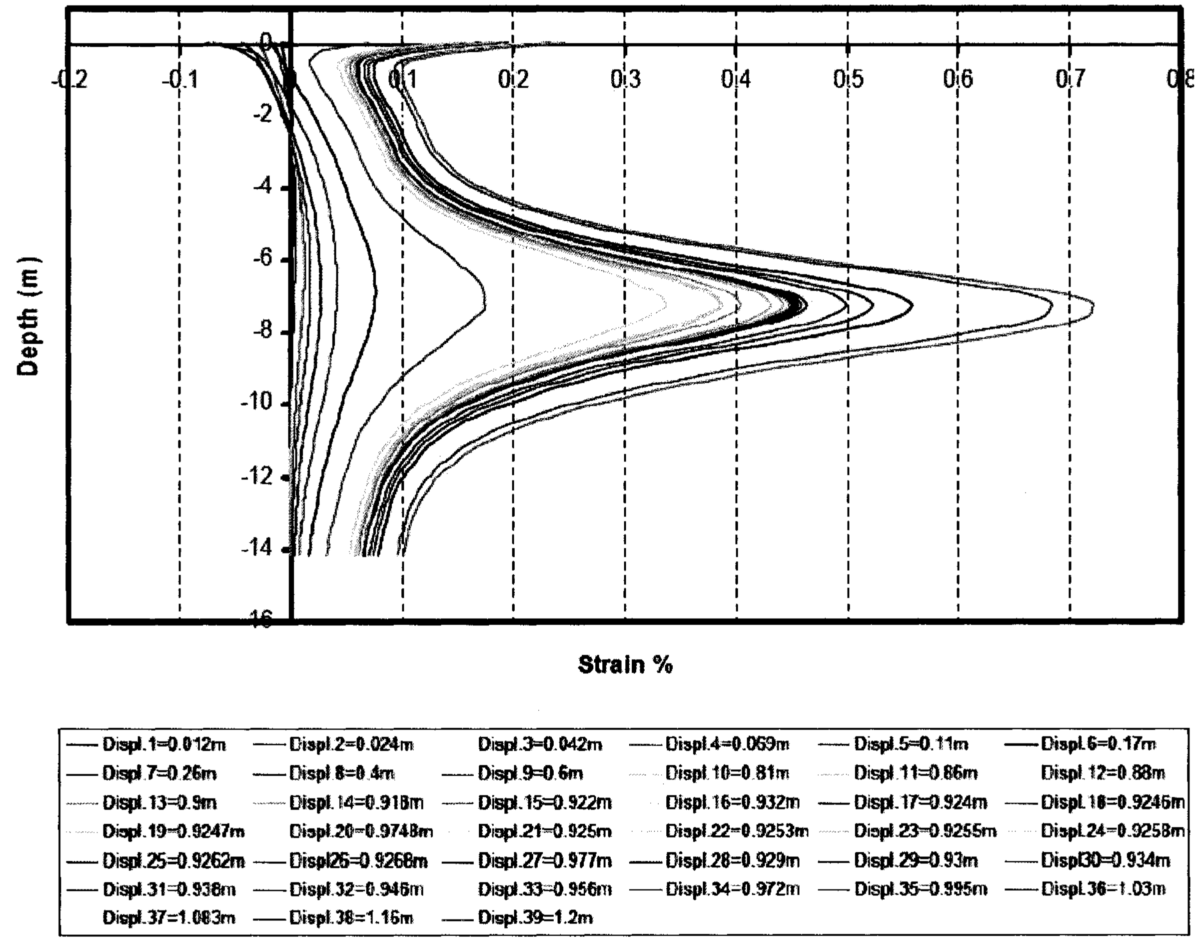


Figure 67 Axial strain distribution along the completion tubing in uniform high strength clay soil profile – Case No.2

The distribution of displacements for the uniform high strength clay is shown in Figure 68. It is observed that the high strength clay layer allowed big displacements of the conductor head at the sea bed level starting from 0.0117 m at the first displacement step to a displacement of 1.171 m at the last step. The other observation is that the point of rotation for the conductor (point which does not move as the loading is applied) shifted up to a depth of 12.5 m when compared to that of the low strength clay.

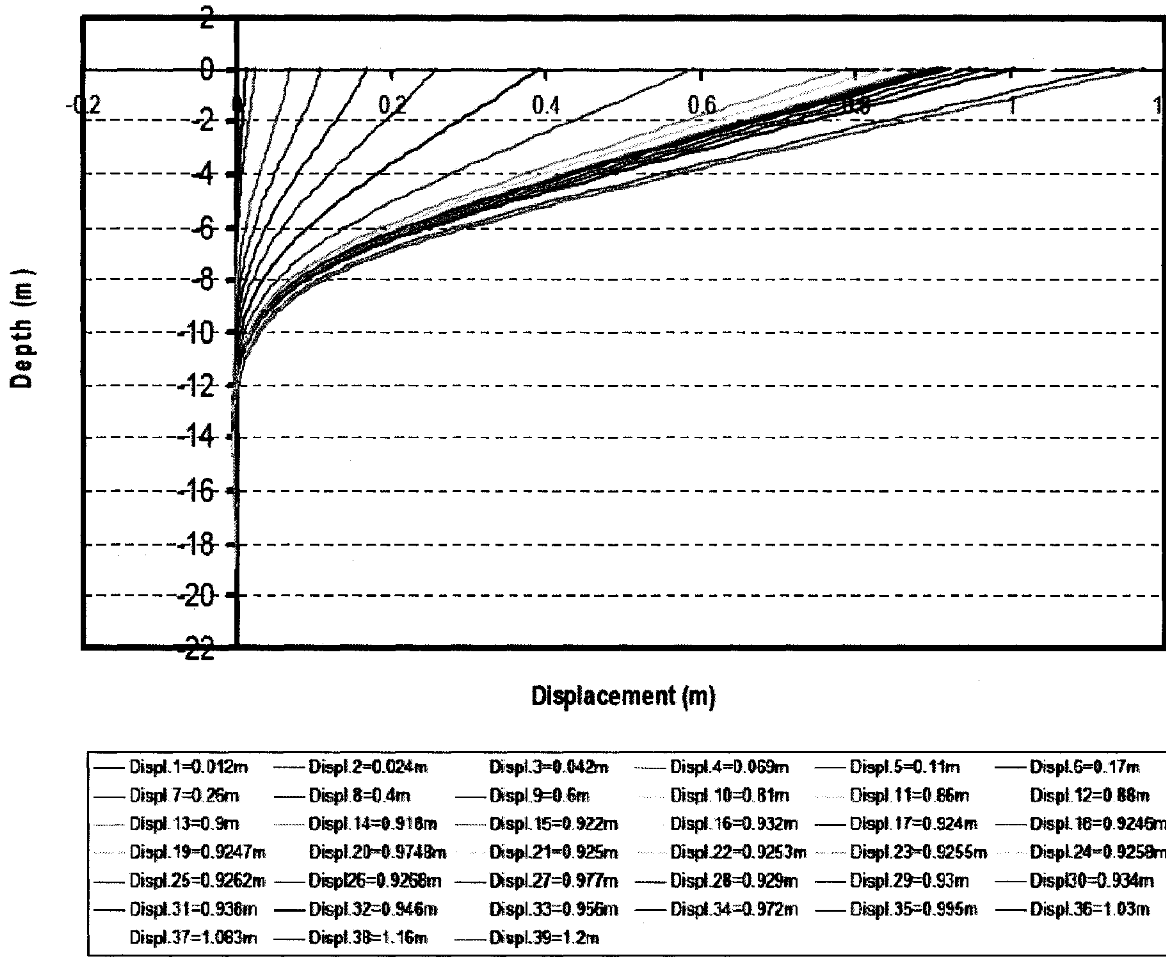


Figure 68 Displacement distribution along the depth in uniform high strength clay soil profile – Case No.2

8.2.3 Uniform Sand Soil – Case 3

Figure 69, shows bending moments and shear forces respectively along the depth of the conductor in uniform sand soil. It should be noted that the maximum bending moment below the mudline, as well as the switching of sign for shear force, moves quite a bit from the depth of approximately 6.25 m all the way to the depth of 7.25 m with generally a good agreement between the shear force and bending moment diagrams.

The maximum value of bending moment was of a magnitude of 10.5 MN.m at a depth of bout 7.2 m and of a slightly bigger value than those noted for the clay soil profiles.

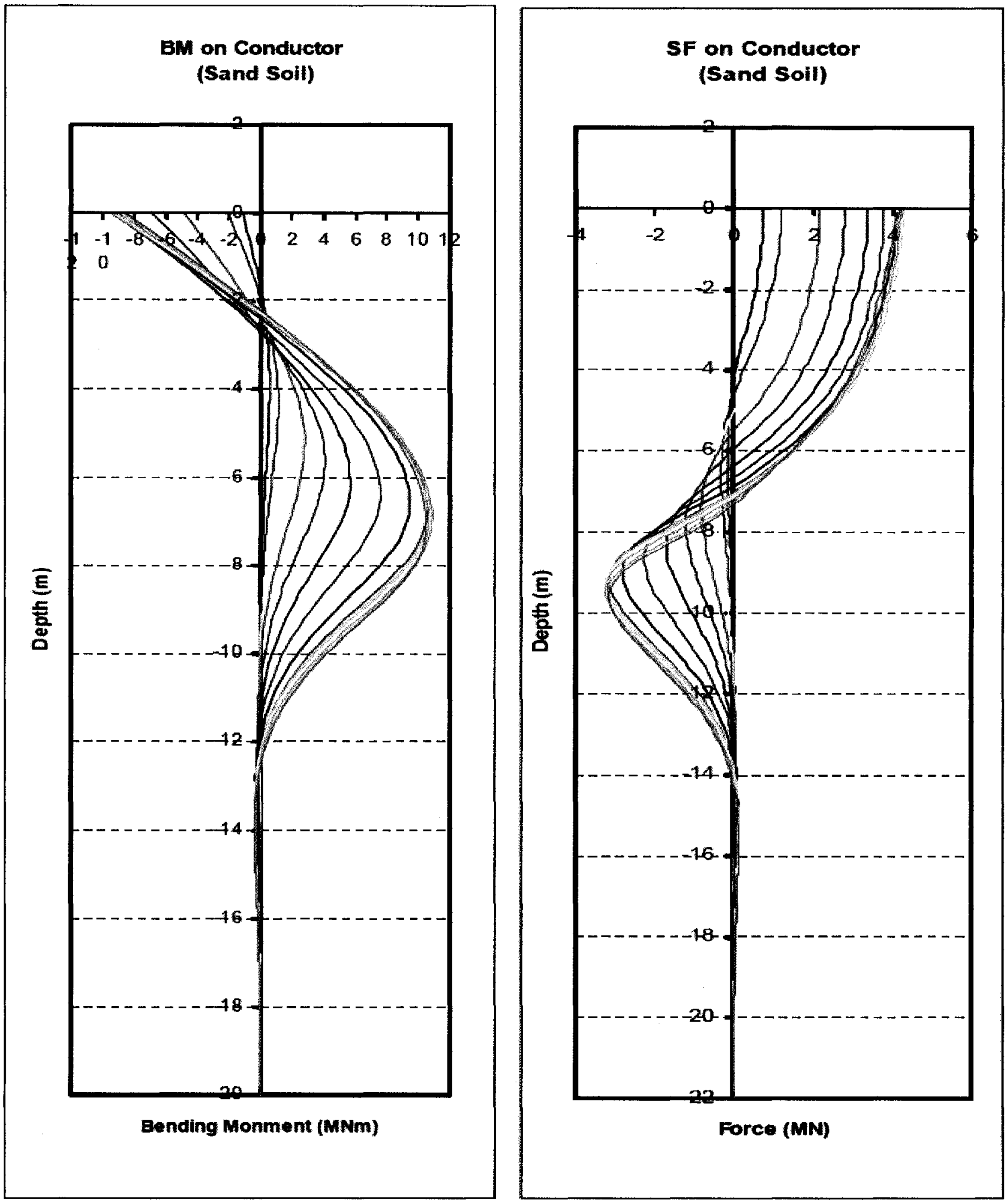


Figure 69 Bending moment and shear force distributions in uniform sand soil profile – Case No.3

Figure 70 shows the maximum von Mises stress distribution along the conductor length, at a depth range between 6 m to 8 m reaching the peak value of 586 MPa at a depth of 7m. The constant stress values below 14 m indicate a constant strain due to axial tension force. Stress and strain values exceeding yield and the implications are discussed in Section 8.3

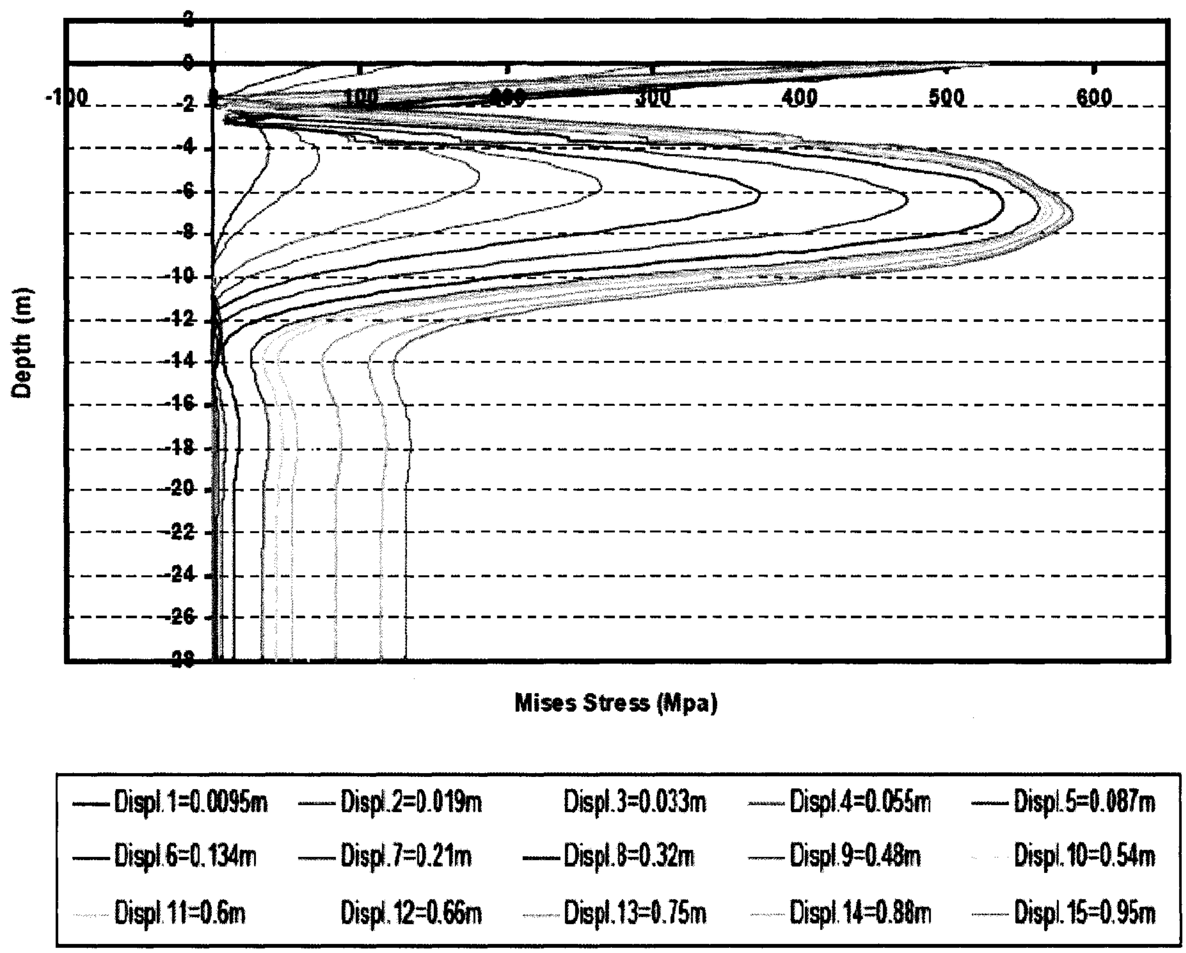


Figure 70 Von Mises stress distribution along the conductor in uniform sand soil profile– Case No.3

The maximum axial strain occurred at a depth of 7.1 m of 2.62 % value (Figure 71). The strain increased for sand soil relative to clay soils; the strain magnitude distribution (range) with depth had variation when compared to clay soils in terms of the values of the strain at the same depths and the peak values and their location.

The magnitude of the peak strain increased by about 65% when compared to the conductor in clay soils indicating an increase in the relative stiffness of the structure.

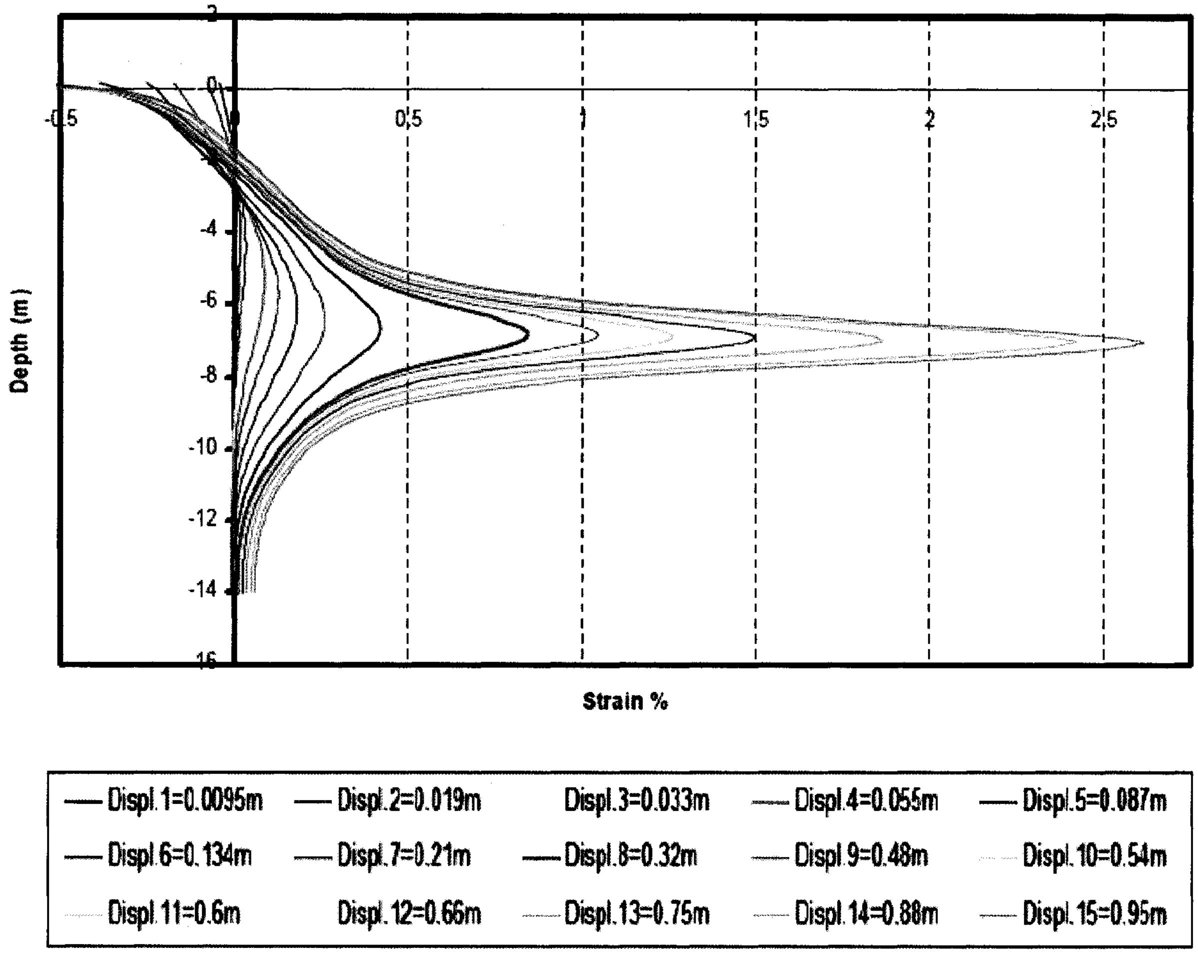


Figure 71 Axial strain distributions along the conductor in uniform sand soil profile– Case No.3

For the completion tubing, the maximum von Mises stress distribution over the length, depth range between 6.5 m to 7.5 m (Figure 72), reaching the peak value 565.7 MPa at a depth of 7.1 m.

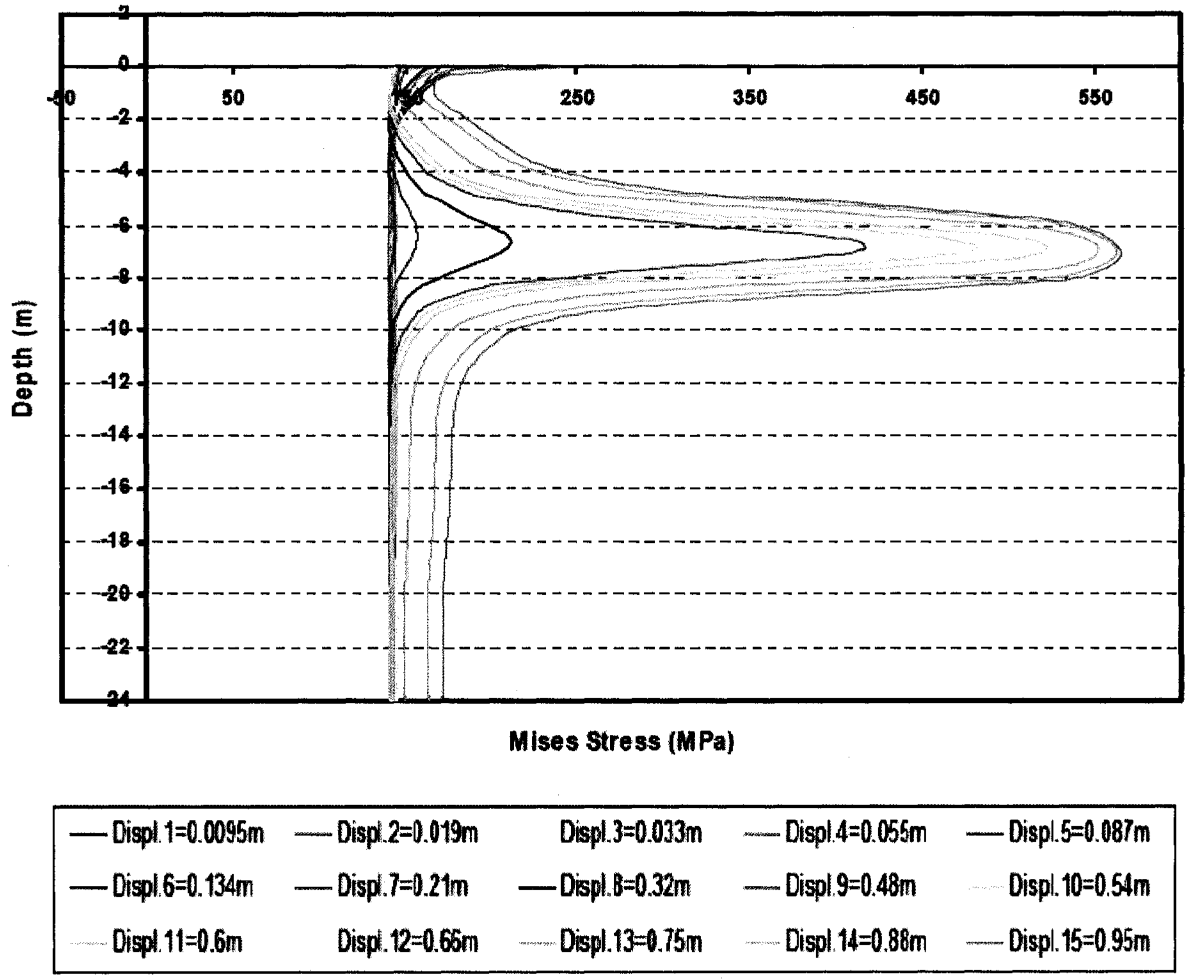


Figure 72 Von Mises stress distribution along the completion tubing in uniform sand soil profile– Case No.3

The maximum axial force of 1.69 MN occurred at a depth of approximately 7.2 m. The distribution of the axial force along the completion length is shown in Figure 73.

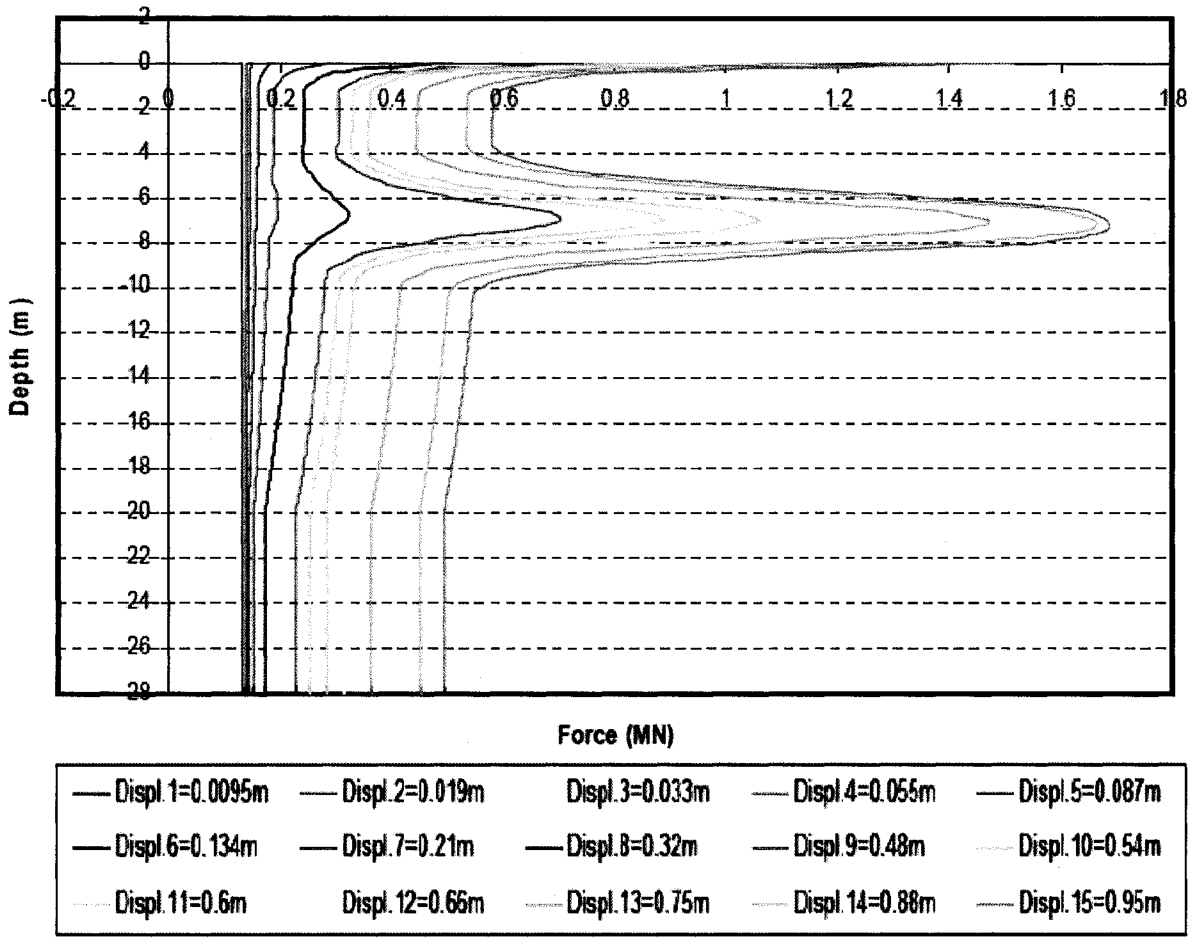


Figure 73 Axial force distributions along the completion tubing in uniform sand soil profile– Case No.3

No significant moment or lateral force developed along the length of the completion. The maximum axial strain occurred at a depth of 7.042 m of 0.95 % value (Figure 74). The peak strain value on the completion increased by about 30% when compared to the strain values of the completion in clay soils. This is an indication of the increase in relative stiffness of the whole system.

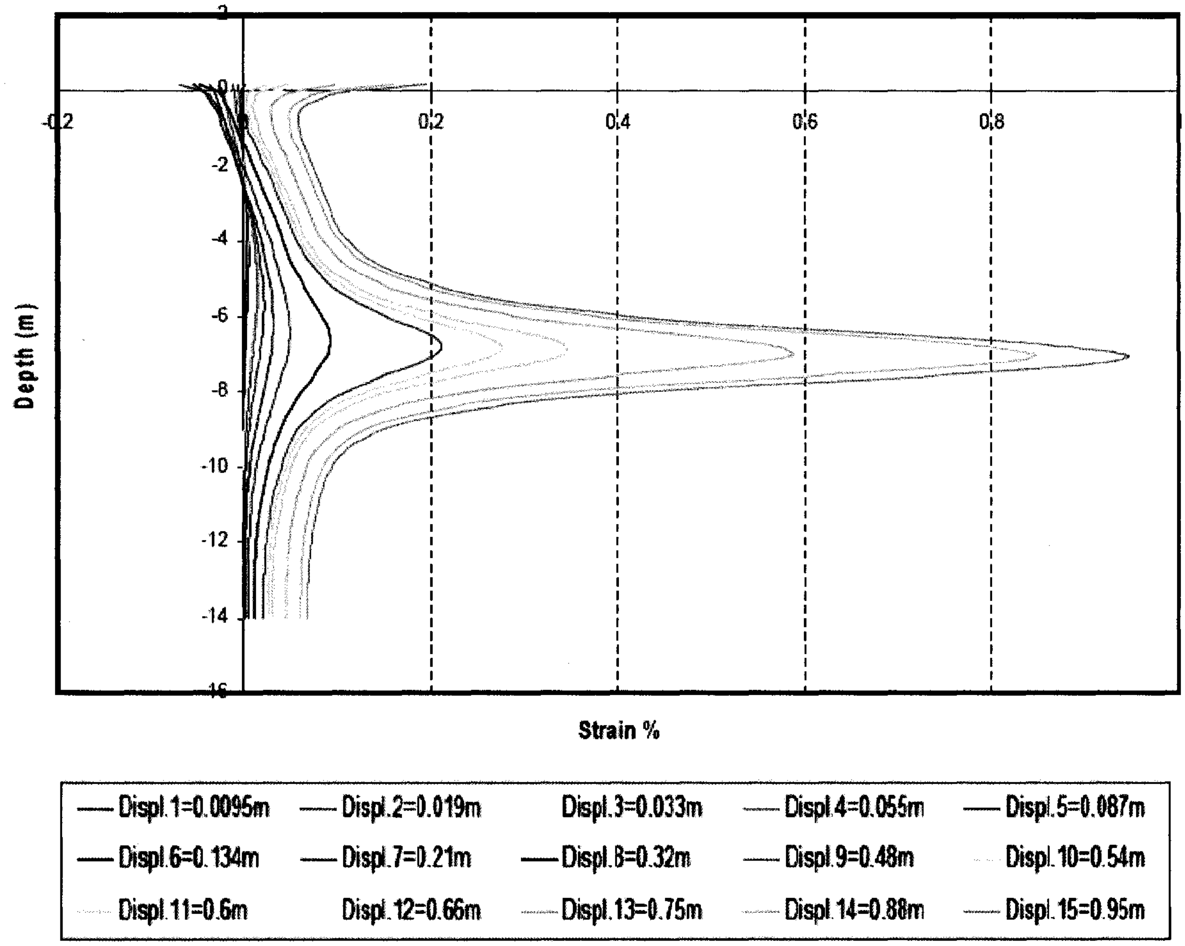


Figure 74 Axial strain distribution along the completion tubing in uniform sand soil profile– Case No.3

The distribution of displacements for the uniform sand soil is shown in Figure 75. It is observed that the uniform sand layer allowed less displacement of the conductor head at the seabed level compared to that in the uniform clay soil, starting from 0.009 m at the first displacement step, to a displacement of 0.894 m at the last step.

In general the propagation of displacements along the depth of the conductor is much less when compared to that of uniform clay. The uniform sand soil layer has added to the stiffness of the conductor as part of the relative system stiffness.

The other observation is that the point of rotation for the conductor (point which does not move as the loading is applied) shifted up to a depth of about 9.6 m when compared to that for the clay profiles.

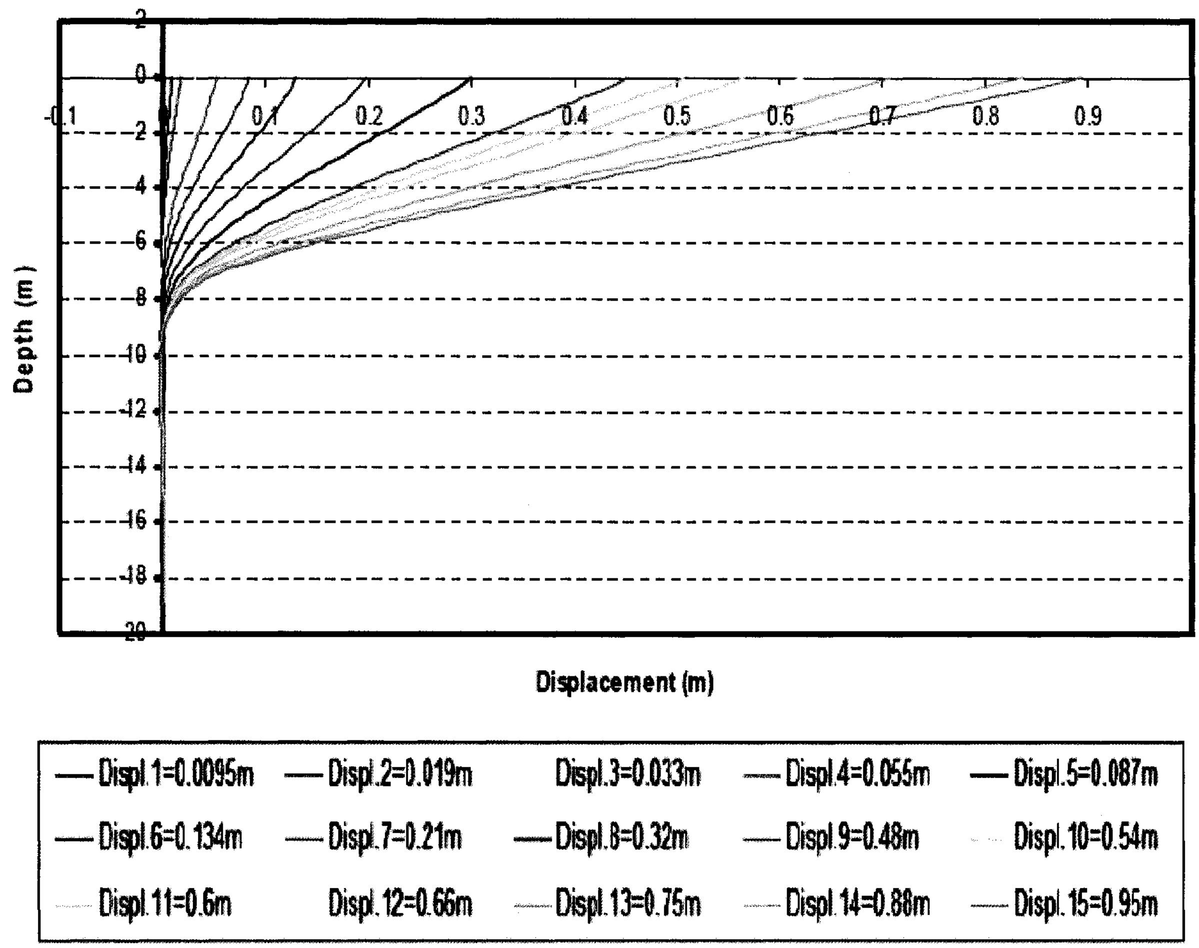


Figure 75 Displacement distribution along the depth in uniform sand soil profile - Case No.3

8.2.4 Layered Soil Profile – Case 4

Figure 76, shows bending moments and shear forces moments respectively along the depth of the conductor in layered soil profile. It should be noted that the maximum bending moment below mudline, as well as the switching of sign for shear force, moves quite a bit from the depth of approximately 6 m all the way to the depth of 7.25 m with generally a good agreement between the shear force and bending moment diagrams.

The maximum value of bending moment was of a magnitude of 10.42 MN.m at an approximate depth of 7.2 m.

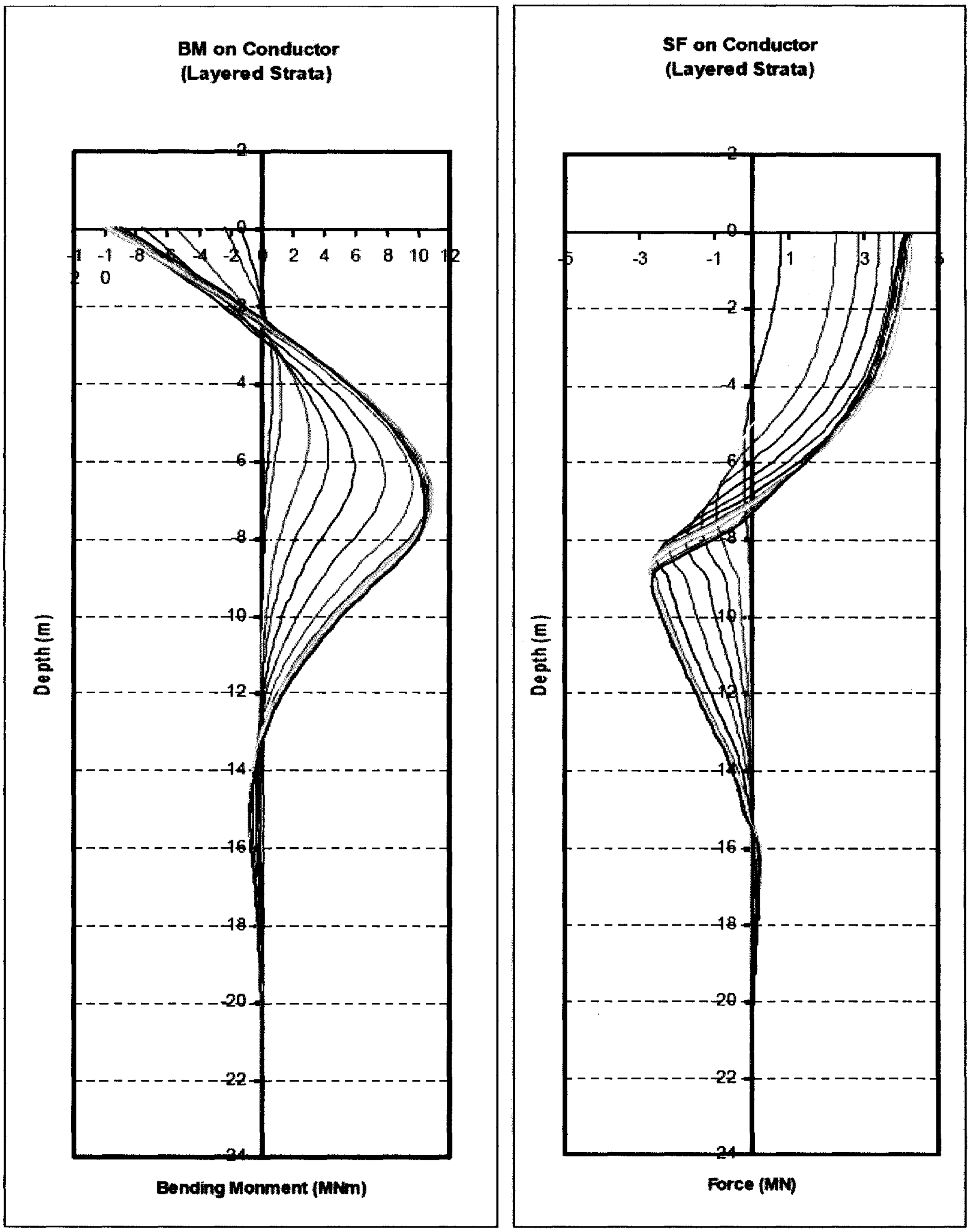


Figure 76 Bending moment and shear force distributions in layered soil profile - Case No.4

Figure 77, shows the maximum von Mises stress distribution along the conductor length, at a depth range between 6.5 m to 7.5 m reaching the peak value of 587 MPa at a depth of 7.1m.

The Von Mises stress distribution is consistent with the Bending Moment distribution through-out the depth along the conductor length. The constant stress values below 20 m indicate a constant strain due to axial tension force. Stress and strain values exceeding yield and the implications are discussed in Section 8.3.

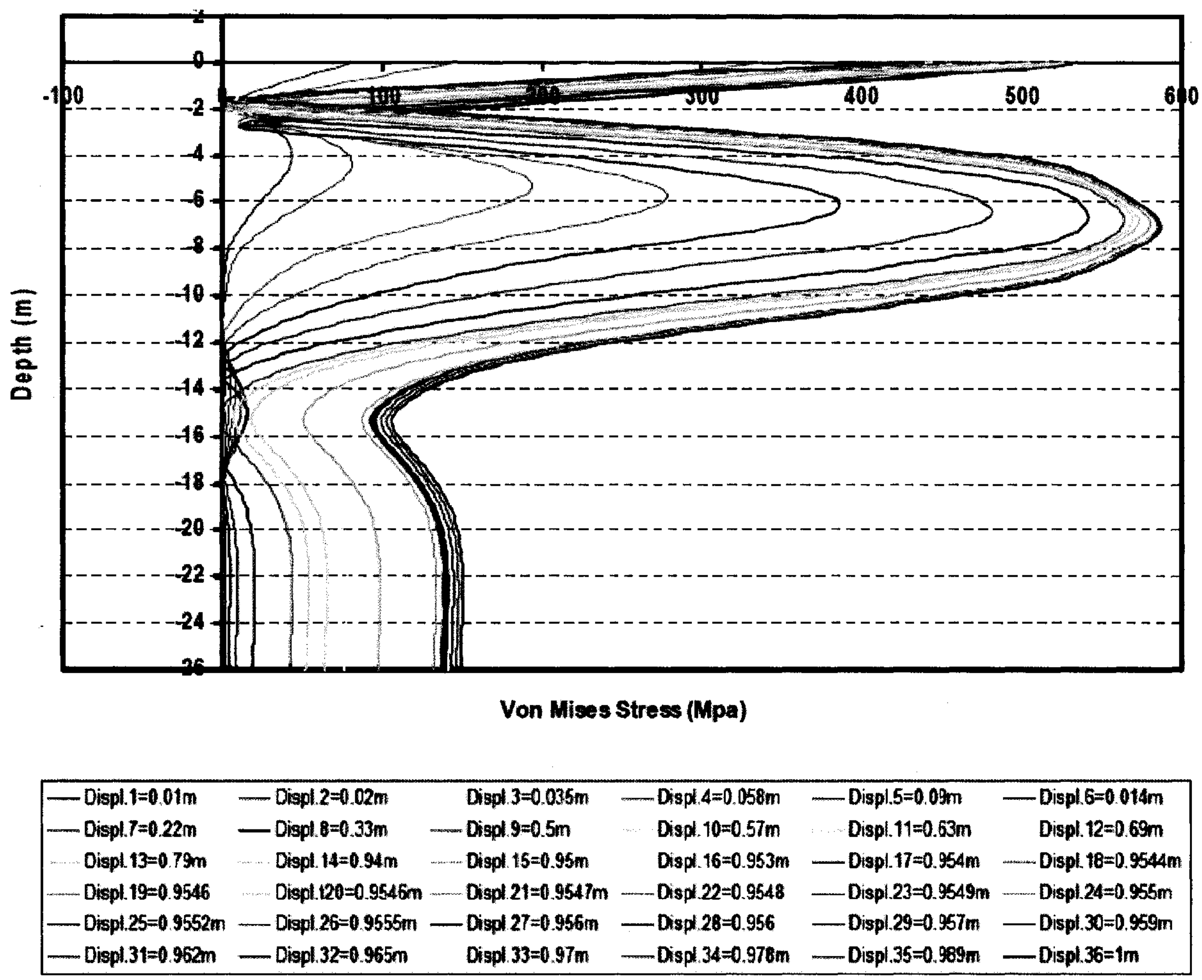


Figure 77 Von Mises stress distribution along the conductor in layered soil profile - Case No.4

The maximum axial strain occurred at a depth of 7.1 m and had a value of 2.75 % as shown in Figure 78.

The switchover from the compressive strains to tensile strains moves from the depth of approximately 1 m to a depth of 3 m. A slightly higher peak strain when compared to sand soil case can be observed in the layered soil case.

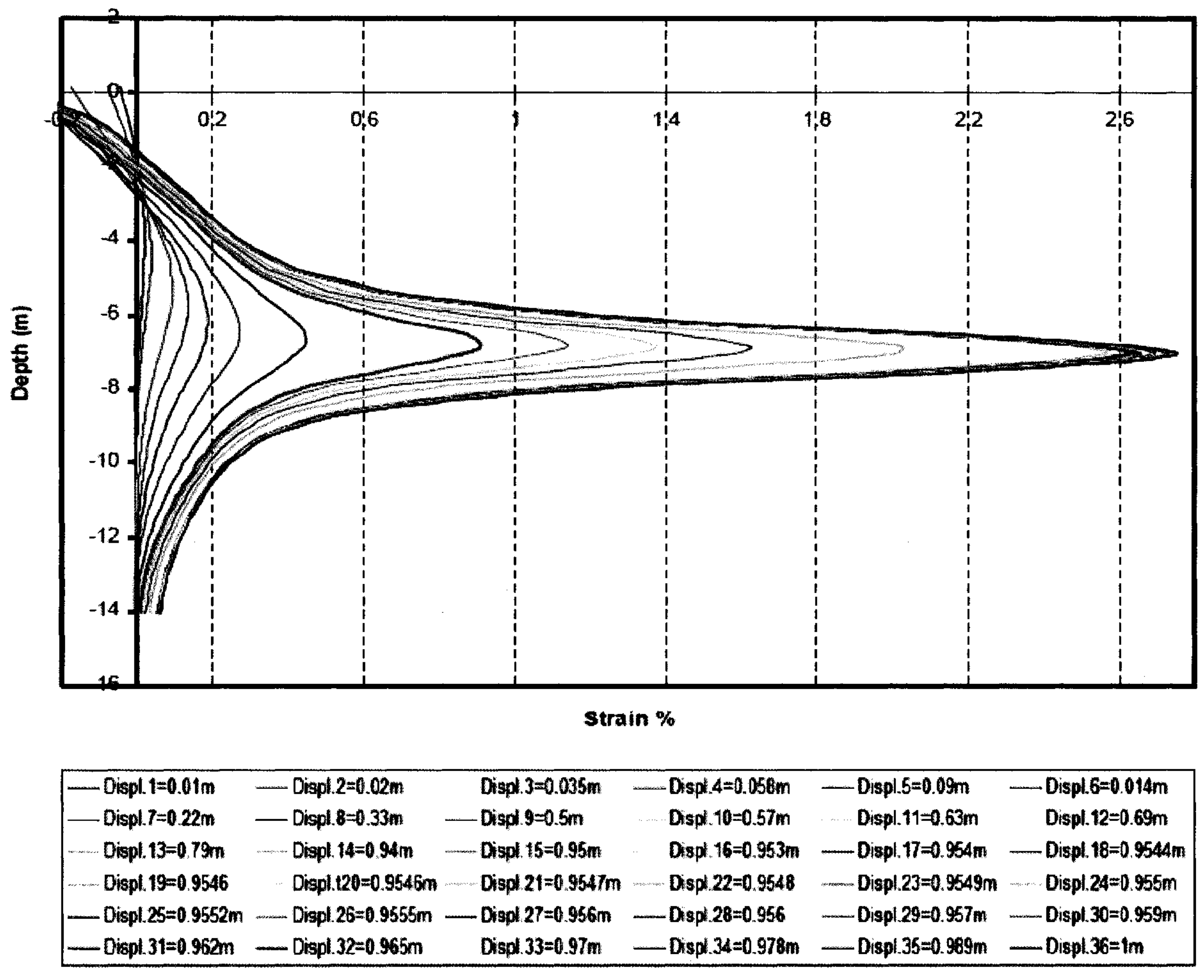


Figure 78 Axial strain distribution along the conductor in layered soil profile - Case No.4

For the completion tubing, the maximum von Mises stress distribution over the length, depth range between 6.5 m to 7.5 m (Figure 79) reaching the peak value 567 MPa at a depth of 7.1 m.

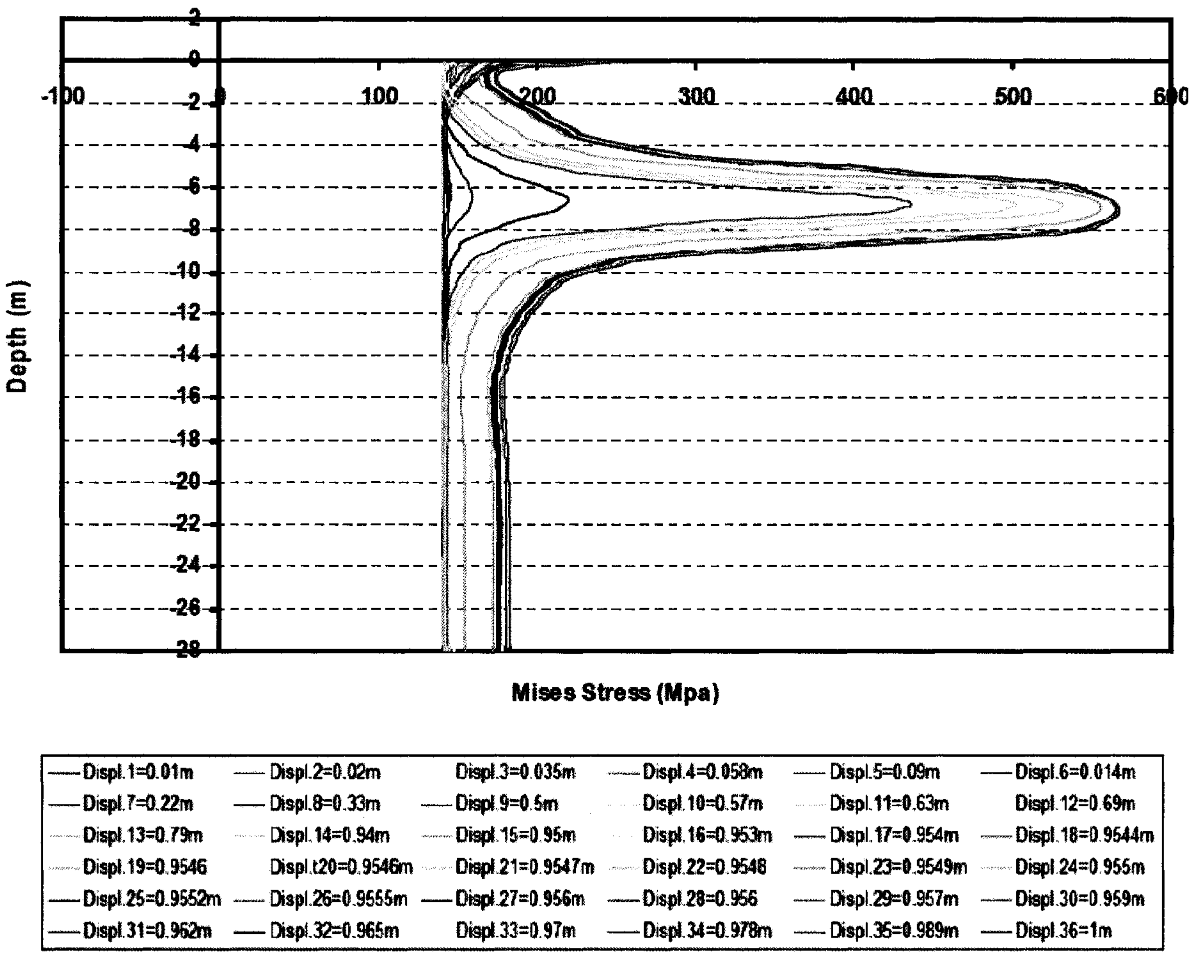


Figure 79 Von Mises stress distribution along the completion tubing in layered soil profile - Case No.4

The maximum axial force of 1.7 MN occurred at a depth of 7.1 m. The distribution of the axial force along the completion length is shown in Figure 80.

No significant moment or lateral force developed along the length of the completion.

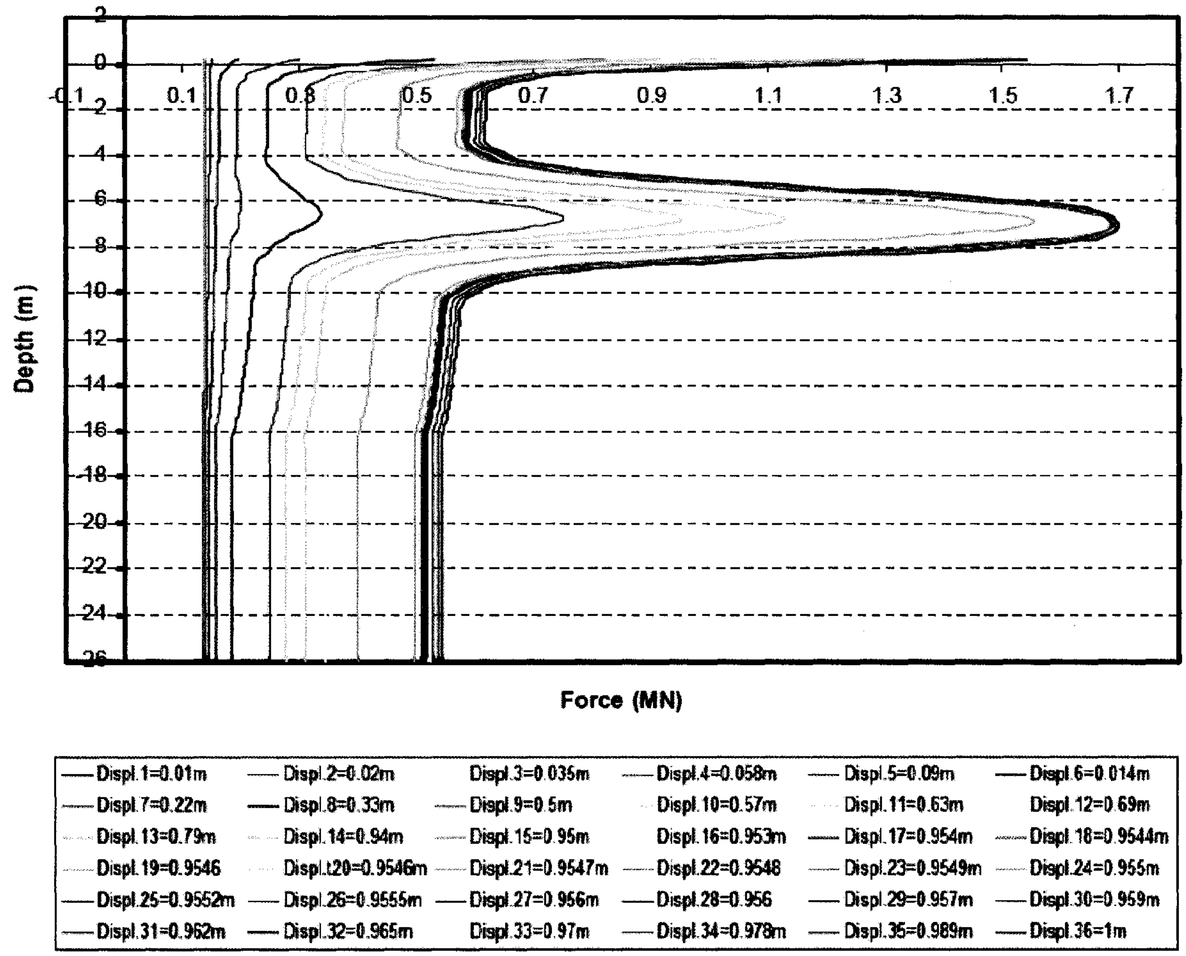


Figure 80 Axial force distribution along the completion tubing in layered soil profile - Case No.4

The maximum axial strain occurred at a depth of 7.1 m of 1.02 % value. (Figure 81)

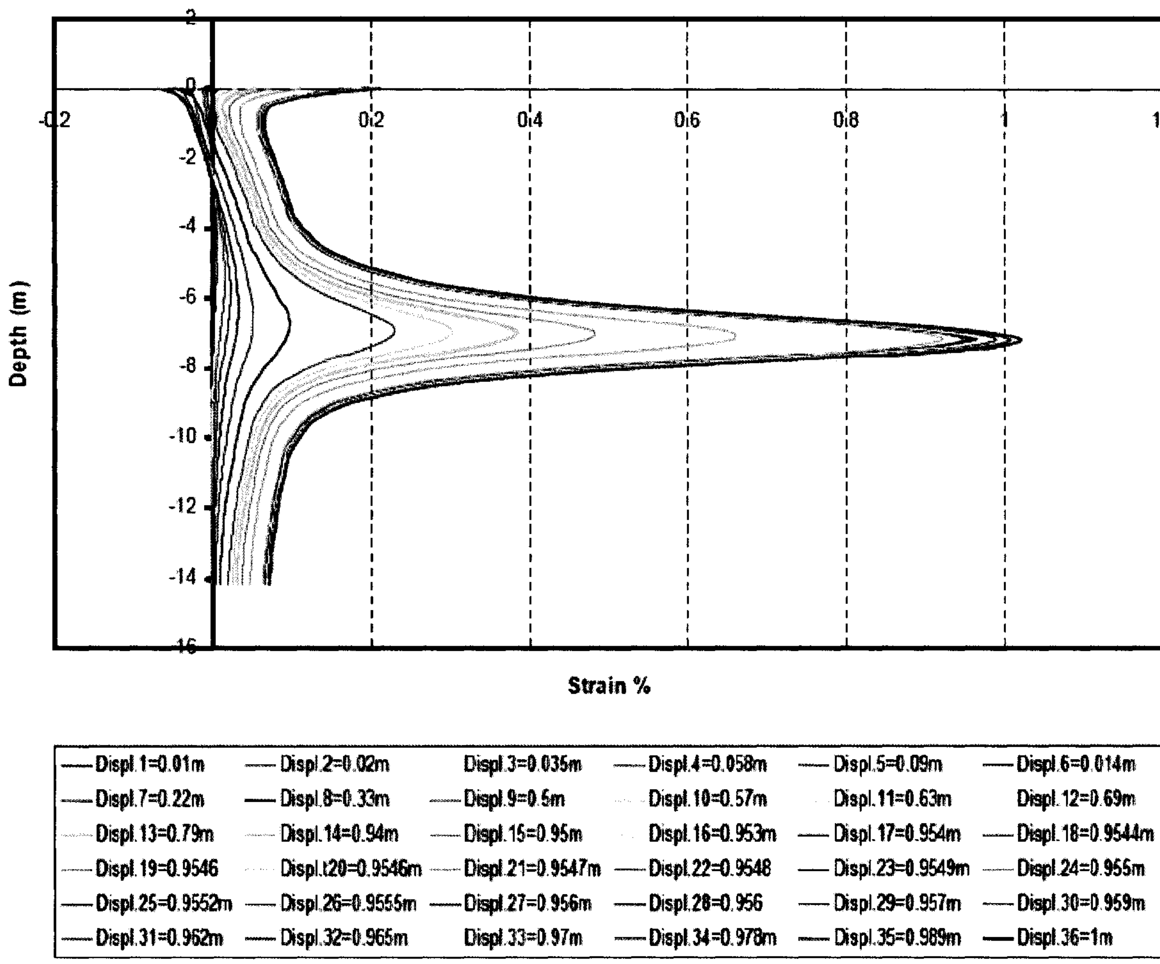


Figure 81 Axial strain distribution along the completion tubing in layered soil profile - Case No.4

The distributions of displacements for the layered soil profile is shown in Figure 82 .It is observed that displacement of conductor head at the seabed level started from 0.0094 m at the first displacement step to a final displacement value of 0.94 m at the last displacement step close to that of the full sand profile noting that the layered profile had a thick layer of sand extending from the sea depth a depth of 6 m approximately.

The decrease in the sand friction angle and inclusion of a clay layer at a depth of the around 6.2 m resulted in the decrease of the stiffness along the conductor pile and resulted in the increase of the propagation of displacements with depth when compared to that of the full sand strata.

The other observation is that the point of rotation for the conductor (point which does not move as the loading is applied) was around a depth of 9.1 m close to that of the full sand strata.

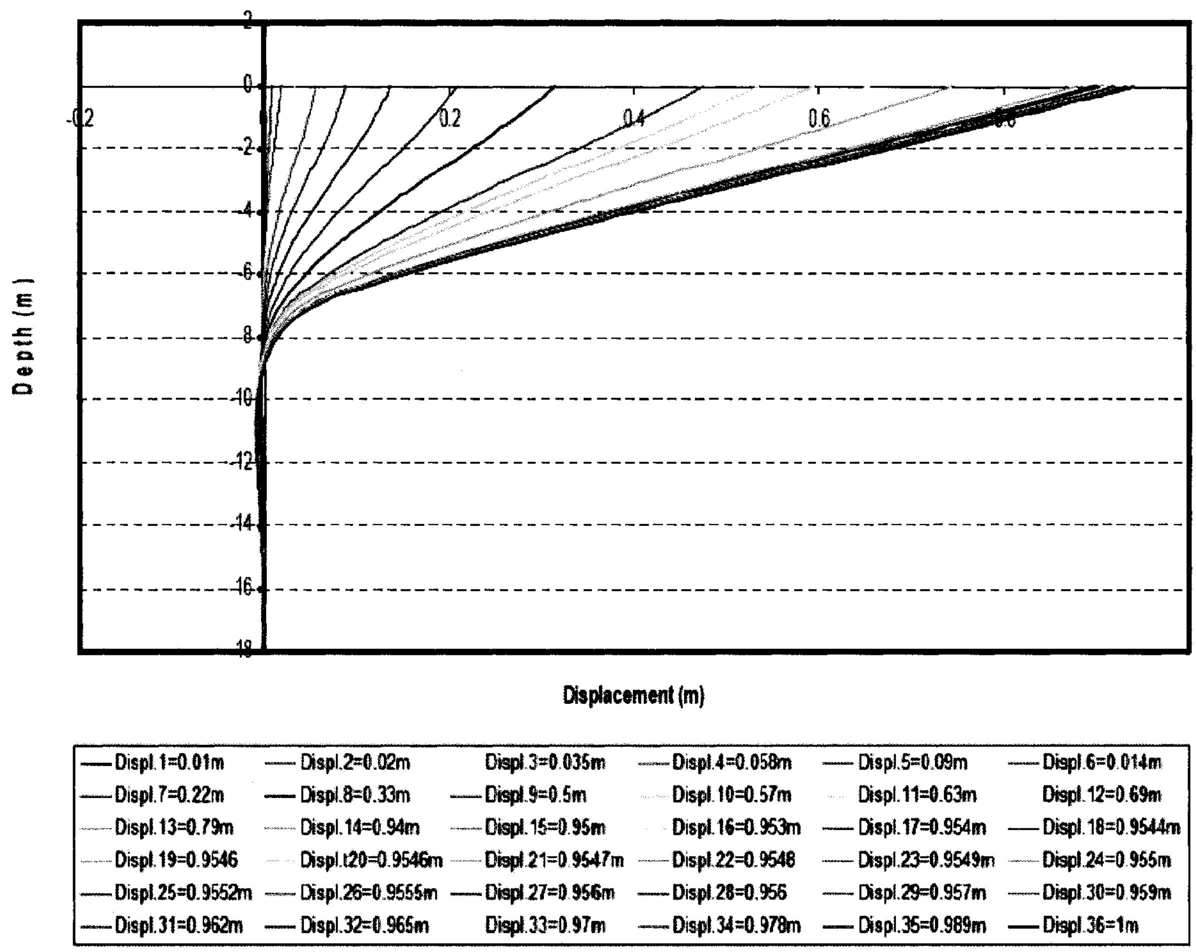


Figure 82 Displacement distribution along the depth in layered soil profile - Case No.4

8.2.5 Layered Soil Profile Under Gouging Ice Berg – Case 5

Figure 83, shows bending moments and shear forces respectively along the depth of the conductor in layered soil profile subjected to displacement by a gouging Iceberg. It should be noted that the maximum bending moment below the mudline, as well as the switching of sign for shear force, moves quite a bit from the depth of approximately 6.2 m all the way to the depth of 7.2 m with generally a good agreement between the shear force and bending moment diagrams.

The maximum value of bending moment was of a magnitude of 10.6 MN.m at a depth of 7.4 m.

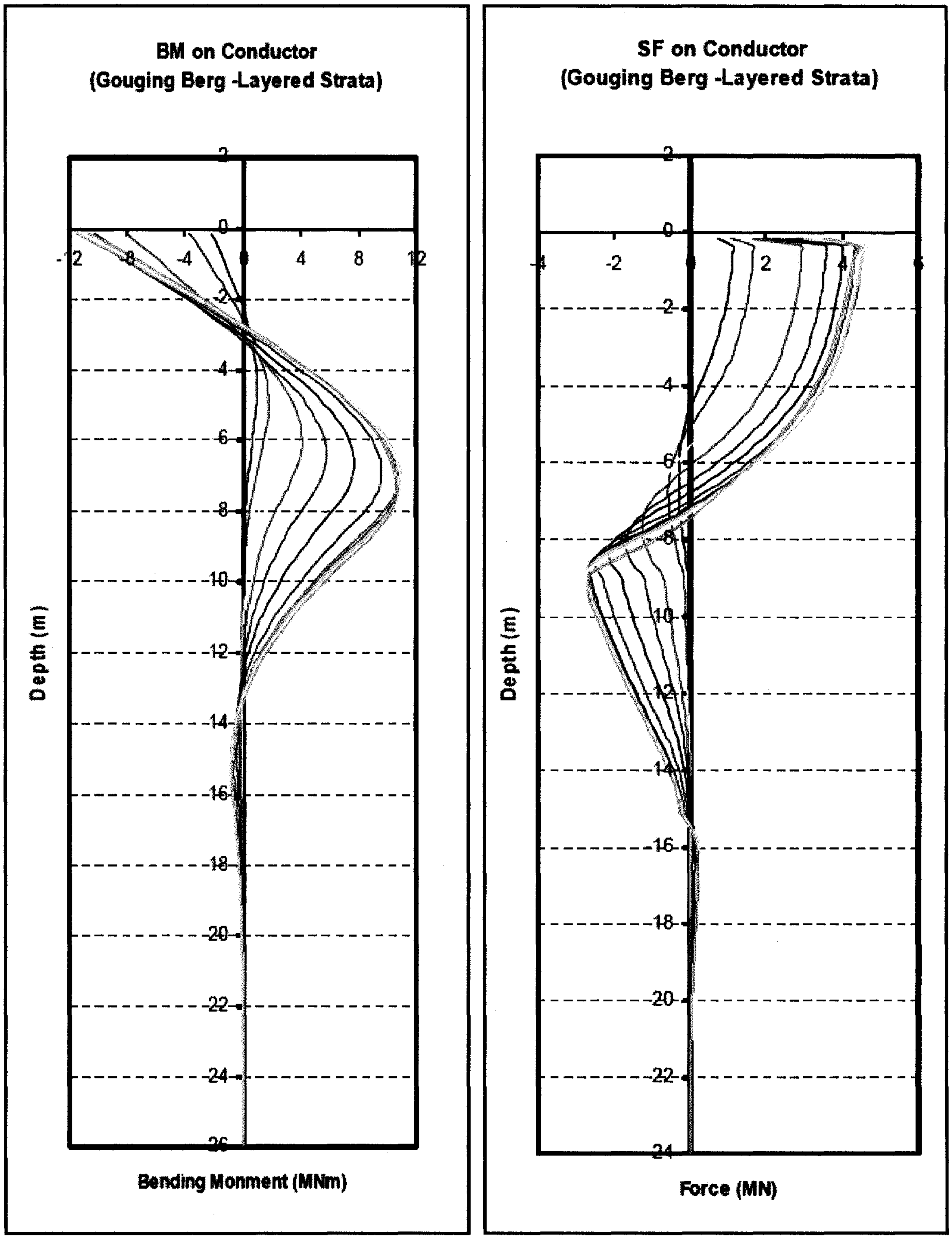


Figure 83 Bending moment and shear force distributions in layered soil profile for well structure under gouging effect - Case No.5

Figure 84, shows the maximum Von Mises stress distribution along the conductor length, at a depth range between 6.55 m to 7.55 m reaching the peak value of 587 MPa at a depth of 6.9 m.

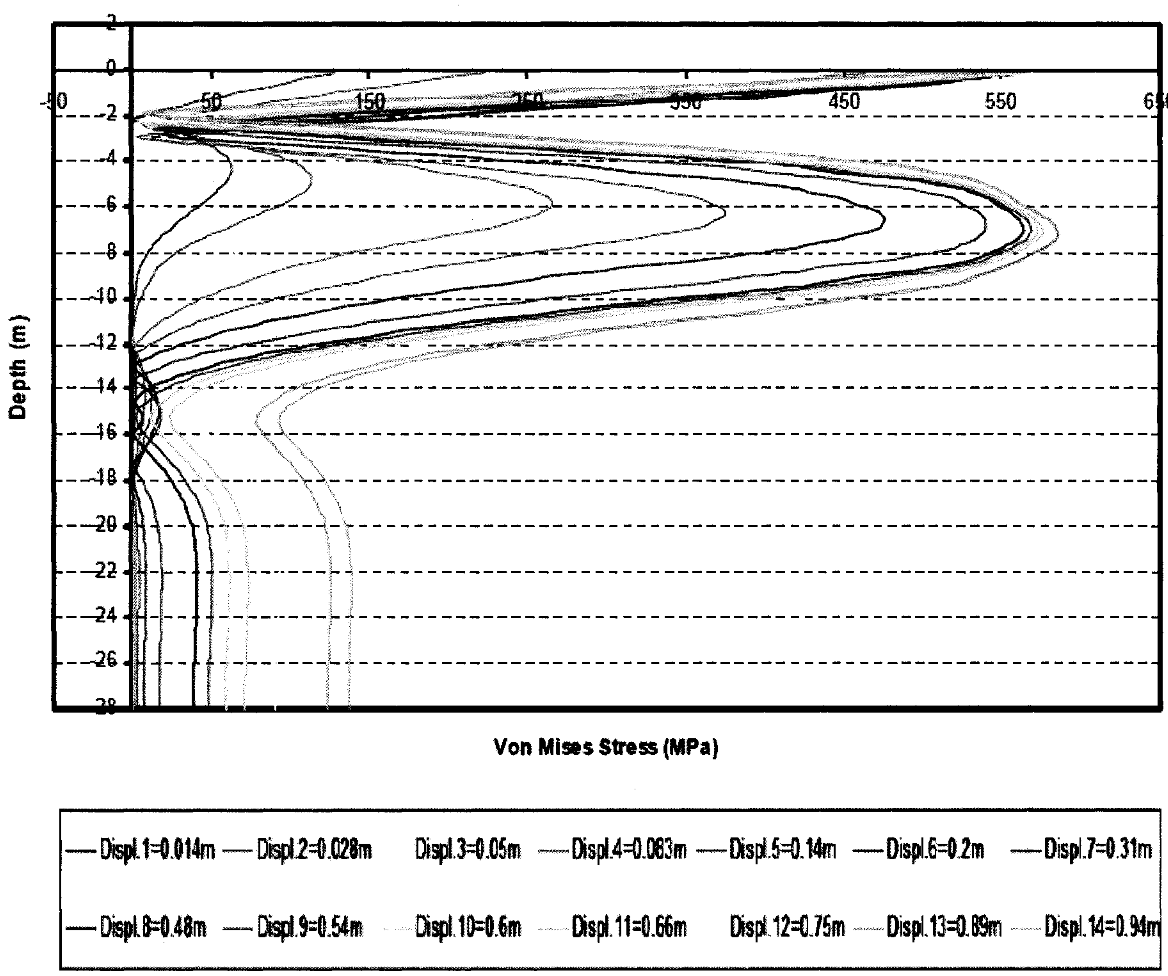


Figure 84 Von Mises stress distribution along the conductor in layered soil profile for well structure under gouging effect - Case No.5

The maximum axial strain occurred at a depth of 7.2 m and had a value of 2.8 % value (Figure 85).

The switchover from the compressive strains to tensile strains moves from the depth of approximately 2 m to a depth of 3 m. A higher peak strain is observed in the conductor under gouging when compared to floating iceberg case. This is expected since the gouging iceberg increases compressive strain at shallow depths due to the displacement of the conductor head above seabed, as well the soil displacement below seabed that a gouging berg causes.

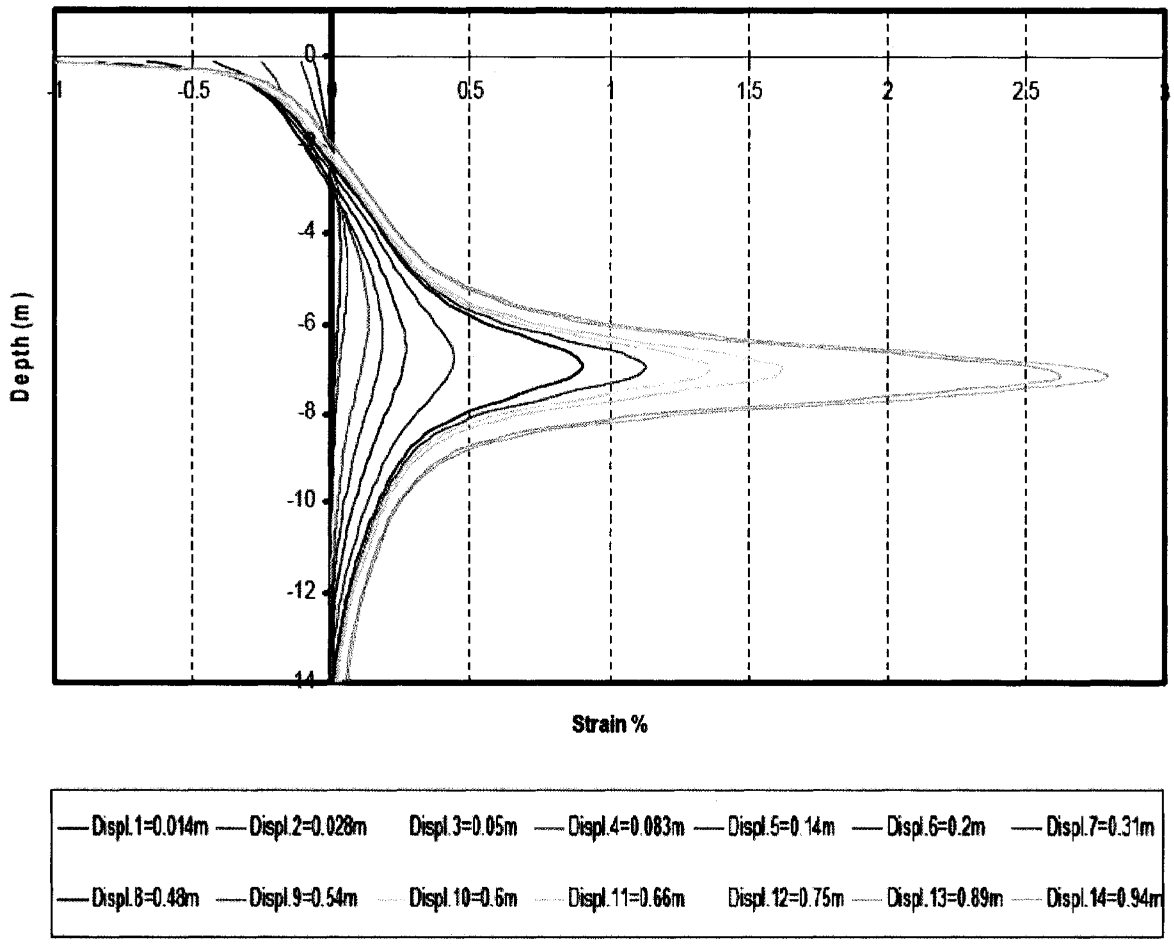


Figure 85 Axial strain distributions along the conductor in layered soil profile for well structure under gouging effect - Case No.5

The completion tubing, the maximum von Mises stress distribution over the length, depth range between 6.56 m to 7.56 m (Figure 86), reaching the peak value 567 MPa at a depth of 7.16 m.

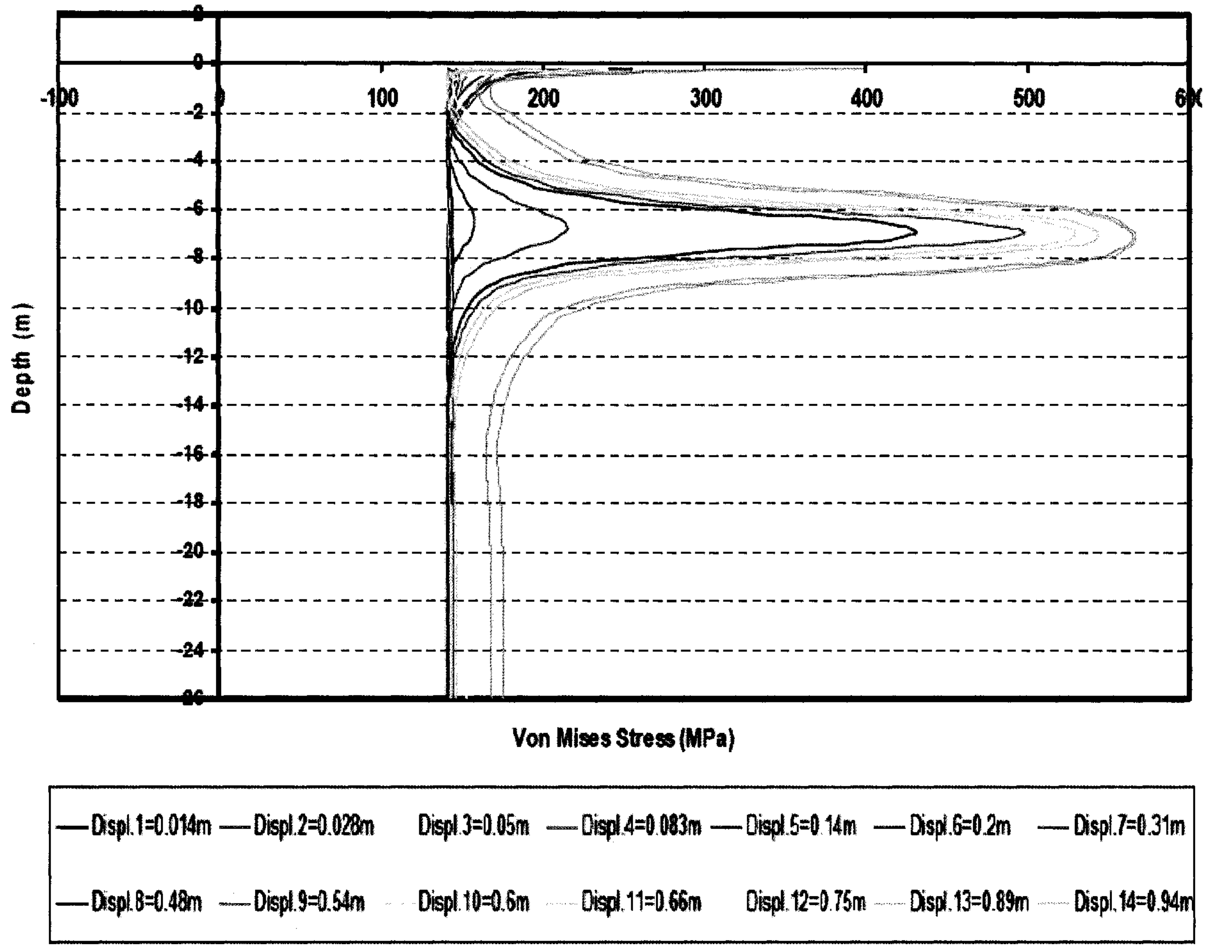


Figure 86 Von Mises stress distribution along the completion tubing in layered soil profile for well structure under gouging effect - Case No.5

The maximum axial force of 1.7 MN occurred at a depth of 7.242 m. The distribution of the axial force along the completion length is shown in Figure 87.

No significant moment or lateral force developed along the length of the completion.

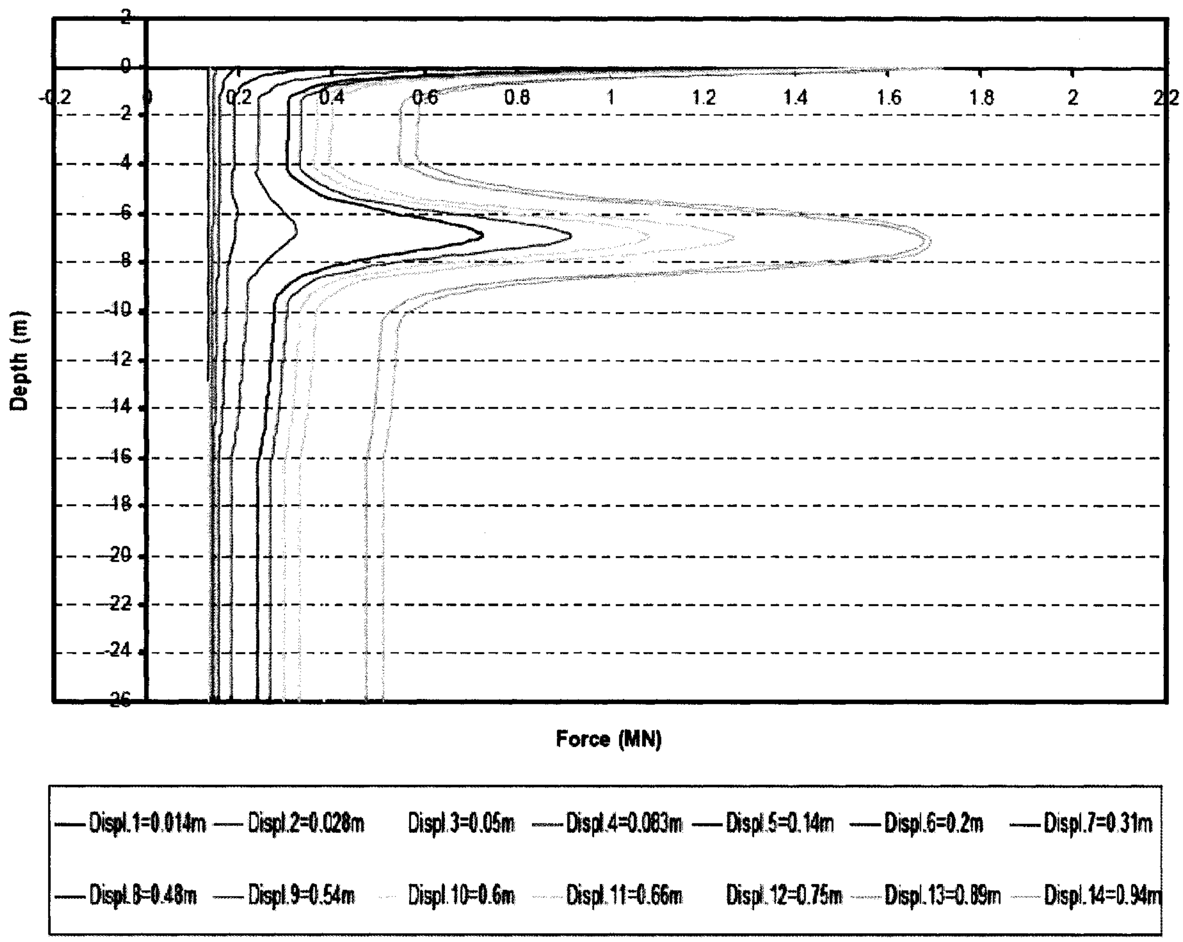


Figure 87 Axial force distributions along the completion tubing in layered soil profile for well structure under gouging effect - Case No.5

The maximum axial strain occurred at a depth of 7.158m of 1.02 % value (Figure 88).

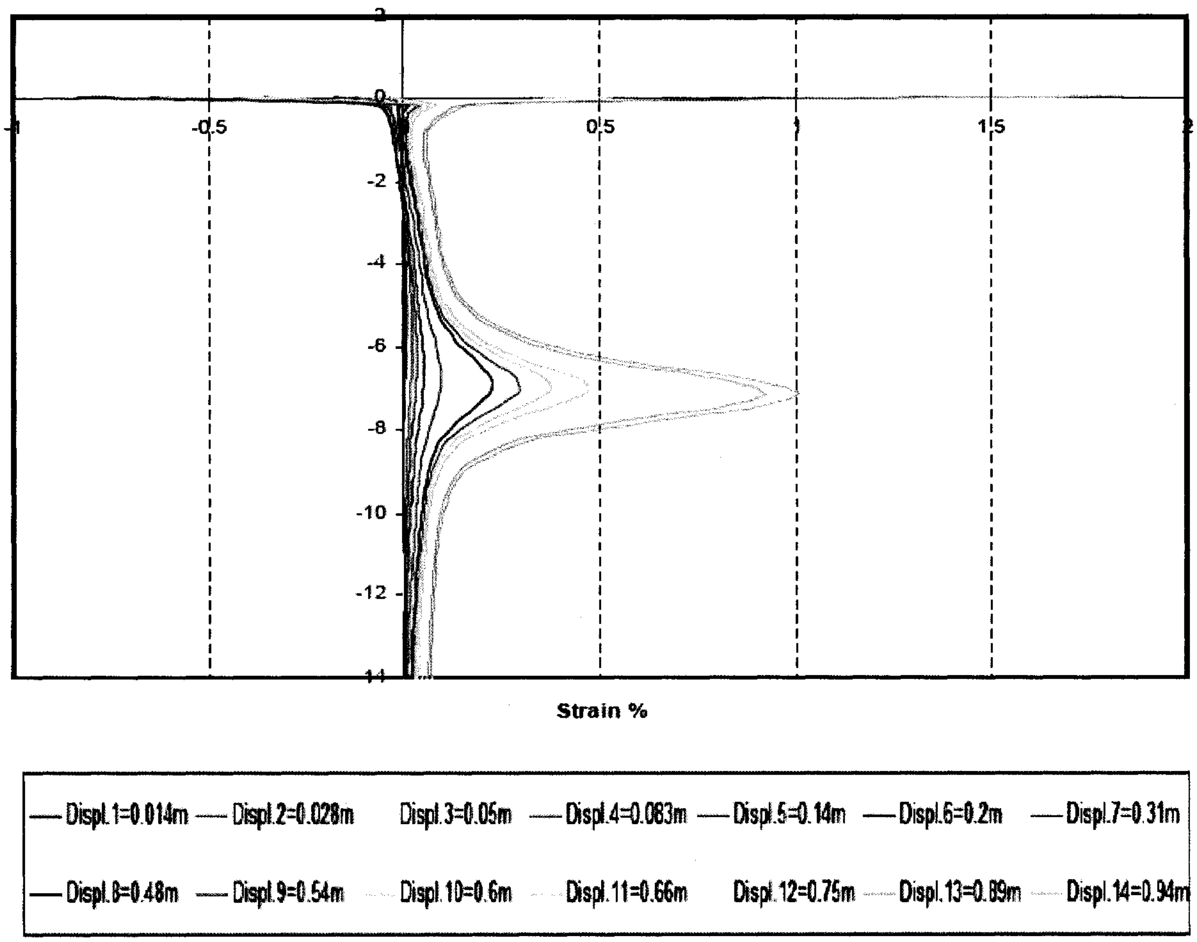


Figure 88 Axial strain distributions along the completion tubing in layered soil profile for well structure under gouging effect - Case No.5

The distributions of displacement for the layered soil profile imposed by a gouging ice berg are shown in Figure 89. It was observed that bigger displacement of value 0.014 m at the conductor head occurred when compared to that of the displacement imposed by a floating berg at the first step .This was expected due to the effect of the displaced soil in addition to the imposed displacement by the berg on the conductor extension above the seabed.

The maximum conductor head displacement was of a value of 0.92 m observed at the last step.

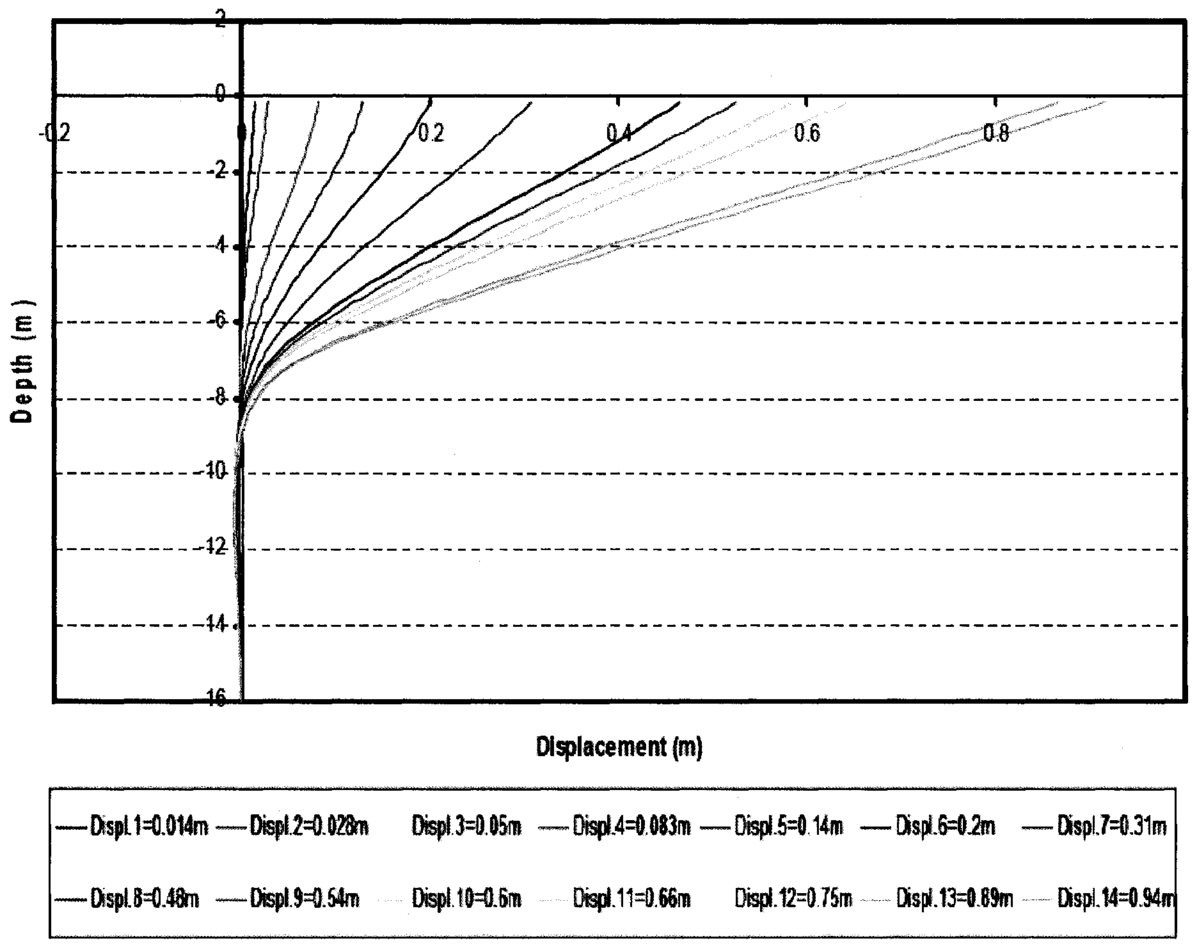


Figure 89 Displacement distributions along the depth in layered soil profile for well structure under gouging effect - Case No.5

The stress build up and distribution showed some difference when compared to stresses imposed by a floating berg on the well structure in the same strata (layered strata), where the maximum moment shifted down having with a slightly bigger value when compared to the moment generated by a floating berg on the conductor.

The other observation is that the point of rotation for the conductor (point which does not move as the loading is applied) almost did not change and was at a depth of 9.16.m.

8.3 Suggested System Analysis and Evaluation

Based on the distribution of various stresses and loads on the conductor pipe and completion tubing in various soil profiles, an assessment was carried out to evaluate the performance of the proposed system subjected to both a floating and gouging icebergs. Depth of the shear key, the wellhead depth and the isolation valve location was suggested and discussed below.

A suitable depth for the shear key would be at a range between 3m to 3.5m and the wellhead at a depth ranging between 13 m to 15 m. The isolation valve on top of the wellhead would be at a depth of 12 m to 12.5 m.

Many reasons support the choice of the above locations such as:

- Maximum bending moments and stresses on conductor pipe and completion tubing for various analyzed strata were observed to be at an approximate range between 5 m to 8.5 m. It would be a good choice to locate the shear key above this zone to avoid sections that could be subjected to local buckling
- As the shear link optimum location shifts up towards the seabed and upon wellhead iceberg interference, less soil resistance will result, enabling sufficient displacement of the shear key. The analysis revealed that a shear key at the mud line would be very effective for floating icebergs scenario.
- An issue of moving and releasing of the sacrificed wellhead could persist for gouging bergs scenario due to the insufficient displacement mobilized of shear

key. The Potential for the requirement of a shear key of tension pull-out mechanism may be a preferred solution.

- The presence of the shear link at such depth range not far away from the seabed enables interference triggered by any unexpected technical or operational complications during the process of wellhead tie back. Clearing and excavating around the wellhead could be done to gain enough access.
- The placement of the isolation valve on top of the wellhead should be at a depth not to be subjected to combined loads or stress that might exceed the maximum recommended values. Extreme stresses can negatively affect the efficiency of the valve seals and the operation mechanism. Similar conditions apply on the SSCSVs.

Based on the data analysis done, the resulting maximum von Mises stress calculated at the last displacement step for each of Case 1, Case 2, Case 3, was 569.3 MPa, 578 MPa, 586 MPa, respectively, and 587 MPa for both of Case 4, and Case 5. Within the same depth of the maximum von Mises stress occurrence, at the same section point, the Mises stress output is traced during all the displacement steps to get the maximum closest value not to exceed the 90% of the SMYS.

For Case 1, a von Mises stress value of 486 MPa (about 88 % of the SMYS) occurred at a displacement conductor head (on seabed level) of 0.41m.

For Case 2, a von Mises stress value of 420 MPa (about76 % of the SMYS) occurred at a displacement conductor head (on seabed level) of 0.26m.

For Case 3, a von Mises stress value of 458 MPa (about 83 % of the SMYS) occurred at a displacement conductor head (on seabed level) of 0.2m.

For Case 4, a von Mises stress value of 467 MPa (84.6 % of the SMYS) occurred at a displacement conductor head (on seabed level) of 0.2m.

For Case 5, a von Mises stress value of 470 MPa (85 % of the SMYS) occurred at a displacement conductor head (on seabed level) of 0.21 m.

The values of the various stress and loads at the shear key level, Isolation valve and wellhead that occurred at the same conductor head displacement mentioned above are summarized in the following 3 tables:

Table 11 Results comparison at shear key level on the conductor

Case No.	Depth (m)	Mises Stress	BM(1)	SF(2)	AF(3)	ε (4)	DV (5)	Displacement(6)
Case 1	3.4	183	2.1	2.7	4.3	0.09	1.9	0.23
Case 2	3.4	160	1.8	2.56	2.39	0.078	1.3	0.14
Case 3	3.44	168	2.32	2.97	1.7	0.082	1.3	0.096
Case 4	3.44	177	2.43	2.9	1.86	0.086	1.1	0.1
Case 5	3.44	110	1.03	3.3	1.72	0.054	1.25	0.1

BM(1) Bending Moment (MNm)
SF(2) Section Force (MN)
AF(3) Axial Force (MN)
ε (4) Axial Strain
DV (5) Deviation from vertical alignment (Degree)
Displacement(6) is in meters

Table 12 Results comparison on the completion shear key and isolation valve levels

Case No.	Mises Stress	BM(1)	AF(2)	AF(3)	ε (4)
Case 1	146	11.1	272	232	0.035
Case 2	141	10.7	244.5	183	0.024
Case 3	141	10.72	188	171	0.021
Case 4	141	10.72	193	174	0.023
Case 5	141	10.72	190	169	0.022

BM(1) **Bending Moment at Shear Key Level (KNm)**
AF(2) **Axial Force at Shear Key Level (KN)**
AF(3) **Axial Force at Isolation Valve Level(KN) at a depth range of 12 m-12.5 m**
ε **(4)** **Axial Strain**

Table 13 Results comparison at wellhead level

Case No.	Depth (m)	BM(1)	SF(2)	AF(3)
Case 1	15	1.16	0.87	2.8
Case 2	15	0.7	0.66	1.44
Case 3	15	0.19	0.28	1
Case 4	15	0.23	0.28	1.1
Case 5	15	0.19	0.28	1

BM(1) **Bending Moment (MNm)**
SF(2) **Section Force (MN)**
AF(3) **Axial Force (MN)**

8.4 Comparison and Comments on Results

8.4.1 Shear Key Level

By looking at the values summarized in Table 11 in Section 8.3, several conclusions can be made:

Bending moments were of approximately the same value for the four cases of the floating berg analysis (Case No.1 to No.4) overlooking the slight fluctuation in value which could be linked to the variation in the percentage of the SMYS considered for each case. The bending moment value for the gouging berg case was of a smaller value almost half when compared to the other four cases (Table 11).

The same thing can be said about the section force for the four Cases No. 1 to No. 4 (the floating berg cases), but on the contrary to the bending moment, the gouging berg case (no.5), showed a bigger value of 3.3 MN (Table 11) by almost 12 % of the value of the floating berg case of the layered strata keeping in mind that both the cases were considered at 85% of the SMYS.

Another important issue to notice was the deviation of the conductor when subjected to the above stresses. In all the Cases No.1 to No.5 the angle of deviation had values less than 2° (Table 11), noting that maximum deviation of the conductor was for the soft clay (Case no.1) with a value of 1.86°.

For the displacement at the shear key level it was noted that the values for the uniform clay soils (low strength and high strength) was of values 0.23 m and 0.14m for Case No.1 and Case No.2 respectively, while the other three cases, exhibited a similar behavior in terms of displacements showing approximately a value of 0.1 m.

The strain values at the shear key level, and below for both the conductor pipe and the completion tubing were far from reaching the upper limit of the ε_{cf}, when looking at the ultimate compressive capacity of the conductor pipe and completion tubing which were 1.8% and 2.9% respectively.

No hazard of local buckling was expected at this location, but still there was a concern of local buckling occurrence through the top sections above the shear key level.

8.4.2 Isolation Valve and Wellhead Level

The axial force noted on the isolation valve, as part of the completion tubing, was not of a high value. A maximum value of 232 kN occurred on the completion tubing of the low strength clay Case No.1,which tapered for the other 4 Cases No.2 to No.5. (Table 12)

No significant von Mises stress, bending moment or section force occurred at the isolation valve level.

From the above comparison (Table 12) we can conclude that the no significant loads or stress occurred on the SSCSVs. expected to be at a depth of 30 m or more.

On the wellhead level, the various loads were not of significant values although the calculated stress values were conservative since conductor modeling did not account for the various heavy sections of the casing hangers and landing subs, but rather uniformity of the wellhead section with the same conductor material and specifications was assumed. The maximum bending moment was of a value of 1.16 MN and 0.7 MN for Case No.1 and No.2 respectively (Table 13). A similar distribution of the section forces and axial forces was noticed where maximum values were recorded for Case No.1 and No.2. (Table 13)

9. Well Work-over and Tie In

9.1 General

Oil wells are very valuable assets for the operating companies; they are very costly especially when drilling offshore and in harsh environment like the North Atlantic of Newfoundland and Labrador. To get an idea about well drilling cost, delineation well in Terra Nova was estimated to cost $30.4 million and about 65 days to complete (C-NOPB, 2005). Therefore, extreme care should be taken during drilling, production and work over operations to preserve this asset.

For a shear link wellhead and after an iceberg damage, a tie-back operation will be required which has to be planned and executed safely, economically and as quick as possible to put the well back into stream. There are numerous equipment, mechanisms and methods used in the drilling, fishing (a technical term used in well workover), and well completion activities for connecting or latching to a pipe or casing in the well bore. The event of an iceberg/wellhead interaction adopting a shear link or any similar protection measure is not frequent or ordinary and even has not happened so far, while conventional well workovers and repairs are everyday operation in oil/gas industry with vast proven technology, tools and methods. As the shear key design is conceptual, the suggested work over method is based on the current technology and practices which have to be evaluated and improved through the future field applications and operations. The aim of this chapter is to give a scenario and serve as a guide of how a work over and tie-back operation will take place.

The presented tie-back scope assumes that the designed shear link system failed as expected with no damage to the conductor sections and tie-back subs below the shear key, and the conductor did not deviate globally more than ±2° from the vertical axis and still with in the acceptable limits for the well re-entry and tie-back.

9.2 Damage Assessment and Observations

The first step following an iceberg impact with a shear link wellhead would be to asses the damage, recover the displaced X-mas tree and have a general assessment of the accident site at the seabed (Figure 90). The main concern will be the assurance of the absence of any visual leak out of the well, indicating the loss of well integrity.

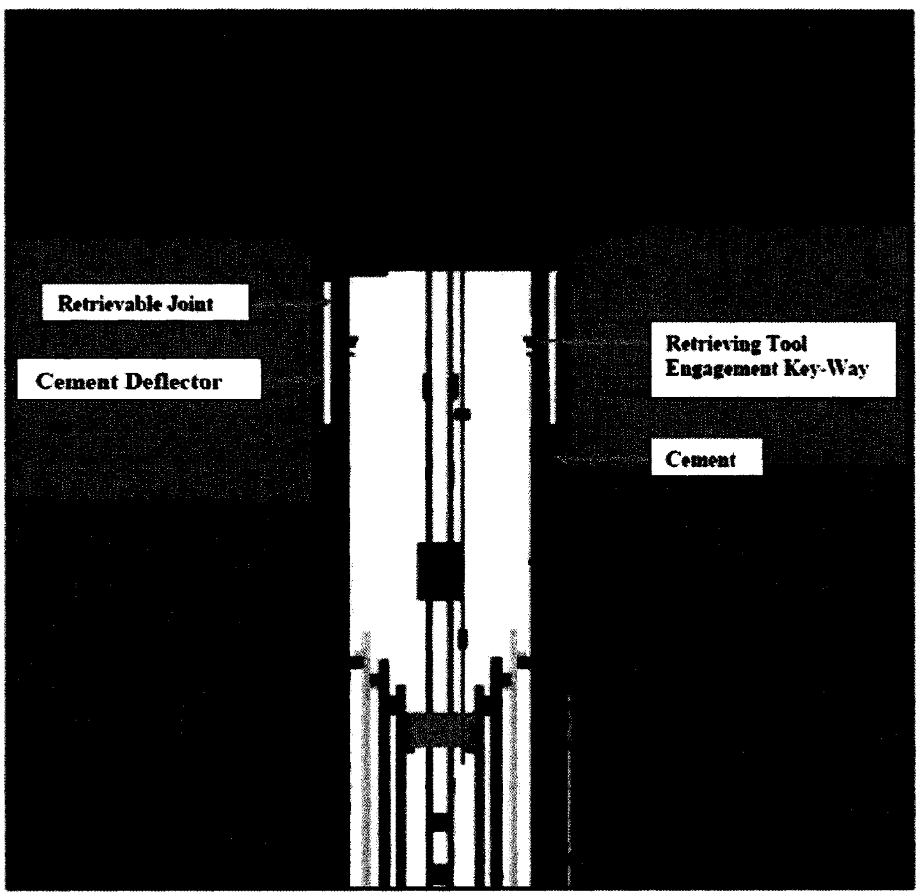


Figure 90 Wellhead after iceberg impact

An ROV equipped with necessary cameras and lights could carry out a survey job efficiently, keeping in mind that saturation diving may be an option, if necessary, in the shallow water depths of the Grand Banks. Checking the straightness and assuring that there is no local damage (e.g. plastic deformation, buckling, tearing) of the conductor, the production tubing and the slim annulus connection line to avoid any problems during tie-back to seabed. The second step would be clearing the debris from around the conductor, and mobilizing in a work-over rig to start the tie-back operation.

Assuming that spoils have fallen into the conductor and partially filled it, there will be a requirement to use suction pumps to remove the debris and spoils from the conductor to clear the tie-back sub threads. Pumps capable of shifting big quantities of soils such as the ones used during the installation of suction piles, would be very efficient to employ in cleaning of the inside of the conductor. An equipped service boat (utility and diving) could carry out the inspection work, recovery of displaced X-mas tree and all the debris and spoil pumping from the conductor, in parallel with the rig mobilization to site.

Once spoils removal and clearing of the tie-back sub is completed, and the rig is on site spuded over the well, a tie-back wash tool is run from the rig floor on a drill pipe. Water is pumped through the drill pipe to the jet nozzles fitted on the wash tool to blast and wash away any contaminates that might be present in the retrieving tool engagement key way. After completing the cleaning job, the next step will be retrieving the damaged conductor joint with the tie-back sub to the surface.

9.3 Tie-back and X-mas tree Installation.

The running/retrieval tool (RT) which is made up on a drill pipe will be lowered into hole. The nominal RT diameter is less than the conductor diameter and has two lug keys situated 180° apart (Figure 91). Once becoming close to the damaged conductor the run in speed is slowed down, to enter the well. The lowering of the RT through the conductor has to be done slowly and carefully till the lugs land on the recess of the RT engagement key way. Then the Drill pipe is turned slowly till the lugs (Keys) on the RT meet the key way machined in the recess.

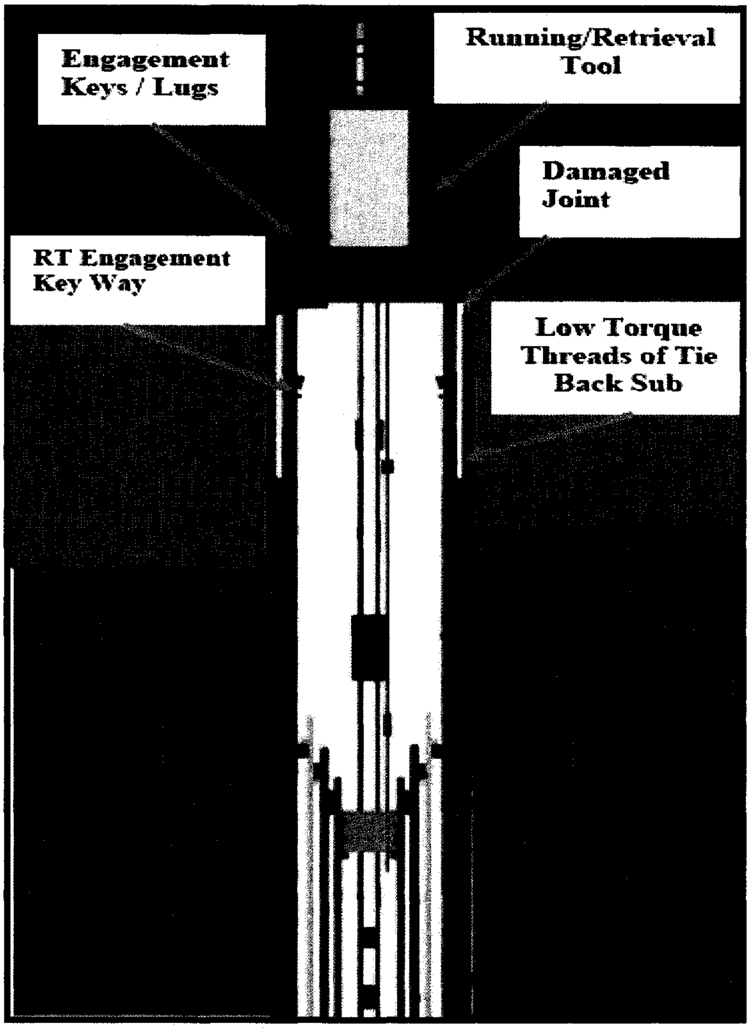


Figure 91 Running/Retrieving tool above the well

At this time, the tool will drop and land on the lower recess of the tie-back sub. Turning the tool to the right to achieve engagement with the tie-back sub, keeping in mind that the tie-back sub has left hand threads, the RT will make almost a full turn till it meets the stoppers in the lower recess and then the force is transferred to the sub itself and the low torque threads start to turn till the retrievable joint is completely loose. In such operations the number of the low torque threads is known and specified by the manufacturer. Once the retrievable conductor joint is released the drill pipe is picked up with the retrieved damaged joint (Figure 92).

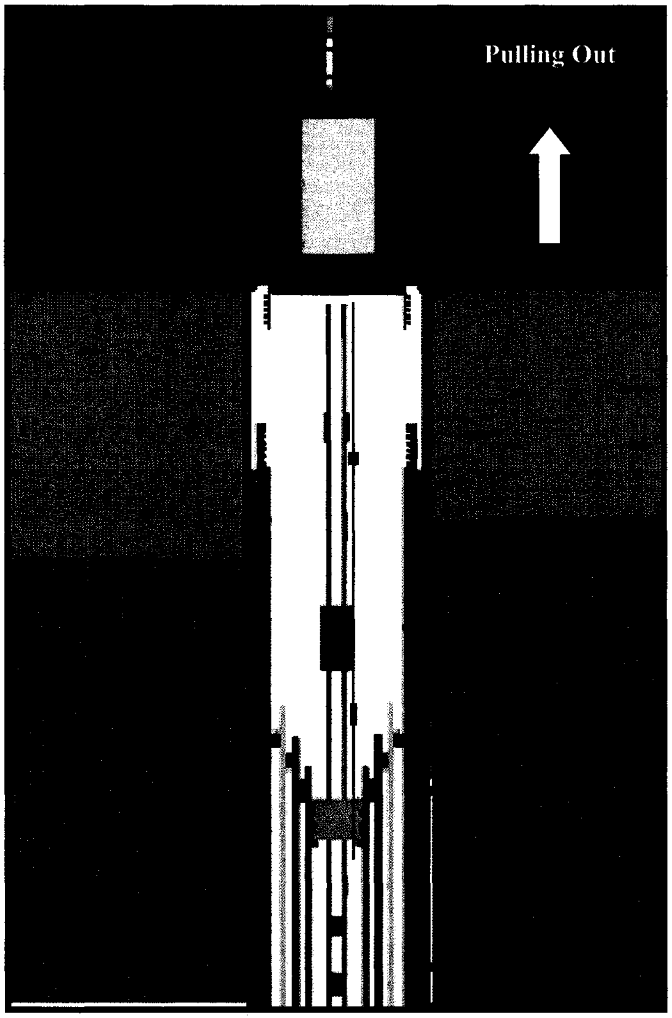


Figure 92 Retrieving the damaged joint

In a similar procedure and repeating the same steps vice versa, starting with running the wash tool with the jet nozzles fitted on and water pumped from the rig, blast and wash away any contaminates that might have accumulated in between the tie-back threads of the wellhead section that will receive the tie-back conductor joint. The RT is fitted to a new retrievable joint and a tie sub on the rig floor. The RT, with the new retrievable joint is made up to a drill pipe stand and then the whole assembly is lowered slowly into the well (Figure 93).

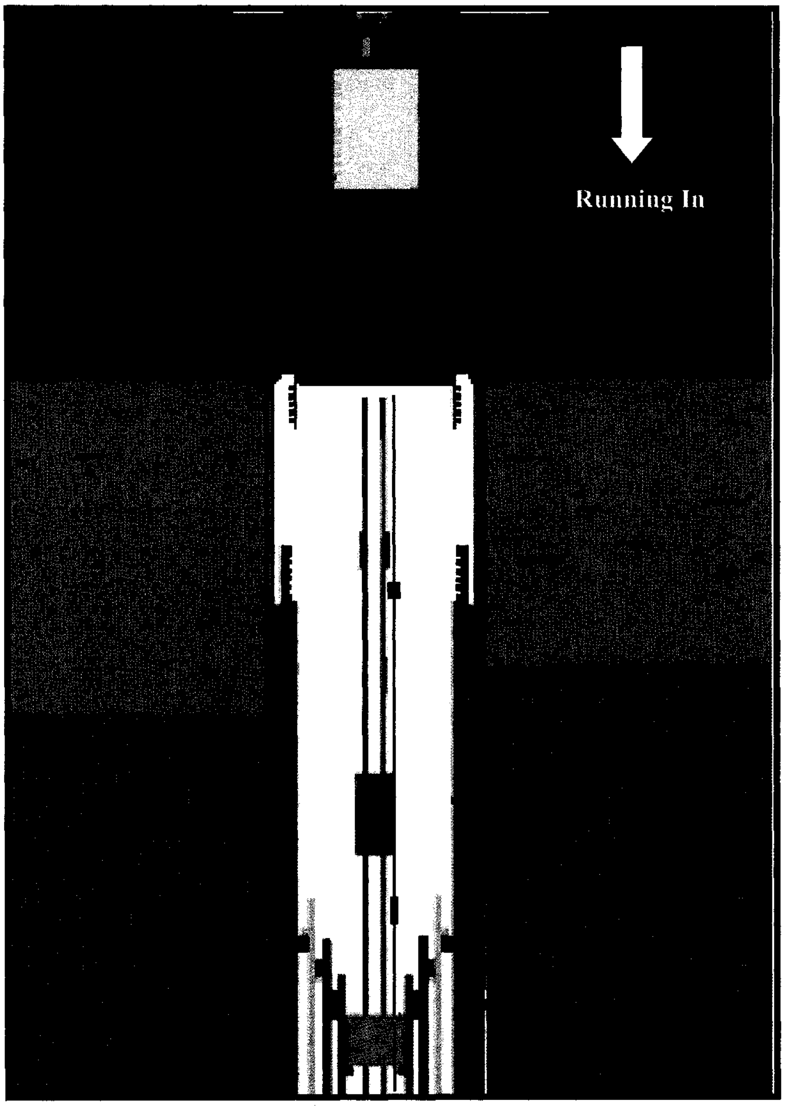


Figure 93 Running of the new retrievable joint with a shear link

Once the tie sub contacts the top of the threads of the wellhead section fitted in the conductor, a careful operation is required at this step and the extra weight of the landing string of the drill pipe and the running tool has to be picked up to decrease the stresses on the threads and to assure a smooth engagement, in which is known in the drilling language as finding the neutral point of the string. Making up of the tie-back sub to the wellhead section has be at a very low speed to avoid any thread damage.

Some companies (e.g. FMC Energy Systems) have developed tie-back subs with a very tough self aligning threads allowing smooth engagement at vertical misalignments up to 2° .

Field experience and discussions with senior FMC personnel (Pers. Comm.. Douglas Robinette, Middle East Manager, FMC Energy System, 2003), have indicated that the maximum allowed vertical misalignment, of ±2° stated in the manuals is conservative. The potential to conduct the tie-back operation at larger misalignment angles may be feasible (Figure 94).

Once it is assured that the joint is made up and the threads turned are counted, a slight pull is made on the joint while the RT is still engaged in place, as a test that the joint is in place and the threads are fully made. Retrieving of the RT is made by making one full turn to the right till the lugs are in line with the key ways and then the tool is pulled up to the rig floor.

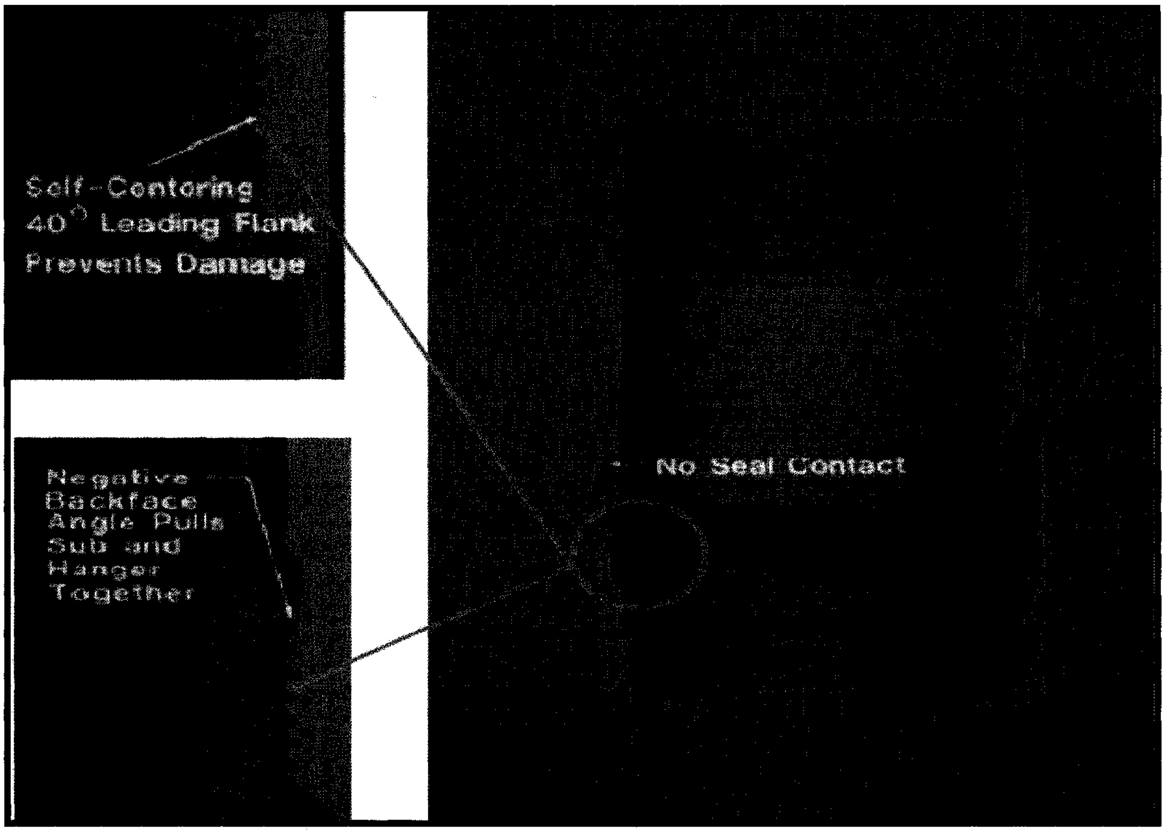


Figure 94 Initial tie-back sub stabbing with misalignment inset – Characteristics of the modified threads (FMC Energy Systems, 1994)

Another feature of these tie-back subs, is that when they are made up to the wellhead section they provide metal to metal seal at two points, one is at the top of the hanger and the other is at the lower nose, and thus providing two barriers in addition to the resilient seal as a third back up seal (Figure 95).

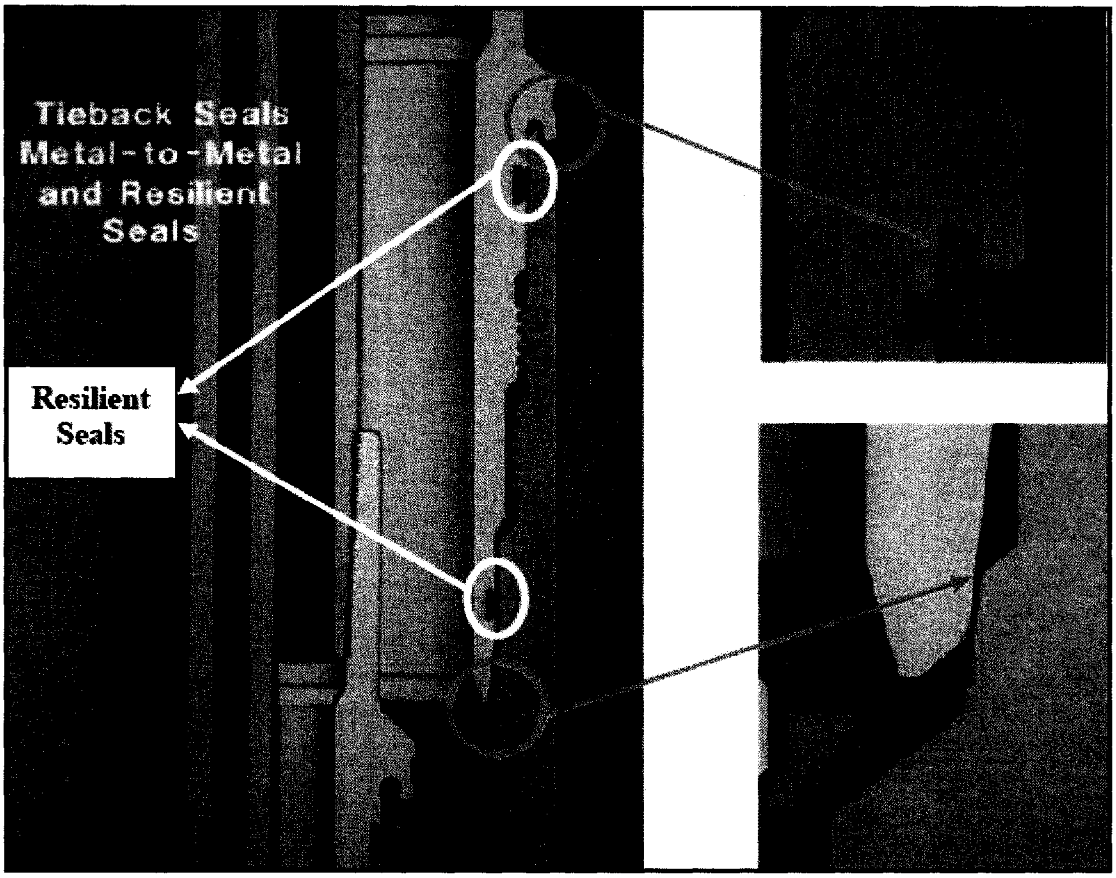


Figure 95 Dual metal seals and resilient seal of the tie -back sub (FMC Energy Systems, 1994)

The replacement of the tie-back of the completion is the next step. The connector of the extended neck tie-back is the a made up of two parts. The fishing of the remaining part of the tie-back would not be a difficult operation, since the neck of the fish (tie-back end) is straight and slick, as well it very close to seabed where lights and cameras of an ROV for monitoring can be used.

An overshot is run to engage to the upper end of the production line tie-back, and once engaged, the assembly is turned to the right (left hand thread) to loosen the connector from the extended neck. A similar operation is done to fish out the slim annulus line connector. The main extended neck of the tubing hanger (completion extension) and the slim extended neck of the annulus line from the hanger are tied-back to the seabed with two new extensions having shear links (Figure 96).

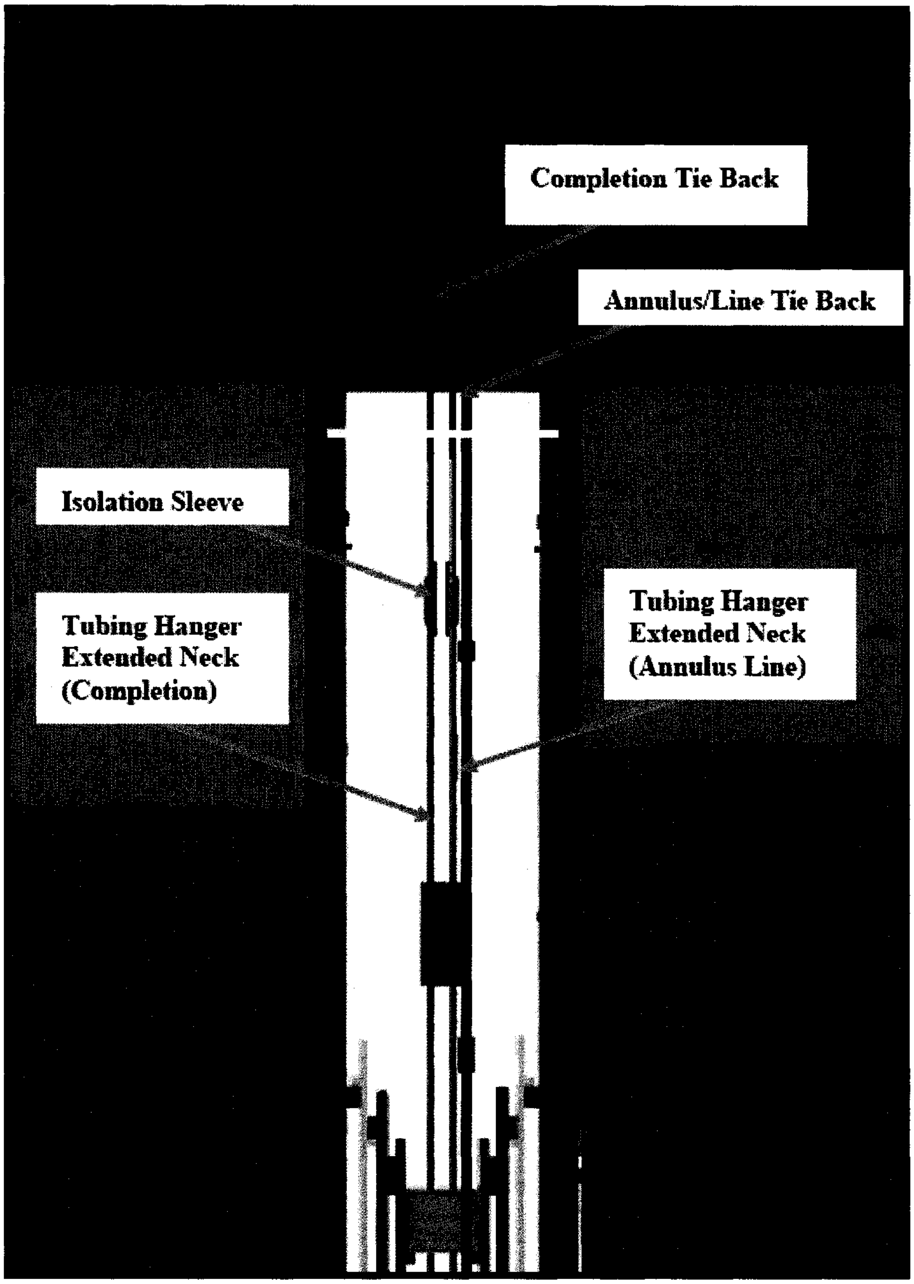


Figure 96 Complete tie back arrangement

At the lower end of the completion tie-back there is a landing nipple profile (locking groove) and seal bore in both the tie-back and the extended neck. A wireline will land an isolation sleeve to allow the hydraulic oil pumped from the X-mas tree control panel through the hole extending along the length of the completion tie-back to bypass the connection and reach the extended neck in its way to the final destination, the actuators of the isolation ball valve and the subsurface surface controlled safety valves (SSCSVs). A similar sleeve is landed in the annulus slim tie-back line to bypass the connection and allow hydraulic oil to reach the two annular safety valves actuators.

The X-mas tree is lowered slowly and then landed and engaged to the top of the conductor retrievable joint and both the production line and annulus slim line are housed and sealed inside the X-mas tree bottom.

Pressure testing of the X-mas tree connection is to be done at first. Then the pressure test of the tie-back neck seals of the completion and annulus line is carried out to assure that there was no seal damage when landing the X-mas tree. The other test to be done is for the annulus between the conductor and the production extension neck. This test will assure that the X-mas tree connector and the tie-back neck seals are holding pressure from below, as well the same test will assure the integrity of the connectors of the tie-backs. Another pressure test would be done against the closed isolation valve from top to assure the integrity of the tie-back connection from inside, and the proper in place seating of the isolation sleeve. Once all tests are done satisfactorily the flow lines are connected to the X-mas tree and tested in preparation to commission the well and resume the normal operation.

10. Conclusions

Several conclusions have been reached, based on the thesis work and the performed analysis as follows:

- The development criteria comparison made for fields on the Grand Banks revealed the importance of looking into other alternatives for protecting the subsea wellheads from the icebergs threat motivated by improving the economics of marginal fields development and unlocking their reserves.
- The shear link subsea wellhead system with redundant barriers and completion sealing components may be feasible and safe system to be used in combination with ice management techniques to reduce risk to achieve or exceed the annual target level of safety of 1×10^{-5} as defined by Safety Class 1, of the CSA standard S471-04. Combining both the annual leak probability to the surrounding environment, and the reduced annual contact probability with a subsea infrastructure component, after considering iceberg management activities resulted in a final annual risk estimate of 1.27×10^{-6} which is $< 1 \times 10^{-5}$. In the absence of any iceberg risk management the calculated annual probability increased by 90% to reach a value of 1.143×10^{-5}, which is $> 1 \times 10^{-5}$.
- The conventional well with out any protection or special design features is not a safe system to adopt considering the potential of severe damage to the tubing hanger and its primary and secondary seals resulting from an iceberg interaction. Combined with the probability of pressure build up in the annulus, the over all risk will be beyond acceptance.

- The reliability of the SSCSVs, actuated block valves, NRVs, and the completion sealing components (packers, tubing hangers...etc) is an effective factor in reducing the overall risk levels in the absence of the surface barrier (X-mas tree).
- The FEA analysis indicated that in the event of an iceberg/wellhead interaction, the SSCSVs are beyond any significant stress or loads above normal operations. The stress and loads on the isolation valve on top of the hanger at the suggested depth were of low magnitude.
- Stress and loads on the wellhead, sub-mudline casing hangers and pack-off seals at the suggested level were of close to normal or less for a similar wellhead on the mudline.
- The conductor pipe displacement at the proposed shear link level may be an obstacle to achieving a smooth release and displacement of the sheared joint and wellhead.
- For the proposed concept, installation of the shear link well head can be done without interrupting the normal drilling operation and does not require any special preparations on the MODU.
- Site preparation for tie back following an iceberg/ subsea wellhead interaction can be done using a utility/diving vessel in advance or during rig mobilization to cut off on the rig cost.
- Using shear link subsea wellheads in major fields as injector wells can be of great benefit in improving the production capabilities for these fields at a low cost/risk investment.

11. Recommendations

The recommendations drawn from this work have been broken down into a number of key areas as presented below:

11.1 Well Operation and Components Reliability

11.1.1 Completion Components Reliability

It was evident of what discussed in Chapter 5 and concluded that the reliability of the SSCSVs, actuated block valves (Isolation Valves), NRVs, and the completion sealing components (Packers, Tubing Hangers...etc) is of the main factors to affect the risk level and keep it below maximum allowable limit. Further studies and improvements on:

- The joint connections performance (considering special premium threads)
- The reliability of annulus isolation valves, and chemical injection valves
- The reliability of packer sealing elements
- The reliability of tubing hanger seals

will have an advantage in reducing the leak probability and increasing the overall safety margin.

11.1.2 Barriers and Sealing Components Redundancy

The benefit of using redundant and independent sealing components will result in an increase in system reliability. The probability of leak for the suggested system was analyzed based on the presence of dual SSCSVs, single isolation valve, dual annular isolation valves single CIV and single packer. Installation of an additional CIV and an additional packer within the completion will drastically reduce the probability of leak to the annulus at a low cost in time and capital.

11.1.3 Annulus Pressure Monitoring

Monitoring is done on continuous basis for production and injector wells annuli, to prevent any excessive pressure build up that might exceed the casing burst pressure. However interference and well major workover is not done to tackle minor leaks, but rather conditions are kept under control by bleeding off the annulus regularly. Well workover is decided once leak rates increase and an extreme situation is reached. It is recommended to review the criteria for annulus pressure monitoring and interference for wells adopting the shear link system.

11.2 Well Structure Engineering

11.2.1 Analysis and Testing

The conducted FEA analysis using a three-dimensional beam elements and spring elements representing the well structure and surrounding soil respectively was a preliminary exercise to understand the response of the casing and production tubing to the imposed displacements by floating/gouging icebergs and to monitor the stress and strain response at various critical well sections.

It is recommended as a next step, to bring the FEA to a higher level of complexity to have a more detailed and accurate analysis on the critical well sections that are of interest (such as the shear key level and sections above and below this elevation).

A continuum FEA model would be the best option for the next analysis. To give certainty and confidence to the achieved analysis results with the continuum FEA model, field trials of a full scale instrumented well structure would be the ideal approach. Prototype testing or centrifuge simulation could also provide valuable insight with respect to the behavior of the well structure subject to iceberg contact loading and soil/structure interaction effects for an approaching ice gouge feature.

Further lab testing is recommended for the conductor pipe and completion tubing materials to obtain stress-strain relationships for input to structural and continuum finite element procedures. An examination of the buckling and post-buckling response of typical geometric parameters and material properties is required to establish compressive strain limits. An evaluation of tensile strain capacity of the well conductor and completions is required. On this basis strain limit criteria can be established.

11.2.2 Shear links and Location

Further specific details on the mechanism, number, and location of sacrificial weak points is recommended. This study has proposed a shear link option. Based on the analysis conducted in this study, due to the relatively small displacement mobilized by the conductor at depth below the mudline, from floating or gouging interacting icebergs, it is recommended to look into the possibility of having another shear link at the mudline level. This may also address concerns related to local buckling and post-buckling response. A controlled failure of the wellhead close to the seabed achieves a better load relief, shear link activation, and X-mas tree displacement. Other options than a shear link (e.g. tension pull-out) may be viable and should be examined.

11.2.3 Well Structure/Iceberg Contact Scenarios

The model calculations were done based on a zero angle of incidence, that is the iceberg was assumed to interact with the well structure at the centerline imposing an idealized lateral displacement. It is recommended to check other possible loading and interaction scenarios that include:

- More complex contact geometry and interaction mechanisms for the iceberg /well structure loading events.
- Icebergs traveling in water are known for their un-predicted movements (pitching, rolling, turning …etc) it is recommended to evaluate these loading conditions and the effect of eccentric contact events.

11.2.4 Subgouge Deformations

An ice gouge of 0.34m depth was used in the analysis that represents the mean depth of the gouge events for the White Rose field on the Grand Banks, which will reveal some uncertainties if the results are generalized for other deeper iceberg gouges. Note that a significant proportion (>95%) of the contact risk arises from floating iceberg features. For gouging ice features, it is recommended to carry out further analysis for rare gouge contact events that may exceed 2m gouge depth. There exists significant uncertainty on the geotechnical load effects, interaction mechanisms and structural behavior for the gouge contact scenarios. Continuum finite element modeling and reduced-scale centrifuge modeling may provide insight on these issues with respect to conditions prior to direct contact for gouging features.

11.3 Tie Back Operation

Tie back operations should be well defined with stress on practicality and availability of all running/retrieving tools and any other specialized tooling with a back up plan for the anticipated complications of the operation. Contractors (wellhead companies ,well completion companies…etc) engagement is very important not only during design, manufacturing and testing stages, but also during planning stages and tie back operations.

11.4 System Introduction

A good start to apply the shear link wellhead concept would be to utilize this option for water injector wells. Not withstanding the importance of public perception, the economic and environmental risk of a water injector well blow out is almost null. The alternative system can be used to showcase the technology as an economical and safe option to be used for the injector wells of major fields on the Grand Banks and provide an opportunity to gain valuable technical experience. Furthermore, the placement of injector wells on the periphery of the reservoir, without being confined within glory holes, would improve production efficiency. Through this approach, a baseline would be established for regulatory approval and a solid technical case can be developed to gain public confidence and acceptance.

11.5 Criteria Establishment

The risk resulting from the leak probability of a subsea well due to an interacting iceberg has not been defined and specified in any existing code or standard.

A study should develop guidance documents or standards that define safety targets and reliability levels based on leak probabilities for subsea well components and barriers in relation to the adopted method of protection. The acceptable risk targets could then be clearly defined and a category to differentiate between minor leaks and major leaks in a similar manner to conventional wells would be useful.

This can be achieved by a collaborative effort of various sectors and partners including oil field operators, research and consulting engineering companies, international and local regulatory authorities, and well equipment engineering and manufacturing companies, all together can reach a final unified view over this topic.

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