Health, Safety and Environmental Management in Petroleum and offshore Engineering

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Module No. # 04

Lecture No. # 02 & 03

Case studies

In the next two lectures, we will discuss in detail, about some case studies where I will show you some application of risk analysis methodologies on different problems quickly.

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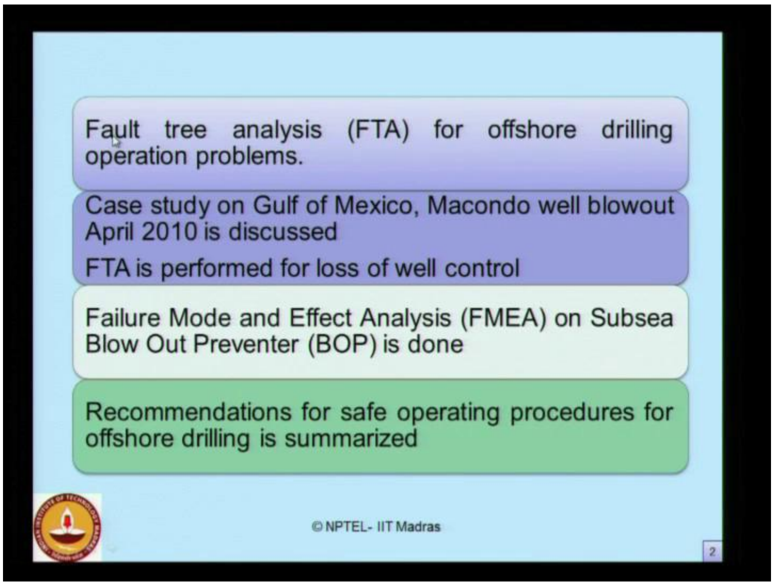

If you look at the application aspect of risk analysis on HSE, interestingly we will try to apply, what we call as on fault tree analysis for offshore drilling operation problem as one of the case study. I will discuss very quickly, the case study on Gulf of Mexico, Macondo well blowout which occurred in the year April 2010. I will show you how a fault tree analysis is performed for loss of the well control for this specific accident scenario. I will also show you the next case study, which we will discuss failure mode and effect analysis. What we call as an FMEA on the subsea blow out preventer. So, we have done a design FMEA on the BOP which will be discussed in this lecture.

Based on the two case studies, we will give some recommendations for safe operating procedures for offshore drilling which will be summarized at the end of these two lectures.

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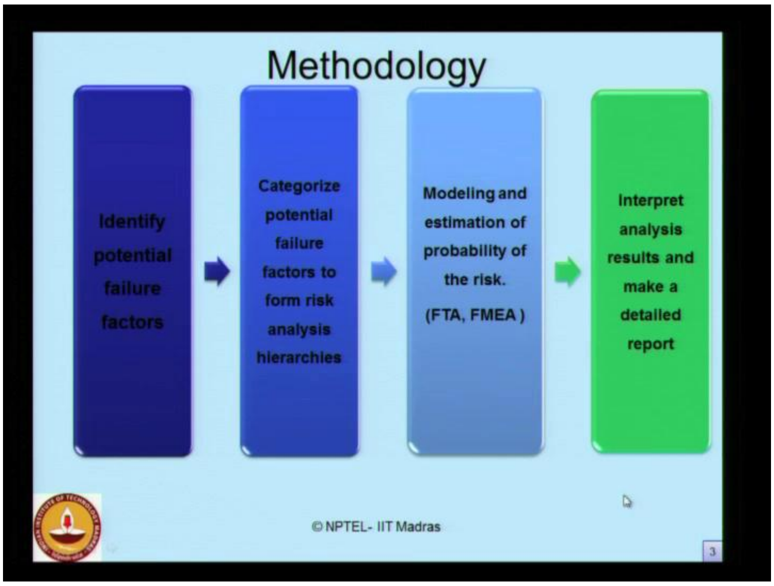

If you look at the overall methodology of risk analysis applied to drilling procedures. The methodology is simple in the four modules as expressed here. First, identify the potential failure factors. So, identifying the potential failure factor, you must know thoroughly the process and the design, principles involved in the elements. After identifying the potential failure factors, categorized them depending upon which factors are having high risk values. That is, categorize the potential failure factors to form what we call as a risk analysis hierarchies. You now got to arrange the risk factors related to these potential factors in an ascending order.

Then, model and estimate the probability of risk using either FTA or FMEA methods. After doing the analysis interpret, the analysis results and then prepare what we call as a detailed report based on your study. So, methodologies on risk analysis have got four different modules. In the first module, we will identify the potential failure factors responsible for that failure. You will categorize them and prioritize them based on the risk factors in on hierarchical manner. You will then model and estimate the probability of the risk involved in these failure factors. Then, interpret the analysis results and prepare a detailed summary report based on your analysis.

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If you look at the stages of risk analysis involved in these case studies. Basically there are three stages where we are connecting our risk analysis to the applied problem. One is, what we call identifying the risk - which is risk identification. Then, we do what we call a QRA - which is a quantitative risk analysis, in this platform, we quantify the risk involved in the process. The third will be - what is our planning and methodology guideline for risk mitigation in the problem.

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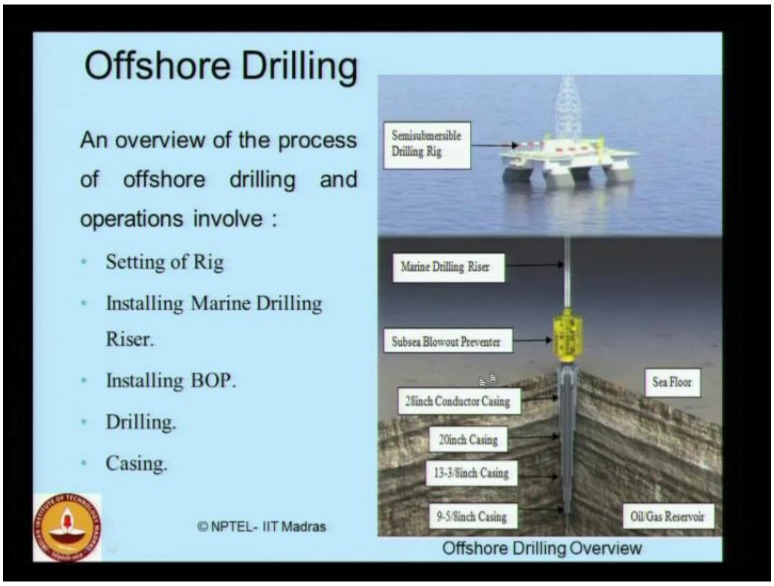

If you look at the offshore drilling process, let us quickly look at then overview of the offshore drilling, as I said before we do the analysis we must understand the overview of the whole process. For the case study of offshore drilling, let us look at this figure, I am having a semisubmersible drilling rig which is being used for drilling at a specific field. This is basically the drilling case this is what we call as a marine drilling riser. I have provided here a subsea blowout preventer which is shown in yellow color.

This is my indication of sea floor. Inside the sea floor I have got different kinds of casing for drilling. This is 28 inch casing, followed by a 20 inches casing, followed by a thirteen-three by eight inch casing, followed by a nine-five by eight inch casing. This is where I, find my oil and gas reservoir from which I am actually drilling. The overview of process of offshore drilling and operation involve the following different stages. Setting up of the rig is the first process let us say. Then installed the marine drilling facility; then install the marine drilling riser; install the blowout preventer; then installed the drilling casing and then perform the drilling.

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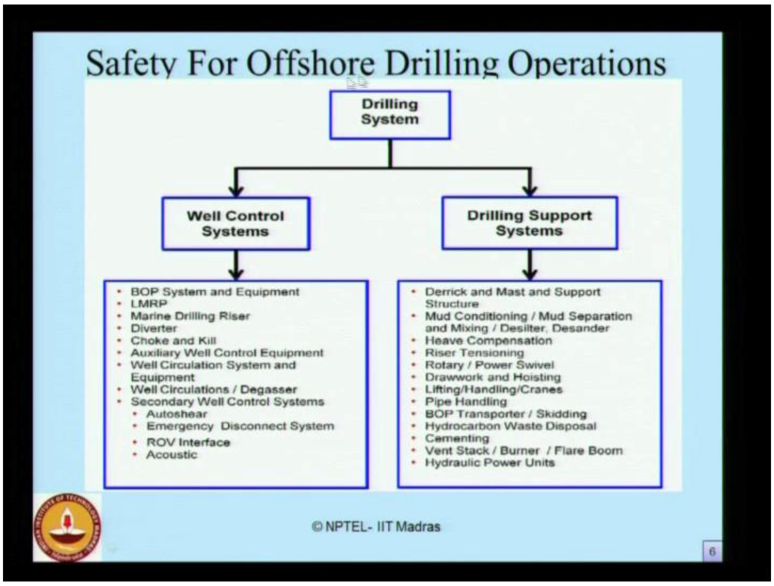

If we look at the safety measures related to offshore drilling operations. The safety measures can be categorized easily using this flow chart. The drilling systems essentially consist of two control mechanisms. One is what we call as well control systems; that are the control system available in the well. The other control system and support systems are available on the drilling area. Combined together is what we call as a drilling system.

If we look at the well control system in detail, the well control system comprises of the blowout preventer system and equipment, the LMRP, the marine drilling riser, a diverter, a choke and kill, an auxiliary well control equipment, well circulation system and equipment, well circulations and degasification systems. Secondary well control systems comprising autoshear, emergency disconnect system, ROV interface and acoustic level.

If you look at the drill support systems, these consist of the derrick and a mass and a supporting structure. The mud conditioning and mud separators, heave compensations devisers, riser tensioning systems, rotary power swivels, draw work and hoisting equipments, lifting handling and cranes used for handling, pipe handling equipments, BOP transporters, BOP skidders, hydrocarbons waste disposal systems, cementing equipments, vent stack, flare boom, burners and hydraulic power units.

We must clearly understand, the distinct differences between the drilling support systems and the well controlled systems, if you really want to look into safety aspects of drilling operation.

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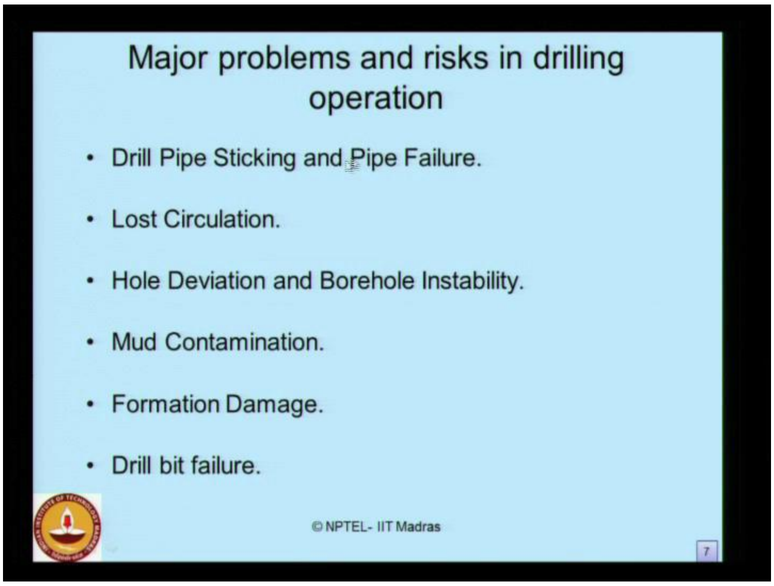

Let us ask a question, what are the major problems and risks that are seen during a drilling operation? There are many risks involved in a drilling operation. Very critical of them are mentioned here. For most, could be your drill pipe sticking and the pipe failure. The major problem can also occur due to lost circulation. It can be either from hole deviation and borehole instability. It can also occur from mud contamination. It can be also be due to formation damage. It can also result from what we called as a drill bit failure. These are the major problems and risks involves in offshore drilling.

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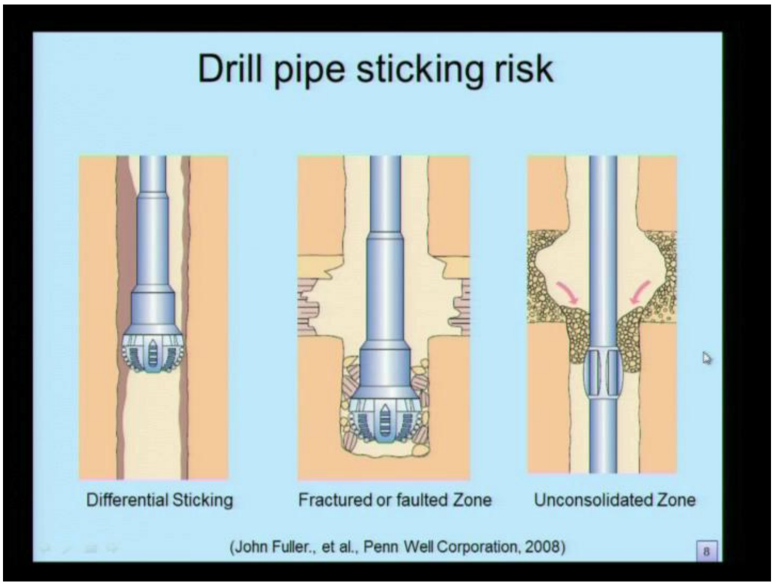

Let us quickly see few of them. What do you understand by drill pipe sticking risk? The drill pipe can stick to the casing or the formation by three different manners. There is a possibility that the sticking can be differential, you can see the scaled formed here is of a different intensity and thickness compared to this. So, when you try to move the drill pipe up and down there is a possibility that the drill pipe can stick on to the surface here; this is what we call as a differential sticking. Sometimes, there can be a faulted zone occurring in between the drilling casing; this is what we call as fractured or a faulted zone and in such cased drilling pipe sticking can also occur.

In some situation, there can be what we call an unconsolidated zone being drilled through, and there is always a canning gain from the consolidated zone which will start blocking that drill pipe sticking. So, these are what we call as drill pipe sticking risk which is referred by John Fuller., et al., Penn Well Corporation, 2008.

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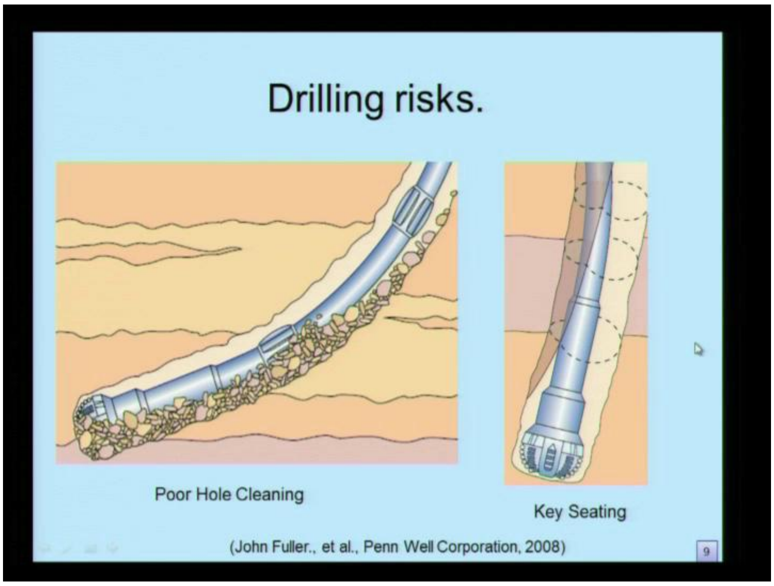

Further, it can also occur due to what we call a poor hole cleaning. You can see here, a residual deposit in the bore hole and this is not being cleaned or drifted properly and this can also result in what we call drill pipe sticking. Sometimes, this can also occur due to what is call key a seating. The key may not seat properly and due to that the drill pipe can also stick.

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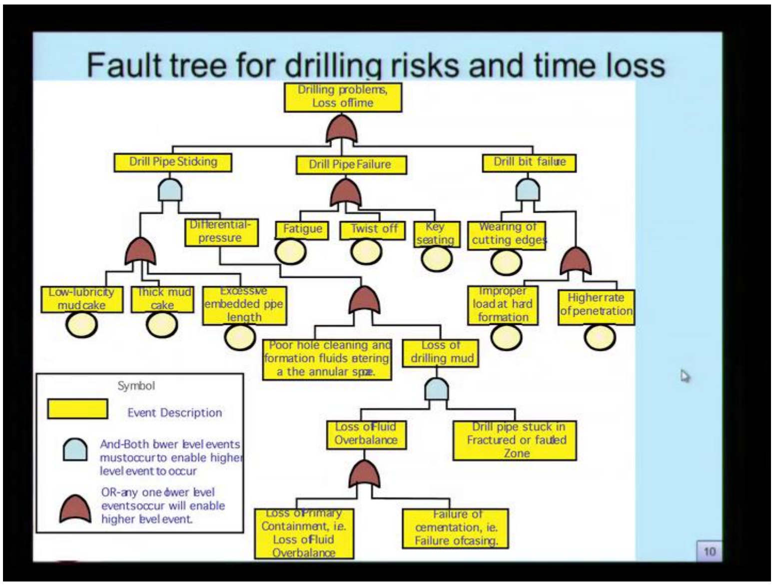

Now, let us see how we are going to do fault tree analysis for the drilling risk and the time loss involved. We have already discussed, a network layout of a fault tree analysis in the previous module. I think, you must have gone through what are the fundamentals of a fault tree analysis. On the basis of that discussion, we try to do a fault tree analysis now for a drilling risk for the specific problem.

The symbols what will use here will be the following. I will describe the event with a closed rectangle. If there are lower events which required both of them to occur for successive events, I will use symbol of this order. Of any one of the need to occur make the drilling rig possible, I will use these symbols. These are standard symbols of logic gate being used in a fault tree analysis, which we have discussed in detail in the previous modules.

Let us look at the fault tree here, as I am drawing it for a drilling risk. I am now addressing drilling problems and loss of time both. The drilling risk can occur mainly from three sources. It can be a drill pipe sticking, it can be a drill pipe failure or it can be a drill bit failure. If we look at the symbol here, either one of them is sufficient to cause a drilling risk, so I am using OR gate here. So, either one of them is sufficient to cause, what we call as a drilling problem or a drilling risk. It can be either due to drill pipe sticking or due to drill pipe failure or due to drill bit failure. So, I have started the fault tree diagram from the top like this. Now, if you look at the drill pipe sticking the reasons for a failure of this order can be from different sources. It can be either due to differential pressure or due to low lubricity which results in a formation of mud cake. The mud cake can also be very quick being formed. It can be also due to excessive embedded pipe length inside.

So, either one of them could be responsible for a drill pipe sticking. Or it can be due to a differential pressure which can be caused due to poor hole cleaning and formation fluids entering the annular space. It can be also due to loss of drilling mud. The loss of drilling mud further can be due to loss of fluid overbalance or drill pipe stuck in the fractured or a faulted zone. Both of them are necessary to cause what we call as a loss of drilling mud that is why I have used an AND gate here. The loss of fluid overbalance can either occur from a loss of primary containment or due to failure cementation which we call a failure of a casing.

Either of a failure, casing or loss of fluid overbalance, can cause the loss of fluid overbalance, put together on the fractured and faulted zone will cause a loss of a drilling mud. Either a loss of drilling mud or poor hole cleaning can results in a differential pressure; differential pressure put together with either one of them can results in drill pipe sticking. This if how a fault tree analysis can be read.

So, ladies and gentlemen based on your experience and literature reading you should be able to identify the different events, responsible for a specific subclass of failure. Let us look at the drill pipe failure. When you look at the drill pipe failure as an event of failure, it can be either due to a fatigue in the drill pipe or it can be a twist off of the drill pipe or it can be caused due to what we call as a key seating. If we look at the drill bit failure it can happen when the wearing of cutting of edges and either one of them is occurring jointly with the wearing of cutting of edges. The wearing of cutting of edges can also jointly occur with improper hard formation or at on higher rate of penetration. Both of them put together either higher rate of penetration along with wearing of cutting edge or improper load at hard formation along with the wearing of cutting edge can result in, what we call as a drill bit failure. So, drilling risk can occur either due to drill pipe sticking or due to drill pipe failure or due to drill bit failure. This is an example of fault tree analysis being carried out for a drilling risk and time loss.

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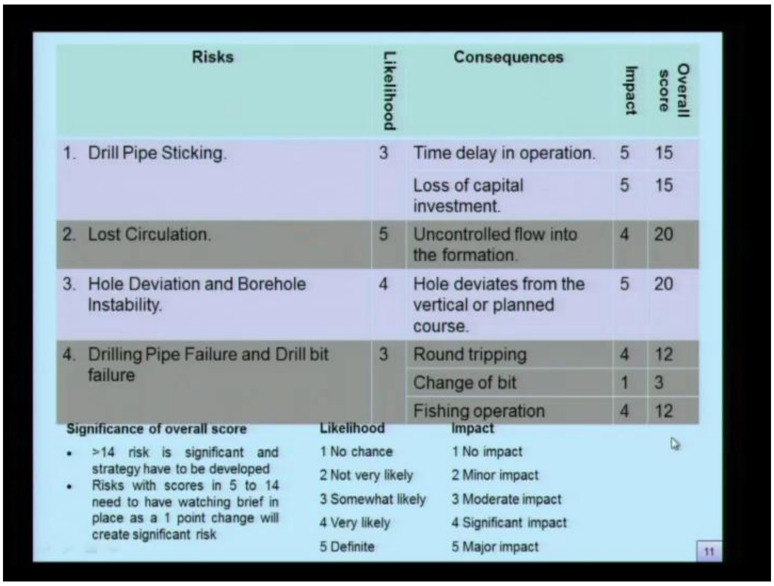

Risks	Likelihood	Consequences	Impact	Overall score
1. Drill Pipe Sticking.	3	Time delay in operation.	5	15
		Loss of capital investment.	5	15
2. Lost Circulation.	5	Uncontrolled flow into the formation.	4	20
3. Hole Deviation and Borehole Instability.	4	Hole deviates from the vertical or planned course.	5	20
4. Drilling Pipe Failure and Drill bit failure	3	Round tripping	4	12
		Change of bit	1	3
		Fishing operation	4	12

Significance of overall score

- >14 risk is significant and strategy have to be developed
- Risks with scores in 5 to 14 need to have watching brief in place as a 1 point change will create significant risk

Likelihood

1 No chance
2 Not very likely
3 Somewhat likely
4 Very likely
5 Definite

Impact

1 No impact
2 Minor impact
3 Moderate impact
4 Significant impact
5 Major impact

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Now, based on this, let us try to classify the risks of these events their likelihood and their consequences if at all they occur. The likelihood of every event is given in a five point scale. If the score is 1, then we can say there is no chance of that particular event occurring. If the score is 5, we can say there is a definite chance of that event occurring. So, the likelihood is nothing but the score given to these events as given from this scale factor of five. Whereas, the impact factor of consequence based on the scale of again five, where if you indicate one though there is a likelihood of any specific event it will cause no impact. If we indicate scale of 5 then, the likelihood would have major impact. After understanding this, let us look into the risks of different events. Drill pipe sticking, loss circulation, hole deviation and borehole instability and drilling pipe failure and drill bit failure.

Based on the fault tree analysis than in the previous slide, I have grouped the risks into four heading. I said the drilled pipe sticking can have a likelihood of somewhat likely I have given a number three. The time delay in operation can be one of the consequences, if a drill pipe sticking occurs and that consequence will have a major impact. The consequence of drill pipe sticking can also be resulting in a loss of capital investment which will have impact of scale of five.

So, the overall score of risk is nothing but the product of likelihood and impact. So, 3 into 5 gives me 15 as well as 3 into 5 gives me 15. So, the drill pipe sticking gives me overall score of 15. Look at the lost circulation the likelihood of lost circulation in a drilling process is definite it will always happen. If at all this happen, the consequence results in uncontrolled flow into the formation and the impact of that will be significant, therefore the overall score of a lost circulation in a drilling failure analysis is 20 which is higher than that of a drilling pipe sticking.

So, ladies and gentlemen based on the fault tree analysis, I am trying to prioritize the order of risk involved in different event as studied earlier. Similarly, if you look at the bore holed instability, the likelihood in drilling formation is generally very likely and the hole deviates from the vertical or planned course of drilling which will have a very serious impact in your whole process. So, the overall score of this could be closed to 20. Whereas the drilling pipe failure or a drill bit failure will have a very less likelihood of 3 and the consequence can be resulting in a score of either 3 or 12, depending upon what kind of consequence you are envisaging for a drill bit failure.

If the significance of the overall score is exceeding 14, then the risk is considered to be significant. For example, if I reach a table back with this number 14 then the overall score of drill pipe sticking is 15; the lost circulation is 20; the borehole instability is 20; it means these kinds of event of drill of risking are very significant. Therefore, we should have a strategy to be developed to control failure due to these kinds of risk occurrence.

If the risk score is between 5 to 14, then must keep on monitoring it continuously, so that it should not create a significant risk subsequently. For example, the change of drill bit can be one of such example in this where the overall score is very low. So, we should constantly monitor the drill bit for its requirement of the change of drill bit.

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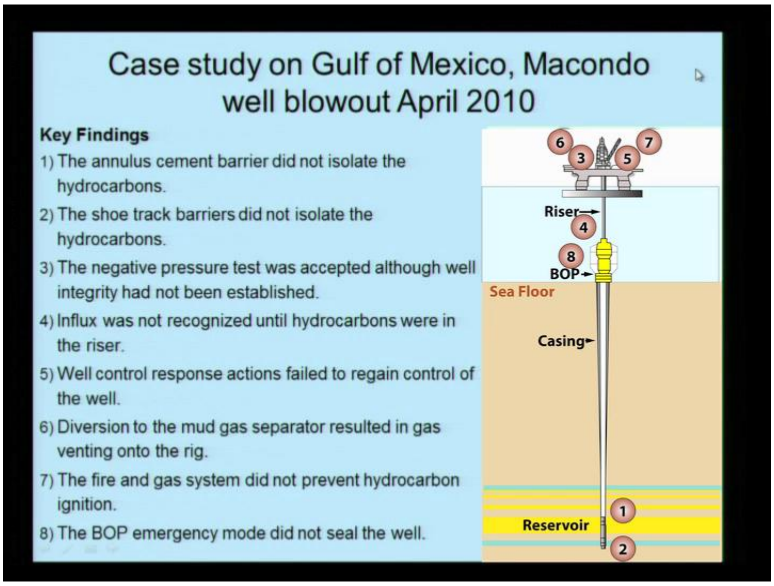

We will now take up the second case study which is on Gulf of Mexico, Macondo well blowout in the month of April, 2010. There are some key finding related to this blowout. The right hand side is a picture, what you see a schematic view of this blowout. This is my drilling rig. This is my riser. This is my blowout preventer. This is my sea floor. I am keeping a BOP just above the sea floor; these are my casing; this is my reservoir shown in yellow color. These are the flow of the reservoir into my drilling. The key finding is found from the literature analysis are the following. The annulus cement barrier did not isolate the hydrocarbon flowing into the casing. It should have isolated to that of carbon.

The second important reason for this blowout is, the shoe track barriers did not isolate the hydrocarbons entry here. Thirdly and very interesting, the negative pressure test which has been carried out was accepted although the well integrity was not established completely. The influx coming in the riser was not recognized until the hydrocarbons enter the risers. The well controlled response being installed on the top of the rig failed to regain the control of the well. They were not effectively working at the time of the blowout occurred in the month of April 2010. The diversion to the mud gas separator, which is being located on the top side resulted in the gas venting onto the rig. The fire and gas system did not prevent the hydrocarbon ignition coming from the riser. The BOP emergency mode did not seal the well completely. So, all these consequence of the events resulted in a blowout of the Macondo well in Gulf of Mexico in the year April 2010.

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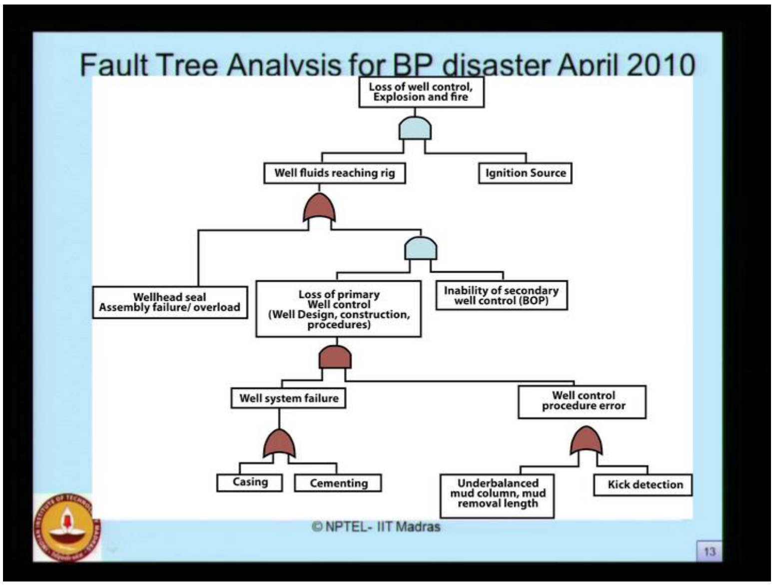

Let us quickly do a fault tree analysis for the BP disaster occurred in April 2010. So, I am using the same symbols for events AND, and the OR gates which I discussed in the previous case study. Let us say, the top most events which I am looking or trying to address is loss of the well control, which resulted in explosion fire of what we call as a BP disaster. The BP disaster could have been occurred as a combination of well fluids reaching the rig and the ignition source being present at that time. The well fluids reaching the rig could be due to any one of these events. The well head seal assembly has fail or loss of primary well control or instability of secondary well control and BOP has combined this to have the well fluids reaching the rig.

When we look at the loss of primary, well control or the well design and construction procedures, this can be also due to well system failure or well controlled procedure errors, put together result in loss of primary well control. The well system failure can be either due to the casing failure or cementing failure. The well controlled procedure error can be due to failure to detect the kick or unbalanced mud column or the mud removal length. So, looking into a very brief analysis of FTA for the BP disaster, we are able to identify the important events which could cause or which could result in this disaster.

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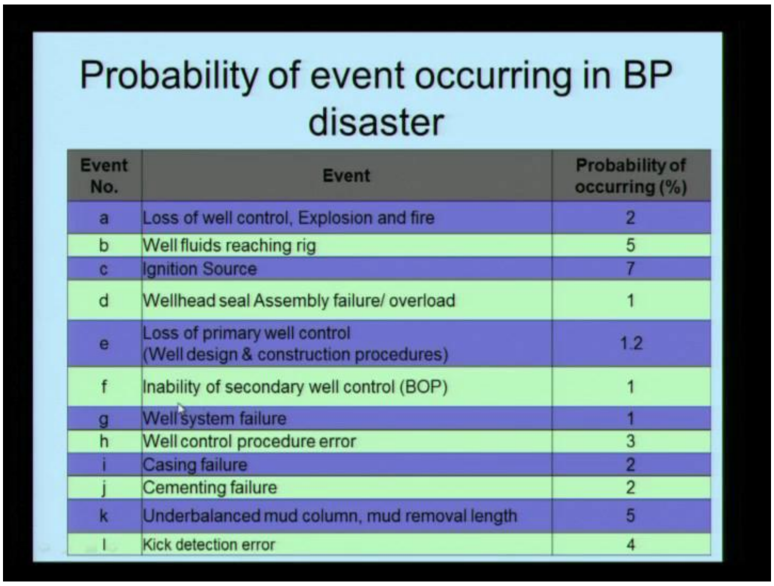

Probability of event occurring in BP disaster

Event No.	Event	Probability of occurring (%)
a	Loss of well control, Explosion and fire	2
b	Well fluids reaching rig	5
c	Ignition Source	7
d	Wellhead seal Assembly failure/ overload	1
e	Loss of primary well control (Well design & construction procedures)	1.2
f	Inability of secondary well control (BOP)	1
g	Well system failure	1
h	Well control procedure error	3
i	Casing failure	2
j	Cementing failure	2
k	Underbalanced mud column, mud removal length	5
l	Kick detection error	4

Based on that the probability of event occurring in the BP disaster, it is being tabulated. We have set event number as A, B, C, D, J, K, L, M, N etcetera. For example, event A could be loss of well control explosion and fire. The probability of well control loss could be two percent on a scale. Well fluids reaching rigs can be a five percent probability of occurrence. The presence of ignition source can be seven percent. Wellhead seal assembly and overload can be hardly one percent. Loss of primary well control can be about 1.2 percent. Like this, we have started giving the probability of occurrence of every event associated with the specific number.

Ladies and gentle man, you can see here the highest number is given for well fluids reaching the rig which is resulted in explosion for a sure. And mud removal length or the mud column imbalance has also cause an important reason for this failure. So, the higher numbers of probability a given for these two the lowest numbers given for overload or wellhead assembly instability to control the accident and the well system failure as an overall.

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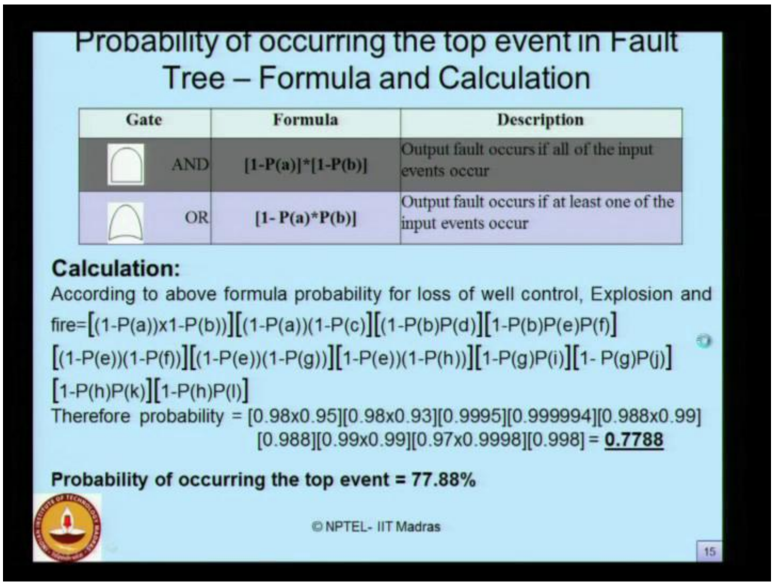

Once a probability numbers are assists, now we can compute what we called as probability of failure or probability of occurrence of the top most events. For an AND gate, if you see in the logic tree, the equation is 1 minus probability of that event product of 1 minus probability of the b event because for and gate you must at least have two events a and b. For an OR gate can either have a or b, therefore the formula used is 1 minus the product of these two probabilities. So, have to looking at the fault tree identifying the events a and b looking at the gates AND or OR gate substitute in this equation try to fill up. I can just explain one value for your computation, for example, let us look at 1 minus P of a product of 1 minus P of b; a is an event of probability 2; b is an event of probability 5. So, I said 1 minus probability of a – 0.98; 1 minus probability of b – 0.95 I worked out a product. Similarly, I can do for all the events of P of a, P of b, P of c, P of d and so on and try to get the joint probability of occurrence of top most event which is around 77.88 percent. So, from the analysis what we carried out it tells me that the probability of failure of BOP or probability of this disaster is about 78 percent which has occurred in reality on April 2010.

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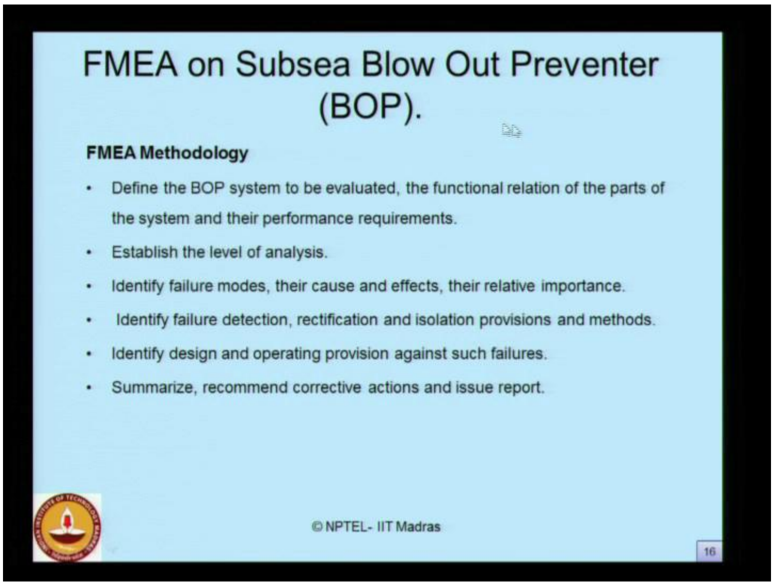

You can also do another case study by explaining, what we call as a failure mode and effect analysis on a subsea blow out preventer. FMEA methodology basically defines the BOP systems to be evaluated, the functional relation of the components of the system and their performance requirements. Then based on this definition and the functional relationship, it establishes the level of analysis. You have to identify the failure modes, their cause and their effects, and their relative importance. Then you will identify the failure detection, the rectification and isolation provisions and methods. You will also identify, the design and operating provision against such failures. Then you will summarize and recommend a corrective actions, then issue a report based on your FMEA study. These are the methodologies by which I can prepare what I call as an FMEA study. I will now apply this study for a subsea blow preventer of a BOP.

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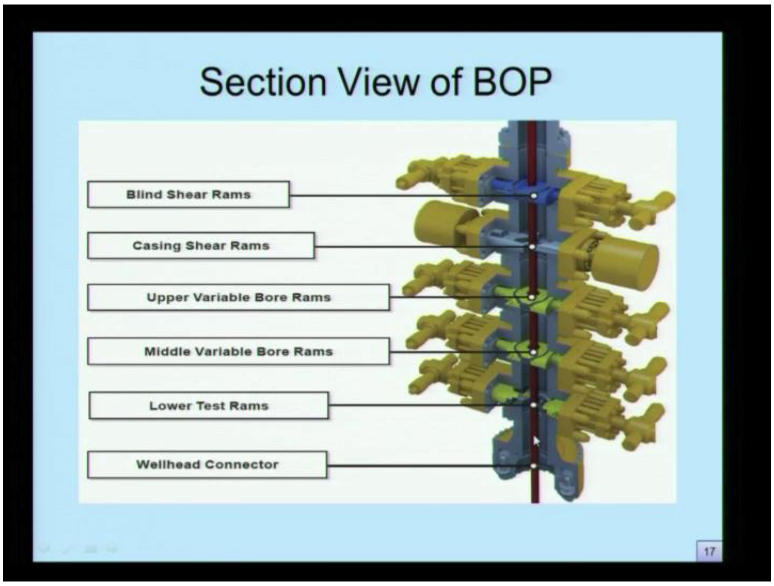

To understand the FMEA thoroughly applied on a BOP. Let us first look at what are the different components of a blowout preventer. The blowout preventer typically has many critical components. The first one from the bottom - this is your operation on a top side; this is your bottom end. The wellhead connector is located at the bottom; the lower test rams are located just above the wellhead connector. Above that are what we call as variable bore rams; above that are upper variable bore rams; above that are the casing shear rams and above that are basically the blind shear rams. The blowout preventer is actually a vertical stack of different kinds of rams provided one above the other.

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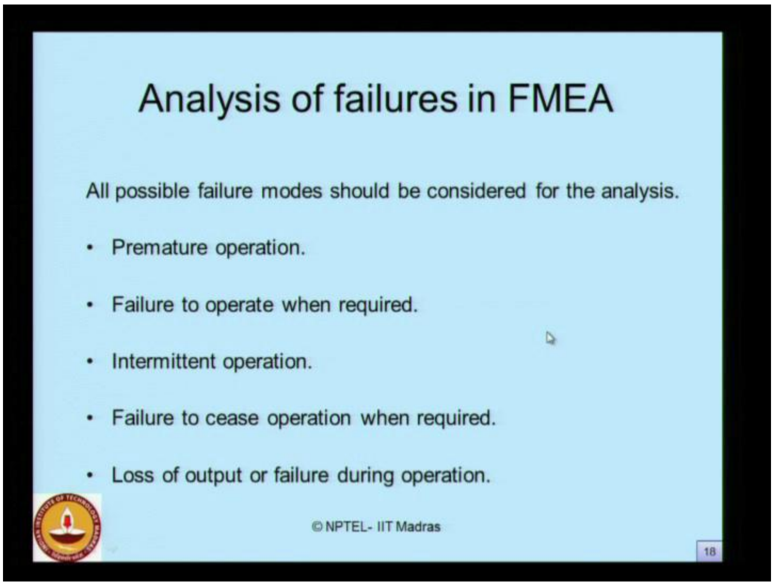

Now, let us look into the analysis of failures through an FMEA study applied on this problem. All possible failure modes should be considered for the analysis. You must also look for a premature operation. You must look for failure to operate when required that is also a possibility. You should also look for intermittent operation, the operation starts and then it fails. You should also look for failure to cease operation - that is you are not able to stop the operation when you required to stop the operation. You should also look for failure during operation.

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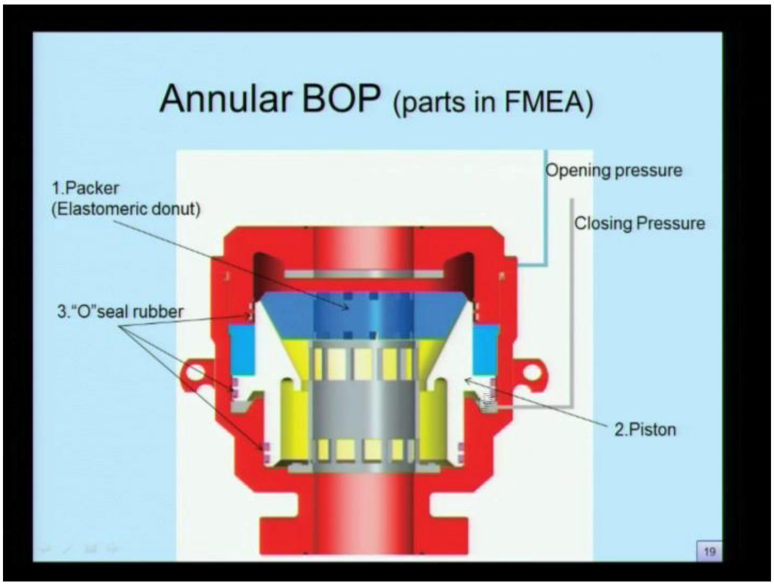

If you look at the annular BOP the parts used in FMEA study, this is the first part what I am looking at is a packer. The actual component used in the annular BOP is an elastomeric donut. The second component is nothing but a piston, which you see in a white color. The third component is actually an “O” seal rubber which is being used here. Now, the other operational conditions what we have looked into which we have got opening and closing pressure which a got to measure at this and these two locations respectively.

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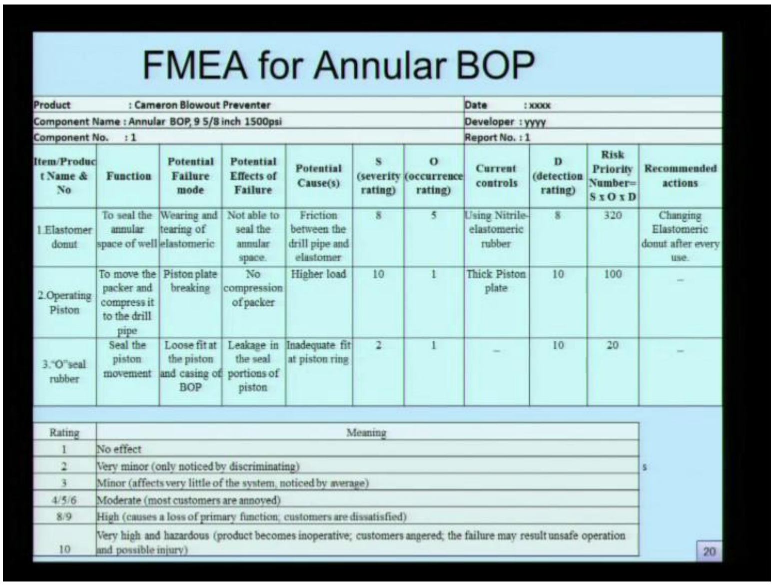

FMEA for Annular BOP

Product : Cameron Blowout Preventer

Date : xxxx

Component Name : Annular BOP, 9 5/8 inch 1500psi

Developer : yyyy

Component No. : 1

Report No. : 1

Item/Product Name & No	Function	Potential Failure mode	Potential Effects of Failure	Potential Cause(s)	S (severity rating)	O (occurrence rating)	Current controls	D (detection rating)	Risk Priority Number= S x O x D	Recommended actions
1.Elastomer donut	To seal the annular space of well	Wearing and tearing of elastomeric	Not able to seal the annular space.	Friction between the drill pipe and elastomer	8	5	Using Nitrile-elastomeric rubber	8	320	Changing Elastomeric donut after every use.
2.Operating Piston	To move the packer and compress it to the drill pipe	Piston plate breaking	No compression of packer	Higher load	10	1	Thick Piston plate	10	100	–
3."O"seal rubber	Seal the piston movement	Loose fit at the piston and casing of BOP	Leakage in the seal portions of piston	Inadequate fit at piston ring	2	1	–	10	20	–

Rating	Meaning
1	No effect
2	Very minor (only noticed by discriminating)
3	Minor (affects very little of the system, noticed by average)
4/5/6	Moderate (most customers are annoyed)
8/9	High (causes a loss of primary function; customers are dissatisfied)
10	Very high and hazardous (product becomes inoperative; customers angered; the failure may result unsafe operation and possible injury)

20

This is an FMEA sheet prepared for the annular BOP. You have seen the working of a BOP very briefly. You have seen the component of an annular BOP as 1, 2, 3 and 4 and 5 are the pressure requirement for opening and closing the valve. So, these are the three components which I am mentioning here, we will look into detail of FMEA.

Thank you.