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Risk Analysis Significantly Reduces Drilling Project Costs: vital in the New Oil Price Era

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Abstract

This paper portrays how drilling project costs can be reduced significantly, through the use of Risk Impact Amalysis, which is vital in the current era of unprecedently low oil prices which puts pressure on the whole chain of oil and gas services.

New ways of thinking and inventiveness are required if we are to keep drilling as opposed to stacking rigs which is happening at an alarming rate particularly on land in the U.S.A. If the cost of drilling cannot be reduced further, rigs will be stacked, several “cold” and the lucky ones “warm’.

This paper desrbibes how, through focused risk anaylsis, a 10,000 rated rig was allowed by the authoriesto drill as opposed to the more normally required 15,000 psi requirement.

Introduction

The problems which the Operator faced were two-fold: - 1) A reduced lack of money due to the still currently low oil price and 2) The reservoir was considered to be marginal at best. Either factor is enough to cancel a project these days, both factors combined usually to delay the project almost definitely. However, perhaps unusually, the Operator’s partners wanted the well to be drilled sooner than later (demand for 15k BOP stack rigs were high at the time) particularly if the costs involved could be reduced.

Many aspects were looked at – ranging from slimhole drilling through to technical limit drilling.

As the rig had been on contract to the Operator for a long time and its performance was very good, and as the sub-surface personnel predicted a SIWHP Shut-in Wellhead Pressure of no greater that 9,450 psi, the question was asked of the Governing Body (HSE) if, certain practices were used, could the rig be utilized?

Fig 1: The 10k-Rated 1982 Fiede & Goldman 9500 Pacesetter Rig the "John Shaw"

Background

The well to be drilled was a near high pressure well with a calculated SIWHP of 9,450 by the Operator's sub-surface team. The rig's BOP stack design was one of 10k, so the question is would you be comfortable drilling a 9,450 psi well with a theortical margin of 550 psi to spare? The answer was no, unless certain criteria could be put in place regarding the Drilling Programme and certain changes could be made to the rig during its up-coming shipyard visit.

So work began to study the key risks associated with drilling a 9,450 psi well with a 10k BOP stack rig. In order to prove complete independence, an independent third-party was tasked with the work covering all operator angles, all drilling contractor angles and the rig itself in light of the tasks to be carried out, the data and information at hand and prodigious amounts of literature.

The key area (which was crucial) was always, throughout the study, to minimize danger to the crew should, following the work, the Governmental body give approval for the drilling of the well. The Governmental body required to see all of the work carried out, particularly the finding and risk mitigation risks pertaining to every risk indentified.

Introduction

The paper details six steps associated with the process (logic / approach) taken with this study to ascertain the possible key risks. Throughout this phase, a risk expert was used, along with a drilling expert, the drilling contractor's rig manager, the senior drilling engineeri of the well, the drilling superintendent and the operator's drilling manager.

Only proven data / information wich could be adequately cross-referenced was utilized for the purposes of accuracy.

The six steps are as follows:-

- Establishing the risk and risk identification framework
- Identification of Risk characteristics
- Data Sourcing / Input Data
- Quantitative Risk Analysis Methodology
- Risk Mitigation
- Final Conclusions Derivation

The "foundations based upon data" approach is portrayed in Figure 2.

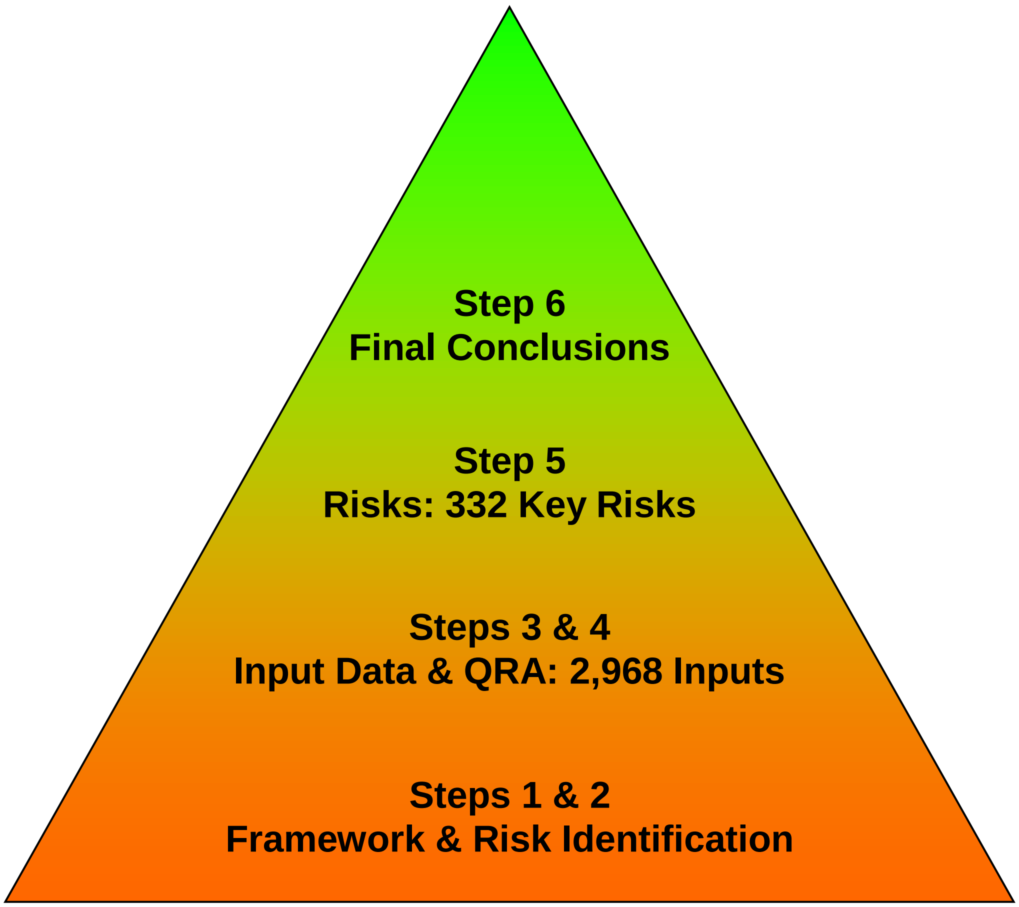

Figure 2: Overview Methodology

With regard to the data necessary to establish the risks (Steps 1 – 3), first-class databases (as listed in the reference section) were utilized. A total of 2,968 inputs were studied throught this phase of the process.

Blowouts

One of the greatest fears in the oil and gas industry is one of blowouts. Blowouts are typically defined as an uncontrolled release of hydrocarbons at the surface. At the very least they are destructive and can result in the loss of human life, marine life, beach / tidal area life, damage to the environment, the loss of equipment, rig and assets, the loss of the company's reputation and the loss of the industry's reputation.

They can also increase business costs, spill carbon dioxide into the air and cause public relations disasters (e.g. Montara, Macondo, etc).

With regard to Step 4, Quantitative Risk Analysis Methodology, the maths, logic and methodology behind the computer programme utilized (which is centred upon Risk Impact, Reference 21) is portrayed, so that the reader is able to see how the structure inherent within the logic of the approach was constructed. Having portrayed how the software works, the next area of the paper shows how the outputs (i.e. quantified risks) were then ranked with respect to both probability of occurrence and impact to the rig and its crew should an event occur. This forced the operator and the drilling contractor into Step 5 – i.e. Risk Mitigation – whereby those issues which would have a significant impact upon safety – even if the likelihood of event possibility was calculated to be remote – had to be addressed. A total of 332 risks were studied during this phase of the process.

The front cover of the June “Drilling Contractor” magazine advertises an excellent article entitled, “Fine years after Macondo: Significant progress made in offshore safety, but industry realizes journey is not over.” So true – since we have continued seeing blowouts since Macondo. One in the Gulf of Mexico (the “Hercules” blowout and the KS Endeavour offshore to Nigeria where two men died.

It seems that blowouts are always a possibily. Granted they are remote possibilities, but when they happen, they wreak havoc. Thus it was a difficult task to try and secure a licence for this rig, but as the Governmental Department’s Guidelines were based upon ALARP (this is risks should be As Low As Reasonably Practicable) it just might be possible.

ISSUE

Based upon the ALARP requirements contained within the Design and Construction Regulations – is drilling a 9,450 psi well with a 10,000 psi BOP stack “As Low As Reasonably Practicable?”

This is the key, fundamental issue with regards to the drilling of this well. On the one hand, it could be argued that a 10,000 psi system should be able to cater for 9,450 psi pressures. On the other hand, it could be argued that the margin of 550 psi is too small for comfort.

Since a 15,000 psi rated rig was not readily available for some time, and since the existing 10,000 psi rig on contract had an excellent safety and performance record with first-class pro-activity from the Drilling Contractor (both onshore and offshore), the question was asked by the Operator, therefore, whether, through extensive risk identification and subsequent risk mitigation or elimination, “could the current 10,000 psi rig be utilised?”

The view taken by the Health and Safety Executive was identical to the theme taken throughout the Design & Construction Regulations – namely, the onus is upon the Operator to show how risks are to be managed, mitigated and averted such that they are ALARP as opposed to one of prescription, which existed prior to the Regulations coming into force.

STUDY FRAMEWORK

With the ALARP principle being 100% key, the study areas – and all related subjects – were “framed” in the context of a blowout and its associated causes so that the causes of all relevant recorded blowouts were fully understandable.

Once understanding was achieved, the work could be extended into the areas of risk aversion / mitigation / elimination such that blowout likelihood was either ‘As Low As Reasonably Practicable’ or as close to nil as possible. With this in mind, work began to achieve these objectives.

The following sections describe the methodologies associated with these tasks, how they were marshalled and worked and how the derivations were utilised to yield the conclusions.

THE PROCESS

The following areas cover the overall process, commencing with how the framework was constructed through to data acquisition, data modelling and eventual conclusion derivation.

Step 1 – Establishing the Risk and Risk Identification Framework
In the first instance, Hazard Identification and Risk Assessment Procedures were utilised as a framework re Hazard, Risk, Consequence and Control / Mitigation Measures. This ensured the following:-

- All risks would be identified and assessed.
- All control / mitigation measures would be identified to remove or reduce the risks to acceptable levels.
- All actions from the risk assessment process would be followed up, included in the appropriate work programme and communicated to personnel involved in the operation.
- There would be a formal auditable and approved record of the risk assessment process.

See Reference 1.

Step 2 – Identification of Risk Characteristics
Here, the typical characteristics of the most likely risks to be involved in the drilling of this well were identified through the analysis of the papers / documents per References 2 – 6. Specifically, the key statement "The duty holders need to assess the risks to people from wells throughout the whole lifecycle of the well and they must have systems in place to reduce those risks to As Low as Reasonably Practicable" had to be fully addressed. Of note is the safety triangle, which suggests that if dangerous occurrences (kicks), i.e. hydrocarbon influxes into the well, are effectively managed, then blowouts are prevented; and if blowouts are prevented then so are fatalities. So the key then is to prevent a kick (hydrocarbon influxes into the well) from occurring in the first place. But, should one occur, then the second key is to control and nullify the effects of the kick.

In accordance with the Safety Case Regulations, the following points were considered to be crucial:-

- Major hazards have been identified.
- Risks from these have been evaluated.
- Management systems are adequate.
- Measures have been taken to reduce risks to "as low as reasonably practicable".
- There are arrangements for audit and report.

At the time the Design and Construction Regulations were enforced:-

- Kicks were more frequent on HPHT wells than on standard wells.
- Likelihood of multiple kicks greater.
- Timeframe longer to bring well back under control.

Accidents on semi-submersibles were reviewed, specifically with regard to event frequencies (Reference 3) in conjunction with well design and well control (Reference 4) where kicks recorded on the HSE's database were reviewed which was an excellent source of material to help frame the work structure in conjunction with Reference 5 which was also considered important since the kick modelling work carried out at RF Rogaland Research in Stavanger, Norway, is well known as are the philosophies covered in this paper re the NPD Norwegian Petroleum Directorate (i.e. "…… that Operating Companies need an adequate decision making tool that permits studies of the effects of implemented risk reducing measures based on local conditions…… looking at causal mechanisms and expert judgements combined with hard data rather than worldwide blowout statistics. It is important in the decision-making process that decision making must be achieved through a detailed stochastic modelling approach which considers the physics of the blowout rather than statistically treated events (which may be at a somewhat coarse level). The subjective theory of probability represents a systematic way of integrating hard data and expert opinions leading to consistency between the risk analysis objectives and the interpretation of the model conclusions.

In conjunction with Reference 6, work could be cross-referenced with well control management and contingency planning.

Step 3 – Data Sourcing / Input Data

With Steps 1 & 2 having defined the framework and general risk characteristics, this next step focused upon the sourcing of appropriate data from industry-respected data banks as follows (References 7 -10) :-

- The Worldwide Offshore Accident Databank
- Accident Statistics for Floating Offshore Units on the UK Continental Shelf 1980-2003 – Health and Safety Executive, UK
- Blowout and Well Release Characteristics and Frequencies – SINTEF, Norway
- Blowouts During Offshore Operations – SCANDPOWER, Norway

Step 4 – Quantitative Risk Analysis Methodology

With the framework for the study now in place, the general risk characteristics categorized and the data sets sourced, the next step, Step 4, proceeds with the actual risk analysis per the following references (References 11 – 12):-

- Risk Assessment of Hydrocarbon Releases – Health and Safety Executive, UK
- QRA Methodologies – General Literature

Risk Analysis Logic & Methodology

This section of the paper summarises the maths, logic and methodology behind the work. This subject area can be complex and so an attempt is made here to make a typically mis-understood subject understandable.

The Decision-Making Process

All decision processes involve risk analysis. At the simplest level, project decisions are based upon assessment of the pros and cons of a situation. We call this a ‘gut feeling’, intuition, instinct or even just a hunch.

Although qualitative analysis may prove to be accurate in many cases, accuracy in assessment tends to fall as the complexity of the problem increases. Moreover, in rigorous engineering activities, informal qualitative approaches are not sufficient to convey the relevance of findings to colleagues. Furthermore when an interdisciplinary analysis is required, qualitative approaches are often unreliable as no single engineer can provide expertise in every field. Quantitative risk analysis is a pragmatic technique for making effective use of engineering experience. The approach uses mathematical modelling to create numerical representations of the project phases and activities.

The Risk Assessment Process

The risk assessment process consists of the following stages:-

1. Risk identification
2. Analysis of risk impact
3. Formal representation of risk and risk impact
4. Mathematical modelling of risk interaction
5. Interpretation of results and presentation of findings

Impact Analysis

The following sub-section gives an overview of impact analysis:-

Each hazard within an activity is considered as having two risk parameters associated with it:-

1. The probability of occurrence of the hazard (P_{occ})
2. The consequences to the operation if the hazard were to occur (specifically, tolerability)

The meaning of the first parameter is self evident, namely the probability of occurrence of the hazard. The second parameter can also be interpreted as a probability – ***the probability of occurrence that would be considered acceptable for that hazard.***

A full account of this QRA process can be found within Reference 21.

Safety Factor

A Safety Factor (SF) can be calculated via the ratio of the tolerable probability of occurrence of the hazard to the probability of occurrence of the hazard. The definition and meaning are as follows:-

Safety factor SF is given by : $SF = P_{tol} / P_{occ}$

Where:- P_{tol} is the tolerable probability of occurrence of the hazard and P_{occ} is the probability of occurrence of the hazard

In terms of SF, a variety of plots / schematics can be used to portray the data / information. For this study, bar charts were utilised since they were readily interpreted by the well designers, Operator staff and Drilling Contractor staff.

Safety Factor Bar Graph

A SF of 1 means that the risk is acceptable as it is less likely, or as likely to occur as that which is considered to be tolerable. Conversely, a SF of less than 1 means that the risk is more likely to occur than that which is considered to be tolerable.

The safety factor bar graph displays the safety factor for each risk as calculated using:-

$$SF = P_{tol} / P_{occ}$$

Figure 2 below shows the value of the Safety Factor versus Risk Content. This allows personnel to see what is “relatively safe” and what “is not relatively safe”.

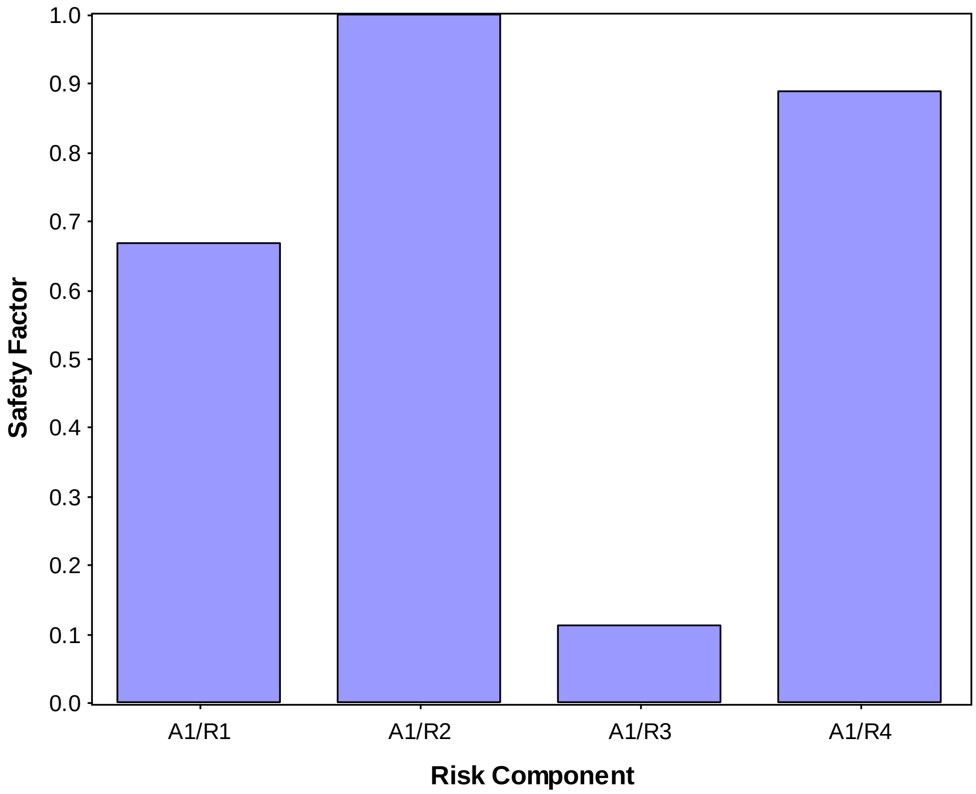

Figure 3: Safety Factor Bar Charts

Overall Safety Factor

In addition to calculating a safety factor for each hazard it is useful to distil the information into a summarizing graphical representation via the calculation of an Overall Safety Factor (OSF). The OSF for an activity is obtained by multiplying the individual SF values for each hazard within an activity together.

i.e.

if $(P_{tol} / P_{occ}) >= 1$: set to = 1

if $(P_{tol} / P_{occ}) < 1$: set to = P_{tol} / P_{occ}

$$OSF = (P_{tol} / P_{occ})_1 \times (P_{tol} / P_{occ})_2 \; \ldots\ldots \times (P_{tol} / P_{occ})_n$$

This is subject to the constraint that SF values that are greater than 1 are set to 1 prior to the multiplication. This prevents activities with one or more, high, SF values from artificially skewing the OSF in the direction of safety.

The maximum possible value of the OSF is 1. A value of 1 implies that all individual hazards are considered to be at least as safe as that which is considered tolerable. An OSF value of 0 implies that one or more hazards are in the category of being considered **highly dangerous**. The smaller the OSF value, the greater the danger associated with the activity. This is illustrated in Figure 4.

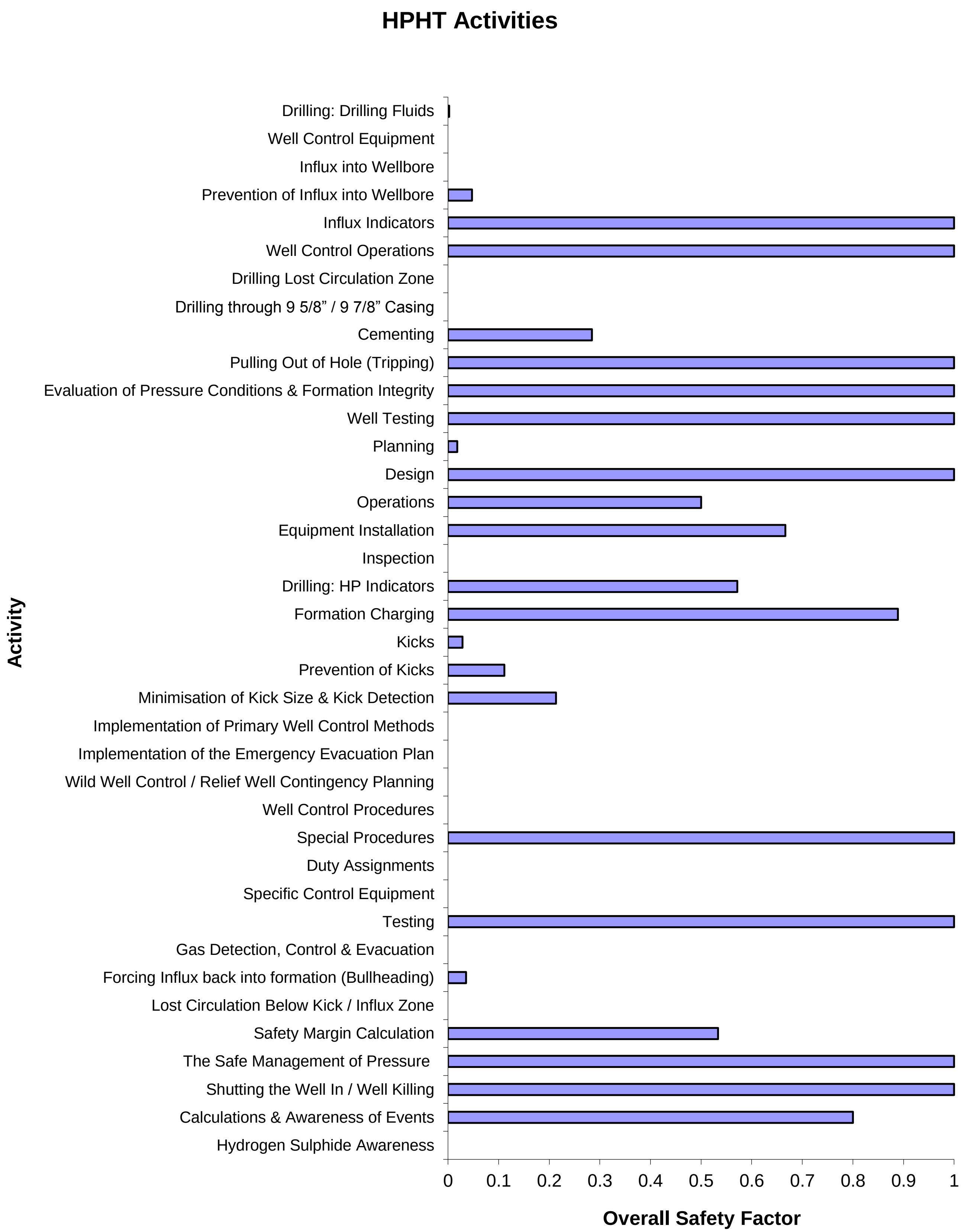

Figure 4: Overall Safety Factor for a Set of Activities

THE RESULTS

The key results (with a correspong safety factor of 0) derived from the study analysis are contained within Table 1 below.

P1/A2/R5	Failure of 10 K Annulars
P1/A2/R7	Failure of whole well control system
P1/A3/R6	Erosion of surface eqpt' due to high flow rates
P1/A7/R3	Drilling into Lost Circulation Zone with gas reservoir above and not being able to shut well in through mal-functioning equipment
P1/A8/R5	Burst casing during well control event
P1/A17/R1	The BOP stack including flexible hoses has not been pressure tested to their full working pressure on the test stump prior to running. (Failure of the BOPE could be catastrophic in an untoward event)
P1/A17/R2	Hoses not visually inspected externally and in accordance with manufacturers recommendations when stack is moved
P1/A23/R12	Non recognition of underground blowout
P1/A23/R19	Failure of BOPE
P1/A24/R2	Failure of Well Control Equipment
P1/A24/R3	Poor operational procedures (e.g. Snorre incident and Saga 2-4/14 blowout)
P1/A24/R4	Poor or zero evacuation support
P1/A25/R1	Non-understanding of blowout scenarios
P1/A25/R3	No overall control philosophy
P1/A26/R15	Mis-calculation of MAASP
P1/A26/R16	Mis-calculation of maximum WP at top of annulus (P.max)
P1/A28/R1	OIM makes poor judgement / does not follow procedure
P1/A28/R2	Company Drilling supervisor makes poor judgement / does not follow procedure
P1/A28/R3	Toolpusher Ditto
P1/A28/R4	Driller Ditto
P1/A29/R1	Failure of Diverter System
P1/A29/R3	Failure of BOP System
P1/A29/R8	Failure of casing
P1/A31/R2	Gas not be detected in the atmosphere of the shale shaker room
P1/A31/R3	If H_2S in is the atmosphere, it may not be detected by equipment (due to equipment failure)
P1/A31/R4	Breathing equipment is non-operable or is not sufficient in quantity
P1/A31/R6	Overboard effluent line washes out
P1/A31/R8	Glycol Injection System fails
P1/A33/R3	Combination of continual losses & continual influx
P1/A38/R1	Non awareness of H_2S

Table 1: Risks with Overall Safety Factor of Zero

Step 5 – Risk Mitigation

With all risks now having been identified and quantified in terms of their severity, it is now possible to begin to effect mitigations such that their likelihood of occurrence – and their ensuing impact should they occur – is much reduced.

The 30 key risks identified as having an Overall Safety Factor of Zero can be grouped into the following areas:-

- Data and Well Design
- Operational Issues
- Equipment Specific Issues

The following tables group the key risks together and the mitigations which were utilized / incorporated to reduce / eliminate the likelihood of the risks occurring.

Data & Well Design: Key Risks & Mitigation

Data & Well Design – Key Risks	
P1/A8/R5	Burst casing during well control event
P1/A25/R1	Non-understanding of blowout scenarios
P1/A26/R15	Mis-calculation of MAASP
P1/A26/R16	Mis-calculation of maximum WP at top of annulus (P.max)
P1/A29/R8	Failure of casing

Data & Well Design – Mitigation
Well Pore Pressure Data Pack – which detailed the 'most likely' pore pressures to be found within the field and so goes a long way in reducing uncertainty with regard to surface pressure should an influx occur. Of key importance was that surface pressure was unlikely to exceed 9,450 psi (the uncertainty range being 9,050 – 9,450 psi).
Well Casing Design Data Pack – which showed the well's casing design to be more than adequate given the expected likely range of surface pressures which would be encountered should a kick be taken; crucially that the casing can withstand a higher pressure (an extra 1,500 psi) than the maximum 9,050 – 9,450 psi range.
The UK's 'Design and Construction Regulations (1996)'. These Regulations ensure that the well is designed and constructed (and 'operated') such that the risks associated with the well are ALARP ('…… as low as reasonably practicable'). A full understanding of these design, construction and operational regulations was essential since it had to be demonstrated to the Authorities that the principles inherent within these regulations had been fully addressed. If they were not, then the Operator simply would not be given approval to drill the well.
Use of Proven Casing Design Software (StressCheck & WellCat).
Use of Highly Qualified Independent Casing Designer.

Table 2: Data & Well Design – Key Risks & Mitigation

Operational Issues: Key Risks & Mitigation

Operational Issues – Key Risks	
P1/A23/R12	Non recognition of underground blowout
P1/A24/R3	Poor operational procedures (e.g. Snorre incident and Saga 2-4/14 blowout)
P1/A24/R4	Poor or zero evacuation support
P1/A25/R3	No overall control philosophy
P1/A28/R1	OIM makes poor judgement / does not follow procedure
P1/A28/R2	Company Drilling supervisor makes poor judgement / does not follow procedure
P1/A28/R3	Toolpusher Ditto
P1/A28/R4	Driller Ditto
P1/A33/R3	Combination of continual losses & continual influx
P1/A38/R1	Non-awareness of H_2S

Operational Issues – Mitigation
Operator's Well Management System – which contained the appropriate design and operating philosophies to address risks and mitigations.
Operator's HPHT Well Control Standards – which allowed for specific HPHT Well Control risks and mitigations to be satisfactorily addressed.
Drilling Contractor's HPHT Well Control Standards. In conjunction with the Operator's HPHT Well Control Standards, this document proved invaluable with respect to risk identification and subsequent risk mitigation.
The Institute of Petroleum Model Code of Safe Practice Document 'Well Control During the Drilling & Testing of High Pressure Offshore Wells' allowed for all of the above to be cross-referenced with a Model Code of Safe Practice.
The UK's 'Design and Construction Regulations (1996)'. These Regulations ensure that the well is designed and constructed (and 'operated') such that the risks associated with the well are ALARP ('…… as low as reasonably practicable'). A full understanding of these design, construction and operational regulations was essential since it had to be demonstrated to the Authorities that the principles inherent within these regulations had been fully addressed. If they were not, then the Operator simply would not be given approval to drill the well.
'Avoidance of Offshore Operations Mis-Management: Norwegian Petroleum Directorate Findings into the 2005 Snorre Incident'. The frank, plain openness of this document showed how catastrophic disasters can compound and escalate very quickly. Learnings were gleaned and factored appropriately into the process.

Table 3 : Operational Issues – Key Risks & Mitigation

Equipment Specific Issues: Key Risks & Mitigation

Equipment Specific Issues – Key Risks	
P1/A2/R5	Failure of 10 K Annulars
P1/A2/R7	Failure of whole well control system
P1/A3/R6	Erosion of surface equipment due to high flow rates
P1/A7/R3	Drilling into Lost Circulation Zone with gas reservoir above and not being able to shut well in through mal-functioning equipment
P1/A17/R1	The BOP stack including flexible hoses has not been pressure tested to their full working pressure on the test stump prior to running. (Failure of the BOPE could be catastrophic in an untoward event)
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P1/A31/R4	Breathing equipment is non-operable or is not sufficient in quantity
P1/A31/R6	Overboard effluent line washes out
P1/A31/R8	Glycol Injection System Fails

Equipment Specific Issues – Mitigation
Drilling Contractor's HPHT Well Control Standards
Full upgrade of Blowout Prevention Equipment – Carried out in ship-yard
Full "flat-line" testing of all Blowout Prevention Equipment
Decision by Operator not to test the well
Decision by Operator to real-time (RFT / MDT) test reservoir pore pressure
Decision by Operator not to bring influx to surface unless pressures accurately assessed through RFT / MDT data acquisition

Table 4: Equipment Specific Issues – Key Risks & Mitigation

Step 6 – Final Conclusions Derivation

With the risks and their mitigations having been identified, the final step – that of Conclusion Derivation – could be taken, such that the Operator and Drilling Contractor should be able to assess whether or not the well could be drilled successfully.

Following extensive review of the study's findings and the fact that the key risks identified as a result of the study were able to be addressed, it was concluded that the well could indeed be drilled since all of the work put into the project and the rig by the Operator and Drilling Contractor rendered the risks ALARP.

As all identified risks following extensive analysis through the use of Risk Impact software were found and proven to be ALARP the UK Regulatory Authorities gave permission to drill.

CONCLUSIONS

The use of Risk Impact software allowed the difficult problem associated with this well to be solved in an excellent manner. Indeed, it is unlikely that permission to drill would have been given by the UK Regulatory Authorities had such an approach not been taken.

The whole project was an excellent success. All parties profited – through both business revenue and through reputation enhancement.

The Operator gained through:-

- Being granted permission to drill, which accelerated the exploration / appraisal programme, thereby focusing cash-flow and helping to define medium to long-term field development plans.
- Improved drilling performance as a result of excellent potential hazard identification.
- Reputation enhancement through its close liaison with the Health and Safety Executive, Drilling Contractor and service suppliers.

The Drilling Contractor gained through:-

- Rig equipment upgrade (largely paid for by the Operator).
- Reputation enhancement (already the best in the industry, the Drilling Contractor's reputation was even further enhanced due to its pro-active approach, focus upon safety and risk mitigation / elimination).

The Shipyard gained through the revenue derived from the rig's equipment upgrading.

The Insurance Company gained through reduced blowout risk likelihood.

The final conclusion is that such work is most definitely applicable for similar projects in South

East Asia where similar economic and safety benefits would most definitely be experienced.

REFERENCES

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4. SPE Paper 56921 "An Analysis of OSD's Well Incident Database : Results can Improve Well Design and Target Well Control Training"
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