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Deepwater Gulf of Mexico Oil Spill Scenarios Development and Their Associated Risk Assessment

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DEEPWATER GULF OF MEXICO OIL SPILL SCENARIOS DEVELOPMENT AND THEIR ASSOCIATED RISK ASSESSMENT

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NOMENCLATURE

ASV	Annular Safety Valve
BC	Base Case
B_o	Oil Formation Volume Factor
BOPD	Barrels of Oil per Day
GoM	Gulf of Mexico
GOR	Gas Oil Ratio
HPHT	High Pressure High Temperature
K	Permeability (mD)
MC	Modified Case
MIC	Modified Improved Case
MMbbl	Million Barrels
P10	P10 refers to a *p*-value of 0.9
P90	P90 refers to a *p*-value of 0.1
P_b	Bubble Point Pressure
PI	Productivity Index
P_R	Reservoir Pressure
QRA	Quantitative Risk Assessment
SCSSV	Surface Controlled Subsurface Safety Valve
UBO	Underground Blow Out
WCD	Worst Case Discharge rate

ABSTRACT

World's growing energy demand has pushed oil companies to explore and produce hydrocarbons in complex and technologically challenging deepwater environments. These difficult and complex operations involve the risk of major accidents as well, demonstrated by disasters such as the explosion and fire on the UK production platform Piper Alpha and capsizing of the Deepwater Horizon rig in the Gulf of Mexico (GoM). Accidents cause death, suffering, pollution of the environment, disruption of business and bad reputation to oil industry.

A quantitative risk analysis technique has been used in this study to identify and categorize risk associated with different life phases of a deepwater well. Volume of oil released to the environment is used as a risk indicator. Five oil spill scenarios related to drilling and production life phases of a deepwater well are modeled.

Risks associated with drilling an exploratory well in the deepwaters of GoM are analyzed in Scenario-1. A representative well location and corresponding reservoir properties were used to estimate the worst case discharge rates (WCD). Fault tree analysis (FTA) was performed to identify and categorize different hazards. Unexpected pore pressure and delayed response to an emergency situation were identified as two most important parameters contributing to overall risk of the system.

In Scenario-2 an underground blowout was modeled by using representative geological settings from Popeye-Genesis field. A shallower low pressure zone is exposed to a deeper high pressure zone during drilling. The time to recharge the shallower zone to its fracture pressure is estimated. The shallower zone will transmit hydrocarbons to sea floor once its fracture pressure is reached. Risks associated with production life phase of a deepwater well are modeled in

scenario-3. A representative well location and corresponding reservoir properties were used to estimate the WCD. FTA showed that sand screen and subsea tree control failures were main elements contributing to risk.

In scenario-4 risk associated with floating production and offloading (FPSO) system for GoM are quantitatively and qualitatively presented. Scenario-5 deals with oil spill risk associated with severe weather conditions. An example mudslide calculation for SP-70 block of GoM is presented.

INTRODUCTION

This section briefly introduces each chapter of the dissertation.

Chapter one covers, basic elements of a spill scenario, introduction of techniques used for Quantitative Risk Assessment (QRA), oil and gas well barriers and their importance, and some of the data sources that can be used to conduct QRA of offshore operations.

Second chapter deals with solution methodology adopted to perform the quantitative risk assessment. Selection of representative well, reservoir properties and fluid flow models are discussed in detail.

In chapter 3 quantitative risk assessment of a deepwater exploratory oil well is presented and is referred as Scenario-1. A representative well from the Mississippi canyon in the Gulf of Mexico is studied for potential worst cases discharge (WCD) rates. Oil spill duration is estimated from historical spill durations and success of different spill response techniques. Product of WCD rate and duration gives the most probable oil spill amount. Blowout frequency is computed using fault tree analysis. Through sensitivity/importance analysis risk prone areas have been identified. The effectiveness of newly built response systems, called capping and containment systems is also analyzed in reducing the risk of large oil spills.

Risks associated with the underground blowout (Scenario-2) are addressed in Chapter 4. It is assumed that during drilling a high pressure reservoir is accidently exposed to a low pressure shallower zone. A conducting fault or a highly permeable zone connects these zones. A representative reservoir's settings from Popeye-Genesis filed in the deepwater GoM is selected to model this scenario. It is assumed that the shallower zone's cap rock sealing capacity is lost when its pressure is reached to its leakoff test value. Then the set of exiting or induced fractures or faults in the cap rock transmits the hydrocarbons to the sea floor. Under these assumptions the charging time for the shallower zone to reach its leak off test value is estimated by conducting reservoir simulations. A parametric study is conducted by changing the shallower zone's volume and connecting zone's permeability and recharging time for shallower zone is estimated.

In chapter 5, quantitative oil spill risk assessment of a production well (Scenario-3) is performed. It is hypothesized that a sand screen failure leads to a blowout. Representative well location, well barriers and reservoir properties in the GoM are selected to compute worst case discharge rates and blowout frequency. Spill duration is estimated based on the historic spill data and the effectiveness of various spill response techniques. Sensitivity/importance analysis is conducted using fault tree analysis and most sensitive areas are identified.

In chapter 6 risk associated with FPSO (Scenario-4) are quantitatively and qualitatively studied. FPSO is different from other production platforms due to its large storage capacity, station keeping requirements and shuttle tanker offloading. A proposed FPSO configuration for GoM is studied to estimate amount of spill during shuttle tanker transportations and fuel offloadings.

Weather induced oil spill risks are analyzed in chapter 7 (Scenario-5). Severe weather can induce, mudslide, damage/destroy platforms and adrift of offshore floating structures. An example oil spill volume calculation due to mudslide damage in SP-70 block of GoM is presented for platform damage, production riser's damage and rupture of large oil carrying pipeline.

Chapter 8 summarizes the conclusion of all of the five modeled oil spill scenarios.

CHAPTER 1: OVERVIEW OF DEEPWATER OIL AND GAS OPERATIONS AND RISK ASSESSMENT

Offshore oil and gas exploration and production operations, involve the use of some of the cutting edge and challenging technologies of the modern time. These technological complex operations involves the risk of major accidents as well, which have been demonstrated by disasters such as the explosion and fire on the UK production platform piper alpha, the Canadian semi-submersible drilling rig Ocean Ranger and the explosion and capsizing of Deepwater horizon rig in the Gulf of Mexico. Offshore production may be one of the major sources of revenue for some of the companies and countries.

Major accidents like Macondo represent the ultimate, most disastrous way in which an offshore engineering project can end up. Accidents cause death, suffering, pollution of the environment and disruption of businesses. They attract attention from the news media and linger in the public memory for a long time, causing concern about safety of offshore oil and gas production operations. People may start questioning about the safety of offshore operations. In order to address these concerns and show that a balance between the interests of safety and the economics of oil and gas production can be achieved, a technique called Quantitative Risk Assessment (QRA) can be used. By conducting QRA, risk and their significance for the entire life phase of an offshore project can be quantitatively estimated. It will help in identifying the safety-critical procedures and equipment. QRA may also be used to show the project's acceptability to regulators and workforce.

1.1 Basic Constituents of a Spill Scenario

The probability of occurrence of an oil spill and its consequences are a combination of the following factors, well's life phase, geological features, reservoir potential, operational complexities, water depths, type of installations and severe weather conditions. These are briefly described below.

a) Well Life Phase: The life phase of a well is very important factor in describing the spill scenario. There are different risks associated with different life phases of a well. Operational conditions and the reservoir's potential to flow varies with well's life phase which result in different hazards with each life phase of an offshore well. For example, there are more risks associated with drilling an exploratory well as compared to drilling a development well. These risks are due to uncertainties in the geology and reservoir being at its full potential at the time of exploratory well. An offshore well's life span can be divided into three broad categories of drilling, production and abandonment phase. These are briefly described below.

1- Drilling can be subdivided into exploratory and development drilling.

2- Production can be subdivided into normal production operations and intervention

3- Temporary Abandonment and Permanent Abandonment

These are shown in Figure 1.

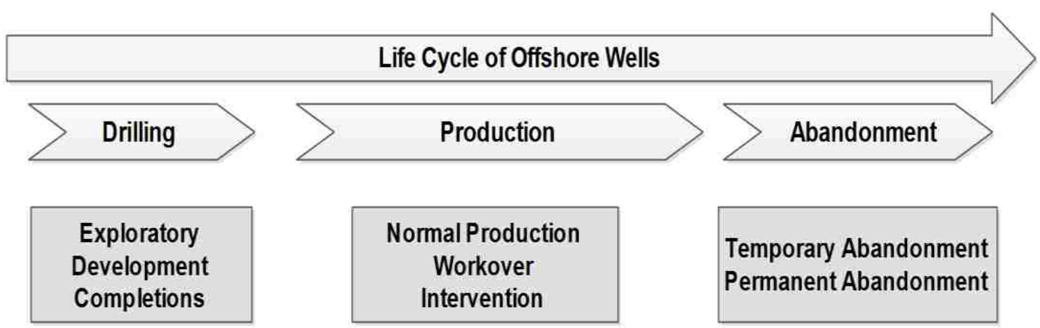


Figure 1: Life phases of an offshore oil & gas well

b) Geological Complexities: In GoM usually the operational window during drilling phase is very narrow, i.e. the difference between pore pressure and formation fracture pressure is very low and most of the reservoirs in the GoM are over pressured as well. These conditions make the deepwater drilling in GoM more risky as compared to other regions of the world.

c) Reservoir Potential: The potential of a reservoir to flow by itself is another major component when estimating the risk associated with an oil well. The reservoir potential depends upon pay zone's thickness, its aerial extent, porosity, permeability, initial reservoir pressure, original oil in place and to what extent the reservoir has been explored.

d) Water Depth: The complexity of the operations during any life phase of an offshore well, increases with water depth. In the ultradeepwater (i.e. WD >3000 ft), the drilling operations become more complex, due to very small drilling window available. As a result either more casing strings should be deployed or some other techniques to successfully drill sections with narrow margins should be used such as dual gradient mud may be used, another complexity. Another example could be the long riser portion that may be exposed to high sea currents resulting in severe induced vibrations and cyclic loads. The sea water temperature decrease from 80F^{o} to nearly 40F^{o} at the 10,000 ft water depth, this will creates additional problems in long riser section and additional consideration has to be taken during responding to a spill event.

e) Ongoing Operations Complexity: The complexity of the ongoing operations, experience of the people conducting these operations and whether standard or ad-hoc procedure are followed to handle the unexpected events are one of the main factor in defining a spill scenario and associated risk. For example there is different risk levels associated with exploratory drilling as compared to development drilling, similarly risk associated with normal production operations are different than that of intervening to enhance the production.

f) Sever Weather Conditions: The regional weather condition are also an important factor, although complex operations like setting casing are avoided during severe weather, but the pattern of weather in different times of the year is also important. Loop currents in the GOM and hurricane season are a typical example. Severe weather can lead to mudflow in shallow water, whose consequences may vary from minor spill of few barrels to a major spill having thousands of barrels of oil. Harsh weather may also result in adrift of Mobile Offshore Drilling Units (MODUS), and if their anchor drags along the seafloor, they may damage pipeline or production risers or subsea trees and can result in an oil spill.

e) Equipment reliability: Equipment reliability is used for the blowout probability calculations. Based on the failure rates of primary and secondary barriers, the failure probability of the whole system is calculated. Improvements in the barriers' reliability will result in decreasing the blowout probability.

g) Path taken by reservoir fluids: The path taken by the reservoir fluids and its final release points are important to find the worst case discharge rate. For example during drilling blowout, hydrocarbon coming out of reservoir can take one of the four following paths, drill pipe, annulus between drill pipe and the casing, open hole flow or flow through the rock behind casing.

1.2 Quantitative Risk Analysis

Hazards are defined as physical situations that have the potential to cause harm. The main hazards to offshore structures are fire, explosion, collision and falling objects. Accidents are the realization of a hazard. Accidents range from minor such as small gas leak to major accidents like deepwater horizon. The term 'risk' is according to international standards (such as ISO 2002) is the 'combination of the probability/frequency of an event and its consequence'. Other standards, like ISO 13702 (ISO 1999b), have a similar definition: 'A term which combines the chance that a specified hazardous event will occur and the severity of the consequences of the event' (Vinnem, 2007). The likelihood of an event may be expressed either as a frequency (i.e. the rate of events per unit time) or a probability (i.e. the chance of the event occurring in specified circumstances). The consequence is the degree of harm caused by the event (John Spouge, 1999). 'QRA' is used as the abbreviation for 'Quantified Risk Assessment' or 'Quantitative Risk Analysis'. Quantitative risk assessment (QRA) is a means of making a systematic analysis of the risks from hazardous activities, and forming a rational evaluation of their significance, in order to provide input to a decision-making process (Spouge, 1999)

A Quantified Risk Assessment of an offshore installation has the following main steps (Vinnem, 2007):

1. Hazard identification
2. Cause and probability analysis
3. Accidental scenarios analysis
4. Consequence, damage and impairment analysis
5. Escape, evacuation and rescue analysis
6. Fatality risk assessment
7. Analysis of risk reducing measures

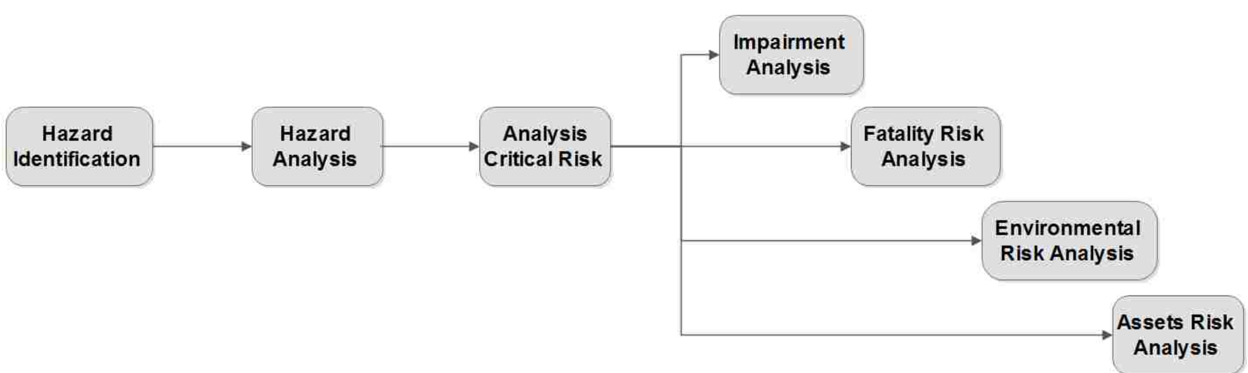


Figure 2: Schematic showing the necessary steps in risk estimation

The consequences of an incident may be related to personnel, environment, assets and production capacity. These are sometimes called ‘dimensions of risk’ (Vinnem, 2007). Only environmental damages are addressed in this study.

1.2.1 Environmental Damage

Environmental damages due to spills are mostly dominated by the large infrequent spills from blowouts, pipeline leaks, storage leaks, transportation leaks and accident involving shuttle tankers. Small frequent process leak in the processing units, usually have low consequences as they do not cause extensive environmental damage. In this study environmental damage is categorized in terms of oil volume spilled to the sea, while the environmental risk is a combination of oil volume released its proximity to shore lines, its decay in reaching the shore lines and the sensitivity of the shore lines to oil spill. For the same volume of spilled oil, areas rich in fisheries and tourism will have greater environmental risk as compared to areas that are not abundant in fisheries and are not tourist’s destinations.

The quantified risk to the environment is a combination of:

- Approximate amount of oil discharged to the environment.
- Frequency of events with similar consequences for the environment.

Environmental consequences are often measured in terms of restoration time and the associated costs. ‘Restoration time’ is the time needed for the environment to go back to the same conditions, which existed before the oil spill. Expected spilled amount per year, V_{sp} , is expressed as:

$$V_{sp} = \sum_{n} f_n q V_n$$

Where f_n is the frequency per year and $V_n$is the amount spilled for scenario n.

The accumulated frequency $f_{spill\ cons\ i}$ of events with similar consequences (restoration time) is defined as (Jan Erik Vinnem, 2007)

$$f_{spill\ cons\ i} = \sum_{n} f_n . p_{n,i}$$

Where $f_{spill\ cons\ i}$ is the accumulated frequency of events with similar consequences and $p_{n,i}$ is the probability of environmental consequence i for scenario n.

Quantification of risk to the environment is estimate as the product of blowout/accident frequency and the resultant spilled volume of oil. The quantitative risk is presented in the form of risk matrix. A high flow rate or a longer duration spill will result in a greater oil volume released to the environment, and therefore has potential for greater consequences. The blowout duration depends on the effectiveness of different response systems deployed. It may range from few hours, to almost 90 days i.e., time taken to drill a relief well in the deepwaters of GoM. Timely capping or containing the well will reduce the overall spill oil volume and will result in reduced risk.

The categories of environmental damage may be defined as follows (Vinnem, 2007):

- **Minor** - environmental damage with recovery between 1 month and 1 year.
- **Moderate** - environmental damage with recovery between 1 and 3 years.
- **Significant** - environmental damage with recovery between 3 and 10 years.
- **Serious** - environmental damage with recovery in excess of 10 years.

In this study damage to the environment is defined in terms of oil volume released to the environment. Therefore for large oil spills, the environmental impact can be defined in terms of spilled oil volume as shown below, these are based on the recovery time after the Macondo incident. It is to be pointed out that environmental damage will also depend on the location of the blowout, its proximity to the environmental sensitive areas alongside the spilled oil volume. Keeping in view of the restoration time for Macondo incident, following approximated ranges are defined

- **Minor:** Impact = 1, Spill amount ≤ 0.5 Million bbls
- **Moderate:** Impact = 2, Spill amount > 0.5 and ≤ 1.5 Million bbls
- **Significant:** Impact = 3, Spill amount > 1.5 and ≤ 3.5 Million bbls
- **Serious:** Impact = 4, Spill amount > 3.5 Million bbls

The probability/frequency of an incident is categorized as

- **Low** ($p \leq 9$ %)
- **Moderate** ($9 < p \leq 29\%$)
- **Significant** ($29 < p \leq 59\%$)
- **High** ($59 < p \leq 100\%$)

These values are based on some estimates about the range of higher and lower values and are purely intuitional.

1.3 Objectives of this Study

The main objectives of the study were to

- Study different life phases of an offshore well, starting from exploratory drilling to permanent plug and abandonment phase, in order to identify the key areas contributing to overall oil spill risk during these life phases.
- Develop a systematic procedure to generate and understand a variety of offshore oil spills scenarios.
- Perform Quantitative Risk Assessment of different spill accidents
- Develop/Suggest strategies to mitigate the risk associated with offshore spills

1.4 Well Barriers and Well Control

To prevent a blowout, a well is equipped with pressure control equipment and barriers. In all well operations, two tested and independent well barriers should be in place at all times. Each barrier is in itself intended to prevent uncontrolled flow of reservoir fluid to the surroundings (called blowout).

1.4.1 Barrier in Normal Drilling Operations

The primary barrier in drilling operations is the hydrostatic pressure of the drilling mud. The hydrostatic pressure is the pressure exerted by the column of mud. Sometimes there is also a pressure contribution from pumping of mud into the well, called circulating mud pressure. In conventional overbalance drilling, wellbore pressure is always kept higher than the pore fluid pressure. Otherwise, an influx of reservoir fluids into the wellbore may occur (called kick). The density of the drilling fluid is adjusted to obtain the appropriate wellbore hydrostatic pressure. The density is controlled by varying the concentration of high specific gravity solids within the fluid, such as barite.

An essential part of well control strategy is to maintain the appropriate mud weight throughout the drilling process. If the pore pressure of the formation increases, the mud density must be increased accordingly, to keep the well overbalance. In overbalance drilling, the hydrostatic pressure created by mud column is always kept between the pore pressure of surrounding formations and fracture pressure at all time. The difference between the formation fracture pressure and formation pore pressure is often referred to as the drilling window. As the casings are set, the overlying formations are secured from collapse or fracture, and the mud weight can be increased for deeper zones.

If the primary barrier is lost, it is crucial that the secondary barrier is functioning and can seal the well. If secondary barrier also fails while having a kick, then the situations can easily escalate into a blowout where reservoir fluids may flow from the well into the surrounding. During drilling secondary barrier are blowout preventer (BOP), casings, cement and wellhead seals. Casing, cement and wellhead seals are passive barriers i.e. once setup they are always there, while BOP is an active barrier, whose systems can be activated when required.

A blowout may only occur when both well barriers fail simultaneously. In addition to the physical well barriers, well control is an important element of preventing a blowout. Well control is the procedure and process related to regaining control of a well in the event of failure or defect in one of the physical well barriers. During a well control situation the secondary barrier will always be important to prevent the uncontrolled flow of hydrocarbons (NORSOK Standard, 2013).

1.4.2 Barriers during Normal Production Operations

The primary barriers in the production phase of the well life are production packer, completion string and surface controlled subsurface safety valve and the most important secondary barriers are subsea tree, casing cement, wellhead and tubing hanger.

1.5 Scenarios Studied

In this study five scenarios related to drilling and production life phase of an offshore well are modeled. The decommissioning phase was not analyzed, as the probability of having a large spill for a short duration is very unlikely as the reservoirs are depleted in that life stage. The five scenarios modeled in this study are briefly described below.

1.5.1 Scenario-1: Drilling/Man-made/High potential

An exploratory oil well drilled in the Mississippi Canyon block in the GoM is studied to analyze the associated oil spill risk. It is assumed that an uncontrolled kick develops into a blowout when the well control procedures failed along with the failure of one of the secondary barrier, mainly blowout preventer. An event tree of the process is shown in Figure 3.

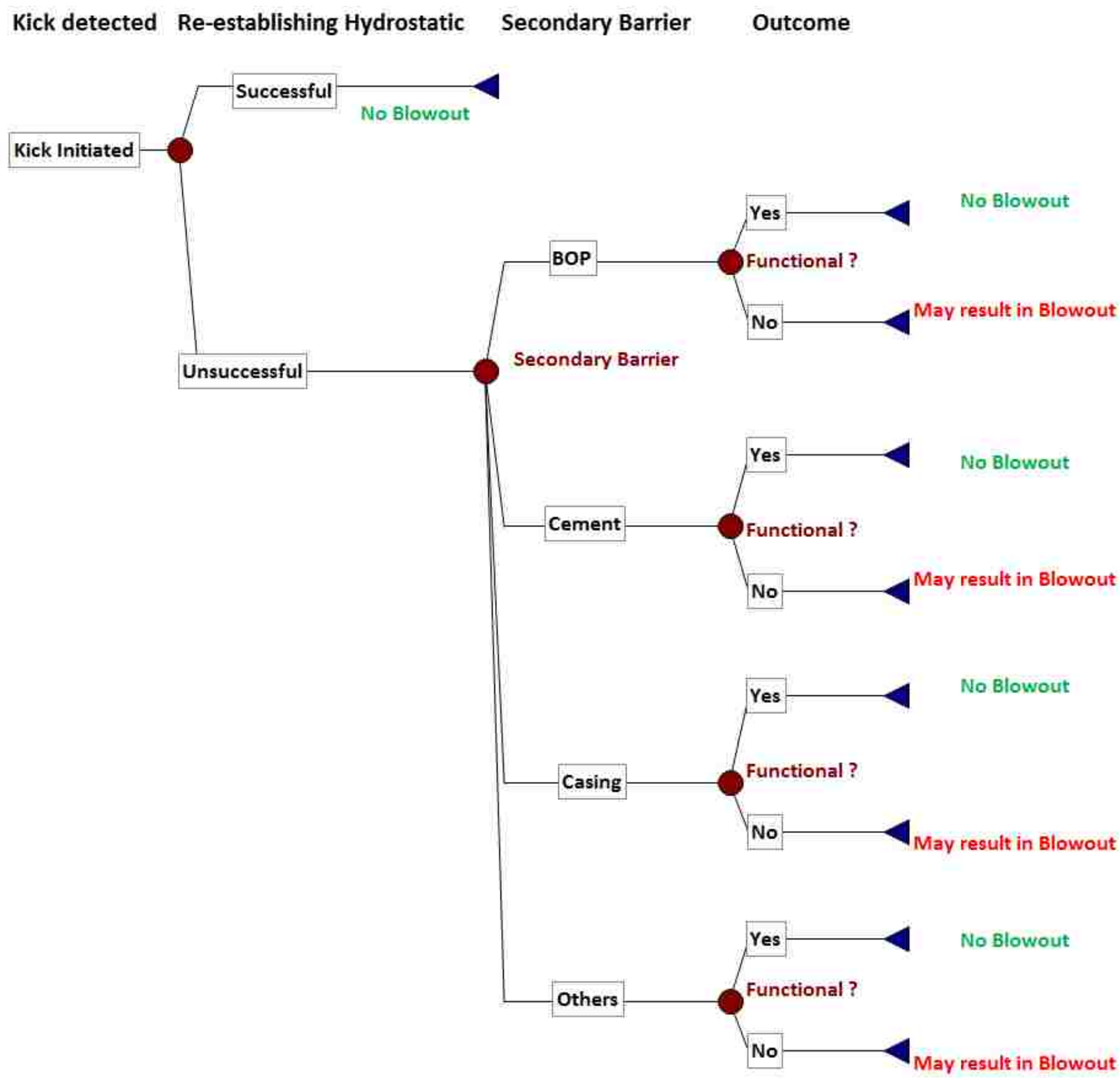


Figure 3: Kick leading to a blowout during exploratory drilling

1.5.2 Scenario-2: Drilling/Underground/Flow outside the well

An underground blowout (UBO) of specific geological features present in the Popeye-Genesis field in the GoM is analyzed in this scenario, to quantify the associated risk. It is assumed that during drilling a high pressure deeper reservoir is accidently exposed to a shallower depleted zone through a conductive fault. When the shallower zone's pressure becomes equal to its leak off test value, it is assumes that it will transmit the hydrocarbons to the sea floor. The consequences of underground blowout range from no visible damage at the surface to total loss of the well. An event tree description of UBO is shown below in Figure 4.

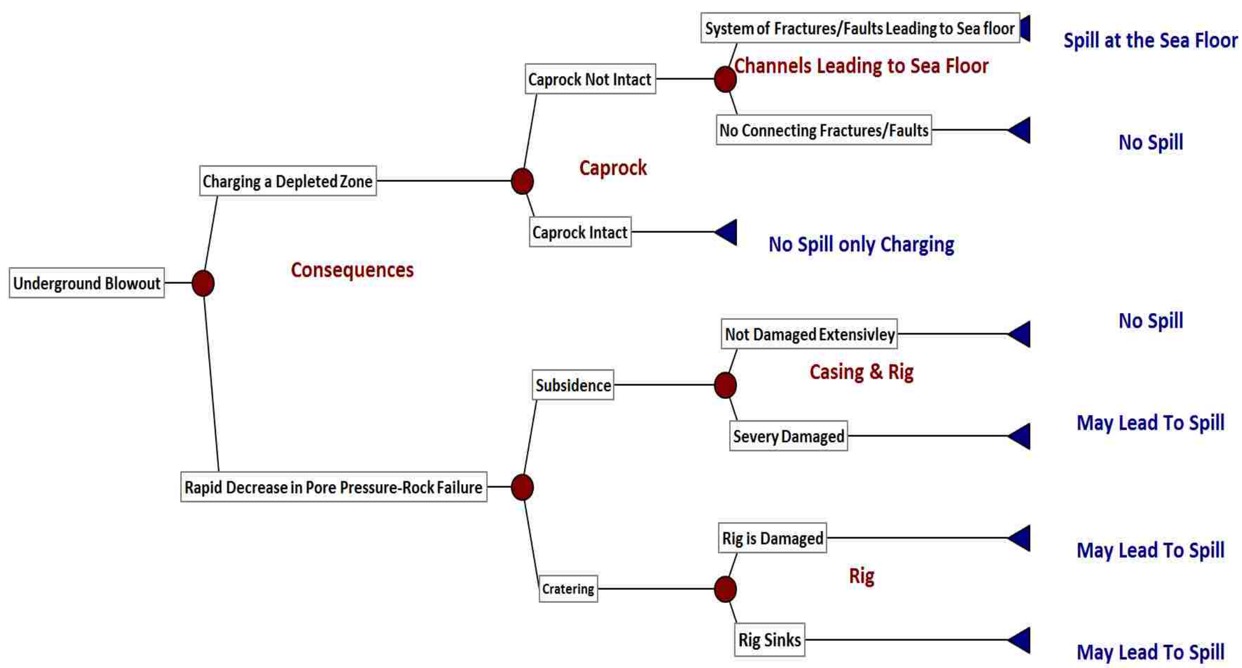


Figure 4: Event tree of an underground blowout

1.5.3 Scenario-3: Production/Man Made/High Potential/ Sand Screen Failure

In this scenario, oil spill risks associated with normal production life cycle of a deepwater well are studied. It is assumed that sand screen failure of a newly completed well leads to a blowout and hydrocarbons are discharged to sea floor. An events tree showing the sequence of events is shown in Figure 5.

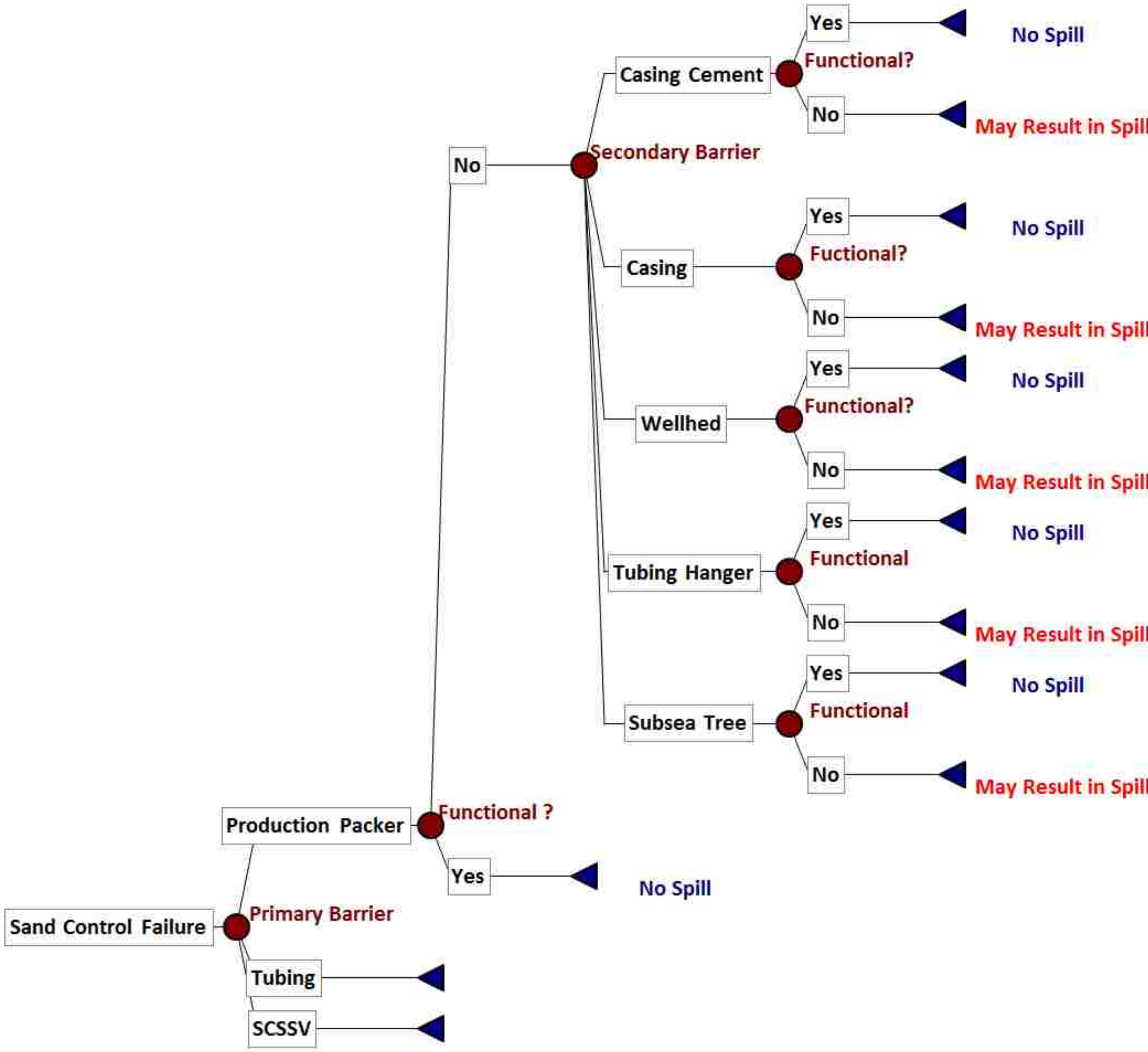


Figure 5: Sand control element failure leading to a blowout for a producing well, the expansion of only the production packer branch is shown

1.5.4 Scenario-4: Production FPSO/Man Made/Nature

In this scenario, the spill risk associated with Floating Production Storage and Offloading (FPSO) vessel are discussed. FPSO has certain advantages over other type of production platforms, due to its reuse, quick mobility and ability to work in harsh weathers. Meanwhile FPSO differs in their large storage capacity, Station keeping requirement and transport through shuttle tankers as shown in Figure 6.

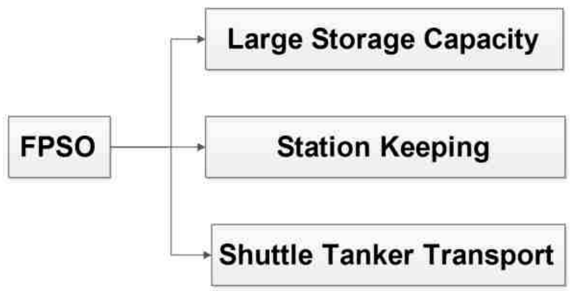


Figure 6: Differences between FPSO and other type of production platforms

1.5.5 Scenario-5: Severe Weather/Loss of Position/Mudslide/Production Halt

In this scenario the oil spill risk associated with severe weather conditions in the GoM are analyzed. GoM is prone to hurricane of categories 1 to 5. This type of severe weather may result in pipeline or platform damage and its consequences can range from minor to very large oil spills.

1.6 Fault Tree Analysis (FTA)

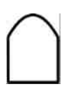
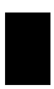
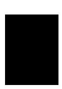
Fault tree analysis is a top-down approach and is a logical representation of the many events and component failures that may combine to cause the system or top event failure (Stamatelatos, 2002). It uses ‘logic gates’ (mainly AND or OR gates) to show how ‘basic events’ may combine to cause the critical ‘top event’. FTA has several potential uses in offshore QRA (Spouge, 1999):

- In frequency analysis, it is commonly used to quantify the probability of the top event occurring, based on estimates of the failure rates of each component. The top event may be an individual failure case, or a branch probability in an event tree, in this study it is the blowout probability.

- In risk presentation through importance/sensitivity analysis, it may also be used to show how the various risk contributors combine to produce the overall risk and sensitivity of top event by variation of basic event.
- In hazard identification, it may be used qualitatively to identify combinations of basic events that are sufficient to cause the top event, known as ‘cut sets’.

If quantification of the fault tree is the objective, downward development should stop once all branches have been reduced to events that can be quantified. Standard symbols used in this study for fault tree construction are shown in, below in Table 1.

Table 1: Standard symbols used in the fault tree analysis

Fault Tree Symbols	Description
	The Circle describes the basic event that requires no further development. In other words, the circle signifies that the appropriate limit of resolution has been reached (Fault Tree Handbook).
	OR GATE - Event occurs if any input events occur
	AND GATE - Event occurs if all input events occur
	TRANSFER IN - Event developed down elsewhere
	TRANSFER OUT - Event developed up elsewhere

In construction of fault tree top down approach is followed. Construction usually starts with the top event, and works down towards the basic events. For each event, it considers what conditions are necessary to produce the event, and represents these as events at the next level down. If any one of several events may cause the higher event, they are joined with an OR gate. If two or more events must occur in combination, they are joined with an AND gate.

1.6.1 Algebraic gate operations with probabilities

OR Gate: Consider a random experiment that can have two possible independent outcomes A and B, which are mutually exclusive. This means that A and B cannot happen during a single trial of the experiment. Like when we toss a coin we cannot have head and tail together. For these mutually exclusive events, the probability of occurrence of either A and B (OR Gate) is given by

$$P(A\ orB) = P(A) + P(B)$$

For events that are not mutually exclusive the probability of occurrence A or B is given by the expression

$$P(A\ orB) = P(A) + P(B) - P(A\ and\ B)$$

For three events A, B and C we have

$$\begin{aligned} &P(A\ or\ B\ or\ C) \\ &\qquad = P(A) + P(B) + P(C) - P(A\ and\ B) - P(A\ and\ C) - P(B\ and\ C) \\ &\qquad + P(A\ and\ B\ and\ C) \end{aligned}$$

If the $P_{A\&B}$ is small ≤ 0.2 than $P(A\ orB) = P(A) + P(B)$ with error ≤ 11%. Then this approximation is called “rare event approximation” (Stamatelatos, 2002).

AND Gate: Now consider the two events that are mutually independent. This means that if some experiment is performed several times, the occurrence of A has no influence on the subsequent event B and vice versa. Then the probability of these mutually independent events (AND Gate) is given by

$$P(A\ and\ B) = P(A)P(B)$$

For events that are that are not mutually independent we need to use the concept of conditional probability. For example $P(B|A)$ is the probability of event B, given that event A has already taken place.

$$P(A \; and \; B) = P(A)P(B|A) = P(B)P(A|B)$$

If A and B are mutually independent, then $P(A|B) = P(A)$ and$P(B|A) = P(B)$.

1.7 Reliability Analysis

The science of reliability prediction is based upon the principals of statistical analysis. Reliability is defined as "the probability that equipment will perform a specified function under stated conditions for a given period of time" which defines a probabilistic approach rather than a deterministic one. This probability can be calculated or stated to reside within certain statistical confidence limits. To calculate the reliability of the system, its failure rate or Mean Time to Failure (MTTF) and /or the Probability of Failure on Demand (PDF) are needed. The most comprehensive subsea equipment reliability data is available through OREDA (Offshore Reliability Data) database software containing the latest data available. The OREDA 2009 Handbook contains offshore subsea and topside equipment reliability data till 2003, from which some of the equipment reliability data is used in this study. As there is increased activity in the past few years in deepwater, so use of data from OREDA online database will provide more accurate results as compared to using the OREDA handbook data.

1.8 Data Sources

Blowouts are one of the main risks associated with the exploration and production operations in deepwaters. The quality check of the input data is an important aspect required to ensure a satisfactory quality risk analysis procedure. Good input data quality will result in providing a realistic risk picture, which is critical for the evaluation of risks and for their use as a basis for decision making. Some of the data sources that are typically used in offshore Quantitative Risk Assessment (QRA) are show in Table 2 & Table 3. Only the main sources are mentioned, besides these a number of papers, reports, etc., may also be used from time to time, for specific subjects. Extensive data is needed for detailed modeling and therefore modeling and data sources are often closely coupled.

Table 2: Some of the blowout and reliability data sources and their availability

Data Type	Source	Coverage	Availability
Blowout Frequency	SINTEF Blowout database	All blowout worldwide	Available on disk: Annual license fee required
	WOAD	All offshore accidents worldwide	Available on disk: Annual license fee required
	BSEE	All accidents and spills on US shelf	Reports
	Offshore Blowout Causes and Control	All blowout worldwide	Book by Per Holand, 1997
	OGP	All blowout worldwide	Reports http://www.iogp.org/data-series#2673467-data-series
System Reliability	OREDA	Most offshore equipment	Book
	BSEE (MMS)	GoM BOP	Reports about BOP and shear rams
	Exprosoft SubseaMaster & Wellmaster	Components in oil wells (BOPs and SCSSVs)	N-7465 Trondheim www.exprosoft.com
	Exprosoft	Surface Controlled Subsurface Safety Valves	STF18 A83002, Reliability of Surface Controlled Subsurface Safety Valves

Table 3: Some of the data sources for equipment leaks, vessel collision, falling objects and transportation accidents. Detailed references can be found in the additional references section

Data Type	Source	Coverage	Availability
Process System Leak Frequency	UK Health and Safety Executive	UK Operations	Report
	OGP	World wide	Report
	Norwegian Petroleum Directorate	Norwegian section	Report
Riser/Pipeline Leak Frequency	AME Loss of containment Report (AME, 2003)	North Sea	Report
	OGP	World wide	Report
	RNNS Report	Norwegian section	Report
Vessel Collision	UK Health and Safety Executive	UK Operations	Report
	BSEE	World wide	Report
Falling objects	WOAD	Worldwide Offshore	DNV report
	OGP	World wide	Report
	UK Health and Safety Executive	North Sea	Report
Helicopter Accidents	OGP	World wide	Report
	UK and Norwegian Civil Aviation Authorities	UK and Norway	Report

CHAPTER 2: FRAMEWORK FOR RISK ASSESSMENT PROCESS

Key elements in developing oil spill scenarios and quantitatively analyzing their associated are estimation of worst case discharge rates and duration of spill. However, there is no standardized method for calculations of these values which can easily be communicated and compared between different scenarios. The first phase of the work process is finding and determining, representative accurate input parameters, which are the most time-consuming part of the analysis, some of the required parameters are shown in Table 4.

Table 4: Typical required input parameters for estimation of worst case discharge rates for drilling and production scenario

Category	Required Parameters Drilling	Required Parameters Production
Reservoir	Thickness	Thickness
	Radius	Radius
	Pressure	Pressure
	Temperature	Temperature
	GOR	GOR
	Bubble point pressure	Bubble point pressure
	Permeability	Permeability
	API gravity	API gravity
	Water cut	Water cut
	Oil formation factor	Oil formation factor
	Fluid type	Fluid type
Well Design	Trajectory	Trajectory
	Casing program	Casing program
	Riser	Riser
	BOP	Subsea Tree
	Drill pipe	Production Tubing
	Open hole section	Packer, SCSSV
Oil Spill Duration	Historical trend	Historical trend
	Relief well	Relief well
	Capping stack	Capping stack
	Coning	Coning
Scenario	Topside release probability	Topside release probability
	Subsea release probability	Subsea release probability
	Flow path probability	Flow path probability
	Reservoir penetration depth	Reservoir penetration depth
	BOP state (opening)	Restriction in Flow path

Here parameters such as representative well location, well geometry, reservoir properties, spill response technologies and probabilities of different blowout scenarios must be accurately determined for true representation of the regional properties. This data must be carefully considered to achieve as accurate results as possible.

2.1 Representative Well Location

Two representative GoM wells, one for Neogene (deepwater) and second from Paleogene period (ultradeepwater) were selected for the analysis purpose.   The two red dots in the flowing Figure 7 show the location of the selected wells. The deepwater well is in Mississippi Canyon while the ultra-deep well is in Alaminos Canyon of Gulf of Mexico.

Figure 7: Map showing GOM blocks with two selected representative well locations (http://www.geographic.org/deepwater_gulf_of_mexico/definitions.html)

2.2 GoM Geology

Neogene Example: An understanding of salt and sediment interaction is critical to assess the risk associated with exploration activities. Minibasins are formed as a result of this interaction. The Neogene geology of GoM can be categorized in four major groups of Plio-Pleistocene Fluvial Sandstone, Upper Miocene Deltaic Sandstone, Middle Miocene Deltaic Sandstone and Lower Miocene Slope and Fan Sandstone. The source rock for these plays is the deep upper Jurassic and through vertical migratory paths, hydrocarbons travelled and trapped by these low lying Neogene traps. Some of the faults in these plays are nearly horizontal and they sometime provide barriers to the flowing fluid and help in trapping the migratory hydrocarbons. Most of these sands are not very thick and multiple sands are stacked as well.

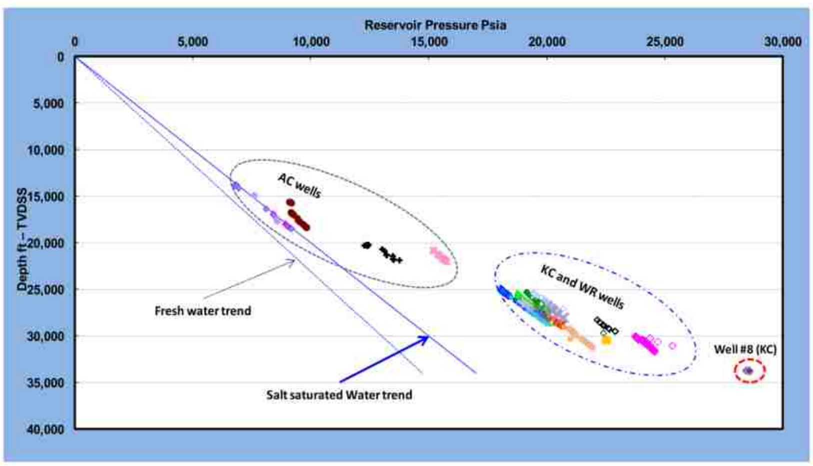
Paleogene Wilcox Example: Deepwater Gulf of Mexico contains numerous geologic plays at different reservoir depths with proven hydrocarbon resource. Among these plays is the Wilcox, where exploration and appraisal drilling has increased since 2001, and reported successes indicate that the play holds significant producible hydrocarbons in the order of multi-billion barrels. However, depth, location, and reservoir characteristics of the offshore Wilcox play present various challenges to commercial development of the Wilcox formation even with today's technology (Joshua Oletu etal. 2013). The deepwater GOM Wilcox trend comprises Upper (or Late) Paleocene to Lower (or Early) Eocene age fan turbidites that stretch over some 400 miles from Alaminos Canyon in the west to Atwater Valley in the east. The Wilcox is a subunit of the Lower Tertiary system. The dominant sediment source is believed to be onshore deltaic, with clastic sediments deposited in a complex slope system, resulting in minibasins and base of slope fans.

2.3 Representative reservoir properties

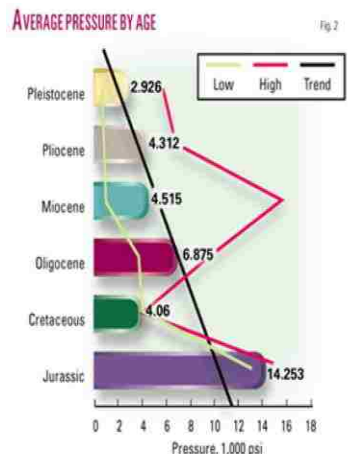
Representative reservoir sand properties both for Paleogene and Neogene reservoirs are briefly described in the following sections.

2.3.1 Reservoir Pressure

The Wilcox is hydrostatically pressured to geo-pressured with reservoir pressures ranging from 7,000 to 29,000 psia (Joshua Oletu etal. 2013) as shown in Figure 8 (a). The general trend is increasing pressure with depth, and with the same depth spatial variations are also present. For example some of the sands can be spotted having the same depth but wide range of pressure.



(a)



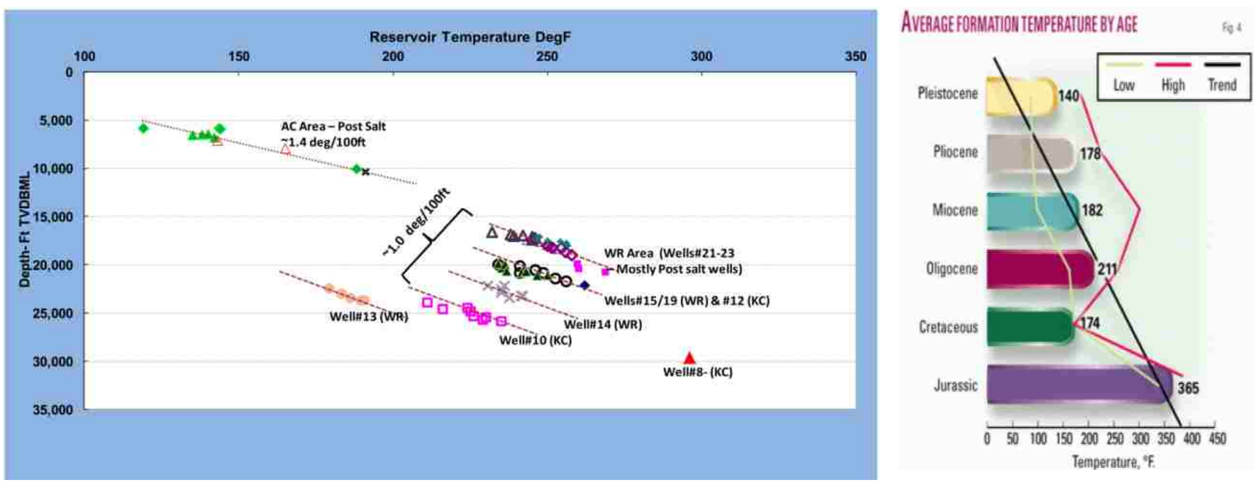
(b)

Figure 8: (a) Reservoir pressure variation for Paleogene period Wilcox sand in the GoM (joshua oletu etal. 2013), (b) pressure variation with depth in the gulf of Mexico with geological time scale (haeberle, 2005)

The general trend of pressure variation with depth in the GoM with geological time scale is also shown in Figure 8 (b). A wide spread and nonlinear behavior can also be spotted. A fitted black trend line shows the approximate values with depth, and the fitted trend could over or under predict as well.

2.3.2 Reservoir Temperature

The Wilcox formation temperature ranges from 130 to 300 F^{o} , and different depth trends could be observed across the basin (Joshua Oletu etal. 2013) as well. Even within a constant depth, there could be a spread in the values of temperature for various sands, shown in Figure 9 (a) and (b). The generic trend for temperature variation with geological time scale, is shown in Figure 9 (b).



(a) (b)

Figure 9: (a) Reservoir temperature variation for Paleogene period Wilcox sand in the GoM (Joshua Oletu etal. 2013), (b) temperature variation with geological time scale (Haeberle, 2005)

2.3.3 **Porosity and Permeability Trends**

The dominant pore type in the Wilcox reservoir sands is intergranular porosity with average effective porosities ranging from 7% to 29%, there are few exceptions as well. Representative sand data used for this study indicate different permeability vs. porosity relationships depending on the Wilcox unit and its location in the basin. The available data also show that apart from only one sand in the ultradeepwater in the Alamos Canyon permeability in general for the Wilcox units is in the order of or less than 10 mD. It is pointed out by Joshua et al. (2013) that due to insufficient core data from wells in the Keathley Canyon and Walker Ridge blocks, the trends need to be validated with additional core data analysis.

2.4 Reservoir Properties with Lognormal Distribution

The representative reservoir properties for both Neogene and Paleocene type of reservoir were obtained from (RPSEA , 2010). Due to the large spread in the reservoir sand properties, therefore instead of a single constant value, a series of values were assumed. In this way, the spatial variation in the reservoir properties can be effectively accounted for.

Table 5: Reservoir properties obtained by fitting lognormal distribution and using Monte Carlo simulation

	Neogene		**Paleogene**	
Variable	P50	P90	P50	P90
PR (psi)	11305	12436	19374	20444
Temperature (F0)	210	222	210	243
Thickness h (ft)	106	126	140	187
Permeability (mD)	246	448	15	20
GOR (SCF/STB)	1700	2033	160	180
Pb (psi)	6306	6306	4500	4500
API Gravity	28	28	25	25
Water Cut (%)	22	23	25	30
Bo (rb/STB)	1.39	1.44	1.153	1.3
Reservoir Radius (ft)	8840	9954	8345	9491
Wellbore Radius (ft)	0.7	0.753	0.54	0.68
Oil Viscosity (Cp)	0.8	0.98	6.12	10.17
PI (STB/day/psi)	19.05	35.68	0.2385	0.3922

It is a well-known fact that permeability variation follows lognormal distribution, therefore a combination of lognormal and triangular distribution was assumed for different reservoir parameters. The input for each parameter is their mean value and the standard deviation. The data for the two type types of selected sands is shown in Table 5. P50 and P90 values of each of the series were found by using @Risk software and Monte Carlo simulation were performed to find the P50 and P90 values for productivity index as well. Simulations for worst case discharge rate were carried out using the P50 values only, as it is the most representative value. For some of the parameters fixed values found in the literature are used, as changing them and fitting a distribution might not represent well the corresponding sand.

2.5 Selected Well Schematics

Two representative well locations, one from the deepwater (Neogene Era sand-Mississippi Canyon) and second one from the ultradeepwater (Paleocene Era sand-Alamos Canyon) were selected to estimate worst case discharge rates. The well schematics are shown in Figure 10.

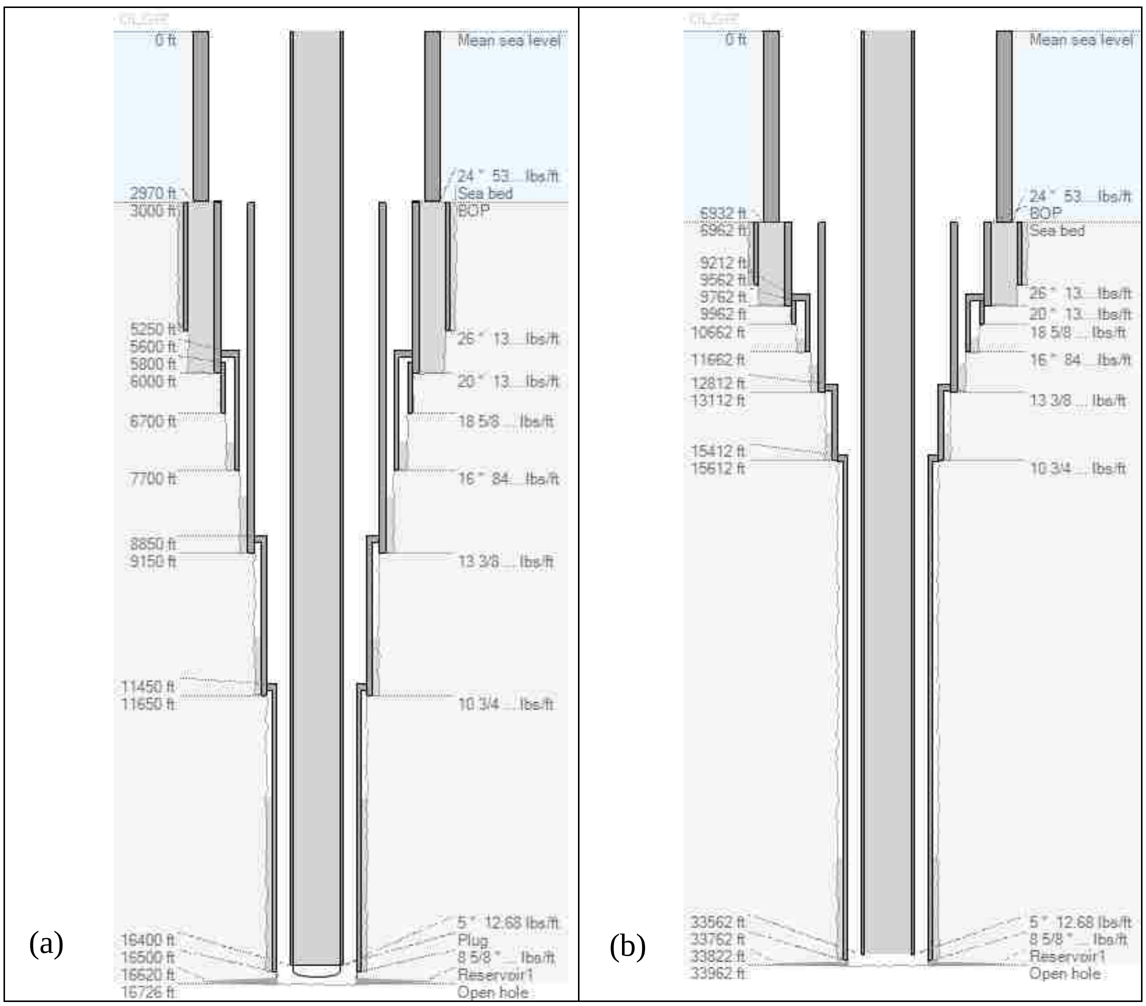


Figure 10: Well schematic (a) deepwater well: Neogene GoM (Fontenot, 2013), (b) Ultradeepwater well: Paleogene

The open hole section is 500 ft with reservoir located at the TVD of 21350 ft. The thermal conductivity of casing material is 27.73 Btu/ft-h-R, heat capacity is 0.119 Btu/lbm-F^o and density 490 lbf/ft^3. The difference between the Neogene and Paleogene well is in the water depth and the length of the last liner, while all other parameters are same for the fluid analysis purpose.

Table 6: The casing program for the selected deepwater Neogene well (Fontenot, 2013)

Casing	Size (inches)	Grade (PPF)	Setting depth (ft)	Shoe Depth (ft)	Top Of Cement (ft)
Conductor	26″	136.4	3000	5250	3000
Surface	20″	133.0	3000	6000	3000
Liner	18-5/8″	94.5	5800	6700	6200
Liner	16″	84.0	5600	7700	7200
Intermediate	13-3/8″	86.0	3000	9150	8150
Liner	10 ¾″	55.5	8850	11650	10650
Liner	8-5/8″	40.0	11450	16726	13450

Only Neogene sand due to their high potential of flow are discussed in detail, while for the selected Paleogene reservoirs, the flow was not significant or not at all. Therefore they are not disused in detail and only flow rates are given in appendix B.

2.6 Fluid Flow Simulation Setup

Black oil is used in the simulation as the reservoir fluid, with the oil, gas and water properties shown in the Table 7.

Table 7: Black oil properties

Component	Specific Gravity
Oil	0.85
Gas	0.64
Water	1

Temperature Profile**:** The sea water temper decreases with water depth from 79 F^o at the sea surface to nearly 40 F^o at 3,000 ft depth selected for deepwater Neogene well. Below the mud line a linear geothermal gradient was assumed with 40 F^o at mudline and then temperature linearly increases with depth to 210 F^o at the target depth of 21350 ft.

Inflow Performance Relationship (IPR)

Two component IPR was used with linear profile for $P_R > P_b$ and quadratic for the case if $P_R < P_b$.

$$q = J(P_R - P_{wf}) \quad \text{for} \;\; P_b \leq P_{wf} \leq P_R$$

where q is the volumetric flow rate, P_R is reservoir pressure, J is productivity index, and P_{wf} is the well flowing pressure.

$$q = J(P_R - P_b) + \left(\frac{J}{2P_b}\right)\left({P_b}^2 - {P_{wf}}^2\right) \;\; \text{for } P_{wf} \leq P_b$$

where P_b is the bubble point pressure. The productivity index for pseudo steady state flow is given by

$$J = \frac{0.007082kh}{B_o\mu_o\left[ln\frac{r_e}{r_w} + s - 0.75\right]} \qquad (1)$$

where k: permeability (mD), h: reservoir thickness (ft), r_e: reservoir radius (ft), rw: wellbore radius (ft), s: skin, μ_o: oil viscosity (cp), βo : oil formation factor

The initial reservoir pressure for the selected sand was above the bubble point pressures. For the partial penetrated well, the IPR was modified using the Papatzacos (1987) method of adding additional skin S_p for partial penetration.

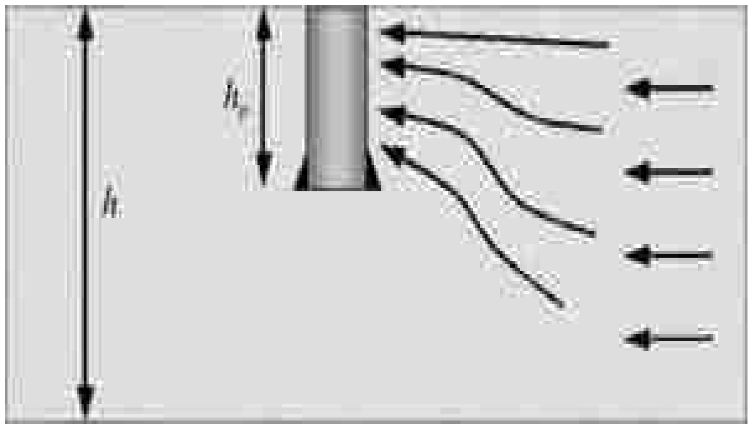


Figure 11: Partial penetration into a reservoir
(http://petrowiki.org/Fluid_flow_with_formation_damage)

$$s_p = \left(\frac{1}{h_{pD}} - 1\right) ln \frac{\pi}{2r_D} + \frac{1}{h_{pD}} ln \left[\frac{h_{pD}}{2 + h_{pD}} \left(\frac{A-1}{B-1}\right)^{1/2}\right] \tag{2}$$

Where the parameters have the following definitions.

$$h_{1D} = h_1 / h, \quad h_{pD} = h_p / h,$$

$$A = \frac{1}{h_{1D} + h_{pD}/4}, \quad r_D = \frac{r_w}{h}\left(\frac{k_v}{k_h}\right)^{1/2}, \quad B = \frac{1}{h_{1D} + 3h_{pD}/4}.$$

With partial skin counted as Sp, the modified productivity index (PI) is shown in Eq. (3)

$$PI = J = \frac{q_o}{\Delta P} = \frac{0.00708\, kh}{\mu_o B_o \left(\ln\left(\frac{r_e}{r_w}\right) - 0.75 + (s + s_p)\right)} \tag{3}$$

Reservoir Pressure Decline

The reservoir pressure decline can be estimated, by using the material balance equation under the assumption that the reservoir is bounded with no aquifer support to maintain the pressure and production occurs due to expansion of the reservoir fluids only. The material balance results in the equation (4)

$$P_t = P_i - \frac{N_p\, B_o}{C_t N_i} \qquad (4)$$

Where

P_t is the pressure at time t

P_i is the initial reservoir Pressure

Np produced oil volume

Ni original oil in place

Ct total reservoir compressibility

Bo oil formation volume factor

Total reservoir compressibility is calculated by using Hall's correlation

$$C_t = 1.87 \times 10^{-6} \varphi^{-0.415}$$

and change in porosity can be estimated as

$$\varphi = \varphi_o exp[C_t(p_t - p_i)]$$

Standing Correlation was used to calculate oil formation volume factor.

CHAPTER 3: OIL SPILL RISK ASSESSMENT OF A DEEPWATER EXPLORATORY DRILLING WELL (SCENARIO-1)

Major offshore accidents such as Macondo well incident highlight one of the possible failure modes and subsequent disasters when an offshore engineering project could go wrong. Such events can happen during any life phase of an offshore well - starting from the exploratory drilling phase to the final phase of plug and abandonment, but their potential to cause major environmental damage is greatest in their early life phase. Major factors that significantly contribute in defining such accident scenarios are the geological and operational complexities, equipment reliability, human factors, geographical/economy location, and weather conditions. The path taken by the reservoir fluids to reach the sea floor is also an important factor in determining the worst case discharge rates, as different paths provide different resistances to flowing fluid. Environmental risk of an oil/gas spill is also a function of the type of hydrocarbons released and amount of oil volume spilled.

A representative well from Mississippi Canyon in the Gulf of Mexico is studied for quantitative risk assessment (QRA) of an oil spill in the exploratory life phase of a well. At the location of the well, sea water depth is 3,000 ft and total vertical depth of reservoir is 16,726 ft. The reservoir sand is associated with Neogene geological period and representative reservoir properties for this well are selected from literature. Due to the large spatial variation of reservoir properties, a single selected value will not truly represent the general behavior in that particular area, therefore a spread of values should be considered. In this study, this spread is in the form of lognormal & triangular distributions. From these distributions P10, P50 and P90 values can be obtained. To find representative value for productivity index, the variables were entered in the form of series and 100,000 iterations of Monte Carlo simulations were performed to find P10, P50 and P90 values. Based on P50 value, the worst case discharge rate calculations were performed by using OLGA & PipeSIM (commercially available multiphase flow simulators). As only finding the WCD rates was the sole motive, therefore black oil fluid model was considered. Based on historical trend of blowing fluid coming to either sea floor or sea surface during blowouts, the following potential pathways are simulated: seabed and topside releases, restricted and unrestricted flow through BOP, flow with and without drill pipe. To study the effectiveness of newly built spill response technologies in reducing the risk of large oil spill associated with deepwater drilling activities; two model cases are considered and compared to each another. First model case is purely based on historical data and the second case is a modified version of the first model case in which the effectiveness of some of the recently built oil spill response systems e.g., capping and containment systems have been analyzed. The historical kick statistics and the equipment reliability data available from different sources is used to compute blowout probability. Reservoir properties combined with the release path is used to estimate WCD. Risk is calculated using the system failure probability and its consequence, and is presented in the form of a risk matrix for the different cases studied.

3.1 Introduction

Deepwater offshore oil and gas production involves usage of some of the most advanced and challenging technologies of the modern time and is the main source of revenue for several companies and countries. These technologically complex operations involve the risk of major accidents as well, which have been highlighted by disasters such as the explosion and fire on the

UK production platform Piper Alpha, the Canadian semi-submersible drilling rig Ocean Ranger, and the explosion and capsizing of Deepwater Horizon rig in the Gulf of Mexico.

Major accidents like Macondo well blowout represent one of the disastrous failure mode in which an offshore engineering project can go wrong. Accidents cause death, suffering, environmental pollution, and business disruption. Due to their catastrophic impacts, these accidents receive large attention from the news media and remain in the public memory for a long time. Questions about the safety of offshore operations start emerging like are offshore platforms safe enough and can major accidents be prevented? How should the offshore industry achieve an appropriate balance between the interests of safety and the economics of oil and gas production? Quantitative Risk Assessment (QRA) is the right tool to address these and other related questions (Spouge, 1999). By carrying out the QRA of offshore operations, it can be quantitatively shown that a balance between economics of oil and gas productions operations and safety is achievable.

3.1.1 Description of Capping and Containment System

In the spill response systems, capping stack is the main component that is kept in readiness state at an onshore location. It is only deployed when the blowing well cannot be shut in with BOP that is already present on the well. Some of these capping systems are designed in such a modular way so that they can be easily transported internationally as well by planes. A capping and containment system in operation is shown in Figure 12 below (MWCC, 2011). In operational mode of a capping stack the following auxiliary systems are also part of the capping and containment system, subsea manifolds, subsea dispersant unit, free standing risers and collections vessels and tankers at sea surface (MWCC, 2011). The capping stack is supposed to be deployed to an existing BOP and can shut or contain the well depending on whether the well can sustain the high shut in pressure. Capping stack also facilitates in injection of dispersants as well, in case they are needed.

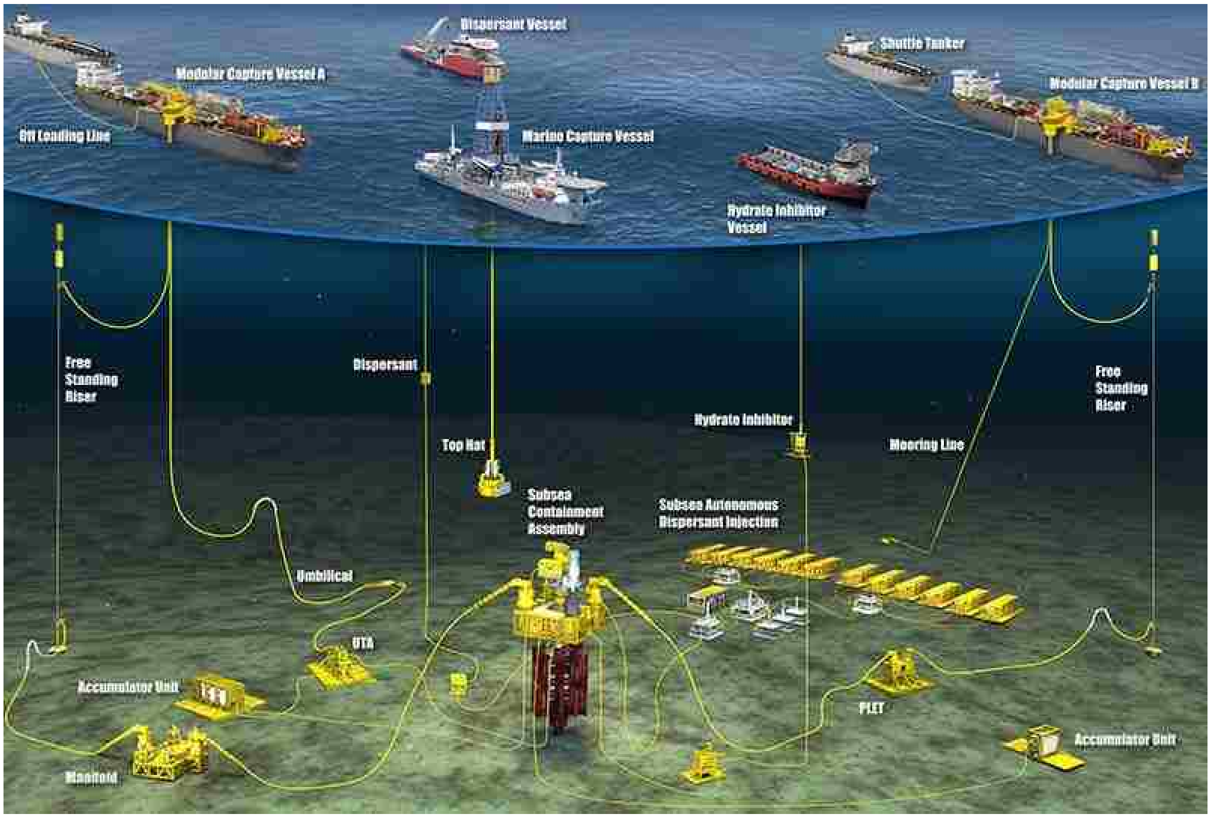


Figure 12: Capping and Containment system of Marine Well Containment Company (MWCC, 2011)

3.1.2 Well Barriers

To prevent a blowout, the well must be equipped with pressure control equipment and barriers. In all well operations, two tested and independent well barriers are in place at all times (NORSOK Standard, 2013). Each barrier in itself is intended to prevent uncontrolled flow of the reservoir fluid to the surroundings (blowout). In the drilling phase, the primary barrier is the hydrostatic pressure maintained by mud and the secondary barriers are BOP, casing, cement and wellhead seals. A blowout can only occur when both of these barriers fails simultaneously. These barriers are shown in Figure 13.

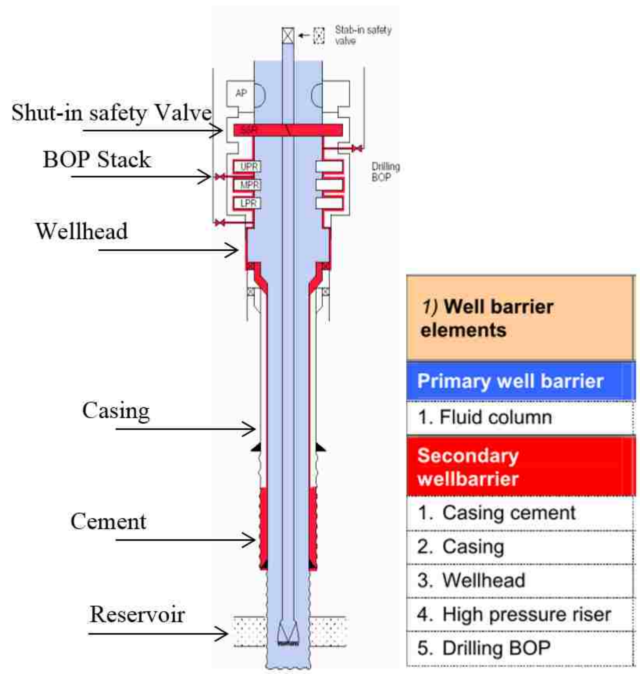


Figure 13: Primary and secondary barriers in a drilling well (NORSOK Standard, 2013)

3.1.3 Methodology

In order to calculate the quantified risk, the incident's probability/frequency and its consequences are required. The incident frequency is computed from Fault Tree Analysis, while consequences in the form of oil volume released to the environment are found from multiphase fluid flow analysis in wellbore.

3.1.4 Representative Well, Reservoir Properties, and QRA Procedure

Representative properties for a reservoir corresponding to the selected well's location are taken from literature (RPSEA, 2010) and are shown in Figure 14, alongside the result of fitted distributions and Monte Carlo simulations.

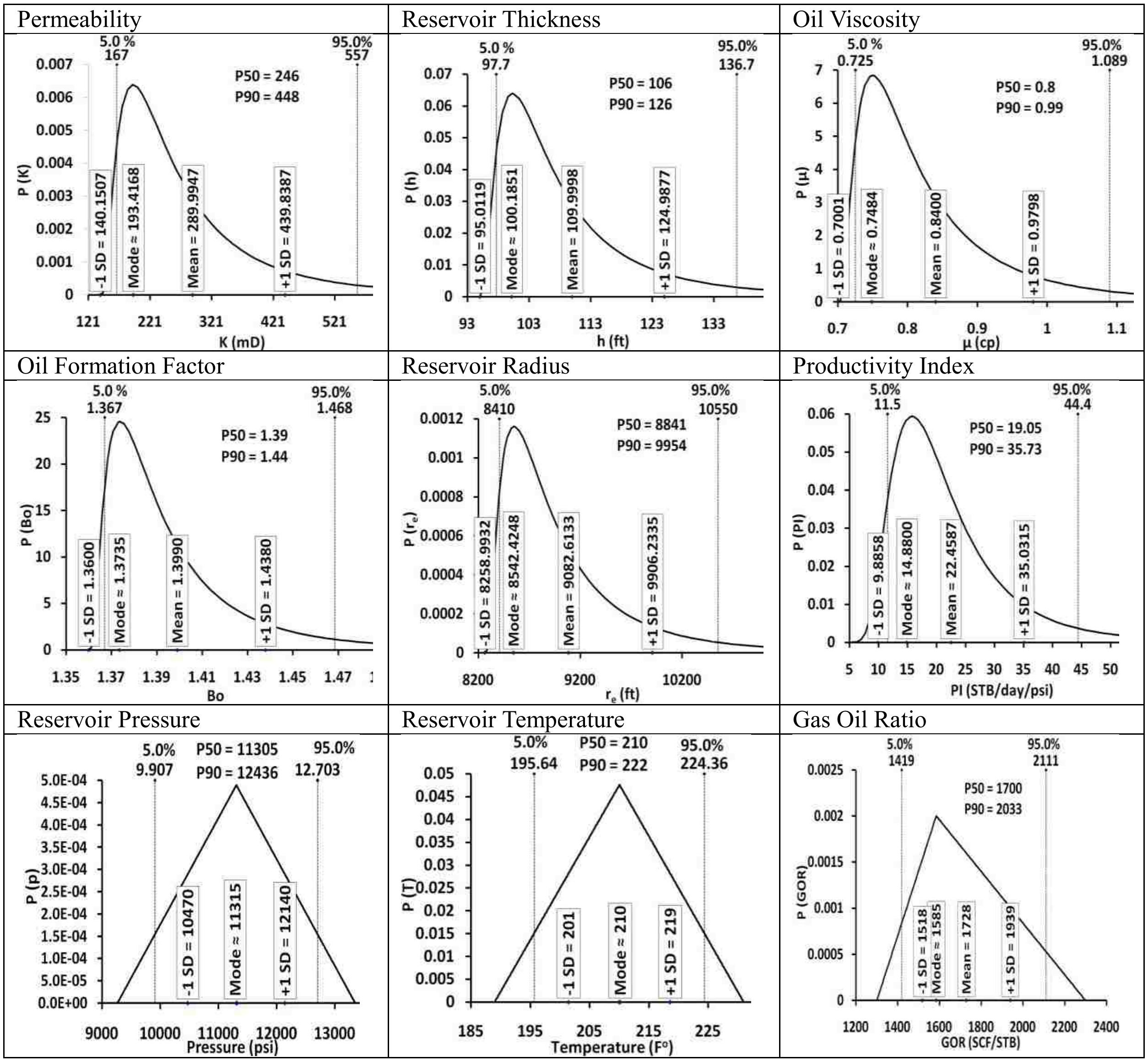


Figure 14: Results of Monte Carlo simulation and fitted log-normal and triangular distribution

The chart for each parameter shows the Mean, Mode, Standard Deviation, 90% Confidence Interval, P50 and P90 values. The flowing potential of a well is usually expressed in the form of productivity index. It is usually denoted by capital letter "J" and is the ratio of fluid flow rate to the pressure draw down.

To ease the readability, the estimated P50 and P90 values for various reservoir parameters are shown in Table 8.

Table 8: Reservoir properties for one of the representative GoM deepwater sand (based on data from RPSEA, 2010)

Variable	P50	P90
P_R (psi)	11305	12436
Temperature (F^0)	210	222
Thickness h (ft)	106	126
Permeability (mD)	246	448
GOR (SCF/STB)	1700	2033
P_b (psi)	6306	6306
API Gravity	28	28
Water Cut (%)	22	23
Bo (rb/STB)	1.39	1.44
Reservoir Radius (ft)	8840	9954
Wellbore Radius (ft)	0.7	0.753
Oil Viscosity (Cp)	0.8	0.98
PI (STB/day/psi)	19.05	35.68

3.2 Historical Trends in the GoM

3.2.1 Kick causes and Frequency

Majority of the kicks 71% in the GoM were caused by low mud weight (Holand, 2007), that signifies the presence of unexpected pore pressures and narrow margins between the pore pressure and fracture gradient. While 19% kicks were caused by lost circulation and 10% due to swabbing effects; the data is shown in Table 9.

Table 9: Deepwater GoM kick data with its causes (Holand, 2007)

Primary cause of kick	No. of kicks	Relative percentage
Low mud weight	34	71%
Lost circulation	9	19%
Swabbing	5	10%
Total	48	100

The data for the kick frequency is extracted from reference (Holand & Awan, 2012). The data includes deepwater kicks for deepwater (depth > 2000 ft) wells spudded during the period of 2007 – 2009 in the GoM outer continental shelf.

Table 10: Well drilled and number of kicks for the exploratory drilling in the GoM deepwaters (Holand, 2007)

Drilling Phase	**No. of kicks**	**No. of Wells**		
		Original	Sidetrack or by-pass	Total
Development	7	42	11	53
Exploratory	74	133	73	206
Total	81	175	84	259

The main source of this data was well activity reports in the BSEE's e-Well system (Holand, 2007). Majority of the kicks > 91% as shown in Table 10 occurred during the exploratory drilling which signifies the presence of narrow margins between pore pressures and fracture gradient. This narrow window prohibits the use of higher density mud, and therefore safety margin cannot be increased above a certain limit**.**

3.2.2 Blowout Frequency

The blowout is defined as an incident where formation fluid flows out of the well or between formation layers, after all the physical well barriers or the activation of these barriers have failed (OGP- No. 434-2, 2010). While the well release is defined as an incident where unintended hydrocarbons flow from the well at some point, but by using the installed barriers the flow is stopped. The historical blow out frequencies for the exploratory and development drilling for Gulf of Mexico are shown in Table 11. Blowout probability assessment is one of the main activity in quantifying the risk related to drilling and well operations. In most of the situations blowout probability is based on statistics, that uses historical data and if recent data set is small as compared to past data; the recent technological or operational improvements may not be portrayed well in the blowout probability analysis. The blowout probability might be considerably reduced in recent years, compared to the early records of historical databases, due to technological advances and better trained rig crews. The probability will also vary greatly from well to well, due to well specific characteristics. This is not reflected in statistical probabilities as they are averaged for the whole region.

Table 11: Blowout probability during exploratory and development drilling in deepwaters of world except North Sea, data mostly consists of GoM (OGP- No. 434-2, 2010)

Operation	**Category**	**Well Type**	**Frequency (per drilled well)**
Exploration Drilling, deep	Blowout (Surface Flow)	Appraisal	1.40E-03
		Wildcat	1.70E-03
	Blowout (underground)	Appraisal	0
		Wildcat	9.30E-04
Development Drilling, deep	Blowout (Surface Flow)	-	3.50E-04
	Blowout (underground)	-	1.30E-04
	Well release	-	2.20E-04

3.2.3 Blowout Duration

Due to non-existence of a standard procedure to calculate blowout probability, the procedure may vary from one oil company to another. Blowout duration is a function of the success of different well killing procedures; some of these are shown in Table 12. The selection of well killing procedure depends on the condition of blowing well, its location and access for the response systems to work. It is also dependent on the availability of rigs in the region and time taken to activate the response resources. A deepwater blowing well can be put under control by crew intervention, successful deployment of capping stack or drilling a relief well. The probability of a well to kill by itself (bridging) in deepwaters is very low in comparison to shallow well (Smith, 2012), as most of deepwater sand are consolidated.

Table 12: Blowout duration for deepwater wells when capping and relief well are the only option considered

Duration range (days)		<7 (Crew Intervention plus Others)	7-15 (Capping Stack Deployment)	15-30 (Capping Stack Deployment)	25-90 (Relief Well Drilling)
Representative duration (days)		7	15	30	90
Probability	Subsea (Base Case)	0	0	0	1
	Subsea (Capping Stack)	0	0.6	0.3	0.1

The representative durations for base and modified cases are determined as

Relief well drilling duration (for deep to ultra-deep waters) = 90 days

Capping Stack option duration = 7*0 + 15*0.6 + 30* 0.3 + 90 * 0.1= 27 days

These values are used to find the volume of oil spilled.

3.2.4 Reservoir Penetration and Kick Occurrences

Kicks may occur at any stage during drilling operations. Data supports the fact that kicks occur relatively quickly after penetrating the reservoir, thus in the very top part of the reservoir section (Oljeindustriens, 2010). In GoM most of the kicks are contribute to unexpected pore pressures i.e., kick occurs as we just tap the reservoir. The probability of occurrence of kick with respect to reservoir penetration is shown in

Table 13. Many kicks may occur as a result of swabbing, i.e., when pulling the drill pipe out of well. For swabbing it has been assumed that the entire reservoir could be exposed, as we tripping out occur when targeted depth is reached and reservoir is fully penetrated (Oljeindustriens, 2010).

Table 13: Relation between reservoir penetration and kick occurrence (Oljeindustriens, 2010)

Drilling depth to the reservoir	**Probability (%)**
Top of the reservoir (5%)	60
Half of the reservoir	20
Full reservoir exposed (drilled to TD)	20

3.2.5 Flow Path Distribution and Restrictions to Flow

The path taken by the reservoir fluid and restrictions in its path are important when calculating the resultant flow rate for that scenario. There are a number a number of flow paths possible for the reservoir fluids to come to surface (Oljeindustriens, 2010 & Smith, 2012). The release to the environment could be at the rig floor or at subsea. The path could be through drill pipe, drill pipe-casing annulus, casing-casing annulus, casing-cement interface, open hole flow or through the rock as shown in Table 14.

Table 14: Historical trends for hydrocarbon release (Oljeindustriens, 2010 & Smith, 2012)

Scenario	**Probability**	**Flow path**	**Probability (%)**
Topside Release	25%	Drill pipe	11
		Annulus	78
		Open hole	11
Subsea Release	75%	Drill pipe	11
		Annulus	78
		Open hole	11

These flow paths may be restricted or unrestricted. In this chapter only flow through the drill pipe, drill pipe-casing annulus and open hole flow are modeled. Flow outside of the casing is modeled in underground blowout scenario chapter-4.

3.2.6 Flow Rate, Spill Duration and Fault Tree Analysis

Commercially available multiphase fluid flow simulators PipeSim & OLGA were used to find the worst case discharge rate under different conditions. A linear geothermal gradient was assumed with well's surrounding temperature at mud line of $40F^o$ and reaching to $210F^o$ at the reservoir depth. The specific gravities of oil, gas and water were taken to be 0.86, 0.67 and 1 respectively. The viscosity was modeled using Vasquez & Beggs (1980) correlation. The roughness of wellbore and casing and drill pipe was assumed to be 0.001 inches. The overall heat transfer coefficient was taken as 2 Btu/hr/ft^2 of a steel pipe. The back pressure at the fluid outlet at seabed is fixed to be 1395 psi based on the average sea water gradient of 0.465 psi/ft for the Gulf of Mexico with a water depth of 3000 ft.

The kick and the BOP equipment reliability data for Fault Tree Analysis are extracted from (MIDE, 2010), which is based on SINTEF Offshore Blowout Database (SINTEF, 2001). The failure rate of each of secondary barrier is assumed to be a uniform average rate with $\pm$ 10% spread in value and is expressed as failures per drilled well. In contrary to normal fault tree analysis where top event's frequency (blowout in this case) is to be found, based on the failure rates of basic events, in this case the top event probability is also known. The tree is calibrated in such a way that to obtain the same blowout frequency, the frequency of only well control procedures is adjusted while all other basic event frequencies are not disturbed and they represent the failure rates of those components, mentioned in the literature. Although a crude assumptions, all the basic events are treated as independent events, so that one's failure will not trigger the failure of others. LOGAN Fault & Event Tree (LOGAN) software is used to conduct Fault Tree and sensitivity analysis.

3.3 Results

3.3.1 Blowout Frequency/Probability Calculation

The results of the Fault Tree Analysis are shown in Figure 16. The high failure rate of secondary barrier is mainly due to BOP's control system's failure, but due to redundancy in control modules, the situation does not result in complete BOP failure. Another main contributor to the blowout are the well control procedures that are adopted after a well is kicked-in to stop the formation fluid from entering into wellbore and remove the kick to regain hydrostatic pressure necessary to keep formation fluids from entering into wellbore. The sub categories of well control procedures failures are adopted from (Anderson et al., 2012).

Monte Carlo Simulations were performed to measure the uncertainty associated with the blowout frequency. One hundred thousand trials were performed and results are shown in Figure 15. The 99, 95 and 90 percentile values are found to be 1.03×10^{-2}, 6.94×10^{-3} and 5.54×10^{-3} respectively.

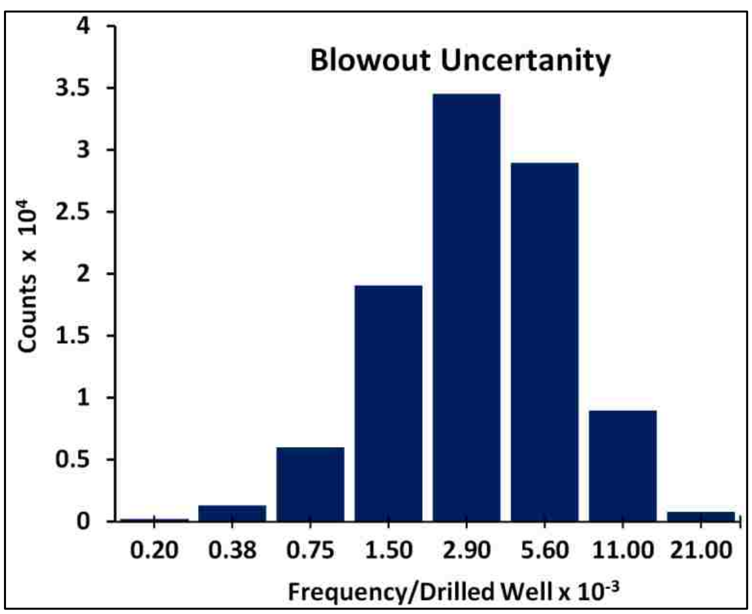


Figure 15: Blowout uncertainty analysis for 100,000 trials of Monte Carlo simulations with a slightly skewed normal distribution having a peak frequency of 2.9×10^{-3}

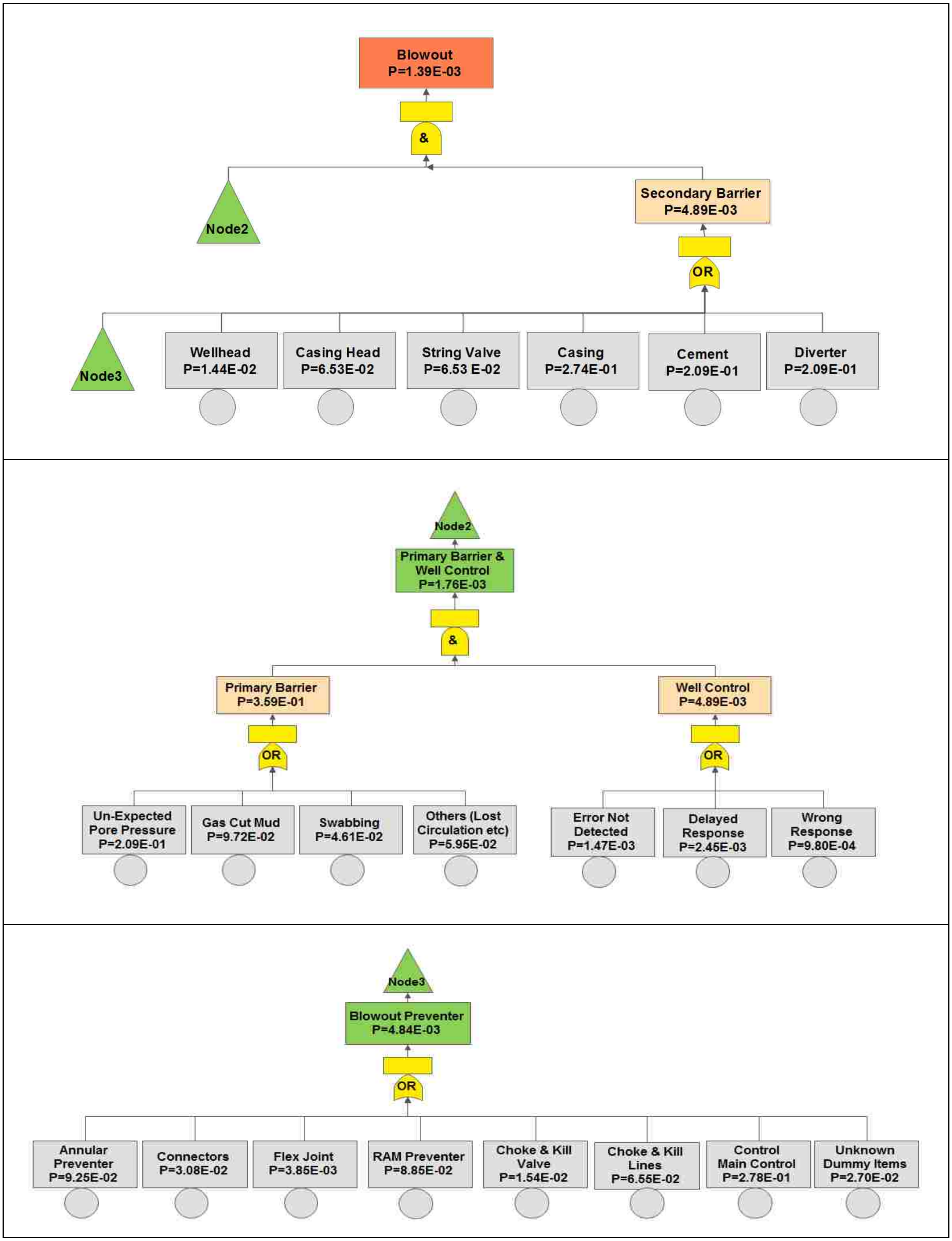


Figure 16: Fault tree analysis of a deepwater exploratory drilling well

3.3.2 Fussell Vesely Importance Measure

Fussell Vesely importance measure in Table 15, show that the blowout probability is mostly influenced by unexpected pore pressure with an importance value of 0.508. It implies that even a minor improvement in decreasing the frequency of occurrence unexpected pore pressure will greatly influence the blowout frequency. The next main important basic event to focus in is the delayed response of personnel supposed to decide quickly and take an action in the emergency situation. Error not detected is the next important basic even.

Table 15: Importance analysis showing the contribution of some of the most influencing basic events with the unexpected pore pressure is the main contributor

Name	Description	Sensitivity
UNEXPPP	Unexpected Pore Pressure	0.508
DELAYEDR	Delayed Response	0.500
ERRORND	Error not Detected	0.300
GASCUTMU	Low Mud Weight Due to Gas Cut	0.236
WRONRES	Wrong Response	0.200
CONTROL	Main Control System	0.195
CASING	Casing Failure	0.192
CEMENT	Cement Failure	0.147
OTHERS	Lost Circulation and Others	0.144
SWABBING	Swabbing Effect Caused Kick	0.112
WELLHED	Wellhead Seals etc	0.101
ANNULAR	Annular Preventer	0.065
RAM	RAM Preventer	0.062
CHKKILLL	Choke & Kill Lines	0.046
CASHEAD	Casing Head Failure	0.046
DIVERTER	Diverter Failure	0.046
STRINGVA	Drill String Valve	0.046
CONNECTR	Connectors All	0.022
UNKNOWN	DUMMY ITEMS	0.019
CHKKILLV	Choke & Kill Valve	0.011
FLEXJOIN	FLEXIBLE JOINT	0.003

This may include the absence/failure of sensors or overlooking some of the potential early indication of a problem. There is a room to improvement in these areas. Unexpected pore pressure can be dealt with better seismic profiling and implementing one of the latest drilling technologies of either wellbore strengthening or drilling with managed pressure. These techniques will allow better control of bottom hole pressure and allow to drill in well sections where drilling window is very small. Delay in the response to an event of immediate concern can be managed with automating some of the initial response decisions and by overseeing the operations by remotely monitoring the rig activities and take quick decisions and guide the personnel on the rig floor.

3.3.3 WCD Subsea Release Calculations for P50 Values

A description of the cases modeled in this study is as following. Case numbers are assigned on the basis of flow path, reservoir penetration and restrictions offered in the flow paths. While case names are assigned, based on the spill response systems and the time they take to cap or contain a well and are shown below

RF: Relief Well with duration of 90 days, **CS**: Capping & Containment System with effective deployment time of 27 days, **CSI**: Capping & Containment System with ideal deployment time of 15 days.

Case ID is the combination of case name and its number. For example for case ID RF1, RF stands for relief well option for duration calculation and 1 denotes that the fluid is coming through drill pipe when the reservoir penetration is 5% and BOP is 100% open to flow. The WCD rates computed, based on the estimated P50 values of reservoir are shown in

Table 16. The maximum oil flow rate of 103,290 bbl/day was computed for RF13 case in which drill pipe is out of the well and no restriction to flow are offered by BOP i.e. BOP is 100% open.

Table 16: Subsea release flow path probability and rates corresponding to P50 value (RPP:Release Point Probability,FPP:Flow Path Probability, PD:Penetration Depth, PDP:Penetration Depth Probability, FSP:Functional State Probability, PPB:Probability Per Blowout)

Release Point	RPP	Flow path	FPP	PD %	PDP	Case ID	BOP Status	BOP FSP	Oil Flow rate (bbl/day)	PPB
Subsea	0.8	Drill String	0.11	5	0.6	RF1	Open	0.1	5942	0.0066
						RF2	Restricted	0.9	5536	0.0594
				50	0.2	RF3	Open	0.1	28928	0.0022
						RF4	Restricted	0.9	18631	0.0198
				100	0.2	RF5	Open	0.1	34546	0.0022
						RF6	Restricted	0.9	21121	0.0198
		Annulus	0.78	5	0.6	RF7	Open	0.1	5796	0.0468
						RF8	Restricted	0.9	5411	0.4212
				50	0.2	RF9	Open	0.1	27945	0.0156
						RF10	Restricted	0.9	17859	0.1404
				100	0.2	RF11	Open	0.1	32644	0.0156
						RF12	Restricted	0.9	20056	0.1404
		Open Hole	0.11	100	1	RF13	Open	0.1	103290	0.0110
						RF14	Restricted	0.9	26434	0.0990

This situation occurs when the well have been drilled to the total depth and preparations are going on for well cementing and due to swabbing effect some influx occurs and situation could not be controlled by using well control procedures. Even though the oil flow rate is highest in this case but fortunately the associated probability per blowout of 0.01 is very low. Therefore risk calculated from the combination volume of spilled oil and associated probability will not fall in high attention yellow zone on risk matrix.

The case of fluid flowing through the annulus when the reservoir is partially penetrated and with restricted flow path has oil flow rate of 5411 BOPD only, but it has the highest probability of 0.4212 per blowout. Therefore the combination of lower oil volume and higher probability will not result in a very high risk, as risk is computed from the product of probability and oil volume. In general the oil flow rates are substantially low when drill pipe was inside the well, due to the resistance it provides to flowing fluids.

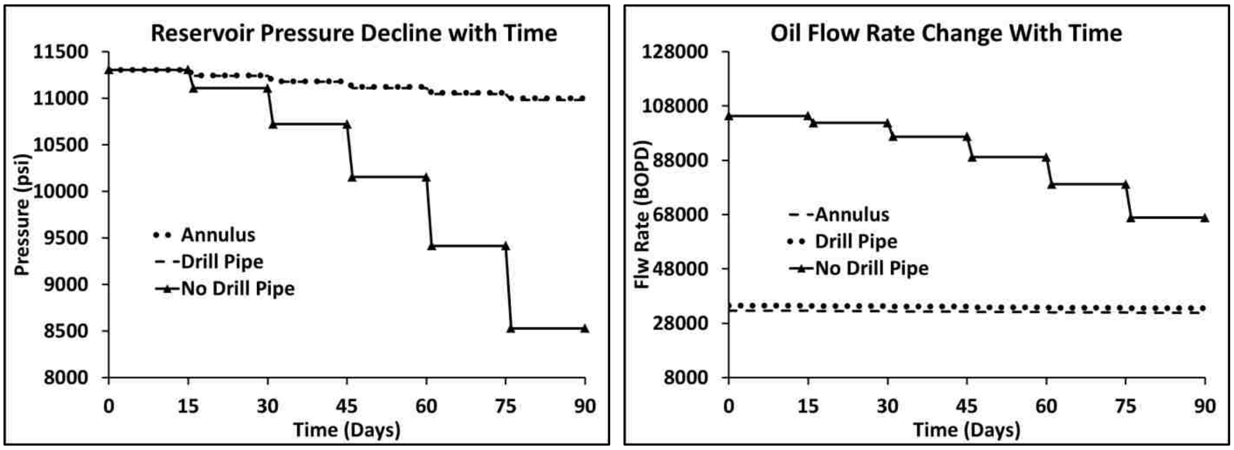


Figure 17: Pressure decline and flow rate variations with time

Among all of the cases studied the following three cases of RF5, RF11 and RF13 have the highest flow rates, because they are for full reservoir penetration and with no flow restriction in the BOP. Full reservoir penetration results in less resistance to flow due to disappearance of partial penetration skin, and therefore for the same pressure drop a higher flow rate occurs if all other parameters remain same. Similar arguments can be made about the case in which BOP offers no restriction to flow. These three cases based on their high oil flow rates were selected for further risk analysis by using the risk matrix. The fluid flow rates for these cases given in Table 16 are initial flow rates when the reservoir has the full potential to flow. As the time progresses in most of the cases reservoir pressure decrease and corresponding flow rate as well, unless the reservoir is connected to an infinite reservoir that can help in maintaining its pressure. The reservoir pressure decline and corresponding flow rates are shown in Figure 17. A pseudo steady state assumption about the reservoir pressure decline is considered with time intervals of 15 days each. The pressure exiting at the start of the interval is taken constant throughout the 15 days period, which is the most conservative approach. No aquifer drive support was considered and the production was assumed to be due to expansion of pore fluids only. For the highest flow rate case of RF13, the reservoir pressure decreases from initial value of 11305 psi to around 8530 psi and flow rate from 104K BOPD to nearly 66K BOPD at the end of 90 days. While for the other two cases the reservoir pressure decline and reduction in flow rate are not substantial.

3.3.4 Implications for Environmental Damage Assessment

Environmental damage is computed from the product of blowout probability and resultant spilled oil volume. It is important to note that not every blowout will result in a large oil spill. Majority of the blowouts are of very short duration i.e., less than 2 days and result in small damage to environment.

Table 17: Risk table categorized for functional BOP state during blowout with only relief well option (PPB:Probability Per Blowout, PPDW: Probability Per Drilled Well)

Scenario	Case ID	PPB	PPDW	Cumulative Oil Volume (bbls)	Impact Factor	Calculated Risk
Relief Well 90 days	RF5	0.0022	3.06E-06	3.06E+06	3	9.17E-06
	RF11	0.0156	2.17E-05	2.90E+06	3	8.67E-05
	RF13	0.0110	1.53E-05	8.07E+06	4	6.12E-05
Capping Stack 27 days	CS5	0.0022	3.06E-06	9.30E+05	2	6.12E-06
	CS11	0.0156	2.17E-05	8.79E+05	2	4.34E-05
	CS13	0.0110	1.53E-05	2.79E+06	3	4.59E-05
Capping Stack 15 days	CSI5	0.0022	3.06E-06	5.18E+05	2	6.12E-06
	CSI11	0.0156	2.17E-05	4.90E+05	1	2.17E-05
	CSI13	0.0110	1.53E-05	1.57E+06	3	4.59E-05

In terms of released oil volume in the past 50 years only 19 spills are reported in the GoM for all of drilling and production activities that are equal to or greater than 1000 bbl of oil. Macondo blowout is the biggest outlier with estimated 4.9 million bbl (Anderson et al., 2012) of oil spilled to environment. The maximum environmental damage is caused when all other efforts to stop the blowing well are failed and relief well is the only response option left. A time frame of 90 days duration is considered to drill a relief well for the water and well depths considered in this scenario.

Please note that duration of relief well drilling may vary depending on the location of the well, water depth and target zone depth below mud line. In majority of the cases the blowout may be put under control in a few days' time frame, either through crew intervention or by the deployment of spill response systems. The probability of spill having 90 days duration is 0.03 only. The conservative approximate duration estimate for the successful deployment of capping and containment system is calculated to be 27 days. Ideally these response systems are designed to cap or contain the blowing well within 15 days' time frame.

The risk calculations for the base and modified cases are shown in Table 17. The cumulative volume of oil discharged to the environment is calculated by using the durations for base and modified cases of 90 and 27 days respectively. The spilled amount estimate is for RF13, i.e., absolute open flow is around 8.07 million barrels of oil, resulting in impact factor of 4. Due to their low flow rates, the cases RF5 and RF11 result in impact of 3. With the application of capping and containment systems the impact factors are substantially reduced.

In the event that the well integrity concerns prohibit the shut in by using capping and containment systems, these systems have the designed capabilities to collect the hydrocarbons up to 100,000 BOPD, which is nearly equal to the maximum oil rate calculated. So most probable scenario is that a large quantity of blowing hydrocarbons will be collected and not released to the environment, even when the well cannot be shut in completely. So in this situation even if we have to drill a relief well, most of the fluids comings out of the well are collected. Capping and Containment systems due to their large fluid handling capacity will substantially decrease the overall amount of oil spilled to the environment.

3.3.5 Construction of Risk Matrix

The risk matrix for the deepwater selected GoM exploratory drilling well is shown in Figure 18. The case RF13 due to its highest oil rate creates falls in the serious impact category, but due to its very low probability of occurrence this case fall in the yellow region, not in red. The yellow region corresponds to the situation, when operations can be carried out but with great caution and ideally green region is the desired operational window. In the red region, no activity is supposed to be carried out.

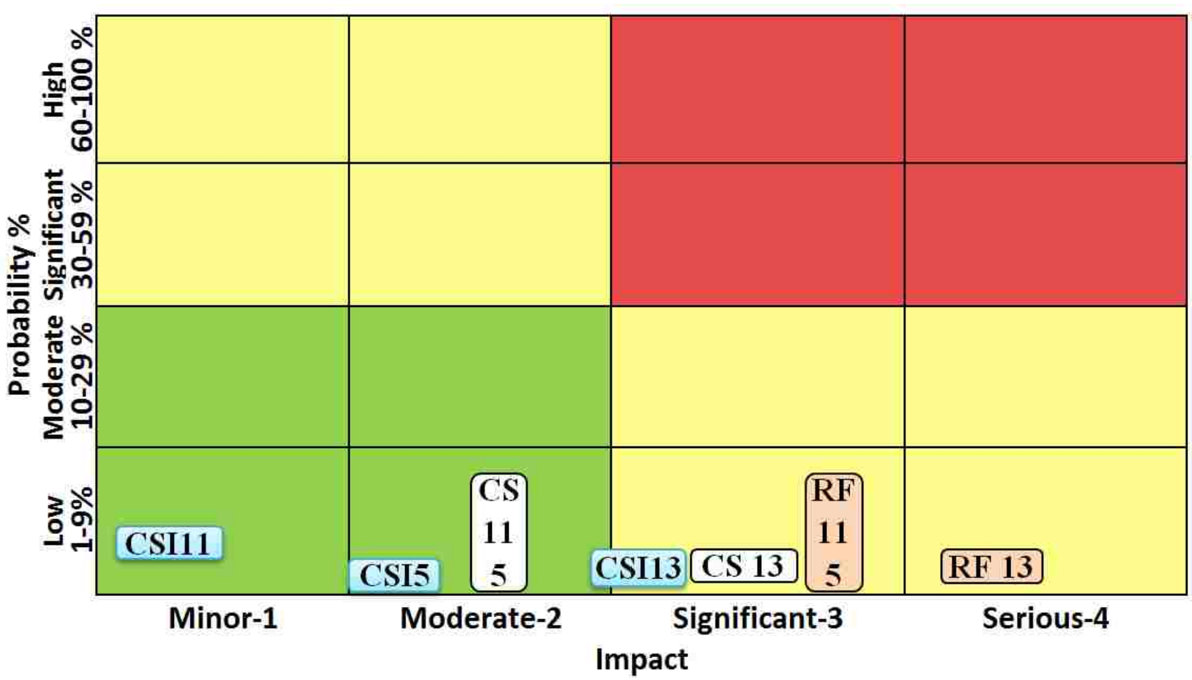


Figure 18: Risk matrix for the deepwater GoM exploratory drilling well

With the deployment of capping and containment response system, the impact category of this case is reduced from serious-4 to significant-3 and that is a substantial impact reduction. But still it is in the cautionary yellow zone. If the capping and containment system is successfully deployed during their designed deployment time frame of 15 days, then the impact category is further reduced and it moves towards the green region.

The impact factor for other cases of flow through annulus RF11 and through drill pipe RF5 are also reduced from significant to moderate level when capping and containment system is available. These results signify the importance of newly built response systems in reducing the risk of large oil spills.

3.4 Concluding Remarks on Risk Associated With Deepwater Exploratory Well

- An example of quantitative risk assessment (QRA) for deepwater exploratory drilling well blowout is presented, QRA facilitated in better understanding of blowout risks.
- The selection of a specific well and corresponding reservoir properties and taking into account the regional variation in reservoir properties by fitting lognormal/triangular distributions and conducting Monte Carlo simulations, provided a realistic representation of the reservoir properties to calculate the worst case discharge rates.
- Unexpected pore pressure, delayed response to an incident and failure to detect the error were found to be three most important basic events contributing to the overall risk of the system. These were identified by conducting Fussell Vesely (FV) importance analysis.
- The FV importance analysis emphasize the need to focus on the technologies to provide early warnings for unexpected pore pressure during drilling phase, eliminating the delays

that can occur when responding to an emergency situation by automation of some of the decision processes and technologically improve the reliability of sensors that detect an error. Crew training and management is also an important element in responding to situations that needs immediate attention.

- The worst case discharge rate of nearly 104,000 BOPD was estimated for the case when drill pipe is out of the hole and BOP offers no restriction to blowing hydrocarbons (conditions specified by BSEE to estimate WCD). The occurrence of this combination of events is amongst the least probable situations. Therefore risk which is a product of probability and spilled oil volume is not very high in this case.
- The 100,000 BOPD oil handling capacity of newly built capping and containment systems is nearly sufficient to either capture or contain the computed worst case discharge oil rate of 104,000 BPD.
- The reservoir pressure drop and resultant reduction in flow rate are not significant in the cases when the fluids are flowing either through drillpipe-casing annulus or through drill pipe.
- The selection of the multiphase correlation also affects the worst case discharge rate estimates and computed values with some other correlation may differ from the values computed in this study, therefore this variation in values must be considered when making decision based on the WCD rates.
- Restrictions in the flow path substantially decrease the fluid flow rate and in some of the circumstances may even choke the flow.
- Newly built response systems are effective in reducing the risk of large oil spill in deepwaters environments, provided that they function properly when they are deployed.

Capping and containment systems are effectives for only one type of failure mode i.e., when the flow is coming through the well, which is the most probable scenario based on the historical blowout data.

- Addition of intervention module in capping and containment systems will enhance their capabilities to deal with other failure modes as well. For example dynamic kill may be used in the case of an underground blowout.
- In the case of a blowing well affecting nearby wells, the situation may become complex and would require additional modules to be added with capping and containment systems or invoke other response systems.

CHAPTER 4: RISK ASSESSMENT OF A DEEPWATER GULF OF MEXICO UNDERGROUND BLOWOUT (SCENARIO-2)

In an underground blowout, the uncontrolled formation fluids from higher pressure formation may charge up shallower overlying low pressure formations or may migrate to sea floor, following the path of least resistance. The consequences of these blowouts range from no visible damage at the surface to the loss of well, loss of drilling rig, seafloor subsidence or hydrocarbons discharged to the environment, a schematic of consequences is shown in Figure 19. When detected, the main difficulty in responding to these events is the uncertainty associated with diagnosing and understanding what is actually happening at the subsurface [Smith et al., 1999]. These blowouts might get unnoticed until the over pressured sands, due to underground blowout are explored.   In this scenario the potential of a deepwater underground blowout are accessed during drilling life phase of a deepwater well in the Gulf of Mexico. A representative well and sand properties located in GoM in Popeye-Basin are selected to address the risk associated with underground blowouts.

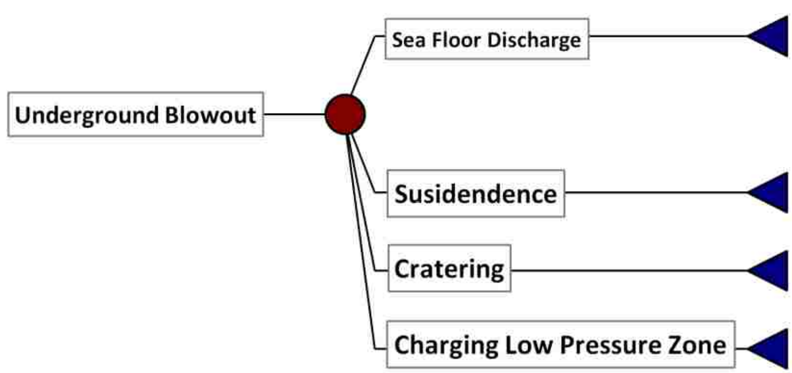


Figure 19: Underground blowout and its consequences

For the underground blowout which results in recharging a low pressure zone, it is assumed that during drilling activity a depleted shallower zone connected to surface with a system of faults and fractures is accidently exposed to a high pressure deeper hydrocarbon zone.

These zones are connected through a conductive fault. The pressure of the deeper zone is high enough to activate the communicating fault and hydrocarbons migrate to depleted shallower zone. It is assumed that a system of exiting fractures in the upper zone is activated when its pressure reaches to the leak of test pressure value. The potential consequences in terms of fluid discharging to sea floor, subsidence occurrence and the probability of cratering are addressed in this study. Inside the wellbore, most sensitive point for formation breakdown is the casing shoe, but it can happen anywhere in the wellbore where formation is the weakest for that particular wellbore pressure. Due to only partial loss of pressure at the surface; it is difficult to determine if the underground blowout has occurred.

4.1 Natural Hydrocarbon Seeps in GoM

4.1.1 Geological Features

Complexity of the northern GOM slope geology is a result of interplay of the sediments (Roberts H. Harry & Carney S. Robert, 1997). Acoustic wipe out zones have been identified, that are extending from subsurface to seafloor, confirming the evidence that the gas and oil migrated to the seafloor through these zones. The faults associated with deep salt bodies have greater potential to act as carrier of hydrocarbons to the sea floor than the faults at the lower depths above salt domes. It has been reported in the literature that some of the plays in the GoM, have sands that have pore pressures exceeding the least principle stress of overlying shale seals and creating new fractures or causing the old one to dilate and allowing fluid migration to upper layers, that sometimes leads to sea floor venting as well (Seldon, 2005).

4.1.2 Popeye-Genesis Minibasin

It has been reported in the literature that in Popeye-Genesis minibasin in the GoM, fluids from the reservoirs are venting to sea floor (Seldon, 2005). Due to rapid depositional rate, the fluids are trapped and they contribute in supporting some of the overburden pressure. When the dipping over pressured permeable sands are contained by the low permeability shale, the pressure in sand has hydrostatic gradient whereas in the cap rock it commonly follows lithospheric gradient. Therefore at the crustal points, the sand pore pressure may become equal to or greater than the least principal stress. The excessive pressure may be responsible to open up the exiting cracks in the rock and allowing the reservoir fluids to escape.

4.1.3 Auger Basin

The Auger Basin lies 215 miles southwest of New Orleans in 3280 ft water depth. It has been reported that some of the reservoirs in the Auger basin are hydraulically connected over a distance of more than 12 miles (Reilly, 2010). Due to small overpressure gradients fluids in these reservoirs move upwards 1-20 mm/year.

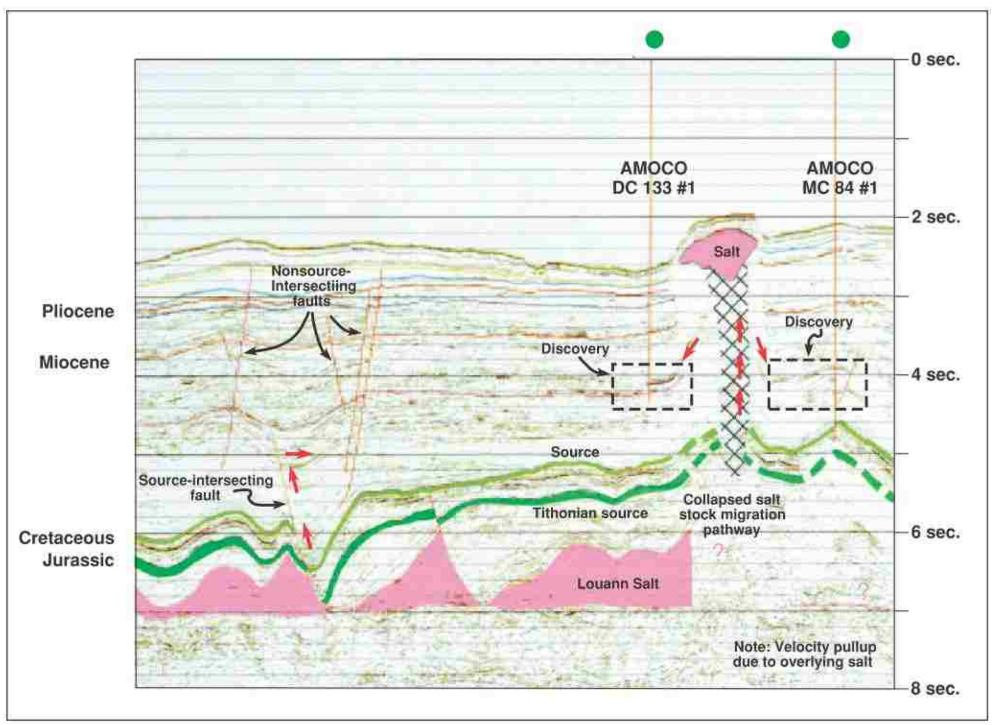


Figure 20: An example seismic map in northern GoM slope with source and migration pathways (From Hood et al., 2002)

Similar to the Popeye minibasin, the pore pressures at the crest of these reservoirs equal or exceed the minimum horizontal stress, and therefore fracturing the cap rock. This was confirmed with drilling a well in the crest of the reservoir, where they found that the pore pressure was equal to minimum horizontal stress as well as overburden stress (Reilly, 2010). On the seafloor above these reservoirs mud volcanic activity has been reported as well. There are other studies (Roger et al., 2003) that confirm that the hydrocarbons venting to sea floor in GoM are coming from deep hydrocarbons sources connected by a system of faults and fractures. It has been reported that alongside faults, the collapsed salt stocks may provide more effective migration pathways than faults when both of them are present (Hood et al., 2002). Source rock and several potential pathways are shown in Figure 20.

4.1.4 Well stability concerns before Macondo shut in during blowout

During the planning phase of Macondo shut in operations, one major concern was the potential leakage of the hydrocarbons at shallower depth due to burst of rupture disks, installed in 16” liner about 4493 ft below mud line, and new pathways that might be triggered as a result, Hickman et al. (2011). The Macondo well penetrated through poorly consolidated interbedded shale, silt and sandstone layers. In most of the GoM deepwater reservoirs, usually the pore pressure are very high, due to rapid deposition of very fine particles and this was the case with Macondo as well. The Macondo well was also geo pressured and the formation pressure in the Macondo well was only 600 psi less than the fracture pressure Hickman et al. (2011), therefore during drilling operation they had to deal with narrow drilling window.

After the blowout BP’s Well Integrity Team (WIT) analyzed the worst possible scenarios after shut in. Then based on the regional geological features, BP’s team suggested that one of the worst case scenario would result if burst disk located at 4493 ft below mudline, shown in Figure

21, are ruptured, than there is no physical barrier behind the liner to stop the escaping hydrocarbons. They also studied the possibility of creation of hydraulic fractures and found that, once the disks are ruptured, the geological settings in the vicinity of the well will allow the creation of hydraulic fractures and the hydrocarbons will migrate to the seafloor.

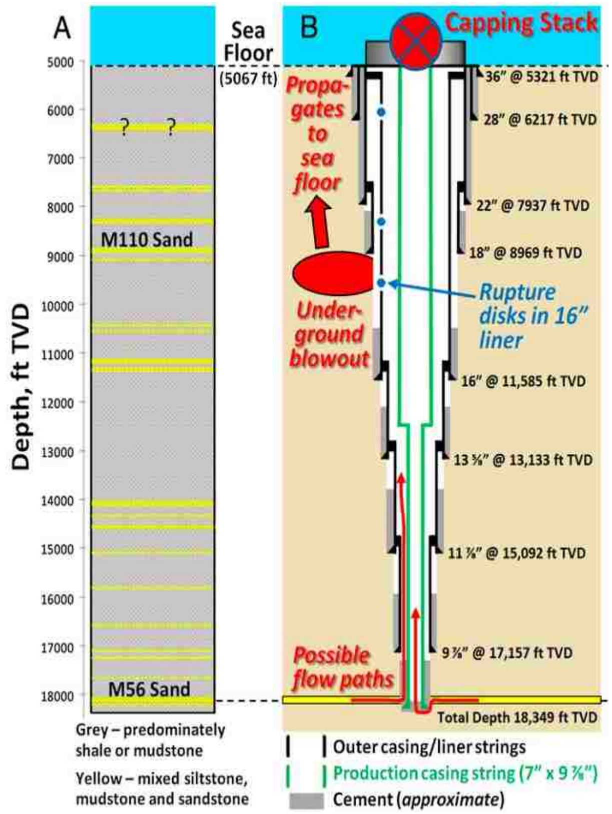


Figure 21: Rupture disk location in Macondo well (From Hickman et al. (2011)

4.2 Crater/Subsidence Hazard

The probability of cratering as a result of underground blowout is greater provided that the blowout is shallower. It has been reported in literature that the possibility of flow coming to the surface outside of the casing is larger, if the blowout is within 3000-4000 ft depth (Grace, 1994). The craters are more destructive when they occur in the vicinity of rigs. The primary mechanism working behind the crater creation is the subsidence of the formation. The reservoir fluid pressure and the rock matrix support the weight of the overlying sediments. In the event of a shallow underground blowout, the fluid pressure in the producing formation may be reduced substantially and overburden is now mostly supported by the rock only, and the formation is compacted. The subsurface compaction may result in the subsidence, depending on the depth and extent of the reservoir. This type of phenomenon may cause large damage to the surface and subsurface facilities (Bruno, 1992). The subsidence has been observed during normal production operations as well.

Case Histories for Crater/Subsidence: Few Examples are presented here to highlight the potential of crater formation of subsidence.

Drilling Crater Case 1: During drilling a gas well, a large crater thought to be 600 ft deep, was created in Conroe Oil Field Texas, in 1933 when a gas well blow out caught fire and it destroyed the rig as well.

Drilling Crater Case 2: A large crater was created in Lake Peigneur in Louisiana that was nearly 1300 ft deep, the rig was destroyed. It was found later on that the drilling crew miscalculated their drilling position and drilled through salt dome and into a salt mine deep under the lake. The impact of the crater was such on a scale that another installation in the lake docks, another drilling platform, a 70 acre island in the middle of the lake, eleven barges, vehicles, trees and a parking lot near the lake were all sucked into the mine below. The pull of the whirlpool was so strong that it reversed the flow of the 12-mile-long Delcambre Canal that drained the lake into the Gulf of Mexico (Staci Lehman, 2014).

Producing Field Case 1: Wilmington oil filed in California subsided nearly 33 ft during 1935-65 period. This caused casing failures in hundreds of well and raising and repairing the facilities resulted in cost exceeding more $100 million, till 1962 (Bruno, 1992).

Producing Field Case 2: In Vahal field which is located in the Norwegian sector of North Sea, at the time of discovery the reservoir pressure was only 494 psi less than the overburden stress of 7005 psi (Pattillo, 1998). During production a substantial subsidence occurred resulting in the failures of tubular in the reservoir and subsidence at the mudline.

4.2.1 Conditions for Vertical Subsidence

If the reservoir is approximated to be disk shaped, with thickness h, radius r and depth to the top of the reservoir as D. Then the simplified expression for the vertical subsidence reduces to (Bruno, 1992).

$$\max s_z = 2C_m(1-\nu)\Delta p\left[h - \sqrt{r^2 + (D+h)^2} + \sqrt{r^2 + D^2}\right]$$

Where ν = Poisson's ratio, Cm = uniaxial compaction coefficient and Δp is uniform pressure drawdown. The uniaxial compaction coefficient is the ratio of change in strain to change in stress. For elastic and isotropic materials, and assuming grain compressibility is small relative to bulk compressibility, the uniaxial compaction coefficient is related to the bulk compressibility through the expression,

$$C_m = \frac{1}{\rho V_c^2}$$

Where ρ is the bulk density and V_c is the compressional wave velocity for the rock. So it can be obtained from the well log analysis.

4.3 Faults Barriers or Migratory Paths

The sealing potential of a fault is attributed to the juxtaposed lithologies across fault and the presence or absence of seals resulting from the fault zone content and structure (Wiprut, 2002). It has been reported in literature that faults capable of slipping are permeable. These faults are critically stressed in the current stress field (Wiprut, 2002). Some of these faults were activated by massive sedimentation during periods of Plio-Pleistocene and salt movement also happened, resulting in providing avenues of vertical transport to the continental slope surface (Roberts, 1998).

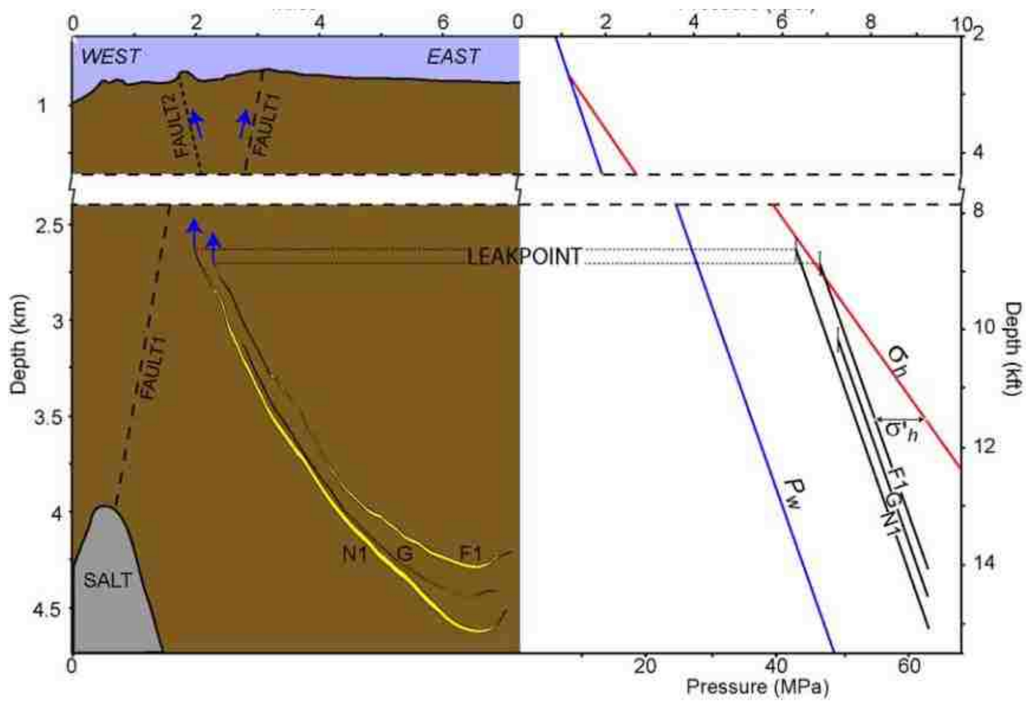


Figure 22: Pressure and Stresses in the Popeye-Genesis minibasin based on leak off test data [From Seldon, (2005)]

Many of these faults cut thick sedimentary sequences that frequently contain geo pressured zones, so this combination of high potential drive and a fault serving as a pathway results in transport of hydrocarbons to sea floor.

4.3.1 Cap Rock Failure

It has been reported in literature that once the cap rock fails, its seal capacity may be reduced substantially sometimes up to 90 %, due to the development of highly connected fracture network (Dewhurst et al., 2002). The scale of the reduction in differential stresses due to re-shearing is shown in Figure 23. It shows that the differential stress needed to deform the rock is greatly reduced once the cap rock seal is broken and re-shearing requires less pressure differential.

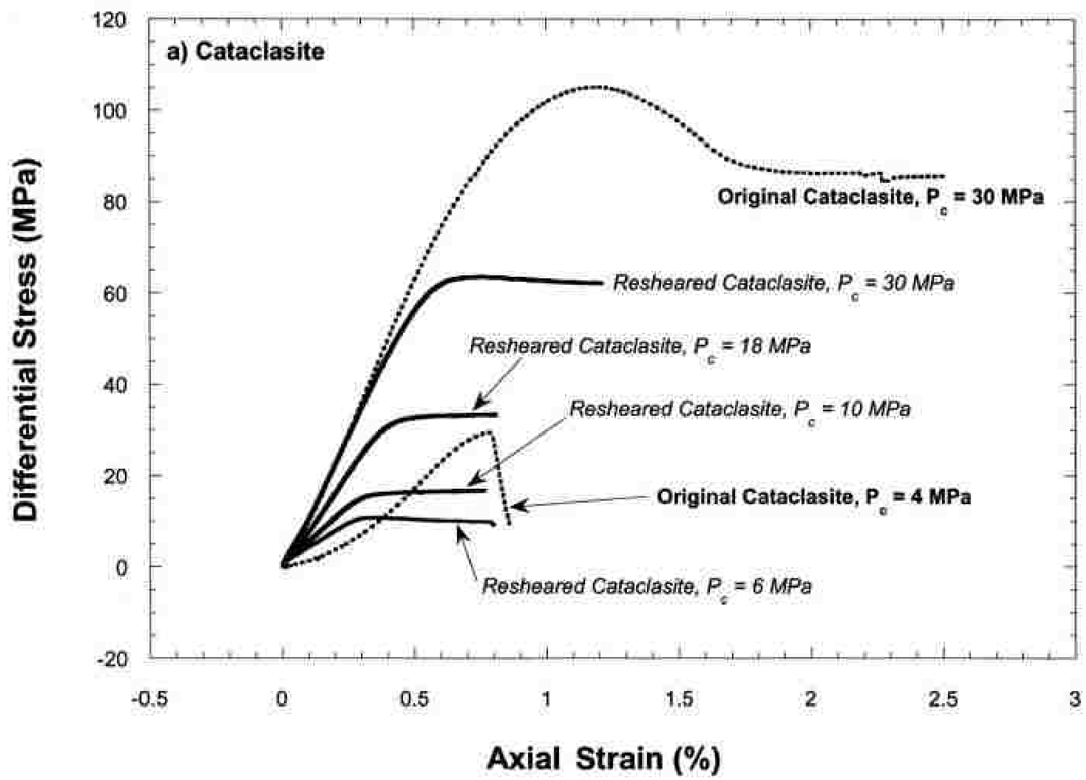


Figure 23: Stress and strain curves for original and re-sheared sandstones [From Dewhurst, 2002]

Once the cap rock seal is broken, the rock failure now can occur due to tensile, shear and mixed mode fracturing. So the geomechanical tools used to predict the trap integrity under reactivation may under predict the seal risk due to the underlying assumption of cohesionless frictional failure (Dewhurst, 2002), as now rock can fail in other modes as well. The mechanics of fracturing process are influenced by grain strength and cataclasite morphology. Pore fluid overpressure in some these sands equals or exceeds the least principal stress, and the fluid pressure is high enough to fracture the cap rock and drive the fluids vertically.

4.3.2 Fault Permeability and Thickness

The fault zone permeability can be empirically represented as a function of fault displacement and shale content (Manzocchi, 1999), by the flowing simplified expression

$$\log k_f = -4SGR - \frac{1}{4} log(D)(1 - SGR)^5 \qquad (1)$$

Where k is the fault permeability in mD, D = fault displacement in meters and SGR = Shale Gouge Ratio. The shale gouge ratio may vary from 1 to 0. This relationship does not provide a reliable estimate when SGR tends to zero.

The fault zone thickness in sand/shale sequences can also be found using a linear relationship

$$t_f = \frac{D}{66} \qquad (2)$$

The calculated values of the fault permeability and thickness are shown in Table 18, based on the assumption that fault movement resulted in displacement of 985 ft (300 m).

Table 18: Calculated value of fault permeability and thickness

Displacement (m)	SGR	Kf (mD)	Thickness (ft)
300	0.6	0.004	15

Conditions for Hydraulic Fracture Formation

Fractures exist in the earth crust at various scales and they contribute significantly in hydrology, engineering geology and petroleum engineering as well. When proper inflow conditions exist, these fractures may provide pathways for liquid flow, or may act like a barrier and prevent flow across itself. In a study conducted by Cook et al., in 2008, it was pointed out that natural gas hydrates present in Keathley Canyon in GoM were controlled by presence of natural fractures. Natural oil and gas seeps are present in the Gulf of Mexico and other petroleum prolific regions of the world (Reilly et al., 2010).

Stresses and Fracture opening and propagation

In the porous media, the weight of the overburden is carried by both the grains and the pore fluid. Therefore, an effective stress, σ_v' is defined as

$$\sigma_v' = \sigma_v - \alpha p$$

Where σ_v = overburden stress, p = pore pressure, α = Biot's poroelastic coefficient (ranges from 0 to 1)

Horizontal and vertical stresses are related through Poisson's ratio ν

$$\sigma_H' = \left(\frac{\upsilon}{1-\upsilon}\right)\sigma_v'$$

Due to the presence of tectonic forces, the horizontal stress varies with direction, and horizontal stresses can be related by

$$\sigma_{H,max} = \sigma_{H,min} + \sigma_{tectonic}$$

Usually the overburden stress is the largest amongst the three principal stresses and these can be expressed as

$$\sigma_v \geq \sigma_{H\,max} \geq \sigma_{H\,min}$$

The minimum horizontal stress can be found by the leakoff test, mini frac test and theoretically by using the following poroelasticity equation

Pressure to Fracture a Formation: The breakdown pressure required for a non-penetrating fluid to fracture a formation for a vertical well is taken from work Hamison (1967).

$$p_{bd\,np} = 3\sigma_{H\,min} - \sigma_{H,min} + T_o - p$$

where

$P_{bd,np}$ = breakdown pressure for non-penetrating fluid

T_o = tensile strength of rock

P = reservoir pressure

The breakdown pressure for penetrating fluid is less than the pressure required for non-penetrating fluid and is given by

$$p_{bd\,penetrating} = \frac{3\sigma_{H\,min} - \sigma_{H,min} + T_o - 2\eta p}{2(1-\eta)}$$

where

$$\eta = \frac{\alpha\,(1-2\upsilon)}{2(1-\upsilon)}$$

The pressure required to propagate the fracture is usually less than the breakdown pressure.

Fracture Permeability: Once fractures are created they can conduct at much higher rates than the reservoir sands. The ratio of fracture permeability to matrix permeability is an important parameter to consider when analyzing the fluid conductance through fractures. The fracture permeability contribution and ranges have been categorized by Matthai (2003), as following

1. For ${k_f}/{k_v} = 10^2$ fracture do not contribute significantly to the effective permeability of the reservoir.

2. For ${k_f}/{k_v} = 10^3 - 10^4$ a transition occurs and the fracture start contributing to the effective permeability of the reservoir.

3. For ${}^{k_f}\!/_{k_v} = 10^5 - 10^6$ main flow is carried by the well connected fractures and contribution of fracture permeability to the effective permeability of the reservoir becomes significant.

Similar arguments can be made about the systems of faults connecting a high pressure deeper zone to a lower pressure shallower zone. If the permeability of this conductive zone is above a threshold value, than it can considerably conduct substantial hydrocarbons in short amount of time, otherwise it may take centuries to overcharge the shallower low pressure zone.

Flow through Fracture: Fluid flow through fractures is usually modeled by the using the concept of two parallel plates. With the assumptions of laminar, incompressible fluid and smooth parallel plates, the Navier-Stokes equation reduces to commonly known cubic law for fracture flow. In reality most of the time, the natural fractures have rough walls and with walls coming to contact each other at some discrete points and reducing the amount of fluid moving through them (Klimczak, 2010). Therefore a model incorporating the roughness of walls and the crookedness of fluid path may be more representative of the true fluid flow in fractures.

4.4 Reservoir Simulation Setup Flow through Faulted Zone

The simulation model used for the analysis is shown below in Figure 24. It is a layered reservoir, divided into 15 layers. The bottom layer represents the source reservoir and the top most layer is the shallower low pressure zone. The intermediate layers have a fault that connects these two zones. An assumption is made that for intermediate layers only faulted region is conductive and fluid migrate through it to depleted top zone. The top most layer or low pressure zone has a set of faults and fracture that can transmit the fluids to the sea floor, provided that the necessary conditions of pressure are met to open up the fractures or reactivation of faults. These onset conditions are met when it is recharged to its leak off test value. The simulation time starts on 01-01-2013 and the reservoir properties of the shallower and deep zones are shown in Figure 24. The deeper zone is 10500 ft long, 10015 ft wide and 106 ft thick.

Table 19: Reservoir properties of shallower low pressure and deeper high pressure zone

Reservoir Property	Deeper Zone	Shallower Zone
Depth Below Mudline (ft)	14052	8772
Porosity	0.23	0.23
Permeability (mD)	246	246
Thickness (ft)	106	106
Sw	0.2	0.8
Initial Pressure (psi)	11302	4332

Parametric Study: The parametric variations, for the flow through fault connecting the two zones are shown in Table 20. The faulted zone's conductance and the ratio of volume of the shallower to deeper zones are varied.

Table 20: Underground blowout cases study flow through a fault

Case #	Ratio of Depleted zone volume to reservoir volume	Permeability (mD)
1	1	0.004
2	1	4
3	1	40
4	0.1	40
5	0.01	40

The reservoir model only showing the zones that contribute to flow are shown in Figure 24. The lower zone is at an approximate depth of 14,000 ft, while the shallower zone lies at a depth of 8,700 ft. These depths are extracted from Figure 22, corresponding to the leak off data available and are total vertical depths from Kelly bushing.

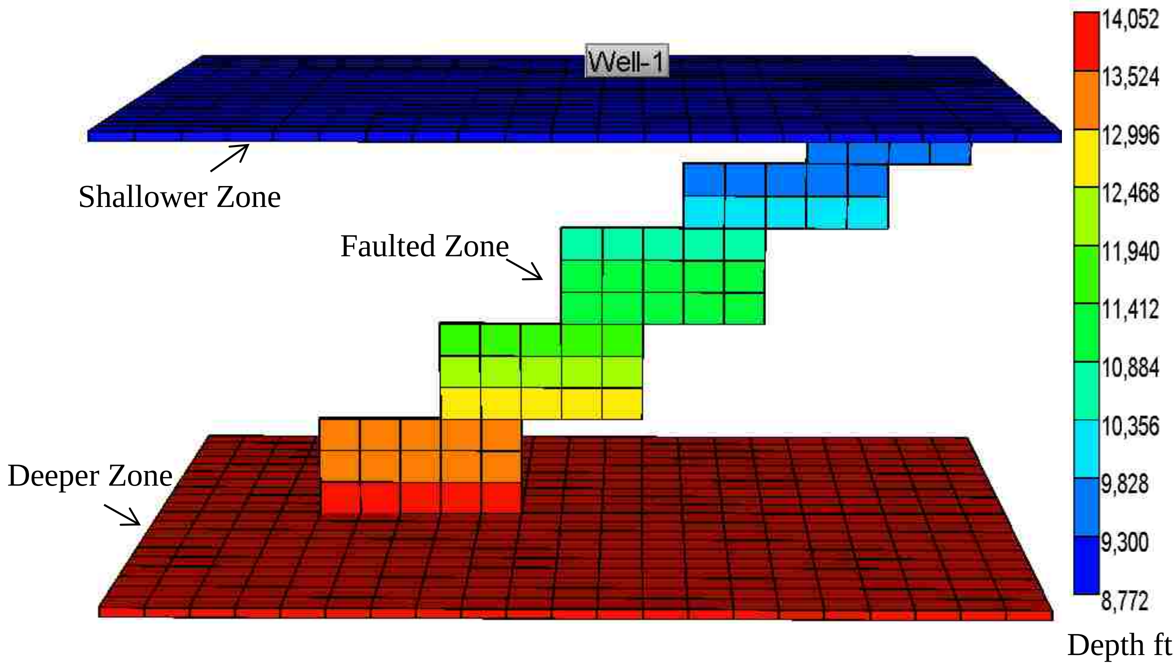


Figure 24: Reservoir simulation model, showing the two interconnecting zones and conductive fault used for studying Underground Blowout

Minimum Horizontal Stress from Leak off Tests

The leakoff data for a well in the Popeye filed is shown in Table 21. This data is used for the example calculation of rock stresses using the reservoir simulation Model.

Table 21: Leak off test data for Popeye Field [From Seldon, 2005]

Well	TVDSS (ft)	LOT (psi)	σ_v (psi)	σ_v -LOT (psi)	Normalized (LOT/ σ_v)
117-A4	4265	2755	2871	116	0.96
117-A4	6331	4466	4742	276	0.94
117-A4	7615	5699	5945	246	0.96
117-A4	9528	7439	7772	333	0.96

It is hypothesized that when the shallower zone is charged to its leak off pressure value, it will transmit the hydrocarbons to the sea floor. As the shallower zone is already fractured, therefore it will now require less pressure differential to initiate or dilate the exiting fractures. In some of the instances the shallower zone's pressure is in equilibrium with the least principal stresses and only a small perturbation will lead to transmit the hydrocarbons to the sea floor.

4.5 Simulation Results flow through Faulted Zone

Case 1: The results for this case are shown in Figure 25. With the use of estimated value of fault zone permeability, hundreds of years are required when the pressure of the higher deeper zone will even be felt by the shallower lower. It may sound shot period of time on the geological scale, but in this study, focus is to highlight the conditions that will result in quick recharging of the shallower zone. So the simulation was terminated after 100 years' time frame.

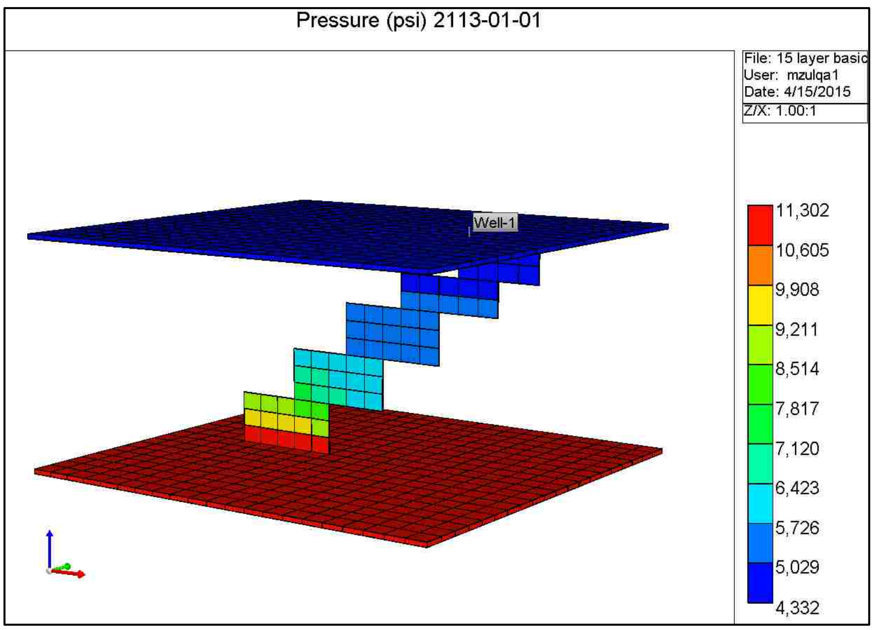


Figure 25: Pressure change propagation after 100 years of flow from high pressure to lower pressure shallower zone

Case 2: In this case the permeability or transmissibility of the fault zone connecting the deeper and shallower zones is increased to one thousand times the estimated value. In this case e both zones have same volume. The pressure in the depleted zones is monitored to see whether it reaches the onset conditions for fracturing or not. During the first 100 years the high pressure of the deeper zone is even not felt by the shallower low pressure zone shown in the Figure 26, so the simulation was terminated after 100 years, in this case as well.

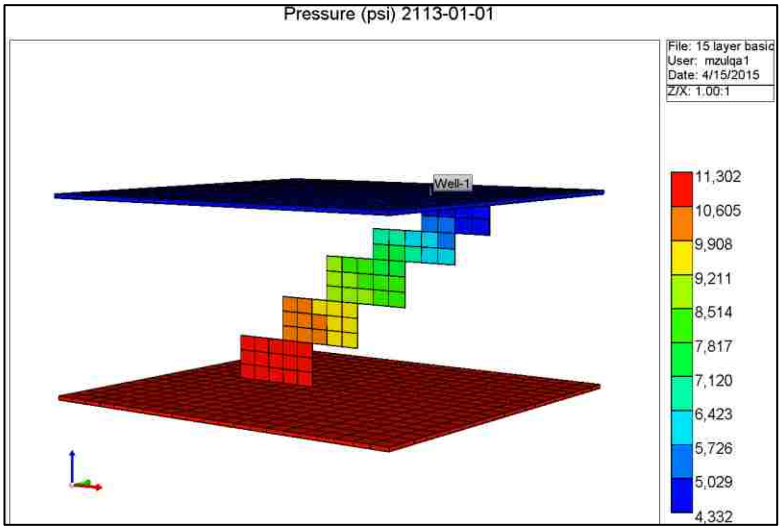


Figure 26: Pressure change propagation after 100 years of flow from high pressure to lower pressure shallower zone

Case 3: In this case the permeability of the connecting zone was increased to 10,000 times the original estimated fault permeability. In this case after 135 years the conditions corresponding to leak off test value of 7439 psi were reached and upper zone will transmit fluid to the sea floor.

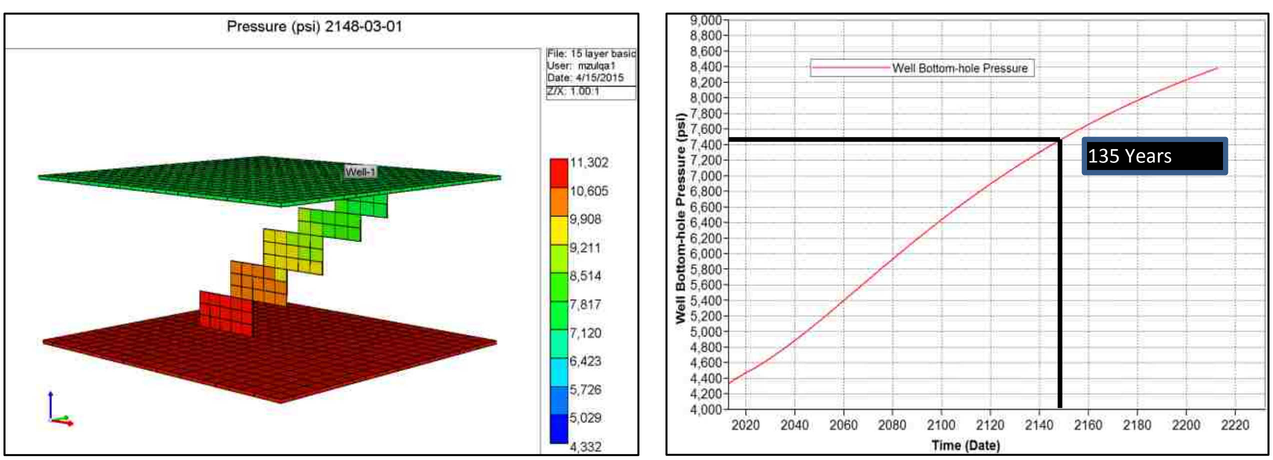


Figure 27: Pressure contour of the deeper and shallower zone and the pressure change with time

Case 4: In this case the upper zone volume is reduced to 1/10 of the original volume; all other parameters remain the same as were in the case 3. In this case 24.5 years are needed to achieve the conditions in the shallower zone to transmit the fluid to the sea floor, under the assumption that once conditions equivalent to leak off test are reached, hydrocarbons can migrate to sea floor.

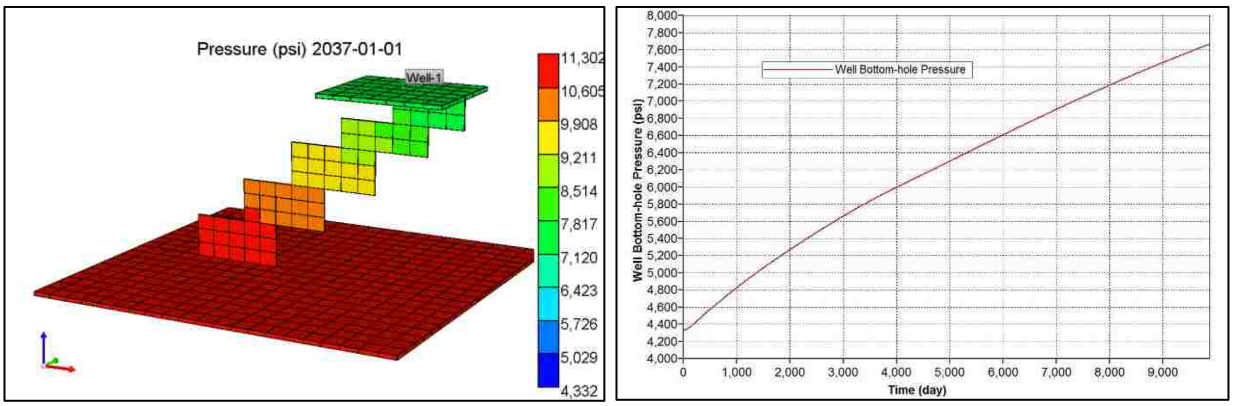


Figure 28: Pressure contour of the deeper and shallower zone and the pressure change with time

Case 5: In this case the shallower zones volume is taken to be one hundredth of the original volume. Due to small volume of the target zone, the conditions for onset of the fracturing are achieved in less than 4 years' time frame only, shown in Figure 29.

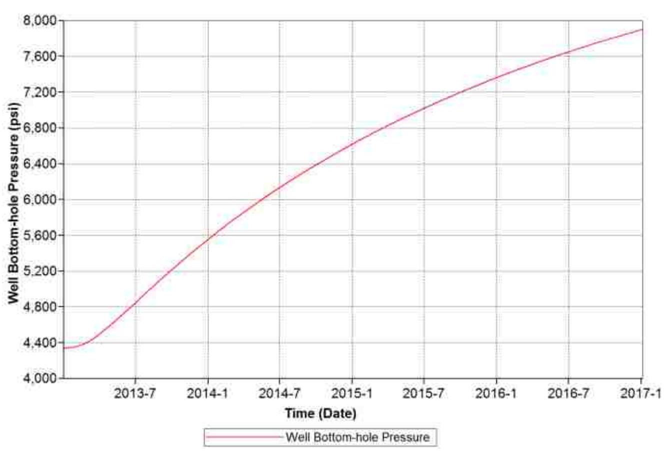


Figure 29: Shallower zones pressure variations with time for Case- 5. Fracture dilation/propagation conditions are met in 3 years' time frame

4.6 Observations & Conclusions

- The consequences of an underground blowout range from no visible damage at the sea surface to the loss of the whole rig. It is difficult to quantitatively estimate the risk due to the involvement of large number of uncertain parameters.
- The potential of hydrocarbons leaking to sea floor is a combination of geological settings, the transmissibility of the paths allowing hydrocarbons to reach sea floor, the pressure of source reservoir and its potential to create fractures in the low lying geological barriers.
- The formulas used to estimate the fault permeability and thickness are very simple and uncertainty exits in the estimated parameters of fault permeability and its thickness.
- The simulation results show that for low permeability k=0.004 mD fault connecting a deep over pressured zone to a shallower low pressure zone, the time taken to recharge the shallower zone to reach its LOT pressure value is more than 100 years.
- A high permeable faulted zone of 40 mD will take 135 years to recharge the low pressure shallower zone to its LOT pressure value.
- In the reservoir model adopted in this scenario, when the ratio of the volume of shallower to deeper zone decrease to 0.1, the recharging time significantly drops to 24 years only. Therefore ratio of the two zones is also an important parameter alongside their pressure differential and the transmissibility of the connecting zone.
- The worst conditions may occur when the hydrocarbons travel through the casing-wellbore annulus and may either reach to shallowest zones lying very close to mud line or leak outside of the well. The casing-wellbore annulus path may have very high permeability due to fractured cement and/or due to micro annulus gaps in this path. In this case the hydrocarbons may appear at the sea floor during the drilling activity.

CHAPTER 5: OIL SPILL RISK ASSESSMENT OF A SAND CONTROL ELEMENT FAILURE LEADING TO BLOWOUT DURING NORMAL PRODUCTION OPERATIONS (SCENARIO-3)

A great effort is under way after Macondo incident to improve the safety of deepwater drilling and production operations and enhance the capabilities of different well barrier to stop the oil spill on its earliest stages. This study is a part of that collective effort to make offshore operations safer and decrease the associated risks. The main objective of modeling this scenario was to investigate the oil spill risk associated with a representative production well in the Gulf of Mexico during its normal production operations. Identification of most critical elements contribution to risk assessment in a subsea production well was also among the objectives. Quantified risk is computed from the product of blowout and volume of oil released to the environment as a result. Blowout frequency is computed from Fault Tree Analysis (FTA) and spilled oil volume is estimated from simulating multiphase fluid flow and heat transfer in wellbores.

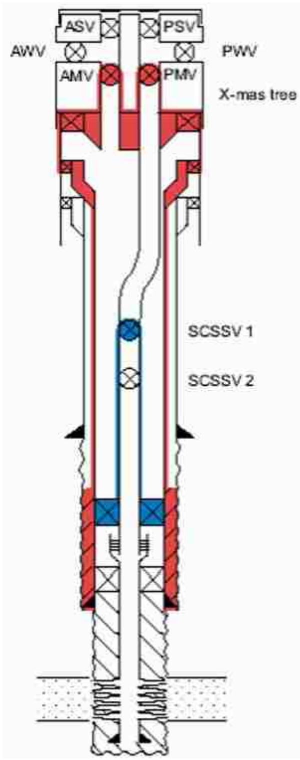
Most of the oil wells are completed with some sort of bottom hole sand control elements to prevent production of sand, when hydrocarbons are produced. The failure of these control elements may have severe consequence and in some cases may result in uncontrolled hydrocarbon flowing to the environment. A representative production well from the Mississippi Canyon in the Gulf of Mexico is selected for the for quantitative risk assessment (QRA) analysis. The well is completed with cased hole gravel pack and with sand control elements in place. The representative reservoir properties for this well are selected from the literature and variations in properties are accounted for by fitting lognormal distribution. Monte Carlo simulations were performed to find distribution of productivity index. P50 value for the reservoir properties distributions and PI from Monte Carlo simulation was used to find worst case discharge rates by using a commercially available multiphase flow simulators OLGA and PIPESIM with black oil fluid model.

A Fault Tree is constructed using LOGAN fault tree analysis software, to find the blowout probability based on the primary and secondary barrier failure data. From the minimal cut set method the importance and sensitivity of different well barrier is analyzed and most critical well barriers are identified.

5.1 Introduction

Quantitative risk assessment provides means to conduct systematic analysis of risk due to hazard activities and evaluation of various risks reducing measure (Spouge, 1999). Risk to an offshore installation may be expressed into the main categories of risks posed to human life, assets, production delay and environment. These are sometimes called “dimensions of risk” (Vinnem, 2007). Environmental risk/damage is analyzed in this study in the form of amount of hydrocarbons released to the environment.

Well Barriers: In order to prevent a blowout, the well must be equipped with pressure control equipment and barriers. As regulatory requirement in all well operations, two tested and independent well barriers should be in place at all times for abnormally pressured formations with flow potential NORSOK Standard (2013). Each barrier in itself is intended to prevent uncontrolled flow of the reservoir fluid to the surroundings. In the production life phase of an offshore well, the primary barriers are production tubing, SCSSV and production packer, while the main secondary barriers are Subsea production Tree, wellhead, tubing hanger, casing and cement behind the casing, these are shown in Figure 30, below. A blowout can only occur when both of these barriers fails simultaneously.



Well barrier elements	See Table	Comments
Primary well barrier		
Production packer	7	
Completion string	25	Production tubing between SCSSV and production packer.
SCSSV	8	SCSSV 1 or SCSSV 2.
Secondary well barrier		
Casing cement	22	
Casing	2	
Wellhead	5	W/ casing hanger and seals.
Tubing hanger	10	
Subsea production tree	33	Annulus bore w/master valve, production bore w/master valve.

Figure 30: Schematic of a horizontal subsea tree (From NORSOK standard D-010, 2013)

Consequences and Risk Analysis: An average production life span of 30 years can be assumed for modeling the risk associated with entire life phase of a deepwater well. In this study to model the worst case discharge rates, only initial life span of a newly completed production well is considered when the well has its maximum potential to flow. Any other spill at some later part of the production well will be less severe. Therefore the analysis presented here may be regarded as a very conservative case, portraying the maximum risk associated with a deepwater production well.

5.2 Literature Survey

The reliability of some of the primary and secondary barriers of a production well are is analyzed in some of the earlier studies. Capderou and Dilorenzo (2012) studied the reliability of completions equipment related to sand control and concluded that a clear distinction can be made between Open Hole Gravel Pack and expandable sand screen completions. Vandenbussche et al. (2012) presented the technique to conduct a well specific assessment and suggested that the risk assessment entirely based on historical data may be very conservative unless it is adjusted with current improvements in terms of technology and operations. Worth et al. (2008) conducted the comparative risk assessment of steam assisted gravity drainage of wells with isolated (double barrier) completion and an open (single barrier) completion. They concluded that both injection and production wells have the potential to create a large spills for a significant amount of time, and that the life time risk of a producing well are mainly related to normal production operations. Woodyard (1982) conducted a risk analysis of a well completion system and compared different completions and concluded that the equipment reliability is changed if workover operations were included in the reliability calculations. Wagg et al., in 2008 studied the reliability of Sand Control Completion (SCC) systems and presented an approach for systematics data collection and usage. They concluded that to reduce the uncertainty in data, the data should be extracted from some main source having a large data set. Lucija et al. (2011) conducted an assessment of offshore production platforms in the Gulf of Mexico and through statistical analysis found that the incidents reported increases with water depth, age of platform, quantity of oil and gas produced and number of producing wells on those platforms. They observed that for each 100 ft of added depth increase, the probability of company-reported incident increase by 8.5 percent.

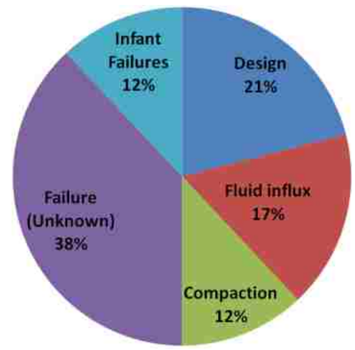
5.3 Methodology

Consequences of blowouts may vary and depends upon a number of factors, including but not limited to its location, water depth, reservoir’s flowing potential, duration of blowout and restrictions in the fluid path. Therefore each blowout may result in different set of consequences.

Sand Control Element (Screen) Failures: The two main failure mechanisms identified in literature for sand screens (King, 2003), are during their installation and failure during the normal production operations. Sand control element failure data is shown in Table 22.

Table 22: Sand control failure from King et al. (2003)

Type of Completion	No. of Wells	Total Well Years	Failures per well year
Cased and	61	366	0.068
Screen Only	194	766	0.055
Cased Hole Gravel	387	1664	0.012
Open Hole Gravel	208	613	0.016
High Rate Water	187	556	0.009
Frac Pack	842	3351	0.005



The main causes of sand screen failure during normal production operations are shown above. Design flaw is one of the major failure mechanisms, shown by the design and infant failures as well. The influx of hydrocarbons for production wells of influx of fluids injected in secondary or tertiary recovery is also a major failure category followed by failure due to formation compaction effects. The unknown failures reported in literature also share a large portion, and warrants further investigation to identify the root causes of these failures, so that future design and installation procedure can take care of these failures as well.

5.4 Primary Well Barrier Failure Analysis

Production Packer: Permanent production packer once set provides a seal for the tubing-casing annulus at the bottom of the tubing and holds the tubing in place. It also facilitate in keeping the completion fluid inside the tubing-casing annulus. The main modes of packer failure are tensile failure, body collapse and packing element failure.

Tubing: The tubing failures during normal production operation is mostly attributed to external loads causing damage, followed by corrosion failure as shown in Figure 31.

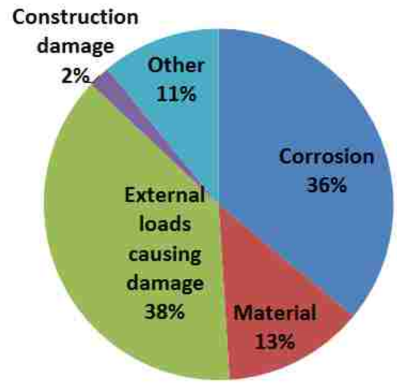


Figure 31: Major tubing failure causes and their contribution King et al. (2010)

Surface Controlled Subsurface Safety Valve (SCSSV): SCSSV is one of the critical primary barriers during production operations and it proved very useful in shutting the wells in the GoM, during hurricane Katrina, Rita and Gustave. Busch (1985) concluded in his study about reliability of the SCSSV, that blowout risk can be substantially reduced by including the SCSSV in the system. Molnes et al. (2000) reported that reliability of SCSSV has been significantly improved over the years from 1983-1999. The data for primary barrier failure rates is summarized in Table 23. The failure rate of tubing or other pipelines is usually expressed as failure per/ mile-year and by using the well depth, it was converted to failure per production well year.

Table 23: Primary barrier failure rates

Element		Failure rate (per prod year)
Production Packer (King, 2010)		0.001656
Tubing (King, 2010)		0.001505
SCSSV (OREDA –Handbook 2009, containing data till 2002)	Mechanical	0.036967
	Control	0.057062

5.5 Secondary Well Barrier Failure Analysis

Secondary barrier failure data has been obtained from different sources, OREDA Handbook-2009 and SINTEF reports available in public domain are two of the main sources. The data is given in Table 24, below. The subsea tree, tubing hanger and wellhead data is extracted from OREDA-2009 Handbook, this data is consists of offshore reliability data upto 2001.

Table 24: Secondary barrier failure rates

Element		Failure rate (per prod year)
Tree (OREDA-Handbook-2009)	Mechanical	0.014542
	Control	0.0461
Wellhead (OREDA-Handbook-2009)	Mechanical	0.002278
Tubing Hanger (OREDA-Handbook-2009)		0.002716
Casing (Holand, 1997)		0.005817
Cement (Holand, 1997)		0.007393

Blowout Frequency: According to OGP (2010, Report No. 434-2), a blowout is defined as an incident where formation fluids, flows out of the well or between formation layers after all the predefined technical well barriers or the activations of the same have failed. The historical blow out frequencies for the normal production operations, excluding workover and wireline operations for world regions other than North Sea (which mostly consist of Gulf of Mexico) are shown in Table 25. Blowout frequency/probability assessment is one of the main activity in quantifying the risk related to production well operations. Due to technological and operational advances in the recent past, the blowout probability might be considerably reduced in recent years, compared to the historical trends. While due to the variation in different production systems, the probability also varies greatly from well to well.

Table 25: Blowout probability during normal production operations OGP (2010)

Category	Frequency (per well year)
Blowout (surface flow)	3.30E-05
Blowout (underground flow)	4.70E-06
Diverted well release	0
Well release	9.50E-06

Blowout Duration: Blowout duration is a function of the success of different well control procedures. It depends on the condition of blowing well, the rate at which hydrocarbons are released, its location and access to the well for different response systems to work, availability of rigs in the region and time taken to activate the response resources. Capping and containment systems are mostly equipped with a set of transition spools that allow them to connect to various standard connectors. These modifications allow them to connect to a variety of subsea productions trees.

Table 26: Blowout duration probability distribution adopted from ACONA (2012)

Duration range (days)	<7 Intervention plus Others	7-15 Capping Stack	15-30 Capping Stack	25-90 Relief Well
Representative duration (days)	7	15	30	90
Probability Subsea Capping Stack	0	0.6	0.3	0.1

A deepwater blowing well can be put under control by crew intervention, successful deployment of capping stack or drilling a relief well. Smith (2012), based on historic blowout data in the GOM, pointed out that probability of a well to kill by itself (bridging) in deepwater is very low in comparison to shallow well, most probably due to consolidation of the sands in deeper waters. Typical blowout duration for a deepwater well is shown in Table 26.

Flow Path Distribution and Restrictions to Flow: The path taken by the reservoir fluid and restrictions in its path are important when calculating the WCD rate for that particular situation. There are a number of flow paths possible for the reservoir fluids to come to surface (Peterson, 2011 & Smith, 2012), shown in Figure 32. The oil discharging to the environment could be at the platform or at sea floor. The path taken by the flowing hydrocarbon could be through production tubing, tubing-casing annulus or through the rock/cement outside the casing. This amount of oil discharging to the environment will depend on the restrictions it has to face to reach the sea floor or sea surface. In this study only flow through the tubing and tubing-casing annulus are modeled. Flow through tubing can only happen, when after the failure of sand control element, SCSSV fails along with tree, but annular flow is prevented as the packer is sealing the annulus at the bottom of the string and is intact.

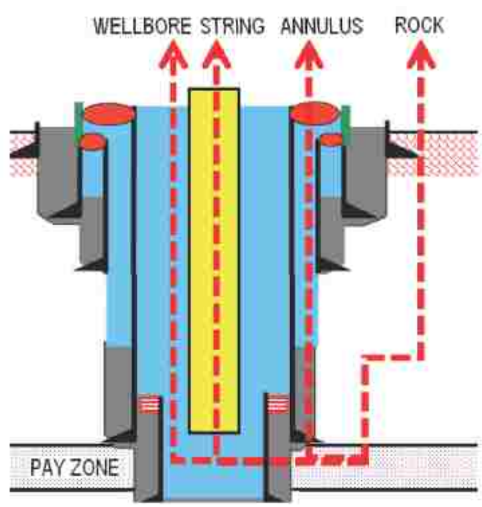


Figure 32: Possible flow paths [From Petersen (2011)]

Flow through casing-tubing annulus happens when the packer and set of annular vales fails to stop the flow after sand control element failure. The flow outside the casing and inside the rock may conservatively be taken as equivalent to the flow inside the tubing, although in reality it may be a fraction of that amount. The case of flow through rock is addressed in chapter-4 related to underground blowouts.

5.6 Analysis Setup

A commercially available steady state multiphase fluid flow simulator PipeSim, with black oil composition model was used to estimate the worst case discharge rates with different set of parametric variations. For heat transfer estimation a linear geothermal gradient was assumed with surrounding temperature around 40F^o at mud line and it leanly increase to 210F^o when reservoir depth is reached (a crude assumption, because temperature first decreases and then increases as we go below the mud line). The specific gravities of oil, gas and water were taken to be 0.86, 0.67 and 1 respectively. The viscosity was modeled using Vasquez & Beggs correlation. The roughness of wellbore and casing and drill pipe was assumed to be equivalent of a steel pipe with value of 0.001 inches. Based on different casing and annular settings, the overall heat transfer coefficient was taken as 2 Btu/hr/ft^2. The pressure at the fluid outlet at seabed is fixed to be 1395 psi based on the average sea water gradient of 0.465 psi/ft (for saline water, usually used for GOM) for a water depth of 3000 ft.

5.7 Results and Discussion

5.7.1 Fault Tree Analysis

The results for the Fault Tree Analysis for a deepwater production well are shown in Figure 33. The high failure rate of primary barrier is mainly due to SCSSV's control system's failure. The delayed response to a potential hazardous event is another area of concern and is one of the main contributors to primary barrier failure frequency. A careful observation of the secondary barrier data shows that the main control system of a subsea tree has the highest failure rate.

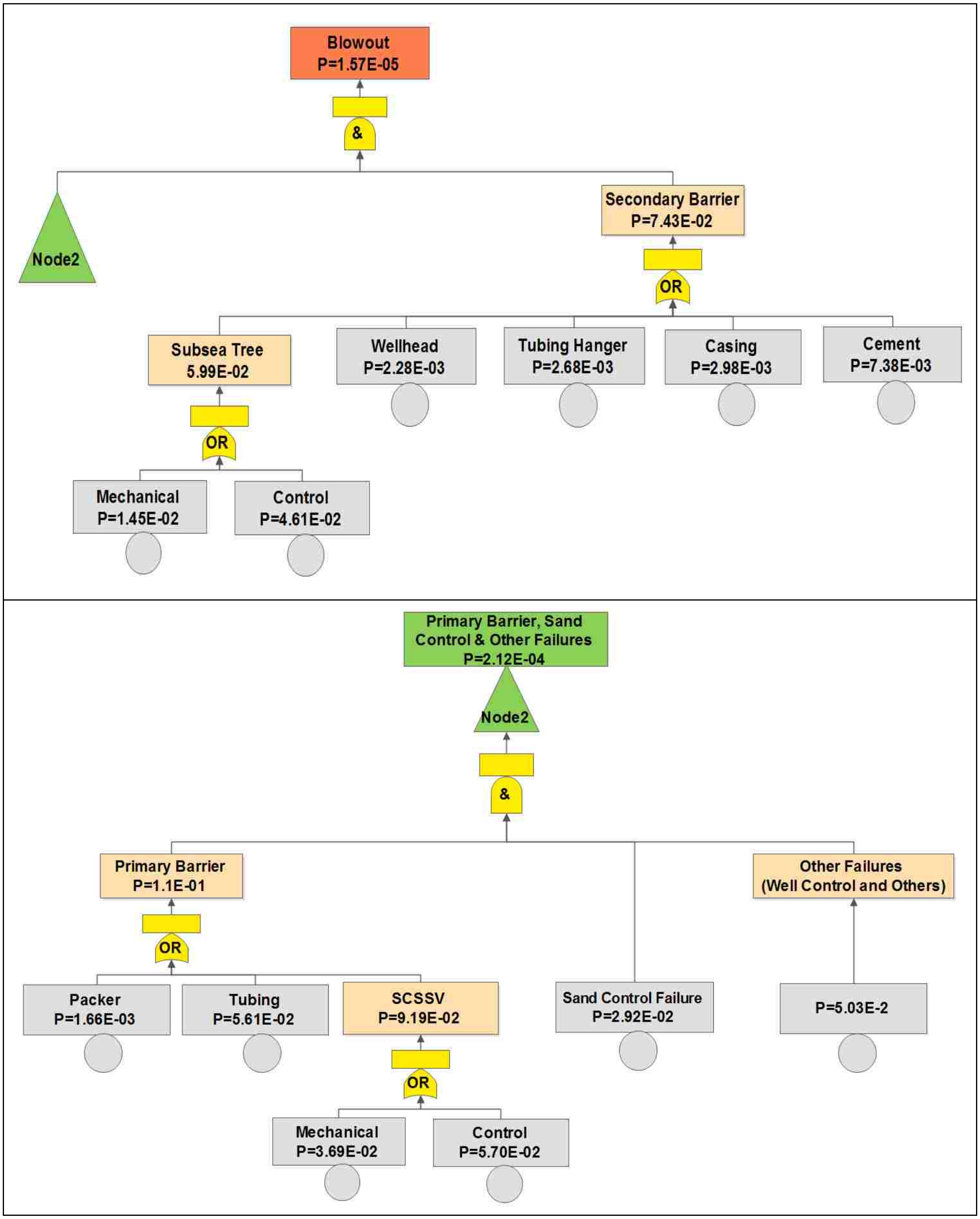


Figure 33: Production fault tree analysis setup

5.7.2 Fussell Vesely Importance (FVI) Measure

The manner in which fault tree was constructed, three basic events of the fault tree namely sand screen failure, subsea tree main control system failure and delayed response to an event of immediate attention are the most importance basic events. As FVI is based on minimal cut seta method, therefore cut sets containing these events have the highest probability to occur as well. FVI measures of all of the basic events in the fault tree are shown in Table 27. Analysis shows that blowout probability is most sensitive to sand screen failure and any improvement in the design of sand screen will greatly reduce the overall blowout probability.

Table 27: Fussell Vesely importance analysis results

Event Name	Sensitivity
SANDCONT (sand control element)	1.00E+00
OTHERS	1.00E+00
TREEELEC (Tree control system)	6.07E-01
SCSSV-EL (SCSSV control)	3.76E-01
TUBING	3.70E-01
SCSSV-ME (SCSSV Mechanical)	2.44E-01
TREEMECH (Tree mechanical)	1.91E-01
CEMENT	9.72E-02
CASING	3.93E-02
TUBHANG (Tubing Hanger)	3.53E-02
WELLHEAD	3.00E-02
PACKER	1.09E-02

The next main important basic event that can substantially reduce the blowout probability is main control system of a subsea tree; it is to be pointed out here that in most of the instances theses control systems has backup redundant system, that automatically takes over in the case of failure of first one. Delayed response of personnel, supposed to decide quickly and take an action in the emergency situation, is the next item to focus on, in order to reduce blowout frequency.

These three main contributors may be dealt with the technological advancements. Sand screen's design is one of the major failure causes mentioned earlier on, therefore design improvements in terms of improving the reliability of these elements will greatly reduce the blowout probability. Delay in the response to an event of immediate concern can be coped with automating some of the initial response decisions and through overseeing the operations by remotely monitoring the operations and take quick decision and guide the personnel on the production platform. Better training of the personnel.

5.7.3 Blowout Uncertainty Analysis

Monte Carlo Simulations were performed to measure the uncertainty associated with the blowout frequency. 100,000 trials were performed. The 99, 95 and 90 percentile values are found to be 1.92×10^{-5}, 1.84×10^{-5} and 1.84×10^{-5} respectively, and are shown in Figure 34, below.

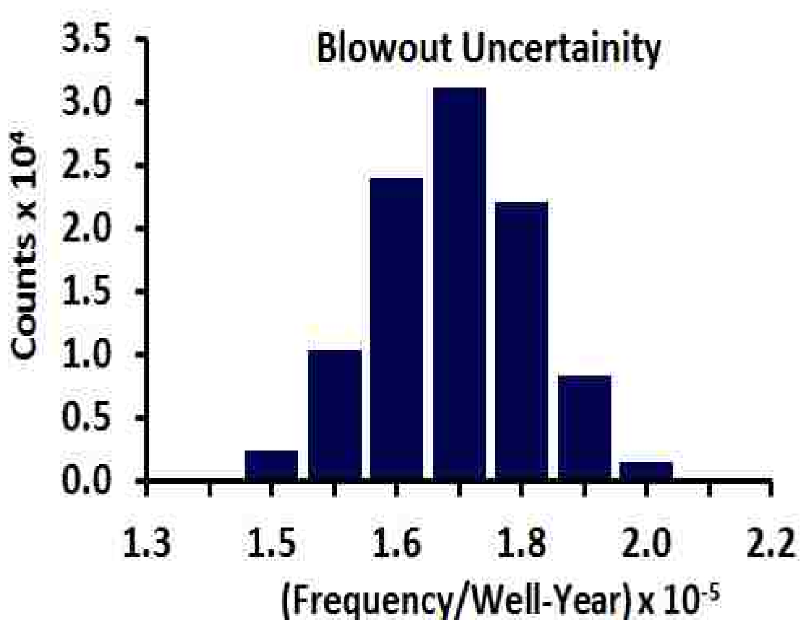


Figure 34: Blowout uncertainty with a nearly normal distribution

The mode of the frequency is around 1.7×10^{-5} blowouts per well year. As the distribution is near normal, so average and mode value are supposed to be very close to each other.

5.7.4 Flow Rate Calculations

The subsea release flow rates obtained for reservoir properties corresponding to P50 value from cumulative frequency distribution are shown in Table 28. The basic assumption for flow rate calculation is that the well is a new production well, and reservoir pressure has not decreased greatly.

Table 28: Subsea release paths and rates, SST: Subsurface Release through Tubing, SSA: Subsea Release through Annulus, FSP: Flow Restriction Probability, PPB: Probability Per Blowout

Flow Path	Prob.	Case ID	SCSSV or ASV	FSP	Oil Flow rate (bbl/day)	PPB
Tubing	0.63	SST1	Open	0.1	34546	0.063
		SST2	Restricted	0.9	21121	0.567
Annulus	0.25	SSA1	Open	0.1	32644	0.025
		SSA2	Restricted	0.9	20056	0.225
Outside Casing	0.12	SSR	NA	1	21121	0.12

It has been assumed that, when actuated both of the SCSSV and ASV will result in restricting the flow 90% of the time. Therefore a probability of 0.9 is assigned for the restricted condition and 0.1 when these valves fails completely and do not offer any resistance the flowing hydrocarbons. The restriction to the flow is described in terms of the flow area open to flow and it is based on literature available a flow restriction of 95% is assumed. Flow in the annulus presented in the Table 28, is the scenario when packer failed but still offer some resistance to flow and some portion of annular area is open to flow.

5.7.5 Environmental Risk Assessment

Environmental risk associated with a blowout, depends on flow rate, location and duration of spill. The flow rate is related to the well's potential to flow and how much resistance fluid faces when flowing either in tubing or annulus and the conditions of different production valve of a subsea tree. Maximum duration of a typical blowout is assumed to be 90 days i.e. time taken to drill a relief well in the deep waters of GoM. In most of the cases the well may come under control well before this period either through crew intervention or some other response system intervention. The probability of a spill duration of 90 days is 10% only as shown in Table 26. The assumption of 90 days duration and unrestricted open hole flow result in the most conservative worst case environmental damage. Calculated impact factor for different flowing conditions for the base and modified cases are shown in Table 29. The duration for the base, modified and ideal cases are 90, 27 and 15 days respectively.

In this analysis above mentioned three cases are compared to each other. Base case is the worst case scenario, when every intervention attempt to stop the flow fails.

Table 29: Impact Factor Calculation for Base and Modified Cases

Scenario	Case ID	PPWY	Cumulative Oil	Impact
Relief Well	BC1	9.89E-07	3.11E+06	4
	BC2	8.90E-06	1.90E+06	4
	BC3	3.93E-07	2.94E+06	4
	BC4	3.53E-06	1.81E+06	4
	BC5	1.88E-06	1.90E+06	4
Capping Stack (27 Days)	MC1	9.89E-07	9.33E+05	4
	MC2	8.90E-06	5.70E+05	3
	MC3	3.93E-07	8.81E+05	4
	MC4	3.53E-06	5.42E+05	3
	MC5	1.88E-06	5.70E+05	3
Capping Stack (15 Days)	MIC1	9.89E-07	5.18E+05	3
	MIC2	8.90E-06	3.17E+05	2
	MIC3	3.93E-07	4.90E+05	3
	MIC4	3.53E-06	3.01E+05	2
	MIC5	1.88E-06	3.17E+05	2

In this case the spill duration of 90 days is considered, which is equal to the time of drilling a relief well to stop the blowing well in the deepwater GoM environment. In the modified case the recently built spill response systems called Capping Stacks are taken into consideration with possibility of some delays in its deployment phase which reduces the duration from 90 to 27 days only. In the modified ideal case it is assumed that the capping stack can be successfully deployed within the 15 days' time frame. These capping stack are designed to be deployed within 15 days' time frame, therefore it is not a crude assumption. These capping and containment systems are basically designed for drilling activities and to be deployed on exiting BOP's or Wellheads, having standard H-4 Hydraulic connectors. These systems are equipped with a set of adopter spools and may be latched to a variety of standard connectors at subsea trees. The impact factor of all of these cases is shown in Table 29.

The above mentioned three cases are compared to each other by using a risk matrix and are shown in Figure 35.

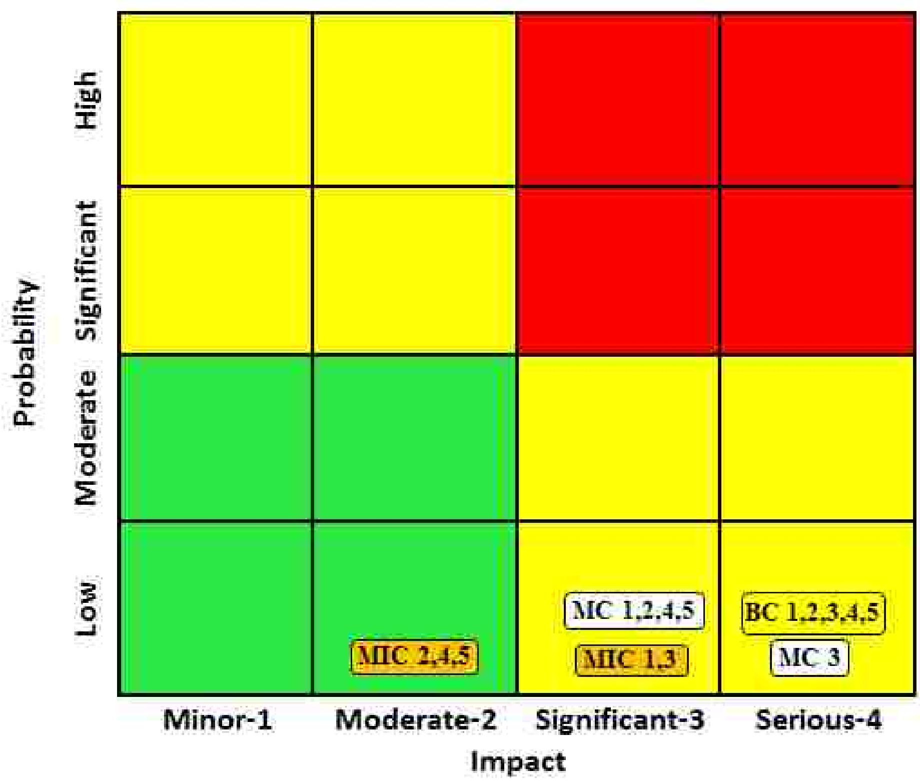


Figure 35: Comparison of all three cases through risk matrix

The entire base subcases results in the category of serious impact, but due to their very low frequency of occurrences, when an overall risk is computed through the product of probability and consequences, their risk level fall in the yellow region, in which operations are conducted with extra safety precautions. The use of the capping stack significantly altered the impact of large spill, by reducing the spill duration and as a result less volume is released to the environment. The modified ideal case is the case when capping stack is successfully deployed within the 15 days intended response time, and as a result it shifts the impact from significant to moderate. This analysis shows the significant contributions that technological improvements can bring in order to reduce large oil spills in the GoM.

There have been technological improvements in other area of production systems as well, that may result in further reducing the frequency of primary and secondary barrier failure rates.

5.8 Concluding Remarks for Scenario-3

- The QRA study of a deepwater production well has been performed and key contributors to overall system safety have been identified through fault tree analysis.
- Sensitivity analysis of all of the basic events in the constructed Fault Tree for a sand screen failure leading to blowout was conducted. It turned out to that the three most important basic events contributing to the frequency of blowout are sand screen failures, subsea production tree's control system failure and well control/other failures.
- It has been suggested by other researchers that the design improvements of the sand screen will greatly reduce their failure rates and in turn blowout frequency associated with production well, as it is one of the most sensitive/important basic event in the system setup, considered for this scenario.

- Subsea production tree's control system is the second most important basic event in the system, and even a small improvement in the reliability of control system will greatly influence the blowout frequency of the entire system.
- Monte Carlo simulation results for blowout probability show a range of values between 1.54-2.0 $\times 10^{-5}$ per well-year, when each of the basic events is varied by ±10%.
- A WCD rate of 34,546 BOPD was estimated using multiphase fluid simulations and it is well within the fluid handling capacity of newly built response systems called capping and containment systems. Newly built response systems are effective in reducing the risk of large oil spill in deepwater environments. Additional tools like adopter spools may be needed to connect capping stack to subsea trees with different connector profiles.
- The blowout frequency modeled by FTA is based on the historical data and therefore it is a conservative estimate. When recent technological improvements are incorporated into FTA, the blowout frequency will be reduced, as in the past few years there have been major improvements in well safety related procedures. New regulatory requirements, equipment reliability improvements and extensive training of crew, all of these will contribute in lowering the blowout frequency estimates.

CHAPTER 6: A REVIEW OF OIL SPILL RISK ASSOCIATED WITH FPSO DEPLOYMENT IN GOM (SCENARIO-4)

FPSO stands for Floating Production Storage and Offloading vessels. They are essentially ship-shaped vessels; either specially built or converted tankers. They produce, store and transport hydrocarbons to either shuttle tankers or deepwater pipeline terminals. The main advantages of FPSO as compared to other offshore platforms are

- They allow production far deeper than fixed platforms. Most of the FPSO's have been deployed to deepwater fields, as they are nearly water depth insensitive as compared to other offshore production platforms.
- They allow development of short-lived, marginal fields in remote locations where fixed platform are not feasible economically.
- They can process large amount of hydrocarbons and have huge storage capacity as well, and the processed fluids are usually transported by shuttle tankers.
- They eliminate the need of cost associated with long pipelines to onshore terminals, especially in ultra-deepwater where seabed pipelines are not cost effective.
- They are particularly effective in remote deepwater.
- They can be relocated to new locations and reused easily.

In terms of spill potential the following capabilities of the FPSO are different than other offshore platforms

1. Station Keeping and buoyancy
2. Shuttle tanker Transport
3. Large storage capacity

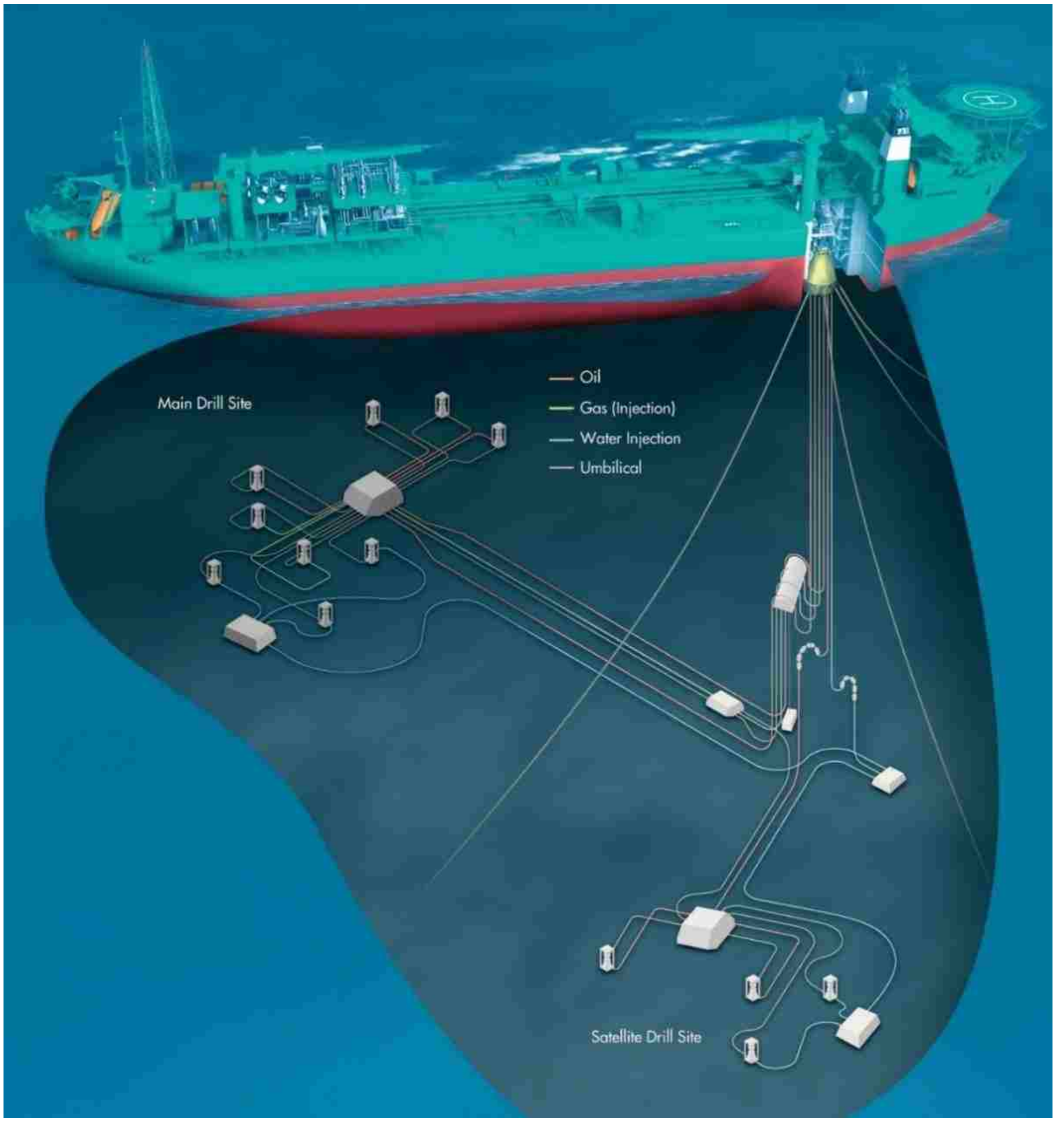


Figure 36: FPSO in operation (From http://www.bluewater.com/wp-content/uploads/2013/03/4.2.3-Subsea-Field-Layout.jpg)

6.1 Typical FPSO Configuration for GoM

The proposed configuration details of a typical FPSO for GoM taken from Regg (2000), are shown in Table 30. A base case and a configuration for analyzing the system's performance is also specified by Bureau of Safety and Environmental Enforcement and is given in Regg (2000).

Table 30: FPSO configuration for GOM deployment from (Regg et al., 2000)

Component	Base Case Characterization	Sensitivity Case Characterization
Size	Up to 150,000 dwt tons	Up to 500,000 deadweight tons
Hull Design	Double-sided/double-bottom	Single hull variations — double-sided/single-bottom; no storage in wing tanks; hydrostatic loading; single-sided other than ship-shaped hull
Storage	500,000 to 1 million bbls of crude	Up to 2.3 million bbls of crude
Processing	Oil — up to 150,000 BPD Gas — up 200 million CFGPD Water — up 70,000 BPD	Oil — up to 300,000 BPD Gas — up 300 million CFGPD Water — up 100,000 BPD
Oil Transfer	Shuttle tanker to shore or other GOM	
Shuttle Tanker	500,000-bbl capacity each; GOM operations; not dynamically positioned	Dynamically positioned
Gas Transfer	Gas sales line to shore or existing infrastructure	Reinjection for later recovery; possible gas to liquids conversion
Mooring	Permanent — up to 12 lines, most likely anchored by suction piles	Disconnectable; may be dynamically positioned
Propulsion	None; may have thruster assist for certain mooring arrangements	Self-propelled; capable of drive-off
Turret	Internal turret; multi-path swivel	
Risers	<3,000 ft water - flexible pipe >3,000 ft water - steel catenary riser(s), free standing riser (for example, GB 388) or other hybrid system	
Subsea	Clustered wells; manifold(s); pipelines; umbilicals	

The data used in this scenario is adopted from sensitivity case characterization configuration given in Table 30. The risk associated with the deployment of FPSO are comparable to other production facilities with some added concerns about the station keeping, large storage capacity and collision with shuttle tanker. Gilbert et al. (2001), conducted the comparative analysis of FPSO with other deepwater developments and concluded that the oil spill and other associated risk with FPSO are comparable to other facilities and major contribution of spill may be due to transportation of oil using shuttle tankers. Spill sources would be the same as for other production facilities: process train (separators, piping, small volume storage tanks), pipelines, and riser/wellbore. The large volume storage associated with an FPSO, transfer operations (from FPSO or other loading facility to the shuttle tanker), and shuttle tanker transport are areas that differ from typical GOM developments (platforms, subsea, other FPS's). A quantitative risk assessment study conducted by Overfield et al., (2000) for FPSO safety, points out that the main risk to the personnel is dominated by fires, explosions and cargo tank explosion. While assets risk are posed by the collision of shuttle tanker, riser leaks, subsea pipeline damage and turret operations. The focus of the study is the impact analysis of the following factors specific to FPSO.

- **Station Keeping FPSO**
- **Transportation Spill Analysis**
- **Large Storage Capacity of FPSO**

These are discussed in detail in the following sections.

6.2 Station Keeping

Position/station keeping is one of the main differences between FPSO and offshore production platform types, due to FPSO's dynamic positioning system. Two options exist for

FPSO station keeping - the majority of existing FPSO's employ a fixed mooring system using anchors and anchor lines; a few rely on dynamically positioned systems that employ a series of thrusters and positioning technology.

6.2.1 Mooring Configurations

There are two main mooring configurations for FPSO: spread mooring in which vessel keeps its orientation fixed and a single point mooring in which the vessel have the freedom to reorient itself to accommodate the weather conditions. One of the variant of single point mooring is the turret mooring, which could be a part of the vessel or externally connected to a FPSO. Spread and single point mooring are shown in Figure 37.

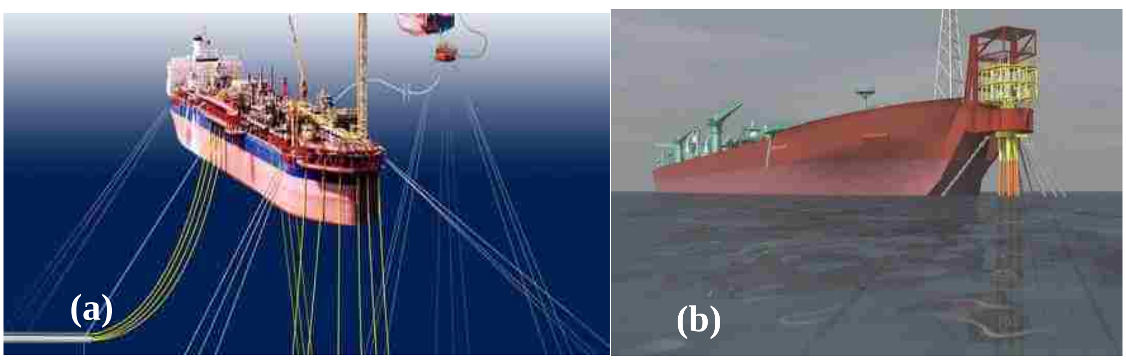


Figure 37: (a) Spread mooring and (b) Single point turret mooring [Reference: energyclaims http://www.energyclaims.net/assets/FPSO-Presentation.pdf)

The turret mooring system allows the FPSO to adjust its position, to accommodate the environmental loads. The factors that influence mooring systems are the combination of wave height, directions of wind and current and vessel size. Riser system should also be analyzed while studying mooring system (Regg-2000). Duggal et al., (2009) studied numerically and experimentally the station keeping of FPSO in harsh weather conditions for 100 year sea conditions for severe connects and disconnects conditions, with turret mooring system. The data for the actual FPSO in severe weather conditions showed that these systems performed reliably in severe weather conditions to disconnect and connect back to subsea installations.

6.2.2 FPSO Roll motion effect on Mooring

It has been reported that hulls of FPSO have been exposed to excessive roll motion up to 20 degrees amplitude (Kinnas, 2005). This excessive motion may result in damaging the mooring lines and halting the operations as well. The solution to this problem has been suggested by Kinnas (2005) as to install of bilge keels on these hulls.

6.2.3 FPSO Yawing Motion

In a study conducted by Kim (2004), a coupled vessel-riser-mooring dynamic system was analyzed experimentally. A scaled down model on a 1:60 Scale was used. It was concluded that when mooring dynamic effects are significant, the dynamic mooring tension can be under predicted with truncated mooring system. Rocha et al., in 2010 performed and FEMCA analysis of different systems contributing in maintaining the balance of FPSO in the case of an emergency situation. They pointed out that amongst the systems they selected for the study, Safety Interlock and Automation System (SAIS) was the least reliable systems and they recommended the design re-evaluation if possible for SAIS. Holdbrook in 2004 conducted a risk based assessment of hull structure and pointed out that the cracking probability of hull structure for FPSO may be higher as compared to fixed offshore structures, as there are more stresses concentrating feature in a typical FPSO hull. A major factor for these cracks may be stresses caused by improper loading and unloading sequence (OGP-Report # 377).

6.3 Fuel Offloading Operations

Most of the FPSOs offload the hydrocarbons to shuttle tankers directly. The direct transport is usually achieved through tandem offloading or side by side offloading. The tandem offloading is considered to be safe. The tandem and side by side off loadings from FPSO to a shuttle tanker are shown in Figure 3.

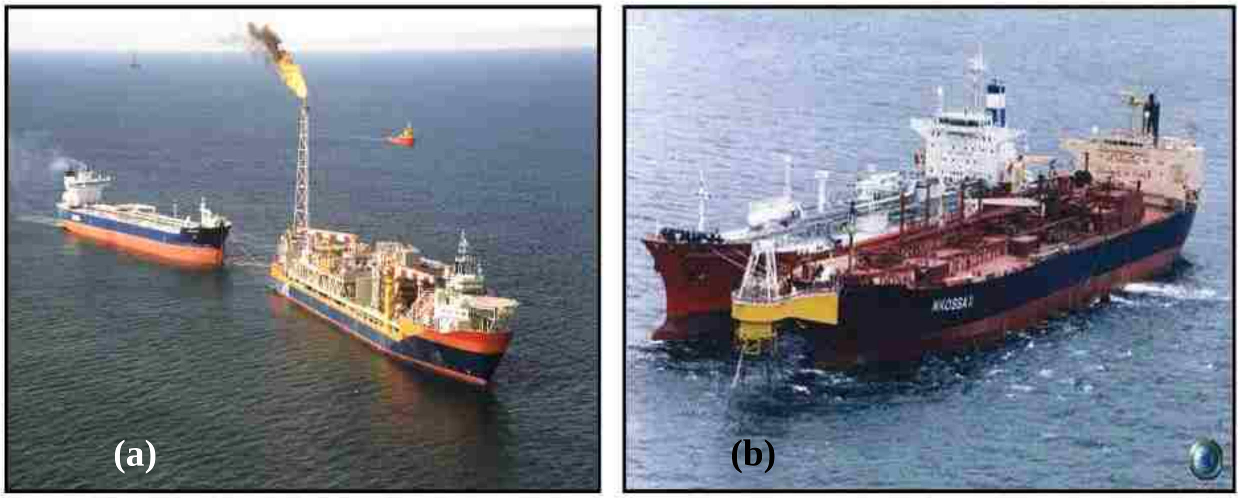


Figure 38: (a) Tandem and (b) side by side offloading from FPSO (From Regg-2000)

The sequence of events that is followed in the tandem offloading is described by Chen (2003) as following

- Approach and Connection: Tanker approaches FPSO and stops at predefined distance and a connection is established between FPSO and tanker to transfer oil
- Loading, disconnection and departure: Oil is transferred to tanker and loading hose and hawser are disengaged and tanker departs away

6.4 Shuttle Tanker Collision Analysis

Shuttle tankers or other supply vessels coming to the FPSO, in the normal weather conditions may have three modes of collision with the FPSO (Lloyd's Register, 2014).

- On their arrival

- Standby Position
- During loading

Each mode has its own related collision frequency and collision energy depending on a number of factors being involved

During Arrival

$$f_c = N \times f \qquad (1)$$

$$E = 0.3685 \times m \times (1 + a) \times v^2 \qquad (2)$$

Where:

f_c = is the collision frequency per year

N = number of arrivals per year

f = collision frequency (per arrival or visit)

v = velocity of vessel when powered (f/s)

m = mass of vessel (lb)

E = collision energy (ft-lb_f)

a = 0.1, added mas factor for water displacement as it is supposed to be ahead on collision,

- **Standby Position:** During the standby position the coming vessel adjust itself dynamically to connect to the FPSO and it may perform dynamic position operations. A possible collision scenario may be that the vessel losses its control and drift towards the FPSO terminal (Lloyd's Register, 2014). In this case the collision frequency and collision energy may be presented as

$$f_c = N \times t \times f_{Drift} \times P \qquad (3)$$

Where:

t = Time in standby mode (hour)

f_{Drift} = Frequency of losing control and drifting-off during standby (per hour)

P = Probability of drifting towards FPSO and hit, provided that drift-off happen during standby position

For impact energy calculations Eq. (2) is applicable, only difference in this case is the change in added mass factor from 0.1 to 0.4, as it is anticipated that the drifted tanker/vessel may collide sideways.

• **Collison during Tandem offloading**: The drive off of a shuttle tanker may be defined as the "unwanted movement of the tanker away from its target location due to its own thrusters". Forward drive off may lead to collision with the FPSO. The data about tandem offloading is scarce and is reported by Chen (2003).

During loading mode two scenarios are possible; the tanker may drive off or drifted away. So the collision frequency for these two scenarios can be described as

For drive off Collision Frequency: $f_c = N \times t \times f_{drive-off} \times P$

For drive off Collision Energy Eq. (2) can be used with a =0.1.

6.4.1 FPSO Tandem Offloading Analysis

The data of tandem off loadings in UK outer continental shelf for the period of 1996-2000 is reported by Chen (2003), and is shown in Table 31. Approximately 1300 tandem transfers were performed during this five year period. The data is for offshore UK and to use it for GoM settings correction factor may be needed, as weather is usually harsh in North Sea, so a factor of 0.8 may be used for GoM environment. But if multiplication factor is not used, data trend shows that 1 station keeping incident in every 27 loadings, 1 forward drive off in 186 loadings and one collision in every 325 loadings.

Table 31: Reported incidents during tandem transfer in offshore UK (Chen-2003)

Number of Tandem Offloadings: 1300	**Station Keeping Incidents**	**Drive Off Forward**	**Collision**
Number of Incidents	49	7	4
Frequency (per loading)	3.769E-02	5.385E-03	3.077E-03

The collision and drive off may result in structural damage and/or minor spill but no major oil spill incident has been reported to date. An estimate of spill related to shuttle tanker transportation is shown in Table 32.

Table 32: Oil tanker oil spill frequencies (From OGP-Report No. 434-10, 2010)

ACCIDENT TYPE	**OIL SPILL FREQUENCY (spills per ship year)**	**OIL SPILL RATE (bbls per ship year)**	**AVERAGE OIL SPILL SIZE (bbls)**
Collision	1.5×10^{-3}	33	21418
Contact	7.2×10^{-4}	1	1085
Fire/explosion	5.1×10^{-4}	11	21792
War Loss	5.1×10^{-5}	0	198
Structural	1.3×10^{-3}	42	32509
Transfer spill	1.7×10^{-3}	2	975
Unauthorized	5.1×10^{-4}	2	2991
Grounding	5.6×10^{-4}	38	67634
TOTAL	6.9×10^{-3}	128	18486

Considering the different production rates and the different capacities of shuttle tankers shown in Table 33, approximate arrivals per year for shuttle tankers are calculated. In normal day to day operations typical values of shuttle tanker arrivals are usually 50-125 per year.

Table 33: Estimation of GoM shuttle tanker arrivals per year

FPSO Daily Production (1000 bbls)	FPSO Annual Production Capacity (Million bbls)	Shuttle tanker Capacity (1000 bbls)	Approximate Arrivals (per years)
75	27.375	250	110
		350	79
		500	55
100	36.5	250	146
		350	105
		500	73
150	54.75	250	219
		350	157
		500	110

Now using the historical data for incidents involving FPSO operations shown in Table 31, an approximate estimate of number of incidents involving station keeping, drive off forward and collision are shown in Table 34. An approximate spill volume calculation involving shuttle tanker collision is also shown.

Table 34: Shuttle tanker related incidents with approximate arrivals for the typical FPSO considered for GoM and different shuttle tanker capacities

Approximate arrivals (per year)	Station Keeping Incidents (per year)	Drive Off Incidents (per year)	Collision	
			Collision (per year)	Spill Volume (bbls per collision)
110	4.13	0.590	0.337	98
78	2.95	0.421	0.241	137
55	2.06	0.295	0.168	196
146	5.50	0.786	0.449	73
104	3.93	0.562	0.321	103
73	2.75	0.393	0.225	147
219	8.25	1.179	0.674	49
156	5.90	0.842	0.481	69
110	4.13	0.590	0.337	98

6.5 All Accidents Involving FPSO UKCS 1980-2005

The incident data for the FPSO units working in the UK outer continental shelf is shown in Table 35. The data set is for limited number of units and needed to be updated, as in the recent past a large number of FPSO units started working worldwide, that will improve the conclusions to be made on the basis of data set.

Table 35: FPSO Incident data UKCS for period of 1980-2005 reported in (HSE - RR567)

	Type of construction			
	Purpose-built		Converted	
Type of event	No. of failures	Frequency (per year per vessel)	No. of failures	Frequency (per year)
Anchor failure	13	0.135	-	-
Blowout	-	-	-	-
Capsize	-	-	-	-
Collision	-	-	-	-
Contact	11	0.114	-	-
Crane	42	0.436	13	0.481
Explosion	2	0.021	-	-
Falling object	54	0.561	16	0.593
Fire	42	0.436	12	0.444
Foundering	-	-	-	-
Grounding	-	-	-	-
Helicopter	1	0.01	-	-
Leakage	1	0.01	-	-
List	1	0.01	-	-
Machinery	-	-	-	-
Off position	1	0.01	-	-
Spill/release	225	2.336	94	3.481
Structural	3	0.031	2	0.074
Towing/towline	-	-	-	-
Well problem	2	0.021	-	-
Other	18	0.187	4	0.148

Amongst anchor failure, off position, collision and spill incidents considered in this study the frequency spill per unit year (2.336) reported in Table 35 is high in both purpose built and converted tankers and needs careful attention.

6.6 Other FPSO Areas of Concern Identified by Researchers

The main issues experienced by FPSO working in United Kingdom Continental Shelf during 1996 to 2002 are pointed out by Smith (2003). These are depicted in Figure 39. Some of the other issues/recommendations highlighted by him are

- Green water loads (3 out of 4 FPSOs were affected by this)
- Hull Strength (3 out of 4 FPSOs suffered cracks between storage tanks)
- Improving mooring understanding for permanently moored systems
- Turret location and design improvements
- Layout of the vessel

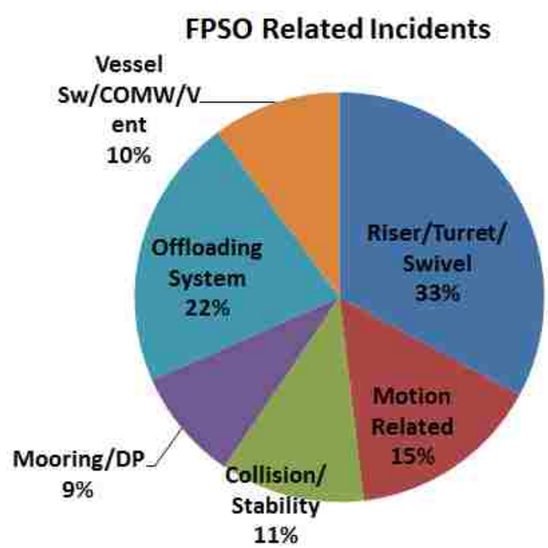


Figure 39: FPSO related incident categorization dada taken from Smith (2003).

6.7 Risk Matrix

Based on the proposed specific FPSO configuration for GoM, a risk matrix is constructed based on the historical trends and calculated spill volume values.

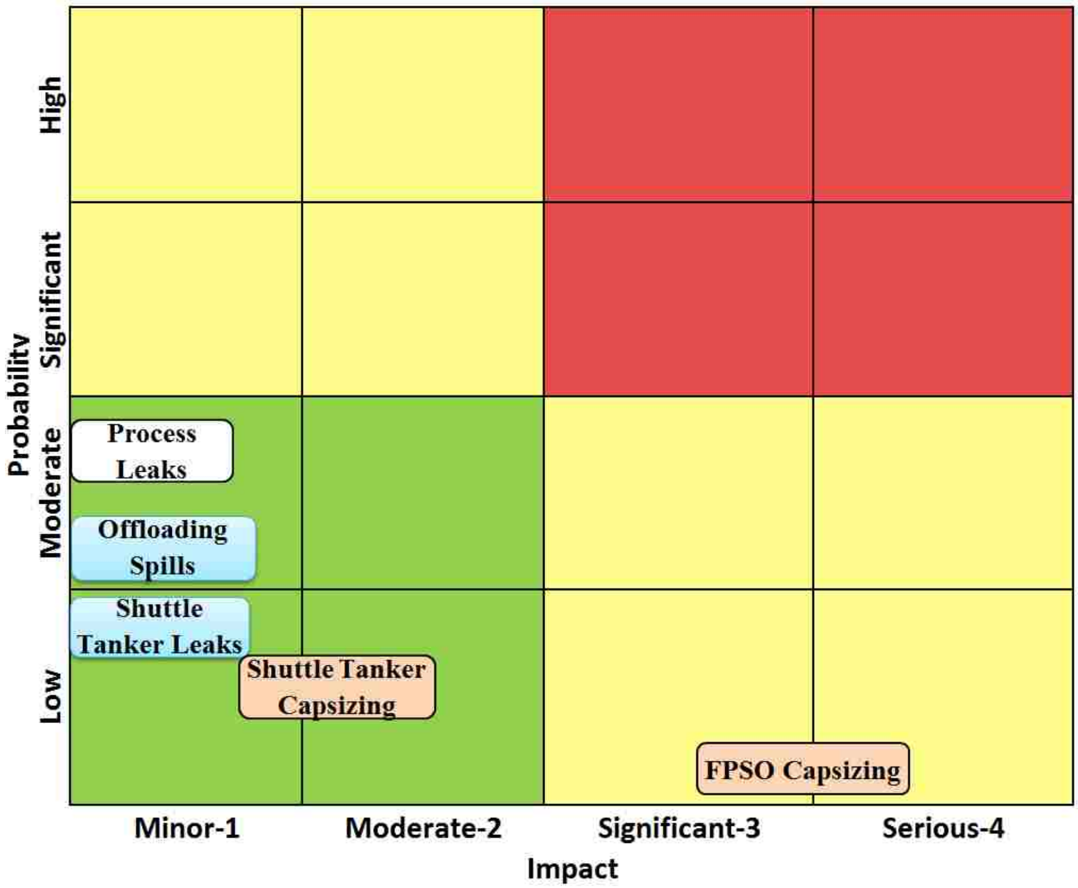


Figure 40: Risk matrix for spills related to FPSO Operations

6.8 FPSO Observations and Conclusions

The deployment of FPSO for hydrocarbon production in GoM has some advantages and some related issues that must be taken care of.

- The proposed FPSO configuration for the GoM has been analyzed and associated risks are qualitatively and quantitatively presented.

- It has been reported by previous researchers that risk associated with FPSO deployment in the GoM are comparable to other production platforms and FPSO needs additional considerations due to its large fluid storage capacity, station keeping requirements and oil transportation mechanism.
- Most of the historical oil spills associated with FPSOs operations actually happened during oil transportation from FPSO to onshore facilities by shuttle tankers.
- Reported oil spill incidents involving FPSO vessel are mainly due to loss of its position keeping and during fuel offloading process. These spills are of very small quantity as compared to shuttle tanker spills.
- An example calculation based on the proposed configuration of FPSO for GoM has been performed to estimate the frequency of shuttle tanker collision with the FPSO and related spill amount.
- Analysis shows that only small amount 100-200 bbl of oil spills will result due to shuttle collision with other vessels including FPSO, and maximum spill amount will result when the shuttle tanker capsizes while carrying hydrocarbons from FPSO to onshore facilities.
- The probability of FPSO capsizing is very low, as there are no reported incidents. But if it is the case, a large oil spill will most probably be expected due to its large fluid storage capacity and other possible damages that can occur to wellheads or subsea installations.
- Amongst the spill response technology, oil skimmers boats seem to be the most appropriate for spills involving shuttle tankers as these are the most frequent spills involving production from FPSO.

CHAPTER 7: OIL SPILL RISK ASSOCIATED WITH SEVERE WEATHER CONDITIONS IN THE GULF OF MEXICO (SCENARIO-5)

Weather is an important factor when analyzing hazards associated with the deepwater drilling and production operations and offshore installations. GoM is prone to hurricanes ranging from category 1 to 5. In the recent past, substantial damage has been reported to offshore infrastructure ranging from pipeline damage to the complete destruction of platforms during hurricanes Katrina and Rita. In GoM most of the offshore installations in the predicted path of the hurricane are evacuated before its arrival, therefore risk posed to personnel is not of concern in this case. Severe weather conditions may result in

a) Mudslide leading to pipeline or platform damage leading to oil release to environment

b) Adrift of offshore structures that may damage other installations

c) Platform damage or destruction due to high wind and sea wave loads

d) Pipeline damage or destruction due to high wind and sea wave loads

e) Well damage and loss of well control

Depending on the extent of the damage oil spill may happen. Another area of concern in terms of economic losses to oil industry is the halt of the production of oil and gas at least for few days. In the past it happened that the production level before the hurricane was not achieved even after more than a year. The subsequent sections address all of these concerns in a detailed manner.

7.1 Hurricane Categories and Their Occurrences in the GoM

The intensity of a storm is estimated from its wind speed and is usually categorized by Saffir-Simpson hurricane wind scale (Saffir 1960 and Simpson 1970), shown in Table 36.

Table 36: Storm classification using Saffir-Simpson Scale

Hurricane Category	**Wind**
5 (Major: Catastrophic Damage)	≥157 mph
4 (Major: Catastrophic Damage)	130–
3 (Major: Devastating damage)	111–
2 (Extremely dangerous)	96–
1 (Very dangerous winds)	74–
Other classifications	
Tropical storm	39–
Tropical depression	≤38 mph

The hurricane season in the GoM may vary with no hurricane activity to several hurricanes occurring in the same season. A trend of sever storm activity in the GoM is shown in Figure 41. Historical path of the majority of big hurricanes in Figure 41, highlight a spatial pattern, indicating that the majority of storms passed through current or older Mississippi river delta.

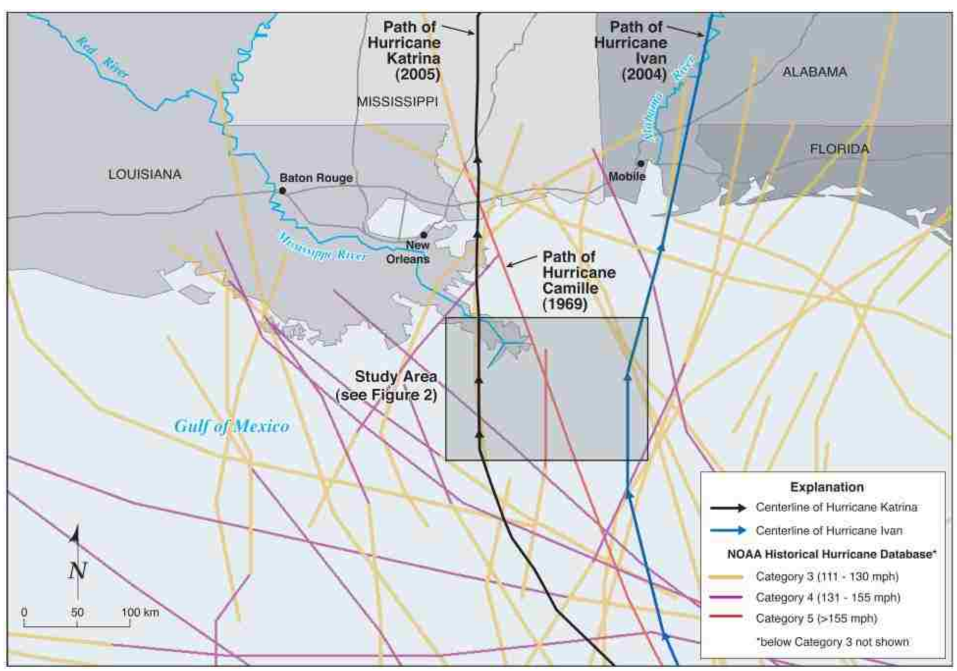


Figure 41: Historical storm paths in the GoM (From Hitchcock et al., 2006)

7.2 Mudslide Slide Hazard in Mississippi Current Delta

In shallow waters of less than 400 ft, the surge wave phenomenon can result in the seafloor failures and a large amount of mud flow can occur from upslope of the river delta to deep water regions (Hitchcock et al., 2006). These mudslides may extend to several thousand feet in lateral direction and about 50 to 150 feet deep (Gilbert at al., 2007). Mudflow sensitive areas in the Mississippi delta are shown in Figure 42.

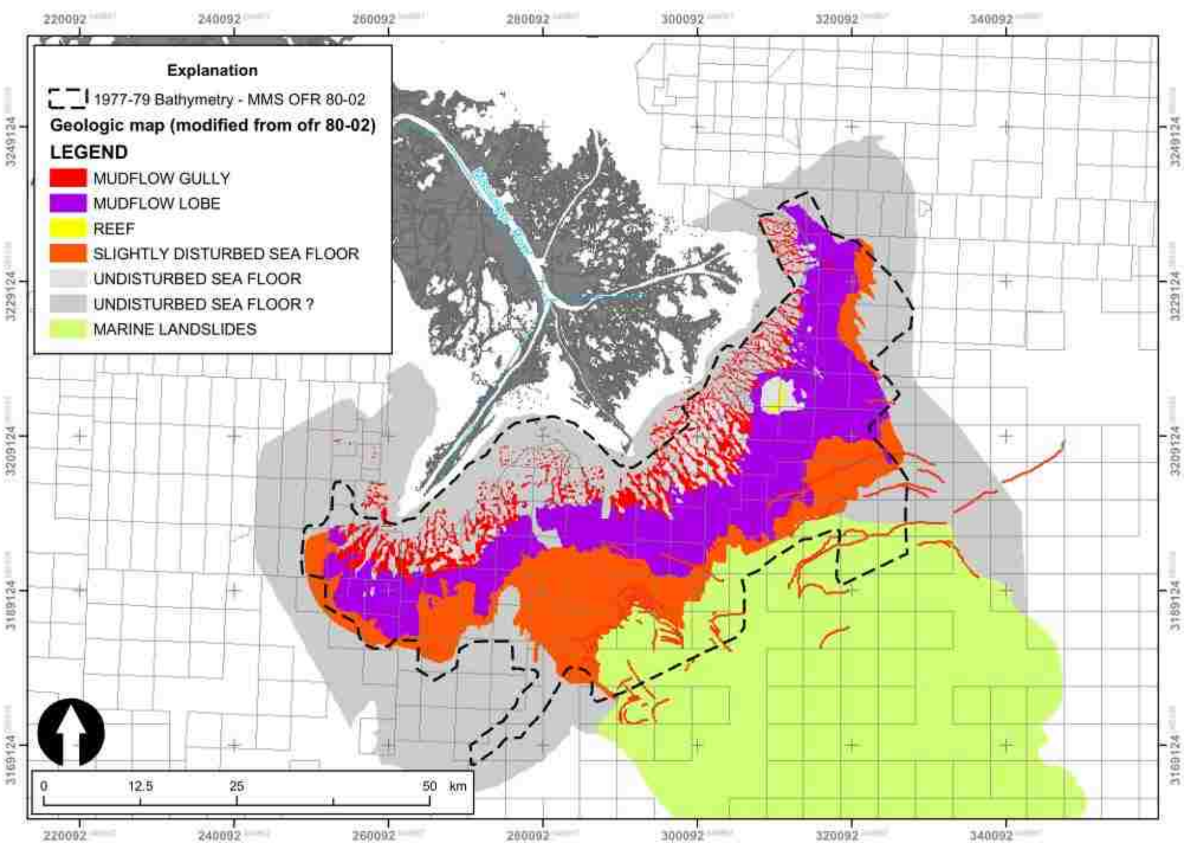


Figure 42: Mud sensitive area in the Mississippi Delta (Hitchcock et al., 2006)

The mud slide is a result of combination of high wave surge very low shear strength soft soil. The shallow water depth areas are more prone to mud slide in the area delineated on the map in Figure 42, to be mudflow sensitive area. When the shear stress generated by the wave motion exceeds the soil shear strength, the mudslide is triggered. The following factor determine (Hitchcock et al., 2006, Nodine et al., 2007) the magnitude of mud slide

- Slope angle
- Water depth
- Shear strength of sediments
- Wave height and wave period

The wave return period is also another important factor for determining the probability of future mudslide occurrence in mudflow prone areas. Nodine et al., (2007), conducted the assessment of mudslide in the current delta of Mississippi river based on the wave return period and identified the sensitive areas, their results are shown in Figure 43.

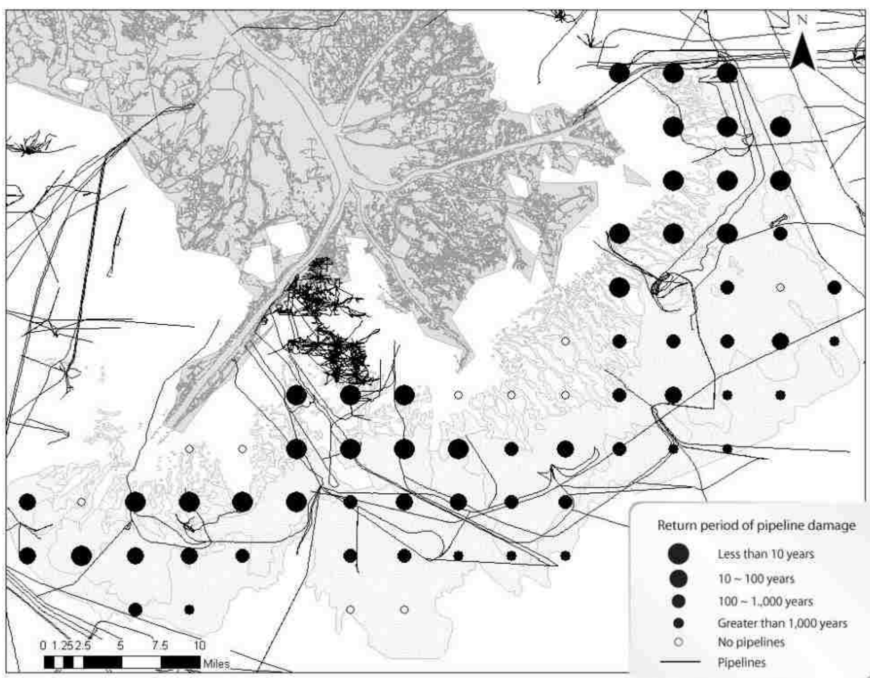


Figure 43: Return period of mudslides and corresponding pipelines in that region [From Nodine et al., 2007)

7.2.1 Installation Damage and Oil Spill due to Mud Slide

Mudslide may damage pipelines and platforms and as a result oil may be released to the environment depidcted in Figure 44. The Minerals Management Service in 2005, published a report of 24 incidents of damage to pipelines caused Hurricane Ivan. The spill due to pipelines and platforms damages is most probably small in magnitude, as production is usually stopped with the arrival of the storm. As the storm gets approaches, all personnel will are evacuated from the drilling rigs and platforms, and production is mostly shut down, even in the areas that are not directly in the path of the storm and this is the Industry’s Standard Practices.

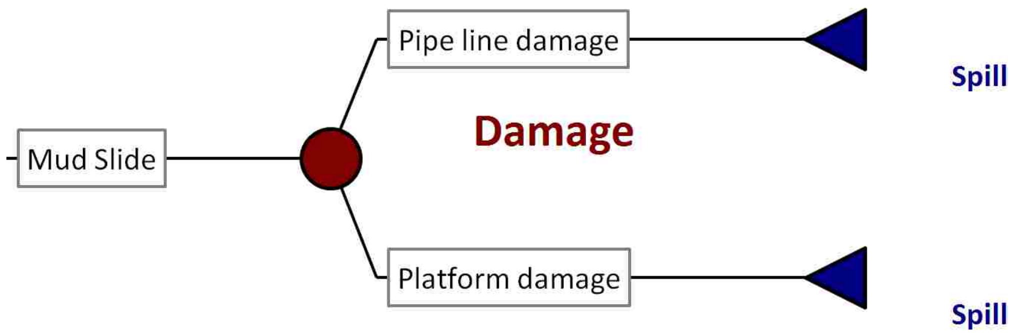


Figure 44: Pipeline and platform damage resulting in oil spills

Complexity of mud slide activity was manifested during hurricane Ivan, when Taylor Energy’s platform “A”, in Mississippi Canyon Block 20 (approximately 11 miles offshore in federal waters) was toppled. The 555-foot high platform slid 400-feet down slope, resting on its side and partially buried in 440-feet of water, shown in Figure 45.

Figure 45: Location of Taylor platform and oil sheen visible at surface [From RRT-6]

All production piping suffered structural damage and twisted together 150-feet below the original mud line. There have been numerous attempts to mitigate the oil sheen still seen at the site; however, the incident is very complex with numerous unforeseen variables and therefore very difficult to respond, (Regional Response Team 6).

7.3 Metocean Data

Metocean Data Gulf of Mexico: API RP 2MET deals with the Metocean conditions in the Gulf of Mexico. It divides the GoM in four regions of west, west central, central and east, these regions are shown in Figure 46.

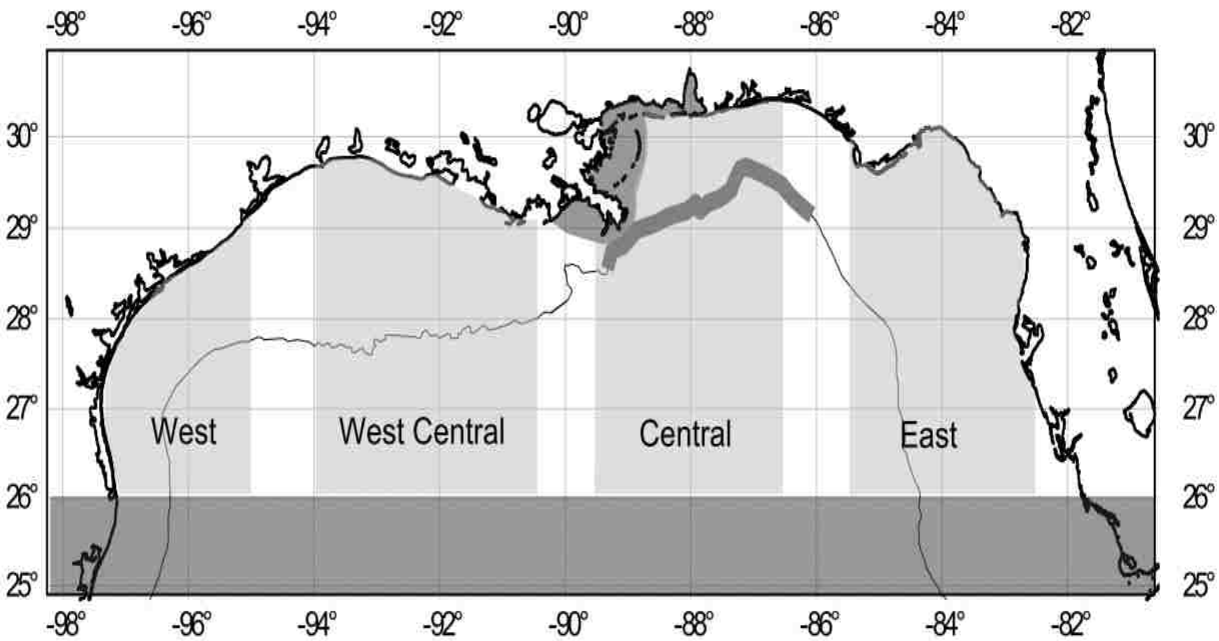


Figure 46: Division for Metocean conditions and region classification (From API RP 2INT-MET 2007).

A sample data for Metocean conditions for central region is shown in Table 37. This data is combined with other data sets related to offshore installation types and is used for quantitative risk analysis.

Table 37: Hurricane condition data for central GoM region (From API 2INT-MET, 2007)

Return period (years)	10	100	1000
Wind			
1-hour Mean Wind Speed (ft/s)	108.3	157.5	220.5
3-Sec Gust (ft/s)	153.9	241.8	370.1
Wave, WD > = 3280 ft			
Maximum Wave Height (ft)	58.1	91.5	128.3
Period of Maximum Wave (s)	11.7	13.9	16.4
Currents, WD > = 492 ft			
Surface Speed (ft/s)	5.4	7.9	11

7.4 Weather Induced Adrift Of Offshore Dynamic Structures

During the past hurricanes in the GoM, especially during hurricane season of 2004 and 2005 a large number of Mobile Offshore Drilling Units (MODUs) that were exposed to hurricane force winds had partial or complete failure of their mooring systems. During hurricane Rita, 14 out of 16 MODUs exposed to the hurricane force winds, failed to keep their station (DNV Report NO. 448 14183). Most of these MODUs were stationed on location by using drag embedment type anchors. A MODU with mooring system is shown Figure 47, below.

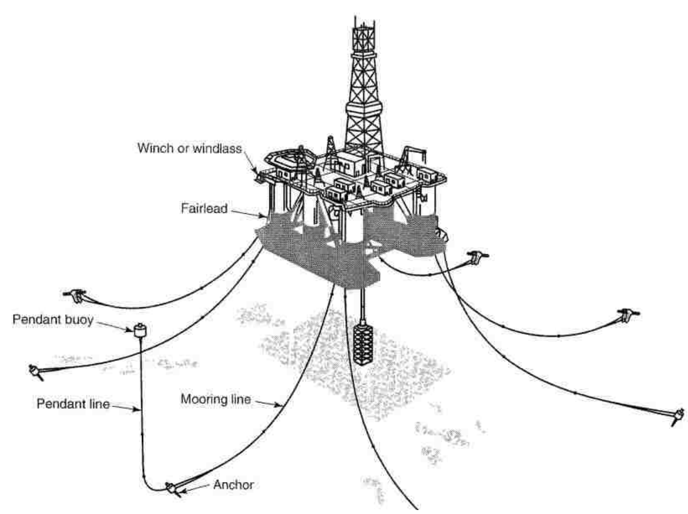


Figure 47: An example of spread mooring [From API-RP 2SK]

These drifting structures were responsible for some of the pipeline damage occurred due to their anchors dragging along the sea floor, and they may damage other surface/subsea facilities as well. Fortunately no collision of drifting MODUs occurred during hurricane seasons of 2005 and 2008. Map of the original rig location before the storm, their drifting path and final location is shown in Figure 48. There have been spills associated with anchors damaging the oil carrying pipelines to onshore facilities during the normal day to day operations. In one of the incident, the drilling rig that was towed dragged the pipeline along the seafloor 650 ft from its original location and 1800 bbls of oil were spilled (Hoover Mary J. 2002).

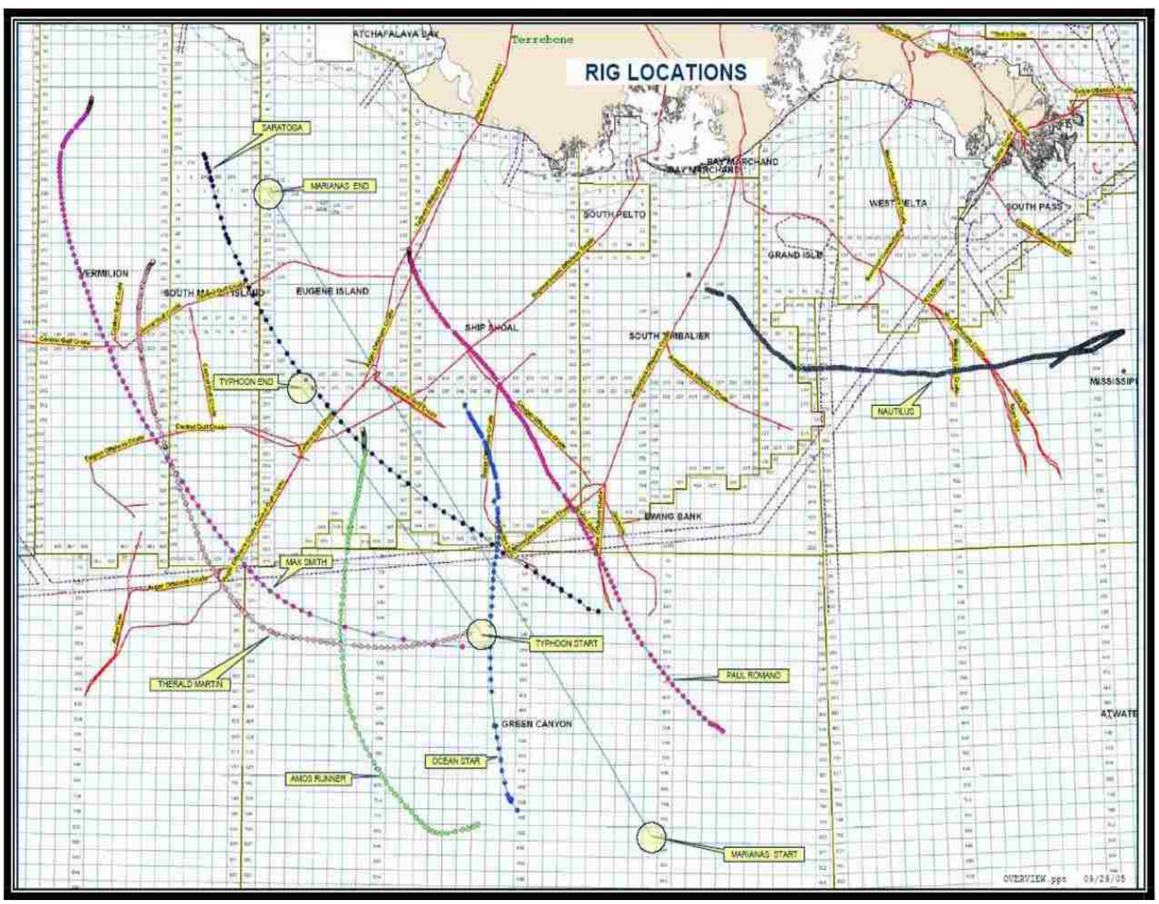


Figure 48: Map of rig locations and paths adrift after hurricane Rita (From DNV Report NO. 448 14183)

The issue of station keeping was addressed promptly by the industry and some new regulations about station keeping were introduce by MMS before the start of new hurricane season in 2006 (Ruinen, 2009).

But later on some mooring failures were also observed in Gustav and Ike hurricanes in 2008 (Petruska et al., 2009), although these were weaker category storms when they entered OCS in GoM. API-RP-2SK deals with the MODU anchoring specifications. For the hurricane season, API recommends a risk based assessment of the mooring system. The factors that are taken into account for risk based system are duration for MODU mooring, infrastructure in the immediate vicinity of MODU and consequence modeling of the mooring line failures (Ruinen, 2009). Keeping in view of these recommendations, the MODU operators have upgraded their mooring systems with bigger anchors and adding more mooring lines. A pre and post 2005 sanctioned comparative study conducted by D'Souza et al., in 2014, shows these enhancements in weight and displacement capacity. Lost mooring incidents of MODUS for hurricane Gustave in 2008 are not reported in literature. But some of the Jack-Up rigs lost position incidents were reported. It can be seen from

Table 38, that during hurricane Gustave in 2008, some of the MODUs drifted away as well. In terms of their capacity to damage other installations, they are comparable to moored rigs. Therefor adrift of whole platform due to severe weather is still a possibility.

Table 38: MODUs Jack-Up drifting from their original location (From Sharples, 2009)

Unit Name	Hurricane	Drift
ENSCO 74	Gustav	No Information
Pride Wyoming	Gustav	30 miles
Rowan Anchorage	Gustav	5000 ft away

7.5 Pipeline Damage Due to High Wind Loads

The majority of the pipeline damages caused by past hurricanes in the GoM mainly occurred at or in the vicinity of the platforms (DNV Report- 44814183), shown in Table 39. Some damages were also reported by the anchor dragging. There were more than 600 pipeline incidents reported to MMS for the Hurricane Katrina and Rita (DNV Report- 44814183). Outside force is the damage not directly caused by the storm.

Table 39: Pipeline damages reports for different hurricanes, NR* stands for not reported

Hurricane	Year	Total damage Reports	Platform Damage	Mudflow Damage	Riser Damage	Pipe damage or Displacement	Outside Force Damage	Others and Unknown
Andrew	1992	485	253	10	103	44	18	57
Lili	2002	120	16	NR*	78	NR*	NR*	6
Ivan	2004	168	20	16	67	38	9	18
Katrina	2005	299	139	1	66	61	9	14
Rita	2005	243	94	0	89	31	8	21

It is to be pointed out that actual pipeline damages may be higher than the number of damage reports, as some of the reports have multiple damage details, sometimes up to 20 (DNV Report- 44814183).

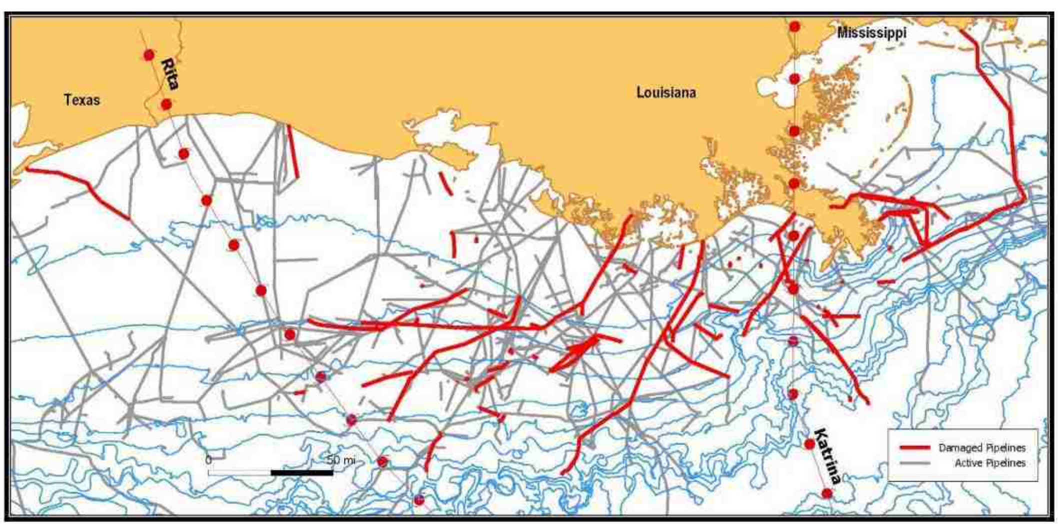


Figure 49: Pipeline damage reported for Hurricanes Katrina and Rita [From DNV Report-44814183]

The above Table 39 only shows the number of reports that MMS received. A visual description of pipeline damages reported to MMS for Hurricanes Katrina and Rita are shown in Figure 49**Error! Reference source not found.**. It is interesting to note that most of the damages seemed occurred away from the main path of the hurricane.

7.5.1 Pipelines Damaged Types and Related Spills

A study sponsored by MMS (DNV Report NO. 448 14183) to investigate the causes of pipeline damages during hurricane Katrina and Rita, revealed that most of the reported incidents occurred in small diameter pipes and in shallow waters less than 100 f t. It was found that almost 70% of the damages reported were at risers, and they occurred at the riser platform interface as shown in Figure 50.

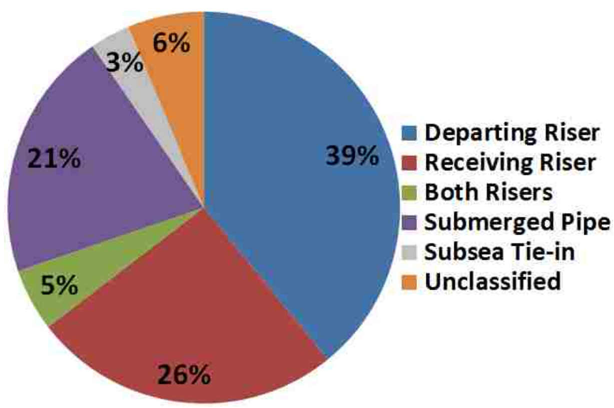


Figure 50: Pipeline damages by its location (DNV Report NO. 448 14183)

72 oil spill incidents were reported for hurricane Katrina and Rita and around 7,300 barrels of crude oil and condensate spilled into GoM, the data is shown in Table 40**Error! Reference source not found.**. The amount of oil spilled as a result of pipeline damage is not very large due to the reason that before any major storm, some precautionary measures are taken and usually production is halted during storm period. Only the amount of oil present in the pipeline may be spilled when the hydrocarbon's source is shut off. If the well is not shut off

properly or SCSSV fails to shut in the well, then depending on the flow potential of the reservoir a range of oil volume may be spilled.

Table 40: Oil spilled due to Hurricanes Katrina & Rita (DNV Report NO. 448 14183)

Storm	Source	Petroleum (bbl)	Crude Oil & Condensate (bbl)	Counts
Katrina	Pipelines	2709.6	2709.6	43
Rita	Pipelines	4577.2	4577.2	29
Total	Pipelines	7286.8	7286.8	72

7.6 Platform Damages Due To High Wind Loads

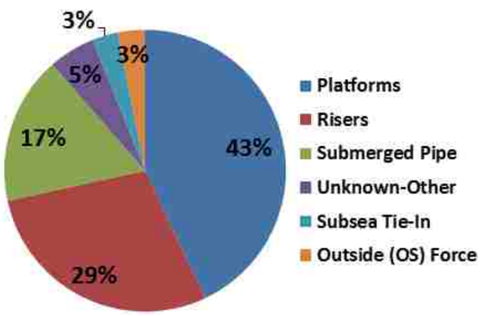
Hurricane Andrew made a landfall on the west of Mississippi current delta and it destroyed 22 platforms and caused damaged to 65, amongst the 700 structures that were lying on its pathway. Data for other past hurricanes is shown in Table 41. The damage caused by hurricanes Katrina & Rita to offshore facilities in GoM was wide spread. MMS reported that nearly 3050 out of 4000 platforms were in the path of these two hurricanes. 116 platforms were destroyed and around 52 were severely damaged by these two storms together.

Table 41: Platform exposed, damaged or destroyed during past hurricanes (From DNV Report-44814183)

Hurricane	Year	Platforms Exposed to Hurricane Forces	Platforms Destroyed	Platform Damaged	Percentage Exposed Platforms Destroyed	Percentage Exposed Platforms Damaged
Andrew	1992	700	22	65	3.10%	9.30%
Lili	2002	800	2	17	0.25%	2.10%
Ivan	2004	150	7	31	4.70%	20.10%
Katrina	2005	1000	47	20	4.70%	2%
Rita	2005	2050	69	32	3.30%	1.60%
Gustav	2008	-------	2	-------	-------	-------
Ike	2008	-------	60	-------	-------	-------

7.6.1 Damage Categories

The damage assessment form the reported incident shows that, the highest incident involved the failure of the platforms, nearly 43%, followed by riser failure 29% and then submerged pipelines around 17 %. The data is shown in Figure 51, below.



Damage Category		Hurricane	
	Total	Katrina	Rita
Platforms	233	141	92
Risers	155	63	92
Submerged Pipe	92	61	31
Unknown-Other	29	14	15
Subsea Tie-In	16	11	5
Other Forces	17	9	8
Grand Total	542	299	243

Figure 51: Reported failure category distribution (From DNV Report- 44814183)

The severity of the damage caused by Rita can be seen in Figure 52, in which Chevron's Typhoon TLP's condition before and after hurricane is shown. The platform capsized during the hurricane.

Figure 52: Chevron's Typhoon TLP - pre and post hurricane Rita condition (From DNV Report-44814183)

7.6.2 Platform related Oil spill

During hurricanes Katrina & Rita a total of 52 oil spill incidents were reported to MMS, and the total amount of spill was not significant in this. A total of 10,366 barrels of petroleum were released to the environment due to the damages or destruction to offshore structures (DNV Report- 44814183). The data is reported in Table 42, below.

Table 42: Oil spilled due to destruction or damages to offshore structures

Storm	Source	Petroleum (bbl)	Crude Oil & Condensate (bbl)	Refined Petroleum	Counts
Katrina	Platforms & Rigs	2842.5	2252.4	590.1	27
Rita	Platforms & Rigs	7522.9	3598.2	3924.7	25
Total	Platforms & Rigs	10365.4	5850.6	4514.8	52

7.7 Mudslide Hazard Calculation

The mud hazard may be defined as wave-induced pressure acting on the sea floor and tendency of sea floor to move (Nodine et al. 2007). The procedure to calculate the mud slide hazard for South Pass Block 70 in GoM, is adopted form (Nodine et al. 2007), and is described below:

1-The maximum wave induced pressure, acting on the sea floor can be calculated with 2D approximation by the following equation

$$P_{max} = \frac{\gamma_w}{2}\left[\frac{H_{max}}{cosh\left(\frac{2\pi d}{L_{H_{max}}}\right)}\right]$$

where $\gamma_w =$ water density, $H_{max} =$ maximum wave height (ft), d = water depth, L_{Hmax} = Maximum wavelength

2-The wave length associated with largest wave is calculated based on the wave speed and peak spectral period data from API RP MET (2007).

$$v = L_{H_{max}} \times t$$

Where v = wave speed (ft), L_{Hmax} = wave length corresponding to maximum wave height, t = wave period (1/sec)

3-Different dimensionless parameters were calculated from known values of water depth (d), maximum wave generated pressure (P_{max}), wavelength of wave (L_{Hmax}), slope angle (β), soil density (γ), soil shear strength (C_o) and shear strength gradient (C_z).

$$\Psi = \frac{\gamma L_{H_{max}} tan\beta}{P_{max}}, \quad \Omega = \frac{C_z L_{H_{max}}}{C_o}, \quad \Phi = \frac{C_z L_{H_{max}}}{P_{max} F}$$

The final product of the analysis is to determine a mudslide initiation threshold factor F. This threshold factor can also be defined as the ratio of the resisting moment to the driving moment or ratio of the developed shear stresses to the undrained shear strength of the soil

$$F = \frac{undrained\ shear\ strength}{acting\ stresses} = \frac{resisting\ moment}{driving\ moment}$$

The chart shown in Figure 53, is used to find the threshold value F for onset of the mudflow. This chart is based on the limit equilibrium model. The value of Ψ and Ω are used to find the value of Φ on the y-axis, then F is found fromΦ. The assumptions behind the chart are that soil shear strength increases linearly with depth and assumes a rigid seafloor (Nodine et al., 2007).

For F ≥ 1, the soil is stable and for F< 1, it is prone to mudslide. The driving mechanism for mudflow is the combination of wave generated pressure, the weight of the soil and slope angle of sea floor.

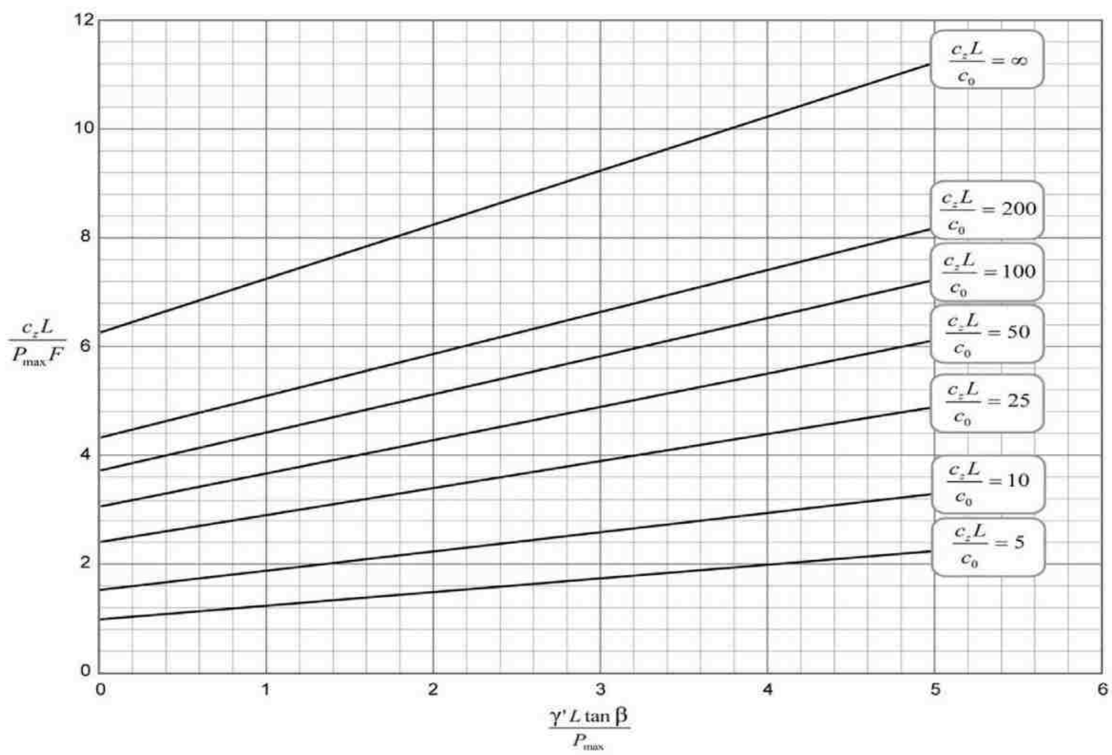


Figure 53: Stability chart based on limit equilibrium stability model to find the value of safety factor (From Nodine et al., 2007)

It is to be pointed here that not every mud slide will lead to damaging the pipeline, and there have been incidents reported (Nodine et al. 2007), when mudslide occurred and the pipeline was not damaged, it was either buried or displaced without any rupture occurring.

7.7.1 Example: Mudslide Risk Assessment for SP-70 Block

An example mudslide calculation for South Pass Block 70 in the Gulf of Mexico is shown below. The analysis parameter are taken from Nodine et al., 2007 and based on the wave return period, the mudslide threshold factor is calculated. Some of the related parameters are shown in Table 43.

Table 43: Parameters specific to South Pass Block 70 (From Nodine et al., 2007)

Water Depth d (ft)	**Slope Angle β (radians)**	**Submerged Soil Density (pcf) γ**	**Water Density (pcf) γ_w**	**Shear Strength at Mudline C_o (psf)**	**Shear Sterngth Gradiant C_z (psf/ft)**
335	0.00023	30	64	50	1.5

The approximate location of the block SP-70 in the GoM is shown below in Figure 54. The block is located about 15 miles southeast of the Main Pass of the Mississippi River.

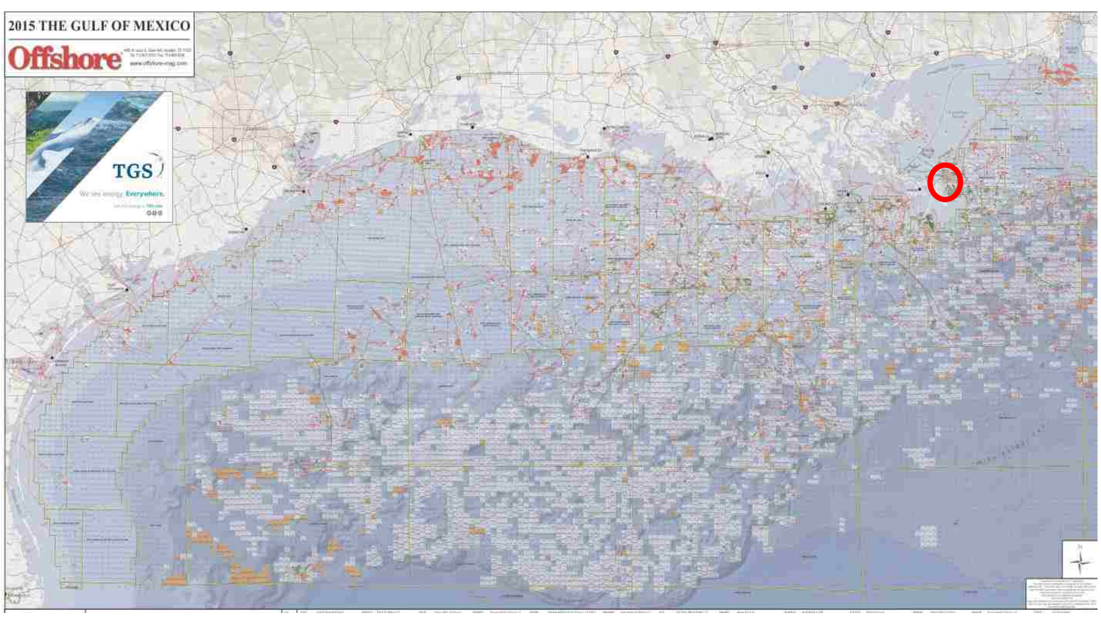


Figure 54: Approximate location of South Pass Block 70 shown by red circle (taken from Offshore Mag)

The data from Table 43, is used to calculate the values of safety factor or mud threshold factor. Mudslide threshold factor for different categories of storms or storms with different return periods are shown in Table 44, below. It can be seen that storms with return period of more than 10 years are of concern. While for a storm with 10 years return period, mudslide threshold factor is above 1 and mudslide most probably may not occur.

Table 44: Safety factor calculations for South Pass block 70 in the Gulf of Mexico

Return Period (Years)	Frequency Per Year	Maximum Wave Height (ft)	Wave Period (s)	Wave Speed (ft/s)	Wavel ength (ft)	Pmax (psf)	Ψ	Ω	Φ	Threshold Factor F
10	0.1	52	11.7	108.3	1267	610	0.0143	38.01	2.9	1.09
25	0.04	70	13	131.6	1711	1206	0.0098	51.32	3.2	0.66
100	0.01	83.5	13.9	157.5	2189	1783	0.0085	65.68	3.3	0.56
200	0.005	87.5	14.1	167.3	2359	1965	0.0083	70.77	3.4	0.53
1000	0.001	104	15.5	196.9	3052	2668	0.0079	91.56	3.6	0.48

As pointed earlier not every mudslide will result in damaging the pipeline in such a way that it will lead to spill. Sometimes pipelines are just buried under the mud or shifted by the mudslide and they can tolerate the damage to some extent before breaking apart or leaking. It also depends upon the life of pipeline and its condition. If it is already corroded and near to fail, than even a small external movement will cause fracture in the pipeline, which can lead to oil spill.

7.7.2 Spill volume calculations: mudslide resulting in pipeline damage

The length of the trunk line pipeline upslope from SP 70 block is approximately 8 miles, due to production shut off, it is assumed that only half of the line may be filled with oil and only upslope portion of the fluid may be leaked, provided that the outside hydrostatic pressure is less than the fluid pressure exerted at the pipeline breakup point. Some oil will also flow due to gravity segregation as well.

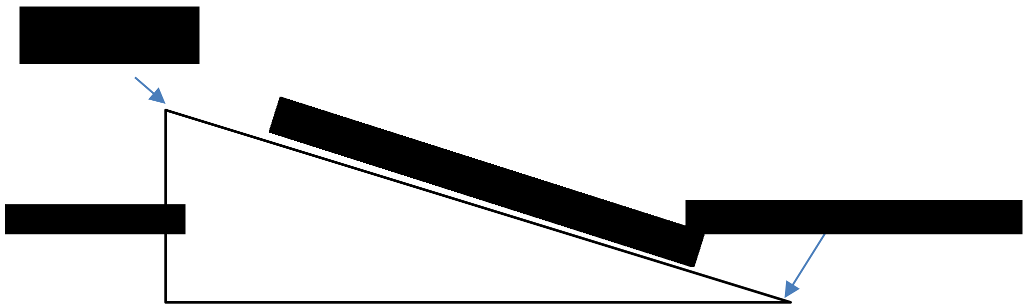


Figure 55: Schematic of trunk line from leaking point to terminal

There are two mechanisms working on the down dip portion of the damaged pipeline, hydrostatic pressure exerted by the column of water and gravity segregation of fluids. At the rupture pint the oil can be leaked only when the hydrostatic pressure of oil in the pipeline exceeds the pressure exerted by the column of 335 ft of water, or due to lighter density oil will rise to the water column. The specific gravity of oil is taken to be 0.8.

$$\rho_o g h_o \geq \rho_w g h_w$$

The amount of oil spill due to trunk pipeline rupture is shown in Table 45. The amount of spilled oil does not falls in the sever category for the example case studied.

Table 45: Amount of oil spilled due to mudslide slide resulting in pipeline rupture

Return Period (Years)	**Frequency Per Year**	**Threshold Factor F**	**Pipeline Diameter**	**Oil Volume to Pipe Volume ratio**	**Spilled Amount (bbls)**
25	0.04	0.663	14	0.7	5630
			16	0.7	7353
			18	0.7	9306
			20	0.7	11489
			24	0.7	16545

7.7.3 Spill volume calculations: mudslide resulting in riser damage

Under the assumption that production was shut in before the arrival of the storm, the amount of oil spilled as a rupture of production risers is shown in

Table 46. Please note that a large amount of soil movement may lead to leaking the wellheads as well, in those scenarios the worst case discharge rate calculations are not easy to perform and the worst case discharge rate calculations will involve the procedure adopted in spill associated with normal production operations.

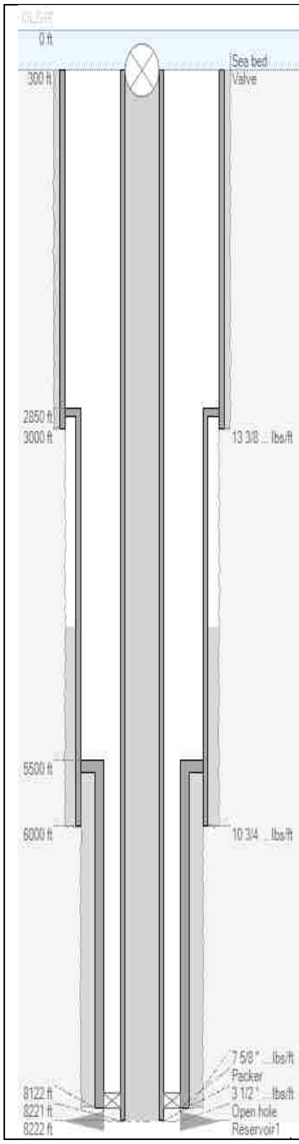
Table 46: Platform spill as a result of riser leaks due to high wind and high wave generated stresses

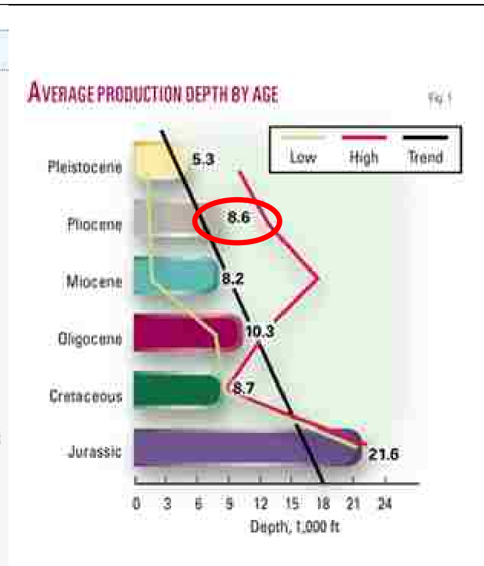
Frequency Per Year	Flow line Size inches	Riser Length (ft)	Number of Risers	Spilled Volume (bbl)
0.04	6	400	2	28
	6	400	4	56
	6	400	6	84
	6	400	8	112

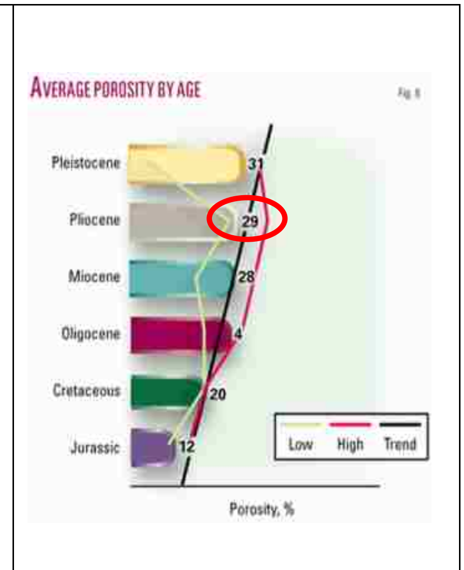
If the reservoir has been produced for a while, than the decline in reservoir pressure over the production life span before the incident happen should be taken into account as well.

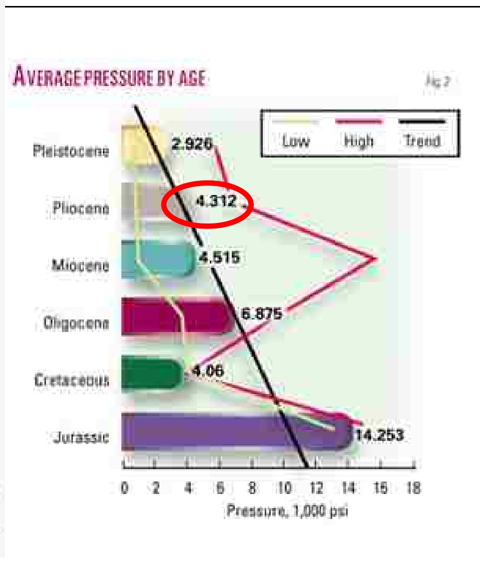
7.8 Mudslide resulting in severely damaging a production platform

To simulate this case a reservoir in the block SP-70 in the GoM is shown in Table 47. The reservoir properties are taken from and a typical well configuration is considered for a typical sand depth. The well schematic and corresponding reservoir properties are shown in Figure 56 below.









Parameter	Value
Pressure (psi)	5482
Temperature (F)	178
Sw	0.28
GOR (SCF/STB)	935
Porosity	0.29
Payzone Thickness (ft)	70
API Oil Gravity	33
Soft Geopressured (psi/ft)	0.7
PI (STB/(day-psi))	7.147

Figure 56: Selected well schematic, regional reservoir properties and the selected values used are shown.

It was assumed that due to severe mudslide platform moved to more than 150 ft from its location. Platforms displacement caused the tubing and casing to be pulled up and SCSSV was damaged and a leak was developed. Leak point is buried under 100 ft of mud & 200 ft of water column with back pressure of 177 psi. Reservoir is saturated at the beginning of spill. Due to shallow water depth of 300 ft and TVD of only 8222 ft, duration for relief well drilling is taken of 60 days. The bent tubing rupture is represented by a leak. When the reservoir pressure is not sufficient enough, the oil will be migrating to the sea floor due to gravity segregation process only and the discharging volume will be not substantial. In this study it is assumed that the leak diameter is a fraction of the production tubing diameter. In some of the cases, leaking diameter can be larger than the tubing diameter, when tubing is ruptured or due to erosion, initial leak diameter is enlarged.

Table 47: Platform spill for a production platform in the shallow water GoM

Reservoir Pressure (psi)	Tubing dia to Leak dia ratio	Flow Rate (bbl/day)	Amount Spilled (bbl)
5482	0.089	6485	389096
	0.179	2886	173150
	0.268	3404	204248
	0.357	3697	221829
4000	0.089	3729	223755
	0.179	5245	314676
	0.268	5912	354739
	0.357	6287	377250
3000	0.089	1932	115890
	0.179	8462	507728
	0.268	9165	549901
	0.357	9579	574747
2000	0.089	0	0
	0.179	0	0
	0.268	0	0
	0.357	0	0

7.8.1 Modeling of Mudslide Risk

The risk modeling or risk quantification for the mudslide during hurricane season can be done in the same way as described for the earlier scenarios of drilling and production and may be expressed as

$$\mathrm{MSR} = \mathrm{MSH} \times \mathrm{MSC} \qquad (1)$$

Where

MSR mudslide risk

MSH mudslide hazard

MSC mudslide consequences

Mudslide Hazard (MSH): Mudslide hazard may be defined and the product of probability of occurrence of mudslide during hurricane season and the scale on which it occurs

$$\text{MSH} = \text{Probability } \times \text{Scale of mudslide}$$

The probability and scale both are related to the regions geological features and the characteristics of hurricane waves.

Mudslide Consequences (MSC): Mudslide consequences may be expressed in terms of number of installations damaged in that particular region in which mudslide happens. A large number of offshore structures in severe mudslide prone regions will result in severe damage as compared to the area with least installations. This was demonstrated in the hurricane Ivan, which passed to the east of Mississippi delta and caused more damage, due to the number of installations in the mudflow prone areas. The areas along the continental slope are highlighted as mudslide prone area with more risk, both in terms of mudslide probability and consequences as well, as these areas also have some of the major offshore structures near the shore lines in shallow waters.

7.9 Production Halt

It is to be pointed out here that almost all of the production activity is halted during the hurricane duration and usually it increases rapidly if there are not severe damages to installations. It may happen that pre storm production level may not be achieved even after one year, as some of the installations are permanently damaged. The percentage of GoM production shut in during the three major storms is shown in Table 48.

Table 48: Production Shut-In due to hurricane, historic trends [data taken from DNV REPORT NO. 448 14183, 2007]

	Oil Production Shut-In		
Period	Ivan	Katrina	Rita
Max Shut-In	82.90%	95.20%	100.00%
1 Day After	72.50%	95.10%	100.00%
2 Days After	64.70%	90.40%	100.00%
3 Days After	51.50%	88.50%	100.00%
4 Days After	41.10%	79.00%	98.60%
5 Days After	39.20%	73.30%	97.80%
6 Days After	34.00%	69.60%	94.70%
7 Days After	27.70%	58.00%	92.80%
14 Days After	28.50%	56.40%	77.50%

As can be observed form the table that most of the production was shut in during the major storms, therefore reported spills for the hurricanes are minor in nature. This shut-in is usually achieved by closing the subsurface safety valves and adopting hurricane preparation plans developed by BSEE.

7.10 Spill Response Technologies for weather induced Spill

Depending on the type of the installation involved and the volumetric rate of hydrocarbons, different spill response systems could be deployed. In the case of the fluid coming from the inside the wellbore and provided that the well integrity is not compromised, a set of suction cones developed along the capping and containment systems can be used for these incidents. If the volumetric flow rate of hydrocarbons is high, capping stacks could also be used in these cases. For the cases in which hydrocarbons are flowing outside the well casings, depending on the nature of the leak either cone shaped collectors shown in Figure 57, or suction tubes may be used.

Figure 57: Cone shaped collector used in oil suction on Taylor Energy's buried platform (from RRT-6)

7.11 Qualitative Risk Matrix

Oil spill risk associated with severe weather conditions are qualitatively presented in the risk matrix shown in Figure 58. Based on the historical spill incident reported in the literature, most of the spills occurs near the platforms, due to wave and wind load damage to risers and they are of very small amount. So these spills have the highest frequency/probability, but their consequences are not very significant, as a result they lie in the yellow region in the risk matrix. The most serious consequences could result when the platform damage leads to a spill from wells as was in the case of Taylor energy's platform. The other serious consequences may arise, if the wellhead is damaged and it leads to spill. It is to be pointed out that during or immediately after the storm, due to problems in mobilization of the response systems, a blowing well may result in very serious consequence.

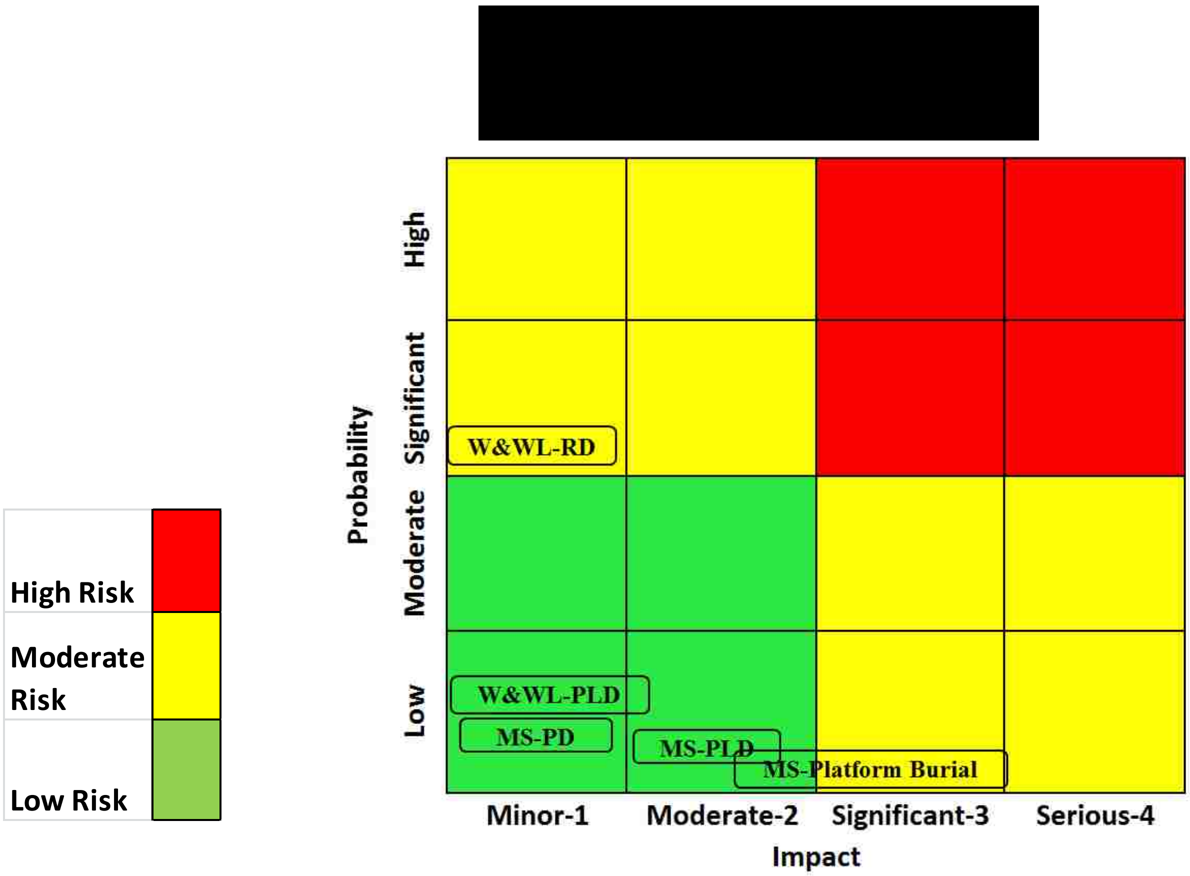


Figure 58: Qualitatively risk matrix for spills due to severe weather conditions

7.12 Conclusions and Observations

- GoM is prone to hurricanes ranging from category 1 to category 5 and in the recent past severe damage to pipelines and platforms has been reported, and there is always the possibility of a spill resulting from either pipeline or platform structural damage.
- Severe weather may also result in drifting of floating offshore structures, especially MODUs. These drifting structures may pose threat to other offshore facilities. Their

collision with other platforms or their anchors dragging along the sea floor may result in severely damaging subsea installations and may lead to a spill.

- A sample analysis perfomed in this study and past huuricane related spill data shows that most of the spills associated with severe weather will be of small amount, as most of the drilling/production operations are stopped before arrival of the storm.
- According to oil industry’s standard procedure for hurricane, all of the production in the expected path of the hurricane is shut down and offshore facilities are evacuated. Therefore damage to pipeline or platform will not lead to a large spill.
- In shallow waters of up to 400 ft in current or old Mississippi river delta, the mudflow caused by high wave surge phenomenon is the biggest hazard for offshore installations. This mudslide may lead to a very complex situation in which it may become difficult to estimate the WCD rate or deploy the proper response system to stop the spill. The burial of Tylor’s energy’s platform is such an example.
- The South Pass block SP-70 in the current Mississippi river delta was selected to conduct the mudslide quantitative risk assessment. An example calculation has been performed for mudslide resulting in pipeline and platform damage and resultant spill amount.
- Aanalysis shows that a storm with return period of 10 years may trigger the mudslide in South Pass-70 block, which may lead to offshore faicilties damage.
- Historical data trend shows that most of the spills reportde for past hurricane, occured in the vicinity of the platforms due to riser damage. The sample caluculation performed show an oil spill of 112 bbls only, in the case that risers are damaged in the vivinity of hypothetical platform in SP-70 block. Amongest the weather related spills, rsiser spills are most frequent but least harmfull in terms of spill amount.

- A worst case discharge rate of 6485 BOPD was estimated by selecting representative well and reservoir properties corresponding to a hypothetical production platform in the SP-70 block, when mudslide results in complete burial of the platform.
- The deployment of response system in this case becomes very difficult, due to difficulty in exactly pointing out the source location. Some type of marking/coating on the conductor casing are suggested, which may be useful in this type of burial scenario to identify the location of the souce.
- Adrift of floating structures is still a hazard, even after stringent regulatory requirements for fastening these systems. The drifting structure can damage other installations on sea surface or subsea and can result in very small to large oil spills.
- Spill response systems for the weather related incidents needs enhancements, especillay collection domes/cones that are usually used in response to such events have not proven very useful in past.

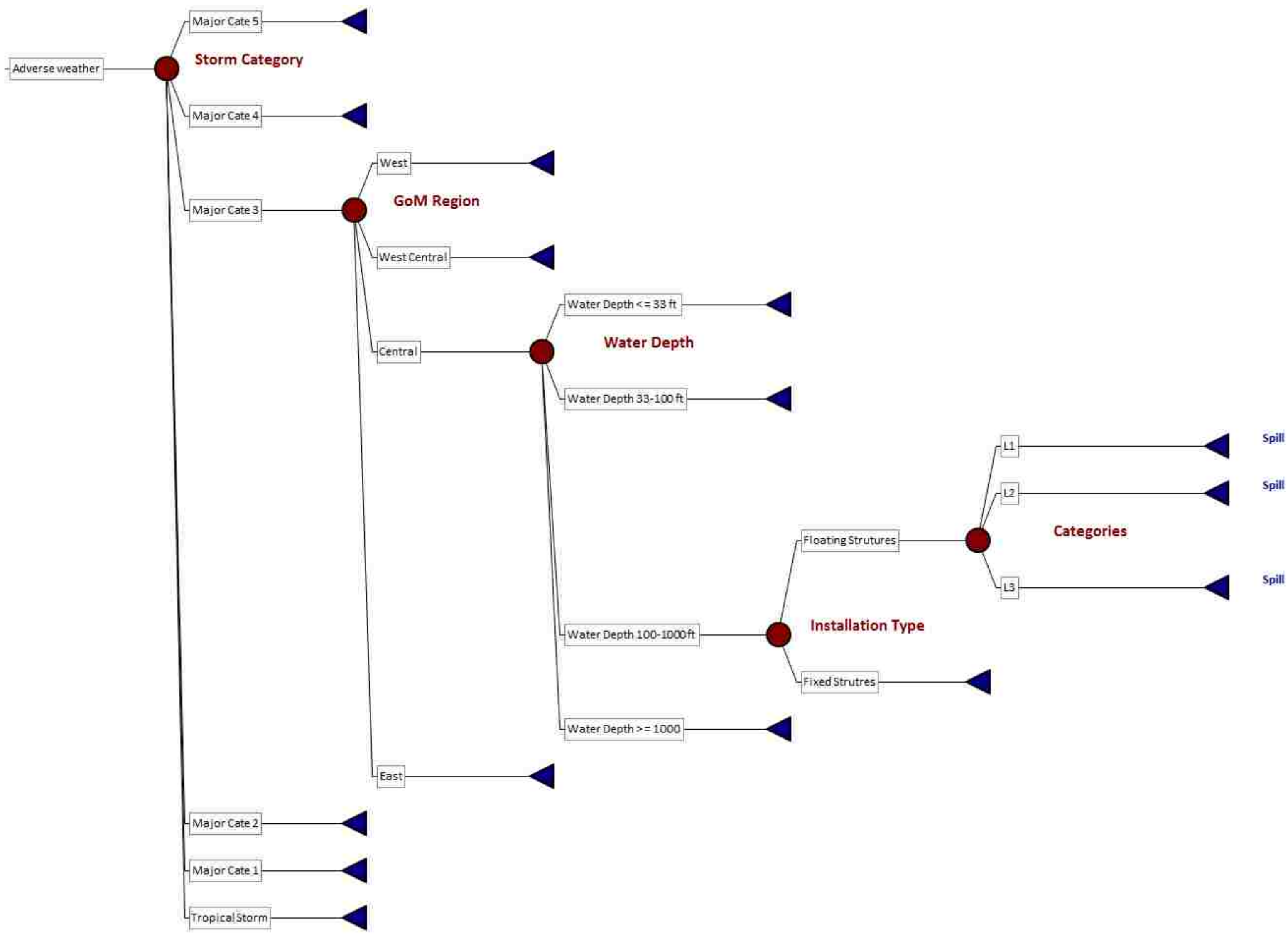


Figure 59: A qualitative presentation of risk assessment steps to be adopted for offshore structures due to adverse weather conditions

CHAPTER 8: CONCLUDING REMARKS AND FUTURE DIRECTIONS

Concluding remarks for all of five oil spill scenarios modeled in this study are given below.

8.1 Scenario-1: Exploratory Well

- An example of quantitative risk assessment (QRA) for deepwater exploratory drilling well blowout is presented, QRA facilitated in better understanding of blowout risks.
- The selection of a specific well and corresponding reservoir properties and taking into account the regional variation in reservoir properties by fitting lognormal/triangular distributions and conducting Monte Carlo simulations, provided a realistic representation of the reservoir properties to calculate the worst case discharge rates.
- Unexpected pore pressure, delayed response to an incident and failure to detect the error were found to be three most important basic events contributing to the overall risk of the system. These were identified by conducting Fussell Vesely (FV) importance analysis.
- The FV importance analysis emphasize the need to focus on the technologies to provide early warnings for unexpected pore pressure during drilling phase, eliminating the delays that can occur when responding to an emergency situation by automation of some of the decision processes and technologically improve the reliability of sensors that detect an error. Crew training and management is also an important element in responding to situations that needs immediate attention.
- The worst case discharge rate of nearly 104,000 BOPD was estimated for the case when drill pipe is out of the hole and BOP offers no restriction to blowing hydrocarbons

(conditions specified by BSEE to estimate WCD). The occurrence of this combination of events is amongst the least probable situations. Therefore risk which is a product of probability and spilled oil volume is not very high in this case.

- The 100,000 BOPD oil handling capacity of newly built capping and containment systems is nearly sufficient to either capture or contain the computed worst case discharge oil rate of 104,000 BPD.
- The reservoir pressure drop and resultant reduction in flow rate are not significant in the cases when the fluids are flowing either through drillpipe-casing annulus or through drill pipe.
- The selection of the multiphase correlation also affects the worst case discharge rate estimates and computed values with some other correlation may differ from the values computed in this study, therefore this variation in values must be considered when making decision based on the WCD rates.
- Restrictions in the flow path substantially decrease the fluid flow rate and in some of the circumstances may even choke the flow.
- Newly built response systems are effective in reducing the risk of large oil spill in deepwaters environments, provided that they function properly when they are deployed. Capping and containment systems are effectives for only one type of failure mode i.e., when the flow is coming through the well, which is the most probable scenario based on the historical blowout data.
- Addition of intervention module in capping and containment systems will enhance their capabilities to deal with other failure modes as well. For example dynamic kill may be used in the case of an underground blowout.

- In the case of a blowing well affecting nearby wells, the situation may become complex and would require additional modules to be added with capping and containment systems or invoke other response systems.

8.2 Scenario-2: Underground Blowout

- The consequences of an underground blowout range from no visible damage at the sea surface to the loss of the whole rig. It is difficult to quantitatively estimate the risk due to the involvement of large number of uncertain parameters.
- The potential of hydrocarbons leaking to sea floor is a combination of geological settings, the transmissibility of the paths allowing hydrocarbons to reach sea floor, the pressure of source reservoir and its potential to create fractures in the low lying geological barriers.
- The formulas used to estimate the fault permeability and thickness are very simple and large uncertainty exists in the estimated parameters of fault permeability and its thickness.
- The simulation result show that for low permeability k=0.004 mD fault, that connects a deep over pressured zone to a shallower low pressure zone, the time taken to recharge the shallower zone to reach its LOT pressure value is more than 100 years.
- A high permeable faulted zone of 40 mD will take 135 years to recharge the low pressure shallower zone to its LOT pressure value.
- In the reservoir model adopted in this scenario, when the ratio of the volume of shallower to deeper zone decrease to 0.1, the recharging time significantly drops to 24 years only. Therefore ratio of the two zones is also an important parameter alongside their pressure differential and the transmissibility of the connecting zone.

- The worst conditions may occur when the hydrocarbons travel through the casing-wellbore annulus and may either reach to shallowest zones lying very close to mud line or leak outside of the well. The casing-wellbore annulus path may have very high permeability due to fractured cement and/or due to micro annulus gaps in this path. In this case the hydrocarbons may appear at the sea floor during the drilling activity.

8.3 Scenario-3: Production Well

- The QRA study of a deepwater production well has been performed and key contributors to overall system safety have been identified through fault tree analysis.
- Sensitivity analysis of all of the basic events in the constructed Fault Tree for a sand screen failure leading to blowout was conducted. It turned out to that the three most important basic events contributing to the frequency of blowout are sand screen failures, subsea production tree's control system failure and well control/other failures.
- It has been suggested by other researchers that the design improvements of the sand screen will greatly reduce their failure rates and in turn blowout frequency associated with production well, as it is one of the most sensitive/important basic event in the system setup, considered for this scenario.
- Subsea production tree's control system is the second most important basic event in the system, and even a small improvement in the reliability of control system will greatly influence the blowout frequency of the entire system.
- Monte Carlo simulation results for blowout probability show a range of values between 1.54-2.0 $\times 10^{-5}$ per well-year, when each of the basic events is varied by $\pm 10\%$.

- A WCD rate of 34,546 BOPD was estimated using multiphase fluid simulations and it is well within the fluid handling capacity of newly built response systems called capping and containment systems. Newly built response systems are effective in reducing the risk of large oil spill in deepwater environments. Additional tools like adopter spools may be needed to connect capping stack to subsea trees with different connector profiles.
- The blowout frequency modeled by FTA is based on the historical data and therefore it is a conservative estimate. When recent technological improvements are incorporated into FTA, the blowout frequency will be reduced, as in the past few years there have been major improvements in well safety related procedures. New regulatory requirements, equipment reliability improvements and extensive training of crew, all of these will contribute in lowering the blowout frequency estimates.

8.4 Scenario-4: FPSO

The deployment of FPSO for hydrocarbon production in GoM has some advantages and some related issues that must be taken care of.

- The proposed FPSO configuration for the GoM has been analyzed and associated risks are qualitatively and quantitatively presented.
- It has been reported by previous researchers that risk associated with FPSO deployment in the GoM are comparable to other production platforms and FPSO needs additional considerations due to its large fluid storage capacity, station keeping requirements and oil transportation mechanism.
- Most of the historical oil spills associated with FPSOs operations actually happened during oil transportation from FPSO to onshore facilities by shuttle tankers.

- Reported oil spill incidents involving FPSO vessel are mainly due to loss of its position keeping and during fuel offloading process. These spills are of very small quantity as compared to shuttle tanker spills.
- An example calculation based on the proposed configuration of FPSO for GoM has been performed to estimate the frequency of shuttle tanker collision with the FPSO and related spill amount.
- Analysis shows that only small amount 100-200 bbl of oil spills will result due to shuttle collision with other vessels including FPSO, and maximum spill amount will result when the shuttle tanker capsizes while carrying hydrocarbons from FPSO to onshore facilities.
- The probability of FPSO capsizing is very low, as there are no reported incidents. But if it is the case, a large oil spill will most probably be expected due to its large fluid storage capacity and other possible damages that can occur to wellheads or subsea installations.
- Amongst the spill response technology, oil skimmers boats seem to be the most appropriate for spills involving shuttle tankers as these are the most frequent spills involving production from FPSO.

8.5 Scenario-5: Weather Induced Spills

- GoM is prone to hurricanes ranging from category 1 to category 5 and in the recent past severe damage to pipelines and platforms has been reported, and there is always the possibility of a spill resulting from either pipeline or platform structural damage.
- Severe weather may also result in drifting of floating offshore structures, especially MODUs. These drifting structures may pose threat to other offshore facilities. Their

collision with other platforms or their anchors dragging along the sea floor may result in severely damaging subsea installations and may lead to a spill.

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- Spill response systems for the weather related incidents needs enhancements, especillay collection domes/cones that are usually used in response to such events have not proven very useful in past.

8.6 Approximations and Limitations

The following are the approximations and limitations of this study

- When conclusions have to be made based on the worst case discharge rates, the uncertainty/variation in the regional reservoir properties used to estimate the WCD should be considered as well. Therefore instead of a single value for WCD, a range of values will most probably justify the underlying assumptions.
- In estimating WCD, wellbore walls were considered as smooth as having uniform circular shape. This condition may not hold well in all the cases and addition of

roughness of wellbore walls due to mud cake or irregular shape of the wellbore due to drilling may lead to either low or raise the WCD estimates.

- Multiphase fluid flow correlations used to estimate WCD have their own uncertainties, due to underlying assumptions/simplification in developing these steady state models. The WCD estimate may differ amongst different multiphase fluid flow models.
- The component failure data available to author and used for production scenario is not the most updated data set available to large offshore operators. The data used set includes offshore reliability data up to 2001, and there has been a lot of offshore activities between 2001 and now. Therefore including the latest data will improve the accuracy of results.
- The BOP and production tree were modeled as a single component, and were not resolved into network of rams/valves and chokes. A detailed model by using the recent component data will definitely improve the reliability or failure rate prediction of these systems.

8.7 Future Directions

The study has the potential to expand in many dimensions; some of them are pointed here. Most of these can only be performed with access to extensive current data sets available and may need team work as well.

- For the exploratory drilling scenario, the failure rate of risers may be included in the analysis, that will incorporate the systems above BOP and whole drilling system may be analyzed including the type of rig.

- The subsea production filed analysis is another area that warrants attention and the entire production system can be modeled, starting form reservoir and terminating at the production facility.
- The GoM lease block may be taken as bases for a comprehensive weather induced risk analysis and a model database may be generated. The input parameters could be the locations and type of the offshore facility. The output may be a report including the entire hazards associated with that particular location and facility type under various scenarios of severe weather.
- The component failure data used in constructing the fault tree can be used to carry out the system reliability analysis as well. The systems may be represented as series or parallel combination and their mean time before the failure can be found. This may be very useful for economic analysis and downtime calculations, to estimate the cost associated with different delays.

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APPENDIX-A: PALEOGENE WELL SCHEMATIC AND WORST CASE DISCHARGE RATES

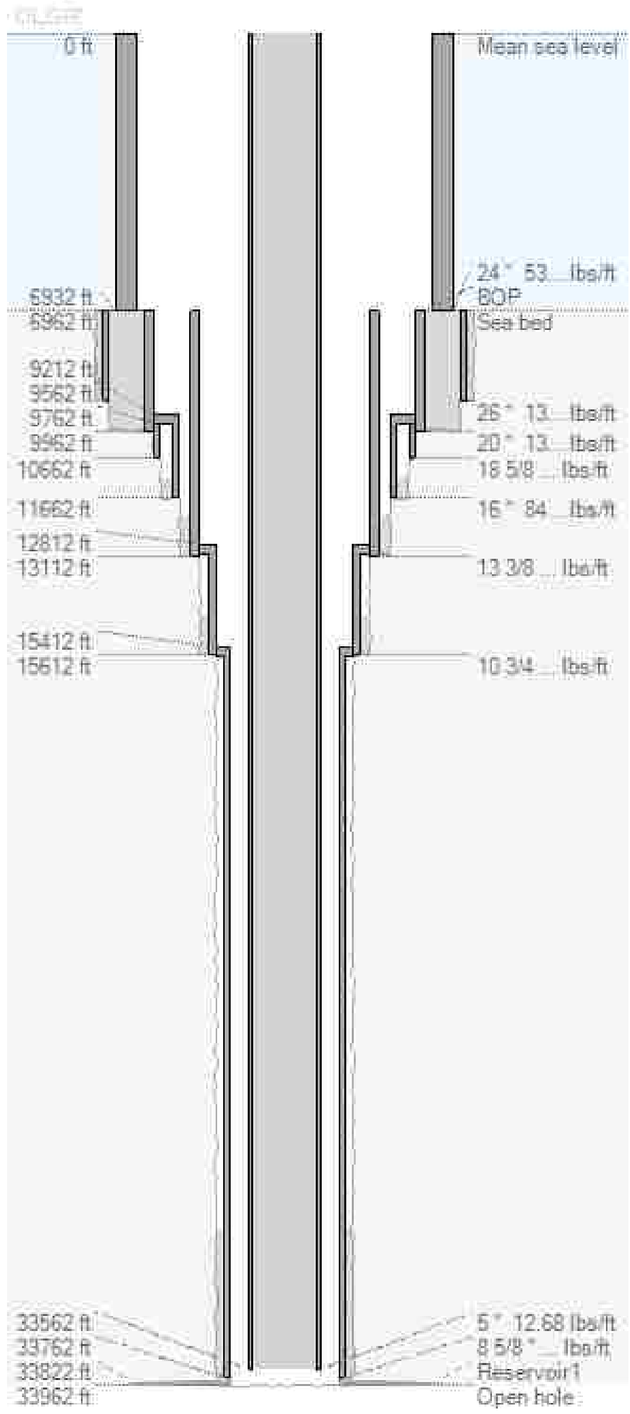

Figure 60: Well Schematic of the ultradeepwater Paleogene well

Table 49: Paleogene period deepwater well (Alaminos Canyon) subsea release rates and probabilities for P50 values of reservoir properties

Release Point	Prob.	Flow path	Prob.	Penetration %	Prob.	BOP Opening %	Prob.	Total Liquid Flow (bbl/day)	Oil Flow rate (bbl/day)	Gas Flow rate (MMSCF/Day)	Prob.
Subsea	0.75	Drill String	0.11	Top 5	0.2	100	0.3	173	131	0.02	0.0066
						5	0.7	174	135	0.02	0.0154
				50	0.4	100	0.3	1210	924	0.13	0.0132
						5	0.7	1210	924	0.13	0.0308
				100	0.4	100	0.3	1999	1522	0.22	0.0132
						5	0.7	1998	1521	0.22	0.0308
		Annulus	0.78	Top 5	0.2	100	0.3	167	124	0.02	0.0468
						5	0.7	164	124	0.02	0.1092
				50	0.4	100	0.3	1113	848	0.12	0.0936
						5	0.7	1115	848	0.12	0.2184
				100	0.4	100	0.3	1893	1440	0.21	0.0936
						5	0.7	1893	1440	0.21	0.2184
		Open Hole	0.11	100	1	100	0.3	1828	1394	0.20	0.033
						5	0.7	1829	1394	0.20	0.077

APPENDIX-B: HISTORICAL SPILLS (INCLUDING ALL) AND THEIR CAUSES IN GOM

Table 50: Historical GoM and PAC Pipeline Spill and their Causes (1972-2010) [Table is taken from (Bercha, 2013)]

CAUSE CLASSIFICATION		Small and Medium Spills 50-999 bbl			Large and Huge Spills >= 1000 bbl			
	HISTORICAL DISTRIBUTION %	# OF SPILLS	EXPOSURE (km-years)	FREQUENCY spill per 10^5 km-year	HISTORICAL DISTRIBUTION %	NUMBER OF SPILLS	EXPOSURE (km-years)	FREQUENCY spill per 10^5 km-year
CORROSION	**6.67**	**3**	**334,764**	**0.896**	**5.88**	**1**	**334,764**	**0.299**
External	2.22	1		0.299				
Internal	4.44	2		0.597	5.88	1		0.299
THIRD PARTY IMPACT	**20.00**	**9**		**2.688**	**64.71**	**11**		**3.286**
Anchor Impact	15.56	7		2.091	35.29	6		1.792
Jackup Rig or Spud Barge	2.22	1		0.299	5.88	1		0.299
Trawl/Fishing Net	2.22	1		0.030	23.53	4		1.195
OPERATION IMPACT	**6.67**	**3**		**0.896**	**5.88**	**1**		**0.299**
Rig Anchoring	2.22	1		0.299				
Work Boat Anchoring	4.44	2		0.597	5.88	1		0.299
MECHANICAL	**6.67**	**3**		**0.896**				
Connection Failure	4.44	2		0.597				
Material Failure	2.22	1		0.299				
NATURAL HAZARD	**53.33**	**24**		**7.169**	**23.53**	**4**		**1.195**
Mud Slide	4.44	2		0.597	5.88	1		0.299
Storm/ Hurricane	48.89	22		6.572	17.65	3		0.896
UNKNOWN	6.67	3		**0.896**				
TOTALS	100.0	45		13.442	100.0	17		5.078

Table 51: GoM and PAC OCS Platform Hydrocarbon Spill Statistics (1977-2010) [Table is taken from (Bercha, 2013]

CAUSE CLASSIFICATION	**Small and Medium Spills 50-999 bbl**				**Large and Huge Spills >=1000 bbl**			
	Historical Distribution %	**Number of Spills**	**Exposure (well-years)**	**Frequency (spill per 10^4 well-year)**	**Historical Distribution %**	**Number of Spills**	**Exposure (well-years)**	**Frequency (spill per 10^4 well-year)**
EQUIPMENT FAILURE	31.50	40	245,486	1.629	12.50	1	245,486	0.041
HUMAN ERROR	11.81	15		0.611				
COLLISION	0.79	1		0.041				
WEATHER	3.94	5		0.204	25.00	2		0.081
HURRICANE	51.97	66		2.689	50.00	4		0.163
UNKNOWN					12.50	1		0.041
TOTALS	100.00	127		5.173	100.00	8		0.326

VITA

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