Final Report

Contract No. 1435-01-99-RP-3995

Risk Assessment of Temporarily Abandoned or Shut-in Wells

Confidential to United States Department of the Interior, Minerals Management Service (MMS)

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NOTICE

TABLE OF CONTENTS

Table of Contents

LIST OF FIGURES AND TABLES

List of Figures and Tables

EXECUTIVE SUMMARY

In this study, a qualitative assessment of the risks presented by temporarily abandoned and shut-in wells was performed.

The risk posed by each well was defined as the probability of a leak to the environment occurring multiplied by an index representing the consequences of such a leak.

Eight well categories were defined, based on combinations of “intrinsic” (that is, belonging to the wellbore itself) attributes:

- fluid type (oil/gas);
- fluid severity (sour/non-sour); and
- wellbore energy (flowing/non-flowing)

In addition, “extrinsic” (that is belonging to the surroundings of the wellbore) attributes were used to determine the impact of a leak in terms of threat to personnel or the environment:

- platform size (major/minor);
- platform personnel exposure (manned/unmanned); and
- environmental location (divided into four zones).

The risk for each combination of intrinsic and extrinsic attributes was calculated. A maximum acceptable risk or risk threshold was then defined, based on a worst-case risk of wells in permanently abandoned (PA) status. This was then applied to all categories to determine maximum time in SI (after a workover) or TA status before the risk reached the threshold. The results were then presented, in tabular form, as a function of well intrinsic and extrinsic attributes.

ACKNOWLEDGEMENTS

The authors would like to acknowledge the contribution of Mr. Mark Stephens, M.Sc., P.Eng., Manager of Pipeline Technology at C-FER for his guidance during the development of the risk model.

1. INTRODUCTION

1.1 Background

During the course of oil and gas production operations, wells may become inactive because of diminished economic returns (which may be temporary, or permanent if at end of reservoir life), or technical problems (*e.g.*, production equipment failure, or casing collapse). Of the approximately 34,000 wells drilled in the Gulf of Mexico Outer Continental Shelf Region (GOMR) since 1947, about half have been permanently abandoned (PA) according to the publicly available MMS "Borehole" database. Of the remaining wellbores, a significant number are non-producing (Figure 1.1).

The MMS provides regulations for placing a well in temporary abandoned (TA) or shut-in (SI) status. In addition to meeting the mechanical requirements (for plugging and stub clearance), an operator must:

> "… provide, within one year of the original temporary abandonment and at successive one-year intervals thereafter, an annual report describing plans for reentry to complete or permanently abandon the well." (30 CFR Ch. II, 250.703)

However, without explicit limits on the maximum time a well may remain inactive, the effect has been an accumulation of temporarily abandoned (TA) wells. Note in Figure 1.2 that while half of the roughly 1800 TA wells in the GOMR have been in that status for less than six years, some wells have been dormant for over 30 years!

For SI wells, the current regulations provide that

> "… completions shut-in for a period of six months shall be equipped with either (1) a pump-through-type tubing plug; (2) a surface-controlled SSSV, provided the surface control has been rendered inoperative; or (3) an injection valve capable of preventing backflow." (20 CFR Ch. II, 250.801 (f))

Another MMS database, "Production for Latest Month," indicates that there are about 8,000 non-producing (and presumably SI) wells in the Gulf of Mexico. The database does not provide the length of time each well has been SI.

The inactive wells in the GOMR represent an increasing life safety and environmental risk over time, which must be weighed against the potential benefits of retaining them for future resource recovery. It is noteworthy that the Province of Alberta in Canada has also experienced a large inventory of inactive wells. The Energy and Utilities Board in that province addressed this concern directly in 1990 when it issued its "Suspension Guidelines for Inactive Wells" (ERCB 1990). In that directive, five well categories were defined, with increasingly rigorous preparation and monitoring requirements of wells in proportion to their perceived risk.

1.2 History of Study

In February, 1999, the MMS issued the following: "White Papers sought for the proposed research and projects to be conducted in support of the Technology Assessment and Research (TA&R) Program." (Commerce Business Daily 1999). One of the topics within that solicitation was:

> "Temporarily Abandoned or Shut-in Wells - Many OCS oil and gas wells are shut-in or temporarily abandoned because they are not producing hydrocarbons in paying quantities or for other reasons and, as such, may be re-entered in the future. MMS is considering updating its policy addressing the length of time wells on the OCS can remain shut-in or temporarily abandoned. An assessment of shut-in and temporarily abandoned wells is desired which will include but not be limited to pollution potential and remedial or mechanical risks of waiting to plug and abandon the wells at a later date. The assessment shall also include an investigation of the economics of permanently plugging these wells as they are abandoned rather than at a future date. General recommendations shall be provided for wells shut-in or temporarily abandoned considering the risks associated with temporary abandonment versus the costs associated with permanent abandonment."

C-FER responded in March, 1999 with its White Paper entitled, "Risk Assessment of Temporarily Abandoned or Shut-in Wells," (C-FER 1999). On the basis of the White Paper, MMS subsequently requested C-FER to submit a formal proposal. This was provided to MMS in April, and culminated in the awarding of the work in July. Work started in earnest in September, 1999 and was completed in July, 2000.

1.3 Objective of Study

The objective of this study was to provide general recommendations to ensure the safety of temporarily abandoned or shut-in wells. These recommendations were based on establishing an acceptable level of risk associated with such wells. In the context of the present project, risk is defined as the probability of a wellbore or wellhead leak to the environment multiplied by a measure of its subsequent adverse consequences.

1.4 Methodology

The chosen approach in this study was to conduct a qualitative assessment of TA and SI wells in order to determine their risk level, according to their main characteristics or attributes. Then the results were examined to identify the combination of well attributes that generated the highest risk. A maximum acceptable risk threshold was thus defined. Without intervention, the risk level of a well increases with time. Therefore, the time at which the risk reaches the threshold determines the maximum time allowable in that status. Wells were grouped into categories, and the results then combined to produce a guide in table form, showing the maximum time a well may remain as SI or TA, depending on its attributes. If an operator wishes to maintain an inactive well, the table provides advice when the well should be converted from SI to TA, or from TA to PA status.

The principal tool used in the assessment was a model developed to determine a well's risk level by:

- defining a common well configuration for each well status (SI, TA, and PA);
- identifying well attributes which influence the level of risk;
- estimating probability of a leak to the environment; and
- determining the corresponding consequences of the leak.

1.5 Organization of the Report

Section 2 describes the setting up of a representative well configuration for both SI and TA status. The attributes considered to best determine a well's risk are also defined. In Section 3, the model for determining leak probability is outlined. The approach to estimating the consequences of a leak is described in Section 4. The combined results of the probability and consequence models are given in Section 5. Final well categories are defined along with the risk threshold , which allows the determination of time limits in each well status. A table is presented summarizing the results. In Section 6 the conclusions and recommendation of the qualitative study are presented. These include a comment on the capabilities and limitations of the qualitative model as well as preliminary recommendations regarding time limits on SI and TA well status. Enhancements to the risk assessment are also proposed.

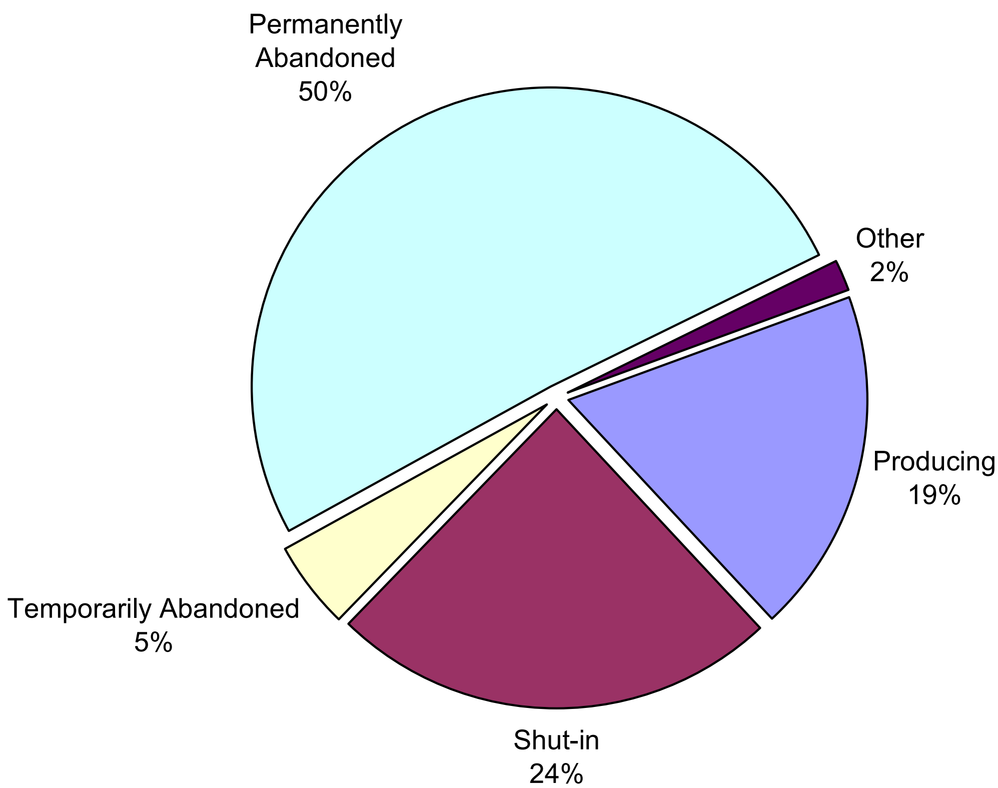


Figure 1.1 Status of wellbores in the GOMR (October 1999).

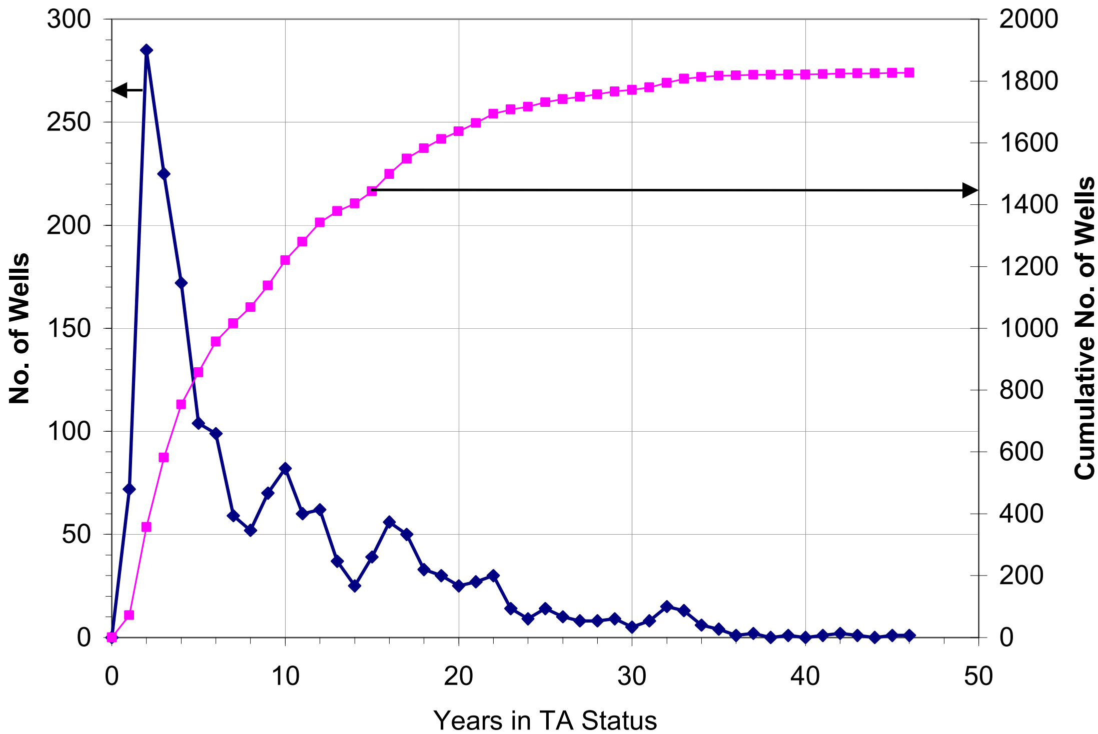


Figure 1.2 Time at status for TA wells in the GOMR (October 1999).

2. WELL CONFIGURATIONS AND ATTRIBUTES

2.1 Well Configurations

The first step in the assessment of risk levels for TA and SI wells was to define the characteristics of offshore well completions. Since this was by nature a qualitative study, a single representative well configuration was sought. According to the MMS "Borehole" database, the offshore well population is dominated by wells in "shallow" waters (400 ft of water depth or less), which is generally considered to be within the reach of conventional platforms (Figure 2.1a). The central focus on platform-based wells as opposed to subsea wells was confirmed by MMS. An examination of the MMS database, "Platform Masters," also shows that the majority of the offshore structures are also in shallow waters (Figure 2.1b). Consequently, the conventional offshore well with a dry Christmas tree on the deck of the platform was taken as the basis for the study.

Representative schematics were constructed for wells within each operational status as follows:

- shut-in (SI): a "flowing well" completion, with the christmas tree, master valves, wing valves, and the subsurface safety valve (SSSV) closed (Figure 2.3);
- temporarily abandoned (TA): no wellhead or riser; the producing formation is isolated with plugs and the casing is plugged below the mudline and capped above mudline (Figure 2.4); and
- permanently abandoned (PA): the terminal state of a wellbore, with plugging of former producing horizons and casing cut off below the mudline (Figure 2.5); a platform may not necessarily be in place over a PA well.

A schematic for a PA well was required to provide a reference against which to compare the risk of SI and TA wells. Note that the diagrams were constructed to be generally consistent with MMS regulations (30 CFR 250 Subpart G, Abandonment of Wells).

2.2 Well Attributes

In addition to the status of the well (SI, TA, or PA), there are other factors which affect the probability and consequences of a leak. In general, only items contained in publicly available MMS data files were considered. Attributes related to the reservoir, wellbore and host platform were considered as follows:

- Reservoir attributes:
  - reservoir energy (flowing/non-flowing): reservoir energy affects the magnitude of a leak. A flowing well is defined as one that has sufficient reservoir energy to produce fluids to surface without external assistance (i.e. artificial lift).

  - fluid type (gas/oil): the consequence of a leak is quite different, depending on whether it consists of fluids mainly in the gas phase or the liquid phase. This has been quantified by C-FER in earlier work related to pipeline releases (Stephens et al. 1996). The relative numbers of gas and oil producers in the GOMR is shown in Figure 2.2.
  - fluid severity (sour/non-sour): wells with sour fluids experience generally higher corrosion rates with a resulting higher probability of failure over time. Furthermore, the presence of sour fluids presents more serious life safety consequences.

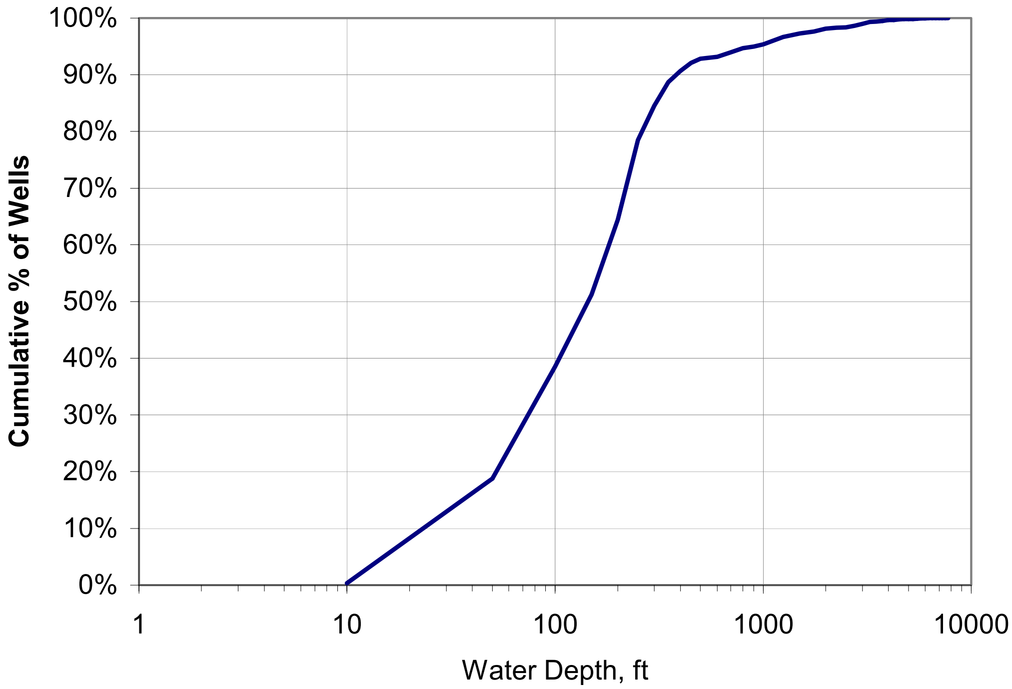
- Wellbore attributes:
  - wellbore component age: the equipment in the well is expected to deteriorate over time (from corrosion, wear, etc.), hampering its reliability and impairing its capacity to perform a specific function. One of the most important aspects of the study was to consider the effect of age upon the level of risk of a well.
  - component type: each type of component (christmas tree, tubing, casing, packer, etc.) has a different reliability associated with it. This was acknowledged in the analysis of component replacement, as in the case of a workover.

- Host platform attributes:
  - environmental zone: the impact of a leak to the environment to both onshore and offshore resources will depend on the location of the leak source. Different environmental "zones" in the GOMR were defined to take this into account.
  - platform size (major/minor): an indicator of the number of people exposed to the consequences of a leak.
  - platform staffing (manned/unmanned): using the MMS nomenclature, another measure of leak exposure for personnel.

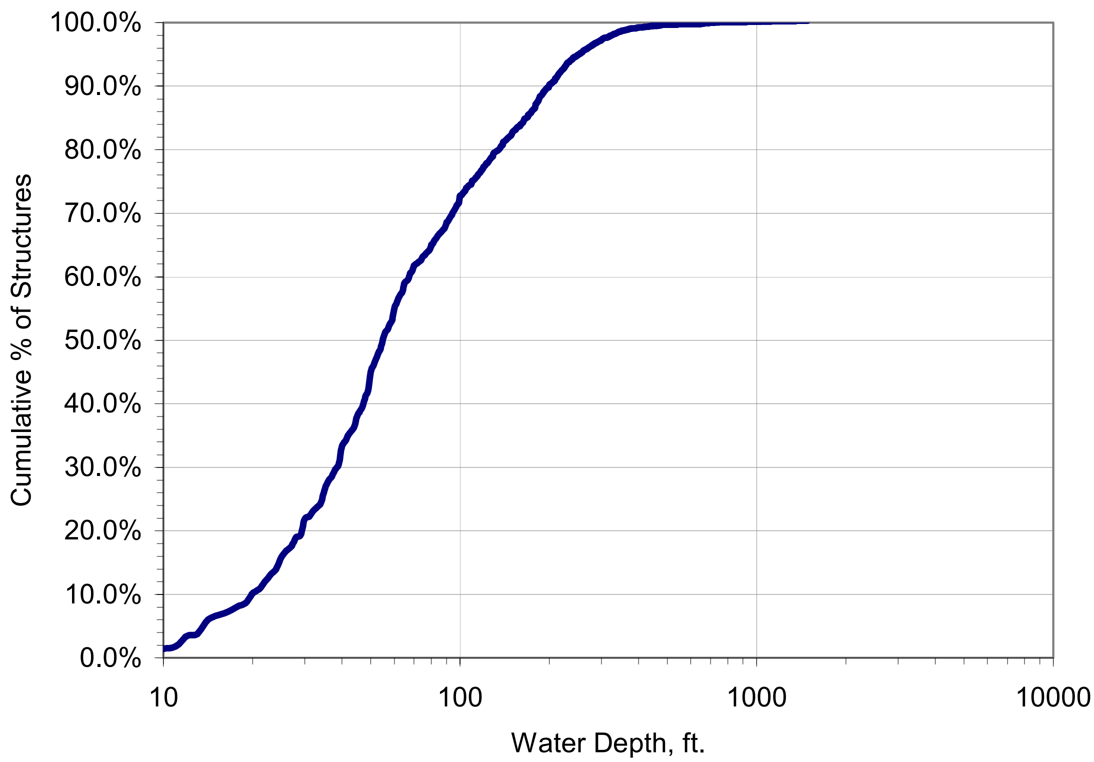
Table 2.1 summarizes the attributes used in the study and indicates whether they were applied in determining the probability or consequences of a leak to the environment. Some other attributes initially considered were:

- reservoir productivity (static reservoir pressure, productivity index (PI), etc- this could enable better estimates of leak volumes);
- type of completion (e.g. tubing string including gas lift mandrels and valves; use of a liner, etc. – could affect probability of leak);
- equipment specifications (materials, pressure ratings, etc. - could affect the rates of deterioration of wellbore components with time, and probability of leak);
- cement integrity (for cement plugs and primary cement – could affect probability of leak); and
- presence of cathodic protection system (could affect equipment deterioration rate).

To take into account these attributes would require obtaining considerably more data, some of it difficult to come by. Therefore, in order to keep the study at a qualitative level, and within the approved budget and schedule, these attributes were set aside. However, they could be revisited in a subsequent detailed, case-specific quantitative risk assessment.



a) Wells.



b) Structures.

Figure 2.1 Water depth distribution of wells and platforms in the GOMR.

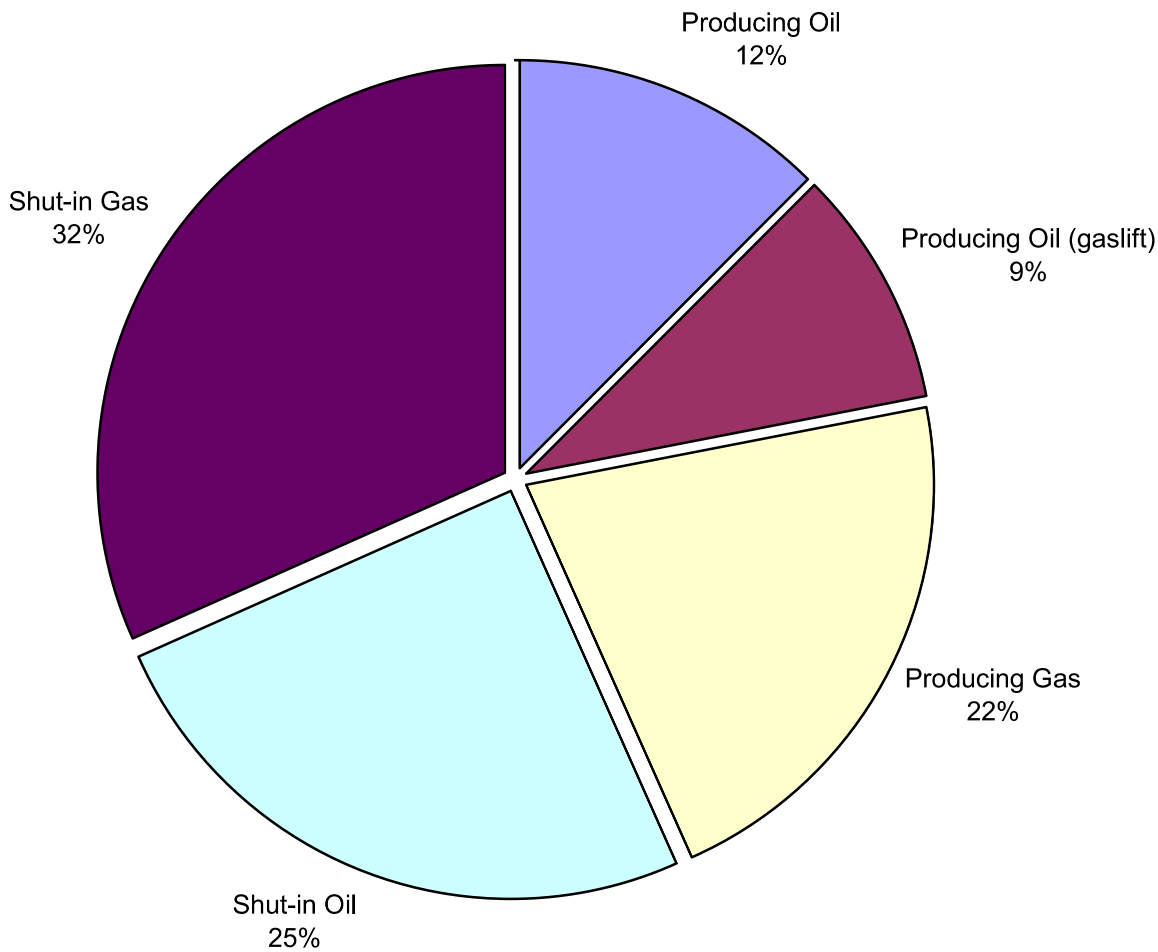


Figure 2.2 Status of producing and non-producing wellbores in the GOMR.

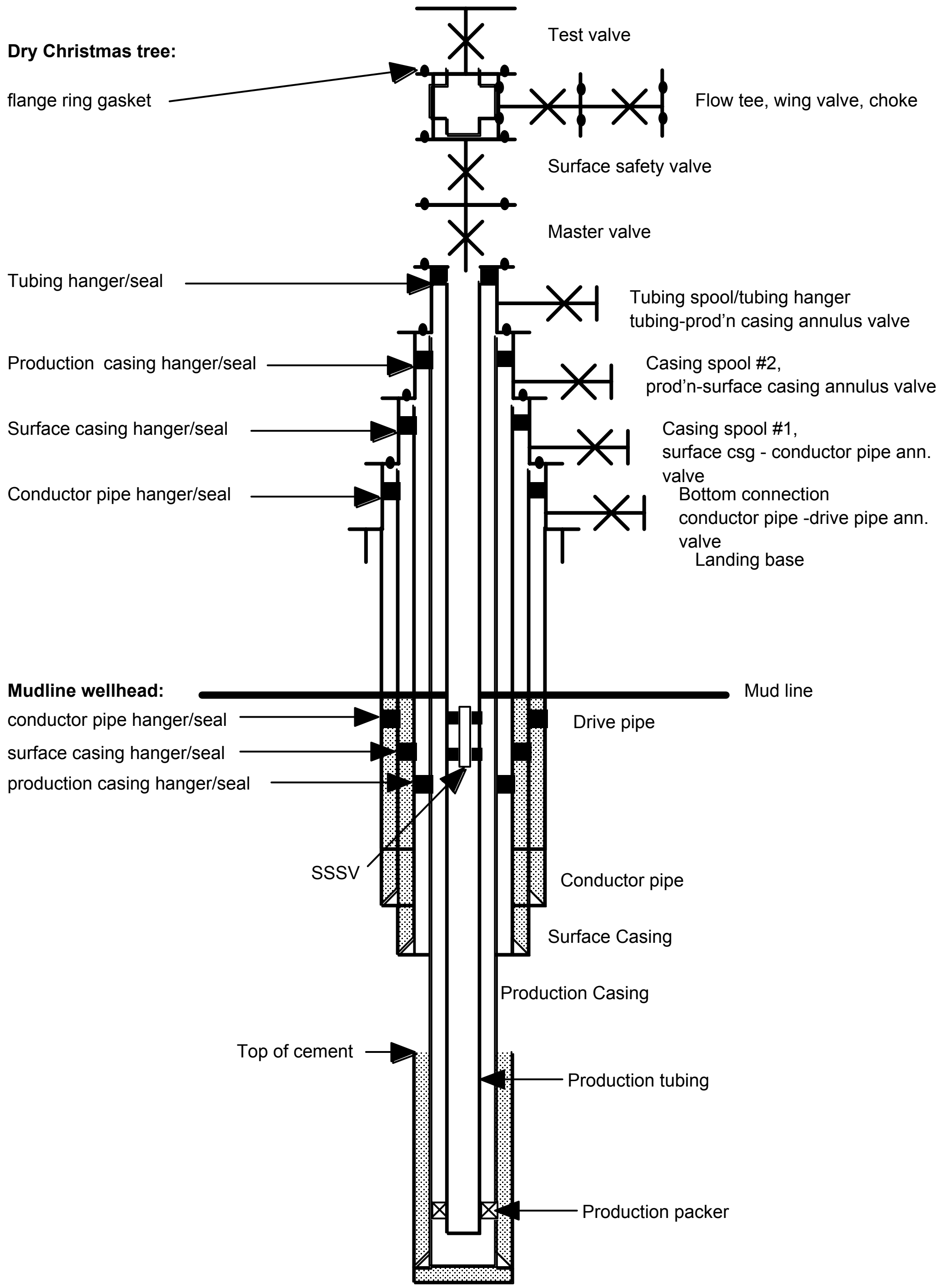


Figure 2.3 SI well schematic.

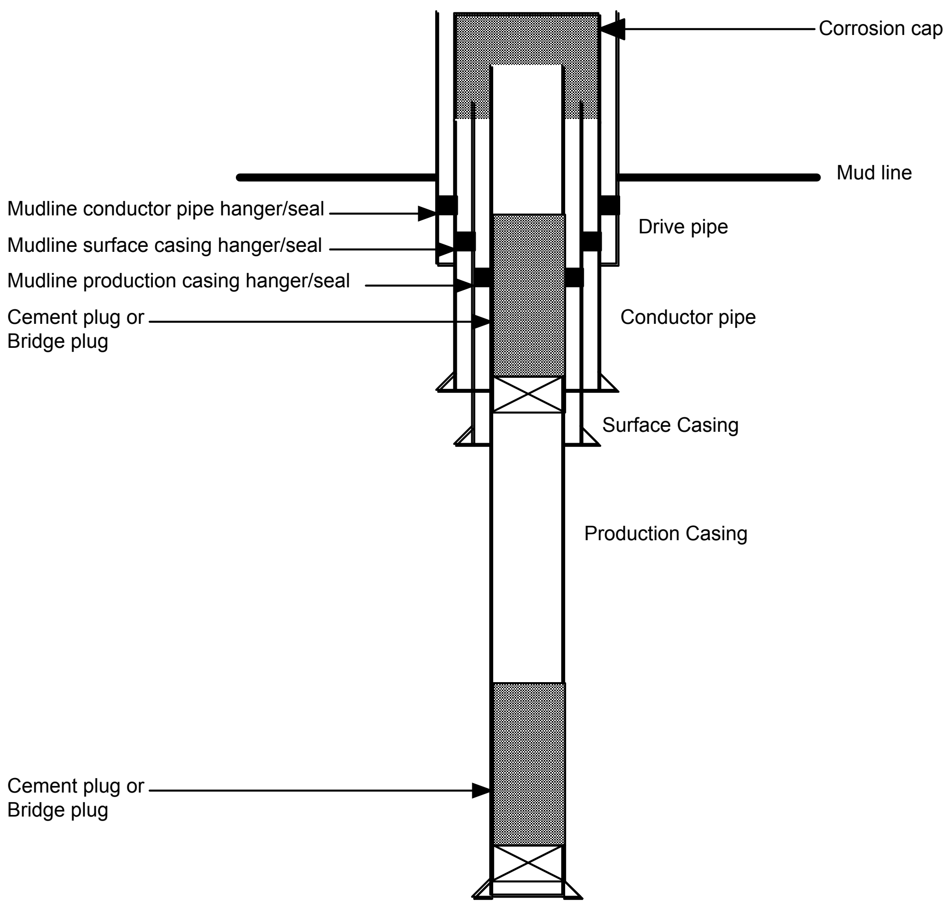


Figure 2.4 TA well schematic.

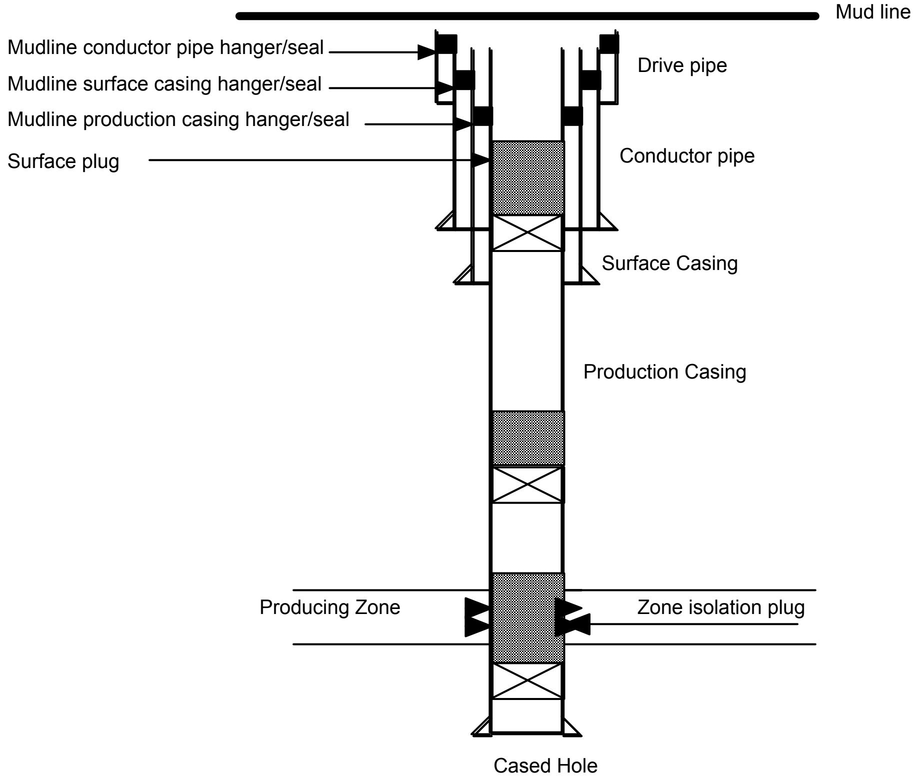


Figure 2.5 PA well schematic.

Attributes		Affects:	
		Probability	Consequences
Reservoir	flowing/non-flowing	No	Yes
	fluid type (gas/oil)	No	Yes
	fluid severity (sour/non-sour)	Yes	Yes
Wellbore	age	Yes	No
	component type	Yes	No
Platform	environmental zone	No	Yes
	major/minor facility	No	Yes
	manned/unmanned facility	No	Yes

Table 2.1 Well attributes used in the risk assessments.

3. LEAK PROBABILITIES

The next step in the risk assessment was to estimate the probability of a leak of reservoir fluids to the environment, (i.e. to any location above the mudline) for each well configuration, depending on its attributes. For each well configuration, potential leak paths were identified by inspection of their respective schematics. Note that for a leak to occur, one or more components in the well have to fail, i.e. they must loose their ability to contain the fluids within the well. The leak paths were then used to construct a fault tree. By assigning a probability of failure to each component, it was then possible to use the fault tree to calculate an overall probability of leak to the environment.

3.1 Leak Paths and Fault Trees

For each well status, the potential leak paths were identified by inspection of their respective schematics (Figures 3.1, 3.2, and 3.3).

A fault tree is a logic diagram portraying the combination of component failure events necessary to cause a system failure. To determine leak probabilities, fault trees were constructed for each well status (Figures 3.4, 3.5, and 3.6). Labels on the fault trees match events on the corresponding leak path schematics. A probability of failure was then assigned to each applicable component as a function of one or more well attributes. Finally, fault tree logic was used to evaluate the overall probability of occurrence of a leak.

For the purposes of this study, potential leak paths were taken to two levels of pipe containment. Therefore, leak paths were considered within the tubing and the production casing of SI wells, and within the production casing and the surface casing in TA and PA wells. It was found that further leak paths would have a negligible effect on the overall probability of the top event (i.e. a leak to the environment). This is because these further leak paths require a longer chain of dependant events, and this has a diminishing overall probability.

Note also that no leak paths were defined through the primary cement outside the production casing. While this was considered during the initial stages of the study, it was felt that the focus was on the most likely leak paths, which have an impact upon the environment. Some common consequences of primary cement problems (such as cross flow to other formations) may have no symptoms at surface. It is possible that a leak through a channel in the primary cement outside the production casing will result in a pressure increase on the “backside” of the production casing, with subsequent leak to the environment. While this was not considered in the study as a whole, a “sidebar” study of sustained casing pressure (SCP) was conducted for a specific set of well attributes (Section 5.5).

3.1.1 SI Well

The possible leak paths for an SI well as illustrated in Figure 3.1 were interpreted in fault tree form (Figure 3.4). Note that the furthest pipe leak considered was through the production casing (into the production casing-surface casing annulus).

When a well is shut-in, pressurized hydrocarbons will be present at least below the production packer in the production casing and in the production tubing below the closed SSSV. There may be some fluids above the SSSV in the production tubing, depending on the sequence of valve shutoffs. However, the volume, trapped above the SSSV would be limited to a relatively small volume, and may be easily de-pressured. Reservoir fluids under pressure in the wellbore could leak through the production packer (event B3 of the fault tree) or the production tubing (B2) into the production casing-tubing annulus. Once in the production casing, fluids could leak through the production casing into the surface casing (B9) or into the environment through the flanged wellhead connection (B5) or annulus valve (B4). From the surface casing, an external leak is possible through the annulus value (B10) or wellhead flanged connection (B11).

Fluids could also leak through the SSSV into the production tubing above the SSSV (B1). From this portion of the tubing, they could leak into the production casing (B8) or to the environment through the flanged connection or the christmas tree (B7), or other locations on the christmas tree (B6).

3.1.2 TA Well

Refer to the leak paths for a TA well in Figure 3.2, and their corresponding fault tree in Figure 3.5. In a temporarily abandoned well the pressurized fluid is present in the production casing below the lower plug. For any leak to the environment, the lower plug has to leak first (B1). Once in the production casing above the lower plug, the fluids can leak through the upper plug (B4) or through the production casing into the surface casing (B2). Fluids above the upper plug will leak to the environment through the corrosion cap (B3). Fluid in the outer casings and conductor pipe can leak to the environment through the hanger seal assembly (B5, B7) and the corrosion cap (B3).

3.1.3 PA Well

The possible leak paths for a PA well (Figure 3.3) are very similar to the paths for a TA well. However, in a TA well, the fluids have to leak through only one lower plug, while in a PA well, there are two plugs to leak past: the zone isolating plug (event B1 of Figure 3.6) and the lower casing plug (B2). Once in the upper portion of the casing, fluids may leak to the surface casing (B4) and to the mudline through the hanger/seal assembly (B5). From the surface casing, a leak may progress to the conductor pipe (B6) and externally through its hanger assembly (B7). Fluids may also leak past the surface plug (B3) to the mudline. Note that there is no corrosion cap in a PA well.

3.2 Well Component Failure Probabilities

In general, the reliability of a component can be described by Billinton and Allan (1983) as:

$$R(t) = e^{-\lambda t} \qquad [3.3]$$

where:

R is the component reliability (probablity of survival, $0 \leq R \leq 1$);
λ is a reliability constant (1/MTTF, Mean Time to Failure, hrs); and
t is time.

Woodyard (1982) accounted for the initial reliability of a component as being non-ideal by introducing the term, *R(0)*, with which equation [3.1] is modified to:

$$R(t) = R(0)e^{-\lambda t} \qquad [3.4]$$

For use in the fault tree, it is convenient to define the probability of failure *Q(t)* as:

$$Q(t) = 1 - R(t) \qquad [3.5]$$

Therefore, the probability of failure of a component, over time, can be determined if its initial reliability, *R(0)*, and its Mean Time To Failure, MTTF are known. For this study, estimates for *R(0)* and MTTF for some of the well components considered were available from several sources:

- Woodyard (1982);
- OREDA (1997); and
- Granhaug and Soul (1996).

However, some concerns arose when examining the data:

- data was not provided for all components being considered;
- even though data for some components was available, it was representative of other operating areas (e.g. North Sea);
- in most cases, the failure data was sparse; for example, well completion data from North Sea operators' records (OREDA 1997) included only 17 equipment failures from a sample population of just 21 wells; and
- the effects of other well attributes (sour, non-sour) were not given explicitly.

In order to ensure consistent treatment of the available data, the following guidelines were used:

- wherever possible, use existant reliability data (both *R(0)* and MTTF values) for the corresponding component (e.g. casing, tubing, packer); otherwise use closest match (e.g. Xmas tree reliability applied to production casing annulus valve and production casing flanged connection);
- if no close match is found, use "engineering judgement" to estimate reliability (e.g. in the case of cement plugs);
- examine the reliability of well components to ensure proper "relative" order (e.g. a packer is assumed to be less likely to fail than a tubing joint):
    - the MTTF of tubing above the SSSV was increased by a factor of 20; this represents an assumed ratio of this portion of the production string to its total length; and
    - the value of *R(0)* for tubing given by Woodyard was found to cause a steep change in early-time probability of leak; it was then adjusted upwards from 0.9 to 0.99, yet still preserving its relative value of being less than that of casing.

The final values of MTTF and *R(0)* used in the study are presented in Table 3.1 for each of SI, TA, and PA wells.

One concern was the treatment of sour fluids, which generally can cause accelerated corrosion and stress cracking. Either of these effects would presumably result in premature component failure. To take this in effect, values of MTTF with sour fluids were reduced as follows:

- wellhead components: by a factor of two;
- wellbore components (packer, SSSV): by a factor of two;
- casing: by a factor of five; and
- tubing: by a factor of ten.

While the selection of these figures was arbitrary, the relative effects of sour fluids were recognized. Tubing strings were assumed to be most affected by sour fluids by virtue of their direct exposure to high temperature, pressure, and erosion. Many wellbore components such as packers feature corrosion resistant alloys, which mitigate the effects of sour fluids. A comparison of the reliability function for some of the key well components used in this study is depicted in Figure 3.7. Note in the figure, the relative reliability of the components, and the pronounced reduction in reliability with sour fluids.

3.3 Overall Leak Probability

The leak probability portion of the risk assessment was calculated using standard fault tree logic. For each well configuration and set of attributes, the probabilities of the basic events were combined to generate the probability of occurrence of the "top event" i.e., a leak to the environment.

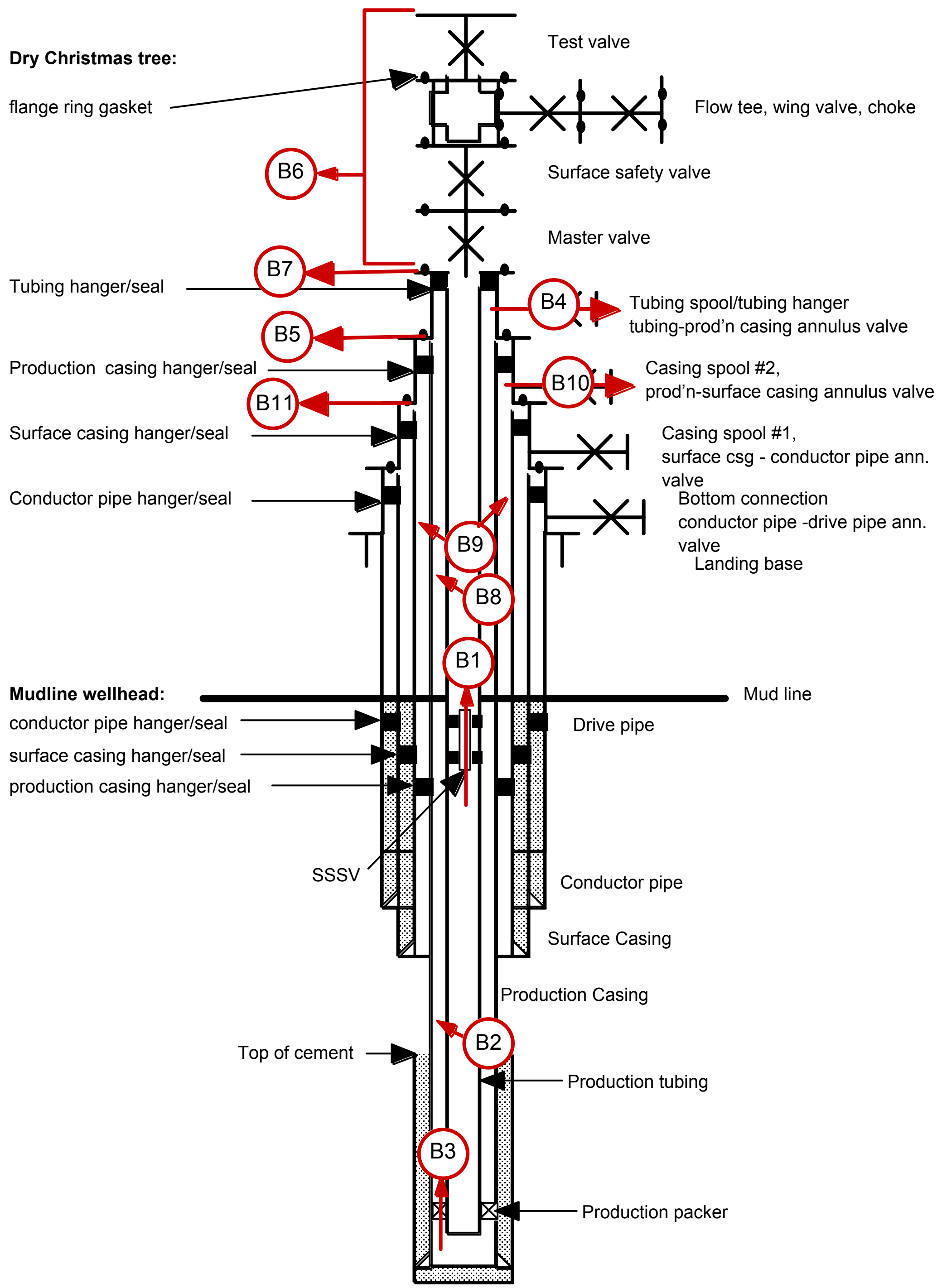


Figure 3.1 Leak paths, SI well.

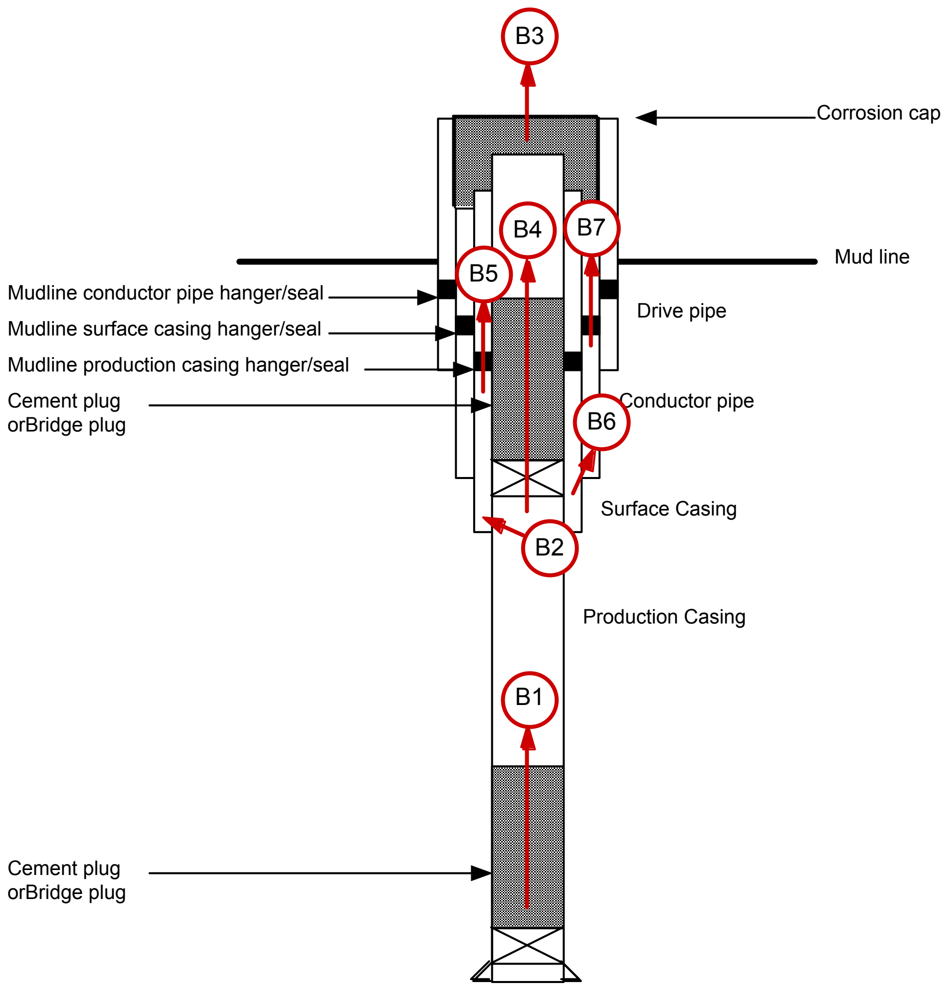


Figure 3.2 Leak paths, TA well.

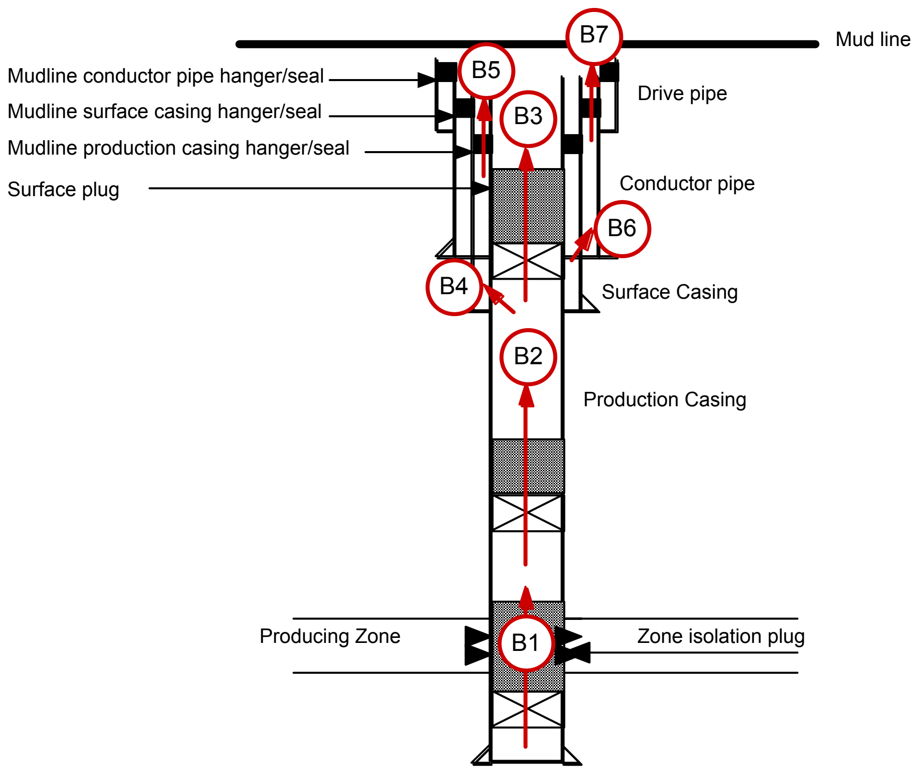


Figure 3.3 Leak paths, PA well.

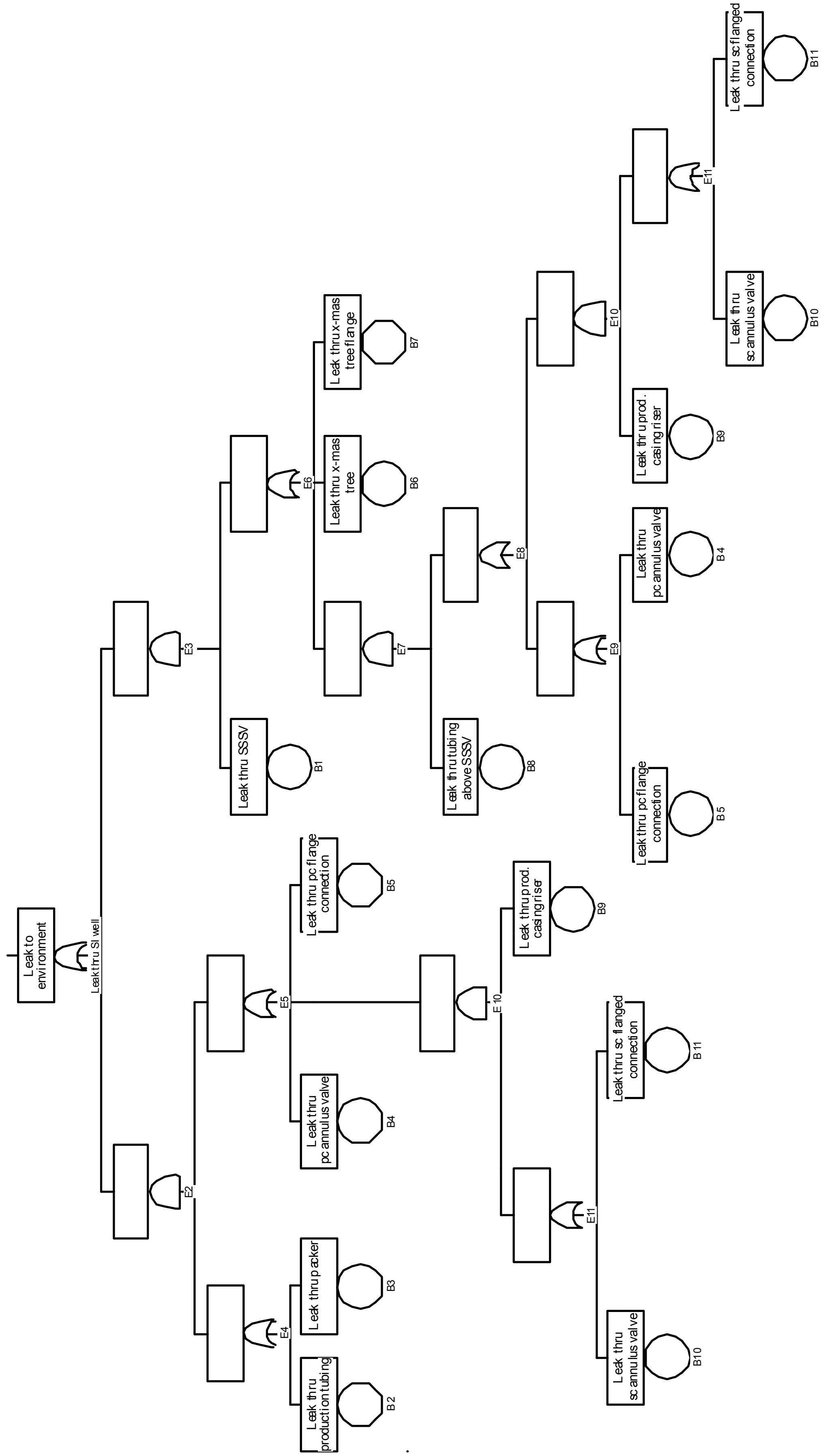


Figure 3.4 Fault tree, SI well.

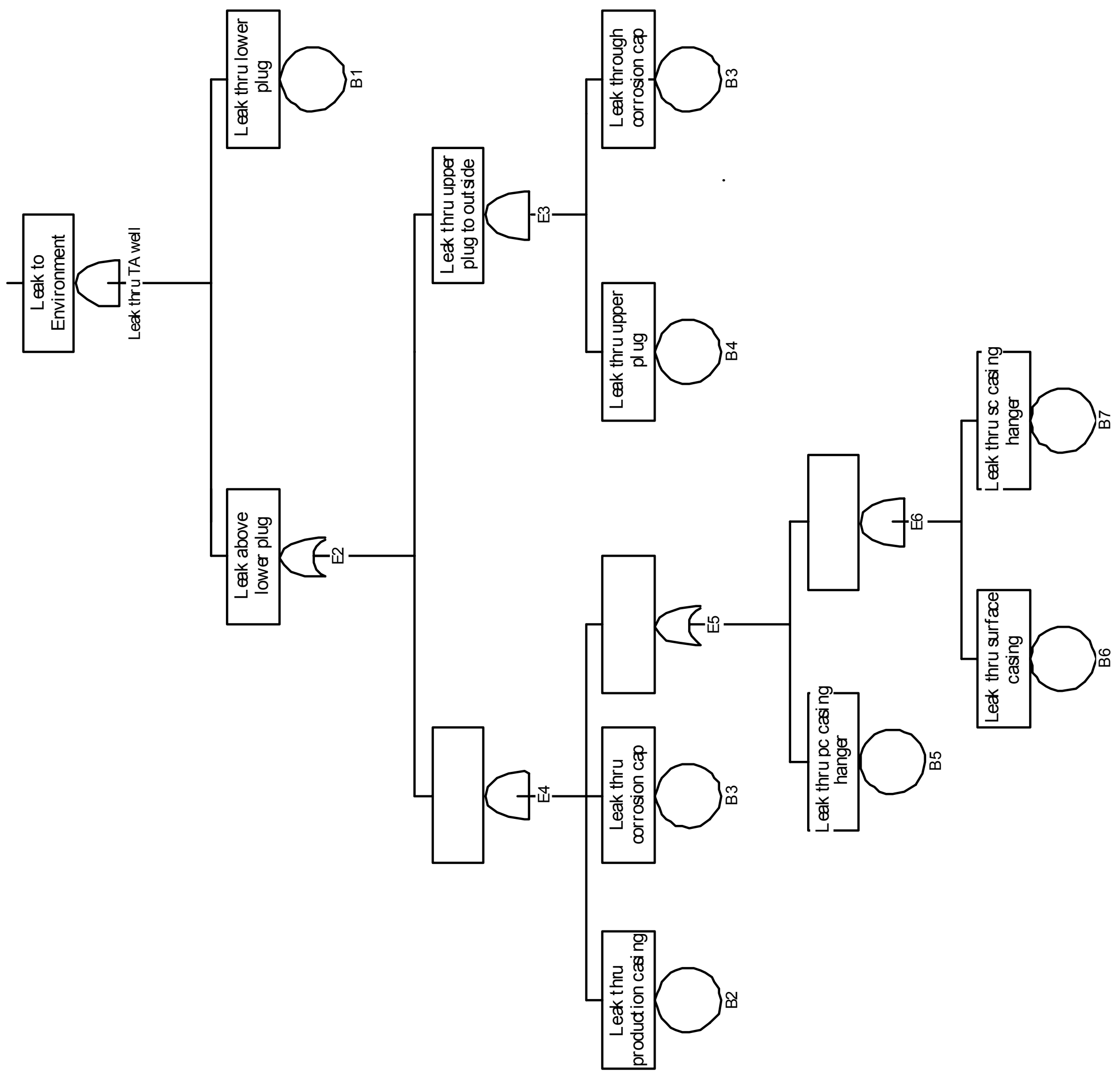


Figure 3.5 Fault tree, TA well.

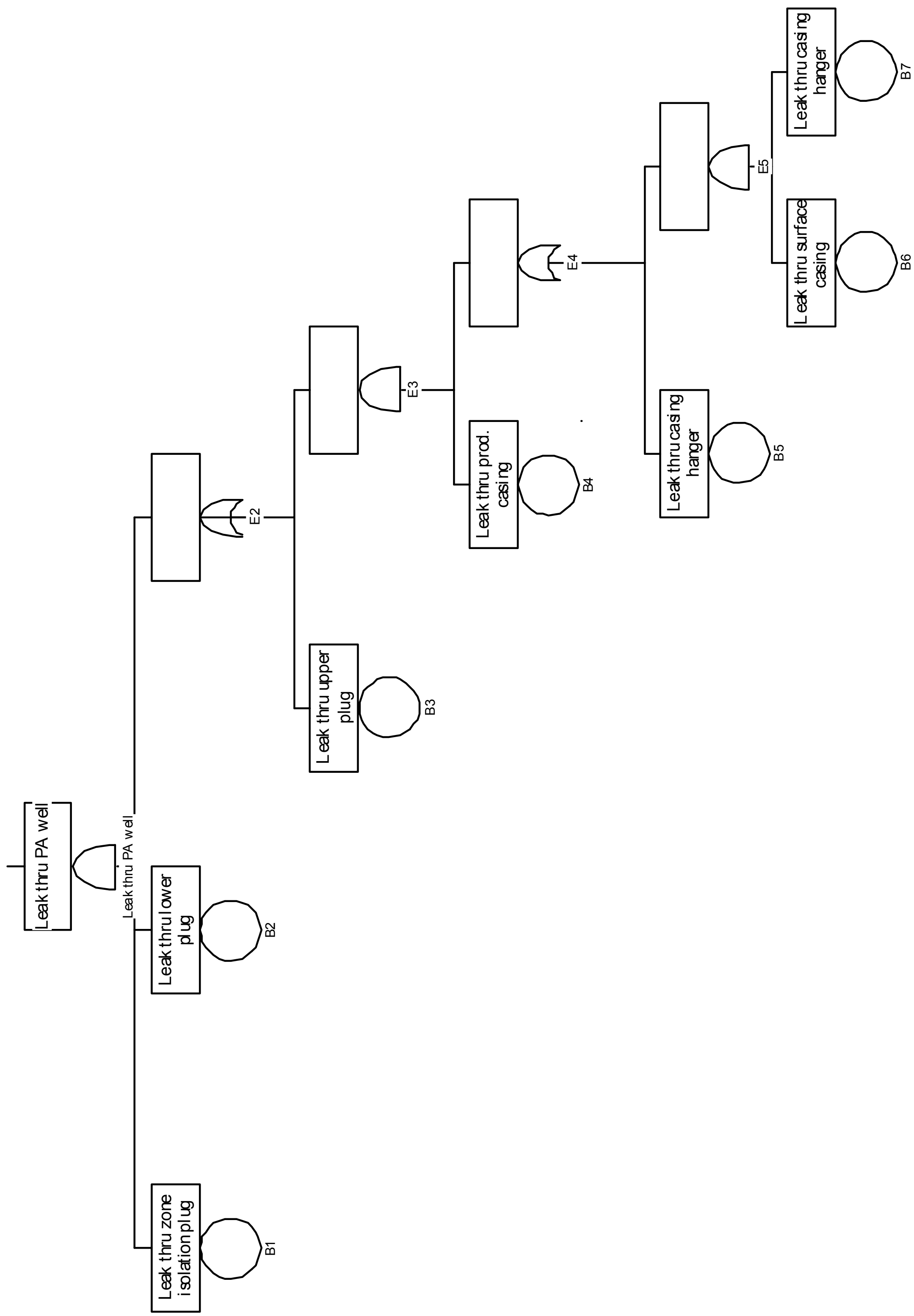


Figure 3.6 Fault tree, PA well.

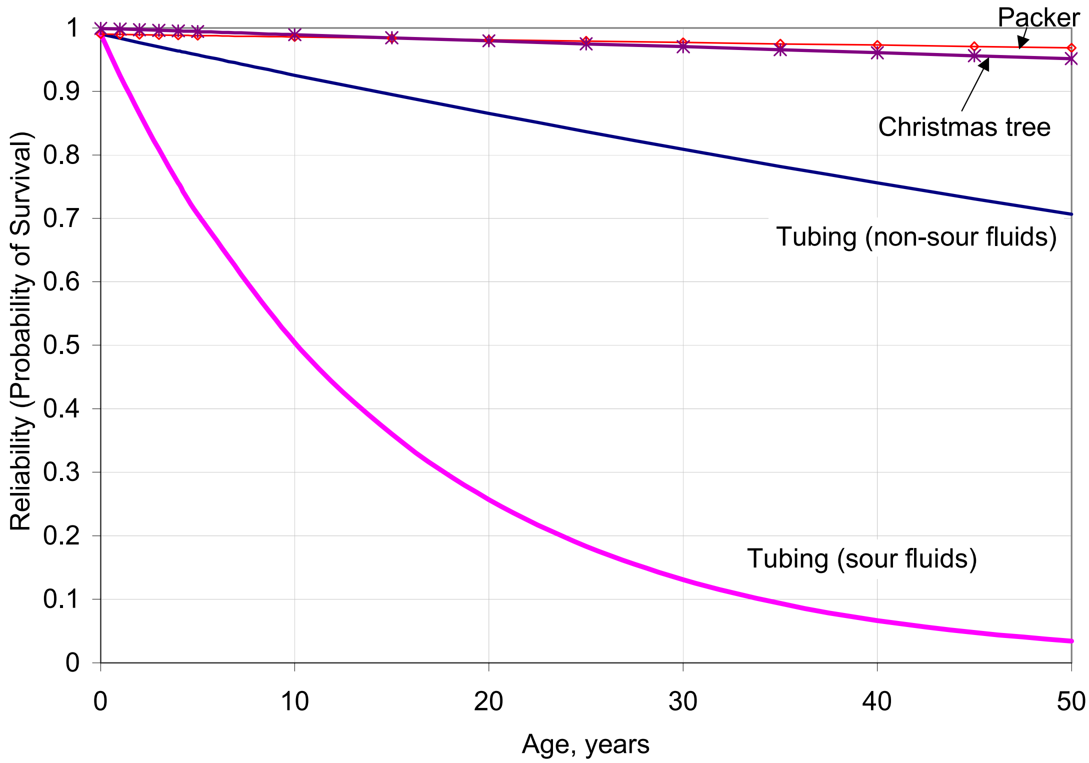


Figure 3.7 The reliability function for selected well components.

Failure Event	Fault Tree Ref.	Initial Reliability R(0)	MTTF: Non-sour	MTTF: sour	Data Source
Leak thru SSSV	B1	0.99	9.06E+06	4.53E+06	"Engineering judgement"
Leak thru production tubing	B2	0.99	1.30E+06	1.30E+05	Woodyard (tubing), R(0) increased from 0.9 to 0.99
Leak thru packer	B3	0.99	2.00E+07	1.00E+07	Woodyard (packer)
Leak thru pc annulus valve	B4	0.999	9.00E+06	4.50E+06	Woodyard (Xtree)
Leak thru pc flanged connection	B5	0.999	9.00E+06	4.50E+06	Woodyard (Xtree)
Leak thru x-mas tree	B6	0.999	9.00E+06	4.50E+06	Woodyard (Xtree)
Leak thru xmas-tree flanged connection	B7	0.999	9.00E+06	4.50E+06	Woodyard (Xtree)
Leak thru tubing above SSSV	B8	0.99	2.60E+07	2.60E+06	Woodyard (tubing), MTTF scaled by 20 for tbg above SSSV
Leak thru prod. casing riser	B9	0.999	1.26E+06	2.52E+05	Woodyard (casing)
Leak thru sc annulus valve	B10	0.999	9.00E+06	4.50E+06	Woodyard (Xtree)
Leak thru sc flanged connection	B11	0.999	9.00E+06	4.50E+06	Woodyard (Xtree)

a) SI well.

Failure Event	Fault Tree Ref.	Initial Reliability R(0)	MTTF: Non-sour	MTTF: sour	Data Source
Leak thru lower plug	B1	0.99	2.00E+08	1.00E+08	"Engineering judgement"
Leak thru production casing	B2	0.999	1.26E+06	2.52E+05	Woodyard (casing)
Leak thru corrosion cap	B3	0.99	2.03E+06	1.02E+06	Granhaug and Soul for MTTF, "judgement" for R(0)
Leak thru upper plug	B4	0.99	2.00E+08	1.00E+08	"Engineering judgement"
Leak thru pc casing hanger	B5	0.99	1.12E+06	2.24E+05	OREDA (MTTF for well completion), "judgement" for R(0)
Leak thru surface casing	B6	0.999	1.26E+06	2.52E+05	Woodyard (casing)
Leak thru surface casing hanger	B7	0.99	1.12E+06	2.24E+05	OREDA (MTTF for well completion), "judgement" for R(0)

b) TA well.

Failure Event	Fault Tree Ref.	Initial Reliability R(0)	MTTF: Non-sour	MTTF: sour	Data Source
Leak thru zone isolation plug	B1	0.99	2.00E+08	1.00E+08	"Engineering judgement"
Leak thru lower plug	B2	0.99	2.00E+08	1.00E+08	"Engineering judgement"
Leak thru upper plug	B3	0.99	2.00E+08	1.00E+08	"Engineering judgement"
Leak thru production casing	B4	0.999	1.26E+06	2.52E+05	Woodyard (casing)
Leak thru casing hanger sealing	B5	0.99	1.12E+06	2.24E+05	OREDA (MTTF for well completion), "judgement" for R(0)
Leak thru surface casing	B6	0.999	1.26E+06	2.52E+05	Woodyard (casing)
Leak thru casing hanger sealing	B7	0.99	1.12E+06	2.24E+05	OREDA (MTTF for well completion), "judgement" for R(0)

c) PA well.

Table 3.1 Well component failure probabilities.

4. LEAK CONSEQUENCES

To complete the risk assessment, a means to estimate the consequences of a leak was required. A methodology was used in which both life safety and environmental aspects were considered. The object of this work was to establish a benchmark for the consequences of a leak. Intermediate analyses were performed in order to obtain the final results, which were a life safety consequence index and an environmental consequence index. These two indices serve as a way to compare one case to another in an ordinal sense (i.e., to help decide which case is "worse" than the other). However, these indices cannot be used quantitatively (for instance, it cannot be said based on the indices that case "A" is X times worse than case "B"; only that case "A" is worse than case "B").

4.1 Methodology

A consequence model was built to assess the probability of losses due to a release of hazardous material into the environment. It considered the progress of an incident from initial release through formation of a fire or toxic cloud to final dispersion. If an ignition source is present, the release can cause either a jet fire (if it is gaseous), or a pool fire (if it is liquid). If there is no initial ignition, a vapour cloud may form and be transported by the wind. The liquid fraction of the release undergoes weathering, and a portion of it may be carried to shore by wind and wave action. The environmental damage it may cause depends on the quantity of spill reaching shore and the characteristics of the shore itself. The life safety concerns considered in this study were mainly related to platform personnel. They included casualties caused by fire or asphyxiation.

The possible environmental effects of a release include: loss of water quality; adverse effects on shoreline animal and plant life; commercial, residential, and recreational property damage; and clean up costs.

Available OCS oil spill trajectory analyses (MMS 1995a, 1997b, 1999) were utilized in this study to assess the shores impacted given the hypothetical spill location of the release. The shoreline sensitivity was determined by using established environmental sensitivity indices and considering the shoreline resources in the Gulf of Mexico OCS. In the consequence model of this study, the originating location of the release and its volume were the major factors considered in determining the extent of the damage. Financial losses not associated to life safety or environmental clean-up costs were not considered explicitly in this qualitative study, because, from a regulatory viewpoint, it is the environmental and human safety consequences that are of primary concern.

4.2 Release Characteristics and Spill Volume

The first part of estimating the leak consequences was to estimate its magnitude. Most spills from platforms probably occur during drilling, workovers, or other well servicing operations

(Woodyard 1982, Edmondson and Hide 1996). Also, according to the MMS (1997a) about 96% of spills in the OCS are one barrel or less in volume. This includes both pipelines and platforms. Large spills are usually categorized as those greater than fifty barrels. Between 1980 and 1996, the median size of large spills from platforms alone was 100 barrels. Historical release data for only non-producing wells are quite sparse. In fact, only four leak incidents relevant to SI, TA or PA wells were obtained from the MMS TIMMS database. The records showed that 1, 2, 5 and 31 bbls had leaked out during each incident. The 31 barrels leaked during a period of approximately two months.

In general, the leak volume can be taken as:

$$leak\_volume = leak\_rate \times leak\_duration \qquad [4.1]$$

with the leak duration assumed to be given by:

$$leak\_duration = leak\_time + repair\_time \qquad [4.2]$$

Assuming the duration of leak to be about the same for all cases, the leak volume then becomes proportional to the leak rate.

The leak rate can be estimated as the product of the leak path size and the driving pressure. The most common failure mechanisms (corrosion, deterioration, and malfunction) cause mainly small leaks. Corrosion is historically known to cause 85% to 90% of small leaks. Therefore, a split of 90% to 10% between small leaks and large leaks respectively was assumed, based on Stephens et al. (1996). A large leak is defined qualitatively as a leak that is an order of magnitude higher in size than the small leak.

The "driving pressure" in an inactive well represents the pressure that can accumulate at the leak point being considered, and that will drive the fluids to the environment. This "driving pressure" can be directly associated with the shut-in pressure of a certain well. In general, flowing wells have higher shut-in pressures, when compared to non-flowing wells; also, flowing gas wells usually have higher shut-in pressures than flowing oil wells.

If a leak occurs in a gas well, it will consist mostly of a gas release, with a small amount of liquid (condensate) possible. If the leak occurs in a flowing gas well, for the reasons above, the amount of gas released to the atmosphere can be quite significant. On the other hand, if a leak occurs in an oil well, it will probably include a quantity of associated (solution) gas. Again, for the reasons above, the amount released will probably be higher for a flowing oil well than for a non-flowing oil well.

To simplify matters, and given the paucity of data, qualitative leak volume indices were defined for use in determining life safety and environmental consequences. In Table 4.1 a base value of 10 was assigned to both gas and liquid volumes being released from a flowing oil well. Since the amount of gas released from a flowing gas well is likely to be higher than from a flowing oil well, the index 100 was assigned to the gas volume being released from a flowing gas well. In the flowing gas well case, a small amount of liquid (condensate) release is also possible. Accordingly, an index of 1 was assigned to the liquid volume being released from a flowing gas well. Since fluid amounts released from non-flowing wells are probably less than that from flowing wells, indexes 10 times lower were assigned to the volumes being released from non-flowing wells. The order of magnitude differences used in the indices were intended to contrast the differences between the cases, although their effect may not represent the exact changes.

4.3 Life Safety Consequence

The life safety impact of a leak depends on the number of people exposed and the probability of casualty, given the occurrence of a leak. In this study, the life safety concerns considered are mainly applicable to platform personnel. Large vessel traffic is restricted to shipping corridors and would probably not be in close proximity to wells. Only support vessels may be in the vicinity and, for this study, their crew are accounted for in the number of platform personnel.

The number of people on a platform was estimated by defining a platform index (Table 4.2). This index uses the platform attributes of size (major/minor) and staffing (manned/unmanned) to give the average number of personnel exposed to risk at any time. Again, the numbers used represent only order of magnitude ranges and can be assumed to be only qualitatively correct.

The probability of casualty (injury or death) for any person on the platform is equal to the probability of an incident for which the associated hazard zone extends to involve the platform, multiplied by the probability of injury or death for the hazard intensity associated with the incident. Hazard zones for a given release can take on different shapes depending upon specific parameters such as the release rate and weather conditions. In this study, since it was assumed that the SI well christmas trees are within the topsides of the platform and SI wells are directly below the platform, it was also assumed that platform personnel were always within the hazard zone of a release.

Given a leak, the individual probability of casualty depends upon:

- the size of leak;
- its probability of ignition; and
- its fluid severity (sour/non-sour) if there is no ignition, to account for toxic gas exposure.

Leak size was represented by the gas volume index. A probability size distribution was fixed at 0.9 for small leaks and 0.1 for large leaks, as mentioned previously. The probability of ignition was considered to be higher for gas wells, owing to the greater likelihood of dispersion (Table 4.3a). For mudline leaks (TA, PA wells), ignition probability was set to an order of magnitude lower, recognizing that a subsea spill may dilute or disperse before reaching surface. Given an ignition, the probability of casualty would depend upon the size of leak (Table 4.3b). Again, the dilution of subsea leaks was considered to reduce that probability.

Leak Consequences

A sour gas release presents an additional hazard to personnel even without ignition. Therefore, a casualty probability was also assigned to this case (Table 4.3c) to account for the presence of a toxic sour gas cloud. The casualty probability was set higher for large leaks. Dispersion for mudline leaks (TA, PA wells) was also incorporated.

The number of casualties are likely to increase with the size of the gas release associated with the leak.. Accordingly, a casualty index was defined as

$$casualty\_index = gas\_volume\_index \times \sum probabilty\_of\_casualty \qquad [4.3]$$

where the total probability of casualty is given by the sum of the following individual casualty probabilities (Figure 4.1):

- small leak, with ignition;
- small leak, no ignition if sour;
- large leak, with ignition; and
- large leak, no ignition, if sour.

Finally, the life safety consequence index was defined as:

$$life\_safety\_cons\_index = platform\_index \times casualty\_index \qquad [4.4]$$

4.4 Environmental Consequence

The environmental impact of a spill depends on a number of factors (Owens and Robilliard 1981) including the:

- location of the original spill;
- volume of oil spilled;
- physical and chemical properties of the oil;
- meteorological conditions at the time of spill;
- animal and plant life activity in the target area;
- human activity (commercial and recreational) in the region; and
- operational constraints on clean up.

These parameters quantify the magnitude of the release, how much of it decays, where it hits the shoreline, and how much damage it causes.

The methodology for environmental impact analysis can be carried out at different levels of detail, with one of three established levels of assessment (Sørgård et al. 1997):

- a source based approach, which is a risk assessment based on discharge characteristics and distance to particularly vulnerable areas; this level will result in a first rough estimate for the environmental risk related to an activity and an early evaluation of environmental risk aspects in the decision process;
- an exposure based approach, which is a risk assessment based on duration, rate and amount of release, and oil drift simulation; this is a more extensive approach; and
- a damage based approach, the most extensive analysis, based on duration, rate and amount of release, oil drift simulation plus the effects on the most vulnerable populations including beach habitats.

A simplified damage based approach was adopted in this study, making use of the previously defined well attributes for the estimation of spill consequences. A detailed consideration of the resources and the ecology of the GOMR was beyond the scope of this study. Therefore, qualitative sensitivity indexing methods as used by Gundlach and Hayes (1978), Adams et al. (1983), and NRC (1994) were adopted to assess the damage done by oil spills. An environmental consequence index was defined as a function of spill volume and its impact on the environment, given an originating spill location.

The spill volume is represented by the parameter liquid volume index, given in Table 4.1b. Conservatively, the weathering, evaporation and depletion of the original spill volume was neglected. Therefore, all the volume that is released at the well was assumed to potentially cause environmental damage. (Note that even though some of the oil may not reach the shoreline, it may, nevertheless, cause some environmental damage to offshore resources.)

Determining environmental impact involved identifying the environmental resources at risk and the likelihood of their being contacted by an oil spill. The land segments defined in the Oil Spill Risk Analysis (OSRA) (MMS 1995a) were adopted (Figure 4.2). The environmental sensitivity of the land segment depends on the resources associated with it. These resources can be obtained from OCS Reports (MMS 1995a, 1997b, 1999), and are summarized in Table 4.4.

Gundlach and Hayes (1978) classify major coastal environments on a scale of 1 to 10 in terms of potential vulnerability to oil spill damage. The scale emphasizes oil residence time, with consideration of initial biological impacts. Exposed rocky headlands, steep wave cut scarps and wave-cut platforms are least affected by oil spills as the waves remove deposited oil soon after impact. Consequently, these shores would be given a sensitivity index of 1 or 2. Coarse-grained sandy and gravel beaches, which are subject to oil penetration and burial, are assigned intermediate index values of 4 to 7. Sheltered environments such as sheltered rocky coasts, salt marshes, and mangroves are the environments most likely to be adversely affected by oil spills. For example, residence times of over 10 years are predicted for some salt marsh areas.

The environmental sensitivity indices used in this study (Table 4.5) were based on Gundlach and Hayes (1978), IPIECA (1991), and Breuel (1981). When there were many resources at the same shoreline, indices were combined as recommended by Breuel (1981) for each land segment (Table 4.4).

Leak Consequences

The results of the spill trajectory analysis for the GOMR, reported in the OSRA (MMS 1995a), established the conditional probabilities of a spill contacting the different land segments, given an originating site (Table 4.6). One hundred and forty-five hypothetical offshore spill sites cover the entire GOMR (as defined by MMS, based on existing lease planning blocks). For this study, these probabilities were combined with the land segment sensitivity indices to assess the total damage potential to all land segments from each spill site. Of the 58 land segments named in the OSRA, only the first 44 (i.e., those within the GOMR itself) were assumed to be potentially contacted by spills (Figure 4.2).

The total damage potential was calculated for each of the GOMR hypothetical spill sites as:

$$damage\_potential_{hypothetical\_spill\_site} = \sum_{land\_segment=1}^{44} environmental\_sensitivity\_index_{segment} * probabilty\_of\_spill\_contact_{segment} \quad [4.5]$$

To simplify the computation of results for this portion of the study, the values for damage potential were discretized into four environmental zones (a value of 4 corresponding to the higher damage potential), as shown in Figure 4.3. Damage potential scores and environmental zones are given together in Table 4.7 for each spill site.

Finally, the environmental consequence index was defined as:

$$environmental\_consequence\_index = environmental\_zone \times liquid\_volume\_index \quad [4.6]$$

4.5 Summary

The consequence model defined two indices in terms of well attributes:

a) a life safety consequence index as a function of:
   - well fluid type (gas, oil);
   - reservoir energy (well flowing, non-flowing);
   - fluid severity (sour, non-sour);
   - platform or structure size (major, minor); and
   - platform staffing (manned, unmanned);

b) an environmental consequence index as a function of:
   - well fluid type (gas, oil);
   - reservoir energy (well flowing, non-flowing); and

Leak Consequences

- environmental zone.

Combining the leak probabilities with these consequences indices determined the overall level of risk presented by a well. This final step of the risk assessment study is described in Section 5.

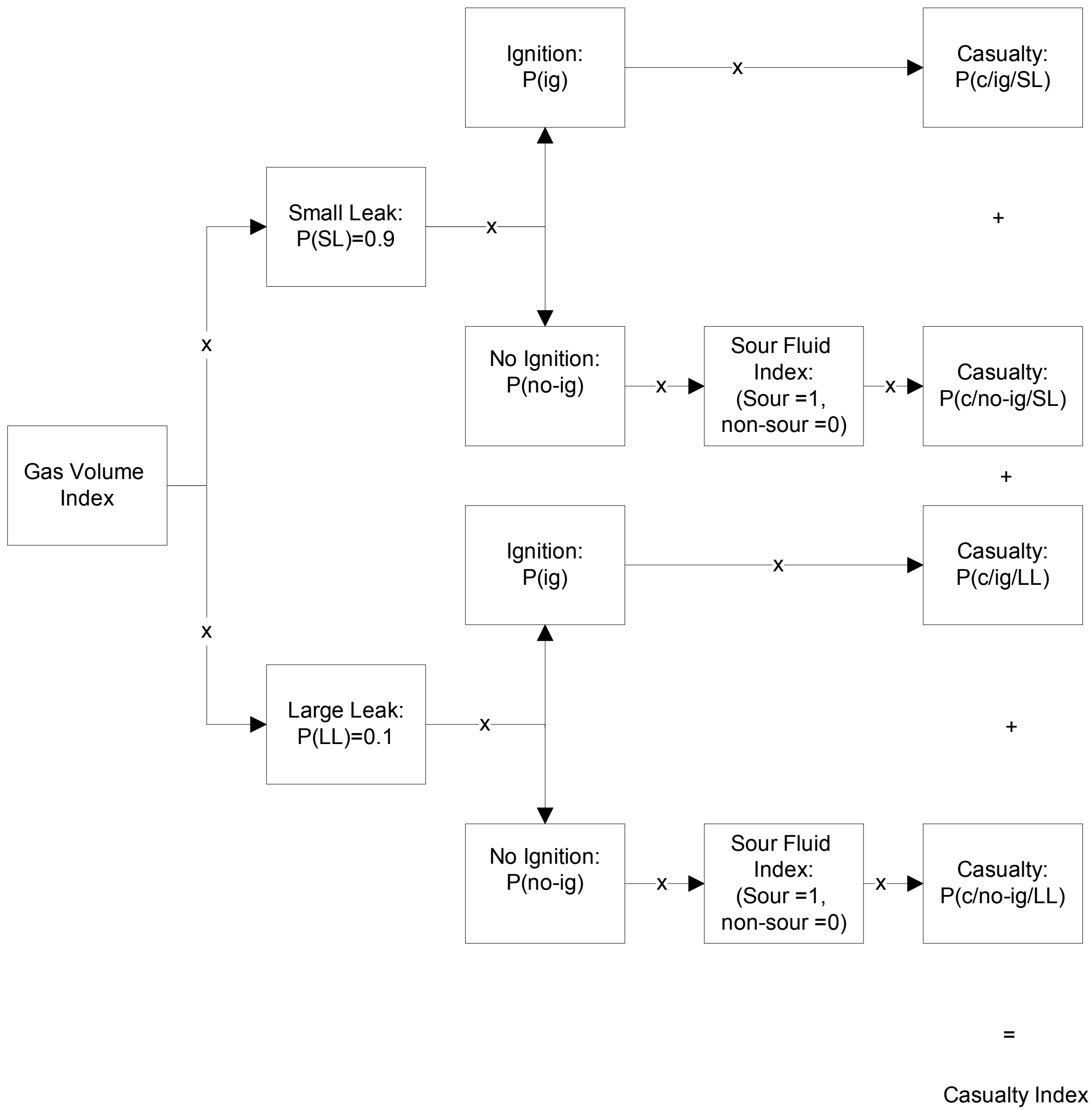


Figure 4.1 Decision tree to calculate casualty index.

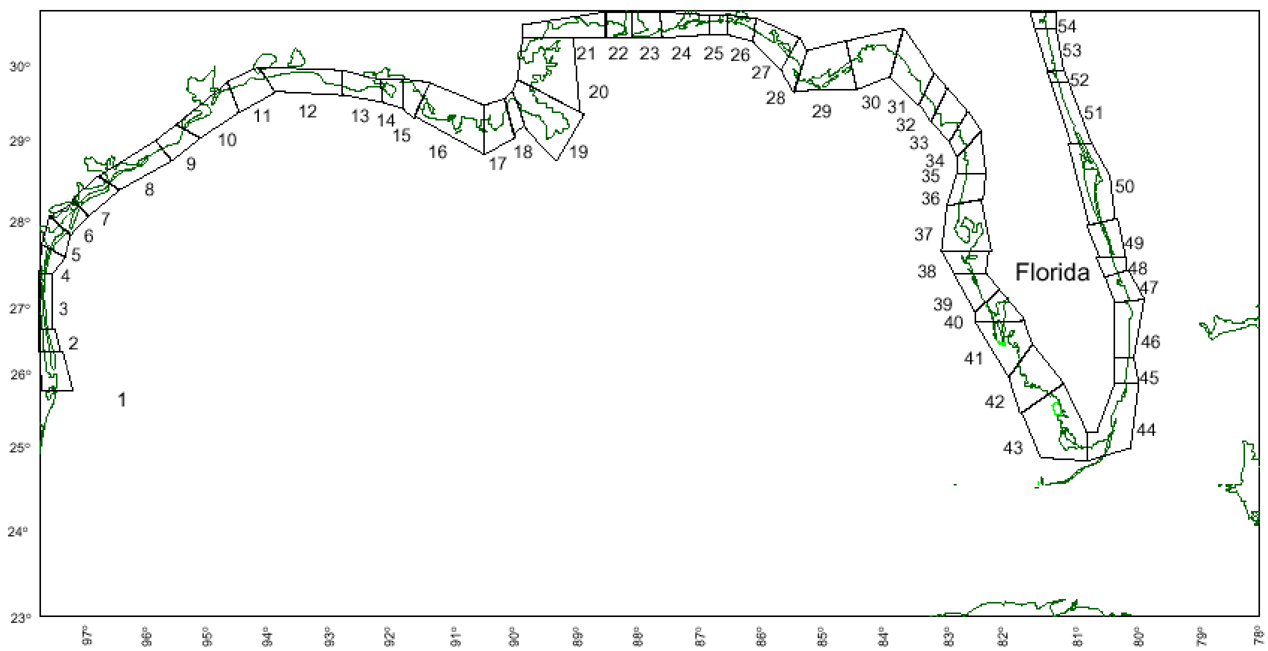


Figure 4.2 Land segments in the GOMR (from MMS 1999).

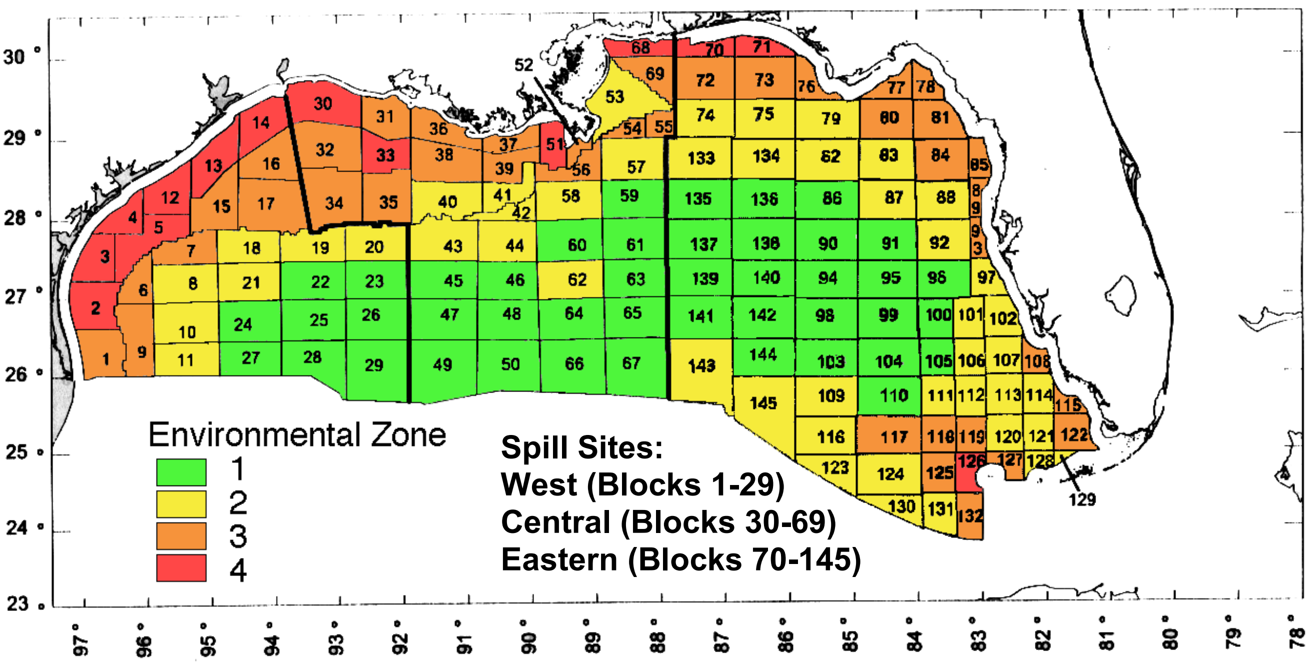


Figure 4.3 Environmental zones in the GOMR (based on hypothetical spill sites).

Gas Volume Index	Flowing State	
Fluid Type	Flowing State	Non-Flowing
Oil	10	1
Gas	100	10

a) Gas volume index.

Liquid Volume Index	Flowing State	
Fluid Type	Flowing State	Non-Flowing
Oil	10	1
Gas	1	0.1

b) Liquid volume index.

Table 4.1 Gas and liquid volume indices.

Platform Index	Staffing	
Size	Manned	Unmanned
Major	50	0.5
Minor	5	0.05

Table 4.2 Platform index.

P(ig)	Well Status	
Fluid Type	SI	TA/PA
Oil	0.1	0.01
Gas	0.5	0.05

a) Probability of ignition.

P(c/ig)	Well Status	
Leak Size	SI	TA/PA
Small (SL)	0.01	0.001
Large (LL)	0.1	0.01

b) Probability of casualty, given ignition.

	P(c/no-ig)	Well Status	
Leak Size	Fluid Type	SI	TA/PA
Small (SL)	Oil	0.01	0.001
	Gas	0.05	0.005
Large (LL)	Oil	0.1	0.01
	Gas	0.5	0.05

c) Probability of casualty, given no ignition (applicable to sour fluids only)

Table 4.3 Ignition and casualty probabilities.

		Environmental Resource(s)								
Segment Number	County/Parish Name	Group 1 (beaches)		Group 2 (bays, lakes)		Group 3 (offshore habitat)		Group 4 (nearshore habitat)	Group 5 (wildlife, recreation)	Combined Sensitivity Index
1	Cameron, Tex.	South Padre Island/Brazos	coastal barrier beach			Laguna Madre	Seagrass bed		Rec. beach	16.0
2	Willacy, Tex.	South Padre Island	coastal barrier beach			Laguna Madre	Seagrass bed		Rec. beach	16.0
3	Kenedy, Tex.	North Padre Island	coastal barrier beach			Laguna Madre	Seagrass bed		Rec. beach	16.0
4	Kleberg, Tex.	North Padre Island	coastal barrier beach			Laguna Madre	Seagrass bed		Rec. beach	16.0
5	Nueces, SanPatricio, Tex.	Mustang Island	coastal barrier beach	Corpus Christi Bay	Bay	Corpus Christi Bay	Seagrass bed		Rec. beach	16.0
6	Aransas, Tex.	St. Joseph Island	coastal barrier beach		Bay	Central Texas		Marsh	Wildlife refuge	16.7
7	Calhoun, Tex.	Matagorda Island	coastal barrier beach	Espiritu Santo/ Matagorda	Bay	Central Texas	Seagrass bed	Marsh	Rec. beach	17.0
8	Matagorda, Tex.	Matagorda Peninsula	coastal barrier beach	Espiritu Santo/ Matagorda	Bay	Central Texas	Seagrass bed	Marsh	Rec. beach	17.0
9	Brazoria, Tex.	Brazos Headland	coastal barrier beach			Eastern Texas		Marsh	Rec. beach	17.0
10	Galveston,Chambers, Tex.	Galveston Island/Bolivar Peninsula	coastal barrier beach	Galveston	Bay	Eastern Texas/ Galveston	Seagrass bed	Marsh	Rec. beach	17.0
11	Jefferson, Tex.	Rollover Pass to Sabine Pass/Sea Rim	coastal barrier beach	Sabine	Lake	Eastern Texas		Marsh	Rec. beach	16.7
12	Cameron, La.	Chenier Plain/ Cameron Parish	coastal barrier beach	Sabine	Lake			Marsh	Rec. beach	16.7
13	Vermilion, La.	Chenier Plain	coastal barrier beach					Marsh		7.0
14	New Iberia, La.	Vermillion/Atchafalaya			Bay					6.0
15	St. Mary, La.	Vermillion/Atchafalaya			Bay					6.0
16	Terrebonne, La.	Caminada	Headland	Timbalier	Bay					6.0
17	Lafourche, La.	Fouchon		Timbalier	Bay				Rec. beach	16.0
18	Jefferson, La.	Grand Isle/ Grand Terre	coastal barrier beach	Barataria	Bay				Rec. beach	15.0
19	Plaquemines, La.	West Plaquemines	coastal barrier beach	Barataria	Bay	East Deltaic Plain		Marsh		6.7
20	Orleans, St. John the Baptist, Tangipahoa, St. Bernard, St. Charles, Livingston, St. Tammany, La.	Chandeleur/ Breton	coastal barrier beach			East Deltaic Plain		Marsh		7.0
21	Hancock, Jackson, Harrison, Miss.	Mississippi Mainland		Mississippi Sound	Bay				Rec. beach+M.H.	26.0
22	Mobile, Ala.	Dauphin Island/Mobile	coastal barrier beach	Mobile/ Perdido	Bay		Seagrass bed		Rec. beach+M.H.	26.0
23	Baldwin, Ala.	Gulf shores/ Mobile	coastal barrier beach	Mobile/ Perdido	Bay		Seagrass bed		Rec. beach+M.H.	26.0
24	Santa Rosa,Escambia, Fla.	Emerald coast/ Escambia/ Pensacola	coastal barrier beach	Santa Rosa Sound	Bay		Seagrass bed		Rec. beach+M.H.	26.0
25	Okaloosa, Fla.	Emerald coast	coastal barrier beach	Choctawatchee	Bay		Seagrass bed		Rec. beach	16.0
26	Walton, Fla.	Emerald coast	coastal barrier beach						Rec. beach	14.0
27	Bay, Fla.	Emerald coast/ Panama City	coastal barrier beach	St.Andrew Bay/ Sound	Bay		Seagrass bed		Rec. beach	16.0
28	Gulf, Fla.	St. Joseph Spit	coastal barrier beach	St. Joseph Bay	Bay		Seagrass bed		Rec. beach	16.0
29	Franklin, Fla.	Apalachicola Bay	coastal barrier beach		Bay		Seagrass bed	Marsh	Rec. beach	17.0
30	Wakulla, Jefferson, Fla.	Big Bend						Marsh		10.0
31	Taylor, Fla.	Big Bend						Marsh	Manatees	20.0
32	Dixie, Fla.	Big Bend						Marsh	Manatees	20.0
33	Levy, Fla.	Big Bend						Marsh	Manatees	20.0
34	Citrus, Fla.	Big Bend						Marsh	Manatees	20.0
35	Hernando, FLa.	Big Bend						Marsh	Manatees	20.0
36	Pasco, Fla.	Big Bend						Marsh	Manatees	20.0
37	Pinellas, Hillsborough, Fla.	SW Florida	coastal barrier beach	Tampa/ Sarasota Bays	Bay		Seagrass bed	Mangrove	Rec. beach+Manatees	27.0
38	Manatee, Fla.	SW Florida	coastal barrier beach	Tampa/ Sarasota Bays	Bay		Seagrass bed	Mangrove	Rec. beach+Manatees	27.0
39	Sarasota, Fla.	SW Florida	coastal barrier beach					Mangrove	Rec. beach+Manatees	27.0
40	Charlotte, Fla.	SW Florida	coastal barrier beach	Charlotte Harbour	Bay		Seagrass bed	Mangrove	Rec. beach+Manatees	27.0
41	Lee, Fla.	SW Florida	coastal barrier beach	Charlotte Harbour	Bay		Seagrass bed	Mangrove	Rec. beach+Manatees	27.0
42	Collier, Fla	SW Florida/ Everglades	coastal barrier beach					Mangrove	Rec. beach+Manatees	27.0
43	Monroe, Fla.	Everglades					Seagrass bed	Mangrove	Manatees	19.0
44	Dade, Fla. (mainland)	Everglades					Seagrass bed	Mangrove	Manatees	19.0

Table 4.4 Environmental resources for selected land segments, GOMR.

Environmental Resource	Relative Sensitivity
coastal barrier beach	4
bay	6
lake	6
seagrass bed	8
fish habitat	10
manatees	10
mangroves	10
marsh	10
recreational beach	10
wildlife refuge	10
recreational beach + manatees	20
recreational beach + marine habitat	20

Table 4.5 Relative sensitivity of environmental resources.

Table 7. Conditional probabilities (expressed as percent chance) that an oil spill starting at a particular location will contact a certain land segment within 30 days, Gulf of Mexico OCS Lease Sales 157 and 161

Land Segment	Hypothetical Spill Location W01	W02	W03	W04	W05	W06	W07	W08	W09	W10	W11	W12	W13	W14	W15	W16	W17	W18	W19	W20	W21	W22	W23	W24	W25
1	23	12	4	2	2	4	1	2	9	2	3	1	n	n	n	n	n	n	n	n	n	n	n	1	n
2	10	15	5	1	3	5	2	1	6	2	3	1	1	n	1	n	n	n	n	n	n	n	n	n	n
3	10	27	21	7	10	13	5	4	10	4	4	4	2	1	4	2	1	2	n	n	1	1	n	1	n
4	4	9	16	5	7	6	3	2	5	2	2	3	1	1	2	1	1	1	n	n	1	n	n	n	n
5	8	11	22	11	11	10	6	5	8	3	4	6	3	1	4	3	3	2	1	n	1	1	n	1	n
6	7	9	16	19	13	11	5	4	6	4	3	8	4	1	6	3	3	3	1	1	2	1	1	1	n
7	7	9	12	34	21	13	12	9	8	8	7	20	9	4	12	7	7	7	3	2	4	2	1	3	1
8	4	3	3	18	19	14	20	15	9	11	7	43	28	10	28	18	19	13	9	4	9	5	3	7	3
9	1	n	n	1	3	2	5	4	1	2	2	7	21	11	10	13	10	7	4	3	4	3	2	2	2
10	n	n	n	1	1	1	4	2	1	1	n	4	18	38	8	23	10	5	7	6	2	3	4	1	1
11	n	n	n	n	n	n	1	1	n	n	n	1	5	21	3	7	3	1	2	2	n	n	1	n	n
12	n	n	n	n	n	n	n	n	n	n	n	n	2	7	1	5	2	1	3	5	1	1	3	n	n
13	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	1	n	2	3	n	1	2	n	n
14	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	1	2	n	n	1	n	n
58	18	4	2	1	1	2	1	1	7	2	4	n	n	n	n	n	n	n	n	n	n	n	n	1	n

Land Segment	Hypothetical Spill Location W26	W27	W28	W29	C30	C31	C32	C33	C34	C35	C36	C37	C38	C39	C40	C41	C42	C43	C44	C45	C46	C47	C48	C49	C50
1	n	1	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n
2	n	1	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n
3	n	1	n	n	1	n	1	1	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n
4	n	1	n	n	n	n	1	n	1	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n
5	n	1	n	n	1	1	2	1	1	n	1	n	n	n	n	n	n	n	n	n	n	n	n	n	n
6	n	1	n	n	1	1	2	1	1	1	n	n	1	n	n	n	n	n	n	n	n	n	n	n	n
7	n	3	1	n	2	3	5	3	5	2	1	1	1	1	1	n	n	n	n	n	n	n	n	n	n
8	1	5	2	n	5	4	11	7	12	5	2	1	4	2	2	1	1	2	1	1	n	n	n	n	n
9	1	1	n	n	5	3	8	5	9	5	2	1	3	2	2	1	1	1	n	1	n	n	n	n	n
10	2	n	n	1	14	9	23	13	14	10	6	3	9	5	6	3	2	2	1	1	1	n	n	n	n
11	1	n	n	n	15	6	12	8	5	5	4	2	5	3	3	2	2	2	1	1	n	n	n	n	n
12	2	n	n	n	50	33	16	27	7	14	16	8	24	13	17	12	9	9	6	5	4	3	2	1	1
13	1	n	n	n	2	28	2	9	2	6	16	5	15	9	11	8	6	6	4	4	3	2	2	n	1
14	1	n	n	n	n	5	n	2	n	2	14	4	7	5	4	4	3	2	4	2	2	1	1	n	1
15	n	n	n	n	n	n	n	1	n	n	5	1	2	1	1	1	1	1	1	n	1	n	n	n	n
16	n	n	n	n	n	n	n	n	n	1	20	29	4	20	3	14	11	4	8	3	6	1	4	n	1
17	n	n	n	n	n	n	n	n	n	n	n	18	n	4	n	3	4	n	3	n	2	n	2	n	1
18	n	n	n	n	n	n	n	n	n	n	n	5	n	n	n	n	1	n	1	n	1	n	n	n	n
19	n	n	n	n	n	n	n	n	n	n	n	5	n	1	n	2	3	n	2	n	1	n	1	n	1
44	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	1
58	n	2	1	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n

Note: ** = Greater than 99.5%; n = Less than 0.5%
Segments with all values less than 0.5% are not shown.

Table 4.6 Conditional spill probabilities in the GOMR (portion of table from MMS 1995).

Spill Site	Damage Potential	Environmental Zone	Spill Site	Damage Potential	Environmental Zone	Spill Site	Damage Potential	Environmental Zone
W1	1201	3	C51	1509	4	E101	537	2
W2	1538	4	C52	1023	3	E102	703	2
W3	1610	4	C53	821	2	E103	159	1
W4	1651	4	C54	1028	3	E104	158	1
W5	1503	4	C55	1087	3	E105	444	1
W6	1321	3	C56	1034	3	E106	520	2
W7	1129	3	C57	739	2	E107	725	2
W8	897	2	C58	783	2	E108	1128	3
W9	1051	3	C59	404	1	E109	509	2
W10	709	2	C60	406	1	E110	464	1
W11	628	2	C61	237	1	E111	810	2
W12	1648	4	C62	707	2	E112	745	2
W13	1587	4	C63	189	1	E113	664	2
W14	1602	4	C64	180	1	E114	896	2
W15	1359	3	C65	308	1	E115	1143	3
W16	1393	3	C66	252	1	E116	867	2
W17	1142	3	C67	490	1	E117	1167	3
W18	907	2	C68	1898	4	E118	1328	3
W19	757	2	C69	1415	3	E119	1213	3
W20	531	2	E70	1968	4	E120	870	2
W21	581	2	E71	1605	4	E121	852	2
W22	453	1	E72	1369	3	E122	1078	3
W23	383	1	E73	1156	3	E123	637	2
W24	376	1	E74	843	2	E124	861	2
W25	199	1	E75	724	2	E125	1315	3
W26	201	1	E76	1161	3	E126	1669	4
W27	300	1	E77	1327	3	E127	1043	3
W28	81	1	E78	1298	3	E128	943	2
W29	47	1	E79	858	2	E129	998	2
C30	1588	4	E80	1043	3	E130	543	2
C31	1362	3	E81	1198	3	E131	850	2
C32	1397	3	E82	540	2	E132	1239	3
C33	1669	4	E83	765	2	E133	560	2
C34	1023	3	E84	1031	3	E134	619	2
C35	1007	3	E85	1294	3	E135	308	1
C36	1062	3	E86	375	1	E136	348	1
C37	1254	3	E87	527	2	E137	138	1
C38	1412	3	E88	831	2	E138	252	1
C39	1256	3	E89	1111	3	E139	135	1
C40	935	2	E90	287	1	E140	210	1
C41	970	2	E91	221	1	E141	225	1
C42	772	2	E92	666	2	E142	141	1
C43	512	2	E93	1048	3	E143	509	2
C44	503	2	E94	175	1	E144	247	1
C45	299	1	E95	96	1	E145	631	2
C46	312	1	E96	458	1			
C47	116	1	E97	918	2			
C48	176	1	E98	141	1			
C49	37	1	E99	99	1			
C50	117	1	E100	326	1			

Table 4.7 Damage potential and environmental index by spill site.

5. RISK ASSESSMENT RESULTS

The fault tree model generated leak probabilities for the main well configurations representing the SI, TA, and PA well status, and for all combinations of applicable well attributes listed in Table 3.1. The consequence model produced life safety and environmental consequence indices for each well status, also defined by the appropriate well attributes. Qualitative environmental and life safety risk levels could now be calculated by multiplying the respective consequence indices by the leak probabilities. The risk level would be a function of well status and its other attributes as previously described. This section describes the result of the risk calculations.

5.1 Component Age Considerations

It should be realized that for each well status defined (SI, TA, PA), all components may not have the same "age". For example, a well completed 20 years ago could have a new tubing string installed in a recent workover. Taking this into account in a rigorous fashion would require knowledge of individual well maintenance histories, which is beyond the scope of this qualitative study. To simplify matters, therefore, it was assumed that most well components (e.g. casing strings, wellhead equipment, cement plugs) age from the time they are installed, with the following exceptions:

- SI wells: it is assumed that the SSSV, tubing and packer were replaced at the latest workover. These components are assumed to be brand new or inspected so that they may be considered suitable for their intended service; their reliability is then set at *R(0)*. This assumption is important because it represents the best possible well condition after a workover, and helps provide some indication of the potential reduction in risk with well maintenance.
- TA wells: cement plugs, corrosion cap were new at time of TA; and
- PA well: cement plugs were new at time of PA.

Consequently, in addition to the current well age, the time of the last major well intervention also becomes important in determining the risk level associated with the well. For TA and PA wells, their major intervention is the well abandonment operation itself, while <u>for SI wells, it is the last workover before the well was shut-in.</u>

The assumptions related to SI wells aid in understanding the effect of well maintenance activities. For example, the case of a shut-in well with its last workover at time = 0 can be interpreted as a well with no maintenance since its initial completion. It therefore serves as a worst case example of deterioration. On the other hand, the risk level of a well just after a workover (time of workover = well age) represents the best case of maintenance. Note, however, that the level of risk of a well *before* the last workover is not considered, since it would require knowledge of the well's workover history.

5.2 Defining Acceptable Risk

Without intervention (in the form of maintenance activities such as workovers), the risk level presented by a well increases with time. The point at which the risk becomes unacceptable determines the maximum time a well can remain in its current status without further intervention.

Defining the acceptable risk level in a qualitative study such as this is somewhat arbitrary. However, a first order estimate was determined as follows:

- the environmental and life safety risk levels were tabulated for all combinations of well attributes;
- the case with the highest risk level was identified for both:
    - environmental risk; and
    - life safety risk;
- it was reasoned that the risk level of PA wells should be acceptable even after a long time; the same should apply to an SI well just after initial completion;
- the greater risk of the two (long-term PA or initial completion) was used to establish the maximum risk level for both environmental and life safety risk for all cases in the study; and
- the maximum time at each status (SI, or TA) for a given set of well attributes was determined as the time at which the risk levels reached the maximum established values.

This procedure yielded two values for the maximum time at status (one related to environmental risk, and the other to life safety risk). The final resolution was to select the lesser of the two time values determined.

The highest environment risk levels were found for the case of an oil, flowing, sour well in environmental zone #4 (Figure 5.1). Based on this case, the threshold environmental risk level was set at 0.01. The life safety risk level was the highest for a gas, flowing, sour well, at a major, manned platform (Figure 5.2), resulting in the life safety threshold being set at 0.1.

5.3 Maximum Time at Status

With the thresholds established, the above procedure was used to determine the maximum age for a well with acceptable risk level. Note that the *remaining* time a well can stay at its current status is computed as:

$$\max\_time@status = \max\_age@status - age\_when\_status\_changed \qquad [5.1]$$

The age when well status changed is the well age when the last workover was performed (SI wells), or well age at conversion to TA or PA.

As shown in Figures 5.1 and 5.2, the maximum age at SI or TA status is determined at the time the risk curve reaches the value of the risk threshold. In Figure 5.1, for example, a well that was TA at five years after initial completion could stay in that status until about 15 years of wellbore age; after that time the environmental risk threshold would be exceeded. This represents a maximum time at TA status of ten years in this case.

Using the model, the maximum time at SI and TA status was computed for all combinations of well attributes and for a range of well ages, and workover or abandonment times. This resulted in approximately 1600 combinations. A portion of these results is given in Table 5.1. A more detailed discussion of shut-in and temporarily abandoned cases follows:

5.3.1 The Shut-in Case

The case of an oil, flowing, sour well in environmental zone #4 is shown in Figure 5.3. This figure depicts the intersection of the risk curves with the risk threshold from Figure 5.1. Note that the risk threshold, if in SI status, is reached only 0.5 years after initial completion. From Figure 5.1, it is also clear that after a certain age, further workovers can no longer reduce the risk below the threshold level. As shown in Figure 5.3, if the well is worked over 0.5 years after the initial completion, the remaining time until the threshold is again reached is about another 0.3 years. This suggests that the risk presented by this well in SI status is unacceptable, and it should be TA or PA if it is not in operation.

Of interest is that platform attributes (major/minor, manned/unmanned) do not change the results, since this case is dominated by the environmental risk.

5.3.2 The TA Case

The maximum amount of time in TA status for the same case (oil, flowing, sour well in environmental zone #4) is shown in Figure 5.4. Observe that consistent with Figure 5.1, the time allowable in TA status is considerably longer. A well TA after two years of operation, for example, could remain in that status for an additional twelve years.

5.4 Well Categories

When the initial results were generated, it was recognized that additional processing or interpretation was required in order to “reduce” the large number of combinations of well attributes to a more manageable level. This appeared possible after observing that in the case of oil, flowing, sour wells, the environmental zone influenced the results while platform attributes did not. In the case of gas wells, the environmental zone was also the most important factor in determining the outcome in a majority of instances, except in the case of a major, manned platform. After examining the results, the most convenient approach was to sort the calculated cases in terms of well attributes as follows:

- *intrinsic* attributes:
    - fluid (oil, gas);
    - energy (flowing, non-flowing); and
    - service (non-sour, sour).
- *extrinsic* attributes:
    - wellbore age at latest workover;
    - platform size (major/minor);
    - platform staffing (manned/unmanned); and
    - environmental zone (1, 2, 3, or 4).

Note that combinations of the intrinsic attributes define a total of only eight well categories, while the extrinsic attributes essentially determine the maximum allowable time in each status for each of these well categories. Figure 5.5 and 5.6, for instance show the effect of environmental zone upon the maximum time allowable in SI or TA status for the case of oil, flowing, sour wells.

As has been discussed earlier, some cases were dominated by the well location (environmental zone), while others were dominated by platform attributes (major/minor, manned/unmanned). The results were then arranged in tabular form (Tables 5.2 and 5.3). To simplify the presentation:

- calculated allowable times were rounded down to the next integer value, in years;
- allowable times longer than 40 years were considered indefinite; and
- times less than one year in any status were not allowed, requiring the well to be converted (i.e. from SI to TA, or TA to PA);

Results for SI wells are given in Table 5.2. Note that the relevant time in the table is the maximum allowable time <u>since the last workover</u>. This is the time affecting component deterioration. For oil wells, the environmental impact was dominant over the life safety impact, therefore the only extrinsic criteria to consider is environmental zone. Note the considerable constraint on oil, flowing, sour wells; in this category they must be either TA or PA to obtain a satisfactory reduction in risk level. Gas wells tend to be dominated by life safety considerations if the platform is both major and manned; otherwise, the environmental zones again determine the allowable SI time (since the last workover).

Table 5.3 illustrates that significant risk reduction can be achieved by temporarily abandoning wells. For a majority of well categories, the allowable time is virtually indefinite (i.e. greater than 40 years). Note, however, that sour wells have limited allowable time, even as TA. Also, one well category (oil, flowing, sour) presents such a risk that even conversion to TA late in life may not reduce the risk below the threshold.

5.5 The Case of Sustained Casinghead Pressure

Sustained casinghead pressure (SCP) is the occurrence of fluid pressure in the casing-tubing or any outer annulus in a well. It is of concern to the MMS, since it is felt that these wells, with one level of pressure containment already compromised, present a higher risk than similar wells without SCP. Additional monitoring requirements have been imposed upon operators of wells with SCP (MMS 1994, 1995b, 1998, 2000).

At the request of the MMS, the risk model was modified to assess the risk presented by an SCP well. The assessment was restricted to one well category selected by MMS staff: oil, non-flowing, non-sour, and one set of extrinsic attributes selected by C-FER: a major, manned platform, and environmental zone #1. From the risk assessment conducted in this study, this represents a relatively benign or low risk situation without SCP. In addition, the well configuration chosen was SI (although SCP may also be an issue with TA wells), and the pressure breach chosen to be in the tubing/casing annulus.

Inspection of the fault tree for the SI well configuration (Figure 3.4), shows that three events can result in wellbore pressure at the tubing/casing annulus:

- production tubing leak (event B2); or
- packer leak (event B3); or
- a combination of:
    - leak through SSSV (assuming it's closed) (event B1) AND
    - leak through tbg above SSSV (event B8).

The probability model constructed from the SI well fault tree was modified for the SCP case. First, the intermediate event (E4), which represents event (B2 OR B3), was forced to a probability of 1.0. The overall resulting probability of leak was called P(A).

Next, using a copy of the SI well fault tree model, the probability of failure for E4 was restored to its original value, and the probabilities of failure for B1 and B8 were forced to 1.0. The overall resulting probability of leak was called P(B).

Finally, the total probability of a leak, *P(t)*, from an SI well, given the occurrence of casing pressure was evaluated as:

$$P(t) = P(A) + P(B) - P(A)P(B) \qquad [5.2]$$

This approach was required since some of the events, which can result in casing pressure, are not mutually exclusive. The new probability (of leak) value was then used along with the consequence models to determine the new environmental and life safety risk levels. The results are presented in Figures 5.7 and 5.8.

Risk Assessment Results

Figure 5.7 shows the environmental risk for the specific well category studied. The tolerable time with sustained casing pressure is effectively zero. Since the consequences did not change with these attributes, compared with the non-SCP case, the increased risk level with SCP is therefore a result of an increased probability of a leak. Note that the risk level increases with time regardless of the time of workover. Since it is assumed that pressure is already present in the casing-tubing annulus, tubing replacement does not reduce the reliability in this case. For comparison, the cases without SCP are also shown for SI, TA and PA.

A similar result is seen in Figure 5.8 for the life safety risk. The presence of casing pressure increases overall risk level. In the life safety case, however, the increased risk is still well below the defined risk threshold. As is seen in the Tables 5.2 and 5.3, the oil, non-sour, non-flowing case is dominated by the environmental risk.

Note that while the SCP model did show an environmental risk increase of about two orders of magnitude, this was contributed entirely from an increase in probability of leak. That is, the consequences remained the same. Furthermore, the model did not consider either:

- the nature of the downhole equipment leaks (small, large); or
- the rate of SCP build up (lower buildup rate may indicate the likelihood of a lower rate release to environment.

This analysis was, however, consistent with that performed for wells not presenting SCP.

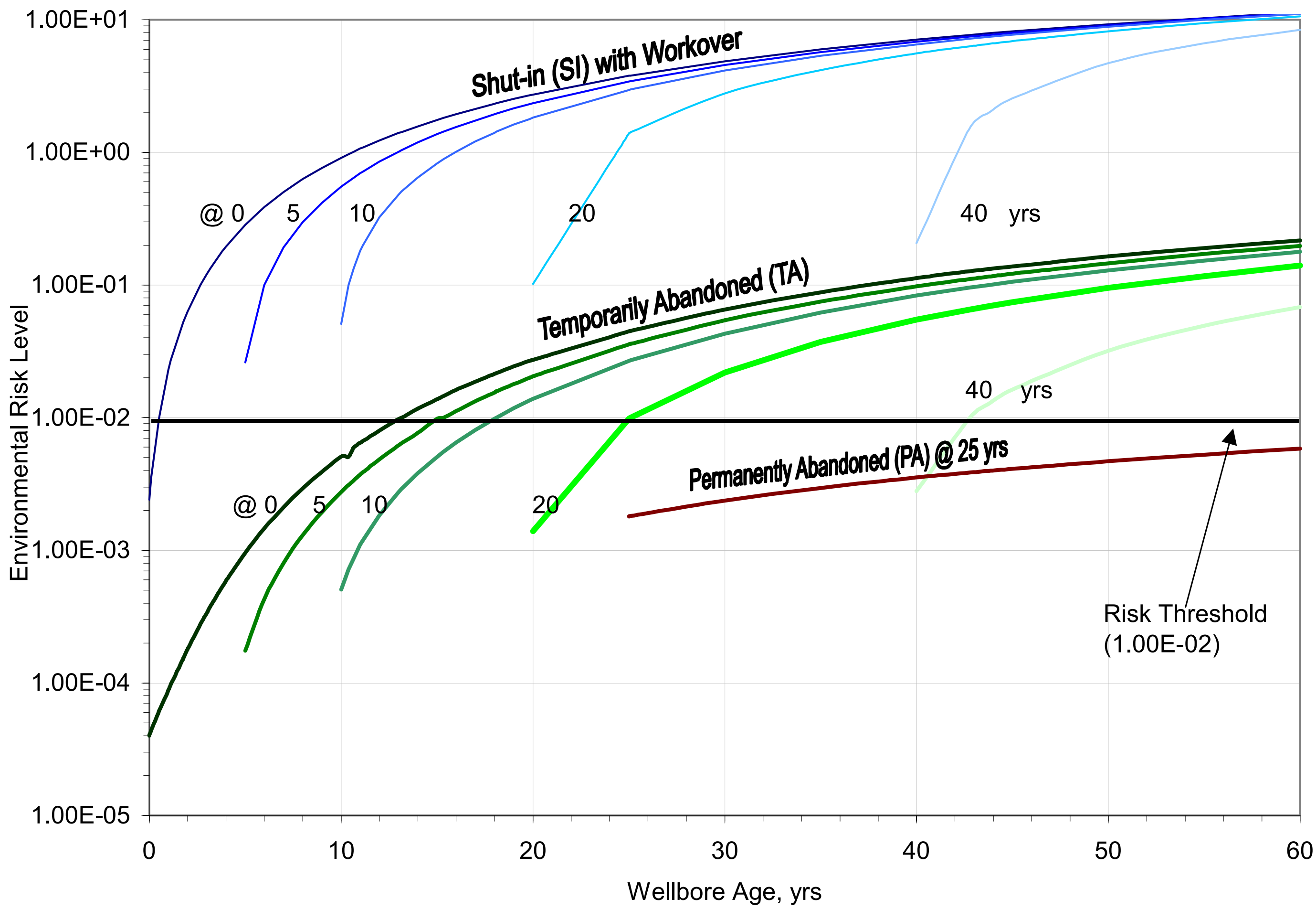


Figure 5.1 Defining maximum acceptable environmental risk level.

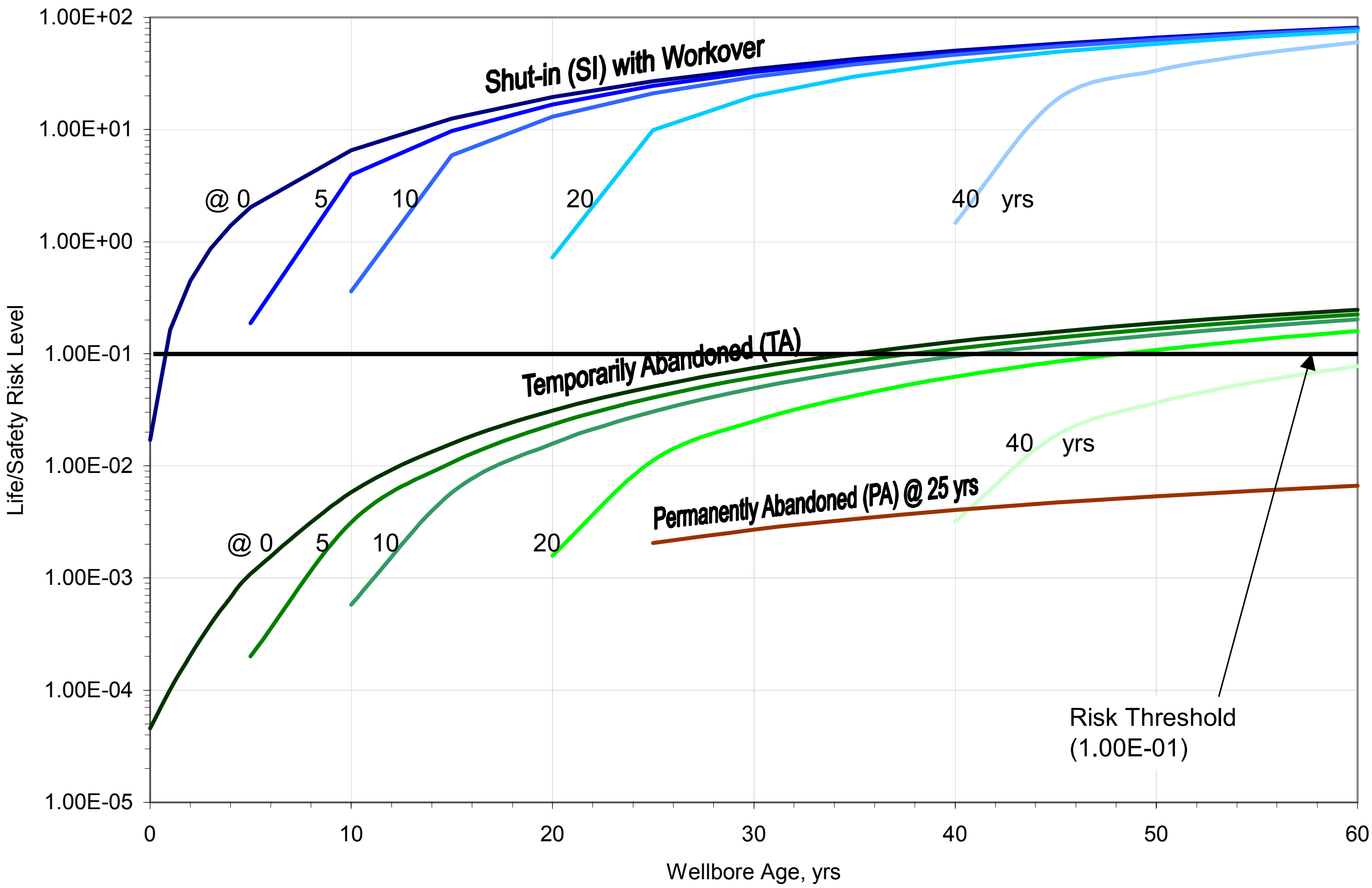


Figure 5.2 Defining maximum acceptable life safety risk level.

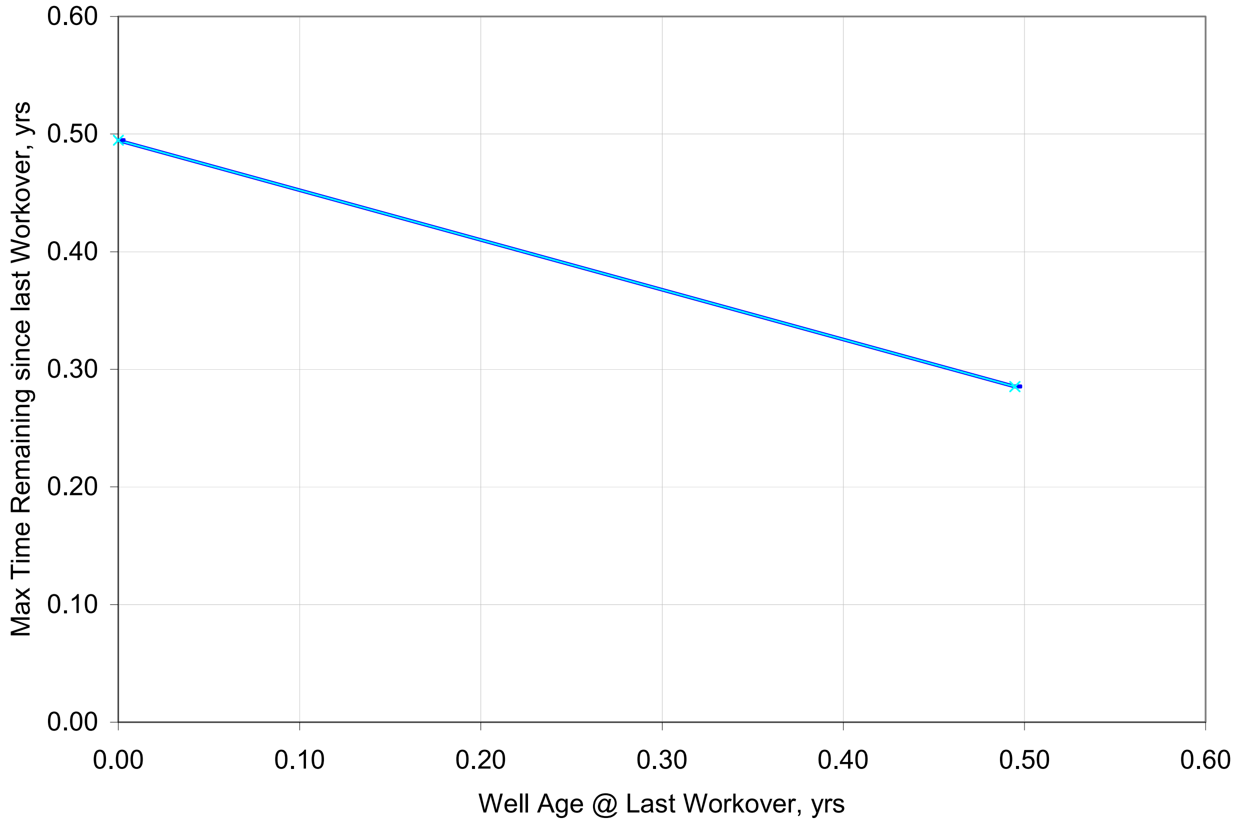


Figure 5.3 Maximum time since last workover for shut-in (SI) oil, flowing, sour well in environment zone #4.

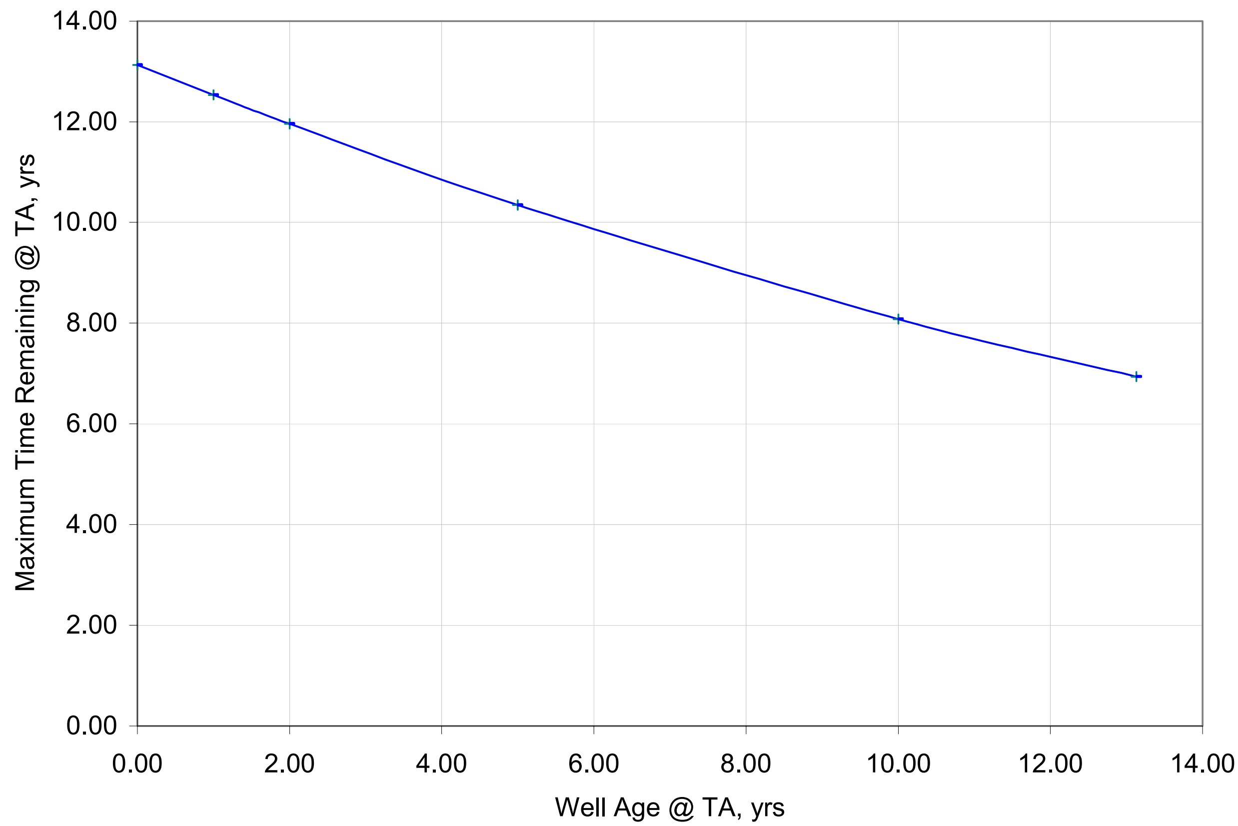


Figure 5.4 Maximum time in TA status for oil, flowing, sour well in environment zone #4.

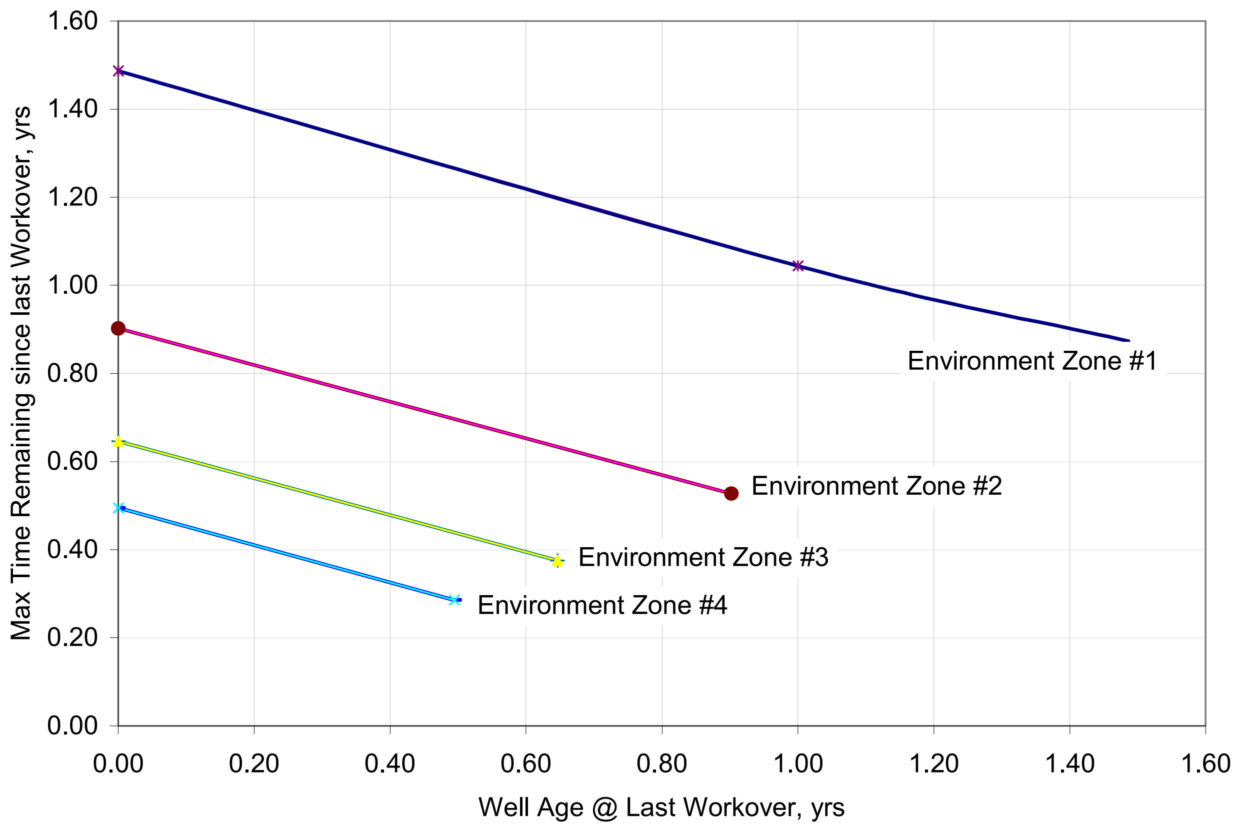


Figure 5.5 Maximum time since last workover for shut-in (SI) oil, flowing, sour wells in each environmental zone.

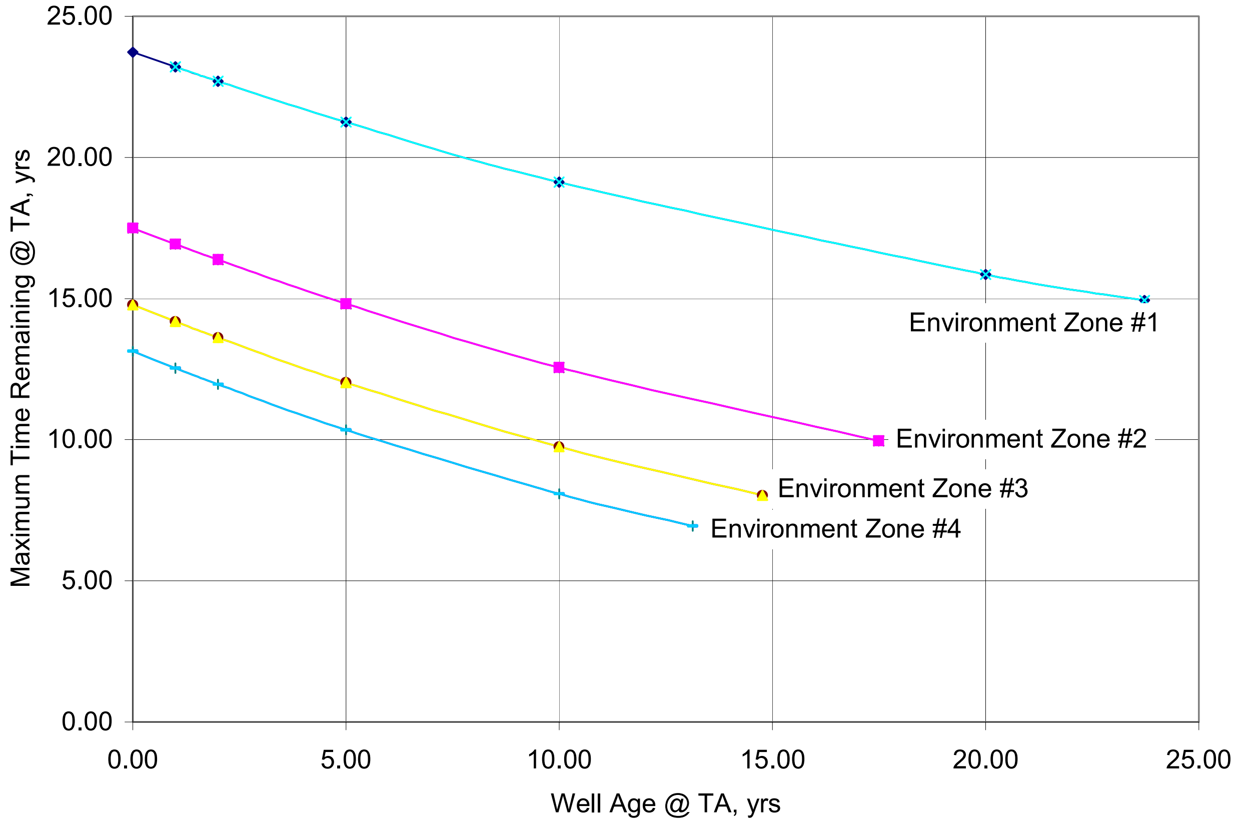


Figure 5.6 Maximum time in TA for: oil, flowing, sour wells.

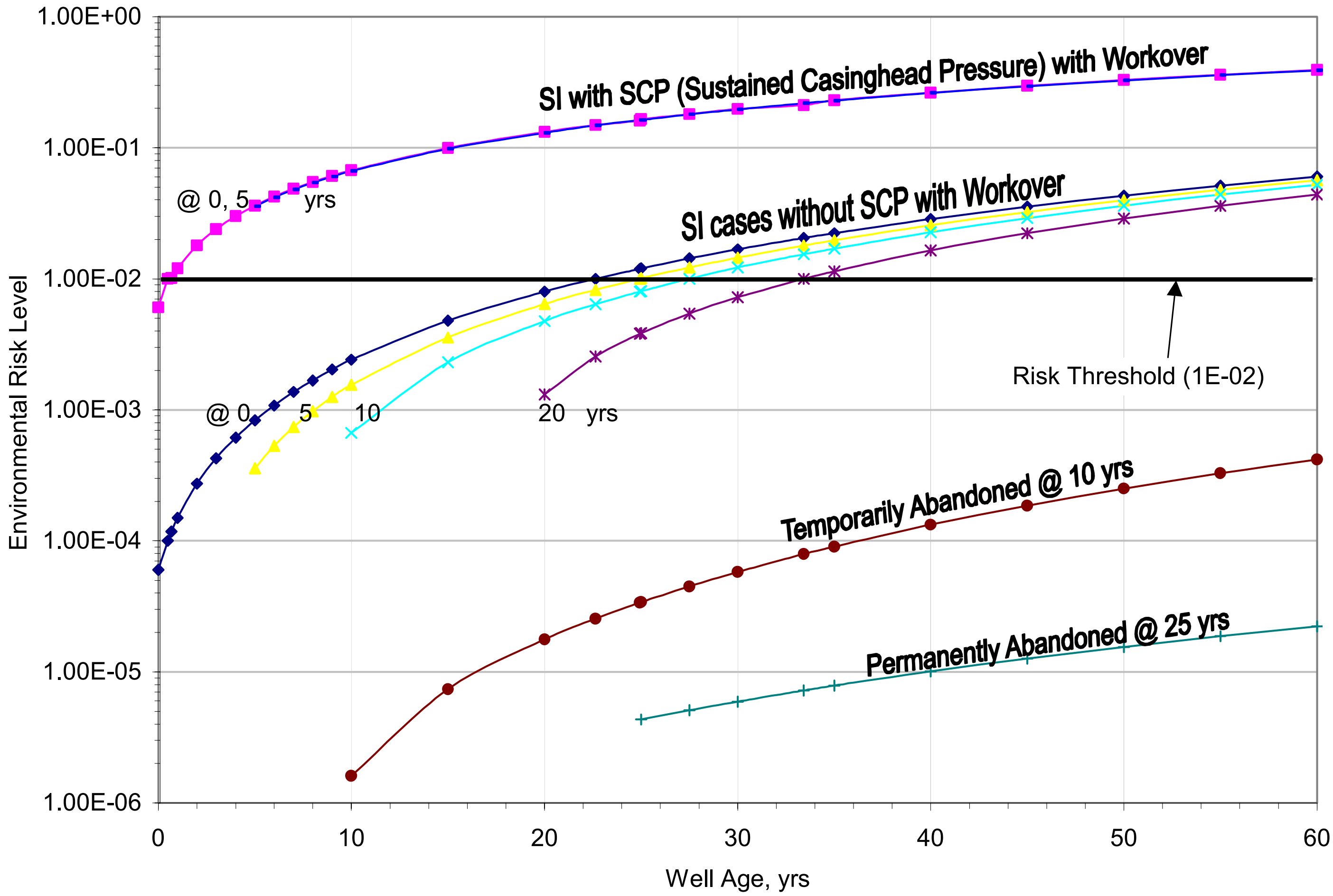


Figure 5.7 Environmental risk v. time for well with SCP (oil, non-flowing, non-sour, environmental zone # 1).

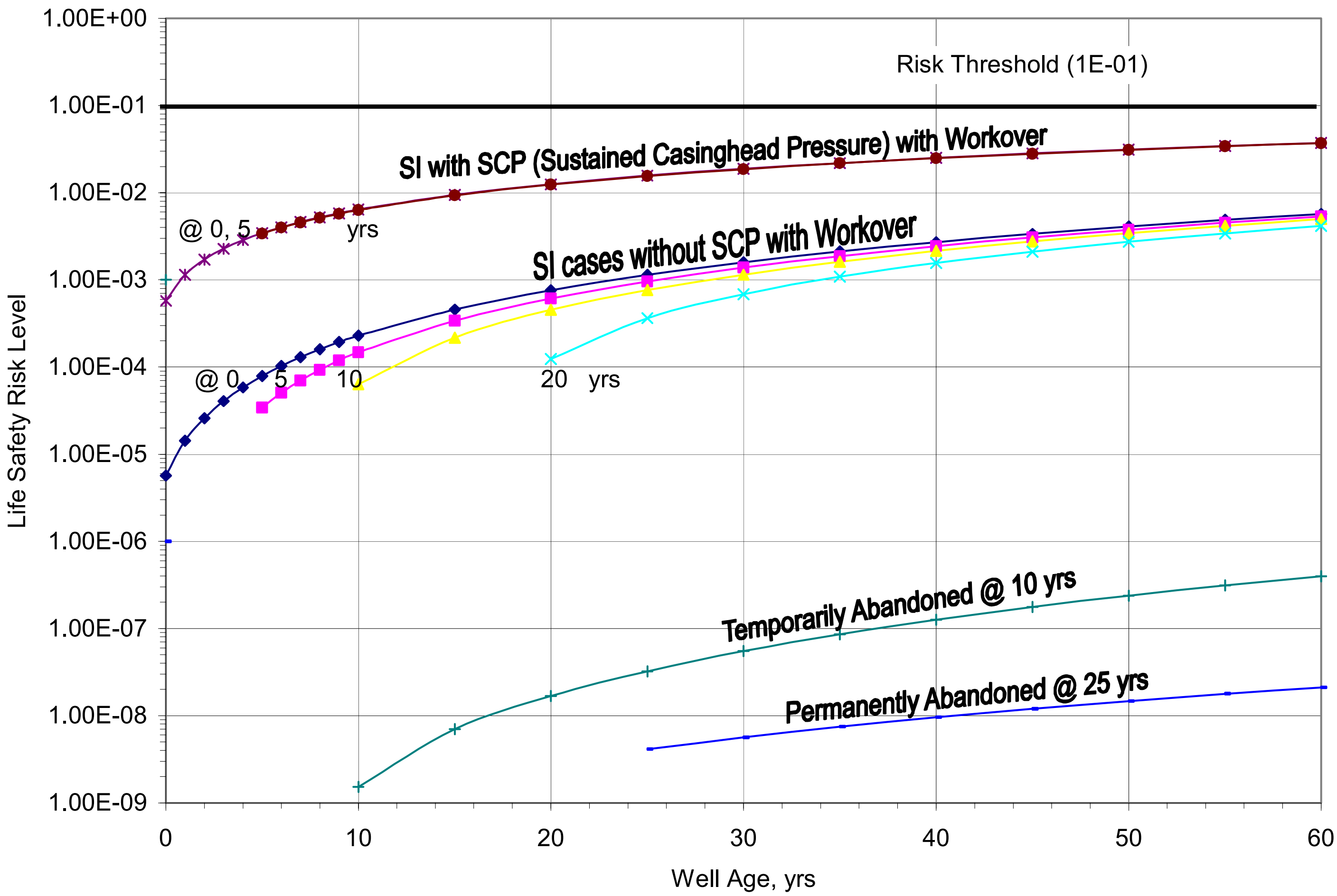


Figure 5.8 Life safety risk v. time for well with SCP (oil, non-flowing, non-sour, major, manned platform).

Fluid	Flow cond.	Sour?	Env. Loc.	Platform size	Manned	Status	Age@CS	Env Max	LS Max age	Env risk	LS risk	Max age	Max TS
Gas	Fl	N-sr	1	Mjr	Mn	SI	0.00	22.63	9.20	0.0100	0.1000	9.20	9.20
Gas	Fl	N-sr	1	Mjr	Mn	SI	1.00	23.07	9.64	0.0100	0.1000	9.64	8.64
Gas	Fl	N-sr	1	Mjr	Mn	SI	2.00	23.52	10.09	0.0100	0.1000	10.09	8.09
Gas	Fl	N-sr	1	Mjr	Mn	SI	5.00	24.93	11.59	0.0100	0.1000	11.59	6.59
Gas	Fl	N-sr	1	Mjr	Mn	SI	9.20	27.07	14.02	0.0100	0.1000	14.02	4.82
Gas	Fl	N-sr	1	Mjr	Unm	SI	0.00	22.63	100.00	0.0100	0.0704	22.63	22.63
Gas	Fl	N-sr	1	Mjr	Unm	SI	1.00	23.07	100.00	0.0100	0.0699	23.07	22.07
Gas	Fl	N-sr	1	Mjr	Unm	SI	2.00	23.52	100.00	0.0100	0.0694	23.52	21.52
Gas	Fl	N-sr	1	Mjr	Unm	SI	5.00	24.93	100.00	0.0100	0.0680	24.93	19.93
Gas	Fl	N-sr	1	Mjr	Unm	SI	10.00	27.50	100.00	0.0100	0.0655	27.50	17.50
Gas	Fl	N-sr	1	Mjr	Unm	SI	20.00	33.39	100.00	0.0100	0.0603	33.39	13.39
Gas	Fl	N-sr	1	Mjr	Unm	SI	22.63	35.10	100.00	0.0100	0.0589	35.10	12.47
Gas	Fl	N-sr	1	Mnr	Mn	SI	0.00	22.63	33.93	0.0100	0.1000	22.63	22.63
Gas	Fl	N-sr	1	Mnr	Mn	SI	1.00	23.07	34.37	0.0100	0.1000	23.07	22.07
Gas	Fl	N-sr	1	Mnr	Mn	SI	2.00	23.52	34.81	0.0100	0.1000	23.52	21.52
Gas	Fl	N-sr	1	Mnr	Mn	SI	5.00	24.93	36.18	0.0100	0.1000	24.93	19.93
Gas	Fl	N-sr	1	Mnr	Mn	SI	10.00	27.50	38.61	0.0100	0.1000	27.50	17.50
Gas	Fl	N-sr	1	Mnr	Mn	SI	20.00	33.39	44.01	0.0100	0.1000	33.39	13.39
Gas	Fl	N-sr	1	Mnr	Mn	SI	22.63	35.10	45.56	0.0100	0.1000	35.10	12.47
Gas	Fl	N-sr	1	Mnr	Unm	SI	0.00	22.63	100.00	0.0100	0.0070	22.63	22.63
Gas	Fl	N-sr	1	Mnr	Unm	SI	1.00	23.07	100.00	0.0100	0.0070	23.07	22.07
Gas	Fl	N-sr	1	Mnr	Unm	SI	2.00	23.52	100.00	0.0100	0.0069	23.52	21.52
Gas	Fl	N-sr	1	Mnr	Unm	SI	5.00	24.93	100.00	0.0100	0.0068	24.93	19.93
Gas	Fl	N-sr	1	Mnr	Unm	SI	10.00	27.50	100.00	0.0100	0.0066	27.50	17.50
Gas	Fl	N-sr	1	Mnr	Unm	SI	20.00	33.39	100.00	0.0100	0.0060	33.39	13.39
Gas	Fl	N-sr	1	Mnr	Unm	SI	22.63	35.10	100.00	0.0100	0.0059	35.10	12.47
Gas	Fl	N-sr	2	Mjr	Mn	SI	0.00	15.35	9.20	0.0100	0.1000	9.20	9.20
Gas	Fl	N-sr	2	Mjr	Mn	SI	1.00	15.79	9.64	0.0100	0.1000	9.64	8.64
Gas	Fl	N-sr	2	Mjr	Mn	SI	2.00	16.25	10.09	0.0100	0.1000	10.09	8.09
Gas	Fl	N-sr	2	Mjr	Mn	SI	5.00	17.70	11.59	0.0100	0.1000	11.59	6.59
Gas	Fl	N-sr	2	Mjr	Mn	SI	9.20	19.95	14.02	0.0100	0.1000	14.02	4.82
Gas	Fl	N-sr	2	Mjr	Unm	SI	0.00	15.35	100.00	0.0100	0.0704	15.35	15.35
Gas	Fl	N-sr	2	Mjr	Unm	SI	1.00	15.79	100.00	0.0100	0.0699	15.79	14.79
Gas	Fl	N-sr	2	Mjr	Unm	SI	2.00	16.25	100.00	0.0100	0.0694	16.25	14.25
Gas	Fl	N-sr	2	Mjr	Unm	SI	5.00	17.70	100.00	0.0100	0.0680	17.70	12.70
Gas	Fl	N-sr	2	Mjr	Unm	SI	10.00	20.41	100.00	0.0100	0.0655	20.41	10.41
Gas	Fl	N-sr	2	Mjr	Unm	SI	15.35	23.70	100.00	0.0100	0.0628	23.70	8.34
Gas	Fl	N-sr	2	Mnr	Mn	SI	0.00	15.35	33.93	0.0100	0.1000	15.35	15.35
Gas	Fl	N-sr	2	Mnr	Mn	SI	1.00	15.79	34.37	0.0100	0.1000	15.79	14.79
Gas	Fl	N-sr	2	Mnr	Mn	SI	2.00	16.25	34.81	0.0100	0.1000	16.25	14.25
Gas	Fl	N-sr	2	Mnr	Mn	SI	5.00	17.70	36.18	0.0100	0.1000	17.70	12.70
Gas	Fl	N-sr	2	Mnr	Mn	SI	10.00	20.41	38.61	0.0100	0.1000	20.41	10.41
Gas	Fl	N-sr	2	Mnr	Mn	SI	15.35	23.70	41.41	0.0100	0.1000	23.70	8.34
Gas	Fl	N-sr	2	Mnr	Unm	SI	0.00	15.35	100.00	0.0100	0.0070	15.35	15.35
Gas	Fl	N-sr	2	Mnr	Unm	SI	1.00	15.79	100.00	0.0100	0.0070	15.79	14.79
Gas	Fl	N-sr	2	Mnr	Unm	SI	2.00	16.25	100.00	0.0100	0.0069	16.25	14.25

Table 5.1 Maximum allowable time since workover (example of results).

Intrinsic Attributes			Age At Latest Workover	Extrinsic Attributes: Platform: major + manned	Platform: All, except major + manned			
				Environmental Zone: All	Environmental Zone: 1	2	3	4
Oil	Non-Flowing	Non-Sour	0	Use Environmental Zone	22	15	12	10
Oil	Non-Flowing	Non-Sour	5	Use Environmental Zone	20	12	9	7
Oil	Non-Flowing	Non-Sour	10	Use Environmental Zone	17	10	7	5
Oil	Non-Flowing	Non-Sour	20	Use Environmental Zone	13	TA or PA	TA or PA	TA or PA
Oil	Non-Flowing	Non-Sour	40	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Non-Flowing	Sour	0	Use Environmental Zone	6	4	3	2
Oil	Non-Flowing	Sour	5	Use Environmental Zone	3	TA or PA	TA or PA	TA or PA
Oil	Non-Flowing	Sour	10	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Non-Flowing	Sour	20	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Non-Flowing	Sour	40	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Flowing	Non-Sour	0	Use Environmental Zone	5	3	2	1
Oil	Flowing	Non-Sour	5	Use Environmental Zone	3	TA or PA	TA or PA	TA or PA
Oil	Flowing	Non-Sour	10	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Flowing	Non-Sour	20	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Flowing	Non-Sour	40	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Flowing	Sour	0	Use Environmental Zone	1	TA or PA	TA or PA	TA or PA
Oil	Flowing	Sour	5	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Flowing	Sour	10	Use Environmental Zone	TA or PA	TA or PA	TA or PA	TA or PA
Oil	Flowing	Sour	20	Use Environmental Zone	TA or PA	PA	PA	PA
Oil	Flowing	Sour	40	Use Environmental Zone	PA	PA	PA	PA
Gas	Non-Flowing	Non-Sour	0	33	indefinite	indefinite	indefinite	37
Gas	Non-Flowing	Non-Sour	5	31	indefinite	indefinite	40	34
Gas	Non-Flowing	Non-Sour	10	28	indefinite	indefinite	38	31
Gas	Non-Flowing	Non-Sour	20	24	indefinite	indefinite	33	37
Gas	Non-Flowing	Non-Sour	40	TA or PA	indefinite	35	25	TA or PA
Gas	Non-Flowing	Sour	0	3	26	16	12	10
Gas	Non-Flowing	Sour	5	TA or PA	22	13	10	7
Gas	Non-Flowing	Sour	10	TA or PA	19	10	7	5
Gas	Non-Flowing	Sour	20	TA or PA	14	TA or PA	TA or PA	TA or PA
Gas	Non-Flowing	Sour	40	TA or PA	TA or PA	TA or PA	TA or PA	TA or PA
Gas	Flowing	Non-Sour	0	9	22	15	12	10
Gas	Flowing	Non-Sour	5	6	20	12	9	7
Gas	Flowing	Non-Sour	10	TA or PA	17	10	7	5
Gas	Flowing	Non-Sour	20	TA or PA	13	8	TA or PA	TA or PA
Gas	Flowing	Non-Sour	40	TA or PA	TA or PA	TA or PA	TA or PA	TA or PA
Gas	Flowing	Sour	0	TA or PA	6	4	3	2
Gas	Flowing	Sour	5	TA or PA	3	TA or PA	TA or PA	TA or PA
Gas	Flowing	Sour	10	TA or PA	TA or PA	TA or PA	TA or PA	TA or PA
Gas	Flowing	Sour	20	TA or PA	TA or PA	TA or PA	TA or PA	TA or PA
Gas	Flowing	Sour	40	TA or PA	TA or PA	TA or PA	TA or PA	TA or PA

Note: Maximum Time greater than 40 yrs is considered indefinite

Table 5.2 Maximum allowable remaining time since last workover for SI wells.

<table>
<tr><th colspan="3" rowspan="4"></th><th rowspan="5">Age At TA</th><th colspan="5">Extrinsic Attributes</th></tr>
<tr><th colspan="5">Platform</th></tr>
<tr><th>major + manned</th><th colspan="4">All, except major + manned</th></tr>
<tr><th colspan="5">Environmental Zone</th></tr>
<tr><th colspan="3">Intrinsic Attributes</th><th>All</th><th>1</th><th>2</th><th>3</th><th>4</th></tr>
<tr><td rowspan="20">Oil</td><td rowspan="10">Non-Flowing</td><td rowspan="5">Non-Sour</td><td>0</td><td rowspan="35">use Environmental Zone</td><td colspan="4" rowspan="5">indefinite</td></tr>
<tr><td>5</td></tr>
<tr><td>10</td></tr>
<tr><td>20</td></tr>
<tr><td>40</td></tr>
<tr><td rowspan="5">Sour</td><td>0</td><td colspan="2" rowspan="5">indefinite</td><td></td><td>37</td></tr>
<tr><td>5</td><td>42</td><td>35</td></tr>
<tr><td>10</td><td>40</td><td>33</td></tr>
<tr><td>20</td><td>38</td><td>31</td></tr>
<tr><td>40</td><td>35</td><td>28</td></tr>
<tr><td rowspan="10">Flowing</td><td rowspan="5">Non-Sour</td><td>0</td><td colspan="3" rowspan="3">indefinite</td><td>45</td></tr>
<tr><td>5</td><td>42</td></tr>
<tr><td>10</td><td>40</td></tr>
<tr><td>20</td><td>68</td><td>48</td><td>40</td><td>34</td></tr>
<tr><td>40</td><td>58</td><td>39</td><td>31</td><td>26</td></tr>
<tr><td rowspan="5">Sour</td><td>0</td><td>23</td><td>17</td><td>14</td><td>13</td></tr>
<tr><td>5</td><td>21</td><td>14</td><td>12</td><td>10</td></tr>
<tr><td>10</td><td>19</td><td>12</td><td>9</td><td>8</td></tr>
<tr><td>20</td><td>15</td><td colspan="3" rowspan="2">PA</td></tr>
<tr><td>40</td><td></td></tr>
<tr><td rowspan="20">Gas</td><td rowspan="10">Non-Flowing</td><td rowspan="5">Non-Sour</td><td>0</td><td colspan="4" rowspan="5">indefinite</td></tr>
<tr><td>5</td></tr>
<tr><td>10</td></tr>
<tr><td>20</td></tr>
<tr><td>40</td></tr>
<tr><td rowspan="5">Sour</td><td>0</td><td colspan="4" rowspan="5">indefinite</td></tr>
<tr><td>5</td></tr>
<tr><td>10</td></tr>
<tr><td>20</td></tr>
<tr><td>40</td></tr>
<tr><td rowspan="10">Flowing</td><td rowspan="5">Non-Sour</td><td>0</td><td colspan="4" rowspan="5">indefinite</td></tr>
<tr><td>5</td></tr>
<tr><td>10</td></tr>
<tr><td>20</td></tr>
<tr><td>40</td></tr>
<tr><td rowspan="5">Sour</td><td>0</td><td>34</td><td colspan="2" rowspan="5">indefinite</td><td rowspan="3"></td><td>37</td></tr>
<tr><td>5</td><td>32</td><td>35</td></tr>
<tr><td>10</td><td>31</td><td>33</td></tr>
<tr><td>20</td><td>28</td><td>38</td><td>31</td></tr>
<tr><td>40</td><td>25</td><td>35</td><td>28</td></tr>
</table>

Note: Maximum Time greater than 40 yrs is considered indefinite

Table 5.3 Maximum allowable remaining time in <u>TA status</u> for wells.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 Accomplishments of the Qualitative Model

A qualitative assessment of the risks presented by SI, TA and PA wells in the GOMR was conducted using a framework capable of estimating probabilities and consequences of leaks as a function of several key well attributes. Combining results enabled the definition of eight categories of wells and the determination of maximum allowable time for these wells in SI status (after a workover) or TA status.

The results suggest that SI wells present wide range of risk levels, depending on their attributes. For example, oil, flowing sour wells were found to exceed the defined risk threshold in a very short time, even immediately after the replacement of key wellbore components during a workover. Significant and lasting reductions in risk can apparently be achieved in most cases by converting a well to TA status. A limited "sidebar" study of sustained casing pressure suggests that the occurrence of SCP greatly increases the risk level presented by a well. This is almost entirely due to the increased probability of failure, since a well with SCP is presumed to have already compromised pressure containment.

The results of the study also suggest that the degree of regulatory rigour applied to wells should be proportional to the risk the wells present to personnel or the environment. However, careful consideration is recommended to MMS when applying the results of the study in formulating "policy decisions", since the actual values computed for both risk level and time remaining in status have a largely qualitative meaning.

It is recommended that a matrix approach, similar to that presented in Tables 5.2 and 5.3, be used to establish the maximum remaining time allowable in SI or TA status, respectively. Given the qualitative nature of this study, however, it is recommended that MMS use the tables only as a starting position in establishing specific time limits in future regulations.

In the Pacific and Alaska OCS regions, the active leases are very close to shore, compared with the distribution seen in the Gulf. Therefore it should be assumed that the probability of a spill contacting these shorelines will be very high. Accordingly, the maximum shut-in times for Pacific and Alaska OCS should assume environmental zone #4 when reading the tables.

It is important to recognize that the risk assessment was based on the assumption that the well suffers no known failures or malfunctions (including SCP). In a practical policy implementation, therefore, a program of periodic monitoring or intervention would be required to verify the well's condition and to maintain it in a safe state.

6.2 Economic Interpretation

The time limits for SI and TA wells, as per Table 5.2 and 5.3, contain economic implications for the operator of a well. In certain cases, the well will be suitable to continue in an SI state for a length of time, with periodic maintenance (such as workovers). The operator will have to weigh the costs of this ongoing maintenance activity against the benefits of postponing well abandonment, temporarily or permanently. This will be a case-specific decision, depending on a number of considerations, including remaining recoverable reserves, workover costs, etc.

However a substantial reduction in risk can be achieved for most well categories by converting wells from SI to TA. Furthermore, the monitoring requirements to verify TA well integrity would be less than for SI wells. With the appropriate regulatory approach, operators could be encouraged to undertake the expense of a TA operation in return for reduced monitoring costs.

6.3 Future Enhancements to the Risk Assessment

The risk assessment was performed in the context of a qualitative study. This necessitated that certain compromises or conscious assumptions be made in order to preserve its general or "broad brush" approach. In some cases, however, the recommended time limits on SI or TA status may be inappropriate if the well in question has design features or circumstances not accounted for in this risk assessment.

Adapting the risk assessment model into a *case-specific* assessment tool would increase its value to both regulator and industry by reducing the generality inherent in the qualitative approach. This would entail several enhancements to the model, as described below:

6.3.1 Well Configuration

The qualitative model used in this study assumed a generic shallow water offshore well with a platform-based christmas tree. However, the actual configuration, from casing shoe to flow tee varies widely among wells. Moreover, new deep-water projects defy the uniform categorization that was possible with platform-based wells. Therefore, additional information about the well would be required to conduct more quantitative assessments, as outlined in Section 2 of this report:

- reservoir productivity (static reservoir pressure, productivity index (PI), etc- this could enable better estimates of leak volumes);
- type of completion (e.g. tubing string including gas lift mandrels and valves; use of a liner, etc. – could affect probability of leak);
- equipment specifications (materials, pressure ratings, etc. - could affect the rates of deterioration of wellbore components with time, and probability of leak);
- cement integrity (for cement plugs and primary cement – could affect probability of leak); and

- presence of cathodic protection system (could affect equipment deterioration rate).

6.3.2 Failure Probabilities

It was found that component reliability data for offshore wells was available only sparsely. As a result, engineering judgement was often used in place of actual failure information. The creation of a domestic database of well equipment failures could serve as an important source of reliability data for the OCS. If important component failure data is still unavailable, it may be necessary to obtain it directly through laboratory testing (for example, this seems to be the case with respect to the serviceability of cement plugs under sour conditions).

Based on the well configurations defined in a case-specific model, a unique fault tree would be required to accurately portray the various potential leak paths. Internal failures, such as SCP, would also be taken into account so that the risk presented by a compromised well could be estimated.

6.3.3 Failure Consequences

For this study, environmental and life safety consequence indices were used to qualitatively assess the consequences of a leak. A quantitative evaluation of consequences would require a better evaluation of leak volumes associated with each incident, as well as a way to combine both environmental and life safety consequences into a single index (perhaps on a dollar value scale).

6.3.4 Risk Levels

In the risk assessment model, the risk thresholds for environment and life safety were defined based on the worst-case well category. These were then applied to all well categories to determined maximum time in a SI or TA status. However, the actual value of the risk threshold could vary, if a different selection method is used.

6.3.5 Extensions to Risk Analysis of Wells

Once a quantitative, well-specific assessment model is built, a software tool that can generate updated risk level for all individual wells in the OCS, based on their geographic location, and current status, becomes feasible.

C-FER has experience in the development of such tools for other applications. The main output of such tools are maps in which risk levels for each component of an overall system are shown according to colour. This has proved very valuable in managing risk of complex systems with a larger number of components, and may be of interest to MMS to help manage the overall risk presented by SI or TA wells in the OCS

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