Drilling and Production Guidelines

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Foreword

The Canada-Nova Scotia Offshore Petroleum Board and Canada-Newfoundland and Labrador Offshore Petroleum Board (the Boards) have issued these guidelines to assist in understanding the requirements of the *Drilling and Production Regulations* (*Regulations*).

The Boards may develop or adopt guidance, standards and recommended practices to support and complement the regulations that they enforce. In all cases, the intent of the Boards is to provide additional information and guidance to the operator so that they may better understand the expectations of the Boards with respect to responsiveness to and compliance with the regulatory requirements.

The authority to issue guidelines and interpretation notes with respect to regulations is specified by subsection 156(1) of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* (CNSOPRAIA) and subsection 151.1(1) of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* (C-NLAAIA) (hereinafter referred to as the *Act*).[1]

In many instances, these guidelines identify a means or method toward achieving regulatory compliance. These means or methods may be based on a number of criteria, including:

- the mandatory requirements of the *Regulations*,
- the experience of the Boards in how compliance may be achieved, or
- industry best practice

Guidelines are not statutory instruments and the description of a means or method in the guidelines is not mandatory, unless referencing a Regulatory or Board requirement. The onus is on the operator to comply with the *Regulations* and to be able to demonstrate to the appropriate Board the adequacy and effectiveness of the methods employed to achieve compliance.

In certain cases, the requirements of the *Regulations* are such that no guidance is necessary. In other instances, the guidelines identify a way towards achieving regulatory compliance. While operators may propose an alternative method that provides an equivalent or better means of compliance with the *Regulations*, the onus remains on the operator to demonstrate to the appropriate Board that their chosen approach meets regulatory requirements. In all cases, the means to achieve compliance with the *Regulations* are to be reflected and described in the Operator's management system and are subject to review and verification either as part of the Board's review of an application for authorization and/or as part of the Board's periodic auditing of systems, specifications, procedures or records during ongoing operations.

Guidance, standards and recommended practices are important to support and complement the goal- or performance-based regulations. The onus is on operators to demonstrate that their use of particular codes and standards are appropriate in relation to the proposed activity. The standards and practices need to be supported by specific assessments of the equipment, installations and operations, and their control measures and associated risks.

The standards, codes and recommended practices referenced in these guidelines are the most recent editions at the time of publication. **Any amendments or subsequent editions to any of these codes, standards or recommended practices will supersede the version specified herein, unless otherwise stipulated by the Boards.**

[1] References to the *Offshore Accord Acts* are to the Federal versions for ease of reference.

The Boards are interested in ensuring that these Guidelines reflect lessons learned through audits and assessments, advancements in technology and improvements to best practice. Amendments will be made to ensure that the Guidelines are continuously improved.

Structure of this Document

This document provides guidance for each section of the *Regulations*. The text of each Regulation appears in **bold** and the guidance immediately follows.

There are a number of terms that are defined in the *Regulations* or in the *Acts* that are critical to a full understanding of the goals and objectives of the *Regulations*. These terms have been italicized within the text of the Regulation and a hyperlink has been provided to the definition. The definitions (which are Section 1 of the *Regulations*) are provided in the Appendix at the end of the document. This Appendix contains definitions for the following:

- terms referenced in the *Regulations* and defined in the *Acts*; and
- terms that are listed in section 1 of the *Regulations*, under Definitions

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1 Interpretation

Section 1 of all the *Regulations* (the *Newfoundland Offshore Petroleum Drilling and Production Regulations* and the *Nova Scotia Offshore Petroleum Drilling and Production Regulations*) specifies the definitions that apply to the *Regulations*. These definitions are provided in Appendix 1, together with a number of definitions that are defined in the Offshore Accord versions of the *Acts* that are critical to understanding the regulatory requirements in order to achieve compliance with the goals and objectives of the *Regulations*.

For the reader's convenience, the defined terms appear in italics within the text of each of the *Regulations* and a hyperlink is provided.

The Guidelines commence at Section 2 of the *Regulations* (on the following page).

PART 1 — BOARD'S POWERS

2 Spacing

The *Board* is authorized to make orders respecting the allocation of areas, including the determination of the size of spacing units and the *well* production rates for the purpose of drilling for or producing petroleum and to exercise any powers and perform any duties that may be necessary for the management and control of petroleum production.

2.1 Spacing Order

CNSOPB and C-NLOPB do not have any explicit spacing requirements. Therefore, no guidance is necessary.

3 Names and Designations

The *Board* may give a name, classification or status to any *well* and may change that name, classification or status.

3.1 Well Classifications

Consistent with the *Acts*, the Boards use the following well classifications to designate wells:

- exploration;
- delineation; and
- development

3.2 Modification of a Well's Classification

The well classification is determined by the Board based on the original purpose of the well. However, on occasion it may be necessary for the Board to modify a well's classification. This could occur if, for example, a well originally intended as a delineation well was subsequently completed and used as a development well. If this were to occur, the Board could modify the well's classification and notify the operator of the change.

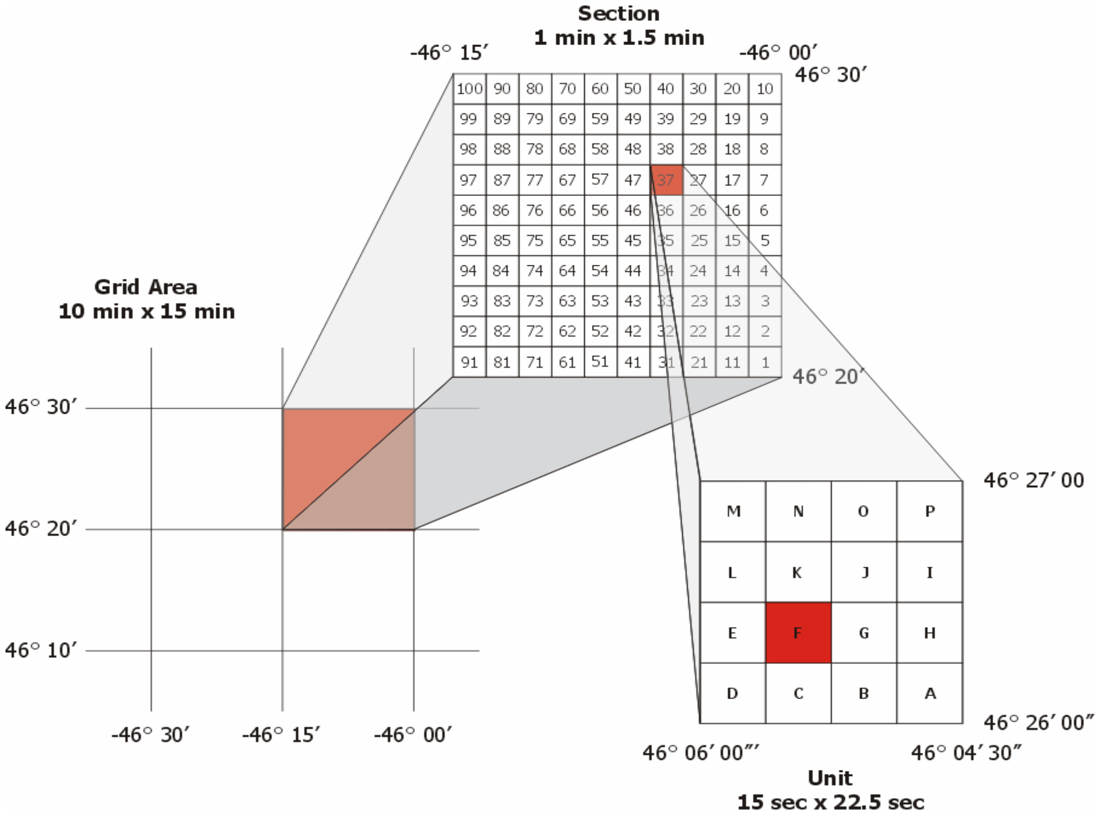
3.3 Modification of a Well's Status

The Board may also change the status of a well. For example, an exploration well could be drilled, suspended and then re-entered and tested several months later. If the test was unsuccessful and the well abandoned, the Board could modify the status of the well from "drilled and suspended" to "drilled and abandoned" and would notify the operator of the change.

3.4 Federal Land Division System for Naming a Well

The Federal land division system is used for naming wells. This system consists of grids, sections and units. A grid is an area that is 10 minutes (10') of latitude by 15 minutes (15') of longitude and is referenced by the latitude and longitude of its northeast corner. Each grid is subdivided into

100 sections numbered from 1 to 100. Each section is further subdivided into 16 units from A to P (see diagram below). For further details on the Federal land division system the operator is referred to the *Land Division Guideline* on the CNSOPB Web site.



Federal land division system for naming a well

3.4.1 Unit and Section Referencing

Wells are named referencing the unit and section at the surface location of the well (e.g. ‘Example Well F-37’, ‘F’ is the unit and ‘37’ is the section at the surface location of the well – see diagram above). If a well is sidetracked (e.g. operational reasons, access a new reservoir target etc.) then an additional letter is added to the name to differentiate the sidetrack from the “parent” well.

3.5 Well Naming Process

For wells drilled under the C-NLOPB’s jurisdiction, the official well name will be included in the Approval to Drill a Well (ADW) when it is issued.

In the case of CNSOPB, the operator should identify a name for the well using the well-naming convention in section 3.5.2 at the time that the application for ADW is submitted. The well name is reviewed by the CNSOPB and if appropriate, it becomes the official well name. If an operator incorrectly assigns the well name (e.g., a well that has been sidetracked is missing the extra letter in its name), it will be corrected by the CNSOPB and the operator will be notified of the revised well name. The official well name will be included in the ADW when it is issued. The well-naming conventions used by each jurisdiction are described below.

3.5.1 C-NLOPB Well Naming Convention

a) Exploration and Delineation Wells

Reverse alphabet notation is used to denote sidetracks. For example, if Galaxy Oil et al. were to drill the Pluto F-29Z sidetrack as an exploration or delineation well, the well name would be assigned as follows: Galaxy Oil et al. Pluto F-29Z, where

Galaxy Oil et al.	Operator and its partners
Pluto	Prospect or field name
F-29	Unit and section number of the surface location of the well
Z	1st sidetrack (2nd sidetrack: ‘Y’; 3rd sidetrack: ‘X’, etc.)

b) Development Wells

For development wells, the well designator is based on the sequence in which the ADW is received by the Board. The well designator is the number that follows the unit and section.

Reverse alphabet notation is used to denote sidetracks. For example, if Galaxy Oil et al. were to drill the Pluto F-29 4Z sidetrack as a development well, the well name would be assigned as follows: Galaxy Oil et al. Pluto F-29 4Z, where

Galaxy Oil et al.	Operator
Pluto	Field name
F-29	Unit and section number of the surface location of the well
4	Sequence number in which the ADW is received by the Board (i.e., 4th development well drilled from F-29 surface location)
Z	1st sidetrack (2nd sidetrack: ‘Y’; 3rd sidetrack: ‘X’, etc.)

3.5.2 CNSOPB Well Naming Convention

a) Exploration and Delineation Wells

Forward alphabet notation is used to denote sidetracks. For example, if Galaxy Oil et al. were to drill the Pluto F-29A sidetrack as an exploration or delineation well, the well name would be assigned as follows: Galaxy Oil et al. Pluto F-29A, where

Galaxy Oil et al.	Operator and its partners
Pluto	Prospect or field name
F-29	Unit and section number of the surface location of the well
A	1st sidetrack (2nd sidetrack: ‘B’; 3rd sidetrack: ‘C,’ etc.)

b) Development Wells

For development wells, the well designator is based on the sequence in which the ADW is received by the Board. The well designator is the number that follows the field name for wells drilled in CNSOPB jurisdiction.

Forward alphabet notation is used to denote sidetracks. For example, if Galaxy Oil et al. were to drill the Pluto 4F-29A sidetrack as a development well, the well name would be assigned as follows: Galaxy Oil et al. Pluto 4F-29A, where

Galaxy Oil et al.	Operator
Pluto	Field name
F-29	Unit and section number of the surface location of the well
4	Sequence number in which the ADW is received by the Board (i.e., 4th development well drilled from F-29 surface location)
A	1st sidetrack (2nd sidetrack: ‘B’; 3rd sidetrack: ‘C,’ etc.)

4 Designations of Zones, Pools and Fields

The *Board* may also
(a) designate a *zone* for the purposes of these Regulations;
(b) give a name to a *pool* or *field*; and
(c) define the boundaries of a *pool, zone* or *field* for the purpose of identifying it.

4.1 General

The Board may give a name for each pool or field and may define their boundaries. Typically, this should be done prior to submission of a development plan to establish a clear link between the development plan and defined pool(s) and field. Because the designation of pools affects the operator, the Board will consult with the operator on pool designations. The following may be a typical process for pool designations:

- The Board’s technical staff and operator would conduct independent assessments of pools within a field;
- The operator submits proposed pool designation and boundaries to the Board;
- The Board’s technical staff reviews the proposal and meets with the operator, if necessary, to reach agreement;
- When agreement is obtained, the Board will notify, by letter, the operator, of the pool name and boundaries; and,
- Adjustments will be made to pool designation as necessary based on new information acquired through drilling and production and consultation with the operator.

The Board may designate a zone within a pool or field and may define its boundaries. Pooling re-designation within a field may take place at any time during the life of a field where production monitoring suggests that pre-production pooling designations are incorrect and need to be changed. It will be used by the Board for resource management purposes. The Board may require that operators allocate pool production/injection on a zonal basis in accordance with the manner in which the well, pool and field is being managed.

4.2 Allocation

Where a pooling change or zonal designation has been made by the Board, the operator of a pool will be required to allocate on a go forward basis production to the Board. Previous production will be allocated on a total amount produced from a pool in agreement with the operator. Because the reallocation of production of pools to secondary pools/zones affects the operator, the Board will consult with the operator regarding pool/zone re-designations and how much each zone or pool has produced. Reallocation of production to secondary pools/zones allows for understanding for resource management purposes and prevention of waste during the entire life of the field.

4.3 Pool Designations

An operator is not compelled to submit a proposal for pool designations. However, if an operator elects to submit a proposal, it should:

- provide a brief description of the reservoir and proposed pools;
- present evidence why the operator believes the hydrocarbon accumulation is separate and, where appropriate, why the operator believes that various sections or parts of the accumulation are in communication;
- provide a depth structure map on the top and base of the pool;
- for each well drilled into the pool, provide the depth to the top and base of the pool; and,
- provide a structural cross-section through the reservoir interval, to include all wells showing the proposed pool.

Other information that should be provided, if available, in support of proposed pool designation includes:

- fluid contacts defined by:
  - log;
  - core;
  - pressure data (wireline, DST);
- reservoir pressure data from wireline pressure surveys and drill stem test;
- fluid analysis;
- geologic data to assess barriers to vertical and lateral flow including fault seal analysis, reservoir distribution, facies maps, logs, cores and drill cuttings;
- spinner surveys;
- seismic data; and
- production data acquired from cased hole logs and the annual pressure survey.

PART 2 — MANAGEMENT SYSTEM, APPLICATION FOR AUTHORIZATION AND WELL APPROVALS

5 Management System

(1) The applicant for an *authorization* shall develop an effective management system that integrates operations and technical systems with the management of financial and human resources to ensure compliance with the Act and these Regulations.

(2) The management system shall include

- **(a) the policies on which the system is based;**
- **(b) the processes for setting goals for the improvement of safety, environmental protection and *waste* prevention;**
- **(c) the processes for identifying hazards and for evaluating and managing the associated risks;**
- **(d) the processes for ensuring that personnel are trained and competent to perform their duties;**
- **(e) the processes for ensuring and maintaining the integrity of all facilities, structures, *installations, support craft* and equipment necessary to ensure safety, environmental protection and *waste* prevention;**
- **(f) the processes for the internal reporting and analysis of hazards, minor injuries, incidents and near-misses and for taking corrective actions to prevent their recurrence;**
- **(g) the documents describing all management system processes and the processes for making personnel aware of their roles and responsibilities with respect to them;**
- **(h) the processes for ensuring that all documents associated with the system are current, valid and have been approved by the appropriate level of authority;**
- **(i) the processes for conducting periodic reviews or audits of the system and for taking corrective actions if reviews or audits identify areas of non-conformance with the system and opportunities for improvement;**
- **(j) the arrangements for coordinating the management and operations of the proposed work or activity among the owner of the *installation*, the contractors, the *operator* and others, as applicable; and**
- **(k) the name and position of the person accountable for the establishment and maintenance of the system and of the person responsible for implementing it.**

(3) The management system documentation shall be controlled and set out in a logical and systematic fashion to allow for ease of understanding and efficient implementation.

(4) The management system shall correspond to the size, nature and complexity of the operations and activities, hazards and risks associated with the operations.

5.1 General

A key requirement of the *Regulations* is for operators to have (and implement) a management system to ensure compliance with the *Regulations* and the *Act*. The management system is intended to ensure companies have documented policies and procedures for how they will carry out their activities while achieving compliance with the safety, environmental protection and resource conservation requirements of these *Regulations*.

The use of management systems is consistent with other international jurisdictions and with other high-hazard industries. The management system is intended to ensure that operators proactively evaluate the project-specific hazards and risks and identify the most appropriate technology, design and operational requirements for the circumstances. The intent is that operators have processes in place to effectively identify and manage safety, environmental protection and resource conservation issues through the lifespan of each project from planning through decommissioning.

5.2 Standards for Management Systems

Management systems should follow the principles set out in *ISO 9000.2015 Quality Management Systems -Fundamentals & Vocabulary* and *ISO 9001.2015 Quality Management System Requirements*. Those aspects of the operator's management system that relate to safety and the protection of the environment should also meet the intent of *CSA Z1000-14 Occupational Health and Safety Management System* or *BS OHSAS 18001:2007 Occupational Health and Safety Management Systems Requirements* and *ISO 14001:2015 Environmental Management Systems - Requirements with Guidance for Use*. While registration of the management system is not required, the standard is a useful tool for the development of management systems.

5.3 Size, Nature and Complexity of Operations

The management system must correspond to the size, nature and complexity of the activities, hazards and risks associated with the operations. Arrangements to coordinate the management and operations of the proposed work or activity among owners of installations, contractors, the operator and others, as applicable, must also be in place.

5.4 Effectiveness of the Management System

The Board will assess the effectiveness of an operator's management system by the operator's ability to manage risk to personnel and the environment and prevent waste of the resource and through verifying compliance with the *Act* and the *Regulations*.

5.5 Maintenance of Management System

Pursuant to section 18 of the *Regulations*, operators must comply with the management system and maintain it to ensure that it remains effective during all activities.

5.6 Document Control

The requirement for the Operator to establish a process for document control is set out in subsection 5(3) of the *Regulations*. Document control processes, among other things, ensure that documents are accurate and current, and ensure the efficient and effective dissemination of changes and revised documents to the appropriate persons.

There should be processes and procedures that address:

- approving documents prior to issue;
- periodically reviewing, updating, or withdrawing documents as necessary;

- ensuring that changes to, and the current revision status of documents are identified;
- ensuring that relevant versions of applicable documents are available at points of use;
- ensuring that documents remain legible, identifiable, available for use and confidential as appropriate;
- ensuring that documents of external origin determined by the organization to be necessary for the planning and operation of the management system are identified; and
- preventing the unintended use of obsolete documents and identifying such documents if they are retained for any purpose
- ensuring the secure storage, protection, retrieval and retention of documents

Documents submitted to the Board pursuant to the *Regulations*, e.g. the Safety Plan, Emergency Response Plan, Environmental Protection Plan, etc. must be controlled copies with updates provided when the documents are revised. The Board may request a controlled copy of other documents on a case-by-case basis.

5.7 Management of Change (MOC) Process

Throughout the execution of a drilling program or production project, continuous improvement will be necessary based on lessons learned. Change can pertain to equipment, materials, procedures, practices, systems, and personnel, including risk assessment and approval processes. Consequently, the Operator must manage all change to ensure that it does not compromise safety or environmental protection. This is particularly relevant where environmental and safety critical systems may be impacted.

The management of change process should:

- define the roles of all levels of the organization in the management of change process that clearly identifies who can authorize any given change;
- include hazard identification and risk management, commensurate with the nature of the proposed change;
- ensure that those responsible for safety and environmentally critical policies and procedures review the proposed changes for acceptability; and
- provide for effective communication with those who are affected.

6 Application for Authorization

The application for authorization shall be accompanied by

(a) a description of the scope of the proposed activities;

(b) an execution plan and schedule for undertaking those activities;

(c) a safety plan that meets the requirements of section 8;

(d) an environmental protection plan that meets the requirements of section 9;

(e) information on any proposed flaring or venting of gas, including the rationale and the estimated rate, quantity and period of the flaring or venting;

(f) information on any proposed burning of oil, including the rationale and the estimated quantity of oil proposed to be burned;

(g) in the case of a drilling installation, a description of the drilling and well control equipment;

(h) in the case of a production installation, a description of the processing facilities and control system;

(i) in the case of a production project, a field data acquisition program that allows sufficient pool pressure measurements, fluid samples, cased hole logs and formation flow tests for a comprehensive assessment of the performance of development wells, pool depletion schemes and the field;

(j) contingency plans, including emergency response procedures, to mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection, which shall

- **(i) provide for coordination measures with any relevant municipal, provincial, territorial or federal emergency response plan, and**
- **(ii) in an area where oil is reasonably expected to be encountered, identify the scope and frequency of the field practice exercise of oil spill countermeasures; and**

(k) a description of the decommissioning and abandonment of the site, including methods for restoration of the site after its abandonment.

6.1 Pre-consultation/Timing of Application

Operators are encouraged to contact the Boards at an early stage in their planning process to gain a full understanding of the application and authorization process. In the case of a new operator or new installation, contact should be made 12-18 months prior to their planned program start to ensure the regulatory requirements and expectations are taken into account throughout the contracting, procurement and planning phases.

In the case of the renewal of an authorization, contact should be made with the Boards at least 6 months in advance of the expiry date.

6.2 Types of Authorization

6.2.1 Operations Authorization (Drilling Program and/or Production Project)

Operators have the option of combining drilling and production activities, including multiple installations into a single Operations Authorization (OA). These options can be discussed at the pre-consultation phase.

Where an application involves a production project, the operator must also ensure that:

- an appropriate Reservoir Management Plan (RMP) is in place. See section 16 and all of Part 8 of the *Regulations* and the associated guidance notes; and
- an approved flow calculation and allocation procedure is in place. See section 7 and associated guidance notes.

6.2.2 Operations Authorization (Construction)

An OA (Construction) is required for the installation of templates and facilities, construction of excavated drill centers or other activities. Construction activities that coincide with diving activities can be included under a Diving Program Authorization (DVPA). This can be discussed during the pre-consultation phase.

6.2.3 Operations Authorization (Installation/Removal)

An OA (Installation/Removal) is required for the installation or the decommissioning/removal of a production facility.

The following additional information should be provided in support of such applications:

a) a description of the vessels and/or barges that are used in the transport, installation and/or removal of installations;
b) a description of the equipment that will be used during installation complete with expected and design loads;
c) measures that will be taken to ensure safety and environmental protection;
d) measures that will be taken to minimize adverse effects on navigation, other maritime operations and the marine environment during installation and/or removal, including the time between installation and/or removal of the jacket and topsides;
e) transportation plan to the installation location or disposal site; and
f) the installation or removal schedule.

6.3 Filing Requirements

An application for an OA may be made by completing and forwarding an application form/letter to the Board. The form/letter must be signed by the operator's senior representative responsible for the program. The application along with supporting documentation should be forwarded to the Board in electronic and hard copies. The issuance of an OA is subject to a number of standard conditions as prescribed by the Board. These conditions are listed on the authorization form, however additional conditions unique to the proposed activity may be appended. A copy of the form is available on the Boards' website.

The lead time for submission of an OA application is not specified by the *Regulations*, however, the timing of submission will be determined/discussed during the pre-consultation phase. In any event, operators should ensure that an OA application along with supporting documentation is provided at least 4-6 months prior to the commencement of the work or activity.

The OA may be issued for a specified period of time, depending on the activity and proposed schedule.

The following is guidance with respect to the OA filing requirements as outlined in sections 6(a) – (k) of the *Regulations*.

6 (a) Scope

A description of the scope of the proposed activities must be provided.

E.g.: *The scope of activities include a (drilling program/production project and/or well operation) utilizing the (name of drilling and/or production installation) on the following licenses: (list the EL's, SDL's, and PL's for which the application is being made).*

Note: The geographic and temporal scope of the proposed program must be covered by the environmental assessment, the Benefits Plan and the financial responsibility documentation in order for it to be included in the authorization.

Operators may also include in their scope a description of certain other work or activity that is related to a drilling program, production project or well operations. In such cases, the application should describe the operator's generic policies and procedures pertaining to such matters in sufficient detail so as to enable the Boards to include the authorization or approval of such activities as part of the operations authorization. This description should focus on the means by which the operator will ensure compliance with regulatory requirements. Activities that may be included as part of the operations authorization include:

- VSP surveys
- Wellsite surveys & site preparation
- Approval to Pre-Drill Wells (to the conductor or surface casing depth)
- Certain well intervention activities (refer to sub-section 10(c) of the *Regulations* and the accompanying guidelines).

6 (b) Execution Plan and Schedule

In the case of a drilling program and/or a program involving well operations, the execution plan and schedule should cover the anticipated activities for the drilling installation for the duration of the authorization (typically three years). Since schedules change over time, the operator is expected to update the appropriate Board regarding material or significant changes. A statement to this effect should be included in the application.

In the case of a development/production project, the operator may reference the execution plan and schedule described in the approved development plan and also include a statement that updates to the Resource Management Plan will be provided as part of the Annual Production Report required by section 86 of the *Regulations.*

6 (c) Safety Plan

A copy of the operator's safety plan shall accompany the application along with installation specific safety plans, if they are not the same document. In the case of multiple installations, where there may be separate operator safety plans and/or installation specific safety plans, a copy of each safety plan shall be provided and listed in the application. The application should reference the title and date of the safety plan(s). See Section 8 of the *Regulations*.

6 (d) Environmental Protection Plan

A copy of the operator's environmental protection plan shall accompany the application. The application should reference the title and date of the environmental protection plan. See Section 9 of the *Regulations.*

6 (e) Flaring and Venting of Gas

In the case of a production project, information on any planned gas flaring or venting, including the rationale and the estimated rate, quantity and period of the flaring or venting shall either accompany the application or a statement should be included respecting the Board's current approval of gas flaring limits. In the case of the latter, the application should reference appropriate documents.

In the case of a drilling program, the application shall indicate that any gas flaring or venting will be in accordance with the Board's approval of any formation flow test. This requires a separate approval under Section 67 of the *Regulations*.

6 (f) Burning of Oil

In the case of a production project, information on any planned burning of oil, including the rationale and the estimated quantity of oil proposed to be burned shall accompany the application or it should be stated that no burning of oil is planned.

In the case of a drilling program, the application shall indicate that any planned burning of oil will be in accordance with the Board's approval of any formation flow test.

6 (g) Drilling & Well Control Equipment

In the case of a drilling installation, a description of the drilling and well control equipment (e.g. International Association of Drilling Contractors (IADC) Equipment List) shall accompany the application. This information should preferably be provided in an appendix to the application and include the technical specifications and ratings for all drilling and well control equipment onboard the installation. The operator's drilling policies and procedures along with well control procedures should also accompany the application. Otherwise, the operator should indicate: "Not Applicable".

6 (h) Processing Facilities and Control Systems

In the case of a production installation, a description of the process facilities and control system shall accompany the application, or in cases where this information has already been provided to the Board, the application should reference the title and date of the document that contains this information. Otherwise, the operator should indicate: "Not Applicable".

6 (i) Field Data Acquisition

In the case of a production project, a document describing the operator's field data acquisition program shall either accompany the application, or in the case where the program is already approved, the application shall reference the document(s) submitted in support of this approval, together with the date of the Board's approval(s). In either case, the program should be consistent with the Board's *Data Acquisition and Reporting Guidelines*.

In the case of a drilling program, the well data acquisition program may be included as part of the application for Approval to Drill a Well. This program should be developed with due consideration of the *Data Acquisition and Reporting Guidelines*.

6 (j) Contingency Plans

Contingency plans should generally consist of an emergency response plan and an oil spill response plan. Two copies of each should accompany the application. The application should reference the title and date of each plan.

In the case where an activity is conducted in an area where oil is reasonably expected to be encountered, the application shall describe the scope and frequency of the field practice exercise for oil spill countermeasures as specified by subparagraph 6j(ii).

A description of any mutual aid agreements, resource sharing arrangements or flight following procedures should also be described in the application unless this information is provided in other documents accompanying the application.

Contingency Plans

Contingency plans should include, but not limited to (as applicable) measures to:

- Prevent emergencies
    - Collision avoidance
    - Flight following and vessel tracking
    - Ice management (as per section 8(g) of the *Regulations*)
    - Precautionary Down-manning
    - Mooring Quick-Release for Floating Installations
    - Severe weather
    - Well control
- Mitigate emergencies
- Respond to emergencies
    - Major hazards
        - loss of hydrocarbon containment
        - serious injury to or the death of any person;
        - fire / explosion;
        - person overboard
        - loss of or damage to support craft;
        - loss or disablement of an installation;
        - loss of well control, including arrangements for drilling of a relief well;
        - criminal activity or threats of criminal activity;
        - medivac / casevac
        - evacuation, escape and abandonment, and/or
        - any other identified hazard
    - Relief well drilling and subsea control arrangements
    - Resource Sharing / Mutual Aid agreements
    - Pollution response and monitoring
    - Search and Rescue

Pursuant to subsection 6(j)(i), operators are required to coordinate their contingency plans with those of appropriate federal, provincial and municipal agencies.

For additional reference see Section 84.8 – Other Routine Notifications.

Plan(s) Content

Plans should include all information necessary to mount an effective response. They should be available and easy for responders to use and include the following:

- response organization chart(s)
- duties and responsibilities of personnel
- on-site and backup medical support
- communications equipment and facilities
- response, reporting and notification procedures
- contact information for responders and identified stakeholders
- drills and exercises
- any necessary support documentation

Plan(s) shall be controlled documents.

Contingency Plan Exercises

The effectiveness of contingency plans, including the interface between offshore and onshore, should be tested periodically through exercises. Operators should describe the frequency of these exercises, including a commitment to conduct an exercise at the onset of the work or activity and regularly thereafter.

Communications Equipment and Facilities

Reliable and effective communications equipment must be provided between shore-based facilities, offshore installations, survival craft, support craft and emergency services (e.g. SAR). Redundant communications systems should be available in the event of the failure of primary systems.

Medical Support

Operators should assess and provide such medical support, services, equipment and facilities as are necessary to ensure safety. Occupational physicians with offshore expertise should be engaged in this assessment. Physicians should be available for consultation with offshore medical staff and/or for travel offshore on a 24/7 basis.

Public Release of Plan(s)

Paragraph 119(5)(f) of the *Canada-Newfoundland Atlantic Accord Implementation Act* (C-NAAIA) and paragraph 122(5)(f) of the *Canada – Nova Scotia Offshore Petroleum Resources Accord Implementation Act* (CNSOPRAIA) permit the public release of contingency plans. The operator therefore should ensure that any personal information that is protected pursuant to the *Privacy Act* and that is necessary to be included within these plans is, to the greatest degree possible, arranged in such a manner to facilitate its ready identification and redaction.

Particulars of Select Contingency Plans

Relief well drilling and subsea control arrangements

The operator is expected to have a contingency plan for the identification and sourcing of an alternate drilling installation(s) that is capable of drilling a relief well. The plan should provide a description of the installation's required operating capability, ancillary equipment, availability, and the schedule for mobilization to the wellsite. The source of supply for a backup wellhead system and all consumables required to set conductor and surface casing for the relief well should also be identified.

The operator should also describe its plans to access subsea well intervention equipment to mitigate an uncontrolled flow of petroleum including the location and readiness of well-capping equipment, subsea dispersant hardware kits and containment systems including the effort that would be required to mobilize the equipment.

Resource Sharing / Mutual Aid agreements

When more than one operator is active in an area, operators are expected to have mechanisms to facilitate the effective exchange of information and, if necessary, to share resources such as vessels and helicopters in order to prevent or respond to emergencies.

Flight following and vessel tracking

Operators are expected to maintain an effective flight following and vessel tracking system to monitor support craft location and status and facilitate mutual aid.

Precautionary Down-Manning

Operators should establish appropriate criteria and procedures respecting precautionary down-manning in response to severe weather, upset conditions, or any other scenario that requires precautionary removal of personnel.

Pollution Response and Monitoring

The pollution response plan should document the procedures for responding to pollution, with particular emphasis on oil spills. The plan should describe spill response resources, including those on site, in the local region, nationally and internationally and arrangements to mobilize to site.

The plan should specifically include:

Spill Scenarios - Including both low-probability large-scale events (e.g. blowouts) and smaller-volume spills that may occur at greater frequency. These spill scenarios will have been described in the relevant environmental assessment document(s).

For drilling operations where oil may be encountered or production operations from oil bearing reservoirs, an oil spill trajectory analysis is required for the larger scale spill scenarios referenced above. Results should be reported for each month that drilling or production operations are planned, and should include a projection for spills originating at the site and followed until the slick volume is reduced to a negligible amount, until a shoreline is reached, or until the slick moves out of the model domain. This analysis, too, normally is described in the corresponding environmental assessment documents.

The types and quantity of response resources described in the plan should be linked, quantitatively to the degree possible, to the spill scenarios it references.

Command Structure - The command structure the operator will use for managing pollution response. Typically a tiered structure is used, corresponding to scales of spill response ranging from those using only at-site resources (Tier 1), through those requiring significant resources sourced nationally (Tier 2 and/or Tier 3), and internationally (Tier 3).

Response Resources - In respect of Tier 3 spill scenarios, the operator should ensure that the fitness for purpose of its designated response resources is evaluated in an arms-length and documented manner. A process such as that described in *Proposed Oil Spill Response Organization (OSRO) Assessment / Self-Assessment Tool*[2] is considered best practice for this purpose. If multiple operators designate the same Tier 3 response resources, they may cooperate in the assessment of those resources. The operator should inform the regulator of the planned scope of this review prior to its conduct.

An operator that proposes to use spill-treating agents (e.g., dispersants) in one or more of its spill scenarios should ensure that it has submitted to the relevant Board's Chief Conservation Officer (CCO) a satisfactory Net Environmental Benefit Analysis[3] in support of its response plan. The Plan should indicate the scenarios under which those agents are to be utilized, including an explicit description of the decision points that will precede their use. The latter decision points must include seeking the approval of the CCO. For additional information, see *Regulations Establishing a List of Spill-treating Agents.*

Personnel Qualifications. **-** Qualifications of key personnel responsible for the management of the pollution response.

Mutual Aid Support Agreements - Summarize and reference formal resource-sharing agreements among operators and/or response organizations, particularly key countermeasures equipment. Copies of these agreements must be provided on request.

Countermeasures Strategies – Strategies that will be used for containment and cleanup in reference to the spill scenarios, including strategies for on-water response at and around the site, shoreline contamination and operations in any ice covered areas.

Real-time Trajectory Modeling - Capability to implement an oil spill trajectory model, using real time wind and current data, to support its response operations.

[2] Appendix 2 to *Finding 9: The Global Distribution and Assessment of Major Oil Spill Response Resources* (IPIECA-IOGP, 2015) [Available at http://www.oilspillresponseproject.org/wp-content/uploads/2016/02/JIP-9-Response-resources.pdf]

[3] See, for instance, *Response strategy development using net environmental benefit analysis (NEBA): Good practice guidelines for incident management and emergency response personnel.* IOGP Report 527 (2015) [Available at http://www.oilspillresponseproject.org/wp-content/uploads/2016/02/GPG-Net-Environmental-Benefit-Analysis.pdf]

Exercises and Training – The schedule for exercising the plan, including at least one annual field exercise of oil spill countermeasures where oil is reasonably expected. A summary report of the oil spill countermeasure exercise(s) should be prepared and submitted to the Board.

Compensation Claims Management - Describe or reference the procedures to manage claims for loss or damages caused by accidental pollution.

Spill Environmental Effects Monitoring – Describe or reference the plan to monitor the environmental effects of any spill that is of sufficient size or potential persistence, or both, to constitute an elevated risk of adverse environmental effects. In particular, if the plan includes the use of spill-treating agents, a protocol for the monitoring of their effectiveness also should be included[4]

Environmental Reference Information - Environmental information necessary to establish pollution cleanup priorities should be referenced in, or appended to, the plan, including:

- biological sensitivity charts that identify the areas containing spill-sensitive flora and fauna;
- socio-economic sensitivity charts that indicate local human uses of the area potentially affected by oil spills;
- physical sensitivity charts that identify shoreline types, coastal currents, ice forms and movement, and the nature of the littoral zone; and
- charts depicting operational resources and considerations.

<u>Search and Rescue</u>

Operators are expected to establish performance standards for search and rescue and demonstrate that these standards are being met.

Search and rescue plans should be coordinated with the Department of National Defense.

In the NL offshore area, operators are expected to maintain a dedicated SAR helicopter on a 24-hour per day basis in support of helicopter operations. This helicopter should be capable of being airborne within 20 minutes. Equipment should include auto-hover, forward looking infrared radar (FLIR), a search light, a rescue-winch and survival equipment suitable for deployment from the helicopter. The functional specification of the helicopter should be submitted to the C-NLOPB. Helicopter SAR technicians should be trained in the operation of the winch and deployment of the survival equipment. SAR helicopter crews must receive adequate training, practice and drills to achieve and maintain proficiency.

6 (k) Decommissioning and Abandonment

In the case of a production project, the operator should indicate whether any decommissioning and abandonment of the installations or facilities is anticipated during the term of the authorization. If so, the operator should submit to the Board a Decommissioning and Abandonment Plan, providing a detailed description of how the marine installations, structures,

[4] See, for instance, *At-Sea Monitoring of Surface Dispersant Effectiveness* (IPIECA-IOGP 2014) [Available at http://www.oilspillresponseproject.org/wp-content/uploads/2016/02/JIP-4-Surface-dispersant-effectiveness.pdf]

pipelines and equipment associated with the work or activity will be removed from or abandoned at the site.

A Decommissioning and Abandonment Plan should consider, at a minimum, the following:

a) safety during decommissioning activities;
b) any potential impacts on the environment;
c) identification of alternative uses;
d) identification of users of the environment;
e) any other Federal or Provincial legislative or regulatory requirements;
f) compliance with any applicable international conventions or agreements; and
g) how an operator will finance/pay for the decommissioning and abandonment.

A Decommissioning and Abandonment Plan should be based on the approved Development Plan concept commitments but should also consider any new regulatory requirements, best practices, or international laws or agreements to which Canada is bound that have since come into force and are applicable to that work or activity. The applicant will be required to undertake an environmental review (such as an environmental assessment (EA)), if the original environmental review does not sufficiently cover the decommissioning and abandonment phase. The decommissioning and abandonment of an existing offshore floating or fixed platform, vessel or artificial island used for the production of oil or gas that is proposed to be disposed of or abandoned offshore or converted on site to another role is a designated activity listed in the *Regulations* Designating Physical Activities under the *Canadian Environmental Assessment Act*, 2012.

A Decommissioning and Abandonment Plan should provide detailed information and commitments respecting, at a minimum, the following:

a) resource conservation considerations and optimization of timing of abandonment and decommissioning to ensure waste prevention;
b) a list and description of the installation, facilities, materials (including hazardous substances) and equipment that will be removed or abandoned;
c) allowances for alternative uses;
d) impacts on nearby facilities;
e) a description of the decommissioning and abandonment options that have been considered by the operator, and the rationale for selecting the preferred approach, including a list and summary of any studies and surveys undertaken to collect baseline information or to support the assessment of available options and the selection of the preferred approach;
f) the installation and equipment decommissioning methods and procedures, including the types of vessels and equipment that will be used;
g) measures that will be taken to ensure safety and environmental protection (this should be captured by the Safety Plan, Environmental Protection Plan, and Contingency Plan also submitted in support of the OA);
h) measures and methods that will be taken to minimize adverse effects on navigation, other maritime operations and the marine environment during and post decommissioning;

i) installation and materials transportation and disposal plan and compliance with ECCC disposal at sea requirements;
j) if the operator is proposing to abandon any equipment or installation components on site, a description of the proposed as left condition, as well as a monitoring plan to monitor, assess and mitigate any adverse impacts on the environment (associated with disintegration, rusting etc.), navigation or other uses of the sea;
k) a verification program to confirm that there are no adverse impacts to marine navigation or other uses of the sea; and
l) an estimate of cost of the decommissioning and abandonment related work or activity.

Operators should note that further requirements pertaining to the decommissioning of production installations are specified in section 9 of the *Guidelines Respecting Financial Requirements.*

6.4 Other Requirements for an Authorization

In addition to the items cited in subsections 6(a)-(k) of the *Regulations*, prior to authorizing any program, the Operator has a duty to:

a) be the registered holder of the necessary licenses;
b) have an approved industrial benefits plan;
c) provide evidence of financial responsibility ;
d) provide an operators declaration pursuant to section 135.1 of the *Canada-Newfoundland Atlantic Accord Implementation Act* (C-NAAIA) and section 143.1 of the *Canada – Nova Scotia Offshore Petroleum Resources Accord Implementation Act* (CNSOPRAIA);
e) provide a Certificate of Fitness, if applicable; and
f) have an approved Environmental Impact Statement / Environmental Assessment

Documentation verifying that these requirements have been met should also be addressed in any application for authorization.

For production projects, no person shall develop a pool or field except in accordance with the approved development plan. For development plan requirements see the separate guidance document and section 16 of the *Regulations*.

6.4.1 Development Plan Amendments

In addition to any approval requirements the Board deems appropriate pursuant to the Acts, an operator shall apply for the approval of an amendment to the approved development plan in accordance with the Acts, where, for example:

a) the operator proposes to
    i) make significant changes in the nature or timing of development activities of the pool or field;
    ii) make substantial modifications or additions to existing production facilities at the pool or field; or
    iii) initiate, in the pool or field, a pilot scheme or reservoir depletion scheme that differs from the one set out in the approved development plan;

b) pool performance or new geological information shows that the recovery method needs to be changed to achieve maximum recovery of petroleum reserves from the pool or field; or
c) increased ultimate recovery of petroleum would be economically obtainable by adopting new technology or methodology.

6.4.2 Operating Licence

The statutory requirements pertaining to operating licenses are specified in the *Acts* and in the *Regulations* respecting oil and gas operations, if applicable.

An operating licence is a prerequisite for any oil and gas operations activity. Any individual or corporation may apply to the Board for an operating licence by completing and forwarding one duly executed copy of the application form to the Board. A sample of the operating licence and the instructions for applying for the licence is provided on the Boards' websites. An operating licence is valid from its commencement date to March 31st next year following its date of issuance.

6.4.3 Exploration/Significant Discovery/Production License

The exclusive right to drill or produce petroleum is conferred to interest holders by an exploration licence, a significant discovery licence or a production licence. The statutory requirements pertaining to these licenses are contained in the *Acts*. Information on these matters may be obtained from the Boards' department(s) responsible for rights, resources, legal and/or land.

6.4.4 Benefits Plan

A Benefits Plan must be submitted to and approved prior to the Board authorizing any work or activity under the *Acts*. Further information on this matter is provided in the *Benefits Plan Guidelines* of the respective Boards.

6.4.5 Financial Requirements

Information on financial responsibility is provided in the *Guidelines Respecting Financial Requirements* found on the Boards website.

6.4.6 Applicant's Declaration

The *Acts* require that prior to the issuance of an OA an operator must provide a duly executed Declaration. This document attests that an applicant for authorization has and will continue to ensure that equipment and installations used in the proposed program are fit for purpose, operating procedures are appropriate and qualified and competent personnel employed. The document is legally binding and operators must be able to demonstrate due diligence in its execution.

Prescribed forms for making this Declaration are available from the Boards.

6.4.7 Certificate of Fitness

Pursuant to the *Acts*, and *Regulations*, an operator is required to obtain and provide to the Board a certificate of fitness for any prescribed offshore installation. The certificate must be issued by one of the recognized Certifying Authorities (i.e., American Bureau of Shipping, Bureau Veritas, DNV GL or Lloyd's Register North America). It is a requirement of the *Act* and a condition of an OA that the certificate remain valid and in force throughout the program.

The Certifying Authority may issue the certificate upon determining that the installation is fit for purpose and meets the relevant provisions of the *Certificate of Fitness Regulations*. In addition for, drilling installations, it is expected that the *IMO Code for the Construction and Equipment of Mobile Offshore Drilling Units*, (2009 MODU CODE) and any amendments to that code, as are made from time to time, are utilized.

Canadian flagged drilling vessels must also meet the requirements of the *Canada Shipping Act*, administered by the Marine Safety Division of Transport Canada.

6.4.8 Environmental Impact Statement / Environmental Assessment

As part of its environmental protection responsibilities under Part III of the *Accord Act*, the Board must evaluate the potential environmental effects of proposed activities in the Offshore Area. This responsibility includes ensuring EAs are conducted for offshore projects for which an EA is not required pursuant to the *Canadian Environmental Assessment Act*, 2012 (*CEAA* 2012).

Development-related activities require an environmental assessment (EA) at the time of Development Plan Application. If the activities proposed under the OA remain within the scope of that EA, no further assessment will be required at the time of application. Similarly, if the operator previously has performed an environmental assessment of exploration or delineation drilling over multiple years, and the currently proposed activities are within the scope of that assessment, no further assessment will be required. The following describes EA requirements if neither of the above cases apply.

For *Accord Act* EAs, at least six months prior to the planned commencement of drilling activities, the operator should submit to the Board a project description that describes the activities to be undertaken, the schedule of those activities and the location. Based on the information provided in the project description, the Board's Environmental Staff will confirm the EA requirements and will provide the operator with a Scoping Document that describes the scope of the assessment to be conducted, including the scope of the factors to be included in the assessment.

Environmental Assessment of designated projects under the *CEAA 2012* will not be subject to the *Accord Act* EA process. The results of a *CEAA 2012* assessment will be incorporated into any relevant authorization(s).

For *CEAA 2012* EAs, the *Regulations Designating Physical Activities* require that a project description be submitted to the Canadian Environmental Assessment Agency (the Agency) in order to determine whether a federal EA is required for a designated project. If the Agency determines that an EA of a designated project is required, an EA by the Agency must be completed and a decision made by the Minister of the Environment and

Climate Change within 365 days. An EA by review panel must be completed within 24 months. These timelines do not include time required by the proponent to provide information.

7 Authorizations Covering a Production Installation

(1) If the application for *authorization* covers a *production installation*, the applicant shall also submit to the *Board* for its approval the *flow system*, the *flow calculation procedure* and the *flow allocation procedure* that will be used to conduct the measurements referred to in Part 7.

(2) The *Board* shall approve the *flow system*, the *flow calculation procedure* and the *flow allocation procedure* if the applicant demonstrates that the system and procedures facilitate reasonably accurate measurements and allocate, on a *pool* or *zone* basis, the production from and injection into individual *wells.*

Requirements are found in the *Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Offshore Areas Drilling and Production Regulations.*

8 Safety Plan

The *safety plan* shall set out the procedures, practices, resources, sequence of key safety-related activities and monitoring measures necessary to ensure the safety of the proposed work or activity and shall include

(a) a summary of and references to the management system that demonstrate how it will be applied to the proposed work or activity and how the duties set out in these Regulations with regard to safety will be fulfilled;

(b) a summary of the studies undertaken to identify hazards and to evaluate safety risks related to the proposed work or activity;

(c) a description of the hazards that were identified and the results of the risk evaluation;

(d) a summary of the measures to avoid, prevent, reduce and manage safety risks;

(e) a list of all structures, facilities, equipment and systems critical to safety and a summary of the system in place for their inspection, testing and maintenance;

(f) a description of the organizational structure for the proposed work or activity and the command structure on the *installation*, which clearly explains

- **(i) their relationship to each other, and**
- **(ii) the contact information and position of the person accountable for the safety plan and of the person responsible for implementing it;**

(g) if the possibility of pack sea ice or drifting icebergs exists at the drill or production site, the measures to address the protection of the *installation*, including systems for ice detection, surveillance, data collection, reporting, forecasting and, if appropriate, ice avoidance or deflection; and

(h) a description of the arrangements for monitoring compliance with the plan and for measuring performance in relation to its objectives.

Operators should refer to the *Safety Plan Guidelines*.

9 Environmental Protection Plan

The *environmental protection plan* shall set out the procedures, practices, resources and monitoring necessary to manage hazards to and protect the environment from the proposed work or activity and shall include

(a) a summary of and references to the management system that demonstrate how it will be applied to the proposed work or activity and how the duties set out in these Regulations with regard to environmental protection will be fulfilled;

(b) a summary of the studies undertaken to identify environmental hazards and to evaluate environmental risks relating to the proposed work or activity;

(c) a description of the hazards that were identified and the results of the risk evaluation;

(d) a summary of the measures to avoid, prevent, reduce and manage environmental risks;

(e) a list of all structures, facilities, equipment and systems critical to environmental protection and a summary of the system in place for their inspection, testing and maintenance;

(f) a description of the organizational structure for the proposed work or activity and the command structure on the installation, which clearly explains

- **(i) their relationship to each other, and**
- **(ii) the contact information and position of the person accountable for the environmental protection plan and the person responsible for implementing it;**

(g) the procedures for the selection, evaluation and use of chemical substances including process chemicals and drilling fluid ingredients;

(h) a description of equipment and procedures for the treatment, handling and disposal of waste material;

(i) a description of all discharge streams and limits for any discharge into the *natural environment* including any *waste material*;

(j) a description of the system for monitoring compliance with the discharge limits identified in paragraph (i), including the sampling and analytical program to determine if those discharges are within the specified limits; and

(k) a description of the arrangements for monitoring compliance with the plan and for measuring performance in relation to its objectives.

Operators should refer to the *Environmental Protection Plan Guidelines*.

10 Well Approval

(1) Subject to subsection (2), an operator who intends to drill, re-enter, *work over*, *complete* or recomplete a *well* or *suspend* or *abandon* a *well* or part of a *well* shall obtain a *well approval*.

(2) A *well approval* is not necessary to conduct a *wire line*, *slick line* or coiled tubing operation through a Christmas tree located above sea level if

- **(a) the work does not alter the *completion interval* or is not expected to adversely affect *recovery*; and**
- **(b) the equipment, operating procedures and qualified persons exist to conduct the *wire line*, *slick line* or coiled tubing operations as set out in the *authorization.***

10.1 Types of Well Approvals

For administrative purposes, the Boards have grouped well approvals under two categories:

- Approval to Drill a Well
- Approval to Alter the Condition of a Well

10.2 Approval to Drill a Well (ADW)

The ADW permits the operator to drill a particular well. The scope of the approval includes all activities associated with drilling the well and may also include well termination (suspension, abandonment or completion). For the CNSOPB, formation flow testing operations may also be approved as part of a well approval in cases where such activities are to be conducted in sequence. Otherwise, well termination and formation flow testing operations would be dealt with subsequent to the well approval process. This is explained further in the guidance for Section 11.

The process for applying for an ADW, including the information that is required to be submitted with the application for ADW is also described in the guidance for section 11 of the *Regulations*.

10.3 Approval to Alter the Condition of a Well (ACW)

The ACW permits the operator to re-enter a well to perform any well operation following completion of the scope of activities covered by the ADW. This could include a workover or the completion, re-completion, suspension, abandonment of a zone or well or any other well operation. In the case of a sidetrack involving a new well, an ADW is required.

An ACW is not required if the planned operation is covered by an existing authorization, or is exempted pursuant to subsection 10(2) of the *Regulations*. This is explained further in sections 10.4 and 10.5 below.

The process for applying for an ACW, including the information that is required to be submitted with the application is described in the guidance for section 12 of the *Regulations*.

10.4 Well Operations Requiring an ACW

An ACW is required to re-enter any well for the purpose of performing:

a) any well intervention on a subsea well unless such interventions were approved as part of the Operations Authorization;
b) any operation that requires the removal of the Christmas tree or the tubing unless such operations were approved as part of the Operations Authorization - an operation on a completed well that requires removal of the Christmas tree or the tubing is defined as a “workover” in the *Regulations*, for which a well approval is explicitly required;
c) any operation involving the suspension or abandonment of a zone or well;
d) any operation that alters the completion interval including:
    i) re-completing the well to another production or injection zone
    ii) squeezing perforations;
    iii) chemical treatment, including acid stimulation;
    iv) any other alteration to the completion interval that has the potential to adversely affect the recovery of petroleum/oil and gas.
e) any operation that requires hydraulic fracturing.

10.5 Well Operations Not Requiring an ACW

Subject to the provisions specified in paragraphs 10(2)(a) and 10(2)(b) of the *Regulations*, the following through-the-tree well intervention operations on platform wells utilizing wire line, slick line or coiled tubing do not require an ACW:

a) drift runs;
b) cased hole logging;
c) subsurface fluid sampling;
d) pressure, temperature or spinner surveys;
e) scale inhibition treatment or removal of scale or fill from a well;
f) servicing or lock-out of tubing-retrievable subsurface safety valves;
g) replacement of wireline-retrievable subsurface safety valves;
h) gas lift servicing and valve replacement;
i) installation of pressure and temperature gauge hangers (or gauges);
j) setting flow control devices such as blanking plugs;
k) re-perforation of existing intervals;
l) chemical treatment for remedial or preventative purposes, such as acid wash and scale inhibition;
m) gas lift operations;
n) introduction of chemical or radioactive tracers into injection wells;
o) replacement of wing, swab or kill valves on Christmas trees (if the tree is not removed); and
p) maintenance of Christmas trees (if the tree is not removed).

Operators should consult with the appropriate Board on a case-by-case basis if uncertainty exists as to whether or not an ACW is required.

Operators are reminded that the elements related to the authorization (management systems, safety plan, environmental protection plan, contingency and emergency response plan) apply to any well approval.

11 Well Approval - Drilling

If the *well approval* sought is to drill a *well*, the application shall contain

(a) a comprehensive description of the *drilling program*; and

(b) a well data acquisition program that allows for the collection of sufficient cutting and fluid samples, logs, conventional cores, sidewall cores, pressure measurements and *formation flow tests*, analyses and surveys to enable a comprehensive geological and reservoir evaluation to be made.

11.1 Application

An application for ADW may be made by completing and forwarding to the Board one duly executed copy of the application form a minimum of 21 days prior to spud. The ADW application forms are available on the Board's websites:

CNSOPB:	http://www.cnsopb.ns.ca
C-NLOPB	http://www.cnlopb.ca

The operator may also be requested to make an oral presentation to the Board summarizing the geological prognosis, the drilling, environmental and operational considerations in respect to the well. This presentation is normally timed to occur at the same time of an ADW submission.

The ADW application should be accompanied by the following information, which, in the case of the C-NLOPB, is prescribed in the ADW Template, a copy of which is available on the C-NLOPB's website.

11.1.1 General Information should include:

a) legal well name and classification (i.e., exploration, delineation or development), except in the case of C-NLOPB - this information is provided to the operator when the ADW is issued;
b) the operator's and participants' working interest;
c) purpose of the well;
d) the rotary table or kelly bushing elevation;
e) the elevation of the surface casing flange of the wellhead;
f) in the case of an offshore well, the water depth;
g) a tentative survey plan showing the location of the proposed well;
h) proposed depth of the well;
i) proposed spud date of the well; and
j) the estimated time required to drill the well.

11.1.2 Technical Information should include:

a) a copy of the wellsite survey report (see also section 11.1.3 of these *Guidelines*);
b) for a bottom-founded unit, a copy of the geotechnical investigation[5] report;
c) a summary of the seafloor and shallow subsurface conditions and a discussion of any shallow hazards to drilling or any other seafloor or shallow hazard such as the inability to hold anchors;
d) a geological prognosis, including the depth and thickness of formations and the depth of markers;
e) a summary of the lithology;
f) the depth and nature of formations where problems such as lost circulation, over-pressure, swelling shale or permafrost are anticipated;
g) pore pressure and fracture gradient profiles inclusive of estimated mud weight;
h) the rig move and positioning procedures in the case of a MODU;
i) the step-by-step sequence of operations;
j) the well evaluation plans (please refer to sections 49-55 and the *Data Acquisition and Reporting Guidelines*);
k) a description of the casing and cementing program as well as details of the casing design (please refer to sections 39 to 42);
l) the proposed casing pressure testing program (please refer to section 43);
m) details of formation leak-off or formation integrity test(s) plans (please refer to section 33);
n) the drilling fluid and solids control plans and procedures (please refer to section 28);

[5] If the geotechnical investigation is done in conjunction with the well site survey, a separate report is not required.

o) directional drilling and survey plans, with targets identified (please refer to section 32);
p) a description of the well control equipment unless such information was included as part of the Operations Authorization (please refer to sections 36 and 37);
q) information respecting pressure testing and function testing well control equipment (please refer to sections 36 and 37);
r) confirmation that the relief well and subsea control arrangements are consistent with the contingency plans provided in support of the authorization (see section 6 (j));
s) record of independent well verification – pursuant to Section 25.6.1;
t) a well barrier summary outlining the primary and secondary barrier envelopes during the proposed operations; and
u) such other information as the Board or any person designated by the Board may require.

11.1.3 Wellsite Surveys

The submission of an application for ADW should be accompanied (or preceded) by documentation demonstrating that the operator has investigated the nature of the seafloor and underlying sediments to identify any potential surface or subsurface hazards such as shallow gas. As these surveys are usually conducted using geophysical methods, an application for Geophysical Program Authorization should be made in accordance with the guidance outlined in the: *Geophysical and, Geological Programs in the Nova Scotia Offshore Area - Guidelines for Work Programs, Authorizations & Reports, January 2015*, in the case of CNSOPB regulated areas; or *Geophysical, Geological, Environmental and Geotechnical Program Guidelines, April 2017*, in the case of C-NLOPB regulated areas.

11.2 Formation Flow Tests

With reference to paragraph 11(b) of the *Regulations* respecting formation flow tests in the context of a well data acquisition program, operators should note that explicit approval of a formation flow test is required pursuant to section 52 of the *Regulations*.

In the case of the CNSOPB, this approval may either be part of a well approval or by way of a separate approval.

For the C-NLOPB, a detailed testing program is to be provided for approval separately from a well approval. Additional information pertaining to this matter is provided on the C-NLOPB’s website.

Requirements pertaining to formation flow testing equipment are specified in section 34 of the *Regulations*.

12 Well Approval - Other

The application shall contain

(a) if the *well approval* sought is to re-enter, *work over*, *complete* or recomplete a *well* or *suspend* or *abandon* a *well* or part of it, a detailed description of that well, the proposed work or activity and the rationale for conducting it;

(b) if the *well approval* sought is to *complete* a *well*, in addition to the information required under paragraph (a), information that demonstrates that section 46 will be complied with; and

(c) if the *well approval* sought is to *suspend* a *well* or part of it, in addition to the information required under paragraph (a), an indication of the period within which the *suspended well* or part of it will be *abandoned* or *completed.*

12.1 Application

An application for an ACW may be made by completing and forwarding to the Board one duly executed copy of the application form a minimum of 21 days prior to the anticipated commencement date of the operation. The ACW application forms are available on the Boards' websites:

CNSOPB:	http://www.cnsopb.ns.ca
C-NLOPB	http://www.cnlopb.ca

The ACW application should be accompanied by the following information, which, in the case of the C-NLOPB, is prescribed in the ACW Template, a copy of which is available on the C-NLOPB's website:

12.1.1 General Information

a) the name and type of well;
b) the proposed start date;
c) any conditions that may affect the safety of the well operation;
d) a technical description of the well operation including
    i) the objective of the work;
    ii) a schematic and description of the downhole equipment and tubulars;
    iii) a schematic of, and relevant engineering data on the Christmas tree and production control systems, (if applicable);
    iv) a well barrier summary outlining the primary and secondary barrier envelopes during the proposed operations;
    v) the shut-in wellhead and bottomhole pressures;
    vi) a description of the workover fluid; and
    vii) the step-by-step sequence of operations;
e) an assessment of the effect of the proposed work on the ultimate hydrocarbon recovery;
f) if the application is to suspend or abandon a zone or a well[6], a report setting out:
    i) the amount of oil, gas and condensate recovered from the well located in the pool;
    ii) an estimate of the amount of gas in place and oil in place remaining in the pool in which the well is located; and
    iii) documentation respecting:
        - whether production from the well can no longer be economically maintained;
        - alternative recovery methods that have been evaluated; and
        - alternative uses for the well that have been evaluated.

[6] Refer to Part 6, sections 57 through 59 for plugging and abandonment requirements.

g) record of independent well verification – pursuant to Section 25.6.1

12.2 Suspensions, Abandonments or Completions

Approval of the suspension, abandonment or completion of a zone or a well may be included as part of an ADW in cases where the well is proposed to be terminated immediately following the drilling of the well, or as part of the ACW in cases where the well is to be re-entered following execution of the scope of activities covered by the ADW.

In either case, information demonstrating compliance with section 46 of the *Regulations* (in the case of completions) or sections 56-59 of the *Regulations* (in the case of suspensions or abandonments) is to be provided to the Board. This information should be as per Section 11 above and 12 as applicable.

For the CNSOPB, details of the proposed well suspension or abandonment program must be forwarded at least 24 hours before termination operations are scheduled to commence. For completions, details are to be provided in either the ADW or the ACW.

For the C-NLOPB, a *Notification to Abandon/Suspend* or a *Notification to Complete* is expected to be provided no later than five working days prior to suspending, abandoning or completing any well. If logs are still being obtained or processed at the time of submission, they should be submitted as soon as they are available. Acknowledgement of the notification submission can only be provided after all log data has been received and reviewed. The notification forms are available on the C-NLOPB's website.

With reference to paragraph 12(c) of the *Regulations*, in the case where the well is to be suspended (other than the short term temporary suspension of operations due to weather, ice, equipment repairs, etc.) the operator should explain why the well is being suspended and should outline the plans respecting the future use for the well and the anticipated timing for re-entry. If additional work is required to abandon the well in the future, these plans should also be described.

13 Granting of Well Approval

The *Board* shall grant the *well approval* if the *operator* demonstrates that the work or activity will be conducted safely, without *waste* and without *pollution*, in compliance with these Regulations.

13.1 General

This regulation sets out the criteria to be met in order for the Board to grant the well approval referred to in subsection 10(1) of these *Regulations*. The onus is on the operator to "demonstrate that the work or activity will be conducted safely, without waste and without pollution".

In the context of this regulation, the operator can "demonstrate" this by submitting appropriate documentation addressing the issues of "safety", "waste" and "pollution" in the context of the activities proposed in the application for well approval and/or by drawing upon the experience of the operator in relation to having executed similar operations safely, without waste and without pollution.

13.2 Special Oversight Measures

The Board may undertake additional oversight measures throughout the various stages of the well implementation process inclusive of the planning, execution, and closeout stages. For the C-NLOPB, details pertaining to the expectations associated with Special Oversight Measures can be found on the C-NLOPB's website. For the CNSOPB the Board will provide details upon request.

14 Suspension and Revocation of a Well Approval

(1) The *Board* may suspend the *well approval* if
- **(a) the *operator* fails to comply with the approval and the work or activity cannot be conducted safely, without *waste* or without *pollution*;**
- **(b) the safety of the work or activity becomes uncertain because**
  - **(i) the level of performance of the *installation* or service equipment, any ancillary equipment or any *support craft* is demonstrably less than the level of performance indicated in the application, or**
  - **(ii) the *physical environmental conditions* encountered in the area of the activity for which the *well approval* was granted are more severe than the equipment's operating limits as specified by the manufacturer; or**
- **(c) the *operator* fails to comply with the approvals issued under subsection 7(2), 52(4) or 66(2).**

(2) The *Board* may revoke the *well approval* if the *operator* fails to remedy the situation causing the suspension within 120 days after the date of that suspension.

14.1 Operator's Failure to Comply

This regulation provides the Board with the authority to suspend a well approval[7] in instances where the operator has failed to comply with any conditions of a well approval or where the operator is not acting in compliance with either the flow system and flow allocation approval (subsection 7(2)); the formation flow test approval (subsection 52(4) or the approval for commingled production (subsection 66(2)).

14.2 Powers of the Board

In addition, this regulation empowers the Board to suspend a well approval if the installation's performance is not at the expected level indicated in the application, or if any auxiliary equipment or support craft is unable to perform as expected. In instances where it is clear that the environmental conditions are such that the operating limits of the equipment (as specified by the operator) are being exceeded, this could also be grounds for the Board to suspend the well approval.

[7] In the context of this regulation, a "well approval" may include an Approval to Drill a Well (ADW) or an Approval to Alter the Condition of a Well (ACW) as described in sections 11 and 12 of the *Regulations*.

14.3 Operator Procedure

In the event that a well approval is suspended, the operator is to suspend operations in an orderly fashion, secure the well in accordance with good oilfield practice and submit a plan to the Board to remedy the situation that gave rise to the suspension.

14.4 Revocation of a Well Approval

Subsection 14(2) of the *Regulations* specifies that, if the operator fails to remedy the situation within 120 days of the date of the suspension of the well approval, the Board may revoke the well approval. In such circumstances, the operator will be provided with the Board's future expectations that could include:

- taking the necessary measures to permanently plug and abandon the well and discontinue any future operations on the well; or
- taking such other remedial action as may be prescribed by the Board based on the circumstances associated with the matter.

15 Development Plans

For the purpose of subsection 139(1) of the Act[8], the *well approval* relating to a *production project* is prescribed.

15.1 Relationship Between Development Plan Approval and Well Approval

This regulation is intended to trigger the *Act* in that a well approval relating to a production project is "prescribed" (defined) by the *Act*. Therefore, a development plan relating to the field or pool must first be approved by the Board in order for the Board to grant the well approval. The *Acts*, however, allows an approval to be granted if the approval of the federal and provincial Ministers is obtained. This provision could be invoked in extenuating circumstances in which a well approval is delayed pending the approval of a development plan. Normally, the operator would be expected to outline the reasons for seeking a well approval prior to having an approved development plan in place. The Board would then assess the matter and forward it to the Ministers along with the Board's recommendation.

16 Resource Management Plan

For the purpose of paragraph 139(3)(b) of the Act[9], Part II of the *development plan* relating to a proposed development of a *pool* or *field* shall contain a resource management plan.

[8] Subsection 139(1) refers to the Federal version of *The Canada-Newfoundland Atlantic Accord Implementation Act*. For the Nova Scotia offshore area, see subsection 143(1) of the *Canada Nova Scotia Accord Implementation Act.*, and subsection 5.1(1) of the *Canada Oil and Gas Operations Act*.

[9] Paragraph 139(3)(b) refers to Federal version of The *Canada-Newfoundland Atlantic Accord Implementation Act* . For the Nova Scotia offshore area, see paragraph 143(3)(b) of the *Canada Nova Scotia Accord Implementation Act*., and paragraph 5.1(3)(b) of the *Canada Oil and Gas Operations Act*.

16.1 Relationship between Development Plan and Resource Management Plan

A key component of both the Development Plan and the Resource Management Plan is to provide for adequate resource management and prevention of waste in accordance with good oil field practice and economics principles.

The development plan establishes a basis for the resource management of a field or a pool. More specifically, the operator's commitments for resource management and prevention of waste are key components of both Part I and Part II of the development plan.

A key component of resource management in Part II of a development plan is the Resource Management Plan (RMP).

Throughout each stage of development, new data is obtained through various activities such as geophysical programs, drilling, well evaluation, reservoir simulations and production. Operators are expected to ensure that this data is analyzed and used to revise the understanding of a pool(s) or reservoir(s).

16.2 Elements of a Resource Management Plan

Based on the latest geological, geophysical, petrophysical and reservoir information available at the time of the development plan application for the authorization to produce hydrocarbons, the RMP should fully describe how the field or pool is intended to be produced over its life, and should provide a detailed evaluation plan to address the main uncertainties, including sensitivities and alternative scenarios.

The RMP is valid for the life of a pool or field and should be modified as new information is acquired. The mechanism for updating the RMP is described in section 86.4.

The RMP should contain the following information:

16.2.1 Geology and Geophysics

A brief description of the geological setting and features of the field(s), and of each pool or hydrocarbon-bearing reservoir, should be presented, including:

a) a brief overview of regional geology;
b) the structural and stratigraphic setting;
c) a depositional and post-depositional history of the reservoir units;
d) any structural and/or stratigraphic traps;
e) the source, generation and migration of hydrocarbons;
f) a representative set of interpreted seismic sections tied to wells, with a discussion of seismic data acquisition, processing and interpretations;
g) the most recently processed seismic cube (time and/or depth);
h) any interpreted faults and fault polygons (digital);
i) details of depth conversion; and
j) a description of any anomalous fluid pressures encountered or predicted from seismic information.

The above descriptions for each pool or hydrocarbon-bearing reservoir should be illustrated by structural cross-sections with stratigraphic and/or biostratigraphic correlations and, for each reservoir unit, paleogeographical and structure maps. The fluid contacts should be noted on the structure maps. Each reservoir sub-unit should be illustrated by:

a) isopach maps of gross and net pay;
b) isoporosity map; and
c) hydrocarbon pore volume maps.

A copy of the maps should be submitted to the Board in paper and digital form. Where a geostatistical approach has been used to construct the geologic model for the reservoir unit, the proponent should consult the Board on the information to be provided.

16.2.2 Petrophysics

A description of petrophysical data and analytical procedures , including:

a) a list of cored intervals;
b) the methods used to adjust core analysis data to reflect subsurface conditions;
c) assumptions and methods used in interpreting log data, including water resistivity values, porosity and permeability relationships, cut-off criteria used to estimate net pays, procedures to calibrate logs and to calculate porosity, permeability and water saturation;
d) any comparisons between data (i.e., porosity, permeability and water saturation) derived from logs and laboratory analyses;
e) the tabulation of reservoir parameters derived for each reservoir in each well, including gross and net pay, average porosity, permeability and water saturation; and,
f) mineralogical analyses of core samples noting any factors which could negatively impact production performance as well as mitigating measures proposed.

16.2.3 Reservoir Engineering

A description of the reservoir data for each pool including:

a) drill stem test results and analyses;
b) reservoir fluids with a discussion of any differences between wells or intervals, potential for carbon dioxide and hydrogen sulfide corrosion, and wax deposition and scaling concerns;
c) if the use of the injection of fluids is proposed, details of the composition of injected fluids, compatibility studies, injectivity and/or pulse tests;
d) reservoir pressures, temperatures and pressure/depth plots; and
e) results of special core analyses including a discussion of parameters (i.e., residual oil and gas saturations, capillary pressure data, relative permeability and critical gas saturations) used in reservoir studies.

16.2.4 Reserve Estimates

Estimates of reserves should be provided for each pool or hydrocarbon-bearing reservoir, and for each individual fault block and reservoir subdivision, setting out the following for each major fault block or sub-unit:

a) assumptions and parameters used (the economic cut-off criteria for estimating the reserves should be clearly stated);
b) volumetric estimates of oil and gas-in-place, distinguishing between solution gas, gas-cap gas and non-associated gas. The volumetric estimate should be presented for a downside, most likely, and upside case. For pools or hydrocarbon-bearing intervals containing a gas cap or non-associated gas, an estimate of the natural gas liquids, including condensate and liquids that may be produced during processing of the gas, along with an estimate of the gas-in-place remaining once these liquids are extracted, should be provided;
c) sensitivity analysis reflecting uncertainty in the data and assumptions;
d) expected recovery efficiencies with a discussion of the relative contributions of natural drive mechanisms and fluid injection plans, and sensitivities to various factors involved in exploitation of the pools; and
e) recoverable reserve estimates for each pool and/or reservoir sub-unit. This should include an estimate, where appropriate, of the condensate and the natural gas liquids expected to be recovered from gas processing.

An assessment of the impact of alternative production systems on reserves should be provided.

16.2.5 Reservoir Exploitation

A description of the proposed reservoir exploitation scheme(s), including:

a) a summary of proposed wells and contingent wells;
b) an overview of alternative schemes considered and the rationale for choosing the proposed scheme;
c) development well requirements for production, injection, observation and disposal including:
    i) any plans for use of existing wells;
    ii) a tentative schedule and locations for drilling production, injection, disposal or observation wells;
    iii) typical tubing programs, including well inflow and tubing flow performance evaluation;
    iv) a discussion of artificial lift requirements; and
    v) a description of future well workovers and an estimate of their frequency.

Information supporting the proposed resource exploitation scheme, including:

a) an overview of the results of studies to assess the impact of well and pool production rate on recovery;
b) where a gas pool or gas cap contains condensate, an assessment of retrograde behavior and the possible need for gas cycling should be addressed;
c) proposed activities for managing the development and production of the reservoirs, including:
    i) a clear statement of the principles and objectives that will be used when making field management decisions and conducting field operations, and in particular, how economic recovery of oil and gas will be maximized over the life of the field;
    ii) a discussion of the rationale for data acquisition programs and a well evaluation strategy for coring, logging, fluid sampling and analysis, testing

during drilling, and production. Where unmanned or subsea facilities may impose restrictions on data gathering, these should be noted;

iii) the potential for workover, re-completion, re-perforation and further drilling should be described;

iv) where options remain for improvement to the proposed development or for further phases of appraisal or development, the criteria and timetable for implementing these should be provided;

v) for gas developments, the criteria for the installation of additional compression should be noted; and

vi) a description of reservoir studies to be undertaken.

d) forecasts of the production and/or injection of oil, gas, associated gas liquids and water, on an annual basis, for each pool and each platform. Forecast of downside, most likely, and upside volumes should be provided;
e) results of any model studies carried out to evaluate possible exploitation strategies, including the assumptions used;
f) discussion of enhanced recovery scheme(s) that were considered and may be used to improve recovery;
g) for each pool, a prediction of the average reservoir pressure over the pool's producing life;
h) gas conservation measures, including quantities involved and methods of utilization. An estimate of the total volume of gas to be flared, used as fuel, used for gas lift, and injected, as well as an annual forecast, should be provided;
i) an overview of the field hydraulic studies, including an assessment of the impact of the flow line sizes and production facilities on recovery; and
j) discussion of the provisions for artificial lift in development wells.

Where wells may be used for cuttings and/or produced water re-injection or other pollution prevention measures, the impact of this in terms of any effects on reservoir management or reservoir performance must be assessed and described.

16.2.6 Deferred Development

Where hydrocarbons have been identified in a portion of the development area for which development is not proposed, including deeper and shallower zones, a discussion of the reasons for not proceeding with development should be included, setting forth the following information:

a) potential reserves;
b) factors which might lead to future development and the possible timing of such development; and
c) steps planned to obtain additional information concerning the hydrocarbon accumulation.

16.2.7 Development Drilling and Completions

The RMP should provide an overview of past drilling activities as well as the proposed drilling program and typical completion designs for the development wells. The proponent is not required to submit detailed equipment designs and operating procedures in this section. These will be examined through the Operations Authorization process and, in the case of individual well designs, through the Approval to Drill a Well process.

The following should be presented where appropriate:

a) a description of drilling hazards and mitigative measures;
b) typical casing programs, with design criteria, for production, injection and observation wells;
c) a description of well control and safety systems for drilling;
d) a description of typical completion methods and equipment. If smart well technology or down hole pressure gauges are not being used, justification should be provided;
e) a description of completion and annulus fluids, including a discussion of corrosion control and fluid compatibility; and
f) a description of typical wellhead equipment.

16.2.8 Production and Export Systems

The RMP should provide a description of the production and export systems, including:

a) Topsides Facilities

    A description of the topsides facilities, supported by schematics, is required. This should include a process flow diagram of the production facilities, indicating the fluid analyses, operating pressures, temperatures, throughput volumes and capacities, accompanied by material balance tables. The description should include the functional design basis, as appropriate, for

    i) the production facilities, including production and test separators and associated crude oil treatment system, gas processing, compression, gas lift, fuel gas and gas flaring systems, produced water system, water injection system, control system, and wellhead and production tree;
    ii) the drilling systems or workover systems included;
    iii) the facilities for the separation, collection, treatment and disposal of oily water, sewage, drilling mud and cuttings, and solid wastes;
    iv) the conceptual approach to fluid measurement, sampling and allocation;
    v) consideration on sour or sweet corrosion, scaling, hydrates and produced sand; and
    vi) single- versus multi-train gas injection consideration.

    A discussion of system bottlenecks and limitations that can give rise to production constraints and contingencies available to maintain production in the event of major equipment failure(s) should be provided. A clear statement of the facilities' maximum oil, gas and water processing capacity should be included. The plan should also include the scope and flexibility for future modification and expansion to address the potential for the proposed development, for any incremental development within the field or any satellite field development. This includes identifying any spare capacity designed into the facilities/pipelines to allow for future development or third-party tie-ins.

b) Subsea Production System

    A description, supported by schematics, of the configuration of any proposed subsea components of the production system is required. The description should include:

    i) satellite wells, clustered wells or template wells; and

ii) the scope and flexibility for future modification and expansion to address any potential for upside, incremental and satellite field development, identifying any spare capacity designed into the system.

c) Export System

A description, supported by schematic drawings, of storage, loading and transportation components of the export system is required. The description should include:

i) the capacity, efficiency factors and operational aspects for each component
ii) a description of any proposed pipelines to or from existing facilities, or for export to shore;
iii) the scope and flexibility for future modification and expansion to address any potential for upside, incremental and satellite field development, identifying any spare capacity designed into the system to allow for future development or third party tie-ins.

16.2.9 Organization Chart

An organization chart showing the reporting relationships of personnel involved in implementing the RMP should be included in the plan.

16.2.10 Operability of the Proposed Development

The expected overall operating efficiency and reliability of the proposed development should be discussed in terms of the effects of:

a) breakdowns in central power generation on process facilities and export systems;
b) equipment redundancy;
c) scheduled maintenance and inspection programs;
d) downtime resulting from environmental conditions such as sea ice, icebergs,
e) sea state and reduced visibility;
f) well workover requirements; and
g) any potential impact on maximizing petroleum recovery.

16.2.11 Development and Operating Cost Data

The RMP should document past expenditures and provide an estimate of development and operating costs in sufficient detail to permit comprehensive financial and economic analysis of the project in support of reservoir development and depletion throughout the life of the field. This information is necessary for monitoring and enforcement to ensure waste does not occur and to provide for maximum recovery of reserves. The cost data should be provided in constant dollars, accompanied by a description of the methodology, assumptions and basis for the cost estimates. A summary of the annual capital and operating costs for the major components of the proposed mode of development, and each alternative evaluated, should be provided. The cost information should include:

a) pre-project costs for seismic, exploration drilling, delineation drilling and studies;
b) drilling capital expenditure;
c) facilities capital expenditure for each major component;
d) decommissioning expenditure;
e) field operating cost, excluding tariffs; and
f) tariff operating cost.

The RMP should contain a provision for providing and updating this information as necessary throughout the life of the field.

PART 3 —OPERATOR'S DUTIES

17 Availability of Documents

(1) The *operator* shall keep a copy of the *authorization*, the *well approval* and all other approvals and plans required under these Regulations, the Act and the regulations made under the Act at each *installation* and shall make them available for examination at the request of any person at each *installation*.
(2) The *operator* shall ensure that a copy of all operating manuals and other procedures and documents necessary to execute the work or activity and to operate the *installation* safely without *pollution* are readily accessible at each *installation*.

17.1 General

The goal and objective of subsection 17(1) is to ensure that this documentation is readily available to personnel in a timely manner. This documentation may be made available in either paper or electronic format (or both). If they are made available only in electronic format (via the Internet or otherwise), provision should be made for printing a hard copy.

With reference to subsection 17(2), the goal is to ensure that appropriate personnel have access to any approved and up-to-date operating manuals, programs, policies, procedures, practices, plans, processes, work instructions or other documentation that is necessary for that person to execute the work or activity assigned to them safely and without pollution. Such documentation may be either in hard copy or electronic format or both, provided that it meets the objective of ensuring that the necessary documentation is readily accessible and is stored and maintained in a format that is available to them in a timely manner.

For additional guidance see API Standard 53 for the required documentation that should be posted on any installation while conducting well operations.

18 Management System

The *operator* shall ensure compliance with the management system referred to in section 5.

See Section 5 for guidance on this matter

19 Safety and Environmental Protection

The *operator* shall take all reasonable precautions to ensure safety and environmental protection, including ensuring that
(a) any operation necessary for the safety of persons at an *installation* or on a *support craft* has priority, at all times, over any work or activity at that *installation* or on that *support craft*;
(b) safe work methods are followed during all drilling, well or *production operations*;

(c) there is a shift handover system to effectively communicate any conditions, mechanical or procedural deficiencies or other problems that might have an impact on safety or environmental protection;
(d) differences in language or other barriers to effective communication do not jeopardize safety or environmental protection;
(e) all persons at an *installation*, or in transit to or from an *installation*, receive instruction in and are familiar with safety and evacuation procedures and with their roles and responsibilities in the contingency plans, including emergency response procedures;
(f) any drilling or *well operation* is conducted in a manner that maintains full control of the *well* at all times;
(g) if there is loss of control of a well at an *installation*, all other *wells* at that *installation* are shut in until the *well* that is out of control is secured;
(h) plans are in place to deal with potential hazards;
(i) all equipment required for safety and environmental protection is available and in an operable condition;
(j) the inventory of all equipment identified in the *safety plan* and the *environmental protection plan* is updated after the completion of any significant modification or repair to any major component of the equipment;
(k) the administrative and logistical support that is provided for drilling, *well* or *production operations* includes accommodation, transportation, first aid and storage, repair facilities and communication systems suitable for the area of operations;
(l) a sufficient number of trained and competent individuals are available to complete the authorized work or activities and to carry out any work or activity safely and without *pollution*; and
(m) any operational procedure that is a hazard to safety or the environment is corrected and all affected persons are informed of the alteration.

19.1 General

In order to meet the goal set out in section 19 Operators must reduce the risk associated with a work or activity to a level that is as low as is reasonably practicable (ALARP) and demonstrate this to the Board.

Operators should focus on the overall objective of the regulation and not only the listing set out in paragraphs (a) through (m), which are not all inclusive of the matters operators need to consider to achieve this goal. Operators should identify and assess all credible major hazards and ensure that systems are in place to identify and assess all occupational hazards. Within this framework, the operator should review each of the requirements specified within section 19 in the context of the safety and environmental hazards that exist for the particular program with a view to ensuring that all reasonable precautions are in place to minimize the risk.

The operator should demonstrate overall compliance with section 19 and the manner in which the operator will manage other issues identified through the hazard identification process.

20 Use of Safety and Environmental Protection Equipment/Safety Instructions

(1) No person shall tamper with, activate without cause, or misuse any safety or environmental protection equipment.

(2) A passenger on a helicopter, supply vessel or any other *support craft* engaged in a *drilling program* or *production project* shall comply with all applicable safety instructions.

Operators are expected to take all reasonable measures to ensure compliance with this regulation and to ensure that all personnel are aware that non-compliance is an offence.

21 Smoking Prohibition

(1) No person shall smoke on an *installation* except in those areas set aside by the *operator* for that use.
(2) The *operator* shall ensure compliance with subsection (1).

21.1 General

Operators are expected to take all reasonable measures to ensure compliance with this regulation and to ensure that all personnel are aware that non-compliance is an offence.

22 Storing and Handling of Consumables

The *operator* shall ensure that fuel, potable water, spill containment products, safety-related chemicals, drilling fluids, cement and other consumables are

(a) readily available and stored on an installation in quantities sufficient for any normal and reasonably foreseeable emergency condition; and
(b) stored and handled in a manner that minimizes their deterioration, ensures safety and prevents *pollution*.

22.1 Quantity and Availability of Stored Consumables

Paragraph 22(a) places responsibility on the operator to determine “sufficient quantities” of consumables in consideration of the anticipated levels of consumption that would be needed for both normal operations and for reasonably foreseeable emergency conditions. This determination should take account the ability to replenish the supplies of consumables in consideration of the remoteness of the area of operations, the re-supply capability and the maximum anticipated consumption levels. The onus is on the operator to determine and quantify the minimum levels of consumables that need to be maintained on-site or are otherwise readily available to meet this requirement and to document and validate this matter within the operator’s management system.

22.2 Manner in Which Consumables are Stored

With reference to paragraph 22(b), the goal is to ensure that all consumables are stored and handled such that they do not deteriorate to the extent that they are unusable. Paragraph 22(b) is also intended to ensure that all consumables are stored and handled safely as well as in a manner that does not result in pollution. In respect of safety and pollution prevention, operators should take accepted industry standards into account as well as Canadian WHMIS and Transportation of Dangerous Goods legislation and the International Maritime Dangerous Goods code.

22.2.1 Fuel

With reference to the term "fuel", this means the fuel necessary to run the installation as well as helicopter or vehicular transportation fuel and any other fuel necessary to meet normal and reasonably foreseeable emergency conditions.

22.2.2 Potable Water

Operators should adhere to the standards used in respect of the storage and handling of "potable water" with a view to ensuring the safety of personnel. Standards respecting "potable water" are set out in the *Guidelines for Canadian Drinking Water Quality* published by Health Canada.

23 Handling of Chemical Substances, Waste Material and Oil

The *operator* shall ensure that all chemical substances, including process fluids and diesel fuel, *waste material*, drilling fluid and drill cuttings generated at an installation, are handled in a way that does not create a hazard to safety or the environment.

In order to meet this goal, operators should formally assess and take all necessary action to mitigate the risk associated with all substances that may be present during offshore operations. In this regard, operators should refer to Part III.1 of *The Act* as it relates to hazardous substances, Part 10 of the *Offshore Marine Installations and Structures Occupational Health and Safety Transitional Regulations*, the Transportation of Dangerous Goods legislation and the International Maritime Dangerous Goods code, the *Environmental Protection Plan Guidelines*, the *Offshore Waste Treatment Guidelines* and the *Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands*.

24 Cessation of a Work or Activity

(1) The *operator* shall ensure that any work or activity ceases without delay if that work or activity
- **(a) endangers or is likely to endanger the safety of persons;**
- **(b) endangers or is likely to endanger the safety or integrity of the *well* or the *installation*; or**
- **(c) causes or is likely to cause *pollution*.**

(2) If the work or activity ceases, the *operator* shall ensure that it does not resume until it can do so safely and without *pollution*.

24.1 General

The operator's management system should address this requirement and the operator's safety plan and the environmental protection plan should describe how the operator intends to achieve compliance.

Personnel should be provided with any necessary information to clarify the conditions or situations under which work or activity must cease as well as any actions that will need to be taken such that the work or activity ceases in a safe manner. Any operating limits governing the ability to conduct any work or activity safely and without causing pollution should be in place, and, in cases where such limits require human intervention, the limits should be unambiguous.

24.2 Preventing a Recurrence and Risk Assessment

With reference to subsection 24(2), the operator must implement any remedial action necessary to prevent a recurrence of the situation that resulted in the cessation of work or activity pursuant to subsection 24(1) and must assess the risk to be equal to or less than the original risk prior to the resumption of the work or activity.

PART 4—EQUIPMENT AND OPERATIONS

25 Wells, Installations, Equipment, Facilities, and Support Craft

The *operator* shall ensure that

(a) all wells, *installations,* equipment and facilities are designed, constructed, tested, maintained and operated to prevent *incidents* and *waste* under the maximum load conditions that may be reasonably anticipated during any operations;

(b) a comprehensive inspection that includes a non-destructive examination of critical joints and structural members of an *installation* and any critical drilling or production equipment is made at an interval to ensure continued safe operation of the *installation* or equipment and in any case, at least once in every five-year period; and

(c) records of maintenance, tests and inspections are kept.

25.1 Installations, Equipment and Facilities

With respect to paragraph 25(a), operators must also ensure that installations, equipment and facilities are

- designed and constructed in accordance with the *Installation Regulations*; and
- prescribed installations have a Certificate of Fitness pursuant to the *Certificate of Fitness Regulations*.

25.2 Support Craft

Guidelines on the design, construction and maintenance of support craft is provided under section 69.

25.3 Environmental Conditions

Notwithstanding the issuance of the Certificate of Fitness and the issuance of certificates by flag states, operators are expected to understand the environment in which the operations take place and satisfy themselves that the designs of the installations and/or support craft are appropriate for that environment and operations.

25.4 Design Codes and Standards

Operators are expected to ensure that the design codes and standards for installations, equipment and facilities, whether owned or contracted, are appropriate.

25.5 Guidance for Specific Items of Equipment

In addition to the requirements pertaining to the design and construction of petroleum installations generally as specified in the *Offshore Petroleum Installations Regulations* and the *Offshore Petroleum Certificate of Fitness Regulations*, operators should refer to the guidance under the *Regulations* that sets out requirements for specific items of equipment.

The following specifications and recommended practices should be considered in the design and construction of drilling facilities:

- *American Petroleum Institute Specification for Drilling and Well Servicing Structures* , API Spec 4F, Fourth Edition, January, 2013;

- *American Petroleum Institute Specification for Wire Rope*, API Spec 9A, Twenty-sixth Edition, May, 2011(up to and including October 2012 errata).

- *American Petroleum Institute Recommended Practice on Application, Care and Use of Wire Rope for Oilfield Service*, API RP 9B, Fourteenth Edition, October 2015.

- *American Petroleum Institute Specification for Drilling and Production Hoisting Equipment*, API Spec 8A, Thirteenth Edition, December 1997 (up to and including May 2001 addendum).

- *American Petroleum Institute Recommended Practice for Inspection, Maintenance, Repair, and Remanufacture of Hoisting Equipment*, API RP 8B, Eighth Edition, May 2014.

- *American Petroleum Institute Specification for Drilling and Production Hoisting Equipment (PSL 1 and PSL 2),* API Spec 8C, Fifth Edition, March, 2012 (up to and including May 2014 errata).

- In addition to API Spec 4F, the derrick and substructure should be designed;

  - to take into account increased dead-load and wind induced load due to the accumulation of ice and snow;
  - to take into account loading due to fastener pre-stress;
  - where it is anticipated that operational conditions warrant, with a setback load greater than indicated in API Spec 4F;
  - where the operator anticipates operations will be conducted at wind speeds higher than indicated in API Spec 4F, to withstand at least the maximum wind speed at which operations will be conducted; and
  - such that the static and, in the case of floating drilling installations, dynamic loadings which form the basis for the design equal or exceed the loads which may be imposed on the derrick during the drilling program.

- If the derrick is manned, it shall be equipped with an escape device to permit personnel at the monkey board level to escape to a point outside the derrick structure.

- The drawworks should be provided with a safety device to prevent the travelling block from striking the crown of the derrick and the rig floor/rotary table.

- The drawworks should be fitted with an auxiliary brake to assist the primary braking system.

- The auxiliary brake should be equipped to monitor level, flow and temperature of the cooling or operating fluid in a manner which assures serviceability of the auxiliary brake.

- The drawworks should be equipped with an automatic fail-safe system capable of stopping a full load if a fault is detected in the primary or auxiliary brake system.

- Alarms should be provided at the driller's station to indicate when;

  - the limiting parameters for the auxiliary braking system have been reached, and the automatic fail-safe system referred to above has been activated.

In addition, operators should follow CAPP's *Standard Practice for Atlantic Canada Offshore Petroleum Industry Safe Lifting Practices, May 2013*.

25.6 Operator's Responsibility to Reduce Risk

It is the operator's responsibility to reduce risk to as low as is reasonably practicable (ALARP) in the context of the following:

- the operator's declaration to ensure facilities and equipment remain "fit for purpose";
- paragraph 5(e) of the *Regulations* that requires that operators' management systems include "the processes for ensuring and maintaining the integrity of all facilities, structures, installations, support craft and equipment necessary to ensure safety, environmental protection and waste prevention";
- paragraph 13 of the *Regulations* that require the "operator to demonstrate that the work or activity will be conducted safely, without waste and without pollution"
- section 19 of the *Regulations* that requires that "The operator shall take all reasonable precautions to ensure safety and environmental protection";
- paragraph 25(b) of the *Regulations* related to inspection and non-destructive examination;
- section 26 of the *Regulations* related to an installation's components and sour service environments;
- section 27 of the *Regulations* that requires that "The operator shall ensure that any defect in the installation, equipment, facilities and support craft that may be a hazard to safety or the environment is rectified without delay."

Accordingly, operators are expected to have in place: (i) a well verification scheme (refer to 25.6.1 below) and (ii) an integrated approach to "asset integrity" as discussed in 25.6.2.

25.6.1 Well Verification Scheme

The operator should establish a well verification scheme to assure that exploration wells are designed, constructed and maintained adequately and all of the components are suitable for their purpose.

The scheme should consist of a written process to validate well integrity objectives through the verification of the well design and construction, work in progress, and the making of reports and recommendations for any part of the well, as deemed suitable. This review should include verification of barriers, equipment, procedures and any other matters that could affect the integrity of the well such that:

- risks to the health and safety of persons from it or anything in it are as low as is reasonably practicable; and
- so far as is reasonably practicable, there can be no unplanned escape of fluids from the well.

The operator is responsible to ensure it is diligent in its internal well verification process prior to submission of any approval to the Board and during well operations. This may be achieved by someone employed by the operator's organization, however; it is important that those carrying out such verification work have appropriate levels of impartiality and knowledge and therefore should not be directly part of the business unit responsible for the delivery of the well. The operator is also responsible for ensuring that suitable action is taken on any recommendations that are made.

The operator should be able to produce confirmation that the well verification has been independently reviewed and consideration/actions are available in response to any recommendations. Sufficient records with details of the verification should be kept to form an auditable trail showing what work has been done, its findings, any recommendations made and any work carried out as a result.

Note: Although this verification scheme is directed to exploration wells it should be considered best practice and may be used on delineation or development wells as a means to ensure appropriate and adequate well barriers are in place at all times.

25.6.2 Asset Integrity

Operators are expected to implement an effective asset integrity program[10] to manage the risk of failure of any structure, plant, equipment or system that could result in an incident.

The operator's asset integrity management program[11] is expected to include the explicit identification of safety critical elements.

25.7 Safety Critical Elements

Safety critical elements (SCE) are components and systems of an installation that prevent incidents or mitigate the effect of an incident including a pollution event. SCE include items such as critical joints and structural members, wellheads, casing and tubing, BOPs and production/injection trees. The SCE associated with each hazard should be referenced to focus attention on the purpose and importance of the SCE. For new facilities, identification of the SCE should occur at the conceptual stage so that the appropriate SCE is selected throughout the design process. For existing installations, a review to establish and validate SCE is expected, with a view to ensuring that any SCE that do not meet performance standards are addressed.

Operators should:

- develop performance standards for each SCE as criteria to be used to assure that the SCE functions as an effective barrier against incidents and to ensure that the equipment operates within an acceptable range;
- periodically review the performance standards to ensure they remain valid; and
- ensure that the interrelationship of SCE is taken into account in relation to the identified hazards.

[10] Asset integrity is the ability of an asset to perform its required function effectively and efficiently while safeguarding life and the environment.
[11] Asset integrity management is the means of ensuring that the people, systems, processes and resources, which deliver integrity, are in place, in use and fit for purpose, over the lifecycle of the asset.

25.7.1 Inspections and Non-destructive Examinations

The prescriptive requirement for comprehensive inspections and non-destructive examination of critical joints, structural members and equipment at least once every five years as specified by paragraph 25(b) of the *Regulations* should be incorporated into the maintenance system for installations, equipment and facilities. Where a code, standard, or OEM document specifies an inspection frequency of less than five years, operators are expected to follow that requirement. Maintenance systems should also describe the approach for the identification and management of all failure mechanisms, e.g., corrosion. This is discussed in greater detail in section 25.10 below.

25.8 Maintenance Management System

Operators' maintenance management systems are expected to include:

- a method of identifying the maintenance routines for SCE;
- a means of ensuring that the impairment of any SCE is identified;
- a process for capturing any deferred maintenance;
- provision for a register of overdue maintenance tasks and a process of analysis and control;
- a process for remedying maintenance backlog items;
- a mechanism to inform management about maintenance backlogs in general and specifically about SCE;
- a means of ensuring that leadership is receiving valid and useful information and is basing decisions upon appropriate information;
- key performance indicators that can be used to evaluate the safety of the installation; and
- provision for verification by certifying authorities.

Operators are expected to identify any SCE that has degraded to the point where it does not meet its performance standard. In instances where SCE is found to be degraded, operators are expected to ensure that it is restored to its established performance standard and to notify the Board.

With particular reference to the need to ensure the accuracy of all pressure gauges associated with circulating, well control and cementing equipment:

- All gauges should be calibrated at least annually, with calibration records maintained on board the installation for at least one year.
- Pressure gauges found to have an accuracy deviation in excess of + 2% of full scale should be repaired or replaced.
- Gauges with an accuracy of ±10 psi (68.9 KPa) should be available for measurement of shut-in drill pipe pressure and shut-in casing pressure.

25.9 Operator's Responsibility

The onus is on the operator to ensure asset integrity. A management of change system to track modifications throughout the life of the installation should be in place. In order to maintain a high standard of operational safety, operators are expected to ensure that personnel, including contractors and vendor service personnel, are competent. A documented competence system is expected (see additional guidance on competency assurance under section 72 of these *Regulations*).

25.10 Certifying Authority's Responsibility

Third-party verification of asset integrity and third-party validation of asset integrity management are within the purview of the Certifying Authority pursuant to the *Certificate of Fitness Regulations*. Operators and installation owners are expected to cooperate with certifying authorities to ensure that a suitable verification scheme is in place.

26 Installation Components and Sour Service Environments

The *operator* shall ensure that

(a) the components of an *installation* and well tubulars, Christmas trees and wellheads are operated in accordance with good engineering practices; and

(b) any part of an *installation* that may be exposed to a sour environment is designed, constructed and maintained to operate safely in that environment.

In order to meet this requirement, operators should develop and adhere to sound operational procedures that are consistent with best practice. Operators should consider "sour" environments when designing, acquiring and operating equipment. Operators must consider the probability of "sour" gas in all exploration drilling. When considering production activities operators must consider the potential for the "souring" of "sweet" fields and of specific items of equipment being exposed to a "sour" environment due to production processes. Operators must consider the functioning of the equipment and barriers with regard to the safety of workers in addition to any effect exposure to a sour environment may have on the integrity of the equipment. Operators should summarize in their Safety Plan how the hazard of hydrogen sulphide and the associated risk mitigation has been addressed.

Where sour environments are anticipated, operators should follow *NACE Standard MR0175/ISO1516 – 2015*.

27 Rectification of Defects

(1) The *operator* shall ensure that any defect in the *installation*, equipment, facilities and *support craft* that may be a hazard to safety or the environment is rectified without delay.

(2) If it is not possible to rectify the defect without delay, the operator shall ensure that it is rectified as soon as circumstances permit and that mitigation measures are put in place to minimize the hazards while the defect is being rectified.

27.1 General

Operators should refer to the G*uidelines* pertaining to section 25 of the *Regulations*. Particular attention is needed in respect of safety critical elements as described in these G*uidelines*.

28 Drilling Fluid System

The *operator* shall ensure that

(a) the drilling fluid system and associated monitoring equipment is designed, installed, operated and maintained to provide an effective *barrier* against formation pressure, to allow for proper *well* evaluation, to ensure safe drilling operations and to prevent *pollution*; and

(b) the indicators and alarms associated with the monitoring equipment are strategically located on the drilling rig to alert onsite personnel.

28.1 General

The primary goal of this regulation is for the operator to ensure that the drilling fluid system is designed, installed, operated and maintained to enable drilling operations to be executed safely and the well to be properly evaluated without pollution. Paragraph 28(a) also places particular emphasis on maintaining the drilling fluid as an effective well control barrier[12].

28.1.1 Preventing the Loss of Mud

With reference to pollution, preventing the loss of whole mud to the sea is of particular concern in the case of oil-based mud or synthetic oil-based mud, but is also applicable to preventing the loss of water-based mud. A system should be in place to ensure all valves within the mud system that may discharge to the sea are managed under a lock-out and permit to work system. When using oil- (or synthetic oil-) based drilling fluids, a material balance should be maintained to track volumes of both base oil and mud discharged, retained, lost down hole or left in the hole.

28.1.2 Indicators and Alarms

This regulation also specifies the need to ensure that indicators and alarms associated with monitoring the drilling fluid are in place and functioning effectively from both a well control perspective and from a pollution prevention perspective.

28.2 Overbalance

Unless the well approval issued by the Board provides for drilling with losses or drilling underbalanced, operators are expected to ensure that the well is filled with a column of drilling fluid of sufficient density to overbalance formation pressure at all times, taking into account swab pressures and trip margins. Operators are expected to ensure that drilling ceases and remedial measures are undertaken if the drilling fluid fails to provide an effective barrier against flow.

28.3 Well Barrier

Drilling fluid qualifies as a well barrier when its level and density can be monitored and maintained such that it overbalances the formation pressure. Otherwise, an alternative barrier must be in place such that a primary and a secondary barrier are available to prevent uncontrolled

[12] In the case of underbalanced drilling operations, the need to maintain the drilling fluid as a barrier is not applicable (see subsection 36(4) of the *Regulation*s).

flow. Two barrier envelopes are required during all well operations after setting surface casing (see sub-sections 36(2) and 36(3) of the *Regulations* and the associated *Guidelines*).

28.4 Riser Margin

For operations from floating drilling installations, the density of the drilling fluid should include a riser margin such that the drilling fluid provides an overbalance with the marine riser disconnected. In deepwater operations where this is impractical, other risk-reducing measures should be in place such as spotting a weighted pill and/or installing a bridge plug with a storm valve below the wellhead prior to disconnecting. Another risk-reducing measure is the use of two blind/shear rams in the BOP stack as an extra seal in the event of a drift-off/drive-off or other unplanned disconnect. (See Section 29.7 Emergency Disconnect for further guidance)

28.5 Lost Circulation

Requirements and expectations related to lost circulation are specified in section 35 of the *Regulations* and the associated G*uidelines*.

28.6 Tripping Operations

Operators are expected to ensure that particular scrutiny is paid to the drilling fluid system while tripping and that equipment and procedures are in place to ensure that any losses or gains are promptly detected and that the appropriate measures are taken to ensure that the drilling fluid is maintained as an effective barrier against flow. Operators should model swab/surge pressure as well as follow tripping schedules with respect to speeds to adequately maintain an overbalanced environment preventing kicks or loss circulation during tripping operations. In the case of losses, operators are expected to take such steps as required to ensure that the loss of drilling fluid is not causing pollution.

28.7 Riserless Drilling

In the case of subsea wells where the conductor and/or surface hole is drilled riserless, the fluid returns at the seabed should be monitored with an ROV or subsea camera for the purpose of identifying any well flow. In these situations, a volume of weighted drilling fluid is to be maintained onboard the drilling installation as a contingency to kill the well. The conductor/surface hole should be displaced to heavy fluid prior to pulling out of hole. These and other measures necessary to mitigate the risk of shallow gas should be part of the operator’s management system.

28.8 Weight-up Drills

Operators are encouraged to perform periodic weight-up drills whereby the density of a small quantity of drilling fluid (4.0 – 8.0 m^3) is increased by 120 – 240 kg/m^3 as a test of the equipment and procedures in relation to the “wait and weight” method of well control. Periodic weight-up drills also serve as a means of verifying the crew’s proficiency is responding to a well kill situation.

28.9 Testing and Completion Operations

During well testing operations and during completion and well initiation operations, a sufficient volume of fluid of adequate density should be available to kill the well.

28.10 Drilling Fluid System

The drilling fluid system should have

- sufficient mud tank capacity to permit the storage of active and reserve drilling fluid to meet all foreseeable requirements, including, in the case of floating drilling installations, adequate reserve mud tank capacity to contain the volume of the marine riser in the event of a planned disconnect;
- sufficient bulk tanks and storage facilities to store the quantities of drilling fluid additives needed to meet all foreseeable requirements;
- equipment and facilities to permit the safe and efficient transfer, handling and mixing of all bulk materials and drilling fluid additives;
- adequate facilities and equipment to enable the drilling fluid properties to be adjusted in a controlled manner;
- equipment with sufficient capacity to permit the safe and effective transfer and mixing of weighting material to enable the density of the drilling fluid to be increased as required while circulating the well and sufficient redundancy in the bulk transfer and mud mixing facilities to permit, with the plugging of any line or the malfunction of any compressor or any mixing device, the continued ability to mix weighted mud on demand;
- adequate pumping capacity to circulate the well in a safe and effective manner at the maximum anticipated flow rates and pressures;
- the necessary pumps, piping, manifolding and valves to permit fluid to be pumped down either the drill pipe or the choke/kill lines;
- mud-gas separation equipment consisting of:
  - an atmospheric degasser capable of removing entrained gas from the drilling fluid following discharge from the choke manifold,
  - a vacuum degasser or equivalent equipment located near the shale shakers capable of removing entrained gas from the drilling fluid returns from the well,
  - vent lines installed on degassing equipment to discharge gas separated from the drilling fluid to a safe location; and
- the necessary shale shakers, centrifuges, and other solids control equipment to enable the efficient removal of drill solids and undesired weighting material from the drilling fluid system.

In the case where synthetic oil-based mud is being used, the solids control equipment should be operated and monitored to ensure that the discharge of drill solids is in compliance with the limits identified pursuant to paragraph 9(i) of the *Regulations*. The *Offshore Waste Treatment Guidelines* provide guidance in this regard.

The design and use of atmospheric degasser mentioned above can consider the technical specifications and recommendations in ENFORM Industry Recommended Practice (IRP), Volume 1, Section 1.7 as an acceptable means of compliance. In addition, the atmospheric degasser should comply with the *American Society of Mechanical Engineers Boiler and Pressure Vessel Code*, ASME, July, 2015.

28.11 Drilling Fluid Monitoring System

The indicators and alarms associated with the drilling fluid system should be capable of measuring, displaying and recording all parameters that may indicate a hazard to personnel, affect the security of the well, or indicate a possible loss of drilling fluid to the sea. As specified by paragraph 28(b) of these *Regulations*, these indicators and alarms must be strategically located on the drilling rig to alert onsite personnel.

28.11.1 Drilling Fluid and Well Surveillance System

The drilling fluid and well surveillance system should consist of

a) mud return or full hole indicator that monitors drilling fluid returns;
b) drilling fluid tank level indicators to measure gains or losses in the active system which, in the case of a floating drilling installation, should be designed and installed to compensate, to the extent practicable, for vessel motion;
c) a tank to accurately measure the drilling fluid displaced from the hole and required to fill the hole during trips; and
d) devices that automatically actuate audible and visual alarms to alert personnel of
    i) an increase above or decrease below pre-set limits of the level of fluid in the drilling fluid tanks;
    ii) an increase above or decrease below pre-set limits of the drilling fluid return indicator; or
    iii) the presence of hydrogen sulphide or high concentrations of hydrocarbon gas
        - in the drilling fluid; or
        - in the air at the bell nipple, shale shakers, active drilling tanks, drill floor and choke manifold, moonpool; and
e) equipment to display the following parameters at the driller’s station:
    i) well depth;
    ii) hook load;
    iii) weight-on-bit;
    iv) rotary torque;
    v) rotary speed;
    vi) rate of penetration;
    vii) pump stroke rate or flow rate of the mud pumps;
    viii) output from the mud return of full hole indicator;
    ix) volume of active fluid in the mud tanks;
    x) volume of fluid in the trip tank;
    xi) the standpipe pressure; and
    xii) any other equipment, drilling fluid or well parameter critical to the safety of the drilling operations or critical to the detection of a loss of drilling fluid to the sea.

Drilling fluid properties are to be measured by fully maintained equipment on a regular basis in accordance with API Recommended Field Testing Practices. Consideration should be given to using a pressurized mud balance in gas-prone areas.

28.12 Mud Logging Unit

A mud logging unit should be installed on a drilling installation at a location remote from the driller’s station. Dedicated personnel competent to measure, monitor, record and report on parameters critical to pressure and kick detection, should continuously staff the mud logging unit. The unit should be equipped to monitor, record and report on the amount and composition of hydrocarbon gases in the return drilling fluid, the density of the drilling fluid, flow rate, pit volumes, drilling fluid returns, trip tank volumes; etc. In general, the mud logging service should monitor and report on all parameters critical to well operations. Mud logging personnel should have direct contact with the driller and other key personnel for emergency notification and should provide regular reports to onboard management.

28.13 Codes and Standards

The following codes and standards, including any addendums, pertaining to drilling fluids and drilling fluid systems should be considered:

- *Recommended Practice for Field Testing Water-Based Drilling Fluids,* API RP 13B-1, ISO 10414-1:2008, *Petroleum and Natural Gas Industries – Field Testing of Drilling Fluids – Part 1 – Water-Based Fluids*;
- *Recommended Practice for Field Testing Oil-Based Drilling Fluids*, API RP 13B-2 Fifth Edition April 2014, ISO 10414-2:2011, *Petroleum and Natural Gas Industries – Field Testing of Drilling Fluids – Part 2 – Oil-Based Fluids*;
- *Recommended Practice for Laboratory Testing Drilling Fluids*, API 131, 2008 ISO 10416, *Petroleum and Natural Gas Industries – Drilling Fluids Laboratory Testing*;
- *Specification of Drilling Fluid Materials*, API Spec 13A,2010 ISO 13500, *Petroleum and Natural Gas Industries – Drilling Fluid Materials*;
- NORSOK Standard D-010, *Well Integrity in Drilling and Well Operations*, Rev. 4, June 2013;
- NORSOK Standard D-001, *Drilling Facilities*, Edition 3, December 2012;
- API Standard 53, *BOP Equipment Systems for Drilling*, Fourth Edition, November 2012; and
- API 16F, *Specification for Marine Drilling Riser Equipment*, First Edition, Includes Addendum 1 (2014).

28.14 Other Guidelines

The following guidelines are also available:

- *Offshore Waste Treatment Guidelines*;
- *Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands*;

29 Marine Riser

(1) The *operator* shall ensure that every marine riser is capable of:
  (a) furnishing access to the *well*;
  (b) isolating the *well-bore* from the sea;
  (c) withstanding the differential pressure of the drilling fluid relative to the sea;
  (d) withstanding the physical forces anticipated in the *drilling program*; and
  (e) permitting the drilling fluid to be returned to the *installation.*
(2) The *operator* shall ensure that every marine riser is supported in a manner that effectively compensates for the forces caused by the motion of the *installation.*

29.1 General

The goal of this regulation is to ensure that the marine riser system does not incur any damage or failure or loses its pressure integrity, and that it permits, at all times, the drilling fluid to be returned to the installation without discharge to the sea.

29.2 Specifications for Floating Drilling Operations

Marine riser systems for floating drilling operations should consider the requirements specified by:

- API 16F, *Specification for Marine Drilling Riser Equipment*, First Edition, Includes Addendum 1 (2014);
- American *Petroleum Institute Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems,* API RP 16Q, First Edition, November 1, 1993 (formerly API RP 2Q and API RP 2K), Reaffirmed, August 2010; and
- *American Petroleum Institute Specification pertaining to the Design, Rating and Testing of Marine Drilling Riser Couplings*, API Specification 16R, First Edition, January, 1997, Reaffirmed, August 2010

29.3 Dynamic Riser Response Analysis

A site-specific dynamic riser response analysis, as discussed in API RP 16Q, should be undertaken based on the water depth, current profiles, anticipated drilling fluid densities, sea states, vessel motions, mooring/positioning system and any other relevant parameter in consideration of the following objectives:

- confirming the integrity of the riser and ensuring that all components are capable of withstanding the differential pressure between the maximum anticipated fluid density and seawater;
- optimizing the configuration of the riser in terms of bare and buoyant joints and pup joints;
- avoiding vortex induced vibrations;
- establishing the top tension requirements for the range of environmental conditions and drilling fluid densities anticipated;
- establishing the operating envelope for the marine riser system in terms of vessel offset or ball/flex joint angles, vessel motions, deflection of the riser, drilling fluid densities, etc… for each of the “drilling”; “connected non-drilling”; “transition from connected to hang-off”, and “disconnected” modes; and
- determining the safe limits to prevent damage or failure during
  - deployment and retrieval;
  - transitioning from connected to hang-off; and
  - hang-off and survival.

The results of the riser analysis, particularly the operating envelope, buoyancy requirements, top tension requirements and operating limits should be provided to onsite supervisory personnel in a clear manner.

Please note that the dynamic riser response analysis should be performed with the best available data for the anticipated well location (i.e. weather data, current profiles, rig characteristics etc.) and should be verified by a competent 3rd party body.

29.4 Marine Riser Tensioning System

The marine riser tensioning system should be equipped with an anti-recoil system where such is required to prevent damage to the riser during emergency disconnection under high tension.

29.5 Telescopic Joints

The telescopic joint (slip joint) should be equipped with a double element packing unit as described in paragraph 2.6.3 (e) of API RP 16Q so that, in the event one of the packing elements fails, the second element can be engaged to minimize the discharge of drilling fluid to the sea. Secondary slip joint element should be fitted in such a way that it will engage automatically in the event of primary failure. The use of single element slip joint packing unit is not acceptable.

29.6 Flex Joints

The following should be available regarding the riser flex joints:

- the working pressure of the proposed flex joint and the maximum calculated differential pressure that the joint will be subject to during the proposed drilling program(s);
- confirmation that the lower flex joint has been satisfactorily pressure tested to the maximum calculated differential pressure;
- the service history of the proposed flex joint, complete with water depths and maximum density of drilling fluid;
- evidence that the flex joint rubber compound seal has been inspected by an approved method for detecting voids in order to qualify the flex joint seal ring; and
- the flex joint should not be more than 5 years old, unless documentation of a full tear down and inspection of the flex joint, according to original equipment manufacturer (OEM) recommended practices, can be provided.

29.7 Emergency Disconnect

Operators should ensure that plans to assure well integrity are in place in the event of:

- an emergency disconnect of the riser;
- structural failure of the marine riser system; or
- any other situation or event with the marine riser system that could give rise to the inability to actuate the BOP stack via the BOP hydraulic or multiplex control system.

For subsea BOP stacks, operators should consider the following measures:

- BOP stack ROV intervention capability; and
- one or more of the following;
  - Autoshear system; or
  - Deadman system; or
  - Acoustic BOP control system

- the back-up system should be independently operated (separate accumulation)

In the case of dynamically positioned vessels (DP) and/or deepwater operations, operators should consider the following measures:

- BOP stack ROV intervention capability;
- Autoshear system; and
- Deadman system;
- The back-up system should be independently operated (separate accumulation).

At a minimum, the ROV must be capable of closing one set of pipe rams, closing one set of blind-shear rams, and unlatching the lower marine riser package. Consideration should be given to the availability of ROV intervention adaptors from an alternate vessel/source necessary for the manipulation of subsea functions should they be unattainable from the drilling installation in the event of an emergency.

Operators utilizing DP vessels should consider the need to implement an acoustic BOP control system and to equip subsea BOP stacks with two shear rams.

29.8 IADC Deepwater Well Control Manual

The IADC Deepwater Well Control Manual provides a practical guide to planning and executing deepwater operations with particular emphasis on the measures that can be taken to both prevent and mitigate the consequences of a drive-off/drift-off or emergency disconnect scenario.

29.9 Inspection and Maintenance

Operators are expected to ensure that a detailed inspection and maintenance program is in place to ensure that the integrity of the marine riser is maintained.

29.10 High Pressure Riser

High pressure riser systems, either temporary or permanent, are to be assessed by the Certifying Authority (CA) as part of their scope of work. It is recommended that Offshore Standard DNV-OS-F201 for dynamic risers dated October 2010 be utilized for this purpose. The operator must ensure that these risers are designed and operated such that:

1. They can withstand all environmental loads as well as any pressure or tension loads that could be expected.
2. The installation is not compromised by any forces applied to or by the riser.
3. Contingency plans are in place, if appropriate, for running and retrieving the riser.

30 Drilling Practices

The *operator* shall ensure that adequate equipment, procedures and personnel are in place to recognize and control normal and abnormal pressures, to allow for safe, controlled drilling operations and to prevent *pollution*.

30.1 General

The primary goal of this regulation is to have an adequate program in place to monitor formation pressures during drilling operations, primarily during operations below surface casing, and to be able to detect any pressure transition zone between normal and abnormal pressure.

Operators are expected to ensure that an assessment of anticipated formation pressures occurs at the well design stage and that all relevant data including offset well data, seismic information and, where applicable, field production and injection data, is analyzed to develop a pore pressure and fracture gradient profile for the well.

30.2 Pressure Detection

Consistent with good oilfield practice, all pressure detection parameters including the rate of penetration, drilling exponent, shale density, cuttings size and shape, mud gas levels, torque, drag, fill, temperature and any other pertinent parameter should be monitored while drilling in an effort to detect any transition zone from normal to abnormal pressure and to detect any kicks. The use of logging while drilling (LWD) may also greatly assist in abnormal pressure detection. If necessary, wire line logs should be acquired if such are needed to confirm formation pressures. Please reference Section 28.12 – Mud Logging.

30.3 Well Control Procedures

Well control procedures, including the well kill approach for various scenarios, should be established and reviewed with crews. Kick detection parameters should be monitored in accordance with practices that have been defined in the drilling program. These procedures and practices shall meet regulatory requirements and should be in line with the practices that are being taught in IADC and International Well Control Forum (IWCF) accredited well control programs. The drilling program should also define the type and frequency of well control drills that will be conducted with crews to ensure proficiency. Critical procedures regarding shutting in the well, activation of the emergency disconnect system and any other critical procedures necessary to ensure well security should also be established. The operator’s policies and procedures on these matters should be clearly documented and communicated to field personnel.

30.3.1 Kick Tolerance

Operators should ensure that adequate kick tolerance exists at all times and that appropriate measures are taken to ensure kick tolerance in the event that abnormal pressure is encountered.

30.3.2 Suspension of Drilling Operations

In cases where insufficient kick tolerance exists, or if maximum anticipated pressures exceed safe margins in terms of the working pressure of BOP equipment, casing shoe/formation strength or the rated burst pressure of the casing, drilling operations should be suspended and the well should be secured. The specific criteria pertaining to these matters should be reflected in the operator’s drilling policies and procedures or otherwise specified within the operator’s management system.

31 Reference for Well Depths

The *operator* shall ensure that any depth in a *well* is measured from a single reference point, which is either the kelly bushing or the rotary table of the *drilling rig*.

31.1 RT to SF

The distance from the rotary table to the seafloor (SF) should be accurately measured to serve as the datum for all subsequent well depth measurements. The distance to the casing flange should be recorded (i.e., RT (or KB) to casing flange).

31.2 Floating Drilling Installations

For operations from a floating drilling installation, the RT-SF elevation will need to be corrected to mean sea level (MSL) taking into account tidal variations. The water depth should also be accurately measured and recorded and the RT elevation above MSL should be determined. An accurate means of indexing wellhead datum should be used whenever setting tools, hangers, etc. in the wellhead. An accurate means to establish BOP space out, including up-to-date tidal information, should be made available to the Driller at all times.

31.3 All Depths Referenced

All well depths, including hole depths, casing depths and all other depths are to be referenced to the RT or KB. This would include both driller's depths and wireline logger's depths as well as measured depths and true vertical depths, all of which should be measured and reported in metres. The following nomenclature may be used:

- mRT (MD) for metres from the rotary table (measured depth)
- mRT (TVD) for metres from the rotary table (true vertical depth).

31.4 Use of Wireline Log Data

Operators are also expected to utilize accurate and reliable wireline log data to properly correlate the perforation of intervals, setting of packers and any other down hole operation requiring accurate depth control.

32 Directional and Deviation Surveys

The *operator* shall ensure that

(a) directional and deviation surveys are taken at intervals that allow the position of the well-bore to be determined accurately; and

(b) except in the case of a *relief well*, a *well* is drilled in a manner that does not intersect an existing *well*.

32.1 General

Operators are expected to ensure that their drilling operations polices, procedures and programs meet these requirements.

Sufficient directional and survey deviation data should be acquired to enable the wellbore to intercept the specified target. The survey tools to be utilized should have sufficient accuracy to achieve this objective. This is particularly critical for wells with predefined spacing and target requirements as production allowable penalties could apply.

32.2 Relief Well Drilling

Survey tools and data must be capable of determining the location of the wellbore with sufficient accuracy to enable relief well drilling operations.

32.3 Multiple Well Drilling

Where multiple wells are drilled from a single location, or from locations in close proximity to each other, survey data should be acquired at a frequency and at an accuracy to ensure that the ellipse of uncertainty and separation factors can be determined in accordance with industry accepted wellbore collision avoidance policies and procedures. In this regard, MWD and/or gyroscopic data may be required to allow the position of the wellbore to be accurately determined so as to prevent it from intersecting an existing well.

32.4 Frequency of Surveys, Proposed Survey Plan and Survey Results

Information respecting the frequency of directional and deviation surveys as well as the proposed survey plan should be included in the application for Approval to Drill a Well (ADW).

The results of the survey should be provided in the Daily Drilling Report (see paragraph 84(a) of the *Regulations*), and in the Well History Report (see section 89 of the *Regulations*).

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33 Formation Leak-Off Test

The *operator* shall ensure that

(a) **a formation leak-off test or a formation integrity test is conducted before drilling more than 10 m below the shoe of any casing other than the conductor casing;**

(b) **the formation leak-off test or the formation integrity test is conducted to a pressure that allows for safe drilling to the next planned casing depth; and**

(c) **a record is retained of each formation leak-off test and the results are included in the daily drilling report referred to in paragraph 84(a) and in the well history report referred to in section 89.**

33.1 General

A formation leak-off test (FLOT) or a formation integrity test (FIT) is needed to establish the pressure limits of the formation and to verify the integrity of the primary cement job at the casing shoe. A secondary objective is to contribute to a database of formation strengths for future well design and well planning purposes.

As noted in paragraph (a) of the *Regulations*, FLOTs or FITs are not required in respect of the conductor casing. The intent is that these tests be conducted for surface casing and all other subsequent casing strings and liners where a BOP is in use and the information is needed for well control purposes.

33.2 Industry Standard Methods

Operators should ensure that FLOTs and FITs are executed in accordance with industry standard methods.

33.3 Recording of Results

As specified by paragraph (c) of the *Regulations*, the results of each test should be recorded on both the daily drilling report and in the well history report. In the case of the latter, pressure charts and calculations should be included in the well history report in sufficient detail to facilitate subsequent interpretation and analysis of the results by others.

34 Formation Flow and Well Testing Equipment

(1) The operator shall ensure that
  - **(a) the equipment used in a formation flow test is designed to safely control well pressure, properly evaluate the formation and prevent pollution.**
  - **(b) the rated working pressure of formation flow test equipment upstream of and including the well testing manifold exceeds the maximum anticipated shut-in pressure; and**
  - **(c) the equipment downstream of the well testing manifold is sufficiently protected against overpressure.**

(2) The *operator* of a well shall ensure that the *formation flow test* equipment includes a down-hole safety valve that permits closure of the test string above the packer; and

(3) The *operator* shall ensure that any *formation flow test* equipment used in testing a well that is drilled with a floating *drilling unit* has a subsea test tree that includes:
  - **(a) a valve that may be operated from the surface and automatically closes when required to prevent uncontrolled well flow; and**
  - **(b) a release system that permits the test string to be hydraulically or mechanically disconnected within or below the blowout preventers.**

34.1 Equipment and Procedures

Equipment and procedures are expected to follow the NORSOK Standard D -007, Edition 2, September 2013, *Well Testing Systems*, provided that they do not conflict with these *Regulations*. In addition, during deepwater testing operations, the operator should consider the need to install a riser sealing mandrel (or equivalent) immediately below the rotary table in association with the rig’s diverter system as a contingency to deal with the possible release of hydrocarbons within the marine riser. If the capability exists, the riser should be circulated during formation flow-testing operations to monitor volumes to detect any influx.

34.2 Pressure Ratings of Equipment

With reference to paragraph 34(1)(b), the rated working pressure relates to equipment upstream of and including the choke, provided that adequate safety pressure relief systems are in place to protect the downstream testing equipment.

34.3 Approval of Formation Flow Tests

Operators should also reference section 52 of the *Regulations* and the associated guidance notes regarding formation flow test approval requirements.

34.4 Down-Hole Safety Valve

With reference to subsection 34(2) of the *Regulations*, the operator should specify in its formation flow test program the type of down-hole safety valve to be used.

The following guidance is provided in reference to the NORSOK D-010 Standard (Rev 4 - June 2013) - *Well Integrity in Drilling and Well Operations*.

For development wells, the surface controlled subsurface safety valve (SCSSV) as required by Section 47 of these *Regulations* and described in NORSOK under completion activities meets the intent of Section 34(2) of these *Regulations* and is considered by the Board to be an acceptable down-hole safety valve for development wells during the temporary flow back of hydrocarbons to a MODU pending tie-back to production facilities.

In respect of well testing activities on exploration and appraisal wells, the Board requires, in accordance with subsection 34(2) of the *Regulations*, the use of a down-hole safety valve (DHSV) in addition to the subsea test tree (SSTT) dual safety valves in place at the BOP level. The down-hole safety valve should be placed in the string below the down-hole test valve (DHTV) and above the test packer. This valve should allow shut-in of the well down-hole if required in the event of a tubing leak, or where potential exists for catastrophic loss of the BOP and SSTT, i.e. ice encroachment, etc. The down-hole safety valve should have the capability of effecting closure of the test string from below yet have pump through capability to allow the well to be killed.

The down hole test valve is considered an operational valve and is not acceptable as a down-hole safety valve under this regulation.

If the inclusion of a down-hole safety valve for well testing activities on exploration and appraisal wells carries additional operational risk this should be communicated to the Board and will be assessed on a case-by-case basis. The decision to not have a down-hole safety valve in the string must be documented and submitted using the Regulatory Query process and any approval will be managed using that process.

35 Well Control

The *operator* shall ensure that adequate procedures, materials and equipment are in place and utilized to minimize the risk of loss of well control in the event of lost circulation.

35.1 General

The plans for addressing lost circulation should be reflected in the operator's management system. The risk of lost circulation and the operator's policies pertaining to lost circulation should be described (or referenced) either in the application for Approval to Drill a Well (ADW) or in the application for Operations Authorization.

35.2 Need to Maintain Circulation

The operator's policies and procedures should specifically address the need to maintain circulation at all times for well control purposes unless the well approval issued by the Board provides for drilling with losses, drilling underbalanced or drilling blind.

Section 22 of the *Regulations* also pertain to the issue of ensuring that adequate plans, procedures, materials and equipment are in place in the event of lost circulation.

36 Well Control Equipment

> **(1) The *operator* shall ensure that, during all *well operations*, reliably operating well control equipment is installed to control kicks, prevent blow-outs and safely carry out all *well* activities and operations, including drilling, completion and work-over operations.**
> **(2) After setting the *surface casing*, the *operator* shall ensure that at least two independent and tested well *barriers* are in place during all *well operations*.**
> **(3) If a *barrier* fails, the *operator* shall ensure that no other activities, other than those intended to restore or replace the barrier, take place in the *well.***
> **(4) The operator shall ensure that, during drilling, except when drilling underbalanced, one of the two *barriers* to be maintained is the drilling fluid column.**

36.1 Industry Standards and Practices

Well control equipment installed pursuant to sub-section 36(1) should conform to accepted industry standards and practices. The following publications should be considered:

- *Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services*, API Recommended Practice 5C7, First Edition, December, 1996 (API RP 5C7), Reaffirmed, December 2007;
- *Recommended Practice for Design and Operation of Completion/Workover Riser Systems*, API Recommended Practice 17G, Second Edition, July 2006 (API RP 17G);
- API Standard for *Blowout Prevention Equipment Systems for Drilling Wells*, API Standard 53, Fourth Edition, November 2012 (API Std 53);
- *Recommended Practice for Diverter Systems Equipment and Operations*, API Recommended Practice 64, Second Edition, November, 2001 (API RP 64), Reaffirmed, January 2012;
- *Specification for Wellhead and Christmas Tree Equipment*, ANSI/API Specification 6A, Twentieth Edition, October 2010, Effective April 1, 2011 (ANSI/API Spec 6A/ISO10423-2009);
- *Specification for Drill-through Equipment*, ANSI/API Specification 16A, Third Edition, June,

2004 (ANSI/API Spec 16A/ISO 13533:2001);
- *Specification for Choke and Kill Equipment*, API Specification 16C, Second Edition, March 2015 (API Spec 16C);
- *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*, API Specification 16D, Second Edition, July, 2004, (API Spec 16D);
- *Specification for the Design and Operation of Subsea Production systems – Subsea Wellhead and Tree Equipment*, API Specification 17D, Second Edition, May 2011 (API Spec 17D);
- NACE Standard MR0175-2015 *Petroleum and Natural Gas Industries – Materials for Use in H2S Containing Environments in Oil and Gas Production*;
- *Mud Gas Separator Sizing and Evaluation*, SPE 20430, G.R. MacDougal, December, 1991;
- NORSOK Standard D-010, *Well Integrity in Drilling and Well Operations*, Rev. 4. June 2013;
- *American Petroleum Institute Specification for Rotary Drilling Stem Elements*, API Spec 7-1, First Edition, March 2006, Reaffirmed, April 2015; and
- *American Petroleum Institute Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*, API RP 14E, Fifth Edition, October, 1991, Reaffirmed, January 2013.

36.2 Well Control System

36.2.1 Blowout Preventer and Control System

Operators should conduct a risk assessment of the configuration of the BOP stack to ensure that it is suitable for the specific operations. Any such assessment should include consideration of the specific items below and any other considerations that are necessary to ensure suitability of the BOP stack to deal with any reasonably foreseeable situation or event:

a) With any blowout preventer closed, except the lower rams, there is a circulation route for fluids from the well annulus through a choke or kill line, and an alternate circulation route out of the well through another choke or kill line;

b) At least two valves should be installed on each choke and kill outlet, one of which should be a hydraulic or electro hydraulically controlled valve which should fail safe (in closed position) in all conditions of flow rate and drilling fluid type and weight which may reasonably be expected during any well operations;

c) In the case of a sub-sea blowout preventer stack, both valves installed on each choke and kill outlet should be remotely operated fail-safe valves;

d) The fail-safe valves referred to above should be protected from falling objects by being located as close to the body of the stack as practicable;

e) An effective means of clearing trapped gas from the BOP’s should be in place;

f) BOPs used in all floating drilling operations should have two sets of shear rams spaced at least 1.2m apart (to prevent system failure if a drill pipe joint or drill collar is across one set of rams during an emergency). Where the shear rams are less than 1.2 m apart, this should be addressed through a risk assessment before drilling operations commence;

g) Drill pipe components positioned in the shear rams during displacement must be capable of being sheared by the blind-shear rams in the BOP stack;

h) The BOP control system on floating, non-moored drilling units should be equipped with an automatic sequencing system whereby all functions necessary to close shear rams and disconnect the lower marine riser package are automatically performed in the correct order by activating a single function on the control panel; and

i) The risk assessment should address the control systems and the executive actions associated with automatic functions for Deadman, Auto-shear, Acoustic, and ESD to ensure that the executive actions are appropriate.

Each ram type preventer should be equipped with an integrated, hydraulic or electro hydraulic controlled or automatic mechanical locking device capable of locking the rams in the closed position.

The main electrical control panel and/or hydraulic control manifold unit of the BOP control system should be located such that it is protected from fire or explosion originating in the well-head, drill floor or spider deck areas and should be easily accessible from outside the well-head, spider deck or drill floor areas.

In addition to the control panels located at the hydraulic accumulators and in the driller's cabin, the BOP control system should be equipped with an additional control panel located in a suitably protected location that is easily and quickly accessible by supervisory drilling personnel.

36.2.2 Choke and Kill System

Operators should conduct a risk assessment of the Choke and Kill System to ensure that it is suitable for the specific operations. Any such assessment should include consideration of the specific items below and any other considerations that are necessary to ensure suitability of the Choke and Kill System to deal with any reasonably foreseeable situation or event:

a) The choke and kill lines should be arranged such that drilling fluid may be pumped into the well through either the choke line or the kill line and simultaneously circulated out of the well through the other choke or kill line;

b) The choke and kill lines should be clearly identifiable by colour coding or other suitable means;

c) The choke and kill lines, choke manifold and ancillary components should be protected from freezing;

d) The choke and kill system should be sized such that pressure losses do not limit or impede well control operations;

e) The choke manifold should be;
   - placed in a readily accessible location for easy control and maintenance;

- designed and arranged to permit replacement or repair of any one choke while simultaneously flowing through any of the other chokes;
- capable of directing flow from any choke; and
- through mud-gas separation equipment and subsequently to the mud pits; and
- through the overboard/diverter line(s)

f) Where the choke manifold is located in an enclosed area the area should be adequately ventilated to prevent the concentration of combustible gases from accumulating to a dangerous level;

g) Every valve on the choke manifold should be clearly marked to indicate its normal position;

h) An overboard discharge line from the choke manifold should be installed which should;
   - be as short and straight as possible with changes in direction minimized and all bends targeted be equipped with block tees to prevent erosion damage;
   - have a rated pressure at least equal to that of the low pressure side of the choke manifold; and
   - be capable of directing the flow of well fluids overboard to opposite sides of the drilling installation.

i) A single overboard line may be used for the discharge of well fluids overboard from the choke manifold, where this configuration can be shown to provide at least the same level of safety;

j) All valves on at least one of the flow lines downstream of the choke manifold should be secured in the open position to prevent inadvertent over-pressuring of the low pressure lines and valves downstream of the choke manifold; and

k) Where flexible lines are used for choke and kill lines, these lines should;
   - comply with *American Petroleum Institute Specification for Choke and Kill Equipment*, API Spec 16C, Second Edition, March 2015; and
   - be capable of resisting fire for a sufficient period of time to shut in the well in an orderly manner for lines not submerged.

36.2.3 High Pressure Kill Pumping System

Operators should conduct a risk assessment of the High Pressure Kill Pumping System to ensure that it is suitable for the specific operations. Any such assessment should include consideration of the specific items below and any other considerations that are necessary to ensure suitability of the High Pressure Kill Pumping System to deal with any reasonably foreseeable situation or event.

A high pressure kill pumping system should be available and include either dedicated internal combustion engine or if electrically powered,

- connected to a back-up power supply; and
- independent of the main power supply.

In addition, pumps required to transfer drilling fluid from the mud pits to the high pressure kill pumping system should also be connected to a back-up power supply, independent of the main power supply.

36.2.4 Ancillary Well Control Equipment

Operators should conduct a risk assessment of the Ancillary Well Control Equipment to ensure that it is suitable for the specific operations. Any such assessment should include consideration of the specific items below and any other considerations that are necessary to ensure suitability of the High Pressure Ancillary Well Control Equipment to deal with any reasonably foreseeable situation or event:

a) at least one high pressure circulating head and associated lines. The high pressure circulating head is not required if the top drive drilling system has a pressure rating at least equal to the pressure rating of the BOP systems;
b) safety valves in the top drive drilling system that are capable of being controlled from the driller's position or otherwise readily available to be safely and quickly closed by drill floor personnel;
c) at least two stabbing valves with appropriate cross-over subs to fit each type of connection in the drill string;
d) at least two back pressure valves;
e) an inside BOP which seals off flow up the drill-stem;
f) float valves capable of being installed near the bottom of each drilling bottom hole assembly (BHA) to prevent flow up the drill-string; and
g) in the case of a floating drilling installation, a hang-off tool.

All ancillary well control equipment should have:

- a pressure rating at least equal to the pressure rating of the BOP systems; and
- a tensile strength at least equal to the drill pipe in use.

36.3 Provision for Adequate Well Barriers

With reference to sub-sections 36(2), (3) and (4), operators should ensure that policies, procedures, equipment and methods respecting well operations provide adequate well barriers at all times. This requirement also applies when operating the well for production purposes. The term "barrier" is defined as meaning any fluid or any plug or seal that prevents hydrocarbons or any other fluid from flowing unintentionally from a formation, into another formation, or unintentionally flowing from a well.

The operator should use dual mechanical barriers when running casing strings to aid in good cement placement and to prevent flow in the event of a failure in the cement. (e.g. float shoe and float collar or dual floats or one float and an additional mechanical barrier.)

36.4 Standard for Well Integrity

A well barrier analysis should be conducted for each well operation, and for each phase of each well operation to the extent that is appropriate. The NORSOK Standard D-010, *Well Integrity in Drilling and Well Operations*, Rev. 4, June 2013 identifies expectations in this regard and should be used in developing appropriate well barrier policies, procedures and work instructions. This standard focuses on well integrity and provides a practical discussion of well barrier envelopes, well barrier elements, testing and acceptance criteria for various barriers as well as related terminology and definitions. In particular, section 15 of this standard describes 50 well barrier elements together with their function and use; testing, verification and monitoring methods; and potential failure modes. The standard covers drilling, well testing, completion, production, wire line, coiled tubing, snubbing, under-balanced drilling, and pumping operations (the latter also includes slurrified drill cuttings reinjection). For additional guidance in relation to well intervention, please refer to NORSOK Standard D-002, *Well Intervention Equipment*, Rev. 2, June 2013.

It is expected that the operator have a program in place for monitoring and ensuring that the well integrity of production wells is maintained throughout the life of the well. A major component to be evaluated is the casing annular pressure. To ensure that the wells are operated safely and also with respect to resource conservation, an annular well pressure monitoring and evaluation program should be in place. It is recommended that the *Recommended Practice for Annular Casing Pressure Management for Offshore Wells*, API Recommended Practice 90, First Addition, August 2006, Reaffirmed, January 2012 be considered and utilized.

36.5 Well Barrier Policies, Procedures and Work Instructions

Operators should ensure that personnel are aware of the well barrier envelopes that are being relied on at any given point in time to prevent uncontrolled flow. Well barrier policies, procedures and work instructions should be supplemented, where appropriate, with schematics illustrating the well barrier elements for each well operation (and for each phase of each well operation) so as to provide the necessary clarity to personnel. Field personnel should also be provided with instructions to follow in the event that a primary or secondary well barrier element fails.

37 Pressure Control Equipment

The *operator* shall ensure that pressure control equipment associated with drilling, coil tubing, *slick line* and *wire line* operations is pressure-tested on *installation* and as often as necessary to ensure its continued safe operation.

37.1 General

The operator is expected to ensure that BOPs and related pressure control equipment, as well as pressure control equipment utilized for slickline, wireline or coiled tubing operations have a rated working pressure greater than the well design maximum calculated surface pressure.

Documentation of maintenance and repair (including any modifications to the BOP stack and control systems) should be maintained and made available for auditing purposes.

37.2 Guidelines for Pressure Testing

The operator is expected to ensure that BOPs, and other pressure control equipment (choke manifold, the choke and kill lines, high pressure riser if applicable, safety valves, stabbing valves, inside BOPs and any other well control equipment) are pressure tested as follows: after installation (If the BOP stack has been fully stump tested, a body test should be conducted to ensure that the wellhead connector is sealed. In this respect stump tests are expected to be conducted just prior to running the BOP); before drilling out any string of casing; before commencing a formation flow test; following repairs or any event that requires disconnecting a pressure seal; and once every 14 operational days. Where well conditions or other hazards preclude pressure testing within the 14 day timeframe, the test may be delayed by no more than 7 days. Deviations from this may be acceptable for blind shear rams in the event that the BOP's are latched to a subsea wellhead and operations do not permit or allow for such tests.

37.3 Pressure Testing Blow-out Preventers and Associated Equipment

The stabbing valve, inside BOP, and lower kelly cock should be pressure tested from the bottom. An inside BOP consisting of a pump down check valve and a landing sub that is an integral part of the string should also be in-flow pressure tested.

A low pressure test in the range of 1,400-2,000 kpa should be conducted prior to the high pressure test. The BOPs and other pressure control equipment should be tested to at least the maximum anticipated section design pressure. The annular(s) should be tested to no more than 70 per cent of the working pressure. For a satisfactory test, all components should maintain a stabilized pressure of at least 90 per cent of the required test pressure over a 5-minute (low test) and 10-minute (high test) interval. Variable bore pipe rams may be tested on only one pipe size in the string.

37.4 Pressure Testing Chokes and Associated Equipment

All valves in the choke manifold, bleed-off, and kill systems should be pressure tested to confirm their isolation. All valves should be tested from the direction in which well fluids may flow. It is recommended that adjustable chokes be confirmed as functional by pumping fluid through the chokes and noting restriction ability. Adjustable choke bodies should be shell tested to the maximum working pressure of the respective downstream valve during stump testing. Testing during operations should be to section design pressure for the subsequent hole section.

37.5 Blow-out Preventer Control System and Diverter System Tests

An accumulator test as outlined in API Standard 53 should be conducted prior to drilling below the surface casing to confirm pump and volumetric capacity of the BOP control system. A function and low pressure test of the diverter system should be performed following its installation.

37.6 Pressure Test Documentation

All pressure test details and results are to be recorded. This is to include electronic records as well as calibration records. Third-party pressure test documentation is an acceptable substitute for detailed data entry in the drilling logbook. This data can be referenced in the logbook and should be available at the well site. A copy should also be available at the operator's shore base.

37.7 Guidelines for Function Tests

The BOPs and other well pressure control equipment should be function tested daily and in such a manner as to ensure all components (including failsafe valves if appropriate) have been tested at least once per week (i.e., a minimum of one component function test per day or preferably per shift to ensure control system operating). A case may be made to do all function tests weekly provided there is a daily check of the control closing system and the accumulators, but the former is preferred. In the case of subsea wells, function tests are to alternate between control pods and between control stations. Choke and kill lines on a subsea BOP should be flushed on a regular basis to ensure no blockages have occurred. It is recommended twice daily when operations permit. Also, for subsea wells, the autoshear and deadman systems, and all ROV intervention functions on the BOP stack should be tested during the stump test. Function testing of deadman systems on the seabed should be visually confirmed by ROV.

37.8 Backup Subsea BOP Systems

Backup subsea BOP systems are to be function tested during each stump test. All ROV intervention functions as well as the autoshear, deadman, and/or acoustic system, if applicable, is also to be tested.

Following installation of the stack on the wellhead, at least one set of rams is to be functioned using the ROV intervention system and then pressure tested. Deadman and acoustic systems, if installed, are also to be tested.

Following the initial subsea test of these systems, tests are to be performed:

- whenever a parameter affecting the system changes (e.g. water depth);
- following any modification to the system; and
- at least once per year.

Operator's plans for arming deadman or autoshear systems during well operations are to be submitted to the Board at the time of its application for operations authorization.

38 Loss of Well Control

If the well control is lost or if safety, environmental protection or resource conservation is at risk, the *operator* shall ensure that any action necessary to rectify the situation is taken without delay, despite any condition to the contrary in the *well approval*.

38.1 General

The onus is on the operator to immediately take the action necessary to rectify the loss of well control such as a blowout at surface, an uncontrolled underground flow of fluids from one formation into another, broaching of fluids at the seafloor or any other loss of well control. The operator is obligated by this regulation to immediately take action to rectify the situation, notwithstanding any ambiguity with respect to any conditions attached to any well approval, and to take such actions with full consideration of safety and the need to protect the environment and to conserve resources.

In order to meet the goal set out in this regulation, operators must develop procedures to be followed if well control is lost. These procedures should address escalating well control events and not be limited to initial in-flux shut-in (i.e. escalating kicks and blowouts). Installation personnel should for example understand when to activate shear rams, disconnect procedures and ESD systems and be drilled to act promptly in extreme situations. Installation personnel should also have ready access to well control experts with advanced well control training.

38.2 Broad Application of Regulation

It is also important to recognize that this regulation is much broader than well control events. It also requires the operator to rectify any situation where the safety of any person or of the installation, the protection of the environment or the conservation of resources is at risk. In this context, "at risk" should be taken to mean a situation that poses an immediate and obvious risk to the safety of any person, or an immediate or actual risk to the environment or any situation that contravenes the principle of conservation of resources. The primary intent of this section is that, if there is an accident or other situation that poses an obvious and clear threat to the safety of persons, the protection of the environment or the conversation of resources, the operator must take immediate action to rectify the situation in terms of alleviating the immediate risk to the safety of personnel, risk to the environment or the waste of resources.

39 Casing Design

The *operator* shall ensure that the *well* and casing are designed so that

(a) the *well* can be drilled safely, the targeted formations evaluated and *waste* prevented;
(b) the anticipated conditions, forces and stresses that may be placed upon them are withstood; and
(c) the integrity of gas hydrate *zones* is protected.

39.1 General

The casing installed in any well shall be designed to withstand burst, collapse, tension, bending, buckling or other stresses that are known to exist or that may reasonably be expected to exist. The performance properties of any casing may be based on those listed in the American Petroleum Institute's *Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing,* API TR 5C3, First Edition, December 2008.

39.2 Conductor Casing

With regard to a floating installation, the conductor casing should be designed to have sufficient structural strength to support the load imposed by the marine riser and by the BOP system. For a jack-up installation, the conductor is to be designed in consideration of the wave and wind loads, taking into account the conductor tensioning system. For platform wells, structural analysis of the conductor casing should pay particular attention to buckling loads.

39.3 Design Factors

The minimum design factors used in a conventional working stress design of well casings is expected to be: 1.0 for burst; 1.0 for collapse; and 1.6 for tension.

39.4 Load Requirements

The operator should consider the casing load requirements and additional design details in the EUB *Minimum Casing Design Requirements* Draft Directive 010 Additional considerations for offshore wells are as follows:

Collapse:

a) The surface casing collapse loads can consider the internal pressure/fluid to be evacuated to at least ½ TVD of the next full-length casing/liner depth, with the lightest mud density after drill out, the same as indicated for intermediate casing in the directive – section 3.2.2 or
b) the surface and intermediate casings can be designed for partial evacuation based on mud column drop, equating with pore pressure. Also, cementing considerations for the slurry inside and outside the casing string are to be considered. The design criteria is to be submitted with the casing design.

Burst:

c) The external water column pressure can be considered along with the pore pressure if the depth of the point being evaluated is below the sea floor.

39.5 Sour Gas Wells

Sour gas wells have additional design requirements as outlined in the EUB Directive 010 and in ENFORM IRP 1 (Critical Sour Drilling). This IRP is also considered a useful document for other drilling considerations not sour-specific.

39.6 Casing Liners

Where casing liners are used in lieu of full casing strings, the casing liner and casing or the casing liner and tie-back should together meet the relevant design criteria set out above.

39.7 Alternative Casing Methods

Alternative casing methods such as load and resistance factor design will be considered, but it is expected that all details regarding casing properties, risk analysis and quality control will be submitted as part of the application to the Board. This also applies to alternative methods included in EUB draft Directive 010. Generally, the simplified method in the EUB Directive would not be used for offshore wells.

In regards to alternate methods included in EUB draft Directive 010 details with respect to casing properties, loads and quality control should also be included. The LRFD method has a risk component in both the load and resistance side. If an operator wishes to use a risk component on either side, this would have to be explained and justified. If a conventional working stress procedure is used as contemplated in Directive 010 then risk analysis would not be required.

39.8 Use of New and Reconditioned Pipe

Any casing installed in a well should be new pipe. Any reconditioned casing should be inspected by a third party to ensure that the casing has adequate strength for its intended purpose.

39.9 Casing Centralization

Any casing or liner string installed should consider the use of centralizers in order to provide the best opportunity to achieve good isolation and cement placement during cementing operations. This is particularly important for deviated wells and critical casing sections.

40 Depth of Well and Casing

The *operator* shall ensure that the *well* and casing are installed at a depth that provides for adequate kick tolerances and *well control* operations that provide for safe, constant bottom hole pressure.

40.1 Well and Casing Design

Operators are expected to design the well and casing to ensure that the geological target is penetrated and adequately evaluated. Development wells are to be designed to maximize the recovery of resources.

40.2 Design Considerations

The operator is expected to take into consideration the following matters respecting the design of the well and casing:

- the pore pressure and fracture gradients;
- kick tolerance;
- the anticipated lithology;
- wellbore instability;
- the presence of potable water zones;
- faults;
- lost circulation zones; and
- drilling hazards.

40.3 Casing Depths and Sizes

Operators are expected to select casing depths and sizes in consideration of the following objectives:

- ensuring that the geological target is penetrated and adequately evaluated;
- preventing the waste of resources;
- ensure that the latching mechanisms are engaged upon installation of each casing string or liner and;
- ensuring the ability to execute well control operations safely.

41 Cementing Programs

The *operator* shall ensure that cement slurry is designed and installed so that

(a) the movement of formation fluids in the casing annuli is prevented and, where required for safety, resource evaluation or prevention of *waste*, the isolation of the petroleum and water *zones* is ensured;

(b) support for the casing is provided;

(c) corrosion of the casing over the cemented interval is retarded; and

(d) the integrity of gas hydrate *zones* is protected.

41.1 General

The cementing program should be designed to prevent the movement of formation fluids in the casing-formation annuli or casing-casing annuli; provide support for the casing; and retard corrosion of the casing. Further guidance on this matter is provided in the *Data Acquisition and Reporting Guidelines*.

Operators are expected to:

a) have documented programs that clearly define mandatory cementing practices, recommended practices and operational guidelines;

b) have detailed policies and procedures on the design, placement and validation programs inclusive of contingencies that should be followed if there are issues experienced;

c) have policies and procedures that should clearly define lost returns, partial returns, full returns and cement volume margin and clearly articulate actions to be taken when such events occur. The density hierarchy between mud and spacers for the cementing program should be clearly defined;

d) clearly define in their well construction plans and in their management system, in general, requirements for reviewing the integrity of barriers at safety-critical milestones, such as prior to removal of the BOP and riser from the wellhead, prior to re-entry of a well after suspension, prior to removal of any barrier etc; and

e) have detailed policies and procedures that define the extent of evaluation that will be conducted to verify appropriate placement of cement in meeting the objectives of the cementing program. This should include clear direction on the circumstances that would dictate the criteria that constitute deeming a cement program as successful or if additional evaluation efforts are required.

Furthermore, following practices outlined in API RP 65 and API Std 65 Part 2 would be considered as an acceptable means of compliance.

41.2 Conductor Casing

The conductor casing, and permafrost casing if required, should be cemented where practicable from the shoe of the casing to the seafloor.

41.3 Surface Casing

In the case of an offshore well, the surface casing should be cemented to the seafloor or to a depth that is not less than 25 m above the base of any previous casing string.

41.4 Intermediate and Production Casing

Intermediate and production casing should be cemented with sufficient cement to:

- isolate all hydrocarbon or potable water zones;
- isolate abnormally pressured intervals from normally pressured intervals; and
- if applicable, rise to a minimum of 150 m above the base of the permafrost.

41.5 Liners

Where practicable, the full length of every casing liner should be cemented.

41.6 Additional Barriers

For the final casing string, the operator should verify the installation of dual mechanical barriers (e.g., dual floats or one float and a mechanical plug) in addition to cement, to prevent flow in the event of a failure in the cement.

42 Waiting on Cement Time

After the cementing of any casing or casing *liner* and before drilling out the casing shoe, the *operator* shall ensure that the cement has reached the minimum compressive strength sufficient to support the casing and provide zonal isolation.

42.1 Drilling a Cement Plug or Shoe

A cement plug or shoe should not be drilled until the compressive strength of the cement is at least 3,450 kPa at bottom hole conditions.

42.2 Cement Specifications

Cement specifications can be found in ISO 10426/API 10A. The recommended practices for testing well, deepwater and foamed cements respectively are provided in ISO 10426-2/API RP 10B-2, ISO 10426-3/API RP 10B-3 and ISO 10426-4/API RP 10B-4.

43 Casing Pressure Testing

After installing and cementing the casing and before drilling out the casing shoe, the *operator* shall ensure that the casing is pressure tested to the value required to confirm its integrity for maximum anticipated operating pressure.

43.1 Surface and Intermediate Casings

The surface and intermediate casings are expected to be pressure tested to a minimum pressure of 70 per cent of the maximum calculated surface pressure and at least 3,500 kPa above the estimated formation leak-off pressure. The casing must be designed to withstand the maximum pressure that could be encountered. Although there have been many exploration wells that have been inadvertently exposed to full pressure, a successful test to a value of 70 per cent is deemed to be adequate to confirm the casing integrity for surface and intermediate casing. The more onerous requirement to test to 100 per cent is not required for these casing strings.

43.2 Production Casing

The production casing for all wells is expected to be pressure tested to the maximum anticipated bottom hole pressure less the calculated gas column equivalent pressure back to surface (i.e.,100 per cent of the maximum calculated surface pressure). In the case of production wells when the density of the reservoir fluid is known, the maximum pressure can be reduced accordingly. The risk of exposing production wells to full pressure is considered greater due to the increased length of time that this casing will be in service. Therefore, production casing needs to be tested to the 100 per cent requirement. Casing hanger latching mechanisms or lock down mechanisms should be engaged at the time the casing is installed in the subsea wellhead.

43.3 Overpressure Wells

In the case of overpressure wells, the operator may need to consider changing the fluid column, running a packer or reducing the surface pressure test requirement in order to meet the casing pressure test criteria outlined above.

Before displacing kill weight fluid from the wellbore the operator should perform a negative pressure test. This could apply to intermediate, production, casings, as well as following testing/plugging of zones, and prior to removing the riser due to riser margin considerations. Step by step procedures for performing any negative pressure tests should be included in the submitted well program. This would apply to any wells “Capable of Flow”. See section 47.2.

43.4 Liners

In the case of liners, the casing and the liner should be tested to the same criteria.

43.5 Additional Requirements

Prior to displacement of drilling fluid from the wellbore, the operator should verify that:

- Two independent barriers, including one mechanical barrier, are in place for each flow path (i.e., casing and annulus), except that a single barrier is allowable between the top of the wellhead housing and the top of the BOP;

- If the shoe track (the cement plug and check valves that remain inside the bottom of casing after cementing) is to be used as one of these barriers, it is negatively pressure tested prior to the setting of the subsequent casing barrier. A negative pressure test must also be performed prior to setting the surface plug;

- Negative pressure tests are made to a differential pressure equal to or greater than the anticipated pressure after displacement. Each casing barrier is positively tested to a pressure that exceeds the highest estimated integrity of the casing shoes below the barrier; and

- Displacement of the riser and casing to fluid columns that are underbalanced to the formation pressure in the wellbore is conducted in separate operations. In both cases, BOPs must be closed on the drill string and circulation established through the choke line to isolate the riser, which is not a rated barrier. During displacement, volumes in and out must be accurately monitored.

43.6 Prolonged Drilling

If a casing string is exposed to casing wear by pipe movement for longer than 30 days, specific actions should be taken to revalidate the casing condition such as a caliper log or pressure test.

43.7 Operator’s Policies and Criteria

The operator’s policies respecting casing pressure testing should be described in the management system and in the casing pressure test values should be specified in the application for an Approval to Drill a Well (ADW) together with the criteria for a successful pressure test.

44 Production Tubing

The *operator* shall ensure that the production tubing used in a well is designed to withstand the maximum conditions, forces and stresses that may be placed on it and to maximize *recovery* from the *pool*.

44.1 General

The operator should demonstrate in their design that all tubing and tubing-related equipment is able to withstand

- maximum temperatures and temperature changes to prevent failure and ensure that the production design is not compromised;
- maximum pressures and pressure differentials to ensure that burst, collapse and buckling do not occur; and
- maximum tensile forces applied during running, setting or pulling of tubing to ensure against failure.

44.2 Tubing Size

The operator is expected to be able to demonstrate that the tubing is sized to maximize recovery in relation to the pressures and fluids to be produced or injected.

44.3 Corrosion Protection

All critical equipment including tubing and associated equipment is expected to be protected from corrosion to prevent loss of strength or function, and meet the requirements of the National Association of Corrosion Engineers, NACE Standard MR0175/ISO15156 – *Materials for Use In H2S-Containing Environments in Oil and Gas Production.*

45 Monitoring and Control of Process Operations

The *operator* shall ensure that

(a) operations such as processing, transportation, storage, reinjection and handling of petroleum on the *installation* are effectively monitored to prevent *incidents* and *waste*;

(b) all alarm, safety, monitoring, warning and control systems associated with those operations are managed to prevent *incidents* and *waste*; and

(c) all appropriate persons are informed of the applicable alarm, safety, monitoring, warning or control systems associated with those operations that are taken out of service, and when those systems are returned to service.

45.1 General

In order to meet the intent of this section, the operator should ensure the effectiveness of management policies and procedures as they relate to the activities described in section 45 of the *Regulations* above.

45.2 Process Control, Emergency Shutdown, and Fire and Gas Detection Systems

Operators are expected to ensure that appropriate and effective process control (PCS), emergency shutdown (ESD), fire and gas detection systems (FGS), and associated equipment are in place, tested, maintained and operated on all production and drilling installations. These systems should provide for executive action to prevent, contain and mitigate accidents in defined circumstances, without the need for human intervention. This guidance does not draw definitive lines separating PCS from ESD and FGS. The operator should define and demarcate those systems that have safety implications consistent with the view expressed in the *Petroleum and Natural Gas Industries - Offshore Production Installations - Analysis, Design, Installation and Testing of Basic Surface Process Safety Systems*, ISO 10418:2003, that these systems should interact to form a “process protection system”. The process protection system should be based upon a documented evaluation process that takes into account all undesirable events that may pose a risk to safety or the environment, or that may cause waste. Any safety implications arising from the interaction of the PCS with the ESD and FGS should be determined. This may affect ESD and FGS systems’ contributions in risk analysis. The operators should manage the PCS to reduce risk to the extent practicable. For further guidance on this matter, the operator should review the *Guidelines* under sections 25 to 27 of these *Regulations*.

45.3 Management

The management of hydrocarbon process, storage and transportation operations includes matters related to

- process control;
- emergency shutdown;
- fire and gas detection and associated executive action;
- alarm management;
- control of isolations and inhibits;
- human factors;
- work control and associated permits and certificates; and

- simultaneous operations and other matters that directly affect process safety.

Management systems should make appropriate provision for

- standards;
- guidance;
- engineering design;
- operational procedures;
- staff competencies;
- maintenance and testing;
- review of operational experience; and
- failure rates.

45.4 Operational and Maintenance Policies and Procedures

The operator should ensure that operational and maintenance policies and procedures complement the automated systems. The management system should include suitable and redundant feedback loops, which ensure that competent staff continue to monitor, validate and audit the implementation of process and process-system maintenance procedures on a regular basis. The management of any changes that result from this ongoing monitoring and validation process is a vital element of the management system.

Procedures for process operations should take into consideration the following:

- initial startup of a new facility;
- normal and temporary operations;
- emergency shutdown, including identification of conditions which require shutdown;
- normal shutdown;
- start-up following an emergency or normal shutdown;
- plant operating limits
- consequences of deviating from established operating limits;
- steps required to correct or avoid a deviation from operating limits; and
- safety systems and their functions

45.4.1 Simultaneous Operations

The management system should identify all operations and maintenance procedures which may not occur simultaneously with process operations and those which may occur simultaneously only when special precautions are in place. The system for controlling routine work activities (e.g., the permit to work system) should be integrated with policies and procedures related to process control and monitoring.

45.4.2 Alarms

The operator should record alarm settings and apply appropriate measures to manage and control changes. Changes to alarm settings should be sanctioned at an appropriate management level. Similarly, inhibits of alarm functions should be controlled. The performance of alarm systems in service should be monitored to ensure continued optimization. The operator should develop formal checklists and procedures to guide personnel, and specifically plant operators, as to how to respond to alarms.

45.4.3 Inhibitions of Safety Functions

Operators are expected to manage any required inhibition of safety functions. The operator is expected to record and communicate all inhibits and to take appropriate remedial action to ensure that risk remains at acceptable levels. The operator should develop formal procedures and checklists that identify applicable safety functions and guide personnel as to how these functions must be managed and controlled. The extended inhibition of safety functions should not be controlled via normal operational or control-of-work procedures. Rather, the need for extended inhibitions should be managed via appropriate and thorough management of change processes that include appropriate levels of risk analysis. Changes to ESD and instrumented protective systems trip settings should be sanctioned by the appropriate management level based on appropriate process risk assessment.

45.4.4 Safety Function Tests

Operators should test safety functions on a regular basis in order to identify otherwise unrevealed failures. Test frequencies should be based on the frequency calculations developed during design, or as specified by codes and standards. These test frequencies should be modified as necessary based on operational data.

45.5 Design, Installation and Testing

The process monitoring and control system should be designed, installed and tested to ensure that it is functional and able to detect and control all hazards. It should have high levels of availability and reliability. Systems should also be amenable to testing and maintenance. The system should have adequate redundancy to survive credible events and should be independent of other major systems.

45.5.1 Standards

Process monitoring and control systems on production installations should be designed, installed, commissioned and tested as outlined in the *Petroleum and Natural Gas Industries - Offshore Production Installations - Analysis, Design, Installation and Testing of Basic Surface Process Safety Systems*, ISO 10418:2003 and *Petroleum and Natural Gas Industries - Control and Mitigation of Fire and Explosions on Offshore Production Installations* – Requirements and Guidelines BS EN ISO 13702:2015. While these standards are not directly applicable to mobile offshore units, many of the principles contained in them may be used as guidance in the design, integration (with MODU systems) and testing of control and monitoring systems for formation flow testing operations. Consequently, the operator should consider these standards when planning and selecting equipment for these operations. This equipment on offshore installations must meet the requirements of sections 17, 18 (Emergency Shutdown System) and sections 28-35 of the *Offshore Petroleum Installation Regulations*. For the design of monitoring and control systems on production installations, the operator should also follow the principles set out in *Ergonomics Design of Control Centers*, ISO 11064.

46 Well Completion

(1) An *operator* that completes a *well* shall ensure that

- **(a) it is *completed* in a safe manner and allows for maximum *recovery*;**
- **(b) except in the case of *commingled production*, each *completion interval* is isolated from any other porous or permeable interval penetrated by the well;**
- **(c) the testing and production of any *completion interval* are conducted safely and do not cause *waste* or *pollution;***
- **(d) if applicable, sand production is controlled and does not create a safety hazard or cause *waste;***
- **(e) each packer is set as close as practical to the top of the *completion interval* and that the pressure testing of the packer to a differential pressure is greater than the maximum differential pressure anticipated under the production or injection conditions;**
- **(f) if practical, any mechanical *well* condition that may have an adverse effect on production of petroleum from, or the injection of fluids into, the *well* is corrected;**
- **(g) the injection or production profile of the *well* is improved, or the *completion interval* of the *well* is changed, if it is necessary to do so to prevent *waste;***
- **(h) if different pressure and inflow characteristics of two or more *pools* might adversely affect the *recovery* from any of those *pools*, the *well* is operated as a single *pool well* or as a segregated multi-pool *well;***
- **(i) after initial completion, all *barriers* are tested to the maximum pressure to which they are likely to be subjected; and**
- **(j) following any *work over*, any affected *barriers* are pressure-tested.**

(2) The *operator* of a segregated multi-pool *well* shall ensure that

- **(a) after the *well* is *completed*, segregation has been established within and outside the *well* casing and is confirmed; and**
- **(b) if there is reason to doubt that segregation is being maintained, a segregation test is conducted within a reasonable time frame.**

46.1 General

Operators should use completion technologies and methodologies that have been proven to be reliable for the expected life of the well. The operator should consider zone characteristics and the type of well completion and/or workover contemplated. The following Industry Recommended Practices should be considered:

- Industry Recommended Practice, Volume 2, 2006, *Completing and Servicing Critical Sour Wells*;
- Industry Recommended Practice Volume 14, 2014 *Non Water-Based Drilling Fluids*; and
- Industry Recommended Practice Volume 15, 2015 *Snubbing Operations*.

For additional clarity outside of the industry standards noted above, NORSOK D-010 may be referenced.

46.2 Production Packer Location

It is considered good practice to install the production packer at a depth that is within the cemented interval of the selected casing section.

46.3 Zonal Isolation

Prior to production from a specific zone, all zones should be hydraulically isolated from any other productive zone. Should zonal isolation not be achieved, the operator is to demonstrate why the well should be allowed to produce, prior to any production occurring. The operator is to correct or change any mechanical well condition if practical to maximize ultimate recovery.

46.4 Commingled Production

The guidance under section 66 of the *Regulations* describes expectations related to approval of commingled production.

47 Subsurface Safety Valve

The *operator* of a *development well* capable of flow shall ensure that the *well* is equipped with a fail-safe subsurface safety valve that is designed, installed, operated and tested to prevent uncontrolled *well* flow when it is activated.

47.1 General

The goal of this regulation is to ensure that there is a reliable barrier against uncontrolled well flow in the event that the well needs to be shut-in due to an emergency or failure of the wellhead or Christmas tree. All subsurface safety valves are to be function and pressure tested at regular intervals, to assure reliability.

47.2 "Capable of Flow"

The assessment of "capable of flow" should be conservative in nature, meaning that if there is a possibility that the well could flow without artificial lift, then the well should be equipped with a subsurface safety valve. In any instance where the operator determines that a well is not capable of flow without artificial lift, the operator should also be satisfied that the field will be managed such that a subsurface safety valve is not required throughout the life of the well. In situations where an operator's assessment warrants the installation of a subsurface safety valve, the need for a safety valve on the tubing side and the need for a safety valve on the annular side should be assessed.

47.3 Injection Wells

For injection wells, the operator may utilize any suitable, reliable and fit-for-purpose subsurface injection valve (in lieu of a subsurface safety valve) provided it meets the objective of the *Regulations* in terms of providing a reliable barrier to uncontrolled well flow when closed. Subsurface safety valves should be periodically tested to the extent necessary to assure reliability.

47.4 Standards

The following standards should be considered:

- *Specification for Subsurface Safety Valve Equipment*, API Specification 14A, Twelfth Edition, January 2015;
- ISO 10432: 2004, *Petroleum and Natural Gas Industries – Downhole Equipment – Subsurface Safety Valve Equipment*;
- *Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*, API Recommended Practice 14B (RP 14B), Sixth Edition, September 2015; and
- ISO 10417; 2004 *Petroleum and Natural Gas Industries – Design, Installation, Operation, and Redress of Subsurface Safety Valve Systems*.

47.5 Setting Depth

The setting depth of a subsurface safety valve should be sufficient to minimize the possibility of hydrates interfering with the proper functioning of the valve. In the case of wells in the Newfoundland and Labrador offshore area, the setting depth should also be selected to prevent damage to the valve in the event of an iceberg scouring the wellhead.

48 Wellhead and Christmas Tree Equipment

The *operator* shall ensure that the wellhead and Christmas tree equipment, including valves, are designed to operate safely and efficiently under the maximum load conditions anticipated during the life of the *well.*

48.1 General

In accordance with good engineering practice, “maximum load conditions” would include, but are not necessarily limited to, pressure, thermal stresses, mechanical loading, corrosion (including, where applicable, environments that contain H_2S, CO_2, brines or other corrosive environments) as well as erosion and wear and all appropriate combinations of loading conditions that may be anticipated.

48.2 Malfunction

In the event of any malfunction that compromises the ability of the wellhead and Christmas tree to function as a barrier or to “operate safely and efficiently”, the operator is expected to take the necessary action in as timely a manner as is practicable to rectify the situation.

48.3 Drilling Operation

In the particular case of a drilling operation, the wellhead (and BOP stack) may be required to function as a barrier against uncontrolled well flow, and, in this sense, the wellhead must conform with section 48.

48.4 Standards

With particular reference to the phrase "designed to operate safely and efficiently" in section 49, the following standards may be considered:

- *Specification for Wellhead and Christmas Tree Equipment*, ANSI/API Specification 6A, Twentieth Edition, (ANSI/API 6A/ISO10423-2009), with the exception that screwed wellhead connections should not be used – connections should be flanged and bolted;
- *Specification for Fire Test for Valves*, API Specification 6FA, Third Edition, April, 1999; and *API Specification for Fire Test for End Connections*, API Specification 6FB, Third Edition, May 1998;
- in the case of subsea wells, (including mudline suspension systems): *Specification for the Design and Operation of Subsea Wellhead and Tree Equipment*, API Specification 17D (Spec 17D), Second Edition, May 2011; and *Recommended Practice for Design and Operation of Subsea Production Systems*, API Recommended Practice 17A, Fourth Edition, January 2006;
- in the case of a sour environment: NACE Standard MR0175-2015 *Petroleum and Natural Gas Industries – Materials for Use in H_2S Containing Environments in Oil and Gas Production*;
- in the case of offshore wells (both subsea wells and platform wells): *Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore*, API Standard 6AV2, Second Edition, March 2014; and
- NORSOK Standard D-010, *Well Integrity in Drilling and Well Operations*, Rev. 4, June 2013.

48.5 Tests and Monitoring

In accordance with standard industry practice, the operator is expected to pressure test, function test and/or leak test wellhead and Christmas tree equipment upon installation and, at appropriate intervals thereafter, throughout the life of the well to assure functionality and reliability. The onus is on the operator to implement a suitable program with a prescribed frequency of testing to meet this objective.

The operator is also expected to ensure that appropriate equipment, systems and procedures are in place to monitor pressures, temperatures and any other parameters necessary to ensure the ongoing reliability and integrity of the wellhead and Christmas tree.

PART 5—EVALUATION OF WELLS, POOLS AND FIELDS

49 Implementation of Data Acquisition Programs

The *operator* shall ensure that the *well* data acquisition program and the *field* data acquisition program are implemented in accordance with good oilfield practices.

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

50 Deviation From a Well or Field Data Acquisition Program

- **(1) If part of the *well* or *field* data acquisition program cannot be implemented, the operator shall ensure that**
  - **(a) a *Conservation Officer* is notified as soon as the circumstances permit; and**
  - **(b) the procedures to otherwise achieve the goals of the program are submitted to the *Board* for approval.**
- **(2) If the *operator* can demonstrate that those procedures can achieve the goals of the *well* or *field* data acquisition program or are all that can be reasonably expected in the circumstances, the *Board* shall approve them.**

Operators should refer to section 2.0 of the *Data Acquisition and Reporting Guidelines*.

51 Testing and Sampling of Formations

The *operator* shall ensure that every formation in a well is tested and sampled to obtain reservoir pressure data and fluid samples from the formation, if there is an indication that the data or samples would contribute substantially to the geological and reservoir evaluation.

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

52 Formation Flow Testing

- **(1) The *operator* shall ensure that**
  - **(a) no *development well* is put into production unless the *Board* has approved a *formation flow test* in respect of the *development well*; and**
  - **(b) if a *development well* is subjected to a *well operation* that might change its deliverability, productivity or injectivity, a *formation flow test* is conducted within a reasonable time frame after the *well operation* is ended to determine the effects of that operation on the *well*'s deliverability, productivity or injectivity.**
- **(2) The *operator* may conduct a *formation flow test* on a *well* drilled on a geological feature if, before conducting that test, the *operator***
  - **(a) submits to the *Board* a detailed testing program; and**
  - **(b) obtains the *Board*'s approval to conduct the test.**

(3) The *Board* may require that the *operator* conduct a *formation flow test* on a *well* drilled on a geological feature, other than the first *well,* if there is an indication that the test would contribute substantially to the geological and reservoir evaluation.

(4) The *Board* shall approve a *formation flow test* if the *operator* demonstrates that the test will be conducted safely, without pollution and in accordance with good oilfield practices and that the test will enable the *operator* to

- **(a) obtain data on the deliverability or productivity of the *well*;**
- **(b) establish the characteristics of the reservoir; and**
- **(c) obtain representative samples of the formation fluids.**

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

53 Submission of Samples and Data

The *operator* shall ensure that all cutting samples, fluid samples and cores collected as part of the *well* and *field* data acquisition programs are

- **(a) transported and stored in a manner that prevents any loss or deterioration;**
- **(b) delivered to the *Board* within 60 days after the *rig release date* unless analyses are ongoing, in which case those samples and cores, or the remaining parts, are to be delivered on completion of the analyses; and**
- **(c) stored in durable containers properly labeled for identification.**

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

54 Submission of Core

The *operator* shall ensure that after any samples necessary for analysis or for research or academic studies have been removed from a conventional core, the remaining core or a longitudinal slab that is not less than one half of the cross-sectional area of that core is submitted to the *Board.*

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

55 Disposal of Cutting Samples, Fluid Samples, Cores or Evaluation Data

Before disposing of cutting samples, fluid samples, cores or evaluation data under these Regulations, the *operator* shall ensure that the *Board* is notified in writing and is given an opportunity to request delivery of the samples, cores or data.

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

PART 6—WELL TERMINATION

Note: The guidelines for PART 6—WELL TERMINATION, sections 56 to 59 of the *Regulations*, are addressed collectively under section 59.

56 Suspension or Abandonment

The *operator* shall ensure that every well that is *suspended* or *abandoned* can be readily located and left in a condition that

(a) provides for isolation of all hydrocarbon bearing *zones* and discrete pressure *zones*; and

(b) prevents any formation fluid from flowing through or escaping from the *well-bore*.

57 Monitoring and Inspection of a Suspended Well

The *operator* of a *suspended well* shall ensure that the *well* is monitored and inspected to maintain its continued integrity and to prevent *pollution*.

58 Seafloor Clearing on Abandonment of a Well

The *operator* shall ensure that, on the *abandonment* of any *well*, the seafloor is cleared of any material or equipment that might interfere with other commercial uses of the sea.

59 Installation Removal

No *operator* shall remove or cause to have removed a *drilling installation* from a *well* drilled under these Regulations unless the *well* has been *terminated* in accordance with these Regulations.

Note: The guidance below pertains to sections 56, 57, 58, and 59 of the *Regulations*.

59.1 General

Operators should note that section 10 of the *Regulations* requires a well approval in order to suspend or abandon a well or part of a well.

59.2 Abandoned or Suspended Wells Must Be Readily Located

The requirement set out in section 56 that ". . . every well that is abandoned or suspended can be readily located…" is also related to compliance with section 75 of the *Regulations* regarding a survey to confirm the location of every well. The operator is obliged to take all necessary measures to ensure that any well that is abandoned or suspended can be readily located in the future.

59.3 Temporary Suspension

In the case where operations on a well are temporarily suspended due to weather, ice or any other reason, the well should be suspended in a manner that "prevents any formation fluid from flowing through or escaping from the wellbore", as specified by paragraph 56(b). Operators should develop appropriate contingency plans, policies and procedures for such instances and should ensure that any necessary packers, hang-off tools or other materials or equipment needed to facilitate the orderly suspension of operations and securing the well are in place. These plans should address various scenarios ranging from the relatively long lead time associated with major storm systems to the need to quickly suspend the well in response to an immediate emergency. The various plans, and the circumstances under which each plan is to be implemented, need to be clearly communicated to the appropriate on-site supervisory personnel. The objective of these plans is to ensure that two barriers are in place, where practical, in respect of any well suspension operation. Such barriers could include:

- drilling fluid (taking into account the need to increase its density, where practicable, to compensate for riser margin);
- packers;
- cement plugs; and
- the BOP stack.

When appropriate, particularly following an emergency disconnect, the operator should ensure that an inspection of the wellhead is conducted to confirm that the barriers are effective and that there are no fluids leaking from the wellbore. It is also necessary to ensure that any well is suspended in a manner that enables the safe and efficient resumption of operations.

59.4 Plugging and Abandonment

In the case of a well or zone abandonment, or in the case where a well or zone is being suspended for an extended period, the following guidance is offered in the context of paragraphs 56(a) and (b) of the *Regulations*:

a) The fluid in abandoned or suspended wells should be of sufficient density to over-balance the formation pressures and, in the case of wells that are suspended, the operator should ensure that the fluid is suitable to:
    i) minimize corrosion; and
    ii) prevent freezing.
b) The bottom of the well should be plugged to prevent the wellbore from becoming a conduit for fluids migrating from deeper formations and to ensure that any formations at the bottom of the well that cannot be detected by wireline logs are isolated. This may be achieved by setting a cement plug at the bottom of the well, unless the conditions are such that it is not practicable to set the plug at the very bottom, in which case the plug should be set as deep as practicable. If the formation at the bottom of the well is salt, the plug should be set immediately above the top of the salt. In cases where casing (or a liner) has been set at final total depth and not drilled out, the operator may rely on the cement in the shoe track to fulfill the function of the bottom hole plug if the operator is satisfied that it is adequate to prevent any fluids from deeper formations from entering the wellbore.
c) Cement plugs should be set in any open hole sections
    i) to isolate any abnormally pressured formations;
    ii) to plug any lost circulation intervals; or
    iii) to isolate any hydrocarbon zones or potable water zones.

d) Except in the case of a development well, any perforated interval to be abandoned should be plugged by setting a cement plug as close as practicable above the top perforation, or by setting a bridge plug as close as practicable to the top perforation and setting a cement plug on top of the bridge plug. In the case where the zone contains gas (or is overpressured), the perforations should be abandoned by squeezing cement into the perforations and then performing a pressure test to at least 3,450 kPa above the formation fracture pressure. In the case of a development well, the uppermost perforated interval should be plugged at the time of abandonment in accordance with one of the methods described above. The isolation of zones in development wells for reservoir management purposes may be accomplished with the use of bridge plugs alone, or any other method that provides for effective isolation of the zone.
e) In the case where there is an open hole below the last string of casing, the deepest casing string (or liner) should be plugged at the time of abandonment by setting a cement plug across the casing shoe that is at least 30 metres in length and that extends at least 15 metres below and 15 metres above the shoe, or by setting a bridge plug in the casing within 100 metres of the shoe and setting a cement plug on top, or by any other method that isolates the open hole portion of the wellbore.
f) Any liner lap should be abandoned by setting a cement plug across the liner lap that is at least 30 metres in length and that extends at least 15 metres below and 15 metres above the lap, or by setting a bridge plug not more than 100 metres above the top of the liner and setting a cement plug on top, unless the operator is otherwise satisfied that the primary cement job on the liner lap is adequate, in which case these reasons should be described in the application for well approval.
g) The innermost casing string should be pressure tested at the time of abandonment and appropriate measures should be taken to seal any leak that is detected.
h) Any annulus that is open to a hydrocarbon-bearing zone, a discrete pressure zone or a potable water zone should be sealed at the time of well abandonment. This may be accomplished by perforating the casing as close to the zone as practicable and squeezing cement into the annulus. Prior to perforating any casing in such instances, appropriate precautions should be taken to deal with the possible influx of hydrocarbons.
i) In any instances where it is necessary to cut and recover casing strings as part of any well abandonment, the casing stub should be plugged by setting a cement plug across the stub that extends at least 15 metres below and 15 metres above the stub, or by setting a bridge plug as close as practicable to the top of the stub and setting a cement plug on top of the bridge plug.
j) No oil-based mud should be left above the uppermost plug in a well unless some other appropriate precautions are taken to ensure that the oil from the mud does not leak to the environment over time.
k) Cement plugs should be at least 100 metres if set in open hole and 30 metres if set in casing, or if this is not feasible due to wellbore conditions, the plugs should be as long as practicable.
l) Cement plugs should be designed to have a compressive strength of at least 3,450 kPa after hardening for eight hours.
m) Any cement plug that is not supported by a bridge plug (or the bottom of the well) should be confirmed to be in place by either tagging the plug or by using some other appropriate means to confirm the presence of the plug.
n) Cement volumes used in connection with barrier installation should be based on caliper logs taken following the completion of drilling the hole section or an equivalent means to determine cement volume.
o) Any bridge plug should be pressure tested to confirm its effectiveness in instances where it is being relied upon as a well barrier element. Typically, this would require that the plug

be tested such that the pressure exerted at the casing shoe is at least 3,450 kPa above the fracture pressure, and, in any event, to a pressure differential of not less than 6,900 kPa.

p) If the shoe track is to be used as a barrier it should be negatively pressure tested (inflow test) prior to setting any further suspension or abandonment plugs. A negative pressure test should also be conducted prior to setting the surface plug. Negative pressure tests should be made to a differential pressure equal to or greater than the anticipated pressure after displacement.

q) Any alternative method that provides an equivalent (or better) degree of security against any formation fluid from flowing through or escaping from the wellbore to that described in these *Guidelines* may be used by the operator if such methods are rationalized in the well approval submitted to the appropriate Board. Any subsequent changes to the proposed well termination program that are necessary as a result of unforeseen circumstances as the program is being executed in the field should provide for wellbore security equivalent to the original program. Any such changes should first be reviewed for equivalency by the operator's management personnel responsible for the well termination program.

r) Operators should also note that
   i) any offset pilot holes should be abandoned with cement; and
   ii) any conductor or surface hole section of a well that is to be abandoned in favour or re-spudding the well should be plugged with cement;

s) All casing should be cut off below the seafloor at a depth below which damage by ice scour cannot reasonably be expected, or one metre, whichever is greater and all refuse should be cleared from the seafloor.

59.5 Time Limit for Well Suspension

In the case of any well that is to be suspended for an extended period during or following the drilling phase, the operator should specify, in the application for well approval, the time limit to which the suspension applies together with any plans to monitor and inspect the well during the period that it is suspended.

Any well that is to be suspended for an extended period after it is completed shall be left in a condition that prevents any formation fluid from flowing through or escaping from the wellbore (see paragraph 56(b)) and shall be monitored and inspected to maintain its continued integrity and to prevent pollution as specified by section 57. The manner in which these objectives are to be achieved, and the proposed time period that the well is to be left in a suspended condition should be outlined in the operator's application for well approval. Specifically, the operator should identify the proposed plugs and any proposed valves that are to be relied on for wellbore security during the period of suspension, as well as the fluids to be left in the tubing and casing-tubing annulus and the status of the wellhead and tree.

The time period for which a well may be suspended is dependent on the condition of the well and the manner in which it has been suspended. In all cases, a status update of all suspended wells should be submitted to the Board every three years.

59.6 Seafloor Clearing Requirements

With reference to section 58, the operator is expected to sever the casing strings at a depth below expected maximum scour depth and at least one meter below the seafloor and recover the wellhead and any other associated subsea equipment, except in the case where the operator has provided justification that recovery of the wellhead is unnecessary to prevent interference with other commercial uses of the sea. Where it is necessary to sever casing strings, mechanical means is preferred over explosives for environmental and safety reasons. In this regard, the operator should make as many attempts as are practical to recover the conductor casing and wellhead using mechanical means and should only resort to the use of explosives where the operator has determined that the continued use of mechanical means to recover the wellhead is impractical. In the event that the use of explosives in respect of an offshore well is necessary, the operator should

- notify the Department of National Defense (Submarine Operations) of the anticipated timing of the operation and the type and amount of explosives to be used; and
- ensure that a marine mammal monitoring protocol is in place aimed at ensuring that explosive operations are not undertaken where it has been determined that any marine mammals are within one kilometer of the drilling installation.

59.7 Operator Responsibility for Terminated Wells

With reference to section 59, “termination” is a defined term in the *Regulations* and means the abandonment, completion or suspension of a well. Operators should also be aware that wells, once abandoned, continue to be subject to sections 167 and 162 of the Nova Scotia and Newfoundland and Labrador Offshore *Accord Acts* as they relate to liabilities, losses and damages from the discharge, emission or escape of oil or gas.

PART 7—MEASUREMENTS

60 Flow and Volume

(1) Unless otherwise included in the approval issued under subsection 7(2), the *operator* shall ensure that the rate of flow and the volume of the following are measured and recorded:
- **(a) the fluid that is produced from each *well*;**
- **(b) the fluid that is injected into each *well*;**
- **(c) any produced fluid that enters, leaves, is used or is flared, vented, burned or otherwise disposed of on an *installation*, including any battery room, treatment facility or processing plant; and**
- **(d) any air or materials injected for the purposes of disposal, storage or cycling, including drill cuttings and other useless material that is generated during drilling, *well* or *production operations*.**

(2) The *operator* shall ensure that any measurements are conducted in accordance with the *flow system*, *flow calculation procedure* and *flow allocation procedure*, approved under subsection 7(2).

This provision is self-explanatory. Therefore, no guidelines are necessary.

Note: For C-NLOPB-regulated areas, the measurements for flow and volume from wells should follow the C-NLOPB's *Guidelines Respecting Monthly Production Reporting for Producing Fields in the Newfoundland Offshore Area* September 2011.

61 Flow Allocation

(1) The *operator* shall ensure that group production of petroleum from *wells* and injection of a fluid into *wells* is allocated on a *pro rata* basis, in accordance with the *flow system*, *flow calculation procedure* and *flow allocation procedure* approved under subsection 7(2).

(2) If a *well* is *completed* over multiple *pools* or *zones*, the *operator* shall ensure that production or injection volumes for the *well* are allocated on a *pro rata* basis to the *pools* or *zones* in accordance with the *flow allocation* procedure approved under subsection 7(2).

61.1 General

Operators should refer to the *Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Offshore Area Drilling and Production Regulations*.

62 Testing, Maintenance and Notification

The *operator* shall ensure
- **(a) that meters and associated equipment are calibrated and maintained to ensure their continued accuracy;**

(b) that equipment used to calibrate the *flow system* is calibrated in accordance with good measurement practices;

(c) that any component of the *flow system* that may have an impact on the accuracy or integrity of the *flow system* and that is not functioning in accordance with the manufacturer's specifications is repaired or replaced without delay, or, if it is not possible to do so without delay, corrective measures are taken to minimize the impact on the accuracy and integrity of the *flow system* while the repair or replacement is proceeding; and

(d) that a conservation officer is notified, as soon as the circumstances permit, of any malfunction or failure of any flow system component that may have an impact on the accuracy of the flow system and of the corrective measures taken.

62.1 General

Calibrations should be carried out using test equipment that is dedicated to the metering systems and is traceable to national standards.

An operator shall calibrate every meter and associated equipment that the operator uses, and maintain the calibration with Part 14 of the *Oil and Gas Conservation Regulations of Alberta*.

A conservation officer should be notified of any failure of flow meters, which are identified in the approved flow system. The operator should provide details of the remedial action being taken, including the procedure used to estimate volumes while the meter is out of service.

Additional requirements are found in the *Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Offshore Areas Drilling and Production Regulations*.

63 Transfer Meters

The *operator* shall ensure that

(a) a *conservation officer* is notified at least 14 days before the day on which any transfer meter prover or master meter used in conjunction with a transfer meter is calibrated; and

(b) a copy of the calibration certificate is submitted to the *Chief Conservation Officer* as soon as the circumstances permit, following completion of the calibration.

63.1 General

Regarding 63(a), operators shall provide 14 days notice of the factory inspection and calibration of primary and secondary equipment, including flow computers, in order that conservation officers may witness these tests at their discretion.

Regarding 63(b), a copy of the calibration certificate for each of these and all subsequent calibrations should be sent to the Chief Conservation Officer. Such certificates should show the reference numbers of the sphere detectors used in the calibration, and the traceability to national standards of the calibration equipment.

Additional requirements are found in the *Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Offshore Areas Drilling and Production Regulations.*

64 Proration Testing Frequency

The *operator* of a *development well* that is producing petroleum shall ensure that sufficient *proration tests* are performed to permit reasonably accurate determination of the allocation of *oil, gas* and water production on a *pool* and *zone* basis.

Requirements are found in the *Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Offshore Areas Drilling and Production Regulations*.

PART 8—PRODUCTION CONSERVATION

65 Resource Management

The *operator* shall ensure that
(a) maximum *recovery* from a *pool* or *zone* is achieved in accordance with good oilfield practices;
(b) wells are located and operated to provide for maximum *recovery* from a *pool*; and
(c) if there is reason to believe that infill drilling or implementation of an enhanced *recovery* scheme might result in increased *recovery* from a *pool* or *field*, studies on these methods are carried out and submitted to the *Board.*

65.1 General

Proper resource management to prevent "waste" as defined in the *Offshore Accord Acts* is an essential part of petroleum development.

Operators should be aware that in order to maximize recovery from a pool, the Board may limit the rate where excessive well rates are detrimental to ultimate recovery.

65.2 Location of Wells

As specified by paragraph 65(b) of the *Regulations*, an operator must locate wells so as to provide for maximum recovery from a pool. The factors to consider when selecting development well locations include:

- proximity of the well to fluid contacts - Are the wells located too close to the contact risking premature breakthrough?
- existence and/or location of fractures and faults - If fractures and faults exist, have development wells been located considering the fractures and faults so as to maximize recovery?
- structural and stratigraphic section - Are the wells located to take advantage of the structural and stratigraphic features of a pool?
- cut-off criteria used to locate wells - Is there a minimum net pay, pore volume or productivity criterion used? If so, is it reasonable?
- spacing, target and allowable considerations
- spacing of producers - Does well spacing provide adequate drainage of the various hydrocarbon-bearing intervals comprising the pool?
- have secondary and tertiary recovery been evaluated, if appropriate?
- spacing between injectors - Does the well spacing provide for adequate pressure support and good sweep efficiency?
- would horizontal, deviated or vertical wells be more effective to produce reserves?
- does the well placement provide for the drainage of multiple pools, i.e., those to be developed, and pools which have been identified but not proposed for development? Is commingled production an option?
- offshore wells – Have adequate well slots been provided if there is upside or future potential requirements?

65.3 Independent Scoping Studies

Prior to development plan submission, the Board may conduct independent scoping studies to assess development well locations. These studies may consist of

- 3D reservoir simulation studies to assess well layout to maximize sweep efficiency; and
- reservoir studies to examine the impact of the well location to fluid contact and well spacing.

65.4 Modifications and Review

During the early stages of development drilling and production, the planned well locations may be modified based on production experience and new geological and reservoir data. Well locations should be examined annually as part of the annual production report review (refer to section 86 – Annual Production Report). The following items should be reviewed:

- Predicted well performance against actual well performance; and
- Location of fluid interfaces should be examined to identify potential by-passed petroleum and locations where infill drilling may be justified.

65.5 Infill Drilling Studies

With reference to paragraph 65(c) of the *Regulations*, the operator will be required to undertake infill drilling studies if the Board determines that such studies are justified. Decisions on the need for infill drilling studies will be made in consultation with the operator.

66 Commingled Production

(1) No *operator* shall engage in *commingled production* except in accordance with the approval granted under subsection (2).
(2) The *Board* shall approve the *commingled produc*tion if the *operator* demonstrates that it would not reduce the *recovery* from the *pools* or *zones.*
(3) The *operator* engaging in *commingled production* shall ensure that the total volume and the rate of production of each fluid produced is measured and the volume from each *pool* or *zone* is allocated in accordance with the requirements of Part 7.

66.1 General

As specified by subsections 66(1) and 66(2) of the *Regulations*, commingled production requires the explicit approval of the Board and commingling of pools can only be permitted if the operator has demonstrated that it will not decrease the total hydrocarbon recovery from the individual pools. The Board will accept commingling of zones in instances where the operator demonstrates that it will enhance recovery of the hydrocarbon resource and where the Board is satisfied that the operator is maintaining prudent reservoir management throughout the production life of the field. The factors to be considered in the context of commingled production is outlined in section 66.2 of these *Guidelines* below.

In addition, operators are expected to ensure that sufficient data is obtained on an ongoing basis to understand reservoir drainage and to justify future reservoir management and development decisions.

66.2 Approval

Operator should apply for approval of commingled production on an individual well basis, at the well completion stage. Commingled production will be considered subject to the following:

- When production testing a well that will undergo commingled production, the operator should carry out the test in a manner that allows the assessment of initial inflow parameters and reservoir characteristics for each pool.
- The operator should document the fluid characteristics for each pool to the Board's satisfaction.
- The operator should demonstrate that sufficient information exists to allow the production from each pool in the commingled well to be allocated to the Board's satisfaction.
- The operator should report the allocated pool production monthly to the Board. Ongoing surveillance of the wells should be maintained to ensure the accuracy of the production allocation throughout the life of the well.
- The operator's resource management plan should document the pool management principles set out above.

The commingled production approval for a well or pool may be revoked if, in the opinion of the Board, the operator is not able to reasonably estimate and document the zonal allocation of flow.

67 Gas Flaring and Venting

> **No *operator* shall flare or vent *gas* unless**
> **(a) it is otherwise permitted in the approval issued under subsection 52(4) or in the *authorization*; or**
> **(b) it is necessary to do so because of an emergency situation and the *Board* is notified in the daily drilling report, daily production report or in any other written or electronic form, as soon as the circumstances permit, of the flaring or venting and of the amount flared or vented.**

67.1 Formation Flow Test or Well Cleanup Operation

Where an operator plans to conduct a formation flow test or well clean-up operation, it must be conducted under an authorization or approval. An application for approval should include the following, where applicable:

- a discussion of the rationale for the formation flow test or well clean-up, including in the case of a formation flow test, the objective of the test;
- estimates of flow rates and volumes to be flared and period for which gas will be flared, together with rationale as to why these are necessary to achieve test objectives;
- discussion of options considered to conserve the gas and why they were rejected; and,
- discussion of any potential safety hazards and the precautionary measures to be taken.

67.2 Continuous Flaring and Venting during Production

Where the operator proposes to flare or vent gas during a production operation, it must be conducted under an authorization or approval. An application should include, where applicable:

- a discussion of the options considered to conserve the gas and why they were rejected;
- the period of time for which it is proposed to flare or vent gas, up to a maximum of the validity of the authorization;
- estimates of the flow rates and volumes proposed to be flared or vented, with a maximum allowable of 0.5% of the monthly gas production volume unless otherwise approved as part of the authorization; and
- a discussion of any potential safety hazards and the precautionary measures to be taken.

67.3 Flaring of Acid Gas

The Board may set a maximum time period and volume for the flaring of acid gas in the flare approval. The Board may set notification requirements in the authorization for the flaring and/or venting of acid gas.

67.4 Compliance

The following will be monitored to ensure the operator complies with the regulatory provisions respecting flaring and the conditions attached to any authorization or approval:

- monthly production records will be monitored to assess whether the volumes of gas and/or oil being flared, or oil being disposed of, are within limits set out in the approval, or that requisite approval has in fact been obtained;
- the annual production report will be similarly monitored; and
- periodic assessments will be made of the feasibility of conserving the oil and/or gas.

68 Oil Burning

No *operator* shall burn *oil* unless

(a) it is otherwise permitted in the approval issued under subsection 52(4) or in the *authorization*; or

(b) it is necessary to do so because of an emergency situation and the *Board* is notified in the daily drilling report, daily production report or in any other written or electronic form, as soon as the circumstances permit, of the burning and the amount burned.

68.1 Formation Flow Test or Well Cleanup Operation

Where an operator plans to conduct a formation flow test or well clean-up operation, it must be conducted under an authorization or approval. An application for approval should include the following, where applicable:

- a discussion of the rationale for the formation flow test or well clean-up, including in the case of a formation flow test, the objective of the test;

- estimates of flow rates and volumes to be burned and period for which oil will be burned, together with rationale as to why these are necessary to achieve test objectives;
- discussion of options considered to conserve the oil and why they were rejected; and,
- discussion of any potential safety hazards and the precautionary measures to be taken.

PART 9—SUPPORT OPERATIONS

69 Support Craft

The *operator* shall ensure that all *support craft* are designed, constructed and maintained to supply the necessary support functions and operate safely in the foreseeable *physical environmental conditions* prevailing in the area in which they operate.

69.1 Design of Support Craft

With regard to the design of support craft, operators should develop a functional specification for each type of support craft used in a work or activity, including aircraft. This specification should contain or reference the physical environmental conditions and criteria prevailing in the area that the craft is intended to support.

69.2 Conformity to Functional Specifications

Conformity to the functional specification is the basis for demonstrating that the support craft can fulfill its functions efficiently and operate safely.

69.3 Construction and Maintenance of Support Craft

With regard to the construction and maintenance of support craft, operators should conduct additional surveys and inspections to fill any gaps associated with certificates issued by flag states, given the specialized service of offshore support craft. The operator’s review of the adequacy of the support craft should take into account the hazards identified, tasks assigned, overall risk, age of the craft and any other relevant factor that is necessary to reduce the risk to a level that is as low as reasonably practicable.

69.4 Certification

Operators are expected to ensure the adequacy of installations and support craft to operate safely in the foreseeable physical environmental conditions prevailing in the area in which they are intended to operate. Operators should review the installation’s or support craft’s work history to validate its ability to function under the maximum load conditions that may be reasonably anticipated during any operations. Pre-hire, post-tow and other surveys focusing on safety critical elements should be undertaken during the contracting process.

Operators are expected to ensure that support craft have the appropriate certification, as described below.

69.4.1 Marine Vessels

All marine vessels should have a current International Safety Management (ISM) certificate. Operators are expected to review the validity and functioning of ISM.

Operators should also refer to sections 25 to 27 of the *Regulations* and the associated *Guidelines*.

69.4.2 Foreign-flagged Vessels

Foreign-flagged marine vessels must comply with the SOLAS convention and, in addition to the requisite flag-state certificates, have a Transport Canada Safety Inspection Certificate.

69.4.3 Helicopters and Other Aircraft

Helicopters and other aircraft are required to have a Certificate of Airworthiness issued by Transport Canada.

In view of the fact that aviation rules and regulations focus exclusively on aviation risks and do not take account of the specific risks associated with providing effective support to offshore operations, operators should not rely solely on aviation regulations and certification when developing the functional specification noted in section 69.1 of these G*uidelines*. In this regard, the operator should consider the following factors when developing a functional specification for helicopters:

a) issues related to redundancy for long over-water flights;
b) the aircraft's ability to land on water in various sea states;
c) the aircraft's ability to communicate with the shore base, the installation, other support craft and lifeboats;
d) the rapid and effective deployment of life rafts and other emergency equipment in the event of an emergency landing on water or a capsize;
e) the configuration and design of aircraft interiors, e.g., doors, windows, upper torso passenger restraints, etc. to protect passengers and allow the most efficient emergency egress of passengers considering both landings on water and helicopter capsize;
f) offshore operational requirements, e.g., weather effects on helicopter load limits, flying at night, the transport of passengers and freight at the same time and any other factor that could affect operational requirements;
g) the amount of reserve helicopter fuel kept on board installations and the rationale used to arrive at this amount;
h) the provision of suitable equipment to assist in underwater escape, e.g., goggles, appropriate breathing escape devices, approved helicopter transportation suits, etc., and how this may impact helicopter design and maintenance; and
i) maintenance systems and the incorporation of automated usage and monitoring systems or other methods to ensure the continued suitability of the aircraft.

69.4.4 Helicopter Deck Operations

The procedures pertaining to helicopter deck operations should be developed in consultation with the helicopter contractor and installation owner to ensure compatibility.

69.4.5 Experience of Helicopter Flight Crews

Helicopter flight crews are expected to have experience both with the aircraft and with offshore operations. Adequate flight time is to be allocated for first-response practice and drills.

70 Support Craft Required for a Manned Installation

(1) The *operator* of a manned *installation* shall ensure that at least one *support craft* is
(a) available at a distance that is not greater than that required for a return time of twenty minutes; and
(b) suitably equipped to supply the necessary emergency services including rescue and first aid treatment for all personnel on the *installation* in the event of an emergency.
(2) If the *support craft* exceeds the distance referred to in paragraph (1)(a), both the installation manager and the person in charge of the *support craft* shall log this fact and the reason why the distance or time was exceeded.
(3) Under the direction of the installation manager, the *support craft* crew shall keep the craft in close proximity to the *installation*, maintain open communication channels with the *installation* and be prepared to conduct rescue operations during any activity or condition that presents an increased level of risk to the safety of personnel or the *installation*.

70.1 General

The operator should consider standby and emergency services in the functional specification referred to in the guidance on section 69.

In order to meet the goals set out in section 70 of these *Regulations*, the operator should define the emergency services required of the standby craft as a function of the hazards identified in relation to the proposed work or activity. The operator is expected to demonstrate to the Board that the vessel and crew can effectively fulfill these functions in the context of these hazards and the prevailing environmental conditions. All marine vessels selected for this function should have a Document of Compliance (DOC) pursuant to the *Atlantic Canada – Standby Vessel (AC-SBV) Guidelines*. Operators should refer to the *AC-SBV Guidelines* for further details. Operators are cautioned that offshore activities usually demand sea keeping, maneuverability, power, firefighting, towing and other capabilities far in excess of this minimum requirement.

The onus is on the operator to provide a vessel that meets the requirements of section 70 of these *Regulations* and to be able to demonstrate this capability to the Board.

71 Safety Zone

(1) For the purposes of this section, the safety zone around an *installation* consists of the area within a line enclosing and drawn at a distance of 500 m from the outer edge of the *installation.*
(2) A *support craft* shall not enter the safety zone without the consent of the installation manager.
(3) The *operator* shall take all reasonable measures to warn persons who are in charge of vessels and aircraft of the safety zone boundaries, of the facilities within the safety zone and of any related potential hazards.

71.1 General

Article 60 of the United Nations Convention on the Law of the Sea (UNCLOS) states that

> *4. The coastal State may, where necessary, establish reasonable safety zones around such artificial islands, installations and structures in which it may take appropriate measures to ensure the safety both of navigation and of the artificial islands, installations and structures.*
> *5. The breadth of the safety zones shall be determined by the coastal State, taking into account applicable international standards. Such zones shall be designed to ensure that they are reasonably related to the nature and function of the artificial islands, installations or structures, and shall not exceed a distance of 500 metres around them, measured from each point of their outer edge, except as authorized by generally accepted international standards or as recommended by the competent international organization. Due notice shall be given of the extent of safety zones.*
> *6. All ships must respect these safety zones and shall comply with generally accepted international standards regarding navigation in the vicinity of artificial islands, installations, structures and safety zones.*

71.2 Collision Avoidance and Vessel-Traffic Management

In order to meet the goals set out in section 71 of these *Regulations*, operators should develop marine collision avoidance and vessel-traffic management procedures including:

- procedures for dealing with authorized and unauthorized vessels;
- procedures for maintaining a radar watch and for plotting targets;
- criteria for declaring vessel collision alerts;
- procedures to alert intruding vessels;
- the role of the standby vessel;
- procedures for securing the installation;
- notification procedures between the installation and shore base; and
- requirements for documenting near-miss events, including definition of a near-miss.

71.3 Radar Systems

All installations and vessels are expected to have effective radar systems that provide 360-degree coverage and are capable of detecting icebergs. Appropriate radar-plotting equipment, appropriate alarms and continuous radar monitoring by competent personnel are also expected.

71.4 Charting of a Safety Zone

All operators should contact the Board with appropriate information related to production installations[13] approximately six months in advance of their installing or locating equipment on-site, and request that a “Safety Zone” be “charted”. The Board will then request the Canadian Hydrographic Service to indicate the “Safety Zone” associated with the production installation on appropriate nautical charts.

[13] The *Installations Regulations* define a “production installation" as “a production facility and any associated platform, artificial island, subsea production system, offshore loading system, drilling equipment, facilities related to marine activities and dependent diving system.”

71.5 Temporary Drilling and Diving Installations

For drilling and diving installations that are temporary or transient, the operator should communicate the appropriate information regarding location and "safety zone" to Transport Canada, where applicable, so they can ensure a "Notice to Mariners" is issued.

PART 10—TRAINING AND COMPETENCY

72 Experience, Training and Qualifications

The *operator* shall ensure that

(a) all personnel have, before assuming their duties, the necessary experience, training and qualifications and are able to conduct their duties safely, competently and in compliance with these Regulations; and

(b) records of the experience, training and qualifications of all personnel are kept and made available to the *Board* upon request.

72.1 General

The requirement of paragraph 72(a) should also be considered in the context of the operator's obligation to provide a declaration as required by the *Acts*.

72.1.1 Competency Assurance Process

In order to meet this goal and to comply with paragraph 5(2)(d) of these *Regulations*, operators should ensure that an effective competency assurance process is in place for all roles and positions that may affect the safety of personnel, resource conservation or the protection of the environment.

Operators should structure the competency assurance process such that no individual may undertake any task that may be critical to safety or the protection of the environment until they are objectively assessed as competent to undertake that task or they are under the direct and immediate supervision of someone who has been assessed competent. These assessments should take place in the context of the overall competency assurance program, which takes into account and documents such factors as training, experience, certification, competency assessment and installation-specific equipment, systems and procedures. The competency assurance system should also consider key responsibilities and activities identified in major hazard risk assessments and identify safety and environmentally critical roles and tasks. The system should include reassessment and re-training. Operators should consider nationally or industry-recognized technical standards in competency. In accordance with the operator's obligation to ensure overall competency, the competency assurance process should include all personnel engaged in the work or activity, including, for example, third-party contractors, leadership, senior managers and other key shore-based personnel. Managers should be trained in competency goals and processes. A good competency assurance process provides competency performance indicators for management and management of change, and provides for regular system audits at all levels of the process.

72.1.2 Minimum Requirements for Training and Certification

The legislation and regulations puts the onus on each operator to assure the full range of competence of all personnel. The Atlantic Canada Offshore Training and Qualifications Standard Practice (TQSP) sets out some of the minimum requirements for training and certification in some key roles and provides some guidance on overall safety and emergency response training.

Operators should abide by Canadian requirements and Canadian industry norms with regard to technical training and trades certification. For example, welders, electricians and mechanical and instrument technicians should have appropriate certification at the journeyman level.

72.1.3 Workplace Committees

The legislation requires that operators and employers ensure that members of workplace committees have the training necessary to enable them to fulfill their duties and functions as a committee member. Refer to Part III.1 of the *Accord Act* and the *Offshore Marine Installations and Structures Occupational Health and Safety Transitional Regulations* for duties, functions and training requirements.

All managers and supervisors should be appropriately trained in the management system and its functioning related to safety and the protection of the environment.

72.1.4 Inspection, Testing, Maintenance, and Operation of Safety Critical Equipment

Competency assurance is particularly important for personnel responsible for tasks related to the inspection, testing, maintenance, and operation of safety critical equipment. Refer to the guidance in sections 25 to 27 of these *Regulations*. In addition to individual competence, operators should ensure that the organization charged with undertaking and completing a work or activity is competent as a whole. All necessary skills and expertise should be provided in sufficient numbers to plan and execute the project safely and without pollution. This includes sufficient redundancy, succession planning and access to additional resources to cope with credible emergency and abnormal situations.

Furthermore, any personnel who maintain, inspect, or repair safety critical equipment must be suitably trained for those tasks inclusive of any qualifications and training criteria specified by the OEM and such maintenance, inspection, and repair is undertaken in accordance with recognized engineering and industry practices.

72.1.5 Records Management and Tracking Systems

Operators are expected to ensure that records are readily available and well organized, in the event that the Board undertakes a review of maintenance, training and competency records. The Board may audit this matter.

73 Impairment and Fatigue

(1) Subject to subsection (2), the *operator* shall ensure that no person shall work when their ability to function is impaired and that no person is required to work
  - **(a) any shift in excess of 12.5 continuous hours; or**
  - **(b) two successive shifts of any duration unless that person has had at least eight hours rest between the shifts.**

(2) The *operator* may allow a person to work in excess of the hours or without the rest period referred to in subsection (1) if the operator has assessed the risk

associated with the person working the extra hours and determined that such work can be carried out without increased risk to safety or to the environment.

(3) If an *operator* allows a person to work in excess of the hours or without the rest period referred to in subsection (1), the *operator* shall ensure that a description of the work, the names of the persons performing the work, the hours worked and the risk assessment referred to in subsection (2) are recorded.

73.1 General

This regulation places the onus on the operator to ensure that "no person shall work when their ability to function is impaired." To meet this goal, operators should have systems in place to manage and control all forms of worker impairment (fatigue, drugs, sickness, etc.) in a systematic manner commensurate with risk to the individual and any risk their impaired function may pose to the safety of other personnel or to the environment. This requirement applies to all persons whose work has a direct effect on the approved work or activity and includes appropriate "onshore" personnel.

73.2 Medical Examinations

Operators should ensure that all personnel are provided with comprehensive and appropriate medical examinations prior to employment and periodically thereafter in accordance with the Canadian Association of Petroleum Producers' guidance document, *Atlantic Canada Medical Assessment for Fitness to Work Offshore*, May 2016. These examinations should be developed in accordance with appropriate hazard and work assessments to protect both the individual and others. Personnel should have access to appropriate medical and other assistance programs, and supervisors should be trained and directed to recognize and act upon common forms of impairment.

73.3 Managing Fatigue

Operators should develop a comprehensive, systematic and documented approach to fatigue management. Operators should develop appropriate practical tools or methodologies to assess and document the risk associated with personnel working extra hours and extra rotation days. These tools and methods can borrow from current approaches to assessing the risk associated with controlled hazardous activities done under work permit and can employ practical "rules of thumb" to limit overtime. The risk assessment should consider both the risk to the individual doing the work and the risk to others, the installation and the environment. The analysis should consider factors such as the work environment (cold, heat, noise, etc.), the nature and risk of the tasks themselves, the total time worked during a rotation and on consecutive days.

PART 11

SUBMISSIONS, NOTIFICATIONS, RECORDS AND REPORTS

74 Reference to Names and Designations

When submitting any information for the purposes of these Regulations, the *operator* shall refer to each *well, pool* and *field* by the name given to it under sections 3 and 4, or if a zone, by its designation by the *Board* under section 4.

This regulation is self-explanatory. Therefore, no guidelines are necessary.

75 Surveys

- **(1) The *operator* shall ensure that a survey is used to confirm the location of the *well* on the seafloor.**
- **(2) The survey shall be certified by a person licenced under the Canada Lands Surveyors Act.**
- **(3) The *operator* shall ensure that a copy of the survey plan filed with the Canada Lands Surveys Records is submitted to the *Board.***

75.1 General

The requirements pertaining to well location surveys, and a description of the land division system used on Canada Lands, is outlined in the *Canada Oil and Gas Lands Regulations* (C.R.C., c. 1518) under the *Territorial Lands Act*. A copy of the Regulations is available on the Boards' Web sites:

CNSOPB:	http://www.cnsopb.ns.ca
C-NLOPB:	http://www.cnlopb.ca

75.2 Seafloor Location

As specified by subsection 75(1), it is the "seafloor" location of the well that must be determined by the survey.

75.2.1 Subsea Well

In the case of a subsea well, this refers to the location of the well at the seafloor, not the "surface" location of the rotary table on the installation.

75.2.2 Platform Well

For a platform well, the "seafloor" location may be assumed to be the location of the well at the wellhead deck level on the installation.

75.3 Subsea Templates

In the case of subsea templates containing multiple well slots, the location of wells may be determined relative to a fixed survey point on the template provided that the technique used for this determination is in accordance with survey practices acceptable to the licenced Canada Lands Surveyor.

75.4 Reporting Requirements

For the purpose of subsection 75(3), one hard copy of the survey plan (and any associated appendices or other support documents) and one electronic copy should be submitted to the appropriate Board after it has been duly registered with the Canada Lands Surveys Records. This survey may be submitted with the well history report referenced in section 89 of the *Regulations*.

75.5 North American Datum

All surveys are to be referenced to NAD 27 as well as NAD 83 until the *Canada Oil and Gas Lands Regulations* are updated from NAD 27 to NAD 83, at which time NAD 83 will suffice.

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76 Incidents

(1) The *operator* shall ensure that
- **(a) the *Board* is notified of any *incident* or *near-miss* as soon as the circumstances permit; and**
- **(b) the *Board* is notified at least 24 hours in advance of any press release or press conference held by the *operator* concerning any *incident* or *near-miss* during any activity to which these Regulations apply, except in an emergency situation, in which case, it shall be notified without delay before the press release or press conference.**

(2) The *operator* shall ensure that
- **(a) each *incident* or *near-miss* is investigated, its root cause and causal factors identified and corrective action taken; and**
- **(b) for any of the following *incidents* or *near-misses*, a copy of an investigation report identifying the root causes, causal factors and corrective actions is submitted to the *Board* no later than 21 days after the day on which the *incident* or *near-miss* occurred:**
  - **(i) a *lost or restricted workday injury*,**
  - **(ii) death,**
  - **(iii) fire or explosion,**
  - **(iv) a loss of containment of any fluid from a well,**
  - **(v) an imminent threat to the safety of a person, installation or support craft, or**
  - **(vi) a significant *pollution event*.**

76.1 General

Operators should be aware that the terms "incident", "lost or restricted workday injury" and "pollution" are defined in these *Regulations*. Also, Operators should note that "spill" is defined in the *Offshore Accord Acts* and that there are spill reporting and response requirements in these *Acts*.

Note: Other terms such as minor injury, serious injury, and disabling injury are defined in the *Accord Act* and the *Offshore Marine Installations and Structures Occupational Health and Safety Transitional Regulations*.

With reference to paragraph 76(1)(b) – press releases and press conferences— this is self-explanatory. Therefore, no guidance is necessary. Detailed guidance on paragraphs 76(1)(a) and subsection 76(2) is provided in the *Incident Reporting and Investigation Guidelines*.

77 Submission of Data and Analysis

(1) The *operator* shall ensure that a final copy of the results, data, analyses and schematics obtained from the following sources is submitted to the *Board*:
- **(a) testing, sampling and pressure surveys carried out as part of the *well* and *field* data acquisition programs referred to in section 49 and testing and sampling of formations referred to in section 51; and**
- **(b) any segregation test or *well operation*.**

(2) Unless otherwise indicated in these Regulations, the *operator* shall ensure that the results, data, analyses and schematics are submitted within 60 days after the day on which any activity referred to in paragraphs (1)(a) and (b) is completed.

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

78 Records

The *operator* shall ensure that records are kept of
- **(a) all persons arriving, leaving or present on the *installation*;**
- **(b) the location and movement of *support craft*, the emergency drills and exercises, *incidents*, *near-misses*, the quantities of consumable substances that are required to ensure the safety of operations and other observations and information critical to the safety of persons on the *installation* or the protection of the environment;**
- **(c) daily maintenance and operating activities, including any activity that may be critical to the safety of persons on the installation, the protection of the environment or the prevention of *waste*;**
- **(d) in the case of a *production installation*,**
  - **(i) the inspection of the *installation* and related equipment for corrosion and erosion and any resulting maintenance carried out,**
  - **(ii) the pressure, temperature and flow rate data for compressors and treating and processing facilities,**
  - **(iii) the calibration of meters and instruments,**
  - **(iv) the testing of surface and subsurface safety valves,**
  - **(v) the status of each *well* and the status of *well operations*, and**
  - **(vi) the status of the equipment and systems critical to safety and protection of the environment including any unsuccessful test result or equipment failure leading to an impairment of the systems; and**

(e) in the case of a floating *installation,* all *installation* movements, data, observations, measurements and calculations related to the stability and station-keeping capability of the *installation.*

78.1 General

The goal and objective of this regulation is to ensure that the operator has systems and procedures in place to maintain accurate and comprehensive records on each of the matters listed in paragraphs 78(a) to (e). As specified by section 80 of these *Regulations*, certain records must be offered to the Board before they are destroyed. In addition, records must be maintained in a manner that is readily accessible for inspection by the Board, as specified by paragraph 81(b) of these *Regulations*. Records may be kept in electronic form, or in hard copy. In either case, it is advisable that back-up copies of records are maintained to the extent that is necessary and appropriate.

78.2 Consolidated Records

It is not necessary that a single consolidated record be kept of the various topics listed in paragraphs 78(a) to (e); the operator may opt instead to keep such records in various places and within various systems if it is more practical and efficient to do so, provided that such records are readily accessible as required.

78.3 Submission of Records to the Board

Operators should also note that the records required by section 78 need not be submitted to the Board (except when the operator is proposing to destroy such records, in which case the Board is to be notified and offered the opportunity to receive the records, or portions of the records). However, as specified by section 84 of the *Regulations*, the operator is obliged to prepare, and submit to the Board daily reports summarizing drilling, geological and production information.

79 Meteorological Observations

The *operator* of an installation shall ensure

(a) that the *installation* is equipped with facilities and equipment for observing, measuring and recording *physical environmental conditions* and that a comprehensive record of observations of *physical environmental conditions* is maintained onboard the *installation*; and

(b) that forecasts of meteorological conditions, sea states and ice movements are obtained and recorded each day and each time during the day that they change substantially from those forecasted.

79.1 General

Operators should be aware that the Board may request that a copy of the site-specific meteorological forecast and a report of ice conditions be provided daily, otherwise operators should refer to the *Physical Environmental Guidelines* for the guidance on this regulation.

80 Daily Production Record

The *operator* shall ensure that a daily production record, which includes the metering records and other information relating to the production of petroleum and other fluids in respect of a *pool* or *well,* is retained and readily accessible to the *Board* until the *field* or *well* in which the *pool* is located is *abandoned* and at that time shall offer the record to the *Board* before destroying it.

80.1 General

The daily production record should contain the following information:

a) for production wells:
   - i) estimated oil, gas and water production (m^3/d) water/oil, gas/oil or gas/water ratios;
   - ii) total number of hours well is in production;
   - iii) average separator or treater pressure and temperature;
   - iv) tubing head and/or subsurface pressure; and
   - v) where a well is tested during the day to which the record applies:
     - the oil, gas and water production rate (m^3/d) and total volume produced on test;
     - hours on test; and
     - pressure and temperature of test separator.

b) for injection wells:
   - i) estimated amount of gas, water, natural gas liquids, oil or other substances injected into the well;
   - ii) the source from which the gas, water, natural gas liquids, oil or other substances were obtained;
   - iii) tubing head pressure and temperature; and
   - iv) the number of hours each substance was injected into the well.

c) an estimate of total oil, gas and water production; also an instantaneous flow rate, static pressure, differential pressure and flowing temperature taken at the same time each day

d) an estimate of total gas, water, natural gas liquids or other substance injected into the well; also of instantaneous flow rate, static pressure, differential pressure, and flowing temperature taken at the same time each day;

e) particulars as to the inventories and disposition of all production including the following:
   - i) open and closing oil in storage;
   - ii) oil and gas volume transferred from the installation; where a ship is used to transport oil, the name of the tanker;
   - iii) gas used:
     - as fuel, and
     - for gas lift operation;
   - iv) oil, gas and/or acid gas flared; and
   - v) oil that is used as a hydraulic power fluid for artificial lift;

f) if oil or gas is sold, the name of the purchaser and/or transporter;

g) estimates should be provided for any produced fluids that were not measured, lost or spilled;

h) details of calibration of meters and associated measurement equipment that is part of the approved flow system;

i) for each approved meter, all information used to calculate a flow volume should be recorded. The information should include where appropriate:
   - i) meter identification number;

ii) instantaneous flow rate;
iii) static pressure;
iv) differential pressure;
v) flowing temperature;
vi) line size;
vii) orifice size;
viii) atmospheric pressure;
ix) basic orifice factor;
x) real gas relative density factor;
xi) flowing temperature factor;
xii) Reynolds number factor;
xiii) expansion factor;
xiv) pressure base factor;
xv) temperature base factor;
xvi) super compressibility factor;
xvii) any other factors used;
xviii) orifice flow constant;
xix) meter conversion factor;
xx) gas and/or liquid analyses and analysis date; and
xxi) relative density.

All factors used in the approved flow calculation procedures should be recorded.

j) any of the flow parameter changes which could influence flow calculations should be noted. These include:
   i) orifice change;
   ii) gas/liquid analyses update; and
   iii) changes to the database used in flow calculations.
k) a record should be kept of all alarms that may have an effect on the measurement accuracy of the flow system. The time of each alarm condition and time of clearing of each alarm should be recorded. Alarms should be provided for the following:
   i) master terminal unit failure;
   ii) remote terminal unit failure;
   iii) communication failures;
   iv) low power warnings;
   v) changes to database;
   vi) high/low differential pressure; and
   vii) over range values.

80.2 Other Instructions Regarding the Daily Production Record

All volumes separated are to be adjusted to standard conditions and in accordance with the allocation and flow calculation procedures approved. The original recording of measurements used to determine the particulars for the record should be included with the record. A daily production record must be kept for each pool. The daily production record should only be submitted to the Board when requested. Typically, the Board will not require this record to be submitted but the conservation officers will require access to the record for auditing purposes. The record form should be viewed by the Board prior to initiation of production to confirm that the appropriate information is being recorded.

The daily production record for a pool is to be retained by the operator until production from the field is abandoned. As specified by section 80, the operator shall offer the record to the Board before destroying it. The daily production record is the primary accounting record to keep track of all fluids produced from a well and injected into a well in a pool and disposition of produced fluids. This record will be reviewed by a conservation officer during an audit of the flow system and allocation and calculation procedures. Where a digital copy of this record exists, the Board may request a copy.

81 Management of Records

The *operator* shall ensure that
(a) all processes are in place and implemented to identify, generate, control and retain records necessary to support operational and regulatory requirements; and
(b) the records are readily accessible for inspection by the *Board.*

This regulation is self-explanatory. Therefore, no guidelines are necessary.

82 Formation Flow Test Reports

The *operator* shall ensure that
(a) in respect of exploration and delineation *wells*, a daily record of *formation flow test* results is submitted to the *Board*; and
(b) in respect of all *wells*, a *formation flow test* report is submitted to the *Board* as soon as the circumstances permit, following completion of the test.

Operators should refer to the *Data Acquisition and Reporting Guidelines*.

83 Pilot Scheme

(1) For the purposes of this section, "pilot scheme" means a scheme that applies existing or experimental technology over a limited portion of a *pool* to obtain information on reservoir or production performance for the purpose of optimizing *field* development or improving reservoir or production performance.
(2) The *operator* shall ensure that interim evaluations of any pilot scheme respecting a pool, field or zone are submitted to the Board.
(3) When the operator completes a pilot scheme, the *operator* shall ensure that a report is submitted to the *Board* that sets out
(a) the results of the scheme and supporting data and analyses; and
(b) the *operator's* conclusions as to the potential of the scheme for application to full-scale production.

83.1 General

An operator will be expected to submit interim evaluations of any Pilot Scheme in accordance with the conditions for the Resource Management Plan (RMP) approval or the Development Plan approval, whichever is applicable. The Board may specify at the time of the RMP approval or the

Development Plan approval the information that should be contained in any interim report of a Pilot Scheme.

83.2 Reports

Upon completion of a Pilot Scheme, the operator must submit a report to the Board that presents the results of the scheme and supporting data and analysis, and the conclusions of the operator regarding the scheme's potential for application to full-scale production. Since each Pilot Scheme will be different, it is suggested that the operator consult with the CCO regarding the information that should be presented in the interim and final reports.

84 Daily Reports

The *operator* shall ensure that a copy of the following is submitted to the *Board* daily:
(a) the daily drilling report;
(b) the daily geological report, including any formation evaluation logs and data; and
(c) in the case of a *production installation*, a summary, in the form of a daily production report, of the records referred to in paragraph 78(d) and the daily production record.

84.1 General

Both the daily drilling and production reports should contain a summary of the information required by section 78 of the *Regulations* along with the following:

- a description of activities on the installation that occurred during the previous day;
- the current status of activities on the installation (as of 06:00 hours);
- an outlook of activities on the installation for the next 24 hours;
- a summary of physical environmental conditions;
- a summary of motion and stability data (where applicable);
- the status of mooring and positioning systems (where applicable); and
- any other information that is required to be provided on the report by the *Regulations* or that is required to provide a full understanding of the status of operations.

84.2 Items in the Daily Drilling Report

With reference to paragraph 84(a) of the *Regulations*, the term "daily drilling report" should be interpreted to mean a daily report in respect of any operation on a well, including drilling, suspension, abandonment, completion, workover, well intervention or any other well operation.

The report should contain sufficient information to provide a full understanding of the operation and to serve as a record for others in the future. In this regard, the report should provide

- a description of activities that occurred during the previous day;
- the current status (as of 06:00 hours);
- an outlook of activities for the next 24 hours;
- the daily and cumulative costs;
- all appropriate well and casing data;
- the properties of the drilling fluid;

- the drilling fluid gas readings;
- directional and deviation surveys;
- the formations encountered;
- results of BOP equipment tests;
- results of any formation leak-off tests (or formation integrity tests);
- a summary of physical environmental conditions;
- a summary of motion and stability data;
- the status of mooring and positioning systems; and
- any other information that is explicitly required to be provided on the report by the *Regulations* or that is required to provide a full understanding of the status of the well and the operations that were conducted on the well.

84.3 Accuracy and Completeness

It is the operator's responsibility to ensure the accuracy and completeness of the report. The report should be prepared by the operator daily and submitted to the Board electronically.

84.4 Format and Content

Information respecting the format and content of the daily geological report and the formation evaluation logs and data specified by paragraph 84(b) of the *Regulations* is provided in the *Data Acquisition and Reporting Guidelines*. Operators should contact the relevant Board for information respecting the daily production report.

84.5 Submission of Reports

The reports specified by paragraphs 84(a) and (b) of the *Regulations* should be provided from the start of activities that are covered by the authorization and until completion of operations that are covered by the authorization. The reports specified by paragraph 84(c) of the *Regulations* should be provided from the commencement of production operations.

84.6 Weather Forecasts and Ice Reports

A copy of the site-specific meteorological forecast and a report of ice conditions should be provided daily to the Board.

84.7 Tour Sheets

One copy of each Tour Sheets (signed) should be submitted monthly to the Board.

84.8 Other Routine Notifications

Besides contact with the appropriate Board, operators should establish routine contacts with the Canadian Coast Guard's Vessel Traffic Services and the Department of National Defence's Search and Rescue in Halifax for notifying these agencies of marine activities and operational matters such as:

a) moves due to pack ice, icebergs, inspection or any other reason;
b) a change in location of the drilling installation due to well termination; and

c) formation flow testing operations involving flaring of hydrocarbons.

85 Monthly Production Report

(1) The *operator* shall ensure that a report summarizing the production data collected during the preceding month is submitted to the *Board* not later than the 15th day of each month.
(2) The report shall use established production accounting procedures.

85.1 General

The statements and worksheets which make up the monthly production report are to be submitted to the Board in both hardcopy and electronic form. The formats for submission of data have been specified by each of the Boards, as described in sections 85.2 to 85.3 below.

85.2 Canada Nova Scotia Offshore Petroleum Board

For the CNSOPB, operators should contact the Board for detailed requirements.

85.3 Canada-Newfoundland and Labrador Offshore Petroleum Board

For the C-NLOPB, operators should refer to the *Guidelines Respecting Monthly Production Reporting for Producing Fields in the Newfoundland Offshore Area* September 2011.

86 Annual Production Report

The operator shall ensure that, not later than March 31 of each year, an annual production report for a pool, field or zone is submitted to the Board providing information that demonstrates how the operator manages and intends to manage the resource without causing waste, including:

(*a*) for the preceding year, details on the performance, production forecast, reserve revision, reasons for significant deviations in well performance from predictions in previous annual production reports, gas conservation resources, efforts to maximize recovery and reduce costs and the operating and capital expenditures, including the cost of each well operation; and

(*b*) for the current year and the next two years, estimates of the operating and capital expenditures, including the cost of each well operation.

86.1 General

The purpose of the annual production report is to provide information necessary to evaluate whether the field is being developed in accordance with the approved development plan and the field is being managed properly to ensure that maximum recovery is being achieved in accordance with paragraph 65(a) of the *Regulations*.

86.2 Submission of Report

The annual production report covering the preceding calendar year must be submitted no later than March 31 of each year. The report is to cover the previous year containing the period January 1 to December 31 inclusive. The annual production report is to be submitted to the Board in both hardcopy and electronic format.

86.3 Details of Report

The annual production report is to present a review of production activities and performance of the wells, zones, pools and field(s) during the reporting period. This report is an important aspect of monitoring and resource management. The annual production report should include updates to the Resource Management Plan and should set out, where applicable, the following:

a) graphs of production from, and injection into, a pool or field(s), including
   i) the daily average oil, water and gas production rate for each month;
   ii) the average gas/oil and water/oil ratios for each month;
   iii) for each type of fluid being injected, the daily average rate of injection per operating day for each month;
   iv) monthly cumulative oil, gas and water production;
   v) monthly cumulative of each fluid being injected; and
   vi) the average formation pressure;
b) where available, the predicted performance based on simulation studies;
c) a review of production from, and injection into, each well that is located in the pool or field, including the following:
   i) appropriate plots as noted in paragraph (a) should be provided for each well. A brief discussion should be provided highlighting wells which have experienced a significant change in production and injection performance and the likely reasons for the change.
   ii) for each injection well approaching the maximum wellhead injection pressure or formation fracture pressure, the following should be provided:
      - a summary of the average wellhead injection pressure for each operating day, month;
      - a summary of the injectivity index per operating day, month which is determined by dividing the average day injection rate by the difference between sandface and formation pressure; and
   iii) a table showing changes in well status (e.g. producer/injector/suspended/abandoned, perforated intervals, artificial lift installation);
d) a review of the production capability of the pool and field, including a discussion on the production capability for each pool and the field in relation to the actual and predicted performance based on reservoir simulation studies as well as the measures which have been implemented or planned to improve or sustain production capability;
e) predicted declines in production capability of the pool or field in the form of a monthly production forecast for each pool, well and the field, and a table listing expected production for the coming year;
f) details of pool performance including a discussion of the performance of each pool with reference to the graphs in paragraph (a) with particulars as follows:
   i) the oil and gas in place, recoverable reserves and recovery efficiency. This should include a discussion of changes with respect to the development plan approved base case;

   ii) a table detailing each pool's yearly daily oil, gas and water rates, total oil, gas and water production for that year, cumulative oil, gas and water production, oil/gas ratio, water/gas ratio, and initial pool production date;
   iii) calculations of the voidage replacement on a monthly and cumulative basis for each pool and each pattern or segment;
   iv) composition of fluids produced from the pool;
   v) pool pressure performance;
   vi) discussion of sweep efficiency including the result of cased hole log surveys, including maps showing the estimated location of displacing fluid fronts; and,
   vii) plan studies to assess pool performance;

g) a summary of the results of any studies conducted to assess infill well potential or to investigate methods to improve recovery as well as information specified in section 65.4 of these *Guidelines*;
h) the impact of drilling, production or other work on the geologic or reservoir model, together with revised structure top map showing well locations and fluid contacts as well as net gross thickness, isoporosity, net thickness and mass;
i) a review of water and/or sand production for each pool, highlighting wells which have experienced water breakthrough and/or sand production and the likely source of the water and/or sand, together with a discussion of the efforts to reduce water and/or sand production;
j) a summary of tests, surveys and alterations in respect of performance of each well and alterations to production equipment for the pool or field, highlighting the following:
   i) a summary of the results of all well tests;
   ii) a summary of total gas and/or acid gas that is flared and vented;
   iii) a listing of cased hole logs run including on which wells and the date;
   iv) the date and type of any well treatment or workover and a discussion of the effect of such measures on well performance behaviour;
   v) a list of special core analysis conducted including a summary of results;
   vi) a summary of results of PVT studies conducted indicating the pool from which samples were acquired; and,
   vii) a listing of alterations to production equipment for the pool or field including a discussion of the effect of the alteration on pool or field production performance.
k) a review of subsurface safety valve performance, including, for each of the subsurface safety valve test, the date of the test, the differential pressure, closure times, the results of the test and the time interval between tests;
l) a listing of any significant modifications to the production installation at the pool or field, including the date modifications were performed, a brief description of the modification, the reason for the modification and the results of the modification;
m) details of the operating and capital expenditures, including the cost of each well operation, for the preceding year, the current-year prediction and the projections for the next two years, including:
   i) the total project capital expenditure for each of the previous two years and the projected total project capital cost expenditures for each of the upcoming three years;
   ii) the total operating cost expenditure for each of the previous two years and the projected total operating cost expenditures for each of the upcoming three years; and
   iii) in addition to (i) and (ii) above, detailed capital and operating cost expenditures in relation to the following categories for each of the previous two year period, together and the projected expenditures for each of the following three years in relation to :
      - new wells;
      - well interventions and workovers;
      - sidetracks;

- facilities routine maintenance;
- facilities upgrades and de-bottlenecks;
- major modifications for third parties; and
- any other expenditures outside these categories; and

iv) an explanation of any large variations from previous annual reports; and

n) upon request, a report that forecasts system deliverability as well as pressures, temperatures, and rate relationships for the production facilities and / or pipelines, or if not requested, the operator must keep this information for at least five (5) years.

86.4 Updates to Resource Management Plan (RMP)

The Annual Production report should contain a section referring to the Resource Management Plan that includes updates or changes to the RMP. The section in the Annual Production report can reference other areas to the report but should highlight the changes to the Resource Management Plan.

The subheadings for the sections in the Annual Production report could include:

Geology and Geophysics
Any changes in geological data/models, methods or interpretations should be presented or referenced.

Petrophysics
Any changes in petrophysical data, methods or interpretations should be presented or referenced.

Reservoir Engineering
Any changes in reservoir engineering data, methods or interpretations should be presented or referenced. Items to consider include:

- drill stem test results and analyses;
- reservoir fluids
- changes in composition of injected fluids, compatibility studies, injectivity and/or pulse tests;
- changes in reservoir pressures, temperatures and pressure/depth plots; and,
- results of special core analyses (i.e. residual oil and gas saturations, capillary pressure data, relative permeability and critical gas saturations) used in reservoir studies.

Reserve Estimates
Any updates to estimates of reserves should be provided for each pool or hydrocarbon-bearing reservoir.

Reservoir Exploitation
Any updates to the approved reservoir exploitation scheme should be provided.

Deferred Development
Any updates to deferred developments should be provided.

Development Drilling and Completions
Any updates to drilling and completions should be provided.

Production and Export Systems
Any updates to production and export systems should be provided, including, in particular:

- Topside Facilities
- Organization
  A typical organization chart is required to show the reporting relationships for personnel employed in implementation of the resource management plan with up to date contact information
- Operability of Development

Development and Operating Cost Data
Updates to the information is necessary throughout the life of the field.

87 Environmental Reports

(1) For each *production project*, the *operator* shall ensure that, not later than March 31 of each year, an annual environmental report relating to the preceding year is submitted to the *Board* and includes
(a) for each *installation*, a summary of the general environmental conditions during the year and a description of ice management activities; and
(b) a summary of environmental protection matters during the year, including a summary of any *incidents* that may have an environmental impact, discharges that occurred and *waste material* that was produced, a discussion of efforts undertaken to reduce *pollution* and *waste material* and a description of environmental contingency plan exercises.
(2) For each drilling *installation* for an exploration or delineation well, the *operator* shall ensure that an environmental report relating to each well is submitted to the Board within 90 days after the *rig release date* and includes
(a) a description of the general environmental conditions during the *drilling program* and a description of ice management activities and downtime caused by weather or ice; and
(b) a summary of environmental protection matters during the *drilling program*, including a summary of *spills*, discharges occurred and *waste material* produced, a discussion of efforts undertaken to reduce them, and a description of environmental contingency plan exercises.

87.1 General

The following content provides guidance on selected sections of information that are expected to be included in the Annual Environmental Report. This guidance is not to be interpreted as an exhaustive listing of all necessary content to be included in the Annual Environmental Report. Refer to the *Regulations* for a complete listing of these requirements.

Operators are referred to the *Physical Environmental Guidelines* with respect to the content of physical environmental reporting under paragraphs 87(1)(a) and 87(2)(a).

The Annual Environmental Report should include the following:

- an incident summary section. This section should include a table that summarizes all environmental incidents that occurred during the year, results of the root cause analysis of each incident and associated follow-up and corrective actions. Operators should also demonstrate that they have examined incidents to see if there were identifiable common issues or trends, and in such cases indicate follow-up actions taken;

- a summary of all substances discharged and their ultimate fate. Efforts to reduce waste discharges, including actions taken to reduce the effects individual wastes may have in the receiving environment, should be summarized in this section;

- a summary of spill contingency planning exercises or any other environmental contingency planning exercises carried out throughout the year. This section should include a brief summary of the exercise scenario, participants, the goal of the exercise, lessons learned as a result of the exercise and resulting changes to be incorporated into future plans and/or exercises; and

- a section on continuous improvement of environmental management systems and associated environmental performance. The summary should include continuous improvement initiatives already undertaken during the project, the results of those initiatives in the previous year, and planned continuous improvement initiatives for the next year(s).

The above guidance also applies to the environmental report to be submitted following completion of drilling programs.

88 Annual Safety Report

The *operator* shall ensure that, not later than March 31 of each year, an annual safety report relating to the preceding year is submitted to the *Board* and includes

(a) a summary of *lost or restricted workday injuries*, minor injuries and safety-related *incidents* and *near-misses* that have occurred during the preceding year; and

(b) a discussion of efforts undertaken to improve safety.

88.1 General

Operators are expected to monitor safety-related trends and warnings and act upon this information in a timely manner. Continuous improvement in risk management is expected.

88.2 Contents of the Annual Safety Report

The annual safety report must include:

- a summary of all occupational diseases, and all accidents, incidents and other hazardous occurrences, that have occurred at any of the operator’s workplaces or on a passenger craft

going to or from any of those workplaces during the calendar year covered by the report, including the number of deaths, the number of serious injuries and the number of minor injuries., along with a summary of common areas of root causes and developing risk trends;
- an explanation of risk management key performance indicators in use, along with a summary of results and analysis (including trending); and
- a summary of both ongoing and completed efforts, programs and improvements to reduce risk.

88.3 Incidents

The report should not focus on individual incidents, which are dealt with in individual investigation reports. The exception to this may be incidents which require ongoing effort to reduce risk.

As incidents often have both safety and environmental consequences, and as environmental factors often contribute to incidents, operators may combine this report with the "Environmental Report" required by section 87.

89 Well History Report

(1) The *operator* shall ensure that a *well* history report is prepared for every *well* drilled by the *operator* under the *well approval* and that the report is submitted to the *Board.*

(2) The *well* history report shall contain a record of all operational, engineering, petrophysical and geological information that is relevant to the drilling and evaluation of the *well.*

89.1 Petrophysical, Geological and Well Evaluation Information

The information to be provided in the Well History Report respecting the petrophysical, geological and well evaluation aspects is described in the *Data Acquisition and Reporting Guidelines.*

89.2 Operational and Engineering Information

The operational and engineering information in the Well History Report should be in sufficient detail to provide a complete history of operations on the well. Particular focus should be paid to the fact that the information in the Well History Report may be used by future engineering and operations personnel as a source of offset well data to plan future wells. As such, operators are encouraged to ensure that any "lessons learned" from the drilling of the well are documented for the benefit of future planning.

In the case where a well is either completed or suspended, the Well History Report should contain information respecting the condition of the well in sufficient detail to be able to properly engineer a program to re-enter the well and conduct subsequent well operations.

In the case where a well has been plugged and abandoned (or plugged and suspended), a detailed record should be included respecting the various plugs and other barriers that are in the well to ensure wellbore security and the prevention of the uncontrolled flow of hydrocarbons from the well.

In particular, the Well History Report should include:

a) well name;
b) operator;
c) name and signature (dated) of the operator’s representative responsible for the accuracy and completeness of the report;
d) a summary of the nature and purpose of the well;
e) status of the well (i.e., either suspended, abandoned, or completed) - refer to the definitions of these terms in section 1 of the *Regulations*;
f) spud date;
g) rig release date - refer to the definition of “rig release date” in section 1 of the *Regulations* as well as the discussion of this matter in section 89.4.1 and 89.4.2 below;
h) drilling installation;
i) RT (or KB) elevation (relative to mean sea level, tide corrected, in the case of an offshore well);
j) water depth (in the case of an offshore well);
k) total depth;
l) date drilling completed – date and hour total depth was reached;
m) coordinates (NAD 83);
n) a summary of operations on the well including a summary of any problems encountered and the steps taken to overcome the problems, as well as the total time delay associated with each problem and a summary of any downtime due to weather, pack ice, or icebergs broken down into hours-per-month;
o) a schematic illustrating the status of the well (casing, tubing, plugs and any other equipment installed in or on the well, and, for completion operations, details of the configuration of the production tree and specifications of any downhole safety valves) ;
p) hole sizes and depths;
q) bit records as per IADC/CAODC codes and formats;
r) OD, ID, drift diameter, weight, grade and setting depth of all casing strings, liners, tubing and any other tubulars installed in the well, as well as any other pertinent information related to the well tubulars, such as the number of joints, type of thread/connection, depths of cross-overs, make and type of casing hangers and seals and any information respecting the failure or leak of any tubular and the results of any pressure test of any well tubular in terms of the magnitude of the test, the time that the test was held and the results of the test;
s) cementing information in respect of the primary cement job of all casing strings and liners including the use of centralizers and scratchers, flushes and spacers, sacks of cement, cement recipe, slurry density, volume pumped and the estimated top of cement behind the casing string or liner (together with the basis of the estimate, i.e., calculated, cement evaluation log, etc.) as well as information respecting the success or otherwise of the primary cement job and the details respecting any remedial cement squeeze, top-up job or the like;
t) drilling fluid information including type of drilling fluid and summary of the properties maintained for each phase of the hole. If an oil based drilling fluid was used, provide information on the total quantity of oil based mud consumed during drilling; a calculation of the total amount of mud-derived oil discharged with cuttings; a description of the effectiveness of cuttings treatment with reference to weekly measurements of oil retention on cuttings, i.e., grams of oil per 100 grams of cuttings, types and sizes of cuttings, and number of samples;

u) a summary and description of any drilling fluid losses;
v) details of any fluid disposal downhole, including volumes, rates, pressures, dates, nature of the fluid;
w) details of any kicks encountered including volumes, pressures and a summary of associated well control operations;
x) a time distribution breakdown of each activity on the well from the hour the well was spudded to the time the rig was released, showing the total hours for each type of operation;
y) a summary of the directional and deviation surveys and the bottom hole co-ordinates, referenced to surface location;
z) FLOT and/or PIT results, including the appropriate details of the test including, but not necessarily limited to, the depth of the well, the depth of the shoe, the fluid density and the results of the test in terms of kg/m^3 MWE; and
aa) details of any fishing operations including a description of any fish left downhole including the details of the fish, the length of the fish, the depth of the top of the fish and, in the case that the fish contains radioactive substances, full details respecting the nature and quantity of the material.

In the case of a well that is suspended, the Well History Report should include:

a) the estimated length and depth of any cement plug placed in the well together with the recipe of the cement slurry, the volume pumped and whether or not the plug was felt or otherwise confirmed to be in place;
b) the results of any cement squeeze operations to abandon any zones including the recipe of the cement slurry, the volume pumped, the final pressure observed and the estimated top of cement inside the wellbore;
c) details of any packer, bridge plug, cement retainer or other mechanical plug set in the well including the type of plug, the depth that it was set and the results of any pressure test performed;
d) details of any retrievable packer, storm choke or other temporary device including the type of plug, the depth of the plug, the result of any pressure test performed and details of any drilling assembly that may be hung below the packer to facilitate well control upon re-entry;
e) details of the wellhead including the type of wellhead, pressure rating, status and any other relevant information;
f) in the case where the well is suspended with either a BOP stack and/or Christmas tree installed, details of the status of this equipment; and
g) where applicable, the location and status of beacons or other equipment to assist re-entry operations.

In the case of a well that has been plugged and abandoned, the Well History Report should include:

a) the information outlined above for suspended wells to the extent that it is applicable;
b) details of any casing cutting operation including the depth of the cut and the manner in which the casing stub has been abandoned with cement and/or mechanical plugs;
c) in the case where an annulus may have been open to a formation, the manner in which the annulus has been plugged and abandoned;
d) information on any equipment that may be left at the well site (or on the seabed in the case of an offshore well) including a description of the equipment, its dimensions, the estimated

height of the equipment above the seafloor and the reasons that made it impractical to recover the equipment; and

e) in the case of the offshore well, the results of any seabed clearance survey conducted with an ROV or other equipment.

In the case of a well that has been completed, the Well History Report should include:

a) the depths of all perforated intervals;
b) details of any production packer and related assemblies including the type of packer, the depth of the packer and the results of any pressure test performed;
c) details of the tubing string including OD, ID, drift diameter, weight, grade and any pressure tests performed in respect of the tubing;
d) information respecting any downhole safety valve or annular safety valve including the type of valve, its depth in the tubing string and the results of any pressure test, function test and/or inflow test performed following the installation of the valve;
e) information respecting any downhole pressure or temperature gauges, gas-lift mandrels and any other equipment installed as part of the completion of the well including the depth of the equipment and any other pertinent specifications and information regarding the equipment; and
f) details respecting the wellhead, and the Christmas tree equipment (and control system) including the vendor, the rated working pressure as well as a schematic of the equipment.

89.3 Submission of the Well History Report

Two hard copies of the Well History Report (together with two hard copies of any appendices or supplementary reports associated with the Well History Report) should be provided to the Board.

An electronic copy of the report should also be provided.

Reports should be prepared on letter-sized paper, suitably bound. Measurements should be given using the S.I. (System International) system. Dates and times should be given as year/month/day/hour.

89.4 Timing of Submission

In the case of an exploration or delineation well, the Well History Report should be provided within 90 days of the “rig release date”. For development wells, the report should be provided within 45 days of the “rig release date”.

“Rig release date” is defined in the *Regulations* as “the date on which a rig last conducted well operations”. In this context, the rig release date may not necessarily coincide with the rig release date that is normally assigned within industry. Typically, industry considers the rig release date to be the date that the rig is either contractually or financially “released” from the well. In this case, the operator should use the following guidelines when determining the “rig release date” as it pertains to triggering the submission of the Well History Report to the Board.

89.4.1 Suspended or Abandoned Wells

In the case where a well is either suspended or abandoned, the “rig release date” should be based on the date that the rig was last used in respect of operations to either suspend or to plug and abandon the well (as appropriate). This may not coincide with the date that the rig is physically removed from the well. For example, the rig release date should not necessarily be based on the date that:

a) the last anchor was racked (in the case of a floating drilling installation);
b) the date that the rig is afloat under tight tow with spud cans clear of the seafloor (in the case of a jack-up);
c) the date that the installation was moved off-site (in the case of a dynamically positioned installation);
d) the date that the rig is skidded to the next well slot (in the case of a platform well); or
e) the date that the rig is physically removed from the wellsite (in the case of a land operation),

unless that date happens to coincide with the date that the rig was last used to suspend, or plug and abandon, the well.

89.4.2 Completed Wells

In the case of a well that has been completed, the rig release date should be taken to mean the date that operations in respect of the completion of the well are concluded and, in this context, completion should also include the perforation of the completed interval. Accordingly, in the case where the rig is released from the well, and a coiled tubing or wireline or other unit is used to perforate the well, the rig release date is considered to be the date that the perforation operation is complete and the perforation equipment is removed from the well.

89.5 Short-term Suspension of Operations

The operator is not expected to prepare a Well History Report in respect of the short-term suspension of operations due to equipment maintenance or repair, weather, ice or other reason even if the rig is released from the wellsite. For example, in the case of an offshore well, an installation could be moved to sheltered waters for repairs, or to avoid extreme weather or ice conditions, in which case it would not be necessary to submit a Well History Report unless:

- the period of suspension is anticipated to be lengthy (generally in excess of 90 days); or
- the operator may not immediately return to the well following its suspension due to plans to use the rig to resume operations on another well.

89.6 Operator’s Responsibility for Information

Notwithstanding the issue of whether or not to submit a Well History Report to the Board in the case where operations are temporarily suspended, this does not obviate the operator’s responsibility to have accurate, comprehensive and up-to-date information available at all times with respect to the status and condition of all wells including the particulars of all downhole equipment, tools, tubulars and well barriers.

89.7 Update to Report

An update should be provided to the Well History Report anytime there is a material change to the status of the well. However, in the case of a change to the well following a workover or other well intervention, this update should be included as part of the Well Operations Report specified in section 90 of the *Regulations*.

89.8 Future Plans for Suspended Wells

In the case of wells that are suspended, the operator should also outline its plans for the periodic monitoring of the well for the purpose of confirming its ongoing security and to ensure that there are no hydrocarbon leaks, pressure build-up or other well integrity issues. The operator should also outline its plans and commitments respecting the re-entry of the well at a future date to resume drilling or production operations and/or to permanently plug and abandon the well. These plans may be provided to the Board separately from the Well History Report.

89.9 Responsibility for Wellbore Integrity

Operators should be aware that they are responsible for wellbore integrity after the termination of the well. This means that the operator must take the appropriate remedial measures for any wells that leak hydrocarbons to the environment even after the well has been officially terminated.

89.10 Well Termination Record

One copy of the Well Termination Record complete with an attached wellbore diagram is required to be forwarded to the Board within 30 days of the well termination date. The Well Termination Record is available on the Board's websites.

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90 Well Operations Report

(1) The *operator* shall ensure that a report including the following information is submitted to the *Board* within 30 days after the end of a *well operation*:
- **(a) a summary of the *well operation*, including any problems encountered during the *well operation*;**
- **(b) a description of the completion fluid properties;**
- **(c) a schematic of, and relevant engineering data on, the downhole equipment, tubulars, Christmas tree and *production control system*;**
- **(d) details of any impact of the *well operation* on the performance of the *well*, including any effect on *recovery*; and**
- **(e) for any *well* completion, suspension or abandonment, the *rig release date*.**

(2) The report shall be signed and dated by the *operator* or the *operator*'s representative.

90.1 General

The operational and engineering information in the Well Operations Report should be in sufficient detail to provide a complete summary of the well operation including, in particular, the information specified in paragraphs 90(1)(a) to (e) of the *Regulations*. As specified by subsection 90(2), the report shall be signed and dated by the operator or the operator's representative.

The report should clearly identify the well and installation and also include a well schematic identifying all changes made as a result of the well operation together with any updates to the perforated intervals.

If the well operation is the initial drilling and completion, suspension or abandonment of a well, then the Well Operations Report will consist of a Board prescribed Well Termination Record that is to be accompanied by a schematic of the well that details the configuration of the well at the time it was terminated. In the event a well is altered, an updated Well Termination Record and new schematic should be supplied to the Board.

90.2 Submission of the Well Operations Report

Three hard copies of the Well Operations Report (together with three hard copies of any appendices or supplementary reports associated with the Well Operations Report) should be provided to the Board.

An electronic copy of the report should also be provided.

Reports should be prepared on letter-sized paper, suitably bound. Measurements should be given using the S.I. (System International) system. Dates and times should be given as year/month/day/hour.

90.2.1 Timing of Submission

As specified by section 91, the Well Operations Report is to be submitted to the Board within 30 days after the end of the well operation.

91 Other Reports

The *operator* shall ensure that the *Board* is made aware, at least once a year, of any report containing relevant information regarding applied research work or studies obtained or compiled by the *operator* relating to the *operator*'s work or activities and that a copy of it is submitted to the *Board* on request.

91.1 General

This requirement is intended to provide the Board with the opportunity to request a copy of any report regarding applied research work or studies that would assist the Board in carrying out its mandate. The onus is on the operator to put a system in place to notify the appropriate Board of these reports. This may be achieved by providing an annual summary of research work or studies for the previous year, either as part of the annual Benefits report, or otherwise.

Appendix 1: Glossary of Terms and Definitions

Terms Defined in the Acts

Consistent with legal drafting principles, definitions that are present in the *Acts* (*Canada-Newfoundland Atlantic Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*) are not replicated in the *Regulations*. This approach is designed to avoid conflict between the *Acts* and the *Regulations*.

The following terms are used in the *Regulations*, but are defined in the *Acts*, and therefore, should be taken to have the same meaning as in the *Acts*.

"delineation well" means a well that is so located in relation to another well penetrating an accumulation of petroleum that there is a reasonable expectation that another portion of that accumulation will be penetrated by the first-mentioned well and that the drilling is necessary in order to determine the commercial value of the accumulation;

"development plan" means a plan submitted for the purpose of obtaining approval of the general approach of developing a pool or field as proposed in the plan;

"development well" means a well that is so located in relation to another well penetrating an accumulation of petroleum that it is considered to be a well or part of a well drilled for the purpose of production or observation or for the injection or disposal of fluid into or from the accumulation:

"exploratory well" means a well drilled on a geological feature on which a significant discovery has not been made;

"field" means a general surface area underlain or appearing to be underlain by one or more pools, and includes the subsurface regions vertically beneath the general surface area.

"gas" means natural gas and includes all substances, other than oil, that are produced in association with natural gas;

"oil" means crude oil regardless of gravity produced at a well head in liquid form, and any other hydrocarbons, except coal and gas, and, without limiting the generality of the foregoing, hydrocarbons that may be extracted or recovered from deposits of oil sand, bitumen, bituminous sand, oil shale or from any other types of deposits on the seabed or subsoil thereof of the offshore area;

"pool" means a natural underground reservoir containing or appearing to contain an accumulation of petroleum that is separated or appears to be separated from any other such accumulation;

"spill" means a discharge, emission or escape of petroleum, other than one that is authorized under the regulations or any other federal law or that constitutes a discharge from a vessel to which Part 8 or 9 of the *Canada Shipping Act*, 2001 applies or a ship to which Part 6 of the *Marine Liability Act* applies.

"waste", in addition to its ordinary meaning, means waste as understood in the petroleum industry and in particular, but without limiting the generality of the foregoing, includes

a) the inefficient or excessive use or dissipation of reservoir energy;
b) the locating, spacing or drilling of a well within a field or pool or within part of a field or pool or the operating of any well that, having regard to sound engineering and economic principles, results or tends to result in a reduction in the quantity of petroleum ultimately recoverable from a pool;
c) the drilling, equipping, completing, operating or producing of any well in a manner that causes or is likely to cause the unnecessary or excessive loss or destruction of petroleum after removal from the reservoir;
d) the inefficient storage of petroleum above ground or underground;
e) the production of petroleum in excess of available storage, transportation or marketing facilities;
f) the escape or flaring of gas that could be economically recovered and processed or economically injected into an underground reservoir; or
g) the failure to use suitable artificial, secondary or supplementary recovery methods in a pool when it appears that such methods would result in increasing the quantity of petroleum ultimately recoverable under sound engineering and economic principles.

“well" means any opening in the ground (not being a seismic shot hole) that is made, is to be made or is in the process of being made, by drilling, boring or other method,

a) for the production of petroleum,
b) for the purpose of searching for or obtaining petroleum,
c) for the purpose of obtaining water to inject into an underground formation,
d) for the purpose of injecting gas, air, water or other substance into an under ground formation,
e) for any purpose, if made through sedimentary rocks to a depth of at least one hundred and fifty metres.

Terms Defined in the Regulations

The terms defined in the *Regulations* vary somewhat between the *Nova Scotia Offshore Petroleum Drilling and Production Regulations* and the *Newfoundland Offshore Petroleum Drilling and Production Regulations*. For ease of reference, the definitions below have been taken from the Federal versions of the *Regulations*.

Where only one definition appears for a defined term below, there are no differences between the three sets of *Regulations*.

1. (1) The following definitions apply in the *Regulations*.

“**abandoned**”, in relation to a well, means a well or part of a well that has been permanently plugged.

“**Act”** means the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act.*
“**Act**” means the *Canada Newfoundland Atlantic Accord Implementation Act.*

“**artificial island**” means a humanly constructed island to provide a site for the exploration and drilling, or the production, storage, transportation, distribution, measurement, processing or handling, of petroleum.

"**authorization**" means an authorization issued by the Board under paragraph 142(1)(*b*) of the *Act*".
"**authorization**" means an authorization issued by the Board under paragraph 138(1)(*b*) of the *Act*".

"**barrier**" means any fluid, plug or seal that prevents petroleum or any other fluid from flowing unintentionally from a well or from a formation into another formation.

"**casing liner**" means a casing that is suspended from a string of casing previously installed in a well and does not extend to the wellhead.

"**commingled production**" means production of petroleum from more than one pool or zone through a common well-bore or flow line without separate measurement of the production from each pool or zone.

"**completed**", in relation to a well, means a well that is prepared for production or injection operations.

"**completion interval**" means a section within a well that is prepared to permit the
(*a*) production of fluids from the well;
(*b*) observation of the performance of a reservoir; or
(*c*) injection of fluids into the well.

"**conductor casing**" means the casing that is installed in a well to facilitate drilling of the hole for the surface casing.

"**drilling program**" means the program for the drilling of one or more wells within a specified area and time using one or more drilling installations and includes any work or activity related to the program.

"**environmental protection plan**" means the environmental protection plan submitted to the Board under section 6.

"**flow allocation procedure**" means the procedure to
(*a*) allocate total measured quantities of petroleum and water produced from or injected into a pool or zone back to individual wells in a pool or zone where individual well production or injection is not measured separately; and
(*b*) allocate production to fields that are using a common storage or processing facility

"**flow calculation procedure**" means the procedure to be used to convert raw meter output to a measured quantity of petroleum or water.

"**flow system**" means the flow meters, auxiliary equipment attached to the flow meters, fluid sampling devices, production test equipment, the master meter and meter prover used to measure and record the rate and volumes at which fluids are
(*a*) produced from or injected into a pool;
(*b*) used as a fuel;
(*c*) used for artificial lift; or
(*d*) flared or transferred from a production installation.

"**fluid**" means gas, liquid or a combination of the two.

"**formation flow test**" means an operation
(*a*) to induce the flow of formation fluids to the surface of a well to procure reservoir fluid samples and determine reservoir flow characteristics; or
(*b*) to inject fluids into a formation to evaluate injectivity.

"**incident"** means
(*a*) any event that causes
(i) a lost or restricted workday injury,
(ii) death,
(iii) fire or explosion,
(iv) loss of containment of any fluid from a well,
(v) imminent threat to the safety of persons, an installation, or support craft, or
(vi) pollution;
(b) any event that results in a missing person; or
(c) any event that causes
(i) the impairment of any structure, facility, equipment or system critical to the safety of persons, an installation or support craft, or
(ii) the impairment of any structure, facility, equipment or system critical to environmental protection.

"**lost or restricted workday injury**" means an injury that prevents an employee from reporting for work or from effectively performing all the duties connected with the employee's regular work on any day subsequent to the day on which the injury occurred whether or not that subsequent day is a working day for that employee.

"**minor injury**" means an employment injury for which medical treatment or first aid is provided and excludes a lost or restricted workday injury

"**multi-pool well**" means a well that is completed in more than one pool.

"**natural environment**" means the physical and biological environment.

"near miss" means an event that would likely cause an event set out in paragraph (a) of the definition of "incident", but does not due to particular circumstances.

"**operator**" means a person that holds an operating licence under paragraph 142(1)(*a*) of the *Act* and an authorization.
"**operator**" means a person that holds an operating licence under paragraph 138(1)(*a*) of the *Act* and an authorization.

"**physical environmental conditions**" means the meteorological, oceanographic and related physical conditions, including ice conditions, that might affect a work or activity that is subject to an authorization.

"**pollution**" means the introduction into the natural environment of any substance or form of energy outside the limits applicable to the activity that is subject to an authorization, including spills.

"**production control system**" means the system provided to control the operation of, and monitor the status of, equipment for the production of petroleum, and includes the installation and workover control system

"**production project**" means an undertaking for the purpose of developing a production site on, or producing petroleum from, a pool or field, and includes any work or activity related to the undertaking

"**proration test**" means, in respect of a development well to which a development plan applies, a test conducted to measure the rates at which fluids are produced from the well for allocation purposes.

"**recovery**" means the recovery of petroleum under reasonably foreseeable economic and operational conditions.

"**relief well**" means a well drilled to assist in controlling a blowout in an existing well.

"**rig release date**" means the date on which a rig last conducted well operations

"**safety plan**" means the safety plan submitted to the Board under section 6.

"**seafloor**" means the surface of all that portion of land under the sea.

"**slick line**" means a single steel cable used to run tools in a well.

"**support craft**" means a vessel, vehicle, aircraft, standby vessel or other craft used to provide transportation for or assistance to persons on the site where a work or activity is conducted

"**surface casing**" means the casing that is installed in a well to a sufficient depth, in a competent formation, to establish well control for the continuation of the drilling operations.

"**suspended**", in relation to a well or part of a well, means a well or part of a well in which drilling or production operations have temporarily ceased.

"**termination**" means the abandonment, completion or suspension of a well's operations.

"**waste material**" means any garbage, refuse, sewage or waste well fluids or any other useless material that is generated during drilling, well or production operations, including used or surplus drilling fluid and drill cuttings and produced water.

"**well approval**" means the approval granted by the Board under section 13.

"**well-bore**" means the hole drilled by a bit in order to make a well.

"**well control**" means the control of the movement of fluids into or from a well.

"**well operation**" means the operation of drilling, completion, recompletion, intervention, re-entry, workover, suspension or abandonment of a well.

"**wire line**" means a line that contains a conductor wire and that is used to run survey instruments or other tools in a well.

"**workover**" means an operation on a completed well that requires removal of the Christmas tree or the tubing.

zone" means any stratum or any sequence of strata and includes, for the purposes of the definition "commingled production", section 7, subsection 61(2), sections 64 to 66 and 74, subsection 83(2) and section 86, a zone that has been designated as such by the Board under section 4.

(2) In these *Regulations*, "delineation well", "development well" and "exploratory well" have the same meaning as in subsection 122(1) of the *Act*.
(2) In these *Regulations*, "delineation well", "development well" and "exploratory well" have the same meaning as in subsection 119(1) of the *Act*.

(3) In these *Regulations*, "drilling installation", "drilling rig", "drilling unit" "drill site", "installation", "production installation", "production operation", "production site" and "subsea production system" have the same meaning as in subsection 2(1) of the *Nova Scotia Offshore Petroleum Installations* Regulations.
(3) In these *Regulations*, "drilling installation", "drilling rig", "drilling unit", "drill site", "installation", "production installation", "production operation", "production site" and "subsea production system" have the same meaning as in subsection 2(1) of the *Newfoundland Offshore Petroleum Installations Regulations*.

"**production platform**" means a production facility and any associated platform, artificial island, subsea production system, offshore loading system, drilling equipment, facilities related to marine activities and dependent diving system.

(5) For the purpose of section 198.2 of the *Act*, any installation is prescribed as an installation.
(5) For the purpose of section 193.2 of the *Act*, any installation is prescribed as an installation..