

A METHODOLOGY FOR CONCEPT RISK ASSESSMENT OF OFFSHORE DEVELOPMENTS

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This paper describes a simple means of ranking the risk levels of offshore development options at the concept selection stage in a systematic and consistent manner. The risks are quantified in terms of:

Individual Risk by discipline;
Temporary Refuge Impairment Frequency;
Potential Loss of Life over development life (from construction to abandonment).

The methodology also assists in very early identification of design features that may act as significant risk drivers and possible control measures.

In this manner it is possible to apply As Low As Reasonably Practicable (ALARP) principles at the earliest stage of concept development. This paper describes the main features of the development of the methodology and its calibration. A case study is also described as are the requirements for future development of the methodology. The paper concludes that whilst some future development is desirable, application of the methodology in its current form is making a major contribution to ensuring future offshore developments have risk levels that are truly ALARP.

Key Words: Concept, Ranking, Risk, Assessment

INTRODUCTION

Preamble

It is self-evident that the development of an offshore oil and gas production installation can never be completely "inherently safe". Nevertheless, the degree of inherent safety can be maximised at the concept selection stage. Maximising inherent safety of a design requires identification and assessment of the major risk contributors early in the project life thereby allowing their control in a cost beneficial manner. This requires a structured hazard identification study [1] followed ideally by some form of Quantified Risk Assessment (QRA) which is both accurate and rapid.

In the absence of some form of QRA early in the life of the project, it is possible that the "engineering judgement" approach will fail to identify all of the major risks and that expenditure will be targeted in areas where there is little benefit. The "engineering judgement" approach has been found to result in a requirement for expensive remedial actions late in project life.

The development of an oil and/or gas facility normally has a long lead time with many development options initially under consideration. This means that there is much design effort required to progress all options to the point where a detailed QRA study (a time and effort consuming process in itself) can be applied. This paper describes a simple, rapid screening tool which permits risk ranking of many design options in a methodical, consistent and auditable manner thereby reducing front end design costs and permitting the targeting of design effort in the best manner. In other words, it adds value to the project, assists in getting the design right first time, and allows ALARP to be built in at the concept selection stage. This is particularly important in view of the current regulatory regime [3] which requires demonstration of ALARP as part of the Design Safety Case.

It is a key feature of the methodology that it can be applied sufficiently rapidly to keep pace with the decision making process in the turbulent atmosphere of the concept development phase.

In general it can be noted that application of the screening methodology is consistent with an increasing trend in the oil and gas industry to conduct more detailed safety study earlier in the design process. The methodology applies equally to new developments and major modifications of existing installations.

Offshore Development

The development costs of an offshore oil and/or gas facility can be of the order of £500M to £1000M. It is clear that getting it right first time has major cost benefits in both design and construction costs. The costs can be split into four main areas.

Drilling	The exploiting of the reservoir of hydrocarbons. Each well drilled has a cost of the order of £5M, but in turn it has a risk of a blowout.
Structure	The structure which holds the facility above the sea. This is potentially unique to each facility and depends upon the weight/design of the topsides facilities, the water depth and the method of transportation of the hydrocarbons to the shore. The structure is one of the more expensive elements and has a long lead time.
Transportation:	The means by which the hydrocarbons are conveyed to the shore.
The Facilities:	Services, accommodation and production equipment.

The development of hydrocarbon accumulations in the UK sector is becoming increasingly complex. The large fields have already been developed in the UK North Sea for the most part so future developments will tend to involve one or a number of smaller accumulations. The declining reservoir size, together with a relatively low oil price, means that increasing ingenuity is required on the designers' part to ensure that costs are minimised.

In order to achieve the required financial return, many current development projects involve exploitation of multiple reservoirs. Typically, there will be a central complex and a number of satellites which may be:

- subsea;
- not normally manned installation (NNMI);
- minimum process facilities (MPF)

The integration of these systems into the central processing facility (CPF) requires subsea piping and risers on the CPF. It should be noted that the CPF can be, and in many cases has been, an existing older platform with available capacity due to declining production from the field for which it was developed.

The depth of the water in which these fields lie is increasing, particularly West of Shetland in the UK and at or beyond the continental shelf elsewhere in the world. This may require novel structures to support all the facilities. This support may be a steel jacket, a gravity-based structure (concrete), a Tension Leg Platform (TLP), a guyed tower, a floating production system (semi-submersible or monohull), etc.

The oil reservoirs are becoming more arduous. The exploitation of new, deeper reservoirs, produces higher pressure and temperature fluids. These require long drilling phases, typically twice as long as previously. Various drilling techniques are being used. These may involve:

- tender assisted drilling;
- cantilevered jack-up drilling;
- drill rig skidded off a jack-up;
- subsea wellheads;
- totally integrated drilling.

Transportation of produced hydrocarbons can involve:

- two phase pipelines;
- single phase pipelines to the shore;
- the storage of oil on or near to the installation and the transport via tankers.

A fundamental safety feature is spatial segregation. Clearly this is more difficult to achieve on an offshore installation than it is on shore. Typically, the cost of land on shore is of the order of £5/m² but offshore it can be of the order of £2000/m². It follows therefore that greater care must be taken with layout in order that segregation does not have to be "bought" at a later design stage.

Risk Drivers

The key risk "initiators" are likely to be as follows:

- Number of wells to be drilled;
- Nature of the reservoir;
- Process equipment - number, size, location and process conditions;
- Number and location of the risers and the nature of the fluids in the risers;
- Manning levels;
- Location of the installation with respect to shipping activity;
- Helicopter transport;
- Seismic risk;
- Structural failure risk.

The extent to which such factors translate to actual threat to life or the asset is very dependent on the design of the concept. The design principles that are important in this respect include:

- Installation layout (single installation, bridge linked installations and the like);
- Manning strategy (manned, not normally manned);
- Location of the temporary refuge (TR) with respect to hydrocarbon hazards;
- The nature and location of the evacuation routes and the shielding from hydrocarbon hazards;
- The location and nature of the evacuation systems eg Totally Enclosed Motor Propelled Survival Craft (TEMPSC);
- Vulnerability of any of the above from collapse of structures;
- The provision of protection such as active or passive fire protection.

It follows that good design practice should consider the following:

- Minimisation of hydrocarbon inventory;
- Segregation of inventory (spatial or otherwise) to inhibit escalation;
- Open layout to limit gas build up and explosion overpressures;
- Protection of key emergency systems;
- Minimise exposure of personnel to direct hazard;
- Shielding of escape routes from hazards;
- Segregation or shielding of the TR and TEMPSC from hazards;
- Limiting the potential for collapse of structures onto the TR and TEMPSC;
- TR Gas and Smoke tightness;
- Keeping the structural members that support the TR and TEMPSC outwith the hydrocarbon area as far as is practicable.

It is evident from this background that there are increasingly many development scenarios to be considered at the concept selection stage, each of which carries its own particular risks and costs. Identifying the correct or optimum design option quickly and applying the optimum level of protection for personnel and the asset requires care and skill. The concept risk assessment methodology described here aims to assist in this process. The essential feature of this methodology is that much of the analysis and assessment is carried out in a series of pre-processed packages which minimise the need for repetitive calculations. This allows rapid assessments without compromising accuracy and auditability.

METHODOLOGY DESCRIPTION

Methodology Steps

The methodology has been split into a series of packages. Within each package there are a series of rules to be applied. The rule based approach ensures consistency of application.

The methodology steps are as follows:

- 1 Data Acquisition
- 2 Ignited Event Frequency
- 3 Immediate Fatality
- 4 TR Impairment
- 5 TEMPSC Impairment
- 6 Structural Failure Risk
- 7 Helicopter Risk
- 8 Occupational Risk
- 9 Diving Risk
- 10 Construction Risk
- 11 Results Presentation

Each of these is described in the following sections to give some general indication of the approach.

Data Acquisition

Data acquisition is the starting point for the analysis. The data should ideally include:

- 1 Platform layout. This should include the location of process areas, risers, TR, TEMPSC and any bridge linked installation.
- 2 Process flow diagrams and operating pressures.
- 3 Equipment count (wells, vessels, turbines, risers etc).
- 4 Drilling programme.
- 5 Basic details of structural design.
- 6 Details of helicopter operations; transit time from shore and frequency of any infield shuttling.
- 7 Manning levels during drilling, production and SIMOPS.
- 8 The need for diver intervention - diver hours per annum.
- 9 Construction effort - likely hours worked offshore.

In practice, not all this information will be available and it is expected that some assumptions may have to be made. These should, of course, be clearly recorded. If information is limited, the study can still commence on the basis of a layout sketch, process flow diagrams, outline operations and maintenance philosophy and drilling programme.

Ignited Event Frequency

The starting point in assessment of hydrocarbon risk is an assessment of the ignited event frequency. The ignited event frequency for any piece of equipment is assessed as follows:

$$\text{leak frequency} \times \text{ignition probability}$$

Using E&P Forum data [2] typical leak frequencies for equipment packages (eg a separator, MOL pump or compressor) have been derived. Using a simple ignition probability model ignited event frequencies have been derived. Values for these parameters are given in "look-up" charts for each package and operating pressure. Modification factors to account for instances of heightened impact risk have also been derived.

Immediate Fatality

Given the base risk (ignited event frequency) and data on manning patterns, it is possible to calculate the risk to an individual from the immediate effects of the incident. This is achieved by applying simple rule sets on fatality probability for those in the vicinity of an incident.

TR Impairment

Calculation of TR impairment frequency is the essence of the model, particularly so as it is the main risk parameter required by the Offshore Installations (Safety Case) Regulations [3]. The underlying theory is that for a given type of installation with a given set of features there is a gearing factor that links ignited event frequency with TR impairment frequency. The theory was given credibility by some early work which calculated the TR impairment ratio (TR impairment frequency divided by ignited event frequency) from a series of detailed QRA studies and found these to be remarkably consistent for similar installation types.

The idea has been developed further and TR impairment ratios have, by analysis of existing QRA and fundamental reasoning, been derived for process, riser and blowout events. Using process events as an example, a rule set has been derived to permit the ratio to be calculated by considering the following factors:

- inventory size;
- level of structural redundancy;
- level of passive fire protection;
- explosion potential and protection;
- TR protection against fire, smoke tightness and positioning;

There is clearly a degree of subjectivity in assessing each of these factors but the methodology manual gives guidance to the user to minimise this.

TEMPSC Impairment

A rule based analysis is used to derive the conditional impairment probability of the TEMPSC given that TR impairment has occurred or is going to occur. At this stage the hydrocarbon delayed fatality risk can be calculated; this is made up of TR fatalities (when the TR is impaired and escape is not possible due to TEMPSC impairment) and TEMPSC fatalities (when the TR is impaired but the TEMPSC is not and fatalities result from TEMPSC use).

Structural Failure

Structural collapse may occur as a result of fatigue/corrosion, ship collision or seismic activity. Coarse estimates of frequency, dependent on installation location and type, are given to permit assessment of all of these mechanisms.

Helicopter Risk

Generic risks are given for take off / landing and transit in helicopters. Both travel to and from shore and in-field shuttling are considered.

Occupational Risk

Generic data is given to allow the assessment of the risk from trips and falls, electrocution etc. At this stage the overall risk to an individual can be calculated.

Diving

A general risk figure is given for divers. This is only likely to be important if the concept requires considerable diver intervention.

Construction

A general risk per man hour estimate is given for offshore construction activities. It is generally not expected that this will influence concept selection but the data is presented to allow such factors to be taken into account should it be so desired.

Results Presentation

The results can be presented in many ways but one of the most effective has been found to be the parameter map shown as Figure 1. In this TR impairment frequency (TRIF) is plotted against individual risk per annum (IRPA). The acceptability bands should be treated as for guidance only. This format lends itself well to illustrating the effect of design changes and risk reduction measures.

Calibration

The methodology has now been calibrated against detailed QRA performed on four Shell Expro and six BP Exploration installations. In general results are encouraging. Without exception, broad trends and ranking are accurately predicted. Absolute values of TR impairment frequency and individual risk are usually predicted to within a factor of two. This is encouraging given the usual error bands associated with QRA. The time to execute each assessment is a small fraction of the detailed assessments; a few days as compared to a few months. This is also encouraging as speed does not compromise accuracy.

CASE STUDY

The methodology has been applied to a number of developments including the Eastern Trough Area Project (ETAP), the Western Area Development tie-backs to Bruce, and the Atlantic Frontier Development (Stages 1 and 2).

As a means to illustrate how the methodology is applied in practice, a series of case studies have been conducted. Whilst these are fictitious they indicate the types of issues that can be addressed and the associated decision making process. It is also worth noting that these case studies were conducted in around one man day thereby demonstrating the ease with which the methodology can be applied.

The case studies are chosen to illustrate some of the problems that might be associated with tie-ing back a series of outlying satellite fields to a central host installation. The cases studied are shown schematically in Figure 2.

Results

Case 1	<p>Process</p> <p>Jacket</p> <p>Location</p> <p>1st generation</p> <p>TRIF</p> <p>IRPA</p> <p>Conclusion:</p>	<p>3 stage separator + compression 3 wells drilled per annum Oil and gas export leg pipeline, SSIVs fitted. 6 legs CNS (1975-1980) 2.3×10^{-3} per annum 0.9×10^{-3} per annum</p> <p>A relatively high TRIF is found which is not atypical of 1st generation installations. The installation might typically be undergoing some form of upgrade programme in order to reduce the TRIF (the effect of which could be assessed by the methodology). Whilst the TRIF is high, the IRPA is not, largely due to good evacuation facilities which allow escape even if the TR is impaired. The high TRIF would however indicate that if the installation were required to act as host to some tie-backs, care would have to be taken to ensure that any risk increase was modest or indeed neutral.</p>
Case 2	<p>Process</p> <p>Jacket</p> <p>Location</p> <p>Modern generation</p> <p>TRIF</p> <p>IRPA</p> <p>Conclusion:</p>	<p>3 stage separator + compression 3 wells drilled per annum Oil and gas export by pipeline, SSIVs fitted. 4 legs CNS (1995) 0.81×10^{-3} per annum 0.83×10^{-3} per annum</p> <p>The TRIF is now a great deal lower. This will be principally due to active application of a Formal Safety Assessment programme throughout the design phase. Whilst any tie-backs would still have to be designed in a manner consistent with the ALARP philosophy, it is seen that there is more scope for coping with risk increases.</p>
Case 3	<p>Process</p> <p>Jacket</p> <p>Location</p> <p>Modern generation</p> <p>Case as case 2 but three new remote fields are tied back to the platform. No SSIVs on the tie-back pipelines</p> <p>TRIF</p> <p>IRPA</p>	<p>3 stage separator + compression 3 wells drilled per annum. Oil and gas export by pipeline, SSIVs fitted. 4 legs CNS (1995)</p> <p>1.1×10^{-3} per annum 0.98×10^{-3} per annum</p>

Conclusion: There is an appreciable increase in both TRIF and IRPA. The TRIF is now predicted to marginally exceed the HSE guidance value of 10^{-3} per annum. However as the HSE value is quoted as being "order of" and as the methodology is relatively coarse, it would not be concluded that the risk is intolerable. Rather the results act as a "flag" to ensure that risk reduction effort is focused to the correct area.

Case 4 As case 4 but SSIVs installed in in-field lines.

TRIF 0.82×10^{-3} per annum
 IRPA 0.84×10^{-3} per annum

Conclusion: Risk levels are seen to be controlled by fitment of SSIVs to all tie-back lines.

Case 5 As case 4 but all risers put on a separate riser platform. SSIVs not fitted on any riser/pipeline.

TRIF 0.80×10^{-3} per annum
 IRPA 0.81×10^{-3} per annum

Conclusion: By placing risers on a separate platform from the TR, risks are seen to be controlled by a similar level than was found for SSIV fitment.

The example is purely for illustration only. It is important to note that the results generated by application of the methodology would tend to be used for guidance only. It would only be in cases where grossly unfavourable trends were apparent that concepts would be directly rejected. It is more likely that the methodology would be used to allow identification of problem areas and testing of solutions for these.

The solutions considered in this particular example (SSIVs or riser platform) are by no means necessarily the most effective or most economic. Other equally effective solutions might involve a protection strategy based on reducing the predicted riser failure rate in the first place.

These examples are simple yet illustrate that there are alternative solutions which may not be obvious by application of "engineering judgement" but do stand out when examined by the methodology. A risk based approach can therefore be used to assist in design of the installation from the very beginning.

FUTURE WORK

Whilst the CRA methodology is reasonably well developed and has been applied in practice on a number of occasions, there is scope for further improvement. Some of the areas being considered in this respect are:

- the addition of asset loss and environmental risk;
- enhanced treatment of FPSOs, TLPs and floaters in general (particularly important as such installations are an increasingly popular alternative for UKCS developments);
- computerisation to reduce application time.

These issues, together with an overall rule-set refinement exercise, will form part of the next stage in the methodology's development. It is hoped that additional participants, beyond the three currently involved (BP Exploration, Shell U.K. Exploration and Production and WS Atkins), can be attracted to support the exercise.

CONCLUSIONS

- 1 A means for rapidly quantifying the risk levels of offshore developments at the concept option evaluation stage has been developed. It can be applied to major modifications of existing installations as well as to new developments. It can also be used to assess the effects of risk reduction modifications.
- 2 The methodology has been calibrated with success against a series of previously conducted detailed QRA studies.
- 3 The methodology has successfully been applied to a number of major UKCS developments. It has been demonstrated that ALARP principles can successfully be built into offshore designs at the concept selection phase.
- 4 The methodology could be used for rapid verification of more detailed QRA.
- 5 A continuing development programme is proposed to allow the methodology to be applied with greater accuracy, speed and effectiveness in the future.

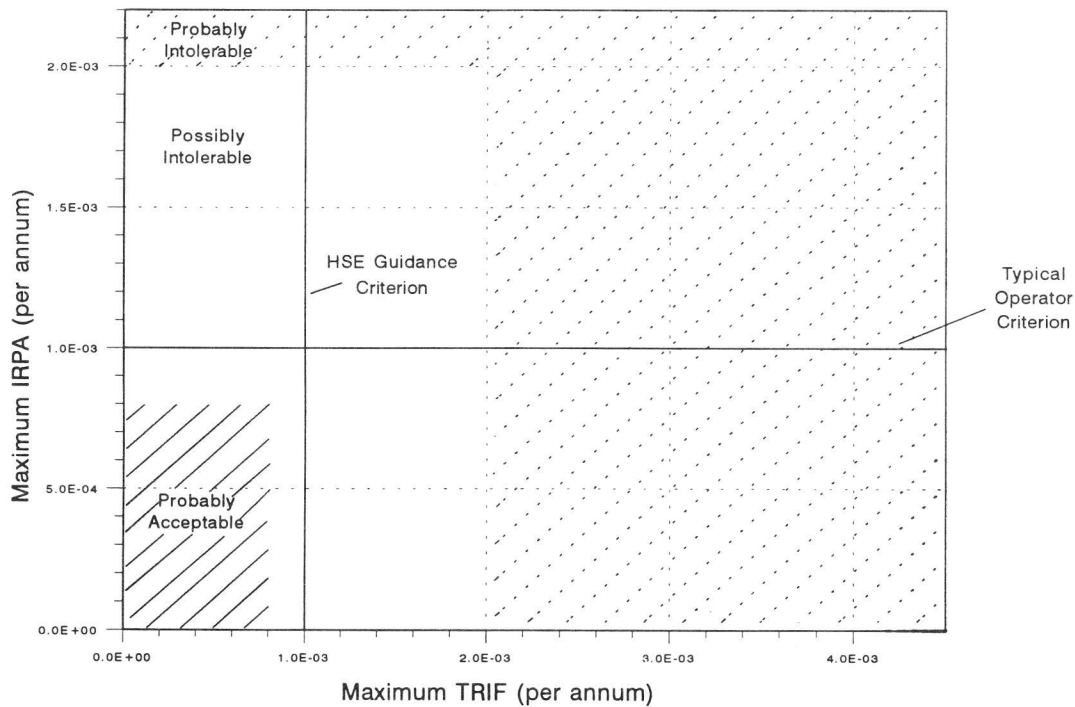
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FIGURE 1: CRA PARAMETERS MAP



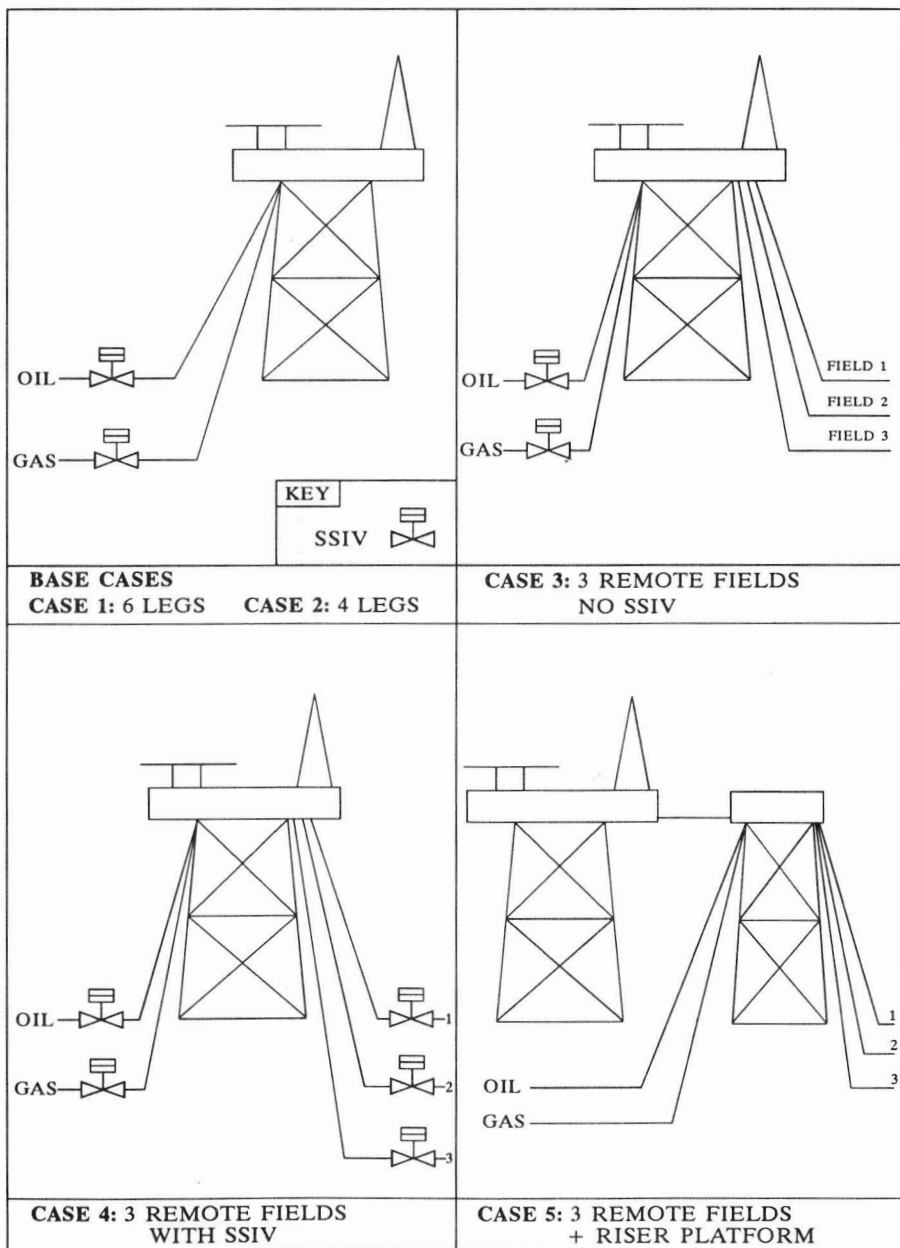


FIGURE 2: CASE STUDIES