Code of Practice: Onshore Petroleum Activities in the Northern Territory

31 May 2019

DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES
DEPARTMENT OF PRIMARY INDUSTRY AND RESOURCES

Document details

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Contents

1 Overview

This **Code** is designed to complement the interest holder's internal risk assessment processes, operating standards and procedures by outlining standards and processes to ensure that:

(a) risk to the public and workers is managed to a level as low as reasonably practicable (**ALARP**) and acceptable

(b) regulated activities are carried out in a manner:

i. consistent with the principles of ecologically sustainable development; and

ii. by which the environmental impacts and environmental risks of the activities will be reduced to a level that is:

a) as low as reasonably practicable; and

b) acceptable.

(c) the applicable NT regulatory requirements, and Australian and international standards/requirements, including the interest holder’s own standards, are communicated and implemented ensuring petroleum activities are managed effectively throughout their lifecycle through appropriate risk assessment, design, construction and management techniques

(d) the integrity of petroleum wells is effectively managed throughout their lifecycle.

2 Scope

This Code applies to all activities involved in both conventional and unconventional oil and gas exploration, appraisal, development and production and ancillary activities in the Northern Territory. This Code covers all petroleum activities.

This Code applies to all petroleum well types including exploration, appraisal, development, monitoring, injection and production wells.

This Code primarily addresses the management of environmental risks and environmental impacts associated with the conduct of regulated activities, along with those safety and operational risks which are closely associated with the environmental risks and environmental impacts, such that they should be addressed together.

3 Application

3.1 Interpretation

Unless the contrary intention requires it:

(a) A reference in this Code to another document is a reference to that document as in effect from time to time.

(b) An expression that is defined in the Petroleum Act 1984 (NT) (**Act**) or the Petroleum (Environment) Regulations 2016 (NT) (**PER**) has the same meaning in this document.

(c) This Code is subject to the Act and the PER. For example, if it is a requirement of this Code that a particular risk must be assessed as being low, compliance with that requirement will not affect the exercise of the Minister's discretion under the PER as to whether the risk is ALARP and acceptable. If there is a conflict between this Code and the PER or the Act, this Code will yield to the PER or the Act (as applicable). The essential relationship between the Code and the PER is that an interest holder must demonstrate in an environment management plan (**EMP**) under the PER how the requirements of this Code will be met (see Schedule 1, cl 10 of the PER).

(d) This Code may be taken to supplement the meaning of **good oilfield practice** which is set out in the Act, but this Code does not purport to be an exhaustive statement of what may be considered to be good oilfield practice under the Act.

(e) References may be used to interpret the meaning of a provision of this Code.

(f) Any requirement to submit information or a document is a requirement to submit that information or document to the relevant Minister. When relevant to assessment and compliance under,

i. The PERs that Minister is the Minister for Environment and Natural Resources,

ii. The Northern Territory Schedule of Petroleum Exploration and Production Requirements 2019 (**the Schedule**), that Minister is the Minister for Primary Industry and Resources.

iii. The contact details which may be used to meet this requirement are as follows:

a) Minister for Environment and Natural Resources, email petroleumEMP.DENR@nt.gov.au or telephone (08) 8924 4218, unless other details are published on the website of the Department of Environment and Natural Resources (DENR) from time to time.

b) Minister for Primary Industry and Resources, email petroleum.operations@nt.gov.au or telephone (08) 8999 6350, unless other details are published on the website of the Department of Primary Industry and Resources (DPIR) from time to time.

3.2 Nature of requirements

The requirements in this Code generally fall into the following categories:

(a) **principles**: these are principles which clarify the purpose and outcomes which operations must achieve in carrying out the regulated activities. The principles underlie the mandatory requirements.

(b) **mandatory requirements**: These are requirements that that must be complied with by interest holders in carrying out the activities. The terms **shall** or **must** are used for mandatory requirements. These are requirements which:

i. if a corresponding principle has been identified, are considered to be the minimum measures required to achieve the principle; and

ii. if no corresponding principle has been identified, are otherwise required to be carried out;

(c) **preferred requirements**: These are practices, methods and techniques which should generally be followed by interest holders unless:

i. there is a convincing justification why they cannot be followed; and

ii. any alternative practice, method or technique that will be followed:

a) if a corresponding principle has been identified, will achieve the principle; or

b) if no corresponding principle has been identified, will result in no greater environmental risks or environmental impacts than if good oilfield practice is followed.

It is noted that Schedule 1, Clause 10 of the PER requires the EMP to specify legislative requirements applicable to the regulated activity and demonstrate how these requirements will be met. In this clause, legislative requirements are specifically defined to include the requirement to comply with the Code.

3.3 Industry Standards

Relevant industry standards, recommended practices, technical reports and industry experience should be considered in the design and implementation of the **well construction** process and all other associated regulated well activities. This includes the use of standards and specifications developed by the American Petroleum Institute (**API**) and the International Organization for Standardization (**ISO**).

3.4 Management plans

Where requirements apply for specific management plans within an EMP, these plans may be integrated or combined with other management plans provided all content and implementation requirements are clearly addressed for the topic area. For example, a spill management plan may be integrated within the Emergency Contingency Plan as a sub-plan of the EMP.

3.5 Alternative to mandatory requirements for well operations management plans

For the purpose of a **well operations management plan** (**WOMP**) prepared according to the schedule and the application of **Part B** of this Code:

(a) This Code addresses industry standards and good oilfield practice for petroleum activities. However, it is not intended to discourage or prevent interest holders from adopting an alternative means of achieving a level of risk that is equal to or less than what would be achieved by complying with this Code.

(b) If an interest holder proposes an alternative to the mandatory requirements in this Code, the underlying principles of the mandatory requirement cannot be compromised and any alternative must adhere to those Principles. The determination of whether an alternative to the mandatory requirements is acceptable will be made by DPIR in collaboration with DENR and will be evaluated on a case by case basis.

(c) The proposal is to be submitted to the Senior Director Petroleum Operations, Energy Division (ED), DPIR, for written approval. Alternate Mandatory requirements are authorised by written approval from the Senior Director Petroleum Operations, Energy Division, DPIR.

Part A – Surface Activities

A.1 Overview

This part of the **Code** aims to ensure that a proposed activity:

(a) minimises surface disturbances;

(b) minimises visual impacts;

(c) minimises impacts to soil resources;

(d) minimises impacts to natural waterways and features associated with aquifer recharge and discharge;

(e) reduces impacts to native flora and fauna;

(f) reduces the risk of weed and pest spread;

(g) avoids where practicable, higher risk landform areas; and

(h) minimises impacts to relevant environmental values in the area.

A.2 Scope and application

Part A applies to all activities that cause disturbance to the surface of the land, including activities such as the preparation of well pads, seismic surveys, access tracks, and other infrastructure. It does not cover large infrastructure constructed during production (gas treatment facilities for example). The scope of this part of the Code includes the following:

(a) construction of a well pad (note additional requirements for well pads are included in section B.4.16);

(b) rehabilitation of the well pad (progressively or at once); and

(c) the permanent placement of infrastructure (such as well pads, gathering lines, roads and access tracks but not transmission pipelines under the Energy Pipelines Act 1981).

A.3 Surface activities mandatory requirements

A.3.1 Site selection and planning

(a) The planning, design, location and construction of petroleum infrastructure must have regard to the considerations in the Land Clearing Guidelines as published on the Department of Environment and Natural Resources (DENR) website and amended from time to time. Specific consideration must be given to the following:

i. suitability of site (e.g. flooding, sheet flow pathways, soil drainage and slope constraints, proximity to watercourses, dune crossings);

ii. erosion and sediment controls;

iii. sensitive receptors;

iv. wildlife movement;

v. biodiversity protection;

vi. water;

vii. weeds; and

viii. cultural heritage.

(b) The following must be demonstrated in regard to the selection of proposed locations:

i. landscape and regional scale impacts have been considered and accounted for at the design phase of development and are informed by baseline ecological studies of areas to be disturbed;

ii. **critical habitats** and **important habitats** are identified and avoided during corridor selection and construction and appropriate controls mechanisms implemented during construction to avoid any impact on them;

iii. the area of vegetation to be cleared for infrastructure development (including well pads, roads and pipeline corridors) has been minimised through efficient design and where possible, use of existing infrastructure and the co-location of shared infrastructure; and

iv. potential environmental nuisance has been avoided and minimised.

(c) Site selection and layout must reduce impacts on existing landscape amenity to a level that is as low as reasonably practicable (**ALARP**) and acceptable by:

i. minimising the surface footprint of all aspects of development; and

ii. ensuring that infrastructure located in proximity to a major public road or locations with high existing amenity value is designed and located in a way that minimises long-term amenity impact.

(d) Infrastructure site/route selection must minimise interference with **wet season** water flow paths and exposure of infrastructure to flooding.

(e) Pipelines and ancillary services must be buried except for the following:

i. temporary infrastructure;

ii. infrastructure located on well pads;

iii. where it is necessary for inspection; or

iv. where burial would not reduce environmental risks or environmental impacts from the infrastructure to levels which are ALARP and acceptable, as demonstrated in the EMP.

(f) All petroleum infrastructure including, petroleum wells, pipelines and gas processing facilities must have a setback distance of at least 2km from an existing or proposed habitable dwelling including all buildings or premises where people reside or work, schools and associated playgrounds, permanent sporting facilities and hospitals or other community medical facilities.

A.3.2 Well pad site selection requirements

A.3.2.1 Principles

Interest holders must minimise the surface footprint of wells and the impact on landscape amenity.

A.3.2.2 Mandatory requirement

(a) Where a petroleum development is targeting a **continuous resource** well pads must be spaced a minimum of 2km apart, measured from the centre of the well pads; or the interest holder must demonstrate:

i. a justification that demonstrates that a well pad spacing of less than 2 km is required to reduce environmental risks and impacts on cultural heritage and other land users to ALARP and acceptable in consideration of site specific constraints (including geohazards, environmental values, cultural heritage, existing land use);

ii. reasons supporting the alternative locations chosen; and

iii. that the proposed locations minimise landscape amenity impacts.

(b) Where a petroleum development is targeting a **compartmentalised resource**, well pad spacing and location must be placed to minimise landscape amenity impacts.

(c) Well pads and well infrastructure installed on the well pad post drilling must have little or no visibility from any major public road that exists at the time the well pad is constructed.

(d) There must be a minimum distance of at least 1km between an existing water supply **bore** used for domestic or stock consumption and a well pad unless:

i. the owner of the water supply bore consents in writing to the location of the well pad; or

ii. hydrogeological investigations and ground water modelling indicate that a different distance is appropriate.

A.3.3 Noise

Noise assessment, planning and management associated with petroleum activities shall comply with the Northern Territory Noise Management Framework Guidelines published by the Northern Territory Environment Protection Authority.

A.3.4 Erosion and sediment control and hydrology

(a) The risk of erosion associated with the activity (taking into account site specific conditions and the nature and timing of works must be assessed in accordance with the Land Clearing Guidelines as published on the DENR website and amended from time to time.

(b) An Erosion and Sediment Control Plan (**ESCP**) (being the **Primary ESCP**) must be developed for the activities by a **suitably qualified person** in accordance with relevant guidelines including specific environmental outcomes and environmental performance standards to be included in the Implementation Strategy in the EMP.

(c) Where the Primary ESCP requires it, a further ESCP (being the **Secondary ESCP**) must be developed by a suitably qualified person in relation to the relevant matters identified in the Primary ESCP and implemented by the interest holder.

(d) Road and pipeline corridor designs must:

i. minimise erosion of exposed road surfaces and drains;

ii. ensure that roads and pipeline surface water flow paths minimise erosion of all exposed surfaces and drains;

iii. comply with relevant guidelines such as the International Erosion Control Association Best Practice for Erosion and Sediment Control (2008), IECA Appendix P: Land Based Pipeline Construction December 2015 (Addendum to IECA 2008) and the Australian Pipeline Industry Association Code of Environmental Practice for Onshore Pipelines 2017.

(e) The requirements of the Land Clearing Guidelines as published on the DENR website and amended from time to time must be complied with in relation to protection of natural waterways as a result of land disturbance and ensure the following:

i. appropriate buffers are implemented around natural waterways;

ii. disturbance in the wet season is minimised;

iii. the number of crossing points is minimised;

iv. crossings are constructed as close as practicable to right angles to the waterway;

v. material changes in the shape of the waterway are avoided;

vi. material changes in the volume, speed or direction of flow or likely flow of water in the waterway are avoided;

vii. alteration to the stability of the bed or banks of the waterway (including by removal of vegetation) is avoided;

viii. erosion risk, sedimentation and pollution of waterways is minimised through the appropriate design and implementation of best practice erosion and sediment control measures.

(f) Directional drilling under waterway crossings must be used in preference to trenching for all buried infrastructure unless geomorphic and hydrological investigations confirm that trenching will have no adverse impact on water flow patterns and waterhole water retention timing.

A.3.5 Biodiversity protection

Surface activities must be undertaken in a manner that avoids and minimises environmental risks and environmental impacts to flora and fauna, **critical habitat** and **important habitat** to ALARP and acceptable in accordance the Land Clearing Guidelines as published on the DENR website and amended from time to time and the following:

(a) Land clearing for corridors, well pads and other operational areas must be kept to a minimum;

(b) All infrastructure stream crossings must provide for appropriate fauna passage;

(c) Where environmental impacts and environmental risks to flora and fauna are unable to be avoided or adequately mitigated by other means, the residual impacts must be offset in accordance with the Northern Territory and/ or Australian Government policy relating to environmental offsets in effect from time to time (if any).

The Implementation Strategy required under Schedule 1 cl. 11 of the PER must provide for records of the nature, location and extent of disturbance of flora and fauna including geospatial information depicting areas cleared to be provided to the Minister.

A.3.6 Weed management

A project specific weed management plan must be developed as part of the EMP which meets the requirements of the *NT Weed Management Planning Guide: Onshore Petroleum Projects* (DENR, 2019) and it must provide at least for the following:

(a) baseline weed assessments prior to regulated activities being undertaken;

(b) ongoing weed monitoring;

(c) provision of a dedicated weed officer; and

(d) consistency with statutory requirements including any relevant threat abatement plans under the federal *Environment Protection and Biodiversity Conservation Act 1999.*

A.3.7 Fire management

(a) A fire management plan at a project level must be developed as part of the EMP which demonstrates the following:

i. analysis of baseline fire information (at least 10 years);

ii. analysis of impacts of the proposed activities on the existing fire management regime(including measures and strategies of government and other stakeholders);

iii. coordination with the landholder and other land users and consistency with the landholder's fire management obligations and strategies (including regional and property fire management plans under the *Bushfires Management Act 2016*)

iv. implementation of the interest holder's appropriate fire mitigation measures, such as:

a) robust monitoring of seasonal conditions and fuel loads;

b) maintenance of fire access trails;

c) maintenance of fire breaks around infrastructure;

d) controlled burns;

e) communication system for monitoring bushfire alerts in the area; and

f) contributing to increased regional fire fighting capacity (such as local volunteer fire brigades);

v. appropriate fire control measures for relevant activities;

vi. annual fire mapping to monitor changes to fire frequency in the relevant area.

(b) infrastructure must be designed, constructed, operated and maintained to mitigate risks of ignition.

A.3.8 Containment of contaminants

(a) Activities that involve wastewater or chemical storage must be carried out according to the wastewater management plan and spill management plan which are part of the EMP (which are further detailed in section C.7 of this Code).

(b) During the wet season, the transport of chemicals and wastewater on unsealed roads must not be undertaken unless the risk of spills is demonstrated to be ALARP and acceptable. This assessment must be included in the EMP and established through a specific assessment of spillage risks in the circumstances. Where it has been determined that wet season transport is ALARP and acceptable and included in the EMP, the outcomes of the risk assessment must be reflected in an emergency contingency plan.

(c) An assessment must be carried out and included in an EMP as to whether any materials (solid or liquid) used in, or produced from activities at a **well site** could be considered to be, or to contain, **hazardous chemicals** or those that may cause environmental harm. The outcomes of this assessment must be described in the spill management plan, as outlined in Part C of this Code.

(d) Use, storage and handling of materials on a site of petroleum activities:

i. which are or contain hazardous chemicals must comply with WHS legislation and appropriate standards for the type of chemicals.

ii. must be in accordance with their approved safety data sheet. The content of a material safety data sheet must meet the minimum requirements mandated by NT Worksafe.

iii. which are chemicals that may cause environmental harm, must be stored to prevent release to the environment and to contain any spills.

iv. which are liquid hydrocarbons, whether separated or mixed with other fluids at a concentration greater than 1% by volume, must not be stored in any open top structure or pit. Aboveground tanks used for storing or separating condensate during well completion must be monitored and have controls to prevent vapours from exceeding the **Lower Explosive Limit** (LEL) of the condensate outside the tank. Tanks used for storing or separating condensate must be grounded.

(e) Sites and facilities where petroleum activities are undertaken must be designed and constructed to prevent spills of potentially harmful chemicals or those that may cause environmental harm to the ground surface or their release from the site.

(f) Any hazardous chemicals or those that may cause environmental harm are to be stored within secondary containment.

(g) Secondary containment must meet all of the following:

i. sufficient capacity to hold 100% of the volume of the largest container stored in the area plus 10%, unless the container is equipped with individual secondary containment;

ii. permeability able to contain materials or waste until it can be removed or treated;

iii. provide for separation of clean and dirty water;

iv. be compatible with the material or waste stored or used within the containment;

v. be resistant to physical, chemical and other failure during handling, installation and use; and

vi. be maintained in good order at all times.

(h) secondary containment requirements can be met with double-lined or double-walled storage tanks.

(i) All secondary containment (when in use) shall be inspected weekly, unless being operated through the wet season during which they should be monitored daily. If the secondary containment is damaged or compromised, repairs must be carried out as soon as practicable.

(j) Materials that escape from primary containment or are otherwise spilled onto secondary containment shall be removed as soon as possible.

(k) Inspection reports and maintenance records of secondary containment shall be kept.

(l) **Well site water** must be managed in accordance with Part C of this Code.

(m) Secondary containment on well sites must be in accordance with section B.4.16.2.

(n) The containment practices to be utilised and the area of the site where containment systems will be employed must be included in the spill management plan, as outlined in section C.7.2 of this Code.

(o) Where the use of secondary containment is not reasonably practicable, evidence must be provided in the spill management plan, required in section C.7.2 of this Code, to qualify why secondary containment is impractical. Should secondary containment not be reasonably practicable, details must also be provided on the monitoring program and resources including, equipment, materials and people, which will be employed to mitigate the risk of a spill and allow for the expedient control and removal of a spill.

A.3.8.1 Preferred requirements

(a) The site layout should be designed to minimise the risk of spills. This may include segregating areas for chemical storage and handling.

(b) Lifecycle chemical handling risks should also be considered, including: balancing stored volumes with transport requirements (avoiding vehicle movements).

A.3.9 Rehabilitation

(a) A Rehabilitation Plan must be included as part of an EMP. It must be developed by a suitably qualified person and must include specific environmental outcomes and performance standards (eg, monitoring and reporting requirements).

(b) The Rehabilitation Plan shall be appropriate to the scale and nature of the activity and include:

i. strategies for the determination of final land use(s) and rehabilitation goals and details of how rehabilitation objectives will be achieved;

ii. a monitoring and maintenance program for reinstated and rehabilitated areas.

(c) Progressive rehabilitation of **significantly disturbed land** which is not required for the ongoing conduct of the petroleum activity(ies) or future activities, must commence as soon as practicable, but not longer than 12 months following the cessation of activities on the land.

(d) All significantly disturbed land must be reinstated to its pre-disturbed condition. For areas that previously contained native vegetation, native vegetation must be re-established such that the corridors become ecologically integrated into the surrounding landscape.

(e) Regular maintenance and at least yearly monitoring of rehabilitated areas must take place to measure compliance with the Rehabilitation Plan.

(f) If contamination is detected, remediation must commence immediately in accordance with the spill management plan and/or emergency contingency plan.

Part B – Well Operations

B.1 Overview

The purpose of this part of the **Code** is to ensure that all petroleum wells in the Northern Territory are constructed, operated, maintained and decommissioned to minimum acceptable standards resulting in long-term **well integrity**, the protection of aquifers and minimisation of fugitive greenhouse gas emissions. Well integrity is fundamental to ensuring safe and sustainable petroleum production.

B.2 Scope and application

This Part B applies to:

(a) all wells, well operations and activities on the well pad, but not permanent production equipment beyond the production wing valve of the wellhead/Christmas tree;

(b) This Code applies to the entire well life cycle, including the following phases:

  i. well integrity management;

  ii. preliminary well planning and well design;

  iii. **well construction** (up to the production wing valve of the **wellhead** / **Christmas tree**);

  iv. well evaluation and **hydraulic fracture stimulation** activities (and associated on site water and waste management); and

  v. well suspension and decommissioning.

(c) within the lifecycle phases above, equipment and material selection, risk assessment (both safety and environment risks), industry practices, monitoring and reporting.

This Code, including this Part B, does not:

(a) address the manufacture or the certification of drilling rigs or associated equipment;

(b) refer to any necessary technical training of the various operators;

(c) address permanent production facilities downstream of the production wing valve; or

(d) cover independent validation and verification requirements for activities during the life-cycle of a well.

B.3 Well operations management plans

Interest holders shall have a well operations management plan (**WOMP**) approved for regulated well activities, as required by the Schedule. WOMPs must address the mandatory requirements set out in this Code.

B.4 Principles, mandatory requirements and preferred requirements

This section B.4 outlines requirements for petroleum wells for the life of the petroleum well including but not limited to drilling, stimulation, completion, **workover**, **interventions**, well testing and decommissioning.

B.4.1 Well Integrity Management

B.4.1.1 Principles

Monitoring and maintenance is required to preserve the well and its equipment in a suitable condition for their useful life. Well integrity management systems aim to ensure the wells meet operational availability and well integrity goals for the entire well lifecycle, as shown in Figure 1.

Wells are designed to be operated such that the following are achieved:

(a) well integrity is maintained at all times and barriers meet the requirements described in section B.4.3 of this Code;

(b) their well integrity is validated through a well integrity testing program;

(c) **well barrier** status is known and technical integrity risks are managed;

(d) the **well operating envelope** is not exceeded; and

(e) all materials and equipment installed in a well must maintain well integrity for the lifespan of its intended use.

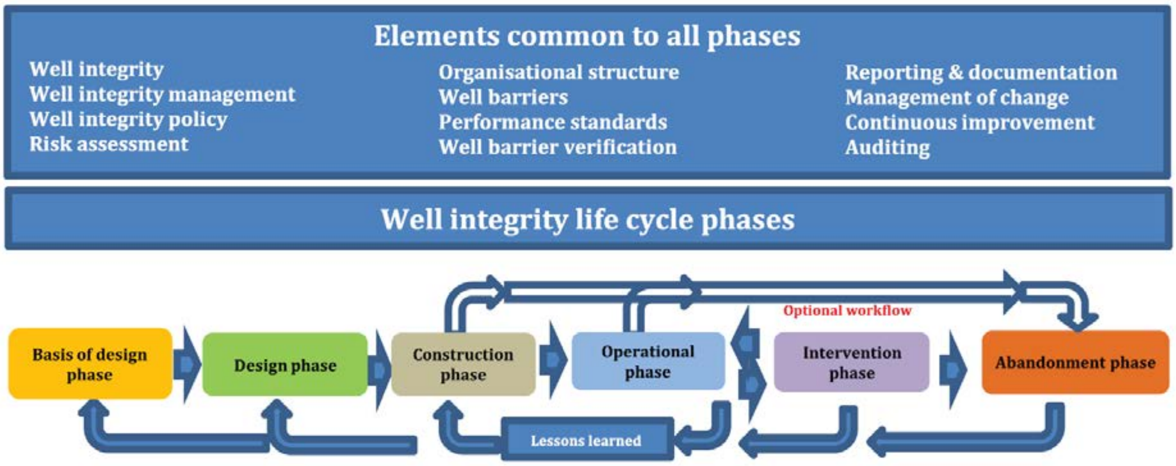

Figure 1: Well integrity life cycle phases and common elements of well integrity management

B.4.1.2 Mandatory requirements

(a) The interest holder must be able to demonstrate that they have a system or process for managing well integrity throughout the whole well life cycle that complies with ISO 16530-1:2017 Well integrity - Part 1: Life cycle governance. This system or process must include a well integrity management system.

(b) In order to continue operating a well which has, or is believed to have, a compromised well barrier, a risk assessment must be conducted in line with the interest holder's risk assessment process and where required remediation action undertaken.

(c) A well integrity testing and validation program must be established for all wells, that includes:

i. subsurface integrity testing (SIT);

ii. well integrity and well barrier validation requirements in accordance with this Code;

iii. a minimum testing frequency for wells in the operational phase of their lifecycle that is commensurate with well's well integrity risks as per the accepted WOMP; and

iv. triggers for well integrity testing based on:

a. well integrity monitoring; and

b. substantive changes to well barriers or well operating envelope.

(d) Casing and tubing wear due to corrosive fluids and erosion, and its impact on well integrity, must be assessed throughout the well life cycle and its impact on well integrity.

B.4.1.3 Preferred requirements

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

(b) Interest holders should conduct annular casing pressure management in accordance with API Recommended Practice 90-2 Annular Casing Pressure Management for Onshore Wells.

(c) **Annulus** pressure monitoring is to provide assurance of the integrity of subsurface **well barrier elements** and their interface with the wellhead. The principal requirements for the management of integrity of well **annuli** are:

i. that adequate access to the annulus is provided for during preliminary well planning and design;

ii. testing during installation of casing, tubing, downhole permanent barriers and wellhead components to confirm the integrity of all barriers that bound each annulus;

iii. monitoring of annulus pressure confirms stability of pressures within defined limits;

iv. annulus pressure is maintained within defined maximum allowable limits; and

v. annulus investigation and remedial measures are carried out to identify and fix annulus integrity problems.

References*:*

- ISO 16530-1:2017, Well integrity - Part 1: Life cycle governance
- NORSOK Standard D-010, Well integrity in drilling and well operations
- Norwegian Oil and Gas Association, 117 –Norwegian Oil And Gas Recommended Guidelines For Well Integrity
- API Recommended Practice 90-2 Annular Casing Pressure Management for Onshore Wells

B.4.2 Aquifer protection

B.4.2.1 Principles

Protection of aquifers is an integral consideration in petroleum well design.

Developing a mechanical reactive barrier for a petroleum well involves the following:

(a) definition or specification of a barrier;

(b) understanding of causes of failure;

(c) asking what signals could be monitored to help predict a failure; and

(d) asking what signals could be monitored to help detect a failure.

The protection of aquifers requires the following to be achieved:

(a) well-defined stratigraphic definition to the base of the deepest recognised **aquifer** in the local area prior to drilling;

(b) aquifers must be considered during the well design process and interest holders must include the design of aquifer isolation in their WOMP;

(c) all **aquifers** in the area must be isolated from the surface and each other and any **hydrocarbon bearing zones** using appropriate barriers, in accordance with section B.4.3.2 of this Code;

(d) groundwater quality monitoring conducted in accordance with section B.4.17 of this Code; and

(e) **drilling fluids** must be designed to minimise environmental harm, in accordance with section B.4.10.2 of this Code.

B.4.2.2 Mandatory requirements

(a) Casing setting depth must be selected to protect resources including aquifers in accordance with section B.4.3.2 of this Code.

(b) All aquifers, in the area must be isolated from each other and from the surface and any hydrocarbon bearing zones by appropriate well barriers, in accordance with section B.4.3 of this Code.

(c) **Primary cementing** design and validation must be carried out in accordance with the interest holder’s well operations management plan and in accordance with B.4.7 of this Code.

(d) Monitoring of barriers and casing condition must be carried out in accordance with the interest holder’s well operations management plan and in accordance with B.4.1 of this Code.

(e) If an aquifer is discovered during drilling that was not identified prior to commencement of drilling, notification to the Minister is required under regulation 23 of the PER. This notification should identify whether or not environmental values of the aquifer have been adequately addressed under the EMP and whether or not the EMP requires revision under regulation 17 of the PER.

B.4.2.3 Preferred requirements

(a) The interest holder’s practices for isolating potential flow zones should follow API Standard 65-2, Isolating Potential Flow Zones during Well Construction.

References:

- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- API Standard 65-2, Isolating Potential Flow Zones during Well Construction
- ISO 16530-1, Well integrity - Part 1: Life cycle governance
- NORSOK Standard D-010, Well integrity in drilling and well operations – latest edition.

B.4.3 Well design and well barriers

B.4.3.1 Principles

Petroleum wells are designed and constructed such that:

(a) well objectives are met;

(b) well barriers are designed to prevent unintentional influx, crossflow to other formation layers and outflow to the external environment;

(c) barrier envelopes are designed such that failure of one barrier should not lead to an uncontrolled release of formation fluids (blowout or cross-flow);

(d) testing and acceptance requirements specified in the WOMP are satisfied;

(e) wells can be monitored and maintained to contain and control well fluids, provide structural support and otherwise retain well integrity throughout all reasonably anticipated **well construction** and **production** load conditions – which may occur during the life of the well; and

(f) zonal isolation between different aquifers, and between hydrocarbon bearing zones and aquifers is achieved.

B.4.3.2 Mandatory requirements

Wells must be designed such that:

(a) casing setting depths and cement isolate aquifers and hydrocarbon bearing zones;

(b) unless paragraph (c) applies, they are constructed, maintained and decommissioned in such a manner that it can be demonstrated there are at least two verified well barriers between:

i. a hydrocarbon bearing zone and aquifers and the surface; and

ii. deep, saline water bearing formations and aquifers/the surface.

(c) where one or more of the following circumstances applies, less than two verified barriers may be provided:

i. during top hole or surface hole drilling where shallow hydrocarbon or water flow risk has been assessed as being negligible;

ii. during diverter drilling;

iii. during well decommissioning when two formations need to be isolated from one another and two barriers are not feasible, and a continuous cement plug extending minimum 50m above to 50m below the interface is placed instead; or

iv. in other circumstances during well life cycle activities when a risk assessment demonstrates that the same level of risk can be achieved as if two verified barriers were in place.

(d) they are constructed, maintained and decommissioned in such a manner that it can be demonstrated that all aquifers are isolated from each other and the surface by a minimum of one verified well barrier;

(e) installation of **BOP** equipment is provided for;

(f) well control is maintained during all well activities;

(g) fit for purpose casing weight and grade are used, having regard to casing corrosion risk and connection suitability;

(h) specific requirements for well construction materials are included in the design;

(i) minimum casing centralisation standards in section B.4.7.2 of this Code are met;

(j) engineered cement slurries and appropriate cement placement techniques are part of the design;

(k) petroleum fluids produced from the well do not crossflow to aquifers; and

(l) wherever **drilling fluid** is being used as a primary barrier, sufficient reserves of drilling fluid and supplies of drilling fluid materials shall be available at the **well site** for immediate use so that the well can be maintained full of drilling fluid.

B.4.3.3 Preferred Requirements

(a) Review information available from previous drilling (offset wells) near the proposed well to assist in the design process for new wells.

(b) Review information on geological strata and formations, and fluids within them, that the well may intersect and any hazards which such strata and formations may contain.

(c) Note formation horizons or zones, from which water **bores** produce, during the offset well review to assist the placement of casing strings.

(d) Select casing hardware, including **liner** hangers, float equipment, centralisers, cement baskets, wiper plugs, stage tools and external casing **packers**, as appropriate as part of the well design to achieve zonal isolation.

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

(f) A barrier should only be considered validated when there is evidence (e.g. leak testing by application of differential pressure, cement integrity test for cement around **casing shoe**, function testing, wireline logging) that the barrier has been placed in its desired location and will perform its required function.

(g) 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.

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

(i) Well design should be completed by **competent personnel**. Review and assurance of well design should be completed by other **competent person**(s) independent from the design originator and their immediate line management, and from the team that has responsibility for the actual construction of the well.

References:

- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- API Standard 65-2, Isolating Potential Flow Zones During Well Construction

- ISO 16530-1:2017, Well integrity - Part 1: Life cycle governance
- NORSOK Standard D-010, Well integrity in drilling and well operations.

B.4.4 High pressure high temperature petroleum well design

B.4.4.1 Principles

For **High Pressure High Temperature** (**HPHT**) wells, a greater awareness of maximum anticipated surface pressures, circulating temperatures, and **well control equipment** capabilities and readiness is required.

High temperature in this context is defined as when the undisturbed bottom hole temperature is greater than 150°C (300°F).

High Pressure in this context is defined as either:

(a) the maximum pore pressure of any porous formation that exceeds a hydrostatic gradient of 0,18 bar/m (0,8 psi/ft) (representing an equivalent mud weight (EMW) of 1,85 SG or (15,4 ppg) or,

(b) needing deployment of pressure control equipment with a rated working pressure in excess of 690 bar (69 MPa, 10 000 psi).

In addition to the objectives outlined in section B.4.3.1, the key outcomes for HPHT petroleum well design include the following:

(a) accurate determination of pressure, temperature, and reservoir fluid characteristics;

(b) modelling to predict temperatures and pressures during well construction and the well life cycle phases;

(c) identifying fit for purpose rig requirements and drill string, downhole tools, well construction equipment, well control equipment;

(d) establishment of specific procedures for drilling, tripping and well control to address high temperature/pressure zones in well; and

(e) contingency planning for well control.

B.4.4.2 Mandatory requirements

(a) For HPHT wells, a pore pressure and fracture gradient (PPFG) plot must be developed and included in the WOMP.

(b) The level of PPFG monitoring and connection fingerprinting required while drilling HPHT wells must be based on a risk assessment. Consideration should be given to real time pore pressure prediction while drilling.

(c) Wells must be designed and operated to prevent the possibility of a temperature rise causing trapped fluid, generating a pressure in excess of the equipment rating.

(d) Industry recognised software must be used for casing design in HPHT wells and where hydraulic fracture stimulation surface treating pressures exceed 70 MPa (10,000 psi). This is to confirm that temperature effects and resultant compression forces in particular are adequately assessed in the casing and tubing design.

(e) For **high temperature wells** the impact of temperature on fluid properties, affecting its ability to perform as a well barrier, must be reviewed.

(f) Rig selection and capability for HPHT operations must satisfy the well construction requirements.

(g) Advanced well control response and equipment must be considered as part of the well design for tertiary well control response.

(h) Specific training for HPHT well control response must be undertaken by personnel in charge of well activity on-site (Tool pushers, Drillers and Assistant Drillers).

B.4.4.3 Preferred requirements

(a) In areas where PPFG cannot be determined accurately through the review of offset data, pore pressure prediction studies based on seismic data and/or other specialist techniques may be used.

(b) In high temperature wells (≥150 °C (300 °F)) the well temperature can vary significantly between a static (geothermal) condition and the dynamic, or circulating, condition of the mud system. Temperatures measured while drilling and logging should be taken into account to help optimise mud properties, **cementing** fluid properties and design.

(c) When drilling with a weighted fluid, the density in and out of the well should be checked at an appropriate frequency to confirm the correct weight is being maintained to control the well. On HPHT wells the fluid should be weighed at a higher frequency than other wells. Modelling of the equivalent static density and equivalent circulating densities should be conducted where accurate control of mud weight is required (e.g. small overbalance scenarios).

(d) Bottom hole assembly (BHA) components should be rated for the anticipated temperature and pressure in the appropriate hole section(s):

i. Consideration should be given to use of both a drilling float valve and a drop in dart sub in the drill string. Consideration should be given to two drop in dart subs in tapered drill strings. Drilling float valves may be ported following a risk assessment.

ii. Consideration should be given to using a drilling stand to facilitate installation of a kill assembly for high pressure pumping that may be needed during a well killing operation when drilling in abnormally pressured hydrocarbon bearing zones with potential to flow.

(e) Consideration should be given to the working temperature rating for well control equipment, which should meet the maximum anticipated continuous exposure temperature for rubber/elastomer components and high pressure hoses. Critical spares should include components exposed to high temperatures while drilling.

References:

- Energy Institute Part 17: Volume 1: High Pressure and High Temperature (HPHT) Well Planning (2009). Model Code of Safe Practice in the Petroleum Industry.

B.4.5 Working with hydrogen sulfide (H_2S)

The scope of this section B.4.5 covers any well location where H_2S is expected to exceed 10 ppm (by volume) in the breathing zone.

B.4.5.1 Principles

Hydrogen sulfide (H_2S) is classed as a hazardous substance and a dangerous good that is sometimes found in fluids encountered in oil and gas producing and gas processing operations. The interest holder is responsible for ensuring that suitable operational practices are in place to manage the risks associated with H_2S.

H_2S management practices include:

(a) characterisation of the probability and concentration levels of H_2S that may be encountered; and

(b) the safe handling of any H_2S encountered during well operations.

B.4.5.2 Mandatory requirements

(a) On detection in **exploration wells** or **appraisal wells**, or where there has been regional evidence of H_2S, a review of reservoir and offset well data must be carried out for a well, or campaign of wells in the same reservoir, to determine the probability and concentration levels of H_2S.

(b) As H_2S is classed as a hazardous substance a risk assessment must be conducted and recorded for all work activities where personnel may be exposed to the substance.

(c) Prior to operations in an H_2S environment, a H_2S management plan must be developed that is consistent with API RP49, Recommended Practices For Safe Drilling Of Wells Containing H_2S.

(d) All drilling contractors and service companies involved in **well site** operations must be notified of predicted H_2S levels and temperatures.

(e) A flare system must be provided to safely collect and burn H_2S gas during well control or well test operations. Flare lines must be located as far away from the well as reasonably practicable.

(f) For operations where H_2S is predicted, continuous H_2S monitoring equipment shall be installed, which is capable of continuously measuring and displaying the concentration of H_2S in ambient air. H_2S gas detectors must be available for personnel working in a known high risk zone when H_2S is present or predicted in any quantity. A H_2S alarm setting of 5 ppm must be used for personal, portable and fixed detectors.

(g) Personnel are to be provided with personal protective equipment to prevent exposure to H_2S if the work area concentration of H_2S are expected to exceed or are found to exceed 10 ppm (by volume) 8-hour **time weighted average** or 15 ppm (by volume) as a **short term exposure level** . Personnel safety provisions do not apply when the atmospheric concentration of H_2S could not exceed 10 ppm (by volume) in the breathing zone.

(h) For H_2S operations, equipment and materials shall be selected on the basis of resistance to **sulfide stress cracking** and corrosion where the partial pressure of H_2S gas exceeds 350 Pa (0.05 psi), or 70 kPa (10 psia) in sour crude systems.

i. If it is proposed to use a material which is intended for 'non H_2S service', a risk assessment and supporting data must be conducted to demonstrate the integrity of equipment or materials over the following timeframes:

a. during a single temporary exposure to sour reservoir fluids (e.g. circulating out a **kick**, or if there is a leak in the test string while production testing) or,

b. in the time between exposure to sour reservoir fluids and completion of evacuation of the well site in the event of uncontrolled total displacement of the well contents by such fluids.

ii. If operations on a well are suspended then the effects of H_2S over the suspension period must be considered.

(i) Elastomers, packing and other non-ferrous parts exposed to H_2S must be resistant at the maximum anticipated temperature of exposure.

(j) A **drilling fluid** program must include the use of a H_2S scavenger to remove any H_2S from the drilling fluid.

(k) When coring operations are conducted in possible H_2S bearing zones, the wearing of breathing equipment and testing for H_2S using hand held sensors must be used for the final 10 stands, and must continue while retrieving the inner core barrels, opening the core barrels and examining the cores. Prior to transportation, cores must be sealed and marked to indicate the presence of H_2S.

(l) If H_2S in the gas phase is predicted during well test operations, H_2S concentration must be monitored at first hydrocarbons to surface and at regular intervals throughout the test.

(m) If H_2S levels exceed original design assumptions or cannot be controlled by the resources available on the rig, then the well must be shut-in. The well must remain shut-in until such a time as the level of H_2S readiness is increased such that operations can continue safely.

B.4.5.3 Preferred requirements

(a) The selection of equipment and materials for use under sour conditions should be done in accordance with NACE Standard MR0175/ ISO 15156.

(b) H_2S sensors that activate and provide audible and visual alarms when sensing 5 ppm (by volume) of H_2S in the atmosphere should be installed and be confirmed functioning.

(c) All fixed and portable detectors should be function tested weekly in accordance with manufacturer's specifications.

(d) H_2S is detected in muds using methods such as the **Garrett Gas Train** method or the Hach test. The GGT will give a quantitative result and is more accurate. Tests provide useful information to help decide scavenger treatment levels. Removal of the H_2S or its resulting sulfide anion from drilling fluid requires its precipitation as an insoluble salt. The addition of zinc carbonate ($ZnCO_3$) to drilling fluid will form insoluble zinc sulfide.

(e) Prior to penetrating known or predicted H_2S zones:

i. all rig H_2S detectors should be confirmed to be functioning correctly and tested;

ii. drilling fluids should be confirmed to be within specification, especially with respect to pH for water based drilling fluids;

iii. the whole-drilling-fluid alkalinity must be greater than 2 ml for non-aqueous fluids; and

iv. the testing frequency for H_2S should be confirmed by the interest holder.

(f) Flaring and well testing should take place only when the wind strength and direction is sufficiently favourable to carry all released gas from the gas flare, oil burner, or otherwise, away from the installation.

(g) Sampling for H_2S should be conducted where safe and practicable, and data used for optimisation of future well designs and surface facilities.

References:

- API Recommended Practice 49, Recommended Practices For Safe Drilling Of Wells Containing H_2S.
- API Recommended Practice 54, Occupational Safety for Oil and Gas Well Drilling and Servicing Operations
- NACE MR0175/ISO 15156-1, 2 and 3, Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production
- NOHSC: 1003 1995, Adopted National Exposure Standards for Atmospheric Contaminants in the Occupational Environment.

B.4.6 Casing and tubing

B.4.6.1 Principles

The casing program should be configured to accommodate all identified sub-surface hazards and to minimise risk either from cross-flow between formations or the uncontrolled release of well fluids to surface, throughout the life of the well.

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

Well casing must be:

(a) designed, installed, tested and maintained in a way that is consistent with the well integrity management system for the well;

(b) designed, installed, tested and maintained in a way that is consistent with the well design and barrier requirements set out in section B.4.3 of this Code; and

(c) designed to consider the required strength, metallurgy (to resist corrosion and erosion), sealing capacity, and **circulation** capacity.

B.4.6.2 Mandatory requirements

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

(b) Casing, casing connections, wellheads, and valves used in petroleum 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 (e.g. hydraulic stimulation), production or injection pressures, potential well control situations, any potential corrosive conditions (H_2S, CO_2, etc.), and other factors pertinent to local experience and operational conditions.

(c) Sections B.4.6.2 (a) and (b) do not apply to a conductor pipe.

(d) Methods of preventing external corrosion that impact well integrity must be applied.

(e) All casing and tubing must be manufactured to the latest edition of API 5CT. The rated capacity of the pipe body and connections must be obtained from the latest edition of API 5CT or the manufacturer’s technical specifications.

(f) Welded joints are permitted in construction of petroleum wells provided they are manufactured in compliance with API 5CT, sections 6, 7, 8, 10, and 13, and Tables C.3/E.3.

(g) The yield stress of **Oil Country Tubing Goods** must be de-rated for temperature.

(h) When designing casing strings and casing connections for petroleum wells, interest holders must design each well, or similar wells, and the casing string using appropriate design safety factors. Design safety factors used must be specified in the WOMP. A generic worst case design and stress analysis may be adopted to cover multiple wells in a field development targeting the same or a similar reservoir.

(i) 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 casing** or **intermediate casing**), and prior to stimulation, diagnostic fracture injection test (DFIT), or completion operations commencing (in the case of **production casing**).

(j) Interest holders must provide DPIR evidence of successful testing of the mechanical integrity of the well through pressure testing prior to hydraulic stimulation or DFIT operations.

B.4.6.3 Preferred requirements

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

(b) 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 particular string and maximum surface treatment pressures for hydraulic 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; and

v. not exceed the rated burst capacity of the casing with a safety factor applied.

(c) Casing connection qualification testing should be to API Recommended Practice 5C5 Connection Application Level (CAL) II or CAL IV, based on the intended service.

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

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

(f) Consideration for use of metal-to-metal seal thread connections should be given to production casing and tubing strings for wells designed for:

i. gas lift,

ii. gas wells that cross hydrocarbon bearing zones or over pressured water zones; and

iii. wells where hydraulic fracturing operations exceed a surface pressure of 49.6 MPa (7200 psi).

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

(h) The potential impact of high casing pressure on cement bond quality should be considered when determining pressures for any casing tests carried out before cement has properly set.

(i) A conductor casing string should be installed to protect a well and equipment against surface formation instability and to enable the circulation of drilling fluid from the well before surface casing is installed.

References*:*

- API Recommended Practice 5A3/ISO 13678, Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements.
- API Recommended Practice 5A5/ISO 15463, Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe
- API Recommended Practice 5B1, Gauging and Inspection of Casing, tubing and Line Pipe Threads
- API Recommended Practice 5C1, Recommended Practice for Care and Use of Casing and Tubing
- API Recommended Practice 5C5/ISO 13679, Recommended Practice on Procedures for Testing Casing and Tubing Connections
- API Recommended Practice 5C6, Welding Connections to Pipe
- API Spec 8A / 8C, Grinding of welds (to suit casing elevators)
- API Specification 5B, Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads
- API Specification 5CT, Specification for 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
- AS1666 Part 1 (1995), Slings used in bundling OCTG
- NACE MR0175/ISO 15156-1, 2 and 3, Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production.

B.4.7 Primary cementing

B.4.7.1 Principles

Well **cementing** is designed, installed, tested and maintained in a way that is consistent with:

(a) the **well integrity** management system (see section B.4.1) for the well, and;

(b) well design and barrier requirements set out in section B.4.3 of this Code.

Primary cementing of casings and/or **liner** strings is designed to:

(a) provide axial support for the casing string to permit further drilling and to provide an anchor for **BOP** equipment;

(b) reduce possibilities of casing buckling and/or collapse, particularly in situations where abnormal formation stresses occur;

(c) provide a seal across permeable and impermeable formations to prevent undesired flow of formation fluids and crossflow behind casing/liner;

(d) provide a seal to protect aquifers from contamination;

(e) seal off the bottom of the casing in order to control pressure; and

(f) provide corrosion protection, in particular such that corrosion rates of steel with an adequate cement coating are sufficiently low that cement encapsulation of steel is accepted as a permanent barrier.

B.4.7.2 Mandatory requirements

(a) The constituents and properties of materials used in primary cementing must be suitable for the intended conditions of use and used in compliance with the relevant **safety data sheet** requirements.

(b) The cement slurry density must be designed to maintain well control, prevent gas channelling and achieve the required compressive strength while avoiding losses during cement placement.

(c) Cement laboratory testing procedures must be carried out (as per ISO 10426-2, API RP 10B-2 - Recommended Practice for Testing Well Cements) on representative samples of the mix water, cement and additives to confirm the resulting slurry used for primary cementing meets the requirements of the well design.

   i. In the case where a number of similar wells are drilled in an area with similar well properties (depths, temperatures, and well design) and well integrity risks, constant cement materials and mix water properties, then a representative lab test is acceptable.

   ii. The testing, as a minimum, must include slurry density, rheology, thickening time, free water, fluid loss (if required), and compressive strength development with time.

(d) The top of cement must be designed in accordance with Table 2.

Table 1: Primary cementing criteria

Property	Primary cementing criteria
Planned **Top of Cement**	**Top of cement** (**TOC**) to comply with barrier requirements set out in section B.4.3 of this part of this Code and the following minimum requirements: • Conductor casing string (other than those placed by jetting or driving) TOC must be designed to surface. • TOC for **surface casing** must be designed to surface. • The TOC for any intermediate and **production casing** strings must overlap with the shoe of the previous casing string by a minimum of 200 m (656 ft). • The designed TOC, if not to surface, for any intermediate or production casing strings must be determined such that it has been demonstrated that the length of the cement column will not undermine the primary cementing Principles. • Where interest holders choose not to bring cement to surface, they should consider that after **decommissioning**, two adjacent cement barriers across all aquifers will be required as per B.4.15.2(d) of this Code. • The required compressive strength slurry for fracture stimulation must be placed up to at least 150 m (500 ft) measured depth above any zone to be hydraulically fractured. • On **high temperature wells** the TOC must be designed to mitigate against wellhead growth due to temperature during flow back and production

(e) In cases where an approved WOMP specifies that production casing will not be cemented across the **production zones**, production casing cement must be designed so that the base of the cement is no more than 30 m TVD above the predicted depth of the shallowest production zone.

(f) Unless conducting a green cement pressure test on bump, a minimum 3.5 MPa (500 psi) compressive strength on the tail cement shall be achieved prior to:

i. pressure testing of casing; or

ii. drilling out the shoe track for a subsequent hole section.

(g) Casing centralisation must be designed to achieve a minimum of 70% standoff across the entire cementing interval.

(h) Centraliser selection must suit application (refer to API Technical Report 10TR4 Selection of Centralizers for Primary Cementing Operations).

(i) Casing centralisation simulation must be undertaken for the proposed casing centralisation plan. Simulation for a vertical well must include:

i. actual deviation at casing depth; or

ii. where the actual deviation is not known, a deviation of three degrees from vertical at casing depth.

(j) Wiper plugs or cementing darts shall be used for production casing to prevent contamination of cement, and to enable plug bump and pressure test of the casing before cement cures.

(k) There must have be a validation procedure for primary cement jobs which must utilise at least one of the validation methods described in Table 4. If it cannot be verified that zonal isolation is achieved through primary cementing, the interest holder must submit that information,

(l) Wait on cement time prior to slacking off or removing BOPs shall be based on the cement achieving a minimum of 700 kPa (100 psi) compressive strength at the temperature of any potential flow zone in the annulus just cemented. Alternatively, interest holders may use an annulus pack-off or mechanical barrier that is compliant with API Standard 65-2 and tested to verify a pressure seal prior to removing BOPs.

(m) when a hydrocarbon bearing zone is intersected during drilling and subsequently cemented, a **Cement Bond Log** should be performed as a verification of hydraulic isolation from aquifers, the surface and other formations where cross flow is prohibited.

(n) 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%.

(o) A minimum required ultimate compressive strength must be determined for cement slurries to be used across zones which may be hydraulically fracture stimulated.

(p) For wells that are to be fracture stimulated, including DFIT in a cased section of a well; zonal isolation of the production casing and liner cementation must be validated by a cement bond log which confirms at least 150 m vertical depth of good cement is in place above the any zone to be hydraulically fractured

B.4.7.3 Preferred requirements

(a) Proper well preparation, hole cleaning and conditioning should be carried out prior to the primary cement job.

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

(c) Cement job design should include proper cement spacer design and volume to achieve the appropriate contact time during pumping. Where a viscosified non-newtonian spacer is used the rheology should be formulated to optimise drilling fluid removal ahead of the cement slurry.

(d) Design of centralizer placement should follow API 10D-2 - Recommended Practice for Centralizer Placement and Stop Collar Testing.

(e) Wiper plugs are recommended for surface and intermediate casings to prevent contamination of cement and to enable plug bump and pressure test of the casing before cement cures.

(f) Calliper logs, where available, may be used to confirm cement volume requirements. The level of excess cement requirements should be based on local field knowledge.

(g) Primary cementing slurry design considerations should include those outlined in Table 3.

Table 2: Primary cementing slurry design considerations

Slurry Property	Consideration
Fluid loss	Should be controlled to maintain cement slurry properties during placement (e.g. avoid dehydration and premature thickening, less efficient mud displacement and possible losses to permeable formations).
Free water	Free water in cement slurries should be limited to avoid weak set cement and formation of gas migration channels.
Compressive strength	Both the thickening time and increase in compressive strength should be measured from the consistometer and UCA (Ultrasonic Compressive Strength Analysis) tests on the cement (at representative bottom hole conditions).

(h) Water and cement slurry samples should be taken (periodically during each cement job) by the interest holder and cementing contractor as an aid to monitoring cement job quality and visual confirmation of thickening time of cement. Cement samples are to be kept until the final Well Barrier Integrity Validation report (Section 302a of the Schedule) for that well is received and approved by the Department of Primary Industry and Resources.

(i) Verification and evaluation recommendations for primary cement jobs are outlined in Table 4.

(j) Baseline cement bond log evaluation should be considered on production casing and liners in each new field area where confirmation of cement placement has not been demonstrated. Confirmation of cement placement should be undertaken by cement returns to surface and adequate displacement volumes and pressures immediately prior to plug bump.

(k) For high temperature wells, best practice is to confirm geothermal temperature has been calibrated from circulating temperatures measured while drilling the well. If necessary, the well should be cooled with adequate circulation prior to commencing cementing operations to minimise chance of thickening time variability from tested cement formulation values.

(l) For high temperature wells, high temperature blend (with silica) slurries should be considered for all cement slurries, particularly where cementing to surface to mitigate wellhead growth. Hot wells may have high flowing wellhead temperatures that can lead to strength retrogression of cement near surface.

Table 3: Validation and evaluation recommendations for primary cement jobs

Job Type	Validation Criteria	Contingency
Casing cementation	• Slurry mixed and placed in accordance with approved cementation procedures. • Shoe track volume not over displaced when displacing cement slurry. • Downhole losses not greater than the excess pumped within the cement procedure, and calculated **TOC** using final circulating pressure (FCP) and measured fluid returns achieves the objective(s) identified within the cementation program. • No significant losses or slumping post-placement of cement. • Casing successfully pressure tested. If drilling out casing, a Formation Integrity Test (FIT) satisfactory after drilling out shoe track.	• Where the validation is inconclusive or not completed, the extension of good quality cement above the shoe, above hydrocarbons or aquifers should be verified by appropriate cement evaluation tools, interpreted by a **competent person**. • **Remedial cementing** / top-up job **cementing** as required.
Liner cementation	• Slurry mixed and placed in accordance with approved cementation procedures. • Shoe track volume not over displaced when displacing cement slurry. • Downhole losses not greater than the excess pumped within the cement procedure, and calculated **TOC** using final circulating pressure (FCP) and measured fluid returns achieves the objective(s) identified within the cementation program. • No significant losses or slumping post-placement of cement. • Casing successfully pressure tested. • Pressure test of liner top **packer** should be performed and recorded to verify zonal isolation. Testing pressures should be no less than 3.5 MPa (500 psi) over the previous casing **leak-off test** at the shoe or inflow tested where practicably possible • If drilling out casing, Formation Integrity Test (FIT) satisfactory after drilling out shoe track.	• Where the validation is inconclusive or not completed, the extension of good quality cement above the shoe, above hydrocarbons or above aquifers should be verified by appropriate cement evaluation tools, interpreted by a competent person. • If failed pressure test on bump, set liner top packer, circulate out excess cement and WOC prior to conducting pressure test again. • If failure again, may opt to run a liner tie back packer on top of the liner top and re-test. • Remedial cementing if necessary.

References*:*

- API Recommended Practice 10B-2/ISO10426-2, Recommended Practice for Testing Well Cements
- API Recommended Practice 10B-4, Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure

- API Recommended Practice 10B-5/ISO 10426-5, Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure
- API Recommended Practice 10B-6/ISO 10426-6, Methods of determining the static gel strength of cement formulations
- API Recommended Practice 10D-2/ISO 10427-2, Recommended Practice for Centralizer Placement and Stop Collar Testing
- API Recommended Practice 10F/ISO 10427-3, Recommended Practice for Performance Testing of Cementing Float Equipment
- API Specification 10A/ISO 10426-1, Specification for Cements and Materials for Well Cementing
- API Specification 10D/ISO 10427-1, Specification for Bow-Spring Casing Centralizers
- API Standard 65-2 Isolating Potential Flow Zones during Well Construction
- API Technical Report 10TR1 Cement Sheath Evaluation
- API Technical Report 10TR2, Shrinkage and Expansion in Oilwell Cements
- API Technical Report 10TR3, Temperatures for API Cement Operating Thickening Time Tests
- API Technical Report 10TR4, Technical Report on Selection of Centralizers for Primary Cementing Operations
- API Technical Report 10TR5, Technical Report on Methods for Testing of Solid and Rigid Centralizers.

B.4.8 Wellheads

B.4.8.1 Principles

The **wellhead** performs the general functions of:

(a) supporting casing and completion tubing strings;

(b) supporting the installation of surface barriers, which include the **BOP** during the drilling phase, and the **Christmas tree** during the production phase; and

(c) providing the arrangement for sealing, testing, monitoring, injecting into, and bleeding off between **annuli**.

B.4.8.2 Mandatory requirements

(a) Wellhead equipment and running tools must be specified in accordance with API Spec 6A/ISO 10423 and NACE MR0175/ISO 15156.

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

(c) Side outlet valves must be rated to the same pressure as the wellhead they are attached to. Moreover, all components on the hanger and Christmas tree and valves must be rated to the well pressure envelope.

(d) Wellheads must have adequate valve outlets accessible and operational for all annuli to allow for monitoring of annuli in accordance with paragraph B.4.1.2 (c).

(e) Wellheads for **high temperature wells** must include design for lock down of hangers, rated for the well conditions.

(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 of usage of a wellhead (i.e. to incorporate gas lift or re-injection) must be fully risk assessed ensure the compatibility of the existing equipment with the proposed usage.

B.4.8.3 Preferred requirements

(a) During initial wellhead installation, and periodic integrity testing, wellhead seal tests should be conducted to test the mechanical integrity of the wellhead sealing components (including valve gates and seals) and confirm they are capable of holding against well pressure.

(b) 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.

References

- An Industry Recommended Practice (IRP) for Canadian Oil and Gas Industry – Volume 5, November 2011.
- API Specification 6A, Specification for Wellhead and Christmas Tree Equipment.
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- NACE Standard MR 0175/ISO 15156 Materials for use in H_2S-containing environments in oil and gas production.

B.4.9 Well control

B.4.9.1 Principles

Well control aims to reduce hazards when conducting petroleum well construction and production operations. The primary purpose of well control is to provide barriers to prevent uncontrolled release of formation fluids to surface or other formations. Well control can be categorised at two levels:

(a) Primary well control - the maintenance of a hydrostatic pressure of fluid in the well, sufficient to balance the fluid pressure (pore pressure) in the formations drilled. In practice a defined excess hydrostatic pressure is maintained to provide a safe level of 'overbalance' to **formation pressure** using weighted drilling or kill fluids in most cases. Where a weighted fluid is not used, primary well control is provided by a combination of pressure and flow control equipment.

(b) Secondary well control - used when the primary well control fails - should there be a loss of hydrostatic pressure or a situation develops where the formation pressure exceeds the hydrostatic pressure, there is the potential for influx of formation fluids into the well. If the well begins to flow, **well control equipment** will be in place to contain any influx of formation fluid and allow it to be safely circulated out of the well.

The guiding principle is to maintain at least two well control barriers in place during all well operations as per section B.4.3 of this Code.

B.4.9.2 Mandatory requirements

(a) There must be a well control manual for all phases of a well's lifecycle available for inspection at well sites (as part of or along with safety management system information), detailing requirements for equipment level, **kick** detection and well control techniques.

(b) During **well construction**, **well control equipment** (e.g. **BOP** stack and wellhead) must be installed for all operations prior to drilling below the **surface casing** string. Well control equipment can be terminated once the well is **decommissioned** or cased and suspended after all hydrocarbon zones and aquifers are isolated and barriers established and verified.

(c) A gas detection system must be used on the well site to identify hydrocarbon bearing zones and potential gas influx.

(d) Well control equipment must be used and operated compliant with API Specifications 16A, 16C and 16D.

(e) If undertaking **underbalanced drilling** or **managed pressure drilling** activities, well control measures must be in place to counter the absence of weighted **drilling fluid** as the primary well control method.

(f) If undertaking underbalanced drilling or managed pressure drilling activities, Rotary Control Devices must use and operated compliant with API Specification 16RCD and non-return valves must use and operated compliant with API Specification 7NRV.

(g) The level of well control equipment required on any operation, and the configuration employed, shall be suitable for the well.

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

(i) Other than annular BOPs, all well control equipment must be rated to exceed maximum anticipated shut-in surface pressure.

(j) **Well control equipment** must be function tested and pressure tested in accordance with API Standard 53 at least every 3 weeks.

(k) The surface gas handling system for drilling operations must be fit for purpose and used within operating limitations, that the potential risks of fire and explosion from free gas are identified and managed, and volumes of gas vented or flared are recorded in accordance with Part D of this Code.

(l) Methods must be established for early identification of fluid influx (well **kick**).

(m) Regular and realistic drills pertaining to on-going or up-coming operations should be conducted to train involved personnel in detection, prevention and recovery of a lost barrier.

(n) Prior to drilling below the conductor casing string in **exploration wells**, or in **development wells** or **appraisal wells** in those areas having known shallow gas accumulations, a system shall be installed to safely divert hydrocarbons and other fluids in the event of pressurised fluids occurring below the shoe of the conductor string.

(o) Methods must be established that prevent blowouts up the drill pipe in case unexpected subsurface pressures are encountered.

(p) The **kick tolerance** of the formation being drilled must be known. This may be demonstrated through a Formation Integrity Test or data from offset wells.

B.4.9.3 Preferred requirements

(a) Additional guidance for selection and use of well control 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/elastomer consumables by heat or light.

(c) Methods for early identification of fluid influx may include monitoring of mud pit level, flowline flow rate and trip volume sheets derived from trip tank measurements.

(d) Queensland Department of Natural Resources Mines and Energy Technical Guidance - Surface Gas Handling System and Mud Gas Separator Design Principles for Drilling Operations should be followed to ensure the surface gas handling system for drilling operation is fit for purpose and used within operating limitations.

(e) Well control equipment should be pressure tested: :

i. every fortnight (14 days), or other interval being a maximum 3 weeks, as per B.4.9.2 (j), depending on the type of operation; and

ii. specifically at the following times:

a) after installation of any new wellhead component and BOP assembly and prior to drilling;

b) when any equipment change is made and after repairs;

c) prior to drilling into a suspected high pressure zone;

d) prior to a production test; and

e) at any time requested by the regulator; and

f) as specified in the WOMP.

References

- API Recommended Practice 59, Recommended Practice For Well Control Operations.
- API Recommended Practice 92U, Underbalanced drilling operations
- API Specification 7NRV, Specification for Drill String Non-return Valves
- API Specification 12J, Specification for Oil and Gas Separators
- API Specification 16A/ISO 13533, Specification for Drill-Through Equipment
- API Specification 16C, Specification for Choke and Kill Systems
- API Specification 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
- API Specification 16RCD, Drill Through Equipment Rotating Control Devices
- API Specification 16ST, Coiled Tubing Well Control Equipment Systems
- API Standard 53, Blowout Prevention Equipment Systems for Drilling Operations.
- ISO 13354, Drilling and production equipment - Shallow gas diverter equipment
- NORSOK Standard D-010, Well Integrity in Drilling and Well Operations
- Technical information sheet - Surface gas handling system and mud gas separator design (DNRM, 2016)

B.4.10 Drilling fluids

B.4.10.1 Principles

The primary objectives for drilling and completion fluids are to:

(a) maintain well integrity and meet well barrier requirements (set out in sections B.4.1 and B.4.3 of this Code respectively);

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

(c) minimise reservoir damage and therefore optimise well productivity; and

(d) improve drilling performance.

Containment of drilling fluids and additives must be considered in the well site layout (see section B.4.16) and as part of a spill management plan (section C.7.2).

B.4.10.2 Mandatory requirements

(a) Drilling fluids must be selected and managed to ensure all products used during well operations on petroleum wells are used in accordance with the manufacturer's recommendations and relevant safety data sheets. The name, type and quantity of each chemical used on each well throughout the well construction process must be recorded.

(b) Drilling fluids shall not contain benzene, toluene, ethylbenzene, or xylene (BTEX) above the levels prescribed in section B.5 of this Code.

(c) Testing of the active drilling fluid must be carried out in accordance with API RP 13B a minimum of twice per day.

(d) The interest holder must implement a system for accurately monitoring drilling fluids during all drilling operations that:

   i. allows the determination of drilling fluid volume gains and losses;

   ii. allows the determination of drilling fluid volumes required to fill the hole on trips;

   iii. allows the determination of density in/out of the well to ensure the correct weight is being maintained to control the well; and

   iv. allows the monitoring and recording of gas readings in the return fluid flow once gas bearing strata are intersected.

(e) The drilling fluid handling system and surface gas handling system for drilling operations must allow for the removal of gas from the drilling fluid in accordance with section B.4.9.2. (j).

(f) The source of water used for all well operations (drilling, **workover** and **hydraulic fracture stimulation**) must be recorded.

(g) Where use of a **non-aqueous drilling fluid** is planned, a risk assessment must be carried out to identify all risks associated with the use of non-aqueous drilling fluid and controls put in place. Confirmation must be demonstrated that the rig is suitable for non-aqueous drilling fluid use, including:

   i. suitable seals and valves and loading/unloading hoses; and

   ii. inclusion in the spill management plan to ensure spills are contained.

(h) At the end of every well where non-aqueous drilling fluid has been used, a summary must be prepared, reconciling whole quantities of non-aqueous drilling fluid left in the well, returned for storage/refurbishment. This information is to be included in the well completion report.

(i) When drilling through local **aquifers** and until these aquifers are isolated by a minimum of two verified barriers, then:

i. only air, water or water-based drilling fluids are permitted to be used; and

ii. chemicals or other substances that could leave a residual toxic effect in the aquifer must not be added to the drilling fluid.

(j) Where H_2S is deemed likely, then:

i. the pH of the fluid must be monitored on a regular basis (a decrease in pH may indicate H_2S contamination), high pH can be used to hold the sulfides in the mud.

ii. sufficient Zinc Carbonate ($ZnCO_3$), Zinc Oxide or Ironite Sponge must be available to treat a fluid system containing up to 500 ppm (by volume) H_2S.

B.4.10.3 Preferred requirements

(a) The drilling fluid selected should be appropriate for the well design including any locally experienced drilling problems and anticipated geological conditions likely to be encountered.

(b) The use of biodegradable substances in the drilling fluid is preferred.

(c) Biocide, oxygen scavenger and/or corrosion inhibitor should be considered for all water based systems, noting mandatory requirements in B.4.10.2 (h).

(d) Drilling fluid should be captured and recycled for reuse as much as practicable.

(e) Products should be chosen, stored, and used at concentrations that minimise the risk to health and safety and environmental harm.

(f) Lost **circulation** material strategies should be documented and sufficient stocks of lost circulation material kept on site for contingency purposes. The amounts should be based on field experience.

(g) A minimum stock of contingency barite (or other weighting agents) should be maintained on location for the **petroleum well** type. The interest holder should ensure barite (or other weighting agents) stocks are documented and sufficient stocks of material kept on site, or are immediately accessible, for worst case scenario, that is; for a serious well control incident/blowout.

(h) For **high temperature wells**, density variation simulation and rheology testing at field/well conditions (e.g. FANN70 testing or equivalent) should be considered to ensure effects of well temperature on the density profile of mud can be accurately predicted for well control purposes.

(i) When drilling with a closed mud system, fluid weight and viscosity in and out of the hole should be checked regularly and recorded by the Drilling Contractor/Well Servicing Contractor. This frequency should be increased during narrow pore pressure / fracture pressure window drilling.

(j) To maintain accurate volume accounting, fluid transfers should not be made from 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 flow-back/ pressure testing.

(k) Well stability analysis should be considered for all deviated wells over 40deg inclination and for wells in areas known to be prone to well instability issues or tectonic activity.

References*:*

- API Recommended Practice 10B-6/ISO 10426-6, Methods of determining the static gel strength of cement formulations
- API Recommended Practice 13B-1/ISO 10414-1, Recommended Practice for Field testing of drilling fluids Part 1: Water-based fluids
- API Recommended Practice 13B-2/ISO 10414-2, Recommended Practice for Field testing of drilling fluids — Part 2: Oil-based fluids
- API Specification 13A /ISO 13500, Specification for Drilling Fluid Materials
- ASTM D412, Standard test Methods for Vulcanized Rubber and Thermoplastic Elastomers – Tension 1
- ASTM D471, 12 Standard Test Method for Rubber Property – Effect of Liquids
- ASTM D2240, 05 2010, Standard Test Method for Rubber Property – Durometer Hardness 1
- 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
- NOHSC: 3017 1994, Guidance Note for the Assessment of Health Risks Arising from Hazardous Substances in the Workplace
- NOHSC: 7039 1995, Guidelines for Health Surveillance
- NOHSC: 1005 1994, National Model Regulations for the Control of Workplace Hazardous Substances - Hazardous Substances Information System (HSIS)
- NOHSC: 1008 2004, National Standard Approved Criteria for Classifying Hazardous Substances

B.4.11 Air and gas drilling fluids

B.4.11.1 Principles

When planning to use air or gas as a drilling fluid, or as a component of a drilling fluid (such as mist, foam, or aerated fluids), the following are required:

(a) **well integrity** must be maintained and **well barrier** requirements met as set out in sections B.4.1 and B.4.3 of this Code**,** respectively; and

(b) hazards and risks associated with potentially flammable and/or explosive mixtures of gasses in the well or at the **well site** must be mitigated to acceptable levels.

B.4.11.2 Mandatory requirements

(a) Compressors and boosters must be located to prevent the ingestion of flammable gasses from drilling activities and fuel stores.

(b) All pressure lines and manifolds must be:

i. identified with appropriate signage;

ii. positioned so that it does not interfere with vehicular access to the drilling location or cross areas on the drilling location frequented by vehicles and persons;

iii. constructed using hoses, pipes, fittings and connections that have a rating sufficient to withstand the maximum supply pressure;

iv. properly restrained to prevent dangerous movement in the event of coupling or hose failure.

(c) A check valve shall be installed on the delivery line at or near the standpipe.

(d) The main air or gas supply line shall have at least two valves:

i. one on the standpipe and accessible from the rig floor;

ii. one located at the compressors and boosters;

iii. each valve shall be rapid acting, clearly labelled and readily accessible.

(e) In relation to blooey, diverter or bleed-off lines:

i. they must only be used during **underbalanced drilling**.

ii. where used, they must be run to a pit or tank capable of catching any drill cuttings produced;

iii. they must extend at least 45 metres from the wellhead and shall, where practicable, be laid downwind of the well, or at right angles to the direction of the prevailing wind;

iv. they must include adequate dust suppression to reduce risks to human health and the environment to a level that is ALARP and acceptable;

v. reservoir liquids must not be produced to the pit or tank;

vi. any geological sample catcher installed on a blooey line shall be designed to avoid flashback and to protect persons from dust; and

vii. a continuous purge of any blooey, diverter or bleed-off diverter line should be conducted using a primary jet during **circulation**, start-up and shut-down, and when making connections.

(f) For well control during air drilling operations, all equipment shall be lined-up for a soft shut-in at all times. It is safety critical to avoid a rapid pressure build-up within the well when the well is known to contain hydrocarbons and air.

(g) Drilling crew from the Assistant Driller and above must be well-control certified and must be trained on soft shutting techniques applicable for **underbalanced drilling** operations.

(h) Explosive limits or mist injection shall be established for circulating media that can introduce O_2 into the circulating system. If explosive limits are not clearly defined, systems which could introduce O_2 should not be used.

(i) Explosive limits shall be documented and posted next to the O_2 monitoring system for all circulating systems that contain O_2. Monitoring stations should include the rig floor, inside the substructure next to the **BOP** stack, and near separation vessels / storage / circulating tanks.

(j) All gas influxes shall be checked for H_2S. If any H_2S is detected, the well must be circulated to a kill fluid immediately. The impact of H_2S to the flammability limits (e.g., LEL) is unpredictable during reservoir inflow flush production events, therefore, with any detection of H_2S air drilling operations shall be terminated.

(k) Sufficient firefighting equipment and systems must be available at the drilling rig to extinguish an ignition at the wellhead or on the rig floor.

(l) Enough kill fluid of sufficient density to be able to kill the well in an emergency must be available on site.

(m) At least one portable gas detector, of a kind acceptable to an Inspector as appointed under the Petroleum Act 1984, must be available for use where air or gas drilling is in progress.

(n) A downhole float valve must be fitted in the drilling string. Top and bottom kelly cocks must also be installed.

(o) The rig substructure must be kept adequately ventilated (either by natural ventilation or by fans).

B.4.11.3 Preferred requirements

(a) The following areas should be addressed in the WOMP to reduce the safety impact of air drilling:

i. cuttings containment;

ii. dust suppression (may include water mist);

iii. containment of well fluids;

iv. waste disposal; and

v. noise suppression (may be required in populated areas).

(b) If the air drilling includes bringing annular returns back through a separator, the following are required:

i. only non-combustible mixtures are involved;

ii. monitor for explosive limits in the return line when drilling fluids include O_2;

iii. an inert gas purge system should be rigged into the separator inlet line, and a pressure relief valve should be installed on the purge line; and

iv. all atmospheric separation systems are electrically bonded and grounded.

(c) Drilling crew from the Assistant Driller and above should be trained in soft shut-in well control practices and familiarized prior to starting air drilling operations.

(d) All personnel on site should receive a localised induction on the equipment, hazardous areas and specific hazards associated with underbalanced drilling operations. This is to be conducted before the underbalanced drilling operations commence.

(e) If the blind rams are used to isolate the well when no pipe is in the hole, ensure operational practices prevent the build-up of pressure in the well when the blind rams are closed and the well is known to contain hydrocarbons and air.

(f) Cold venting of the returning gas phase is recommended to avoid fire/explosion ignition source risks, unless H_2S is present. Site-specific dispersion modelling should be conducted to ensure the flammable plume above the vented area does not impose explosion and/or flammability hazards.

References*:*

- API Recommended Practice; RP 92U Underbalanced Drilling Operations

B.4.12 Well evaluation, logging, testing and coring

B.4.12.1 Principles

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

(a) to characterize reservoir properties, including the following:

i. petrophysical properties;

ii. formation fluid properties;

iii. geomechanical properties; and

(b) to evaluate reservoir productivity.

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

B.4.12.2 Mandatory requirements

(a) Equipment must be available to attempt recovery of survey or logging equipment lost down hole.

(b) If a radiation source cannot be retrieved from down hole, all relevant information must be submitted in writing and an approval must be sought in relation to disposal of a radiation source under the *Radiation Protection Act 2004* (NT).

(c) When coring operations are conducted, the testing for gas using hand held 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.

(d) Well testing requirements for subsurface **open hole** tests are as follows:

i. Well & 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 reservoir pressure less the hydrostatic of a gas column to surface plus any kill or surface treatment pressure.

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 Specification 6A, NACE MR-01-075, ASME B31.3 (Spools & X-Over).

(e) Extended production testing (EPT) requirements:

i. A production testing program must include (but is not limited to):
   a. proposed timing and duration;
   b. the equipment proposed to be used for the test including accurate flow measurement device(s);
   c. the well schematic; and
   d. the proposed method of disposal of the petroleum, **produced water**, **flowback fluid** or gas produced (see Part C of this Code).

ii. All well test equipment must be located in appropriate hazardous classification areas.

iii. For cased hole testing a pressure test that exceeds the maximum anticipated pressures must be completed to demonstrate mechanical integrity and define a maximum allowable operating pressure (MAOP).

iv. For open hole testing a pressure test to the MAOP of the pressure-exposed elements of the system must be completed.

v. All flowlines, valves and equipment used in a production test must have a rated working pressure in excess of all anticipated pressures and must be tested and operated in accordance with relevant standards.;

vi. Pressure monitoring capability must be available at the wellhead. During the well test, actual flowing conditions must be recorded and compared to predicted values.

vii. The well test surface equipment must be designed, prepared and operated in accordance with API Specification 6A, NACE MR-01-075, ASME B31.3 (Spools & X-Over).

(f) Diagnostic Fracture Injectivity Testing (DFIT) requirements:

i. Pressures, rates, and volumes shall be recorded during the DFIT.

ii. For cased hole DFITs a pressure test that exceeds the maximum anticipated pressures must be completed to demonstrate mechanical integrity and define a MAOP. Refer to B.4.6.3 (c).

iii. For open hole DFITs a pressure test to the MAOP of the pressure-exposed elements of the system must be completed. Refer to B.4.6.3 (c).

B.4.12.3 Preferred requirements

(a) Where appropriate (e.g. when hole conditions and pressure regimes dictate), secondary well pressure control equipment should be 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 **well operating envelope**, if applicable.

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

References*:*

- Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) - Disposal of Naturally Occurring Radioactive Material (NORM)
- Australian Radiation Protection and Nuclear Safety Agency (ARPANSA), Code of Practice for the Safe use of sealed radioactive sources in borehole logging (1989)

- API Specification 6A, Specification for Wellhead and Christmas Tree Equipment
- NACE MR0175/ISO 15156-1, 2 and 3, Petroleum and natural gas industries – Materials for use in H2S-containing environments in oil and gas production
- ASME B31.3 – Process Piping
- NOHSC: 1013 1995, National Standard for Limiting Exposure to Ionising Radiation
- NOHSC: 3022 1995, Recommendations for Limiting Exposure to Ionising Radiation

B.4.13 Hydraulic stimulation and flowback operations

B.4.13.1 Principles

Hydraulic fracture stimulation and flowback operations are conducted to improve or enable the recovery of hydrocarbons. Hydraulic fracture stimulation and **flowback** operations must seek the following:

(a) to maximize the potential for enhanced petroleum recovery from the resource;

(b) to ensure protection of aquifers is maintained during all operations phases for hydraulic stimulation and flowback;

(c) to not exceed the **well operating envelope** and to maintain **well barriers**;

(d) to **flowback fluids** in such a manner as to ensure all recovered flowback fluid is isolated and does not come into contact with aquifers or pollute soil or soil substrate; and

(e) to manage any gas contained within flowback fluids.

Containment of hydraulic fracturing fluids and additives must be considered in the well site layout (see section B.4.16) and as part of wastewater management and spill management plan (see section C.7).

B.4.13.2 Mandatory requirements

(a) **Hydraulic fracture stimulation** activities must be designed to not impact aquifers.

(b) **Hydraulic fracturing fluid** additives must be selected and managed to ensure all products used during well procedures on petroleum wells are used in accordance with the manufacturer's recommendations and relevant **safety data sheets**.

(c) In accordance with Schedule 1, Part 2, Clause 6 and Part 3, Clause 11 of the **PER**, the Implementation Strategy of an EMP for petroleum activities that include hydraulic fracture stimulation must include details of monitoring and reporting of the as-pumped composition of any hydraulic fracturing fluid used. As a minimum, the following must be recorded and reported for each stage (where a stage in this context means all fluids pumped at a particular depth interval):

   a. total volume of hydraulic fracturing fluid pumped,

   b. quality of water used (tested for analytes in section C.8of this Code. Analyses do not need to be repeated if the same water source is used for multiple stages) and

   c. typical and maximum concentrations of chemicals or other substances used.

(d) Hydraulic fracturing fluids must not contain benzene, toluene, ethylbenzene, or xylene (BTEX) above the levels prescribed in section.B.5 of this Code.

(e) A WOMP that includes hydraulic fracture stimulation must take into account location and characteristics of known **geohazards** and any other wells near the well to be hydraulically stimulated.

(f) WOMPs must demonstrate that fractures are contained within the proposed stimulation area, containing the target zone(s) and that the stimulated area and target zone(s) are sufficiently separated from aquifers.

(g) Well integrity must be validated before and after hydraulic fracturing operations.

(h) A pressure test that exceeds the maximum anticipated hydraulic fracture stimulation pressures at screenout conditions must be completed to demonstrate mechanical integrity and define a MAOP.

(i) Pressure communication between casing annuli must be monitored and controlled while conducting hydraulic fracture stimulation.

(j) The pressure kickout on the pump units and in-line pressure relief valves (where utilised) must be set below the MAOP.

(k) All flowback activities must be managed to minimise the release of gas to atmosphere, in accordance with the following requirements:

i. For **exploration wells and appraisal wells** and **low pressure wells** (including those with a **low gas to oil ratio**), all flowback fluid must be either:

  a. routed directly to a completion combustion device with a continuous ignition device (e.g. a pilot flame) or,

  b. routed to a well completion vessel and with flowback fluid sent to a separator as soon as the separator will function and then directing the separated gas to a completion combustion device with a continuous ignition device.

ii. For all **development wells** undergoing hydraulic fracture stimulation, unless it is not technically feasible to do so, the operator must:

  a. route all saleable quality gas from the separator to a gas flow line or collection system; or-inject the gas into the well or another well;

  b. use the gas as an onsite fuel source; or use the gas for another useful purpose that a purchased fuel or raw material would serve; or

  c. where technically infeasible, direct the gas to a combustion device with a continuous ignition device

iii. Despite parts i. and ii. of this subsection, venting is only permitted during flowback activities when:

  a. the gas flow is insufficient to allow the separator to function properly; or

  b. the use of a combustion device creates a fire or safety hazard or where heat emissions may negatively impact the environment

iv. Where venting is the only technically feasible option for managing produced gas, the technical considerations preventing the use of the recovered gas must be recorded and included in the operator’s annual report.

v. Volumes of gas emitted during the **separation flowback stage** must be measured using direct measurement as governed under the *Commonwealth National Greenhouse and Energy Reporting (Measurement) Determination* (2008), and reported in accordance with Part D of this Code.

(l) Hydraulic fracture stimulation operations must not be conducted in a formation that does not have more than 600 m vertical separation to the nearest aquifer unless it can be demonstrated that the risks of connectivity with the nearest aquifer is ALARP and acceptable.

B.4.13.3 Preferred requirements

(a) **Pressure testing** to confirm mechanical integrity of the well, as required in B.4.13.2 should be completed as soon as reasonably practicable prior to hydraulic fracture stimulation operations.

(b) The risk of casing deformation should be considered as part of the well design risk assessment process and they should document any resultant control measures in the operations programme(s).

(c) The use of industry recognised software and geo-mechanics data should be used to develop the final stimulation design.

(d) The proposed design of the hydraulic 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 hydraulic fracturing fluids migrating from the designed fracture zone(s).

(e) Water used in hydraulic fracture stimulation operations should be recycled for reuse wherever reasonably practicable.

(f) As far as reasonably practicable, fluids with the lowest toxicity should be used in hydraulic stimulation, and the concentrations used should be the minimum required to facilitate effective operations. Chemical suppliers should be required to meet these guidelines.

(g) Volumes of injected hydraulic fracturing fluid and pumping pressure should be accurately monitored and recorded.

(h) Reference should be made to API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines.

References

- API Guidance Document HF1, Hydraulic Fracturing Operations— Well Construction and Integrity Guidelines
- API Guidance Document HF2, Hydraulic Fracturing Operations— Water Management Associated with Hydraulic Fracturing
- API Guidance Document HF3, Hydraulic Fracturing Operations— – Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing
- Energy Safety Canada, Drilling and Completions Committee, IRP24: Fracture Stimulation (2016).
- NOHSC: 3017 1994, Guidance Note for the Assessment of Health Risks Arising from Hazardous Substances in the Workplace
- NOHSC: 7039 1995, Guidelines for Health Surveillance
- NOHSC: 1005 1994, National Model Regulations for the Control of Workplace Hazardous Substances - Hazardous Substances Information System (HSIS)
- NOHSC: 1008 2004, National Standard Approved Criteria for Classifying Hazardous Substances
- NOHSC: 2007 1994, National Code of Practice for the Control of Workplace Hazardous Substances

B.4.14 Workover and Intervention

B.4.14.1 Principles

Any re-completion or well modification needs to be designed to ensure the well is operated within the maximum expected pressures and load conditions until final decommissioning. Well integrity must be maintained, as set out in section B.4.1 of this Code.

B.4.14.2 Mandatory requirements

(a) Well barrier elements must be in place to intervene on the well during workover and intervention activities. as specified in section B.4.3 of this Code.

(b) Fit for purpose well design and construction materials must be used workover and intervention activities as specified in this Code (sections B.4.6, B.4.7, and B.4.8).

(c) All new barriers or new well operating envelopes must be verified and clearly documented and reported by submission of an updated well barrier integrity validation (WBIV) report to DPIR.

(d) The potential for accumulation of naturally occurring radioactive materials (NORM) in well equipment must be assessed and appropriate measures put in place to reduce risks to the health and safety of people and the environment are put in place.

B.4.14.3 Preferred requirements

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

(b) During well intervention, or workovers 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 should be used to determine mechanical integrity and help predict possible issues for intervention in similar wells.

References:

- ISO 16530-1:2017, Well integrity - Part 1: Life cycle governance
- NORSOK Standard D-010, Well integrity in drilling and well operations
- ARPANSA, 2008, Safety Guide for the Management of Naturally Occurring Radioactive Material (NORM)

B.4.15 Well suspension and decommissioning

B.4.15.1 Principles

The goal of well decommissioning is to permanently seal the well to prevent the flow of fluids into, out of and along the well at the end of its useful life.

The decommissioning objectives are to ensure:

(a) well integrity is maintained at all times, as set out in section B.4.1 of this Code;

(b) all aquifers are isolated from the surface, each other and from permeable hydrocarbon zones;

(c) permeable formations containing fluids at different pressure gradients and/or significantly different salinities are isolated from each other to prevent crossflow;

(d) discrete, permeable hydrocarbon zones are isolated from each other (unless co-mingling of discrete zones is permitted), or a minimum of one well barrier is set above the shallowest co-mingled zone (if co-mingling is permitted);

(e) all permeable hydrocarbon zones are isolated from the surface; and

(f) the site is rehabilitated and left safe and free from contaminants as per section A.3.9 of this Code.

Decommissioning and monitoring of decommissioned wells is conducted through a two stage process as summarized in Table 5.

The primary considerations for **suspension** of a petroleum well are to ensure that:

(a) well integrity is maintained at all times as set out in section B.4.1 of this Code;

(b) monitoring requirements can be met and that production can readily be resumed; and

(c) all safety requirements are met.

B.4.15.2 Mandatory requirements for decommissioning wells

(a) Decommissioning and monitoring of decommissioned wells must be conducted through a two stage process, as shown in Table 5.

Table 4: Two Stage Decommissioning Process

Stage	Description
One	• Interest holder places downhole barriers across all identified **hydrocarbon bearing zones** and aquifers to be zonally isolated as per section B.4.15.2. • This includes placing of **casing shoe** cement plug and any cased hole plugs for permanent zonal isolation in accordance with section B.4.15.3: *Cement plug requirements and validation methods*. • A surface cement plug is not placed in the well and the **wellhead** is not removed at this stage. • The well is left in a state that casing **annuli** and casing can be monitored for pressure (i.e. verify **well integrity**) with all downhole barriers in place. • Monitoring of pressures at an agreed frequency for duration of 1-6 months, depending on well risk and classification as per approved WOMP. • Concurrently to the well integrity monitoring, the **well pad** may be rehabilitated as much as practicable.
Two	• On successful validation of no well integrity issues, the interest holder completes wellhead removal and surface cement plug placement as per section B.4.15.2. • These may be rigless activities as required. • Well status is officially changed to fully decommissioned once requirements of section B.4.15.2 are satisfied. • Site rehabilitation may be completed.

(b) Cement must be used as the primary sealing material. Cement testing must be carried out as per requirements set out in section B.4.7.2 of this Code.

(c) Biocide, oxygen scavenger and/or corrosion inhibitor must be used in water-based fluid used for the decommissioning process.

(d) All aquifers must be isolated:

  i. from each other and the surface by a minimum of one well barrier; and

  ii. from any permeable hydrocarbon bearing zones by a minimum of two well barriers.

(e) Cement plugs must conform to the requirements as detailed in section B.4.15.3.

(f) BOPs and/or the wellhead must not be removed until the cement plug across the surface casing shoe or the plug across the uppermost perforations has been verified.

(g) Cement plugs for decommissioning or suspension must be verified as follows:

  i. Off bottom open hole cement plugs are to be verified by tagging the plug with a minimum 2270 kg (5000 lb) drill string weight.

  ii. For consecutive stacked cement plugs with the first plug set on bottom or solid base (e.g. mechanical **packer**, other verified cement plug) validation of the top of good quality cement to be carried out by tagging the top plug with a minimum 2270 kg (5000 lb) drill string weight. If using a sacrificial stinger to set **open hole** plugs, no tag is necessary where no losses are observed during cement placement.

  iii. For a cased hole cement plug with the bottom of the plug exposed to open hole validation is to be done by tagging the top plug with a minimum 2270 kg (5000 lb) drill string weight and by pressure testing to 3.5 MPa (500 psi) above the estimated (or previously recorded) leak-off pressure (within the limits of the casing and wellhead pressure ratings).

iv. For a cased hole cement plug supported by a pressure tested bridge plug, validation may be by post cement job report and calculations, or by tagging the plug with a minimum 2270 kg (5000 lb) drill string weight.

v. For an unsupported cased hole cement plug barrier not exposed to open hole below, validation is to be done by tagging the plug with a minimum 2270 kg (5000 lb) drill string weight.

vi. For a final surface cement plug extending from ground level no validation is required. A shallow set plug is not considered a permanent barrier given the very low **formation pressures** at ground level. Well barriers are to be established with the plugs below the surface cement plug.

vii. When a sacrificial string is used to place a cement plug, validation may be via a combination of:

   a. pressure testing to confirm isolation; and

   b. validation of the conduct of the cement job.

(h) Prior to wellhead removal, zero pressure on any casing or annulus must be confirmed. Wellheads must be removed, and casing must be cut as per *Case: Surface cement plug* detailed in B.4.15.3: *Cement plug requirements and validation methods*.

(i) A steel marker plate cut from corrosion resistant alloy or similar grade steel for corrosive environments must be installed after the wellhead has been cut off detailing the following:

i. the identifying name of the well or bore;

ii. the total depth in metres of the well or bore;

iii. the date the well or bore was decommissioned; and

iv. the marker plate shall be covered with soil to ground level.

(j) Complete and accurate records of the entire decommissioning procedure must be kept, with these records submitted as part of the legislative reporting requirements for the decommissioning of petroleum wells.

(k) The potential for accumulation of NORM in well equipment must be assessed and appropriate measures put in place to reduce risks to the health and safety of people and the environment.

B.4.15.3 Cement plug requirements and validation methods

Cement plugs must conform to the requirements in Table 6, Figure 2, and Figure 3.

Table 5: Cement plug requirements and validation methods for well decommissioning

Case	Diagram	Description and Validation
Open hole/ uncased hole section	(a)	Validated cement plug(s) must be placed to provide cement coverage extending from at least 50 m below the base of, to at least 100 m above the top of, any **hydrocarbon bearing zone** or aquifer and between permeable zones of different pressure regimes or salinity.
Cased hole section (unperforated)	(b)	Validated cement plug(s) placed adjacent good **annulus** cement must be placed to provide cement coverage at least 50 m below the base of, to at least 50 m above the top of, any **hydrocarbon bearing zone** or aquifer and between permeable zones of different pressure regimes or salinity.
Casing shoe with open hole below	(c)	Validated cement plug(s) must be placed to provide cement coverage at least 50 m above and 50 m below the **casing shoe**.
Casing shoe with open hole below (with lost circulation)	(d)	Where lost **circulation** conditions exist a mechanical barrier may be set within 45m above the **casing shoe** (but typically not within the drilled out shoe track) with at least a 50m cement plug set above the mechanical barrier, adjacent to good **annulus** cement.
Cut and recovered casing	(e)	Validated cement plug(s) must be placed to provide cement coverage at least 50 m above and 50 m below the casing cut.
Production or HPHT zone Liner Laps	(f)	A cement plug barrier is to be set across each **liner** top with at least 50m of cement above the liner top.
Perforated casing	(g)	Default requirement: To isolate zones and cover all perforated intervals, a validated cement plug must extend from at least 50m below the base of the lowermost perforated interval to at least 100m above the top of the uppermost perforated interval. Option: A validated mechanical barrier with 50m cement on top may be used above the top most perforated interval. A validated cement plug of minimum length 50m, or a mechanical barrier, must be used to isolate perforated intervals of different pressure regimes. A validated cement plug extending from at least 50m below the base of the lowermost perforations is still required.
Wellhead removal	-	Cut casing a minimum of 1.5 m below ground level, and covered with a minimum of 30 cm of cement.
Surface cement plug	-	A surface cement plug extending from 15 m below the surface to 50 m below the base of the deepest aquifer shall be placed in the innermost string of casing that extends to the surface.

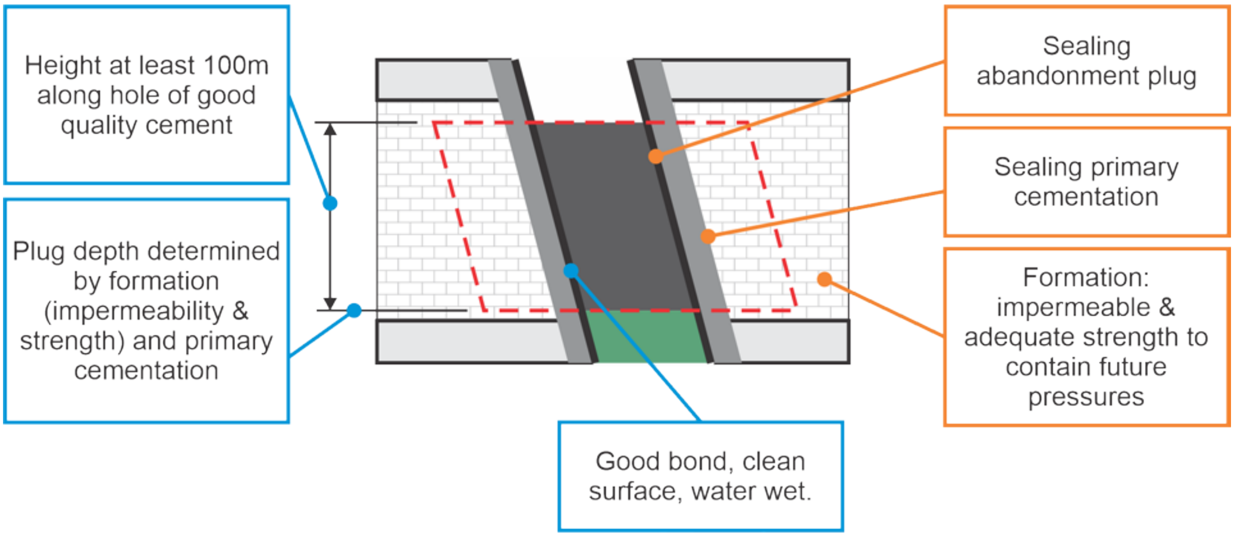

Figure 2: General cement plug requirements for well decommissioning

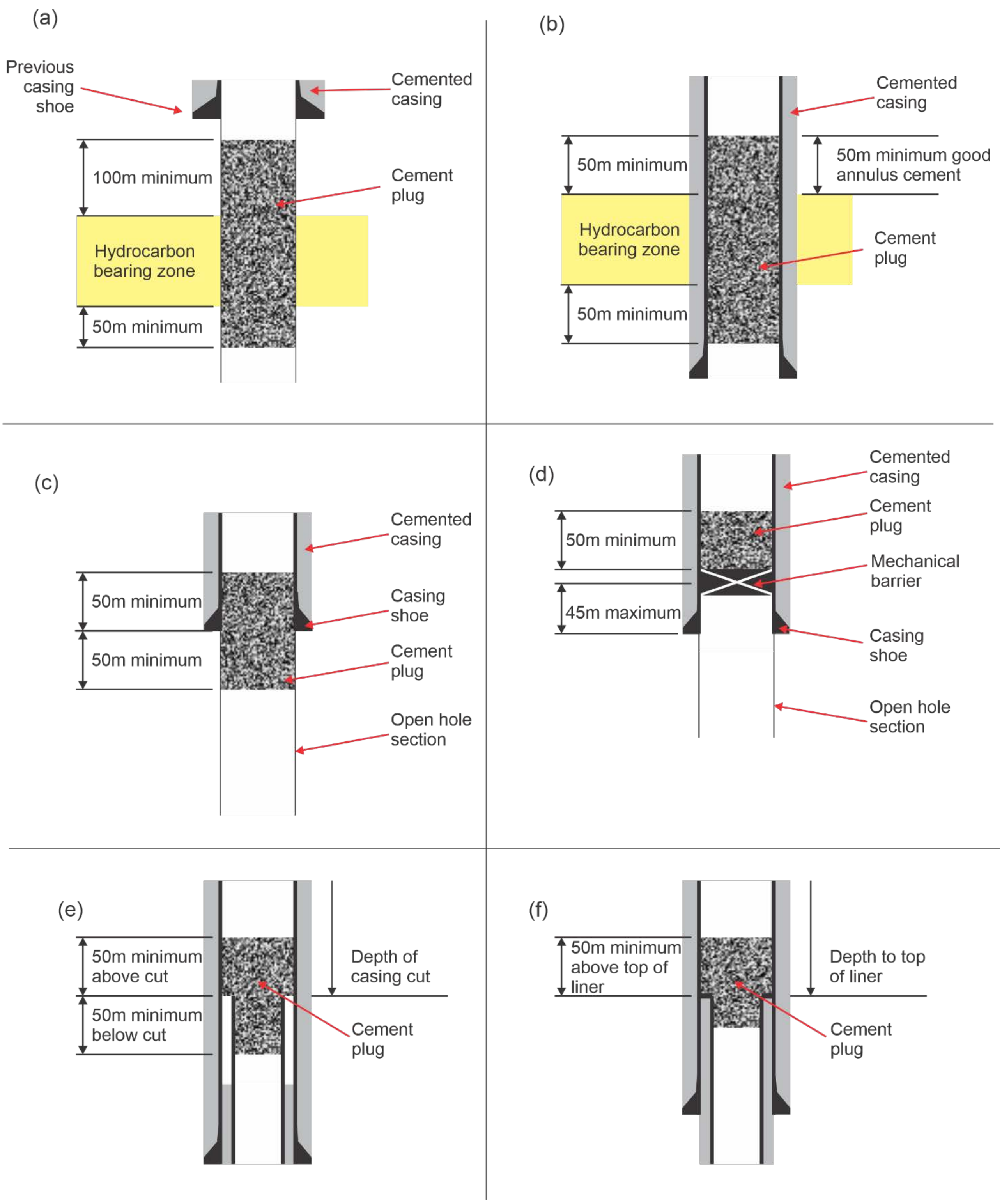

Figure 3: Specific requirements for cement plugs for well decommissioning. See Table 6 for details.

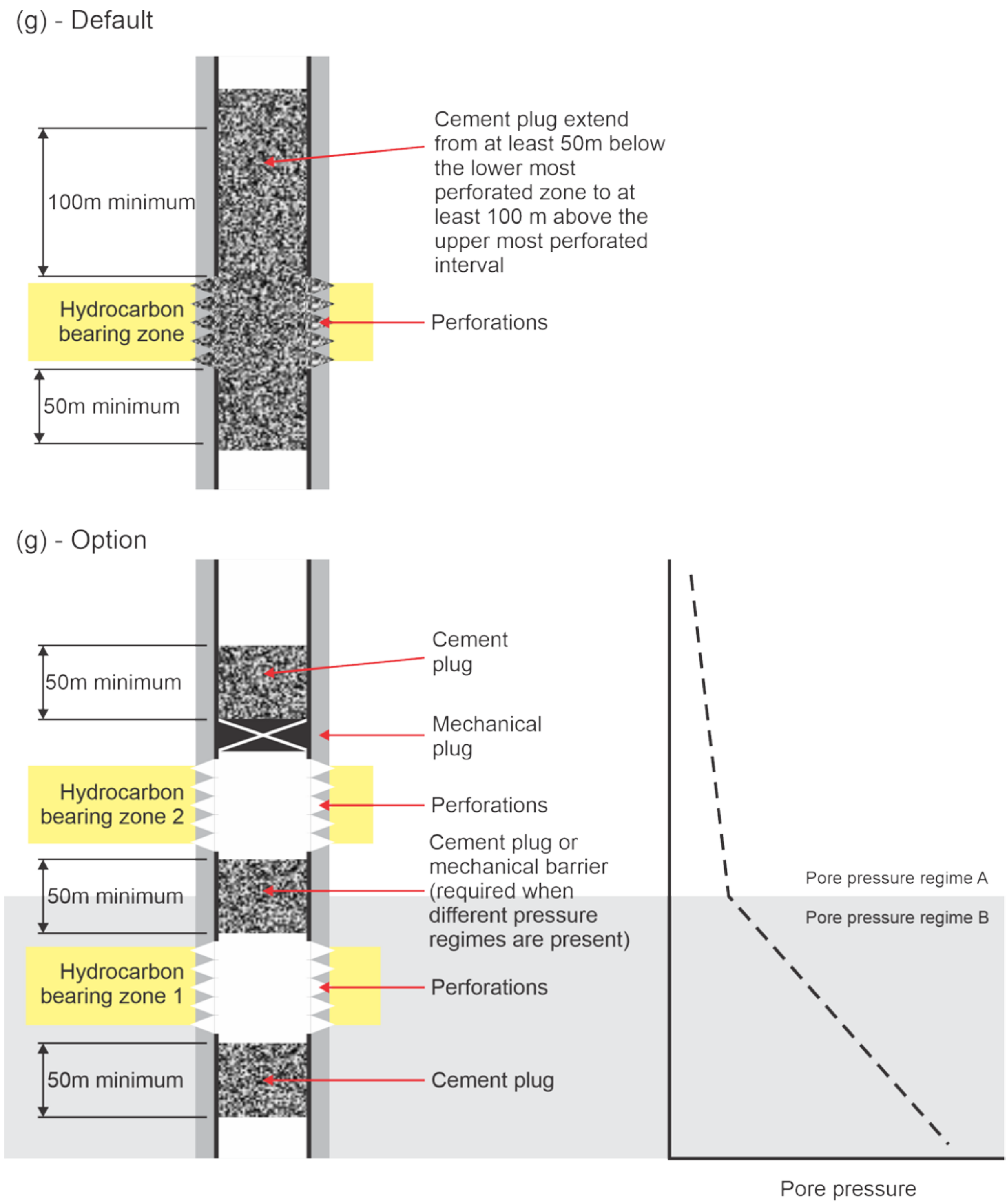

Figure 3 continued

B.4.15.4 Mandatory requirements for suspension of wells

(a) Two validated well barriers must be used for well suspension, except:

  i. during re-entry, workover and other maintenance work; or

  ii. during temporary suspension of open hole sections due to weather or other operational reasons such as batch operations.

(b) The potential for accumulation of NORM in well equipment must be assessed and appropriate measures put in place to reduce risks to the health and safety of people and the environment.

(c) The wellhead must be protected from collisions and reckless acts by third parties with the following minimum requirements:

  i. the wellhead must be fenced off; with signage reflecting well name and interest holder contacts.

  ii. all valve handles must be either removed, or chained and padlocked.

B.4.15.5 Preferred requirements for well suspension and decommissioning

(a) The following matters should be considered when decommissioning or suspending a well:

  i. the construction characteristics of the well and well integrity status at time of suspension or decommissioning;

  ii. the integrity of the cement column;

  iii. the geological formations encountered;

  iv. potential loss zones;

  v. hydrogeological conditions (i.e. location of aquifers);

  vi. environmental risk;

  vii. regulatory requirements, title conditions and industry standards, and

  viii. perforated and hydraulic fracture stimulated zones.

(b) It is preferred to use integrated open hole volume calculated from calliper logs (when available) to calculate cement volumes.

(c) Balanced cement plugs should be set on a hi-vis pill unless setting first plug directly on hole bottom.

(d) Balanced cement plug volumes pumped should incorporate allowances for open hole and cased hole contamination.

(e) 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.

References*:*

- ARPANSA, 2008, Safety Guide for the Management of Naturally Occurring Radioactive Material (NORM)
- Oil & Gas UK, 2018, Well Decommissioning Guidelines, Issue 6.

B.4.16 Site material and fluids management

B.4.16.1 Principles

The **well site** should be laid out to minimise the potential for harm to others and the environment.

B.4.16.2 Mandatory requirements

(a) The well site must be selected and designed in accordance with Part A of this Code.

(b) The well site must be designed and operated to minimise the risk of causing a fire on the well site or in the surrounding environment.

(c) The well site must be clearly identified in a permanent manner with the well name, well number, major hazards and details of the interest holder.

(d) The name of the person-in-charge of any active well operations must be displayed in writing at all approaches to the well site.

(e) The well must be adequately secured to prevent access by wildlife.

(f) The well site must be designed and operated to minimise the potential for releases of contaminants to the environment and the impacts of such a release.

(g) An assessment must be carried out as to whether any materials (solid or liquid) used on, or produced at, a well site could be considered to be, or to contain, **hazardous chemicals** or those that may cause environmental harm. The outcomes of this assessment must be described in the spill management plan, as outlined in Part C of this Code.

(h) Use, storage and handling of materials on site must be conducted in accordance with section A.3.8 and Part C of this Code**,** and:

  i. secondary containment must be instituted on areas of the well site where any hazardous chemicals or those that may cause environmental harm are to be stored or handled during all well operations.

  ii. areas where any hazardous chemicals or those that may cause environmental harm are to be stored or handled must be lined to be sufficiently impervious and able to contain spilled material or waste until it can be removed or treated. This lining may be a geomembrane or a suitably constructed clay liner.

B.4.16.3 Preferred requirements

(a) The well site layout should be designed to minimise the risk of spills. This may include segregating areas for chemical storage and handling.

(b) Lifecycle chemical handling risks should also be considered, including: balancing stored volumes with transport requirements (avoiding vehicle movements).

B.4.17 Groundwater monitoring

B.4.17.1 Principles

Groundwater is a key environmental receptor in onshore petroleum exploration and development in the Northern Territory. Groundwater monitoring serves as a signal to differentiate natural and human-induced perturbations in the well pad area. Where an impact is detected, further investigation is required and any necessary remediation is undertaken to ensure water quality guidelines are met.

B.4.17.2 Mandatory requirements

(a) An accurate understanding must be gained of what aquifers exist at the well site and their depth from surface, and their relationships to each other and other hydro-stratigraphic units during the well design phase.

(b) Where there is an intention to hydraulically fracture the well(s) at a well site:

  i. At least six months of local baseline data for water quality indicators of the key aquifers that may be affected by the activity must be acquired:

    a) prior to drilling the well(s); or

    b) prior to hydraulic fracturing where six months monitoring data from the control bore is not achievable before drilling due to circumstances that lie outside of the control of the interest holder;

    c) the minimum suite of water quality indicators to be monitored are listed in Table 7, however monitoring of additional water quality indicators may be necessary based on the interest holder's risk assessment conducted for an EMP.

  ii. Electrical conductivity data from the monitoring bore(s) must be measured as soon as practicable after the completion of construction of the monitoring bore (s) until decommissioning of all wells on the well site. Results submitted to the regulator:

    a) by electronic means from the well site as soon as they are available; or

    b) if the requirement in a) is unachievable to implement in the first stages of exploration, an alternative plan and timetable may be proposed before hydraulic fracturing commences, detailing how electrical conductivity information will be regularly submitted.

(c) Any guidelines published by the Northern Territory Government from time to time relating to groundwater monitoring parameters, methodologies and frequencies for petroleum operations must be followed. This includes the Preliminary Guideline: Groundwater Monitoring Bores for Exploration Petroleum Wells in the Beetaloo Sub-basin.

(d) Any guidelines published by the Northern Territory Government from time to time relating to reporting and data submission, and groundwater monitoring data standards must be followed.

(e) In karstic groundwater terrain, which is common in the Northern Territory, a precautionary **stratigraphic bore hole** (which potentially can be used as a water production **bore**) to the base of the deepest recognised aquifer may be required at the **well pad** for an accurate understanding of what **aquifers** and potential **geohazards**, if any, exist at the site and their depth from surface.

(f) Records must be maintained for each **well**, or group of similar wells, if grouping the wells is appropriate given their similarity.

Table 6: Minimum suite of analytes for groundwater monitoring.

General	LOR	Cations and Metals	LOR
pH	0.01 pH units	Calcium	1 mg/L
Electrical conductivity	1 µS/cm	Chromium	0.001 mg/L
Total Dissolved Solids	10 mg/L	Copper	0.001 mg/L
Total Suspended Solids	1 mg/L	Iron	0.05 mg/L
Alkalinity	1 mg/L	Lead	0.001 mg/L
Gross Alpha	0.05 Bq/L	Magnesium	1 mg/L
Gross Beta	0.1 Bq/L	Manganese	0.001 mg/L
Water level	±10 cm (AHD)	Mercury	0.0001 mg/L
Groundwater pressure		Potassium	1 mg/L
Anions		Silver	0.001 mg/L
Chloride	1 mg/L	Arsenic	0.001 mg/L
Fluoride	0.1 mg/L	**Barium**	0.001 mg/L
Sulfate	1 mg/L	Boron	0.05 mg/L
Nitrate	0.01 mg/L	Cadmium	0.0001 mg/L
Nitrite	0.01 mg/L	Lithium	0.001 mg/L
Petroleum		Selenium	0.01 mg/L
TRH	100 µg//L	Silica	0.1 mg/L
PAH Suite	0.5 µg//L	**Strontium**	0.001 mg/L
BTEX	1 µg/L	Sodium	1 mg/L
Diss. Methane	10 µg/L	Zinc	0.005 mg/L
Diss. Ethane	10 µg/L		
Diss. Propane	10 µg/L		

References

- Preliminary Guideline: Groundwater Monitoring Bores for Exploration Petroleum Wells in the Beetaloo Sub-basin

B.5 BTEX Limits

Benzene, toluene, ethylbenzene, or xylene (BTEX) are only permissible in drilling or fracturing fluids, at or below the levels prescribed and when it is either,

- Naturally occurring in water used to make up the drilling or fracturing fluid
- Present as a contaminant in chemicals or other substances used in drilling or stimulation fluids and has no beneficial use

B.5.1 BTEX Prescribed Levels

B.5.1.1 Drilling and stimulation fluid chemical additives

(a) The combined chemicals or other substances used at their maximum possible concentrations for a particular drilling or stimulation cannot increase BTEX levels of the overall fluid above the BTEX content of the base water of the fluid by more than those levels prescribed in Table 8.

Table 7: BTEX Levels in drilling fluids when drilling through local aquifers.

Compound	Maximum Level (ppb or µg/L)
benzene	1*
toluene	180#
ethylbenzene	80#
xylene	200

**From Version 3.5 of the Australian Drinking Water Guidelines Paper 6 National Water Quality Management Strategy. National Health and Medical Research Council, National Resource Management Ministerial Council, Commonwealth of Australia, Canberra as updated in August 2011. # Australian and New Zealand Environment Conservation Council Environmental Protection Guidelines (ANZECC 2000) 99% protection level.*

B.5.1.2 Recycled produced water and flowback fluid

(a) **Produced water** or **flowback fluid** used in drilling fluids or hydraulic fracturing fluids must not contain BTEX at levels greater than those expected in water produced (including flowback) from the well being drilled.

(b) In the event BTEX levels expected in produced water or flowback fluid from the well being drilled are not known, then the BTEX levels in water used for drilling fluids or stimulation fluid cannot exceed the levels prescribed in Table 9.

B.5.1.3 BTEX levels in drilling fluids when drilling through local aquifers

(a) Despite sections B.5.1.1 and B.5.1.2 and pursuant to section B.4.10.2 (i) of this Code, drilling fluids used to drill through aquifers and until these aquifers are isolated by a minimum of one verified well barriers cannot contain BTEX levels at the greater of,

i. minimum BTEX levels in the local aquifers; or

ii. The levels listed in Table 8.

Table 8: BTEX Levels in water used for stimulation and drilling fluids.

Compound	**Maximum Level (ppb or µg/L)**
benzene	600#
toluene	180#
ethylbenzene	80#
xylene	200#

 # Australian and New Zealand Environment Conservation Council Environmental Protection Guidelines (ANZECC 2000) 99% protection level.

Part C — Well site water management

C.1 Overview

The purpose of this part of the Code is to ensure that wastewater produced from, and water used in, petroleum activities in the Northern Territory is managed to at least minimum particular standards and to reduce environmental impacts and environmental risks.

C.2 Scope and application

This Code provides a framework for the management of water used in and produced by petroleum activities including storage, handling, transport, re-use, recycling, treatment and disposal of wastewater.

C.2.1 Water and wastewater to which this Code applies

The requirements of this Code, regarding water and wastewater apply to the following:

(a) water that has been used in or produced from petroleum wells, whether it is being re-used, recycled, treated, or disposed of, and includes **flowback fluid**, **produced water**, **drilling fluids**, completion fluids, well suspension fluids and **non-aqueous drilling fluids**;

(b) “waste material” and material containing “contaminants” as defined in s 117AAB of the **Act;**

(c) wastewater meeting the definition of waste under the *Waste Management and Pollution Control Act 1998* (NT);

(d) water that has been acquired or used in petroleum activities that is being disposed of, (for example, unused volumes of **hydraulic fracture fluid** or drilling fluid, raw water, or waters described in C.2.1 (a)); and

(e) residual drilling waste, e.g. muds and cuttings (which may be more or less in a solid state) in addition to the fluids mentioned in (a) to (d) above;

but not to the material set out in section C.2.2

C.2.2 Water and wastewater to which this Code does not apply

The requirements in this Code regarding water and wastewater do not apply to the following:

(a) recoverable hydrocarbons (e.g. oil, condensate and natural gas) produced from a well;

(b) acquisition, storage and disposal of potable water;

(c) storm water which has not come into contact with petroleum products or wastes on site;

(d) sewage; or

(e) wastewater or waste that is generated from petroleum activities once it leaves the site of an approved petroleum activity.

C.3 Wastewater management framework

This section of the Code establishes a framework for the management of wastewater from petroleum activities. This framework covers an individual activity or a group of activities that are conducted together (either spatially or in time, or both) and would be limited to those petroleum activities defined in an overarching EMP (see Section A.1).

The components of the wastewater management framework, as summarised in Figure 4, include:

(a) Estimate the quantities and quality of water and wastewater from the petroleum activity.

(b) Define the methods and approaches that will be used to store, treat, and reuse water and ultimately dispose of wastewater, including what activities will be undertaken at the site of the approved petroleum activity.

(c) Estimate the quantities and quality of wastewater, or wastewater derived solids that will be removed from the petroleum site.

(d) Provide for the relevant activities and the environmental risks and environmental impacts they involve in a **Wastewater Management Plan** (WWMP) and a **Spill Management Plan** (SMP), as part of the EMP.

(e) Monitor, manage and report in accordance with the WWMP and SMP.

All stages of the framework should be developed in consideration of the waste management hierarchy (section C.3.1, any government policies relevant to wastewater and any relevant corporate policies and procedures of the interest holders.

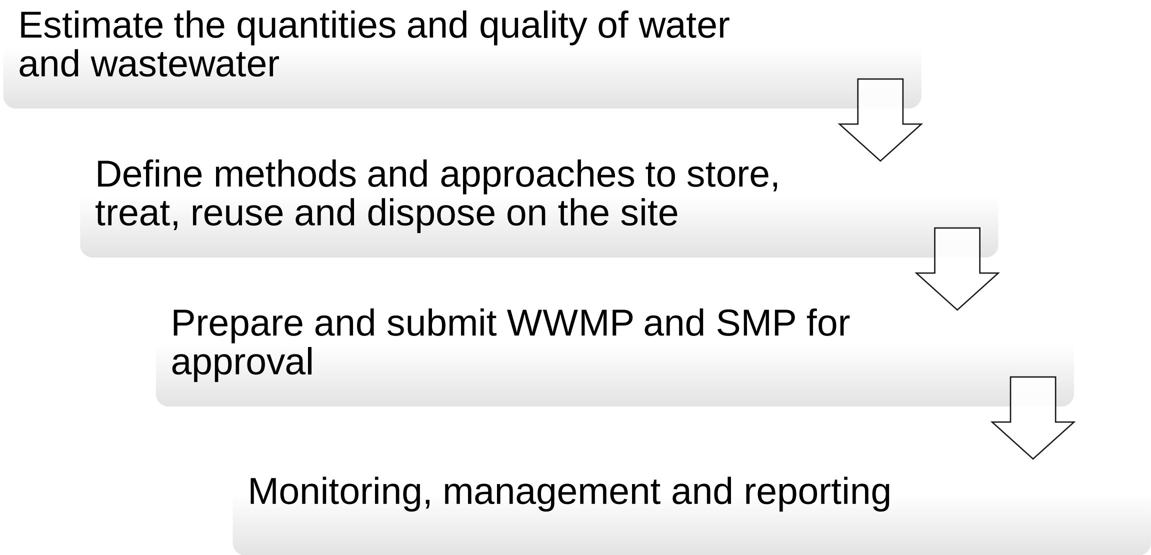

Figure 4: Framework for the design, approval and implementation of wastewater management for a Petroleum Activity

C.3.1 Waste management hierarchy

The waste hierarchy outlined in the National Waste Policy, 2018, must be implemented by interest holders when developing their WWMP. In short, the hierarchy involves the following:

1. Avoid: eliminate or substitute an activity that results in wastewater.
2. Reduce: lower the generation of wastewater as part of a process or activity.
3. Reuse: use of wastewater for the same or alternative petroleum activity without treatment, or with minimal treatment.
4. Recycle: beneficial re-use of wastewater for another purpose without treatment, or with minimal treatment.

5. Treat: bring wastewater back into use through treatment to improve water quality or to make quality suitable for disposal.
6. Dispose.

The following tiered questions can be used when identifying efficient water uses and reducing wastewater production:

1. Is the generation of wastewater required or can it be avoided?
2. Can the wastewater generating process be substituted?
3. Can measures be put in place to lower the amount of wastewater generated?
4. Can return wastewater from a task be used, or re-employed elsewhere without treatment?
5. Is it technically, economically and environmentally feasible to return wastewater for reuse following treatment?
6. What are the by-products of treatment (e.g. potentially concentrated waste streams of higher hazard) and how can they be managed / disposed of?
7. How will the final wastewater be disposed of?

C.4 Design requirements

C.4.1 Drilling fluids

C.4.1.1 Principles

Drilling fluids contain the original fluid, some formation fluids and cuttings of the formation being drilled and other materials used in well drilling activities e.g. cement, LCM etc. Drilling fluids can have a substantial volume of solids derived from additives (such as bentonite clay) and drill cuttings. Management of drilling fluid as a waste must manage the liquid and solid components appropriately.

C.4.1.2 Mandatory requirements

(a) Waste drilling fluid shall be managed in accordance with the WWMP and SMP.

(b) Any residual drilling fluids and cuttings must be contained within:

  i. engineered pits, lined with an impermeable membrane with coefficient of permeability of less than 10^{-9} m/s tested in accordance with AS 1289.6.7.2 and with resistance to tearing >0.5kN (ASTM D 4073); static puncture >0.5kN (ASTM D 4833) and tensile strength >20 kN/m (ASTM D 7275); or

  ii. above ground storage tanks with secondary containment measures as detailed in B.4.16.2 (h).

(c) An assessment of environmental impacts and environmental risks posed by the drill cuttings and residual drilling fluids must be carried out.

(d) Disposal options for drill cuttings and residue from drilling fluids must take into account the results of the assessment in C.4.1.2 (c).

(e) Leachability testing of drill cuttings must be undertaken in accordance with the Australian Standard Leaching Procedure (Australian Standards AS4439.2 and 4439.3) by a NATA accredited laboratory The analytes and method for drilling waste assessment for this assessment are shown in Table 10.

(f) If seeking approval to dispose of residue from drilling fluids on-site, the EMP that is submitted must include a certification from a suitably qualified third party that the material is of acceptable quality for disposal to land by the proposed method and that environmental harm will not result from the proposed disposal. In this context, suitably qualified third party means a person who:

  i. has qualifications and experience relevant to performing the function including but not limited to:

    a. a bachelor's degree in science or engineering; and

    b. 3 years' experience in undertaking soil contamination assessments; and

  ii. is registered under section 68 of the *Waste Management and Pollution Control Act 1998* (NT); and

  iii. is not an employee of, nor have a financial interest or any involvement which would lead to a conflict of interest with the interest holder.

(g) Control measures must be implemented to minimise the interactions of wildlife, stock, and human receptors with drilling fluids.

C.4.1.3 Preferred requirements

(a) Recycling and re-use of all solids waste should be maximised, to minimise volume of waste that must be disposed of on-site or transported and managed off-site.

Table 9: Analytes and method for drilling waste assessment

Analyte	**Method Code**	***LOR***	**Units (on a dry weight basis)**
Sampled			
Ag	iMET2SAICP	*0.5*	mg/kg
Al	iMET2SAICP	*10*	mg/kg
As	iMET2SAICP	*1*	mg/kg
B	iMET2SAICP	*5*	mg/kg
Ba	iMET2SAICP	*0.1*	mg/kg
Be	iMET2SAICP	*0.05*	mg/kg
C	(combs)	*0.05*	%
CO3	(combs)	*0.25*	%
Cd	iMET2SAICP	*0.05*	mg/kg
Cl	iCO1SEDA	*5*	mg/kg
Co	iMET2SAICP	*0.1*	mg/kg
Cr	iMET2SAICP	*0.05*	mg/kg
Cu	iMET2SAICP	*0.1*	mg/kg
EC_25C	iEC1SASE	*0.2*	ms/m
F	eF1ST	*50*	mg/kg
H2O_105C	iMOIS1SAGR	*0.1*	%
Hg	iMET2SAMS	*0.02*	mg/kg
Mn	iMET2SAICP	*0.2*	mg/kg
Mo	iMET2SAICP	*0.5*	mg/kg
N	(total)	*0.005*	%
Ni	iMET2SAICP	*1*	mg/kg
P	(totals)	*10*	mg/kg
Pb	iMET2SAICP	*0.5*	mg/kg
Se	iMET2SAICP	*2*	mg/kg
Sr	iMET2SAICP	*0.2*	mg/kg
TIC	(combs)	*0.05*	%
TOC	(combs)	*0.05*	%
V	iMET2SAICP	*0.2*	mg/kg

Analyte	**Method Code**	***LOR***	**Units (on a dry weight basis)**
Zn	iMET2SAICP	*5*	mg/kg
pH *	iPH1SASE	*0.1*	
Benzene	eBTEXSoil	*0.5*	mg/kg
Toluene	eBTEXSoil	*0.5*	mg/kg
Ethylbenzene	eBTEXSoil	*0.5*	mg/kg
Xylene	eBTEXSoil	*1*	mg/kg
Total BTEX	eBTEXSoil	*2.5*	mg/kg
TPH C6-C9	eTPHSoils	*25*	mg/kg
TPH C10-C14	eTPHSoils	*50*	mg/kg
TPH C15-C28	eTPHSoils	*100*	mg/kg
TPH C29-C36	eTPHSoils	*100*	mg/kg
Total TPHs	eTPHSoils	*275*	mg/kg
Acenaphthene	ePAH1SOIL	*1*	mg/kg
Acenaphthylene	ePAH1SOIL	*1*	mg/kg
Anthracene	ePAH1SOIL	*1*	mg/kg
Benz(a)anthracene	ePAH1SOIL	*1*	mg/kg
Benzo(a)pyrene	ePAH1SOIL	*1*	mg/kg
Benzo(b+k)fluoranthene	ePAH1SOIL	*1*	mg/kg
Benzo(g,h,i)perylene	ePAH1SOIL	*1*	mg/kg
Chrysene	ePAH1SOIL	*1*	mg/kg
Dibenzo(a,h)anthracene	ePAH1SOIL	*1*	mg/kg
Fluoranthene	ePAH1SOIL	*1*	mg/kg
Fluorene	ePAH1SOIL	*1*	mg/kg
Indeno(1,2,3-cd)pyrene	ePAH1SOIL	*1*	mg/kg
Naphthalene	ePAH1SOIL	*1*	mg/kg
Phenanthrene	ePAH1SOIL	*1*	mg/kg
Pyrene	ePAH1SOIL	*1*	mg/kg
Total PAHs	ePAH1SOIL	*16*	mg/kg
ASLP Extract Analysis			
Ag	iMET1WCMS	*0.001*	mg/L
Al	iMET1WCICP	*0.05*	mg/L
As	iMET1WCMS	*0.001*	mg/L
B	iMET1WCICP	*0.05*	mg/L

Analyte	Method Code	*LOR*	Units (on a dry weight basis)
Ba	iMET1WCICP	*0.002*	mg/L
Be	iMET1WCICP	*0.001*	mg/L
Cd	iMET1WCMS	*0.0001*	mg/L
Cl	iCO1WCDA	*1*	mg/L
Co	iMET1WCICP	*0.005*	mg/L
Cr	iMET1WCICP	*0.001*	mg/L
Cu	iMET1WCMS	*0.001*	mg/L
Hg	iHG1WCVG	*0.0001*	mg/L
Hg	iMET1WCMS	*0.0001*	mg/L
Mn	iMET1WCICP	*0.001*	mg/L
Mo	iMET1WCMS	*0.001*	mg/L
Ni	iMET1WCMS	*0.001*	mg/L
Pb	iMET1WCMS	*0.001*	mg/L
Se	iMET1WCMS	*0.001*	mg/L
Sr	iMET1WCICP	*0.001*	mg/L
V	iMET1WCICP	*0.005*	mg/L
Zn	iMET1WCICP	*0.005*	mg/L
pH_ASLP	iASLP	*0.1*	pH unit
Gross Alpha		0.05	Bq/L
Gross Beta		0.1	Bq/L

C.4.2 Management of produced water and flowback fluid

C.4.2.1 Principles

Produced water and **flowback fluid** are to be managed in a manner which limits effects on the environment and safety.

C.4.2.2 Mandatory requirements

(a) All produced water and flowback fluid must be held in above-ground enclosed tanks at all times following release from the petroleum well other than in the following circumstances:

i. it is being treated for reuse or disposal

ii. it is being reused as explicitly authorised in an approved wastewater management plan (see Section C.7.1)

iii. it is being disposed of as explicitly authorised in an approved waste management plan (see Section C.7.1)

iv. it is being removed from site for lawful disposal elsewhere

(b) All above-ground enclosed tanks must:

i. meet secondary containment requirements set out in Section A.3.8 (g);

ii. limit the ingress of rainwater into the tank to an amount that is ALARP and acceptable;

iii. where connected together, be designed and operated to prevent the uncontrolled discharge of multiple tanks should one tank fail;

iv. be designed and operated to prevent overtopping;

v. be designed and constructed to any standards that apply in the Northern Territory for the type of structure and be able to withstand bushfires and wind loading conditions reasonably expected in the area; and

vi. be designed to reduce the risk of a build-up of explosive gasses to a level that is ALARP and acceptable.

C.4.2.3 Preferred requirements

(a) Recycling and re-use of all fluids should be maximised and the off-site transport and disposal of fluids should be minimised.

C.5 Monitoring mandatory requirements

C.5.1 General monitoring requirements

(a) Monitoring programs must be described in the WWMP and SMP and must address the requirements in this section C.5. The WWMP and SMP must identify specific monitoring methods based on the predicted contaminants, volumes and concentrations based on chemicals used in drilling and hydraulic fracturing as well as potentially naturally occurring contaminants and radioactive materials.

(b) The quantity and quality of all water stored on site must be monitored.

(c) All water and wastewater samples should be collected by **suitably qualified personnel** and tested using established field and laboratory protocols. This includes, but is not limited to, the use of suitable sample containers, preservation methods, holding times, chains of custody, analytical methods, and laboratory quality assurance/quality control (QA/QC) procedures.

(d) All laboratory analyses and tests must be undertaken by a laboratory that has National Association of Testing Authorities (NATA) accreditation for such analyses and tests where available.

(e) Where there are no NATA accredited laboratories for a specific analyte or substance, then duplicate samples must be sent to at least two separate laboratories for independent testing or evaluation.

C.5.2 Drilling materials

(a) The quality and quantity of **drilling fluid** and drill cuttings shall be recorded while within the area in which the petroleum activity is approved to occur.

(b) Interest holders must analyse the composition of drill cuttings and residual **drilling fluids** as it is identified to determine whether it is consistent with assumptions used for the assessment of environmental hazards and the design of proposed disposal methods made in accordance with section C.4.1.2.

(c) Prior to off-site management, disposal or transport, residual drilling waste shall be tested:

i. for radioactivity from NORMs to determine if the waste is classified under the *Radiation Protection Act 2004* (NT); and

ii. as required by the *Waste Management and Pollution Control (Administration) Regulations* 1998 (NT), which may require testing to classify the waste.

C.5.3 Hydraulic fracturing fluid monitoring

(a) A hydraulic fracturing fluid monitoring program must be established and implemented to characterise and record the quality and quantity of the fluid used to hydraulic fracture a well. The monitoring program must meet the requirements of section B.4.13.2 (c) of this Code.

C.5.4 Flowback fluid monitoring

(a) For hydraulic fracturing, the interest holder must implement a **flowback fluid** monitoring program must be established and implemented to characterise the quality and quantity of flowback fluid generated during **flowback** activities.

(b) The monitoring program must characterise flowback fluid quality through the following measures:

i. continuous monitoring (sampling frequency of at least once per 24 hours) of electrical conductivity, pH and temperature

ii. monitoring at least weekly for a duration long enough that the quality of the flowback fluid is sufficiently stabilised against criteria described in the WWMP, and tested for the analytes listed in section C.8.

iii. monitoring of the flowback fluid storage, as required by C.5.5 (c).

(c) The monitoring program must measure flowback fluid volume by recording the cumulative flowback fluid volume for each well at one month, 3 months, 6 months and 12 months after flowback has commenced.

C.5.5 Produced water and flowback fluid storages

(a) The quantity and quality of **produced water** and flowback fluid must be recorded while within the area in which the petroleum activity is approved to occur, in accordance with the methods specified in an approved WWMP or SMP.

(b) Stored volume and available freeboard for all produced water and flowback fluid storage facilities must be monitored at least weekly, unless being operated through the wet season during which they should be monitored daily.

(c) A sample from all produced water and flowback fluid storages must be taken at least once every 6 months, and tested for the analytes listed in section C.8.

C.6 Reporting mandatory requirements

C.6.1 Water and wastewater tracking and reporting requirements

(a) The movement of water and wastewater must be tracked and include:

i. volumes of **produced water** and **flowback fluid** from each well;

ii. volumes of water transferred into each tank;

iii. estimates for evaporation rates from each tank;

iv. volumes of water planned to be, and ultimately, reused in petroleum operations including drilling and hydraulic fracturing;

v. volumes of water and wastewater used for other purposes including dust suppression and construction water;

vi. volumes of water and wastewater removed from site and its destination (whether by vehicle or pipeline) including details of the licence number of the any licensed waste transporters; and

vii. volumes of any spills of water or wastewater.

(b) Wastewater tracking must be documented in an auditable chain of custody system.

(c) Wastewater tracking must be in accordance with other legislative requirements such as those imposed under the *Waste Management and Pollution Control Act* 1998 (NT) and the *Radiation Protection Act 2004* (NT).

(d) Wastewater tracking documentation must be reported to the Minister at least annually in accordance with the framework provided in the EMP.

C.7 Mandatory requirements for management plans for wastewater and spills

C.7.1 Wastewater management plan

(a) An EMP for a petroleum activity must include a wastewater management plan (**WWMP**).

(b) A WWMP must address all water and wastewater management activities which are proposed, as defined in section C.2.1 and as excluded by section C.2.2 of this Code.

(c) The WWMP must include a description of the activities that will generate waste and wastewater, including any activities that may generate drilling materials (refer to definition in Section C.4.1), **produced water**, **flowback fluid** and any other waste which is proposed to be handled, stored or transported away from the area in which the activity is approved to be carried out, specifically including:

i. A characterisation of the anticipated wastewater streams that will be generated, including the chemical characteristics and volumes of each.

ii. A risk assessment in relation to the potential impact to the environment from water and wastewater management activities proposed as part of the petroleum activity.

iii. The proposed method and location of water and wastewater storage, transportation, treatment, disposal and re-use proposed as part of the proposed activity, with reference to any requirements mandated by this Code (refer to section C.4).

iv. Strategies to minimise or reduce the volume of wastewater that will be disposed of off-site and the expected quality and quantity of water and wastewater that will be treated and re-used within the petroleum activity.

v. Estimates for the 1 in 1000 average recurrence interval (ARI) rainfall rate using Australian Rainfall & Runoff methodologies for the critical period during which there would be greatest risk of overtopping of any structures holding wastewater which are not enclosed.

(d) The **WWMP** must include:

i. An implementation plan of control measures to prevent the interactions of wildlife, stock, and human receptors with wastewater.

ii. A program for monitoring and reporting on the effectiveness of mitigation measures for avoiding wildlife, stock and human interactions.

C.7.1.1 Wastewater treatment, reuse and disposal

The WWMP must include a specific detailed risk assessment for any proposed on site wastewater treatment or disposal which addresses at a minimum the following:

(a) For any proposed **produced water** and **flowback fluid** treatment processes occurring outside of enclosed tanks (including volume reduction via evaporation) the WWMP must demonstrate that all associated environmental risks and environmental impacts have been reduced to a level that is ALARP and acceptable and must:

i. Incorporate wastewater containing infrastructure that meets secondary containment requirements set out in Section A.3.8 (g);

ii. Include a plan to transfer **produced water** and **flowback fluid** into above-ground enclosed tanks (see section C.4.2.2) at least 8 hours in advance of any predicted significant rainfall event as specifically defined based on local weather conditions and other site specific risks;

iii. Include a strategy (including environmental performance standards and measurement criteria) for detecting and responding to predicted significant rainfall events, with a focus on the wet season;

iv. Specify minimum freeboard for treatment infrastructure to accommodate total rainfall anticipated (based on 1:1000 year average recurrence interval rainfall estimates, as determined in C.7.1 (c) v.) for the period that treatment infrastructure contains wastewater;

v. Where volume reduction is to occur via evaporation, demonstrate how fluid levels will be managed to maximise the rate of evaporation relative to the volume of fluid held in the treatment infrastructure.

(b) For any proposed on site wastewater reuse, the following requirements must be included:

i. An analysis of environmental impacts and environmental risks associated with proposed treatment, handling and reuse; and

ii. Proposed environmental performance standards (including specific control measures) and measurement criteria which demonstrate that these risks have been reduced to a level that is ALARP and acceptable.

C.7.1.2 Monitoring

(a) A monitoring plan that:

i. outlines the sampling locations, sampling frequency, proposed analytical methods and analytical detection limits, and any quality assurance and quality control measures that will be implemented;

ii. reflects all monitoring requirements mandated by this Code and the EMP, as well as any monitoring determined to be necessary as a result of the WWMP risk assessment;

iii. requires all field measurements and sampling to be undertaken by suitably qualified personnel and to utilise equipment that is suitably maintained, laboratory checked and calibrated;

iv. requires all laboratory analyses be conducted at a National Association of Testing Authorities (NATA) accredited laboratory, where available for the particular parameter.

C.7.2 Spill management plan

(a) An EMP for a petroleum activity must include a Spill Management Plan (**SMP**).

(b) The content of an SMP as stipulated by this Code may be incorporated into an emergency contingency plan that is also required to be submitted as part of an EMP.

(c) The SMP must assess and manage the risks posed by potential spills of waste, wastewater produced oil or condensate, fluids and any chemicals used or stored as part of petroleum activity.

(d) The SMP must contain the following:

i. a description of the chemicals, water and wastewater and the way that they will be stored , transported and transferred as part of petroleum activity, this includes fluids which are mixed and/or pumped on site;

ii. a description of the spill scenarios which may occur whilst undertaking ta petroleum activity, including some assessment of the duration of the activity and the mechanism, location, quality and quantity of a material that may be spilled;

iii. a risk assessment of the potential impact to the environment from a spill, that:

a. identifies the range of spill scenarios that may result from the relevant activities;

b. assesses risk to the environment from the proposed spill scenarios.

iv. a description of the procedures and processes to be used to prevent or minimise the risk of a spill from occurring, e.g. segregating areas for chemical storage and handling from the rest of the well site, management of storm water in containment facilities and minimising the volume of material that must be stored at the site.

v. a description of methods that will be used to detect a spill, including the monitoring methods, frequency of monitoring and the minimum volume spill or leak that would likely be detected between monitoring events (including buried pipelines); and

vi. a spill management response strategy, including a communications plan.

(e) Where the petroleum activity includes well operations, the SMP must also incorporate the requirements of section B.4.16 of this Code.

C.8 Wastewater chemistry analytes

Physio-chemical parameters

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes* *Frequency and guideline value*
Dissolved oxygen (DO)	mg/L	0.1	Can be measured *in situ*
Electrical Conductivity (EC)	μS/cm	1	Can be measured *in situ*
Total Dissolved Solids (TDS)	mg/L	10	
Total Suspended Solids (TSS)	mg/L	5	
pH	pH Units	0.01	Can be measured *in situ*
Sodium Adsorption Ratio	Ratio	0.01	No units of measure
Temperature	°C	0.1	Can be measured *in situ*

Nutrients

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Nitrate	% saturation and mg/L	0.01	Can be measured *in situ*
Nitrite	mg/L	0.01	
Total Nitrogen	mg/L	0.1	
Total Kjeldahl Nitrogen	mg/L	0.1	
Ammonia	mg/L	0.01	
Reactive Phosphorus	mg/L	0.01	
Total Phosphorus	mg/L	0.01	

Anions

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Sulfate (SO_4^{-2})	mg/L	1	
Chloride (Cl^-)	mg/L	1	
Carbonate (CO_3^{-2})	mg/L	1	
Bicarbonate (HCO_3^-)	mg/L	1	As $CaCO_3$ equivalent
Bicarbonate Alkalinity	mg/L	1	As $CaCO_3$ equivalent
Hydroxide Alkalinity	mg/L	1	As $CaCO_3$ equivalent
Total Alkalinity	mg/L	1	As $CaCO_3$ equivalent
Nitrite (NO_2^-)	mg/L	0.01	
Nitrate (NO_3^-)	mg/L	0.01	

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Fluoride (F^-)	mg/L	0.1	
Bromide (Br^-)	mg/L	0.01	
Total Cyanide	mg/L	0.004	

Major Cations

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Sodium (Na^+)	mg/L	1	
Magnesium (Mg^{2+})	mg/L	1	
Potassium (K^+)	mg/L	1	
Calcium (Ca^{2+})	mg/L	1	

Metals and metalloids (total and dissolved)

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Aluminium	mg/L	0.01	
Antimony	mg/L	0.001	
Arsenic	mg/L	0.001	Potentially also consider As (III) and As (V)
Barium	mg/L	0.001	
Beryllium	mg/L	0.001	
Boron	mg/L	0.001	
Cadmium	mg/L	0.0001	
Chromium	mg/L	0.001	
Cobalt	mg/L	0.001	
Copper	mg/L	0.001	
Iron	mg/L	0.05	
Lead	mg/L	0.001	
Manganese	mg/L	0.001	
Mercury	mg/L	0.0001	
Molybdenum	mg/L	0.001	
Nickel	mg/L	0.001	
Selenium	mg/L	0.001	
Silica	mg/L	0.1	
Silver	mg/L	0.001	

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Strontium	mg/L	0.001	
Thorium	mg/L	0.001	
Tin	mg/L	0.001	
Uranium	mg/L	0.001	
Vanadium	mg/L	0.05	
Zinc	mg/L	0.001	
Other radionuclides and gross alpha, beta, and gamma radiation	Bq/L	0.05-0.1	

Benzene, Tolouene, Ethylbenzene, Xylenes (BTEX)

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
Benzene	µg/L	1	
Toluene	µg/L	2	
Ethylbenzene	µg/L	2	
M and p Xylene	µg/L	2	
o Xylene	µg/L	2	
Total Xylenes	µg/L	2	

Total Recoverable Hydrocarbons (TRH) – ASC NEPM (2013) fractions

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
TRH C_6 - C_{10}	µg/L	20	
TRH C_6 - C_{10} less BTEX	µg/L	20	
TRH $>C_{10}$ - C_{16}	µg/L	100	
TRH $>C_{10}$ - C_{16} less Napthalene	µg/L	100	
TRH $>C_{16}$ - C_{34}	µg/L	100	
TRH $>C_{34}$ - C_{40}	µg/L	100	
Total TRH C_6 - C_{40}	µg/L	100	

Polycyclic Aromatic Hydrocarbons (PAH)

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
3-Methylcholanthrene	µg/L	1	
7, 12-Dimethylbenz(a)anthracene	µg/L	1	
Acenaphthene	µg/L	1	
Acenaphthylene	µg/L	1	
Anthracene	µg/L	1	
Benzo (a) pyrene	µg/L	0.5	
Benzo (b) fluoranthene	µg/L	1	
Benzo (ghi) perylene	µg/L	1	
Benzo (k) fluoranthene	µg/L	1	
Benzo (a) anthracene	µg/L	1	
Chrysene	µg/L	1	
Dibenz (ah) anthracene	µg/L	1	
Fluoranthene	µg/L	1	
Fluorene	µg/L	1	
Indeno (1,2,3-cd) pyrene	µg/L	1	
Napthalene	µg/L	1	
Phenanthrene	µg/L	1	
Pyrene	µg/L	1	
Carcinogenic PAHs (benzo[a}pyrene equivalents	µg/L	0.5	See ASC NEPM (2013) for potency factors
Total PAH	µg/L	0.5	

Phenols

Parameter	*Reporting Units*	*Limit of reporting (<LOR)*	*Notes*
2,3,4,6-Tetrachlorophenol	µg/L	1	
2,4,5-Trichlorophenol	µg/L	1	
2,4,6-Trichlorophenol	µg/L	1	
2,4-Dichlorophenol	µg/L	1	
2,4-Dimethylphenol	µg/L	1	
2,4-Dinitrophenol	µg/L	1	
2,6-Dichlorophenol	µg/L	1	
2-Chlorophenol	µg/L	1	

Parameter	***Reporting Units***	***Limit of reporting (<LOR)***	***Notes***
2-Methyl-4,6-dinitrophenol	µg/L	1	
2-Nitrophenol	µg/L	1	
4-Chloro-3-methylphenol	µg/L	1	
4-Nitrophenol	µg/L	1	
Dinoseb	µg/L	1	
Hexachlorophene	µg/L	1	
m- and p-Cresol	µg/L	1	
Pentachlorophenol	µg/L	1	
Phenol	µg/L	1	

Organic Carbon

Parameter	***Reporting Units***	***Limit of reporting (<LOR)***	***Notes***
Dissolved Organic Carbon (DOC)	mg/L	1	
Total Organic Carbon	mg/L	1	

Other Analytes

Parameter	***Reporting Units***	***Limit of reporting (<LOR)***	***Notes***
Bromide	mg/L	0.01	
Chlorine/Chloride	mg/L	1	
Formaldehyde	mg/L		

Part D — Methane emissions monitoring, leak management, detection and reporting

D.1 Overview

This part of the Code sets out best practice minimum standards for regional methane emissions assessments and monitoring, and identifying, classifying, rectifying and reporting leaks of methane from petroleum activities. Interest holders may have their own operating procedures for leak detection, monitoring and classification that go beyond this standard.

Management of risks associated with leaks from petroleum and natural gas wells, gathering systems and their associated processing facilities is dependent on rigorous design standards, robust safety obligations and effective governance programmes.

The purpose of this Code is to ensure that:

a) risk to the public, production workers and the environment is managed to a level that is ALARP and acceptable;

b) regulatory and applicable Australian Standard requirements, as well as the operator's internal requirements, are understood and implemented;

c) timely leak repair and periodic surveys will be managed effectively for the life of production and

d) greenhouse gas emissions from industry are minimised, and adequately quantified and reported to the Northern Territory Government for subsequent open publication.

The reporting resulting from this Code will ensure that regulators are appropriately informed and the petroleum industry's performance on methane emission management is appropriately measured and controlled.

D.2 Scope and application

This Code applies only to upstream methane emissions from wells, processing facilities and other infrastructure associated with gas production in onshore shale gasfields. The Code addresses **upstream** assessment, detection, remediation and reporting of gas leaks at wells, field compression stations, gathering systems, water treatment facilities and processing plants located on petroleum tenure.

This Code of Practice addresses the following upstream infrastructure:

(a) pre-exploration and pre-operation baseline assessments,

(b) routine periodic air monitoring,

(c) leak management, detection and repair,

(d) venting and flaring,

(e) other emission sources from gas production infrastructure and

(f) reporting requirements.

This part of the Code does not apply to methane emissions from **downstream** gas infrastructure.

This Code sets a standard for conducting baseline methane emission assessments in gas production (or potential gas production) regions in the Northern Territory. In addition, the Code standardises procedures for the detection, remediation and reporting of methane emissions from well site facilities, gathering systems, processing plants and other infrastructure to ensure that these facilities are monitored effectively by petroleum interest holders and to minimise the industry's greenhouse impact. The Code is designed to be considered and used in conjunction with the interest holder's internal risk assessment processes and operating procedures under their safety management systems.

Where a requirement to monitor, detect and report emissions is already in place within existing Territory or Federal legislation, specific reference in this Code shall be made to that requirement to avoid duplication. Explanatory guidance is provided on what industry practices are critical to ensure emissions resulting from natural gas activities are minimised as far as reasonably practicable.

D.3 General Safety

For methane to reach a flammable state, it must be present at a concentration of between 5% (**lower explosive limit** or **LEL**) and 15% (**upper explosive limit**) of gas in air. In gas-detection systems, the amount of gas present is often indicated as a percentage of LEL. It should be noted that the explosive limits of methane are different to many other flammable gasses so it is important that gas detection systems are appropriate for the application.

Zero percent LEL denotes an atmosphere that is free from a combustible gas whereas 100 % LEL denotes an atmosphere in which the gas concentration has reached its **lower flammable limit**, i.e. 5% or 50,000 ppm (by volume).

D.4 Regional methane monitoring

This section outlines requirements for the establishment of a baseline and ongoing monitoring of methane emissions in a region. Three types of regional monitoring programs are required:

- **Baseline Methane Assessments**, described in D.4.1, are conducted to characterise the ambient methane levels, which may vary with seasons, and to identify the major sources of methane prior to a prospective activity. This assessment may be done in conjunction with baseline methane surveys conducted for a Strategic Regional Environmental Baseline Assessment (SREBA).
- **Regional Methane Assessment Programmes**, described in section D.4.2, are conducted to characterise the existing natural and anthropogenic sources of methane emissions across each permit or licence area and adjacent areas before the commencement of exploration activity and immediately after the commencement of full-scale production.
- **Routine Periodic Atmospheric Monitoring Programmes**, described in D.4.3, are conducted to provide for periodic monitoring so that any changes in methane emissions can be detected during the life of a project that has entered the production phase. These assessments use the Regional Methane Assessment Programmes as their baseline.

These assessments are conducted by or on behalf of the Northern Territory Government, funded by industry, and must be designed and implemented by a suitably qualified and experienced professional who is approved by the Minister.

D.4.1 Baseline Methane Assessment

D.4.1.1 Principles

Baseline methane assessment refers principally to measuring atmospheric methane levels, identifying and quantifying sources within a prospective or active gas production region before any activities have occurred. The primary purpose of a baseline assessment is to establish a benchmark against which the impact of gas development can be assessed over time. Baseline assessments should therefore be undertaken for the broader region (or catchment) where the activity may occur as well as any surrounding areas that may be influenced by the prospective activity.

Sources of methane that may contribute to baseline levels can be natural (e.g. wetlands, bushfires, geological seeps) or anthropogenic (agriculture, gas production, mining activities, water bores). The aim of a comprehensive baseline study is to characterise the ambient methane levels, which may vary with seasons, and identify the major sources of methane prior to a prospective activity. Where possible, for identified sources, the methane emission rates should be measured or estimated to assess their relative contribution to the region's total methane emissions; however it is acknowledged that this is often difficult and estimates may have large uncertainties.

This established baseline assessment is the platform from which future periodic monitoring can be based on and allows post-exploration and production comparisons to be made. Of particular relevance to gas production are areas of potentially higher risk of gas leakage through increased landscape emissions caused by gas and water extraction. Such areas should be given particular attention during baseline assessment and routine monitoring programmes as described in the following sections.

Increases in methane emissions associated with natural gas developments can be divided into two sources: an increase in geological emission sources potentially induced by the activity or an increase from infrastructure emission sources. Both sources contribute to the broader methane emissions of a region.

Geological methane emissions are those which are associated with the discharge of gas from hydrocarbon producing formations typically located at the margins of a geological basin. These emission sources are often associated with natural gas discharge pathways such as seeps. Since these seeps may be affected by gas extraction, it is important that any geological seeps identified during baseline assessments are monitored for changes over time. Monitoring may involve quantification of emissions although other methods that only detect changing emission characteristics (e.g. periodic surface flux measurements) may also be appropriate. Other geological emission types are related to anthropogenic sources, such as coal mines, abandoned mineral and petroleum wells and water bores.

Infrastructure methane emissions are those associated with petroleum exploration and development infrastructure and activities. These emissions are a combination of controlled (engineered) and uncontrolled releases (leaks) and are confined within a discrete footprint of wells, gas processing facilities, pipelines and other related infrastructure.

Because gas processing facilities may produce atmospheric emissions in addition to methane (from flaring or gas-fuelled engines, for example), baseline studies should include the measurement of CO_2, oxides of nitrogen (NOx) and particulate matter at future petroleum exploration and development infrastructure sites. These emissions should be measured both before and after the commencement of gas production to assess the impact of processing infrastructure.

D.4.1.2 Mandatory Requirements

(a) Methane assessment (i.e. mobile surveys of ambient methane concentration; identification and location of main methane sources; quantification of emission rates if possible) must be undertaken for the region or catchment for at least six months prior to the granting of exploration approvals involving hydraulic fracturing.

(b) In areas where hydraulic fracturing has already occurred, methane assessment (i.e. mobile surveys of ambient methane concentration; identification and location of main methane sources; quantification of emission rates if possible) for the region must be undertaken for at least a year prior to the granting of **production approvals**.

(c) Assessment of ambient air for methane, CO_2, oxides of nitrogen and particulate matter must also be included.

(d) Measurements of CH_4, CO_2 and other thermogenic indicators such as ethane should also be collected at areas of high risk of landscape emissions induced by the gas production, before the commencement of gas production and continuing while gas production occurs. This could include the installation of fixed monitoring stations to be used for future routine monitoring.

(e) Baseline assessment must be undertaken by persons or organisations approved by the Northern Territory Government.

D.4.1.3 Preferred requirements

(a) The design of a regional baseline methane assessment programme should attempt to characterise as many as practicable potential methane sources utilising appropriate methods such as mobile surveys of the region, surface flux chambers, plume dispersion techniques and various others techniques as appropriate.

(b) The methodology should align with that described in any methane baseline methodology described in Technical Guidance Notes of the SREBA Framework where such documents are available.

D.4.2 Regional Methane Assessment Programme (RMAP)

D.4.2.1 Principles

The existing natural and anthropogenic sources of methane emissions across each permit or licence area and adjacent areas must be characterised by identifying and locating the sources and, where possible, estimating the emission rate from each source either by direct measurement or other estimation methods. It is acknowledged, however, that some emission estimates may have high uncertainties. An integral component of all RMAPs, however, will be detailed methane concentration surveys across the target region.

The RMAP establishes the foundation for all future monitoring programmes in a region.

D.4.2.2 Mandatory requirements

(a) An RMAP must be developed to characterise existing natural and anthropogenic sources of methane across each permit or licence area and adjacent areas.

(b) An RMAP must be developed and implemented by a suitably qualified and experienced professional who is approved by the Minister.

(c) The RMAP must be submitted for approval.

(d) RMAPs must be undertaken at the following frequency:

  i. three baseline surveys within six months prior to the granting of exploration approvals involving hydraulic fracturing;

  ii. in areas where hydraulic fracturing has already occurred, three baseline surveys within 12 months prior to the granting of any production approvals; and

  iii. within six months of full-scale production commencing.

(e) The results of baseline surveys must be submitted as they become available.

D.4.2.3 Preferred requirements

(a) In developing an RMAP consideration should be given to the following:

  i. A desktop review of the potential sources of gas within the tenure and their potential location; including natural biogenic sources, other industries (such as mining, intensive agriculture, waste treatment facilities) and geological (outcrop emissions).

  ii. A conceptual geological model of the relevant tenure to assist in identifying priority areas where there is a higher potential of emissions from the landscape and gas production. The priority areas identified within the conceptualisation must be the focus of monitoring and include:

    a. outcrop and subcrop areas where gas bearing formations are close to the surface;

    b. areas with anecdotal evidence of natural seeps or shallow gas being encountered during water bore or mineral exploration drilling;

    c. areas of historic mineral bore or petroleum exploration wells which dissect **hydrocarbon bearing zones** - these may act as conduits to the surface;

d. areas with evidence of methane being present in underlying groundwater;

e. areas of faulting, igneous intrusions or other geological features which may allow gas or migrate to the surface; and

f. areas of current or future potential natural gas production and processing facilities.

iii. An outline of the baseline survey methodology and justification, with consideration of:

a. any methane baseline methodology described in Technical Guidance Notes of the SREBA Framework;

b. the type of emission source to be assessed, i.e. landscape emissions versus shale gas production;

c. the type of survey, which may include the following:

i. mobile methane surveys (vehicle or airborne);

ii. fixed atmospheric measurements;

iii. flux chamber surveys;

d. the limitations of the method, including limits of detection, sampling frequency, accuracy and access requirements.

iv. An outline of how emissions will be characterised, including how emission rates will be estimated and isotopic analyses for source attribution.

(b) If fixed monitoring stations are used as part of ongoing monitoring programmes, data should be made continuously available to the public.

D.4.3 Routine periodic atmospheric monitoring programme

D.4.3.1 Principles

The routine periodic atmospheric monitoring programme allows for periodic monitoring so that any changes in methane emissions can be detected over the life of a project that has entered the production phase. The RMAP forms the baseline to which the routine periodic atmospheric monitoring programme compares.

D.4.3.2 Mandatory requirements

(a) Periodic monitoring of the broader region comparable to the RMAP must be undertaken every five years upon the commencement of production. In addition, fixed atmospheric monitoring stations must be established at least 12 months prior to the commencement of gas production within a **production licence** at petroleum infrastructure sites.

(b) The number and location of monitoring sites must be sufficient to demonstrate shale production activities have not resulted in a regional enrichment of methane (and where relevant other GHG and particulate matter) above the background. The location of stations must consider constraints such as visual amenity, land access, access to power and vegetation clearing constraints.

(c) Each monitoring station must be capable of monitoring the following parameters:

   i. meteorological conditions (ambient temperature, wind direction, wind speed, relative humidity, precipitation and solar radiation);

   ii. ambient concentrations of methane; and

   iii. carbon dioxide, oxides of nitrogen and particulate matter (at least PM10).

(d) The routine atmospheric monitoring programme must be developed and implemented by a suitably qualified and experienced professional who is approved by the Minister.

(e) The results from the stations must be made available to the public through the Northern Territory Government provided portal in the requested format.

(f) If fixed monitoring shows statistically significantly higher methane levels compared to the usual levels measured at the site, the operator must undertake an investigation to determine the source of the higher methane levels and, if necessary, rectify the leak or induced natural seepage. A written report detailing the levels of methane measured, the duration of the unusual readings and the results of the investigation (including remedial actions) must be submitted within one month of the significantly higher-level methane event being detected.

D.5 Emissions Detection and Management

This section outlines requirements for the prevention, monitoring, management and reporting of methane emissions from, petroleum activities.

D.5.1 Methane Emissions Management Plan

D.5.1.1 Principles

The Methane Emissions Management Plan (MEMP) aims to reduce emissions to ALARP and acceptable via emissions detection and management. Active monitoring and management aims to reduce fugitive methane emissions from petroleum activities.

D.5.1.2 Mandatory requirements

(a) Interest holders must conduct a risk assessment to identify the risks posed by leaks from operating plant.

(b) The risks and controls identified within the risk assessment shall form the basis of a MEMP for emissions from wells, gathering systems and processing facilities. A MEMP must contain the following as a minimum:

   i. equipment selection, design standards and maintenance practices to avoid leaks and otherwise minimise emissions;

   ii. monitoring methodology in accordance with section D.5.3 of this Code;

   iii. monitoring frequency, in accordance with section D.5.2 of this Code;

   iv. leak classification in accordance with section D.5.5 of this Code;

   v. leak response (e.g. isolated, rectified, monitored); and

   vi. emissions reporting.

D.5.1.3 Preferred requirements

(a) The MEMP should be consistent with the emissions management plan described in **US NSPS 2016** and relevant parts of the following sections:

i. §60.5397a;

ii. §60.5410a;

iii. §60.5415a; and

iv. §60.5420a.

References:

- US NSPS 2016. US Federal Regulations Title 40 – Protection of Environment Chapter I - Environmental Protection Agency, Subchapter C – Air Programs, Part 60 – Standards of Performance for New Stationary Sources, Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015.

D.5.2 Inspection Frequency and Procedure

D.5.2.1 Principles

Routine inspection aims to detect fugitive methane emissions from petroleum activities as soon as practicable so that they can be mitigated.

D.5.2.2 Mandatory requirements

(a) regular visits must be made to operational well sites, gathering systems and processing facilities in accordance with their approved MEMP;

(b) all operational personnel must carry and monitor personal calibrated gas detectors during every routine operational visit to well sites and processing facilities;

(c) all persons completing emission detection activities must be properly trained and competency-assured;

(d) leak inspections must be conducted on the minimum frequencies detailed in Table 11;

(e) leak inspections of individual operating plant must be undertake at an increased frequency as determined by the risk assessment and in consideration of previous audit/inspection findings for those specific facilities; and

(f) where the operator uses optical gas imaging for leak detection, an annual inspection using **US EPA Method 21** must also be performed on the facility.

Table 10: Emission inspection minimum frequency

Facility or system	Operator leak detection
Above ground facility – Petroleum well pad equipment	6 monthly
Low pressure pipeline and fittings	Annually
Steel or high pressure pipeline	Annually
Compressor stations and pneumatic devices	Quarterly
Processing plant	Annually
All gas containing equipment following major maintenance (e.g. repacking, replacement of seals)	Within 48 hours of recommissioning

D.5.2.3 Preferred requirements

(a) The inspection frequency should be consistent with the monitoring requirements in US NSPS 2016 and relevant parts of the following sections:

i. §60.5397a;

ii. §60.5410a; and

iii. §60.5415a.

D.5.3 Standard Leak Detection Instruments

D.5.3.1 Principles

Instrument selection and operation are selected to ensure that they are fit for purpose and maximise the probability of detecting methane leaks.

D.5.3.2 Mandatory requirements

(a) Operational leak detection methods must be described and approved in the MEMP.

(b) Leak testing must be conducted using either:

i. USEPA Method 21; or

ii. optical gas imaging (OGI).

(c) If other superior methods are available, these may also be proposed in the MEMP.

(d) All gas leak surveys must be conducted by **suitably qualified personnel** using appropriate gas detection instruments calibrated in accordance with the manufacturer's requirements.

(e) Gas detectors must be maintained and tested in accordance with manufacturer's instructions.

(f) If USEPA Method 21 is used, the gas detection instruments, operation and calibration procedures defined in USEPA Method 21 must be followed.

(g) If OGI is used for leak detection, the instrument must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm (by volume) at a flow rate of ≤60 g/hr from a quarter inch (6.4 mm) diameter orifice.

D.5.3.3 Preferred requirements

(a) The minimum requirements for gas detection instruments, operation and calibration procedures should be consistent with the requirements in US NSPS 2016 and relevant parts of the following sections:

i. §60.5397a.

References

- USEPA Method 21. US Federal Regulations Title 40 – Protection of Environment Chapter I - Environmental Protection Agency, Subchapter C – Air Programs, Part 60 – Standards of Performance for New Stationary Sources, Appendix A-7 to Part 60—Test Methods 19 through 25E

D.5.4 General Leak Detection Procedure

D.5.4.1 Principles

Leak detection and monitoring methods are selected to ensure that they are fit for purpose and are conducted by a **suitably qualified person** to maximise the probability of detecting methane leaks.

D.5.4.2 Mandatory requirements

(a) monitoring for leaks on above-ground facilities including all infrastructure on well pads, processing facilities and gathering systems (including vents, drains and valve manifolds) must be conducted by a suitably qualified person, using a method in accordance with an approved MEMP.

(b) If a leak is found and it is safe to do so, the operator will:

i. clearly identify and record the source of the leak;

ii. if using USEPA Method 21, record the concentration of methane at the surface of the component for a sustained period of approximately twice the response time of the instrument in accordance with USEPA Method 21;

iii. for OGI methods, record the video image of the leak according to the requirements of the Alternative Work Practice to Detect Leaks from Equipment.

(c) If a liquid petroleum leak is found and it is safe to do so, the operator will:

i. record the estimated volume of liquid leaking or leaked over time; and

ii. clearly identify and record the source of the leak.

(d) for paragraphs (c) and (d), if the leak is too large or not safe to measure it will be assumed that the leak is above the reportable threshold level identified in section D.5.5.

D.5.5 Leak Classification

Leaks are categorised according to the below classifications, and the requirements for each kind of leak are set out below.

D.5.5.1 Minor Leak

A minor leak is a leak that:

(a) originates from an above ground source;

(b) is an unplanned release;

(c) yields a methane concentration of 500 ppm (by volume) to 5000ppm (by volume) when measured at the surface of the component according to USEPA Method 21; or

(d) any emission visible with an OGI instrument.

Leaks identified during commissioning or bringing equipment back into service are not classified as minor leaks, however they should still be recorded and reported where required under other frameworks (such as federal legislation or the incident reporting framework of Part 3 of the PERs).

D.5.5.2 Significant Leak

A significant leak is a leak originating from above ground facilities, gathering systems and subsurface pipelines that meets one of the following criteria:

(a) A leak due to an unplanned release from an above ground petroleum facility that, when measured at the surface of the component according to USEPA Method 21; gives a sustained **Lower Explosive Limit** (LEL) reading greater than 10% (5000 ppm by volume) of the LEL.

(b) A leak due to an unplanned release from a gathering system - subsurface pipeline that, at ground level; gives a sustained reading greater than 500 ppm (by volume) for a 15 second duration.

(c) A liquid petroleum (condensate / oil) loss of containment that exceeds 200 litres of hydrocarbons.

When it is safe to measure leaks, leaks that are classified as significant leaks during commissioning or bringing equipment back into service should be recorded and reported as per Section D.5.6.2.

It will be assumed that a leak is above the threshold level for reporting significant leaks if the leak is too large or not safe to measure. Such leaks should be recorded and reported as per Section D.5.6.2.

D.5.6 Leak Remediation and Notification

It should be noted that the notification requirements of this part apply in addition to the notification requirements of Part 3 of the PERs. For example, a leak that does not require notification under this part may still constitute a contravention of an environmental performance standard and as such be required to be reported as a recordable incident under regulation 35.

D.5.6.1 Minor Leaks

A minor leak is defined in section D.5.5.1.

(a) All minor leaks must be documented and repaired as soon as practicable, but in any event within 30 days of identification.

(b) In the event of the 30 day deadline being unachievable, the Minister must be notified within the 30 days and provided with the reason for the delay and a target date for completion of the work.

D.5.6.2 Significant Leaks

A significant leak is defined in Section D.5.5.2.

In the event that a significant leak is detected:

(a) the safety management system requirements for risk assessment and emergency response must be followed.

(b) For all significant leaks, the interest holders first priorities are as follows:

  i. an exclusion zone a must be established around the leak and appropriate restrictions on access to the exclusion zone must be imposed, along with any other necessary immediate controls;

  ii. the leak shall be repaired or made safe as soon as practicable immediately after detection, as follows;

    a. the gas leak must be isolated, repaired if possible, contained or otherwise made safe within 72 hours of detection of the leak;

    b. in the event of the 72-hour repair deadline being unachievable, the reason for the delay and a target date for completion of the work must be submitted to the Department of Primary Industry and Resources before the deadline passes; and

    c. if it is contended that the risks of immediately repairing a leak exceed the risk posed by the leak, an extension of the 72-hour deadline may be sought if provided that other measures to mitigate the risk are undertaken (e.g. ensuring no ignition sources or personnel are permitted in the exclusion zone).

  iii. complying with the other steps in this section D.5.6.2 must not compromise, impair or delay the operator’s actions to immediately make the site safe and establish exclusion zones.

(c) The interest holder must make the following notifications:

  i. appropriate notifications must be given to Northern Territory Government departments in compliance with any legislative requirements:

    a. along with all other details required under relevant legislation, this notification must include the date of identification, nature and level of leak, operating plant site name, number and location as well as initial steps taken to minimise the risk; and

    b. in the case of an emergency situation, a notification to the Department of Primary Industry and Resources’ emergency hotline number 1 300 935 250 must be made within 24 hours;

  ii. the land owner or occupier of the property on which these leaks are occurring must be notified if the leak cannot be repaired immediately.

(d) Remediation work must be conducted in accordance with the following:

   i. Only commence work after a suitable risk assessment has been undertaken and relevant safety procedures are followed including consideration of all the required Personal Protective Equipment (PPE) and emergency response materials.

   ii. For leaks identified on well equipment - higher order controls, such as containment by repair, must be implemented wherever possible.

(e) For leaks identified on gathering systems (where an excavation is necessary to effect repair) repairs must be completed as soon as reasonably practicable in consideration of the location of the site, safety to personnel and the public, potential environmental harm, likely access to the site from landholders or the general public, and landholder/community concerns in relation to the leak.

(f) For leaks identified on well casings or adjacent to the well casing (where a work over rig is necessary to effect repair) repairs must be completed as soon as reasonably practicable in consideration of the location of the well, safety to personnel and the public, potential environmental harm, likely access to the well from landholders or the general public, and landholder/community concerns in relation to the leak.

(g) A written close-out report must be submitted within 5 business days of the remediation of the leak, specifying the date of identification, nature and level of leak, location and name of the operating plant, and the rectification actions taken.

(h) If finalising the remediation is delayed more than 7 business days from the identification of the leak an update must be submitted on that day. The final close out report shall be provided when all work is completed.

(i) Full cooperation with relevant regulators is required.

D.5.7 Compressors and pneumatic devices

D.5.7.1 Principles

To ensure that compressors and pneumatic devices are designed, selected and operated to minimise or eliminate fugitive emissions.

D.5.7.2 Mandatory requirements

Emissions from compressors and pneumatic devices must be reduced through compliance with the following requirements:

(a) emissions from new, modified, or reconstructed wet seal centrifugal compressors (except for those located at well sites) must be captured and routed to a control device;

(b) the rod packing on each new, modified, or reconstructed reciprocating compressors must meet one of the following:

   i. it is changed on or before 26,000 hours of operation; and

   ii. it is changed on or before every 36 calendar months; or

   iii. it routes all emissions through a closed vent system under negative pressure.

(c) The use of pneumatic controllers on new, modified, or reconstructed infrastructure must comply with the following requirements:

   i. for gas processing facilities and compressors they must be driven by instrument air systems with a zero natural gas emissions

   ii. for other infrastructure, and where low-bleed pneumatic controllers are used, they must have a natural gas bleed rate no greater than 0.17 $m^3 h^{-1}$ (6 scf/h)

(d) The use of pneumatic pumps must comply with the following requirements:

   i. for gas processing facilities and compressors they must be driven by instrument air systems with a zero natural gas emissions.

   ii. for well sites, pneumatic pump emissions must be routed to a control device that must achieve greater than 95 % emission reduction.

   iii. for existing well sites, which have been modified or reconstructed, it is permissible to direct emissions to an existing control which achieves less than 95% emissions reduction where it is able to be demonstrated that the environmental risks associated with this have been reduced to ALARP and acceptable.

D.5.8 Flowback activities

All flowback activities must be managed in accordance with the Part B of this Code. Gas produced during the **separation flowback stage** must be measured using direct measurement in accordance with the Commonwealth National Greenhouse and Energy Reporting (Measurement) Determination (2008).

D.5.9 Venting and Flaring

D.5.9.1 Principles

Venting and flaring of natural gas should be eliminated or minimised where practicable.

D.5.9.2 Well Related Activities Mandatory Requirements

(a) .For well construction activities **Reduced Emissions Completions (REC)** should be employed where technically feasible so that gas is captured for sale or other use.

(b) Where **REC** are not practicable:

   i. flaring should be used rather than venting; and

   ii. venting should only be used where capture or flaring is not possible.

(c) Emissions from exploration, well construction (including during **flowback**) and **workovers** must be measured and reports submitted. These emissions should be measured using methods consistent those specified under the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Other methods may be used if approved in an EMP.

D.5.9.3 Gas Processing Activities Mandatory Requirements

(a) Where natural gas is vented or flared at a gas processing or other downstream facility, emissions must be estimated and reported. Methods used for this purpose must be consistent with the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Other methods may be used if approved in an EMP.

D.5.9.4 Other Fugitive Emission Sources Mandatory Requirements

(b) In addition to leaks, venting and flaring considered in the preceding section of this Code, methane may also be released in significant quantities during certain planned and unplanned operations. These include some maintenance operations were gas in pipelines or other equipment is blown down, system upsets or accidental releases. Such emissions must be estimated using methods consistent with the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Other methods may be used if approved in an EMP.

D.6 Reporting

D.6.1 Principles

All mandated government reporting is complied with; and all detectable leaks and emissions are reported on an annual basis.

D.6.2 Mandatory requirements

(a) Reports of baseline assessments must be submitted at the conclusion of each field campaign.

(b) Emissions reporting must be in accordance with Section D.5.6. The natural gas industry is required to estimate and report all greenhouse gas emissions to the Australian Government's Clean Energy Regulator on an annual basis. Hence emissions associated with venting and flaring as described in Section D.5.9 must be consistent with the reporting requirements of the Clean Energy Regulator but must be provided separately to the Northern Territory Government in accordance with this Code. In cases where interest holders are below the reporting threshold specified by the Commonwealth *National Greenhouse and Energy Reporting Act (2007)*, emissions must still be reported to the Northern Territory Government under this Code. Emissions reported to the Northern Territory Government will be made available for subsequent open publication.

The operator must submit an annual report to the Northern Territory Government summarising the following:

(c) The records of the stages of **flowback** activities including:

  i. the date and time of the onset of flowback;

  ii. the date and time of each attempt to route **flowback fluid** to the separator;

  iii. the date and time of each occurrence in which the operator reverted to the **initial flowback stage**;

  iv. the date and time of well shut in or connected into adjacent gathering lines;

  v. the date and time that temporary flowback equipment is disconnected.

  vi. the total duration of venting, combustion and flaring over the flowback period.

(d) The cumulative number of hours of operation for each reciprocating compressor, or the number of months since initial start-up or the previous reciprocating compressor rod packing replacement.

(e) The results of leak detection surveys (in the annual report under the Act) outlining:

  i. the extent of compliance with the leak management plan;

  ii. a summary of monitoring undertaken during the period;

  iii. a summary of minor and significant leaks identified during the reporting period, including the date of identification and repair for each leak and those leaks that could not be repaired; and

  iv. an explanation of why any component could not be repaired and what actions will be taken to either decommission the component or otherwise remedy the problem.

D.6.3 Preferred requirements

A range of voluntary reporting also exists such as the Carbon Disclosure Project and the Dow Jones Sustainability Index.

Acronyms

The following acronyms are contained in this document.

Acronyms	Full form
ALARP	As low as reasonably practicable
API	American Petroleum Institute
BHA	Bottom hole assembly
BOP	Blowout preventer
BTEX	A subset of volatile organic chemicals(VOCs) including benzene, toluene, ethylbenzene and xylenes
CBL	Cement bond log
DENR	Department of Environment and Natural Resources, Northern Territory of Australia
DFIT	Diagnostic Fracture Injectivity Testing
DPIR	Department of Primary Industry and Resources, Northern Territory of Australia
ESCP	Erosion and Sediment Control Plan
H_2S	Hydrogen sulfide
HPHT	High pressure, high temperature
HT	High temperature
kg	Kilograms
lb	Pound or Pounds
LEL	Lower explosive limit
m	Metres
MAOP	Maximum allowable operating pressure
mm	Millimetres
MPa	Mega pascals
NGER	National Greenhouse and Energy Reporting scheme
NORM	Naturally occurring radioactive material
NOx	Nitrogen Oxides
NSPS	New Source Performance Standards (USEPA)
NT	Northern Territory
OGI	Optical gas imager
pH	Index of acidity or alkalinity of water.
PM_{10}	particulate matter 10 micrometres or less in diameter
PPFG	pore pressure and fracture gradient

Acronyms	Full form
ppg	Pounds per gallon (United States of America)
psi	Pounds per square inch
REC	Reduced emissions completion
TVD	Total vertical depth
WOMP	Well operations management plan

Definitions

Term	Definition
Annulus **Annuli**	The volume between wellbore and casing or between casing and tubing. A-annulus refers to the annulus between the tubing and **production casing**. B-annulus refers to the annulus between the production casing and the previous (larger diameter) casing.
Appraisal well	A well drilled principally to define more accurately the extent or nature of a previously discovered oil or gas accumulation.
Aquifer	A body of rock that is sufficiently permeable to conduct groundwater and currently supplying, or potentially being able to supply, water for environmental, cultural or consumptive (stock or domestic) uses, as determined by the Northern Territory Government.
Blowout preventer **BOP**	A device attached immediately above the casing, which can be closed to shut in the well.
Bore (or **water bore**)	Includes a water observation bore, water supply bore or injection bore.
Casing or **casing string**	A pipe placed in a well to prevent the wall of the hole from caving in and to prevent movement of fluids from one formation to another.
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 bond log **CBL**	A log obtained from a downhole logging tool that determines the quality of cement bond on the exterior casing wall.
Cement plug	Portion of cement placed at some point in the wellbore.
Cementing	The application of a liquid slurry of cement and water to various points inside and outside the casing.
Christmas tree	The assembly of control valves and pressure gauges attached to the Wellhead to control the flow into or out of the well after the well has been drilled and completed.
Circulation	The process of pumping a fluid down the well and back up to the surface in a drilling or **workover** operation.
Code	Unless otherwise specified, refers to this Code of Practice.
Compartmentalised resource	A resource restricted in lateral extent where petroleum has migrated from source rocks to a definable reservoir.
Competent person **Competent personnel**	A person with the necessary ability, knowledge and relevant experience to conduct the task or activity.
Completion or **completions**	A flowpath in a well that allows the production of fluids from a discrete formation interval through the well, or the injection of fluids into a discrete formation interval through the well, and includes the necessary sub-surface equipment independent of other flowpaths in the well.

Term	Definition
Continuous resource	A resource hosted in source rock with significant lateral extent, such as a shale.
Development Well	A well that is drilled within the expected limits or boundaries of a petroleum accumulation and that is drilled principally to produce, or to facilitate the production of, the petroleum reserves from that accumulation.
Downstream	For the purposes of this document, downstream begins where the production of gas ends; that is the final processing required to meet the needs of other industry such as electricity production, cooking, making fertiliser as well as LNG transportation.
Downstream	Petroleum industry processes associated with post-production activities such as refining, transportation and marketing of petroleum products.
Drilling fluid	A fluid circulated during drilling to lift cuttings from the wellbore to the surface and to cool the drill bit. Also known as drilling mud.
Exploration well	A well drilled with a view to discovering a new oil or gas accumulation, or to obtaining stratigraphic information that may assist in the discovery of a new oil or gas accumulation.
Flaring	The controlled burning of natural gas for purposes other than producing energy.
Flowback	The process of allowing fluids and entrained solids to flow from a well following hydraulic fracture stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracture stimulation or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production.
Flowback fluid	As defined in the *Petroleum (Environment) Regulations 2016*.
Formation pressure	The pressure of fluids within the pores of a reservoir.
Fugitive Emissions	The term fugitive emissions in relation to the oil and gas industry refers to all non-combustion sources of greenhouse gasses (mainly methane) but also to the disposal of waste streams either by venting or flaring.
Garrett Gas Train	An instrument used for quantitative analyses of sulfides and carbonates in drilling fluid.
Geohazard	Geological hazards (such as caverns, karstic formations, voids and faults) which could negatively impact on the objectives of well operations.
Good Oilfield Practice	As defined in the *Petroleum Act 1984*
Hazardous chemical	As defined in the Northern Territory Work Health and Safety (National Uniform Legislation) Regulations, wastes and contaminants as defined under the *Petroleum Act 1984* and waste listed under the *Waste Management and Pollution Control Act 1998.*

Term	Definition
High pressure, high temperature wells **HPHT**	High temperature in this context is defined as when the undisturbed bottom hole temperature is greater than 150°C (300°F). High Pressure in this context is defined as either: (a) the maximum pore pressure of any porous formation that exceeds a hydrostatic gradient of 0,18 bar/m (0,8 psi/ft) (representing an equivalent mud weight (EMW) of 1,85 SG or (15,4 ppg) or, (b) needing deployment of pressure control equipment with a rated working pressure in excess of 690 bar (69 MPa, 10 000 psi).
High temperature wells **HT**	High temperature (HT) wells, typically ≥150 °C (300 °F) bottom hole static temperature.
Hydraulic fracture stimulation	A process used to enhance the productivity of a gas well. It involves pumping a specifically blended fluid, charged with proppant such as sand, down a well at high pressure to force passageways into the target formation(s). The proppant keeps the passageways open once the pressure is released and serves to improve the productivity of the well.
Hydraulic fracturing fluid	A fluid injected into a well as part of a stimulation operation. Hydraulic fracturing fluids contain water and proppant, and gels, friction reducers, crosslinkers, breakers and surfactants similar to household cosmetics and cleaning products; these additives are selected for their capability to improve the results of the stimulation operation and the productivity of the well.
Hydrocarbon bearing zone	A zone that can produce sustained flows of hydrocarbons under a particular set of conditions imposed on it by a petroleum well. Levels of flow potential shall be assessed for the risk to people, or the environment.
Initial flowback stage	The initial flowback stage begins with the onset of flowback where the pressure is insufficient for the separator to function. The initial flowback stage ends when the gas flow increases to a point where the separator can function correctly.
Interest holder	A person who holds a petroleum interest for a regulated activity.
Intermediate casing	The string of casing that may be set in a well after the **surface casing** and preceding **production casing** / **liner**.
Intervention or **well intervention**	An operation carried out by re-entering an existing well.
Kick	An unplanned entry of water, gas, oil or other formation fluid into the wellbore during drilling.
Kick tolerance	Maximum influx volume that can be circulated out of well without breaking down the weakest zone in well
Leak inspection	A leak inspection of the petroleum operating plant. This inspection is required by the petroleum operator's asset integrity process and should be completed by a **competent person** and would make observations on the integrity of existing petroleum operating plant. This inspection will include (as a minimum), a comprehensive leak survey of all components of the petroleum operating plant.

Term	Definition
Leak-off pressure	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.
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.
Liquid petroleum	Petroleum that is transported from a petroleum well to a processing facility in a liquid phase excluding associated water.
Low gas to oil ratio well	Wells with a Gas to Oil Ratio of less than 300 scf of gas per stock tank barrel of oil produced
Low pressure well	Wells which produce oil or gas at an insufficient pressure to maintain flow.
Managed pressure drilling	An adaptive drilling process used to precisely control the annular pressure to be close to the pore pressure throughout the wellbore whilst drilling.
Mandatory requirements	These are requirements that that must be complied with by interest holders in carrying out the activities. The terms **shall** or **must** are used for mandatory requirements. These are requirements which: i. if a corresponding principle has been identified, are considered to be the minimum measures required to achieve the principle; and ii. if no corresponding principle has been identified, are otherwise required to be carried out.
Methane emissions	Methane emissions from petroleum operations include **fugitive emissions**, contained emissions (those occurring at combustion), and any possible influence on natural emissions or shallow gas held in subsurface strata.
Non-aqueous drilling fluid	Non-water based drilling fluid or well circulating fluid. Common non-aqueous drilling fluid systems are mineral oil or synthetic fluid (SBM) based invert emulsions.
Oil country tubular goods	Oil Country Tubular Goods are tubes that are used in oil and gas production. These include drill pipe, well casing and production tubing.
Open hole	The uncased portion of a well.
Operation or petroleum operation	any activity relating to exploration for, or the production, processing or transportation of, petroleum
Packer	Downhole equipment that consists of a sealing device which is used to block the flow of fluids through the annular space between pipe and the wall of the wellbore.
Petroleum	As defined in the *Petroleum Act 1984*, Northern Territory of Australia
Petroleum Act	*Petroleum Act 1984*, Northern Territory of Australia
Petroleum (Environment) Regulations **PER**	Petroleum (Environment) Regulations 2016, Northern Territory of Australia

Term	Definition
Petroleum interest	As defined in the *Petroleum Act 1984*
Petroleum wells	Exploration, appraisal and development wells as defined in this code
PM10	Particulate matter 10 micrometres or less in diameter
Preferred requirements	These are practices, methods and techniques which should generally be followed by interest holders unless: i. there is a convincing justification why it cannot be followed; and ii. any alternative practice, method or technique that will be followed: a. if a corresponding principle has been identified, will achieve the principle; and b. if no corresponding principle has been identified, will result in no greater environmental risks or environmental impacts than if the good oilfield practice was followed.
Primary cementing	The process of placing a cement sheath around a casing or liner string.
Principles	These are principles which clarify the purpose and outcomes which operations must achieve in carrying out the activities. The principles underlie the mandatory requirements.
Produced water	As defined in the *Petroleum (Environment) Regulations 2016*.
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.
Reduced emissions completion	A well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.
Remedial cementing	Remedial cementing is usually done to correct problems associated with **primary cementing**.
Routine operational visit	A routine check or visit by production operators to complete an operational check or complete planned or unplanned maintenance. These visits can include normal operational functions for example checking filters, drains etc. Petroleum production operators shall carry and monitor personal calibrated gas detectors during every routine operational visit to wells and processing site facilities.
Safety data sheet	Safety data sheets (Also known as SDS and previously known as a Material safety data sheet or MSDS) are documents that provide critical information about hazardous chemicals.
Schedule	Schedule of Onshore Petroleum Exploration and Production Requirements, Northern Territory of Australia as amended from time to time.

Term	Definition
Separation flowback stage	The period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.
Short term exposure level	A 15 minute **time weighted average** exposure which should not be exceeded at any time during a working day.
Significantly disturbed land	land which: a) is contaminated land; or b) has been disturbed and requires human intervention to rehabilitate it to the condition it was in immediately before the disturbance (e.g. land which is now more susceptible to erosion, reduced land use capability or reduced water quality downstream of the land).
Stratigraphic bore hole	Core or other slim holes primarily drilled for the purpose of recovering information about lithology, stratigraphy and geological structure.
Subsurface integrity test	Testing conducted to confirm a well's operating envelope is intact and to confirm wellhead, tubing and annular integrity by application of pressure.
Suitably qualified person	A person who has professional qualifications, training or skills or experience relevant to the nominated subject matters or tasks and can give authoritative assessment, advice and analysis about performance relevant to the subject matters using relevant protocols, standards, methods or literature or conduct tasks in accordance with requirements.
Sulfide stress cracking	A form of hydrogen embrittlement which is a cathodic cracking mechanism, affecting susceptible alloys of steels.
Surface	A natural ground surface or the top of the **BOP** flange when installed.
Surface casing	A drilled and cemented pipe used to provide blowout protection, to seal off water/hydrocarbon sands, and 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.
Time-weighted average	The average airborne concentration of a particular substance when calculated over a normal eight-hour working day, for a five-day working week.
Top of Cement **TOC**	Top of cement is the depth to the top of the cement return in a well **annulus**. Top of cement can be verified visually when cement returns to surface are anticipated. Alternatively, the final lift pressure (differential in hydrostatic pressure between the annular and the inside of the casing) can give an indication of the actual top of cement, which can be verified later with a cement bond log or equivalent.
Underbalanced	Wellbore condition in which the pore pressure exceeds the wellbore hydrostatic pressure.

Term	Definition
Underbalanced drilling	A drilling activity employing equipment and controls where the pressure exerted in the wellbore is intentionally maintained less than (**underbalanced**) the pore pressure in any part of the exposed formations. (e.g. drilling with Nitrogen, air, air-mist, foam drilling media)
Upstream	Petroleum industry processes associated with hydrocarbon exploration and production activities.
US NSPS 2016	US Federal Regulation Title 40 – Protection of Environment Chapter I - Environmental Protection Agency, Subchapter C – Air Programs, Part 60 – Standards of Performance for New Stationary Sources, Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015.
USEPA Method 21	USEPA method for determination of volatile organic compound leaks from process equipment. US Federal Regulations Title 40 – Protection of Environment Chapter I - Environmental Protection Agency, Subchapter C – Air Programs, Part 60 – Standards of Performance for New Stationary Sources, Appendix A-7 to Part 60—Test Methods 19 through 25E
Validation	The assurance that a product, service, or system meets the all stakeholders needs and expectations, including regulatory requirements.
Venting	The intentional safe release, without combustion, of natural gas into the earth's atmosphere
Verify	Test of a product, service, or system to prove that it meets all its specified requirements at a particular stage of its lifecycle.
Well	As defined in the *Petroleum Act 1984*
Well Barrier	A system of one or several **well barrier elements** that contain fluids within a well to prevent uncontrolled flow of fluids within or out of the well.
Well barrier element	A component part of a well designed to prevent fluids or gases from flowing unintentionally from a formation, into another formation, into an adjacent well barrier envelope or to escape at surface.
Well Barrier Integrity Validation (WBIV) report	As defined in the Schedule of Onshore Petroleum Exploration and Production Requirements, Northern Territory of Australia
Well construction	Well construction includes the following phases • Planning and design • Drilling • Evaluation • Stimulation (hydraulic fracturing) • Well testing • Completion • **Intervention** and **workover** • Suspension • Decommissioning

Term	Definition
Well control equipment	Includes the: • BOP stack; • BOP control system; • full open safety valves; • circulating hose (and circulating head); • drill-string safety valves (inside BOPs); • mud and cement pumps; • the choke lines; • kill lines and manifold; • mud gas separator; • all associated pipework, connections, fittings and valves; • drill through equipment; • pressure storage systems (e.g. accumulators).
Well Integrity	Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well.
Well operating envelope	Limited range of parameters in which operations will result in safe and acceptable equipment performance.
Well pad	A well pad is the area upon which the well is constructed. During **well construction**, the drill rig is located on the well pad.
Well site	Well site refers to the area used for **well construction** activities and potentially includes the **well pad**, storage of equipment and materials associated with well construction and accommodation for well construction personnel. That is, the entire land area that was cleared and used for the well construction activity.
Wellhead	The casing head and includes any casing hanger or spool, or tubing hanger, and any flow control equipment up to and including the wing valves. The surface termination of a wellbore that incorporates a means of hanging the production tubing and installing the **Christmas tree** and surface flow-control facilities.
Wet season	The months of October to April inclusive.
Workover	Well procedure to perform one or more remedial or maintenance operations on a producing well to maintain or attempt production increase. Examples of workover operations are downhole pump repairs, well deepening, plugging back, pulling and resetting liners, squeeze cementing and re-perforating.