



Utilizing Risk Management in Development and Application of New Technology

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Abstract

Exploration and development drilling continues to move toward deeper water and deeper reservoir depth. Significant costs, technical challenges and high consequences of failure characterize the trend. Technology plays an important role in reducing drilling time and well cost. Application of technology (proven technology applied to new areas and new technology) has considerable potential, but also has high risk exposure.

A risk management process becomes essential for successful drilling programs. In most situations, capital expenditure and operational expenditure are used to determine which path a project should take. A third component, expenditure associated with risk, is not often considered and yet can drastically alter the overall expenditure of a selection.

Case studies are presented in this paper of application of risk management to several different areas including intelligent well completions, dry tree completions, active heave drawworks and dual gradient drilling. In all cases the application of risk management reduced risks in terms of both economics and safety.

Introduction

By the end of the decade, deepwater wells will supply 10% of the world's oil. As technology improves, that number will grow.¹

The deeper water and deeper reservoir targets of exploration and development drilling have significant impact on the cost to find and produce oil and gas. The three biggest contributors to these high costs are high consequences of failure, longer operational times and technical complexity/challenges. Technology is the answer to both driving down the cost of overall drilling and creating reservoir viability where previous techniques resulted in economic marginality. Proven technology applied in new areas and new technology have been employed for four fundamental reasons: cheaper rig rate solutions; increased mechanical efficiency; flat time elimination; process assurance and control. Cheaper rig rate solutions have all been aimed at enabling the use of younger generation, smaller capacity rigs to drill the same wells as the 5th generation

dynamically-positioned drillships. Examples of these technical solutions include drilling with Surface BOP stacks and high pressure riser, slimhole drilling, expandables, mono-bore drilling, and the use of artificial seabeds. Examples of technologies to increase mechanical efficiency include dual activity (dual derrick) designs and rigs with off-line standbuilding capabilities. Technologies applied to eliminate drilling flat time include casing/liner drilling, managed pressure drilling and dual-gradient drilling. Process assurance and control technologies include integration of intelligent bottom hole assemblies (BHA) with telemetry drillpipe, topside drilling controls and 3-D earth models.²

While these technologies and as yet to be utilized technologies have considerable potential to help drive down the cost of drilling, they also have the potential for exposure to higher risk.

The Role of Risk Management

A risk management process becomes essential for successful development and application of technology in drilling programs. Key components of risk management, as it relates to drilling applications, include identification and management of well control risks, economic risks associated with non-productive time, unplanned events and equipment reliability, and appropriate qualification of technology prior to application.

When evaluating risks related to deepwater drilling and completion operations, it is essential to understand the specific issues and challenges. A number of technical guidelines and recommended practices are available that can provide basic input and general understanding of risk management, but not in any significant detail. In order to assure all potential issues are properly understood and lessons learned from previous projects are incorporated into the risk management plan, a systematic risk identification process (through multidiscipline team-based sessions) should be conducted.

These risk identification exercises also serve to educate people. Personnel skills needed to manage these challenges have to be related to the technical, commercial and financial risks of the drilling program. People have to be able to predict, understand and

prevent risks. Managing the risks identified in the risk identification process, can improve profits by reducing the cost of the drilling and completion operations, and assure that appropriate decisions are made.

In most situations, capital expenditure (CAPEX) and operational expenditure (OPEX) are used to determine which path a project should take. A third component, expenditure associated with the risks (RISKEX), is not often considered and yet can drastically alter the overall expenditure of a selection to the point of making it a bad choice. Figure 1 illustrates a scenario where consideration of CAPEX and OPEX only would lead to selection of Alternative 1, but adding RISKEX into the consideration makes Alternative 2 the more economical choice. Quantitative risk analysis is a systematic approach to evaluating the uncertainties or risks related to a concept or a system, and can strengthen the decision making process.

Equally important, but often poorly handled, is the implementation phase of the risk management plan. In order to reduce risks or reduce the consequences of the risks, actions need to be specific, measurable, agreed upon, reasonable and time-based.³ Too often risk management is perceived as having little or no value because of poorly executed implementation phases. If actions are vague or inadequately defined and there is no clear ownership, then risks can impact the program in a manner consistent with previous project failures.⁴

Case Studies

The following case studies illustrate the role of risk management techniques in development and application of both new technology and proven technology applied to new areas.

Active Heave Drawworks

GlobalSantaFe initiated an independent third-party review of the new Integrated Active Heave Hoisting System on the Development Driller I and II in order to minimize the risks and uncertainties related to the new system. A risk based approach was adopted to assure all possible issues were appropriately addressed and evaluated.

Codes and standards have been developed to help ensure that the design of drilling systems meets a minimum standard. Unfortunately the development of technology has outpaced the rate at which these standards are updated. Tools such as failure mode and effects analysis (FMEA) and other risk assessment practices are therefore adopted to proactively identify shortcomings that may otherwise go unnoticed. These risk assessment practices are about anticipating failures (and their consequences) and taking planned, rehearsed steps to improve the system. It is about coordinating and integrating all the processes across various disciplines and contractors, and building confidence in the safety and reliability of the system.

The two main challenges related to the evaluation of the integration of the Hoisting System were the complexity of the system and interface issues between sub-contractors.

The drilling industry has seen a technical revolution from local and manual operation of machinery to advanced computer controlled and screen operated systems in interaction with field instruments and machinery. These modern sophisticated pieces of equipment are very complex. Complexity demands an increased requirement for design reviews, failure analysis and the integration of sub-systems to reduce the probability of failure or shutdown of the entire system.

The integration of the Hoisting System becomes even more essential with several vendors providing the sub-systems. Each vendor has to have the same understanding of the importance and consequences of single point failures in their sub-system to the overall system. Critical control signals, command signals, sensors, man-machine interface, etc. all need to be evaluated as part of one complete system. This "system integration" is often complicated due to the commercial agreements between the customer and each vendor. The vendor's requirements for confidentiality will also add to the complexity of a proper "system integration" process.

A process was facilitated to capture the specific challenges related to interfaces, and assure that all sub-contractors were aligned and fully understood how their contribution affected the safety and reliability of the over all system. The results of this study were multifold: a significant reduction of the risk of major accidents due to component failures within the system, increased reliability and availability of the system, improved rig owner understanding of the system (and thus information required to make appropriate decisions on equipment usage and on the establishment of operating limits of the system and the rig), and an overall increase of confidence in the system provided.

Dry Tree Completions

A Joint Industry Project (JIP) was initiated to develop a risk-based methodology to quantify the lifecycle cost associated with drilling and production riser systems.⁵ The methodology was developed to permit selection of riser systems with the lowest total cost considering drilling, completion, production, and well intervention activities. These decisions typically had been based on Capital Expenditures (CAPEX) and Operational Expenditures (OPEX), with little consideration for the risk exposure. By introducing a third component to the economic "balance", namely risk expenditures (RISKEX), it is possible to take a balanced, mature appraisal of the uncertainties and risks involved that may have detrimental consequences on initial, intermediate and long-term revenue streams.

The methodology developed focused on assessing the reliability of the well components and well control barriers, assessed the relevant barrier during the various operational steps, including drilling and completion operations and finally evaluated the potential consequence of a hydrocarbon release.

The risk of loss of well control is ever present with any hydrocarbon producing facility. For deepwater risers, new components are introduced, existing well components are used in more novel applications, and well dynamic loads become a more significant factor compared to shallow water platform well systems. Failures of well system components are usually due to a combination of otherwise minor problems and events. Failures rarely occur due to a component being overloaded by excessive pressure or excessive riser stresses. Most well system leaks result from a combination of factors such as a small defect in a seal, insignificant damage in the sealing surface, less than perfect seal installation and inability to detect a small leak when field testing. Multiple redundancies must be designed into a well control system to provide necessary reliability because it is impossible or at least impractical to avoid all possible failures.

During drilling operations, the mud column replaces the tubing as a well control barrier. The mud column in a riser exerts greater pressure than surrounding seawater pressure since mud density is higher than seawater density. A riser leak or disconnected riser allows mud column pressure to equalize with surrounding seawater pressure. This difference in mud column pressure and seawater pressure is termed "riser loss". When "riser loss" is several hundred psi or more, a leaking connection or small hole worn in the riser will soon erode to become a large hole as mud is forced from the riser.

In shallow water, there is sometimes enough excess mud column pressure, termed "riser margin", to contain formation pressure if the riser leaks or is disconnected. The "riser margin" is typically 300 to 700 psi for drilling operations and 100 to 300 psi for completion and workover operations. When "riser margin" is greater than "riser loss", the riser/casing and BOP system provides one barrier and the mud column provides an independent second well control barrier. The mud column and riser system provide independent well control barriers only when water depth is shallow and/or formation pressure gradients are low. In deep water when high mud weights are required to contain formation pressure, the "riser loss" is greater than "riser margin", and the mud column no longer represent an independent well control barrier.

Oil blowouts, in particular low gas content blowouts, tend to decay as the reservoir pressure drops. Bridging or natural exhaustion may occur before other methods of control are successful. Bridging is very unpredictable and is not considered a valid contingency plan for regaining control of the well. Drilling a relief well may be

required as a final solution to regain control of a blowout. The time needed to acquire and mobilize a rig, drill a relief well and perform a kill operation can vary from at least several weeks to several months. In deepwater, the seawater column may provide sufficient back-pressure to prevent bridging. The risk of having to drill a relief well in order to control a blowout might therefore increase as more wells will not bridge-over. Historical data was used to support the probability of the well to bridge over, and to calculate the amount of hydrocarbons which may leak to the environment.

The consequence costs per barrels spilled were based on analysis of historical oil spill data taking into account clean up cost, outrage (public disapproval) cost, facility damage cost, removal cost, business interruption and liability damage.

The methodology has been applied to assist a number of operators in making riser decisions in the Gulf of Mexico and other places in the world. In this case example, an operator was evaluating dual or single casing riser for a development in 5,000 ft. The development included five dry tree production wells with an estimated production life of 10 years. Several re-completion activities and side track operations were planned, and the anticipated reservoir pressure would require mud weights in the excess of 13 ppg. The production rates from the wells were expected to be between 10,000 – 15,000 BOPD. A comparison of the calculated risk costs (RISKEX) is shown in Table 1.

Riser System Concept:	RISKEX
Alt. 1: Dual Casing Riser	USD \$537,000
Normal Production Operation (5 wells)	104,000
Initial Installation (5 ops)	65,000
Up-hole Frac Pack (2 ops)	134,000
Sidetrack Operation (2 ops)	167,000
Wireline Selective Completion (1 op)	1,000
Repair Tubing Leak (1 op)	66,000
Alt. 2: Single Casing Riser	USD \$10,238,000
Normal Production Operation (5 wells)	1,646,000
Initial Installation (5 ops)	3,352,000
Up-hole Frac Pack (2 ops)	1,839,000
Sidetrack Operation (2 ops)	2,258,000
Wireline Selective Completion (1 op)	3,000
Repair Tubing Leak (1 op)	740,000

Table 1

Based on the quantitative risk calculations, it was concluded that there is a significant risk exposure related to the single casing riser alternative. This risk exposure is mainly driven by the completion and workover operations, and the risk results are very sensitive to an increased number of well intervention operations. As one of the main benefits related to a dry tree completion compared to a subsea completion is the direct well access and the ability to easily perform well interventions, there was a good chance that more well interventions could be performed. When comparing the estimated RISEX for a single casing riser with the additional CAPEX related to a dual casing riser, the dual casing riser alternative was selected for this particular development.

Subsea Completion Systems

A similar Joint Industry Project (JIP) was initiated to evaluate the risk based lifecycle cost associated with different completion alternatives.⁶ The objective of this JIP was to provide a systematic approach to support the decision between dry and wet completion systems. A detailed reliability assessment of subsea completion components were performed with active support and participation from equipment manufacturers. The data and methodology was then implemented into a model which allowed the user to evaluate the implication of equipment reliability on the over all lifecycle cost for a field development. The costs related to completion failures were factored into this integrated lifecycle cost model, including intervention costs and cost related to deferred or lost production.

The reliability data and knowledge of completion systems and components generated through the JIP, has successfully been used to assist a number of operators selecting completion systems. In the case example, an operator was evaluating different strategies for completing a subsea well. The operator wanted to stack a number of completions in order to produce from multiple pay zones simultaneously. One of their concerns was the reliability of these stacked subsea completions, and the increased economical consequence related to possible delays during the initial completion operation and failures of the completion components.

To address this concern an integrated financial risk assessment of the completion alternatives was performed. The objective of this risk assessment was to address this risk exposure in an integrated model including the costs and potential impact on the revenue stream related to initial completion risks, equipment failures, reservoir uncertainties and the required interventions that may be required during the total life of the field. Three different completion alternatives were evaluated; completing and producing three zones, four zones and five zones.

To systematically compare the different alternatives,

all the information was generated through a risk identification process, quantified and implemented into the financial risk model. To compare the three alternatives on an equal basis, the lost production potential by completing less than five production zones was included as a cost element in the risk model for the other two completion alternatives. This lost opportunity for additional revenue, was then combined with the operational expenditures and risks related to delays, equipment failures and reservoir uncertainty into the overall financial risk model. The result of this comparison is given in Figure 2.

This risk assessment demonstrated that there was a significant value in completing more than three zones. The expected increased revenue stream gained by completing four zones compared to three zones significantly compensates the potential risk exposure. Five completions also apparently seems to provide better value than four, however the difference is much less. To make a decision between these two alternatives, the uncertainty was evaluated in more detail. Figures 3 and 4 illustrate the comparison between four and five completed production zones. The figures show probability distributions generated from Monte Carlo analyses. Figure 3 represents an event distribution for four completions and Figure 4 for five completions. For both event distributions, there are some scenarios which can result in a negative cost, and some scenarios which result in positive cost. A comparison of both shows that the distribution for five completions has a higher percentage of events resulting in negative cost, therefore significantly more negative risk with completing five zones.

From the risk assessment it was concluded that there was a significant value in completing more than three production zones. Based on a comparison of the expected values, five completions also provide a better value than four, however, due to the potential significant negative economic risk exposure, the operator selected to complete the well with four completion zones.

Conclusions

By implementing risk management plans and applying risk and reliability techniques to drilling projects, risks are reduced. Even more important, opportunities can be discovered and decisions can be made with a better understanding of the total risks and consequences.⁷

The future of exploration and development drilling will rely heavily on development and application of new technology. The increased risk of applying this technology can be mitigated with proper risk management techniques. These techniques can be used to proactively identify shortcomings that may otherwise go unnoticed. Having a better understanding of the uncertainties involved ultimately results in possibilities to reduce those uncertainties and assist in

the decision making process when evaluating the application of technology.

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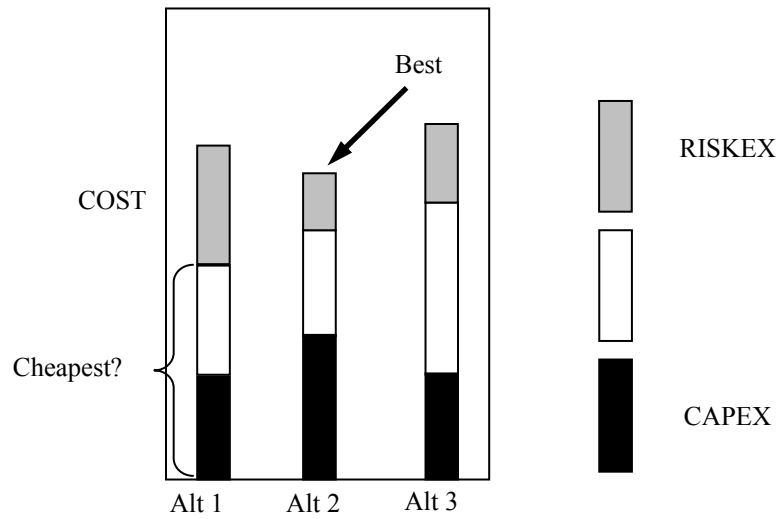


Fig. 1- Alternative Selection using RISKEX

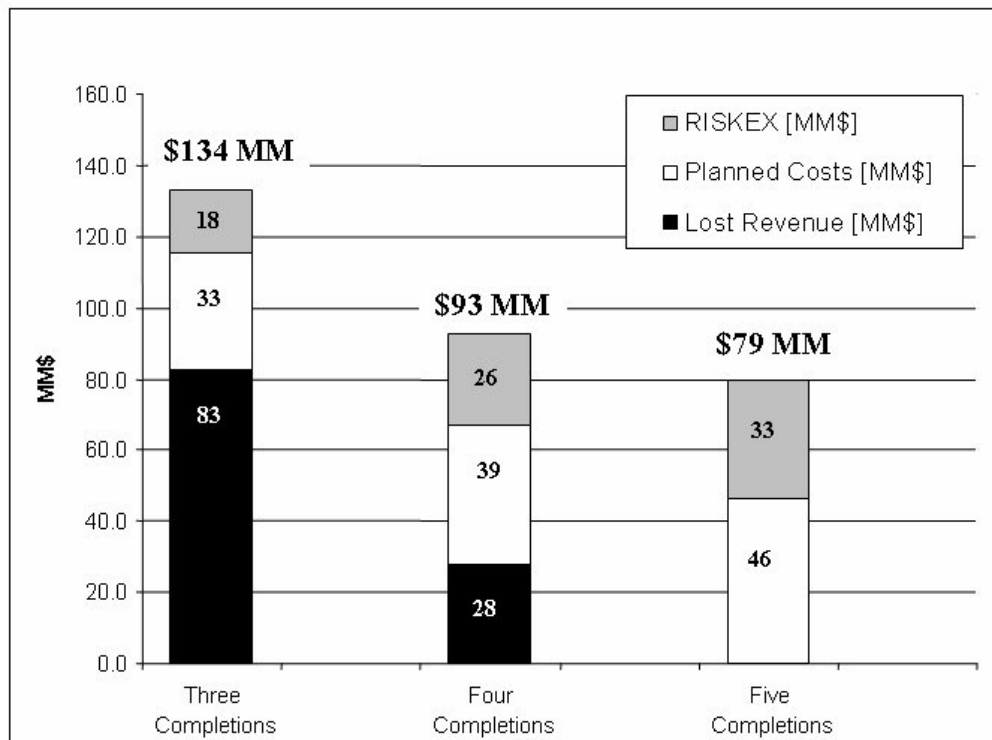


Fig. 2- Completion Alternatives

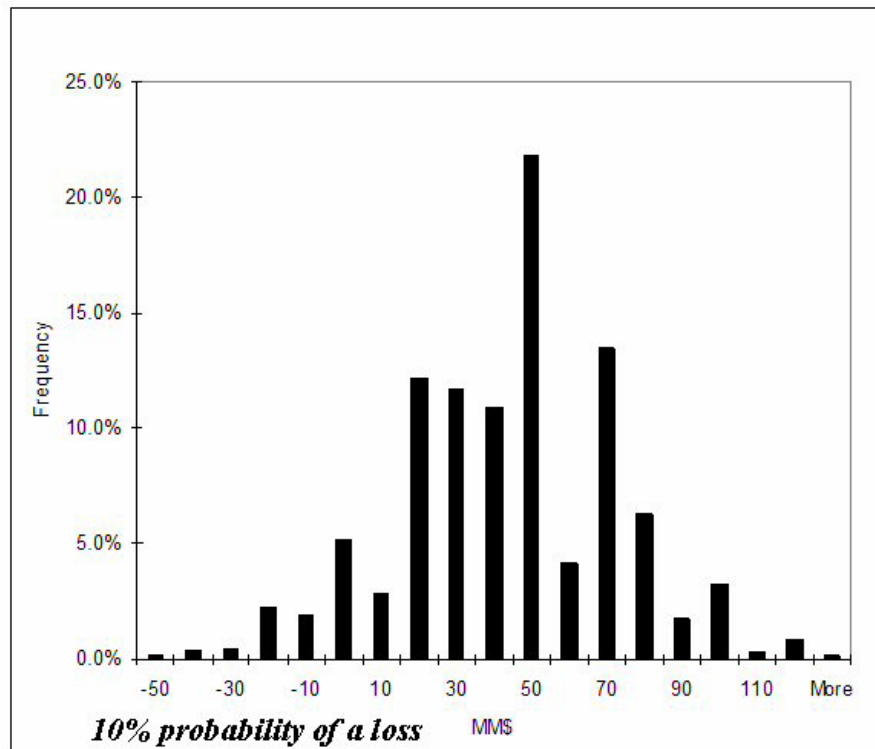


Fig. 3- Event Distribution for 4 Completions

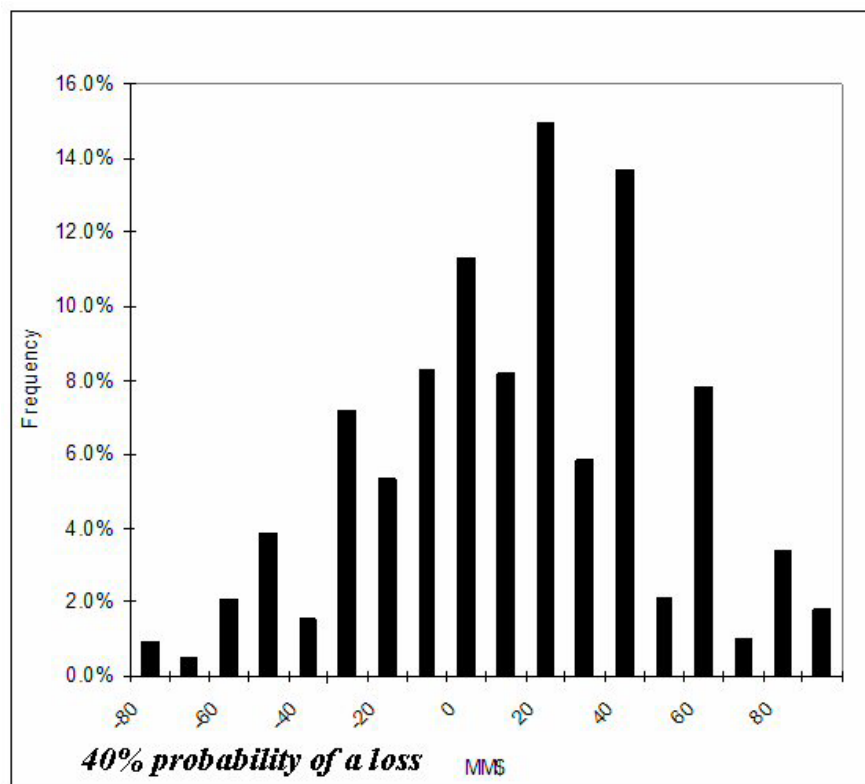


Fig. 4- Event Distribution for 5 Completions