Mining, Exploration and Geoscience
Department of Regional NSW

Code of practice

Construction, operation and decommissioning of petroleum wells

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May 2023	1.1	Minor amendments to clarify the role of the Department and the EPA in approving alternative means of compliance

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Title

The NSW code of practice for construction, operation and decommissioning of petroleum wells.

Purpose

The purpose of this code is to provide a minimum set of mandatory requirements to ensure that petroleum wells are designed, constructed, operated, maintained and decommissioned to ensure their long-term integrity in NSW. The code also advises on how good industry practice can be applied by titleholders.

The code combines and replaces the existing well integrity and fracture stimulation codes for coal seam gas and extends these requirements to all petroleum activities. The code better aligns with other jurisdictions and clearly articulates the mandatory requirements and guidance for the construction, operation and decommissioning of petroleum wells to ensure human health and environmental protection.

Scope and application

The code applies to wells as defined in the *Petroleum (Onshore) Act 1991*) and covers the following well life phases:

- Well planning and design
- Well construction (up to the production wing valve of the wellhead)
- Well evaluation
- Well completion (including fracture stimulation activities)
- Well production and operation
- Well workovers and interventions
- Well integrity management
- Well suspension
- Well decommissioning

The code sets out activities, actions, technical requirements, responsibilities or responses to events. The mandatory requirements and recommendation section of this document are divided into 3 categories:

- Principles: these are the fundamental requirements that must be adhered to during the lifecycle of the well.
- Mandatory requirements: these requirements define the practices, methods and techniques the titleholders must comply with.
- Good industry practice: these are recommended practices, methods and techniques for titleholders to follow, these can assist titleholders in achieving compliance, but on their own do not constitute satisfactory compliance.

A list of relevant industry standards and recommended practices is at Appendix 3 – Industry Standards.

The code is also designed to ensure that:

- risks to the environment (surface water and groundwater, air, vegetation and fauna) are identified, eliminated where possible or minimised through appropriate management practices
- regulatory requirements are understood and implemented.

The code must be used in conjunction with the titleholders' internal risk assessment processes and operating procedures.

The following types of drilling do not fall within the meaning of a petroleum well to which the code applies:

- seismic shot holes
- tiltmeter and monitoring bores.

The code does not apply to, or cover, drilling for groundwater, including monitoring for groundwater, where water bore drilling is licensed under the *Water Act 1912* or *Water Management Act 2000*.

Implementation and enforcement

The code is intended to be imposed as a condition of a petroleum title. Schedule 1B of the Petroleum Act provides for conditions of a petroleum title that may be imposed by the Minister or prescribed Regulations. The current version of the legislation is available from www.legislation.nsw.gov.au.

This code applies as a condition of title to petroleum wells in NSW that have not been decommissioned or which have not already been approved for decommissioning under a previous framework before the publication of this code.

Titleholders are required to comply with the code to ensure that activities relating to well integrity are compliant with the imposed condition of the petroleum title under the Petroleum Act. The NSW Environment Protection Authority (EPA) is responsible for enforcing compliance with petroleum title conditions. The EPA does not regulate work, health and safety matters, which are the responsibility of Mining, Exploration and Geoscience (Resources Regulator).

In the case of any inconsistency between the code and any legislative requirements, the legislative requirements prevail to the extent of any inconsistency.

Review and revision of the code will be undertaken every 3 years or earlier if required.

Notification of non-compliance

Notification of an identified non-compliance with the mandatory requirements of the code or an approved alternative means of compliance must be submitted as soon as reasonably practical but no later than 5 business days from the identification of the non-compliance.

Notifications must be sent to the EPA by email to info@epa.nsw.gov.au

Alternative means of compliance

If a titleholder is unable to achieve the mandatory requirements as set out in this code, then the titleholder can apply to the Department proposing an alternative means of compliance to the mandatory requirements, provided it meets the same or better outcomes to those required in the code. An application seeking an alternative means of compliance may be submitted at any time to the Department by email to titles@regional.nsw.gov.au

An alternative means of compliance may only be approved by the Department in writing. In determining an application for approval, the Department must consult with, and consider technical advice provided by, the EPA. An approved alternative means of compliance will take precedence over the mandatory requirements of this code.

Definitions

In this document, references to ‘the Department’ mean Mining, Exploration and Geoscience within the Department of Regional NSW.

In the code, the words ‘must’ and ‘mandatory’ indicate a requirement. It is essential that titleholders and other people comply with these requirements.

In the code, the word ‘should’ indicates a recommended course of action. Words such as ‘consider’ or ‘may’ indicate matters that may be chosen from options.

Other definitions and abbreviations are provided in the Glossary at Appendix 1.

Legislative framework in NSW

Before outlining the requirements for petroleum titleholders in NSW, it is important to consider legislative requirements for petroleum exploration and production in general.

Exploration for and production of petroleum is subject to the Petroleum Act with the grant of petroleum titles by the responsible Minister. The Petroleum Act provides for the Minister to grant petroleum exploration licences, petroleum assessment leases and petroleum production leases.

All production projects and most exploration activities require environmental assessment under the *Environmental Planning and Assessments Act 1979* before they can be carried out and many need development approval, or approval from Mining, Exploration and Geoscience (Resources Regulator).

All well activities must be carried out in accordance with the *Work Health and Safety Act 2011*, which places the primary duty of care on the person conducting the business or undertaking, and also the NSW *Work Health and Safety (Mines and Petroleum Sites) Act 2013* and the NSW Work Health and Safety (Mines and Petroleum Sites) Regulation 2022.

There are additional requirements in relation to water management and environment protection. Certain petroleum activities also require approval under other legislation, for example:

- *Protection of the Environment Operations Act 1997*
- *Water Act 1912*
- *Water Management Act 2000*
- *State Environmental Planning Policy (Resources and Energy) 2021*
- *State Environmental Planning Policy (Planning Systems) 2021*

Other legislation may apply to certain activities, for example the *National Parks and Wildlife Act 1974* or *Biodiversity Conservation Act 2016*.

The *Environment Protection and Biodiversity Conservation Act 1999* (Commonwealth) requires approval by the Commonwealth Environment Minister for certain 'actions'.

1. Mandatory recording and reporting data

Accurate information about well drilling, completion, fracture stimulation, workover, suspension and well decommissioning must be recorded. Titleholders must ensure that these records are well maintained in an accessible way for the periods specified (section 97E of the Petroleum Act) or, if no such retention periods are specified, for five years following the decommissioning of a well.

Titleholders must also keep geological plans, maps and records for work relating to the petroleum title, and submit plans and reports on the progress of operations in accordance with Part 8a of the Petroleum Act and Part 4 of the Petroleum (Onshore) Regulation 2016. Further detail is contained in the guideline *Onshore Petroleum Reporting and Data Submission*.

1.1. Well life cycle records

A record of all work undertaken on a well must be maintained for each well's entire life through to decommissioning.

1.1.1. Good industry practice

Records to be maintained may include, but are not limited to, the following:

- engineering design basis
- kick tolerance/well control design assumptions
- blowout preventer (BOP) pressure testing requirements, and actual test records
- laboratory test results for cement slurries

- casing tallies for all casing strings run (including lengths, weights, grades, inside diameter, outside diameter, setting depth)
- cementing records for each casing string in each well
- casing pressure test reports
- leak off test and/or formation integrity test reports
- wireline logs
- core description reports
- stratigraphy encountered including zones that flowed or loss zones
- surface location and downhole survey records
- downhole installation records/schematic
- records of chemicals used downhole, including any chemicals used in drilling fluid, treatment and workover or other well procedures (name, type CAS number and volume of each chemical used should be recorded)
- records of drilling and cementing, including any problems encountered
- risk assessments
- well drilling and completion programs including casing running and cementing procedures
- daily rig reports
- daily geological reports, if relevant
- service company reports.

1.2. Cementing reports

Cementing reports, including all materials and compression strength versus time graphs, cement pump charts and pressure records, problems encountered during cementing (losses etc.), logging reports including well deviation details and details of centraliser placing must be completed and submitted to the Department with well completion reports.

2. Mandatory requirements and recommendations

2.1. Well design and barriers

2.1.1. Principles

Petroleum wells must be designed to ensure the environmentally sound, safe production of hydrocarbons and other wellbore fluids by containing them inside the well, protecting groundwater resources, isolating the productive formations, and by proper execution of treatment, stimulation and completion operations. Titleholders must ensure that a suitable well design, construction and integrity assurance process is in place, maintaining necessary well documentation and undertaking regular audits of the process for all wells.

Well design and construction must ensure that no leaks occur through or between any casing strings. The fluids produced from the well must travel directly from the producing zone to the surface inside the well conduit, without contamination of groundwater or other aquifer resources, and must avoid leakage.

All wells must be designed to ensure the safe and environmentally sound production of petroleum by:

a) preventing any interconnection between hydrocarbon bearing formations and aquifers
b) ensuring that fluid (oil, gas and water) is contained within the well and associated pipework and equipment without leakage
c) ensuring zonal isolation between different aquifers is achieved

d) not introducing substances that may cause environmental harm

e) testing and acceptance requirements being satisfied

f) monitoring and maintaining wells to contain and control wellbore fluids, provide structural support and otherwise retain well integrity throughout all reasonably anticipated construction, testing, production, intervention, workover, suspension and decommissioning load conditions that may occur during the well's life; and

g) ensuring the completion components are designed to operate within the maximum expected pressure and load conditions until final decommissioning.

2.1.2. Mandatory requirements

The design basis for petroleum wells must incorporate the following:

a) Planned casing setting depths, taking into account aquifer and production zone locations, and the requirements for well control.

b) Provision for installation of pressure control equipment based on risk assessment.

c) BOP equipment to API Standard 53.

d) Specification of appropriate casing weight and grade, and casing running procedures.

e) Specification of appropriate well design and construction materials.

f) Specification of appropriate casing centralisation.

g) Specification of engineered cement slurry and effective cement placement techniques.

h) Design to ensure all fluids produced from the well travel directly from the production zone to the surface without contaminating groundwater.

i) Design to ensure wells are constructed, operated, maintained and decommissioned with 2 verified well barriers between a hydrocarbon bearing or abnormally pressured formation and the surface, unless one of the following scenarios can be demonstrated through risk assessment:

   i. There is no natural lift mechanism for hydrocarbons or water to flow to surface; or

   ii. during top hole or surface hole drilling where shallow fluid risk has been assessed as being negligible; or

   iii. during diverter drilling; or

   iv. during planned underbalanced and managed pressure drilling where surface equipment design limits are not exceeded; or

   v. between the surface and the hydrocarbon bearing zone for a petroleum well during its producing phase. Titleholders must have appropriate processes in place to address well integrity risks; or

   vi. during well decommissioning when 2 overlying formations need to be isolated from one another and two barriers are not feasible, then a continuous cement plug must be placed in accordance with section 2.3 of the code; or

   vii. in other circumstances during well life cycle activities when a risk assessment has been completed as per the titleholders' risk management process.

All well designs and construction procedures should include contingency planning to mitigate the effects of failures in the event of unplanned process upsets or events during construction.

2.1.3. Good industry practice

a) Offset well information should be reviewed to assist in the design process for new wells.

b) Nearby water bores should also be included in the record keeping and data set as part of the offset review.

c) Consideration should be given to the potential for tubular corrosion including review of offset data detailing any evidence of tubular corrosion. If there is potential for corrosion or corrosion has been observed, titleholders need to conduct a risk assessment and act to ensure maintenance of well integrity.

d) Titleholders should identify aquifers and ensure that these zones are isolated to ensure their long-term protection. Formation horizons or zones from which water bores produce should be noted during the offset well review and used to assist the programmed setting depths for casing strings.

e) Sustainable construction practices and operating procedures should be used, for example, to conserve water use and minimise waste.

f) Casing hardware including float equipment, centralisers, cement baskets, wiper plugs (top and bottom), stage tools and external casing packers should be selected as appropriate as part of the well design to ensure integrity of the required zonal isolation.

g) Titleholders should review information on geological strata and formation, and fluids within them, that the well may intersect and any hazards that strata and formations may contain.

h) Schematic drawings of well barrier arrangements should be prepared for the well or group of wells of similar well design and architecture.

i) A barrier should only be considered verified when there is physical evidence that the barrier has been placed in its desired location and will perform its required function.

j) The test pressures for verifying well barriers should be applied in the direction of flow towards the external environment. If this is not possible or introduces additional risk, the test pressure can be applied against the direction of flow towards the external environment, provided the well barrier is designed to seal in both flow directions.

k) A barrier placement and verification procedure should be developed to identify satisfactory establishment of barriers at each relevant stage of well operations during well construction.

l) Borehole stability analysis should be considered for all deviated wells >40 degrees inclination and for wells in areas known to be prone to wellbore instability issues.

2.2. Casing and tubing

2.2.1. Principles

Casing and tubing must be designed to withstand the various compressive, tensile and bending forces that are exerted while running-in the hole, as well as the collapse and burst pressures that it may experience during different phases of the well's life, for example, cementing, pressure testing, stimulation and production cycles.

Casing strings must be designed to facilitate installation of pressure control equipment. As well as providing a mechanism for extracting fluid from the production zones, casing and tubing also act to protect other resources such as groundwater.

The casing program must be designed to accommodate all identified sub-surface hazards and to minimise risk either from crossflow between formations or the uncontrolled release of wellbore fluids to surface, throughout the life of the well.

Casing setting depths must be selected to provide an adequate safety margin between the formation fracture pressure and anticipated pressures during well control and casing cementation operations.

2.2.2. Mandatory requirements

a) Casing, casing connections, wellheads, and valves used in wells must be designed to withstand the loads, pressures and temperatures that may act on them throughout the entire well life cycle. This includes casing running and cementing, any treatment pressures, production pressures, any potential corrosive conditions, and other factors pertinent to local experience and operational conditions.

b) Casing and tubing stress analysis must be carried out on all reasonably foreseeable load scenarios that may be imposed on the well. Casing design must consider both uniaxial and triaxial analysis.

c) Conductor pipe does not need to meet the requirements in (a) or (b).

d) Methods of preventing external corrosion that impact well integrity must be considered and implemented where appropriate.

e) Barriers must be installed to prevent surface pollutants from entering the well and prevent wellbore fluids (oil, gas, water) from escaping to the surface environment.

f) When designing casing strings and casing connections for petroleum wells, titleholders must design each well (or similar well type's) casing string using appropriate design safety factors. A generic worst-case design and stress analysis may be adopted to cover multiple wells in a field development targeting the same/similar reservoir. Commonly used design safety factors are:

   - collapse: 1.0
   - burst: 1.1
   - static tension: 1.3
   - triaxial analysis: 1.25

   The design safety factors used must be appropriately justified and need to be appropriate for the anticipated well life, service conditions and local experience.

g) All steel casing and tubing must be manufactured to the latest edition of ISO 11960. The rated capacity of the pipe body and connections must be obtained from the latest edition of ISO 11960 or the manufacturer's technical specifications. Any material other than steel used for casing and tubing must have appropriate manufacturing specifications and verifiable properties.

h) To verify casing integrity during the well construction process, casing must be pressure tested prior to drilling out for the next hole section (in the case of surface or intermediate casing), and before completion operations commencing (in the case of production casing). The test pressure must be greater than the maximum anticipated formation pressure possible at the surface but must not exceed the burst pressure rating of the casing with the design safety factor applied.

i) Minimum surface casing setting depth must be sufficient to meet isolation requirements of shallow aquifers and provide an acceptable kick tolerance for the next hole section to be drilled. The kick tolerance criteria must be selected by the titleholder and be dependent upon knowledge of the local pore pressure and fracture gradient profiles, and of the likely kick conditions in the well.

j) Steel casing connections must be made up to ensure an aligned, round, secure, and leakproof joint.

k) Welded connections are not permitted for the joining of casing or tubing in a well unless they are seamless and electric-welded casing, tubing and pipe manufactured in compliance with ISO 11960.

l) The yield stress of oil country tubular goods (OCTG) must be derated for temperature.

2.2.3. Good industry practice

a) For casing run in petroleum wells, pipe body and connections should have verifiable properties (i.e. in terms of burst, collapse and tensile strengths). Note that casing manufactured to API specifications must by definition meet strict requirements for compression, tension, collapse and burst resistance, as well as quality and consistency.

b) Casing and tubing design should be carried out with the aid of industry recognised software, to confirm that temperature effects and flow back induced compression forces are adequately assessed in the casing and tubing design.

c) When making up a casing connection it is important to apply the recommended torque. Too much torque may over-stress the connection and result in failure of the connection. Too little torque may result in leaks at the connection.

d) The correct use of casing dope, appropriate temperature application and its impact on torque make-up should be incorporated into casing running procedures.

e) Titleholders should consider the potential impact of high casing pressures on cement bond quality (especially before cement has properly set) when determining pressures for any casing tests.

f) Titleholders, their drilling contractors and their well-site supervisors should review and ensure compliance with the work program to run, install and test all casing strings during well construction.

g) Long term monitoring and recording of the casing condition should be undertaken.

h) Pressure tests to verify casing integrity should:

  i. be greater than the maximum anticipated surface pressure if the well is voided to reservoir fluid, allowing for possible leak off at the previous casing shoe.

  ii. be equal to the maximum annulus pressure utilised for pressure testing of completion strings/tools for the string and maximum surface treatment pressures for fracture stimulation.

  iii. not exceed the casing design factor for the pressure test load.

  iv. not exceed the rated capacity of the weakest component of the casing string.

  v. not exceed the rated burst capacity of the casing with a safety factor applied. A typical safety factor is 70% to 80% of rated burst capacity.

i) Casing connection qualification testing should be to ISO 13679 based on intended service.

j) Compression rating of connections should be applied to casing and tubing design as per the manufacturer's recommended values.

k) Where appropriate, suitable allowance should be made for lifecycle wear, erosion and corrosion. Casing wear should be monitored closely in high angle wells during well construction, as well as during the well life.

l) Consideration should be given for use of metal-to-metal seal thread connections in production casing and tubing strings for wells designed for gas lift, and non-CSG gas wells that cross hydrocarbon bearing or over-pressured water zones.

2.3. Cementing

2.3.1. Principles

Petroleum wells must be cemented to:

a) prevent migration paths and isolate the targeted zone from other formations.

b) protect groundwater from contamination.

c) maintain aquifer pressures and quality.

d) obtain and maintain well integrity.

e) protect the casing from corrosion. Corrosion rates of steel with an adequate cement coating are sufficiently low that cement encapsulation of steel is accepted as a permanent barrier.

f) provide axial support for the casing string to permit further drilling and to provide an anchor for BOP equipment.

g) reduce possibilities of casing buckling and/or collapse, particularly in situations where abnormal formation stresses occur.

h) seal off the casing shoe, or equivalent, in order to control pressure.

2.3.2. Mandatory requirements

a) To prevent interconnection between zones of differing pressure and water quality:

   i. all surface casing must be cemented from shoe to surface.

   ii. for cementing production and intermediate casing, titleholders must design to ensure cement is either brought to surface or designed to an appropriate safety overlap distance of at least 50 m back inside the previous casing shoe. However, where titleholders choose not to bring cement to surface, they must consider that after decommissioning, two adjacent cement barriers across all aquifers will be required under this code.

   iii. testing pressures must take into account collapse pressure of the inner casing string and fracture gradient at the outer casing shoe.

b) Cement constituents and properties must be suitable for the intended conditions of use and used in compliance with the relevant safety data sheet (SDS) requirements.

c) Appropriate cement laboratory testing procedures must be carried out (ISO 10426-2, API RP 10B-2) in advance of the well being drilled or decommissioned to ensure the resulting slurry meets the requirements of the well design.

d) In the case where similar wells are drilled or decommissioned in an area with similar well properties (depths, temperatures and well design), constant cement materials and mix water properties, then a representative lab test may be acceptable. The testing, as a minimum, must include:

   i. slurry density

   ii. rheology

   iii. thickening time

   iv. free water

   v. fluid loss (if required)

   vi. fluid compatibility (cement, source/mix water, drilling fluid, spacers used)

   vii. mechanical properties

   viii. compressive strength development with time.

e) Wait on cement setting time:

   i. Slacking off or removing BOPs – must be based on the cement achieving a minimum of 100 psi (0.7 MPa) compressive strength at the temperature of any potential flow zone in the annulus just cemented. Alternatively, titleholders may use a mechanical barrier that is compliant with API 65 – Part 2 and tested to verify a pressure seal prior to removing BOPs.

   ii. Pressure testing of casing (unless conducting a green cement pressure test on bump) or drilling out the shoe track for a subsequent hole section – must, as a minimum, have achieved a minimum compressive strength of 500 psi (3.5 MPa) based on the laboratory testing time for cement surrounding the casing shoe.

f) Titleholders must ensure all zones (both hydrocarbon bearing and aquifers) are isolated with cement with a minimum ultimate compressive strength of 500 psi (3.5 MPa).

g) Titleholders must determine and document in their well procedures a minimum required ultimate compressive strength for cement slurries to be used across zones which may be hydraulically fracture stimulated.

h) Titleholders must ensure that the required compressive strength slurry for fracture stimulation is placed at least 150 m above any zone to be fracture stimulated. This must be verified by cement log evaluation. API Guidance Document HF-1 addresses this issue.

i) During all cement jobs, where the casing being cemented is installed to the surface, cement returns to surface must be continuously monitored and recorded to confirm the effectiveness of the cement placement. Pressures during the cement job and immediately prior to plug bump must be similarly recorded as a potential indicator of height of cement column and downhole problems.

j) Calcium chloride or other chloride-based accelerants must not be added to the cement mix unless the free water content of the cement is specified as <2% as per the free water test outlined in API RP 10B-2.

k) Casing centralisation simulation must be undertaken for the casing centralisation plan to achieve a minimum of 70% standoff across the total cementing depth. This equates to 23 mm for 9-5/8" casing in 12-1/4" hole, 13 mm for 7" casing in 8- 1/2" hole, 21 mm for 5-1/2" casing in 7-7/8" hole.

l) Centralisation calculations for a vertical well must include a deviation of 3 degrees from vertical at casing depth unless otherwise proven. Where the actual deviation exceeds three degrees, the actual deviation data must be used. Refer API 10D-2.

m) Titleholders must review centraliser selection and application in the API Technical Report 10TR4 Selection of Centralisers for Primary Cementing Operations. An appropriate wiper plug assembly must be used for production casing to enable plug bump and pressure test of the casing before cement cures.

n) Titleholders must have a verification procedure for primary cement jobs. Acceptable verification and evaluation methods for primary cement jobs are outlined in Table 1. Titleholders must use at least three of the verification methods described in Table 1.

o) If surface casing is set shallower than 60 m true vertical depth (TVD), the next casing string must be cemented to surface.

Where cement is not returned to surface, cement evaluation logging or pressure testing must be performed and recorded, to verify isolation of the casing/casing annulus has occurred, after the cement has reached a compressive strength of 500 psi (3.5MPa) at surface conditions. In wells in which it will take greater than 36 hours to reach a compressive strength of 500 psi (3.5MPa) at surface conditions, then 36 hours wait time can be used.

Table 1: Verification and evaluation methods for primary cement jobs

Completion type	Verification criteria	Contingency
Requirements which cover both casing and liner completions	- Slurry mixed and placed in accordance with contractor approved cementation procedures and the cement job pressure charts show pressure rise during cement displacement in line with expectations - Shoe track volume not over displaced when displacing cement slurry - Downhole losses not greater than the excess pumped within the	- Where the verification is inconclusive, the cement job and zonal isolation requirements must be verified by appropriate cement evaluation tools, interpreted by a competent person. - Remedial cementing/top-up job cementing as required.

Completion type	Verification criteria	Contingency
	cement procedure, and calculated TOC using final circulating pressure and measured fluid returns achieves the objectives identified within the cementing program. - No significant losses or slumping post-placement ofcement. - Casing successfully pressure tested. - A successful appropriate cement integrity test such as aformation integrity test (FIT) or leak off test (LOT). The titleholder must select a test suitable to the conditions. - Appropriate cement evaluation log	
Additional liner only requirements	Pressure test of liner top packer must be performed and recorded to verify zonal isolation has occurred after all the cement has reached a compressive strength of 500 psi (3.5 MPa). Testing pressures must be no less than 500 psi (3.5 MPa) over the previous casing FIT or LOT at the shoe.	- If a failed pressure test occurs on bump, set liner top packer, circulate out excess cement and WOC before conducting pressure test again. - If the pressure test fails again, a liner tie back packer on top of the liner top may be run and then re-tested.

2.3.3. Good industry practice

Titleholders should ensure:

a) proper wellbore preparation, hole cleaning and conditioning prior to the cement job. Once casing has been run to landing depth, titleholders should circulate a minimum of one-hole volume immediately prior to commencing cementing procedures.

b) movement of the casing (rotation and reciprocation) is considered where appropriate to improve drilling fluid removal and promote cement placement.

c) cement design avoids cement shrinkage giving rise to the propagation of fractures and leakage paths

d) cement job design includes proper cement spacer design and volume to ensure the appropriate contact time during pumping.

e) caliper logs in production hole sections, where available, is used to confirm cement volume requirements and standoff calculations. The level of excess cement requirements should be based on local experience.

f) water and cement slurry samples are taken (periodically during each cement job) by the titleholders well site supervisors as an aid to monitoring cement job quality and visual confirmation of speed of cement set up. Cement samples should be maintained on-site for the duration of the well with results recorded in reports.

g) leak-off tests (LOT) or formation integrity tests (FIT) are used on drill out of surface casing shoes as a potential guide to shoe integrity (i.e. good cement around the casing shoe) as well as assisting with well design for well control risk.

h) all cementing operations are carried out with proper mixing, blending and pumping of the cement job at the wellsite. These activities should be properly supervised and recorded in cementing reports. This includes recording any cementing problems encountered.

i) Note: a cement mixed/ blended to the relevant specifications may be prepared off site.

j) wiper plugs are used for surface and intermediate casings to prevent contamination of cement and to enable plug bump and pressure test of the casing before cement cures.

k) baseline cement log evaluation is considered in each new field area where confirmation of cement placement has not been demonstrated. Confirmation of cement placement should be undertaken by recording cement returns to surface together with adequate displacement pressures or pressures immediately prior to plug bump. Cement evaluation logging should continue until repetitive success of slurry design and cement placement together with adequacy of cement bond for zonal isolation is confirmed (e.g. five wells in each new field or area of different geological conditions). There may be instances after repetitive success has been shown, such as when a new cementing provider is used or a new design is implemented, that cement log evaluation should take place. The additional cement evaluation log requirements for wells that are to be hydraulically stimulated should be noted.

2.4. Wellheads

2.4.1. Principles

The wellhead is a part of the defined safe operating envelope for the duration of the well life. The primary purpose of a wellhead is to:

a) ensure well integrity at the surface

b) provide the suspension point and pressure seals for the casing strings that run from the bottom of the hole sections to the surface pressure control equipment

c) support the BOP during the drilling phase and equipment during the production phase

d) provide the arrangement for the sealing, testing, monitoring, injecting into and bleeding off between annuli.

Wellheads may be threaded or welded onto the first string of casing, which has been cemented in place during drilling operations, to form an integral part of the well structure.

2.4.2. Mandatory requirements

a) Titleholders must use wellhead equipment that complies with API Specification 6A Wellhead and Tree equipment/ISO 10423 and NACE MR0175/ISO 15156.

b) Titleholders must monitor wellheads for leaks in accordance with their well integrity management system and leak detection and repair program.

c) Wellhead and production tree pressure rating must exceed all reasonably expected loads for the entire life of the well. Wellhead product specification level (PSL) and trim must be matched to fluid properties, pressure and temperature of flowing conditions.

d) Side outlet valves must be rated to at least the same pressure as the wellhead unit they are attached to. All wellhead components must be rated to the well pressure envelope.

e) Wellheads must have adequate valve outlets accessible and operational for all annuli to allow for monitoring of annuli pressure.

f) Casing to wellhead pressure tests (‘P’ seal area or equivalent) must not exceed 80% of the collapse rating of the casing.

g) Any change to use of a wellhead must be risk assessed by the titleholder to ensure the compatibility of the existing equipment with the proposed usage.

2.4.3. Good industry practice

a) Wellheads should be designed to take into account maximum axial loading. If an emergency slip and seal assembly is run this might affect the maximum axial loading.

b) Titleholders should ensure that during initial wellhead installation and subsequent well intervention workovers, wellhead seal tests are conducted to test the mechanical integrity of the wellhead sealing components (including valve gates and seals) and confirm they can hold against well pressure.

2.5. Well control

2.5.1. Principles

The primary purpose of well control is to provide barriers to prevent the uncontrolled release of formation fluids to the surface. Well control for overbalanced drilling can be defined as:

a) Primary well control – the maintenance of a hydrostatic pressure of fluid in the wellbore, adequate to balance the fluid pressure (pore pressure) in the formations drilled. In practice this means an excess of hydrostatic pressure is maintained to provide a safe level of ‘overbalance’ to formation pressure.

b) Secondary well control – used when the primary well control fails resulting in formation fluids flowing into the well. Appropriate pressure control equipment will be in place to contain any influx of formation fluid and allow it to be safely handled e.g. safely circulated out of the well.

The requirements for well control systems will vary when underbalanced or managed pressure drilling techniques are used. However, in all operations the guiding principle is to maintain at least two well control barriers when hydrocarbon release is possible.

2.5.2. Mandatory requirements

a) Titleholders must address well control in safety management systems. Titleholders must have a well control standard document available at well sites, detailing requirements for equipment level, kick detection and well control techniques.

b) During well construction, titleholders must install well pressure control equipment (e.g. BOP stack and wellhead) for all operations after the installation of the surface casing. Well pressure control equipment can be removed once the well is decommissioned or cased and suspended after all hydrocarbon zones and aquifers are isolated and barriers established and verified.

c) Titleholders must use pressure control equipment compliant with API Specifications 16A, 16C and 16D.

d) The level of pressure control equipment required on any operations, and the configuration employed, must be suitable for the well, the subject of a risk assessment and documented accordingly.

e) Titleholders must function and pressure test pressure control equipment in accordance with API Standard 53, including drill through equipment, choke and kill line systems and pressure storage systems (e.g. accumulators).

f) Titleholders must use best industry practice for early identification of fluid influx (well kick). This may include monitoring of drill fluid pit level, flowline rate and trip volume sheets derived from trip tank measurements.

g) Titleholders using underbalanced techniques must ensure a well control risk assessment is conducted and control measures to counter the absence of primary well control are documented.

h) Working temperature rating for well pressure control equipment must meet the maximum anticipated continuous exposure temperature for rubber/elastomer components.

i) All well pressure control equipment, including connections, valves, fittings, piping etc (excluding annular BOPs), must be rated to exceed maximum anticipated shut-in surface pressure.

j) A hydrocarbon and gas monitoring system must be used on the well site to identify hydrocarbon bearing formations and potential gas influx. Any identified hydrocarbon or gas bearing formations and hydrocarbon and gas properties must be recorded by the titleholder.

2.5.3. Good industry practice

a) Additional guidance for the selection and use of well pressure control equipment is documented in API Standard 53 - Blowout prevention equipment systems for drilling wells.

b) Safety critical spares for BOP equipment should be readily accessible. Storage should prevent degradation of rubber and elastomer consumables by heat or light.

c) Regular and realistic training drills, relevant to operations, should be conducted for all personnel involved in detection, prevention and recovery of a lost barrier.

2.6. Fluids

2.6.1. Principles

Fluids are used throughout the lifecycle of a well including during drilling, completion, workovers and stimulation. While drilling, fluid is usually circulated down the drill string and up the annulus between the drill string and hole wall. This drilling fluid serves to lubricate the drilling assembly, remove the formation cuttings drilled, maintain pressure control of the well, and stabilise the hole being drilled. Drilling fluid is generally a mixture of water, clays, fluid loss control additives, density control additives, and viscosifiers.

The drilling fluid used for the majority of wells in NSW is water based. It may be either fresh water or may be based on salt brine. Potassium chloride, the principal salt component, is often used as a weighting agent and to help control swelling clays. Organic polymers or clay may be added to the base fluid to raise the viscosity and aid in removal of drill cuttings.

After use, drilling fluid is returned to the drilling sumps where the solids settle to the bottom of the sump. The liquid may then be recirculated.

Losing drilling fluids downhole is undesirable as they are the primary means of controlling pressure within the well and maintaining removal of formation cuttings drilled. When a loss is detected, loss circulation material (LCM) may be incorporated in the drilling fluid. LCM prevents fluid loss by blocking the pores/fractures in the host rock.

Underbalanced drilling techniques may be used for drilling where air, nitrogen or other underbalance ‘aerated’ fluids are used as a drilling medium.

Titleholders and drilling contractors undertaking underbalanced drilling must ensure that all risk assessment, well design, operational and crew training requirements are addressed prior to and during execution of the project.

Disposal of fluids must be done in accordance with the relevant activity approval and all regulatory requirements.

The primary objectives for drilling and completion fluids are to:

a) maintain primary well control as per the well barrier requirements

b) optimise hole conditions for the retrieval of geological and reservoir data

c) minimise reservoir damage and therefore optimise well productivity

d) improve drilling performance.

2.6.2. Mandatory requirements

a) Fluids must be selected and managed to ensure all products used during the well lifecycle are used in accordance with the manufacturer's recommendations and relevant safety data sheets (SDS).

b) The name, type, CAS number (or SDS) and quantity of each chemical used on each well throughout the life of the well must be recorded

c) Oil-based fluids or fluids containing benzene, toluene, ethylbenzene or xylene (BTEX) compounds must not be used for petroleum drilling in NSW. (www.industry.nsw.gov.au/policies/items/ban-on-use-of-btex-compounds-in-csg-activities)

d) The source of water used for all well procedures (drilling, workover and stimulation) must be recorded for future well monitoring purposes.

e) Personnel, including contractors, must be aware of the environmental impact and spill emergency procedure of the products and substances in use on site.

2.6.3. Good industry practice

a) Drilling fluid should be a carefully monitored and controlled mixture designed to:

   i. achieve best drilling results and ensure efficient removal of formation cuttings and

   ii. control formation pressures; and minimise damage to formations.

b) Titleholders should ensure that the drilling fluid selected is appropriate for the well design to accommodate any locally experienced drilling problems and anticipated geological conditions likely to be encountered.

c) Using biodegradable substances in the drilling fluid is preferred.

d) Products should be chosen, stored, and used at concentrations that minimise the risk of causing environmental harm.

e) Titleholders should use established, effective drilling practices to achieve a stable, uniform, and, as far as possible, in-gauge hole.

f) Titleholders should consider water quality used in cement mixes.

g) Biocide, oxygen scavenger and corrosion inhibitor should be considered for all water-based systems.

h) Fluids should be captured and recycled for reuse as far as practicable

i) Lost circulation material strategies should be documented, and sufficient stocks of lost circulation material kept on site for contingency purposes and based on field experience.

j) When drilling with a closed fluid system, fluid weight and viscosity in and out of the hole should be checked regularly and recorded by the drilling contractor or well servicing contractor. This frequency should be increased during narrow pore pressure/fracture pressure window drilling.

k) To maintain accurate volume accounting, fluid transfers should not be made from or to the active system while drilling through critical pore pressure ramps, unknown pore pressure zones, narrow pore pressure/fracture pressure window drilling, during cementing operations or negative flowback/pressure testing.

l) Use of air or gas drilling fluids in underbalanced drilling operations should be in accordance with API RP 92U Underbalanced Drilling Operations.

2.7. Evaluation, logging, testing and coring

2.7.1. Principles

The types of logs that are run in a petroleum well are selected by geologists and engineers at the time the well is designed. The main evaluation data is typically gathered with wireline logging tools or logging-while-drilling (LWD) tools. Common logging tools used for evaluation of petroleum wells include natural gamma ray, density, calliper, resistivity, sonic and image logs.

Logging produces valuable information on all formations logged to accurately determine the nature and type of all strata encountered. This information is used in optimising future well design and drilling operations as well as determination of the actual depth and thickness of all subsurface formations in the drilled hole. Review of well logs assists in setting casing strings in the correct place to achieve well design objectives and to properly achieve the isolation requirements of the casing and cement.

Formation testing may be carried out on some wells. The formation is sampled by either drill pipe conveyed drill stem test tools or by wireline deployed test tools.

In some exploration wells, the well design may be modified to cut 'cores' of the strata encountered. This involves drilling a core of solid rock and recovering it to surface. The core is examined for geological information and any coals are tested for gas content.

In petroleum exploration and development, formation evaluation is used to characterise formation fluids and determine the ability of a well to produce hydrocarbons. Formation evaluation seeks to:

a) characterise reservoir properties, including:
   i. petrophysical properties
   ii. formation fluid properties
   iii. geomechanical properties;
b) evaluate reservoir productivity.

Cuttings samples, core samples, fluid samples and other samples from the well drilling process must be collected, stored and distributed according to legislative and regulatory requirements.

2.7.2. Mandatory requirements

a) Samples of formation cuttings, cores and fluid samples must be kept in accordance with legislative requirements.
b) Appropriate equipment must be readily available to recover survey or logging equipment lost downhole.
c) Well testing requirements (for wells that will not flow to surface, only the relevant requirements are applicable):
   i. Well test programs must be prepared. For all DSTs a well and tool schematic must be prepared and included in the well test program.
   ii. All well test equipment must be located in appropriate hazardous classification areas.
   iii. Clear and accurate definitions of temperature and pressure ratings must be provided for all surface equipment. Any pressure de-rating due to elevated temperatures must be addressed in the emergency shutdown and monitoring systems
   iv. The line to the testing choke manifold must be rated and pressure tested to the maximum expected surface pressure as calculated from the reservoir pressure less the hydrostatic pressure of a gas column to surface plus any kill or surface treatment pressure (e.g. fracture stimulation).
   v. Pressure monitoring capability must be available at the wellhead. During the well test, actual flowing conditions must be recorded and compared to predicted values.
   vi. The well test surface equipment must be designed, prepared and operated in accordance with API 6A, NACE MR-01-075, ANSI B31.3 (Spools and crossovers).
   vii. Emergency response procedures must be in place.
d) Managing and transporting explosives must be in accordance with applicable regulatory requirements.

e) The titleholder must ensure that service companies providing radioactive or explosive materials have appropriate licences and procedures for the safe transport, handling and use of:

   i. radioactive sources in formation evaluation tools
   ii. radioactive tracers
   iii. density measurement equipment
   iv. radioactive markers in well completions and well test strings
   v. explosives to be used in drilling, well completions and well testing operations.

f) When coring operations are conducted, the testing for gas using handheld sensors at the rig floor must be conducted while retrieving the inner core barrels as well as when opening the core barrel and examining the cores.

g) If an emitting source cannot be retrieved from downhole, an approval to dispose of it must be sought from the NSW EPA. Information regarding this can be found at: www.epa.nsw.gov.au/your-environment/radiation/management-licence/info-radiation-management/disposal-of-regulated-material

2.7.3. Good industry practice

a) Where appropriate (e.g. when hole conditions and pressure regimes dictate), titleholders should ensure secondary well pressure control equipment is in place during logging operations. This may include such equipment as wireline lubricators or pack-offs.

b) Casing and tubing stress analysis should consider the well test load cases to confirm the operating envelope for the well, if applicable.

c) Hole conditions should be assessed prior to running emitting sources into a well.

2.8. Fracture simulation

2.8.1. Principles

Fracture stimulation is conducted to improve recovery of hydrocarbons. The underlying principles are to:

a) ensure protection of aquifers is maintained during all operational phases for fracture stimulation and flow back

b) ensure operations are carried out such that the well operating envelope is not exceeded and well barriers are maintained

c) use and source water as per approved regulatory practices

d) flow back fluids in such a manner as to ensure all recovered fluids are isolated and do not come into contact with aquifers or pollute soil or soil substrate.

2.8.2. Mandatory requirements

a) Titleholders wanting to undertake fracture stimulation activities must prepare and implement a fracture stimulation management plan (FSMP). The FSMP must be appropriate to the nature, scale, intensity and potential impacts of the proposed fracture stimulation activity.

The FSMP must:

b) set out the fracture stimulation activities to be carried out by the titleholder

c) set out the management controls for those activities which ensure the effective prevention, or where that is not possible, mitigation, of risks associated with the fracture stimulation activity

d) set out a summary of the impact assessment undertaken for the fracture stimulation activity, including a description of the location, scale, timing, duration and hours of operation of the activity, and any other relevant features of the activity

e) identify the well(s) and zones to be fracture stimulated

f) identify:

   i. all chemicals proposed to be injected as part of the fracture stimulation process

   ii. the proposed source of water for the fracture stimulation fluid

   iii. the proposed maximum (or minimum where relevant) volumes and concentrations of those chemicals.

g) have monitoring arrangements set out that provide for the assessment and determination of the following:

   i. before fracture stimulation (before pumping is commenced):

      1. annular and/or casing/tubing pressure, monitored at the surface

      2. bottom hole pressure[1], calculated from the surface

   ii. during fracture stimulation:

      1. bottom hole, annular and surface injection pressure

      2. the volume, composition, and pumping rate of fracture fluids and proppants at surface conditions

   iii. post-stimulation:

      1. the volume and quality of flowback and produced water (to determine whether induced inter-aquifer connectivity has been prevented)

      2. casing/tubing pressure (to verify that the integrity of the well and well equipment has been maintained)

h) include methodologies to verify the location, length and orientation of the fracture growth (such as micro-seismic observations), unless the titleholder can confirm each of the following:

   i. the applicable geomechanical and fluid transport model has been validated by fracture growth modelling in previous wells

   ii. the previous monitoring that is relied upon was associated with a fracture stimulation activity in the same hydrocarbon bearing formation, with similar geological properties and location as the current fracture stimulation activity.

   iii. aquifers, offset well or other sensitive features are not within the buffer zone nominated in the impact assessment.

i) include a reference to a trigger action response plan (TARP). The TARP must:

   i. address the risks identified in the fracture stimulation risk assessment

   ii. set out the procedures to be followed and actions to be taken in the event of:

      1. well blowout or loss of integrity

      2. impacts to offset boreholes and/or wells

      3. impacts to an aquifer

[1] Although measuring bottom hole pressure directly through gauges is preferred, determination of an estimated bottom hole pressure using standard industry practices is acceptable.

4. deviation of observed fracture propagation behaviour away from expected modelled propagation behaviour.

Additionally:

j) Wells that are to be hydraulically stimulated require evaluation of cement bond quality using appropriate cement evaluation tools. Cement evaluation logging must continue until repetitive success of slurry design and cement placement, together with adequacy of cement bond for zonal isolation is confirmed (e.g. five wells in each new field or area of different geological conditions). If there is a material change after repetitive success has been shown, such as when a new cementing provider is used, there are issues in the cement job/s or a new design is implemented, then cement evaluation logging must take place again until repetitive success of slurry design and cement placement.

k) If the annulus between the production casing and the surface/intermediate casing has not been cemented to the surface, the pressure in the annular space must be monitored and controlled while conducting fracture stimulation.

l) The pressure relief valves on the pump units must be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing and wellhead.

m) Post fracture stimulation, flow-back or produced fluids must be recovered and managed as per approved regulatory practices.

n) Post fracture stimulation, a report is to be submitted to the department within 30 days of the completion of the activity. The report must include:

   i. identifying information concerning the title, the contractor, and the location of the well

   ii. commencement and completion dates of fracturing for each well

   iii. details of each interval fractured

   iv. summary of operations (including volume and type of chemicals used in each stage)

   v. assessment of the fracture stimulation for every targeted zone including:

      1. annular pressure data (if available)
      2. casing and tubing pressure
      3. bottom hole pressure with time
      4. bottom hole calculated proppant concentration
      5. rate that fracturing fluid was pumped over time and the total volume pumped at each stage
      6. composition of the fracturing fluid and any other chemicals introduced into the well (quantity of each component; concentration of each component; name of chemical compounds contained in fluid)
      7. maximum surface pressure at each stage
      8. estimated fracture gradient for the target interval
      9. details of equipment and diagnostic techniques used
      10. if an event related to the fracturing activities has caused material environmental harm, details of each step taken to mitigate the harm.

2.8.3. Good industry practice

a) Stimulation design should take into account the location of known faults.

b) Titleholders should consider the risk of casing deformation as part of the well design risk assessment process and they should document any resultant control measures in the operations program(s).

c) Industry recognised software and geo-mechanics data should be used to develop the final stimulation design.

d) The proposed design of the fracture geometry should be included in the stimulation design including (fracturing) target zones, sealing mechanism(s) (both natural geological seals as well as adequate casing and annular cement) and aquifers, so as to minimise possibility of stimulation fluids migrating from the designed fracture zone(s).

e) Water used in hydraulic stimulation operations should be captured and recycled for reuse as far as reasonably practical.

f) Title holders should refer to API Guidance Document HF1, *Hydraulic Fracturing Operations Well Construction and Integrity Guidelines.*

2.9. Well integrity management

2.9.1. Principles

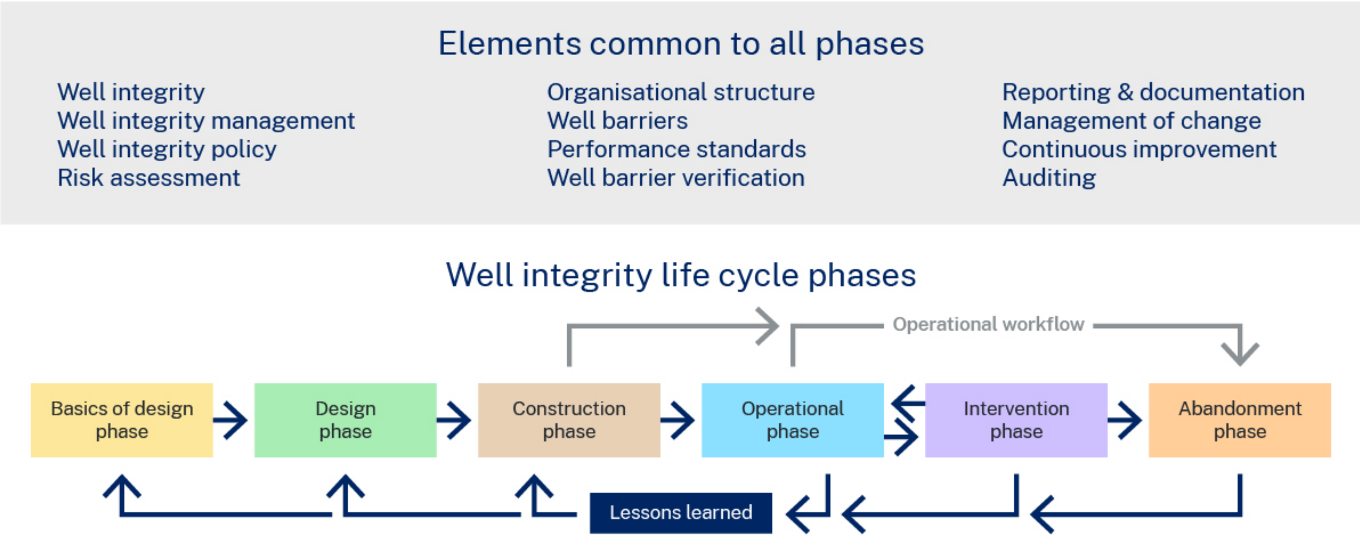
Well integrity ensures containment and prevents the escape of fluids to subsurface formations or the surface. The elements common to the phases of well integrity management are shown in Figure 1.

The titleholder must prepare a well integrity management system (WIMS) that sets out how well integrity is to be maintained for the well life cycle. The WIMS must address the elements in Figure 1.

The Work Health and Safety (Mines and Petroleum Sites) Regulation 2022, clause 30 (7) requires a well integrity control plan be prepared. When preparing a WIMS titleholders should review the requirements for a well integrity control plan (WHS (MPS) Regulation 2022 Schedule 2 – clause 5) and consider addressing these in their WIMS. The control plan if properly prepared can fulfill the requirements for a WIMS.

Relevant well integrity standards, such as ISO 16530-1 ISO 16530-2 and NORSOK D-010, should be reviewed when compiling a WIMS.

Figure 1: Elements common to the phases of a well integrity management system (ISO 16530-1:2017 Petroleum and natural gas industries – Well Integrity, Part 1: Life cycle governance.)



Monitoring and maintenance is required to preserve the well in a suitable condition for its useful life. Well integrity management systems and associated documents for subsurface assets aim to ensure that wells meet operational availability objectives and well integrity goals for the full lifecycle of the well.

Wells are designed to be operated such that:

a) well barrier status is known and technical integrity risks are managed; and

b) well safe operating envelopes are not transgressed.

2.9.2. Mandatory requirements

a) The titleholder must be able to demonstrate that verification of well integrity and barriers exists through maintenance and monitoring, and through the establishment of a WIMS. Monitoring mechanisms and their frequencies must be determined through a risk assessment or asset integrity management guidelines.

b) The WIMS must outline:

   i. a regular wellhead maintenance program
   ii. inspections for identification of leaks
   iii. routine operational visits
   iv. monitoring and management of annuli pressures
   v. barrier maintenance and verification
   vi. assessment during the well life cycles of the wellhead, tubing and casing, for any wear due to erosion or corrosion, and its impact on well integrity
   vii. risk assessment and response levels for impaired barriers
   viii. well integrity records to be maintained.

c) The titleholder must ensure up-to-date integrity records are maintained and documented, with the existing risk level of wells and any other relevant observations related to well integrity documented.

d) Well integrity records must contain the current operational status and completion status of all wells.

e) If a well integrity issue is discovered, a risk assessment must be completed and any identified control measures, such as well monitoring, or abatement measures, must be implemented for the well to continue operating.

f) Where a well integrity issue is identified involving one or more barriers being severely degraded or failed and not readily remediated the EPA must be notified as soon as reasonably practical but no later than 5 days. This includes where the well risk level set out under the WIMS increases to require additional monitoring and/or corrective action. Notification must be made in accordance with this code.

2.9.3. Good industry practice

a) All surface equipment associated with the well barrier envelope should have a preventative maintenance program in place.

b) If the annulus is being abnormally charged with gas, an analysis of the gas content should be considered to determine the source and nature of the potential leak.

c) Well barriers should be identified and monitored or tested along with their related function and associated acceptance criteria as necessary. The barriers should be maintained as necessary through the well lifecycle and re-established/compensated for when impaired. Parameters that could affect well integrity negatively should be monitored.

d) Titleholders should conduct regular annular casing pressure management in accordance with relevant standards. Consideration of the provisions of API RP 90-2 Annular Casing Pressure Management for Onshore Wells is recommended unless specified otherwise in this code.

2.10. Workover and intervention

2.10.1. Principles

Well workovers and interventions can be done either as remedial work to restore barriers or to possibly enhance production and reconfigure the completion of the well. The workover may involve replacing tubing or a pump, testing pressure seals and measuring or logging well parameters such as flowrates and temperatures in the well, fluid sampling and pipe integrity.

Workovers and interventions are to be designed and implemented to meet relevant industry standards.

2.10.2. Mandatory requirements

a) The titleholder must ensure well barriers are in place to intervene on the well and if necessary, risk assess any deviations.

b) The titleholder must use fit-for-purpose well design and construction materials as dictated in this code.

2.10.3. Good industry practice

a) Well barrier schematics should be developed and included in the workover/intervention program. Barrier verification requirements should be clearly outlined in the well workover/intervention program.

b) During well intervention, when equipment is removed from a well or depressurised for maintenance, a breakdown or visual inspection should take place of all equipment to confirm condition after being in service.

c) Evidence of corrosion for recovered equipment should be used to determine mechanical integrity and help predict possible issues for intervention in similar wells.

d) All new barriers or new operating envelopes should be verified and recorded prior to handover of the well back to production or decommissioning.

2.11. Well suspension

2.11.1. Principles

Well suspension applies to a shut-in well, which has additional requirements as defined by the titleholder's well integrity management system due to the length of time shut-in. Appropriate consideration is to be given in the titleholder's well integrity management system for wells that are suspended for significant periods of time.

The main considerations when suspending a well are:

a) All fluids from the well must be contained, and water cannot enter the well from the surface

b) Monitoring requirements can be met, and production can readily be resumed

c) Safe recommencement of operations can occur

d) All safety requirements are met.

The following matters are to be considered when suspending a well:

e) Well construction and completion

f) Well integrity history including the integrity of the cement columns

g) Geological formations encountered

h) Potential loss zones

i) Hydrogeological conditions

j) Environmental risk

k) Regulatory requirements, petroleum title conditions and industry standards
l) Perforated and hydraulic fracture stimulated zones.

2.11.2. Mandatory requirements

a) Two tested well barriers must be used for well suspension, except:
   i. during re-entry, workovers and other maintenance work
   ii. during temporary suspension of open-hole sections due to weather or other operational reasons
   iii. for wells, where a single barrier has been identified as appropriate in the WIMS.
b) Suspended wells must be classified and addressed in a titleholder's well integrity management system.
c) Appropriate well suspension fluids must be used. Water-based fluid with biocide, oxygen scavenger and/or corrosion inhibitor must be used in the wellbore in-between or above isolation plugs.
d) The well site must:
   i. display appropriate safety signs
   ii. be secured with a locked fence around the well
   iii. be maintained clear of vegetation around the well
   iv. have wellhead valves securely chained and locked or have their handles removed.
e) A program must be in place for regular inspections to check for gas leaks and well integrity monitoring and maintenance matters in accordance with the titleholder's WIMS.
f) A record must be kept of all inspections in accordance with the titleholder's WIMS.

2.12. Well decommissioning

2.12.1. Principles

Petroleum well decommissioning is required to ensure the environmentally sound and safe isolation of the well, protection of groundwater resources, isolation of the productive formations from other formations, and the proper removal of surface equipment.

Well decommissioning is to be conducted such that well barriers contain and control wellbore fluids, provide structural support and otherwise retain well integrity throughout the well decommissioning load conditions. Barriers used for the decommissioning of a well or a section of a well are permanent well barriers. The only permanent well barriers are open hole cement plugs or cement plugs in casing with good quality cement on the outside. Other materials may be considered by the titleholder but need qualification so that they can be considered permanent barriers.

The well decommissioning objectives are to ensure:

a) isolation of aquifers from each other and from permeable hydrocarbon zones
b) isolation of permeable hydrocarbon zones from each other
c) permeable formations containing fluids at different pressure gradients and/or significantly different salinities are isolated from each other to prevent crossflow
d) there is no pressure or flow of hydrocarbons or fluids at surface both internally in the well and externally behind all casing strings
e) recover/remove surface equipment to prevent adversely interfering with the normal activities of the owner of the land on which the well is located
f) the site is left safe and free from contaminants.

The following matters are to be considered when decommissioning a well:

g) The construction characteristics of the well including, but not limited to:
   i. confirmation of cement tops
   ii. integrity of the cement column
   iii. integrity of the casing and tubing
   iv. any obstruction in the well
   v. sustained pressure/flow in casing annulus.
h) geological formations encountered.
i) potential loss zones and zones prone to flow
j) hydrogeological conditions i.e. location of aquifers
k) environmental risk
l) regulatory requirements, petroleum title conditions and industry standards
m) perforated and fracture stimulated zones.

2.12.2. Mandatory requirements

a) Before commencing sub-surface decommissioning activities, the titleholder must confirm the absence of pressure/flow externally behind all casing strings. A surface casing vent flow test must be used to detect the presence of flow/pressure build-up.
b) If a positive surface casing vent flow is detected the titleholder must identify and remediate the source of the flow during decommissioning operations.
c) Before conducting the final surface decommissioning activities, the titleholder must confirm the absence of pressure/flow internally within the well and externally behind all casing strings to surface. Wells with no history of external flow/pressure may be cut and capped immediately. All other wells must be monitored for a minimum of 6 months before conducting surface decommissioning (cut and cap).
d) Sucker rods, pumps and tubing (unless sacrificial stinger) and any other debris/junk in the wellbore that can practicably be removed are removed.
e) Any well that is to be decommissioned must be sealed and filled in such a manner to prevent leak of fluids.
f) Cement must be used as the primary sealing material. Cement testing should be carried out as per requirements set out in Section 2.3 - “Cementing” of this code.
g) A 50 m weighted high-vis pill must be spotted below each cement plug that is not set directly above a physical barrier (hole bottom is included as a physical barrier) and where there is any potential for losses below the cement plug i.e. any open section.
h) Cement must not be placed in plugs of more than 200 m lengths without use of coil tubing or sacrificial stinger unless a risk assessment indicates the integrity of the cement plug will not be compromised.
i) A surface cement plug minimum 10 m in length must be placed at the top of the inner most casing. The surface plug acts as a barrier to prevent any long-term ingress into the wellbore and is not deemed to be a pressure containing barrier. Well barriers are to be established below the surface cement plug. If the top of surface cement plug is less than 10 m below the surface the casing can be topped up with cement.
j) There must be a continuous cement barrier with a minimum 30 m length adjacent to the impermeable formation (cap rock) overlying the uppermost hydrocarbon zone.
k) There must be a minimum of two adjacent cement barriers across all aquifers above the upper most hydrocarbon production zone. This can be achieved by the following:

i. Having the surface casing set below the aquifer and cemented to surface and the production casing cemented from 30 m below the base of the lowermost aquifer to 30 m above the uppermost aquifer. In cases where the production zone is less than 30 m below the lowermost aquifer, casing is to be cemented from as low as practical below that aquifer

ii. Fully cementing the inner most casing string from the production zone to the surface provided the cement plug(s) are adjacent to good annulus cement

iii. If production casing has not been cemented with an overlap inside the surface casing shoe the titleholder must remediate the well until the required barriers are achieved. This could involve removing the production casing above the cement top if technically and commercially feasible to do so or performing remediation cement squeezes. Cement top-up jobs are not an approved method of remediation unless isolation can be confirmed with cement log evaluation.

Note: Section 2.12.3 Cement plug requirements and verification methods of this code provides generalised diagrams depicting how decommissioning barrier requirements may be met as described in this section.

l) Cement plugs for decommissioning must meet the minimum requirements as detailed in Section 2.12.3 Cement plug requirements and verification methods of this code and consider the following:

i. The preferred method where possible is to cement the inner casing string to surface while noting the recommended maximum plug length and the requirement for a surface cement plug

ii. A mechanical barrier (e.g. bridge plug) may be used in appropriate situations as a support to set a cement plug on top of it. If a mechanical barrier is used it must be set as close as is practicable above perforations. When a mechanical barrier is used, it or the cement plug directly above it must be verified by tagging it with a minimum 5000 lb (2270 kg) set down weight and pressure tested to 500 psi (3.5 MPa) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings)

iii. Consecutive stacked cement plugs set inside casing do not require additional tagging or pressure testing provided the initial base is verified appropriately i.e. the lower most cement plug of the stack is appropriately verified, or the mechanical barrier set is appropriately verified, or the well bottom has been tagged. Verification of the stacked cement plugs above the bottom plug may be completed via the post job cement report and appropriate calculations

iv. If using a sacrificial stinger to set open hole plugs, provided no losses observed during cement placement then no tag is necessary. This assumes the open hole plug is not set off bottom

v. For a final surface cement plug extending from ground level, the top of cement must be visible and at surface. A shallow set plug is not considered a permanent barrier given the very low formation pressures at ground level. Well barriers must be established and verified with the plugs below the surface cement plug

vi. If unable to achieve the required 5000 lb (2270 kg) set down weight (e.g. plug is too shallow or coiled tubing is used) the minimum force with which plugs must be verified is maximum string weight.

Note: that the use of slick-line or wireline is not an approved method of verifying the tops of plugs.

m) Plugs that do not pass pressure testing must be remediated until the requirements are achieved as noted below:

i. If sufficient depth is available to meet requirements an additional cement plug may be installed and retested

   ii. For failed mechanical barriers an additional mechanical barrier may be installed and retested
   iii. If insufficient depth is available, the plugs must be circulated or drilled out. The plugs must then be rerun and pressure tested.

n) Plugs that are confirmed as too low or too high after tagging are unacceptable. The titleholder must remediate until requirements are achieved as noted below.
   i. A plug is too low if it has a top less than 15 vertical meters above the zone it was intended to cover. Such a plug must be built up to required depth and its location confirmed.
   ii. High plugs must be drilled out if the theoretical plug base is less than 15 vertical metres below the base of the zone it was intended to cover. The plug must be recemented and its location confirmed.

o) BOPs and/or wellhead must not be removed until the cement plug across the surface casing shoe or plug across the uppermost perforations has been physically tagged for correct location and pressure tested.

p) Wellheads must be removed, and casing must be cut greater than 1.5 m below surface.

q) A steel wellhead marker plate, of corrosion resistant alloy or similar grade steel, must be installed to cover all casing strings.

r) Marker tape must be laid about 20 cm above the top of the casing.

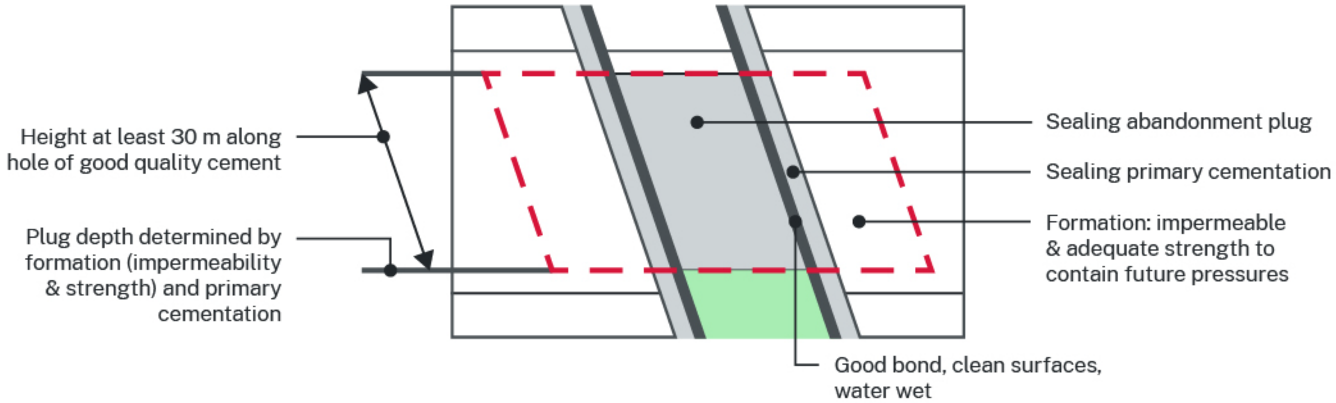
s) The marker plate must be permanently marked with the following details, in addition to any other details required by the Department:
   i. name of the well
   ii. total depth of the well in metres
   iii. the date of decommissioning of the well.

t) Complete and accurate records of the entire decommissioning procedure must be kept, with these records submitted as part of the titleholder's legislative reporting requirements for the decommissioning of petroleum wells.

2.12.3. Cement plug requirements

The following figures provide guidance about the manner in which cement plugs are to be set within a well to achieve the objectives required during decommissioning.

Figure 2: Cement encased casing - well barrier



Legend for figures	
	Cement
	Abandonment fluid and/or additional cement
	High-viscosity pill. Section below plugs with high-vis plugs can also be filled entirely with cement to provide a solid base.

Figure 1: Open hole/ uncased hole section (no lost circulation)

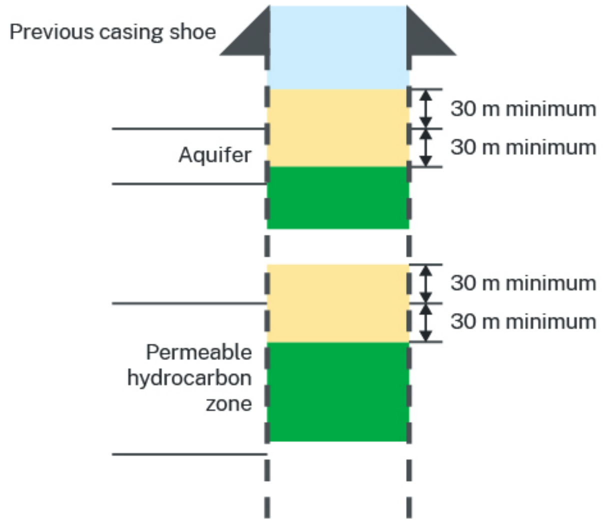


Figure 4: Cased hole section

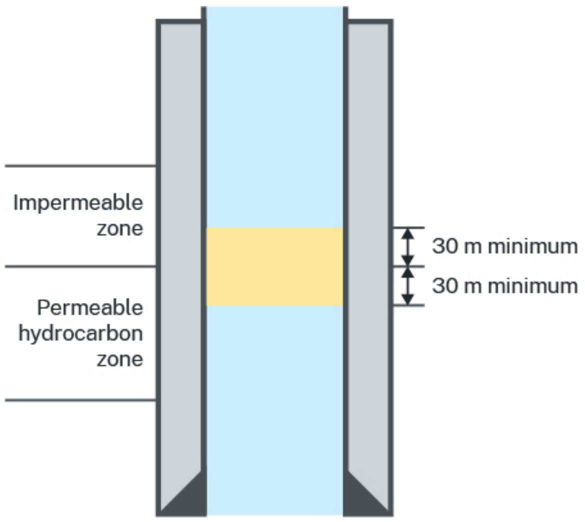


Figure 5: Casing shoe or equivalent with open hole/ uncemented liner below

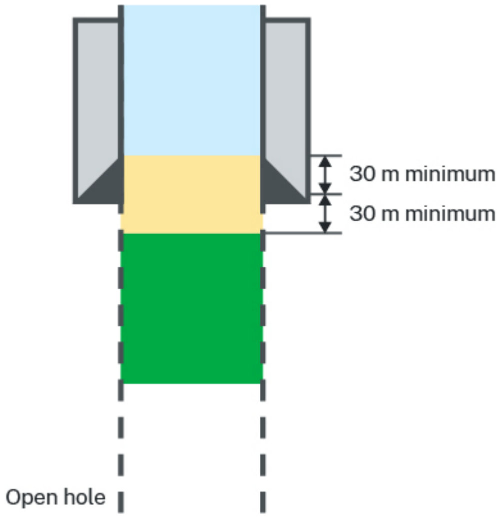


Figure 2: Casing shoe with open hole below (with lost circulation) or casing shoe with uncemented liner below

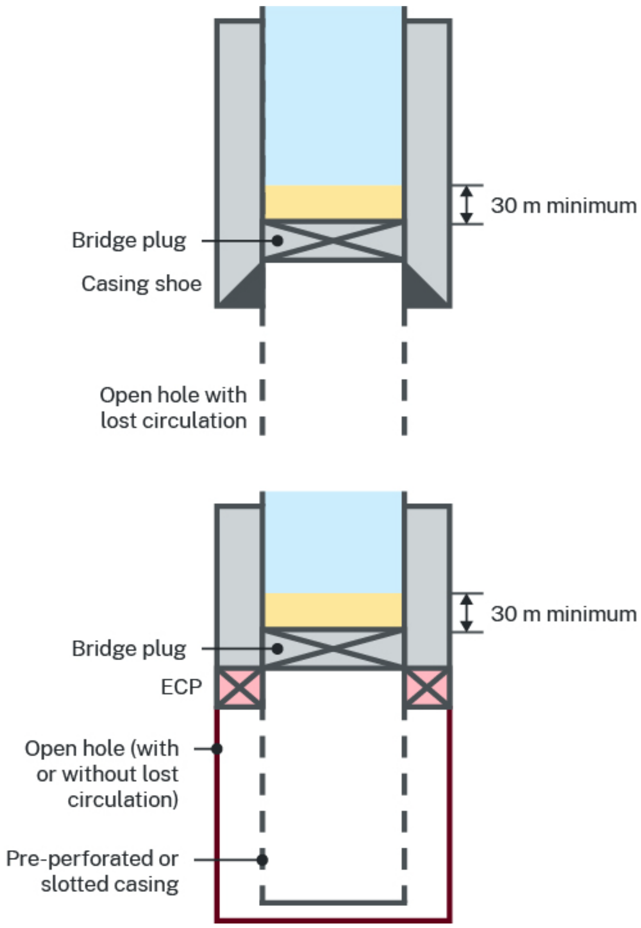


Figure 3: Cut and recovered casing/liner

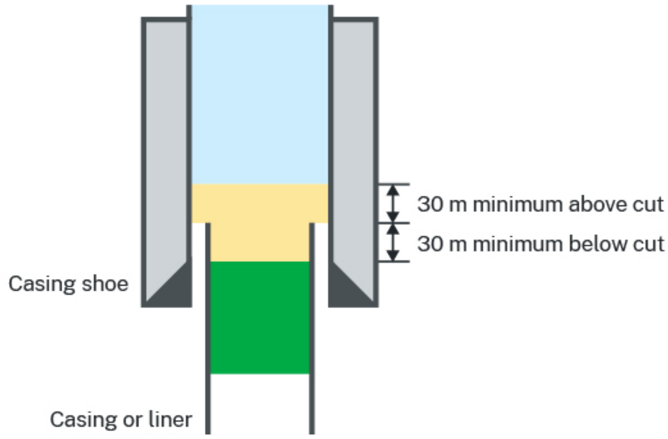


Figure 4: Perforated casing

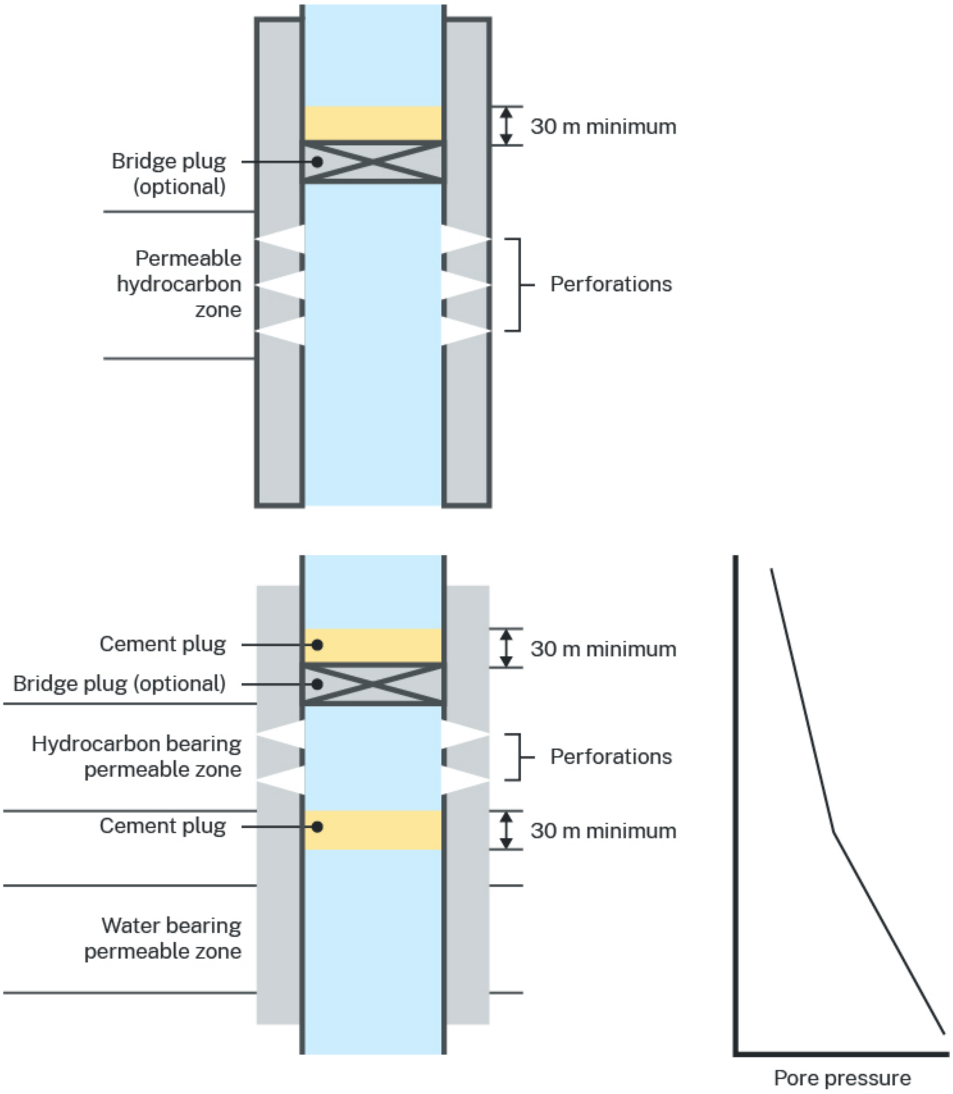
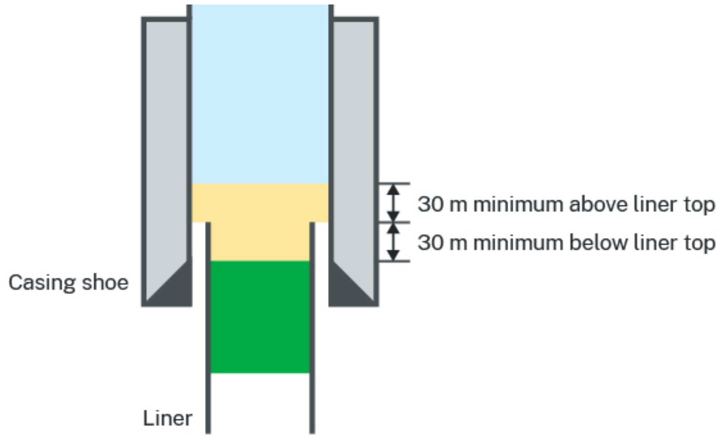


Figure 9: Production liner laps



2.12.4. Cement plug verification methods

Completion type	Requirements
Open hole/uncased hole section	• Off bottom open hole cement plugs to be verified by tagging the plug with a minimum 5000 lb (2270 kg) set down weight. • Verified cement plug(s) must be placed to provide cement coverage at least 30 m above and 30 m below the top of any permeable hydrocarbon or aquifer and between permeable zones of different pressure regimes or salinity.
Cased hole section	• For a cased hole cement plug barrier that is either unsupported or supported by a high-vis pill and not exposed to open reservoir below, verification to be done by tagging the plug with a minimum 5000 lb (2270 kg) set down weight. • Verified cement plug(s) placed adjacent to good annulus cement must be placed to provide cement coverage to surface or at least 30 m overlap with the impermeable formation overlying the uppermost hydrocarbon zone. • Verified cement plug(s) must also be placed to provide minimum 30 m coverage above aquifers unless these are already isolated by two cemented casing strings.
Casing shoe or equivalent with open hole below	• Verified cement plug(s) must be placed to provide cement coverage at least 30 m above and 30 m below the previous casing shoe. • For a cased hole cement plug with the bottom of the plug exposed to open hole, verification to be done by tagging the top plug with a minimum 5000 lb (2270 kg) set down weight and by pressure testing to 500 psi (3.5 MPa) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).
Casing shoe or equivalent with open hole below (with lost circulation) or casing	• Where lost circulation conditions exist or there is open hole behind casing/liner below the shoe, a mechanical barrier may be set as close as is practicable above the casing shoe with at least a 30 m cement plug set above the mechanical barrier, adjacent to good annulus cement (only applicable if co-mingling is allowed).

Completion type	Requirements
shoe or equivalent with uncemented liner below	
Cut and recovered casing/liner	• Cement plug must be verified by tagging the plug with a minimum 5000 lb (2270 kg) set down weight and by pressure testing to 500 psi (3.5 MPa) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings). • Verified cement plug(s) must be placed to provide cement coverage at least 30 m above and 30 m below the casing cut.
Perforated casing	• A mechanical barrier with cement on top may be used. • For a cased hole cement plug exposed to open perforations below, verification to be done by tagging the top of the first cement plug extending above the perforations with a minimum 5000 lb (2270 kg) set down weight and by pressure testing to 500 psi (3.5 MPa) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings). • Verified cement plugs must be placed to provide cement coverage to at least 30 m above perforated intervals. • Verified cement plug must be used to isolate perforated intervals of different pressure regimes, as per regulatory requirements. If co-mingling is allowed, a plug placed above the perforated intervals is sufficient.
Production liner laps	• A cement plug barrier must be set across each liner top in the form of a T-plug with at least 30 m of cement below and at least 30 m of cement above liner top. • Cement plug must be verified by tagging the plug with a minimum 5000 lb (2270 kg) set down weight and by pressure testing to 500 psi (3.5 MPa) above the estimated (or previously recorded) leak off pressure (within the limits of the casing and wellhead pressure ratings).

2.12.5. Good industry practice

a) Use integrated open hole volume calculated from calliper on wireline logs to calculate cement volumes where possible (this applies mostly to exploration wells that are to be decommissioned).

b) If no caliper data is available, 20% - 30% above theoretical volume or local knowledge should be used, along with local hydrogeological knowledge and offset well data.

c) Plugs should normally be a minimum of 30 m in length (height). If the hole is badly washed out, it may be better to set two short plugs over the washed out section then to try to cover this interval with one plug.

d) After placement of a cement plug the rate to pull the work string should be controlled to avoid intermixing of the plug and other fluids in the hole.

e) When placing a plug, excess cement should be used and circulated off the top of the plug to minimise contamination issues.

f) Work-string wiper dart/balls should be used to separate cement and fluids during displacement. If wiper darts are used, a catcher sub should be included in the work-string.

g) Displacement rates during cement plug placement should be kept as high as possible without exceeding the open-hole fracture gradient. This aids in the displacement of the wellbore fluids by the spacer and cement flowing up the annulus. Spacer volumes should be adjusted to provide adequate contact time based on the estimated displacement rate.

h) The wait on cement (WOC) time for tagging should be based on the pre-job lab testing of the slurry at bottom hole static temperature (BHST), preferably on an ultrasonic cement analyser (UCA). Typically, the time to 500psi (3.5MPa) compressive strength is adequate for tagging cement. If the cement plug does not take weight, it is recommended to increase WOC in 4 hour increments up to a maximum of 12 hours additional WOC time.

i) Balanced cement plug volumes pumped should incorporate allowances for open hole and cased hole contamination

j) In order to pull dry pipe after placing a balanced cement plug, the plug should be well under-displaced to enable the plug to fall into a hydrostatically balanced position.

Appendix 1 – Glossary

Term	Definition
annular space (annulus)	The space between two concentric objects, such as between the wellbore and casing or between casing and tubing, where fluid can flow. A-annulus – annulus between the tubing and production casing B-annulus – annulus between the production and previous casing
API	American Petroleum Institute
appraisal well	A well drilled to define more accurately the extent or nature of a previously discovered hydrocarbon accumulation. Also see 'Exploration well'.
aquifer	Has the same meaning as in the Water Management Act 2000, 'a geological structure or formation, or an artificial landfill, that is permeated with water or capable of being permeated with water'. Note: For the purposes of this code, the term aquifer is understood to mean a groundwater system that can yield useful volumes of groundwater. For groundwater management in NSW the term 'aquifer' has the same meaning as 'groundwater system' and includes low yielding and saline systems.
barrier	Any verified means of preventing an uncontrolled release or flow of wellbore fluids from one formation to another or to the surface.
BHST	bottom hole static temperature
BOP	Blowout preventer. Equipment installed on a wellhead assembly to contain wellbore fluids either in the annular space between casing and the tubulars, or in an open hole during well drilling, completion, and testing operations.
CAS number	A unique identifier for chemical substances. A CAS registry number provides an unambiguous way to identify a chemical substance or molecular structure when these are many possible systematic, generic, proprietary or trivial names.
casing	Joints of pipe (can be a single string or multiple strings) run in a well that, together with cement, prevent the wall of the hole from caving in and to prevent movement of fluids along the drilled hole. Commonly at least partly cemented in the wellbore.
casing shoe	The bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string
cement	Powder consisting of alumina, silica, lime and other substances that hardens when mixed with water. Different specifications of cement are used for different purposes. Extensively used to bond casing to the walls of the wellbore.
cementing	The application of liquid slurry of cement and water to various points inside and outside the casing.
cement plug	A balanced plug of cement slurry placed in the wellbore.
centraliser	A device fitted with a hinged collar and bowsprings to keep the casing or liner in the centre of the wellbore to help ensure efficient placement of a cement sheath around the casing string.
circulation	The process of pumping a fluid down the well and back up to the surface in a drilling or workover operation.
completion	A generic term used to describe the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well. The point at which the completion process begins may depend on the type and design of well.
completion (or workover) program	A document that describes the detailed well procedures and risk mitigation for activities including completions, testing, intervention, well repair and/or decommissioning.

Term	Definition
contractors	Third parties contracted by the lease tenure holder to provide well engineering equipment including drilling rigs, materials, equipment and services.
coring	Process of cutting a vertical, cylindrical sample of the formations.
corrosion	Any of a variety of complex chemical or electrochemical processes (except rust) by which metal is destroyed through reaction with its environment.
CSG	coal seam gas Has the same meaning as in the Resources and Energy State Environmental Planning Policy
decommission (well)	Also known as decommissioning or plug and abandonment. A process that involves permanently sealing a well, removing associated surface infrastructure and rehabilitating the site.
drilling fluid	Any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures and emulsions of liquids, gases and solids) used in operations to drill boreholes into the earth.
ECP	external casing packer
evaluation	Includes mud logging, wireline logging, and formation evaluation while drilling, coring and well testing.
exploration well	A well-constructed to explore for petroleum. In this Guideline, the definition of exploration wells also applies to appraisal wells and gas monitoring wells.
FIT	formation integrity test. A test of the strength of a formation that is conducted after drilling out a casing shoe track. In a FIT the leak off pressure is not reached.
fluid	Liquid or gas (oil, gas, water)
formation pressure	Force exerted by fluids in a formation
good cement	Cement that has been verified to position, quantity and quality
good annulus cement	Cement that has been verified to position, quantity and quality in the casing annulus
groundwater	Water that occurs beneath the ground surface in the saturated zone
hydrocarbon zone	A petroleum reservoir.
intervention	An operation carried out by re-entering an existing well.
fracture stimulation	The process by which petroleum wells are 'stimulated' when fluids or gases and proppant, such as sand, are forced at high pressure to create a conductive flow path into the target formation resulting in enhanced flow of hydrocarbons to the wellhead. The proppant keeps the flow-paths open once the pressure is released and serves to improve the productivity of the well.
kick	An entry of water, gas, oil or other formation fluid into the wellbore during drilling. It occurs because the pressure exerted by the column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation, thus causing flow.
leak-off	The magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure.
leak-off test	Progressive wellbore formation pressure test until leak-off to provide well integrity information. During the test, a real-time plot of injected fluid versus fluid pressure is plotted. The well designer must then either adjust plans for the well to this leakoff pressure, or if the design is sufficiently conservative, proceed as planned.
liner	A casing string that does not extend to the top of the wellbore, but instead is anchored or suspended from inside the bottom of the previous casing string.
must	is used when a standard is mandatory.

Term	Definition
offset well information	Near well information available from previous drilling in the immediate vicinity of the proposed well.
operations	Any work conducted including rig moves, drilling, running and cementing casing, evaluation, completion, workover and decommissioning.
open hole	The uncased portion of a well. All wells, at least when first drilled, have open hole sections. While most completions are cased, some are open, especially in horizontal or extended-reach wells where it may not be possible to cement casing efficiently.
packer	Piece of downhole equipment that consists of a sealing device. Used to block the flow of fluids through the annular space between pipe and the wall of the wellbore.
PCE	pressure control equipment During drilling operations well pressure control equipment typically includes the BOP stack, BOP control system, full open safety valves, circulating hose, drill string safety valves (inside BOPs), mud and cement pumps, the choke and kill lines and manifold, mud gas separator and all associated pipework and valves.
permeable hydrocarbon zone	A petroleum reservoir that has sufficient permeability regardless of the required completion design (e.g. hydraulic stimulation) to produce petroleum.
petroleum	Has the same meaning as it has in the *Petroleum (Onshore) Act 1991*.
petroleum title	Has the same meaning as it has in the *Petroleum (Onshore) Act 1991*.
production casing	A casing string that is set across the reservoir interval and within which the primary completion components are installed.
production zone	Hydrocarbon producing zone of the formation.
SDS	safety data sheet
should	is used when a standard is recommended as part of good industry practice.
surface	A natural ground surface or the top of the BOP flange when installed.
surface casing	Casing run from surface to suitably competent strata, fully cemented in position, and the connection point for blowout preventers used to seal off water/hydrocarbon sands to prevent loss of circulation. Also used to seal off water sands, weak formations and/or lost circulation zones. In some cases, surface and intermediate casing requirements are provided by the same string.
surface casing vent flow test	A 10-minute bubble test conducted in accordance with good oilfield practice. Any gas flow (e.g. bubbles) must be recorded as a positive vent flow.
suspended well	A well that is shut-in for an extended period of time with two tested barriers in place.
title holder	The company or person with tenure over a petroleum title.
well	Has the same meaning as it has in the *Petroleum (Onshore) Act 1991*.
Wellhead	Means casing head, and includes any casing hanger or spool, or tubing hanger and any flow control equipment up to and including the wing valves.
well intervention	An operation carried out by re-entering an existing well.
workover	Well procedure to perform one or more of a variety of remedial operations on a producing well to attempt production increase. Examples of workover operations are pump repairs, well deepening, plugging back, pulling and resetting liners, squeezer cementing and re-perforating.
WIMS	well integrity management system.

Appendix 2 – Contacts

Department of Regional NSW

Mining, Exploration and Geoscience

www.regional.nsw.gov.au/meg

NSW Environment Protection Authority

www.epa.nsw.gov.au/about-us/contact-us

NSW Department of Planning, Industry and Environment

Water Division

www.industry.nsw.gov.au/contact-us

Planning and Assessment

www.planning.nsw.gov.au/Contact-Us

Appendix 3 – Industry standards

The following industry standards may be appropriate for the application of this code. This list is not exhaustive and other standards may be referenced by the title holder where appropriate.

- API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines
- API RP 10D-2/ISO 10427-2, Recommended Practice for Centraliser Placement and Stop Collar Testing
- API RP 10B-2/ISO 10426-2 Recommended Practice for Testing Well Cements
- API RP 10B-4, Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure
- API RP 10B-6/ISO 10426-6 Methods for determining the static gel strength of cement formulations
- API SPEC 10A/ISO 10426-1 Specification for Cements and Materials for Well Cementing
- API SPEC 12J, Specification for Oil and Gas Separators
- API SPEC 16A, ISO 13533, Specification for Drill-Through Equipment
- API SPEC 5B, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads
- API SPEC 5CT/ISO 11960, Specification for Casing and Tubing
- API SPEC 6A/ISO 10432, Specification for Wellhead and Christmas Tree Equipment
- API SPEC 8A/8C, Grinding of wells (to suit casing elevators)
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations
- API Standard 65-2, Isolating Potential Flow Zones During Well Construction
- ASTM D412, Standard test methods for Vulcanized Rubber and Thermoplastic Elastomers – Tension 1
- ASTM D471 - 16a, Standard Test Method for Rubber Property – Effect of Liquids
- ASTM D2240 - 15e1, Standard Test Method for Rubber Property – Durometer Hardness 1
- ISO 13354, Drilling and production equipment – Shallow gas diverter equipment
- ISO 13503-1 Petroleum and natural gas industries – Completion fluids and materials – Part 1: Measurement of viscous properties of completion fluids
- ISO 13503-3, Petroleum and natural gas industries – Completion fluids and materials – Part 3: Testing of heavy brines
- API RP 5A3/ISO 13678, Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements
- API RP 59, Recommended Practice for Well Control Operations
- API RP 90-2, Annular Casing Pressure Management for Onshore Wells
- API RP 92U, Underbalanced drilling operations
- ISO 10407, Drill Stem Design and Operating Limits
- ISO 16530-1, Well integrity – Part 1: Life cycle governance
- ISO 16530-2, Well integrity – Part 2: Well integrity for the operational phase
- NORSOK Standard D-010, Well integrity in drilling and well operations

- API RP 5A5 Field Inspection of New Casing, Tubing and Plain-end Drill Pipe/ISO 15463, Petroleum and Natural Gas Industries - Field Inspection of New Casing, Tubing, and Plain- end Drill Pipe
- API RP 5B1 Gauging and Inspection of Casing, tubing and Line Pipe Threads
- API RP 5C1 Recommended Practice for Care and Use of Casing and Tubing
- API Technical Report 5C3, Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing
- API RP 5C5 Procedures for Testing casing and tubing connections /ISO 13679 Petroleum and Natural Gas Industries Procedures for Testing Casing and Tubing Connections
- API RP 5C6 Pipe with welded connectors
- API RP 10B-5 Recommended practice on determination for shrinkage and expansion of well cement formulations at atmospheric pressure
- ISO 10426-5 Petroleum and natural gas industries Cements and materials for well cementing Part 5: Determination of shrinkage and expansion of will cement formulations at atmospheric pressure
- API SPEC 10D Specification for Bow-string Casing Centralizers/ISO 10427-1 Petroleum and Natural Gas Industries – Equipment for Well Cementing – Part 1: Casing Bow-Spring Centralizers
- API SPEC 10F Cementing Float Equipment Testing/ISO 10427-3, Petroleum and natural gas industries – Equipment for well cementing – Part 3: Performance testing of cementing float equipment
- API TR 10TR1, Cement Sheath Evaluation
- API TR 10TR2, Shrinkage and Expansion in Oilwell Cements
- API TR 10TR3, Temperatures for API Cement Operating Thickening Time Tests
- API TR 10 TR4, Technical Report on Methods for Testing of Solid and Rigid Centralizers
- API TR 10TR5 Methods for Testing of Solid and Rigid Centralizers
- API SPEC 13A Specification for Drilling Fluids materials
- ISO 13500 Petroleum and Natural Gas Industries - Drilling Fluid Materials -Specifications and Tests
- API RP 13B-1Recommended Practice for Field Testing Water-based Drilling Fluids/ISO 10414-1, Recommended Practice for Field Testing Water- Based Drilling Fluids
- API RP 13DRheology and Hydraulics of Oil-well Drilling Fluids
- API RP 53, Blowout Prevention Equipment Systems for Drilling Operations
- API RP 54, Occupational Safety for Oil and Gas Well Drilling and Servicing Operations
- API RP 59, Recommended Practice for Well Control Operations
- API SPEC 16C, Choke and Kill Systems
- API SPEC 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
- API SPEC 16RCD, Specification for Rotating Control Devices
- API SPEC 16ST Coil Tubing Well Control Equipment Systems
- ANSI/API Specification 15LR, Low Pressure Fibreglass Line Pipe and Fittings
- ANSI/API Specification 15HR, High Pressure Fibreglass Line Pipe
- ANSI B31.3 – 2018, Process Piping

- ASTM D2996-17 Standard Specification for Filament-Wound “Fibreglass” (Glass-Fibre-Reinforced Thermosetting-Resin) Pipe
- ASTM D2517 – 18 Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings
- AS/NZS 1477-2017 PVC Pipes and Fittings for Pressure Applications
- AS 2634 – 1983 Chemical Plant Equipment – Made from Glass-Fibre Reinforced Plastics (GRP) Based on Thermosetting Resins
- API RP 90-2 Annular Casing Pressure Management for Onshore Wells.

These standards and specifications are listed as a reference and should be used as and where appropriate to the overall management of integrity of petroleum wells.