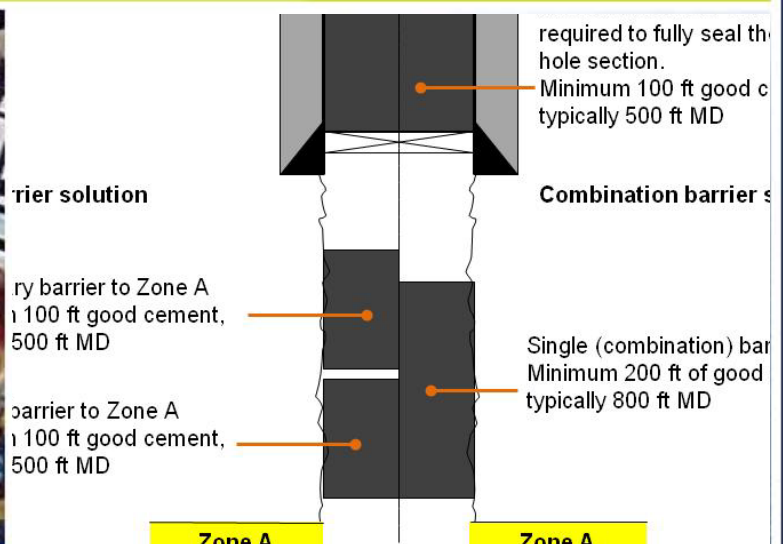


Guidelines for the suspension and abandonment of wells

Issue 4
July 2012



regional hydrostatic pressure gradient i.e. 0.45 psf/ft for the UK

permanent abandonment: The action taken to ensure the well is isolated from surface and from lower pressured zones, of exposed fluids and pressures in any well that will not be re-entered.

permanent barrier: A verified barrier that will maintain a permanent barrier must extend across the full cross section of the well. When considering isolation from surface, the point of potential influx is referred to as the **first barrier**. The point of potential influx above the point of potential influx is referred to as the **second barrier**.

permeable zone: Any zone in the well where there is the potential for fluid movement on application of a pressure differential.

Guidelines for the suspension and abandonment of wells

Issue 4, July 2012

© The United Kingdom Offshore Oil and Gas Industry Association Limited (trading as Oil & Gas UK), 2012.

All rights reserved. No part of this publication may be reproduced, stored in a retrieval system, or transmitted in any form or by any means, including electronic, mechanical, photocopying, recording or otherwise, without prior written permission of Oil & Gas UK.

Any material within these guidelines that has been reproduced has been done so with the permission of its owners. Contains public sector information licensed under the Open Government Licence v1.0, which can be found at <http://www.nationalarchives.gov.uk/information-management/uk-gov-licensing-framework.htm>

The information contained herein is given for guidance only. These guidelines are not intended to replace professional advice and are not deemed to be exhaustive or prescriptive in nature. Although the authors have used all reasonable endeavours to ensure the accuracy of these guidelines neither Oil & Gas UK nor any of its members assume liability for any use made thereof. In addition, these guidelines have been prepared on the basis of practice within the UKCS and no guarantee is provided that these guidelines will be applicable for other jurisdictions.

While the provision of data and information has been greatly appreciated, where reference is made to a particular organisation for the provision of data or information, this does not constitute in any form whatsoever an endorsement or recommendation of that organisation.

ISBN: 1 903 003 84 2

PUBLISHED BY OIL & GAS UK

London Office:

6th Floor East, Portland House, Bressenden Place, London, SW1E 5BH
Tel: 020 7802 2400 Fax: 020 7802 2401

Aberdeen Office:

Exchange 2, 3rd Floor, 62 Market Street, Aberdeen, AB11 5PJ
Tel: 01224 577250 Fax: 01224 577251

Email: info@oilandgasuk.co.uk

Website: www.oilandgasuk.co.uk

Contents

1	Objectives	7
2	Scope	7
3	Material requirements for permanent barriers.....	8
3.1	Plugging materials.....	8
4	Number of permanent barriers	9
5	Requirements of permanent barriers	10
5.1	Position requirements	10
5.2	Length requirements	12
5.3	Openhole requirements.....	13
5.4	Cased hole requirements.....	15
6	Verification of a permanent barrier	17
6.1	Cement barrier	17
6.2	Casing cement	18
6.3	Guidance on verification.....	19
7	Special considerations for abandonment.....	21
7.1	Well design.....	21
7.2	Partial abandonment for sidetracking or for other reasons.....	21
7.3	Irrecoverable radioactive sources	22
7.4	High angle and horizontal wells (wells > 70°)	22
7.5	Multilateral wells	23
7.6	Liner laps.....	24
7.7	Casing cuts.....	24
7.8	Removal of downhole equipment.....	24
7.9	Control lines, ESP cables, gauge cables	24
7.10	Through-tubing abandonments	25
7.11	HPHT wells.....	26
7.12	Wells containing H ₂ S.....	26
7.13	Wells containing CO ₂	26
7.14	Gas wells and high GOR wells.....	26
7.15	Sealing formations	26
7.16	Reservoir compaction and subsidence	27
7.17	Annular fluids	27
7.18	Shallow permeable zones	27
7.19	Hydrocarbons of biogenic nature	27
7.20	Removal of subsea equipment	27
7.21	Removal of surface equipment	28
8	Required standards for temporary abandonment (suspension)	29
8.1	Types of suspension	29
8.2	Principles of temporary abandonment	30
8.2.1	Number and type of barriers.....	30
8.2.2	Well re-entry considerations	30
8.3	Acceptable barriers	30

8.4	Verification of temporary barriers	31
8.5	Trawlability of suspended wells	31
8.6	Inspection scheme for suspended wells	31
9	Statutory notifications, approvals and record keeping.....	32
9.1	Notifications of proposed suspension or abandonment and permit applications.....	32
9.1.1	HSE requirements	32
9.1.2	DECC requirements	32
9.2	Notifications on completion of operations	33
9.3	Record keeping	34
	Appendix A Basic well data required for well abandonment.....	35
	Design input data sheet	36
	Appendix B Barrier integrity – potential issues and mitigations.....	37
	Appendix C P&A code.....	42
	Appendix D Suspended subsea E&A wells categorisation	45
	Appendix E Irretrievable radioactive sources – SEPA.....	47
	Appendix F References and further reading.....	48
	Appendix G Background to these guidelines.....	49

If you have any feedback on these guidelines, please send your comments (referring to the relevant paragraph number shown in the grey column) to wlcpf@oilandgasuk.co.uk. Unfortunately the workgroup may not be able to provide individual responses to feedback submitted. Feedback received will be used to improve the guidelines when they are next revised.

Foreword

These guidelines have been prepared to steer well-operators on the considerations that need to be taken when suspending operations in a well for a limited period of time and when finally abandoning a well.

The guidelines provide minimum criteria to ensure full and adequate isolation of formation fluids both within the wellbore and from the surface or seabed. In the case of temporary abandonment, this is for at least the expected duration of the temporary abandonment and covers the requirement to re-enter the well safely. If it is uncertain how long the well will be suspended, or if it may be designated abandoned without re-entry, the well should be suspended according to the abandonment guidelines.

Furthermore, the guidelines help well-operators to comply with the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 (SI 1996/913), hereafter referred to as DCR. Those regulations in DCR relevant to well suspension and abandonment are 13, 15 and 16 and cover well integrity, design for abandonment and materials. The regulations are goal-setting in nature and lay down the standard that should be achieved.

DCR also applies to all wells drilled under UK Landward licences. Local authorities may apply additional requirements for well abandonment.

In essence, DCR requires well-operators to prevent, on a permanent basis, escape of fluids from the well. Allowance should be made for deterioration of some components of the well over time and the possible recovery of hydrocarbon-bearing formations to virgin pressure.

The regulations require that general practice is to reduce the risk to as low as is reasonably practicable (ALARP).

The intent of these guidelines is to provide the framework for the decision-making process that should accompany any well suspension and abandonment activity. Some of the requirements are prescriptive, in that barriers must be provided. However, the requirement for each barrier should be identified, and conversely, the case for omitting a barrier must be justified, on a well-by-well basis.

It is anticipated that a well-operator will wish to develop its own standards and procedures which can be applied simply and effectively, to achieve an adequate standard of isolation. The well-operator's standards and procedures may vary as formations and fluids vary in depth and pressure. However, it is believed that application of the principles contained in these guidelines will lead the engineer to a safe, efficient and effective solution, by examining the circumstances of the individual well and identifying the key requirements. It will further aid demonstration of compliance with Regulations 13, 15 and 16 of DCR.

It is recognised that the key to a simple temporary or permanent abandonment often lies with the soundness of the initial well design and effectiveness of the primary casing cementations. The benefits of successful cementation should lead to an easier suspension or abandonment.

11

This revision, Issue 4, has been made to clarify and update some areas of the guidelines based on well-operator experience and feedback. It supersedes the guidelines that were originally published in 1995 and then revised and published as Issue 1 in July 2001, with updates in July 2005 as Issue 2 and in March 2009 as Issue 3.

12

Interpretation

In these guidelines:

- reference to any legislation or publications includes a reference to that legislation, publication as may be amended, extended or re-enacted from time to time;
- reference to the singular shall include the plural and vice versa;
- reference to “include” means “including but not limited to”;
- the headings are used for convenience only; and
- regard has only been made to the jurisdictions within the UK.

Glossary

distinct permeable zone: A group of permeable zones that were **originally** within the same pressure regime, and where uncontrolled flow between subzones can be shown to be acceptable. For example where:

1. It will not create a change in pressure control requirements; **and**
2. It will not have an adverse effect on reservoir management; **and**
3. It will not result in "contamination" of the fluids in one of the subzones i.e. freshwater.

good cement: Cement that has been verified as to position, quantity and quality as stated in Section 6 of these guidelines.

highest point of potential inflow: The top of a permeable zone or top perforation, whichever is shallower.

overpressured zones: Permeable zones where the pressure is in excess of the regional hydrostatic pressure gradient i.e. 0.45 psi/ft for the North Sea.

permanent abandonment: The action taken to ensure the permanent isolation from surface and from lower pressured zones, of exposed permeable zones, fluids and pressures in any well that will not be re-entered.

permanent barrier: A verified barrier that will maintain a permanent seal. A permanent barrier must extend across the full cross section of the well and include all annuli. When considering isolation from surface, the first barrier above the point of potential influx is referred to as the **first barrier**; the next barrier above the point of potential influx is referred to as the **second barrier**.

permeable zone: Any zone in the well where there is the possibility of fluid movement on application of a pressure differential.

A permeable zone is considered **hydrocarbon-bearing** if moveable hydrocarbons are present or likely to be present in the future.

potential internal pressure: The maximum anticipated pressure that may develop below barriers in the wellbore following abandonment or suspension. This may include the possible effects of secondary and tertiary recovery techniques or the recovery of the reservoir to its original pressure.

temporary abandonment (suspension): Action taken prior to leaving the well to ensure adequate isolation of permeable zones, fluids and pressures in any well that will be re-entered or abandoned at a later date.

temporary barrier: A verified barrier that is designed to maintain a seal over a finite period of time for the purpose of **suspension**. A temporary barrier is not required to extend across the full cross section of the well and include all annuli

well: A well includes the original wellbore, any sidetrack from it and any hole section as defined by Regulation 2, DCR.

List of abbreviations

ALARP	as low as reasonably practicable
API RP	American Petroleum Institute Recommended Practice
BOP	blowout preventer
CDA	Common Data Access Limited
DCR	The Offshore Installations and Wells (Design & Construction, etc) Regulations 1996 (SI 1996/913)
DECC	Department of Energy and Climate Change (Previously BERR, DTI and DoE)
E&A	exploration and appraisal
EA	Environment Agency
ECD	equivalent circulating density
ESP	electrical submersible pump
GOR	gas oil ratio
HPHT	high pressure high temperature
ID	inside diameter
JNCC	Joint Nature Conservation Committee
MCAA	Marine and Coastal Access Act
MD	measured depth
MoD	Ministry of Defence
NORSOK	Norwegian Petroleum Industry Standards
OD	outside diameter
OPEP	Oil Pollution Emergency Plan
PON	Petroleum Operations Notice (DECC)
POOH	pull out of hole
RSA	Radioactive Substances Act
SEPA	Scottish Environment Protection Agency
SS	Subsea
TOC	top of cement
TTOC	theoretical top of cement (calculated from job records)
UKCS	United Kingdom Continental Shelf
UKOOA	UK Offshore Operators Association – now Oil & Gas UK
VRP	viscous reactive pill
WONS	Well Operations and Notification System

27

1 Objectives

28

To provide guidelines for the isolation of permeable zones when a well is abandoned, or suspended with a view to re-entry or later abandonment, in compliance with current UK legislation.

29

2 Scope

30

These guidelines apply to all exploration, appraisal and development wells that are being permanently abandoned or suspended.

31

It should be recognised that each well is unique and should be considered on an individual basis.

32

Although these guidelines were written by Oil & Gas UK which represents the UK offshore industry, the principles of the guidelines apply to onshore and offshore wells. Special regulatory conditions may apply to onshore wells.

3 Material requirements for permanent barriers

The main characteristics of abandonment materials should be as follows:

- very low permeability – to prevent flow of fluids through the barrier;
- long-term integrity – long-lasting isolation characteristics of the material, not deteriorating over time;
- resistance to downhole fluids and gases (e.g. CO₂, H₂S, hydrocarbons);
- mechanical properties suitable to accommodate loads and changes in the pressure and temperature regime, including changes in service over the entire life cycle of the well (e.g. due to conversion of producers to water injectors, steam injection, unconsolidated formations etc);
- non-shrinking and able to bond to the casing and formation:
 - to prevent flow between the barrier-plug and/or casing annulus; and
 - to prevent change of position of the barrier in the well.

The downhole placement technique of the plugging material is extremely important, especially in cases of through-tubing applications. Allowances will have to be made on the volumes to cater for contamination and shrinkage. A support (such as a bridge plug or a viscous pill) to prevent slumping of the cement slurry, is recommended for all cement plugs.

3.1 Plugging materials

Cement is currently used in wells as the prime material for abandonment purposes. This does not preclude the use of other materials. Alternative materials should, in principle, conform to the requirements above. The long-term integrity of materials should be documented. Once placed, there should be a means by which the barriers can be verified. Separate guidelines have been compiled for the qualification of barrier materials.

See *Guidelines on qualification of materials for the suspension and abandonment of wells* (Oil & Gas UK).

4 Number of permanent barriers

All distinct permeable zones penetrated by the well should be isolated, both from each other and from surface or seabed by a minimum of one permanent barrier.

Two permanent barriers from surface or seabed are required if a permeable zone is hydrocarbon-bearing or overpressured and water-bearing. The second permanent barrier is a backup to the first.

The two permanent barriers may be combined into a single large permanent barrier (combination permanent barrier), provided it is as effective and reliable as the two barriers and is an appropriate method to achieve the objectives that two barriers would otherwise have provided. The barrier should be verified in accordance with Section 6 of these guidelines. This decision should be fully risk assessed and documented.

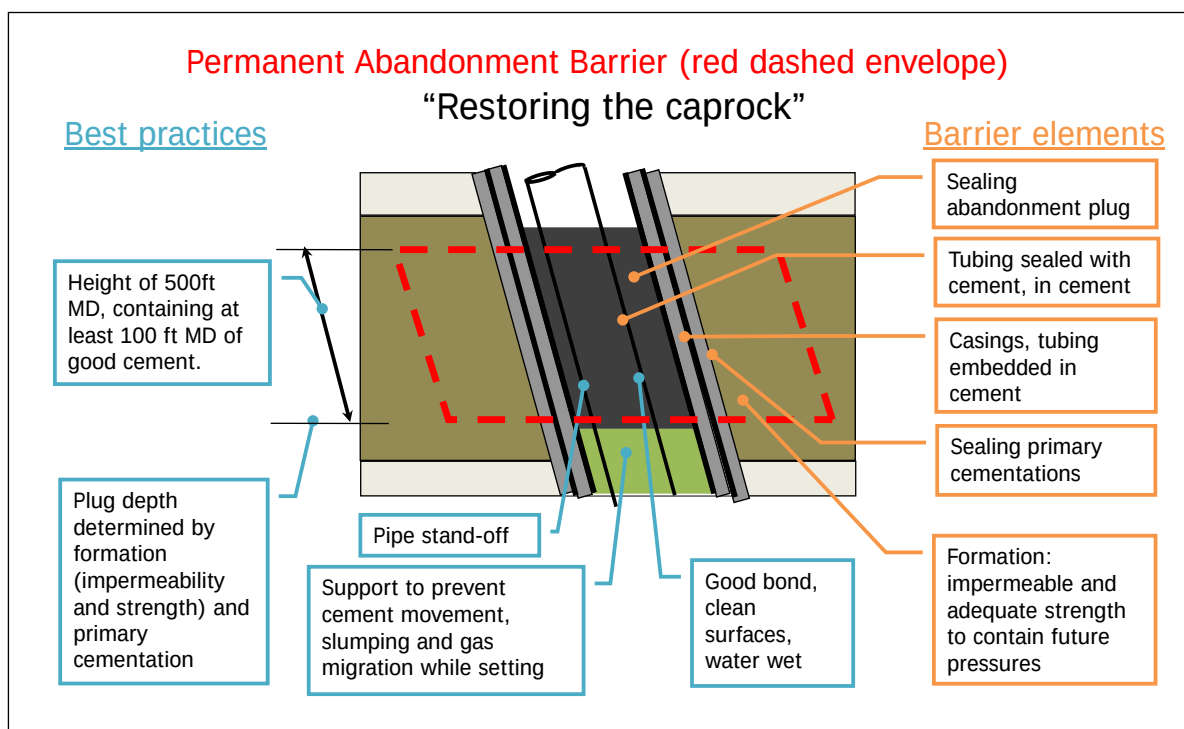


Figure 1. Schematic of a permanent barrier showing the barrier envelope (red dashed line) to restore the caprock, its barrier elements and recommended practices. Best practices are shown in blue boxes, barrier elements are shown in orange boxes.

5 Requirements of permanent barriers

A schematic of a permanent barrier is shown in Figure 1. This indicates the elements that constitute a permanent barrier, as well as recommended practices.

5.1 Position requirements

The following location of permanent barriers to achieve isolation from surface/seabed is recommended:

The **first barrier** should be set across or above the highest point of potential inflow (top permeable zone or top perforations, whichever is shallower), or as close as reasonably possible. It should be lapped by annular cement if set inside a liner or casing. In situations where the base of the barrier is significantly above the point of inflow (e.g. set on top of production packer), the formation fracture pressure at the **base** of the barrier should be in excess of the potential internal pressure. Such exposure may arise from a leak into the casing at the permeable zone.

The **second barrier**, when required, should be set with the following considerations:

- backup to the first barrier: the same considerations apply with respect to the second barrier being positioned such that the formation fracture pressure at the base of the second barrier is in excess of the potential internal pressure; and
- relative position of cement in the annulus and shallow permeable zones.

Note that the second barrier of one permeable zone can be the first barrier for another, shallower positioned, permeable zone (Figure 2).

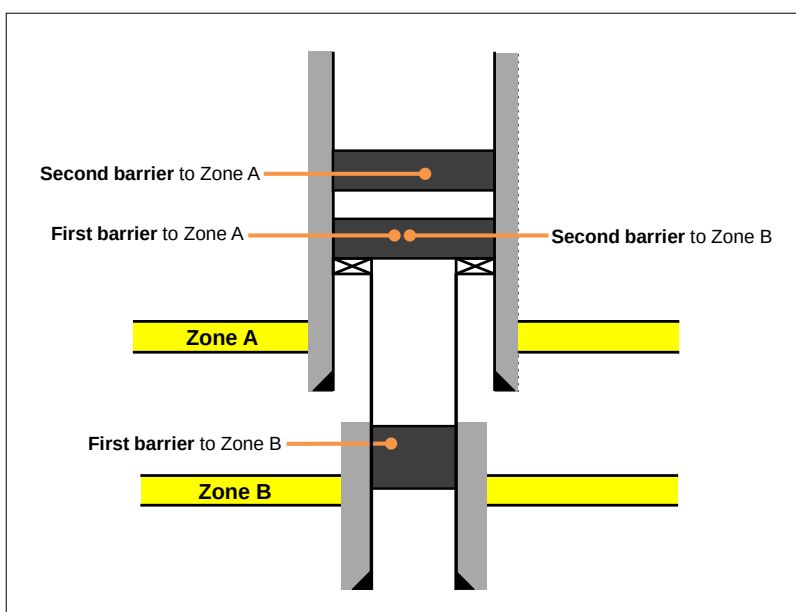


Figure 2. General requirements for well abandonment

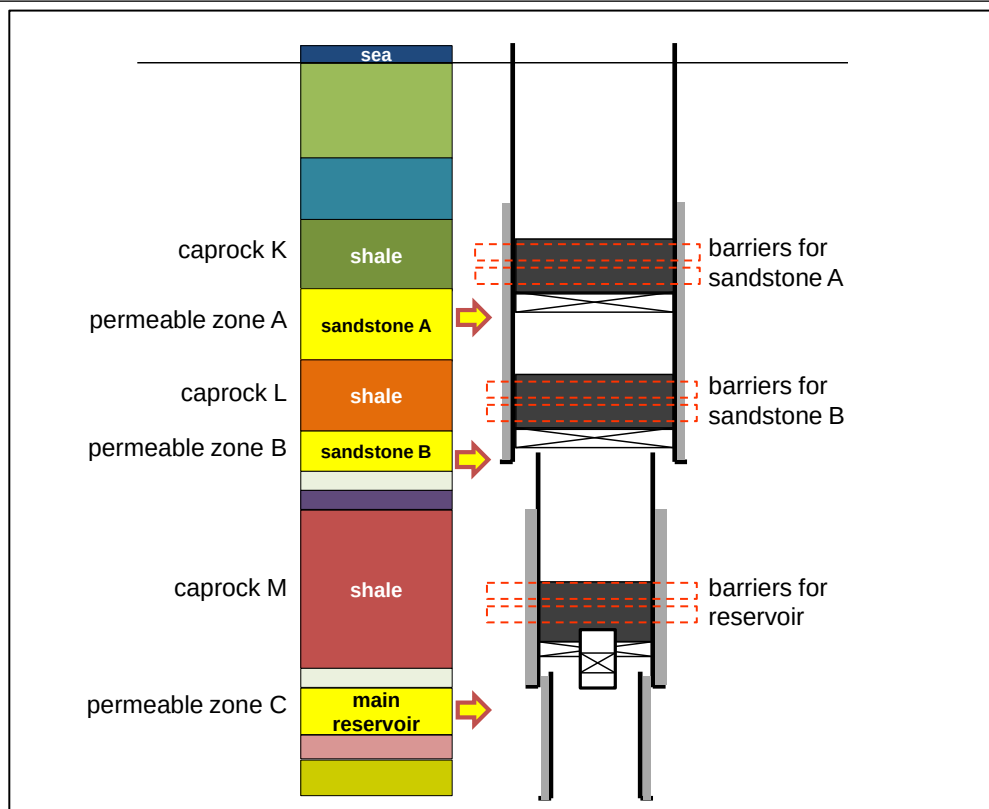


Figure 3. Example of the position of permanent barriers as determined by the actual geological setting, i.e. relative to the formations identified as permeable zone or caprock. In this illustration the main reservoir and sandstones A and B are considered hydrocarbon-bearing and/or overpressured, hence require two barriers opposite a competent caprock.

Note 1: In this example two barriers are shown per permeable zone. This will be the case if barriers cannot be shared, i.e. caprock L is not capable of containing the maximum anticipated pressure from the main reservoir or caprock K is not capable to contain the pressure of sandstone B.

Note 2: In this example the barriers are placed on a packer or bridge plug as a firm support to prevent slumping of the cement slurry down the well or gas migrating upwards as the cement is thickening.

5.2 Length requirements

A cement column of at least 100 ft measured depth (MD) of good cement to constitute a permanent barrier is considered good industry practice. Generally, where possible, 500 ft MD barriers are set. The top of the first barrier should extend at least 100 ft MD above the highest point of potential inflow.

Where distinct permeable zones are less than 100 ft MD apart, then a 100 ft MD column of good cement below the base of the upper zone, where practical, should suffice.

Where casing is part of a permanent barrier, at least 100 ft MD of good cement in the annulus is a requirement in order to form a permanent barrier. The internal cement plug must be adjacent to the annular good cement over a cumulative distance of at least 100 ft MD of overlap. This overlap section of the plugs must be of good quality cement on both sides.

When a combination permanent barrier is chosen to replace two barriers:

- A cement column of at least 200 ft MD of good cement is considered to constitute such a permanent barrier. In this case generally an 800 ft MD barrier is set.
- The top of this barrier should provide at least 200 ft MD of good cement above the highest point of potential inflow.
- The internal cement plug must be adjacent to the annular good cement over a cumulative distance of 200 ft MD of overlap. This overlap section of the plugs must be of good quality cement on both sides.

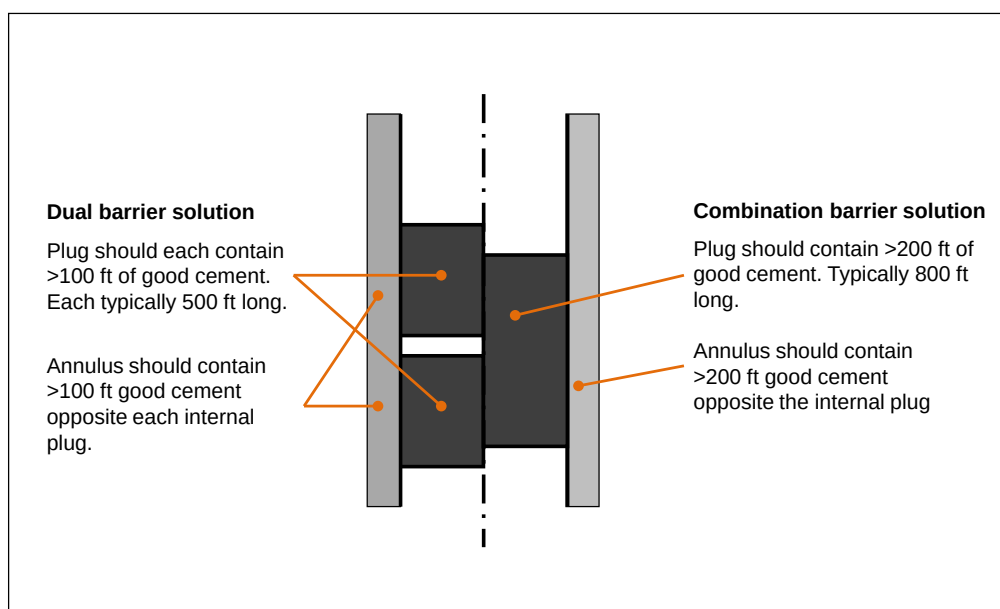


Figure 4. Comparison of length for dual and combination barriers.

5.3 Openhole requirements

The requirements stated in Sections 4 and 5 apply to any permeable zone in open hole. In addition, a permanent barrier is required in cased hole or extending at least 100 ft of good cement into cased hole. The barrier across cased hole is to fully isolate the open hole. See examples in Figures 5 and 6.

Permeable zones that belong to different pressure regimes should be separated by one permanent barrier.

Where the pressure from a permeable zone is anticipated to exceed the formation fracture pressure anywhere in the open hole, it should be isolated by two permanent barriers or a combination barrier in openhole. See example in Figure 7.

Note: In addition to the required barriers, additional further cement may be placed in openhole, but these would normally not be subject to verification.

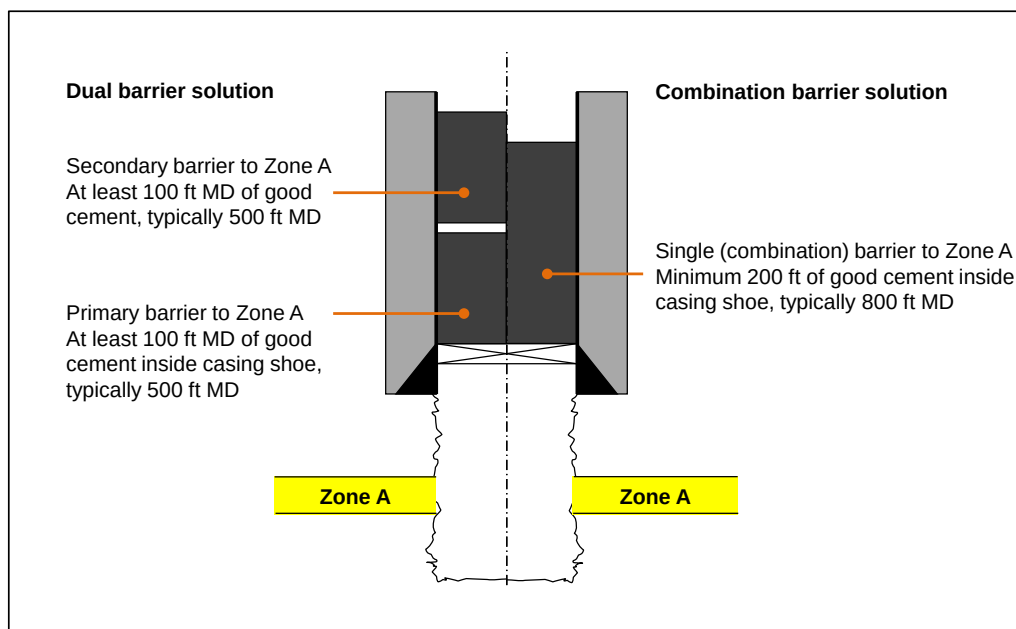


Figure 5. Example of openhole permanent barriers if potential internal pressure does not exceed the casing shoe fracture pressure.

65

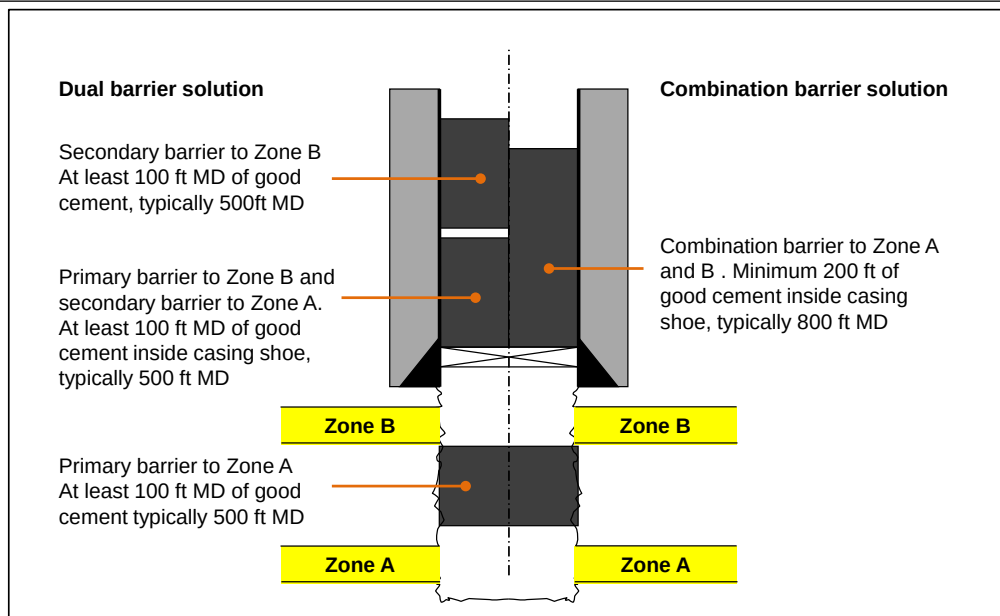


Figure 6. Example of openhole permanent barriers if zone A requires isolating from zone B, but the potential internal pressure from zone A does not exceed the casing shoe fracture pressure (one permanent barrier is adequate).

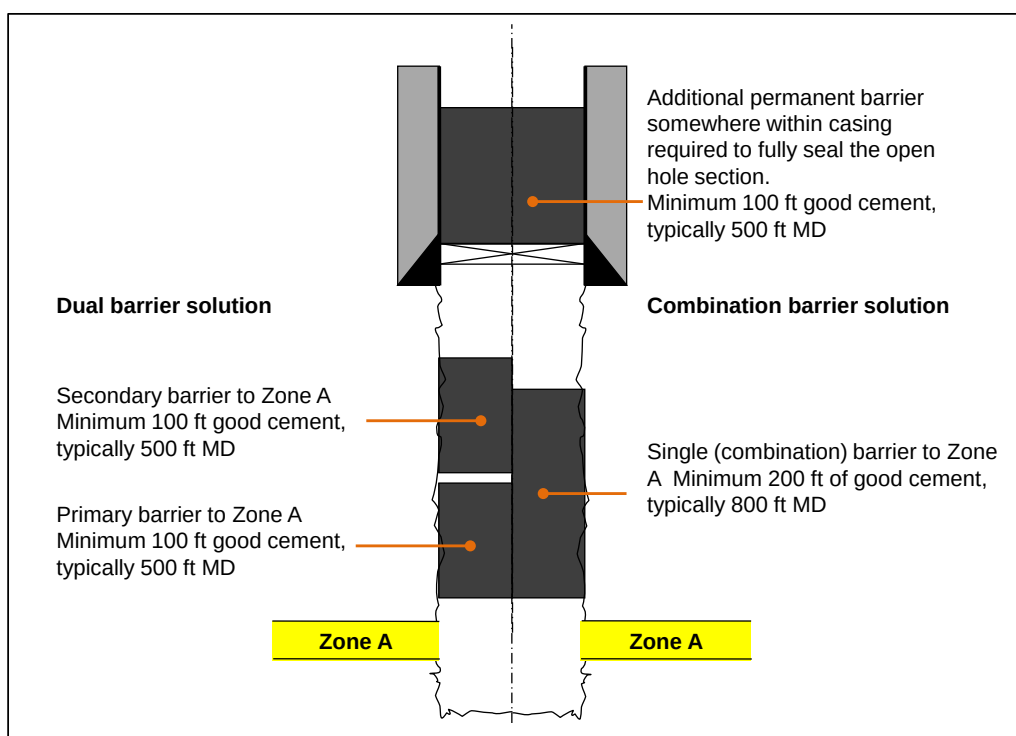


Figure 7. Example of openhole permanent barriers if potential internal pressure exceeds the casing shoe fracture pressure (two permanent barriers are required).

66

5.4 Cased hole requirements

Cemented casing is not considered to constitute a permanent barrier to flow (laterally) into or out of the wellbore. This is because of the possible migration of fluids as a result of potential casing leak(s) in conjunction with an incomplete localised cement sheath (refer to Figure 8).

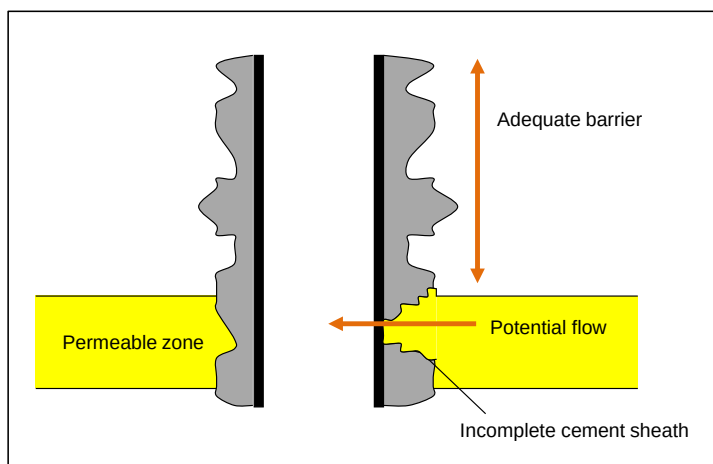


Figure 8. Casing alone is not a permanent barrier to lateral flow.

However, cemented casing is a sufficient barrier to vertical flow in the annulus as long as there is sufficient confidence in the quality of the cement in the annulus.

The existing top of cement (TOC) in the annulus can be established by measurement with tools such as sonic cement bond logs, or by record of the parameters during cement placement.

If the estimate of TOC is based on differential pressure or monitored volumes measured during the original cement job, then a longer cement column is required to allow for uncertainty. In this case, a column of 1,000 ft MD of annular cement above the base of the primary permanent barrier should be allowed to ensure annular cementation. This 1,000 ft column is considered adequate for two barriers or a combination barrier. This may be reduced or increased on a well-by-well basis depending on the confidence level of the TOC (refer to Figure 9).

Any record of problems during the original cementation or well life cycle may dictate a need for remedial cementation. Where there is insufficient cement behind the casing to provide a permanent barrier, remedial cementing may be necessary. This may be achieved by: retrieving the casing; placing cement in the annulus by a suitable means such as perforating or circulating; or by section milling. See relevant entries in Appendix B for potential issues and possible mitigations.

Formations that belong to different pressure regimes should be separated by one permanent barrier internally, i.e. a cement plug inside the casing overlapping good annular cement. This should be attempted whether the casing is perforated or not.

It is not always necessary to place cement across perforations.

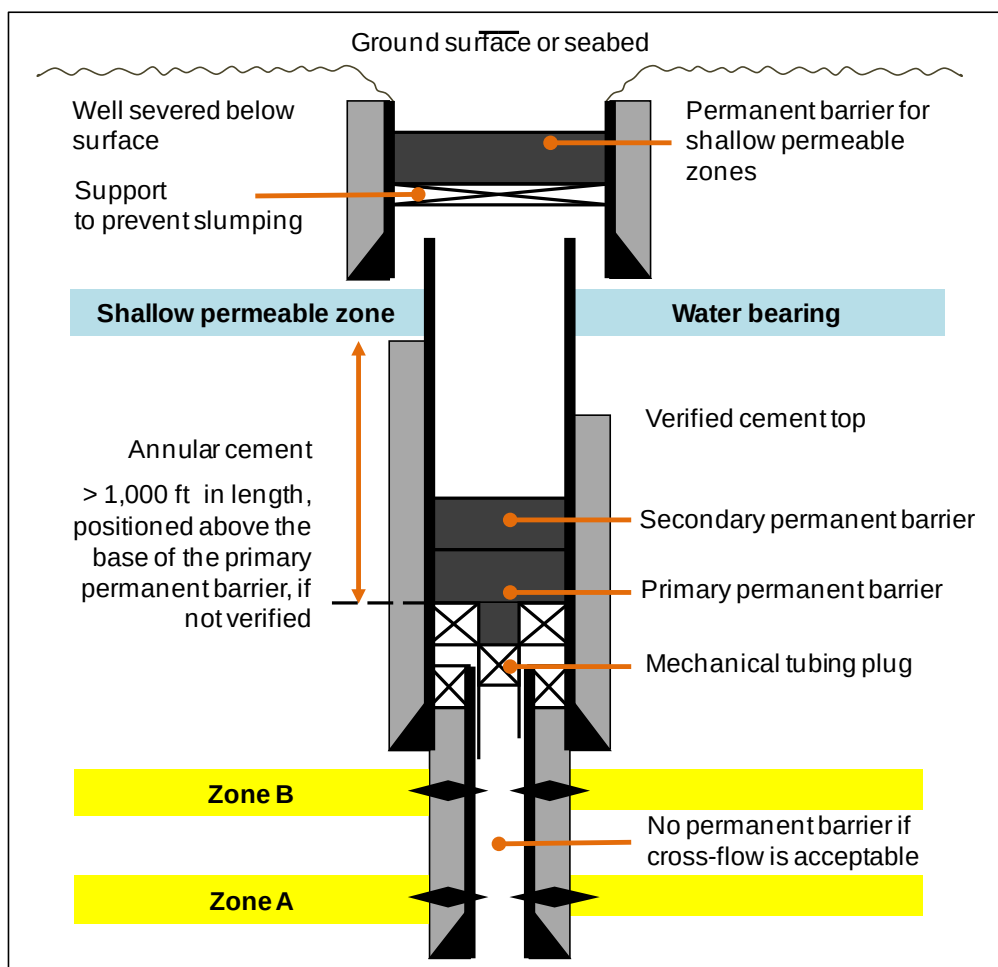


Figure 9. Example of a cased hole abandonment schematic

6 Verification of a permanent barrier

Any permanent barrier should be verified to ensure the barrier is placed at the required depth and will have the required sealing capability.

Verification requirements are dependent upon the individual well and job design.

6.1 Cement barrier

The cement barrier should be verified by the following:

- The barrier installation should be documented, including records from the cement operation (volumes pumped, returns during cementing, water-wetting pills, etc).
- The strength development of the cement slurry should be confirmed. This is primarily done using pre-job testing with representative rig component samples cured at anticipated downhole temperature and pressure. Surface samples taken during the job may also be used as an indicator but should be treated with caution since the inability to replicate downhole pressure and temperature will have a significant impact.
- The position of a barrier should be verified by tagging, or by measurement to confirm the depth of the firm cement plug.
- The cement plug should be verified:
 - entirely in open hole, a barrier should be verified by a weight test.
 - on drillpipe this is typically 10 to 15 klbs.
 - on wireline, coiled tubing or stinger this weight will be limited by tools and geometry.
 - in cased hole, a barrier should be verified with a documented pressure or inflow test.
- A pressure test should:
 - be a minimum of 500 psi above the injection pressure below the barrier (e.g. into perforations or open formation below the casing shoe);
 - but not exceed the casing strength minus wear allowance or damage the primary casing cement, whichever is lower.
- An inflow test should be to at least the maximum pressure differential to be experienced by the barrier after abandonment. For guidelines on inflow testing, please refer to the Oil & Gas UK *Well Integrity Guidelines*.

As an exception, if, in cased hole, a tagged and pressure tested mechanical plug or previous cement plug is used as a foundation for the barrier, then:

- pressure-testing of this barrier may not be meaningful; and
- tagging this barrier, to verify the position, may not be meaningful either. (Omission of the tag on the barrier set on a mechanical plug should be replaced as a minimum with a tag on the mechanical plug after pressure testing).

However any decision not to tag should be risk assessed, considering well conditions, plug length/volume, track record, job performance, and other verification methods used. If circumstances exist that increase the risk (e.g. shortened cement plug, high pressure and temperature, well integrity concerns, method of placement) then tagging would be advised.

6.2 Casing cement

The position (TOC) of the annular cement should be verified by:

- logs (e.g. cement bond, temperature, sonic); or
- estimation on the basis of records from the cement operation (e.g. volumes pumped, returns during cementing, differential pressure etc).

The sealing capability of the casing cement should be assessed with supporting evidence which may include:

- logs;
- absence of sustained casing pressure during the life cycle of the well;
- the leakoff test when the casing shoe was drilled out;
- absence of anomalies during the original cementing operations (e.g. if losses occurred during a casing or a liner cement operation consideration should be given to running a sonic cement bond log); and
- centralisation, washouts, lead/tail slurry, annulus pressures, field experience, excess, should be considered.

If the theoretical top of cement (TTOC) is used as the confirmation of placement then the assumption is that sealing has occurred somewhere in the annulus cement.

In the absence of information or inconclusive evidence then a log or remediation should be considered.

6.3 Guidance on verification

The following tables are aimed to help clarify the intent of the verification requirements; as such they do not cover all scenarios.

Permanent barrier, primary				
Barrier type	Verification			
	Well bore / tubing		Annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	Pressure test	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Through-tubing on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately (see Section 7.10)	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Cased hole	Tag	Pressure test	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Cased hole on a mechanical barrier	Tag cement, or measure to volume confirm depth of firm barrier, subject to risk assessment	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Open hole	Tagging	N/A	N/A	N/A

92

Permanent barrier, secondary				
Barrier type	Verification			
	Well bore / tubing		Annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	As above. pressure test may be omitted if there is insufficient space to verify independently on volumes	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Through-tubing on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test cement in tubing and annulus separately (see Section 7.10)	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Cased hole	Tag	As above. pressure test may be omitted if there is insufficient space to verify independently on volumes	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	FIT or liner lap Pressure test or inflow test
Cased hole on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	As above. pressure test may be omitted if there is insufficient space to verify independently on volumes	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Open hole	Tagging	N/A	N/A	N/A

93

Permanent combination barrier				
Barrier type	Verification			
	Well bore / tubing		Annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	Pressure test	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Through-tubing on a mechanical barrier	Tag	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately (see Section 7.10)	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Cased hole	Tag	Pressure test	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Cased hole on a mechanical barrier	Tag cement	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	FIT or liner lap Pressure test or inflow test

7 Special considerations for abandonment

7.1 Well design

Regulation 13, DCR, imposes a general duty on well-operators:

...ensure that a well is so designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned that:

a. so far as is reasonably practicable, there can be no unplanned escape of fluids from the well; ...

Regulation 15, DCR, provides that the well-operator shall:

...ensure that a well is so designed and constructed that, so far as is reasonably practicable:

a. it can be suspended or abandoned in a safe manner; and

b. after its suspension or abandonment there can be no unplanned escape from it or from the reservoir to which it led.

It is recognised that the key to a simple suspension or abandonment lies with the soundness of the initial well design and effectiveness of the primary casing cementations.

Well-operators must consider the abandonment of a well as part of the design and modification process to fully evaluate the potential future effects of design decisions.

7.2 Partial abandonment for sidetracking or for other reasons

Well-operators must comply with Regulations 13 and 15, DCR, when partially plugging for sidetracking or for other reasons.

The plug to abandon the original wellbore should be designed, placed and verified as a permanent barrier for subsequent well abandonment. It is recognised, depending on well design, that a temporary barrier may be adequate provided this does not compromise the placement of permanent barriers for the final abandonment of the well.

If a permanent barrier is being used as the kick-off plug, then the remaining barrier, after kick-off, should conform to the minimum requirements of a permanent barrier.

104 Isolation of the abandoned hole section should consider the following:

105 **Between zones:** It is recognised that isolation between zones is not always
106 achievable where fishing operations are unsuccessful.

106 **From new hole:** The requirements for permanent abandonment of the original
wellbore have to be considered prior to the sidetrack, since this may be difficult to
achieve in the future. Isolation needs to be considered to ensure adequate well
control in subsequent drilling operations. For deep sidetracks in the reservoir,
isolation from the subsequent casing annulus, across the sidetrack point, may be
required for reservoir management during production life.

107 **From surface/seabed:** The final permanent abandonment of the well should
comply with the requirements of these guidelines with respect to **all wellbores**.

108 7.3 Irretrievable radioactive sources

109 Advice on current reporting requirements should be sought from the
Environmental Agency or Scottish Environment Protection Agency, as
appropriate. Current advice from SEPA can be found in Appendix E.

110 7.4 High angle and horizontal wells (wells > 70°)

111 In principle, the abandonment of a horizontal well is no different from a standard
well. The only difference is in the means of ensuring a satisfactory isolation, which
is in general more difficult to achieve.

112 It is likely that if uncemented casing is run as the production liner, the wellbore will
contain only one distinct permeable zone for reservoir management purposes. If,
however, more than one distinct permeable zone is present, the completion
design should consider the future abandonment, e.g. annular isolation between
zones. Therefore, in general, the abandonment requirements should be
established at the planning/completion design stages of the well and the zones
may then be isolated as per the guidelines with minimum effort.

113 In the case of one distinct permeable zone, a mechanical device (e.g. a bridge
plug) set just above the start of the reservoir with a cement plug on top would be
sufficient as a first permanent barrier, as long as it has full lateral annular
coverage (refer to Figure 8).

114 If more than one distinct permeable zone is present, annular and internal isolation
should be attempted between zones. It is recognised there can be significant
difficulties in achieving annular isolation through cementing in an uncemented
production liner in the horizontal or near horizontal section.

115 The general recommendation of the guidelines is to achieve barriers with over
100 ft of good cement; this is an along hole measurement. In designing the
abandonment of a high angle well, the final vertical thickness of the barrier should
be considered.

116

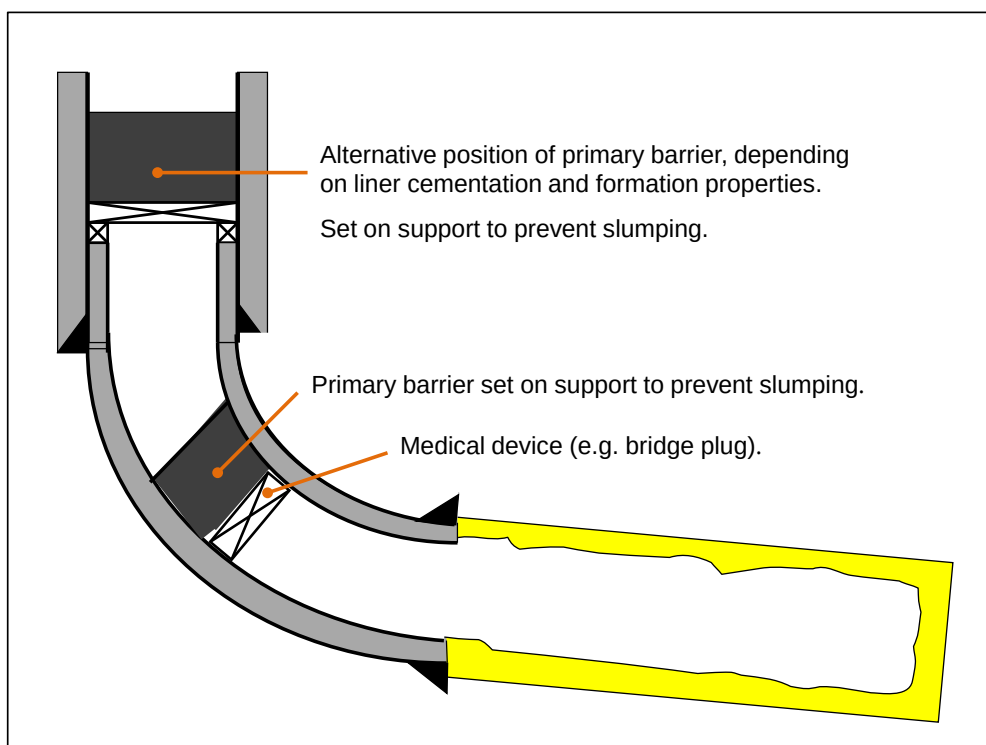


Figure 10. Example abandonment of the lower section of a high angle well

117

7.5 Multilateral wells

118

Considerations for multilateral wells may include:

- future abandonment in the well design, since in some cases it will be very difficult to regain access to the original wellbore;
- possibly different pressure regimes in the lateral branches of the well; and
- cementing off annuli above the laterals.

7.6 Liner laps

When a liner lap is part of a permanent barrier, at least 100 ft good cement should be assured in the liner lap.

It is common practice to set liner top packers immediately after the cement job. The liner lap and packer are normally tested together; therefore, it is not possible to know whether the cement in the liner lap, or the packer is holding the pressure. Although this is sufficient for the producing life of a well, a liner packer is not a permanent barrier.

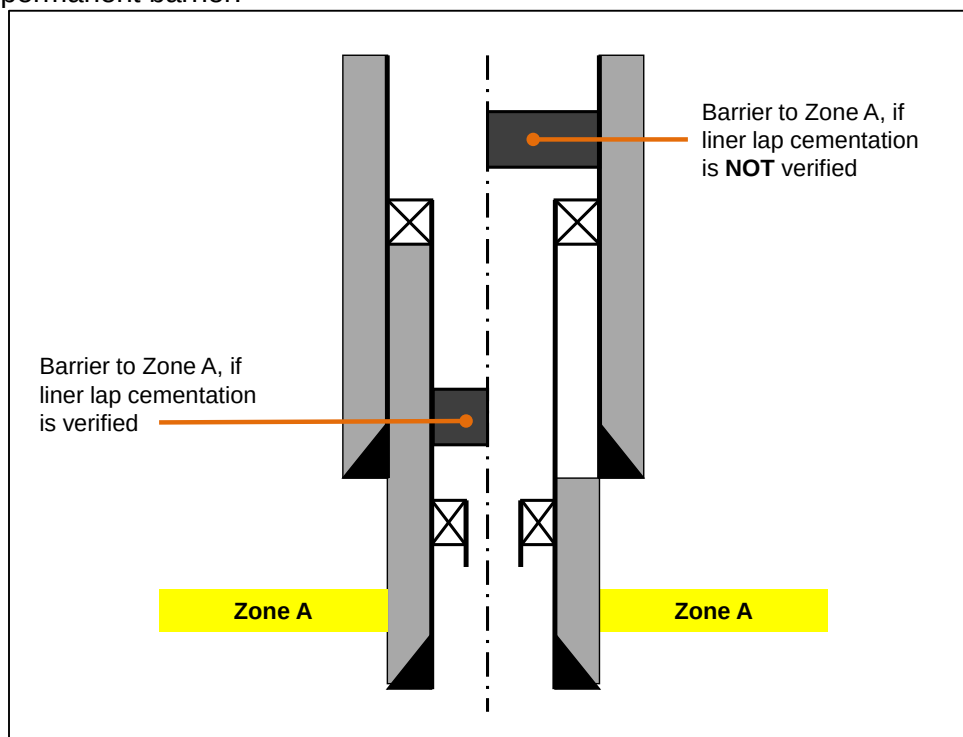


Figure 11. Liner lap cementation

7.7 Casing cuts

As with full casing strings, there should be at least 100 ft of good cement behind a cut casing if it is to be part of a permanent barrier.

7.8 Removal of downhole equipment

The removal of downhole equipment is not a requirement provided the isolations outlined in these guidelines are achieved. This will, for instance, be the case with through-tubing abandonments, where part of the completion and casing strings will be left downhole.

7.9 Control lines, ESP cables, gauge cables

Cables and control lines should not form part of permanent barriers, since they may be a potential leak path. This includes cables and lines associated with the completion or casing/liner.

7.10 Through-tubing abandonments

Allowances (e.g. additional plug length and a base for slurry) should be made for the possibility of cement slumping or fingering in the annulus. Allowances should also be made for high angles at the point of placement, eccentricity and small radial clearances. This might otherwise result in not having a full annular coverage of cement for that barrier.

When well completion tubulars are left in hole and permanent barriers are installed through and around the tubulars, reliable methods and procedures to install and verify position of the permanent barrier inside the tubulars and in the tubular annulus should be established.

There is not an accurate method of determining TOC in both tubing and annulus. For example, using wireline to tag plugs by itself may not be conclusive; cement deposits or other debris inside the completion may stop a drift. However, tagging combined with quality control of cement placement (e.g. measurements of volumes/losses, base for plug, cement density, strength development) and pressure testing both annulus and tubing, ideally separately, can be used to confirm the presence of a permanent barrier. No single method should be relied on exclusively.

For shallow-set production packers there may be inadequate formation strength at the packer setting depth for the potential internal pressure.

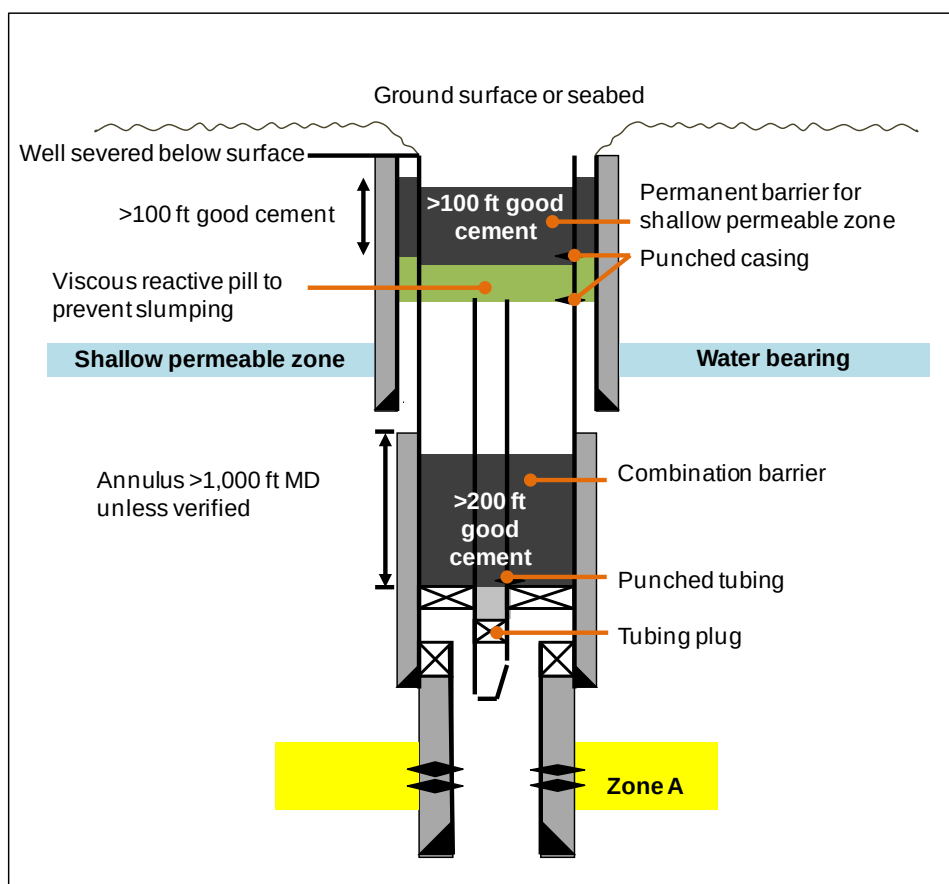


Figure 12. Example of through-tubing cased hole abandonment

7.11 HPHT wells

The placement and number of barriers (Sections 4 and 5) apply to the temporary abandonment or abandonment of HPHT wells. With the increased complexity and criticality of these wells, there should be special emphasis on recharging to high pressure, caprock depletion, thin pressure transition zone, liner deformation, temperature cycling, primary cement degradation due to high temperature, reservoir compaction and subsidence, etc.

7.12 Wells containing H₂S

The barriers placed in a well containing H₂S should be chosen and designed to withstand the corrosive environment it is intended to isolate.

7.13 Wells containing CO₂

This paragraph applies to naturally occurring CO₂. Sequestration of CO₂ is outwith the scope of these guidelines.

The barriers placed in a well with significant concentrations of CO₂ should be chosen and designed to withstand the potential effects of the gas on cement, steel components of the well and on subsurface formations.

CO₂ may degrade cement in the presence of water, in particular Portland cement, increasing its permeability. CO₂ will also accelerate corrosion of steel and can increase the permeability of subsurface formations, for example by hydration and fracturing of shales.

7.14 Gas wells and high GOR wells

Gas wells (or high GOR wells) have the added complication of potential gas migration through barriers. This can be the case for overpressured, hydrostatic or subhydrostatic reservoirs. It is advised to carefully select the type of barrier material and the placement technique to counteract this condition.

7.15 Sealing formations

Certain formations (e.g. certain shales or certain salts) are known to move as a result of stress differences. These formations are able to close an annulus space where cement is missing. Typically, such moving formation is a geological feature that is observed fieldwide and is not an isolated well related feature. The formation must be impermeable and have adequate strength; these properties must be lasting at the prevailing conditions.

If it can be demonstrated that the resulting seal of the formation against the casing is adequate to prevent flow of the present fluids at the anticipated future pressures, then such a seal is acceptable as a replacement for a good annulus cement bond.

148

The qualification of a formation seal in a particular well requires:

1. Proof that the formation has the required fracture strength to withstand the anticipated future pressures.
2. Verification that the length of the seal exceeds 100 ft (per barrier), whereby the bond log response must be equivalent to that of good cement, or better. Each well requires two independent logging tools (e.g. a sonic cement bond tool and a circumferential cement evaluation tool) to be run to confirm the bonding between the casing and the formation with no channels. Interpretation of the logging results should be performed by a qualified and trained cement evaluation log specialist and documented.
3. Validation that the bond log response can be interpreted as not leaking at the anticipated future pressures. This can be achieved by means of a pressure test between 100 ft spaced perforations.

149

The verification and validation should be documented.

150

7.16 Reservoir compaction and subsidence

151

Some geological environments are prone to formation compaction and/or subsidence of the seabed. The related geological movements should be considered when selecting the position and properties of permanent barriers.

152

7.17 Annular fluids

153

Fluids that are positioned above the uppermost barrier in a well and cannot be legally discharged should be removed with best efforts. This is the part of the well which will be exposed to the environment after wellhead removal.

154

Well-operators should review the *Guidance Notes for Petroleum Operations Notice No 5 – Application to abandon or temporarily abandon a well*, within the DECC Well Operations and Notification System (WONS).

155

7.18 Shallow permeable zones

156

The decision to isolate shallow permeable zones in a well will depend on local conditions, on a well-by-well basis (e.g. whether the shallow permeable zone is vertically connected to seabed).

157

7.19 Hydrocarbons of biogenic nature

158

Hydrocarbons of biogenic nature originate from shallow formations and can occur anywhere. If observed around wells, these hydrocarbons do not necessarily indicate a failure of a permanent barrier. Biogenic hydrocarbons can be identified by means of composition analysis (fingerprinting).

159

7.20 Removal of subsea equipment

160

Redundant subsea equipment must not present a hazard to other users of the sea.

161 It is seen as good practice to retrieve all casing strings to a minimum of 10 ft
162 below seabed. This requirement mainly exists to accommodate fishing activities in
the area after the well has been abandoned.

162 The recommended minimum depth of 10 ft below seabed has to be reviewed on a
well-by-well basis, taking into account the prevailing local conditions with respect
to sand waves and scouring.

163 All subsea equipment and debris should be retrieved where practical and a
seabed clearance certificate issued. The certificate should clearly identify any
objects / debris left at the site. The minimum recommended radius of search is 70
metres from the well.

164 In certain cases, the retrieving depth of casing strings should be reviewed in light
of large (e.g. concrete) structures permanently remaining at seabed in the area
around the well(s). In this case no casing strings should extend above the
remaining structure.

165 For platform or template abandonments the requirements for removal may differ
and should be specified on a well-by-well basis and in discussion with DECC.

166 **7.21 Removal of surface equipment**

167 On land wells, the required condition of the wellsite will be agreed with the
relevant local authorities.

8 Required standards for temporary abandonment (suspension)

8.1 Types of suspension

Wells can be suspended for various reasons and can be classified as follows:

- **Short-term suspension** – for removal of BOPs, batch drilling of wells (top hole only, or partially drilled wells down to any depth), to accommodate pipe lay activities in the field, etc.
- **Long-term suspension** (temporary abandonment) – E&A wells that are considered for field development.

Long-term suspension (temporary abandonment) of E&A wells should be the exception rather than rule.

A proposed suspension period of over 18 months should be in compliance with DECC requirements (PON 5 – *Application to abandon or temporarily abandon a well*) and be specifically justified by performing an assessment to demonstrate that the barriers will maintain their integrity for at least the proposed period of suspension.

8.2 Principles of temporary abandonment

8.2.1 Number and type of barriers

In common with the guidelines for permanent abandonment, two temporary barriers are required for isolation of hydrocarbon-bearing or overpressured permeable zones from the surface / seabed. A single barrier is acceptable for normally pressured water-bearing zones.

In general, a temporary barrier should consist of a pressure-tested mechanical device or good cement (see Section 6). Kill weight fluid can constitute a temporary barrier in certain circumstances. This can include occasions when a full column of fluid can be monitored and maintained. This topic is covered in the Oil & Gas UK *Well Integrity Guidelines*.

Even though temporary barriers can be used for temporary abandonment purposes, consideration should be given to follow the principles of permanent abandonment.

8.2.2 Well re-entry considerations

Since a suspended well will, by definition, be capable of being re-entered, the temporary abandonment must be carried out so that the well can be re-entered safely, and then secured using pressure control equipment without compromising the barriers in place. Placement of the second barrier, if required, should consider the consequences of potential failure of the first (deeper) barrier. Furthermore, consideration should be given to set the shallowest barrier sufficiently deep, in order to facilitate re-entry of the well. Furthermore, all fluids present in the wellbore at the time of temporary abandonment above the uppermost barrier should be considered with permanent abandonment in mind (refer to Section 7.17).

8.3 Acceptable barriers

The well-operator should assess and define the type and suitability of any mechanical, fluid or cement barriers, including their verification. Due consideration should be given to the anticipated period of the temporary abandonment, the subsurface environment and the type of well.

Pressure tested casing is an acceptable temporary barrier to flow into the wellbore.

A cemented shoe track is not a barrier unless it is specifically designed to be one and proved by adequate testing. Shoe tracks should be treated as open-ended casing unless they are designed and can be tested to demonstrate that they are an adequate barrier to flow from the well. This topic is covered in the Oil & Gas UK *Well Integrity Guidelines*.

Shoe track valves are an aid for cementing and do not qualify as a temporary or permanent barrier. The shoe track is part of the barrier envelope even when below the source of inflow. Similar considerations may apply for the liner lap, see Section 7.6.

187 A cap used in mudline suspension systems may be considered a temporary
188 barrier if it has been pressure tested in the direction of flow and can be removed
under protection of pressure control equipment.

188 **8.4 Verification of temporary barriers**

189 Any first barrier should be pressure and/or inflow tested. Any barrier that may
subsequently be used as a permanent barrier, (i.e. the well may not be re-
entered), should meet the requirements of the abandonment guidelines in Section
6.

190 **8.5 Trawlability of suspended wells**

191 Well-operators have a duty of care to other users of the sea.

192 Well-operators must ensure that the presence of suspended wells is notified to
the necessary agencies (Section 9). This is important, since suspended wells do
not normally have exclusion zones (500 m).

193 Depending on the specific conditions (well status, subsurface conditions, marine
activity levels, etc), well-operators should consider wellhead protection, which will
provide protection to both wellheads and trawlers.

194 **8.6 Inspection scheme for suspended wells**

195 Well-operators are required by Regulation 18, DCR to include all wells in their
arrangements in writing for well examination. Regulation 18, DCR applies
throughout the life cycle of a well until it is permanently abandoned and includes
any suspended well. Well-operators should consider physical inspection schemes
for long-term suspended wells. The frequency of inspection, which should be
justifiable, should be set by the well-operator and take account of well status,
subsurface conditions and marine activity levels.

9 Statutory notifications, approvals and record keeping

9.1 Notifications of proposed suspension or abandonment and permit applications

9.1.1 HSE requirements

The Health and Safety Executive, Offshore Safety Division, must be notified of the proposed programme as required by Regulation 17 of the Offshore Installations (Safety Case) Regulations, 2005 (or equivalent regulation on land), if it has not already been submitted in the original drilling notification. Notification may be made by e-mail to Well.Notifications@hse.gsi.gov.uk

The programme and execution of the suspension or the abandonment should be reviewed as part of the well examination process.

Abandonment and suspension operations should be included in weekly reports on well activity submitted to the Health and Safety Executive, Offshore Safety Division, as required by Regulation 19, DCR.

9.1.2 DECC requirements

The following link provides useful references on legislation, notification and guidance for well abandonment and suspension.

http://www.ukooaenvironmentallegislation.co.uk/Contents/Topic_Files/Offshore/Well_abandonment.htm

Consent for suspension or abandonment of a well must first be sought from DECC through the Well Operations and Notification System (WONS) by completing a PON5. Refer to the website of DECC for guidance.

OPEP: An Oil Pollution Emergency Plan (OPEP) must be in place for suspension and abandonment activities. The OPEP requires consideration of relief well drilling. Guidance notes on OPEPs are available from the DECC website: http://og.decc.gov.uk/en/olgs/cms/environment/leg_guidance/epc_offshore/epc%20offshore.aspx and http://og.decc.gov.uk/en/olgs/cms/environment/leg_guidance/oprc/oprc.aspx

Chemical Permit (PON15): If chemicals are planned to be used and/or discharged, or there is a contingency for their use and/or discharge, then a Chemical Permit must be submitted to DECC. If chemicals or oil-based mud currently in the well could be discharged when the wellhead is severed, this should be included in the narrative of the Chemical Permit.

Oil Discharge Permit: If the proposal could result in the discharge of any reservoir hydrocarbons, a separate application should be made to obtain an Oil Discharge Permit / Oil Pollution Prevention & Control (OPPC) Permit. Refer to: https://www.og.decc.gov.uk/environment/oppc_guide.pdf

Marine Licence: The removal of elements of the well from the seabed and the use of explosives for severance requires a Marine Licence under the Marine and Coastal Access Act (MCAA) 2009. Full details can be obtained from the Environmental Management Team at DECC (emt@decc.gsi.gov.uk). See also <http://www.legislation.gov.uk/ukpga/2009/23/notes/>

209

Disturbance Licence: The use of explosives for severance also needs to be assessed to determine the requirement of a disturbance licence. This assessment should be included in the impact assessment relating to the Marine Licence. Guidance on disturbance assessments and mitigation measures relating to the use of explosives can be found on the JNCC website at: <http://www.jncc.gov.uk/>

210

9.2 Notifications on completion of operations

211

The following agencies and authorities should be informed of the completion of suspension or abandonment of a well:

- DECC – within one working day of completion of operations by WONS notification. See also Section 9.3.
- Any other notifiable body as per the licence for the area (e.g. MoD, JNCC, and local authority etc) within 30 days.
- The HSE do not require additional notification other than the weekly reports.
- DEAL – notification of change of well status. (www.ukdeal.co.uk)

212

Additionally, for subsea wells, the following should be notified immediately on completion of abandonment or suspension operations:

- The United Kingdom Hydrographic Office (e-mail oilandgas@ukho.gov.uk)
- Oil & Gas UK (e-mail wells@oilandgasuk.co.uk)
- Kingfisher Information Service, Sea Fish Industry Authority (e-mail kingfisher@seafish.co.uk)

213

These notifications should contain the following information:

- The well number, as per PON12;
- Geographical coordinates, preferably in latitude and longitude. Please state horizontal datum (e.g. ED50);
- Water depth including reference datum (e.g. mean sea level, lowest astronomical tide); and
- The maximum height of each well above seabed, including any protection structure.

214

Details of any buoy marking of the well locations.

215

The notification to Kingfisher should include a request that this information is notified in the next four issues of the Kingfisher fortnightly bulletin.

216

Changes in well status notified to DECC through WONS will automatically update the well status in DEAL (www.ukdeal.co.uk).

9.3 Record keeping

Records of suspended wells should be carefully retained in order to ease the re-entry, or final abandonment of a well. Records should contain at least the following detailed information:

- Status diagrams including the relevant depths of casing shoes, formation tops and completion particulars. The top of cement in each annulus and the means by which it was verified (e.g. sonic cement bond log, calculation, pressure).
- The position of each barrier, placement method and the means by which the barrier was verified, (e.g. pressure or inflow test, tagging etc).
- DECC request status diagrams and, if appropriate, seabed clearance certificates. These should be uploaded to the appropriate notification in WONS as soon as possible on completion of operations.
- Original cementing records should be retained.
- Original chemical use records should be retained.
- Formation pressures and formation fracture pressures should be noted, as should any permeable and especially overpressured or hydrocarbon-bearing zones.
- Particular attention should be given to detailing the wellhead arrangement and any corrosion caps fitted.
- Description of fluids left in all annuli and inside casings or tubulars.

Records of abandoned wells should contain, in addition to the above, information related to the removal of wellhead and casing strings.

All records of abandoned wells are Licence Data and must be retained in perpetuity as determined by the Licence Model Clauses and PON 9.

CDA members should ensure that details of abandonment or/and suspension operations and final well status diagram are uploaded to CDA (www.cdal.com) for future reference.

222

Appendix A Basic well data required for well abandonment

223

The following information should be gathered as a basis of the well barrier design and abandonment programme:

224

1. Well configuration (original, intermediate and present), including depths and specification of permeable formations, casing strings, primary cement behind-casing status, wellbores, installed completion, sidetracks, etc.

225

2. Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and with an eternal perspective) are included.

226

3. Logs, data and information from primary cementing operations in the well.

227

4. Estimated formation fracture gradient.

228

5. Specific well conditions such as scale build-up, casing wear, collapsed casing, fill, or similar issues.

229

230

Design input data sheet

DECC well name or number:	
Field name:	
Date of information:	
Information required	
	What and where are the permeable zones? (e.g. any zone in the well where there is the possibility of fluid movement on application of a pressure differential)
	What are the contents of each zone? Are they hydrocarbon-bearing or water-bearing? A permeable zone is considered hydrocarbon-bearing if any moveable hydrocarbons are present or likely to be in future.
	Is crossflow acceptable between these zones? If not, which zones need to be permanently isolated?
	What was the original reservoir pressure? Are later field activities likely to increase reservoir pressure above this level (e.g. water injection)?
	What are the latest pressures in these zones? - normally pressured, - overpressure, - subhydrostatic Overpressure considered where the pressure is in excess of the regional hydrostatic pressure gradient 0.45 psi/ft.
	What are the present fracture gradients in the wellbore, if known?
	Are there any subsurface hazards (e.g. shallow gas, H ₂ S, CO ₂ , major faults)?
	What is the maximum anticipated pressure that may develop below plugs set in the wellbore following abandonment? Any future use of reservoir?
	What is highest point of potential inflow? (e.g. the top of a permeable interval or top perforation whichever is shallower)
	What is the current operational and integrity status of the well? e.g. flowing, injecting, plugged or in poor mechanical condition (e.g. leaking xmas tree valve, leaking tubing, casing integrity or annular pressure anomalies). Is the well operating under dispensation from policy?
	Unknown well conditions (more than two years from last well entry, or well has scale / asphaltting problems or hydrate formation potential exists)
	Well history summary: - current well schematic, including all annuli fluids; - previous abandonment activities, including sidetracks; - tubular records, cementing records, pressure tests, casing logs (e.g. sonic cement bond logs, calliper logs, etc) mud log, openhole logs.
	What is the lightest fluid gradient between each permeable zone and its permanent barrier?
	Information on the type of service the well has seen during its life cycle (e.g. production, gas lift, water injection, gas injection, ESP, production histories).

231

Appendix B Barrier integrity – potential issues and mitigations

232

As outlined in Section 5.2, a cement column of at least 100 ft MD of good cement is considered to constitute a permanent barrier.

233

Generally, where possible, 500 ft MD barriers are set, or in the case of a combination permanent barrier an 800 ft plug is typically set to achieve a column of at least 200 ft MD of good cement. These typical plug lengths provide significant excess to account for non-ideal conditions.

234

Generally the additional cost of placing more cement is far outweighed by the implications of a leaking barrier. However circumstances may arise where it is impractical to place such a typically sized barrier. In these scenarios the plug placement should be risk assessed to determine if a reduced length will still achieve the required 100 ft MD of good cement.

235

Provided below are examples of some of the potential issues and good industry practice which well-operators may consider when carrying out a risk assessment. This list is not exhaustive and cannot cover every scenario and should therefore be used in combination with good engineering judgement.

236

The following key is used in the tables to show whether the potential issue is:

✓ applicable

ST stinger-set plugs

X not applicable

TT through-tubing set plugs

237	ST	TT	Potential issue	Possible mitigation
	✓	✓	Low top of cement due to insufficient cement volume Underestimation of hole size due to washout or erroneous pipe dimensions.	- Caliper the interval and choose plug setting depths that are in gauge sections of the hole. - Allow sufficient cement excess to account for worst case ID. - Check pipe dimensions (i.e. ID and OD). - Tag top of cement to confirm. - Double check operational calculations.
	✓	✓	Cement slippage downhole due to cement density or losses - Cement density is higher than fluid in which it is placed. - TOC no longer at required depth. - Soft cement plug due to contamination with mud (higher risk with synthetic or oil-based muds). - T-plug on casing stumps. - Plugs across milled sections without support for cement. - Applicable to internal cement plugs and annulus cement plugs.	- Ensure cement plug is set on suitable base that supports the cement slurry. - Mechanical base such as previously tested cement plug, cementing packer, or completion packer is preferred. - Fluid base such as a VRP or viscous mud pill. - For VRP ensure suitable reaction with mud and cement via lab testing. - Verify that the pill can carry the cement and that the fluid can carry the pill using a scale model testing to replicate wellbore geometry (e.g. glass cylinder test). - Consider setting cement plug at hole section with lower inclination. 30-70 degrees is high risk area for slippage if using a fluid base. - Treat losses or use mechanical base . - Tag or wash down to confirm.
	✓	x	Swabbing or disturbing the plug when using a work string Contaminating or stringing out the plug when pulling pipe out of cement. High risk in highly deviated or horizontal wellbores or when density difference between mud and cement is small.	- Pipe OD should be optimised to ensure sufficient clearance to avoid swabbing when POOH, but large enough to maintain suitable annular velocities during plug placement. Take into account OD of couplings. - Pull pipe out of cement slowly (typically 30-50 ft/min) and break connections carefully. - Cement rheology is optimised and designed with non progressive gels. - In highly deviated holes (>70-80°) consider pumping out of balanced cement plug, synchronising tripping speed and pump rate. - Consider the use of sacrificial cementing string where tail pipe is mechanically disconnected removing the need to pull the workstring through the cement plug. - Use caution with longer plugs (e.g. longer than 800 ft) as increased length brings greater risk of gel development and swabbing or sticking the work string. If longer plugs are necessary then additional focus should be given to the slurry design and properties. - Tag or washdown to confirm top of firm cement. - Monitor for losses when circulating after pulling pipe above the plug to ensure the plug is not lost into the formation due to induced losses from ECD.
	✓	✓	Cement strength not developing due to poor materials or erroneous mixing procedures	- Slurry designed and tested in lab, preferably with rig samples of materials before job. - Consider actual slurry tested in surface sample. - Quality control of materials. - Supervision by cementing specialist. - Consider temperature log as input to design .

238	ST	TT	Potential issue	Possible mitigation
	✓	✓	Contamination of cement during placement Contamination and dilution of cement with spacer or mud during placement.	- Pump sufficient volume of suitable spacer to separate cement from mud. - Ensure good mud/spacer/cement hierarchy (density and rheology) to minimise channeling. - Allow sufficient cement excess to account for likely contamination volumes at leading and trailing edges. - A diverter tool on the end of the drillpipe will direct the flow outward and upward thereby minimizing any intermixing of cement and drilling mud during plug placement. - Use of mechanical separation such as wiper dart or foam wiper balls ahead and behind cement. - Ensure cementing string is an appropriate distance above plug before circulating clean. - Use of computer modelling to predict fluid interfaces and risk of mud channels. Optimisation of key variables such as pump rates, spacer volumes ahead and behind, and fluid rheologies. - Wash down with workstring, if available, to confirm hard cement. Shallow tag may indicate contamination.
	✓	✓	Fluid or gas percolation through cement when hardening Gas or overpressured formation fluid may enter the wellbore during gelling of the slurry and create a channel through the plug.	- Consider gas tight cement slurry that goes from liquid to solid in short time period. - Where possible, maintain pressure on well bore as the cement sets. - Consider isolating gas-bearing perforations with a mechanical device.
	x	✓	Unable to circulate cement into place via perforations in casing or tubing - Unable to circulate, which may result in re-perforations and a shallower barrier. - Leaking tubing allows cement flow to split, loss of volume control. - Fluid contamination and cement slumping into the void below perforations. - Damage of next bigger casing may be undesirable.	- Size and phasing (high side) of perforations adequate to prevent blockage. - Keep pressure. If low flow, extend circulation time at increasing rate. - Use of computer modelling to predict fluid interfaces and risk of mud channels. Optimisation of key variables such as pump rates, spacer volumes ahead and behind, and fluid rheology. - If sump below perforations is significant, consider placing a viscous fluid base such as a VRP via additional perforations below the planned cement plug depth. - For production tubing, perforate as close as possible to the production packer. This will reduce the length of sump below the perforations and the tubing above the packer may have some standoff from the casing wall to help reduce the risk of channeling. - Leaking tubing may require coiled tubing or retrieval of the tubing string. - Use punchers in preference to perforating guns if the next bigger casing is to be protected.

239	ST	TT	Potential issue	Possible mitigation
	✓	X	Contamination of cement due to overdisplacement when using a removable workstring Contamination of cement with spacer or mud due to overdisplacement when using a removable stinger or workstring (e.g. coiled tubing).	- Consider verification of the string volume. - Consider using a cement unit for displacement rather than rig pumps since fluid volumes can be physically metered in displacement tanks. - Indicator ball catchers can be used in the string to help achieve accurate displacement. - Under displace the cement by appropriate volume to allow it to u-tube into position. Especially critical for tapered cementing strings. - Computer modelling of cement placement to optimise key variables such as pump rates, spacer volumes ahead and behind, and under displacement volumes. - Returns may show cement traces or tag expected to be shallow.
	✓	✓	Channelling of cement Cement flows up path of least resistance, leaving mud channel and lack of competent isolation. Risk when pipe is eccentric.	- Select pipe OD and pump rates to ensure suitable annular velocities during plug placement. - Wash the interval to be plugged at maximum annular velocity possible. - A diverter tool on the end of the drillpipe may assist washing of the section. - Condition and optimise mud prior to cementing. Consider use of low YP and non progressive gels. - Consider rotating the cementing string during cement placement to help break up gelled mud and constantly change the flow pattern in the annulus. - Ensure good mud/spacer/cement hierarchy (density and rheology) to minimise channeling. Pressure test or inflow test to confirm. - Returns showing cement traces or shallow tags are indicative of cement channeling. - Avoid reciprocating the pipe when placing the cement plug. - Cement systems should be designed to have zero free water for any hole sections with >20° inclination.
	✓	✓	Lack of bond to casing or formation - Failure to remove fluid, debris, deposits, or corrosion contaminants resulting in poor cement bond or cement channeling with potential to compromise barrier seal. - Shrinkage of cement creating microannulus.	- Extend circulation time at high rate. - Circulate fluid trains of cleaning agents until returns are clean. Consider the use of acid and soap washes ahead of cementing which may aid removal of any contaminants such as rust, scale, hydrocarbon and oil-based mud residue. - If surfaces downhole could be contaminated with oil residue, then use suitable surfactants in the cement spacer to ensure surfaces are water-wet. - Ensure good mud/spacer/cement hierarchy (density and rheology) to minimise channeling. - Pump sufficient volume of suitable spacer to separate cement from mud. - A diverter tool on the end of the drillpipe will direct the flow outward and provide jetting action to aid wellbore cleanup. - Consider use of computer modelling to predict fluid interfaces and risk of mud channels. Optimisation of key variables such as pump rates, spacer volumes ahead and behind, and fluid rheology. - The use of suitable additives in the cement will improve bonding and minimise shrinkage.

240	ST	TT	Potential issue	Possible mitigation
	X	✓	Unable to seal annulus by perforate and circulate/squeeze • Unable to circulate, which may result in accepting annulus fill as a permanent barrier. • Suboptimal displacement of resident fluids may leave a channel. • Fluid contamination and cement slumping into the void below perforations. • Perforation damage of adjacent casings may be undesirable.	• Select depth where no or little cement is present in the casing annulus or where there are low risks of pack off due to fill by solids. • Size and phasing (high side) of perforations adequate to prevent blockage. • Hold squeeze pressure as cement sets or consider using a cement retainer. If minimal circulation is achieved, extend circulation time at increasing rate. • Cleaning of debris, mud, grease from annulus requires circulation and cleaning fluids. • Consider use of a wash tool designed to allow circulation between perforations prior to cementing. • Use of computer modelling to predict fluid interfaces and risk of mud channels. Optimise key variables such as pump rates, spacer volumes ahead and behind, and fluid rheology. • If a sump below perforations is significant, consider placing a viscous fluid base such as a VRP via additional perforations below the planned cement plug depth. • Consider punchers or pipe cutters as an alternative to perforating guns if the next bigger casing is to be protected. A quarry test may be considered. • Abrasive jetting is an alternative for wireline perforating, creating larger holes in casing and washing behind casing to enhance cleaning and circulation rates. Perforation washing over an extended length is a further alternative technique to achieve this.
	✓	X	Unable to repair annulus casing cement by section milling • Unable to achieve adequate window length. • Lose the connection to the hole. • Fluid contamination as a result of small slurry volumes and cement slumping into the void outside below the casing stub. • Losses during placement.	• Consideration should be given to milling inside previous casing. This allows an expandable packer to be set in the bottom of a window as a support for the cement slurry. • Achieving window length is optimized by milling cemented casing without centralisers and minimise number of collars to be milled. Roundtrips may result in losing the hole. • Avoid pack-off and stuck pipe by keeping the hole clean and be prepared for swarf handling. Milling rate is controlled by hole cleaning and ability to handle large volumes of swarf. • Where a second section is milled, the loose pipe may start rotating and prevent further progress. • The milled section should be cleaned out to remove debris, e.g. by means of underreaming if against formation. • Sealing capability, length of window and number of barriers will depend on type and pressures of fluids, and height of caprock. The basis for selection is to be documented, i.e. the effectiveness of the operation through long-term monitoring. • When setting two independent cement plugs in a single long window, the contamination risk increases due to small volumes pumped. Consider pumping excess and circulating out to the middle of window. The first plug will provide support for the second plug.

Appendix C P&A code

A “P&A code” is introduced to indicate a work scope of plug and abandon operations. It applies to any well and all work phases. It is used for high level cost estimation and benchmarking.

The previously defined “UKOOA category” is only applicable for subsea suspended wells and in particular used for surface abandonment in multi-client campaigns. This is retained in Appendix D.

P&A code description

The scope of work to abandon a well can be represented by a code that commences with two letters indicating the location of the well, followed by 3 digits representing the complexity of each of the 3 phases of well abandonment, e.g. PL 1-3-3 or SS 0-4-3.

The two letters simply define the physical location of the well.

- **PL** – platform well
- **SS** – subsea well
- **LA** – land well

The three digits represent three distinct abandonment phases, whereas their value reflects the work scope and equipment required.

- 1st position refers to phase 1 – reservoir abandonment

Primary and secondary permanent barriers set to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved. Complete when the reservoir is fully isolated from the wellbore.

- 2nd position refers to phase 2 – intermediate abandonment

Includes: isolating liners, milling and retrieving casing, and setting barriers to intermediate hydrocarbon or water-bearing permeable zones and potentially installing near-surface cement. The tubing may be partly retrieved, if not done in phase 1. Complete when no further plugging is required.

- 3rd position refers to phase 3 – wellhead and conductor removal

- 251 The P&A code is a high level indication and does not need to finesse subdivisions of work, e.g. diagnostic and preparatory operations. Allowance for such tasks should be included within the most appropriate phase.
- 252 For each phase, a digit is chosen (0 to 4) that best reflects the complexity type of the abandonment work, according to the following:
- 253 **TYPE 0:** No work required – a phase or phases of abandonment work may already have been completed
- 254 **TYPE 1:** Simple rigless abandonment – using wireline, pumping, crane, jacks. Subsea will use a well intervention vessel and be riserless
- 255 **TYPE 2:** Complex rigless abandonment – using coiled tubing or hydraulic workover unit, wireline, pumping, crane, jacks. Subsea wells will use a well intervention vessel with riser.
- 256 **TYPE 3:** Simple rig-based abandonment – requiring retrieval of tubing and casing using a drilling rig.
- 257 **TYPE 4:** Complex rig-based abandonment – may have poor access and poor cement requiring retrieval of tubing and casing, milling and cement repairs
- 258 The complexity type of a phase can be determined through a set of questions as described in the *Guideline on well abandonment cost estimation*, available through Oil & Gas UK.
- 259 The P&A code can be used to record the abandonment complexity and methodology for the three phases for a well at a location in a table. See examples 1 and 2.

Well abandonment classification example 1

For a platform well, of which the reservoir will be abandoned by a coiled tubing unit, then requiring the tubing to be pulled and shallow barriers placed by a rig and the conductor removed by a rig as well, the P&A Code would be **PL 2-3-3**.

Platform well			Abandonment complexity				
			TYPE 0 No work required	TYPE 1 Simple rigless	TYPE 2 Complex rigless	TYPE 3 Simple rig-based	TYPE 4 Complex rig-based
Phase	1	Reservoir abandonment			x		
	2	Intermediate abandonment				x	
	3	Wellhead conductor removal				x	

Well abandonment classification example 2

For a platform well, already abandoned across the reservoir, then a complex intermediate P&A using a rig and standard conductor removal by a rig, the P&A Code would be **PL 0-4-3**

Platform well			Abandonment complexity				
			TYPE 0 No work required	TYPE 1 Simple rigless	TYPE 2 Complex rigless	TYPE 3 Simple rig-based	TYPE 4 Complex rig-based
Phase	1	Reservoir abandonment	x				
	2	Intermediate abandonment					x
	3	Wellhead conductor removal				x	

Appendix D Suspended subsea E&A wells categorisation

The industry has evolved a categorisation system to describe the suspended status of subsea wells, particularly exploration and appraisal wells.

The system can be subjective and arose from a previous suspension practice of placing a cement plug in the production casing, but with no adjacent annular cement. This would not constitute a permanent barrier (refer to Section 5 and Figure 13).

It is important that a full review of the well is made when categorising a well and looking at options to abandon it. A risk assessment should be carried out considering the well status, proposed programme and ability to conform to legislation and the well-operator's policy.

The categorisation system commonly used is:

Category	Definition
1	The well has been sufficiently suspended that final abandonment only requires removal of the wellhead.
2.1	The well has one annulus uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annulus or placing a separate barrier. This type of well may be abandoned with a drilling rig or a well intervention vessel.
2.2	The well has two annuli uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annuli or placing a separate barrier. This type of well may be abandoned with a drilling rig or a well intervention vessel.
3	The suspended condition of the well is not suitable for full abandonment without significant intervention. Typically, with current technology, the abandonment programme will require a drilling rig to effect the operation.
4	The well has not been categorised into one of the above.

The categories may be prefaced with ML or SS indicating either a mudline suspension system or subsea wellhead on the well.

For subsea wells there is a further categorisation relating to how the well location may affect ease of access:

274

Category	Definition
1	Location has no access restrictions.
2	Location may limit ease of access because:
2a	On a template with other wells that are developed or planned for development.
2b	Less than 50 m from other subsea infrastructure or pipelines.
2c	Within the 500 m safety zone of an installation or a subsea development.
2d	The well has an identifiable problem where the risk associated with abandonment requires additional study.
2e	Is deeply buried under the seabed.

275

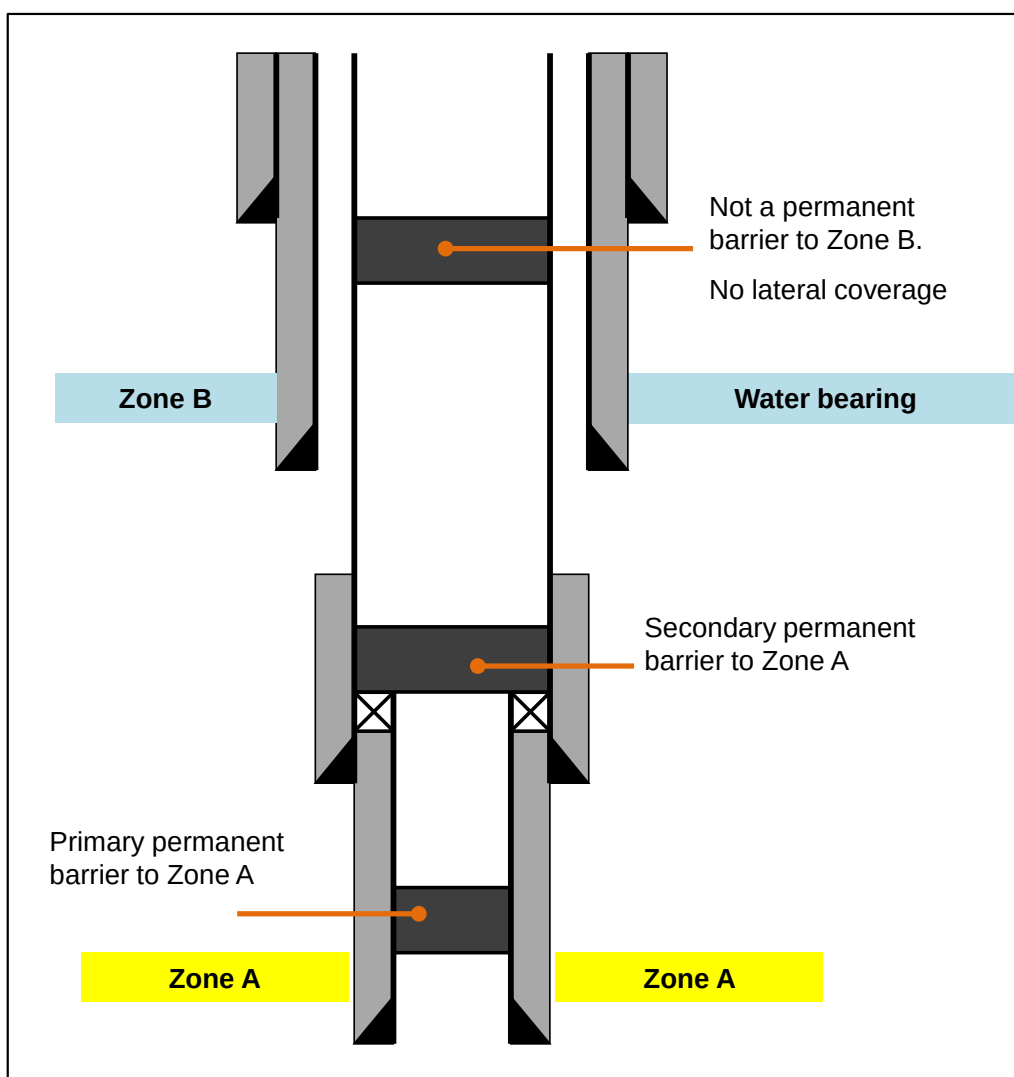


Figure 13. Example of category 2.1 suspended well

276

Appendix E Irrecoverable radioactive sources – SEPA

277

Best efforts should be made to recover radiation sources from the well, but avoiding any damage to the encapsulation of the radioactive material.

278

In case of radioactive sources that cannot be recovered from downhole, note the reporting requirements in the Radioactive Substances Act, 1993 (RSA 1993). Sources that cannot be recovered must be notified to the Scottish Environment Protection Agency (SEPA) (telephone number 0800 80 70 60) as appropriate. The notification should include full details of the radioactive source(s) and the registered owner and registration licence number if possible. Ideally this notification should be made when control of the radioactive source(s) has been lost so that any abandonment plan can be agreed.

279

Where a source cannot be recovered, it should be located as accurately as possible (surveyed and tagged) and, where possible, isolated preferably with cement plugs. The cement plug should extend at least 100 ft above the radioactive source. The main aim of isolation is to fix the source in place and to isolate it from potential fluid movement. Alternatives to cement plugs should be agreed with the HSE and Environment Agency or SEPA as appropriate. Well records should be annotated with the relevant information and a warning plaque fixed at the wellhead.

280

In the event that further drilling operations may be undertaken in the vicinity of the well the well-operator's standards and procedures for anti-collision should be implemented and any necessary mitigations agreed with SEPA.

281

Where there is a likelihood of subsequently drilling into the well containing the radioactive source, the use of coloured cement should be considered at all times.

282

Appendix F References and further reading

283

Guidelines on qualification of materials for the suspension and abandonment of wells, Issue 1 July 2012, Oil & Gas UK, ISBN 1 903 003 85 4

Guideline on well abandonment cost estimation, Issue 1, April 2011, Oil & Gas UK, ISBN 1 903 003 69 3

Well integrity guidelines, Issue 1, July 2012, Oil & Gas UK, ISBN 1 903 003 82 9

The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996, SI 1996/913, ISBN 0 22 054451 X

The Offshore Installations (Safety Case) Regulations 2005, SI 2005/3117, ISBN 978 0 11 073610 5

NORSOK Standard D-010 *Well integrity in drilling and well operations* (Revision 3, August 2004)

API RP 57 (January 1986, now withdrawn)

Mining Regulations of the Netherlands WJZ0206360 (January 2003)

284

Appendix G Background to these guidelines

285

These guidelines were written by the Well Suspension and Abandonment (WSA) workgroup which was formerly known as workgroup 5. The members of this group during the revision of these guidelines included:

286

Jules Schoenmakers (Shell Upstream Europe), workgroup colead
Simon Hough (Chevron Upstream Europe), workgroup colead
Phil Chandler (InterAct, part of Acteon)
Stan Bain (ADTI)
Tom Gillibrand, William Inglis (BP Plc)
Peter Irvine (ConocoPhillips (U.K.) Ltd)
Max Baumert (ExxonMobil International Ltd)
Colin Wight (Halliburton)
Donald Dobson (Health and Safety Executive)
Oliver Willis (Helix Well Ops (UK) Ltd)
Graeme Johnston, Steve White (Hess Limited)
Jorgen Berg, Frank Calder (Schlumberger Oilfield Services)
Martin Mosley, Giancarlo Pia (Talisman Energy (UK) Limited)
Andrew McHardy (Total E&P UK Limited)
Garry Skelly (Well Abandonment Limited)
Theodora Tucker (Oil & Gas UK)

287

Workgroup 5 was previously part of the Decommissioning Steering Group which was formed by DECC and industry (represented by Oil & Gas UK). Recently this group has been restructured and it was felt that Workgroup 5 should be incorporated into another Oil & Gas UK group, the Well Life Cycle Practices Forum (WLCPPF).

288

The WLCPPF was set up in December 2010 by Oil & Gas UK as a vehicle for implementing the OSPRAG Technical Review Group recommendations (available from <http://www.oilandgasuk.co.uk/publications>) and as a permanent forum in which well-related pan-industry issues can be identified and discussed.

289

The WLCPPF is also the interface of choice for HSE and DECC to engage the UK offshore industry on well-related matters. The WLCPPF has representatives from 45 different operators and well management companies, and over 60 companies have been involved in the various workgroups and review cycles.